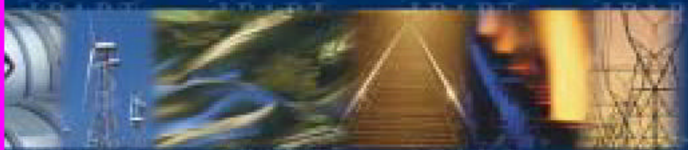
NSW Electricity Distribution Pricing 2004/05 to 2008/09

Draft Report



INDEPENDENT PRICING AND REGULATORY TRIBUNAL
of New South Wales

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

NSW Electricity Distribution Pricing

2004/05 to 2008/09

.

Other Paper OP-18

January 2004

ISBN 1 877049 37 9

Request for submissions

Submissions are invited from interested parties on this draft report and the draft determination. Unless confidentiality is sought, the submissions are generally available for public inspection at the Tribunal's offices and will be available on-line in PDF format from the time of processing of the submission until 3-4 weeks after the release of the final report of an inquiry. The Tribunal may exercise its discretion not to exhibit any submissions based on their length or content (containing material that is defamatory, offensive, or in breach of any law).

Submissions should have regard to the specific issues that have been raised. There is no standard format for preparation of submissions but reference should be made to relevant issues papers and interim reports. Submissions should be made in writing and, if they exceed 15 pages in length, should also be provided on computer disk in word processor, PDF or spreadsheet format.

Submissions must be received by 5 March 2004.

All submissions should be sent to:

NSW Electricity Distribution Pricing 2004/05 to 2008/09
Independent Pricing and Regulatory Tribunal
PO Box Q290
QVB Post Office NSW 1230

Confidentiality

If you want your submission, or any part of it, to be treated as confidential, please indicate this clearly. The Tribunal may include in its publications a list of submissions received during the course of a particular review or inquiry. It may also refer to submissions in the text of its publications. If you do not want your submission or any part of it to be used in any one of these ways, please indicate this clearly.

A request for access to a confidential submission will be determined in accordance with the *Freedom of Information Act* and *National Electricity Code*.

Privacy

All submissions will be treated in accordance with the *Privacy and Personal Information Act 1998*. Any personal information you give us will not be reused for another purpose.

Public information about the Tribunal's activities

Information about the role and current activities of the Tribunal, including copies of latest reports and submissions can be found on the Tribunal's web site at www.ipart.nsw.gov.au.

Inquiries regarding this review should be directed to:

Fiona Towers ☎ 02 9290 8420
Lisa Spence ☎ 02 9290 8440
Emma Kelso ☎ 02 9290 8453
Anna Brakey ☎ 02 9290 8438
Michael Seery ☎ 02 9290 8421

Independent Pricing and Regulatory Tribunal of New South Wales
Level 2, 44 Market Street, Sydney NSW 2000
☎ (02) 9290 8400 Fax (02) 9290 2061
www.ipart.nsw.gov.au
All correspondence to: PO Box Q290, QVB Post Office NSW 1230

TABLE OF CONTENTS

FOREWORD

The Tribunal has issued this draft distribution pricing determination and report under the National Electricity Code. This is the second determination it has made under the Code. As from 1 July 2004, a new form of regulation—a weighted average price cap—will apply to the four NSW distribution network services providers (DNSPs).

In recent years, electricity consumers in NSW have seen average electricity network prices fall in real terms. At the same time, they have increased their demand for electricity and, hence, their use of distribution networks. Peak demand has risen even more sharply, placing a strain on the existing distribution infrastructure. The response of the DNSPs has been to increase growth-related capital expenditure, with little attempt to use demand management alternatives to network investment.

Increasing demand has put greater pressure on distribution networks, requiring greater capital and maintenance spending. The Tribunal has had little option but to allow for increased revenues and, therefore, prices over the next regulatory period. All four DNSPs requested substantial increases in average distribution prices over the next regulatory period. This is underpinned by proposed total capital and operating expenditure of $8 billion dollars over five years, proposed adjustments to their opening asset values, and proposed rates of return on assets that are at the high end of the range.

After careful analysis of these proposals and having regard to the requirements of the Code, the Tribunal has found that most of the proposed expenditure is justified, but that adjustments to the opening asset values and the proposed higher rates of return are not. This draft decision allows modest increases in the distribution component of electricity bills. These increases are likely to translate into small increases in customers' final electricity bills, as distribution charges form about one third of these bills.

The Tribunal is disappointed to note that the DNSPs' proposals suggest they plan to make limited use of demand management to moderate the need for growth-related expenditure during the next regulatory period. As indicated in its final report of its Inquiry into the Role of Demand Management, it strongly believes there is untapped potential for efficient and commercially viable demand management in NSW. Through this determination, it has aimed to remove the regulatory barriers to its increased use. DNSPs should be working to overcome the cultural and other barriers within their own organisations to fully explore the use of demand management options to better manage increasing capital spending and improve asset utilisation.

Given the very large expenditures on the network by the DNSPs, the Tribunal is also concerned that these businesses deliver levels of service standards that are consistent with these expenditures. For this reason, the draft decision introduces an incentive mechanism for service reliability. This mechanism, known as an S-factor, will provide a direct link between prices and service quality. The S-factor will allow DNSPs to increase their prices within a limited range, depending on how they perform against defined service quality targets. The Tribunal has also recommended to the Minister for Energy that he introduce a guaranteed service level in the DNSPs license conditions in relation to reliability.

The Tribunal believes that this draft determination balances the interests of all key stakeholders. This draft determination will protect consumers from significant price shocks while ensuring that DNSPs can make sufficient investment in their networks to continue to deliver a safe and reliable supply to their customers as well as appropriate commercial returns to their owner. The Tribunal invites submissions on its Draft Distribution Pricing Report. The Tribunal expects to release its final decision in May 2004 with the new determination to apply from 1 July 2004 to 30 June 2009.

Thomas G Parry
Chairman
January 2004

1 OVERVIEW

The Independent Pricing and Regulatory Tribunal of New South Wales (the Tribunal) is the Jurisdictional Regulator for electricity in NSW. It has responsibility for regulating the prices charged for distribution services by the state's four Distribution Network Service Providers (DNSPs)—EnergyAustralia, Integral Energy, Country Energy and Australian Inland. It regulates these prices under the National Electricity Code (the Code), in accordance with the objectives and principles set out in the Code.

The Tribunal's current determination on distribution service prices will expire on 30 June 2004. For the next regulatory period—1 July 2004 to 30 June 2009—new regulatory arrangements will apply. This report explains the Tribunal's draft determination for this period, and outlines the new arrangements. The draft determination itself is provided as a separate document.[1]

The Tribunal invites interested parties to comment on the draft report and determination. Submissions are due by close of business Friday 5 March 2004. Following consideration of submissions, it expects to issue a final determination in May 2004.

1.1 Overview of draft determination

Over the past seven years, average electricity network prices have reduced in real terms by 24 per cent, while average demand or energy consumption has risen by 31 per cent. Peak demand has risen even more sharply, placing strain on the existing infrastructure. DNSPs have responded by increasing their growth-related capital expenditure programs, with little focus on demand management options. This has resulted in lower asset utilisation.[2] In some cases, growth-related expenditure has been at the expense of replacement or refurbishment expenditures, which has placed even greater strain on the existing infrastructure.

The trend of increasing consumption and reducing prices is no longer sustainable. All four DNSPs requested substantial increases in average distribution prices over the next regulatory period. Their proposed increases are driven by a proposed total expenditure program of $8 billion dollars over five years, proposed adjustments to their opening asset values, and proposed rates of return on assets that are at the high end of the range. The DNSPs proposals suggest limited use of demand management to moderate the need for growth-related expenditure.

The Tribunal examined these proposals in detail. It accepts the view of its total cost consultant that the DNSPs' total expenditures in the past regulatory period (1999 to 2003) were prudent, and that their proposed capital expenditure programs are generally efficient, (there is scope for small reductions in the capital expenditure programs of EnergyAustralia and Integral Energy). But it does not accept that adjustments to the opening asset values are justified, nor that the proposed rates of return are appropriate. Even so, the DNSP's revenue requirements are significantly higher than in the last regulatory period. This means real increases in the distribution component of electricity bills are required.

1 IPART, *Draft Determination NSW Electricity Pricing 2004/05-2008/09*, January 2004.

2 Asset utilisation relates to use of network over all time periods not just at the time of peak demand.

The Tribunal also considered carefully how these increases should be spread over the regulatory period. All four DNSPs proposed a larger increase in distribution prices in 2004/05 (a P-nought adjustment) followed by 'smaller' increases in the following years.

In the 1999 determination, the Tribunal chose to use a revenue glide path approach, so price changes (and therefore the DNSPs' revenue changes) would be spread more evenly over the regulatory period. This approach is also known as the straight line smoothing option. For EnergyAustralia and Integral Energy, the 1999 determination provided for them collecting a higher amount of revenue than their projected total costs provided for in the determination. (However, their actual operating and capital expenditures turned out to be well in excess of those allowed for the 1999 determination.) For Country Energy and Australian Inland, it resulted in them collecting a lower amount of revenue than their costs.

The Tribunal recognises the impact of this approach on revenue recovery levels. However, it believes that the straight line smoothing option provides appropriate incentives for DNSPs. For example, continuing to use the straight line smoothing option in the face of cost increases would signal to DNSPs that the Tribunal is committed to symmetrical treatment of efficiency carryover, whereby both cost reductions and cost increases are carried across regulatory periods via the glide path mechanism.

For the 2004-2009 determination, the Tribunal proposes to use a hybrid of the P-nought and straight line approaches. The hybrid approach provides the same incentives as straight line smoothing, but to a lesser degree. Thus, it provides a reasonable balance between incentives and price impacts on one hand, and the level of revenue recovery on the other hand. In addition, it allows the Tribunal to more easily manage competing outcomes in the overall price review. These outcomes include the financial risks facing the business and the need to ensure an adequate revenue base for expenditures necessary to maintain service standards.

Table 1.1 shows the Tribunal's draft decision on the average allowable increases in distribution prices for the 2004-2009 regulatory period. These increases are substantial, but significantly less than proposed by the DNSPs.

Table 1.1 Draft decision on distribution prices compared with DNSP proposals

	Standardised DNSP's proposals[1]		Draft decision	
	DNSP's proposed annual price increase – distribution	**NPV of costs not recovered**	**Annual distribution price increase**	**NPV of costs not recovered**
EnergyAustralia	CPI + 19.4% in 2004/05 then CPI + 1%	0	CPI + 6.5% in 2004/05 then CPI+1.4%	$34m
Integral Energy	CPI + 11.1% in 2004/05 then CPI + 1%	0	CPI + 1.1% in 2004/05 then CPI +1.1%	$17m
Country Energy	CPI + 13.2% in 2004/05 then CPI plus 5.7%	$233m	CPI + 6.5% in 2004/05 then CPI + 2.5%	$182m
Australian Inland	CPI + 15.6% in 2004/05 then CPI + 6.6%	$12m	CPI + 6.5% in 2004/05 then CPI + 2.5%	$21m

Note 1
In developing their pricing proposals then DNSPs have used differing assumptions over a number of parameters. Table 1.1 presents each DNSP proposal based on a common assumption for inflation, and a common split between prescribed and excluded services.

For example, in 2004/05 a typical residential customer living in Sydney[3] and using 7,500kWh pa would see nominal price increase in their final bill of approximately $46 a year, or just less than $1 per week.[4] Similarly, a residential customer in regional NSW using 7,500kWh pa would see nominal price increase in their final bill of approx $58 a year, or approximately $1.10 per week.[5]

Table 1.2 shows the forecast average cumulative real distribution price increases over this period (compared with 2003/04 prices). These increases will translate into much smaller increases in customers' final electricity bills, as distribution charges form somewhere between 20 to 40 per cent of these bills, depending on which network and retail tariffs the customer is on.

Table 1.2 Real cumulative distribution price increases for the 5 years to FY2009

DNSP	Increase
EnergyAustralia	12. 6%
Integral Energy	5.6%
Country Energy	17.6%
Australian Inland	17.6%

The draft determination also sets out a 'package' of decisions that establishes how the Tribunal intends to regulate network tariffs (comprised of DUOS tariffs and 'transmission cost recovery tariffs'), and other fees that DNSPs can charge for distribution services over the 2004-2009 regulatory period. This package includes:

- a weighted average price cap for distribution use of system (DUOS) tariffs and miscellaneous and monopoly fees
- recovery of transmission-related payments (including TUOS charges paid to transmission network service providers, inter-distributor transfer payments and avoided TUOS charges)
- price limits for total network tariffs for residential and non-residential customers
- an exhaustive list of charges for both miscellaneous charges and monopoly fees
- pricing principles, public consultation and pricing information disclosure requirements
- an in-principle decision to provide for a demand management 'add-on' so that DNSPs can retain some or all of the avoided distribution costs arising from a demand management project
- a light-handed form of regulation for excluded distribution services.

3 A network customer of EnergyAustralia.

4 This assumes no distribution price restructuring and that all components of the final electricity bill (distribution, transmission and retail) increase for residential customers by 3 per cent real. Prices are ex-GST. Under the weighted average price cap DNSPs have considerable discretion as to how much individual tariffs can change subject to them complying with the overall price control formula and price limits.

5 ibid.

In addition, because the Tribunal's 2004 draft determination provides for significantly higher levels of expenditure by the DNSPs, it is important that DNSPs deliver levels of service standards that are consistent with these expenditures. To regulate this, the Tribunal has introduced a regulatory package, including an incentive mechanism for reliability (an S-factor). The S-factor provides a direct link between price and service quality. The Tribunal considers that this is a critical component of the regulatory framework, especially in light of the large amount of capital expenditure that the DNSPs have proposed for the coming regulatory period. The S-factor will allow DNSPs to increase prices to a greater or lessor degree depending on their service quality performance relative to defined service quality targets. The Tribunal has also recommended to the Minister for Energy that a guaranteed service level in relation to reliability be introduced.[6]

1.2 Structure of report

This report explains the Tribunal's draft determination in detail, including why it reached its decisions and what those decisions mean for the DNSPs, customers and other stakeholders:

- Chapter 2 provides background information, including an overview of the public consultation process, an outline of the electricity industry, recent operating statistics for the DNSPs and what network prices mean for end use customers.
- Chapter 3 outlines the new regulatory framework that will apply from 1 July 2004, and the key components of the 'regulatory package', including specifying the weighted average price cap, the length of the regulatory period and the definition of prescribed distribution services.
- Chapter 4 discusses the components of the building block methodology the Tribunal used to determine the DNSPs' revenue requirements, including efficient capital, operating and maintenance expenditure, asset value, return on capital, and return of capital (depreciation).
- Chapter 5 outlines the Tribunal's approach to calculating the real price increase for each DNSP (the X-factor in the weighted average price cap) and how its decisions are expected to affect the DNSPs' financial viability.
- Chapter 6 outlines the Tribunal's approach to service quality and the introduction of a S-factor.
- Chapter 7 discusses demand management-related issues, including congestion pricing, avoided distribution costs, avoided TUOS and negotiation guidelines.
- Chapter 8 discusses other issues, including the Tribunal's decisions on cost pass through and risk hedging mechanisms, and its decision not to revisit the issue of capital contributions.
- Chapter 9 details the arrangements applicable to charges for miscellaneous and monopoly services.
- Chapter 10 discusses the arrangements for the recovery of transmission-related payments.
- Chapter 11 explains the limits that will be placed on price movements.

6 IPART, *Review into Guaranteed Customer Service Standards and Operating Statistics, Draft Recommendation,* October 2003.

- Chapter 12 outlines network pricing setting arrangements. It covers pricing principles, information disclosure obligations for the DNSPs, and arrangements for assessing compliance.
- Chapter 13 sets out what services are excluded distribution services, and the arrangements for the light-handed regulation of these services.

The Tribunal members who considered this draft determination were Dr Thomas Parry (Chairman), Mr James Cox (Full-time Member), and Ms Cristina Cifuentes (Member).

The Tribunal is currently seeking the views of key stakeholders and members of the public on this draft determination prior to making its final determination. Submissions are due by close of business on Friday 5 March 2004. The Tribunal will hold a public forum on Friday 19 March 2004, and plans to release its final decision in May 2004.

To assist it in making its final decision, the Tribunal also invites comments on:

- The draft report that reviews demand forecast by McLennan Magasanik Associates.
- The draft report by PB Associates on possible incentive rates for incorporating into the S-factor.
- The final report by SKM on options for treating avoided distribution costs and congestion pricing in the regulatory framework.

All these reports are available on the Tribunal's website. Submissions on these reports are due on Friday 5 March 2004.

2 BACKGROUND

2.1 Process undertaken for this review

As part of the process leading to the draft determination, the Tribunal undertook a public consultation process and extensive analysis to determine the detail required to apply to the regulatory arrangements for the period starting 1 July 2004.

The Tribunal effectively began this review in 2001, when it considered the economic regulatory arrangements to apply to NSW DNSPs. To date, the Tribunal has:

- Engaged Allen Consulting to prepare a discussion paper released in March 2001 on the integration of service standards and price, *The Incorporation of Service Quality in the Regulation of Utility Prices.*
- Issued a discussion paper, *Form of Economic Regulation for NSW Electricity Network Charges - Discussion Paper,* in August 2001 and received submissions.
- Held a public forum on the form of regulation on 21 February 2002 and received further submissions.
- Released a Draft Notice Under Clause 6.10.3 of the Code, *Economic Regulatory Arrangements,* and received public submissions.
- Released the Final Notice Under Clause 6.10.3 of the Code, *Economic Regulatory Arrangements*, on 25 June 2002.
- Released a discussion paper on defining prescribed distribution services, *Review of Prescribed Distribution Services*, in June 2002.
- Released an industry-wide paper on the weighted average cost of capital, *Weighted Average Cost of Capital*, in August 2002.
- Released an issues paper, *Regulatory Arrangements for the NSW Distribution Network Service Providers from 1 July 2004, Issues Paper*, in November 2002.
- Released its draft financial models and explanatory notes for public comment in November 2002.
- Released the terms of reference for its total cost review (capital and operating expenditure) and received public submissions in October 2002.
- Engaged consultants to undertake the total cost review—Meritec Limited (New Zealand) in December 2002.
- Established a Pricing Issues Consultation Group comprised of representatives from the DNSPs, independent retailers, customer representative groups and other regulators for the purpose of developing an alternative pricing methodology to Part E of the Code, in January 2003.
- Released a draft decision on prescribed and excluded distribution services, *Review of Prescribed and Excluded Distribution Services, Draft Decision*, in February 2003.
- Released an issues paper *Providing Incentives for Service Quality in NSW Electricity Distribution*, in May 2003.
- Released a Secretariat discussion paper on inclining block tariffs, *Inclining Block Tariffs for Electricity Network Services* in July 2003.

- Released Meritec's *Total Cost Review - Draft Report,* in July 2003.
- Held public forums in April and July 2003 to discuss submissions from DNSP, non-DNSP stakeholders and the draft report from the Total Cost Review.
- Engaged SKM to advise on congestion pricing and the treatment of avoided distribution costs, with a draft report released in July 2003.
- Engaged PB Associates, to advise on the quality of DNSPs' information systems for collecting service quality information and to advise on appropriate incentive rates for a service quality incentive mechanism with their report being released in July 2003.
- Released a report prepared by PB Associates, *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability* in July 2003.
- Engaged Allen Consulting, to advise on the appropriate treatment of depreciation and subsequently released its report for comment, *Principles for determining regulatory depreciation allowances* in September 2003.
- Released a Secretariat Discussion Paper, *2004 Electricity Distribution Review - Preliminary Analysis,* in September 2003.
- Released a discussion paper of the DNSPs growth forecasts, *Determining sales volumes for the 2004 electricity network review*, in July 2003 and subsequently engaged a consultant, McLennan Magasanik Associates, to review the DNSPs' submitted growth forecasts, releasing its draft report in December 2003.
- Released SKM's final report, *Reducing Regulatory Barriers to Demand Management – Avoided Distribution Costs and Congestion Pricing for Distribution Networks in NSW* in December 2003.

Appendix 1 lists all public submissions received by the Tribunal.

2.2 The National Electricity Code

As Jurisdictional Regulator for NSW, the Tribunal is responsible for regulating distribution service prices in the state under the National Electricity Code. The Tribunal's specific functions include:

a) Formulating guidelines and rules to apply to distribution service pricing.

b) Determining which distribution services should be deemed to be 'prescribed distribution services'.

c) Determining the form of economic regulation for prescribed distribution services.

d) Determining the length of the regulatory control period.

e) Determining, if it chooses to depart from the pricing methodology in Chapter 6, Part E of the Code, the alternative pricing methodology that is to apply.

f) Placing limits on the annual variation in published distribution service prices.

In determining its approach to these functions, the Tribunal considered the Western Australian Supreme Court decision in *Epic*.[7] Although the decision relates to the National Gas Code, the principles it establishes extend beyond gas and provide considerable guidance in relation to the matters the Tribunal should relevantly consider under the National Electricity Code. The Tribunal has therefore had regard to the principles in *Epic* and the recent decisions of the Australian Competition Tribunal.

The introduction to chapter 6 of the Code summarises the key principles and core objectives which are intended to apply to the pricing arrangements which the Tribunal administers.

Clause 6.10.1 specifies the arrangements that govern Part D of the Code. Clause 6.10.2 requires that the regime administered under Part D of the Code seek to achieve specified outcomes. Clause 6.10.3 requires that the regime be administered in accordance with stated principles. These provisions are reproduced in full in Appendix 2B.

In the exercise of specific functions, the Code also stipulates matters that the Tribunal should take into account or have regard to. For example, the matters it should have regard to in setting the regulatory cap under clause 6.10.5. In exercising its functions the Tribunal has had regard to these specific matters and to the broader objectives and principles under the Code, stated above.

The Tribunal does not regulate transmission prices. The Australian Competition and Consumer Commission has responsibility for regulating transmission companies in Australia. However, transmission charges are passed through by the DNSPs to retailers and on to customers and the Tribunal's regulatory framework needs to accommodate this pass-through.

2.3 The electricity industry

Australia's electricity industry has undergone significant structural change over the past 10 years, including reform of the New South Wales industry including disaggregation of generators, transmission, distribution and retailing; the full privatisation of the Victorian market and major privatisation in South Australia; and the introduction of full retail contestability in the NSW, Victorian, South Australian and Australian Capital Territory markets.

The NSW electricity industry comprises the following bodies (Figure 2.1):

- *generators, including embedded generators,* who generate electricity and sell it to retailers through the wholesale market and are connected to either the transmission or distribution networks
- *transmission network service providers*[8] (TNSPs) who convey electricity along the high voltage network
- *distribution network service providers* (DNSP) who convey electricity from the transmission systems to end-users via a lower-voltage network
- *retailers* who buy electricity from generators in the wholesale market and sell electricity to consumers

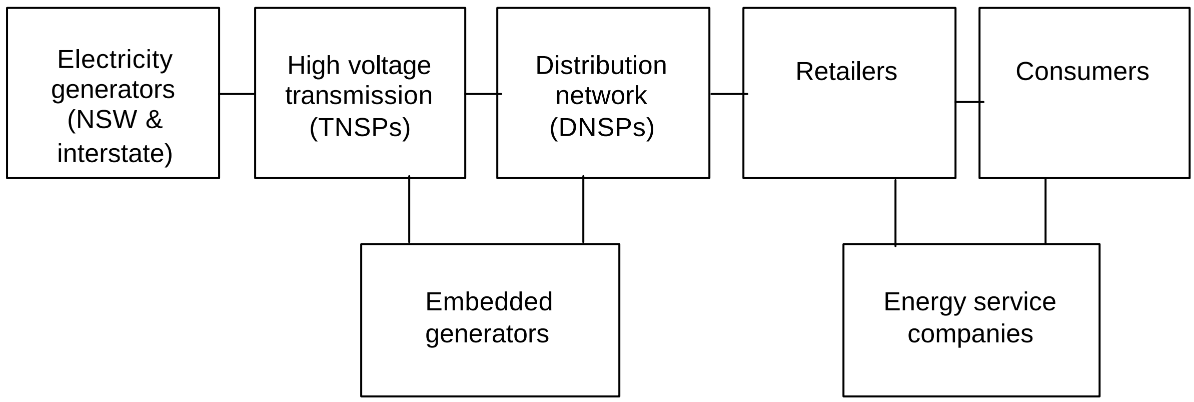
7 *Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Limited* [2002] WASCA 231.

8 The Australian Competition and Consumer Commission (ACCC) regulates transmission revenues and prices are established in accordance with the National Electricity Code.

- *energy service companies* who provide energy management services possibly in partnership with retailers, to reduce energy costs for end-users.

Figure 2.1 shows how these bodies interact with each and with consumers.

Figure 2.1 NSW electricity industry structure



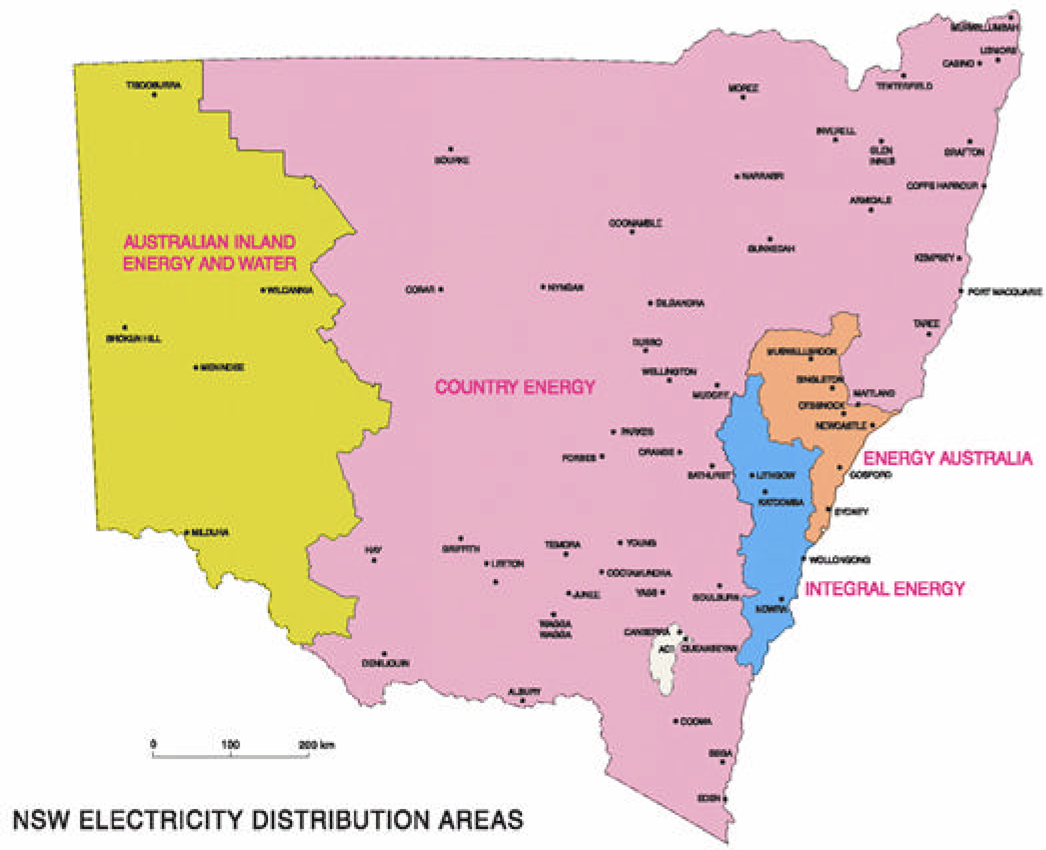
The introduction of the National Electricity Code and subsequent national electricity market has meant that generators and retailers now participate in the wholesale market administrated by the National Electricity Market Management Company Limited. Most customers in NSW purchase electricity from a retail electricity company.

The TNSPs (TransGrid, EnergyAustralia and interstate suppliers such as Powerlink) transport electricity from the generators to a number of points in each DNSP's area and charge the DNSPs the cost of transmission. The DNSPs (EnergyAustralia, Integral Energy, Country Energy and Australian Inland) then distribute the electricity to retail customers. The electricity retailers bill consumers an amount of money for using each individual service (see section 2.5). Energy service companies may provide energy management services in partnership with retailers to reduce energy costs for end-users.

2.3.1 DNSPs' areas of operations

The NSW DNSPs' areas of operation vary widely (see Figure 2.2). EnergyAustralia and Integral Energy operate predominantly in densely populated urban districts, with a larger number of customers over relatively small geographic areas. Australian Inland and Country Energy operate in sparsely populated rural regions, over much larger geographical area.

Figure 2.2 Operating areas of NSW DNSPs



Source: Ministry of Energy and Utilities, *2001/02 NSW Electricity Network Performance Report*, June 2003.

2.3.2 Operating statistics

The differences in these areas of operations result in diverse operating statistics across the DNSPs (Table 2.1).

Table 2.1 DNSP operating statistics for FY2002

	EnergyAustralia	Integral Energy	Country Energy	Australian Inland
Total service area (sq km)[1]	22,275	24,500	582,000	155,000
Total system length (km)[1]	56,645	33,081	177,693	9,349
Per cent of total system length underground (%)	24	27	2	0.4
Maximum demand (MW)[1]	4,985	2,994	1,909	90
Energy sold (GWh)[2]	25,402	13,864	9,965	402
Annual load factor (%)[1]	61	64	63	55
Total customers[2]				
Residential	1,314,973	705,950	628,422	15,511
Non-residential	149,305	70,371	87,808	3,396
Total	1,464,278	776,321	716,230	18,907

Source: 1. DNSP individual Price and Service Reports 2002.
2. IPART financial model.

2.4 What network tariffs mean for consumers

While most consumers never receive a bill from their DNSP, the level of network tariffs ultimately affects the final price they pay for electricity. Customers pay a retail price for electricity to retailers, which comprise of a retail tariff and a network tariff. The network tariff is set by the DNSP to recover the costs associated with the conveyance of electricity through the network, and is further comprised of:

- distribution use of system (DUOS) tariffs
- 'transmission cost recovery tariffs' which represents the transmission-related costs incurred by DNSPs (the largest costs are the transmission charges paid to transmission network service providers).[9]

Total network tariffs make up around 40 per cent of a typical bill for an EnergyAustralia and Integral Energy residential customer. For large business customers, network tariffs can comprise up to 60 per cent of the final bill.

In addition, DNSPs may also charge miscellaneous and monopoly fees for work they perform for specific customers, or on behalf of customers through accredited service providers.

9 The Tribunal has called what is commonly known as TUOS tariffs, 'transmission cost recovery tariffs'.

3 REGULATORY FRAMEWORK

The Tribunal has made draft decisions that establishes how it will regulate the network tariffs and other fees DNSPs can charge for prescribed distribution services over the 2004 regulatory period. Network tariffs include distribution use of system (DUOS) tariffs and transmission cost recovery tariffs.[10] Other fees include charges for miscellaneous and monopoly services.

An overview of the new regulatory arrangements is provided below—including the length of the regulatory period, the services that are subject to these arrangements, and the key elements of the regulatory package.

3.1 Length of the regulatory period

The Tribunal's draft decision is that the regulatory period commencing 1 July 2004 will be a five year regulatory period, ending 30 June 2009.

The Code requires that the Tribunal apply the form of economic regulation for a period of at least three years.[11] In deciding on a five-year regulatory period, the Tribunal considered the implications of the length of the regulatory period on the incentives for efficiency improvements, the predictability and stability of the regulatory environment and the effectiveness of regulation. In general, a longer regulatory period provides:

- greater incentives for achieving increased efficiency, by allowing the DNSPs to retain more of any gains (in the form of higher profits) arising from cost reductions
- a more stable and predictable regulatory environment for the DNSPs, which may lower business risk and lead to better investment decisions
- fewer regulatory reviews and lower costs for stakeholders.

However, it can also have undesirable impacts, including:

- delaying the delivery of benefits from efficiency gains to consumers
- increasing the risk that industry and technological changes will create significant disparity between costs and revenues.

The Tribunal believes that a five-year regulatory period strikes a balance between providing incentives for improving efficiency, reducing regulatory uncertainty and minimising the risk that changes in the industry affect the appropriateness of the regulation. Other regulators in Australia appear to hold similar views. For example, the jurisdictional regulators for distribution businesses in Victoria and South Australia have adopted five-year regulatory periods, while the Queensland regulator has adopted a four-year period. The Australian Competition and Consumer Commission has adopted a five-year regulatory period for Transmission Network Service Providers.

10 The Tribunal has called what is commonly known as TUOS tariffs, 'transmission cost recovery tariffs', which recover transmission (TUOS) charges paid to TNSPs, avoided TUOS payments and inter-distributor transfer payments to other DNSPs. DNSPs bill customers on the basis of the total network tariff, although customers will be able to access the DUOS and transmission cost recovery tariff split if required.

11 Clause 6.10.5 of the National Electricity Code.

In addition, all stakeholders who responded to the Tribunal's issues and analysis papers[12] for this review supported a five-year period.

3.2 Prescribed distribution services

The Tribunal's draft decision is that prescribed distribution services will be defined by exclusion—that is, prescribed distribution services include all distribution services provided by the DNSP except for those listed by the Tribunal as excluded distribution services (see Table 3.1).

The Tribunal based its decisions about whether or not to include individual services in the list of excluded services primarily on the level of competition in the provision of those services. Its analysis and rationale for these decisions and the separate, more 'light-handed' regulatory arrangements that will apply to excluded services are discussed in detail in Chapter 13.

Table 3.1 List of excluded distribution services

Customer funded connections	Design and construction of new connection assets; construction of customer-funded network augmentations
Customer-specific ancillary services	Including maintenance of private poles and customer installations; asset relocation works; conversion to aerial bundled cable; temporary, stand-by, reserve or duplicate supplies; and other customer-requested services which are non-standard (however recoverable work undertaken by DNSPs in emergency conditions and separately defined monopoly services, remain as prescribed distribution services)
Metering services for types 1- 4 meters	Including meter supply, installation and maintenance; meter reading, meter tests
Public lighting – construction and maintenance	Construction and maintenance of street lighting assets

3.3 Regulatory arrangements for prescribed distribution services

The Tribunal's draft decision is that the regulatory arrangements for prescribed distribution services include:

- **A weighted average price cap for DUOS tariffs and miscellaneous and monopoly fees.** This includes using a building block approach to determine each DNSP's notional revenue requirement, then using this notional revenue requirement to calculate the amount by which its average prices can change
- **Recovery of DNSP's transmission-related costs through transmission cost recovery tariffs.** This includes transmission charges they pay to TNSPs, avoided TUOS payments and inter-distributor transfer payments.
- **Limits on price movements that apply to the total network tariff and charges for miscellaneous and monopoly services.**[13]

12 IPART, *Regulatory arrangements for the NSW Distribution Network Service Providers from 1 July 2004 Issues Paper*, November 2002 and IPART, *2004 Electricity Distribution Review - Preliminary Analysis Secretariat Discussion Paper*, September 2003.

13 Excluding customers on individually calculated prices.

- **DNSPs being responsible for setting network tariffs, subject to adherence to pricing principles and requirements for the disclosure of price information and public consultation.**
- **A separate form of light-handed regulation for excluded distribution services.**

Each of these elements is discussed in detail below. Figure 3.1 illustrates the components of the building block approach the Tribunal used to determine the notional revenue requirement for each DNSP. Figure 3.2 illustrates the approach it used to calculate the X-factors based on these revenue requirements. It also illustrates how charges for miscellaneous and monopoly services and transmission cost recovery tariffs will be set, and the inter-relationship between parts of the pricing framework.

Figure 3.1 The 'building block' approach to assessing notional revenue requirements for 2004-09

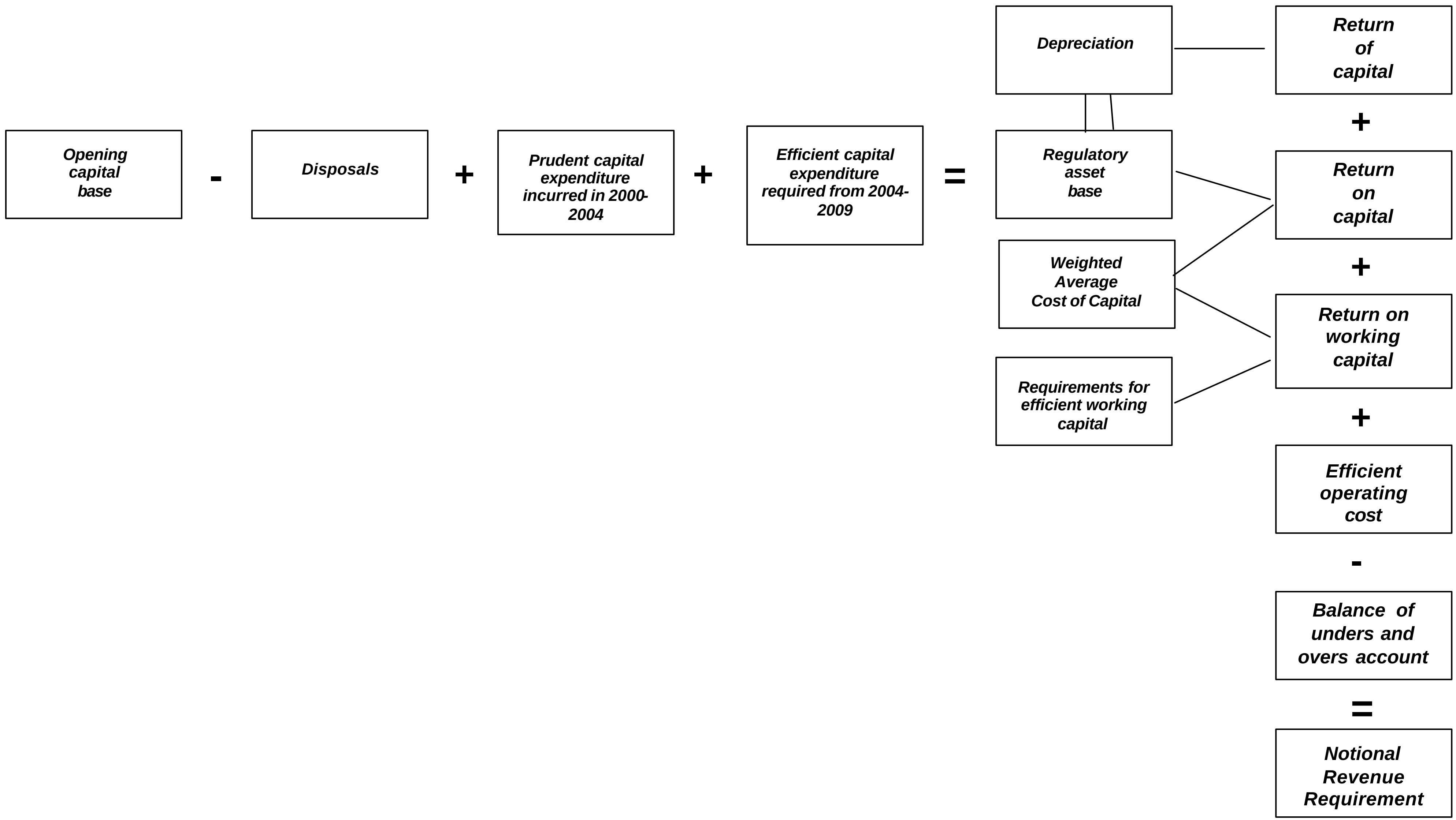
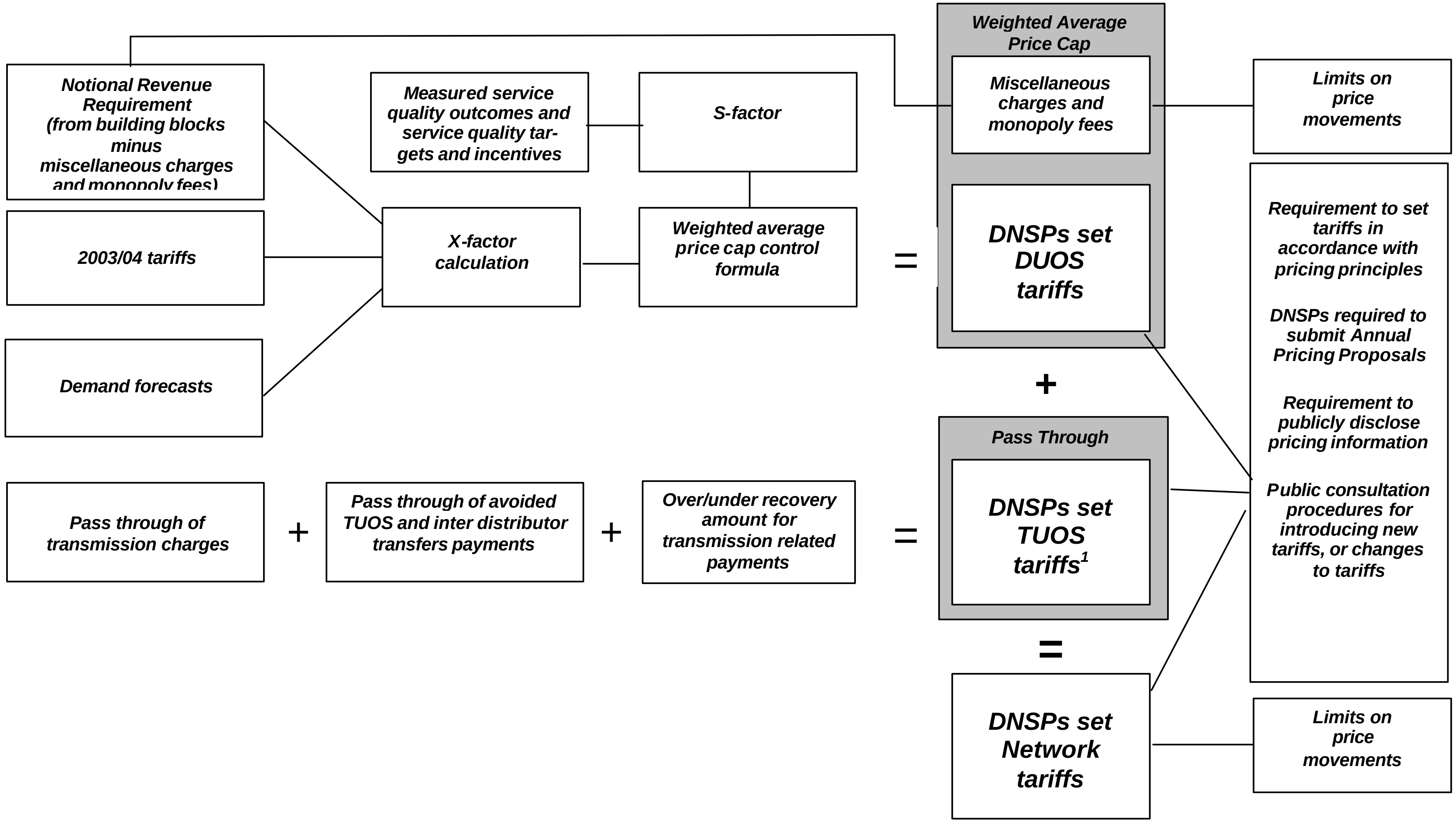


Figure 3.2 Regulatory arrangements from 1 July 2004 – 30 June 2009



[1] *That is, Transmission Cost Recovery Tariffs.*

3.3.1 The weighted average price cap for DUOS tariffs and miscellaneous charges and monopoly fees

DUOS tariffs, miscellaneous charges and monopoly fees will be regulated under a weighted average price cap. The weighted average price cap control formula will take the form, for year *t+1*:[14]

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} * q_{ij}^{t-1}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} * q_{ij}^{t-1}} \leq 1 + \Delta CPI + X_{t+1} + S_{t+1} \qquad i=1,\ldots,n \text{ and } j=1,\ldots,m.$$

where:

the DNSP has n Relevant Prescribed Distribution Service Charges which each have up to m components;

p_{ij}^{t+1} is the proposed price for component j of the Relevant Prescribed Distribution Service Charge i for Year *t+1;*

p_{ij}^{t} is the price charged by the DNSP for component j of the Relevant Prescribed Distribution Service Charge i in Year t (being the Year which immediately precedes Year *t+1*);

q_{ij}^{t-1} is the Audited Quantity of component j of the Relevant Prescribed Distribution Service Charge i that was charged by the DNSP in Year *t-1* (being the Year immediately preceding Year t);

S_{t+1} is a service quality incentive factor that will reward or penalise the DNSP for their performance on service quality relative to service quality targets set by the Tribunal;

X_{t+1} is the allowed real change in average prices from year t to year *t+1* of the regulatory control period as determined by the Tribunal, as set out for that DNSP in Annexure 6 of the determination and discussed in chapter 5 of this report; and

ΔCPI is the change in the Consumer Price Index in the 12 month period from January of the Year *t-1* to December of the Year *t,* as compared with the preceding twelve month period (see below).

14 The Tribunal has expressed the weighted average price cap in the form CPI+X, rather than the more usual CPI-X. This reflects the fact that real price increases are expected in the coming regulatory period. A positive value of X indicates a real price increase.

Prices and quantities

The weighted average price cap operates by restricting the (weighted) average change in the DNSP's prices (DUOS tariffs, miscellaneous charges and monopoly fees) to a limit determined by the constraint specified by the expression on the right hand side of the above equation. The prices are weighted by the corresponding quantities sold by the DNSP. In setting prices for the upcoming year *t+1*, DNSPs must ensure that the average price change relative to the prices it is charging in the current year *t* satisfy the constraint. For 2004/05, the prices for the 2003/04 are to be taken as those specified in Annexes 3 and 6 of the 2004-2009 draft determination.

The quantities used to weight the DNSPs prices are the audited quantity data from the previous year *t-1*. The use of quantity weights with a two year lag is required as these are the most recent audited data available.

The treatment of prices and quantities for new tariffs, new tariff components and in the event of customer movement instructed by the DNSP, is discussed in the section *'Adjusting the weighted average price cap for tariff reform'*, below.

Calculating the change in CPI (DCPI)

The Tribunal's draft decision is that the change in CPI (DCPI) is the change in the Consumer Price Index, All Groups, Weighted Average of eight Capital Cities, over a 12 month period from January to December, compared with the preceding 12 month period.

The ΔCPI term in the weighted average price cap formula allows network charges to be indexed for inflation. The year-on-year change in CPI is calculated as:

$$\Delta CPI = \left(\frac{CPI_{Mar,\ t-1} + CPI_{June,\ t-1} + CPI_{Sept,\ t} + CPI_{Dec,\ t}}{CPI_{Mar,\ t-2} + CPI_{June,\ t-2} + CPI_{Sept,\ t-1} + CPI_{Dec,\ t-1}} - 1 \right)$$

where:

CPI is the consumer price index, All Groups index number for the weighted average of eight capital cities as published by the Australian Bureau of Statistics

t refers to the financial year; and

the corresponding subtext (for example, June, *t-1*), means the CPI for the quarter and of the financial year indicated (in the example, the quarter ending in June of the financial year immediately before financial year *t*).

The Tribunal based its CPI measure on December quarter data to allow DNSPs sufficient time to prepare their pricing proposals, and for the Tribunal to review these proposals in time for final prices to be published on 31 May each year. The Tribunal considers this to be preferable to using March data and compressing the time available for the price approval process. The use of December CPI data was supported by stakeholders.

The Tribunal's use of a year on year definition (rather than a quarter-on-quarter approach) provides a more stable measure, and one that better reflects the flow of income that DNSPs receive throughout the year. This approach is consistent with the definition applied across all sectors that the Tribunal regulates, and there was general support among stakeholders. The Tribunal saw no reason to move away from the CPI for eight capital cities measure in favour of a Sydney based measure.

Calculating the amount by which average prices can change – the X-factors

The X-factor in the weighted average price cap formula determines how prices can change in real terms over the regulatory period. To set the weighted average price cap, the Tribunal has:

- undertaken a building block analysis to determine a notional revenue requirement for each year of the regulatory period for each DNSP
- tested these notional revenue requirements using financial analysis to ensure they will allow the businesses to remain financially viable
- taken the notional revenue requirements and, using growth forecasts, converted them into average allowable real price changes (the X-factors).

In deciding how to spread these price changes over the regulatory period, the Tribunal has used a hybrid of the P-nought and straight line approaches. EnergyAustralia, Country Energy and Australian Inland will be allowed a larger real price increase in the first year of the regulatory period, and a smaller increase in each of the remaining years. Integral Energy will be allowed a smaller, consistent real price increase in each year of the regulatory period.

The notional revenue requirements for each DNSP and the reasons underlying the Tribunal's decision on the X-factors are discussed in chapters 4 and 5.

Service quality incentives — S-factor

The Tribunal has introduced a package of service quality incentives for DNSPs. The S-factor in the weighted average price cap is a key component of this package. The S-factor allows a DNSP's price cap to be adjusted (up or down) each year within the regulatory period, depending on its service reliability performance relative to pre-determined reliability targets. The Tribunal believes this direct link between prices and service quality is important, particularly given the large amounts of capital expenditure DNSPs propose over the coming period, much of which is expected to be spent on maintaining or improving service quality.

The Tribunal decided to focus the S-factor on reliability because available data indicate this aspect of service quality is important to most customers, and because reliability performance is readily quantified, using data DNSPs already collect. The Tribunal intends to publish details of DNSP performance or other aspects of service quality, to provide, at least some, non-monetary incentive for DNSPs to maintain and improve service quality. However, it recognises that DNSPs are currently updating their information systems, and the accuracy of the data currently available is not certain. For this reason, it has opted to have the S-factor operate so that there is no monetary incentive until financial year 2006/07, and to limit monetary incentives to total network measures of reliability rather than measures based on feeder type. The Tribunal will also allow the impact of events to be excluded from the reliability measure, if they meet the current Steering Committee on National Regulatory

Reporting Requirements (SCNRRR) Normalised Distribution Network (unplanned) definition.

The reliability targets for each DNSP are fixed for the regulatory period, and are based on its own projections of what its capital and operating expenditure programs should achieve.

The Tribunal sees the introduction of this S-factor as an important first step in developing more comprehensive service quality incentives in subsequent regulatory periods.

The Tribunal's decisions in relation to the S-factor and the analysis behind these decisions are discussed in Chapter 6.

Adjusting the weighted average price cap for tariff reform

The model the Tribunal used to calculate the X-factor in the weighted average price cap assumes a relationship between consumption, load profiles and tariffs based on the 2003/04 tariff structures. This means that if there is significant tariff reform and customer movement between tariffs during the regulatory period, revenue will accrue at a different rate to that calculated under the model.[15] Furthermore, the weighted average price cap formula is calculated using historical quantities of consumption, and when new network tariffs or new network tariff components are introduced, no data relating to previous quantities sold are available.

The Tribunal is concerned that with no adjustments for these circumstances, this may create a level of revenue risk during the two year lag period. Either:

- there is a disincentive for the DNSPs to pursue tariff reform if a new tariff structure or new tariff contributes to revenue at a slower rate, or
- the tariff reform initiative may lead to revenue accruing at a faster rate, which is not incorporated in the weighted average price cap calculation.

This may occur in the following circumstances:[16]

- an existing customer moves to a new tariff, or to an alternative existing tariff
- an existing tariff has its structure changed, either by introduction of a new tariff component or a change to its criteria.

In order to accommodate these circumstances, the Tribunal has decided to include 'reasonable' estimates for the quantity q_{ij}^{t-1} factor in the weighted average price cap equation for these circumstances, until actual audited data is available. This will specifically be required for:

- the introduction of new tariffs
- the introduction of new tariff components, or

15 Revenue from new customers, whether they move to an existing tariff or new tariff, has been taken into account in the X-factor calculation via a growth assumption.

16 Note that the weighted average price cap incorporates revenue from existing customers based on their existing (or previous) tariff, hence the purpose of any adjustments would be to measure the revenue difference between the new tariff/component and the previous tariff, for existing customers, for the two years until actual data is available.

- for existing tariffs where significant customer movement occurs due to tariff reform and the DNSPs' direction (that is, movement between existing tariffs).

An adjustment to the historical volumes of the 'current network' tariff - that is, the tariff from where the customer originated from, will also be required.

The detail of this process is set out in Appendix 3. It has been adapted from the process used by ESC Victoria in their 2000-2005 Determination to estimate quantities for new tariffs or new tariff components.

3.3.2 Charges for miscellaneous and monopoly services

For its draft decision the Tribunal has determined an exhaustive list of maximum charges for miscellaneous and mandatory charges for monopoly services, indexing the current prices to 2004 dollars.

The Tribunal considers that charges for miscellaneous and monopoly services are prescribed distribution charges. As illustrated in Figure 3.2, it included the costs for these services in the notional revenue requirement before the X-factors were calculated for the DUOS tariffs. When the Tribunal assess DNSPs' compliance with the weighted average price cap, charges for miscellaneous and monopoly services will be included in the weighted average price cap.

Miscellaneous charges and monopoly fees are subject to a zero nominal limit on price movements and so will remain unchanged from the values listed in Annexure 3 of the legal determination for the length of the regulatory period.

Chapter 9 discusses miscellaneous and monopoly services.

3.3.3 Recovery of transmission-related payments through transmission cost recovery tariffs

The Tribunal's draft decision is that DNSPs can recover transmission-related costs by setting transmission cost recovery tariffs to recover:

- **transmission charges they expect to pay to transmission network service providers**
- **avoided TUOS payments they expect to pay to embedded generators, calculated in accordance with the Code**
- **interdistributor transfer payments they expect to make to other DNSPs.**

Once the actual transmission charges, avoided TUOS payments and interdistributor transfer payments are known, they will be offset against actual revenue collected by the DNSPs through their transmission cost recovery tariffs. Any under or over recovery of the costs will be recorded in a transmission overs and unders account.[17] Recovery (or return) of the balance in the account will occur at the next price change date, via an adjustment to transmission cost recovery tariffs, subject to the limits on total network tariffs and price stability. The Tribunal may depart from the price limits on network tariffs if a significant balance accumulates in the transmission overs and unders account. The Tribunal will consider applications for departure from the price limits if the balance of the account is

[17] Any outstanding balances in the account will attract a nominal return, based on the nominal WACC, to compensate for the time value of money.

expected to reach twenty per cent of actual transmission-related payments incurred in the previous year.

These arrangements are discussed in detail in Chapter 10.

3.3.4 Limit on price movements of network tariffs and other fees

The Tribunal's draft decision is that it will limit price movements on total network tariffs and other fees, for all customers — both residential and non-residential — except for larger customers on individually calculated (CRNP) tariffs, as set out in Table 3.2.

Table 3.2 Limits on price movements for 2004-09 regulatory period

DNSP	Limit on price movements for residential customers	Limit on price movements for non-residential[1] customers
EnergyAustralia, Country Energy and Australian Inland	**2004/05:** ΔCPI + 6.5% **Remaining years:** ΔCPI + 4.5%	**2004/05:** ΔCPI + 6.5% **Remaining years:** ΔCPI + 4.5%
Integral Energy	**Each year**: ΔCPI + 4.5%	**Each year**: ΔCPI + 4.5%
All DNSPs	Maximum increase in fixed charges of $30 per financial year Zero nominal increase for miscellaneous charges and monopoly fees	N/A Zero nominal increase for miscellaneous charges and monopoly fees

1. Excluding CRNP (cost reflective network pricing) customers.

These limits on price movements are intended to protect customers against significant price shocks as a result of tariff restructuring. In establishing the limits, the Tribunal has sought to provide DNSPs with sufficient headroom above the constraint imposed by the weighted average price cap to allow tariff restructuring. The Tribunal has provided for departure from the limits on price movements for increases in transmission charges, where these may lead to an accumulated balance in the transmission overs and unders account of twenty per cent of actual transmission-related payments incurred in the previous year (see Chapter 10).

The limits on price movements will apply to individual network tariffs and will have the form:

$$\frac{\sum_{j=1}^{m} r_j^{t+1} * q_j^{t-1}}{\sum_{j=1}^{m} r_j^{t} * q_j^{t-1}} \leq 1 + \Delta CPI + L_{t+1}$$

where:

the Network Tariff has up to m aggregate components;

an aggregate component of a Network Tariff means the aggregate of any DUOS Tariff component and its corresponding Transmission Cost Recovery Tariff component (if any), in accordance with clause 7.2 of the determination;

r_j^{t+1} is the proposed price for aggregate component *j* of the Network Tariff for Year *t+1;*

r_j^{t} is the price charged by the DNSP for aggregate component *j* of the Network Tariff in Year *t* (being the Year immediately preceding Year *t+1*);

q_j^{t-1} is the Audited Quantity of aggregate component *j* of the Network Tariff that was charged by the DNSP in Year *t-1* (being the Year immediately preceding Year *t*);

L_{t+1} is the price limit for year *t+1*; and

ΔCPI is the change in the Consumer Price Index over the 12 month period from January of the Year *t-1* to December of the Year *t,* compared with the preceding 12 month period.

The Tribunal has also imposed a maximum increase in fixed charges of $30 per year for residential customers.

Full details of the Tribunal's decision on the limits on price movements are set out in Chapter 11.

The Tribunal has decided that miscellaneous and monopoly fees should not be increased in nominal terms from their 2004/05 values.

3.3.5 Network price setting arrangements

Part E of Chapter 6 of the Code applies to the pricing of prescribed distribution services. Under clause 6.11(e) of the Code, the Tribunal has established an alternative pricing methodology, which sets out the arrangements the DNSPs must follow when setting prices and making tariff changes during the 2004 - 2009 regulatory period.

The key elements of the Tribunal's alternative pricing methodology are:

- a set of principles that the DNSPs must apply in setting their total network tariffs
- information disclosure and public consultation
- a process for assessing the compliance of annual pricing proposals with the determination.

These elements are discussed in detail in Chapter 12.

3.3.6 Regulation of excluded distribution services

The Code specifies that the Tribunal may apply a 'light handed' form of regulation to these services. Chapter 13 sets out the regulatory arrangements to apply to these services.

4 ESTABLISHING THE COST BUILDING BLOCKS

As Chapter 3 discussed, the Tribunal has introduced new regulatory arrangements for distribution prices for the 2004-2009 regulatory period. These new arrangements include a weighted average price cap to set DUOS tariffs and miscellaneous and monopoly fees. With this form of regulation, the Tribunal estimates how much revenue each DNSP requires using the building block methodology. Then, given forecast demand for electricity, it calculates the amount by which its average prices can change so as to generate this revenue (see Chapter 5).

The building block methodology involves the addition of cost blocks that represent forecasts of each DNSP's efficient operating and maintenance expenditure, an allowance for a return on assets, a return of capital (depreciation), and an allowance for the cost of working capital for each year of the regulatory period. The Tribunal also adjusts these building blocks to account for the closing balance of the unders and overs account from the 1999 regulatory period.

The size of these cost blocks depends critically on the underlying assumed rate of growth in the DNSP's energy volumes and demand over that period, so the Tribunal examined these assumptions closely. In addition, the return on assets and return of capital blocks depend on the opening value of the DNSP's regulatory asset base, and any additions to this asset base through the regulatory period as a result of capital expenditure. Therefore, the Tribunal also takes into account:

- the opening value of the regulatory asset base at 1 July 2003
- the level of efficient capital expenditure forecast through the regulatory period
- the rate of return on the regulatory asset base
- the depreciation profile.

This chapter discusses the Tribunal's draft decision on the growth assumptions underlying the building blocks for each DNSP, and its draft decisions on efficient capital, operating and maintenance costs, the opening value of the regulatory asset based, return on assets, return of capital (depreciation), and working capital. It also outlines how the Tribunal intends to treat the DNSPs' closing unders and overs account balances at 30 June 2004.

Box 4.1 Code requirements

Economic regulation is to be of the prospective CPI-X form or some incentive based variant of the CPI-X form and may take into account the performance of a DNSP under prescribed and other service standards (cl 6.10.5(a)).

The Tribunal must specify the form of economic regulation to be applied which is to be either a revenue cap, a weighted average price cap or a combination (cl 6.10.5(b)).

In setting a regulatory cap the Tribunal must take into account each DNSPs revenue requirements during the regulatory control period having regard to a number of matters (cl 6.10.5(d)).

4.1 Growth assumptions underlying the cost building blocks

The underlying assumptions about how demand will grow over the regulatory period have a critical impact on a DNSP's projected capital and operating costs. For example, if a higher growth rate is assumed, operating and maintenance expenditure is likely to be higher, to enable the DNSP to meet the greater demands on its network. Higher growth could also lead to greater capital expenditure, as assets might require replacement sooner or there might be a need to expand the capacity of the network to meet higher levels of demand.

Growth assumptions also affect the calculation of the X-factors in the weighted average price cap (see Chapter 5). The Tribunal also notes a theoretical incentive exists under a weighted average price cap for DNSPs to underestimate demand forecasts.

For this price review, the DNSPs were asked to provide forecasts for low, medium and high growth scenarios in their cost building block and weighted average price cap models. The medium scenario was intended to represent the DNSPs' 'most likely' scenario. The Tribunal engaged Meritec Ltd (New Zealand) to assess these forecasts as part of a total cost review (see section 4.2). However, only EnergyAustralia provided costs for all three scenarios in time for this review.[18] This meant Meritec could only review DNSPs' forecast costs under a medium growth scenario. In addition, due to time constraints, Meritec only performed a high-level assessment of the forecasts.

The Tribunal later released a paper, *Determining Sales Volumes for the 2004 Electricity Network Review*, in July 2003. Responses to this paper called for an expert review of the growth forecasts. The Tribunal then engaged McLennan Magasanik Associates (MMA) to:

- critique the DNSPs' low, medium and high growth scenarios
- determine throughput and demand forecasts for each DNSP.

MMA delivered its draft report in December 2003.[19] This report is now available on the Tribunal's website. Stakeholders are invited to make submissions on MMA's report along with submissions on the Tribunal's draft report.

The Tribunal's draft decision on which growth scenarios to use in establishing each DNSP's cost building blocks, and its analysis and rationale for that decision are outlined below.

4.1.1 Summary of draft decision

Based on the submissions made to the Tribunal, its own analysis and its review of MMA's report, the Tribunal is inclined to adopt MMA's growth forecasts. However, it is conscious that there is a close correlation between growth and costs and that it does not have cost projections based on MMA's growth forecasts. Therefore, for the purposes on this draft determination, it has adopted:

- **EnergyAustralia's forecast costs under its high-growth scenario**
- **Integral Energy's, Country Energy's and Australian Inland's costs under its medium-growth scenario.**

[18] Integral Energy provided some additional cost data for the low and high scenarios.

[19] *Review of demand forecasts for the 2004 electricity network review – draft report to IPART* – MMA, December 2003.

Subject to comments made on the MMA report, the Tribunal proposes to adopt MMA's growth forecasts for its final determination. It invites DNSPs to submit any projected additional costs they may incur as a result of these higher forecasts. The Tribunal will have these costs reviewed for efficiency by its consultant.

4.1.2 Tribunal's analysis and rationale

Although MMA reached similar conclusions on overall energy sales growth for the coming regulatory period, its disaggregated forecasts differ from those of the DNSPs by considerable amounts (Table 4.1). For residential sales, MMA forecast much higher growth for EnergyAustralia than the DNSP's modelling indicated, and lower growth for the other DNSPs. For non-residential sales, it forecast higher growth than Integral Energy, Country Energy and Australian Inland, and a similar level of growth as forecast by EnergyAustralia.

Table 4.1 Forecast 2009 Network Demand (GWh)[1]

	EnergyAustralia		Integral Energy		Country Energy		Australian Inland	
	Res	Non-Res	Res	Non Res	Res	Non-Res	Res	Non-Res
MMA forecasts	10,973	18,358	6,358	12,470	5,108	6,297	112	329
DNSP forecasts	10,196	18,398	6,486[2]	12,273[2]	5,200	6,012	116[3]	321[3]
Difference (%)	**7.6%**	**-0.2%**	**-2.0%**	**1.6%**	**-1.8%**	**4.7%**	**-3.4%**	**2.5%**
Overall difference	2.6%		0.4%		1.7%		0.9%	

Notes:

1. Based on DNSP's medium scenario.
2. Includes Inter-distributor transfers.
3. Updated volumes have been used for the IPART financial model.

The largest overall difference between MMA's and the DNSPs' own forecasts is for EnergyAustralia, while the overall difference for Integral Energy is very small. The main reasons for the differences between MMA's forecasts and those of each DNSP are outlined in Box 4.2.

Box 4.2 Key reasons for overall differences in MMA and DNSP growth forecasts

EnergyAustralia

MMA found EnergyAustralia's forecast residential customer growth to be low compared to the growth observed in recent years. While it concurs with EnergyAustralia's view that customer growth is likely to be slower in the DNSP's area of operation over the period 2004/5 to 2008/9 than it was over 1997 to 2003, it expects the reduction in growth to be smaller than EnergyAustralia forecast.

MMA also concluded that EnergyAustralia's assumptions understate usage per customer. MMA did not see any quantitative data to suggest that EnergyAustralia has taken into account factors such as changing household size, the continuing trend for customers to want higher levels of comfort, and the impact of new electrical appliances. EnergyAustralia's forecasts therefore show a significant reduction in average usage per customer, which is at odds with what has been observed for almost every year since 1994.

Integral Energy

MMA has forecast lower growth in customer numbers than Integral Energy. But, for the same reasons as outlined for EnergyAustralia, it has forecast higher usage per customer. These two effects balance each other out to some extent, so that there is only a 2 per cent difference between MMA's and Integral Energy's forecasts for residential customers.

For non-residential customers, MMA has forecast higher growth in usage than Integral Energy, but the overall difference between MMA and Integral is limited to 1.6 per cent as Integral Energy also assumes higher use of cogeneration.

Country Energy

The main difference between MMA's forecasts and Country Energy's is for the non-residential sector. MMA forecast higher growth in non-residential demand than Country Energy, (which based its forecasts on NIEIR forecasts).

Australian Inland

MMA forecast higher non-residential demand than Australian Inland, based on higher forecast consumption by the major mine company in the DNSP's area. MMA also forecast lower residential demand than Australian Inland, because it assumed lower growth in average usage than Australian Inland.

MMA also forecast different rates of growth in peak demand than did the DNSPs (Table 4.2). Forecast peak demand is an important driver of capital expenditure requirements. Typically, the greater the growth in peak demand, the higher the capital expenditure required.

Table 4.2 Forecast growth in peak demand

Maximum Demand[a]	Projection scenario Low %	Medium %	High %	MMA %
EnergyAustralia				
Summer	1.6	2.9	**3.8**	**3.4**
Winter	0.8	1.4	**1.9**	**2.7**
Integral Energy[b]				
Summer	2.1	2.7	**3.2**	**3.3**
Winter	1.3	2	**2.5**	**2.9**
Country Energy				
Summer	2.3	**3.1**	4.4	**3.3**
Winter	**2.1**	2.8	4	**2.4**
Australian Inland				
Summer	N/A	N/A	N/A	N/A
Winter	N/A	N/A	N/A	N/A

Notes:
(a) The DNSP forecasts are those published in the Tribunal's discussion paper, *Determining Sales Volumes for the 2004 Elelctricity Network Review,* DP65, July 2003, Table 2.1, p 3.
(b) Integral Energy uses compound annual growth rates rather than average annual growth rates to forecast maximum demand. N/A denotes that no maximum demand forecasts were submitted.

In general, MMA forecast higher growth in peak demand than EnergyAustralia and Integral Energy. Both MMA and the DNSPs forecast summer peak demand to grow at a much faster rate than overall consumption, which has implications for network resource allocation. MMA's forecast is higher than EnergyAustralia's and Integral Energy's medium scenarios, due to MMA's higher consumption forecasts, and because it assumes air conditioning usage will be higher.

MMA forecast much higher growth in winter peak demand than EnergyAustralia, and significantly higher growth than Integral Energy (medium scenarios). This reflects MMA's assumption that average consumption will continue to grow over time, which feeds into winter peak growth.

On balance, based on its own analysis the Tribunal has decided to adopt MMA's forecasts for its final determination. MMA's forecasts are independent—it has no vested interest in under or over estimating demand. In addition, the Tribunal has reviewed MMA's forecasts closely, and believes its assumptions are reasonable and conservative. For example, MMA has assumed that the 'comfort' factor (the trend growth residual unexplained by other usage factors) will decrease to half of its trend effect. The half assumption allows for demand management/appliance efficiency effects – where demand management or improved appliance efficiency do not curb residential usage, demand will be higher than forecast.

More information on MMA's review of the DNSPs' forecasts is provided in Appendix 4.

4.2 Efficient capital, operating and maintenance expenditure

In previous reviews, the Tribunal has considered each DNSP's proposed capital expenditure and operating and maintenance expenditure separately. However, it recognises that there is the potential for businesses to trade-off capital expenditure for operating expenditure and vice versa, and that this could affect service quality. As such, for this draft determination, it decided to undertake a joint review of capital and operating and maintenance expenditure.

To assist with this, the Tribunal engaged Meritec Ltd (New Zealand) to undertake a total cost review of each DNSP's capital, operating and maintenance expenditure.[20] The aim of this review was to provide the Tribunal with an overall strategic view of:

- whether the DNSPs' past capital expenditure was prudent and so should be allowed for when rolling forward the regulatory asset base
- whether the DNSPs' proposed levels of capital expenditure are reasonable and efficient for nominated security of supply and service standards
- whether the DNSPs' proposed levels of operating and maintenance expenditure are reasonable and efficient for nominated security of supply and service standards.

The Tribunal's draft decision on the appropriate capital, operating and maintenance expenditure allowances in each DNSP's building block revenue requirement, and its analysis and rationale for each aspect of this draft decision is explained below. Full details of Meritec's analysis can be found in its final report, which is available on the IPART website.[21]

4.2.1 Summary of draft decision

The Tribunal's draft decision in relation to capital expenditure for the period 1998/99 to 2002/03 is that this expenditure was prudent, and that an allowance for this expenditure, shown in Table 4.3, should be included when rolling forward the regulatory asset base.

Table 4.3 Capital expenditure to be allowed for when rolling forward the regulatory asset base ($million, nominal)

	1999	2000	2001	2002	2003
EnergyAustralia	141	256	272	293	294
Integral Energy	98	98	97	147	148
Country Energy	147	124	142	181	221
Australian Inland	3	3	3	4	3

EnergyAustralia's numbers include transmission assets.
Source: IPART Financial Model.

20 Meritec prepared a detailed questionnaire and information template for the DNSPs to complete. These were submitted to Meritec at the same time as the DNSPs made their submissions to IPART (ie 10 April 2003).

21 Meritec Limited (New Zealand), *Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers - Final Report*, October 2003 (available on IPART website www.ipart.nsw.gov.au).

The Tribunal's draft decision in relation to projected capital expenditure for the period 2004/05 to 2008/09 is to allow the amounts shown in Table 4.4.

Table 4.4 Projected capital expenditure used in building block revenue requirements ($million, nominal)

	2004	2005	2006	2007	2008	2009
EnergyAustralia	330	443	452	454	446	468
Integral Energy	228	259	254	234	256	265
Country Energy	229	237	242	245	255	261
Australian Inland	5	3	3	3	3	3

Source: IPART financial model.

In making this draft decision, the Tribunal has:

- Reduced EnergyAustralia's proposed capital expenditure under its medium growth scenario by 6.2 per cent per annum,[22] and added to this all of EnergyAustralia's proposed additional capital expenditure under its high growth scenario. Before finalising its determination, the Tribunal will review EnergyAustralia's revised projections of capital expenditure based on the higher growth forecasts that MMA has provided.
- Reduced Integral Energy's proposed capital expenditure under its medium growth scenario by 9 per cent per annum.
- Allowed Country Energy's proposed capital expenditure program under its medium growth scenario.
- Allowed Australian Inland's proposed capital expenditure program under its medium growth scenario.

The Tribunal's draft decision in relation to operating and maintenance expenditure for the period 2004/05 to 2008/09 is to allow the expenditures shown in Table 4.5.

Table 4.5 Projected operating and maintenance expenditures used in building block revenue requirements ($million, nominal)

	2005	2006	2007	2008	2009
EnergyAustralia	290	305	314	321	327
Integral Energy	207	212	220	227	235
Country Energy	210	218	226	235	244
Australian Inland	10	10	10	10	10

22 See footnote 32.

In making this draft decision, the Tribunal has:

- Allowed EnergyAustralia's proposed operating and maintenance expenditure under a high growth scenario, and allowed an additional amount of $4 million per annum in recognition that the proposed reduction in capital expenditure implies an increased need in operating expenditures.
- Allowed Integral Energy's proposed operating and maintenance expenditure under a medium growth scenario, and allowed an additional amount of $5 million per annum in recognition that the proposed reduction in capital expenditure implies an increased need in operating expenditures.
- Allowed Country Energy's proposed operating and maintenance expenditure under a medium growth scenario.
- Allowed Australian Inland's proposed operating and maintenance expenditure under a medium growth scenario.

4.2.2 Prudency of capital expenditure for the period 1998/99 to 2002/03

In making a decision on the return on assets building block, the Tribunal considers whether the DNSPs' capital expenditure over the current regulatory period was prudent.[23] An allowance for the proportion deemed to be prudent is then included when rolling forward the regulatory asset base.

All four DNSPs have spent considerably more in the current regulatory period than they projected in their submissions for the 1999 determination, and than the Tribunal allowed for in that determination (Table 4.6).

Table 4.6 Projected and actual capital expenditure 1998/1999 to 2002/3

$M (1998 prices)	EnergyAustralia	Integral Energy	Country Energy	Australian Inland
DNSP projection	687	437	784	15
Tribunal's allowance	885	412	793	16
Actual (nom)	1,383	778	1,002	21
Actual (real $1998)	1,266	708	916	19

Source: Meritec, Capital and Operating Expenditure, Final Report, October 2003, Table 6A.
Notes: Covers full period from 1998/99 to 2002/3.
Includes capital contributions, metering and streetlighting.

The DNSPs argued that all of this expenditure was prudent, and emphasised in particular the unexpected high growth in electricity demand, especially in peak periods. Integral Energy also emphasised the need to make greater replacements to its ageing asset base, and declining service quality beyond that envisaged at the time of the determination.

23 In its submission to the Tribunal, the Energy Markets Reform Forum (EMRF) argued that the test used to determine whether past expenditure should be included in the regulatory asset base should be an efficiency test, and that the use of the prudency test is contrary to the Code. However, the Tribunal considers the Code requirements are consistent with the use of a prudency test.

EnergyAustralia commissioned SKM to assess their 1999/00 to 2003/04 major projects for prudency. SKM concluded that all projects assessed were prudent, based on the information available at the time. SKM did however say that "…some reconsideration of scope and timing may have been warranted, based on information that came to hand after the initiation of the project."[24] PB Associates were commissioned by Integral Energy to assess the prudency of some of its capital expenditure projects – PB Associates found that the costs they examined were prudent.

The Tribunal asked Meritec to review the prudency of each DNSP's capital expenditure over the 1998/99 to 2002/03 period. Meritec found "no reason to judge the individual project and programme expenditures incurred during the period imprudent".[25]

In relation to DNSPs' higher than projected capital spending, Meritec noted a range of factors that contributed to this over spending—including:[26]

- significant non-system capital expenditure overruns
- in some cases, significant expenditure on IT system improvements
- higher than expected growth in demand (especially in the Sydney area)
- evidence of air conditioning load growth and a shift in peak demand from winter to summer in some locations
- DNSPs' perceived need for increased expenditure on refurbishment (although this category of expenditure was not a major contributor to the total over-spend, Meritec noted that asset ages did not suggest there was any urgency to undertake this work)
- additional statutory obligations.

On balance, based on its own analysis, the Tribunal decided to accept Meritec's recommendation that capital expenditure during the period 1998/99 to 2002/03 was prudent.

4.2.3 Projected capital expenditure for 2004/05 to 2008/09

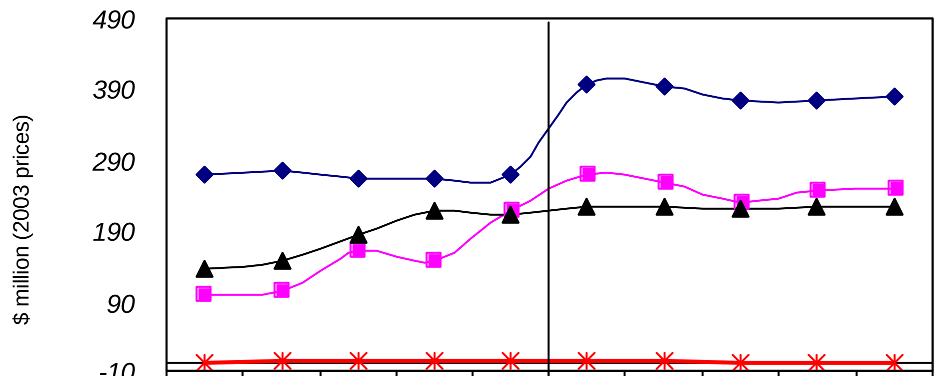
The DNSPs proposed total capital expenditure of $4.3 billion (2003 prices) over the coming regulatory period. This is 24 per cent higher than their expenditure in the current regulatory period ($3.5 billion in 2003 prices). In contrast, the Essential Services Commission's Performance Report for 2002 shows that Victorian DNSPs are spending less in capital and operating expenditure than allowed for in its last determination (see Appendix 5).

Both EnergyAustralia and Integral Energy propose substantial increases in capital expenditure—43 per cent and 71 per cent respectively. A number of stakeholders have expressed 'serious concerns' regarding the magnitude of the capital expenditure programmes. For example, the Energy Markets Reform Forum (EMRF) questioned whether the DNSPs have the capacity to implement such large capital expenditure programmes. Country Energy proposes a 24 per cent increase, while Australian Inland proposes to reduce its capex program by 24 per cent, or approximately $5 million in real terms.

24 See EnergyAustralia April submission, Attachment 11, p 1, available on IPART's website.
25 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 23.
26 ibid, pp 22-23.

The Tribunal notes that a large proportion of capital expenditure in the 1999 regulatory period was related to growth (see Table 4.7). This reflects the growth in demand that occurred early in this period, particularly the growth in summer peak demand. The DNSPs argue that to accommodate this higher growth-related expenditure, they had to reduce their replacement capital expenditure over this period. As a result, they have run down their assets. This means that in the coming regulatory period, they will need to place greater emphasis than usual on replacement capital expenditure.

Figure 4.1 DNSPs' actual and proposed capital expenditure, 2000-2009 (2003 prices)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Energy Australia	271	275	264	263	270	398	394	374	375	379
Integral Energy	101	106	162	148	218	270	257	230	248	249
Country Energy	138	148	185	218	213	225	224	222	224	224
Australian Inland	3	3	4	3	5	3	3	3	2	2

Source: DNSPs' submissions to Meritec Total Costs Review.

Note: Transmission related expenditure and capital contribution works and public lighting related expenditure are excluded.

Table 4.7 DNSPs' actual and proposed capital expenditure, 2000-2004 and 2005-2009

2003 prices ($million)	EnergyAustralia (medium growth scenario)				
Fin yr ending 30 June ->	2000-2004	% of total	2005-2009	% of total	% change
Renewal- end of life	233	17%	527	27%	126%
Environmental, safety etc	75	6%	207	11%	177%
Growth	699	52%	842	44%	20%
Reliability	54	4%	101	5%	86%
Non system capex	159	12%	175	9%	10%
Metering	48	4%	60	3%	25%
Other capex (Y2K, FRC)	76	6%	7	0%	-91%
Total	**1,344**	**100%**	**1,919**	**100%**	**43%**

2003 prices ($million)	Integral Energy (medium growth scenario)				
Fin yr ending 30 June ->	2000-2004	% of total	2005-2009	% of total	% change
Renewal- end of life	158	21%	401	32%	154%
Environmental, safety etc	17	2%	21	2%	21%
Growth	318	43%	569	45%	79%
Reliability	18	2%	105	8%	480%
Non system capex	184	25%	117	9%	-36%
Metering	18	2%	41	3%	133%
Other capex (Y2K, FRC)	23	3%	-	0%	-100%
Total	734	**100%**	1,254	**100%**	**71%**

2003 prices ($million)	Country Energy (medium growth scenario)				
Fin yr ending 30 June ->	2000-2004	% of total	2005-2009	% of total	% change
Renewal- end of life	308	34%	417	37%	36%
Environmental, safety etc	14	2%	-	0%	-100%
Growth	260	29%	325	29%	25%
Reliability	29	3%	-	0%	-100%
Non system capex	238	26%	313	28%	31%
Metering	29	3%	64	6%	119%
Other capex (Y2K, FRC)	23	3%	-	0%	-100%
Total	**901**	**100%**	**1,119**	**100%**	**24%**

2003 prices ($million)	Australian Inland (medium growth scenario)				
Fin yr ending 30 June ->	2000-2004	% of total	2005-2009	% of total	% change
Renewal- end of life	1.0	6%	-	0%	-100%
Environmental, safety etc	3.6	20%	2.3	17%	-37%
Growth	3.8	21%	3.5	26%	-9%
Reliability	3.8	21%	4.3	31%	13%
Non system capex	5.5	30%	3.6	26%	-34%
Metering	0.3	2%	-	0%	-100%
Other capex (Y2K, FRC)	0.1	1%	-	0%	-100%
Total	**18.1**	**100%**	**13.7**	**100%**	**-24%**

Source:DNSPs' submissions to Meritec's Total Costs Review .
Notes
1. Columns do not add due to rounding.
2. Transmission related expenditure, capital contributions, and public lighting are excluded.

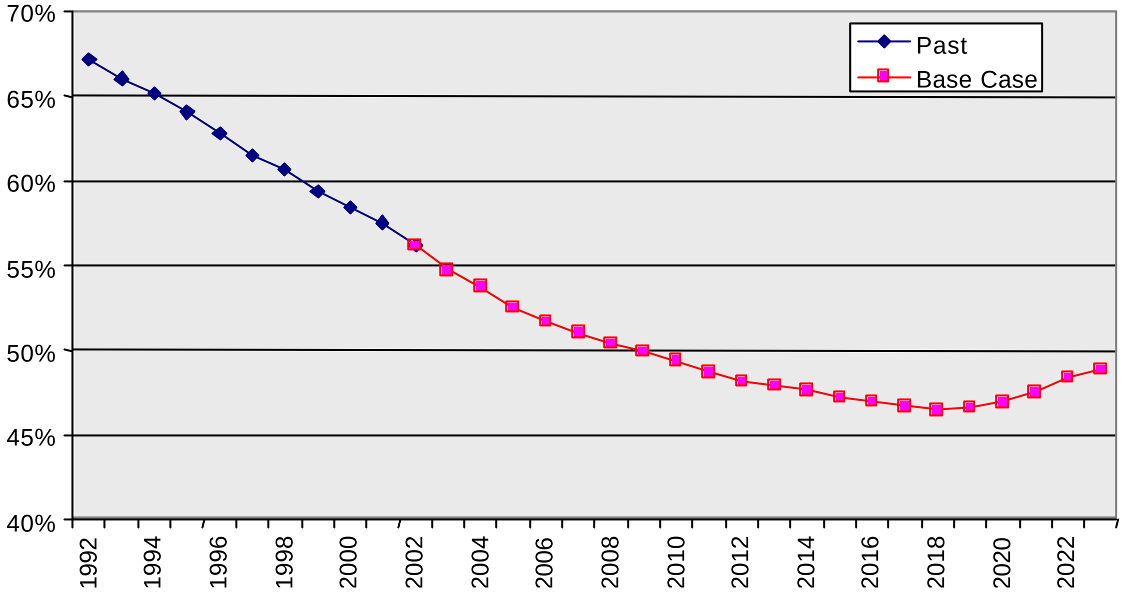
Meritec collected information on the age of each DNSP's assets and developed asset age profiles. It also calculated an implied asset age as a percentage of standard life.[27] The implied ages are:

- EnergyAustralia — 57 per cent
- Integral Energy — 46 per cent
- Country Energy — 53 per cent
- Australian Inland — 35 per cent.

This shows that EnergyAustralia's and Country Energy's assets are, on average, older than those of Integral Energy and Australian Inland. The Tribunal notes, however, that Integral Energy has a large number of assets that are reaching the end of their useful life. For example, when you look at the weighted average remaining life of its assets, it is clear that this remaining life has been declining since 1992 (Figure 4.2).

Using its asset age profiles as a guide, Meritec estimated each DNSP's renewal-based capital expenditure requirements, with more emphasis being placed on asset condition.[28]

Figure 4.2 Weighted average remaining life of Integral Energy's assets



Source: Integral Energy.

27 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 25.
28 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 7.

Meritec concluded in relation to the overall efficiency of each DNSP's projected capital expenditure for the period 2004/05 to 2008/09 that:

- EnergyAustralia, Country Energy and Integral Energy have similar renewal expenditures as a percentage of network replacement cost (1.7-1.8%);
- Integral Energy's total expenditure as a percentage of network replacement cost is higher at 4.5% than EnergyAustralia's or Country Energy's at 4.0% and 3.4% respectively[29];
- overall capex in the range 4% to 4.5% of network replacement cost as proposed by EA and IE respectively … appeared high to us in the prevailing low-growth environment[30]

Meritec recommended that EnergyAustralia should reduce capital expenditure over the period to 2014 by 10 per cent and that Integral Energy should reduce capital expenditure over the period to 2014 by 9 per cent.[31] When applied to the period 2004 to 2009, these reductions translate to reductions of 6.2 per cent per annum and 12.6 per cent per annum respectively.[32] The differences relate to how each DNSP had programmed its expenditure during the 10-year program. Meritec recommended that Country Energy's and Australian Inland's proposed capital expenditure should be accepted.[33]

Meritec's main reasons for the recommended reductions are:

- doubts over the methodology used to determine the magnitude and timing of replacement capital expenditure
- general concern over the magnitude of the capital expenditure programs in aggregate.[34]

When asked whether the reductions should be evenly spread across the review period Meritec stated:

> The report was silent on how reductions should be spread over the review period in IPART's modelling. Uniformity of annual application would, however, be a reasonable starting-point in the absence of information requiring adjustment for committed or urgent projects.[35]

29 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 26.

30 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 27.

31 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 27.

32 Meritec recommended that all of the growth component of EnergyAustralia's capital expenditure should be allowed (1.6 per cent of network replacement cost), but that the remainder of the expenditure should be reduced from 2.4 per cent of network replacement cost to 2.0 per cent. That is, a reduction in the total capital expenditure allowance from 4.0 per cent of network replacement cost to 3.6 per cent. This equates to a 6.2 per cent reduction in capital expenditure for EnergyAustralia per annum for 2004-09, or roughly $24 million per annum, or $119 million over the 2004-09 period. Similarly, for Integral Energy, Meritec recommended that all of the growth component of capital expenditure be allowed (1.7 per cent of network replacement cost) but that the remainder of the expenditure should be reduced from 2.8 per cent of network replacement cost to 2.4 per cent. That is, a reduction in the total capital expenditure allowance from 4.5 per cent of network replacement cost to 4.1 per cent. This equates to a 12.6 per cent reduction in capital expenditure for 2004-09, or about $32 million per annum.

33 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 27.

34 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 27.

35 Meritec, Clarification Note, 17 October 2003, response no 1.

The Tribunal notes that Meritec has accepted that capital expenditure related to growth is required, and recommended that any reductions should apply to replacement capital expenditure. In its analysis, Meritec determined that replacement-related capital expenditure was excessive by reference to a fixed proportion of network replacement asset value. As noted above, both EnergyAustralia and Integral Energy have argued that they have deferred replacement capital expenditure in the current period to accommodate growth. EnergyAustralia has stated that the reduction proposed by Meritec would have the effect of reducing expenditure on replacement by 25 per cent over the period 2005/09.[36] Similarly, Integral Energy has stated that the reduction could be as high as 30 per cent.[37]

In coming to a conclusion on the appropriate amount of capital expenditure to include in the roll forward of the regulatory asset base for the period to 2008/09, the Tribunal has had regard to the very substantial amount of capital expenditure that has already been spent and is forecast to be spent by the DNSPs. In total EnergyAustralia plans to spend $3.2 billion ($2003) over the 9 years to 2008/09. Likewise, Integral Energy plans to spend $2 billion and Country Energy $2 billion ($2003).

The Tribunal has also considered other stakeholders concerns about the magnitude of the programmes. **On balance having considered all the available information including Meritec's report, and all submissions received, a reduction of 6.2 per cent per annum off EnergyAustralia's medium growth capital expenditure scenario,[38] as proposed by Meritec, seems appropriate.** Further, as discussed in section 4.1, the Tribunal proposes to adopt MMA's growth forecasts for its final determination. However, it is conscious that there is a close correlation between growth and costs and that it does not have cost projections for MMA's growth forecasts.

The Tribunal notes that under EnergyAustralia's high growth scenario, it has proposed an additional $282 million in capital expenditure over the regulatory period. **For this draft determination, the Tribunal has included these additional amounts in full, as an estimate of the additional expenditure EnergyAustralia is likely to require, given MMA's higher forecast growth rates. Before finalising its determination, the Tribunal will require EnergyAustralia to submit revised projections of capital expenditure based on the MMA's higher growth forecasts, and will review these projections.**

However, a reduction of 12.6 per cent per annum for Integral Energy (as recommended by Meritec) is in the Tribunal's view too high. The Tribunal is concerned that Integral Energy may have difficulty in meeting a reduction in its capital expenditure of this magnitude without it having adverse impacts on its service standards performance. The Tribunal does however believe that some reduction is appropriate. In response to the Meritec recommendations Integral submitted to the Tribunal that:

> In particular, Integral believes that adoption of the reductions proposed by Meritec will have the following negative impacts:
>
> A reduction in renewal expenditure will require Integral to leave a larger proportion of aging assets in service, with correspondingly reduced performance levels compared to new assets. This will result in an increased number of outages, both for maintenance and due to failure, which will increase the risk of supply interruptions to customers. In

36 Correspondence to IPART dated 14 November 2003, p 1.

37 Correspondence to IPART dated 14 November 2003.

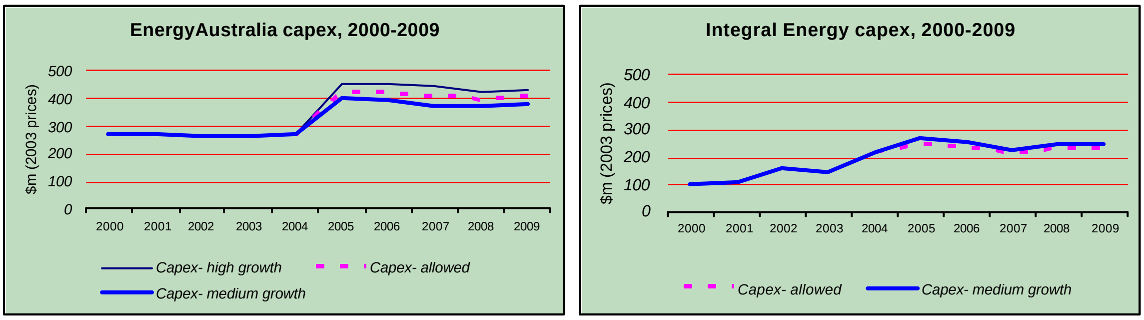
38 The 6.2 per cent reduction is applied to system capital expenditure only.

addition, these aged assets will incur additional operating costs due to increased frequency of routine and fault/emergency maintenance, when compared to new equipment.

In making a decision, the Tribunal has considered the principles and objectives of the Code and the requirements of Clause 6.10.5. On balance, the Tribunal believes a 9 per cent reduction is appropriate for Integral Energy.[39] This reduction is in line with Meritec's recommended reduction for the period to 2014. By applying this reduction for the period to 2008/09, the Tribunal recognises that there is some potential for Integral Energy to shift capital expenditure between the regulatory periods.

Figure 4.3 presents both EnergyAustralia and Integral Energy's proposed capital expenditure and the capital expenditures proposed under this draft report.

Figure 4.3 EnergyAustralia and Integral Energy's capital expenditures



As a result of these reductions in capital expenditure, the Tribunal considers it appropriate to provide offsetting operating expenditures. This issue is discussed below in section 4.2.4.

However, the Tribunal believes that there should be opportunities for cost-effective demand management, which could defer some capital expenditures.

39 The 9 per cent reduction is applied to system capital expenditure only.

4.2.4 Proposed operating and maintenance expenditure for 2004/05 to 2008/09

All four DNSPs have proposed real increases in their operating and maintenance expenditure for the coming regulatory period (Table 4.8).

Table 4.8 DNSPs' actual and forecast operating expenditure (2003 prices)

	2000-2004 $m	2005-2009 $m	% change
EnergyAustralia	1,246[1]	1,423	14%
Integral Energy	907	990	9%
Country Energy	1,036	1,102	6%
Australian Inland	45	47	4%
DNSPs Total	3,234	3,562	10%

Source: DNSPs' submissions to Meritec Total Costs Review.
Note 1: Includes transmission assets.

All four also spent significantly more on operations and maintenance during the current regulatory period than they forecast at the time of the 1999 determination. For example, EnergyAustralia's actual operating and maintenance expenditure was 22 per cent higher in real terms than it forecast for the 1999 determination (after adjusting for transmission operating expenditure). Integral Energy's, Country Energy's and Australian Inland's actual operating expenditures were 7.7 per cent, 20 per cent and 4 per cent respectively, higher in real terms than they forecast.

The Tribunal notes that EnergyAustralia's consultant (SKM) found that the operating expenditure allowed for in the 1999 determination was significantly below the industry average in Australia. SKM also found that new factors over which EnergyAustralia has 'little or no control' have increased operating and maintenance expenditure in the 1999 to 2004 period, and will continue to do so in the coming regulatory period. SKM found the factors having the biggest impact on costs to be:

- regulation 2001 health and safety requirements
- increased vegetation management, responding to requirements to increase safety clearances
- costs associated with the introduction of Full Retail Competition.

SKM's analysis, which included cross-jurisdictional comparisons, concluded that "SKM projected operating and maintenance expenditure for EnergyAustralia represents an appropriate and efficient level of expenditure, given the age profile of the EnergyAustralia system."[40] The Tribunal notes that EnergyAustralia's projected operating expenditure is slightly less than the level SKM estimated to be efficient.

Country Energy also noted several of the items mentioned above as key drivers of operating costs, and also argued that they had not been taken into account in the 1999 determination. Country Energy also argued that the benchmarking study commissioned by the Tribunal for

40 EnergyAustralia submission on the 2004 Distribution Determination, 10 April 2003, p 51.

the 1999 review had failed to sufficiently account for the 'relative uniqueness' of the Country Energy network. Consequently, Country Energy argued that the 1999 Determination provided insufficient allowance for operating and maintenance expenditure, and that increased expenditure would be needed for the 2004 regulatory period to avoid compromising network operations.

The Tribunal asked Meritec to review the efficiency of each DNSP's proposed operating and maintenance expenditure for the coming regulatory period.[41] Meritec made the following observations:

- Country Energy's projections showed no movement from FY 2003 to FY 2004 but a 9% increase from FY 2004 to FY 2009
- EnergyAustralia's projections showed an increase of 7% from FY 2003 to FY 2004 and a further increase of 8% from FY 2004 to FY 2009
- Integral Energy's projections showed an increase of 7% from FY 2003 to FY 2004 but as with Australian Inland this is offset by a decrease from FY 2004 to FY 2009, the overall increase from FY 2003 to FY 2009 being just under 4%
- In summary the increases projected by EnergyAustralia and Country Energy were higher than for the other two DNSPs and were occasioned by increases from FY 2004 onwards that bore a reasonable correlation with projected energy sales growth.[42]

Meritec provided the following breakdown of the operating expenditures over the 6 years to 2008/09 as shown in Table 4.9.[43]

Table 4.9 Operating projections for the 6 years to 2008/9 ($millions, 2003 prices)

	Energy Australia	Integral Energy	Country Energy	Australian Inland
Network operation	249	153	162	3
Pole replacement	43	0	0	5
Reactive maintenance	383	101	430	1
Vegetation control	119	105	114	1
Other preventive maintenance	154	229	53	15
Other	538	524	485	29
Total	1,486	1,111	1,244	54
Expenditures as percentage of total				
Network operation	17	14	13	5
Pole replacement	3	0	0	9
Reactive maintenance	26	9	35	2
Vegetation control	8	9	9	3
Other preventive maintenance	10	21	4	27
Other	36	47	39	53
Total	100	100	100	100
Projected expenditures in 2004 as a per cent of 2003	107%	106%	100%	112%
Projected expenditures in 2009 as a per cent of 2004	108%	96%	109%	93%

41 IPART, *Terms of Reference for the Total Cost Review*.

42 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 36.

43 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 36.

Meritec found that:

- EnergyAustralia's proposed operating expenditure should be adjusted to reflect an increase of no more than 10 per cent in real terms[44] from FY 2003 to FY 2009
- the other DNSPs' proposed operating expenditures should be accepted
- before adjusting the projections in future assessments for notional increases in the cost of materials, labour or plant, the cost of operating expenditure should be examined to check that DNSPs are maintaining cost-effective operational structures and that their overheads are reasonable.[45]

The Tribunal notes Meritec based its review on an estimate of each DNSP's operating and maintenance expenditure for 2002/03, as actual operating expenditures were not available in time for its review. For the draft determination, the Tribunal has used actual expenditures for 2002/03 as these are now available. It will ask Meritec to review these actual expenditures for efficiency before it makes its final determination. The Tribunal also notes that when EnergyAustralia's actual expenditure for 2002/03 is taken into account, its proposed expenditure is in line with the amount implied in Meritec's recommendation.

Meritec also notes that:

- Opex should reflect economies of scale
- Opex should also reflect other pertinent considerations including asset ages noting that aged assets involve more cost than new ones [46]

Since the Tribunal has been regulating the DNSPs, they have achieved significant improvements in efficiency, and the easy gains may have already been made. The Tribunal has undertaken some partial productivity analysis (see Appendix 5). Partial measures reflect output relative to a single input. Obviously, no single partial indicator can provide a complete measure of operational performance. If viewed in isolation, partial productivity indicators can be misleading. For instance, an improvement in labour productivity could reflect a shift to contracting out labour-intensive functions. Similarly, a reduction in operating and maintenance expenditure may reflect changes in capitalisation policy. Nevertheless, if a range of partial productivity measures is considered, it can provide a general impression of efficiency levels and rates of change.

As shown in Appendix 5 in terms of the partial measures associated with operating expenditures (opex per customer, and opex per MWh) both EnergyAustralia's outcomes in the current regulatory period and its forecast in the next period are lower than the other NSW DNSPs. The SKM study commissioned by EnergyAustralia showed EnergyAustralia's operating cost at the last determination to be significantly below the average for Australian distributors (in terms of, for example, operating costs per customer). It also showed EnergyAustralia's forecast operating costs for the next regulatory period to be broadly in line with the industry average.

---

44 Meritec originally said 'nominal terms', but in response to the Tribunal's request for clarification, it changed this to real terms.

45 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 39.

46 Meritec Ltd, Capital and Operating Expenditure, Final Report, October 2003, p 38.

Taking this analysis into consideration, and the results of Meritec's review of the efficiency of the proposed operating and maintenance expenditures, the Tribunal has decided not to reduce any DNSP's proposed operating and maintenance expenditures. In light of the reductions to their capital expenditure programs, the Tribunal has also made offsetting adjustments to the operating and maintenance programs for EnergyAustralia and Integral Energy.

Both EnergyAustralia and Integral Energy argued that if the reductions to their capital expenditure programs came from their proposed replacement capital expenditure, they would need to defer this expenditure and that this would put their systems in jeopardy. Both DNSPs indicated they would require additional operating expenditure to maintain any assets whose replacement is deferred. Integral Energy engaged PB Associates to help it consider the trade-off between capital and operating expenditure. PB Associates noted:

> These studies indicated an approximately linear trend such that a $10 million per annum reduction in renewal capital expenditure would result in an approximately $0.6 to $0.8 million per annum increase in operating expenditure.[47]

The Tribunal applied this estimate to the capital expenditure reductions proposed for EnergyAustralia and Integral Energy, and found that additional operating expenditure of $4 million and $5 million per annum respectively was appropriate.

Therefore, the Tribunal has made an off-setting adjustment to the operating and maintenance expenditures of $4 million per annum for EnergyAustralia and $5 million per annum for Integral Energy.

Further, as discussed in section 4.1, the Tribunal proposes to adopt MMA's growth forecasts for its final determination. However, it is conscious that there is a close correlation between growth and costs and that it does not have cost projections for MMA's growth forecasts. The Tribunal notes that under EnergyAustralia's high growth scenario, it has proposed an additional $23 million in operating expenditure over the regulatory period. **For this draft determination, the Tribunal has included this additional amount in full, as an estimate of the additional expenditure EnergyAustralia is likely to require, given MMA's higher forecast growth rates. Before finalising its determination, the Tribunal will require EnergyAustralia to submit revised projections of operating expenditure based on the MMA's higher growth forecasts, and will review these projections.**

4.3 The opening regulatory asset base for 2004/05

A DNSP's regulatory asset base is a measure of the financial value invested in it by its owner, and it has a substantial impact on distribution prices through its links to the allowances in the cost building blocks for the rate of return and depreciation. The Tribunal must determine an opening value for each DNSP's regulatory asset base at 1 July 2003. This value is then rolled forward to 2008/09 to determine the building block allowances for depreciation and rate of return.

The Tribunal has taken a financial view of the regulatory asset base, which means that once struck, its financial value is effectively detached from the underlying physical assets. This financial view means that, on a forward looking basis, in providing a return of and on the

47 Integral Energy submission to 2004 Electricity Network Review, 10 April 2003, p 126.

regulatory asset base, the Tribunal is seeking to maintain the owner's financial investment in real terms. This approach is consistent with the approach the Tribunal has taken in other reviews in water and gas sectors, and in the 1999 determination on distribution prices.

In making its decision on the opening values of the DNSPs' regulatory asset bases for the coming regulatory period, the Tribunal has considered a range of issues raised by stakeholders, including:

- the appropriate methodology for establishing the opening regulatory asset base
- whether it should conduct a ODV revaluation of pre-1999 assets in the asset base
- the treatment of the capital expenditure incurred during the 1999-2004 regulatory period that was in excess of the regulatory allowances
- proposed adjustments to the 1998 regulatory asset used in the calculation of the opening asset base for this regulatory period
- a proposed allowance for timing differences associated with the recent changes to the taxation treatment of contributed assets.

The Tribunal's draft decision on each of these issues, and its analysis and rationale for these decisions is outlined below. More detailed analysis of these issues is provided in Appendix 6. Box 4.3 details the relevant Code provisions.

The Tribunal is aware that under a strict financial view, there would be no role for the Tribunal to remove stranded or redundant assets from the regulatory asset base. However, it believes that there are strong benefits from it retaining the power to do this. These include creating an incentive for DNSPs to ensure that their investment decisions are prudent, and that customers are not required to pay for assets that are not used to service their demands.

4.3.1 Summary of draft decision

The Tribunal's draft decision is that it will establish the opening regulatory asset base for the 2004-09 regulatory period by:

- **rolling forward the 1998 regulatory asset base to 30 June 2003 on the basis of actual prudent capital expenditure**
- **rolling the regulatory asset base at 30 June 2003 forward to 30 June 2004 on the basis of the forecast capital expenditure allowed by the Tribunal in this draft determination.**

The opening asset base at 1 July 2003 will be calculated by:

- **indexing the initial 30 June 1998 regulatory asset base[48] for actual CPI**
- **adding actual prudent capital expenditure to 30 June 2003**
- **deducting regulatory depreciation as allowed for in the Tribunal's 1999 determination[49] and depreciation on allowed full retail contestability (FRC) costs, indexed for actual inflation**
- **deducting actual disposals.**

48 As specified in Table 6.1 of the Tribunal's 1999 Determination, *Regulation of New South Wales Electricity Distribution Networks,* NCDet99-1, December 1999, p 49.

49 Ibid, p 61.

The Tribunal's draft decision is that it will not allow adjustments to the 1998 regulatory asset base as part of the roll forward methodology.

The opening regulatory assets base for each DNSP is shown on Table 4.10.

Table 4.10 Opening regulatory asset bases for 2004-09 regulatory period nominal values

DNSP	Opening asset base $m
EnergyAustralia	4,104
Integral Energy	2,212
Country Energy	2,369
Australian Inland	65
Total	8,750

Box 4.3 Code requirements

The Code provisions in relation to calculation of asset values are quite broad. Clause 6.10.3(e)(5) of the Code provides that the Tribunal is to regulate a DNSP's revenues according to the principles that:

- assets created under a take or pay contract are valued in a manner consistent with the provisions of that contract;
- assets in existence and in service on 1 July 1999 (referred to here after as 'existing assets) are valued at the value determined by the jurisdictional regulator or consistent with the asset base already established through previous regulatory arrangements.
- any valuation of assets brought into service after 1 July 1999, or to re-evaluate existing assets is to be done in a manner determined by the jurisdictional regulator having regard to:
  (i) the agreement by the Council of Australian Governments that the deprival value should be a preferred approach
  (ii) any subsequent COAG decisions; and
  (iii) other matters reasonably required to ensure consistency with the Code objectives.

In addition, the Tribunal is required to ensure that its decision on asset valuation is consistent with the objectives and principles of the Code.

4.3.2 The opening regulatory asset base will be established by rolling forward the 1998 regulatory asset base

The Tribunal's view is that a roll forward approach is more appropriate than periodic revisions of the regulatory asset base, such as revaluations based on depreciated optimised replacement cost (DORC) value. It believes that periodic revaluations increase regulatory uncertainty for DNSPs. The roll forward approach is also consistent with the Tribunal's financial view of the regulatory asset base, discussed above. The basis for this decision is discussed in more detail in Appendix 6.

4.3.3 Pre-1999 assets will not be subject to an ODV revaluation

The Energy Markets Reform Forum (EMRF) argued that the Tribunal should re-value each DNSP's pre-1999 assets, to remove stranded and redundant assets from the regulatory asset base. In its 1999 determination, the Tribunal indicated that it "may consider calculating an ODV value for each DNSP for pre-1999 assets"[50]. Clause 6.10.3(e)(5)(iii) of the Code allows the Tribunal to re-value the pre-1999 assets on a basis determined by the Tribunal, but requires it to have regard to the Council of Australian Governments' (COAG's) preferred deprival value approach and any subsequent COAG agreements, and other matters necessary to ensure consistency with the objectives of network price regulation specified in clause 6.10.2.

The Tribunal's draft decision is not to undertake an ODV of the pre-1999 assets for the following reasons:

- it would be inconsistent with the Tribunal's preferred position of a roll forward of the existing regulatory asset base
- it would add to the level of regulatory uncertainty for DNSPs, which the Tribunal is seeking to avoid by the application of a roll-forward methodology
- it would be inconsistent with a financial view of the asset base
- the ODV methodology suffers from practical problems associated with the circularity between the economic value of the firm, the regulatory asset base and prices.[51]

4.3.4 No ex-post recovery of foregone rate of return on capital overspend, but recovery of foregone depreciation allowed

All the DNSPs, with the exception of Australian Inland, incurred higher actual capital and operating expenditure than provided for in the 1999 determination. As discussed in section 4.2.2, Meritec reviewed each DNSP's capital expenditure during the 1999 regulatory period, and found that this expenditure was prudent. The Tribunal agrees with Meritec's recommendation that the capital expenditure is prudent. The Tribunal will roll forward the regulatory asset base on the basis of prudent capital expenditure.

In principle, if this expenditure had been fully anticipated at the time of the 1999 determination, the DNSPs would have received higher allowances for regulatory depreciation and for a rate of return on this expenditure. The Tribunal has considered whether the DNSPs should be compensated for this foregone depreciation and rate of return and has decided that:

- the capital overspend will be rolled into the regulatory asset base at its undepreciated value — that is, DNSPs will be allowed to recoup the depreciation on this overspend from future customers
- there will be no ex-post recovery of the foregone rate of return on the capital overspend.

50 Ibid, p 55.

51 The value of the regulatory asset base depends upon the economic value of the firm which are based upon the regulated prices charged by the firm which are based upon the required return on the regulatory asset base.

Practically, this draft decision means that regulatory depreciation rather than actual depreciation will be deducted when rolling forward the regulatory asset base.

To achieve regulatory consistency, the Tribunal will also not allow ex-post recovery of operating expenditure incurred above that allowed in the 1999 determination. In addition, the Tribunal will apply a symmetrical approach when a DNSP underspends capital and operating expenditure relative to the regulatory allowances. Specifically, this means:

- the DNSP will be allowed to retain the rate of return on the difference between allowed and actual capital expenditure
- regulatory depreciation will be used to roll forward the regulatory asset base so that the regulatory asset base will be written down more than if actual depreciation were used
- the DNSP will be allowed to retain the difference between allowed and actual operating expenditure.

The Tribunal's draft decision seeks to balance the need to maintain the incentives in the regulatory framework for DNSPs to pursue capital and operating cost efficiencies, and the need to ensure that DNSPs are not unduly disadvantaged for undertaking unforeseen prudent expenditure. The basis for the Tribunal's decision is discussed more fully in Appendix 6.

4.3.5 No adjustments to the 1998 regulatory asset base as part of the roll forward

Country Energy and Integral Energy proposed several adjustments to their initial 30 June 1998 regulatory asset base, prior to it being rolled forward to establish the opening value for the 2004-09 regulatory period (see Appendix 6). They argue these adjustments are necessary to correct for perceived deficiencies in the original DORC valuation, conducted on behalf of NSW Treasury. Broadly, they relate to the inclusion of un-recognised assets and changes in the way assets were valued in NSW Treasury's original 1998 valuation study.

The Tribunal's draft decision is not to allow any adjustments to the 1998 regulatory asset base. In making this decision, the Tribunal took into consideration that, although its 1999 determination aligned the regulatory asset base to the 1998 DORC value for most DNSPs, it has indicated in various determinations, including the 1999 determination, that it is concerned about and does not support the DORC valuation of assets as the sole determinant of regulatory asset values.

Since the 1999 determination, other regulators have identified issues with the DORC methodology. For example, the Productivity Commission reviewed the national access regime and, in relation to the DORC valuation, found:

> … there is evidence that, as currently implemented for some industries, the DORC approach creates considerable additional costs and uncertainty for regulated firms and access seekers alike. Yet evidence of DORC's conceptual superiority is not often evident in these cases.[52]

52 Productivity Commission, *Review of the National Access Regime, Inquiry Report,* Report No 17, 28 September 2001, p 366.

In its discussion paper on the review of the draft statement of regulatory principles, the ACCC has signalled it preferred position to lock in the asset base and apply a roll forward methodology. In its discussion paper, the ACCC noted that:

> Having regard to the merits of the ODRC methodology relative to rolling forward the asset base, we do not consider revaluations based on ODRC to be feasible in the short-term nor does it provide appropriate incentives for regulated transmission providers over the longer term. A preferred approach is for the regulatory asset base to reflect the level of capital expenditure undertaken and return of funds received over the regulatory period – that is, the rolling forward methodology.[53]

The Tribunal also took into consideration the principles and objectives of the Code in making its decision. In particular, it considered the implications of the DNSPs' proposals for regulatory certainty, economic efficiency, competition and the balance of interests between network users and the DNSPs' owner. It concluded that it would be inappropriate to make adjustments to the 1998 regulatory asset base as part of the roll forward. The Tribunal's basis for this decision is discussed in more detail in Appendix 6.

4.3.6 No adjustments relating to tax on contributed assets

NSW DNSPs came under the National Taxation Equivalent Regime (NTER) from 1 July 2001, and so are now required to pay corporate tax on contributed assets. When they were under the NSW Taxation Equivalent Regime, capital contributions were exempted from tax equivalent payments. EnergyAustralia submitted that this change adversely affects its business, due to timing differences between the tax paid on the capital contribution and the benefits of the tax shield derived from the depreciation of the contributed asset for tax purposes. It proposed that the Tribunal recognise the tax paid by EnergyAustralia on capital contributions as capital expenditure on the assets, and so include this expenditure in the regulatory asset base.

The Tribunal's draft decision is not to allow EnergyAustralia's proposed treatment of the tax on contributed assets. In establishing a weighted average cost of capital (WACC) on the basis of the statutory tax rate rather than an effective tax rate (see section 4.4), the Tribunal has elected not to involve itself in the DNSPs' tax affairs. It therefore considers that using a statutory tax rate rather than an effective tax rate in the derivation of the WACC provides sufficient compensation to DNSPs for the timing difference identified by EnergyAustralia. The Tribunal notes that taxation timing differences (such as those resulting from different depreciation rates, accrual and payment of service leave) are a common occurrence, and sometimes work in favour of the DNSPs.

4.4 Return on capital

The allowance for the rate of return on the DNSP's regulatory asset base covers the opportunity cost of capital invested in the DNSP by its owner. It typically represents around 30 to 40 per cent of the DNSP's building block revenue requirement, and so has a significant impact on prices and financial outcomes for it and its customers.

[53] ACCC, Discussion Paper 2003 Review of the Draft Statement of Principles for the Regulation of Transmission Revenues, p 26, quoting its consultant Jeff Baulchin, *Methodology for updating the Regulatory Value of Electricity Transmission assets, Attachment A to the Discussion Paper*, August 2003.

There are several approaches for calculating an appropriate rate of return on the regulatory asset base. The Tribunal's preferred approach is to use the Weighted Average Cost of Capital approach to determine an appropriate range for the rate of return. As for previous determinations, the Tribunal has used a real pre-tax WACC. The WACC is a weighted average of the cost of debt and equity. The Tribunal has used the Capital Asset Pricing Model to derive the cost of equity, and calculated the cost of debt as a margin over the risk-free rate.

In making its draft decision on the rate of return, the Tribunal has exercised its judgement to determine the WACC, taking into consideration the objectives and principles in the Code, including the legitimate interests of utilities and other stakeholders. The Tribunal's draft decision, and the analysis and rationale for this decision are outlined below. The relevant provisions of the Code are included in Box 4.4.

4.4.1 Summary of draft decision

The Tribunal's draft decision is that for the purposes of calculating the building block allowance for the return on capital, a real pre-tax rate of return of 6.8 per cent will be applied. This decision reflects the Tribunal's finding that the industry weighted average cost of capital is in the range of 6.2 to 7.6 per cent.

The return on capital allowances for each DNSP are those shown in Table 4.11.

Table 4.11 Return on capital building block components, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	288	312	337	360	383
Integral Energy	156	168	179	189	200
Country Energy	165	176	186	195	204
Australian Inland	4	5	5	5	5

Box 4.4 Code requirements

The Code requires that the regulatory regime administered by the Tribunal must have regard to a number of matters including the need to provide a fair and reasonable risk-adjusted cash flow rate of return on efficient investment given efficient operating and maintenance practices (cl 6.10.3(e)(5)).

4.4.2 Tribunal's analysis and rationale

The Tribunal's view is that the industry average real pre-tax WACC was in the range of 6.2 and 7.6 per cent, based on the parameters shown in Table 4.11. Some of these parameters are different to the values submitted by the DNSPs. The key points of difference are the:

- nominal and real risk-free rate
- market risk premium
- debt margin
- debt beta
- asset beta
- dividend imputation factor, or gamma.

The difference between the Tribunal's and the DNSPs' value for equity beta reflects the differences in the assumed asset beta and debt margins.

The Tribunal's nominal risk free rate is derived from the Ten Year Commonwealth Government Bond Rate. Its real risk free rate is derived using Treasury indexed bonds, adjusted to reflect a ten-year maturity. The Tribunal took a 20-day average as at 19 November 2003 to derive these estimates. This approach is the same as the Tribunal used for the 1999 determination and other determinations. The higher values identified by the Tribunal reflect the recent general increase in interest rates. The Tribunal will update this value in preparing its final determination.

Table 4.12 WACC parameters

Parameter	DNSPs submitted values	Values from 1999 Determination	Value for 2004-09 regulatory period
Nominal risk free rate	5.17-5.50%	6.62%	5.8%
Inflation	1.90-2.20%	3.0%	2.3%
Real risk free rate	3.06-3.30%	3.52%	3.5%
Market risk premium	6.0	5.0-6.0	5.0-6.0
Debt margin	1.45-1.52%	0.8-1.0%	0.9-1.1%
Debt to total assets	60%	60%	60%
Dividend imputation factor (gamma)	0.4[54]	0.5-0.3	0.5
Tax rate	30%	30-36%	30%
Asset beta	0.425-0.48	0.35-0.50	0.35-0.45
Debt beta	0.06-0	0.06	0.06-0
Equity beta	1.05-1.10	0.78-1.14	0.78-1.11
Cost of equity (nominal post-tax)	11.60-12.09%	10.5-13.5%	9.7%-12.5%
Cost of debt (nominal pre-tax)	6.65-7.00%	7.4-7.6%	6.7-6.9%
WACC (nominal post-tax)	6.79-7.07%	6.6-7.5%	6.0-7.0 %
WACC (real pre-tax)	7.50-7.80%	5.0-8.5%	6.2-7.6%

54 Value is the mid-point of submitted values from DNSPs.

The market risk premium represents the additional return over the risk-free rate of return that an investor requires for the risk of investing in a diversified equity portfolio. The Tribunal decided that a value of between 5 and 6 per cent is appropriate for this premium. The DNSPs submitted that 6 per cent would be appropriate. Other regulators such as the ACCC have assumed a value of 6 per cent in their WACC calculations.

The Tribunal reviewed the DNSPs' submissions on this matter and examined estimates of the market risk premium derived using a number of different approaches for calculating this value—including historical-based approaches, supply-side approaches, surveys of finance professionals and extrapolation from foreign markets. It concluded that there is insufficient evidence to change the market risk premium range from that used in the 1999 determination.

The debt margin represents the cost of debt a company has to pay above the nominal risk-free rate. The debt margin is related to current market interest rates on corporate bonds (or Treasury Corporation (T-Corp) borrowings), the maturity of debt, the assumed capital structure and the credit rating. The Tribunal's estimate of the debt margin is lower than the DNSPs', but slightly higher than the one applied in the 1999 determination. This increase in the debt margin compared to the 1999 determination reflects the Tribunal's finding that the debt margins it used in its past decision are lower than those used by other regulators.

The Tribunal considers that the debt margins submitted by the DNSPs are too high. It reviewed benchmark credit ratings and T-Corp's indicative borrowing rates. It found that the most recent regulatory decisions by the ACCC indicate that debt margins as measured in debt capital markets have fallen. Recent capital market data suggest that debt margins for BBB+ and A rated companies fell during 2003 to between 80 and 92 basis points for 5-year maturities.

The debt beta reflects the risk of a debt security and how it correlates with the market. The Tribunal believes a value of between 0.06 and 0 is an appropriate value for the debt beta. This is consistent with the range specified by the DNSPs. In past determinations, the Tribunal has used a debt beta of 0.06, with the exception of the 2003 metropolitan water decision which applied a range of 0.06 to 0.14. The Tribunal decided on the range of 0.06-0 on the basis that it:

- reflects the capital market view that the debt beta is equal to zero
- is consistent with recent decisions by the ACCC, which assume a debt beta of zero
- takes account of research by Elton et al[55] and Allen Consulting Group[56] that suggest that the debt beta value is greater than zero.

The asset beta is a measure of the covariance of excess returns above the risk-free rate with the excess returns on the market, if the business were 100 per cent equity financed. The equity beta represents the covariance of the excess returns of a share with the excess returns on the market. The asset beta values adopted by the Tribunal are lower than those proposed by the DNSPs. The Tribunal reviewed estimates of asset betas of comparable Australian companies and found that there is evidence that these betas are decreasing. In light of this,

55 Elton et al. *Explaining the rate spread on corporate bonds*, The Journal of Finance, Vol LVI, No. 1, 2001, pp 247-277.

56 The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Report for the ACCC, 2002.

the Tribunal considers there is insufficient evidence to increase the asset beta values to those submitted by the DNSPs. It also decided to narrow the range for the asset beta by lowering the upper bound of this range. The equity beta range is approximately in line with the values applied by the Tribunal in the 1999 determination, which reflects offsetting changes to the asset beta and the debt beta parameters.

In its Moomba to Sydney pipelines decision, the ACCC has taken a new approach by directly estimating the equity beta. The Commission decided on an equity beta of one, after having considered a number of different scenarios using a pool of comparable Australian companies. The Commission de-and re-levered these comparable equity betas using different debt beta values. In adopting this approach the Commission was deliberately conservative since the available evidence, although limited, suggest that an equity beta considerably below this is consistent with Australian conditions. The Tribunal, having considered the possible implications for incentives to invest, has adopted a similarly conservative approach.

The gamma parameter represents the value of imputation credits. The Tribunal believes 0.5 is an appropriate value for this parameter. This is higher than the values submitted by the DNSPs, and at the upper bound of the range it applied in the 1999 determination. For this determination, the Tribunal has reviewed currently available supporting evidence on the value of gamma and concluded that an appropriate value for gamma is within the range 0.4 to 0.6. It decided to use 0.5, as this represents the mid-point of this range and is the value used by all other Australian regulators.

Several DNSPs argued that the presence of asymmetric risk means that investors would require a higher rate of return than implied by the WACC. However, the Tribunal decided not to include an allowance for asymmetric risk in the WACC. It believes that including such a premium would be inconsistent with the assumptions underlying the Capital Asset Pricing Model, as investors would be compensated for risks that are theoretically not included in the fair calculation of the cost of their capital. It does not accept the DNSPs' argument that the consumer is counterparty to asymmetric risks, as investors can diversify their investments regardless of who the counterparty to any specific risk may be.

For the purposes of calculating the building block allowance for the return on capital, the Tribunal's draft decision is that a real pre-tax rate of return of 6.8 per cent is appropriate. This is derived from applying the mid-points of the parameter ranges identified in Table 4.12.

The Tribunal's analysis for this decision is discussed in more detail in Appendix 7.

4.5 Return of capital (depreciation)

Depreciation is an allowance in the notional revenue requirements that represents the return of capital invested by the shareholder in the DNSP's business. It is an important cost building block, representing around 25 per cent of a DNSP's total notional revenue requirements.

The Code does not specify how the Tribunal should establish the allowance for depreciation in the building blocks. In the 1999 determination, it used a straight line depreciation profile, based on the asset lives established by the NSW Treasury asset valuation study. It also indicated that it would provide scope for alternative depreciation profiles to be used in the future, provided these can assist in managing market risks and managing variations in the prices of new investment. It required that proposed alternative deprecation profiles be net present value neutral compared with straight line depreciation.

The Tribunal's draft decision on the method it will use to calculate the return of capital allowance for the 2004 determination, and the analysis that supports this decision, is summarised below.

4.5.1 Summary of draft decision

The Tribunal's draft decision is that it will use the straight line depreciation method to calculate the return of capital (depreciation) allowance for each DNSP. For the draft determination, it will use the asset lives as proposed by the DNSPs.

The return of capital allowance for each DNSP is shown in Table 4.13.

Table 4.13 Return of capital building block components, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	170	189	209	229	247
Integral Energy	127	139	152	164	178
Country Energy	132	147	163	179	196
Australian Inland	3	3	4	4	4

4.5.2 Straight line depreciation method will be used

The Tribunal decided to continue to use a simple straight line depreciation method to calculate the allowance for return of capital. It believes that this approach is superior to alternatives in terms of simplicity, consistency and transparency. It addition, the DNSPs support the continued use of this approach. So too does the Allen Consulting Group, which the Tribunal engaged to advise it on depreciation issues.[57] The Tribunal's reasons for this draft decision are explained in more detail in Appendix 8.

However, the Tribunal will consider proposals from DNSPs and other stakeholders for alternative depreciation profiles before making its final determination. Any proposals must be NPV neutral and must explain why an alternative depreciation profile is necessary in terms of managing risks for DNSPs and also consistency with the objectives and principles contained in clauses 6.10.2 and 6.10.3 of the Code. Proposals will need to demonstrate that alternative profiles offer significant benefits over the straight line approach.

57 The Allen Consulting Group, *Principles for determining regulatory depreciation allowances*, September 2003, p 2.

4.5.3 Asset lives proposed by DNSPs will be used

To apply the straight line depreciation method, the Tribunal needs to estimate the lives of the assets being depreciated. For the draft determination, the Tribunal decided to use the asset lives proposed by DNSPs. Where a DNSP has not proposed alternative asset lives, the Tribunal decided to use the asset lives used in the 1999 determination, which were based on NSW Treasury's 1999 study.

Only EnergyAustralia proposed alternative asset lives in submissions. On average, these are longer than asset lives determined by NSW Treasury's study, which led to a lower depreciation component in EnergyAustralia's cost building blocks.

Although the Tribunal has used these revised asset lives in its modelling for this draft decision, it requires EnergyAustralia to demonstrate why the revised lives better meet the principles and objectives of the Code prior to making its final determination. It will also consider proposals from other DNSPs for changes to asset lives. These proposals will need to explain why the revised asset lives better meet the principles and objectives of the Code. In addition, the Tribunal will commission an independent assessment of the asset lives proposed by EnergyAustralia, and the other DNSPs.

The changes in asset lives will apply on a prospective basis only — that is, the changes will apply from 2004/05. The Tribunal will not recalculate depreciation for the 2004 regulatory period. This is consistent with accounting conventions and ensures that the net present value of the depreciation allowances does not changed over the lives of the assets. The Tribunal's 1999 report to the Premier contains a fuller discussion of this point.[58]

4.6 Working capital

The Tribunal believes DNSPs should be allowed to recover the cost of maintaining an investment in working capital. Since the allowance for a return on and of fixed assets in the cost building blocks is just sufficient to cover these costs, a separate amount is made available for working capital. The Tribunal's draft on this allowance, and the analysis behind this decision is summarised below.

---

58 IPART, *Pricing for Electricity Networks and Retail Supply, Report Volume 1,* Report Rev99-5.1, June 1999, pp 100-102.

4.6.1 Summary of draft decision

The Tribunal draft decision is to include an allowance for working capital in the cost building blocks, based on a simplified payment cycle approach.

The allowance for working capital for each DNSP is shown in Table 4.14.

Table 4.14 Allowance for cost of working capital, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	6.2	5.8	5.9	6.4	7.0
Integral Energy	2.7	2.8	3.1	3.4	3.6
Country Energy	3.7	3.9	4.3	4.6	5.0
Australian Inland	0.0	0.0	0.0	0.0	0.1

4.6.2 Tribunal's analysis and rationale

The Tribunal estimated a reasonable level of working capital for each DNSP, based on a simplified payment cycle approach. Specifically, this is based on the amount of time that payments (based on operating and capital expenditure) and receipts (network revenue) are outstanding. The calculation also adds in the value of inventory (which is also based on the level of capital and operating expenditure). Since the building block revenue requirement is expressed in nominal terms, the return on net working capital is calculated as a nominal return equivalent to the WACC applied to the regulatory asset base.

Thus, working capital is calculated as follows:

- Receivables @ 45 days of total network revenue (DUOS + TUOS + other regulated) *less*
- Payables @ 30 days of operating costs (including TUOS costs) + capital expenditure *plus*
- Inventory @ number of days of operating costs (excluding TUOS costs) + capital expenditure as at 30 June 2003.

4.7 Treatment of the 1999 determination's outstanding unders and overs account balance

The revenue cap form of regulation under the Tribunal's 1999 determination required the operation of an unders and overs account to record any under- or over-recovery of the DNSP's Aggregate Annual Revenue Requirement (AARR). None of the DNSPs are expecting to have a zero balance by the end of the current regulatory period on 30 June 2004. The Tribunal wrote to the businesses in mid-October, asking them to update their forecasts of their closing balances for June 30, 2004. The new forecasts are:

- Country Energy forecasts **under**-recovery of $1.7 million
- Australian Inland forecasts **under**-recovery $3.2 million
- EnergyAustralia forecasts **over**-recovery balance of $99 million
- Integral Energy forecasts **over**-recovery balance of $73 million.

Under the proposed weighted average price cap form of regulation, revenue is not capped and so an unders and overs account arrangement will not be required for DUOS tariffs.[59] This means the Tribunal needs to decide how to incorporate the closing account balances from the current regulatory framework into the proposed regulatory framework for the 2004-09 regulatory period. The Tribunal's draft decision and analysis are summarised below.

4.7.1 Summary of draft decision

The Tribunal's draft decision is that the outstanding unders and overs account balances will be incorporated into the notional revenue requirements for the 2004-09 regulatory period. The forecast closing balance at 30 June 2004 will be added/ deducted from the notional revenue requirements depending on whether a closing under/over recovery balance is forecast.

Any forecast error resulting from a difference between the actual closing balance as at 30 June 2004 and the forecast closing balance that was incorporated into the notional revenue requirements in the final decision will be added to the transmission overs and unders account.

The amounts to be incorporated into the building block revenue requirements are listed in Annexure 8 of the legal determination. The annual adjustments to the notional revenue requirements for each DNSP are shown on Table 4.15.

Table 4.15 Adjustments to building block revenue requirements for closing unders and overs account balance, 2004/05 to 2008/09 (nominal values)

DNSP	2004/05 $m	2005/06 $m	2006/07 $m	2007/08 $m	2008/09 $m
EnergyAustralia	-20.8	-22.7	-24.9	-27.2	-29.8
Integral Energy	-15.3	-16.7	-18.3	-20.0	-21.9
Country Energy	0.4	0.4	0.4	0.5	0.5
Australian Inland	0.7	0.7	0.8	0.9	1.0

4.7.2 Tribunal's analysis and rationale

The Tribunal decided that the outstanding unders and overs account balance will be added/deducted from the building block revenue requirements for the 2004-09 regulatory period. As part of their submission in response to this draft report, the Tribunal asks each DNSP to provide revised forecasts of its closing balance at 30 June 2004 to be incorporated into the financial modelling for the final determination.

59 The Tribunal has, however, adopted an unders and overs account for transmission revenue which will be treated as a pass-through amount, to account for differences in forecast and realised values each year.

The Tribunal believes its draft decision is intergenerationally equitable, and allows for some mitigation of price increases for most customers in NSW. In the case of outstanding over-recovery balances, both price stability and intergenerational equity suggest that the over-recovery balance should be incorporated into the regulated revenues in the next regulatory period. Returning the over-recovery in the next regulatory period would mean current customers, who have paid the higher-than-required prices, are more likely to benefit from the lower prices under the Tribunal's approach. Deducting this over-recovery balance from the notional revenue requirements in 2004-09 will also reduce expected price increases to a certain degree.

In the case of closing under-recovery balances, intergenerational equity arguments for incorporation of the under recovery amount during the 2004-09 regulatory period are similar as for the over recovery amount. However, in this situation incorporation of the under recovery amount would tend to increase prices during the 2004-09 regulatory period compared to what they would otherwise have been. However, given that the size of Country Energy's forecast closing balance is small, the Tribunal's analysis suggests these price impacts are immaterial. For this reason, it has decided to add any closing under-recovery balance to the notional revenue requirements in the 2004-09 regulatory period.

The Tribunal recognises that its recommendation will mean that Australian Inland's revenue requirements and price path are increased. Practically, the Tribunal's decision on Australian Inland's price path (see chapter 5) means that it will lose much of the benefit of the under-recovery account balance — with much or all of the under-recovery balance simply adding to the revenue shortfall. The Tribunal believes that is justified in Australian Inland's situation in which it has indicated that that it is prepared to accept a lower rate of return as it transitions to more sustainable prices by foregoing some revenue. The Tribunal's view is that if Australian Inland is prepared to forego some revenue during the 2004-09 regulatory period, there is little basis for protecting revenue from the 1999 regulatory period.

The Tribunal's analysis supporting its decision is described in detail in Appendix 9.

The closing unders and overs account balance has been incorporated into the building block revenue requirements evenly across the regulatory period — that is, 20 per cent each year. The amount included in these revenue requirements is also inflated by the nominal rate of return, to ensure that the recovery amount is maintained in net present value terms. The Tribunal believes that this approach is a neutral method of including the outstanding account balance into the building block revenue requirements.

Appendix 9 contains a fuller discussion of the Tribunal's analysis.

5 CALCULATING THE AMOUNT BY WHICH AVERAGE DISTRIBUTION PRICES CAN CHANGE (THE X-FACTORS)

Once the Tribunal has established appropriate values for each building block component for each DNSP (see Chapter 4), it determines the notional annual revenue requirement for each DNSP. Then, taking into account the forecast growth in demand (see Chapter 4), the Tribunal calculates the amount by which each DNSP's average prices can rise or fall in each year of the regulatory period to generate its notional revenue.[60] This amount is represented by the X-factor in the weighted average price cap formula.

This chapter provides an overview of the Tribunal's draft decision on average distribution price changes, and explains key aspects of this decision, including the notional revenue requirements for each DNSP, the approach used to calculate the X-factor for each year, and the decision not to introduce a 'fixed-term' efficiency carryover mechanism. It also outlines the major outcomes of the draft decision for customers, the DNSPs and their owner. The Code requirements specifically considered in relation to this decision are outlined in Box 5.1.

5.1 Summary of draft decision

The Tribunal's draft decision is that average distribution prices may increase annually by the change in CPI plus an 'X-factor' as shown in Table 5.1.

Table 5.1 DNSPs' distribution price outcomes

	Standardised DNSP's proposals[61]		Draft decision	
	DNSP's proposed annual price increase – distribution	NPV of costs not recovered	Annual distribution price increase	NPV of costs not recovered
EnergyAustralia	CPI + 19.4% in 2004/05 then CPI + 1%	0	CPI + 6.5% in 2004/05 then CPI+1.4%	$34m
Integral Energy	CPI + 11.1% in 2004/05 then CPI + 1%	0	CPI + 1.1% in 2004/05 then CPI +1.1%	$17m
Country Energy	CPI + 13.2% in 2004/05 then CPI plus 5.7%	$233m	CPI + 6.5% in 2004/05 then CPI + 2.5%	$182m
Australian Inland	CPI + 15.6% in 2004/05 then CPI + 6.6%	$12m	CPI + 6.5% in 2004/05 then CPI + 2.5%	$21m

The key implication of this decision for customers is in real terms average distribution prices across NSW will increase by a total of 11.6 per cent over the five years, or approximately 2.3 per cent per annum. Distribution prices are typically about 30 per cent of electricity bills.

60 Actual revenue will depend on actual growth and so may be more or less than notional revenues.

61 In developing their pricing proposals then DNSPs have used differing assumptions over a number of parameters. Table 5.1 presents each DNSP proposal based on a common assumption for inflation, and a common split between prescribed and excluded services.

Box 5.1 Code requirements

The Code specifies that the form of economic regulation to applied by the Tribunal is to be of the prospective CPI-X form, or some incentive based variant of CPI-X and may take into account the performance of a DNSP under prescribed and other service standards (cl 6.10.5(a).

5.2 Determining notional annual revenue requirements

As Chapter 4 discussed, the Tribunal determines the amount of revenue each DNSP will need in each year of the regulatory period using a 'building block' approach. However, it does not simply add up the appropriate value of each of building block. As it has noted on many occasions, the Tribunal does not support the application of a procedure-bound methodology in which key decisions on major components of the revenue requirements are made in isolation of other key components. Rather, it considers the interaction of the key components, the impact on the DNSPs profitability, prices and the overall implications for all stakeholders.

For the coming regulatory period, all four DNSPs requested substantial increases in average distribution prices, and proposed a larger increase in the first year followed by smaller increases in the remaining years (Table 5.1). The DNSPs' proposed increases are driven primarily by significant increases in both capital and operating expenditures over the five years to 2009. Their total forecast costs for this period are $7.9 billion (2003 prices). This is 18 per cent higher than their actual expenditure during 2000-2004 regulatory period, which was $6.7 billion (2003 prices).

The Tribunal is concerned by the large levels of both capital and operating expenditures recently undertaken and forecast by the DNSPs. Over the past 7 years, demand for electricity has become increasingly peaky, and DNSPs have responded by increasing network investment to meet peak demand. This has resulted in poor asset utilisation. In the next five years, DNSPs claim that their ageing distribution assets will require either increased maintenance or increased replacement programs. However, the Tribunal believes that there should be opportunities for cost-effective demand management, which could defer some capital expenditures.

It is also concerned that the price increases proposed by Country Energy and Australian Inland would have unacceptable outcomes for stakeholders. These DNSPs proposed cumulative real price increases over the five years of 41 per cent and 49 per cent respectively.

Taking all these factors into consideration, together with its own analysis of the likely impact on DNSPs' profitability and ability to pay dividends to their owner, the Tribunal has determined the notional annual revenue requirements for each DNSPs, as shown in Table 5.2.

Table 5.2 Notional annual revenue requirement for each DNSP, 2004/05 to 2008/09 ($nominal)

$M	2004/05	2005/06	2006/07	2007/08	2008/09
EnergyAustralia					
Operating expenditure	290	305	314	321	327
Return of capital (depreciation)	170	189	209	229	247
Return on capital	288	312	337	360	383
Return on working capital	6	6	6	6	7
Unsmoothed revenue requirements	**755**	**813**	**865**	**916**	**963**
Less correction of previous under/over recovery balance	21	23	25	27	30
Less revenue from non-DUOS sources	5	5	6	6	7
Unsmoothed revenue requirements	**729**	**785**	**834**	**882**	**927**
Smoothed revenue requirements	**726**	**771**	**818**	**872**	**928**
Integral Energy					
Operating expenditure	207	212	220	227	235
Return of capital (depreciation)	127	139	152	164	178
Return on capital	156	168	179	189	200
Return on working capital	3	3	3	3	4
Unsmoothed revenue requirements	**492**	**523**	**553**	**584**	**616**
Less correction of previous under/over recovery balance	15	17	18	20	22
Less revenue from non-DUOS sources	5	5	5	5	6
Unsmoothed revenue requirements	**472**	**501**	**530**	**559**	**589**
Smoothed revenue requirements	**466**	**495**	**525**	**555**	**588**
Country Energy					
Operating expenditure	210	218	226	235	244
Return of capital (depreciation)	132	147	163	179	196
Return on capital	165	176	186	195	204
Return on working capital	4	4	4	5	5
Unsmoothed revenue requirements	**511**	**545**	**579**	**614**	**650**
Less correction of previous under/over recovery balance	0	0	0	0	(1)
Less revenue from non-DUOS sources	6	6	7	7	7
Unsmoothed revenue requirements	**505**	**539**	**573**	**608**	**643**
Smoothed revenue requirements	**462**	**493**	**525**	**561**	**599**
Australian Inland					
Operating expenditure	10	10	10	10	10
Return of capital (depreciation)	3	3	4	4	4
Return on capital	4	5	5	5	5
Return on working capital	0	0	0	0	0
Unsmoothed revenue requirements	**18**	**18**	**19**	**19**	**19**
Less correction of previous under/over recovery balance	(1)	(1)	(1)	(1)	(1)
Less revenue from non-DUOS sources	0	0	0	0	0
Unsmoothed revenue requirements	**19**	**19**	**19**	**20**	**20**
Smoothed revenue requirements	**12**	**13**	**14**	**15**	**16**

Columns may not add due to rounding.

This draft decision is in line with the requirements of the Code, under which the Tribunal must make a judgement in determining the notional revenue requirements and average price changes that meet the principles and objectives of the Code. Specifically, clause 6.10.2 provides for reasonable and well-defined regulatory discretion which permits an acceptable balancing of the interests of owners, users and the public interest.

The Tribunal believes that if it was to allow Country Energy and Australian Inland to increase their average distribution prices to a level that would recover the full value of their cost 'building blocks' (as determined by the Tribunal and discussed in Chapter 4), the outcome would be unacceptable for stakeholders and not meet the objectives of public interest and equity as required under the Code. The Tribunal considers that its draft decision to allow these DNSPs real price increases of 17.6 per cent over next five years represents an acceptable balancing of stakeholder interests and meets the principles and objectives of the Code.

5.3 Calculating the X-factors

Having considered the principles and objectives of the Code, the relative merits of each approach, and the current level of prices, the Tribunal has adopted a hybrid p-nought/straight line revenue smoothing approach in calculating the X-factors for EnergyAustralia, Country Energy and Australian Inland. For Integral Energy it has adopted a straight line smoothing approach.

The Tribunal's issues paper outlined three broad approaches for calculating the amount by which prices need to change to deliver the notional revenue requirement to DNSPs over the regulatory period:

1. **Net Present Value (NPV) approach with single X-factor**: a single X-factor is set to ensure expected revenue equals expected notional revenue requirements (in NPV terms)
2. **NPV approach with P-nought adjustment**: an initial X-factor is set to allow prices to rise sufficiently to ensure expected revenue is equal to notional revenue requirements in the first year. A second X-factor is set for the rest of the regulatory period to ensure expected revenue equals expected notional revenue requirements over the entire regulatory period
3. **Straight line revenue smoothing (glide path):** a single X-factor is set so that prices change smoothly over the regulatory period in real terms to ensure that the expected revenue in the final year of the regulatory period equals the notional revenue requirements in that year.

In addition, Country Energy and Australian Inland proposed a hybrid approach that combines a P-nought adjustment with straight line revenue smoothing. This approach involves two X-factors. The first X-factor is set to deliver a desired P-nought adjustment to prices in the first year of the regulatory period. A second X-factor is set so that prices increase smoothly over the rest of the regulatory period and expected revenue in the final year of the period is equal to the expected notional revenue requirement in that year.

In deciding which approach to use, the Tribunal considered the different implications of each. These include:

- **Price stability.** How volatile will the price path be under this approach? Will customers face large jumps in prices and/or changes in direction (increases followed by falls) during the regulatory period?
- **Revenue recovery.** Does the option allow for recovery of notional revenue requirements? Does it allow a reasonable return on investment?

- **Transitional issues into the regulatory period commencing 2009.** What does the option imply for revenue in the final year of the 2004-09 regulatory period? Is the notional revenue requirement for the final year (2008/09) over or under recovered, potentially requiring a realignment of revenues going into the next regulatory period?
- **Implications for incentives.** What implications are there for incentives for efficient operation and investment? Does the approach allow businesses some form of efficiency carryover?
- **Regulatory consistency.** How does the option compare with the approach in the 1999 determination? What are the implications for the 2009 determination?

Appendix 10 provides an evaluation of each method's likely outcomes, and also provides additional explanation of the different methods of calculating X-factors.

In the 1999 determination, the Tribunal chose to use a revenue glide path approach, so price changes (and therefore the DNSPs' revenue changes) would be spread more evenly over the regulatory period. This approach is also known as the straight line smoothing option. For EnergyAustralia and Integral Energy, the 1999 determination provided for them collecting a higher amount of revenue than their projected total costs provided for in the determination. (However, their actual operating and capital expenditures turned out to be well in excess of those allowed for in the 1999 determination.) For Country Energy and Australian Inland, it resulted in them collecting a lower amount of revenue than their costs.

The Tribunal chose the straight line approach at that time to reduce volatility in annual revenues, reduce the potential for price shocks to customers and provide stronger incentives for the future. It sought to avoid, for the metropolitan DNSPs, a significant reduction in average prices in the first year followed by increases in subsequent years.

In terms of stronger incentives for the future, the Tribunal intended for the straight line approach to act as a form of efficiency carryover mechanism that shared the cost reductions achieved in the 1996-99 regulatory period between DNSPs and customers. Instead of passing these benefits directly onto customers in the first year of the new regulatory period, the Tribunal decided that it was appropriate to smooth the benefit sharing over the entire new regulatory period.

Regulatory consistency is closely related to the incentive properties of the regulatory regime. For example, the straight line approach in the 1999 regulatory period allowed the (metropolitan) DNSPs to keep a share of the then forecast cost reductions. Continuing to use this approach for the coming regulatory period, in the face of cost increases, would signal to DNSPs that the Tribunal is committed to a symmetric treatment of efficiency carryover whereby both cost reductions and cost increases are carried across regulatory period via the straight line approach. To a lesser degree, the hybrid P-nought/straight line approach does this also.

On the other hand, the NPV approaches are distinct departures from the current regulatory period's approach. This could be interpreted as an asymmetric approach that favours DNSPs and weakens the incentive properties of the regulatory regime.

The hybrid P-nought/straight line approach provides a trade-off between incentives and price impacts on the one hand, and the level of revenue recovery on the other hand. It also allows the Tribunal to more easily manage competing outcomes in the overall price review. These outcomes include the financial risks facing the business and the need to ensure an adequate revenue base for expenditures necessary to maintain service standards.

On balance, the Tribunal has decided for this draft determination to use the hybrid P-nought/straight line approach for three of the DNSPs—EnergyAustralia, Country Energy and Australian Inland – as it believes that this approach is the most reasonable in the current circumstances. As indicated section 5.2 , the Tribunal believes that if it was to allow Country Energy and Australian Inland to increase their average distribution prices to a level that would recover the full value of their cost 'building blocks' the outcome would be unacceptable for stakeholders and not meet the objectives of public interest and equity as required under the Code. For Country Energy and Australian Inland the hybrid P-nought/straight line approach does not provide for the matching of expected revenues and the expected notional revenue requirements in the 2008/09.

For Integral Energy, the Tribunal has decided for this draft determination to use the straight line revenue smoothing approach. The expected profile of Integral Energy's notional revenue requirements is such that the Tribunal did not consider that a P-nought adjustment was required. This decision continues the Tribunal's approach to efficiency carryover established in its 1999 Determination.

Using these approaches, the Tribunal then calculated the amount by which each DNSP's average distribution prices would need to increase to recover the notional revenue requirement shown in Table 5.2, given the forecast growth in network demand as recommended in section 4.1.

5.4 No 'fixed-term' efficiency carryover mechanism

The Tribunal's draft decision is not to introduce a fixed-term efficiency carryover for the 2004 regulatory period.

In addition to continuing the existing 'straight line or glide path' approach to efficiency carryover (discussed in 5.3 above), the Tribunal also considered introducing a 'fixed-term' efficiency carryover mechanism, similar to the one adopted by the Essential Services Commission in Victoria. With this kind of mechanism, DNSPs would be allowed to retain the benefits of any efficiency out-performance for a *fixed* number of years, irrespective of when these gains were realised during the regulatory control period.[62]

A fixed-term efficiency carryover mechanism can strengthen incentives for efficiency in two main ways:

- First, it removes the incentive that exists towards the end of the regulatory period for DNSPs to defer making out-performance efficiencies until the *next* regulatory period, so they can retain the benefits of that out-performance for the full duration of a regulatory period. Removing this incentive could result in the benefits of efficiency out-performance being passed on to customers faster than they otherwise would.

62 Such a mechanism could also require DNSPs to bear the costs of any efficiency under-performance for the same fixed number of years.

- Second, depending on the length of the retention period adopted, it allows DNSPs to retain the benefits associated with efficiency out-performance for a longer time (*on average)* than they otherwise would, thereby increasing their incentive to make efficiencies.

However, it can also have disadvantages. These include:

- Increasing information costs. Establishing and running a fixed-term efficiency carryover mechanism is a relatively information-intensive process. It requires DNSPs to provide details of all efficiency gains made over and above those assumed at the regulatory review, for each year of the regulatory period. The regulator then has to assess this information to ensure that it is correct.
- Establishing endogenous efficiency gains/losses. Strictly speaking, the fixed-term efficiency carryover mechanism should apply only to endogenous efficiencies (ie, those within the control of the DNSP). (Rewarding a DNSP for efficiency gains arising due to external factors, rather than due to any effort on its part would be potentially unfair to customers, and would have no positive impact on incentives, as DNSPs cannot control exogenous costs.) This would require DNSPs to separate endogenous efficiencies from exogenous ones. In practice, this can be very difficult, and can involve significant administrative costs. Because of these difficulties, the ESC Victoria decided to assume that all efficiency gains or losses are endogenous, and to assume that if any exogenous efficiency gains/losses do occur, these gains and losses will balance each other out over time. The Tribunal notes that such a solution is only possible in the case of a symmetric efficiency carryover mechanism (where both efficiency gains and losses are carried over).
- Reducing clarity and transparency. As DNSPs have emphasised, the introduction of a fixed-term efficiency carryover mechanism would add an extra layer of complexity to the price control formula. Some DNSPs have argued that introducing a fixed-term efficiency carryover mechanism at the same time as moving to a weighted average price cap would involve too much complexity, and be too confusing for both DNSPs and customers. The Tribunal notes that DNSPs can only respond to incentives when these incentives can be readily understood.

Given these disadvantages, the Tribunal believes that for the 2004-09 regulatory period, the costs associated with establishing a fixed-term efficiency carryover mechanism would exceed the benefits—particularly given its draft decision to continue its existing approach to efficiency carryover (in the form of the straight line revenue smoothing approach, albeit with a hybrid P-nought straight line approach for some DNSPs, as described above).

However, the Tribunal notes the strong theoretical arguments for a fixed-term efficiency carryover mechanism. It also considers that because assets are to be rolled into the regulatory asset base using regulatory depreciation as opposed to actual depreciation, the case for introducing a fixed-term efficiency carryover mechanism at the next review is stronger. The Tribunal therefore intends to conduct further work during the 2004 review period, to assess the case for introducing a forward-looking fixed term efficiency carryover mechanism from 2009. However, it does not intend to introduce a backward-looking fixed-term efficiency carryover mechanism in 2009.

5.5 Outcomes for customers

These X-factors are expected to result in the average cumulative real distribution price increases over the five years to FY2009 (from 03/04 prices) shown in Table 5.3.

Table 5.3 Total distribution price increases (in addition to inflation) over the five years FY2009

Distribution Network Service Provider	Real Cumulative Price Increase
EnergyAustralia	12.6%
Integral energy	5.6%
Country Energy	17.6%
Australian Inland	17.6%

The cumulative increases in final customer electricity bills will be less than this, because distribution charges form somewhere between 20 to 40 per cent of these bills, depending on which network and retail tariffs customers are on.

Price increases in 2004/05

A typical residential customer living in Sydney[63] and using 7,500 kWh pa would see nominal price increase in their final bill of approximately $46 pa less than a $1 per week.[64] Similarly, a residential customer in regional NSW using 7,500 kWh pa would see nominal price increase in their final bill of approx $58 pa or approximately $1.10 per week.[65]

Table 5.4 Impact of price increases for typical customers of EnergyAustralia[66] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential					
Low usage (3500 kWh)	156	425	164	449	24
Typical usage (7500 kWh)	285	825	301	871	46
Business					
40 MWh	1,391	4,304	1,568	4,714	410
80 MWh	2,655	8,536	2,994	9,349	813

63 Being a customer of EnergyAustralia network

64 This assumes no distribution price restructuring and that all components of the final electricity bill (distribution, transmission and retail) increase for residential customers by 3 per cent real. Prices are ex-GST. Under the weighted average price cap DNSPs have considerable discretion as to how much individual tariffs can change subject to them complying with the overall price control formula and price limits.

65 Ibid.

66 Ibid.

Table 5.5 Impact of price increases for typical customers of Integral Energy[67] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential					
Low usage (3500 kWh)	217	488	224	512	24
Typical usage (7500 kWh)	389	936	403	982	46
Business					
40 MWh	1,610	4,352	1,670	4,550	198
80 MWh	3,154	8,560	3,271	8,950	390

Table 5.6 Impact of price increases for typical customers of Country Energy[68] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential - Urban					
Low usage (3500 kWh)	241	547	254	578	31
Typical usage (7500 kWh)	414	1,039	437	1,097	58
Residential - Rural					
Low usage (3500 kWh)	302	690	319	728	38
Typical usage (7500 kWh)	523	1,242	553	1,311	69
Business					
40MWh	2,459	5,756	2,773	6,304	548
800 MWh	4,803	11,328	5,416	12,407	1,079

Table 5.7 Impact of price increases for typical customers of Australian Inland[69] ($nominal)

Customer type	2003/04 distribution bill	2003/04 retail bill	2004/05 distribution bill	2004/05 retail bill	Increase in annual retail bill
Residential - Urban					
Low usage (3500 kWh)	147	461	156	487	26
Typical usage (7500 kWh)[1]	265	910	280	960	51
Residential - Rural	277	473	293	499	26
Low usage (3500 kWh)	462	1,135	488	1,198	63
Typical usage (7500 kWh)					
Business					
40 MWh	2,167	5,516	2,443	6,041	525
80 MWh	4,247	10,848	4,788	11,881	1033

Note: Rows may not add due to rounding.

67 Ibid.
68 Ibid.
69 Ibid.

If no tariff restructuring were to occur, then similar annual price increases are likely to continue for the rest of the next regulatory period. Tariff reform however may lead to different customer impacts. EnergyAustralia and Integral Energy have proposed introducing an inclining block network tariff for their small business and residential customers. If this were introduced those customers who consume small amounts of electricity may see smaller increases whereas those customers that consume greater amounts may see price increases greater than those indicated above.

5.6 Outcomes for DNSPs and their owner

The Tribunal expects that these price movements will allow DNSPs to pay total dividends to the State Government (which owns all four DNSPs) over the five years of $598m in real terms.

Forecast returns for each DNSP are presented in Table 5.8. These forecasts are based on 70 per cent of after tax profits paid as dividends.

Table 5.8 Forecast dividends for the 5 years to FY2009 (2003/04 prices)

$M	2004/05	2005/06	2006/07	2007/08	2008/09	Total
EnergyAustralia	67	64	65	69	77	342
Integral Energy	32	34	33	34	36	169
Country Energy	14	15	16	18	20	82
Australian Inland	0	1	1	1	2	5
Total	**113**	**113**	**114**	**123**	**135**	**598**

Columns may not add due to rounding.

NSW Treasury targets investment grade rating (= BBB+) for its state owned businesses. The Tribunal believes that its draft pricing decision will not adversely affect the DNSPs' financial position. Its analysis and financial modelling indicates that the DNSPs will be able to maintain or improve their financial position, earn a reasonable rate of return and pay reasonable dividends. All four DNSPs can maintain their investment grade rating for all of the key financial indicators.

Financial outcomes for each of the DNSPs are presented in appendices 13 to 17. Table 5.9 provides a summary of the outcomes of this draft determination for each of the DNSPs.

Table 5.9 Projected outcomes for the 5 years to 30 June 2009 (2003/04 prices)

$M	EnergyAustralia	Integral Energy	Country Energy	Australian Inland
NPV of costs foregone	34	17	182	21
Cumulative real distribution price increase	12.6%	5.6%	17.6%	17.6%
Average real distribution price as at 30 June 2009 (c/kWh)	2.46	3.15	4.76	2.96
Total dividends	342	169	82	5
Change in net debt (from 2003)	236	269	163	NA[1]
Overall projected NSW Treasury rating in 2009	BBB+	A+	A	NA[1]

Notes
1. NA as Australian Inland is in a net cash position.
2. Projected outcomes are based on actual gearing.

The majority of the financial ratings are affected by whether the DNSPs' forecast actual gearing or notional gearing is used. The ratings are presented in the appendices for both actual and notional gearing. The actual gearing is a matter for government as owner.

6 PROVIDING INCENTIVES FOR SERVICE QUALITY

6.1 Introduction

Several of the issues papers the Tribunal released for this review emphasised its desire to establish a direct link between price and service quality as part of the 2004 determination for distribution prices.[70] This issue is particularly important, given the large amounts of capital expenditure the DNSPs have proposed for the coming regulatory period, a substantial proportion of which is to be spent on network maintenance, plus some on service quality improvement.

The arguments for linking prices to service quality were discussed in the May 2003 Service Quality Issues Paper. In brief, a profit-maximising monopoly business subject to CPI-X incentive regulation can have a theoretical incentive to reduce costs by reducing service quality. Introducing a more direct link between allowed expenditures (and therefore prices) and the quality of the services delivered for that expenditure is a way of avoiding this incentive. Where a CPI-X approach is being applied, it is also an important consideration of customers to ensure they are getting value for their higher charges.

The Tribunal's draft decision on the most appropriate way to link prices to service quality for the 2004 regulatory period, the key issues and options the Tribunal considered, and the analysis that underpins the decision are explained below. The Code requirements specifically considered in relation to this decision are outlined in Box 6.1

6.2 Draft Decision

The Tribunal's draft decision is to introduce an integrated package of measures to provide incentives for service quality, consisting of the following components:

- **an S-factor for service reliability measures, initially in a paper trial from July 2004, with the introduction of some monetary incentives in July 2006**
- **the collection and publication of service standards performance statistics, covering service reliability measures, quality of supply measures, and customer service measures**
- **subject to Ministerial approval, Guaranteed Customer Service Standards covering service reliability, quality of supply, and some customer service measures.**

Box 6.1 Code requirements

In setting the weighted average price cap, the Code directs the Tribunal to have regard to the service standards applicable to the DNSP and any other standards imposed on a DNSP under a regulatory regime administered by the Tribunal with the agreement of the relevant user (cl 6.10.5(d)(2)).

70 IPART, *Providing Incentives for Service Quality in NSW Electricity Distribution – An Issues Paper*, May 2003 and IPART, *Regulatory Arrangements for the NSW Distribution Network Service Providers from 1 July 2004 – Issues Paper*, November 2002.

6.3 Options and issues considered

In making its draft decision, the Tribunal considered three main options for creating incentives for service quality as part of the distribution price determination. It also considered the way in which these incentive mechanisms would interact with the incentives created by the Guaranteed Customer Service Standards and operating statistics related to service quality.

6.3.1 Options for linking price and service quality

One option the Tribunal considered was to use information submitted by the DNSPs as part of the review process. This information sets out the levels of service reliability that the DNSP proposes to achieve for its nominated levels of operating and capital expenditure. The Tribunal could compare these proposed levels with the service reliability outcomes achieved during the regulatory period. It could then adjust the DNSP's allowed revenues at the next regulatory reset if it believed the DNSP had failed to deliver a level of service quality consistent with its allowed expenditures.

Several DNSPs opposed this option, pointing out that it amounted to a 'penalty only' regime, and objecting to any 'retrospective' adjustments to allowed revenue. The Tribunal acknowledges the 'penalty only' nature of such a regime. It also considers that the incentives it would create may not be as strong as those created by other options.

A second option considered was to use performance monitoring and publication. Performance monitoring involves the regulator collecting data on service quality, and using it to monitor a DNSP's performance over time and, where appropriate, allowing performance comparisons between DNSPs. The regular collection of these data can further strengthen the incentives to improve service quality that this creates.

The third option the Tribunal considered was to introduce an 'S-factor'. An S-factor is an extra component that is added to the price control formula, and which allows a DNSP's price cap to be adjusted (either upwards, downwards or both) within a regulatory period to reflect its service quality performance relative to certain pre-specified levels.[71] The S-factor can take a number of different forms, and can use many different measures of service quality, and different levels of data aggregation. The Tribunal believes that this option would create strong incentives for DNSPs to maintain and improve service quality.

The key issues it considered in relation to establishing an S-factor include:

- which service quality measures should be included within the S-factor
- whether the impacts of any events should be excluded when assessing a DNSP's service quality performance
- the precise type of mechanism/formula to be used
- whether the S-factor should be symmetric (ie should include both penalties and incentives)
- the timing of any price adjustments resulting from the S-factor

71 The S-factor therefore operates in the same way as the X-factor in the basic CPI-X formula. That is, CPI-X becomes CPI-X+S (depending on the form of the scheme, S could be positive, negative or either).

- whether deadbands or rolling averages should be used to smooth performance variations
- what the appropriate 'target' levels are (levels on which the S-factor would be based)
- what the incentive rates should be (the basis for penalty/reward setting)
- whether there should be caps on the amount of revenue exposed.

The Tribunal considered how to take existing data constraints and expected data improvements into account when developing the S-factor, both in the short and medium term. It commissioned PB Associates to examine the availability and accuracy of the DNSPs' reliability data, and its suitability for use in any S-factor for the 2004-09 regulatory period.[72] The results of this study and subsequent information provided by stakeholders indicate that there are currently significant data constraints at lower levels of aggregation, and some limitations to data accuracy. The PB report noted that data accuracy and availability is improving, but that it will take DNSPs some time to complete these improvements.

6.3.2 Interactions with Guaranteed Customer Service Standards and Operating Statistics

As well as examining these three options, the Tribunal considered the interactions between providing incentives for service quality as part of the price determination, and the current Section 9 Review of Guaranteed Customer Service Standards and Operating Statistics. Guaranteed Customer Service Standards are another way of creating incentives for service standards improvements, particularly when accompanied by a payment to customers when a standard is not met. Operating statistics provide a key source of data for monitoring and publication.

6.4 Tribunal's analysis and rationale

The Tribunal concluded that a combination of introducing an S-factor that focuses on service reliability only, and monitoring and publishing DNSP's performance against a wider range of service quality measures is at present the most effective way of providing strong incentives for DNSPs to improve their service quality. This decision, and the way in which the S-factor will be established, is explained in detail below.

6.4.1 Service quality performance monitoring and publication

The Tribunal's draft decision is that a range of DNSP service quality performance statistics be collected and published. The Tribunal's draft decision is that this be done through the operating statistics recommendations included in the Tribunal's Review of Guaranteed Customer Service Standards and Operating Statistics.[73]

72 *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability* – Prepared for IPART by PB Associates, October 2002 (released on IPART's website July 2003).

73 See the Tribunal's *Review into Guaranteed Customer Service Standards and Operating Statistics – Draft Recommendations* – published at www.ipart.nsw.gov.au on 7 October 2003.

The Tribunal believes it is useful to collect and publish service quality performance data for all DNSPs in a common format for a number of reasons. First, it provides the regulator and other interested parties (including customers, DNSPs themselves, and other stakeholders) with a source of information that can be used to monitor DNSP service quality performance. For example, this information might be used to identify any worsening performance trends, allowing these areas to be targeted for improvements. If common definitions are adopted, some performance comparisons between DNSPs might also be made (both within NSW and with distributors in other jurisdictions[74]).

Second, where these data are published, the DNSP is provided with an incentive to avoid poor service quality, to avoid any adverse publicity that may be associated with a relatively poor performance.

Third, data collection, monitoring and publication provide incentives for service quality over a wider range of service quality measures than is possible using an S-factor alone. For example, including a very large number of service quality measures within an S-factor would make it much more complicated. In addition, it is difficult to include certain measures in an S-factor, because quantitative data are not available or sufficiently accurate – for example, this applies to many customer service and quality of supply performance measures, which can be difficult or very costly to measure directly, but for which complaints data might be monitored and published.[75]

In addition, collecting and publishing service quality data will not be difficult to do, as DNSPs already collect a considerable amount of performance data (much of which is already collected and published by the MEU and/or the Tribunal). This will limit the *additional* cost to DNSPs associated with this decision.[76]

The Tribunal notes the close interconnections between this decision and the Section 9 review of Guaranteed Customer Service Standards and operating statistics that it is currently conducting. The Tribunal's Draft Recommendations to the Minister for this review propose that operating statistics for electricity distributors be collected and published for a range of measures including service reliability, quality of supply, and customer service measures.[77]

The Tribunal sees advantage in considering Guaranteed Customer Service Standards and operating statistics, and measures to link prices to service quality under the regulatory review as two parts of an 'integrated package' of incentives for service quality. A copy of the Tribunal's Draft Recommendations to the Minister on Guaranteed Customer Service Standards and Operating statistics can be found on the IPART website.

---

74 The Tribunal notes the value of the development of the Steering Committee on National Regulatory Reporting Requirements (SCNRRR) National Regulatory Reporting guidelines in this regard.

75 Examples include voltage fluctuations at the individual customer level, and the quality of telephone services.

76 Details of the data currently collected and published by the MEU can be found in its annual Electricity Network Performance Report. Details of data currently published by the Tribunal can be found in its annual electricity Price and Services report, and its annual Electricity Distribution and Retail Licences Compliance Report. Details of the Tribunal's proposed changes to current operating statistics collection can be found in its Review into Guaranteed Customer Service Standards and Operating Statistics Draft Recommendations.

77 Further details can be found in the Tribunal's *Review into Guaranteed Customer Service Standards and Operating Statistics – Draft Recommendations* – published on www.ipart.nsw.gov.au on 7 October 2003.

The Tribunal also notes that the MEU collects and publishes further data, including SAIFI, SAIDI and CAIDI data (for the DNSP networks as a whole, for the worst performing feeders and, from 2003, by feeder types) which also provides very useful information.[78] Use of these measures is discussed further in the section on S-factors below.

6.4.2 Introducing an S-factor

The Tribunal's draft decision is that an S-factor be introduced from July 2004 based on service reliability data only, running in 'paper trial' form for the first two years of the period, and with monetary incentives from July 2006 for aggregate reliability data only.

The Tribunal believes an S-factor should be introduced from 2004 for two main reasons. First, although the collection and publication of service quality data can provide incentives to avoid poor service quality performance, these incentives are of the 'moral suasion'/avoidance of poor publicity type, rather than *monetary* incentives. The Tribunal considers that the provision of monetary incentives would substantially strengthen the overall incentives.

Second, the Tribunal believes it is important that prices are directly liked to service quality. As noted already, this is particularly important given the large amounts of capital expenditure the DNSPs propose over the coming period, a significant proportion of which is expected to be spent on maintaining (and in some cases improving) system reliability. It considers that the S-factor (as set out below) is a transparent way of achieving this link.

Over recent months the Tribunal has consulted with key stakeholders on the ways in which an S-factor might work. Most stakeholders expressed support for an S-factor of some form – either with monetary incentives from 2004, or initially in the form of a paper trial, moving to monetary incentives at a later date. Country Energy expressed opposition to an S-factor.

The reasons for the Tribunal's decision to base the S-factor only on service reliability data are discussed later in this section.

The Tribunal has decided to adopt a paper trial for the first two years of the regulatory period (ie monetary incentives from 2006/07 only) for two main reasons. First, some stakeholders have expressed concerns regarding data accuracy. The Tribunal notes that the DNSPs are currently undertaking programmes to improve data accuracy and availability. The PB report[79] estimated that these programmes should be complete for all DNSPs by 2005/06. Although some DNSPs will not have fully completed their data improvement programmes in 2004/05[80] the Tribunal has had to consider the trade-off between data accuracy concerns and further delays to the implementation of monetary S-factors, and the implications for incentives to deliver service quality for customers. The Tribunal also sees significant value in introducing some limited monetary incentives before the next review, to allow lessons to be learned and to allow an easier transition to a potentially more extensive scheme from 2009.

---

78 SAIDI is the System Average Interruption Duration Index (total number of minutes off supply experienced by a customer on average), SAIFI the System Average Interruption Frequency Index, and CAIDI the Customer Average Interruption Duration Index.

79 *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability* – Prepared for IPART by PB Associates, October 2002 (released on IPART's website July 2003).

80 2004/05 data would be used in a 2006/07 S-factor.

Second, the Tribunal notes that were it to adopt a monetary S-factor from 2004, due to the lags in collecting and verifying data, this would require data from 2002/03 to be used in the S-factor calculation. This would imply service quality performance from the *current* regulatory period being used to determine S-factors in the *coming* regulatory period – the Tribunal considers this inappropriate as such an approach was not signalled to DNSPs at the last review.

The Tribunal has decided to only apply monetary incentives to performance on the network as a whole as opposed to, for example, performance on each feeder type.[81] The reason for the Tribunal's decision is that the accuracy of feeder type data is currently considered to be insufficient for use in a monetary S-factor.[82]

Choice of measures

The Tribunal's draft decision is that the S-factor will initially include reliability measures only (based on SAIDI). It may be appropriate to expand the S-factor to cover a wider range of service quality measures at the next review, if data availability and accuracy have improved sufficiently.

Stakeholders have emphasised, and the Tribunal agrees, that the measures of service quality included in any S-factor should reflect what is important to customers. Although a survey of electricity customer preferences covering all the DNSP areas in NSW has not recently been undertaken, the Tribunal considers that there is enough existing information from other sources for it to be confident that service reliability is of key importance to the vast majority of customers.

In addition, the measures included in an S-factor must be quantifiable, using available data. DNSPs have been collecting reliability data using SAIDI, SAIFI and CAIDI measures for a significant amount of time, using common basic definitions.[83] Other measures of service quality – such as some aspects of quality of supply and customer service – are not so easily quantifiable or measurable, and so are less-well suited to an S-factor at this stage. In the future the S-factor might be expanded to include other measures of service quality as data availability improves.

The Tribunal considers it appropriate to base the S-factor on SAIDI alone at this stage for the following reasons.

- SAIDI, the total average minutes off supply experienced by an individual customer in a single year, is affected by both the frequency of interruptions (SAIFI) and the average duration of those interruptions (CAIDI). SAIDI is therefore able to capture both of these aspects of service quality.
- Because SAIFI affects SAIDI, an S-factor that was based on these two measures would implicitly be attaching greater weight to the frequency of interruptions than the duration of interruptions. The Tribunal considers that there is insufficient evidence to

---

81 CBD Feeders, Urban Feeders, Rural Short Feeders and Rural Long Feeders.

82 See for example - *Review of NSW Distribution Network Service Provider's Measurement and Reporting of Network Reliability* – Prepared for IPART by PB Associates, October 2002 (released on IPART's website July 2003).

83 See *National Regulatory Reporting for Electricity Distribution and Retailing Businesses* – Utility Regulators Forum, March 2002. The issue of which definition of excludable events (ie events whose impact on reliability are not included in the statistics) should be adopted is considered later in this section.

conclude that customers are significantly more concerned about the frequency of interruptions compared to the duration of interruptions.

- The Tribunal is keen to avoid any perverse incentives that might be created by including CAIDI with SAIFI and SAIDI in the S-factor. For example, if the rate at which a DNSP reduces the frequency of interruptions exceeds the rate at which it reduces the total duration of interruptions, CAIDI will increase. If CAIDI was included in the S-factor, this could lead to a DNSP being penalised for rising CAIDI figures despite it making improvements in terms of both the frequency and total duration of interruptions.
- While momentary interruptions - for example, as measured by the Momentary Average Interruption Frequency Index (MAIFI) - can present a significant service quality issue for some customers, data on momentary interruptions is currently very limited, and comprehensive statistics are unlikely to be available for some time.

Excludable events

The Tribunal's draft decision is that the current Steering Committee on National Regulatory Reporting Requirements (SCNRRR) Normalised Distribution Network (unplanned) definition of SAIDI should be used for the S-factor. Outages excluded from this definition should be excluded from the SAIDI statistics for purposes of the S-factor.

In general, stakeholders agree that where events are very clearly outside the control of the DNSPs, *and* where the DNSPs were completely unable to mitigate the impacts of these events, they should be excluded from the S-factor statistics. They also broadly agree that this means that events arising due to transmission outages, insufficient generation or directed load shedding (including directed load shedding by customers) should be excluded.

Some stakeholders also felt that the impact of significant natural events (such as major bushfires and storms) and major events caused by third parties (such as accidents) should be excluded. The DNSPs for example, argued that the extent to which they can mitigate the impacts of these events on reliability statistics is very limited.

The Tribunal agrees that some exclusions should be permitted. It also agrees that a major natural or third party event, like a large bushfire, can leave repair crews stretched and DNSPs genuinely limited in the extent to which they can minimise outage times. It also acknowledges that very rare events of an exceptional nature may fall outside reasonable and efficient planning guidelines. However, the Tribunal believes excluding *all* of the reliability impacts associated with natural or third party events would limit the incentive for DNSPs to mitigate these impacts to the extent possible.

The Tribunal also believes that criteria for exclusions need to be tightly defined, so there is no ambiguity about what events might qualify for exclusion. Such ambiguity could lead to extra administrative costs for DNSPs and the regulator, and the possibility of disputes and uncertainty.

The Tribunal also considers that momentary interruptions should be excluded from reliability statistics for the S-factor. The Tribunal notes that the ability of DNSPs to measure momentary interruptions is currently limited and that SCNRRR recommended that the collection and publication of momentary interruptions be optional.

In addition, it believes it is appropriate to exclude planned interruptions from the S-factor reliability statistics. If planned interruptions were included, this might create a perverse incentive, discouraging DNSPs from conducting maintenance work that requires supplies to be interrupted.

Given these considerations, the Tribunal has decided that the current SCNRRR '"Normalised Distribution Network, unplanned"' definition be used for exclusions. Under this definition, the events to be excluded are:

- transmission outages
- directed load shedding

and outages which:

- exceed a threshold SAIDI impact of 3 minutes *and*
- are caused by exceptional natural or third party events *and*
- the DNSP cannot reasonably be expected to mitigate the impact of the event on interruptions by prudent asset management.

That is, events other than transmission outages and directed load shedding must meet all of the latter three conditions to qualify as an excludable event. Momentary interruptions and planned interruptions (of which customers have been notified) are also excluded.

EnergyAustralia and Country Energy expressed opposition to the use of the "three minutes on SAIDI" threshold for determining excludable events.[84] However, the Tribunal considers that it would be difficult to find an alternative measure that was similarly objective and transparent. It believes adopting the SCNRRR definition, with which DNSPs are already familiar and which has been recommended for consistent use across Australian jurisdictions, should provide a clear guide as to what events should be excluded. This should minimise the scope for confusion, and minimise administrative costs for DNSPs and the regulator alike.

The Tribunal also hopes that by adopting a measure which excludes the events described above, the year to year variability observed in reliability performance will be somewhat reduced (although not completely removed), thereby reducing risk for the DNSPs.

The Tribunal will also collect and publish data on *overall* sustained interruptions (as collected by the MEU), using the SCNRRR definitions.[85]

84 EnergyAustralia and Country Energy have argued that the nature of their networks mean that natural events such as storms can arise which may not lead to a 3 minute or more impact on SAIDI, but which may still be significant in terms of their impact on these particular networks.

85 In addition to the SCNRRR 'Normalised Distribution Network' (unplanned) definition, data are collected to the SCNRRR 'Overall' definition, which includes all sustained interruptions, and to the 'Distribution Network' definition, which excludes interruptions arising due to transmission outages and directed load shedding, but which includes all other interruptions (planned and unplanned). See *National Regulatory Reporting for Electricity Distribution and Retailing Businesses* – Utility Regulators Forum – March 2002.

Type of mechanism

The Tribunal's draft decision is that the S-factor mechanism be added to the weighted average price cap formula in the form:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} * q_{ij}^{t-1}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} * q_{ij}^{t-1}} \leq 1 + \Delta CPI \ + X_{t+1} + S_{t+1}$$

where

p_{ij}^{t+1} is the proposed price for component j of relevant prescribed distribution service charge i in the coming year (year $t+1$)

p_{ij}^{t} is the price currently being charged by the DNSP for component j of relevant prescribed distribution service charge i (year t)

q_{ij}^{t-1} is the audited quantity of component j of relevant prescribed distribution service charge i that was charged by the DNSP in the previous year (year $t-1$)

X_{t+1} is the real change in average prices for the DNSP from year t to year $t+1$ of the regulatory control period as determined by the Tribunal

ΔCPI is the percentage change in the Consumer Price Index over the 12 month period from January of the previous year (year $t-1$) to December of the year t, compared to the preceding 12 month period.

and where S_{t+1} is given by:

$$S_{t+1} = \sum_{f} I_f * (T_{f,t-1} - A_{f,t-1})$$

where:

S_{t+1} is the change in price from year t to year $t+1$, for the DNSP in question

I_f is the incentive rate expressed as an adjustment to the weighted average price cap, per minute of SAIDI, for network type f, where f is total network, CBD feeders, urban feeders, rural short feeders or rural long feeders[86]

$T_{f,t-1}$ is the DNSP's SAIDI performance target for network type f in year $t-1$[87]

$A_{f,t-1}$ is the DNSP's actual SAIDI performance for network type f in year $t-1$

86 Where the definition of each feeder type is consistent with the SCNRRR definition.

87 Year $t-1$ has to be used as data for year t will not be available at the time of the price adjustment.

The Tribunal believes that the S-factor should be based on the gap between target and actual performance for each year of the regulatory period. It considers this more appropriate than, for example, having an S-factor that takes into account the extent to which the size of the gap between target and actual performance has changed from year to year. Its reasons include:

- Simplicity – the Tribunal considers that a simple formula will enhance transparency for DNSPs and customers alike, and ensure that DNSPs understand the incentive properties of the scheme. Simplicity is also particularly important at this stage, given that the S-factor is being introduced for the first time in NSW electricity distribution in the next regulatory period.[88]
- Incentives – the Tribunal wishes to ensure that if a DNSP exceeds its target in two successive years by an equal amount in each year, it is rewarded with incentive payments for beating that target in both years, rather than only being rewarded when it beats the target in one year by more than it did in the previous year.

Where a paper trial applies, the incentive rate would be set to zero, but the other aspects of the formula would continue to operate (that is, targets would still be set for each network type, and the gap between targets and actual performance measured and noted for each network type). For example, for the first two years of the paper trial, ***I*** would be set to zero for all DNSPs and all network types. In the last three years, ***I*** would be set to zero for CBD, urban, rural short and rural long feeder categories, but would be non-zero for the network as a whole category.

Symmetry

The Tribunal's draft decision is that the S-factor be symmetric in design, allowing an increase in the average weighted price cap where service quality improves, and a decrease where service quality declines. Caps on revenue exposed would also be symmetric.

Most stakeholders agree that a symmetric S-factor is appropriate. The Tribunal notes that in some cases, a 'penalty only' S-factor may be appropriate, particularly where there is evidence that customers do not want any further increments to service quality. While there is some evidence[89] that most customers may be broadly satisfied with current levels of reliability, the Tribunal believes that this issue can be reflected in choice of target levels and incentive rates, both of which are discussed later in this chapter.

Country Energy, while not in favour of an S-factor, argued that were an S-factor to be introduced, it should only involve reward payments, and no penalty payments, on the grounds that penalty payments would result in less money being available for maintenance and repairs. However, the Tribunal argues that such a system would fail to provide any monetary incentive to ensure that service quality does not decline. Indeed it could be argued that DNSPs would be better off if they reduced maintenance expenditure and allowed service quality to fall, rather than spending more money and keeping service quality constant. The Tribunal also considers that if penalties do apply, they should be paid by reducing dividends rather than by cutting the maintenance budget allowed for in distribution prices, and therefore for which customers will be paying.

---

88 It may be appropriate to refine the scheme at future regulatory reviews, once all stakeholders have greater familiarity with the workings of an S-factor.

89 For example customer survey information provided to IPART by Integral Energy as part of their 2003 Network Review submission.

The Tribunal considered whether 'symmetry' should involve equal incentive rates for a unit increase in reliability and for a unit decrease in reliability, or whether it should involve *higher* incentive rates for reliability increases to reflect the fact that it may cost a DNSP more to achieve a reliability increase than it would save by allowing an equivalent reliability decrease. This approach has been taken by, for example, the ACCC,[90] which noted that as service reliability reaches high levels, improving it further involves greater costs per unit of improvement than would be the case for lower levels of reliability.

The Tribunal acknowledges that as reliability reaches high levels, the costs of delivering further improvements may be greater than at lower levels of reliability. However, the Tribunal has insufficient information to determine the nature of this relationship, and whether/to what extent DNSPs may have reached this point. While levels of reliability are good on large parts of the DNSPs networks, there are some areas of reliability where performance is less strong. The Tribunal has noted that it is particularly keen to provide incentives to improve service quality on the worst performing parts of the network, to the extent that information constraints allow.

The Tribunal also considers that having different incentive rates for service quality improvements and service quality reductions would introduce a further layer of complexity. Given the relatively limited nature of the monetary S-factor proposed for the coming regulatory period, and the fact that the S-factor is new, the Tribunal does not think that it is appropriate to apply different incentive rates for reliability increases compared to reliability decreases at this stage. However, it is an issue that could be revisited at future regulatory reviews as DNSPs become more familiar with the workings of an S-factor, and if more supporting information is available.

Timing of price adjustments

The Tribunal's draft decision is that price adjustments be made annually, as part of the general annual price adjustments under the weighted average price cap formula.

The Tribunal favours an S-factor that adjusts prices for changes in service quality relative to targets on an annual basis for electricity distribution, as it considers that this provides the most immediate incentives for DNSP management to improve service quality.

While some respondents to consultation supported annual price adjustments, others favoured the 'adding up' of annual S-factor performance results to make a single price adjustment at every regulatory review, arguing that this would smooth any "natural" year to year variability in reliability performance. However, the Tribunal is concerned that this would reduce the incentive power of the S-factor. The Tribunal also notes that other measures have been included in the S-factor mechanism to try and minimise DNSP risk associated with year to year 'natural' variability in reliability performance, such as capping of the total amount of revenue exposed (discussed later in this chapter), and excluding the impact of major natural/third party events.

90 ACCC, *Draft Decision – Statement of Principles for the Regulation of Transmission Revenues – Service Standards Guidelines*, May 2003.

Rolling averages and deadbands

Given current data constraints, and the relatively limited nature of the S-factor proposed for the 2004-09 period, the Tribunal's draft decision is to not incorporate rolling averages or deadbands into the S-factor at this stage.

Country Energy and Australian Inland emphasised the 'natural' variability that occurs in their performance statistics from year to year. They argued that this natural variability will make it difficult for them to be sure of meeting their reliability targets in any single year, and that some form 'smoothing' of these effects should be included in any S-factor. The Tribunal considered two options for doing this – the use of rolling averages and deadbands.

By taking a rolling average (for example the average of performance over the past three years, as opposed to the performance in the past one year to determine P_{actual}), year to year data variability could be smoothed somewhat. However, the Tribunal is concerned that insufficient data are currently available to base an S-factor on rolling averages. DNSPs are currently improving their data systems, and as data at the aggregate level improve in accuracy, there is a concern that *perceived* (ie, reported) service reliability will appear to be worse for the next couple of years' data. This would mean that the rolling average would be based on data that were not strictly comparable.[91]

The Tribunal also notes that the DNSPs have only recently started collecting data by feeder type, and have concerns about the accuracy of these data at this stage. This means that three years' historic data are therefore not currently available from which to calculate a rolling average S-factor at this stage for this level of data disaggregation. For these reasons, the Tribunal considers the use of rolling averages in the S-factor to be inappropriate at this stage. However, it may consider this issue again, when a longer series of reliable and consistent data is available.

The use of 'deadbands' – or are performance ranges within which variations in a DNSP's performance would not lead to any incentive/penalty payment – is another way to reduce the impact of year-to-year variability in reliability performance. With this approach, the S-factor would only apply when a DNSP's performance fell outside the deadband range. (For example, a deadband could take the form of a 1 per cent variation in SAIDI. An improvement or reduction on SAIDI of less than 1 per cent would not result in any S-factor price adjustments).

The Tribunal is concerned that the use of deadbands would reduce the incentive power of the S-factor. For example, if a DNSP expects its performance to fall within the deadband region, irrespective of the level of effort it makes to improve that performance, the DNSP has no (monetary) incentive to maximise its performance *within* the deadband. The wider the deadband, the greater the reduction in incentive power. The Tribunal does however note that if DNSPs are uncertain as to whether their performance will fall within the deadband range or not, this incentive problem will be lessened.

[91] The fact that perceived reliability is likely to worsen over time could also affect an S-factor that is based on single year as opposed to rolling average data if targets were not set with this in mind. By asking DNSPs to propose their own targets, this effect is allowed for to the extent that the DNSPs have information on the likely impacts of this effect. Moreover, the rolling average approach would have the additional disadvantage of 'locking in' the inconsistency for several years.

In addition, it believes that deadbands would add a further level of complexity to the S-factor formula. This may reduce transparency and increase uncertainty, with DNSPs potentially unsure as to whether an improvement in reliability performance would result in an S-factor reward or not. For these reasons, the Tribunal has decided that deadbands will not be included in the S-factor for the 2004-09 period.

The Tribunal wishes to point out that several other features of the S-factor mechanism reduce the need for either deadbands or rolling averages. First, monetary S-factors will be based on aggregate data only (where year to year data variation is expected to be lower). Second, the relatively wide exclusions policy will reduce year to year variability considerably. Third, it is proposed that monetary S-factors will only apply from July 2006, and that the total amount of revenue exposed in any one year will be capped at a relatively small amount (0.5 per cent). Fourth, the symmetric nature of the proposed S-factor should ensure that even if 'natural' year to year variations are observed, the *expected value* of variation will be zero, and the risk will not be asymmetric.

Nevertheless, some year to year variability may still be seen in reliability performance, particularly at the lower levels of disaggregation. It may therefore be appropriate to qualify any published feeder-type data showing performance against targets, explaining that some variability would be expected in any single year.

Target-setting

The Tribunal's draft decision is that the targets adopted should be the forecast performance levels submitted by the DNSPs themselves, in response to the Tribunal's September 2003 data request. For EnergyAustralia, who did not submit forecast performance levels, information from the original April 2003 EnergyAustralia submission has been used to set targets for the draft determinations.

As noted in section 6.4.1, the Tribunal faces some data availability and accuracy constraints in establishing an S-factor for the 2004-09 regulatory period. It believes that the use of, for example, historic or comparative data to establish forward-looking targets for the S-factor could lead to inaccurate targets being set. This concern arises due to the risk that as DNSP data measurement systems become more accurate, the number of observed interruptions could increase. Moreover, most DNSPs have only recently begun to collect data at the 'feeder-type' level.

In general, stakeholders preferred that targets for any S-factor be set on the basis of information provided by the DNSPs themselves, rather than on the basis of comparative, historic or other calculations by the Tribunal. Given these considerations the Tribunal has decided to use the annual reliability forecasts provided by each DNSP in response to its September 2003 information request. EnergyAustralia did not submit data in response to this information request. However, the Tribunal considers it very important that a link between prices and service quality is established for EnergyAustralia given the very large amounts of expenditure it has proposed for the coming regulatory period. The Tribunal has therefore used the information provided in EnergyAustralia's original April 2003 submission. The targets for each DNSP are set out in the attachment.

Note that this attachment shows forecast performance levels submitted by the DNSPs both for the network as a whole and by feeder type. Because of concerns regarding the accuracy of the feeder-type data, the Tribunal will not link feeder-type data to any monetary incentive during this regulatory period. However, it considers it important that data continue to be collected at this level of aggregation and used in a 'paper trial' S-factor.

Incentive rates

The Tribunal's draft determination is that incentive rates should be based on the following marginal costs:

- **EnergyAustralia: $4,000 per MWh of unserved energy**
- **Integral Energy: $6,000 per MWh of unserved energy**
- **Country Energy: $8,000 per MWh of unserved energy**
- **Australian Inland: $6,000 per MWh of unserved energy.**

The sums outlined above have been drawn from a report commissioned by the Tribunal from PB Associates, who were asked to estimate appropriate incentive rates for the S-factor, based on existing information.[92] It should be noted that these figures are estimates, and the Tribunal invites comment on them from all stakeholders, supported by relevant information as appropriate.[93] The Tribunal notes that if more data becomes available, these figures may change, and that such a change would be likely to result in an upward revision to the $4000 to $8000 range identified above. A copy of the PB Associates report has also been placed on IPART's website for comment.

These figures are at the lower end of the range of marginal costs estimated by the consultants. The Tribunal considers the lower figures to be appropriate for two key reasons. First, a primary motive for the S-factor is to help ensure that the DNSPs deliver, at a minimum, the levels of service quality that are consistent with their nominated expenditures for the 2004-09 regulatory period. The Tribunal considers that the adoption of incentive rates that are based on cost information submitted by the DNSPS as part of the network review achieves maximum consistency with this motive.

Secondly, the Tribunal has not seen any evidence to suggest that customers *as a whole* would like to see significant improvements to service quality *beyond* those already included in the DNSP's Network Review submissions. Indeed, evidence submitted by, for example, Integral Energy, who conducted a service standards customer survey, suggests that a significant majority of customers are generally happy with current levels of service reliability. The Tribunal notes that an S-factor based on SAIDI performance for the network as a whole cannot provide incentives to target reliability improvements at specific parts of the network (for example, the worst performing parts of the network). However, other initiatives, such as the introduction of minimum standards, or the introduction of GCSS for service reliability could provide some incentives in this area.

The Tribunal also considers it appropriate to base incentive rates on the marginal cost to DNSPs of improving reliability rather than the value that customers attach to service quality improvements. A key reason for this is that the value customers attach to service reliability can vary considerably between customers and with time of day, week, season etc.

---

92 PB Associates, *Providing Incentives for Service Quality – Incentive Rates for S-factors*, December 2003.

93 Note that the EnergyAustralia figure of $4,000 per MWh is based on EnergyAustralia's 'standard' definition of SAIDI, as opposed to the SCNRRR 'Normalised Distribution Network – unplanned' definition which has been used for the other DNSPs.

The Tribunal proposes that the incentive rates outlined above would apply for both service reliability increases and decreases. The Tribunal notes PB Associates' observations that penalties for service quality decreases should arguably be based on customer value estimates. However, this could involve a significantly higher penalty rate for service reliability reductions than incentive rate for reliability increases, which would introduce asymmetric risk for the DNSPs. This could be of particular concern given the fact that the S-factor is being introduced for the first time, and so uncertainty as to likely outcomes may be greater at this stage than at subsequent reviews.

The table below converts the incentive rates expressed as $ per MWh of unserved energy into rates expressed as a percentage adjustment to the weighted average price cap per minute of SAIDI, which is the form in which they would be applied for the S-factor formula as described earlier in this chapter. For example, were Country Energy to beat their SAIDI target in any one year by one minute, the Country Energy weighted average price cap would be increased by 0.0313 percent (that is, the S-factor for that year would be 0.000313).

Table 6.1 Estimated incentive rates for DNSPs

	$/MWh	% adjustment* per minute of SAIDI	Incentive Rate (I)
EnergyAustralia	4,000	0.0297	0.000297
Integral Energy	6,000	0.0355	0.000355
Country Energy	8,000	0.0313	0.000313
Australian Inland	6,000	0.0277	0.000277

*to weighted average price cap.

Caps on revenue exposed

The Tribunal's draft decisions is that a cap of 0.5 per cent per annum on the maximum amount of actual DUOS revenue exposed under the S-factor be introduced for the 2004-09 period.

There is broad support among stakeholders for a cap on total revenue exposed under any monetary S-factor scheme, as this would limit the level of risk DNSPs are exposed to. The Tribunal agrees that such a cap is appropriate, particularly given that the S-factor is new for the NSW electricity industry, and that there are some concerns about data accuracy and variability from year to year.

A 0.5 per cent cap would significantly limit the risk for DNSPs, while still providing some monetary incentives. It may be appropriate to increase this cap (or possibly remove it entirely) at the next review, once all stakeholders have a better understanding of the workings of an S-factor, and once more accurate data have been available for a greater number of years.

In addition, the Tribunal considers that a percentage of revenue cap is more appropriate than a fixed dollar amount, as the NSW DNSPs vary significantly in size. Stakeholders also expressed support for this approach.

Finally, the Tribunal also considers that the cap should be symmetric (ie, ensuring both potential penalties and potential incentives are capped at 0.5 per cent of revenue) so as to be consistent with its views on symmetry (outlined above).

Improvements to data quality

The Tribunal's draft decision is that the DNSPs are required to provide annual updates on their progress in implementing their data improvement programmes. Updates would include details of progress against original completion timetables, and details of the impacts on data availability and quality.

The Tribunal is aware that the DNSPs are currently improving their data collection systems. These improvements will allow them to collect more accurate and more detailed reliability data, including data by feeder type. The Tribunal has also indicated that in the longer run, it would like to move towards the use of data that reflects the experience of individual customers, allowing service quality incentive schemes to concentrate on providing incentives for improving the worst-performing parts of the network. The Tribunal notes that it will be some years before this level of data is available.[94]

The Tribunal considers it important that progress towards achieving better data availability and accuracy is maintained throughout the coming regulatory period. To encourage this, it will require that DNSPs provide regular (annual) updates on progress with their data improvement plans, including details of the resulting data capability and improvements in accuracy.

Although PB Associates noted in its report that information at the feeder-type level is expected to be available from the DNSPs by 2005, some of the DNSPs (Integral Energy and EnergyAustralia) have recently suggested that these data will not be available until 2006.

94 For example, while EnergyAustralia hope to have this information available within the coming regulatory period, Australian Inland estimate that it will be at least five years before they have this data available.

ATTACHMENT FORECAST PERFORMANCE LEVELS

The tables below show the forecast SAIDI data submitted by the DNSPs, which the Tribunal proposes be used as the basis for S-factor 'targets'. It is important to note that the DNSPs have raised some concerns regarding the accuracy of the feeder-type data, and have emphasised that these figures are estimates. Some differences between actual outcomes and targets for these feeder-type measures might therefore be expected. Data constraints are the key reason for the Tribunal's draft decision to adopt a paper trial for feeder-type data for 2004-09.

Note that the data shown below are for the SCNRRR Normalised Distribution Network (unplanned) definition. Integral Energy, Country Energy and Australian Inland also provided forecast performance data for SAIFI and CAIDI.

Integral Energy

Normalised Distribution Network Interruptions (unplanned)	2004/05	2005/06	2006/07	2007/08	2008/09	Average
SAIDI						
Total	114	108	103	97	92	103
CBD	-	-	-	-	-	-
Urban	59	56	54	51	48	54
Rural Long	122	115	110	104	98	110
Rural Short	143	135	129	121	115	129

Country Energy

Normalised Distribution Network Interruptions (unplanned)	2004/05	2005/06	2006/07	2007/08	2008/09	Average
SAIDI						
Total	301	361	361	354	347	345
CBD	-	-	-	-	-	-
Urban	107	129	129	126	124	123
Rural Long	631	757	757	742	727	723
Rural Short	309	371	371	363	356	354

Australian Inland

Normalised Distribution Network Interruptions (unplanned)	2004/05	2005/06	2006/07	2007/08	2008/09	Average
SAIDI						
Total	157.9	157.9	150.0	150.0	150.0	153.2
CBD	-	-	-	-	-	-
Urban	150.3	150.3	150.3	150.3	150.3	150.3
Rural Long	195.7	195.7	183.0	183.0	183.0	188.1
Rural Short	68.6	68.6	66.9	66.9	66.9	67.6

EnergyAustralia

EnergyAustralia chose not to submit the information described above. The Tribunal has therefore based the targets below on information contained in EnergyAustralia's original April 2003 submission.

	2004/05	2005/06	2006/07	2007/08	2008/09	Average
SAIDI*						
Total	102	102	102	101	101	102
CBD	28	27	26	25	24	26
Urban	91	91	91	91	91	91
Rural	310	308	306	304	302	306

* Note that these figures are based on Figure 32 and Table 7 of EnergyAustralia's April 2003 submission. These figures appear to have been given to the 'standard' definition – this is understood to exclude transmission outages, momentary interruptions, and 'major natural events' which the distributor cannot reasonably have been expected to design for.

7 PROVIDING INCENTIVES FOR DEMAND MANAGEMENT

The Tribunal is concerned about DNSPs' substantial increases in capital expenditure and worsening asset utilisation, and the effect this is having on the cost of electricity for end-users. As demand has become increasingly peaky, DNSPs have responded by augmenting the network so that it has more capacity to meet this peak demand. That has resulted in poor asset utilisation. For example, 10 per cent of EnergyAustralia's network capacity is used for less than one per cent of the time. Poor asset utilisation raises the average per kWh cost to end-users.

The Tribunal's 2002 inquiry into demand management[95] found that demand management options can be a cost-effective way of relieving network capacity constraints, and can improve capital efficiency with flow on benefits to customers in the form of lower costs. Yet, DNSPs undertook very few demand management activities over the current regulatory period. For example, their total expenditures on demand management are equivalent to just over 1 per cent of their expenditure on network assets (Table 7.1).

Table 7.1 Comparison of demand management expenditure with expenditure of system assets

		1999	2000	2001	Totals
EnergyAustralia					
Demand management expenditure	$'000	0	2,240	1,610	3,850
Expenditure on system assets	$'000	116,941	196,700	224,200	537,841
% of expenditure on system assets	%	0.0	1.1	0.7	0.7
Integral Energy					
Demand management expenditure	$'000	1,362	1,323	418	3,103
Expenditure on system assets	$'000	43,274	70,606	74,233	188,113
% of expenditure on system assets	%	3.1	1.9	0.6	1.6
Country Energy					
Demand management expenditure	$'000	1,957	1,414	4,921	8,292
Expenditure on system assets	$'000	106,530	82,243	112,062	300,835
% of expenditure on system assets	%	1.8	1.7	4.4	2.8
Australian Inland					
Demand management expenditure	$'000	0	0	0	0
Expenditure on system assets	$'000	2,292	1,625	1,807	5,724
% of expenditure on system assets	%	0	0	0	0
All DNSPs					
Demand management expenditure	$'000	3,319	4,977	6,949	15,245
Expenditure on system assets	$'000	269,037	351,174	412,302	1,032,513
% of expenditure on system assets	%	1.2	1.4	1.7	1.5

Source: Ministry of Energy and Utilities, *NSW Electricity Network Management Report,* various years.

95 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, Review Report No. Rev02-2, October 2002.

The demand management projects that DNSPs have undertaken have had significant pay-off in terms of avoided network costs. In 2000/01 — the latest year for which data has been published — DNSPs spent a total of $6.9 million on demand management projects. These projects delivered an estimated pay-off of $28.4 million in savings in operating expenditure and deferred capital expenditure, which represents a benefit-cost ratio of over 4:1.[96] In the previous year, the pay-off was even more significant, with demand management spending of around $5 million delivering more than $62 million in avoided operating and capital costs benefits — a benefit-cost ratio of over 12:1.

The Tribunal believes these high pay-off rates suggest that there is substantial untapped economic potential for demand management to reduce network costs but questions why this potential not being tapped. The Tribunal's demand management inquiry identified a number of barriers to network driven demand management. Some of these are regulatory barriers, which the Tribunal is seeking to address through the 2004 - 2009 Determination, by clarifying the treatment of various elements of the regulatory framework. The Tribunal's role in encouraging greater use of demand management options and how this determination will help to reduce the barriers are discussed below.

However, the Tribunal's inquiry also identified other 'soft constraints' that inhibit greater use of network driven demand management options, including embedded generation. These include the structure of DNSPs' planning processes and their relative expertise and experience with non-network alternatives. In these areas, it is the DNSPs that are best placed to improve these processes and build their capacities to deal with non-network alternatives. The development of the market for non-network alternatives on the back of pro-market network planning processes and structures will also help.

7.1 Tribunal's role in supporting demand management

Increasing the use of demand management options in electricity networks requires action by several market players — DNSPs, retailers, demand management providers and end-users. The cultural shift that is required within DNSPs is something that can best brought about from within those businesses. However, the Government, as policy maker, and the Tribunal, as the distribution price regulator, can also play a role, by ensuring the regulatory and policy environment allows demand management options to compete with network options on an equal basis.

The Tribunal can take action to improve the regulatory framework to support network driven demand management.

Several stakeholders, in submissions to 2004 distribution price review, argued that the Tribunal should go further than this. For example, the Total Environment Centre proposed that it earmark a substantial and mandatory amount for demand management to be administered by a special purpose fund. However, the Tribunal reminds stakeholders that it is not a policy-making body. Many of recommendations arising from its inquiry into demand management, including the establishment of a demand management fund, are matters of policy for Government. It also notes that the Government has recently announced the creation of a taskforce to advise on the establishment of a new energy demand management fund.

96 Ministry of Energy and Utilities, *2000-01 NSW Electricity Network Management Report*, p 27.

The key issues requiring Government policy consideration are:

- whether current programs for energy efficiency within the NSW Government should be reviewed and strengthened
- whether the Government wishes to increase support for programs aimed at improving the extent and quality of information to end-users about energy efficiency
- whether there should be a review of Government policy for rolling-out interval metering to residential customers
- whether the Government wishes to support the development of aggregators in the energy market or facilitate the development of energy contracts incorporating real-time energy signals
- whether the Government wishes to monitor the impact of the design of the National Energy Market and market rules on demand management.[97]

Should the Government make policy decisions on these issues, the Tribunal may be required to have a role in implementing the decisions.

7.2 How the 2004 determination helps reduce the barriers to demand management

The Tribunal's report on the demand management inquiry recommended that it take a range of actions, to help reduce the barriers to network driven demand management[98] (see Appendix 11). In summary, these recommendations were that the Tribunal:

- consult further with stakeholders in establishing guidelines on the treatment of avoided distribution costs and demand management payments
- encourage DNSPs to undertake trials of localised congestion pricing in regions of emerging constraint of the distribution network
- work with DNSPs and other stakeholders to develop network planning processes that provide greater darity to the treatment of investment in non-network projects and demand management
- work with DNSPs to develop a framework for assessing the economic prudence of loss management investments
- confirm that rebates on network charges or DNSP payments for load reductions should be included as negative revenue in calculating regulated revenue and compliance with side constraints
- formally set out its methodology for calculation of avoided TUOS payments that may be passed through in network charges.

97 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, Review Report No. Rev02-2, October 2002, pp iii-vi.

98 The focus of the discussion here is on network-related demand management solutions — the Tribunal also made a number of recommendations to support the development of environmentally and retail driven demand management options.

It also recommended several other actions that are related to the regulatory environment, but are outside its jurisdiction. These include that:

- that negotiation guidelines and standardised connection agreements be developed under the framework of the National Electricity Code or as part of NSW Demand Management Code of Practice
- that an industry-based working group develop Standard Offer contracts for demand management as part of the review of NSW Demand Management Code of Practice.

The way in which the 2004 distribution price determination addresses each of these recommendations is discussed below. The Tribunal's response to these recommendations has also had regard to the requirements of the Code.

7.2.1 Clarifying the treatment of avoided distribution costs and demand management payments

Demand management projects can potentially enable a DNSP to avoid distribution costs that it would otherwise have to pay—for example, they can enable a DNSP to reduce or defer capital expenditure. The DNSP and the demand management provider may, as part of the demand management agreement, negotiate a payment to the provider that shares the benefits of these avoided distribution costs between the DNSP and the provider. The Tribunal's regulatory framework already allows for the recovery of demand management payments. In the 1999 Determination, demand management payments were permitted to be added to the AARR of the DNSP.

In its report on the demand management inquiry, the Tribunal recommended that it clarify the regulatory treatment of these avoided distribution costs—in particular, whether it will allow only the actual payment (the demand management payment) between the DNSP and the demand management provider to be passed through, or whether it will allow up to the full amount of the avoided distribution costs (net of demand management costs) to be passed through in prices. The Tribunal also needs to clarify the treatment of revenues foregone as a result of the implementation of the demand management project reducing volumes sold. These foregone revenues can also act as a financial disincentive to DNSPs undertaking demand management projects.

The Tribunal is considering these issues as part of this determination. However, it has not yet reached a draft decision. In principle, it believes it would be appropriate to allow DNSPs to retain some or all of these avoided costs, to provide them with a positive financial incentive to undertake demand management projects. Such an incentive is desirable, in light of the many barriers to demand management.

However, it is not clear whether this can be done a practical manner. To help it establish this, the Tribunal commissioned SKM to examine options for treating avoided distribution costs and foregone revenue in the regulatory framework. This report is available on the Tribunal's website. It is still considering the recommendations in the SKM's report and will clarify its draft decision in a discussion paper to be issued in February.

This discussion paper will outline the Tribunal's response to SKM's proposals for the treatment of avoided distribution costs, and will invite stakeholder comment on these proposals and on the Tribunal preferred approach. In particular, it will explore the possibility of including in the weighted average price cap form of regulation, a 'D' factor that provides for the pass-through of avoided distribution costs (or compensation for foregone revenue), where these have not already been factored into the DNSP's notional revenue requirements. The paper will also canvass other options such as passing through avoided distribution costs with transmission payments.

The discussion paper will also consider the case study presented in the SKM report relating to the Castle Hill project in Integral Energy's area. The Tribunal believes that there is considerable merit in ensuring that the outcomes from this project, in terms of the benefits from deferred capital expenditure, are adequately reflected in the notional revenue requirements for Integral Energy for the 2004-09 regulatory period. The Tribunal proposes to work with Integral Energy to confirm the details of the Castle Hill project.

It should be noted that the Tribunal is not considering whether it should be mandatory for DNSPs to pay demand management providers a share of the avoided distribution costs (in a similar manner as the Code requires for avoided TUOS payments to embedded generators). The Tribunal believes that payments between the DNSP and the demand management provider are a matter for commercial negotiation between the two parties.

7.2.2 Encouraging DNSPs to trial congestion pricing

The Tribunal supports the use of both price and non-price demand management measures to reduce growth in peak demand and thus relieve network capacity constraints. It believes that appropriately structured prices that signal the costs of network congestion can play an important role in assisting DNSPs manage emerging areas of network constraint.

By effectively signalling network costs, such congestion prices create an incentive for end-users to modify their energy use where or when network capacity is constrained. For example, this constraint might occur in particular geographical areas of the network or generally across the network at peak times. Congestion prices might therefore apply at particular locations or across the network at particular times of the day.

Although the available empirical evidence suggests that, in general, customers' consumption does not change much in response to price changes,[99] the experience of distribution businesses in other countries suggests that pricing signals supported by non-price measures can be very successful in limiting growth in demand. For example, SKM's report on congestion pricing cites a New Zealand example where the introduction of congestion pricing allow a substantial amount of capital expenditure to be deferred — both at the distribution network level and in the transmission network.[100]

99 See, for example, chapter 6 of the Secretariat's discussion paper on inclining block tariffs — IPART Secretariat, *Inclining Block Tariffs for Electricity Network Services, Secretariat Discussion Paper*, Discussion Paper DP64, June 2003.

100 SKM, *Reducing Regulatory Barriers to Demand Management: Avoided Distribution Costs and Congestion pricing for distribution Networks in NSW, Final Report*, November 2003, chapter 8.

As outlined in Chapter 3, the Tribunal has adopted an alternative pricing methodology to the one set out in the Code. This approach makes DNSPs responsible for setting prices and making tariff changes (in line with pricing principles and other requirements). Thus the onus is on DNSPs to ensure that their tariffs are structured in a manner that provides proper signals to customers as to the cost of their consumption on network costs. The Tribunal re-iterates its recommendation from the inquiry into demand management that DNSPs undertake trials of localised congestion pricing in regions of emerging constraint of the distribution network.[101]

To assist them, the Tribunal has tried to ensure that the regulatory framework for the next regulatory period will provide sufficient flexibility for DNSPs to structure their prices in a cost-reflective way. DNSPs have suggested that the limits the Tribunal placed on individual price movements (side constraints) in the 1999-2004 regulatory period created a significant impediment to tariff restructuring (see Chapter 11). The Tribunal believes that the limits on price movements specified in this draft determination provide sufficient headroom for DNSPs to undertake significant tariff restructuring — including trials of localised congestion pricing.

7.2.3 Developing network planning processes

As the demand management inquiry discussed, one of the major barriers to greater use of demand management options is the culture within DNSPs that favours traditional engineering solutions and pays little more than lip service to alternative options. For this reason, the Tribunal recommended that it work with DNSPs and other stakeholders to develop planning processes that allow better consideration of demand management by DNSPs.

DNSPs face a difficult planning task in terms of providing sufficient capacity in their network to meet demand that is inherently uncertain over time. The Tribunal is aware of circumstances where networks have been augmented to meet an anticipated growth in demand, only to see that demand disappear as a result of dips in economic activity, leaving the DNSP with excess network capacity. An advantage of demand management projects is that they might allow a DNSP to defer network investments until demand conditions are more certain or established. The demand management project therefore has an 'option value' benefit. The Tribunal would like to work with DNSPs to ensure that this option value benefit is adequately reflected in DNSPs' network planning processes, and to ensure that the regulatory framework recognises these benefits in assessing the prudency of capital expenditure.

There is also a need for the market to play a greater role in promoting demand management solutions. This requires DNSPs to embrace more open processes where they test the market through standard offers rather than relying on internal assessment processes.

101 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, Review Report No. Rev02-2, October 2002, p 68.

The Tribunal believes that there are significant benefits to be gained through improvements in the network planning processes. It therefore intends to establish a network planning working group to address these issues. The working group will involve members of the Tribunal's secretariat, DNSPs and other relevant stakeholders. Its objectives will be to:

- promote greater clarity in network planning processes as to the treatment of investment in non-network projects and demand management
- clarify how the regulatory framework assesses the prudence of investment in non-network projects and demand management
- identify any changes required to ensure the regulatory framework consistently assesses the prudency of investments in non-network projects and demand management
- identify options for encouraging more open processes that allow DNSPs to test the market for demand management solutions
- identify means of reflecting the option value benefits from demand management projects in project assessment and ensuring the regulatory framework recognises these benefits in assessing prudency.

It is expected that the working group will finalise a methodology before or soon after the commencement of the 2004-09 determination period, to provide the greatest amount of certainty for DNSPs faced with capital expenditure decisions. The results of the working group process that have implications for the regulatory framework will be submitted to the Tribunal for its approval.

7.2.4 Assessing the prudence of loss management investments

As electricity passes through an electricity network, a certain amount of energy is lost as a result of the resistance of the network components. As a result, customers need to purchase greater quantities of electricity than they actually consume at their premises. As it is customers rather than DNSPs that bear these costs, the Tribunal has incorporated incentives in the regulatory framework for DNSPs to invest in loss management initiatives. These incentives are currently the form of allowing DNSPs to roll into their asset bases prudent expenditure on loss management equipment, which allows them to earn a return on and of these investments.

However, DNSPs have argued that barriers remain. For example, in its submission to the Tribunal's demand management inquiry, Integral Energy argued that because DNSPs do not bear the cost of higher losses, there is little incentive to invest in loss minimisation—and if they do, there is a risk that the optimisation process may remove these assets from their asset base.[102]

In its submission to the distribution price review, Country Energy commented that the consultants who undertook Treasury's 1998 valuation of the DNSPs' assets had optimised out a number of loss reducing investments, and that the 1998 regulatory asset value should be adjusted upwards to take account of the value of these investments. The Tribunal has decided not to make adjustments to the 1998 regulatory asset value in establishing the opening asset base for 2004 (see Chapter 4). It also notes that the investments Country

102 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, Review Report No. Rev02-2, October 2002, p 65.

Energy referred to were part of the pre-1999 asset base, and any adjustments allowing the DNSPs to earn a rate of return on and of these assets would not affect their utilisation.

However, it is concerned about maintaining incentives for investing in loss reducing assets in the future. The treatment of expenditures to replace or augment existing loss reduction assets has implications for the incentives that DNSPs have for investing in these assets.

In its 1999 report to the Premier on pricing for electricity networks and retail supply,[103] the Tribunal supported the principle that the value of loss reductions should be taken into account when assets are rolled into the asset base. The Tribunal now re-affirms this position:

- prudent loss management investments will be rolled into the asset base
- economic loss management investment should not be optimised out of the regulatory asset bases.

To assess whether a loss management investment is prudent, the net present value of losses saved as a result of the investment need to be estimated. The Tribunal believes that, in principle, this value should be based on the Long Run Marginal Cost of generation. However, it recognises that this value is not directly observable in the market place and that a variety of estimates could emerge. A more pragmatic approach could be to value losses at an average of national electricity market pool prices for NSW. This could be an historical average based upon observable data and would overcome the practical difficulties of deriving an estimate of Long Run Marginal Cost.

To help resolve this issue, the Tribunal will establish a working group in 2004 to develop a methodology for assessing the economic prudence of loss management investment. This working group will seek to identify:

- an appropriate methodological framework for calculating the amount of energy loss avoided as a result of the investment, including any relevant avoided losses occurring on the transmission network
- an appropriate methodology for calculating the per kWh value of energy loss based upon an observable historic average of pool prices
- how DNSPs could incorporate the estimates of the value of loss reductions into their capital expenditure planning assessment processes and what implications, if any, this has for the methodology applied by the Tribunal for assessing the prudence of capital expenditure.

The overarching objective of this working group will be to ensure that the DNSPs are able to follow a methodology for assessing the value of loss reduction investments that is consistent with the Tribunal's approach to assessing the prudence of these investments as part of the roll forward of the asset base. The results of the working group process will be submitted to the Tribunal for its approval.

It is expected that the working group will finalise a methodology before or soon after the commencement of the 2004-09 determination period, to provide the greatest amount of certainty for DNSPs faced with decisions to replace or augment loss management assets.

103 IPART, *Pricing for Electricity Networks and Retail Supply*, *Report, Volume* 2, Rev99-5.2, June 1999, p 152.

7.2.5 Confirming the treatment of rebates and payments for load reductions under the weighted average price cap

Under the revenue cap form of regulation applied in the 1999-2004 regulatory period, rebates on network charges and DNSP payments for load reduction are included as negative revenue in calculating regulated revenue and compliance with side constraints on changes in network charges. Under the weighted average price cap form of regulation for the 2004-09, these payments will be included as negative prices.

The inclusion of rebates and payments for load reduction as negative prices and associated quantities in the weighted average price cap will allow DNSPs to increase other tariffs to recover the cost of the payments. This will have the same effect as the inclusion of the payments as negative revenue under the revenue cap arrangements in the 1999-2004 regulatory period.

7.2.6 Setting out the methodology for avoided TUOS payment pass through

In December 2003, the Tribunal published a guideline outlining its methodology for calculating the amount to be added to the AARR of a DNSP seeking pass through of avoided TUOS payments.[104] That methodology:

- identifies that only Customer TUOS usage charges (as defined in the Code) are subject to pass-through
- outlines the application of the with and without test contained in the Code
- describes the process for DNSPs to follow in applying for the pass through of avoided TUOS payments in their AARR.

The Tribunal's objective in publishing the methodology is to make transparent the calculation of the amount that DNSPs are allowed to pass through for avoided TUOS payments in network charges. The Tribunal believes that the methodology will help potential embedded generators estimate the revenue they might expect to earn from avoided TUOS payments from DNSPs. The Tribunal stresses that it does not regulate the avoided TUOS payments between DNSPs and embedded generators. The level of avoided TUOS payments is a commercial matter for the DNSP and the embedded generator, consistent with clauses 5.5(h),(i) and (j) of the Code.

The Tribunal's approach to the pass through of avoided TUOS payments for the 2004-09 regulatory period is discussed in detail in Chapter 10.

7.2.7 Negotiating guidelines and standardised connection agreements, and developing standard offer contracts

The Tribunal's report on its inquiry into demand management also recommended that negotiation guidelines, standardised connection agreements and standard offers be developed, to help facilitate the use of demand management options. The actions required to implement these recommendations are outside of the Tribunal's regulatory jurisdiction as part of the 2004-2009 Determination.

---

104 http://www.ipart.nsw.gov.au/papers/elec_TUOS_meth03.pdf

However, given the importance of these issues, the Tribunal would like to reiterate its recommendations in these areas. The demand management inquiry identified that the difficulty of negotiating fair connection agreements is one of the key barriers to the greater use of embedded generation. The Tribunal recommended that negotiation guidelines and standard connection agreements be developed under the framework of the National Electricity Code or, if appropriate, undertaken in New South Wales under the auspices of the NSW Demand Management Code of Practice. In particular, the Tribunal believes that these guidelines should address the issue of deep versus shallow connection charges.

Under the National Electricity Code,[105] DNSPs are required to establish a negotiating framework to apply to negotiations between the DNSPs and its customers (who are eligible to negotiate). Under the Code, the framework must be approved by the Jurisdictional Regulator (Tribunal). The Tribunal encourages the DNSPs to specifically address negotiations with embedded generators within this framework.

The Tribunal also identified a need for the development of Standard Offer contracts for demand management. Standard Offer contracts can provide strong, simple signals to potential demand management suppliers and reduce the costs of demand management by avoiding the need for negotiating individually tailored agreements. The Tribunal recommended that an industry-based working group develop Standard offer contracts for demand managements as part of the review of the NSW Demand Management Code of Practice.

105 Clause 6.14.7 of the National Electricity Code.

8 OTHER ISSUES CONSIDERED IN RELATION TO THE WEIGHTED AVERAGE PRICE CAP

In making its draft decision on the weighted average price cap formula for regulating DUOS tariffs, the Tribunal considered a range of additional issues that could affect the application of this form of regulation. These issues include:

- whether to include a correction factor to allow for factors arising in the 1999 regulatory period to be carried forward into the 2004 regulatory period
- whether to include a mechanism to allow DNSPs to pass through unforeseen costs
- whether to introduce a risk hedging/benefit sharing mechanism to account for significant differences in the actual and projected growth forecasts underlying the calculation of the X-factors
- how to treat revenue DNSPs earn from renting and access to, power poles and cable ducts
- whether to reopen its 2002 determination on capital contributions.

The Tribunal's review and public consultation process identified no issues in the 1999 regulatory period that need to be carried forward into the 2004 regulatory period via a correction factor. Therefore, a correction factor is not required. The Tribunal's draft decision on each of the other issues, and its analysis and rationale for these decisions, is discussed below.

8.1 Unforeseen cost pass-through mechanism

EnergyAustralia, Integral Energy and Country Energy proposed that the Tribunal include a mechanism in the price control formula to allow any material costs that a DNSP did not foresee, or could not quantify at the time of the review, and which were beyond its control, to be passed-through to customers *during* the regulatory control period.

8.1.1 Draft decision

The Tribunal's draft determination is that a cost pass-through mechanism should not be introduced for the 2004 to 2009 regulatory period for any costs arising during that period that were unforeseen at the time of the 2004 determination.

8.1.2 Tribunal's analysis and rationale

What is the case for a cost pass-through mechanism?

EnergyAustralia, Integral Energy, and Country Energy argued that under the current arrangements, if an event occurs that substantially increases a DNSP's costs, but was not foreseen at the last regulatory review, these costs would not have been included in allowed revenues. As a result (all other things being equal), the DNSP's rate of return would be lower than that allowed for at the review, and its customers would be paying a price that is 'too low'. Such events might include a change in health and safety obligations that increases operating costs, or an 'extreme' event that might have direct or indirect impacts on costs (for example, on insurance costs).

Unforeseen events might also occur that *reduce* DNSP costs—for example, a change in taxation laws in the favour of DNSPs. Allowed revenues would then be higher than required, and DNSPs would enjoy a higher rate of return than that allowed at the last review. Customers would then be paying 'too much'.

Because the events that might cause an unforeseen increase or decrease in costs are either not known, or cannot be readily quantified in advance, but have an impact on the DNSPs' rate of return, there is a *risk* for the DNSPs that the actual rate of return will be lower than that allowed for at the review. If the probability of unforeseen cost increases outside the control of the DNSPs is greater than the probability of unforeseen cost decreases, this risk will also be *asymmetric*. It is to reduce this risk (by sharing it with customers) that DNSPs seek a cost-pass through mechanism.

Arrangements to pass through the costs associated with certain unforeseen cost increases outside the control of the regulated utility have been made by several other regulators, including the ESC Victoria and the ACCC.[106]

What costs could a cost pass-through mechanism apply to?

In their submissions, the DNSPs identified a number of different cost categories to which a cost pass-through mechanism might apply. They argued that a business in a workably competitive market would be able to pass these costs on to customers, and that regulated utilities should be provided with similar opportunities to do so. For example, EnergyAustralia argued that cost pass-through arrangements should apply to *all* of the following types of unforeseen costs:[107]

- cost changes due to changes in statutory requirements that are either unforeseen at the time of the review, or too uncertain to be taken into account at that time – for example, changes to the taxation system, or a change to legislation which changes operating costs
- cost changes due to unforeseen, very rare events that the DNSP cannot avoid/mitigate, and where insurance against the event is not feasible or cost-effective – for example, a terrorist attack
- cost changes do to unforseen changes in non-statutory cost drivers – such as the unforeseen but significant increases in insurance costs seen in recent years.

Integral Energy and Country Energy argued along similar lines.[108]

---

106 See for example Attachment 17 of EnergyAustralia's April 2003 submission for further details.

107 See EnergyAustralia April submission, particularly Attachment 17. EnergyAustralia suggested that a 're-opener' should apply for significant policy changes or *force majeure* events.

108 Integral Energy has also argued that cost pass-though arrangements should apply to *any* events which have a significant impact on costs but are outside Integral Energy's control, are "outside the normal course of business" and could not be taken into account when the revenue requirement was set. Integral Energy further suggested that 'pass through' should apply to cost changes arising due to changes in taxation or other levies, regulatory changes, changes in insurance costs/availability and any events causing costs which could not reasonably be insured against. Integral Energy suggested that a 're-opener' should apply for significant policy changes or *force majeure* events.

Should an unforseen cost pass-through mechanism be introduced?

The Tribunal has considered the advantages and disadvantages of introducing an unforeseen cost pass-through mechanism for the items outlined above, or some sub-set of those items, taking into account the Code requirements outlined in Box 8.1.

Box 8.1 Code requirements

The Code specifies that in setting the notional annual revenue requirements, the Tribunal is to have regard to the right of the DNSP to recover reasonable costs not limited to State and Commonwealth taxes, charges paid to TNSPs and other DNSPs for distribution services and payments to embedded generators (cl 6.10.5(d)(7)).

The Tribunal concluded that for an unforseen cost-pass through mechanism to be viable, it would need to meet each of the following criteria:

- provide clear definitions of eligible costs
- keep administrative costs to a manageable level
- balance the interests of customers and DNSPs in terms of incentives for efficiency
- allow the change in costs to be readily distinguished from costs already allowed for as part of the 2004 Network Review.

The Tribunal does not believe that an unforeseen cost pass-through mechanism in the form proposed by the DNSPs can meet all of these criteria. Nor does it consider that a more narrowly defined unforeseen cost pass-through mechanism (for example, one restricted to cost changes arising due to statutory changes only) can meet these criteria.[109] It has therefore decided not to introduce a cost pass-through mechanism in July 2004. Its reasoning, and the implications of the decision for DNSP risk and the Weighted Average Cost of Capital are discussed below.

Providing clear definitions of eligible costs

The Tribunal considers it essential that any unforeseen cost pass-through mechanism very clearly defines the costs that are eligible for pass through. Without this clarity, DNSPs and customers alike would face considerable uncertainty about the likely impacts of an unforeseen event on prices during the regulatory period. Moreover, any confusion about which costs qualify might result in significant administrative costs for both the DNSP and the regulator, due to invalid applications and possible disputes over validity.

The Tribunal does not consider that the unforeseen cost pass-though mechanism proposed by the DNSPs can meet this criterion. For example, there is likely to be considerable difficulty in defining what constitutes a 'rare event'. While statistical definitions might be used for certain natural events, such as a cyclone or catastrophic bushfire, robust information may not be available to provide similar, objective criteria for other types of events.

109 The September 2003 Secretariat Paper put forward the possibility of introducing an unforeseen cost pass-through mechanism restricted to cost changes arising from statutory changes only.

These definitional issues would be less difficult for unforeseen cost changes arising from statutory changes. However, the Tribunal believes a cost pass-through mechanism including only these costs would still fail to meet other criteria discussed below.

Restricting administrative costs

The Tribunal considers the administrative costs associated with an unforeseen cost pass-through mechanism could potentially be very large, and outweigh the benefits of such a mechanism. It considers that to meet the Code requirements for efficiency and cost-effectiveness (Clause 10.6.2(a)), it would need to assess every cost pass through case, possibly with the help of consultants, to ensure that only efficient costs were passed through. This would involve the DNSPs providing detailed applications, and the Tribunal investing significant resources in assessing them.

Although administrative costs could be minimised by adopting materiality thresholds, and do not present an insurmountable obstacle on their own, the Tribunal believes they are an added difficulty when considered along side its other concerns about the cost pass-through mechanism.

Implications for incentives

Some stakeholders were concerned that if DNSPs are able to pass any unforeseen costs straight through to customers, this could reduce their incentives to minimise these costs. That is, the efficiency incentives of a 'pure' CPI-X regime (where prices are de-linked from costs for the duration of the regulatory period) would be reduced, and the regulatory regime would move closer to rate of return regulation. The Tribunal notes that Clauses 6.10.3(e)(1) and 6.10.5(a) of the Code require an incentive-based regulatory regime.

The Tribunal considers that these difficulties could be reduced by careful assessment of each cost pass-through application to try to ensure that only efficient costs are passed-through. However, information asymmetries will impose some limit on the extent to which this is possible. It is also aware of the argument that, provided it were possible to ensure that only events outside the control of DNSPs were eligible for cost pass-through, the scope for DNSPs to 'pad' cost pass-through applications with inefficient costs would be limited.

Distinguishing between cost changes and costs already allowed for

To ensure that customers are not 'over-charged', the Tribunal considers it absolutely essential that only those costs that have not already been allowed for in the 2004 determination would be eligible for pass through.

The Tribunal's approach to the economic regulation of DNSPs has been to assess their nominated costs at a relatively high level, rather than requiring them to submit very detailed cost information (for example at the individual project level). It considers that assessing very detailed cost information would amount to 'micro-management' of the business, which would be inappropriate. The DNSPs, not the regulator, are best placed to manage their business on a day-to-day basis.

Because of this approach, however, the Tribunal does not have detailed information as to exactly what costs have been included in DNSP projections. Therefore, should a pass-through event arise, it would not have enough information to ensure that the costs included in a DNSP's pass-through application have not already been allowed for. For this reason, the Tribunal considers that it would not be practical to implement an unforeseen cost pass-through mechanism.

Implications for risk and the Weighted Average Cost of Capital (WACC)

Several DNSPs argued that there were a several sources of asymmetric risk in the 2004 distribution network review:

- insurance costs
- regulatory risk
- easements
- asset stranding
- risks arising from the weighted average price cap including forecast error risk, market risk, and natural uncertainties
- statutory changes.

Bearing in mind the argument that introducing an unforeseen cost pass-through mechanism would reduce asymmetric risk, the Tribunal considered the implications of its decision not to introduce such a mechanism on the WACC.[110]

The Tribunal has made a number of observations on this point. First, a question arises about whether the items the DNSPs argue should be included in a cost pass-through mechanism involve asymmetric risk. Second, if the risks are asymmetric, they would need to be non-diversifiable for them to be included in the WACC. The Tribunal considers that a significant proportion of the events that would fall into the DNSPs' proposed definition of a cost pass-through mechanism appear to be diversifiable.

Third, while the DNSPs have argued that there are sources of asymmetric risk, and that (at least some of) these could be dealt with through an unforeseen cost pass-through mechanism, no stakeholders have provided any evidence to suggest that such risks were not also present at the *last* review.

The Tribunal has therefore not seen any evidence to suggest that any such risks were not taken into account in the WACC for the 1999 regulatory period. It has not made any adjustments to its WACC calculations to remove an allowance for the risk associated with unforeseen cost changes. That is, the Tribunal's WACC figure continues to include an implicit allowance for these risks through a conservative beta.

Given these observations, the Tribunal does not consider that there is a case to increase the WACC given its decision not to implement an unforeseen cost pass-through mechanism.

8.2 Risk hedging/benefit sharing factor

Under a weighted average price cap form of regulation, the X-factors have been set to recover the notional revenue requirements based upon a forecast level of sales. The actual revenues earned by DNSPs will fluctuate according to the actual level of sales. This creates a 'forecast risk' for DNSPs to manage during the regulatory period.

110 For example, EnergyAustralia argued that were the Tribunal not to introduce an unforeseen cost pass-through mechanism, an upward adjustment would be needed to the WACC to reflect this.

In its notice on the form of regulation[111], the Tribunal raised the option of including a 'hedging factor' in the weighted average price cap formula that addressed this forecast risk. The issues paper described the introduction of a possible 'H-factor' for inclusion in the price control equation:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} * q_{ij}^{t-1}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} * q_{ij}^{t-1}} \leq (1+\Delta CPI + X_{t+1} + S_{t+1})(1+H)$$

The intent, as signalled in the notice on the form of regulation, was to offer a sharing of risk between customers and DNSPs when actual sales volumes are *significantly* higher or lower than forecast. That is, the mechanism would apply above a threshold level of divergence from forecast growth (for example, if actual growth is within Y percentage points of forecast growth).

8.2.1 Draft decision

The Tribunal's draft decision is not to introduce a risk hedging factor in the weighted average price cap control formula.

8.2.2 Tribunal's analysis and decision

During the Tribunal's consultation process, the DNSPs expressed varying views on introducing a risk hedging factor. EnergyAustralia was opposed to such a factor, while Integral Energy argued strongly for its introduction. In its response to the Secretariat's preliminary analysis discussion paper[112], Integral Energy proposed a risk hedging factor along the lines of the option included in Tribunal's issues paper. While initially opposing the introduction of a risk hedging factor, Country Energy indicated that it would be interested in pursuing a mechanism as proposed by Integral Energy to deal with asymmetric risk.[113]

The introduction of a risk hedging factor is primarily about managing the financial risks associated with uncertain volume forecasts:

- the risk for the DNSP if volumes turn out significantly below forecast, resulting in revenues below expected levels
- the risk for customers if volumes turn out significantly above forecast, resulting in higher than expected revenues.

111 IPART, *Notice under clause 6.10.3 of the National Electricity Code – Economic Regulatory Arrangements,* NCR-10, June 2002.

112 Integral Energy, *2004 Electricity Network Review Preliminary Analysis Response,* 20 October 2003, pp 16-18.

113 Country Energy submission, 20 October 2003, pp 12-13.

However, it is not clear to the Tribunal that a risk hedging factor based upon revenues is necessarily the appropriate means of dealing with this risk. Indeed, in their joint submission on the form of regulation, the DNSPs argued that the weighted average price cap was superior in terms of the ability of businesses to manage volume risk than other approaches that placed constraints on the revenues that the DNSP could earn.[114] This is likely to be one of the factors underlying EnergyAustralia's opposition to the risk hedging factor, on the grounds that it would constrain the revenue earned by DNSPs.

In particular, the Tribunal considers that the focus on risk to revenue is inappropriate, as it is the risk to profit that matters to the DNSP's owner. It notes that the DNSP's profit risk can be mitigated by managing costs and aligning tariff structures to underlying costs. For example, in the case of lower-than-expected demand, while revenues would be lower than expected, it would be expected that capital and operating expenditures would similarly be lower than expected. If tariff structures are aligned to underlying costs, then the impact on profit will be mitigated by the reduction in costs. Similarly, a higher than expected growth rate would need to be supported by higher capital and operating costs. The impact on profits would unlikely be as great as indicated by the increase in revenues alone.

A problem with a risk hedging factor is that it could, say in the case of higher than expected growth, reduce the DNSP's revenues with no regard to the underlying cost of meeting this demand. The 'sharing' between DNSP and customers could reflect the costs to the DNSP, but the problem would be trying to determine the shares. Similarly, if growth were lower than expected, then the risk hedging mechanism would provide more revenue to the DNSP which would also benefit from having lower costs as a result of lower demand. The impact on the DNSP's profits would be uncertain.

Further, in their submissions on the form of regulation, the DNSPs argued that weighted average price cap provides incentives for DNSPs to price efficiently, moving tariffs more in line with marginal costs.[115] This would mean costs are more closely aligned with tariffs, reducing the risks to DNSPs from volume fluctuations.

The Tribunal recognises that the DNSPs will face more volume risk under a weighted average price cap than under a revenue cap. This risk can, in part, be managed by better alignment between tariff structures and cost structures. However, to the extent they face a residual profit risk that cannot be diversified away (as per the assumption of the CAPM), this risk should be compensated for via the establishment of an appropriate rate of return on assets. The DNSPs have raised the issue of volume risk being asymmetric, but they have not demonstrated that this is material nor that this risk cannot be diversified away. In light of this, the Tribunal does not believe it is necessary to introduce a risk hedging factor for the 2004-09 regulatory period.

114 NSW Distribution Businesses' submission to IPART's Discussion Paper (DP48), September 2001, p 9.
115 *Ibid*, Attachment 1, p 19.

8.3 Revenue from pole and duct rentals

Some DNSPs receive payments for the use of the power poles and cable ducts ('pole rentals') for non-electricity related purposes. These payments are typically received from, but not limited to, telecommunications companies. The revenue a DNSP earns from this source could, in principle, affect its notional revenue requirements, and thus the X-factors in its weighted average price cap. The Tribunal considered whether it should adjust to notional revenue requirement to account for this revenue.

The Tribunal has made a draft decision that pole and duct rentals are a non-distribution service (see Chapter 13). As such, they are not subject to regulation by the Tribunal. However, regulated assets are used to provide this service, although the Tribunal understands that DNSPs do not currently allocate any regulated asset costs to them.

The Tribunal believes there is an in-principle case for applying a portion of the incremental profits earned by DNSPs from pole and duct rental activities, as an offset to their notional revenue requirements. This offset would share with a DNSP's regulated business customers the benefits it derives from using regulated assets to service non-regulated customers. Another way of looking at this offset is that it would effectively allocate a portion of the cost of the regulated asset base to the cost of providing non-distribution services such as pole rentals.

The Tribunal notes that this issue has been considered by regulators in South Australia and the United Kingdom. In the United Kingdom, OFGEM provides for a sharing of revenues derived from telecommunications companies by deducting a proportion of net revenues earned from regulated revenue requirements.[116] The South Australian regulator has yet to release its decision.

8.3.1 Draft decision

The Tribunal's draft decision is that it will make no adjustment to the DNSPs' notional revenue requirements for revenue earned from pole and duct rentals.

8.3.2 Tribunal's analysis and rationale

In confidential submissions to the Tribunal, the DNSPs have indicated that revenue earned from pole and duct rentals is modest relative to their regulated business revenues. In balancing the potential benefits to regulated customers against the likely administrative costs for DNSPs and the Tribunal, the Tribunal has decided that it will make no adjustment to the notional revenue requirements for revenue earned from pole and duct rentals in the 2004-09 regulatory period.

The Tribunal's decision means that DNSPs will retain the full benefit of profits earned from pole and duct rentals as part of their non-regulated business activities. The Tribunal's decision also means that all incremental costs associated with pole and duct rental services should be excluded from the building block costs underlying the notional revenue requirements and the calculation of the X-factor. The Tribunal will write to the DNSPs following the release of this draft determination to confirm that these costs are excluded from their cost projections.

116 OFGEM, Open letter on energy networks providing telecommunications services, 30 October 2001.

8.4 Capital contributions

The Tribunal's capital contributions policy has implications for the type of charges that DNSPs can levy under the weighted average price cap. In particular, EnergyAustralia has proposed introducing an infrastructure charge, which the Tribunal considers to be a form of capital contribution. The proposed infrastructure charge is to apply to new and upgraded three-phase or large installations. EnergyAustralia's submission notes that the charges are intended to 'reflect a user-pays principle for the cost of providing capacity demanded with very poor load utilisation'.[117]

The Tribunal's April 2002 review capital contributions[118] determined that, as a general rule:

- customers will pay the costs of providing and installing the lines and equipment up to a defined point of connection point to the network
- the defined point ('the linkage point') is the point on the network at which the use of assets changes from shared among customers generally to dedicated to one or more customers
- the DNSP will be required to pay for all other costs — that is, those incurred beyond the linkage point.

There are two exceptions to this general rule where customers can be required to contribute to:

- rural customers defined as customers in those parts of the network where the 'after diversity maximum demand' per kilometre of line is less than 300kVA or where the local council has zoned the area as rural
- large customers defined as customers that would require more than 50 per cent of the capacity of the existing network be augmented.

EnergyAustralia's proposed infrastructure charge does not fall within the definitions of the exceptions to the general rule and, since it involves recoupment of shared network costs, it is inconsistent with the Tribunal's determination on capital contributions.

Given that the capital contributions determination has been in operation for little more than 18 months and the Tribunal is not aware of any issues arising from its implementation, the issue it considered for this 2004 distribution pricing determination was whether there is sufficient merit in the introduction of an infrastructure charge to justify re-opening the capital contributions determination to accommoda te EnergyAustralia's proposal.

8.4.1 Draft decision

The Tribunal's draft decision is that it will not re-open its April 2002 determination on capital contributions.

117 EnergyAustralia's submission, 10 April 2003, p 77. Other than indicating that the infrastructure charge has been calculated to capture a significant proportion of funding necessary to augment the network capacity, the submission does not detail how the infrastructure charges will be derived. However, EnergyAustralia has indicated verbally to the Tribunal's Secretariat that the infrastructure charges would be based on costs associated with shared network assets.

118 IPART, *Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales*, *Final Report*, Determination No.1 2002, April 2002.

8.4.2 Tribunal's analysis and rationale

Because the infrastructure charge is designed to recover a proportion of shared network costs, the key issue is whether the capital contributions determination should be re-opened to allow for capital contributions to recover more than just direct customer connection costs.

In making its 2002 decision on capital contributions, the Tribunal considered whether the capital contributions should recover shared network costs and decided against this on the basis that:

- the Tribunal's view that usage charges, not capital contributions should be the primary form of price signal
- connection costs vary widely, depending on the network conditions in the area the customer is located
- advice from the Tribunal's consultant (Meritec) that it is conceptually difficult to link augmentation costs with specific connections and that no robust basis for estimating connection-driven augmentation costs by customer category could be determined
- augmentation costs are driven by growth of existing customers' loads as well as by new connections.

On this last point the Tribunal noted in its determination:

> … the efficiency arguments for signalling costs to new users are weak for existing assets. For the most efficient utilisation of the capacity, the principle is that if capacity is scarce the costs of rationing or expanding that capacity should be signalled to all users not just some.[119]

The Tribunal believes its conclusions on the difficulties associated with identifying augmentation costs and the inequities and inefficiencies of charges only for new customers remain valid.

The proposal for the infrastructure charge has, however, been raised against a background of growing demand that requires significant capital investment to ensure that there is sufficient capacity to meet demands on the system during system peak periods. At the time the original determination was made, these capacity constraints were not identified as a critical issue affecting pricing.

The Tribunal has argued that, in its view, usage charges rather than capital contributions should be the primary form of price signal. However, metering constraints for some customer groups mean that the current charge structure does not adequately signal the cost of peak period consumption. This is the case for residential and small business customers in particular. It may be the case that an infrastructure charge could complement the existing charge structure by targeting customer with peakier loads.

However, EnergyAustralia has also proposed that, as part of its suite of tariff reforms, time of use meters would be installed for those customers that install fixed wired (or three-phase) air conditioners. Presumably, these customers would also be liable for an infrastructure charge under EnergyAustralia's proposal. The installation of time of use metering would

119 IPART, *Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales*, *Final Report*, April 2002, p 4.

allow more accurate price signalling for this group of customers and would appear to weaken the arguments for an infrastructure charge for residential and small business customers.

For larger customers with interval metering, the Tribunal does not accept that the argument that an infrastructure charge offers better signals to customers than usage prices holds up. With interval meters these customers can face charges that are based upon both the time of consumption and the capacity/demand they impose on the system. The indicative charge structure proposed by EnergyAustralia includes substantial charges for connections at high voltage or low voltage substation level. It seems likely that these charges are seeking to recover up-front capital costs that could be recovered by targeted usage charges on customers with interval metering.

The Tribunal's view is that there is not a strong case for re-opening its capital contribution determination to accommodate an infrastructure charge. The Tribunal considers that the same signals relating to the costs of capacity could be more appropriately sent through usage charges rather than through an up-front charge. The Tribunal has not seen any evidence that customers are more responsive to upfront charges than on-going usage charges.

9 CHARGES FOR MISCELLANEOUS AND MONOPOLY SERVICES

Miscellaneous services are 'non-routine' services related to the distribution of electricity, such as special meter readings, meter testing and disconnection for non payment. Monopoly services are services related to extensions, augmentations or connections to the network that only DNSPs can perform. For example, when a customer is required to pay for an extension to the network (that is, to make a capital contribution), the customer can choose to have the DNSP or an independent accredited service provider (ASP) perform the work.[120] However, to maintain the safety and integrity of the network, some of the services involved in this work can only be performed by DNSP. These monopoly services include design checking, installation inspection and energising/de-energising the network.

As Chapter 3 outlined, the Tribunal considers miscellaneous and monopoly services to be prescribed distribution services. In regulating the charges for these services, it attempts to protect customers by making these charges as cost reflective as possible.

In the 1999 determination, it established an exhaustive list of miscellaneous and monopoly services and set a maximum fee for each miscellaneous service and a mandatory fee for each monopoly service. Its draft decision on the regulation of these charges for the 2004 regulatory period, and its analysis and rationale for this decision is discussed below.

The Tribunal has not yet considered how the DNSPs should charge for 'recoverable' works undertaken by DNSPs in emergency situations. It will consider this matter before making its final determination.

9.1 Draft decision

The Tribunal's draft decision is that it will continue to regulate charges for miscellaneous and monopoly services by determining an exhaustive list of maximum or mandatory charges. The current list of miscellaneous services will be amended by:

- **Deleting the charge for the miscellaneous service associated with establishing a new account at an existing premise. The cost of this service is now to be recovered via DUOS charges.**
- **Introducing an after-hours reconnection charge of no more than $75 that can be applied when a customer requests reconnection outside normal working hours.[121] This charge is in addition to the applicable disconnection charge.**

The current list of charges for monopoly services will be amended by:

- **adding a new charge called a site establishment charge for new accounts at a new premise**
- **introducing over-time rates for monopoly services that can be applied when supplying accredited service providers (ASPs) request that the service be provided outside normal working hours. In these circumstances, the DNSP may charge up to**

120 Capital Contributions are regulated under a separate Tribunal determination (*Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales*, *Final Report*, Determination No.1 2002).

121 Normal working hours are between 7.30am and 4.00pm except on Saturdays, Sundays and Public Holidays.

175 per cent[122] of the standard fee for that portion of the service performed outside normal business hours. Where the DNSP requires that the work be conducted outside normal business hours then standard rates will apply.

Charges for miscellaneous and monopoly services can increase by the change in CPI since the last determination (approximately 17 per cent) via a once-only adjustment on 1 July 2004. No further changes are permitted for the remainder of the regulatory period.

The exhaustive list of miscellaneous services and the maximum fee that can be charged for each service is shown in Table 9.1. The DNSPs must not charge for any miscellaneous services other than those listed. However, they are free to charge less than the listed amount.

The exhaustive list of monopoly services and the mandatory fee for each service is shown in Table 9.2. The DNSPs must not charge for any monopoly services other than those listed. In addition, unless specified in the table, they must levy the fee shown in the table every time they provide that monopoly service, regardless of whether it is provided to the DNSP's contracting business or to an independent ASP. This is consistent with the Tribunal's determination in the ring-fencing guidelines.[123]

The hourly rates that pertain to the charges for monopoly services are displayed in Table 9.3.

Table 9.1 Maximum Charges for miscellaneous services for the 5 years to 30 June 2009 (nominal $)

Miscellaneous Service	$
Special meter reading	$35.00
Meter test	$58.00
Supply of conveyancing information - desk inquiry	$29.00
Supply of conveyancing information - field visit	$58.00
Off-peak conversion	$47.00
Disconnection visit (acceptable payment received)	$35.00
Disconnection at meter box	$70.00
Disconnection at pole top/pillar box	$117.00
Rectification of illegal connection	$175.00
Reconnection outside business hours	$75.00

Note: Conditions relating to charges for miscellaneous services are provided in Annexure 3 at Clause 3.2.

122 This means that if the charge for the service for normal time is $100 then if the service is carried conducted after hours at an ASP's request the total charge is $175.

123 IPART, *Distribution Ring Fencing Guidelines - Final Decision*, September 2002.

Table 9.2 Charges for monopoly services for the 5 years to 30 June 2009 (nominal dollars)

Monopoly Service	Underground urban residential subdivision (vacant lots)	Rural Overhead Subdivisions and Rural Extensions	Underground Commercial and Industrial or Rural Subdivisions (vacant lots - no development)	Commercial and Industrial Developments	Asset Relocation Or Street Lighting
Design Information	Up to 5 lots $126 6 to 10 lots $189 11 - 40 lots $315 Over 40 lots $378	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (See para 4.2)
Design Certification	Up to 5 lots $63 6 to 10 lots $126 11 - 40 lots $189 Over 40 lots $252	1 - 5 poles $63 6 -10 poles $126 11 or more poles $189	Up to 10 lots $126 11 - 40 lots $189 Over 40 lots $378	R3 per hour	R2 or R3 per hour (See para 4.2)
Design Rechecking	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (See para 4.2)
Inspection Fee	Grade: A per lot / B per lot / C per lot First 10 lots: $32 / $76 / $158 Next 40 lots: $19 / $44 / $95 Remainder: $6 / $25 / $44	Grade: A per pole / B per pole / C per pole 1-5 poles: $38 / $76 / $139 6-10 poles: $32 / $63 / $126 11+ poles: (see para 4.2) $25 / $44 / $95	Grade: A per lot / B per lot / C per lot First 10 lots: $32 / $76 / $158 Next 40 lots: $32 / $76 / $158 Remainder: $32 / $76 / $158	R2 or R3 per hour	R2 or R3 per hour (see para 4.2)
Access Permit	Residential Subdivisions: $21.00 per lot combined fee	$935 max. per access permit	$935 max. per access permit	$935 max. per access permit	$935 max. per access permit
Substation Commissioning		$701 per substation (See para 4.2)	$701 per substation (see para 4.2)	$701 per substation (see para 4.2)	$701 per substation (see para 4.2)
Administration	Up to 5 lots $153 6 - 10 lots $204 11 - 40 lots $255 Over 40 lots $306	Up to 5 poles: $153 6-10 poles: $204 11 or more poles $306	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of Arrangement	$153				
Re-Inspection	R2 per hour (max 1 hour per level 2 reinspection)				
Access	R1 per hour				
Authorisation	$126				
Inspection of Service Work (Level 2 work)	All Service connections: A Grade : $16 per NOSW B Grade: $26 per NOSW C Grade: $76 per NOSW (NOSW = Notification of Service Work)				
Site Establishment	$110				

Note: Conditions relating to charges for miscellaneous services are provided in Annexure 3 at Clause 4.2.

Table 9.3 Labour rates

Labour class	Hourly rate
Admin R1	$51
Design R2a	$63
Inspector R2b	$63
Engineer R3	$76

9.2 Tribunal's analysis and rationale

DNSPs earn approximately 2 per cent of their total distribution revenue from miscellaneous and monopoly services. In 2002/03, they earned $14.3 million from miscellaneous services and $8.9 million from monopoly services (Table 9.4). Nevertheless, the charges for these fees can have a impact on the individual customers required to pay them.

The costs to the DNSP of providing these services are included when establishing each DNSPs notional revenue requirement using the building blocks methodology (see Chapter 5). Then an estimate of the annual revenue each DNSP earns from these services is deducted from their notional revenue requirement before the X-factors are calculated for the DUOS tariffs.

Table 9.4 Total DNSP revenue from miscellaneous charges and monopoly fees in 2002/03 (nominal dollars)

Revenue Source	Energy Australia	Integral Energy	Country Energy	Australian Inland	Total
Network Revenue (DUOS and TUOS)	$800m	$509m	$511m	$18m	$1838m
Miscellaneous Charges	$0.6m	$7.6m	$5.7m	$0.4m	$14.3m
Monopoly Fees	$3.6m	$2.4m	$2.9m	$0m	$8.9m

Source: Regulatory accounts 2003.

To help it determine how miscellaneous and monopoly services should be set for the coming regulatory period, the Tribunal established two consultation groups in December 2002. These groups, which included representatives from the DNSPs, the Public Interest Advocacy Centre (PIAC), an energy retailer, EWON, MEU, National Electrical Contractors Association (NECA), other accredited service providers, held four meetings over December 2002 to May 2003.

9.2.1 Amendments to the current list of miscellaneous services

Deleting the charge associating with establishing an account at an existing premise

Under the current regulatory arrangements, DNSPs can charge an account establishment fee whenever a customer moves into a premise. In their submissions, both PIAC and EWON argued that this fee impacts adversely on those that can least afford it.

EnergyAustralia does not levy account establishment fees, but Integral Energy and Country Energy receive approximately $5 million and $3.7 million per annum respectively in account establishment fees. This represents two-thirds of their revenue from miscellaneous services.

While the Tribunal recognises that charges for miscellaneous fees constitute only a small part of the DNSPs' total revenue, it is concerned about removing a fee that constitutes such a large component of revenue from miscellaneous services for these DNSPs. Nevertheless, it believes establishing account records is a normal part of doing business—and therefore the costs associated with establishing an account are more appropriately recovered through general distribution tariffs.

Maintaining a single disconnection and reconnection charges

There are specific requirements that the DNSP must meet before a customer can be disconnected. Currently, DNSPs may charge a disconnection charge that includes the cost of reconnection. At the miscellaneous fees consulting group meetings, the DNSPs argued for separate disconnection and reconnection charges. However, the Tribunal is concerned that a separate reconnection charge would allow the DNSPs to disconnect a customer who subsequently moves residence, and then charge the new occupant a reconnection charge. For this reason, it decided to retain combined disconnection and reconnection charges. These charges apply where the reconnection is performed during normal business hours.

Introducing an after-hours reconnection charge

While maintaining a single disconnection/reconnection charge where customers are reconnected during normal business hours the Tribunal is aware that a proportion of customers who have been disconnected may wish to be reconnected immediately, rather than waiting until the next working day. These after-hours reconnections impose additional costs on the DNSP. The Tribunal has therefore determined an after-hours reconnection charge that may be applied where a customer requests a reconnection be performed outside normal working hours.[124]

124 For the purposes of this charge the Tribunal determines that normal working hours are 7.30am to 4.00pm on normal working days except on Saturday, Sunday and Public Holidays.

9.2.2 Amendments to monopoly services

Introducing a new charge for site establishment

The DNSPs proposed the introduction of a charge for site establishment (new account at a new address). They stated that there is significant amount of coordination involved in supplying contractors (ASPs) with a new meter, collecting accurate location details, coordinating with NEMMCO and assigning a NMI.

The Tribunal accepted their argument, and decided to add a charge for site establishment to the list of monopoly services and charges.

Introducing overtime rates for monopoly services

During its review of the regulation of monopoly services, the Tribunal became aware of some confusion about whether DNSPs could charge overtime rates for these services.

The Tribunal has sought to balance ASPs' need to have monopoly services provided outside normal working hours to fit their or the end-use customer's demands with the need to provide certainty and consistency in pricing. It therefore decided that DNSPs may charge overtime rates when they provide monopoly services outside normal business hours at the ASP's request. However, DNSPs may not charge overtime rates where the DNSP requires the work to be conducted outside normal business hours.

The overtime rate shall be a maximum of 175 per cent of the standard monopoly fee for that part of the service conducted after hours.

9.2.3 Increasing charges for miscellaneous and monopoly services from 1 July 2004

In their submissions, the DNSPs sought changes to the level of charges for miscellaneous and monopoly services. For example, Integral Energy and EnergyAustralia sought significant increases in miscellaneous charges and monopoly fees followed by yearly indexation. However, the level of proposed charges varied significantly between DNSPs. In addition, it appeared that the DNSPs' financial systems could not provide sufficiently disaggregated information about the costs of these services.

Nevertheless, the Tribunal is aware that miscellaneous charges have not risen since 1997 and monopoly charges have not risen since 1999. It considers that a one-off increase in miscellaneous charges and monopoly fees is appropriate, to reflect economy-wide increases in costs. The Tribunal has therefore decided to increase these fees by approximately the change in the CPI over the period of the current determination. This change is 17 per cent in nominal terms rounded to whole dollars.

10 TRANSMISSION RECOVERY ARRANGEMENTS

10.1 Introduction

Network tariffs levied by the DNSPs comprise two elements—DUOS (distribution use of system) tariffs and transmission cost recovery tariffs[125]– even though most end-users only see the bundled retail tariff.[126] For the 2004 regulatory period, the weighted average price cap will determine the DUOS tariff, while transmission-related costs, including transmission charges paid to TNSPs, avoided TUOS payments to embedded generators and inter-distributor transfer payments, will be recovered through transmission cost recovery tariffs.

The transmission recovery arrangements for the 2004 regulatory period set out a cost recovery framework in relation to transmission related costs incurred by the DNSPs, and are intended to preserve the pricing signals inherent in transmission charges set by the ACCC, where possible. Transmission charges paid by the DNSP to transmission network service providers form the largest component of the arrangements, currently between 28 and 43 per cent of total network costs incurred by the DNSPs.[127] Other costs that the Tribunal has determined should be recovered through transmission cost recovery tariffs are avoided TUOS payments and inter-distributor transfer payments.

The Tribunal's draft decision on the transmission recovery arrangements is outlined below, then the key elements of these arrangements are discussed in more detail. The relevant Code requirements the Tribunal considered for this decision are shown in Box 10.1.

10.2 Summary of draft decision

The Tribunal's draft decision is that the transmission recovery arrangements will operate as follows:

- **The DNSP will set transmission cost recovery tariffs annually to recover the following forecast costs (together referred to as Transmission-Related Payments):**
  - **transmission charges to be paid to TNSPs for use of the transmission system (use of system and connection charges, net of settlement residue payments)**
  - **avoided TUOS to be paid to embedded generators under the National Electricity Code**
  - **payments to be made to other DNSPs for use of their network (inter-distributor transfer payments).**
- **The DNSP will record the difference between the actual Transmission-Related Payments it pays and the revenue it receives through transmission cost recovery tariffs, in an overs and unders account.**
- **The DNSP will aim to reduce the balance of the overs and unders account by adjusting transmission cost recovery tariffs in the following year by a Transmission Recovery Amount. In setting this amount the DNSP must take into account limits**

125 The Tribunal has called what is commonly known as TUOS tariffs 'transmission cost recovery tariffs', as they recover more than the transmission charges paid to TNSPs.

126 The retail tariff is further comprised of a retail tariff and a network tariff.

127 *Regulated Network Business Statement of Financial Performance (nominal)* submitted to the 2004 Review 10 April 2003. 2003/04 'TUOS line costs' as a percentage of 'Total costs before depreciation'.

on total network tariffs and price stability over the regulatory period. The Tribunal will review the amount the DNSP has chosen to recover annually.

- **The Tribunal may consider increasing the price limits on network tariffs, should the balance of the overs and unders account accumulate to more than twenty per cent of the value of actual transmission-related payments incurred in the previous year.**

In addition, the Tribunal will publish a guideline, separate to the draft determination, setting out a methodology for calculating avoided TUOS payments.

Box 10.1 Code requirements

The Tribunal must have regard to the right of a DNSP to recover reasonable costs arising from charges paid to Transmission Network Service Providers and other distribution network service providers, arising from the provision of distribution services (cl 6.10.5(d)(7)).

Part E of the Code states that the DNSP must pay transmission service costs and makes provision for these costs to be allocated by the DNSPs using an appropriate methodology agreed by the Tribunal (cl 6.13.7(a),(b)).

The Code requires DNSPs to make payments to embedded generators, calculated as the avoided transmission costs arising from the connection of the embedded generator to the DNSP's network (cl 5.5(h),(i)). The payments are to be included as part of the aggregate annual revenue requirements (cl 5.5(j)).

10.3 Separating network tariffs into DUOS tariffs and transmission cost recovery tariffs

The transmission recovery arrangements apply to the setting of transmission cost recovery tariffs within the bundled network charge. This means, for regulatory purposes, the DNSP needs to separate network tariffs into DUOS and 'transmission cost recovery' tariffs.

Under the regulatory arrangements used for the 1999 Determination, total network tariffs were regulated through a revenue cap form of regulation, and separate distribution and transmission tariffs were not required. However, the Pricing Principles and Methodologies,[128] required the DNSPs to preserve the economic signals present in the structure of TUOS charges (from TNSPs) when allocating these charges to distribution network users, where practicable.[129] This principle will continue under the alternative pricing methodology for the 2004-2009 Determination.

[128] IPART, *Pricing Principles and Methodologies for Prescribed Distribution Services*, June 2002.

[129] Furthermore, clause 6.18A of the Code requires the DNSP to provide the unbundled DUOS and TUOS charges to users with the appropriate metering equipment, if requested by the customer.

In August 2002, the DNSPs proposed a Joint Allocation Methodology for separating network tariffs into DUOS and 'transmission cost recovery' tariffs.[130] The Tribunal included the following principles from that methodology in the 2004 Issues Paper for consultation:[131]

- Total TUOS allocated to network tariffs aligns with total estimated transmission charges to be paid by a DNSP.
- Transmission charges are allocated to network tariffs in a way that reflects the cost drivers present in transmission pricing.
- DNSP site-specific cost reflective network pricing (CRNP) customers should have transmission charges allocated in a way that preserves the location and time signals of transmission pricing as per clause 6.10.2(b)(4) of the Code.
- DNSP network tariffs for smaller customer classes may have transmission charges allocated on an average basis, as location signals cannot be preserved.

DNSPs cited a range of challenges in relation to allocating transmission charges, including difficulties associated with equitably allocating the general and common service fixed charge as a fixed network access charge, and passing through location price signals when the end price is applied to many customers within the network. In these instances, DNSPs allocated transmission charges for these customer classes on an averaged basis.

The Joint Allocation methodology was applied by the DNSPs to their 2003/04 network tariffs, which were submitted to the Tribunal for the purposes of modelling the X-factors. The 2003/04 DUOS tariffs will be the tariffs used for p_{ij}^{t} in the calculation of the 2004/05 network tariffs under the weighted average price cap.

10.4 Tribunal's analysis and rationale

The Tribunal has developed separate arrangements for the recovery of transmission-related costs to ensure that the transmission-related costs required to be recovered under the Code, are not dependent on volumes sold under the weighted average price cap.

The Tribunal has opted for an overs and unders account to accommodate the variation in transmission-related costs incurred, and revenue received via transmission cost recovery tariffs, as outlined in section 10.4.4. The DNSP will be able to recovery the difference in costs and revenues by adjusting the transmission cost recovery tariffs going forward.

The components of the transmission recovery arrangements are outlined below.

---

130 Joint Submission by Integral Energy, EnergyAustralia, Country Energy and Australian Inland, *TUOS Allocation Methodology*, 29 August 2002. The Tribunal has replaced the term 'TUOS' tariff with 'transmission recovery' tariff, to indicate that the tariff recovers more than just TUOS charges paid to TNSPs.

131 IPART, *Regulatory Arrangements for the NSW Distribution Network Service Providers from 1 July 2004, Issues Paper*, November 2002.

10.4.1 Transmission charges

Transmission network service providers charge DNSPs for the use of the shared transmission network. These transmission charges are regulated by the ACCC. Transmission charges can be paid to TransGrid, EnergyAustralia or, in the case of Country Energy or Australian Inland, to other transmission companies.

The transmission charges paid are a cost to the DNSP and therefore need to be recovered through network tariffs.

10.4.2 Avoided transmission use of system (TUOS) payments

In most cases, embedded or distributed generators are connected directly to the distribution network, and this means they do not need to use the transmission network to transport the electricity they generate. Thus, 'avoided TUOS' represents the transmission charges that would have been payable on this electricity. The potential for payment to an embedded or distributed generator of the transmission costs avoided by the DNSP is seen as an important means of ensuring distributed generation are treated comparably with other generators.

The Code specifies that the full benefit of the avoided TUOS charge must be passed through by the DNSP to the embedded generator.[132] Furthermore, the avoided TUOS payments made by DNSPs are to be treated as a component of their regulated revenues.[133]

For the 2004-2009 regulatory period, the Tribunal decided that the DNSPs' recovery of avoided TUOS payments is best facilitated through the transmission recovery arrangements. It is a transmission-related cost and the payment should not be subject to volume or price risk, as it would if it formed part of the weighted average price cap formula. Furthermore, these payments are not known prior to the commencement of the regulatory period.

The Code also specifies the approach the DNSP must use when calculating the amount of avoided TUOS to be paid. This amount is to be based on the charges that it would have been paid if the embedded or distributed generation project had not been connected to the network. [134]

Despite the provisions in the Code, the Tribunal recognises that there is still considerable uncertainty regarding the calculation of the avoided TUOS payments. Recommendation 7 of the Tribunal's demand management report,[135] proposed that the Tribunal formally set out its methodology for the calculation of avoided TUOS.

For 2003 and 2004, the Tribunal has published a guideline setting out the accepted methodology for calculating avoided TUOS payments. The guideline was developed after extensive consultation with the DNSPs and was presented for comment at the Pricing Issues Consultation Group.

132 *National Electricity Code*, clause 5.5(h).

133 *National Electricity Code*, clause 5.5(j).

134 *National Electricity Code*, clause 5.5(i).

135 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, October 2002.

The Tribunal intends to continue with this approach for 2004 onwards. Where DNSPs calculate the payments in accordance with the guideline, the actual payments made will be included as part of the transmission recovery arrangements and recovered via transmission cost recovery tariffs. Should the DNSPs adopt a methodology other than that outlined in the guideline, the DNSPs will be required to demonstrate that the methodology is consistent with the Code as part of the annual pricing compliance process, before the payments are included for recovery.

10.4.3 Inter-distributor transfer payments

Inter-distributor transfer (IDT) payments are made by one DNSP to another, for conveying electricity through its distribution network. In principle, a DNSP makes IDT payments to another DNSP for carriage of electricity on behalf of its customers and receives IDT revenue (receipts) for providing a similar service for other DNSPs. There is little in-principle difference between a DNSP carrying electricity to supply its own network customers and carrying electricity on behalf of another DNSP to supply that DNSP's customers.

The Tribunal has included inter-distributor payments in the transmission recovery arrangements, while inter-distributor receipts will be treated as a revenue item in the weighted average price cap. This is similar to the current regulatory period, where receipts are included as part of the base revenue requirement and IDT payments by a DNSP are passed through with transmission charges.

10.4.4 Transmission overs and unders account

The transmission cost recovery tariffs will be set by the DNSP based on a forecast of the transmission-related payments (the sum of transmission charges, inter-distributor transfer payments and avoided TUOS payments) to be incurred in the corresponding year *t+1*.[136] At the end of each year, the DNSP will realise actual transmission revenue from the transmission cost recovery tariffs, and incur actual transmission-related payments. The difference will be recorded in an overs and unders account. The Tribunal has established a means to facilitate recovery of this difference over the regulatory period by adjusting transmission cost recovery tariffs going forward.

The DNSPs will set transmission cost recovery tariffs for the following year, to recover:

- the forecast Transmission-Related Payments for year *t+1* (based on transmission charges, inter-distributor payments, avoided TUOS) and a
- 'Transmission Overs and unders Recovery Amount' – an adjustment amount determined each year by the DNSP, and approved by the Tribunal, aimed at achieving a zero balance in the Transmission overs and unders account in year *t*.

The value of the 'Transmission Overs and Unders Recovery Amount' for each year, should be equal to the value of the forecast balance of the transmission overs and unders account for year *t*, however, the DNSP will be constrained each year by:

- the price limits on total network tariffs
- ensuring price stability in network tariffs throughout the regulatory period.

136 Note that TransGrid releases its prices on 15 May each year, hence both volume and price forecasts are made by the DNSP at the time of submitting proposed network tariffs to the Tribunal in April.

Each year, the DNSP will be required to justify to the Tribunal the 'Transmission Over/Under Recovery Amount' in light of the constraints above, by providing the following information as part of the annual pricing proposals:

- actual balance of the overs and unders account as at end of year *t-1*
- forecast balance of the overs and unders account for year *t*, substantiated by estimates of the components of the Transmission-Related Payments and revenue from transmission cost recovery tariffs
- actual and forecast movement in DUOS tariffs, transmission cost recovery tariffs and total network tariffs over the regulatory period, including average and individual tariff changes
- other information the DNSP or the Tribunal sees as necessary in order to assess the appropriateness of the recovery amount.

Should the Tribunal determine that the 'Transmission Over/Under Recovery Amount' submitted by the DNSP is inconsistent with the above objectives, the Tribunal may determine a 'Transmission Over/Under Recovery Amount' that is within the constraints, and the annual pricing proposals must be adjusted accordingly.

Ideally, the transmission recovery arrangements should be a mechanistic process where the balance of the overs and unders account is reduced to zero, or close to zero, over two years. However, the Transmission Over/Under Recovery Amount' may be less than the forecast balance of the overs and unders account for year *t,* as the DNSP may opt for a phased approach to recovering transmission costs over the regulatory period to maintain price stability, or, the limits on total network tariffs may restrict the full recovery of the balance in any one year. Any unrecovered amount for that year will remain in the overs and unders account to be considered when setting network tariffs in the following year. The DNSP will be compensated for the time value of money through an interest component on any outstanding balance (equal to the nominal WACC).

Note that in the first year of the regulatory period, the transmission overs and unders account will have an amount added to it, equal to the forecast error arising from the difference between the actual 1999-2004 distribution unders and overs account balance for network tariffs for 30 June 2004, and the forecast of this balance included in the weighted average price cap for modelling purposes. The forecast was provided to the Tribunal in October 2003 and the DNSPs will be requested to update this in February 2004. More detail on this is set out in Chapter 4 and Appendix 9.

Increasing the price limits on network tariffs in any one year

In the Draft Determination, the Tribunal has provided for an increase in the price limits on network tariffs in the event that an unreasonable balance accumulates in the transmission overs and unders account. This could occur as a result of large transmission price increases.

The Tribunal will decide whether or not to relax the price limits on network tariffs (that is, will increase the percentage amount by which network tariffs are allowed to move), if it is likely that the transmission overs and unders account balance will reach *twenty per cent* or more of the actual transmission-related payments paid out in the previous year. As an example, EnergyAustralia paid out transmission charges and inter-distributor payments to the value of $153 million in 2003/04, hence 20 per cent of this equates to approximately

$30 million which would need to accumulate in the overs and unders account until the Tribunal would consider increasing the price limits that would apply in the following year.[137]

This provision is intended to address the DNSPs concerns about recovery of the balance within the network price limits, and other stakeholders' concerns about the accumulation of an overs and unders account balance over a number of years. It is particularly important in light of the large transmission price increases from 1 July 2004 requested by the NSW transmission companies, TransGrid and EnergyAustralia. The ACCC's final determination on these transmission charges will not be available until August 2004, after the DNSPs have set their network charges for 2004/05. In this situation, any relaxation of the limits if required, would not occur until year two of the regulatory period, that is, for 2005/06 prices.

The Tribunal provided a similar concession in the 1999 Determination, in relation the expiration of the derogation relating to transmission pricing.[138] ESC Victoria also relaxed network price limits in 2002 and 2003 to accommodate transmission charge increases.

Other options considered to deal with transmission related forecast errors

The Tribunal reviewed the correction factor approach adopted by ESC of Victoria in its transmission control formula, as well as the operation of the overs and unders account in the Tribunal's 1999 Determination. Both methods have their advantages and disadvantages.

The correction factor in the Victorian determination is a mechanistic model based on a set of formulae that aims to return the difference over a two-year period. It relies on the transmission rebalancing constraint[139] to limit price shocks to transmission tariffs, however, it does not provide the DNSP or the regulator the discretion to recover or repay the differences over a transitioning period in light of future forecast balances or previous tariff changes.

The Tribunal believes that an overs and unders account is necessary to ensure that the amount the DNSP needs to repay (recover) is recorded in an audited and accountable way, particularly as there is a two year time lag between setting tariffs and the latest available actual data. The Tribunal does note however, that sizeable balances accumulated in the 1999 Determination unders and overs account. These balances were not anticipated and led to regulatory uncertainty about their treatment. Neither the Tribunal, nor stakeholders, want this to re-occur in the 2004 regulatory period. In light of this experience, the Tribunal has developed new operating rules, which it hopes will help to transition the balance to zero in an even-handed manner.

137 *Regulated Network Business Statement of Financial Performance (nominal)* submitted to the 2004 Review, 10 April 2003 [2003/04 'TUOS line costs plus inter-distributor receipts' * 20%].

138 IPART, *Regulation of NSW Electricity Distribution Networks, Determination and Rules,* December 1999, p 22.

139 Similar in concept to the Tribunal's limits on price movements.

11 LIMITS ON PRICE MOVEMENTS

Through the weighted average price cap, the Tribunal limits the overall average change DNSPs can make to network prices across all customers. However, DNSPs have considerable scope for restructuring their network tariffs within the constraint of the overall cap. Customers could potentially face significant increases in individual tariffs as a result of any tariff restructuring.

In previous determinations, the Tribunal has placed limits on the amount by which individual tariffs can move in a year, to protect customers from significant price shocks. For the 2004-09 regulatory period, it has also decided to place limits on price movements. The Tribunal's draft decision on the form and extent of these limits, the issues and options it considered in making its decision, and the analysis and rationale that supports its decision is discussed below. The relevant Code requirements the Tribunal considered for this decision are shown in Box 11.1.

11.1 Draft decision

The Tribunal's draft decision is that:

- **limits on price movements will apply to total network tariffs; there will be no separate limits on DUOS or 'transmission cost recovery' tariffs**
- **limits on price movements will apply to both residential and non-residential customers, except customers on individually calculated (CRNP) tariffs**
- **the Tribunal will consider relaxing limits on price movements to allow the recovery of transmission-related payments, if the balance of the transmission overs and unders account reaches twenty per cent**
- **miscellaneous charges and monopoly fees will have a zero nominal price increase**
- **limits on price movements applying to individual network tariffs will take the form:**

$$\frac{\sum_{j=1}^{m} r_j^{t+1} * q_j^{t-1}}{\sum_{j=1}^{m} r_j^{t} * q_j^{t-1}} \leq 1 + \Delta CPI + L_{t+1}$$

where:

the Network Tariff has up to m aggregate components;

an aggregate component of a Network Tariff means the aggregate of any DUOS Tariff component and its corresponding Transmission Cost Recovery Tariff component (if any), in accordance with clause 7.2;

r_j^{t+1} **is the proposed price for aggregate component** ***j*** **of the Network Tariff for Year** ***t+1;***

r_j^t is the price charged by the DNSP for aggregate component *j* of the Network Tariff in Year *t* (being the Year immediately preceding Year *t*+1);

q_j^{t-1} is the Audited Quantity of aggregate component *j* of the Network Tariff that was charged by the DNSP in Year *t-1* (being the Year immediately preceding Year *t*);

L_{t+1} is the price limit for year *t+1*; and

DCPI is the change in the Consumer Price Index over the 12 month period from January of the Year *t-1* to December of the Year *t*, compared with the preceding 12 month period.

- an additional constraint will be applied to movements in any fixed charge components of tariffs.

The allowable increase in the tariff (L_{t+1}) for residential and non-residential customers will be as listed in Table 11.1.

Table 11.1 Limits on price movements for 2004-09 regulatory period

DNSP	Limit on price movements for residential customers	Limit on price movements for non-residential customers[1]
EnergyAustralia, Country Energy and Australian Inland	**2004/05:** ΔCPI + 6.5% **Remaining years:** ΔCPI + 4.5%	**2004/05:** ΔCPI + 6.5% **Remaining years:** ΔCPI + 4.5%
Integral Energy	**Each year**: ΔCPI + 4.5%	**Each year**: ΔCPI + 4.5%
All DNSPs	Maximum increase in fixed charge of $30 per year Zero nominal increase for miscellaneous charges and monopoly fees	N/A Zero nominal increase for miscellaneous charges and monopoly fees

Note:
1. Excluding CRNP (cost reflective network pricing) customers.

Box 11.1 Code requirements

The Code provides that the Tribunal may place limits on the annual variation in published distribution tariffs. The pricing outcomes for distribution customers must not be inconsistent with any applicable jurisdictional requirements and any price cap level (cl 6.14.4).

11.2 Issues and options considered

In its notice of the form of regulation,[140] the Tribunal stated that it would impose limits on price movements for total network tariffs. The Tribunal's primary objective in introducing these limits is to protect customers from price shocks.

Several DNSPs argued in their submissions that the application of limits on price movements in the 1999-2004 regulatory period limited their ability to restructure tariffs. For example, Country Energy said that:

> The current side constraints have precluded Country Energy from undertaking any significant rebalancing or restructuring. Since network prices were set initially in 1996, side constraints have effectively restricted price relativities from being altered. In fact, side constraints have acted as a tighter control than the CPI-X control. As a result, network prices and structures have generally been adjusted in accordance with the side constraints for each year of the regulatory period. The Tribunal should provide distributors with a greater degree of flexibility over the structure of their prices.[141]

Integral Energy submitted that:

> These side constraints significantly limit Integral's ability to restructure tariffs, particularly domestic tariffs. Integral submits that the Tribunal should modify the side constraints for the upcoming regulatory period to ensure that they do not continue to impede tariff reform.
>
> … Integral is committed to domestic tariff reform given the desirable outcomes from an economic efficiency and equity perspective. To facilitate tariff reform as part of the forthcoming regulatory period, Integral proposes that side constraints be relaxed significantly, particularly for customers with high consumption and/or high summer consumption.[142]

Tariff restructuring is an important issue for DNSPs for at least two reasons. First, as a result of amalgamations, DNSPs have to consolidate a large number of, sometimes inconsistent, tariffs into a consolidated pricing schedule. For Country Energy, in particular, this is a major task requiring restructuring of tariffs to reduce the number of tariffs, and to reduce the disparities between similar customers who are on different tariffs depending on which former supply region they are located.

Second, DNSPs are seeking to improve the cost reflectivity of tariffs. As discussed in Chapter 7, the Tribunal encourages DNSPs to trial congestion pricing to address network constraints. The move toward more cost-reflective pricing will require tariffs to be restructured in a manner that places a greater weight on times or locations where there is network congestion.

---

140 *Notice under clause 6.10.3 of the National Electricity Code - Economic Regulatory Arrangements.*

141 Country Energy submission, 10 April 2003, pp 9-12.

142 Integral Energy submission, 10 April 2003, p 201.

The Tribunal has considered how it can practically apply limits on price movements in the 2004-09 regulatory period, in a way that balances the interests of customers (by protecting them from price shocks) and the needs of DNSPs (by providing them with flexibility to restructure their tariffs). The key issues the Tribunal considered were:

- whether price limits should be imposed on DUOS tariffs, in addition to the total network tariff
- how the price limits should be structured
- the level at which the price limits should be set
- whether price limits should apply to all customers or only to residential customers, as in the 1999 determination
- whether the Tribunal should have the discretion to relax the limits on price movements under certain circumstances.

11.3 Tribunal's analysis and rationale

The Tribunal decided that it will place limits on total network tariffs only, and on the total tariff rather than its individual components. These limits will (in most cases) be set to provide headroom of at least 2 per cent above the overall weighted average price cap X-factor, which should provide DNSPs with flexibility to rebalance tariffs while still protecting customers from large price increases. The limits will apply to both residential and non-residential customers. And the Tribunal will allow consider applications from DNSPs to relax the limits for the pass through of transmission payments in specific circumstances. The Tribunal's analysis and rationale for each of these decisions is explained below.

11.3.1 Limits will be applied to network tariffs only

In its *Notice under clause 6.10.3 of the National Electricity Code - Economic Regulatory Arrangements* the Tribunal established that it would apply limits on price movements to the total network tariff. In general, DNSPs are opposed to these limits. For example, in its supplementary submission, EnergyAustralia said:

> EnergyAustralia also reiterates its call for a total network side constraint to be dropped from the regulatory regime. As noted earlier, this could result in either TUOS charges not being passed through in full or the required distribution revenues not being achieved over the regulatory period. In addition, side constraints would act to dampen the pricing signals that are required to inform customers and their behaviour.[143]

The Tribunal disagrees with this assessment of the impacts of a total network tariff. Because it has adopted a transmission overs and unders account for differences between actual transmission related amounts, DNSPs will be able to recover all transmission charges over time. Further, they will not be forced to reduce DUOS charges to recover transmission charges.

143 EnergyAustralia's supplementary distribution submission, 20 October 2003, p 33.

The Tribunal has decided to place limits on price movements on the total network tariff only. There will be no separate limits on price movements for the DUOS (or transmission cost recovery) tariffs. The Tribunal considers that this approach:

- provides customers with protection on their combined network tariff rather than individual components
- provides the DNSPs greater flexibility to restructure their tariffs by allowing them to move DUOS up and down, or vice versa, in order to still meet the limits on price movements
- is consistent with the Tribunal's 1999 determination
- ensures DNSPs are able to pass through transmission related costs while at the same time mitigating potential price shocks to customers (through the transmission overs and unders account mechanism).

The Tribunal does not see merit in applying limits on price movements to DUOS tariffs in addition to the total network tariffs. It believes this would add an additional layer of complexity, while providing little additional protection. It would also restrict DNSPs' flexibility to restructure tariffs. In addition, the introduction of the weighted average price cap means there is no longer a need to place a limit on movements in DUOS tariffs—this limit is effectively achieved by the X-factor in the weighted average price cap.

11.3.2 Price limits will be structured to provide DNSPs with flexibility to restructure tariff components

The Tribunal considered two options for structuring price limits:

1. Applying limits on price movements for each network tariff component. Tariffs usually comprise multiple components – for example, a fixed rate (a service availability charge) and a variable rate. Under this approach each component would be subject to a limit on price movement.
2. Applying limits on price movements for each network tariff. Under this approach, the DNSPs would calculate the average price for a tariff class under the previous prices and the average price received for that same tariff class under the new prices,[144] to determine whether the average price had increased by more than the limit on price movement.

The Tribunal's draft decision is that the limits on price movements should apply to the network tariff rather than the individual tariff components. The Tribunal considers that this approach is less prescriptive and provides DNSPs with more flexibility to restructure the components within tariffs. It is also the approach currently adopted by the ESC in Victoria through its joint rebalancing constraint. As discussed below, the Tribunal has introduced an additional limit on fixed charge components of residential customer bills. While this restricts tariff restructuring to some degree, the Tribunal considers that it is necessary to avoid adverse impacts on low income and low consumption customers.

144 Assuming the same consumption.

The limits on movements in individual network tariffs will be such that the weighted average increase in the tariff components is not able to exceed the specified price limit. The formula will be similar to that of the weighted average price cap control formula, but would apply to each tariff individually. It will take the form:

$$\frac{\sum_{j=1}^{m} r_j^{t+1} * q_j^{t-1}}{\sum_{j=1}^{m} r_j^{t} * q_j^{t-1}} \leq 1 + \Delta CPI + L_{t+1}$$

where:

the Network Tariff has up to m aggregate components;

an aggregate component of a Network Tariff means the aggregate of any DUOS Tariff component and its corresponding Transmission Cost Recovery Tariff component (if any), in accordance with clause 7.2;

r_j^{t+1} is the proposed price for aggregate component *j* of the Network Tariff for Year *t+1;*

r_j^{t} is the price charged by the DNSP for aggregate component *j* of the Network Tariff in Year *t* (being the Year immediately preceding Year *t*+1);

q_j^{t-1} is the Audited Quantity of aggregate component *j* of the Network Tariff that was charged by the DNSP in Year *t-1* (being the Year immediately preceding Year *t*);

L_{t+1} is the price limit for year *t+1*; and

ΔCPI is the change in the Consumer Price Index over the 12 month period from January of the Year *t-1* to December of the Year *t,* compared with the preceding 12 month period.

Like the weighted average price cap control formula, this constraint on the average change in the tariff components uses fixed quantities as weights. The Tribunal will use the latest audited quantities, which means there will effectively be a two-year lag. These quantities are the same as those applied in the weighted average price cap control formula.[145]

Some DNSPs suggested alternative approaches. For example, in its supplementary submission, Integral Energy stated that it considers that the limits on price movements should apply to any fixed charge and the first block component of a tariff, and that no limit should apply to subsequent block components. The Tribunal is concerned that such an approach would potentially expose customers with larger consumption to large price increases. As the Secretariat discussion paper on inclining block tariffs highlighted, the

145 Including 'reasonable' estimates where applicable.

Tribunal is concerned that these could be low-income customers with large consumption. PIAC shares this concern.

11.3.3 The limits on price movements are set at a level that facilitates tariff restructuring while protecting customers from price shocks

As already noted, the Tribunal's objective in a setting limit on price movements for network tariffs is to protect consumers from price shocks. In setting the level of this limit — that is, the value of the L-factor—the Tribunal has aimed to balance this objective with the need to provide DNSPs with sufficient flexibility to restructure tariffs.

To facilitate tariff restructuring, the Tribunal needs to provide sufficient headroom above the X-factor to allow DNSPs to increase network tariffs by more than the average level as determined by the X-factor. This headroom would provide DNSPs with the flexibility to rebalance network tariffs and to also recover the revenue allowed under the overall constraint of the weighted average price cap.

The Tribunal has decided that the limit on price movements should provide headroom of at least 2 per cent above the overall weighted average price cap constraint.[146] To improve transparency and administrative simplicity, the Tribunal has decided to set common price limits across all DNSPs. **For the last four years of the regulatory period, the limit on price movements will be set at 2 per cent above the largest X-factor set by the Tribunal. The limit on price movements will therefore be 4.5 per cent above the change in CPI — that is, 2 per cent above the X-factor for Country Energy and Australian Inland (which have the largest annual ongoing X-factors).**

In the first year of the regulatory period, the Tribunal set an X-factor of 6.5 per cent for all the DNSPs except Integral Energy. If the Tribunal were to set the price limit at 2 per cent above this X-factor, the price limit would 8.5 per cent in real terms. The Tribunal believes this would leave customers vulnerable to very large price impacts in that year. **It has therefore decided that the limit on price movements in the first year will be set at 6.5 per cent in real terms for EnergyAustralia, Country Energy and Australian Inland, and 4.5 per cent in real terms for Integral Energy.**

The Tribunal acknowledges that setting the limit on price movements equal to the X-factor means that all tariffs need to increase by 6.5 per cent on average if the DNSP is to recover their expected notional revenue requirements. This places some constraint on the DNSPs to move some tariffs up and others down in the first year. However, the Tribunal considers that the benefits of greater price stability for customers, who already face significant price increases in 2004/05, justify the tighter limit on price movements in 2004/05. The Tribunal expects that the headroom provided in remaining years of the regulatory period will be sufficient to facilitate tariff restructuring.

The Tribunal does not have information about the full extent of the tariff reforms proposed by DNSPs. However, its analysis suggest that the above limits will provide significant opportunities for tariff reform, including the introduction of an inclining block network tariff as proposed by EnergyAustralia and Integral Energy. The Tribunal invites stakeholders to make submissions in response to this draft decision if they believe that the level of the limits

146 With the exception of 2004/05.

on price movements will inhibit tariff restructuring. DNSPs submissions should clearly demonstrate how the constraint will hinder their proposed tariff reforms.

In making its draft decision, the Tribunal also considered a proposal put forward by Country Energy, which submitted that:

> We believe that if customer level side constraints are utilised they should be negotiated at the time of price changes so that they can align with individual distributors' medium term pricing strategy.[147]

The Tribunal considers that this proposal would increase regulatory uncertainty during the regulatory period and would increase administration costs for both the Tribunal and the DNSPs during the regulatory period, at annual price resets. It therefore does not favour this approach.

Additional constraint on fixed charge components of the network tariff

Under the weighted average price cap approach, DNSPs could apply very large increases to the fixed charges by decreasing the volume-based charges. The fixed charge particularly affects low-income and low-consumption customers. The Tribunal is concerned about the impact of rapid increases in fixed charges on these customers.

The Tribunal has therefore decided that the fixed component of any network tariff for residential customers should not increase by more than $30 per annum. This limit is in line with the current limits on price movements, under which residential customer bills cannot increase by more than $30 per annum or 2 per cent (whichever is greater).

The $30 limit per year on the movement in the fixed charge applies as an *additional* constraint over and above the limits imposed by the constraint on the weighted average increase in the tariff components, discussed above. That is, any increase in the fixed charge must be accommodated within the overall limit on price movement constraint, but cannot be more than $30 per year.

Zero price limit on charges for miscellaneous and monopoly services

The Tribunal has determined an exhaustive list of charges for miscellaneous and monopoly services to apply from 1 July 2004 and which will remain unchanged for the regulatory period (see chapter 9). As prescribed distribution services, the charges are regulated under the weighted average price cap form of regulation, which allows the DNSPs to restructure tariffs as they see fit. The Tribunal has set a zero nominal limit on price movements for charges for miscellaneous and monopoly services, which requires DNSPs to maintain these charges at their 1 July 2004 values.

147 Country Energy submission to the 2004 electricity network review, pp 9-12.

11.3.4 Limits on price movements will apply to both residential and non-residential customers

Under the current determination, limits on price movements on the total network price apply to residential customers only. A range of stakeholders support continuing limits on price movements for residential customers. For example, in its submission to the review, the Public Interest Advocacy Centre (PIAC) stated:

> … residential customers have far less capacity to represent their interests to the individual networks than do larger commercial and industrial customers … the introduction of the weighted average price cap actually makes side constraints more important for residential end-users.[148]

In addition the Energy and Water Ombudsman of New South Wales (EWON) argued that:

> … limits on price movements are required for residential customers. In particular, customers who are on fixed or low incomes are vulnerable to the smallest of price increases. Our experience with customers who are experiencing difficulty paying their accounts suggests that for some low income households, the smallest alteration in either income or expenditure can expose them to financial difficulty.[149]

However, AGL ES&M and Integral Energy suggested that customers on low incomes should be protected through government support agencies.

There was also some support for extending the limits on price movements to non-residential customers. For example, EWON commented that:

> In regards to non-residential customers, we note that in our experience some small business customers are as vulnerable to sharp price increases as residential customers…[150]

However, DNSPs were generally opposed to this. For example, EnergyAustralia submitted that:

> …there is currently no network side constraint for business customers and [EnergyAustralia] believes it is not appropriate for such a mechanism to be introduced. The ability to achieve tariff reform will be severely dampened if a business side constraint is adopted.[151]

Under the current determination the Tribunal does not apply individual limits on price movements to non-residential customers. It does, however, apply limits on price movements to small non-residential **retail** customers that have not entered negotiated tariffs (and remain on a regulated tariff) of the greater of CPI+5% or $50 per annum.

148 PIAC submission to the 2004 electricity network review, p 7.

149 EWON submission on the *2004 Electricity Distribution Review – Preliminary Analysis – Secretariat Discussion Paper*, 20 October 2003, p 5.

150 EWON submission on the *2004 Electricity Distribution Review – Preliminary Analysis – Secretariat Discussion Paper*, 20 October 2003, p 5.

151 EnergyAustralia submission to the 2004 electricity network review, p 76.

Queensland, Victoria and South Australia apply limits on network price movements for non-residential customers. In Victoria and South Australia, there is no differentiation between the limits for residential and non-residential customers. In Queensland, the limits on network price movements for contestable customers (those consuming more than 200 MWh per annum) are CPI+5% while the limits for non-contestable customers are CPI+2%.

If the Tribunal were to apply limits on network price movements to residential customers only, then non-residential customers may be left exposed to large network price increases. The Tribunal would be concerned if this led to a situation where the achievements of DNSPs in winding back historical cross subsidies between residential and business customers were reversed. It also notes that non-residential customers would remain exposed to large network price increases resulting from major tariff reform.

In light of these concerns, and its decision to provide at least 2 per cent headroom in the tariffs to accommodate tariff restructuring[152], the Tribunal has decided to apply limits on price movements to both residential and non-residential customers. For non-residential customers, limits on network price movements will be restricted to those customers that are not on individual network prices based on a cost reflective network price (CRNP) methodology.[153]

For very large customers, the DNSPs calculate individual prices based on a CRNP methodology. These customers will be able to use the negotiation frameworks required under clause 6.14.7 of the Code to negotiate with the DNSPs in setting prices.

As noted above, the additional $30 cap on annual increases in fixed charges will only apply to residential customers. The Tribunal does not believe the same equity arguments relating to low-income households apply to non-residential customers.

11.3.5 The Tribunal will consider applications to increase price limits for the recovery of transmission-related payments but not congestion pricing

As discussed in Chapter 10, the Tribunal has decided that it will allow for the relaxation of price limits on network tariffs to avoid large balances accumulating in the transmission overs and unders account during the regulatory period. It also considered whether it should be able to relax the limits on price movements to facilitate congestion pricing by DNSPs. In its report to the Tribunal on demand management, SKM argued that the Tribunal will need to consider 'relaxing side constraints where these are inhibiting the ability to send meaningful congestion prices'.[154]

SKM prepared its report before the Tribunal had decided on its approach to the limits on price movements. The Tribunal's view is that its proposed structure of the limits on price movements — a constraint on the weighted average of tariff components — provides DNSPs with sufficient flexibility to restructure tariffs to provide sharper signals of congestion costs. The SKM report found that the average price for constrained end-users should not rise by an unreasonable amount, with any increase in peak charges offset as far as possible by a

152 With the exception of 2004/05.

153 The CRNP process is a cost allocation mechanism based upon the structure of the present network using a fully distributed cost of supply analysis and is an assessment of long run incremental pricing for the individual assets used by the individual customer.

154 SKM, *Reducing Regulatory Barriers to Demand Management, Avoided distribution costs and congestion pricing for distribution networks in NSW, Final Report*, November 2003, p 73.

corresponding decrease in off-peak charges.[155] This would suggest that the Tribunal would not need to relax its limits on price movements — which require an increase in one component at a rate higher than the limit (L) to be offset by a lower change to another component.

The Tribunal believes its limits on price movements are structured in a manner that accommodates SKM's findings. The Tribunal also notes that since the limits on price movements apply to tariffs rather than individual customer bills, the introduction of a new congestion tariff is not affected by the limits on network price movements.

155 ibid, p 52.

12 PRICE SETTING ARRANGEMENTS FOR NETWORK TARIFFS

Part E of Chapter 6 of the Code sets out a methodology for pricing prescribed distribution services. However, under clause 6.11(e) of the Code, the Tribunal (as Jurisdictional Regulator) may develop an alternative pricing methodology to that set out in Part E.

For the 1999 Determination, the Tribunal established an alternative pricing methodology known as the *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services*[156] (PPM). The primary reason for doing so was that the approach in Part E restricted DNSPs to a charging methodology and cost allocation procedure that would potentially produce outcomes that were in conflict with the objectives and principles for regulating distribution pricing.[157]

For this same reason, the Tribunal believes it is prudent to continue to use a similar pricing methodology for the 2004-2009 regulatory period, particularly as the existing PPM has achieved a substantial degree of acceptance with stakeholders and is supported by interstate jurisdictions.

The details of the alternative pricing methodology for the 2004-2009 regulatory period, and the arrangements the DNSPs must follow when setting prices and making tariff changes, are set out below. The Tribunal appreciates the involvement of the Pricing Issues Consultation Group[158] in developing these arrangements.

12.1 Summary of draft decision

The Tribunal's draft decision is to adopt an alternative pricing methodology to replace clauses 6.11 – 6.14.3 of Part E of the Code. Under the alternative methodology:

- **Price changes will occur once a year on 1 July[159] and the DNSPs will provide annual pricing proposals to the Tribunal for assessment against the requirements of the Determination, including the weighted average price cap formula, transmission recovery arrangements and limits on price movements for network tariffs.**
- **Prices must be developed by the DNSP in accordance with the Tribunal's principles which address the objectives of the Code.**
- **The DNSPs must publish a Network Strategy Statement at the beginning of the regulatory period and provide an Annual Pricing Report for the public at the time of annual price changes.**
- **Public consultation must occur for changes to tariff structures or criteria, the introduction of new tariffs, or changes to the Network Strategy Statement.**
- **In the absence of a compliant pricing proposal, default pricing arrangements will apply at the discretion of the Tribunal.**

156 Released in March 2001.

157 Set out in clauses 6.10.2 and 6.10.3 of the Code.

158 The Pricing Issues Consultation Group was established by the Tribunal for consultation on pricing issues in relation to the 2004-2009 distribution review. A list of members and meetings held is set out in Appendix 12.

159 There is provision for an additional price change date to be agreed with the Tribunal.

Box 12.1 Code requirements

Part E of Chapter 6 of the Code applies to the pricing of prescribed distribution services. Under clause 6.11(e) of the Code, the Tribunal may develop an alternative pricing methodology to that set out in Part E.

The Tribunal has elected to replace clauses 6.11 – 6.14.3 of Part E of Chapter 6 of the Code with an alternative pricing methodology. The remaining clauses of Part E are still operative.

12.2 Tribunal's analysis and rationale

The approach to price regulation embodied in the Tribunal's alternative pricing methodology for the 2004-2009 regulatory period, continues to be based on the following key propositions - it:

- Recognises that prices cannot be set by simply using a mechanical model. Judgement is required.
- Leaves DNSPs responsible for translating the overall caps set by the Tribunal into prices. DNSPs know their costs and customers better than the Regulator.
- Makes the DNSPs accountable for the pricing decisions through the public disclosure of their costs and pricing strategies.
- Provides for the Tribunal to reject network price changes where the network prices are inconsistent with the Tribunal's Determination.

The framework has largely been drawn from the existing PPM, which sets out pricing principles and rules that are consistent with the objectives in Part D of the Code. Underpinning the methodology is public scrutiny of the price setting process. The principles are translated into pricing outcomes via compliance criteria for annual pricing proposals, and information disclosure requirements.

The Pricing Issues Consultation Group (PICG) discussed whether the Tribunal should have a greater role in determining and approving price structures. Some stakeholders felt that the Tribunal should be more involved in the price setting process, particularly given that there are different incentives for pricing under a weighted average price cap compared to a revenue cap, and the fact that a considerable amount of tariff reform is proposed for the coming regulatory period.

The Tribunal has chosen to leave the responsibility for the development of prices with the DNSPs as they have a better understanding of their costs and customers. Having a transparent process and limits on price movements will reduce the need for intervention in the price setting process. However, in the absence of specific tariff approval or detailed assessment of cost and tariff structures, the Tribunal believes that the DNSPs need to justify changes to tariffs in light of pricing objectives. This is particularly in light of the significant tariff reform proposed for the coming regulatory period to address growing peak demand. For this reason, the annual compliance process, information disclosure requirements and public consultation requirements have been strengthened.

12.2.1 Pricing principles for network tariffs

The pricing of prescribed distribution services involves allocating the costs that underlie those services and formulating prices to recover those costs. A basic premise of the Tribunal's approach is that DNSPs should be responsible for determining their prices, given that they have a better understanding of their cost structures, the needs of users and their sensitivity to price signals, the level of network utilisation and the likelihood of the emergence of congestion.

Nevertheless, important regulatory issues arise from the exclusive position of DNSPs in providing access to the electricity network. The Code recognises the importance of providing a mechanism for managing these and other effects, and sets out objectives for the economic regulation of distribution pricing, which translate into:

- economic efficiency
- revenue sufficiency
- equity.

In some cases, there is tension between pricing objectives, which requires a balance to be struck. While the objectives can provide signposts for pricing, they do not provide simple rules. As a result, pricing decisions will involve a significant element of judgement and subjectivity. To be effective the regulatory approach must allow for these practical limitations.

Recognising this, the principles underlying the alternative pricing methodology aim to achieve prices for prescribed distribution services that:

- Reflect economic costs by:
  - being subsidy free
  - having regard to the level of available capacity
  - signalling future investment costs
  - discouraging uneconomic bypass
  - allowing negotiation to better reflect the economic costs of specific services.
- Return an appropriate revenue stream while recovering the gap between marginal and average costs in the least distorting manner possible.
- Promote equity, stability and consistency of outcomes by:
  - having regard to the impact of price changes on customers
  - being transparent
  - being based on published costs and methods.

A full list of the principles, and an explanation of each principle, is set out in Attachment 1 to this chapter. They are largely based on the pricing principles in the existing PPM which were developed in conjunction with the industry as a result of recommendations in the Tribunal's 1999 Section 12A report in relation to distribution and retail pricing.[160]

160 IPART, *Pricing for Electricity Networks and Retail Supply Report Rev99-5.1 Volume II,* June 1999.

12.2.2 Annual pricing proposals compliance process

For each year in the regulatory period commencing 1 July 2004, the DNSPs must submit annual pricing proposals to the Tribunal to demonstrate compliance with the form of regulation. The Tribunal will assess the proposals against the following criteria:

1. proposed DUOS tariffs meet the weighted average price cap control formula
2. proposed 'transmission cost recovery tariffs' satisfy the requirements of the transmission recovery arrangements
3. miscellaneous charges and monopoly fees are levied in accordance with the determination
4. proposed prices do not exceed the limits on price movements for network tariffs
5. proposed network tariffs comply with the pricing principles, information disclosure requirements and public consultation procedures.

In the absence of a compliant pricing proposal, default pricing arrangements will be initiated by the Tribunal.

2004/05 prices and the annual pricing proposals process

1 July 2004 coincides with the commencement of new transmission charges by the NSW TNSPs.[161] The NSW transmission companies, TransGrid and EnergyAustralia, have requested large transmission price increases, however the ACCC's final determination on the transmission charges will not be available until August 2004, after the DNSPs have set their network tariffs for 2004/05. The TNSPs will base their charges on 1 July on the ACCC's draft determination due out in May. It is unknown at this point whether the TNSPs will have an additional price change after 1 July once the final determination has been released, or carry out an end of year adjustment.

The network tariffs to be submitted by the DNSPs to the Tribunal in April 2004, will need to be based on the DNSPs' best estimate of transmission charges. The DNSPs will however be constrained by the price limits on total network tariffs set by the Tribunal in the final determination. Under the Tribunal's transmission recovery arrangements set out in Chapter 10, any amount not recovered, or over-recovered by the DNSPs, will be recorded in the transmission overs and unders account. Once the balance in the overs and unders account accumulates to greater than twenty per cent of the transmission-related costs (Transmission-Related Payments), the Tribunal has made provision to increase the price limits on total network tariffs in the following year in order to reduce the balance of the account more rapidly than would occur otherwise.

The Tribunal's final determination for network tariffs is due for release in May 2004. A modified timetable for the 2004/05 pricing proposals is set out in Table 12.1. This includes submission of a draft Strategy Statement and Annual Prices Report (discussed in section 12.3.3 below) by 31 May. All these documents should be made public, in draft form, at the time of submission to the Tribunal.

161 Transmission charges can account for up to 40 per cent of a total network tariff.

Timeline for annual pricing proposals process 2005/06 – 2008/09

Under Part E of the Code[162] distribution service prices must be published by 31 May each year (for prices to apply in the following year on 1 July). Furthermore, under the current retail determination, default retailers are required to provide the Tribunal with 30 days notice of default retail prices. In light of this, DNSPs will be required to submit their proposed prices to the Tribunal in early April according to the timetable set out in Table 12.1. Public consultation, as set out in section 12.2.4, will need to have occurred prior to this time. The Tribunal may also require the DNSP to make its pricing proposals available to the public.

Table 12.1 Timeline for network price changes

Action	Date for 2004/05 network tariffs	Dates for following years in regulatory period
1. DNSPs to submit to the Tribunal and place on their website: – annual pricing proposals – draft annual prices report – draft Network Strategy Statement	31 May 2004	first Monday in April
2. The Tribunal to notify DNSPs of compliance/ non-compliance – If compliant => DNSPs to notify all retailers and customers – If non-compliant => DNSP submits alternative proposal to the Tribunal	15 June 2004	20 working days after first Monday in April
3. Final date for DNSPs to submit an alternative proposal to the Tribunal	18 June 2004	23 working days after first Monday in April
4. Final date for notification of compliant pricing proposal by the Tribunal – If compliant => DNSPs to notify retailers and customers – If non-compliant => default arrangements enacted at Tribunal's discretion	28 June 2004	31 May
5. Commencement of network price changes	1 July 2004	1 July
6. Submission of final Network Strategy Statement	30 September 2004	

12.2.3 Information disclosure requirements

As noted above, the alternative pricing methodology continues with the basic premise that DNSPs should have responsibility for their pricing structure. To allow the DNSPs this flexibility however, the Tribunal needs to have confidence that the cost allocation methodologies and future pricing strategies will lead to efficient prices and will achieve the overall objectives of the Code. Information disclosure and public consultation play an important role in creating this confidence.

162 *National Electricity Code,* clause 6.14.5.

Public disclosure enables comparisons by customers and regulatory authorities of prices, costs and other elements of performance – whereby regulated companies come under pressure to compare their performance and make improvements where possible. It provides a basis for decision making by customers who are making investment decisions based on service quality and cost.

During the 1999-2004 regulatory period, the DNSPs published a Price & Services Report each year. The information they were required to disclose in this report included demonstrating compliance with the pricing principles, detailed cost and pricing methodologies, and the reporting of actual financial, operating and service quality data. Although the information is useful to stakeholders, the production and structure of the reports has proved to be large and cumbersome – for the DNSPs to prepare, for the Tribunal to use in assessing compliance, and for the customers who wish to use them. With the assistance of the Pricing Issues Consultation Group, the information disclosure requirements have been revised for the 2004/05 - 2008/09 regulatory period to consolidate the information and to present it in a more timely and user-friendly way. Additional information will also be required on new tariffs and changes to tariff structures to ensure that they meet the pricing principles.

Network Strategy Statement

DNSPs will be required to publish a Network Strategy Statement at the beginning of the regulatory period. The purpose of this document is to set out the DNSP's medium term pricing strategies and demonstrate how the strategies meet the pricing principles. Stakeholders, including DNSPs, have indicated their support for this proposal at the Pricing Issues Consultation Group meetings and in their submissions, particularly as this information is currently repeated annually in the Price and Service reports.

The main features of the Network Strategy Statement will be each DNSP's medium-term pricing strategies, disclosure of the tariff setting process, cost allocation methodologies and cost of supply modelling. In particular, DNSPs will need to explain the extent to which their prices incorporate the pricing principles, and how they relate to the proposed expenditure programs and service standards levels.

DNSPs will be required to address the following broad questions:

- *Are the prices subsidy free?* The test for this is whether prices are between the stand-alone and incremental costs of supply. DNSPs will be asked to demonstrate that prices lie within this range and explain how they determined the range.
- *Do prices have regard to an acceptable cost of supply model?* The cost modelling used in the development of the proposed prices should be disclosed. This should include an explanation of the basis for the allocation of transmission costs to distribution network prices, and the basis for determining individually calculated network prices.
- *Do prices reflect the future need for augmentation of the network?* Prices may be expected to be higher in locations where the system is closer to capacity. DNSPs will be asked to report on the significance of locational congestion and related capital spending requirements across their network. DNSPs should explain their decision to use or avoid locational price signals in the context of the congestion costs they face.
- *Does the structure of prices reflect marginal economic costs?* DNSPs should explain the extent to which prices signal marginal costs and the basis for their decisions on the weights applied to the fixed and variable price components.

- *What is the impact of the DNSPs price strategies on price stability in the medium term?* The medium term price strategies and the expected impact on price outcomes for customer classes should be described. DNSPs should indicate whether the strategies are likely to create material adjustment costs for some users and if so the management options available to users and transitional measures that the DNSP may adopt.
- *What level of service performance is provided for the prices charged?* DNSPs will be asked to report and explain the level of reliability and quality of service they provide to localities across their service areas. Variations in service levels should be explained and expected medium term trends described.

The Network Strategy Statement must provide an indication for each customer class of the direction of prices, with reference to a cost of supply range and the pricing principles. DNSPs are to provide further detail on specific tariff changes, or methodology changes, in the year prior to the change via the public consultation procedures and their Annual Prices Report.

For amendments to the Network Strategy Statement, such as changes to the pricing procedures, cost methodologies or strategies, the determination requires public consultation to occur. The Tribunal is mindful that such changes can have important ramifications for tariff levels, particularly for individually calculated prices. Furthermore, stakeholders should be notified if tariff reform is proceeding differently to what has been advised.

More detailed public consultation will be required for the introduction of new tariffs, or changes to tariff structures prior to the next annual price changes. The information and procedures to be followed in this instance are set out in section 12.2.4 of this report.

Given the timing of the final determination and the submission of annual pricing proposals for 2004/05, the DNSPs may release a draft Network Strategy Statement based on the draft determination. A final Network Strategy Statement, after public consultation, should be provided in September 2004.

Annual Network Pricing Report

The draft determination requires the DNSPs to provide a report for the public, to explain the annual change in network tariffs, and demonstrate the impact the tariffs are likely to have on customer bills. It is proposed that the report:

- list new prices with discussion of changes in tariffs, structure or criteria, and any new or obsolete tariffs
- explain how the DUOS tariffs comply with the weighted average price cap control formula, the transmission cost recovery tariffs comply with the transmission recovery arrangements and the network tariffs do not exceed the limits on price movements
- demonstrate the impact of the price changes on typical customer's bills and forecast average prices, including the impact on price stability in the short term
- confirm that the proposed prices are consistent with the pricing principles and Network Strategy Statement.

This report will be submitted to the Tribunal with the annual pricing proposals submissions. The annual network pricing report will also be made available by the DNSP to the public at the same time as the annual pricing proposals submission.

The DNSPs will also be required to undertake specific public consultation on changes to tariffs structures and the introduction of new tariffs in the year prior to the change. The information provided as part of this public consultation process will form the basis of the information to be included in the annual network pricing report.

12.2.4 Public consultation requirements

Throughout the 2004 review process, public scrutiny has forced the DNSPs to re-evaluate their proposed tariff strategies, with significant modifications occurring in some instances – Integral Energy has withdrawn their proposal for a seasonal tariff to concentrate on time-of-use tariffs, and has revised their threshold level for the inclining block tariffs.

Hence, the aim of the public consultation requirements is to ensure that:

- DNSPs are aware of the customer impacts of their proposed prices
- customers and stakeholders can have an input into determining whether the prices proposed by the DNSPs meet the pricing principles and the compliance criteria established by the Tribunal.

Most DNSPs acknowledge that they currently undertake informal public consultation with their customer councils and PIAC at the time of the annual pricing proposals, hence the Tribunal believes that having a requirement to explain the reasons for, and impacts of, tariff changes, is not too onerous.

The draft determination requires public consultation to occur in two instances: firstly, for any amendments to the Network Strategy Statement, and secondly, for the introduction of new tariffs, or changes to tariff structures in the year prior to the change occurring. The information and procedures to be followed in these instances are set out in Annexure 14 in the 2004-2009 draft determination.

It has been proposed that stakeholders that would like to be advised when public consultation is occurring should register with the DNSP on a 'Register of Interested Parties' list on their website. In the case of customers with individually calculated network prices who may be affected by any changes, they should be notified individually.

Public consultation on tariff changes for 2004/05

Under the modified timetable in Table 12.1, public consultation on the draft Network Strategy Statement should occur prior to submission of the final statement in September 2004, however the DNSPs have indicated that they wish to undertake some tariff reform commencing 1 July 2004. Consistent with the draft decisions above, the Tribunal will require the DNSPs to undertake public consultation specifically for these proposals prior to submission of the annual pricing proposals for 2004/05.

The Tribunal is aware that the final tariff charges for 2004/05 will depend on the outcomes in the final determination, due for release in May. The Tribunal believes the public consultation requirements can be fulfilled, using the information in the draft determination, particularly as the intent of the public consultation requirements is to indicate changes to tariff structure and criteria.

12.2.5 Default arrangements for non-compliant price proposals

The purpose of the default arrangements is to allow the Tribunal to direct prices in the event that a DNSP does not submit a compliant pricing proposal. The Tribunal expects that this will only occur in exceptional circumstances.

In terms of the provisions, stakeholders, especially retailers, have indicated they prefer that the Tribunal not make any price changes until a complying proposal is submitted - so that only one price change is made during the year. However, the Tribunal is concerned that if a situation arises whereby prices are due to decrease, that is, (?CPI+X+S) < 0, and a compliant proposal is not submitted, then the DNSP is over-collecting revenue for that time period.

The Tribunal has adopted the following default arrangements, such that:

1. If (?CPI+X+S) = 0, for the DNSP in that year, network tariffs will not change on 1 July.
2. If (?CPI+X+S) < 0, for the DNSP in that year, the Tribunal may change network tariffs on 1 July by an amount determined by the Tribunal.

The annual pricing proposals timetable (Table 12.1) indicates when the default arrangements will be enacted, however, the Tribunal has the discretion to decide whether it is a material breach or not and whether the default arrangements should be implemented. Should the Tribunal decrease prices in the event of a non-compliant proposal, the Tribunal may decide to hold prices at this level for the duration of the year in order to limit the number of price changes in any one year.

12.3 Comparative Price and Service Report by the Tribunal

The Tribunal will continue to provide a public comparative report on the DNSPs' historical performance, including financial, operational, service quality, capital expenditure, and consumption by customer class and average prices for the financial year. The Tribunal will begin compiling the report after the receipt and approval of the Regulatory Accounts on 30 October each year. The Tribunal proposes to aim for release of the report in February/March each year.

ATTACHMENT NETWORK PRICING PRINCIPLES

1. ***Prices are to be consistent with the form of regulation, including any price limits on network tariffs determined by the Tribunal.***

   A primary function of prices is the recovery of revenues consistent with efficient costs and regulatory objectives. The form of regulation administered by the Tribunal allows for financial viability where operations meet reasonable efficiency targets. For equity reasons the Tribunal also limits the annual change in some prices.

2. ***Prices should be based on a well-defined and clearly explained methodology.***

   Where there is substantial market power, open and transparent pricing practices are essential.

3. ***Price development should incorporate an analysis of the cost of service provision that includes:***
   - ***(a) definition of the classes of service provided and the parameters by which the quantum and standard of service in each class are measured***
   - ***(b) an examination of the cost elements that arise from the use, operation and expansion of the network***
   - ***(c) for each class of service and each cost element, identification of the relationship between the quantum and standard of service provided and the level of current and future cost***
   - ***(d) an allocation of existing and future network costs to service classes***
   - ***(e) the translation of allocated costs into service prices at the defined service standard, and***
   - ***(f) estimates of the range of subsidy-free prices for each service class.***

   The measurement and allocation of costs form the basic building blocks of price development. A range of feasible approaches exist. However, for DNSPs to be able to demonstrate that their prices are soundly based, efficient and transparent, the process of price development must be rigorous and systematic.

4. ***Prices are to signal the economic costs of service provision, by:***
   - ***(a) being subsidy free (greater than incremental costs and less than stand alone costs)***
   - ***(b) having regard to the level of available service capacity, and***
   - ***(c) signalling the impact of additional usage on future investment costs.***

   Prices can influence how customers use the distribution network and how DNSPs operate and maintain it. They can also influence the level of investment undertaken in expanding capacity. Where prices reflect the economic value of the resources used in providing a service, they make an important contribution to economic efficiency and welfare.

   Economic efficiency requires that prices give correct signals for the use, operation and expansion of the network. This encompasses both allocative and dynamic efficiency. These objectives share a common starting point: the efficient, forward-looking costs of meeting additional network loads.

There is considerable debate over the measurement of the upper and lower bounds for the range of subsidy-free prices (ie stand alone cost and incremental cost). The alternative pricing methodology does not mandate a particular methodology. Rather, it allows DNSPs to select the approach they consider most appropriate to their circumstances.

5. ***Where prices based on 'efficient' incremental costs under-recover allowed revenues, the shortfall should be made up in a manner that minimises the effect on consumption and investment while having regard to the impact on users.***

Economic efficiency requires that usage prices recover at least avoidable costs. This can lead to a shortfall in revenue, since for most parts of the network avoidable costs are less than average costs for most of the time ('sunk costs'). In considering revenue make-up options, minimising the impacts on consumption and investment decisions are important criteria.

6. ***Provided that economic costs are covered, prices should be responsive to the requirements and circumstances of users in order to:***
   (a) discourage uneconomic bypass, and
   (b) allow negotiation to better reflect the economic value of specific services, including services associated with embedded generation and other options.

Users may have individual service requirements that vary from the standard form offered. To maximise the economic benefits available from use of the network, an approach to pricing that is responsive to user requirements and circumstances will be required.

7. ***When allocating TUOS charges to distribution network users DNSPs should, to the extent possible, preserve the pricing signals present in the structure of TUOS charges. (Information on allocated TUOS charges should be available to users on request, to the extent possible).***

Network tariffs include an allowance for charges paid by DNSPs for use of the transmission system. DNSPs should have regard to the economic signals present in the structure of TUOS charges when determining the basis for allocating the charges across users of the distribution network.

Users may have an interest in knowing the extent of their contribution to the distributor's TUOS charges. Availability of this price information may lead to more efficient consumption and investment decisions.

8. ***Information on customer class price levels and structures, service standards, underlying costs, price derivation methods and rationale and medium term price and service strategies should be publicly disclosed in order to allow:***
   (a) current and potential users to understand the basis for prices and to take account of prices and service standards in their consumption, investment and location decisions
   (b) interested parties to better assess the range of opportunities for meeting user requirements, including through services associated with embedded generation, demand management and other options that may reduce users' costs and lead to more efficient outcomes.

Access to information is a key factor affecting market efficiency. The availability and transparency of price information is an essential ingredient for sound decision making. Since investment decisions rely on expectations about the future, this applies equally to information on future prices and service levels.

Some network services are potentially open to competition in meeting users' requirements. Where alternative or competing forms of service provision may be available, users should have the opportunity to choose the option with the lowest economic cost.

9. ***Underlying service classifications, cost data, cost allocations and other elements that contribute to pricing decisions should be periodically reviewed and updated where relevant to reflect industry developments and changes in user requirements and preferences, methods of service provision and costs.***

Changes in areas such as metering technology, retail competition, alternative forms of service provision and user preferences can lead to shifts in the nature of efficient network prices. For prices to remain efficient they should reflect such developments.

10. ***Where DNSP price strategies lead to proposed price movements or price restructuring that may be expected to impose significant adjustment costs on users, transitional price options, a phased approach or other measures should be offered to assist in the management of adjustment costs.***

End users make decisions on location, production and investment in electricity-consuming equipment that are influenced by existing prices. Thus substantial or frequent price changes can impose unreasonable or inequitable adjustment costs on them. Such pricing practices can also reduce economic efficiency by increasing the level of uncertainty and risk.

13 REGULATION OF EXCLUDED DISTRIBUTION SERVICES

The Tribunal has defined prescribed distribution services 'by exclusion', and will apply a separate form of regulation to excluded distribution services as provided for under clause 6.10.5 of the National Electricity Code. A draft report was released in February 2003,[163] which proposed a list of excluded distribution services to be regulated, at least initially, through a combination of pricing principles, information disclosure and price monitoring.

The Tribunal has now considered the submissions it received to the February draft report, and has made a series of draft decisions. These decisions, the Tribunal's analysis and the regulatory package to apply to excluded services are discussed below.

13.1 Summary of draft decision

Prescribed distribution services are 'those distribution services that are not listed as excluded distribution services'. The list of excluded distribution services is shown in Table 13.1, and will remain fixed for the entire regulatory period.

Table 13.1 List of excluded distribution services

Customer funded connections	Design and construction of new connection assets; construction of customer-funded network augmentations
Customer-specific ancillary services	Including maintenance of customer installations and private poles, asset relocation works; conversion to aerial bundled cable; temporary, stand-by, reserve or duplicate supplies, other customer-requested services which are non-standard (however recoverable work undertaken by DNSPs in emergency conditions and separately defined monopoly services, remain as prescribed distribution services)
Metering services for types 1- 4 meters	Including meter supply, installation and maintenance; meter reading, meter tests
Public lighting construction and maintenance	Construction and maintenance of public lighting assets

All excluded distribution services, will initially be subject to a regulatory package of pricing principles, price monitoring and price disclosure. Where it can be demonstrated that 'effective' competition exists in the provision of that service in a specified market, the regulatory package will be removed and no regulation will apply. This will be determined via satisfaction of a 'competition test', outlined in section 13.3.2.

For services associated with construction and maintenance of public lighting, additional information disclosure and price monitoring requirements will apply.

163 IPART, *Review of Prescribed and Excluded Distribution Services Draft Decision*, February 2003.

Box 13.1 Code requirements

In determining which distribution services should be deemed 'prescribed distribution services' the Tribunal is to have regard to:

* the principles for regulation of distribution service pricing described in clause 6.10.3
* the extent of effective competition in the provision of that distribution service
* whether sufficient competition exists to warrant the application of a regulatory approach which is more 'light handed' than the approach in clause 6.10.5
* the effectiveness of the form of economic regulation specified under clause 6.10.5 in achieving the efficiency objectives included in clause 6.10.2
* the form if any, of that regulation.

Distribution services that are not prescribed distribution services are deemed excluded distribution services (cl 6.10.4(b)).

The Tribunal may apply a regulatory approach to excluded distribution services that is more 'light-handed' than the regulation applied to prescribed distribution services in clause 6.10.5 (cl 6.10.4(b)).

To implement a light handed regulatory approach for excluded distribution services the Tribunal has relied on the rule making power under the Code (cl.6.10.1(h)).

13.2 Tribunal's analysis and rationale

In general, stakeholders who responded to the Tribunal's draft report on prescribed and excluded distribution services supported the decision to define prescribed distribution services 'by exclusion'. However, some raised concerns about the list of excluded services, about the decision to fix this list for the regulatory period, and the components of the proposed regulation. These aspects of the Tribunal's draft decision are explained below.

13.2.1 List of excluded services

The Tribunal has based its decision on whether a distribution service should be excluded, on the extent of competition in the provision of that service. The Code of Contestable Works administered by the Ministry of Energy and Utilities sets out which services are contestable in NSW and the Tribunal used this as a starting point.

The Tribunal included a proposed list of excluded services in the February draft decision.[164] In general, stakeholders agreed that customer funded connections and customer-specific ancillary services should be excluded services. However, there was debate about including metering, public lighting and inspection of customer installations on this list. The Tribunal's decisions for the purposes of the draft determination are outlined below.

Metering services

Metering services for types 1-4 meters will be regulated as excluded distribution services, however metering services for types 5-7 meters will be regulated as prescribed distribution services.

164 IPART, *Review of Prescribed and Excluded Distribution Services Draft Decision*, February 2003.

Types 1-4 meters are mandated for second tier customers with loads greater than 160MWh. Meter services for type 1-4 meters have been contestable since full retail competition was introduced, and there is a relatively robust competitive environment surrounding the provision of these services.

In its draft report, the Tribunal proposed to also include metering services for types 5-7 meters, on the list of excluded services. However, there remains considerable uncertainty about the provision of these services at both a State and national level.

Metering services for types 5-7 meters are currently the responsibility of the local distribution network service provider under a derogation in the Code,[165] and this derogation is due to expire 30 June 2004. Once this derogation expires, these services would be contestable as they may be provided by service providers other than the DNSP. The Ministry of Energy and Utilities is conducting a review of the appropriateness of contestability, but has not yet made a final policy decision. The Joint Review of Meteorology Procedures is also considering the provision of metering services, as part of its investigation into whether it is feasible for DNSPs to roll out interval meters.[166] Until these questions are resolved, the Tribunal has decided that it is appropriate that all services associated with metering for type 5-7 meters, are regulated as prescribed distribution services.

The Tribunal's decision will not prevent metering services for types 5-7 meters from becoming contestable during the regulatory period. However, in these circumstances, a separate charge for metering services would need to be separated out from the existing network charge and included within the weighted average price cap, in order to have transparent price signals.

Submissions from Integral Energy, Country Energy, EnergyAustralia and the Energy and Water Ombudsman of NSW supported metering services for types 5-7 meters, being classified as a prescribed distribution service.

Construction and maintenance of public lighting

The Tribunal has decided to include construction and maintenance of public lighting assets on the list of excluded distribution services.[167] Under the Ministry of Energy and Utilities Code of Practice of Contestable Works, this is a contestable service, and has been since 1997. However, there is little evidence of competition in the market for this service.

Under the 1999 Determination, constructing and maintaining street lights is considered a prescribed service. Several stakeholders claim that this is one of the impediments to competition emerging. The Tribunal does not wish to hinder the development of competition in the provision of this service, and so has listed it as an excluded distribution service for the 2004-09 regulatory period. However, it recognises that there are a number of issues that need to be resolved and has therefore set additional criteria for the regulation of this service.

165 Clause 9.17A.1(d) of the Code is a derogation which makes the local network provider the responsible person for providing metering services in NSW.

166 The Parer review also recommended the roll-out of interval meters which would be the responsibility of the DNSP.

167 There are two other services associated with public lighting that are not excluded services. The first—providing distribution services to deliver energy to the public light—is a prescribed distribution service. The second—providing the energy consumed by the public light—is considered by the Tribunal to be a non-distribution service. As such, it is not affected by the 2004-2009 Determination.

The Tribunal recognises that stakeholders are divided in their views on whether construction and maintenance of public lighting should be an excluded distribution service, and how it should be regulated. The Tribunal is of the belief that the service must be excluded on the grounds of contestability, however recognises that there will be transitioning problems. The Ministry of Energy and Utilities will be establishing a working group on public lighting, which the Tribunal hopes will consider the issues surrounding the provision of the service, particularly service quality and ownership. The Tribunal strongly supports the development of minimum standards of service in this area.

Inspections and maintenance of private poles

The Tribunal will treat maintenance of private poles as an excluded distribution service, however inspections of private poles will remain a prescribed distribution service activity.

Private poles refers to electricity poles that are located on a customer's premises, and are used to convey electricity to the customer's place of residence or for use on their premises. All DNSPs currently inspect private poles as part of their core functions in order to ensure the safety of the surrounding network. The Tribunal believes this should continue to be funded as a prescribed distribution service with no separate charge.

Maintenance on the other hand, is a contestable service and can be performed by accredited service providers. Any maintenance required to be carried out on the private poles should be the responsibility of the customer. For this reason it has been treated as an excluded service and the DNSP may levy a separate charge for this service.

Inspection and maintenance of customer installations

The Tribunal has decided not to list inspections of customer installations as an excluded distribution service, as proposed in the February draft decision. It has been noted that DNSPs carry out inspections of customer installations under network safety regulation requirements, to ensure the safety of the network.[168] Given this, the Tribunal believes this service should be regarded as a prescribed distribution service. Note that inspections carried out in order to meet the safety management plan, are different from inspections of work undertaken by accredited service providers, which is separately charged for as a monopoly fee.

Maintenance of customer installations however will be treated as an excluded distribution service. It is a contestable activity and is excluded on a similar basis as the maintenance of private poles.

13.2.2 Fixing the list for the determination period

The Tribunal has decided to fix the list of excluded distribution services for five years to correspond with the length of the regulatory period for prescribed distribution services.

Setting the list of excluded distribution services for the regulatory period should not restrict a prescribed distribution service from becoming contestable during this time. However, the manner in which the DNSP charges for the service will need to be considered at the time of it

168 The *Electrical Supply (Safety and Network Management) Regulation 2002* requires network operators to implement a customer installation safety plan which includes an inspection regime and takes into account the Code of Practice – Installation Safety Management.

becoming contestable. Under the weighted average price cap arrangements, DNSPs may introduce new prescribed distribution charges, or amend existing charges. If a prescribed distribution service becomes contestable during the regulatory period, the DNSP should set a separate charge for this service, to provide the appropriate price signals. In most cases, this will require the existing charge to be separated, or 'unbundled', from the existing network charge.

13.2.3 Non-distribution services

In developing the list of excluded distribution services, the Tribunal considered whether services provided by the DNSP were non-distribution services. Non-distribution services are not regulated by the Tribunal under the Code, and are not affected by the Tribunal's 2004-2009 determination for distribution services. The services that the Tribunal considers as non-distribution are listed on Table 13.2.[169]

Table 13.2 Non-distribution services

Service
Provision of energy for public lighting
Purchase of electricity from photovoltaic cells or embedded generators (note that charges to these customers for use of the distribution system to transport the electricity are distribution services)
Generation, transmission or retail services
Services provided outside the DNSPs responsible distribution area
Pole and duct rental

13.3 Regulation of excluded distribution services

Initially, the Tribunal will regulate all excluded distribution services via a 'regulatory package' comprising of pricing principles, information disclosure and price monitoring. Where it can be demonstrated to the Tribunal that an excluded service satisfies the 'competition test' as outlined in section 13.3.2, that service will no longer be regulated. However, the 'regulatory package' can be reinstated at a later date, if market circumstances change.

The Tribunal believes that those markets that have effective competition should not be subject to unnecessary regulation. The difficulty lies in determining what is 'effective competition'. Services that are contestable (that is, can be legally provided by service providers other than the DNSP), may still be mostly provided by the local DNSP. However, in some circumstances, even though the DNSP may have the greatest share of the market, the threat of competition ensures that the prices and service provision are at a competitive level.

169 This list is not exhaustive and provides an indication of the types of the services the Tribunal considered.

13.3.1 'Regulatory package' for excluded distribution services

The Tribunal's draft decision on prescribed and excluded distribution services[170] proposed a regulatory package for excluded distribution services, based on pricing principles, annual information disclosure and annual price monitoring. The Tribunal has decided to maintain these three elements, but has reduced the compliance requirements, except for construction and maintenance of public lighting.

In considering this matter, the Tribunal took into account the fact that all the services now on the list of excluded distribution services are contestable. If, during the regulatory period, the Tribunal is presented with evidence that the regulatory package is ineffective, it will undertake public consultation in considering a revised form of regulation for excluded distribution services.

The three elements of the regulatory package are discussed below.

Pricing principle

Prices are to signal the economic costs of service provision by being subsidy free (that is, they should lie between incremental costs and stand alone costs).

This principle provides an upper and lower bound for the pricing of services. Where prices reflect the economic value of the resources used in providing a service, they make an important contribution to economic efficiency and welfare.

There is considerable debate about how best to measure the upper and lower bounds for the range of subsidy-free prices (ie stand alone cost and incremental cost). The Tribunal has decided not to mandate a particular methodology. Rather, each DNSP can select the approach it considers most appropriate to its circumstances.

Information disclosure

DNSPs are required to provide a description of the excluded distribution service, associated terms and conditions, indicative prices, rates and services associated with the provision of the excluded distribution service, on its website, and in hard-copy if requested by a customer or the Tribunal.

The Tribunal has recommended minimum provisions for information disclosure as these services are available in the contestable market. Further information disclosure may disadvantage the incumbent service provider, and would require a more rigorous monitoring regime. Disclosure of some information however should occur to enable customers and stakeholders to compare DNSPs' prices and other elements of their performance. In a competitive market, such information should be freely available, so companies come under pressure to compare their performance and make improvements where possible.

170 Released in February 2003 (www.ipart.nsw.go.au).

Price monitoring

The Tribunal will monitor pricing on a market surveillance basis. If it receives a complaint, the Tribunal will investigate whether the information has been disclosed as represented above and whether the price satisfies the pricing principle described above.

The Tribunal has decided not to require DNSPs to submit information on prices for excluded services annually to the Tribunal for assessment, as proposed in the February draft decision. It was concerned that restricting the DNSPs to annual prices changes would put them at a disadvantage in a competitive market. Furthermore, given that most of the excluded distribution services have been contestable for some time, it considered it prudent to reduce the requirements, except for construction and maintenance of public lighting.

Additional criteria for construction and maintenance of public lighting

DNSPs are required to make the following information available on its website:

- **the overall costs of providing public lighting services**
- **the basis of the costing methodology**
- **the associated standard of service provided, and**
- **outline of prospective changes in costing methodology, service levels or charges.**

One month prior to any change in charges the DNSP must also make available on its website:

- **the new charges**
- **justification for the changes, and**
- **demonstrate the impact on customers.**

The DNSP is required to submit the information and proposed prices to the Tribunal two months prior to any change in charges. The Tribunal will be able to reject the proposed prices and require the DNSP to submit an alternative proposal should the DNSP have not provided sufficient information to justify a price change.

The Tribunal has decided to include additional information disclosure and price monitoring requirements for public lighting to manage its transition to a competitive market during the next regulatory period. DNSPs will have to justify changes in public lighting charges by demonstrating an associated change in costs or methodology. It will also have to notify customers of the changes in advance.

The DNSPs may argue that it is not in their competitive interest to disclose the costs of their business, or highlight any prospective changes to their charges or charging structure. The Tribunal believes that in the absence of sufficient competition, this is necessary to ensure that any increases in charges are justified on a cost basis and that customers are provided with sufficient notice of the impact of any increases. Furthermore, while a competitive market is being developed, it provides prospective service providers with an indication of the costs involved and the levels of service expected by customers.

13.3.2 Competition test

The Tribunal believes 'effective' competition exists where no company has enough market power to allow it to raise prices, lower service quality and restrict services and still maintain profitability. A company that attempts such actions in the face of competition would be expected to lose customers and face lower profits.

This classification includes the situation where a DNSP has a significant share (or all) of the market, but where the threat of competition places sufficient competitive pressure on the DNSP to prevent it from exercising its market power to the detriment of consumers (that is, 'potentially competitive' markets).[171]

In applying the competition test, the Tribunal will have regard to:

- the structural features of the market, which looks at the barriers to entry and the level of competition
- the conduct of firms in the market, which looks at outcomes in the market in terms of supplier behaviour and consumer outcomes.

The structural element examines the pre-conditions for effective competition while the outcomes element focuses on the effectiveness of competition. The structural element of the test is largely a standard component of similar tests applied in other jurisdictions. The Tribunal is proposing that it be augmented by the outcomes component of the test (parts (d) and (e) below) to improve the information base for decision making by the Tribunal.

(a) **Definition of the market.** The market for the service should encompass all services that are in close **competition** with that service.

(b) **Number of firms and the degree of market concentration.**

(c) **Barriers to entry and exit.** Low barriers to entry will facilitate entry to the market and ensure that competitive pressures are brought to bear not only on the DNSP but also all entrants to the market. The Tribunal will need to examine the extent to which there are barriers to entry to the market.

(d) **Supplier behaviour.** Effectively competitive markets may be characterised by actual entry and exit of firms and innovation in service delivery.

(e) **Customer outcomes.** The customer is the ultimate beneficiary of effective competition in the market. The Tribunal will need to see evidence that the customers are benefiting from competition in the market.

To have the 'regulatory package' removed from the excluded distribution service, a DNSP will need to apply to the Tribunal, and demonstrate that there is 'effective' competition for the particular service in terms of these criteria (the full list of criteria to be considered is set out in the attached Rule). The Tribunal will then apply the competition test by forming a judgement on the effectiveness of competition on the basis of information provided by the DNSP.

171 This is to be distinguished from the use of the term 'potential for competition' in the February Draft Decision which referred to a service which is not contestable under the Code of Contestable Works, however has the potential to become contestable in the future.

Applying the test requires observations on the competitive outcomes in the market. For services that have just become legally contestable, there will be no observations on which the Tribunal can judge the effectiveness of competition. In light of this, the Tribunal will not apply the competition test until at least 12 months after a market has become legally contestable.

13.3.3 Re-instatement of the 'regulatory package' to an excluded distribution service

The Tribunal has determined that the 'regulatory package' can be re-instated to a service that has previously passed the competition test, if the circumstances surrounding the provision of that service have changed. A DNSP or a third party will need to apply to have the regulation re-instated. This application will need to demonstrate that the service no longer satisfies the criteria listed. The Tribunal will then reapply the competition test and make a decision.

The Tribunal considered stakeholder comment[172] on this issue, and believes such a provision is necessary to protect customers in the event of an unanticipated change in the market for the provision of that service, for example, a major accredited service provider withdraws.

172 Origin Energy submission to Review of Prescribed and Excluded Distribution Services, 22 April 2003; AGL Energy Sales & Marketing submission to Review of Prescribed and Excluded Distribution Services, April 2003.

APPENDIX 1 LIST OF SUBMISSIONS

Table A1.1 2004 Electricity Network Review Issues Paper - DNSPs

Australian Inland
Country Energy
EnergyAustralia
Integral Energy

Table A1.2 2004 Electricity Network Review Issues Paper

(individual)
AGL Energy Sales & Marketing
AGL Retail Energy Limited
Australian Consumers' Association
Australian Council for Infrastructure Development Limited
Australian Environment Business Network (AEBN)
Combined Pensioners & Superannuants Assoc. Orange Branch
Connect Engineering Pty Ltd
Country Energy Rural Advisory Group
Energy Markets Reform Forum
Energy Users Association of Australia
Environment Protection Authority
Foldraft Pty Ltd
National Electrical Contractor's Association
Origin Energy Retail
Peak Environment Groups of NSW
Public Interest Advocacy Centre
South East Power Lines & Electrical Services
Street Lighting Improvement Program
Tenants' Union of NSW
West Wallsend Combined Pensioners Assoc

Table A1.3 2004 Draft Decision on Prescribed and Excluded Distribution Services

AGL Retail Energy Limited
DNSPs
National Electrical Contractor’s Association
Next Energy
Origin Energy

Table A1.4 Providing Incentives for Service Quality in NSW Electricity Distribution

AGL Retail Energy Limited
Australian Inland
Country Energy
Energy Markets Reform Forum
EnergyAustralia
Integral Energy
Ministry of Energy and Utilities
Origin Energy Retail
Public Interest Advocacy Centre

Table A1.5 Total Cost Review - Meritec Draft Report

Australian Inland
Country Energy
Energy Markets Reform Forum
Integral Energy
Total Environment Centre

Table A1.6 Determining Sales Volumes for 2004 Electricity Network Review

Agility
AGL Energy Sales & Marketing
Country Energy
EnergyAustralia
TransGrid
TXU Electricity Limited

Table A1.7 Comments on Secretariat's Preliminary Analysis Discussion Paper and Supplementary Submissions to 2004 Review

AGL Energy Sales & Marketing
Australian Inland
Country Energy
Energy and Water Ombudsman NSW
Energy Markets Reform Forum
Energy Users Association of Australia
EnergyAustralia
Environment Protection Authority
Integral Energy
Origin Energy Retail
Public Interest Advocacy Centre
Street Lighting Improvement Program
Total Environment Centre
TransGrid

Public Forums

21 February 2002	Forum on form of regulation
11 April 2003	DNSP presentations to interested parties
11 July 2003	Public Presentation on Draft Report on Meritec's Total Cost Review
17 July 2003	Public Presentation of submissions by non DNSP stakeholders
29 July 2003	Providing incentives for service quality

APPENDIX 2A CODE REQUIREMENTS

Code requirement	Reference in 2004-2009 draft determination
Definition of prescribed and excluded services 6.10.4(a)	Chapters 3 and 13
Definition of the form of light landed regulation for excluded distribution services 6.10.4(b)	Chapter 13
Economic regulation either prospective CPI minus X or an incentive based variant 6.10.5(a)	Chapter 3
Specification of the form of economic regulation 6.10.5(b)	Chapter 3
Length of the regulatory period 6.10.5(c)	Chapter 3
Demand growth which the distribution network owner is expected to service over the regulatory period 6.10.5(d)(1)	Chapter 4 and Appendix 4
The service standards applicable over the regulatory period 6.10.5(d)(2)	Chapter 6
Price stability over the regulatory period 6.10.5(d)(3)	Chapter 5 and Chapter 11
Judgement of the potential efficiency gains to be realised in expected operating, maintenance and capital costs 6.10.5(d)(4)	Chapter 4 and Appendix 5
The weighted average cost of capital 6.10.5(d)(5)	Chapter 4 and Appendix 7
Provision of a fair and reasonable risk adjusted cash flow rate of return on efficient investment 6.10.5(d)(6)	Chapters 4 and 5 Appendices 5, 6, 7 and 8
Recovery of reasonable costs arising out of but not limited to taxes, transmission and avoided transmission costs 6.10.5(d)(7)	Chapters 4 and 10
Correction factor from the previous regulatory period 6.10.5(d)(8)	Chapters 3, 4, 5 and 8
Any changes in energy losses in the distribution network	Chapter 7
The on-going commercial viability of the distribution network 6.10.5(d)(10)	Chapter 5 and Appendices 13 to 16
Other relevant financial indicators 6.10.5(d)(11)	Chapter 5 and Appendices 13 to 16
Application of an alternative pricing methodology to the approach set in Part E of chapter 6 6.11(e)	Chapter 12

APPENDIX 2B CLAUSES FROM THE NATIONAL ELECTRICITY CODE

6.1.1 Summary of key principles and core objectives of network pricing

(a) Without limiting the application of any other provision of this *Code*, this clause 6.1.1 summarises the key principles and core objectives which are intended to apply to the *network* pricing arrangements in this Chapter 6.

(b) The key principles underlying the *transmission* and *distribution* pricing provisions in this Chapter 6 are intended to:

(1) promote competition in the provision of *network services* wherever practicable;

(2) facilitate a commercial environment which is transparent and stable, and which does not discriminate between users of *network services*; and

(3) regulate the non-competitive market for *network services* in a way which seeks the same outcomes as those achieved in competitive markets.

(c) The core objectives intended to be achieved by the application of the *transmission* and *distribution* pricing provisions in this Chapter 6 are:

(1) efficiency in the use, operation, and maintenance of, and investment in, the *network*, and in the location of *generation* and demand;

(2) upstream and downstream competition;

(3) price stability; and

(4) equity.

6.10.2 Objectives of the distribution service pricing regulatory regime to be administered by the Jurisdictional Regulators

The *distribution service* pricing regulatory regime to be administered under Part D of the *Code* must seek to achieve the following outcomes:

(a) an efficient and cost-effective regulatory environment;

(b) an incentive-based regulatory regime which:

(1) provides an equitable allocation between *Distribution Network Users* and *Distribution Network Owners* of efficiency gains reasonably expected by the *Jurisdictional Regulators* to be achievable by the *Distribution Network Owners*;

(2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to *Distribution Network Owners* on efficient investment, given efficient operating and maintenance practices of the *Distribution Network Owners*;

(3) ensures consistency in the application of regulations applicable to:

(i) *connection* to *distribution networks*;

(ii) *distribution service* pricing; and

(4) provides for the recovery by *Distribution Network Service Providers* of *Customer TUOS usage charges* from those *Distribution Customers* that have a *metering installation* capable of capturing relevant *transmission system* and *distribution system* usage data, in a way that preserves the location and time signals of the *Customer TUOS usage prices*;

(c) prevention of monopoly rent extraction by *Network Owners*;

(d) an environment which fosters an efficient level of investment within the *distribution* sector, and upstream and downstream of the *distribution* sector;

(e) an environment which fosters efficient operating and maintenance practices within the *distribution* sector;

(f) an environment which fosters efficient use of existing infrastructure;

(g) reasonable recognition of pre-existing policies of governments which are *Distribution Network Owners* regarding *distribution* asset values, revenue paths and prices;

(h) promotion of competition in upstream and downstream markets and promotion of competition in the provision of *network services* where economically feasible;

(i) reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;

(j) reasonable certainty and consistency over time of the outcomes of regulatory processes, recognising the adaptive capacities of *Code Participants* in the provision and use of *distribution network* assets;

(k) reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of *Distribution Network Owners, Distribution Network Users* and the public interest.

6.10.3 Principles for regulation of distribution service pricing

The regime under which the revenues of *Distribution Network Owners* and *Distribution Network Service Providers* (as appropriate) are to be regulated is to be administered by the *Jurisdictional Regulators* in accordance with the following principles:

(a) Concerns over monopoly pricing in respect of the *distribution network* will, wherever economically efficient and practicable, be addressed through the introduction of competition in the provision of *distribution services*.

(b) Where pro-competitive and structural reforms alone are not a practicable or adequate means of addressing the problems of monopoly pricing in respect of *distribution services* or protecting the interests of *Distribution Network Users,* the form of economic regulation to be applied is described in clause 6.10.5.

(c) The form of economic regulation applied by the *Jurisdictional Regulators* must not be changed during a *regulatory control period*.

(d) Subject to clause 6.10.3(c), if a *Jurisdictional Regulator* proposes to amend the form of economic regulation specified in clause 6.10.5 applied to a *Distribution Network Owner,* the *Jurisdictional Regulator* must:

(1) give two years prior notice to the *Distribution Network Owner* of the new economic regulation arrangements to apply from the commencement of the next *regulatory control period*; and

(2) publish a description of the process and timetable for re-setting the form of economic regulation at a time which provides all affected parties with adequate notice to prepare for, participate in, and respond to that process, prior to the commencement of the *regulatory control period* to which that form of economic regulation is to apply.

(e) The regulatory regime to be administered by the *Jurisdictional Regulator* must be consistent with the objectives outlined in clause 6.10.2 and must also have regard to the need to:

(1) provide *Distribution Network Owners* with incentives and reasonable opportunities to increase efficiency;

(2) create an environment in which *generation*, energy storage, demand side options and *network augmentation* options are given due and reasonable consideration;

(3) take account of and be consistent with the allocation of risk between *Network Owners* and *Network Users*;

(4) take account of and be consistent with any obligations of *Code Participants* in relation to *distribution networks* under Chapter 5;

(5) provide a fair and reasonable risk-adjusted cash flow rate of return to *Distribution Network Owners* on efficient investment given efficient operating and maintenance practices on the part of the *Distribution Network Owners* where:

(i) assets created at any *time* under a *take or pay contract* are valued in a manner consistent with the provisions of that contract;

(ii) subject to clause 6.10.3(e)(5)(i), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at a value determined by the *Jurisdictional Regulator* or consistent with the regulatory asset base established in the *participating jurisdiction*;

(iii) subject to clause 6.10.3(e)(5)(i), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the *Jurisdictional Regulator*. In determining the basis of asset valuation to be used, the *Jurisdictional Regulator* must have regard to:

(A) the agreement of the Council of Australian Governments of 19 August 1994, that *deprival value* should be the preferred approach to valuing *network* assets;

(B) any subsequent relevant decisions of the Council of Australian Governments; and

(C) such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2; and

(iv) benchmark returns to be established by the *Jurisdictional Regulator* are to be consistent with the method of valuation of new assets and revaluation, if any, of existing assets and consistent with achievement of a commercial economic return on efficient investment;

(6) provide reasonable certainty and consistency over time of the outcomes of regulatory processes having regard for:

(i) the need to balance the interests of *Network Users* and *Network Owners*;

(ii) the capital intensive nature of the *distribution* sector, the relatively long lives of *distribution* assets, and the variable and frequent *augmentation* of the *distribution network*;

(iii) the need to minimise the economic cost of regulatory actions and uncertainty;

(iv) relevant previous regulatory decisions made by authorised persons including:

(A) the initial revenue setting and asset valuation decisions made by a government at a time at which that government was a *Distribution Network Owner* in the context of industry reform pursuant to the Competition Principles Agreement;

(B) decisions made by *Jurisdictional Regulators* and any regulatory intentions previously expressed; and

(C) decisions made by ministers under jurisdictional legislation.

APPENDIX 3 ADJUSTMENTS TO THE WEIGHTED AVERAGE PRICE CAP FORMULA FOR TARIFF REFORM

The weighted average price cap control formula is calculated using historical audited quantities of consumption. When tariff reform or customer movement occurs, this is not reflected in the weighted average price cap calculation for two years until actual data are available to be used in the formula.

This Appendix sets out the adjustment process which examines how tariff reform initiatives are incorporated in the weighted average price cap formula, when setting prices for year *t+1*. It provides for estimates for the historical quantity weights q_{ij}^{t-1} , to be used in the following circumstances:

- the introduction of new tariffs, where a new tariff is one in which there were no customers on it in the previous year
- the introduction of new tariff components for existing tariffs, or
- where significant customer movement will occur between existing tariffs, at the DNSPs' direction.

In these circumstances, the following processes are to be adopted in calculating compliance with the weighted average price cap formula.

A3.1 Value of q_{ij}^{t-1} when new tariffs, or new tariff components, are introduced

When a new tariff or a new tariff component is introduced, there are no historical quantities available. In order to incorporate these tariff proposals in the weighted average price cap, the Tribunal will allow 'reasonable estimates' to be submitted by the DNSP, based on the quantities that would have been sold, if the new tariff (or new component) had been introduced in year (*t-1*). The Tribunal has developed the following process in order for the DNSP to arrive at 'reasonable' estimates.

Firstly, the DNSP must nominate a corresponding 'current network tariff/s', which represents the tariff that the customers who are expected to move to the new tariff are currently on. In the case of a new tariff component, the corresponding 'current network tariff' component will be the tariff for which the new component is being introduced. The DNSP must provide 'reasonable estimates' for q_{ij}^{t-1} for all units of measure for both the new tariff and the 'current network tariff/s'.

Secondly, the DNSP must make the following assumptions when calculating the 'reasonable estimates' for year *t-1:*

1. The only customers that would have moved to the new tariff/component in (*t-1*) were as a result of the direction of the DNSP due to tariff reform (as permitted under the customer's standard network connection contract).[173] This means that no new

[173] Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.

customers are included in the estimate,[174] nor customers that request to change tariffs either voluntarily, or do so through the actions of the retailer.

The Tribunal believes that estimates for voluntary customer movement should not be included in the first year, as the rate at which customers switch to a new or modified tariff is quite uncertain as it depends on the marketing efforts of the DNSP.

2. Customers have the same consumption and load profile on the new tariff/ component as they did on the 'current network tariff'. This implies that the sum of the 'reasonable' estimates for year *t-1* for each unit of measure on the new tariff plus the 'reasonable' estimates for year *t-1* for each unit of measure on the 'current network tariff', equals the actual audited quantities that occurred for the 'current network tariff' in year *t-1*.

   Despite the fact that in some circumstances, a change in profile may be expected in response to the new tariff (eg particularly for demand management responses), there is likely to be a transitionary phase which will occur over the two years until actual quantities are reflected in the formula.

Value of q_{ij}^{t-1} when new tariffs/ tariff components were introduced in year t-1

In the year after a new tariff or new tariff component has been introduced, there is still not a full year of actual historical data available to be used for q_{ij}^{t-1}, hence the DNSP will be required to submit 'reasonable' estimates for both the new tariff and the corresponding 'current network' tariffs. The DNSP may base the 'reasonable' estimates on the actual quantities that have occurred to date on the new tariff and 'current network tariff'. The DNSP must demonstrate how it has arrived at the estimates, including an analysis of whether the customers consumption or load profile has changed when moving from the 'current network tariff' to the new tariff, and the extent of voluntary customer movement that may have occurred in that year.

A3.2 Value of p_{ij}^{t} when new tariffs or new tariff components are introduced

The p_{ij}^{t} prices of the corresponding 'current network tariff' components will be used as the p_{ij}^{t} prices for the new tariff components. A corresponding 'current network tariff' component may be any component that is measured in the same units of measure as the new tariff component. If there is no corresponding component with the same units of measure, p_{ij}^{t} will be taken as zero.

174 New customers have been allowed for in the growth assumption used when setting the X-factor.

Example 1 Introducing a Step Rate or Inclining Block tariff component

Tariff Reform		p_{ij}^{t}	p_{ij}^{t+1} (proposed)	q_{ij}^{t-1}
Existing tariff – standard domestic				
Fixed charge	$ pa per customer	$30		25,000 customers
Variable rate (all consumption)	c/kWh	0.04		10,000 kWh
Proposed tariff with new component				
Fixed charge	$ pa per customer	$30	$25	25,000 customers
Variable rate 1 (consumption up to 5000kWh)	c/kWh	0.04 (as above)	0.02	5000kWh
Variable rate 2 (consumption over 5000kWh)	c/kWh	0.04 (as above)	0.05	(10,000 – 5,000) = 5,000kWh

A3.3 Value of q_{ij}^{t-1} when customer movement occurs between existing tariffs at the DNSPs' direction

If the DNSP proposes to move a number of customers between existing tariffs, the rate at which revenue will accrue is different to what will be calculated under the weighted average price cap. In these circumstances, the Tribunal will require the DNSP to submit 'reasonable estimates' for q_{ij}^{t-1} for the tariff that the customer is currently on, and the tariff that the DNSP will move the customers to (the 'replacement' tariff).

For compliance purposes, the assumptions the DNSP must make when calculating the 'reasonable estimates' are:

1. The customer movement occurred in (*t-1*).
2. The only customers that moved were as a result of the direction of the DNSP due to tariff reform (as permitted under the standard network connection contract).[175] The estimates are not to include customers that may move at their discretion or due to the retailer discretion (voluntary movement).
3. Customers have the same consumption and load profile under either tariff.

This provision will encompass tariff reform initiatives to existing tariffs, where the DNSPs may change the structure or associated criteria of a tariff, and it may longer not be appropriate for some customers to be on the changed tariff, given their existing consumption and load profile.

'Reasonable estimates' will also be required in the year following the movement, given that a full year of actual data will not be available when setting the prices in the next year.

175 Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.

A3.4 The Tribunal's assessment of 'reasonable' estimates

When assessing the 'reasonableness' of quantity estimates provided, the Tribunal will take the following information into account:

a) The actual audited quantities sold in relevant units under the 'current network tariff' in previous years.

b) A forecast of the number of distribution customers that the DNSP states they will move to the new tariff/component, and the reasons for the move.

c) A forecast of the number of distribution customers that the DNSP expects will remain on the 'current network tariff'.

d) A forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that are to be moved to the new tariff/component.

e) A forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that will remain on the 'current network tariff'.

f) A forecast of the DUOS tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will be moved the new tariff/component.

g) A forecast of the DUOS tariff, and associated revenue, the distributor expects will be payable by those distribution customers that will remain on the 'current network tariff'.

h) Further information as required by the Tribunal to support the numbers.

APPENDIX 4 GROWTH FORECASTS

As discussed in Chapter 4, forecast growth in demand for electricity over the regulatory period affects the capital and operating costs of the DNSPs, as well as the calculation of X-factors in the weighted average price cap.

Following the submission of the DNSPs' growth forecasts, the Tribunal released a paper, entitled *Determining Sales Volumes for the 2004 Electricity Network Review*[171], in July 2003. The paper provided an overview of the growth forecasts submitted by the DNSPs and comparisons against historical, TransGrid and ABARE forecasts. The DNSPs' forecasts were in most cases lower than recent historic growth and other forecasts.

The responses to the Tribunal's paper called for a review of the growth forecasts by an independent expert. As a result, the Tribunal engaged McLennan Magasanik Associates (MMA) to:

- critique the DNSPs' low, medium and high growth scenarios
- determine throughput and demand forecasts for each DNSP.

This appendix provides an overview of the:

- Tribunal's paper on determining sales volumes, including TransGrid and ABARE projections
- DNSPs' submitted growth forecasts, including underlying methodologies/ assumptions as presented in the Tribunal's paper
- MMA's report.

A4.1 Tribunal Paper

The Tribunal's paper *Determining Sales Volumes for the 2004 Electricity Network Review* outlined the theoretical incentive for DNSPs to understate their volume forecasts in order to earn greater revenue than would be required to recoup costs.

If actual sales turn out higher than forecast, then DNSPs will earn more than is required to recoup costs. However, if actual sales turn out lower than forecasts, then DNSPs will not earn enough to recover their costs.

The paper noted that in terms of their most likely 'medium' growth scenarios, the DNSPs are projecting average annual growth rates for energy sales of between 1.5 and 2.0 per cent over the next regulatory period. Across all the DNSPs, the weighted average growth rate in energy sales is forecast to be 1.8 per cent.[172] In general, customer numbers are projected to grow at a slower rate than energy sales, by between 0 and 2.3 per cent a year. This suggests that DNSPs project consumption per customer to increase.

The Tribunal's paper presented the growth forecasts submitted by the DNSPs and the methodologies and key drivers underlying their growth forecasts. These are reproduced below. In developing their submissions, the DNSPs were asked to provide estimates for low,

171 Available on the Tribunal's website www.ipart.nsw.gov.au

172 The weights applied were actual customer numbers and energy sales for 2001/02.

medium and high growth scenarios, with the respective medium scenarios intended to be the 'most likely' scenario at the time submissions were prepared.

Under the medium growth scenario, the DNSPs are forecasting average annual growth rates of between 1.4 and 2.8 per cent for maximum demand in winter, and average annual growth of between 2.7 and 3.1 per cent for maximum demand in summer. The fact that summer demand growth is expected to grow faster than consumption has important implications for network costs and network pricing.

A4.1.1 TransGrid's forecasts

As part of its annual planning review process, TransGrid prepares load forecasts for NSW. These forecasts are used to facilitate ongoing planning, analysis and identification of network constraints. The forecasts are also provided to NEMMCO for inclusion in its annual Statement of Opportunities. The latest publicly available forecasts from TransGrid were included in its 2003 Annual Planning Report, which was released in June 2003.[173] These forecasts are the most up-to-date and supersede those included in the NSW Statement of System Opportunities, which were produced in October 2001.

Table A4.1 summarises the expected low, medium and high growth scenarios for 2004 to 2009, as contained in 2003 TransGrid's Annual Planning Report. The series presented is 'End-use Consumption' representing the energy actually consumed by customers — residential and commercial and also large industrial loads including those supplied directly from the transmission network. Customers are predominantly supplied from the distribution network but could also be supplied from distributed generators located at the customer's site or, in the case of large customers, directly from TransGrid. Because the TransGrid series includes customers supplied from the transmission network and also customers supplied by on-site distributed generation — and so does not pass through distribution networks — the series is not directly comparable to the DNSP forecasts. However, TransGrid reports that beyond 2005, its projections assumed steady industrial load.[174] This suggests the growth rates reported in Table A4.1 are largely attributable to growth in residential and commercial customers supplied via the distribution network and should be broadly comparable to the DNSPs' projections.

Table A4.1 TransGrid projections 2003, end use consumption for NSW

	Scenario					
	Low		Medium		High	
	GWh	%	GWh	%	GWh	%
2004/05	69460	-	69840	-	70520	-
2005/06	70860	2.0	71520	2.4	72740	3.1
2006/07	72080	1.7	73270	2.4	75140	3.3
2007/08	73250	1.6	74940	2.3	77470	3.1
2008/09	74380	1.5	76660	2.3	79680	2.9
Average		1.7		2.4		3.1

It should be noted that TransGrid's forecasts have not yet been subject to any review, public consultation or regulatory approval.

173 This is available on TransGrid's website: http://www.transgrid.com.au/media/20030630_apr2003.html.

174 Personal communication, TransGrid, 11 June 2003.

A4.1.2 ABARE's forecasts

ABARE forecasts that electricity demand in New South Wales will grow by 2.1 per cent each year from 2004/05 to 2009/10, which broadly spans the 2004-09 regulatory period. This projection is lower than TransGrid's medium scenario and higher than the weighted average of the DNSPs' forecasts.

Its energy projections are based on ABARE's model, E4cast. E4cast is a partial equilibrium model of the Australian energy sector that estimates the main interdependencies between energy production, conversion and consumption. The model incorporates real incomes and industry production trends, fuel prices and technical change (or improvements in energy efficiency). The model covers a number of different fuels and forecasts end use consumption across twenty sectors.

Some key assumptions of the model include:

- Gross State Product is forecast to grow at an annual rate of 3.1 per cent between 2000/01 and 2005/06 and up to 2019/20.
- Demand for each fuel source is estimated to fall by 0.5 per cent per year up to 2019/20 based on technical changes in the drive to achieve greater energy efficiency.

A4.2 DNSP forecasts

A4.2.1 EnergyAustralia

Methodology

EnergyAustralia's forecasts are based on modelling and analysis of historical and expected trends in energy market, economic and demographic conditions in the EnergyAustralia region. The impacts of the following drivers are considered in developing the forecasts:

- economic activity
- residential customer numbers and customer characteristics, including appliance holdings
- 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
- short-term abnormal weather and day type impacts
- political, economic and market uncertainties associated with future trends in the above issues.

The analysis features a disaggregated approach. The prospects for the residential and non-residential sectors are assessed and forecast independently, using statistical models. The residential forecast is based on an end-use forecasting approach that disaggregates electricity usage into 17 common electrical appliances. Key inputs into the forecast modelling are:

- Independent projections of residential sector customer numbers, provided by the National Institute of Economic and Industry Research (NIEIR), based upon its socioeconomic modelling and judgement about future population and housing trends in EnergyAustralia's network area.

- Projections of penetration rates for the appliances in the model, based upon historical trends and in-house judgement about future trends.
- Projections of annual average consumption for the appliances in the model, based upon load research information. Annual efficiency improvements for certain appliances are incorporated. These efficiency gains were assumed on the basis of historical trends published in the Australian Greenhouse Office report *Strategic Study of Household Energy and Greenhouse Issues*, June 1998.

The non-residential forecast is based on an econometric model that identifies the statistical relationship between electrical energy consumption and NSW Gross State Product (GSP). The key input to the forecast modelling is projected economic activity within EnergyAustralia's region. The projections were sourced from NIEIR, but were increased by EnergyAustralia, as it considerd that NIEIR had overestimated the extent of drift of investment to the western part of Sydney, particularly in the context of the 2004-09 period. The NIEIR forecasts are included in Table A4.2 below.

In recognition of the inherent uncertainty in predicting future trends in the drivers of electricity consumption, EnergyAustralia analysed a range of projections corresponding to three economic and energy market scenarios (high, expected and low growth). As noted above, the detailed economic and demographic projections in each scenario have been provided by NIEIR. EnergyAustralia indicated that the scenarios that underpin the global forecasts are consistent with those used in NEMMCO's Statement of Opportunities. The forecast process features regular and ongoing reviews and updates of the forecasts and the forecast procedures.

Key assumptions and drivers of forecasts

Table A4.2 summarises the assumed trends in the key drivers of the global forecasts.

Table A4.2 Assumptions underlying EnergyAustralia's scenarios

Driver	Source	Projected Scenario outcome		
		Low	Medium	High
Economic Growth – NSW	NIEIR	1.8% pa	2.9% pa	3.8% pa
Economic Growth – EA	NIEIR	1.7% pa	2.8% pa	3.7%pa
Residential Customers:				
Overall Nos	NIEIR	0.7% pa	1.0% pa	1.2% pa
• % with Air Conditioning	EA	50%	58%	63%
• % with OP Water	EA	39%	40%	41%
• % with Elec Heat/Cooking	EA	60%/65%	62%/67%	65%/70%
• ?Average Consumption	EA models	-0.6% pa	-0.2% pa	0.3% pa
Weather Conditions		Average	Average	Average

Source: EnergyAustralia.

EnergyAustralia notes that energy growth over the 2004-09 period is expected to be lower than experienced during the current regulatory period. It suggests the reason for this is a combination of factors:

- marginally lower economic growth in the EnergyAustralia region, reflecting a weaker global economic outlook, the impact of increasing household debt and a gradual shift of activity toward western Sydney as transport and infrastructure improvements take effect
- lower growth in residential customer numbers, with growth returning to near long term rates after recent above average growth (fuelled by urban consolidation and strong dwelling building activity)
- stabilisation of average consumption per residential customer as a result of penetration of natural gas and solar as alternative fuel sources, and as air conditioning penetration growth slows as saturation levels are approached
- improvements in energy efficiency due to improved public awareness of energy efficiency and demand side management issues.[175]

A4.2.2 Integral Energy

Methodology

Integral Energy applied different methodologies for residential, non-residential and special categories (such as inter-distributor transfers and streetlighting etc). These methodologies and resulting forecasts were subject to independent review. The methods applied were:

- end-use forecasting for energy consumption by residential customers based on
  - forecast customer numbers
  - average consumption for each household appliance
  - forecast changes in penetration rates for each appliance
  - forecast efficiency improvements
- causal (econometric) forecasting for energy consumption by non-residential customers based on the relationship between electricity consumption and NSW Gross State Product and real average electricity prices
- qualitative assessments of annual growth rates for the special categories of demand
- forecasts of customer numbers based on:
  - historical trends in population and number of dwellings in Integral's area as provided by ABS census data
  - historical information on the relationship between regional economic activity and number of non-residential customers and also specific regional planning information at a local government area level.

Key assumptions and drivers of forecasts

Underlying the non-residential forecasts are macroeconomic projections of NSW Gross State Product and regional economic activity. Integral Energy commissioned NIEIR to develop projections for these aggregates. Table A4.3 summarises the specifications of scenarios underlying the NIEIR forecasts. Integral's submission does not identify the assumed values for these aggregates.

175 EnergyAustralia submission, Appendix 3, pp 4-5.

Table A4.3 Assumptions underlying Integral Energy's scenarios

Scenario	Assumptions
Medium (Base) Case	• Interest rates are held at near current levels. • Prudent government expenditure maintains growth. • Housing and equity prices stabilize towards the mid to late period. • Households begin to reduce debt relative to income; this increases savings but reduces household demand growth. • Growth in NSW GSP consistent with current economic forecasts.
High Case	• Strong public and private sector investment in Australian industries. • Full time employment growth and income increases leading to strong household driven growth.
Low Case	• Rapid world recovery places upward pressure on interest rates. • High debt service costs lead to very slow household consumption growth. • Falling house and equity prices result in wealth losses. • Government reduces infrastructure investment. • Increased import penetration stifles established industry sector growth. • Slow down in growth of NSW GSP compared to current economic forecasts.

Source: Integral Energy submission, pp 176-7.

Integral Energy identify some key factors influencing its forecasts:

- Significant demographic change in its area with rapid growth in population, number of dwellings and household incomes.
- High and rapidly increasing penetration of weather sensitive appliances, such as air conditioners and swimming pool pumps, influenced by high inland summer temperatures in Integral's area.
- A slowing in the economic growth rates affecting consumption in the non-residential sector, which accounts for a large proportion of overall energy consumption. This will offset expected growth in the residential sector consumption.

A4.2.3 Country Energy

Methodology

Country Energy commissioned NIEIR to develop forecasts for customer numbers, energy sales and system demand. NIEIR developed forecasts on the basis of the old county council areas that were merged to form Country Energy's supply area. The forecast methodology involved a top-down approach, where the economic outlook for Australia is allocated between the states, and then between different regions within each state.[176] Country Energy's forecasts are based on a combination of time series and regression econometric models that:

- forecast trends in energy sales
- determine the relationship between energy sales and economic and demographic variables and other key drivers of demand.

176 Country Energy submission, pp 8-8.

Specifically, electricity sales are determined from a regression model based on average electricity consumption for residential dwellings and the number of domestic premises, taking account of factors affecting energy consumption—including real income growth, weather variables, population growth, gross state product and real electricity prices. In the model, non-residential electricity sales are linked to gross state product. Growth rates in customer numbers are based on NIEIR's regional economic model, which is based on projections of gross regional product, population growth, construction activity and dwelling stock that have been tailored specifically to the region serviced by Country Energy.[177]

Full details of this methodology and key assumptions can be found in NIEIR's full report to Country Energy, which was included as Attachment C to the Country Energy submission. This is available on the Tribunal's website.

Key assumptions and drivers of forecasts

The key macroeconomic assumptions identified in Country Energy's submission that underlie its projections are:

- Regional economy (defined as Country Energy's area) forecast to grow at 2.1 per cent through to 2012 — 0.9 per cent under the statewide average.
- Housing expected to grow at average rate of 1.2 per cent per annum.
- Population of Country Energy's area is forecast to grow at an average rate of 0.5 per cent — 0.5 per cent below the statewide average. The population growth rate is lower than the expected increase in housing, suggesting a fall in the number of persons per dwelling.

The base case scenario for residential energy sales are assumed to be supported by high sales of air conditioning and an upturn in dwelling construction from 2004/05. Business sales are expected to mirror GSP growth in the Country Energy area. Country Energy's high and lower growth scenario are based on higher and lower assumed GSP and population growth rates.

A4.2.4 Australian Inland

Australian Inland's projections are based on overall network energy trends since 1989/90. Adjustments have been made for the consumption of its major CRNP customer that accounts for around one-third of Australian Inland's total supply. Including its CRNP customer, Australian Inland has experienced average growth of around 1.6 per cent. Over the past decade there has been significant variations across years and regions within Australian Inland's area.[178]

The key features of Australian Inland's sales projections are:

- a relatively flat projection for the CRNP customer under all scenarios
- general sales growth based on historical growth trends for non-CRNP customers
- the high growth scenario incorporating a potential new mining operation (still regarded as speculative in nature.

177 Country Energy submission, pp 8-10.
178 Australian Inland submission, p 24.

Customer numbers are assumed to show no growth over the regulatory period. This reflects recent trends where population is tending to fall in the northern region centred around Broken Hill, are rise in the southern region.[179]

A4.3 MMA's report

Responses to the Tribunal's paper called for an expert review of the growth forecasts submitted by the DNSPs. The Tribunal engaged McLennan Magasanik Associates (MMA) to do this review, and prepare independent forecasts of customer numbers, energy consumption and peak demand for each DNSP. More specifically, it asked MMA to critique the DNSPs' low, medium and high growth scenarios and determine throughput and demand forecasts for each DNSP.

MMA delivered its draft report – *Review of demand forecasts for the 2004 electricity network review* in October 2003. This report is now available on the Tribunal's website. The Tribunal has invited stakeholders to make submissions on the report, along with their submissions on the Tribunal's report on its draft decision.

MMA's review was based on requesting and clarifying historical, methodological and forecast data from the DNSPs and a desk-top review of other available material (including further historical, demographic, weather and economic information). The methodology was restricted to publicly available data and data supplied by the DNSPs. This meant that analysis was generally possible only in two sectors, residential and non-residential, rather than by more disaggregated customer and size classes.

In summary, despite similar overall energy sales growth conclusions, MMA's disaggregated forecasts differ from those of the DNSPs by considerable amounts. MMA have forecast much higher residential growth for EnergyAustralia, but lower residential growth for the other DNSPs. They derived higher non-residential forecasts for Integral, Country Energy and Australian Inland, but reached a result similar to EnergyAustralia's non-residential modelling.

The largest difference was for EnergyAustralia. Differences between business and domestic customers largely cancel out for Integral Energy.

MMA has generally forecast higher peak demand growth than EnergyAustralia and Integral Energy. Summer demand is forecast to grow at a much faster rate than overall consumption, with implications for network resource allocation.

MMA's projections are conservative in their assumptions. MMA has assumed that the 'comfort' factor (the trend growth residual unexplained by other usage factors) will decrease to half of its trend effect. MMA notes that it is difficult to predict a residual, given the lack of drivers to base the predictions on. The half assumption allows for demand management/appliance efficiency effects – where demand management or improved appliance efficiency do not curb residential usage, demand will be higher than forecast.

The key approaches taken by the DNSPs in the forecasting methodology and MMA's comments on these is summarised in Table A4.4.

179 Personal communication, Australian Inland, 10 June 2003.

Table A4.4 DNSP forecasting methodology and assumptions

Residential	Non-residential	MMA Comment
EnergyAustralia		
• Customer number forecast from NIEIR • Average usage per customer using EA appliance model	• Demonstrated relationship between electricity and Gross State Product (GSP) • Move to use same relationship with Network Region Gross Product (NRGP) • NIEIR forecast for GSP	• Forecast residential customer number growth is low compared to recent history • Appliance model suggests a significant shift in average usage from recent history • Strong relationship demonstrated between GSP (but not NRGP) and non-residential usage
Integral Energy		
• Customer number forecast based on history and NIEIR • Average usage per customer using IE appliance model	• Assumed relationship between non-residential electricity and GSP and real price of electricity • Assumed elasticities which reduced significantly over time • NIEIR forecast for GSP and price	• Customer number growth seems high compared to recent history • Appliance model suggests a significant shift in average usage from recent history • No relationship demonstrated for the combined relationship between electricity, GSP and real price • Elasticities are based on judgement alone. This and the rapid reduction in elasticities are not supported • Need to separate forecasts for business and inter distributor transfers (IDT) in the non-residential sector
Country Energy		
• Prepared independently by NIEIR • Methodology not transparent	• Prepared independently by NIEIR • Methodology not transparent	• Historical information limited and very patchy • NIEIR breakup of sectors is very different to that of Country Energy • Forecast information is very different to that prepared by NIEIR in terms of sector numbers
Australian Inland Energy		
• No change in customer numbers • Trend for volume	• No change in customer numbers • Initial reduction in demand for major non-residential customer then flat • Trend for volume for remaining non-residential customers	• Very limited history • Changes to major customer not justified • Trend for other customers not justified

Source: MMA report, pp i-ii.

MMA has used a combination of historical trends and key drivers to produce independent forecasts for each DNSP.

Table A4.5 below summarises the key drivers assessed in MMA's independent forecasting approach, and the methodology used.

Table A4.5 MMA forecasting approach and methodology

Key Driver	MMA approach, methodology and comments
Residential customers	Combination of historical growth and forecasts, taking into account demographic data and forecasts from ABS, NIEIR and the Metropolitan Development Program from Planning NSW. Customer growth is expected to moderate somewhat from recent history but not necessarily shift geographically.
Appliances and average usage per residential customer	Consideration given to history for both general tariff and off-peak loads, appliance models, penetration rates and energy efficiency trends. MMA approach balances historical trend and appliance modelling. Average use per customer is expected to moderate compared to recent history.
Economic Growth	MMA has established a strong relationship between GSP and electricity consumption for the state as a whole, with an elasticity of 0.87. MMA has confirmed the strong relationship between GSP and electricity consumption for the EA network with an elasticity of 0.8. The state wide relationship has been used for all DNSPs apart from EnergyAustralia. MMA has used a common NIEIR GSP forecasts across all DNSPs.
Weather Impact	MMA could not reproduce the impacts estimated by EnergyAustralia and Integral Energy. MMA has therefore used trend analysis.
Price	Both the changes to real price of electricity and the elasticity are very uncertain. MMA has not used any price forecasts or relationship in forecasting.
Cogeneration and major new projects	Own-use by expected additional cogeneration has been used to offset growth in the non-residential sector.
Maximum Demand	Based on MMA's residential appliance model, changes to customer numbers and customer peak usage for the residential sector and load factors for non-residential usage for each DNSP.
Demand Management	Continuation of energy appliance efficiency trends and reduced residential 'comfort factor' growth. No other impact of current programs assumed on either energy or Maximum Demand.

Source: MMA report, pp ii-iii.

APPENDIX 5 OPERATING AND CAPITAL EXPENDITURES

A5.1 Introduction

This appendix provides a comparative assessment of the DNSPs' expenditure in the period 1999/00 to 2003/04 and what they propose for the forthcoming control period (2004/05 to 2008/09). The assessment is made on the basis of partial performance measures: capital and operating expenditure per customer, capital and operating expenditure per MWh energy distributed, capital and operating expenditure/regulatory asset base (RAB) ratio.

Any assessment of total costs is only as good as the data set. As the network business is not a standalone business direct and indirect costs must be assigned to the network business. While there is little room for discretion with direct costs the allocation of indirect and joint costs is often arbitrary and can vary between DNSPs. This would impact on any comparative assessment.

Partial measures reflect output relative to a single input. Obviously, no single partial indicator can provide a complete measure of operational performance. If viewed in isolation, partial productivity indicators can be misleading. For instance, an improvement in labour productivity could reflect a shift to contracting out labour-intensive functions. Similarly, a reduction in operating and maintenance expenditure may reflect changes in capitalisation policy.

Nevertheless, if a range of partial productivity measures is considered, it can provide a general impression of efficiency levels and rates of change.

A5.2 Meritec total costs review

The Tribunal engaged Meritec (New Zealand) Ltd to undertake a comprehensive review of DNSPs' actual and forward distribution expenditure with a particular focus on the prudency and efficiency of the expenditure.[180]

Table A5.1 DNSPs' actual and forecast capital and operating expenditure (2003 prices)

	Capital expenditure			Operating expenditure			Total costs		
2003 prices ($m)	2000-2004	2005-2009	% change	2000-2004	2005-2009	% change	2000-2004	2005-2009	% change
EnergyAustralia	1,344	1,919	43%	1,246	1,423	14%	2,588	3,342	29%
Integral Energy	734	1,254	71%	907	990	9%	1,641	2,244	37%
Country Energy	901	1,119	24%	1,036	1,102	6%	1,937	2,221	15%
Australia Inland	18	14	-24%	45	47	4%	63	61	-4%
DNSPs Total	2,997	4,306	44%	3,234	3,562	10%	6,230	7,868	26%

Notes
1. Columns do not add due to rounding.
2. Transmission related expenditure and capital contribution works, public lighting are excluded.

Source: DNSPs' submissions to Meritec's Total Costs Review.

180 Meritec, *Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers Final Report*, October 2003.

The NSW DNSPs forecast distribution expenditure (capital and operating expenditure) of $7.9bn (2003 prices) for 2005-2009. This is 18 per cent higher than actual 2000-2004 expenditure of $6.7bn (2003 prices).[181] The forecast expenditure comprises $4.3bn capital expenditure and $3.6bn operating expenditure. The forecast capital expenditure is 24 per cent higher than the 2000-2004 capital expenditure in real terms while the forecast operating expenditure is 10 per cent higher than the operating expenditure incurred in 2000-2004.

EnergyAustralia forecasts the greatest increase (in 2003 prices) in both capital and operating expenditure, followed by Integral Energy and Country Energy. EnergyAustralia and Integral Energy's combined capital and operating expenditure is projected to increase by 29 per cent and 20 per cent respectively. The total costs for Country Energy will rise by 2 per cent in 2005-2009. Australian Inland forecasts a $5m decrease in capital expenditure but its operating expenditure is projected to increase by $2m in real term in 2005-2009.

Table A5.2 presents the capital expenditure/operating expenditure mix of the DNSPs' distribution expenditure for the period 2000-2004 and 2005-2009. The capital expenditure/operating expenditure mix varies slightly from 52/48 in 2000-2004 to 55/45 in 2005-2009. This compares with the Victorian distributors' ratio (1996-2002, actual) of 48/52 which indicates the Victoria distributors spent slightly more in operating expenditure than capital expenditure.

Table A5.2 Capital and operating expenditure mix in 2000-2004 and 2005-2009

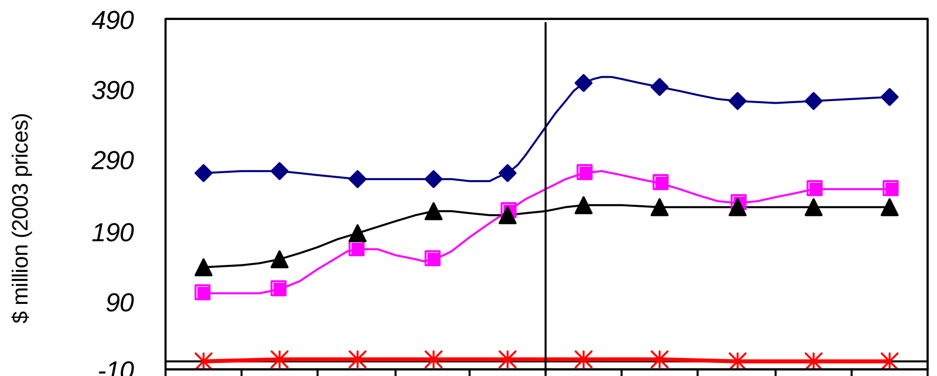
	2000-2004		2005-2009	
2003 prices ($m)	Capex/total costs	Opex/total costs	Capex/total costs	Opex/total costs
EnergyAustralia	52%	48%	57%	43%
Integral Energy	45%	55%	56%	44%
Country Energy	47%	53%	50%	50%
Australia Inland	29%	71%	22%	78%
DNSPs Total	48%	52%	55%	45%

Notes:
1 Columns do not add due to rounding.
2 Transmission related expenditure and capital contribution works, public lighting are excluded.
Source: DNSPs' submissions to Meritec's Total Costs Review.

181 The capital and operating expenditure presented in Table A5.1 excludes expenditure relating to public lighting, transmission assets and capital contribution works.

Figure A5.1 shows the actual and forecast capital expenditure of the DNSPs in each of the years from 2000 to 2009.

Figure A5.1 NSW DNSPs' capital expenditure 2000-2009 (2003 prices)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
EnergyAustralia	271	275	264	263	270	398	394	374	375	379
Integral Energy	101	106	162	148	218	270	257	230	248	249
Country Energy	138	148	185	218	213	225	224	222	224	224
Australian Inland	3	3	4	3	5	3	3	3	2	2

Note 1 Transmission related expenditure and capital contribution works and public lighting related expenditure are excluded.
Source: DNSPs' submissions to Meritec Total Costs Review.

A5.3 Total costs for 1999/2000 to 2003/04

Table A5.3 compares the partial performance measures of the DNSPs in 1998/99 (the year immediately before the start of the period- 1999/00 to 2003/04 with 2003/04 (the end of the current period). The rate of change in these ratios over the period indicates the change in DNSPs' input cost in relation to the change of their outputs.

Table A5.3 NSW DNSPs partial performance measures, FY 1998/99 and 2003/04

	Total cost/customer			Total cost/MWh sold			Total cost/cir km		
2003 prices	1999 $	2004 $	% Change	1999 $	2004 $	% Change	1999 $'000	2004 $'000	% Change
EnergyAustralia	284	353	24%	15	18	17%	8	11	28%
Integral Energy	366	530	45%	20	29	46%	9	12	45%
Country Energy	510	570	12%	38	41	8%	2	2	13%
Australia Inland	585	797	36%	28	36	30%	1	2	30%

Notes:
1 Columns do not add due to rounding.
2 Transmission related expenditure and capital contribution works are excluded.
Source: DNSPs' submissions to Meritec's Total Costs Review.

Over the period, the NSW DNSPs reported increases in distribution expenditure (both capital and operating expenditure) which grew faster than their respective customer base and demand. As a result, the input costs on a per customer, per MWh distributed and per circuit km basis increase over the period.

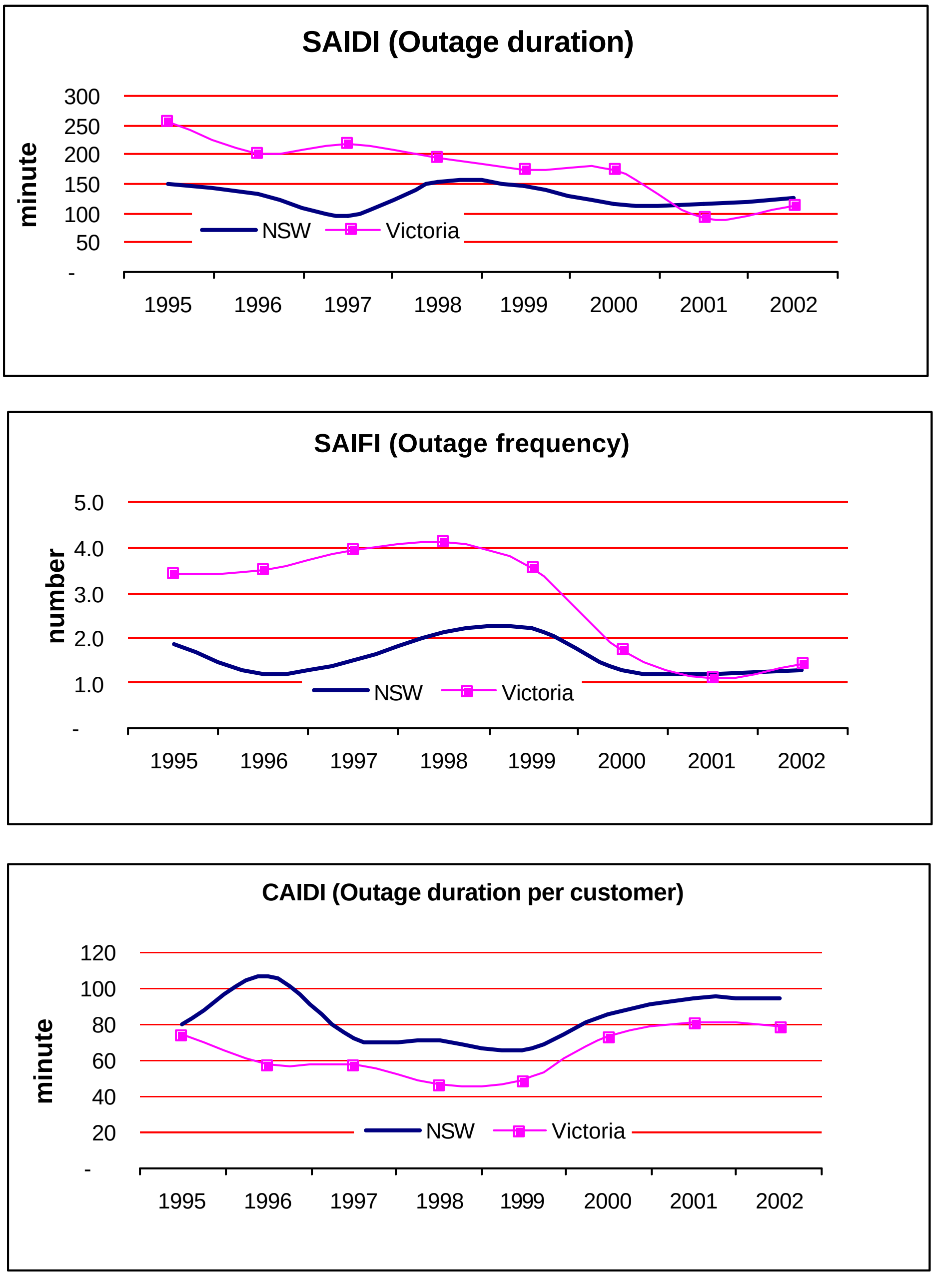
Integral Energy reported the greatest cost increase as measured by the cost per customer (45 per cent), MWh distributed (46 per cent) and circuit km (45 per cent) in real terms. Over the same period Integral Energy's load and customer base respectively grew by 9 per cent and 10 per cent.

A5.4 How expenditure has impacted on system reliability

Figure A5.2 presents the profile of reliability indices, SAIDI, SAIFI and CAIDI of the NSW and Victorian distribution system over the period 1995 to 2002.[182]

[182] The data is drawn from ESAA, *Electricity Australia*, 1997 to 2003.

Figure A5.2 NSW and Victorian DNSPs network reliability indices (1995 to 2002)



Source: ESAA, *Electricity Australia*, 1997 to 2003.

Generally, NSW customers experienced smaller number of outages (SAIFI) and shorter duration (SAIDI) per annum than the customers in Victoria. However, on average each outage experienced by a NSW customer was longer than Victoria over the period as reflected in CAIDI.

EnergyAustralia notes in the *Electricity Network Performance Report 2001/02* that the increased number of major natural events in 2001/02 is a major contributing factor to the worsening system reliability in its distribution area.[183] EnergyAustralia proposes to increase its capital expenditure on reliability from $58m in 2000-2004 to $101m in 2005-2009 (in 2003 prices).

183 EnergyAustralia, *Electricity Network Performance Report, 2001/02*, p 18.

Integral Energy submits that system reliability has worsened since 1999/2000. The factors that contribute to this include adverse weather, defective equipment, human element, lightning, loss of bulk supply, tree contact and bushfires etc.[184] Integral Energy proposes to commit $105m in 2005-2009 to improve system reliability. This represents four times the expenditure in 2000-2004 (or $25m) in real terms.

A5.5 Forecast total distribution costs from 2004/05 to 2008/09

Table A5.4 compares the partial productivity measures based on DNSPs' actual and forecast expenditure:

- capital and operating expenditure/regulatory asset base (RAB)
- capital and operating expenditure/customer
- capital and operating expenditure/MWh energy distributed
- capital and operating expenditure/circuit km.

The amounts shown in Table A5.4 are for the five year period 2000-2004 and 2005-2009.

184 Integral Energy, 2004 Network Review submission to IPART, April 2003, pp 71-72.

Table A5.4 Partial performance measures- NSW DNSPs

2003 prices		EnergyAust 2000-2004 actual	EnergyAust 2005-2009 projected	% change	Integral Energy 2000-2004 actual	Integral Energy 2005-2009 projected	% change	Country Energy 2000-2004 actual	Country Energy 2005-2009 projected	% change	Aust Inland 2000-2004 actual	Aust Inland 2005-2009 projected	% change
Capex	$m	1,344	1,919	43%	734	1,254	71%	901	1,119	24%	18	14	-24%
Opex	$m	1,246	1,423	14%	907	990	9%	1,036	1,102	6%	45	47	4%
Capex + Opex	$m	2,589	3,342	29%	1,641	2,244	37%	1,937	2,221	15%	63	61	-4%
Average RAB	$m	3,819	4,512	18%	1,978	2,374	20%	2,059	2,617	27%	61	62	1%
Avg Customer no.	'000	1,461	1,569	7%	774	862	11%	720	768	7%	19	19	1%
Avg GWh sales	GW	28,260	31,754	12%	13,918	15,703	13%	10,012	10,845	8%	413	442	7%
Avg Circuit km	km	48,581	51,259	6%	33,147	37,337	13%	180,306	186,627	4%	9,300	9,925	7%
Network growth													
Customer no.	%	9%	6%		10%	12%		4%	7%		1%	1%	
MWh energy dist.	%	16%	12%		9%	11%		8%	9%		5%	8%	
System length	%	6%	9%		10%	18%		3%	5%		6%	9%	
Ratios (5 yrs)													
Capex/RAB	%	35%	43%	21%	37%	53%	42%	44%	43%	-2%	30%	22%	-26%
Opex/RAB	%	33%	32%	-3%	46%	42%	-9%	50%	42%	-16%	74%	77%	3%
(Opex+capex)/RAB	%	68%	74%	9%	83%	95%	14%	94%	85%	-10%	104%	99%	-5%
Capex/cutomer	$	920	1,223	33%	948	1,455	53%	1,251	1,457	16%	955	716	-25%
Opex/customer	$	853	907	6%	1,171	1,149	-2%	1,438	1,435	0%	2,388	2,472	4%
(Opex+capex)/customer	$	1,772	2,130	20%	2,119	2,604	23%	2,689	2,892	8%	3,343	3,187	-5%
Capex/MWh distributed	$	48	60	27%	53	80	51%	90	103	15%	44	31	-30%
Opex/MWh distributed	$	44	45	2%	65	63	-3%	103	102	-2%	110	107	-3%
(Opex+capex)/MWh distributed	$	92	105	15%	118	143	21%	193	205	6%	154	138	-10%
Capex/circuit km	$'00	28	37	35%	22	34	52%	5	6	20%	2	1	-29%
Opex/circuit km	$'00	26	28	8%	27	27	-3%	6	6	3%	5	5	-2%
(Opex+capex)/circuit km	$'00	53	65	22%	50	60	21%	11	12	11%	7	6	-10%

Notes:

1 Columns do not add due to rounding.

2 Transmission related expenditure and capital contribution works are excluded.

Source: DNSPs' submissions to Meritec Total Costs Review.

A5.6 NSW DNSPs capital expenditure

Table A5.5 analyses the DNSP's actual and forecast capital expenditure in 2000-2004 and 2005-2009 respectively.

Table A5.5 NSW DNSPs capital expenditure for 2000-2004 and 2005-2009

2003 prices ($million)	EnergyAustralia (medium growth)				
Fin yr ending 30 June ->	**2000-2004**	**% of total**	**2005-2009**	**% of total**	**% change**
Renewal- end of life	233	17%	527	27%	126%
Environmental, safety etc	75	6%	207	11%	177%
Growth	699	52%	842	44%	20%
Reliability	54	4%	101	5%	86%
Non system capital expenditure	159	12%	175	9%	10%
Metering	48	4%	60	3%	25%
Other capital expenditure (Y2K, FRC)	76	6%	7	0%	-91%
Total	**1,344**	**100%**	**1,919**	**100%**	**43%**
2003 prices ($million)	**Integral Energy (medium growth)**				
Fin yr ending 30 June ->	**2000-2004**	**% of total**	**2005-2009**	**% of total**	**% change**
Renewal- end of life	158	21%	401	32%	154%
Environmental, safety etc	17	2%	21	2%	21%
Growth	318	43%	569	45%	79%
Reliability	18	2%	105	8%	480%
Non system capital expenditure	184	25%	117	9%	-36%
Metering	18	2%	41	3%	133%
Other capital expenditure (Y2K, FRC)	23	3%	-	0%	-100%
Total	**734**	**100%**	**1,254**	**100%**	**71%**
2003 prices ($million)	**Country Energy (medium growth)**				
Fin yr ending 30 June ->	**2000-2004**	**% of total**	**2005-2009**	**% of total**	**% change**
Renewal- end of life	308	34%	417	37%	36%
Environmental, safety etc	14	2%	-	0%	-100%
Growth	260	29%	325	29%	25%
Reliability	29	3%	-	0%	-100%
Non system capital expenditure	238	26%	313	28%	31%
Metering	29	3%	64	6%	119%
Other capital expenditure (Y2K, FRC)	23	3%	-	0%	-100%
Total	**901**	**100%**	**1,119**	**100%**	**24%**
2003 prices ($million)	**Australian Inland (medium growth)**				
Fin yr ending 30 June ->	**2000-2004**	**% of total**	**2005-2009**	**% of total**	**% change**
Renewal- end of life	1	6%	-	0%	-100%
Environmental, safety etc	4	20%	2	17%	-37%
Growth	4	21%	4	26%	-7%
Reliability	4	21%	4	31%	13%
Non system capital expenditure	5	30%	4	26%	-34%
Metering	0	2%	-	0%	-100%
Other capital expenditure (Y2K, FRC)	0	1%	-	0%	-100%
Total	**18**	**100%**	**14**	**100%**	**-24%**

Notes:

1 Columns do not add due to rounding.

2 Transmission related expenditure, capital contributions and public lighting are excluded.

Source:DNSPs' submissions to Meritec's Total Costs Review.

A5.7 Comparing NSW DNSPs with Victorian distributors

Table A5.6 compares the NSW DNSPs' forecast expenditure for 2005-2009 with the Victorian DNSPs[185].

Table A5.6 Partial performance measures- comparison of NSW with Victorian DNSPs

2003 prices	Capital expenditure + operating expenditure per customer (2000-2004) $	Capital expenditure + operating expenditure per customer (2005-2009) $	Capital expenditure + operating expenditure per MWh sold (2000-2004) $	Capital expenditure + operating expenditure per MWh sold (2005-2009) $	Capital expenditure + operating expenditure/ RAB (2000-2004) %	Capital expenditure +operating expenditure/ RAB (2005-2009) %
EnergyAustralia	1,772	2,130	92	105	68%	74%
Integral Energy	2,119	2,604	118	143	83%	95%
Country Energy	2,689	2,892	193	205	94%	85%
Australian Inland	3,343	3,187	154	138	104%	99%
Victorian DNSPs minimum (1998-2002)	1,416	(United Energy)	103	(CitiPower)	62%	(CitiPower)
Victorian DNSPs mean (1998-2002)	1,706		120		71%	
Victorian DNSPs maximum (1998-2002)	2,063	(CitiPower)	137	(TXU)	75%	(AGL)

Notes:

1 EnergyAustralia RAB excludes transmission assets.

2 The Victorian ratios cover 5 years to 2002. The mean is the weighted average of all Victoria DNSPs.

Source: DNSPs' submissions to Meritec's Total Costs Review; IPART financial modelling (Meritec total costs) and ESC, Electricity Distribution Business-Comparative Performance Report for 2002.

A5.8 NSW DNSPs system utilisation and regulatory depreciation

Table A5.7 presents the asset utilisation ratios of the NSW DNSPs. The utilisation ratios indicate that DNSPs with large urban concentrations generally have higher utilisation.

185 Essential Services Commission (Victoria), *Electricity Distribution Businesses- Comparative Performance Report for 2002*, August 2003.

Table A5.7 NSW DNSPs network system assets utilisation

		Energy Aust	Integral Energy	Country Energy	Aust Inland
Network Utilisation:					
Overall power transformer capacity (Nameplate MVA)	MVA	16,375	10,347	7,718	155
Corresponding utilisation ratio	%	31	34	27	58
Substations transforming to an intermediate voltage level:					
Total load transferred through these substations	MVA	4,047	2,801	np	np
(n-1) nameplate capacity of transformers	MVA	4,420	2,787	297	25
Corresponding utilisation	%	92	100	np	np
Substations transforming to distribution voltage:					
Total load transferred through these substations	MVA	5,598	3,071	2,095	np
(n-1) nameplate capacity of transformers	MVA	6,260	3,300	3,265	70
Corresponding utilisation	%	90	93	64	np
Distribution substations:					
Total system MD less HV customer demand	MVA	np	5,334	2,488	61
Distribution transformer capacity	MVA	np	7,620	6,769	208
Utilisation ratio	%	np	70	37	29
Energy losses as percentage of energy entering the system	%	4.7	5.5	9.5	10.5[1]
Customers per km of system length	no.	31	24	4	2
Customers per sq km of service area	no.	66	33	1.2	0.12

Note 1: Excluding Australian Inland's largest CRNP customer.
Source: Meritec, Review of capital and operating expenditure of the NSW DNSPs- Final Report, September 2003, Table 1 and 2.

Table A5.8 compares the average depreciation of the DNSPs' distribution assets in the 1999 Network Determination and that forecast by the DNSPs for 2005-2009.

Table A5.8 Regulatory depreciation and average assets life

		Energy Aust	Integral Energy	Country Energy	Aust Inland
Average depreciation - 1999 Network determination forecast	%	4.8%	5.6%	5.2%	5.1%
Average depreciation - Draft 2004 determination (2005-2009)	%	4.4%	6.0%	6.3%	5.6%
Average assets life - 1999 Network determination forecast	yr	21	18	19	19
Average assets life - DNSP forecast (2005-2009)	yr	23	17	16	18

Source: 1999 Network Determination.

A5.9 Regulatory asset value ratios

Table A5.9 compares the NSW DNSPs' regulatory asset value (RAV) for the period 2000-2004 and 2005-2009 with the Victorian distributors as a proportion of the DNSPs' customer numbers, energy consumption and system length.

Table A5.9 NSW and Victoria regulatory asset value per customer

	RAB/ Customer	RAB/ Customer	RAB/ MWh sold	RAB/ MWh sold	RAB/ cir km	RAB/ cir km
	2000-2004	2005-2009	2000-2004	2005-2009	2000-2004	2005-2009
NSW DNSPs	**$000**	**$000**	**$**	**$**	**$**	**$**
EnergyAustralia	2.6	2.9	135	142	79	88
Integral Energy	2.6	2.8	142	151	60	64
Country Energy	2.9	3.4	206	241	11	14
Australia Inland	3.2	3.2	148	140	7	6
NSW mean	**2.7**	**3.0**	**150**	**163**	**29**	**34**
Victorian Distributors	**1998-2002**		**1998-2002**		**1998-2002**	
AGL	2.1		139		na	
CitiPower	3.3		166		na	
Powerco	2.6		172		na	
TXU	2.3		189		na	
UE	2.1		169		na	
Victorian mean	**2.4**		**169**		na	

Note 1: EnergyAustralia's RAB excludes transmission assets.RABs based on Meritec total costs.
Source: DNSPs' submissions to Meritec's Total Costs Review; IPART financial modelling Meritec total costs) and ESC, Electricity Distribution Business- Comparative Performance Report for 2002.

APPENDIX 6 THE REGULATORY ASSET BASE

This appendix presents the Tribunal's analysis on issues affecting the calculation of the opening regulatory asset base (RAB) on 1 July 2004 for the 2004-09 regulatory period, including:

- the methodology used for calculating the opening RAB
- the treatment of capital and operating expenditure incurred during the 1999 regulatory period that was in excess of the regulatory allowances in the 1999 determination.

A6.1 Establishing the opening RAB

The Tribunal's decision for the 2004/09 Draft Determination is to calculate the opening RAB for 2004/05 by rolling forward the RAB from the 1999-2004 regulatory period. The Tribunal has decided not to make any ex-post adjustments to the 1998 RAB upon which the roll forward is based.

A6.1.1 Issues and options considered

The Tribunal's November 2002 issues paper proposed a roll forward approach for calculating the opening RAB for the 2004 regulatory period. Under this approach, the opening value for 2004 is calculated by rolling forward the initial 1998 RAB from the 1999 regulatory period, making adjustments for:

- inflation
- prudent capital expenditure
- actual depreciation
- actual asset disposals.

In their submissions, Integral Energy and Country Energy both indicated a preference for a depreciated optimised replacement cost (DORC) based approach— that is, recalculating the DORC valuation as the basis for the RAB. They argued that the DORC valuation more closely emulates valuation in true market conditions and supports the promotion of competition from alternatives such as remote and embedded generation. On the other hand, EnergyAustralia argued that the roll-forward approach reduces uncertainty for DNSPs:

> 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.[186]

Integral Energy and Country Energy also proposed a range of adjustments to the 1998 RAB. These adjustments were to correct for perceived deficiencies in the valuation conducted in 1998, which was conducted for Treasury on behalf of the businesses by a consultant engaged by Treasury. When it decided on the opening RAB for the 1999 regulatory period, the Tribunal determined that the values calculated by the Treasury valuation formed the upper end of the range for the initial value of the RAB.

186 EnergyAustralia submission to 2004 Review, April 2003, p 54.

The adjustments proposed by the DNSPs included:

- an adjustment of the unit values used to value assets to better reflect replacement costs in 1998 than the 1995 values used in the original study (Country Energy[187])
- an adjustment to reflect better asset age information and alternative methodology for estimating the age of the assets (Integral Energy)
- the re-optimisation of loss minimising investments in line with Tribunal policy (Country Energy)
- the inclusion of unrecognised assets:
  - assets that were not included in the original valuation such as underground connection assets (Country Energy)
  - assets that were not on the asset register of Great Southern Energy (Country Energy)
- an adjustment to reflect the alternative methodology used for valuing rural distribution transformers (Country Energy).

The Energy Markets Reform Forum (EMRF) requested that the Tribunal calculate an Optimised Deprival Value (ODV) value for each DNSP's pre-1999 assets and, in particular, seek to remove stranded and redundant assets from the RAB. It noted that, in the Tribunal's Section 12A report to the Premier, the Tribunal indicated that if the cost of capital were to increase or other circumstances change, the Tribunal reserved the right to calculate an ODV value for each DNSP.

EMRF argued that 'other circumstances' have changed sufficiently to warrant this:

> The EMRF considers that the "other circumstances" have been triggered in the light of the very substantial overruns in capital investment expenditures in the current regulatory period and in the large amounts sought by the DNSPs for the next regulatory period (which substantially increases the RAB and network prices), and the changes in pricing structures said by the DNSPs to a be more cost reflective approach with the move to inclining block tariffs.
>
> Given the circumstances in which the Tribunal arrived at the RAB in 1999, the Tribunal apparently had doubts about the robustness of the figures to have led it to reiterate in several instances (both in its Report to the Premier and its 1999 Determination) that it would conduct an ODV value for each DNSP's pre-1999 assets.
>
> Accordingly, the EMRF reminds the Tribunal of its earlier decision and requests that the Tribunal calculates an ODV value for each DNSP's pre-1999 assets, and in particular seek to remove stranded and redundant assets from the RAB.[188]

Although EnergyAustralia raised the issue of unit values and unrecognised assets noted by Country Energy, it did not propose any adjustments to 1998 RAB. However, it did propose several adjustments to the opening 2004/05 RAB. These were to include:

- holding costs on capital expenditure in excess of the allowance provided for in the 1999 determination

187 This issue was also raised by Integral Energy and EnergyAustralia but was not included as part of their price proposal.

188 EMRF submission to 2004 Network Review, 10 April 2003, p 5.

- an allowance for actual disposals being different from the Tribunal's forecast in the 1999 determination
- an allowance for the NPV loss associated with income tax changes relating to capital contributions.

The first two of these adjustments largely relate to the issue of ex-post adjustments to account for actual outcomes differing from the projections underlying the 1999 determination allowances. This issue is addressed in section A6.2 below, which discusses the Tribunal's proposed treatment of the DNSPs' capital overspend. The issue of the holding costs on the tax on contributed assets is discussed further below.

A6.1.2 Tribunal's analysis and rationale

In deciding how to calculate the opening RAB, the Tribunal's key consideration was the fact that has taken a financial view of the RAB in the past. That is, a DNSP's RAB has been taken to represent the shareholder's financial investment in the business.[189]

This financial view means that, on a forward looking basis, in providing a return on and of the RAB, the Tribunal seeks to maintain the shareholder's financial investment in real terms. It also means that, once the financial value of the RAB is struck, the RAB is effectively detached from the underlying physical assets. Changes in the replacement costs of assets, service lives and methodologies for optimisation do not affect the value of the RAB (except that they might affect the profile of depreciation over time). Changes in these values do not require a re-valuation of the RAB.

The Tribunal's draft decision to roll forward the RAB without making any adjustments to the 1998 RAB is consistent with this financial view.

Methodology for calculating the opening RAB for the 2004 regulatory period

Like EnergyAustralia, the Tribunal believes that the roll-forward approach reduces uncertainty for DNSPs. Indeed, in its report to the Premier in 1999, it noted that:

> The use of an inflation adjusted asset valuation for the on-going RAB diminishes the possibility of regulatory opportunism.[190]

The Tribunal believes that periodic revisions to the RAB (as would occur if Integral Energy's and Country Energy's proposals were accepted) would increase the level of regulatory uncertainty for DNSPs. Furthermore, it does not believe that a DORC valuation is an appropriate basis for determining the RAB for a regulated network business. In its 1999 Section 12A report to the Premier, it concluded that:

- economic analysis can place limits on the valuation of sunk assets with an upper limit being the cost of bypass by an outside firm, that is, the DORC value
- there is no significant economic argument to support basing the initial capital base on the DORC valuation of sunk assets, especially considering the impact of a high initial RAB on economic efficiency

189 IPART, *Pricing for Electricity Networks and Retail Supply, Volume 1*, Rev99-5.1, June 1999, p 82.
190 IPART, *Pricing for Electricity Networks and Retail Supply, Volume 1*, Rev99-5.1, June 1999, p 65.

- a higher initial capital base will tend to reduce allocative efficiency and may limit the potential for downstream competition
- the risk of uneconomic bypass is likely to be higher if prices are set too high.[191]

For these reasons, the Tribunal does not favour periodic revaluations of the RAB based on changes in DORC values. It will therefore calculate the 2004 opening value for the RAB by rolling forward the 1998 RAB value.

The Tribunal is aware that under a strict financial view of the RAB, there would be no role for it to remove stranded or redundant assets from the RAB. But it believes that there are strong benefits from it retaining the power to do so—including encouraging the DNSPs to maintain a disciplined approach to ensuring that their investment decisions are prudent and that customers are not required to pay for assets that are not used to service their demands.

The Tribunal notes that its decision is consistent with the approach taken by the Essential Services Commission (ESC) in Victoria, in its regulation of electricity network businesses.[192] It is also consistent with the ACCC's preferred position in its review of its draft statement of regulatory principles, which is to lock in the RAB for electricity transmission businesses, as detailed in it discussion paper for its review of the Draft Statement of Principles for regulating transmission businesses.[193]

ODV re-valuation of existing assets

The Tribunal has decided not to undertake an ODV re-valuation of pre-1999 assets for the following reasons:

- it would be inconsistent with the Tribunal's preferred approach of rolling forward the existing RAB
- it would add to the level of regulatory uncertainty for DNSPs, which the Tribunal is seeking to avoid by the application of a roll-forward methodology
- it would be inconsistent with the Tribunal's past financial view of the RAB
- the ODV methodology suffers from practical problems associated with the circularity between the economic value of the firm, the RAB and prices.[194]

The DNSPs' proposed adjustments to the 1998 RAB

The Tribunal has decided not to make adjustments to the 1998 RAB as part of the roll forward approach to calculating the opening RAB for 2004.

The establishment of a RAB for a regulated business is not straightforward, and is often controversial. The DORC valuation is one of a large number of valuation approaches. Indeed, the Code (clause 6.10.3) points to COAG's agreement that deprival value should be the preferred approach to valuing network assets. As discussed above, the Tribunal is not

---

191 ibid, p 67.

192 Essential Services Commission of Victoria, *Electricity Distribution Price Determination, Volume 1*, September 2000, p 111.

193 ACCC, *Discussion Paper, 2003 Review of the Draft Statement of Principles for the Regulation of Transmission Revenues*, August 2003, p 26.

194 The value of the RAB depends upon the economic value of the firm which are based upon the regulated prices charged by the firm which are based upon the required return on the RAB.

convinced that the DORC valuation is necessarily an appropriate basis for establishing an opening value for the RAB.

The Tribunal notes that under deprival value approaches, such as ODV, there should be no presumption that an increase in DORC value should necessarily be translated into an increase in the RAB value. The ODV value is calculated as the lesser of the DORC value and the economic value of the assets. If the RAB is determined by the economic value of assets rather than the DORC value, then adjustments to the DORC value would not necessarily be reflected in the RAB value.[195] The New Zealand Ministry of Economic Development has noted that the economic value of assets rather than the DORC value is most likely to apply in network segments in rural areas with remote, lengthy lines.[196]

While the Tribunal has not adopted an ODV estimate of the RAB, it believes that this methodology illustrates that there is not a clear-cut case for increases in DORC values automatically flowing through to regulatory asset values, particularly in rural networks where the economic value of the network may be less than the DORC value of the assets.

In making a decision on the DNSPs' proposals, the Tribunal has, among other things, had regard to the implications of its decision for:

- regulatory certainty
- economic efficiency (allocative and dynamic) and competition
- the balance of interests between network users and the DNSPs' owner.

Regulatory certainty

Country Energy's and Integral Energy's proposed adjustments to the 1998 RAB would, if implemented, lead an increase in these DNSPs' RAB values. Their proposals were based on the results of the most recent asset valuation study of DNSPs' assets. However, the Tribunal is concerned about the potential asymmetry of information it faces. It does not know whether there would also be appropriate adjustments to the RAB that would reduce its value. Indeed, Country Energy point out that:

> …SKM has recently conducted a fresh ODRC valuation of CE's assets for NSW Treasury, valuing the network at $3,530 million at June 2002. A full ODRC valuation addresses issues that will tend to both increase *and decrease* the RAB, and as such do not give CE any opportunity to exploit perceived information asymmetry by highlighting only issues that would increase its RAB.[197]

This suggests that there is the possibility that downward adjustments to the 1998 RAB could be made that may offset the proposed increases. As Integral Energy's submission in response to the Secretariat's preliminary analysis points out, this issue could be resolved through an independent expert examining the DORC valuations. However, the Tribunal's view is that this approach would mean that it is effectively revaluing the 1998 RAB for all

---

195 The Tribunal recognises the well known problem that the calculation of the economic value involves a circularity because of the links between prices and the RAB. However, these problems can be overcome. For example, in New Zealand, the Ministry of Economic Development's handbook on ODV recommends applying prices calculated as the maximum long run sustainable tariffs – defined as tariffs above which customers would disconnect.

196 New Zealand Ministry of Economic Development, *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses*, Third Edition, April 1999.

197 Country Energy submission to IPART on Secretariat Discussion Paper, 20 October 2003, p 29.

DNSPs. As it and other stakeholders have argued previously, revaluations of the RAB increase the level of regulatory risk, which the Tribunal is seeking to avoid by taking a financial view of the RAB and rolling forward the existing RAB.

Economic efficiency and competition

Country Energy's and Integral Energy's proposed adjustments would represent significant additions to their opening 2004 RABs. For Country Energy, the Tribunal estimates that they would add up to $600 million or around 25 per cent to its opening RAB value. For Integral Energy, they would add approximately $190 million or 9 per cent to its opening RAB value.

The Tribunal is concerned that increases of this magnitude would, when translated to prices, have adverse consequences for allocative efficiency, by increasing the gap between the economically efficient marginal cost price and the regulated average price.[198] As it argued in its 1999 Section 12A report to the Premier, this divergence places a constraint on economically efficient consumption, generating 'deadweight' costs to the community. Further, higher valuations can retard downstream competition as downstream firms try to earn sufficient revenue to pass upstream to the regulated firm in order to cover the higher asset value.

Country Energy argued that the value of the RAB has no implications for allocative efficiency and that the difference between average and marginal prices is largely a pricing issue.[199] The Tribunal agrees that more rational tariff structures that reflect the cost of congestion on the network are preferred. However, given the largely fixed costs of providing network services, a purely cost reflective tariff structure would mean that costs would be recovered largely through fixed charges. The practical reality is that DNSPs do recover the majority of costs through volumetric charges. This is largely seen by the community as an equitable basis for sharing costs. As such, the value of the RAB directly affects volumetric prices with implications for allocative efficiency.

Integral Energy's submission questioned whether the allocative efficiency argument is consistent with the Tribunal's focus on demand management.[200] The Tribunal recognises that in some congested parts of the DNSPs' networks, variable tariffs may be lower than the Long Run Marginal Cost of augmenting supply in those areas and that increases in the value of the RAB may increase prices closer to Long Run Marginal Costs. However, it does not accept that this is true for all network tariffs. Further, it considers that local network constraints are best handled through targeted congestion tariffs or other demand management initiatives, rather than through a general increase in prices.

The Tribunal does not believe its decision not to adjust opening RAB values will have any adverse impacts in terms of dynamic efficiency (incentives for investment). While certain assets may not be formally recognised as contributing the RAB value, the DNSP will still be required to maintain and replace the assets if required. As long as the associated maintenance and replacement expenditure is recognised in future notional revenue requirements, the business will retain the incentive to undertake these maintenance and replacement activities.

---

198 While DNSPs do recover a portion of costs via a fixed charge (as part of a two part tariff), the majority of the largely fixed business costs are recovered by the variable component.

199 Country Energy submission to IPART on Secretariat Discussion Paper, 20 October 2003, p 27.

200 Integral Energy, *2004 Electricity Network Review Preliminary Analysis Response,* October 20 2003, p 26.

In response to the Secretariat's discussion paper on its preliminary analysis, Integral Energy and Country Energy raised concerns about the implications for dynamic efficiency of not allowing adjustments to the 1998 RAB. Country Energy suggested that the Tribunal's decision would place at risk any DNSP expenditures that are not explicitly approved by the Tribunal. It submitted that:

> This is inconsistent with the incentive approach adopted by the Tribunal that requires DNSPs to expend capital and operating expenditure in the hope that these will be subsequently recognised by the Tribunal as prudent. An environment in which reasonable expenditures made by a DNSP during a determination can be excluded on the basis that they were sunk by the time they will be approved at the next determination places undue risks on the business.[201]

The Tribunal does not accept this view. The issue at hand relates to the treatment of assets in existence at 1 July 1999, defined in the Code as sunk assets. The DNSPs have already spent capital on these assets, and the only relevant investment decisions they now need to make relate to the maintenance and replacement of these assets. The Tribunal's regulatory framework is very clear on the treatment of expenditures on 'new assets' since 1999 — capital expenditures will be tested for pudency and prudent expenditure rolled into the RAB. There is no question of the Tribunal treating expenditures on new assets in the manner suggested by Country Energy.

Integral Energy and Country Energy also expressed concern that if the Tribunal were not to allow their proposed adjustments, it would not be honouring the implicit regulatory contract between the Tribunal and the DNSPs covering the DORC valuation of its sunk assets. Integral Energy's submission noted that:

> The case for adjusting the RAB is relatively simple and relies on the following logic. Prior to the establishment of the current regulatory regime a decision was taken, consistent with the National Electricity Code, that future regulatory revenues should be set to recover the 1998 ODRC value of existing assets plus future reasonable capital and operating expenditures. That decision reflected the trade off between the need to compensate infrastructure owners for sunk costs and to minimise the prices faced by customers. In doing so a regulatory contract was entered into between the infrastructure owner and the regulator (on behalf of customers).
>
> The argument for revaluing the RAB now is essentially an argument that failure to comply with the regulatory contract will be inequitable and will also increase the perceived level of regulatory risk faced by businesses. If the value established in 1998 can be shown to not accurately reflect the true ODRC value at that time then, under this argument, it is appropriate to make this adjustment such that the original 'regulatory contract' is met.[202]

The Tribunal is particularly concerned about maintaining a regulatory environment that minimises regulatory uncertainty for DNSPs and other stakeholders. However, it disagrees with the contention that its recommendation to make no adjustments to the 1998 regulatory asset value can be construed as breaking a 'regulatory contract' with DNSPs. It does not believe that its 1999 determination created an expectation among DNSPs or other

201 Country Energy submission to *2004 Network Review Preliminary Analysis Secretariat Discussion Paper*, 20 October 2003, p 29.

202 Integral Energy submission to *2004 Network Review Preliminary Analysis Secretariat Discussion Paper*, 20 October 2003, Appendix 1, p 13.

stakeholders that the DNSPs' RABs would be adjusted if inaccuracies were identified in the 1998 Treasury DORC valuation. Moreover, the Code does not require the Tribunal to maintain a RAB based on a DORC valuation for sunk assets.

The Tribunal also point out that its regulation of distribution assets differs from the ACCC's regulation of transmission assets, which includes (draft) regulatory principles that explicitly recognise a DORC valuation of the RAB. The Tribunal's 1999 determination and the preceding report to the Premier included strong criticisms of the principle of DORC valuation. The 1999 determination adopted a value for the RAB that was aligned with the DORC valuation for most DNSPs, but did not indicate that it had accepted the DORC concept as a valuation methodology, as the ACCC has done.

For Country Energy in particular, it would not have been reasonable to expect that a higher DORC valuation would automatically flow into an increase in its RAB. At the time the Tribunal determined the RABs for the businesses that were merged to form Country Energy, the pre-existing policy of the NSW Government, as indicated in a letter to the Tribunal from the Premier, was to constrain the asset values for rural distributors to avoid real price increases in network charges.[203] In light of its decision to write down Australian Inland's RAB in 1999 to avoid real network price increases, the Tribunal considers there is no certainty that, had the adjustments identified by Country Energy been known at the time of the 1999 determination, they would have resulted in a higher 1998 RAB.

Integral Energy and Country Energy proposed that the Tribunal increase their RABs on the basis of their revised engineering-based estimates of the 1998 RAB. However, stakeholders will be aware that the Tribunal's regulatory framework places weight on a range of factors, not just the RAB. In its 1999 determination the Tribunal wrote:

> As it has often signalled, the Tribunal is concerned that an approach that places too much emphasis on the asset value and rate of return may not produce appropriate outcomes and may counter the goals of incentive regulation.[204]

In making its decision on the 1998 RAB, the Tribunal undertook extensive analysis of the issues surrounding the determination of an appropriate level for the initial 1998 RAB. Its decision considered a range of factors, including:

- the principles and objectives set out in the Code, including balancing the interests of stakeholders
- the degree of subjectivity of approach
- implications for economic efficiency and competition
- equity, in terms of impacts on customers and the service provider
- transparency, in terms of stakeholders' expectations
- practicality
- pre-existing government policies.[205]

203 IPART, *Pricing for Electricity Networks and Retail Supply, Volume 1*, Rev99-5.1, June 1999, p 66.

204 IPART, *Regulation of New South Wales Electricity Distribution Networks*, NEC Determination 99-1, December 1999, p 31.

205 The Tribunal's analysis is outlined in both the 1999 Determination and the Tribunal section 12A report to the Premier, which was an input to the draft report.

The Tribunal believes that its past processes and decisions clearly signal to DNSPs and other stakeholders that, in considering proposals to amend the 1998 RAB, it will take account of a range of factors, not only the revised estimates of the 1998 revaluation. It therefore believes the DNSPs could not reasonably have formed an expectation of a regulatory contract that involved adjustments to the RAB on the basis of engineering assessments of the DORC valuation of assets alone—and so does not accept that its draft decision breaches any implicit regulatory contract. In addition, it does not believe its decision will have adverse consequences for dynamic efficiency.

Equity and balancing competing interests

As a result of pre-existing government policies in 1999, the value of the DNSPs' RABs was set at the high end of the range the Tribunal considered feasible for all DNSPs except Australian Inland. If the Tribunal were to adjust the 1998 RAB value, then this would push regulatory values even higher. Given that the assets in question are sunk, it believes this would effectively result in a financial transfer from customers to the DNSP' owner, but at a cost to economic efficiency and regulatory certainty with little other benefit.

The DNSPs suggested that the Tribunal's draft decision does not take account of revenue sufficiency by not allowing a commercial return on the assets not reflected in the 1999 RAB. The Tribunal notes that there is no one correct method of estimating the value of sunk assets and that the valuation of sunk assets in a RAB requires balancing competing outcomes. In terms of commercial outcomes, it notes that its determination leaves the DNSPs in sound financial positions (see Chapter 5).

Adjustments relating to tax on contributed assets

The Tribunal has decided not to make an allowance in the RAB for net present value of losses associated with changes in the income tax provisions for contributed assets. In its April 2003 submission, EnergyAustralia requested a $14 million adjustment to its RAB to compensate it for the cashflow timing difference noted above:

> From 1 July 2001, EnergyAustralia has paid tax on assets excluded from the RAB (ie capital contributions), resulting in a loss of value in present value terms to Energy Australia, being the difference between tax payment on the capital l contribution in the year of receipt and recovery of tax depreciation over the life of the asset (20 years). This loss in value represents the time value of money impact.

To overcome this, EnergyAustralia suggested that including the loss of value (that is, the difference between the tax paid and the depreciation tax shield) should be capitalised and included in the RAB from 1 July 2004. This asset would then earn a rate of return both on the asset and of the asset.

Under its regulatory framework, the Tribunal does not seek to compensate the DNSPs for any gain or loss arising from the tax effect accounting regime. Taxation timing differences (for example — resulting from different depreciation rates, accrual and payment of service leave) are a common occurrence, and sometimes work in the DNSPs' favour and sometimes do not.

In basing the weighted average cost of capital (WACC) on the statutory tax rate rather than an effective tax rate, the Tribunal has elected not to involve itself in the tax affairs of the DNSPs. It therefore considers that the use of a statutory tax rate provides sufficient compensation to DNSPs for the timing difference associated with income tax payable on capital contributions.

A6.2 Treatment of capital and operating overspend from the 1999 regulatory period

The treatment of the DNSPs' capital and operating overspend is relevant to the calculation of the opening value of the RAB, as it affects the amount of depreciation the Tribunal will take into account in this calculation, and whether an allowance for foregone rate of return is included. The Tribunal has decided that:

- it will not allow any ex-post recovery for the foregone rate of return on the capital overspend by DNSPs
- it will roll the overspend into the RAB at its undepreciated value — the roll forward of the RAB will occur on the basis of regulatory depreciation rather than actual depreciation during the 1999 regulatory period
- it will not allow any ex-post recovery of any overspend on operating expenditure.

A6.2.1 Options and issues considered

All four DNSPs reported higher capital and/or operating expenditure than was allowed for in the 1999 determination. The Tribunal indicated in that determination that prudent capital expenditure would be included when establishing the opening RAB for the 2004 determination. However, there is a question about whether DNSPs should be compensated for:

- foregone rate of return (interest costs) on the capital overspend
- depreciation costs on the capital overspend.

There is a further question about whether they should be compensated for excess operating expenditure incurred during the current regulatory period.

In making its decision on the treatment of the capital overspend, the Tribunal considered two key issues:

- Should DNSPs be allowed to recoup the foregone rate of return on the difference between actual capital expenditure and the regulatory allowance provided for in the 1999 determination?
- Should DNSPs be allowed to recoup the foregone depreciation on the difference between actual capital expenditure and the regulatory allowance provided for in the 1999 determination?

The question about the treatment of depreciation is equivalent to asking whether the capital overspend should be rolled into the RAB at an undepreciated or depreciated value. If it is rolled in at an undepreciated value, then the DNSPs would be allowed to recoup the full amount of depreciation from future customers. Practically, the roll-in of undepreciated overspend would mean that only the regulatory depreciation allowance under the 1999 determination would be deducted from the actual value of prudent capital expenditure incurred during the 1999 regulatory period.

EnergyAustralia and Country Energy proposed ex-post recovery of both foregone rate of return and depreciation, while Integral Energy proposed recouping only depreciation (see Table A6.1). Australian Inland did not submit a position on this issue.

Table A6.1 DNSP views on treatment of excess expenditure

DNSP	Capital expenditure		Operating expenditure
	Return on capital	Return of capital	
EnergyAustralia	Seeking recovery of holding costs of $87.8m	Undepreciated excess capital expenditure to be rolled into RAB	Not sought
Integral Energy	Not sought	Undepreciated excess capital expenditure to be rolled into RAB (estimated increase in RAB of $115m)	Not sought
Country Energy	Seeking capitalisation of foregone return on excess expenditure	Undepreciated excess capital expenditure to be rolled into RAB	No position stated
Australian Inland	No position stated	No position stated	No position stated

Integral Energy argued that ex-post recovery of a rate of return on excess capital expenditure and excess operating costs would weaken the incentive regime. However, it argued for a recoupment of the foregone depreciation because:

- the capital expenditure was prudently incurred
- the provision of economically efficient price signals requires the value of the regulated RAB to be maintained at the appropriate level
- the 1999 determination did not meet the features of a well-designed incentive-based regulation scheme and consequently risk allocation and reward principles were breached
- it is necessary to ensure that its business is provided with signals to invest necessary capital expenditure in similar situations in the future (and is consistent with Code requirements that the regulator fosters an environment that encourages efficient levels of investment).[206]

206 Integral Energy submission to 2004 Network Review, April 2003, p 55.

Country Energy submitted that it should be allowed a return on the excess capital expenditure and be allowed to roll the capital overspend into the RAB at its undepreciated value — that is, recover foregone depreciation. It argued that this is appropriate because:

- past prudent expenditure should be recognised in the RAB and that DNSPs should receive a return on this expenditure
- failure to do so would increase uncertainty for businesses in making this expenditures and act as a disincentive for investment
- Clause 6.10.5 of the Code requires the Tribunal to take account of reasonable costs that the DNSP is entitled to recover
- the Tribunal's consultant excluded some $80 million in non-system expenditure which was projected by Country Energy at the time of the 1999 determination and subsequently deemed prudent by Meritec in its most recent review.[207]

Origin Energy put the view that DNSPs should be allowed to recoup any under-recovered return on and return of capital on prudent capital expenditure in excess of that projected for the current regulatory period, and that they should be required to repay any underspending. It argued that:

- the DNSPs should not be allowed to recover any overspending on operating expenditure with a view to encouraging improvements in the efficiency of their operations
- the allowed rate of return should not be reduced, even if DNSPs are allowed to recover costs associated with unexpected capital spending because this is the minimum return required by the asset owner to invest in the assets in the first place.[208]

The Total Environment Centre's submission on behalf of the peak environment groups argued that 'DNSP's should only be able to recoup foregone interest or depreciation on capital expenditure in excess of forecasts when these costs result from demand management programs.'[209] It believes that this would act as a risk hedging safeguard and may address DNSP hesitation around demand management. It further argued that allowing the DNSPs to recoup the foregone rate of return and depreciation on network expenditure would encourage poor planning and inefficient capital expenditure.

The Australian Environment Business Network (AEBN) submits that the 'under-recovered return should not be recovered by increased prices to consumers'.[210] It argued that the shareholder should bear this cost and not consumers.

AGL Energy Sales and Marketing (AGL ES&M) submitted that compensation for the additional capital expenditure should only be considered if it can be demonstrated that the expenditure was prudent and efficient. It should be established that:

- the under-recovered return was a result of circumstances beyond the DNSP's control
- the DNSPs were significantly disadvantaged

207 Country Energy submission in response to Secretariat Discussion Paper, 20 October 2003, pp 45-47.

208 Origin Energy Retail submission, 10 April 2003, p 2.

209 Total Environment Centre submission, 10 April 2003, p 3.

210 Australian Environment Business Network submission, 10 April 2003, p 15.

- the previous regulatory regime did not allow for adequate compensation for such events. [211]

A6.2.2 Tribunal's analysis and rationale

Treatment of rate of return on overspend

The Tribunal has decided not to allow any ex-post recovery of the rate of return on the capital overspend. This decision is motivated by its concern to maintain incentives in its regulatory framework for DNSPs to pursue capital and operating cost efficiencies. The Tribunal believes that if it were to allow DNSPs to recover the foregone rate of return (as well as depreciation) then its regulatory framework would be effectively operating as a cost-plus regime. It believes DNSPs would see few benefits from reducing capital and operating expenditure since they would bear none of the financial risk of higher expenditures. In making its decision, the Tribunal had regard to a number of submissions arguing the importance of maintaining an incentive framework that encouraged efficiency improvements.

For example, the Energy Markets Reform Forum (EMRF) argued that 'it is essential that there are incentives for DNSPs to improve the efficiency of their operations, rather than perpetuate a cost-plus culture'. It put the view that DNSPs should not be allowed to transfer all their business risks to customers, except in exceptional circumstances which must be fully documented, made transparent and independently assessed. It also argued that 'the regulated return on assets (in particular, the market risk premium) must be reduced if DNSPs are allowed to recover a proportion of their business risk costs (in exceptional circumstances.'[212]

Integral Energy also highlighted the importance of avoiding ex-post adjustments to protect the integrity of the incentive regime:

> Similarly, the incentive effects of a regime are weakened if adjustments are made ex-post outside the regulatory contract to address "unacceptable" outcomes. In well-designed regulatory regimes, the mechanisms for sharing benefits between customers and shareholder are well understood; therefore, regulated businesses are able to make informed decisions about investments and performance improvement initiatives.
>
> Ex-post "clawbacks" that are outside the regulatory contract, either to claim back "undue rewards" or by not allowing for unanticipated cost-overruns (due to inadequate revenues being provided at the beginning of the regulatory period, or to address risks that were outside the control of the business), impair the predictability and stability of the incentive mechanism. Such ex-post adjustments encourage gaming behaviour by businesses, both during the review process, in its subsequent actions during the regulatory period. This behaviour substantially weakens the incentive and is likely to reduce net social welfare over the medium to long term.[213]

As noted above, a number of submissions argued that the Tribunal should allow ex-post recovery of both the foregone rate of return and depreciation to maintain positive incentives for investment. For example, EnergyAustralia submitted:

211 AGL Energy Sales and Marketing submission, 10 April 2003, p 3.
212 EMRF submission to 2004 Network Review, 10 April 2003, p 7.
213 Integral Energy submission to 2004 Network Review, 10 April 2003, pp 50-51.

> If the holding costs on the additional capital expenditure are not recognised in full in the regulatory framework, the net present value of the capital investment would be negative, resulting in a net loss of value of EnergyAustralia. A negative return is a disincentive to invest, which EnergyAustralia believes is not consistent with clause 6.10.2(b) of the Code, which requires that the regulatory framework seek to provide (positive) incentives for investment in capital.[214] (EnergyAustralia submission, p 56.)

The Tribunal disagrees with EnergyAustralia's contention that a negative *ex-post* return is inconsistent with clause 6.10.2(b). Firstly, clause 6.10.2(b) requires that the regulatory regime:

> …provides for, *on a prospective basis*, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Business Owners on efficient investment, given efficient operating and maintenance of the Distribution Network Owners' (National Electricity Code, clause 6.10.2(b)(2), emphasis added).

Clause 6.10.2(b) is very much forward looking. In making the 1999 determination and allowing a real, pre-tax rate of return of 7.5 per cent on the expected capital base, including expected investment of the regulatory period, the Tribunal believes that it has satisfied both Clause 6.10.2(b) and also 6.10.2(d). The fact that ex-post returns have turned out lower than 7.5 per cent is due to the capital expenditure and is a risk the businesses have been compensated for in providing a WACC that is substantially more than the risk free rate of return.

In addition, clause 6.10.2(b) makes no reference to positive incentives. The implication of EnergyAustralia's position is that it should not be allowed to make a negative return on investment and should be insured against this risk by a regulatory regime that guarantees them to recoup any such losses from customers at a future date. As noted above, an asymmetric treatment of over spending compared with under-spending would mean that the rate of return on assets would need to be substantially closer to the risk free rate of return than was allowed for in the current determination. EnergyAustralia does not recognise this trade-off in its submission, claiming a real pre-tax WACC of 7.5 per cent for the 2004 regulatory period.

Treatment of depreciation of overspend

The Tribunal has decided to roll in the capital overspend into the RAB at its undepreciated value, allowing the DNSPs to recoup the foregone depreciation incurred during the 1999 regulatory period.

The Tribunal believes that incentives for cost efficiencies could be strengthened further if DNSPs were required to forego depreciation on the capital overspending as argued in the Secretariat's discussion paper on its preliminary analysis. However, while it believes that its approach to foregone rate of return is well signalled in its 1999 determination, it accepts that this determination is less clear on how depreciation of any unexpected capital expenditure would be treated.

In light of decisions by other regulators (such as the ACCC and the ESC in Victoria) to roll forward RABs on the basis of regulatory rather than actual depreciation, the Tribunal accepts that in the absence of any explicit signal to the contrary, DNSPs could have reasonably formed a view that it would have treated depreciation on overspend in a similar manner to

214 EnergyAustralia submission to the 2004 Distribution Network Review, 10 April 2003, p 56.

other regulators. The Tribunal is concerned about providing a regulatory framework that is transparent and limits uncertainty for DNSPs. It has therefore decided to allow DNSPs to recover foregone depreciation on the capital overspend — that is, to conduct the roll forward of the RAB on the basis of regulatory rather than actual depreciation.

The Tribunal's decision means that when the RAB is rolled forward at future regulatory resets it will be on the basis of regulatory rather than actual depreciation, regardless of whether actual capital expenditure is higher or lower than regulatory allowances.

Incorporating the capital overspend at its undepreciated value into the financial modelling used to support this determination is computationally more difficult than incorporating it at its depreciated value. Several submissions in response to the Secretariat discussion paper argued that the opposite was true. However, those submissions do not appear to have fully understood the operation of the Tribunal's financial model. If the overspend were to be rolled in at its depreciated value, the RAB would have been rolled forward on the basis of actual capital expenditure by asset type with the model calculating the actual depreciation associated with that expenditure. The model does not distinguish between allowed capital expenditure and capital overspend. The Tribunal will need to make a number of modelling assumptions to incorporate its decision on recovery of depreciation into the financial modelling.

In the 1999 determination, the Tribunal provided an aggregate depreciation allowance for DNSPs derived from an overall capital expenditure projection. The Tribunal did not break that allowance down by individual asset category or even according to system and non-system asset categories. This decision reflects its approach to provide an overall expenditure allowance, leaving capital and operating decisions to the DNSP. The issue is then how the regulatory depreciation should be allocated against the actual expenditure by asset type incurred during the 1999 regulatory period.

The Tribunal recognises that a number of approaches are possible. In the modelling for this draft determination, it incorporated the depreciation on the overspend in the following manner:

- The RAB is rolled forward from 1 July 1998 to 30 June 2004 using actual capital expenditure.
- The difference between allowed depreciation and actual depreciation (as calculated by the model) for the period 1 July 1999 to 30 June 2004 is indexed to 2003/04 prices and added to the opening RAB on 1 July 2004.
- The total difference in depreciation is allocated to system and non-system assets in proportion to the overspend in these asset categories.
- The system and non-system adjustments are respectively allocated to individual asset classes in proportion to the opening value of assets on 1 July 2004.

Treating the overspend in this manner means that the remaining lives of assets are actual remaining lives (as calculated by the model). The capital overspend will thus be depreciated over the actual remaining life of the asset, rather than over its full economic life.

The Tribunal welcomes comment on this approach from stakeholders.

Treatment of operating cost overspend

To be consistent with its decision not to allow the ex-post recovery of foregone rate of return on the capital overspend, the Tribunal has decided not to allow any ex-post recovery of operating expenditure in excess of that allowed for in the 1999 determination.

APPENDIX 7 RATE OF RETURN

The rate of return is applied to the regulatory asset base to yield a return on assets. The rate of return, or cost on capital is calculated using the weighted average cost of capital (WACC), which is a weighted average of the cost of debt and equity. Regulatory decisions in Australia have generally determined the cost of debt as a margin over the risk free rate, while the cost of equity is calculated using the Capital Asset Pricing Model (CAPM). The return on capital component constitutes a major part of the base revenue requirement.

A7.1 Draft determination on the WACC structure

Finding 1: The Tribunal found for the draft determination that it was appropriate to use a real pre-tax WACC using the statutory tax rate.

In 2002, the Tribunal decided to use a pre-tax real WACC using statutory tax rates in its cost of capital calculations. The Tribunal will use a real pre-tax WACC in the 2004 electricity network review as the regulatory asset base is rolled forward in real terms.

The use of a real pre tax WACC does not necessarily entail the use of the statutory tax rate. However, it would be very difficult and intrusive for the Tribunal to replicate the business's actual tax planning in the financial modelling. The Tribunal therefore has decided to use the statutory tax rate for the 2004 electricity distribution determination.

A7.2 Draft determination on the rate of return

Finding 2: The Tribunal's view for this draft determination is that the industry average WACC is in the range of 6.2-7.6 per cent, using the parameters in Table 7.1.

Table A7.1 WACC parameters

Parameter	Value
Nominal risk free rate (19/11/03)	5.8%
Inflation (19/11/03)	2.3%
Real risk free rate (19/11/03)	3.5%
Market risk premium	5.0-6.0
Debt margin	0.9%-1.1%
Debt to total assets	60%
Dividend imputation factor (gamma)	0.5
Tax rate	30%
Asset beta	0.35-0.45
Debt beta	0.06-0
Equity beta	0.78-1.11
Cost of equity (nominal post-tax)	9.7%-12.5%
Cost of debt (nominal pre-tax)	6.7-6.9%
WACC (nominal post-tax)	6.0-7.0 %
WACC (real pre-tax)	**6.2-7.6%**

Utilities have argued in the past that regulatory WACCs have been decreasing over time without apparent reason. They are concerned that lower WACCs will deter investment in utility assets. In its Tasmanian Transmission Network Revenue Cap final decision, the ACCC addresses the utility's criticism of decreasing regulatory WACCs. It argues that the WACC is made up of a number of parameters and that most of these have not changed over time (market risk premium, gearing, equity beta). The parameters which have changed (ie risk free rate, debt margin) are related to current market conditions. These changes reflect the changes in the rate of return required by similar investments.[215]

In its draft decision, the Tribunal has adopted a conservative approach in estimating those parameters that are not directly dependent on current market conditions. The Tribunal is of the opinion that its draft decision on the WACC results in a number that would not deter investment in utility assets in a competitive market.

A7.3 Approach to calculating the WACC

The weighted average cost of capital (WACC) of a firm is the expected cost of the various classes of its capital (eg equity, debt, etc), weighted by the proportion of each class of capital to the total capital of the firm. In the regulatory context, the WACC represents the rate of return that regulators have applied in setting the allowed revenue and reference tariffs for regulated businesses.

The Tribunal uses the following formula to calculate the nominal post tax WACC:

$$WACC = \frac{R_e \times (1-t)}{[1-t\times(1-g)]} \times (\frac{E}{D+E}) + R_d \times (1-t) \times \frac{D}{D+E}$$

Where:

R_e = cost of equity

R_d = cost of debt

t = the statutory tax rate

? = imputation tax credits

E = proportion equity in capital structure

D = proportion debt in capital structure

E/D+E = the level of equity funding

D/E+D = the level of debt funding

215 ACCC, *Tasmanian Transmission Network Revenue Cap: Final Decision*, 10 December 2003.

The cost of equity, (R_e) can be calculated by using the Capital Asset Pricing Model, CAPM. The CAPM is based on the assumption that an investor in an asset requires additional returns to compensate for the risk borne. Thus, the CAPM asserts that the required rate of return on a risky asset is a function of the risk free rate (R_f), plus a risk premium that reflects the return on a well–diversified portfolio of assets over the risk free rate, (R_m-R_f), where R_m is the return on the market), scaled by the beta (or relative risk). The cost of equity can then be calculated as follows:

$$\boxed{R_e = R_f + b_e \times (R_m - R_f)}$$

This equation introduces an additional term, beta. Beta ($ß_e$) is a measure of the risk of the asset relative to the equity market index. It is measured as the covariance of the excess returns[216] of the asset with the excess returns of the equity market. Thus, beta measures the risk of the asset relative to the co-movement with the overall market that cannot be eliminated by the investor through diversification.

A number of public submissions address the cost of capital of the DNSPs and the use of the WACC model.

The DNSPs have proposed a WACC of 7.5 per cent for Energy Australia and Country Energy and 7.8 per cent for Country Energy and Australian Inland. The DNSPs in their submissions argue that Australian regulatory WACCS are declining and are below WACC decisions of Overseas regulators.

The Energy Users Association of Australia (EEAA) argues that a WACC set at a too high level would ultimately impact on the international competitiveness of Australia. Moreover, it argues the Tribunal should not focus solely on the impact of the cost of capital on future investments in distribution access, but take a broader view in regards to how increases in the cost of capital impact on broader economic benefits. The EEAA argues that Australian regulated rates of return are higher than those observed in the UK and the US. A study done in 1996 indicates that expected returns on Australian equities (between 1979-1995) are slightly below those for the US and the UK.[217]

The Energy Markets Reform Forum (EMRF), considers that the regulated rate of return on assets (in particular the market risk premium) must be reduced if DNSPs are allowed to recover a proportion of their business risk costs through an allowance for asymmetric risk or a cost pass through mechanism. The EMRF argues, that if the DNSPs are allowed to fully recover the cost of unexpected capital expenditure in the 2004 review, it would simply mean that DNSPs are allowed to shift their business risk onto customers by passing these cost on to them. If this is the case, owners of utilities should not be compensated for taking on these risks and consequently, the rate of return should be reduced

Origin Energy Retail argues in their submission that inadequate returns are harmful for investments in the industry. Origin therefore supports a rate of return commensurate with prevailing market conditions and risks involved. The Origin submission does not indicate what this rate of return would be.

216 Excess returns are defined as the excess returns above the risk free rate.

217 Erb, C. Harvey, C. Viskanta, T. *Expected returns and volatility in 135 countries*, Journal of Portfolio Management, Spring 1996, pp 46-58.

The Tribunal has considered these submissions in its analysis of the individual WACC parameters and its draft decision on the rate of return.

The various assumptions made by the Tribunal in regards to the input parameters that form part of the WACC calculation are discussed below.

A7.4 Risk free rate and inflation

Finding 3: The Tribunal decided for the draft determination that it would continue to use the 20-day average of the 10-year Commonwealth Government Bond Rate Index for calculating the nominal risk free rate. It further found that it will continue to use the difference between the 20-day average of the 10-year Commonwealth Government Bond Rate Index and the 20-day average of 10-year Treasury Indexed Bonds[218], using the Fisher equation to derive the inflation rate.

The nominal risk free rate is readily observable in the market as there are a number of instruments traded in relatively deep markets. In past decisions, the Tribunal has used the 20-day average of the yields on 10-Year Commonwealth Government Bond Rate Index to obtain the nominal risk free rate.

The Tribunal rolls over the RAB in real terms. It is therefore appropriate to use the real risk free rate in the calculation of the cost of capital. In past decisions, the Tribunal has subtracted the appropriate forecast inflation rate from the 10-year Commonwealth Government Bond Rate Index to obtain the real risk free rate. As this is done at a specific point in time before the pricing determinations, the Tribunal has no influence on what the actual rates will be.

Inflation and consequently the risk free rate are more difficult to observe in the market as there is only one instrument available, Treasury Capital Indexed Bonds. In the past, the Tribunal has used the difference between the 10-Year Commonwealth Government Bond Rate Index and the treasury indexed bond yield (using the Fisher equation), to obtain an estimate of expected inflation.

A7.4.1 Submissions

The following positions and comments on the risk free rate have been submitted for the 2004 electricity network review.

218 Where no 10-year maturities are available the Tribunal will use the midpoint of the two closest maturities as an estimate of the 10-year yield.

Table A7.2 Submissions on risk free rate and inflation

	Position	Comments
EnergyAustralia (NECG)	Supports the use of the yield of the 10-year Commonwealth bond as the appropriate maturity for the nominal risk free rate. Supports the use of the 20-day average of actual yields in the determination of the nominal and real risk free rate. Supports the use of treasury indexed bonds for the determination of the real risk free rate and the Tribunal's methodology to derive inflation from the difference between the nominal and real rates using the Fisher equation.	Asset maturities should be matched with similar debt maturities.
Integral Energy	Supports the use of the yield of the 10-year Commonwealth bond as the appropriate maturity for the nominal risk free rate. Supports the use of the 20-day average of actual yields in the determination of the nominal and real risk free rate. Supports the use of treasury indexed bonds for the determination of the real risk free rate and the Tribunal's methodology to derive inflation from the difference between the nominal and real rates using the Fisher equation.	Approach is used by the majority of Australian regulators. Methodology takes into account investment horizons, data availability and the basis for calculation of the other WACC parameters.
Country Energy (KPMG)	See above (Integral Energy)	See above (Integral Energy)
Australian Inland	No comments	No comments

The Tribunal released a paper on its preliminary analysis in September 2003. None of the DNSPs has expressed disagreement with the Tribunal's methodology used to determine the nominal and real risk free rates and inflation. There have been no submissions on this issue from the public.

A7.4.2 Tribunal's analysis

Nominal risk free rate

There are two main different views on the choice of the maturity profile of the nominal risk free rate:

- the nominal risk free rate should reflect the life of the assets, or
- the nominal risk free rate should reflect the length of the regulatory period.

Most regulators are adopting the first view. The argument behind this view is that investors who are taking a position in the physical asset do take into account the life of the asset when making the investment decision and not the duration of the regulatory period. Investors are unable to reset their discount rates at the regulatory reset date as they have already taken the investment decision. The 10-year bond best reflects this view as it is the longest maturity available in Australia and is trading in a deep market.

Regulators with the exception of the ACCC (which is using 5-year maturities) are using the 10-year Commonwealth bond market to estimate the nominal risk free rate. There are currently no maturities available that match the expected life of regulated assets. The 10-year bond market is also the most liquid of long maturity bond markets.

The ACCC has argued that matching the bond maturity to the length of the regulatory period minimises expectation errors and this is appropriate for the single period nature of the CAPM. The ACCC further argues that a regular review of investments by investors warrants the use of a shorter bond rate.[219]

However, the Tribunal considers that it is appropriate to choose a bond maturity for the estimation of the risk free rate that reflects the appropriate financing of these assets. Given the relatively long life spans of the regulated assets, it would be inappropriate to use short term maturities for financing purposes.

Real risk free rate

The use of a pre-tax real WACC necessitates the use of a real risk free interest rate. To be consistent with the use of the 10-year Commonwealth Government Bond Rate Index, the Tribunal currently uses the yield on Treasury indexed bonds, adjusted to a reflect a 10-year maturity, to derive the real risk free rate.

Change in CPI

The Tribunal has in the past used the difference between the 10-year Commonwealth Government Bond Rate Index and the Treasury indexed bond yield (using the Fisher equation), to obtain an estimate of expected inflation.

Some of the regulated Australian companies have proposed a different approach in estimating the change in CPI. For example, Envestra[220] derived a real risk free rate by taking the difference between the yields on Commonwealth Government securities and its own inflation forecast (using the Fisher equation). Envestra used the midpoint of the Reserve Bank of Australia's target range as an inflation forecast.

In principle, the differential should reflect full information available, including the various economic forecasts of inflation implicit in the bond rate difference.

A7.4.3 Reasons for decision

The DNSPs have all agreed in their submissions with the Tribunal's past methodologies used in the estimation of the real/nominal risk free rates and the change in CPI. Furthermore, no public submissions have been received on this issue.

Given the above analysis, the Tribunal sees no reason to depart from its past methodologies to estimate the risk free rate and inflation as in previous decisions.

219 NECG, *Weighted Average Cost of Capital,* response to IPART Discussion Paper DP56 on behalf of EnergyAustralia, 2002.

220 Envestra, Response to Consultation Paper No. 1, July 2001, p 13, (ESC).

A7.5 Market risk premium

Finding 4: The Tribunal decided for the draft determination that it would use a market risk premium range of 5 - 6 per cent.

The market risk premium (MRP, also referred to as equity premium) represents the additional return over the risk free rate of return that an investor requires for the risk of investing in a diversified equity portfolio. The measurement of the MRP is a highly contentious issue.

Historical-based measures are the most widely used estimates of the MRP. This approach is simple but it also yields considerably different results depending upon the chosen time horizon used in the sample of equity and risk free returns. Other methods that can be used to estimate the market risk premium include supply–side approaches, surveys and extrapolation from foreign markets.

In past decisions, the Tribunal has used a MRP range of 5-6 per cent. It has considered various market studies and submissions to arrive at this estimate.

A7.5.1 Submissions

The following positions and comments on the market risk premium have been submitted for the 2004 electricity network review:

Table A7.3 Submissions on the MRP

	Position	Comments
EnergyAustralia (NECG)	6%	Evidence shows that MRP should be about 7%. In the context of recent regulatory precedent, EA however recommends a MRP of 6%.
Integral Energy	6%	The current use of a 5-6% range is inconsistent with standard practice amongst Australian and US regulators, and historical averages.
Country Energy (KPMG)	MRP should not be below 6%	In view of recent global economic developments, the appropriate MRP range is 6-7%.
Australian Inland	6%	No comment.

The Tribunal released a paper on its preliminary analysis in September 2003. In response to this publication, both EnergyAustralia and Country Energy propose a market risk premium of 6 per cent would be more appropriate. Integral Energy argues that the Secretariat should adopt a market risk premium range of 6 – 8 per cent.

A7.5.2 Tribunal's analysis

The Tribunal has considered a wide range of data on estimates of the MRP. It also considered four different approaches which can be used to estimate the MRP, which are historic based approached, supply-side studies, surveys and extrapolation from foreign markets.

Table A7.4 provides a comparison of MRPs used in recent regulatory decisions as well as MRPs submitted by regulated companies and MRPs used by institutional investors.

Table A7.4 MRP comparison

Regulator	Value
OFWAT (1999)	3.5%
OFGEM (2002)	3.5%
IPART (electricity 1999)	**5-6%**
IPART (metropolitan water 2003)	**5-6%**
QCA (2001)	6.0%
ACCC (2003) Murraylink	6.0%
ACCC (2003) Transend (draft)	6.0%
ACCC (2001)	6.0%
Offgar (2001)	6.0%
ESC (2000-02)	6.0%
Business	**Value**
EnergyAustralia submission (2003)	6.0%
Integral Energy submission (2003)	6.0%
Country Energy submission (2003)	6.0%
Australian Inland submission (2003)	6.0%
SPI PowerNet submission (ACCC, 2002)	6.0%
ElectraNet submission (ACCC,2002)	6.5%

The MRP used by the Tribunal is lower than that used by all other Australian regulators. British regulators also use a lower MRP.

Available supporting evidence

There is ample research available on the market risk premium. There is however no consensus on what the appropriate value of the MRP should be.

Table A7.5 summarises the views the MRP estimates used by some Australian institutional investors and their advisers.

Table A7.5 MRP estimates

Banking	Value
Mercer (2002)[221]	3.0%
BNP[222]	5.0%
Henderson Global Investors (1950-2002)	5.4%
Henderson Global Investors (1901-2002)	6.0%
Henderson Global Investors (1950-1999)[223]	6.2%

The figures in Table A7.5 seem to indicate that MRP estimates in the market have fallen in recent times when compared to the 5-6 per cent the Tribunal used in past decisions. However, these MRPs are used by institutional investors and may be downward biased.

There are four main ways in which the MRP can be estimated. These are discussed below. All Australian regulators currently use a historic based approach to estimate the MRP.

Historic based approaches

There are a number of studies on historical based MRPs available that are regularly referred to in regulatory decisions. These studies are summarised in Table A7.6.[224]

Table A7.6 Historical based MRPs[225]

Source	Period	Risk premium (arithmetic)	Risk Premium (geometric)
AGSM - Arithmetic average[226]	1964-1998	4.8	2.8
AGSM - Arithmetic average, incl. Oct. 1987	1964-1995	6.2	4.1
AGSM - Arithmetic average, incl. Oct. 1987	1964-Sep. 2000	6.2	4.4
Officer[227]	1946-1991	6.0-6.5	-
Hathaway	1947-1991	6.6	-
Officer[228]	1882-2001	7.2	-
AGSM - Arithmetic average, excl. Oct. 1987	1964-Sep. 2000	7.7	6.4
AGSM - Arithmetic average, excl. Oct. 1987	1964-1995	8.1	6.6

221 Mercer Investment Consulting, Victorian Essential Services Commission Australian Equity Risk Premium, 1 July 2002.
222 Cited in: BRW June 29, 2001 Vol 23, Nr 25.
223 AMP Henderson Global Investors.
224 The discussion of historic based approaches is restricted to studies on the arithmetic average. No geometric average is used by any Australian regulator.
225 Both arithmetic and geometric average results are shown where available.
226 All AGSM studies in this table are sourced from: IPART, *Regulation of NSW Electricity Distribution Networks*, section 5.4.2, Table 5.4, December 1999.
227 Officer, R. "Rates of return to shares, bond yields and inflation rates: An historical perspective", in *Share Markets and Portfolio Theory; Readings and Australian Evidence*, 2ed, University of Queensland Press, 1992.
228 Dimson, E, Marsh, P and Staunton, M., *Triumph of the Optimist: 101 years of Global Investment Returns*, Princeton University Press, 2002.

Officer has provided the following MRPs with values for the standard error associated to the estimations.

Table A7.7 MRP and standard error of the mean[229]

Time period	MRP %	Standard deviation %	Standard error of the mean %
1882-2001	7.19	16.97	1.55
1882-1950	8.00	11.11	1.34
1882-1970	8.16	13.70	1.45
1882-1990	7.40	17.33	1.66
1900-2001	7.14	17.94	1.78
1950-2001	6.51	22.60	3.13
1970-2001	3.37	24.38	4.31

As indicated in Table A7.7, the estimates of the MRP have a very large standard error and a high standard deviation. Given the uncertainties surrounding the statistical estimation of the MRP, the Tribunal believes that it is appropriate to include some element of judgement when determining the MRP.

Table A7.8 shows a number of country market risk premiums as estimated by the London Business School.

Table A7.8 London Business School historic MRP estimates[230]

London Business School (1900-2001)	Value
UK	5.5%
Canada	5.7%
US	6.7%
France	6.7%
Australia	**7.9%**
Germany	9.6%
Japan	10.0%
World	**5.4%**

Except for UK regulators and Mercer, the Tribunal's MRP range is well in line with what other regulators and institutional investors are using. The mid point of the MRP range used by IPART is also very close to the world average as estimated by the London Business School. It is however below the historical-based estimate of the market risk premium for Australia.

229 Dimson, E, Marsh, P and Staunton, M., *Triumph of the Optimist: 101 years of Global Investment Returns*, Princeton University Press, 2002.

230 Dimson, E, Marsh, P and Staunton, M., *Global Evidence on the equity risk premium*, London Business School, September 2002.

The historical–based approach in estimating the MRP that investors will be able to realise the same level of returns as they have in the past. However, the high MRP implied by the historical-based approaches can be explained by a number of factors which have impacted on share markets around the world during the last 50 years or so:

- equity cash flow exceeded expectations,
- required rate of returns fell as investment risk declined and
- the scope for diversification increased.[231]

Given that the outlook for medium-term GDP growth is well below 6-8 per cent, it is unlikely that the forward looking market risk premium will fall within this range.[232] It is also clear that uncertain economic outlooks have caused the level of investment risk to rise which in turn will cause the required rate of returns to rise. Lastly, as global equity markets are becoming more and more integrated, the effects of diversification are lessened.

The above evidence suggests that there is fundamental uncertainty about whether the share market will be able to provide investors with the same level of returns as it has in the past. The Tribunal therefore considers that it cannot base its decision on an appropriate value of the market risk premium solely on historical-based approaches.

Supply side approaches

Most of the research available on supply side approaches have been undertaken in the US. The supply side approaches generally estimate the MRP as the sum of the expected dividend yield and the expected capital gain of shares. Most studies use the dividend growth model as a proxy for capital gains.

The MRPs resulting from supply side approaches are generally lower than the historic based generated MRPs. It is however, questionable if financial ratios or the dividend growth model provide accurate forecasts of future share returns.

Table A7.9 MRP supply side approaches

Source	Methodology	Period	Equity premium
Fama and French (2002)[233]	Dividend growth	1951-2000	3.8%
Jaganathan, McGrattan & Scheriban (2000)[234]	Dividend growth	1926-1999	4.3%
Fama and French (2002)	Dividend growth	1872-2000	4.4%
Fama and French (2002)	Earnings growth	1951-2000	4.8%
Jaganathan, McGrattan & Scheriban (2000)	GNP growth	1926-1999	5.7%

231 Dimson, E, Marsh, P and Staunton, M., *Global Evidence on the equity risk premium,* London Business School, September 2002.

232 Cornell, Bradford, *The Equity Risk Premium: the long run future of the stock market*, 1999, NY, Wiley.

233 All Fama and French studies are sourced from: Fama, E. and K. French, *The equity premium*, Journal of Finance, Vol. LVII, no. 2, 2002.

234 All Jaganathan, McGrattan & Scheriban are sourced from: Jaganathan, R.E., McGrattan and A. Scheriban, *The declining US Equity Premium*, Federal Reserve Bank of Minneapolis Quarterly Review, Vol. 24, no. 4, 2000.

The Tribunal does not consider that there is enough evidence available to base the estimation of the MRP solely on supply side studies. However, the supply side studies presented above indicate that a different approach to estimating the market risk premium yields considerably lower estimates than the historical-based approach.

Surveys

There have been a number of surveys on the expectations of the MRP conducted in both the US and Australia. The problems associated with these surveys are that they are conducted at a specific point in time, that is, they reflect current market sentiment and cannot be consistently applied over a long term period such as the regulation of infrastructure assets. On the other hand, they do reflect the MRP institutional investors or Chief Financial Officers are using to evaluate investment decisions. A number of recent US and Australian surveys are summarised in Tables A7.10 and A7.11.

Table A7.10 MRP - US surveys

US Surveys	Time of survey	Responses	Equity Premium
Graham & Harvey (2001) - Chief Financial Officers[235]	June 2000-Sep. 2001	1116	4.2
Welch (2001) - Finance Academics[236]	August 2001	510	mean: 5.5
			median: 5.0
Welch (2000) - Finance Academics[237]	Oct. 1997 - late 1998	226	mean: 7.1
			median: 7.0

Table A7.11 MRP - Australian surveys[238]

Jardine Fleming Capital Markets Survey 2001		Australia		United States	
	Responses	Past	**Expected**	Past	Expected
Asset Consultants/Trustees	4	6.67	**3.13**	5.67	2.13
Brokers	20	5.05	**4.50**	5.93	4.68
Corporate Managers	11	6.05	**5.27**	5.78	4.55
Academics	26	6.30	**4.92**	6.72	5.17
Total	61	5.87	**4.73**	6.26	4.70

235 Graham, J. and C. Harvey, *Expectations of Equity Risk Premia, Volatility and Asymmetry from a Corporate Finance Perspective,*' working paper, Duke University, 2001.

236 Welsh, I. *Views of Financial Economists on the Equity Premium and on Professional Controversies*, Journal of Business, Vol. 73, no. 4, pp 501-537, 2001.

237 Welsh, I, *The Equity Premium Consensus Forecasts Revisited*, Cowles Foundation Discussion Paper, No. 1325, Yale University.

238 Jardine Fleming Capital Partners Limited, *The Equity Risk Premium – An Australian Perspective*, Trinity Best Practice Committee, September 2001.

In the Australian context, the expected MRPs from surveys are lower than the historic based estimates. The MRPs provided by the surveys are also the MRPs finance professionals will apply in their investment decisions. The Tribunal considers it appropriate to take these estimates into account. These MRPs are forward looking as compared to the backward looking nature of MRPs generated by the historic based approach. They are also in line with the Tribunal's view that it is better to use capital market estimates to the extent available.

Extrapolation from foreign markets

There is one study in Australia that attempts to extrapolate the Australian MRP from US data. Bowman (2001)[239] derived an estimate of the Australian MRP using the US MRP and making adjustments for incremental risk factors. He considered the following factors:

- taxation: no clear adjustment, perhaps a reduction
- market differences: addition to benchmark of 1.5-3.75 per cent
- country risk: no adjustment although likely an increase, and
- time horizon: deduction from benchmark of 1.4 per cent.

In his analysis, Bowman estimates an Australian MRP of 7.8 per cent.

There is no evidence that the extrapolation from foreign markets is a better indicator of the Australian MRP than the other methods used. Besides the difficulties in estimating the US MRP, this approach also involves the estimation of adjustment factors which add more uncertainty to the accuracy of the estimation.

A7.5.3 Reasons for decision

The Tribunal has considered all of the DNSPs submissions on the market risk premium. The DNSPs generally propose the use of a MRP of 6 per cent. EnergyAustralia, Integral Energy and Country Energy argue, that the MRP is more likely to be in the 6-7 per cent range. The Tribunal has considered these submissions but has not found sufficient grounds for an increase in the MRP range in light of the various evidence it has reviewed. The Tribunal has adopted a MRP range of 5-6 per cent in its draft determination.

A7.6 Debt margin

Finding 5: The Tribunal decided for the draft determination that it would use a debt margin range of 0.9– 1.1 per cent. It further found that it would not include any transaction costs relating to the cost of debt raisings in this margin.

The debt margin represents the cost of debt a company has to pay above the nominal risk free rate. The debt margin is related to current market interest rates on corporate bonds (or NSW Treasury Corporation borrowings), the maturity of the debt, the assumed capital structure and the credit rating.

A number of regulators have in recent decisions included an allowance for the cost of raising debt in their decisions. In previous decisions, the Tribunal has not included any allowance for the cost of raising debt in their decisions on the debt margin.

239 Bowman, R G., *Estimating market risk premium*, JASSA, Issue no. 3, Spring 2001, pp 10-13.

A7.6.1 Submissions

The following positions and comments on the debt margin have been submitted for the 2004 electricity network review.

Table A7.12 Submissions on the debt margin

	Position	Comments
EnergyAustralia (NECG)	The Tribunal's debt margin is too low.	Debt margin should be benchmarked off credit markets and include transaction and hedging costs.
Integral Energy	The Tribunal's debt margin is too low.	Use a market based approach (eg credit rating and observed market yields). Include transaction costs allowance.
Country Energy (KPMG)	The Tribunal's debt margin is too low.	Should be consistent with assumptions adopted in relation to gearing levels and target credit ratings, and should reflect prevailing market conditions.
Australian Inland	No comment.	No comment.

The Energy Users Association of Australia submitted that the cost of debt proposed by the Tribunal in the Secretariat's discussion paper (1.4-1.5 per cent) is more than 50 bp higher than judged efficient by the ACCC in its recent draft Transend determination (0.8 per cent).

The Tribunal released a paper on its preliminary analysis in September 2003. In response to this publication, Country Energy noted that CBA Spectrum data indicates the following 20-day averages for debt margins over the 10-year Commonwealth Government bond as at 9 July 2003:

- 113 bp for BBB+ rated debt, and
- 142 bp for BBB rated debt.

Country Energy consequently considers that a debt margin range of 1-1.2 per cent is reasonable. In addition, Country Energy considers that it is necessary to build in an allowance for debt raising costs of 12.5 bp.

EnergyAustralia, Integral Energy and Australian Inland have not provided any additional comments on the debt margin.

A7.6.2 Tribunal's analysis

For the draft determination, the Tribunal has reviewed a number of recent regulatory decisions as well as a number of methodologies which can be used to determine the debt margin.

Table A7.13 provides a comparison of debt margins used in recent regulatory decisions and as submitted by regulated companies.

Table A7.13 Debt margin comparison

Regulatory Decisions	Value
IPART (metropolitan water 2003)	**0.7-1%**
IPART (electricity 1999)	**0.8-1%**
QCA rail (2001)	1.20%
ACCC (2001)	1.20%
Offgar (2001)	1.20%
ESC transmission (2002)	1.40%
ESC electricity (2000)	1.50%
OFGEM electricity (2002)	1.4-1.8%
QCA gas (2001)	1.60%
QCA electricity (2001)	1.65%
OFGEM transmission (2002)	1.70%
OFWAT (1999)	1.5-2%
Business Submissions	**Value**
GasNet submission (ACCC, 2002)	1.20%
Integral Energy submission (2003)	1.45%
EnergyAustralia submission (2003)	1.48%
Australian Inland submission (2003)	1.50%
Country Energy submission (2003)	1.52%
ElectraNet submission (ACCC, 2002)	1.72%
SPI PowerNet submission (ACCC, 2002)	1.85%

The figures in Table A7.13 indicate that the debt margins used by the Tribunal are considerably below those used by other regulators and those submitted by the regulated businesses.

There are a number of methodologies available to the Tribunal to estimate the debt margin. The Tribunal has reviewed two methodologies, the use of benchmark credit ratings and the use of T-Corp's indicative borrowing rates. The Tribunal has also reviewed the benchmark debt maturity and considered the possible inclusion of transaction costs.

Use a benchmark credit rating

Table A7.14 provides an overview of recent regulatory decisions regarding the debt margin.

Table A7.14 Debt margin – recent decisions

Date	Regulator	Business	Margin	Benchmark Credit rating	Benchmark Maturity
Oct-03	ACCC	Murraylink	86	A	10 years
Oct-03	ACCC	Moomba to Sydney	92	BBB+	5 years
Sep-03	ACCC	Transend (draft)	80	A	5 years
Dec-02	ACCC	SPI PowerNet	110	A	5 years
Dec-02	ACCC	ElectraNet	111	A	n/a
Oct-02	ESCOSA	APT	120	n/a	n/a
May-02	ACCC	ARTC	120	A+	n/a
Nov-01	ACCC	Powerlink	120	n/a	n/a
Oct-01	Offgar	Tubridgi	120	n/a	n/a
July-01	QCA	QR	120	A	n/a
Nov-02	ACCC	GasNet	146	BBB+	n/a
Dec-02	ACCC	NT Gas/ABDP	154	BBB+	n/a
Oct-01	QCA	QLD gas distribution	155	BBB+	n/a
Oct-02	ESC	Vic. Gas distributors	165	BBB+	n/a
Nov-01	QCA	Gladstone Water (draft)	180	BBB	n/a

The sample provided in Table A7.14 result in the following ranges being set for debt margins (excluding any transaction and hedging costs):

- for BBB credit ratings a debt premium of 180 bp in 2001
- for BBB+ credit ratings a debt premium range of 146-165 bp in 2002 and 155 bp in 2001
- for A credit ratings a debt premium range of 110-111 bp in 2002 and 120 bp in 2001
- for A+ credit ratings a debt premium of 120 bp in 2002
- for A credit ratings a debt premium of 80-86 bp in 2003 (using different maturities), and
- for BBB+ rated companies a debt premium of 92 bp for a 5 year maturity.

The Tribunal will base its decision on an appropriate debt margin for the NSW DNSPs on an investment grade credit rating (BBB+-BBB).

The most recent regulatory decisions indicate however, that debt margins as measured in debt capital markets have fallen.

In its recent decisions, the ACCC has used capital markets estimates of debt margins for BBB+ and A rated companies. The data was obtained from CBA spectrum prior to the release to the decision.[240]

The data in Table 14 suggests that debt margins for BBB+ and A rated companies fell during 2003. The latest regulatory decision on BBB+ rated company debt with a maturity of 5 years suggests a debt margin of 92 bp is appropriate. The 10-year maturity debt for A rated companies has a debt margin of 86 bp.

However, the debt margins used by the ACCC have either a different credit rating (Murraylink and Transend) than what the Tribunal is using for the NSW DNSPs (BBB+), or they are based on a different maturity (Moomba to Sydney pipelines and Transend are both based on a 5-year maturity whereas the Tribunal uses a 10-year maturity). The Tribunal has to make adjustments to take into account these differences.

It has to be stressed that these premiums do not include any transaction or hedging costs. Australian regulators have recently started to include an allowance for debt issuance costs in the debt premium. The following recent regulatory decisions allow for debt raising costs in the debt margin or OPEX.

Table A7.15 Debt margins and transaction costs

Date	Regulator	Business	Debt raising cost	Total debt margin	Benchmark credit rating
Sep-03	ACCC	Transend (draft)	Included in Opex	80	A
Dec-02	ACCC	SPI PowerNet	10.5	120.5	A
Dec-02	ACCC	ElectraNet	10.5	121.5	A
Nov-02	ACCC	GasNet	12.5	158.5	BBB+
Oct-02	ESC	Vic. Gas distributors	5	165	BBB+

The argument behind including an allowance for debt raising costs in the debt margin is that transaction costs occurred when issuing debt are deducted from the gross proceeds. This results in the yield of the securities to the issuer being derived from the net proceeds and not from the full issue price. This results in a higher yield for the issuer than for the investor.[241]

NSW DNSPs borrowings

As most of the regulated utilities regulated by the Tribunal are government-owned businesses, they borrow their debt through the NSW Treasury Corporation. The current rating for NSW government issued debt are summarised in Table A7.16.

240 For Moomba to Sydney pipelines, a 40-day average of debt issued by BBB+ entities up to 17/09/03 has been used. For the Murraylink and Transend decisions, a 10-day moving average has been used. The ACCC does not specify the period of measurement but mentions that the measurement occurred just prior to the release of the decisions. Data from CBA spectrum may differ from that of other providers due to differences in data collection and analysis methodologies employed.

241 A 1-year $10 million discount security issue with a coupon of 6 per cent and associated transaction costs of 5 per cent would yield :

- to the investor: 10,000,000/1.06 = $ 9,433,962 implying a yield of 6 per cent
- to the borrower: (10,000,000-500,000)/1.06 = $ 8,962,264 implying a yield of 11.578 per cent.

Table A7.16 NSW government debt ratings

Agency	Long term	Long term	Short term
	AUD issues	foreign currency issues	AUD
Standard & Poor's	AAA/stable	AAA/stable	A+
Moody's	Aaa	Aaa	Prime-1

The Tribunal has had regard to this charge when determining the effective interest rate public utilities are incurring when borrowing through NSW Treasury Corporation.

The credit ratings of selected NSW utilities (Standard & Poor's, as at July 2003) are summarised in Table A7.17.

Table A7.17 NSW utilities credit ratings

Company	Credit ratings	
	National	International
Sydney Water	AAA	AAA
EnergyAustralia	AA	AA
Integral Energy	AA	AA
Country Energy	AA	AA
AGL	A-	A-

In addition, Part 2C, clause 22D of the *Public Authorities (Financial Arrangements Act) 1987 No 33* states that:

> An authority must, if the Treasurer requires, pay to the credit of the Consolidated Fund a fee determined by the Treasurer in respect of a guarantee which is provided by or under this Act and which is directly or indirectly related to the obtaining of financial accommodation by the authority, the effecting of a financial adjustment by the authority or the participation in a joint financing arrangement by the authority.

The Government Guarantee Fee policy is designed to ensure competitive neutrality between Government businesses and their private sector counterparts.

The policy requires Government businesses to borrow at a cost reflective of their individual credit worthiness. The guarantee fee represents an extra charge to make up the difference between the interest paid by the Government business and what they would have paid in the absence of a Government guarantee.[242]

Benchmark debt maturity

In order to establish the debt margin, the Tribunal must establish a benchmark maturity for debt issues. Most Australian regulators are using a benchmark maturity of 10 years. Some regulators have recently used a benchmark maturity of 5 years, (ACCC for SPI PowerNet in 2002).

242 NSW Treasury, *Commercial Policy Framework, Government Guarantee Fee Policy For Government Businesses*, Policy & Guidelines Paper, September 2002.

The advantages of using a 10-year maturity benchmark over a 5-year benchmark is that the 10-year bond issues are more liquid than the 5-year bond issues. The 10-year bond market is also used to determine the risk free rate for other Tribunal decisions.

The benchmark debt maturity is to reflect the industry norm. Given the relatively long life of the assets in the network distribution business it seems to be adequate to assume that these assets are most efficiently financed by using long-term debt, matching the life of the assets. It therefore seems reasonable to take the 10-year maturity as a benchmark.

Inclusion of transaction costs

There are two ways in which transaction costs can be included in the revenue requirement allowance for the DNSPs:

- include it in the operating cash flow projections, or
- include it as an allowance in the debt margin.

The implications of transaction costs on the yield of debt issues for issuers has been discussed earlier. Transaction costs increase the yield on debt issues for the issuer, implying a higher cost of debt than captured in the debt margin derived from credit rating benchmarks.

The disadvantage of including an allowance for debt issuance costs in the debt margin is that companies get compensated in the WACC for debt issuance costs even if they do not issue any debt during the regulatory period. However, companies also incur these costs when refinancing outstanding debt.

The Tribunal has decided not to include the cost of raising debt in the operating cash flow. The Tribunal considers the debt margin range of 0.9-1.1 per cent to be sufficiently conservative to allow for the recovery of transaction costs.

A7.6.3 Reasons for decision

The Tribunal will use a debt margin range of 0.9-1.1 per cent in its draft determination, reflecting an investment grade credit rating (BBB+) and a maturity of 10 years. This is based on the Tribunal's assessment of current market data.

The Tribunal will not include an additional allowance for transaction costs in its draft determination as it considers that it has made a sufficiently conservative allowance in its debt margin range.

A7.7 Debt to total assets (capital structure)

Finding 6: The Tribunal decided for the draft determination that it would use a benchmark capital structure of 60 per cent gearing.

The capital structure represents the target level of debt and equity funding of a company. Theoretically, companies have an economic incentive to structure their capital optimally. The assumption that there is an optimal capital structure for a company implies that a company would maintain this structure when issuing new debt or equity by balancing these issues so that they do not change their target capital structure.

The capital structure impacts on both the cost of debt and equity, as higher debt levels (represented by the gearing ratio) imply higher financial risk as the entity has to service higher interest payments. This directly affects the cost of additional debt issues and indirectly the cost of capital.

A7.7.1 Submissions

The following gearing ratios and comments have been submitted for the 2004 electricity network review.

Table A7.18 Submissions on the capital structure

	Position	Comments
EnergyAustralia (NECG)	Accepts the current practice of applying an assumed 60% capital structure.	Debt margin is to be assessed on the basis of the assumed capital structure.
Integral Energy	Supports use of 60% gearing ratio.	Supports use of an industry benchmark rather than the actual gearing level of a regulated company.
Country Energy (KPMG)	60% gearing ratio is not an unreasonable level.	No comment.
Australian Inland	Uses a gearing ratio of 60% in its submission.	No comments.

All of the DNSP's support the use of the industry benchmark 60 per cent gearing ratio. Energy Australia makes the comment that the Tribunal should assess the debt margin on the basis of this assumed capital structure.

The Tribunal released a paper on its preliminary analysis in September 2003. In response to this publication, Country Energy has submitted that it concurs with the proposed gearing ratio of 60 per cent debt and 40 per cent equity.

None of the other DNSPs have commented on the gearing ratio in their submissions.

A7.7.2 Tribunal's analysis

The Tribunal currently adopts a gearing ratio of 60 per cent to the companies it regulates, except for transport. This gearing level is based on industry benchmarks.

Comparison with other regulators and market based information

Table A7.19 provides a comparison of the capital structure used in recent regulatory decisions as well as the capital structures submitted by regulated companies.

Table A7.19 Capital structure comparison

Regulator	Value
OFWAT (1999)	50%
OFWAT (1999)	50%
QCA rail (2001)	55%
IPART (electricity 1999)	**60%**
IPART (metropolitan water 2003)	**60%**
QCA electricity (2001)	60%
ACCC (2003) Murraylink	60%
ACCC(2003) Transend (draft)	60%
QCA gas (2001)	60%
ACCC (2001)	60%
Offgar (2001)	60%
ESC (2000-02)	60%
OFGEM transmission (2002)	60-70%
Business	**Value**
EnergyAustralia submission (2003)	60%
Integral Energy submission (2003)	60%
Country Energy submission (2003)	60%
Australian Inland submission (2003)	60%
GasNet submission (ACCC, 2002)	60%
ElectraNet submission (ACCC, 2002)	60%
SPI PowerNet submission (ACCC, 2002)	60%

Table A7.19 indicates that all Australian regulators as well as regulated companies are assuming a benchmark gearing level of 60 per cent, except for transport.

Available supporting evidence

Table A7.20 shows the gearing level for a number of Australian transmission and distribution companies.

Table A7.20 Gearing levels

	Financial year			
Company	**FY99**	**FY00**	**FY01**	**3 year average**
AGL	31%	36%	46%	38%
United Energy	55%	31%	48%	45%
Envestra	87%	83%	81%	84%
Simple average				**55%**

Source: ASIC filings, annual accounts and ASX share price data. Market capitalisation at each point is taken as the average of the previous 20 trading days. Debt is defined as total debt less cash and loan note principal.

The simple average gearing ratio of the three selected companies is 55 per cent. It should also be noted, that the companies listed in the table above are not only operating in the regulated transmission and distribution businesses, but also operate in a number of unregulated fields or hold material amounts of shares in other unregulated companies[243].

The gearing level of 60 per cent assumed by Australian regulators may seem somewhat high compared to the gearing levels observed for similar companies in the market. However, regulated business segments are in general less risky than the overall business structure or the unregulated business activities of the companies listed in the table above. The less risky a business segment, the more debt it will be able to take on without driving its level of financial risk to an unsustainable level.

A7.7.3 Reasons for decision

The Tribunal considers that a 60 per cent gearing ratio is a reasonably conservative assumption on the capital structure of regulated businesses. As a higher gearing ratio increases the cost of debt (the credit rating and consequently the debt margin), as well as the cost of equity, the Tribunal considers that this benchmark capital structure allows for a high enough margin so as not to jeopardise future debt raisings.

A7.8 Gamma

Finding 7: The Tribunal decided for the draft determination that it would use a gamma of 0.5.

Under the Australian dividend imputation system, investors receive a tax credit (franking credit) for the company tax the entity they are investing has paid. This avoids the investor being taxed twice on their investment returns, once at the company level and once on the personal tax level. Since July 2000, a cash rebate is available to any Australian recipient of franking credits where these credits otherwise could not be fully utilised. This is the case where the franking credits exceed the recipient's taxation liability. Foreign investors cannot utilise these franking credits.

The value of imputation tax credits is represented in the CAPM by the term gamma. The rational behind including the value of gamma in the CAPM is that if investors are receiving a tax credit from their investment, they would accept an investment with a lower return than if there were no tax credits attached to this investment. The gamma is an important input in the CAPM as a high value, for example one, would reduce the cost of capital considerably.

The debate in Australia about what value to assign to gamma, has centred about the assumptions that capital markets are either fully integrated or fully segregated. The use of a domestic CAPM, with a domestic MRP and betas, should entail that capital markets are fully segregated and that the marginal investor is domestic. Gamma should therefore be close to one.

On the other hand, if regulators are assuming that capital markets are fully integrated and that the marginal investor is foreign, they would have to use an international version of the CAPM. This would imply a gamma value of zero as foreign investors cannot use imputation tax credits.

243 For example, United Energy has 66.3 per cent shareholding in Uecomm, a company operating in the data communication services field. Under Australian accounting standards, this entails a consolidation of the accounts of the two companies, which in turn affects United Energy's capital structure.

A7.8.1 Submissions

The following positions and comments on the gamma have been submitted for the 2004 electricity network review.

Table A7.21 Submissions on gamma

	Position	Comments
EnergyAustralia (NECG)	There is no credible case for IPART to shift the gamma above the well established position of a range of 0.3-0.5.	Assumes that Australian capital markets are fully integrated which would involve a gamma of 0. Also notes the high level of uncertainty associated with gamma.
Integral Energy	Assumes a gamma value of 0.4.	Uses the mid-point (0.4) of the 0.3-0.5 range used in the 1999 Determination.
Country Energy (KPMG)	Supports use of a gamma range of 0.3-0.5.	The range used by the Tribunal is a conservative estimate of the value of gamma. There should be more research undertaken to determine the true value of gamma.
Australian Inland	No comments	No comments

The Tribunal released a paper on its preliminary analysis in September 2003. In its submission, Country Energy concurs with the Secretariat's proposed gamma range. None of the other DNSPs have submitted any additional comments on the value of imputation tax credits.

A7.8.2 Tribunal's analysis

The Tribunal has reviewed a number of recent regulatory decisions as well as the different options available to estimate the value of imputation tax credits. Table A7.22 provides a comparison of gamma values used in recent regulatory decisions as well as gamma values submitted by regulated companies.

Table A7.22 Gamma comparison

Regulator	Value
IPART (electricity 1999)	**0.3-0.5**
IPART (metropolitan water 2003)	**0.3-0.5**
ACCC (2003) Murraylink	0.5
ACCC (2003) Transend (draft)	0.5
QCA (2001)	0.50
ACCC (2001)	0.50
Offgar (2001)	0.50
ESC (2000-02)	0.50
Business	**Value**
EnergyAustralia submission (2003)	0.40
Integral Energy submission (2003)	0.40
Country Energy submission (2003)	0.40
Australian Inland submission (2003)	0.40
GasNet submission (ACCC, 2002)	0.50
ElectraNet submission (ACCC, 2002)	0.50
SPI PowerNet submission (ACCC, 2002)	0.50

The figures in Table A7.22 indicate that the Tribunal is the only regulator using a gamma range. All the other regulators are using a gamma of 0.5.

Available supporting evidence

There are four options which are commonly discussed in Australian regulatory decisions.

- Set the gamma equal to one.
- Set the gamma equal to zero.
- Set the gamma equal to 0.5.
- Choosing a gamma range that reflects uncertainties.

Option 1

This option is based on the assumption that the marginal investor in Australia is domestic. This investor can fully utilise any franking credits which are distributed by companies. There are essentially two issues with this option.

First, this option relies on the assumption that capital markets are fully segregated and that the marginal investor is domestic. Given the reliance of Australian industries on direct foreign investments, this is highly unlikely. On the other hand, the Tribunal uses a domestic version of the CAPM. The use of the domestic CAPM is based on fully segregated markets and franking credits should therefore be fully valued.

Second, a gamma of 1 assumes that investors are fully utilising any franking credits distributed to them and that they take the value of these credits into account when making investment decisions. There are a number of different studies available which have attempted to value gamma. These are summarised in Table A7.23.

Table A7.23 Gamma studies

Study	Method	Period	Gamma
Cannavan, Finn & Gray[244]	Futures and LEPOs[245]	Futures: 1994-99 LEPOs: 1995-99	0
Brukner, Dews & White (1994)[246]	Dividend drop-off	1987-1990	0.335
Twite & Wood (2002)[247]	Derivatives prices	16/05/94-31/12/95	0.45
Hathaway & Officer (1999)[248]	Aggregate taxation statistics	1989/90-1994/95	0.6
Hathaway & Officer (1999)	Dividend drop-off	1/1/85-30/06/95	0.63
Chu & Partington (2001)[249]	Rights issues	01/91-12/99	close to 1

The studies in Table A7.23 imply that the values of gamma may lie anywhere between zero and one. The rights issues study assigns a value close to one to gamma. This might be due to the fact that CFOs attach a higher value to gamma than investors. The futures and LEPOs study assigns a value of zero to gamma. This study was conducted to test whether the 1997 tax law amendment that was designed to prevent the trading of imputation credits substantially affected their economic value. It shows that prior to 1997 the implied value of tax credits was higher (up to 50 per cent of face value) in large, high-yielding companies. The study also finds that the change in tax laws had a significant effect – it is difficult to detect any value in tax credits at all after the amendment.

Option 2

This option is based on the assumption that the marginal investor in Australia is foreign and cannot utilise any franking credits.

The issue with this option is that identifying the marginal investor as foreign would imply the use of an international CAPM. The Tribunal and all other Australian regulator are currently using a domestic version of the CAPM. The use of a domestic CAPM under the assumption that the marginal investor is foreign would be inconsistent with the theoretical underpinnings of the CAPM.

On the other hand, utilities are increasingly arguing that there is little evidence that the value effects of dividend imputation are being included in valuations being undertaken by companies and investors in the broader market.[250] They further argue that foreign shareholders are the marginal price-setters of the Australian market and cannot utilise any franking credits.

244 Cannavan, Finn & Gray, *The value of dividend imputation tax credits in Australia*, article accepted for Journal of Finance but not yet published, 2003.

245 LEPOs: low exercise price options.

246 Brukner, Dews & White, *Capturing Value from Dividend Imputation*, McKinsey and Company, 1994.

247 Twite & Wood, *The Pricing of Australian Imputation Tax Credits: Evidence form Individual Share Futures Contracts*, working paper, AGSM, p 22, 2002.

248 Both Hathaway & Officer studies are sourced from: Hathaway & Officer, *The Value of Imputation Tax Credits*, working paper, Melbourne Business School, p 13 and table 1, 1999.

249 Chu, H., Partington G. *The market value of dividends: theory and evidence from a new method*, working paper, UTS, 2001.

250 See for example KPMG, *Country Energy. The appropriate weighted average cost of capital for the electricity distribution network*, 2003.

While the DNSPs have put these arguments in their recent submissions to the Tribunal, they nevertheless recognise that the Tribunal is taking a conservative approach by using a gamma range of 0.3-05, compared to other Australian regulators who are using a gamma value of 0.5.

Option 3

Most Australian regulators have adopted a gamma value of 0.5. The ESC and the ACCC have also stated on numerous occasions that a gamma value of 0.5 is the minimum value they consider should be attributed to franking credits.

The basis of this option is the assumption that the marginal investor in Australian equities is domestic. However, companies do not normally distribute all of their earnings in dividends in one year. Franking credits will therefore not reach a value of 100 per cent. Most regulators are therefore assuming a mid point value of gamma equal to 0.5.

The WACC is highly sensitive to the gamma value and a higher gamma implies a lower WACC. If the 0.5 value for gamma is based on the argument that there is much uncertainty surrounding the true value of gamma, regulators should adopt an appropriate range reflecting that uncertainty.

On the other hand, the studies that have been carried out on the gamma value suggest that gamma is close to 0.5. This excludes the Chu & Partington study which suggests a gamma close to one. However, this study is using rights issues to value gamma. The reliability of this study has been questioned as it relied on a relatively small sample of 26 right issues from 23 companies.

Option 4

The Tribunal has in past decisions adopted a gamma range of 0.3-0.5 in its cost of capital calculations. By choosing this range, the Tribunal has recognised the uncertainties surrounding the true value of gamma and chooses a conservative estimate. The lower bound of the range is consistent with the view that most market based valuations assign a value of zero to gamma.

A7.8.3 Reasons for decision

The Tribunal has considered the submissions made by the DNSPs as well as the research available on the value of imputation tax credits. The Tribunal has in the past used a gamma range of 0.3-0.5. This range was based on the fact that there is no conclusive gamma value which can be derived from the research available. However, there does not seem to be any conclusive evidence that the gamma is lower than 0.5 rather than higher than 0.5. The research reviewed in this draft determination seems to indicate that the value of gamma is within the range of about 0.4-0.6. This implies a midpoint of 0.5 which is also the value used by all other Australian regulators.

None of the DNSPs, except EnergyAustralia argue that the value of gamma should be lower than the range used by the Tribunal in the past. The Tribunal could not find any evidence that the value of gamma should be lower than this range. Given the research reviewed in this draft determination, the Tribunal has decided to use a gamma value of 0.5 in its draft determination.

A7.9 Tax rate

Finding 8: The Tribunal decided for the draft determination that it would use the statutory tax rate.

Regulators have in the past used two different methodologies to estimate the tax rate applied to regulated business:

- use the statutory company tax rate which is currently 30 per cent and apply this rate consistently to industries, or
- attempt to estimate the effective tax and apply this rate consistently to industries.

When using the statutory tax rate, the relevant corporate tax rate is applied in the cash flow modelling (post-tax WACC) or included as an allowance in the WACC (pre-tax WACC).

The use of an effective tax rate requires the regulator to estimate the actual tax rate a business is paying. The effective tax rate varies considerably from business to business. It is dependent among others, on factors such as:

- the depreciation method a business uses
- the existence of foreign tax credits
- interest payments and
- the planning of discretionary expense items.

The effective tax rate is then used in the same way as the statutory tax rate.

A7.9.1 Submissions

In addition to the evidence presented above, the following comments on the tax rate have been submitted for the 2004 electricity network review.

Table A7.24 Submissions on the tax rate

	Position	Comments
EnergyAustralia (NECG)	Statutory tax rate	Statutory tax rate is less intrusive than effective tax rate.
Integral Energy	Statutory tax rate	Effective tax rate is administratively complex and does not provide the right incentives.
Country Energy (KPMG)	Statutory tax rate	Is fundamentally opposed to the use of an effective tax rate.
Australian Inland	Statutory tax rate	No comment.

All four DNSP's are in favour of a statutory tax rate. The comments largely mirror the main concerns with the use of an effective tax rate mentioned earlier in this appendix:

- it is information intrusive, and
- it does not provide the right incentives.

The Tribunal released a paper on its preliminary analysis in September 2003. None of the DNSPs has raised any issues with the use of the statutory tax rate.

A7.9.2 Tribunal's analysis

The measurement of the effective tax rate is a highly contentious issue for regulated companies. There are two main issues with the use of an effective tax rate.

- efficiency considerations
- information requirements and modelling difficulties.

Efficiency considerations

The existence of numerous tax concessions act to reduce the effective tax paid by a company on its pre-tax profits. The main issue being that the effective tax rate in effect passes on benefits derived from the accelerated tax depreciation immediately to customers. This may in the long run reduce a company's incentive to invest and may also undermine the incentive for an economically efficient tax planning strategy.

Using the statutory tax rate leaves regulated companies ample room to benefit from efficient tax planning strategies as these benefits are not immediately passed-through to customers.

Information requirements and modelling difficulties

In addition to the extensive additional information the use of an effective tax rate would require, there are also a number of issues which would impact on the overall modelling of the revenue requirement:

- the treatment of some items under tax law differs from their treatment under the regulatory regime (eg depreciation)
- the circularity that is created, when tax, which is a function of revenue, is also explicitly included as an input in the revenue requirement, and
- the information asymmetry that exists between the regulator and regulated companies.

A7.9.3 Reasons for decision

The Tribunal favours the use of a statutory tax rate because:

- it is less information intrusive than the effective tax rate, and
- it is easier to model and more transparent.

The Tribunal has therefore used the statutory tax rate of 30 per cent in its draft determination.

A7.10 Debt beta

Finding 9: The Tribunal decided for the draft determination that it would use a debt beta of 0.06-0.

The debt beta reflects the risk of a debt security and how it correlates with the market. The debt beta mainly reflects the default risk of debt securities. The relative riskiness of an individual security is reflected in the issuing company's credit rating.

The debt beta is in practice unobservable and unmeasurable. The Tribunal therefore has to make use of an estimation method. In past determinations, the Tribunal has used a debt beta of 0.06. In the 2003 metropolitan water determination it has used a debt beta range of 0.06-0.14.

A7.10.1 Submissions

The following positions and comments on the debt margin have been submitted for the 2004 electricity network review.

Table A7.25 Submissions on the debt beta

	Position	Comments
EnergyAustralia (NECG)	Debt beta = 0.06	A debt beta equal to zero would be more appropriate. Debt beta should only incorporate systematic risk.
Integral Energy	Debt beta = 0	There is no compensation for default risk and the expected return on debt is equal to the risk free rate, therefore the value of the debt beta must be equal to zero. (This is based on the CAPM.).
Country Energy (KPMG)	Debt beta = 0..06	Comments that common market practice is to adopt a debt beta equal to zero.
Australian Inland	Debt beta = 0.06	No comments.

The Tribunal released a paper on its preliminary analysis in September 2003. In its submission to this publication, Country Energy, Integral Energy argue that the Tribunal should use a debt beta value of 0.06 instead of the proposed range of 0.14-0.06. EnergyAustralia did not provide any additional comments on the debt beta value.

A7.10.2 Tribunal's analysis

The Tribunal has considered a number of approaches used to estimate the debt beta. In regulatory decisions in Australia, three main approaches have been taken:

- estimate the debt beta using the debt risk premium
- estimate the debt beta using the CAPM or adjusted models, and
- assume the debt beta is equal to zero.

Estimating the debt beta using the debt risk premium

The Tribunal's current approach in estimating the debt beta reflects the first approach. According to the credit ratings assigned to Australian utilities and infrastructure providers, corporate debt issues are generally more risky than comparable risk free Commonwealth issues (currently rated AAA).

This methodology is based on the assumption that corporate bond returns move systematically with other assets in the market whereas government bonds do not. Consequently, corporate bond expected returns would require a risk premium to compensate for the nondiversifiability of corporate bond risk, just like any other asset. In this case the debt beta would be greater than zero.[251]

Elton et al have demonstrated that a part of corporate bond spreads represents a risk premium which is independent from default and liquidity risk. They quantify this risk premium to be approximately 0.26 on average for US industrials BBB rated companies across 2-10-year maturities.

The Allen Consulting Group argued in 2002, that the upper bound for the debt beta, using a market risk premium of 6 per cent and a debt margin of 1.2 per cent is 0.17. It admits however, that it is unable to quantify the size of any potential liquidity premium. It therefore proposes a debt beta range of 0.15-0.[252]

Table A7.26 summarises the credit ratings of a number of Australian utilities (Standard & Poors, July 2003).

Table A7.26 Australian utilities – credit ratings

Company	Credit ratings	
	National	International
Sydney Water	**AAA**	**AAA**
EnergyAustralia	**AA**	**AA**
Ergon Energy	AA	AA
Integral Energy	**AA**	**AA**
Country Energy	**AA**	**AA**
Delta Electricity	AA-	AA-
AGL	**A-**	**A-**
CityPower	A-	A-
Powercor	A-	A-
Origin	BBB+	BBB+
Alinta	BBB	BBB
Envestra	BBB	BBB
United Energy	BBB	BBB
TXU electricity	BBB-	BBB-

In the 1999 electricity network determination the Tribunal estimated the debt beta directly and assigned a value of 0.06 to it. In the 2003 metropolitan water decision, the Tribunal assumed a debt beta range of 0.14-0.06. However, the Tribunal also assumed a benchmark capital structure of 60 per cent debt financing in that decision. There is no evidence that the credit ratings of the above mentioned companies would be the same under the benchmark credit rating.

251 Elton et al. *Explaining the rate spread on corporate bonds*, The Journal of Finance. Vol LVI, No. 1, 2001, pp 247-277.

252 The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities,* Report for the ACCC, 2002.

Estimating the debt beta using the CAPM

In the past, the Tribunal has not used the CAPM to estimate the debt beta. The assumptions underlying the CAPM clearly state that investors should only be rewarded for taking on economy-wide risk. The debt beta reflects default risk, a type of risk that is clearly unsystematic and is therefore not included in the CAPM framework.

In the Victorian gas distribution access arrangements for 2003, the ESC has used a modified version of the CAPM framework including margins for debt raising costs, default and liquidity. It remains however unclear how these modifications would make the CAPM framework more viable.

Assuming the debt beta is equal to zero

The rationale behind the assumption that the debt beta should be set equal to zero is that the debt beta is only used in conversion formulae (re-levering and de-levering of equity betas). The debt beta is not observable in the market.

Furthermore, the conversion formulae are all based on the CAPM framework. In this framework, the role of the debt beta is to show how there is a sharing of a firm's systematic risk of equity and the systematic risk of debt. If debt has risk that is rewarded in the market, but assumed away in the CAPM world, then they would not be relevant to the de-levering and re-levering process.

A number of regulators (ACCC, ESC) have in recent regulatory decisions assumed a debt beta of zero.

Table A7.27 Debt beta – recent regulatory decisions

Regulator	Decision	Date	Debt beta
ESC	Transmission	2002	0.18-0
ACCC	TransGrid	2000	0.06-0
ACCC	Gasnet	2003	0.18
ACCC	Epic	2003	0.06
ORAR	WNR rail	2003	0
ORAR	WAGR rail	2003	0
ACCC	Murraylink	2003	0
ACCC	Transend (draft)	2003	0

A7.10.3 Reasons for decision

The Tribunal has previously indicated that to the extent possible it favours financial market estimates in the determination of the parameters of the WACC. If the regulated businesses (or their regulatory asset bases) were publicly traded companies, there would be no need to use the debt beta as the equity beta could be directly observed in the market.

However, the use of the Monkhouse formula which is used to de-lever the equity beta to an asset beta and to re-lever the asset beta to an equity beta adjusted for the benchmark capital structure necessitates a debt beta. In their submissions, EnergyAustralia and Australian Inland do accept a debt beta value of 0.06 but argue that it is common market practice to adopt a debt beta value of zero. Country Energy proposes a debt beta of 0.06 but also comments that the debt beta should be set equal to zero if the Tribunal is to use common market practice in its WACC parameter determinations. Lastly, Integral Energy proposes a debt beta of zero under the assumption that there is no compensation for default risk in the CAPM framework.

The Tribunal has considered the available evidence as well as the DNSPs submissions. It has concluded that it should adjust the debt beta to reflect the capital markets view that the debt beta is equal to zero as well as recent decisions by the ACCC which use a debt beta of zero. The Tribunal is also taking into account the Elton et al and the Allen Consulting Group studies[253] which show that the debt beta value is greater than zero. It therefore considered it appropriate to use a debt beta range of 0.06-0 in its draft decision.

The Tribunal also considered dropping the use of the Monkhouse formula in favour of alternatives which do not require a debt beta as an input. However, most Australian regulatory decisions in the WACC use the Monkhouse formula and the Tribunal has not found any evidence that other formula may be more accurate in the de- and re-levering process.

A7.11 Asset and equity beta

Finding 10: The Tribunal decided for the draft determination that it would use an asset beta range of 0.35-0.45 which results in an equity beta range of 0.78-1.11.

The equity beta represents the covariance of the excess returns[254] of a share with the excess returns on the market. The asset beta measures the same covariance if the business/or RAB would be 100 per cent equity financed. As the RAB of utilities are not publicly traded, the Tribunal has to estimate an equity beta.

The estimate of the equity beta must reflect the degree of leverage of the regulated firm. When using proxy betas derived from comparable Australian companies, it is crucial to:

- Remove the effect of leverage by converting the equity beta to an asset beta.
- Re-lever the asset beta using the assumed gearing ratio to obtain an estimate of the equity beta.

There are three basic approaches to estimating equity betas:

- Direct estimation from observed share price information.
- Comparable companies.
- First principles.

253 Elton et al. *Explaining the rate spread on corporate bonds*, The Journal of Finance. Vol LVI, No. 1, 2001, pp 247-277, and The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities,* Report for the ACCC, 2002.

254 Excess returns are defined as the excess returns above the risk free rate.

The following positions and comments on the asset and equity beta have been submitted for the 2004 electricity network review.

Table A7.28 Submissions on the asset and equity beta

	Position	Comments
EnergyAustralia (NECG)	Asset beta = 0.475 Equity beta = 1.09	Asset beta is increasing due to high systematic risk and the shift to a weighted average price cap.
Integral Energy	Asset beta = 0.425 Equity beta = 1.05	Values based on comparison to comparable Australian and Overseas companies and recent regulatory decisions.
Country Energy (KPMG)	Asset beta = 0.475 Equity beta = 1.09	There are a number of non-beta risk factors that should be taken into account when assessing an appropriate beta for Country Energy.
Australian Inland	Asset beta = 0.48 Equity beta = 01.10	The appropriate asset beta should take into account specific risk factors such as low customer density.

The Tribunal released a paper on its preliminary analysis in September 2003. In response to this publication, EnergyAustralia argues that the shift form a revenue cap to a price cap exposes the NSW DNSPs to significantly greater systematic risk. The mid-range equity beta value should therefore be higher than that used in the 1999 determination. Integral Energy comments that it is concerned about the proposed equity beta range of 0.975-0.98.

Country Energy and Australian Inland have not commented on the equity beta value.

The Tribunal has also mentioned that it is reviewing the use of the Monkhouse formula. Both EnergyAustralia and Country Energy have expressed concerns about abandoning the Monkhouse formula.

A7.11.1 Tribunal's analysis

The Tribunal has reviewed a number of recent regulatory decisions on asset and equity beta values as well as the options available for their estimation.

Table A7.29 provides a comparison of asset and equity betas used in recent regulatory decisions as well as betas submitted by regulated companies.

Table A7.29 Asset and equity beta comparison

Regulator	Value	
	Asset	Equity
QCA electricity (2001)	0.45	0.71
IPART (metropolitan water 2003)	**0.3-0.45**	**0.76**
QCA rail (2001)	0.45	0.76
IPART (electricity 1999)	**0.35-0.5**	**0.96**
QCA gas (2001)	0.55	0.97
ACCC (2003) Murraylink	0.4	1
ACCC (2003) Transend (draft)	0.4	1
ACCC Powerlink (2001)	0.40	1
ESC (2000) electricity	0.40	1
ACCC (2001) Epic	0.50	1.16
Offgar (2001)	0.65	1.33
Business		
SPI PowerNet submission (ACCC, 2002)	0.585	1
Integral Energy submission (2003)	0.425	1.05
EnergyAustralia submission (2003)	0.475	1.09
Country Energy submission (2003)	0.475	1.09
Australian Inland submission (2003)	0.48	1.1
ElectraNet submission (ACCC, 2002)	0.45	1.12
GasNet submission (ACCC, 2002)	0.60	1.4

The figures in Table A7.29 indicate that the Tribunal's asset betas are slightly lower than those used by other regulators.

Available supporting evidence

The Tribunal is concerned that there are a number of issues with the current methodology of estimating the equity/asset beta:

- Directly estimating a value for the asset beta leaves out the first step of the estimation cycle (estimating a proxy equity beta, de-lever it to an asset beta and then re-lever it to an equity beta reflecting the capital structure of the regulated business).
- Estimates of the asset beta are based on regulatory decisions taken in Australia and overseas, and the use of a domestic CAPM model is not consistent with the use of overseas beta values.

Recent evidence suggests that it is possible to some extent to estimate a proxy equity beta by using a set of Australian comparable companies.

In its 2003 Review of Gas Access Arrangements, the ESC thoroughly discussed the possibility of using a pool of comparable Australian publicly listed companies to derive a proxy equity beta. It found that by doing so, it would arrive at a substantially lower equity beta than in previous decisions. It therefore concluded that "…the derivation of the proxy is one of the matters upon which conservative exercise of judgement is justified."[255]

255 ESC, *2003 Review of Gas Access Arrangements*, 2003.

There is a limited number of utility companies traded on the Australian Stock Exchange. Those that are traded are not always directly comparable to the asset bases IPART is regulating. Table A7.30 provides the equity betas and gearing levels of some of the publicly traded utilities in Australia.[256]

Table A7.30 Publicly traded utilities betas and gearing

Company (June 2003)	Equity beta	Gearing
AGL	-0.01	52%
United Energy	-0.03	42%
Envestra	0.39	80%

The advantages of establishing a pool of comparable companies is that it:

- would reflect an environment of competitive neutrality
- would be consistent with current market practice
- would be transparent.

The disadvantages are that:

- there are no directly comparable companies traded in Australia
- consequently the pool of comparable Australian companies would be quite small, and
- using the latest estimates instead of historical averages may deliver distorted figures due to the impact of short and medium term volatility.

In order to establish a proxy beta for the NSW DNSPs, the Tribunal has to de-lever the proxy equity beta to an asset beta and then re-lever it to reflect the target capital structure of 60 per cent gearing. This is done by using the Monkhouse formula. Using the information from Table A7.30, the following equity beta estimates have been derived.

Table A7.31 Equity betas

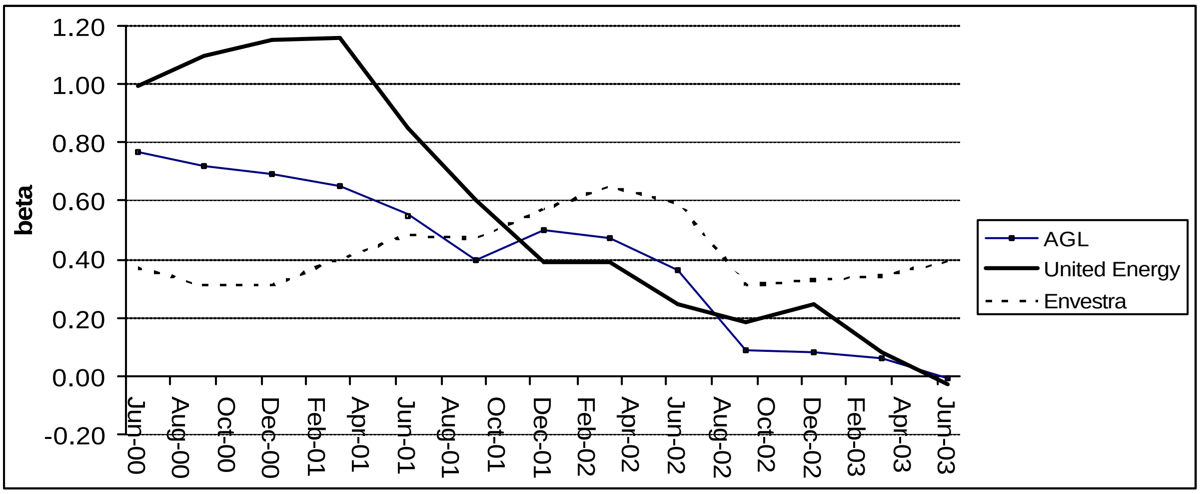
	Equity beta	Asset beta	Asset beta	Equity beta	Equity beta
		Beta debt = 0	Beta debt = 0.06	Beta debt = 0	Beta debt = 0.06
AGL	-0.01	-0.01	0.01	-0.01	-0.02
United Energy	-0.03	-0.02	0.00	-0.03	-0.04
Envestra	0.39	0.22	0.24	0.35	0.35
Simple average	0.12	0.06	0.08	0.10	0.10

Table A7.31 indicates that equity betas derived from a pool of comparable companies would be much lower than what the Tribunal has used in the past.

256 Equity betas: AGSM Risk Management Services, June 2003.
Gearing levels: Standard & Poor's Australia and New Zealand Credit Stats 2003, June 2003, pp 31-32, cited in ACCC, *Final Decision: Moomba to Sydney Pipelines System Access Arrangement*, 2003.

However, using actual market data is an objective reflection of what a rational investor expects to earn from an investment for a given level of risk. The Tribunal has collected a time series of beta estimates obtained from the AGSM risk measurement service. The data seem to indicate that beta values have fallen over the last years.

Figure A7.1 Equity beta trends



The Tribunal sees considerable merit in deriving a proxy beta that is based upon the latest estimates of companies for sufficiently comparable companies. The Tribunal has in the past indicated that it prefers the use of financial market data. The difficulty that arises with the use of financial market data is that neither the beta, nor the capital structure of the regulatory asset base is known. It is however possible to take into account the trend of beta values for comparable companies when estimating the beta values for the regulatory asset base of NSW DNSPs.

In its Moomba to Sydney pipelines decision, the ACCC has taken a new approach by directly estimating the equity beta. The Commission decided on an equity beta of one, after having considered a number of different scenarios using a pool of comparable Australian companies. The Commission de-and re-levered these comparable equity betas using different debt beta values. In adopting this approach the Commission was deliberately conservative since the available evidence, although limited, suggest that an equity beta considerably below this is consistent with Australian conditions. The Tribunal, having considered the possible implications for incentives to invest, has adopted a similarly conservative approach.

A7.11.2 Reasons for decision

The Tribunal has reviewed the use of the Monkhouse formula and has come to the opinion that there is not enough evidence that the use of an alternative methodology would be more appropriate. It will therefore continue using the Monkhouse formula in its draft decision.

In their submissions, the NSW DNSPs have used a mid-point asset beta range of 0.425-0.48 and a mid–point equity beta range of 0.94-1.10 in their cost of capital calculations. In its 1999 electricity network determination, the Tribunal used an asset beta range of 0.35-0.5 and an equity beta range of 0.78-1.15.

Given the above evidence of decreasing betas of comparable Australian companies the Tribunal considers that there is not sufficient evidence to increase the asset beta values to those submitted by the DNSPs.

The Tribunal however recognises that a reduction of the asset beta would create an unnecessary level of regulatory uncertainty for the DNSPs. The Tribunal has therefore decided to narrow and slightly lower the upper bound of the asset beta range to 0.35-0.45 in its draft determination. This results in an equity beta range of 0.78-1.11.

A7.12 Asymmetric risk

Finding 11: The Tribunal decided for the draft determination that it would not include an allowance for asymmetric risk in the WACC in its draft decision.

For the 2004 electricity network distribution review, all DNSPs, except Australian Inland, have addressed the issue of asymmetric risk in their submissions. The DNSPs argue that the presence of asymmetric risk entails that investors would require a higher rate of return than that implied by the WACC. The DNSPs argue that if the Tribunal does not make a specific allowance for asymmetric risk in the WACC, there should be other mechanisms, namely a cost pass through mechanism to allow for costs incurred due to these risks.

The Tribunal has had regard to the DNSPs submission on asymmetric risk and has come to the following conclusions:

- An allowance for asymmetric risk distorts a utility's incentive to adopt the most efficient risk profile. Such an allowance may entice the business not to take out appropriate insurance or it may change operational strategies which can impact on the overall risks profile.
- Asymmetric risk may, in some cases, be diversifiable. If it is, there is no reason why there should be an explicit allowance for these risks in the determination.
- Regulators are taking a conservative approach when estimating the WACC parameters. As such, there is already an implicit allowance for regulatory risk included in the cost of capital.
- Businesses have provisions in their OPEX forecasts to account for some of these risks. These provisions are taking the form of estimated premiums for self-insurance.

A7.12.1 Tribunal's Analysis

The DNSPs identify a number of asymmetric risks:

- Insurance.
- Regulatory risk.
- Easements.
- Asset stranding.
- Risks arising from the use of the WAPC
  - forecast error risk
  - market risk
  - natural uncertainties.

- Statutory changes.

The DNSPs argue that if there is no specific allowance included in the WACC to account for these risks, the appropriate mechanism in addressing these is through a cost pass-through mechanism. However, the Tribunal has to balance the demands of investors with the willingness of consumers to pay for a particular service. This raises the question, does an allowance for asymmetric risk allocate risk appropriately? The two main issues which have to be considered are:

- Does the inclusion of a specific allowance for asymmetric risk create incentives for the regulated businesses not to choose the most efficient structure of risk management?
- Are asymmetric risk diversifiable or not? This ultimately leads to the question of who is best placed to manage these risks, the utilities, customers or owner of utilities?

Risk Management

The starting point of analysis of who should bear asymmetric risk is how businesses manage their overall risk portfolio. A business has basically two options to insure against risk:

- take out insurance
- self-insure.

Self-insurance can take on a number of forms. Firstly, businesses may take on more risk by increasing their deductibles and thereby reducing the insurance premium.

Alternatively, the business can change operational strategies which impact on the risks they bear for a given amount of insurance. For example, investments in distribution assets are infrequent and lumpy. The DNSPs might have an incentive to delay new investments if they judge that they are subject to an unreasonable level of risk. These risks may arise from forecasting errors, revenue uncertainty or market risk. These strategies are difficult to quantify in both monetary terms and the impact they may have on the future sustainability of the network, but are likely to result in the business bearing more risk.

Furthermore, there is a high level of information asymmetry in regards to investment decisions between the DNSPs and the regulator. For example, by using real options models[257] when making investment decisions, the DNSPs are in fact able to quantify the value of delaying capital investments. The regulator does not have this information. This means that there is a trade off between allowing regulated companies to pass through costs which could give an incentive to over-invest, and on the other hand not to allow a cost pass through mechanism and risking an underinvestment in network distribution assets. The regulator should therefore create an incentive framework where DNSPs are encouraged to undertake necessary investments rather than delaying them due to regulatory uncertainties.

257 Traditional investment theory says that when a firm evaluates a proposed project, it should calculate the project's NPV and if it is positive, go ahead. Real options theory assumes that businesses also have some choice in when to invest. In other words, the project is like an option: there is an opportunity, but not an obligation, to go ahead with it. The value of the option to defer or not to undertake a project is added or subtracted to the traditional NPV.

Furthermore, there are a number of reasons why a business may not be able to take out insurance or limit its insurance level as it would be uneconomical to do so:

- if the business believes that the insurance premium is in excess of the true insurance cost
- the required insurance is not readily available
- the business has sufficient resources to withstand the risk in question
- the business holds other insurance policies which include a range of exclusions, and the cost of writing back these exclusions exceed the perceived value of the risk, and
- the insurer requires the company to bear a reasonable share of each claim to provide an incentive for it to manage its risks more effectively.

The scope to which a business is insured against unique events can range from being fully insured to fully self insured. In reality, a business would chose an optimal level of insurance, taking some of the risk on as self-insured through for instance the acceptance of higher insurance deductibles or simply not insuring some risks at all.

This entails that the firm has made a decision on how much risk it is willing to take on. Including a specific allowance for asymmetric risk in the WACC would provide the regulated business with perverse incentives.

- Firstly, due to the information asymmetries, the regulator does not know if the regulated company has taken a conscious decision not to insure a particular risk.
- Secondly, an allowance for asymmetric risk may create an incentive for regulated businesses not to insure or self insure and therefore create more business risk than would be optimal.
- Thirdly, in a competitive market, a business who decided not to insure a particular risk would not be able to pass on the costs it incurs should that event actually occur. The only instance where this would be possible is if that risk is economy wide and as such this risk would be included in the beta of the firm.

The aim of the regulator should be to provide the business with incentives to either take out insurance or to self-insure. The question is if an allowance for asymmetric risk impacts on the efficient management of the business operations.

A7.12.2 Is asymmetric risk diversifiable?

The question of whether asymmetric risk is diversifiable or not is a crucial one. If it is, then any risk that is considered as being asymmetric would be included in the overall risk portfolio of a business. This entails that the business has taken on a specific risk profile which is known to investors and as such investors wouldn't require any additional allowance in the rate of return for taking on these risks. As these risks are diversifiable, the investor would either accept that the business has chosen an optimal insurance portfolio, or if he doesn't, invest in an asset which faces a different risk profile so that the overall investment matches the risk profile of the investor.

If asymmetric risks are not diversifiable, these risks would be included in the beta of the firm. This holds true for a publicly traded firm with an observable beta. In the case of regulatory asset bases, beta values are not readily observable in the market. Instead the regulator estimates a proxy beta. In the past, the equity betas assumed by Australian regulators for electricity distribution networks have been close to the market beta of 1. This implies that the risk associated with investing in the regulatory asset base of a DNSP is no more or less than the risk of investing in the overall market. Beta values around 1 compare favourably to the DNSPs to the beta values of publicly traded infrastructure companies, with similar core businesses and adjusted for different capital structure.

The Tribunal has estimated the following equity beta values adjusted to reflect a 60 per cent gearing level for some Australian publicly listed utilities.[258]

Table A7.32 Equity betas

	Equity beta	Asset beta Beta debt = 0	Asset beta Beta debt = 0.06	Equity beta Beta debt = 0	Equity beta Beta debt = 0.06
AGL	-0.01	-0.01	0.01	-0.01	-0.02
United Energy	-0.03	-0.02	0.00	-0.03	-0.04
Envestra	0.39	0.22	0.24	0.35	0.35
Simple average	0.12	0.06	0.08	0.10	0.10

Table A7.32 indicates that the adjusted equity beta values of comparable Australian companies are substantially lower than the equity beta values assumed by the Tribunal.

The DNSPs argued in their submissions that if the Tribunal is not making a specific allowance for asymmetric risks, it should increase the beta. However, under the assumption that asymmetric risk is not diversifiable, there is no proof that it has not been included in the beta of the DNSPs in the past. The beta values assumed by regulators seem to be a conservative estimate compared to what is observable in the market. By taking a conservative approach in estimating the equity beta, regulators are making an implicit allowance for regulatory uncertainties.

If on the other hand, the Tribunal agrees on a cost pass through mechanism under the assumption that asymmetric risk is not diversifiable, should the beta of the DNSPs be reduced? If risk is transferred from investors to consumers and if this risk is something that has been present in the past and not been explicitly included in the rate of return, then there is an argument for a reduction of the beta. Otherwise investors would get rewarded for taking on a risk that has been transferred from the investor to the consumer.

It is not clear however, if the DNSPs are not already self-insured and therefore are claiming a self-insurance premium in their OPEX requirement for some of the risks that can be classified under natural disasters, such as bushfires for example. EnergyAustralia has commissioned Trowbridge Deloitte to assess their risk premium estimates. EnergyAustralia is already including an allowance for general liabilities and other non-insured events in its OPEX. The annual allowance made by EnergyAustralia equals to $5.5 million. Trowbridge Deloitte estimates this allowance to be equal to $5.58 million plus $0.44 million for EnergyAustralia's

258 Equity betas: AGSM Risk Management Services, June 2003.

transmission assets. The risks considered in the estimation of this amount include the following uninsured events:

Table A7.33 Uninsured events[259]

Self-insured risks	Risk Premium Estimate Distribution Assets ($millions pa)
Property related risks	
Tower failure from non-catastrophic events	0.68
Tower failure from catastrophic events	0.31
Damage by 3rd parties	0.86
Damage to substations (including within $10 million deductible)	0.64
Total property related risks	2.49
Current insurance risks	
Public/general liability (excl. bushfires)	2.65
Bushfire liability	0.38
Total current insurance risks	3.03
Credit risks	
Counterparty credit risk	0.05
Insurer's credit risk	0.01
Total credit risk	0.06
Other risks	
Regulatory risk	-
Easements	-
Asset stranding risk	-
Total for other risks	-
Total cost associated with self-insured risks	**5.58**

The only risks that are not already included in the OPEX are regulatory risk, easements and asset stranding risk.

Asset stranding risk relates to a sunk cost and there should therefore not be any specific allowance to account for this risk. The risk associated with asset stranding is accounted for when taking the investment decision. Furthermore, this kind of risk would be accounted for in the cash flows and not in the discount rate. Allowing for a cost pass through for these costs would in fact compensate the DNSPs twice.

As for easements, Trowbridge Deloitte argues that it is appropriate for EnergyAustralia to have a prudent capital expenditure program for this risk rather than attempt to forecast and pay for the costs of easement disputes.

Finally, on the issue of regulatory risk, it could be argued that regulators are making sufficiently conservative assumptions elsewhere in their regulatory framework to compensate businesses for the cost of taking on this risk. For example, as much as DNSPs are not explicitly compensated by the regulator for taking on asymmetric risk, there are enough opportunities for DNSPs to profit from events considered to be asymmetric such as

259 Trowbridge Deloitte, *Analysis of Non-Insured Events*, Energy Australia, May 2003.

increases in the WACC at the next regulatory reset or forecast errors which favour the DNSPs. In addition, consumer advocates have also argued that the WACC parameters used in the calculation of the cost of capital are reasonably conservative to allow for these risks.

A7.12.3 Reasons for decision

The Tribunal is not including an allowance for asymmetric risk in the WACC in its draft decision.

Including such a premium in the WACC would be inconsistent with the assumptions underlying the CAPM. It would compensate investors for risks that are theoretically not included in the fair calculation of their cost of capital and which in turn would transfer the cost of bearing these risks from the regulated business to consumers.

The CAPM used in the calculation of the cost of equity explicitly does not take into account risk that is not related to the overall economy. The underlying assumption is that investors can diversify away any firm-specific risk by holding a diversified portfolio of investments. The argument brought forward by utilities is that this assumption does not hold in the case of regulated businesses as the counterparty to these risks is the consumer. For example, NECG argues, that "The beneficiaries of regulation are final consumers, and since investors cannot directly purchase a claim on the residual income of final consumers, their ability to avoid this type of risk is limited."[260] However, in a footnote, NECG admits that indirect diversification may be obtained by investing in other negatively correlated businesses. However, according to modern portfolio theory (MPT), the only risk that should be priced in the CAPM is the market risk. Any firm specific risk can diversified away through the construction of a minimum variance portfolio. The argument that the consumer is the counterparty to asymmetric risks does not hold as investors can diversify their investments regardless of who the counterparty to any specific risk may be.

260 NECG, *Regulatory Risk*, 2001.

APPENDIX 8 DEPRECIATION

The Tribunal's decision for the draft determination is to continue its application of simple straight line depreciation of the DNSPs' regulatory asset bases. The Tribunal will use the asset lives proposed by the DNSPs for the purposes of this draft decision.

In the lead up to its final determination, the Tribunal will commission an engineering consultant to review the appropriateness of changes to asset lives proposed by EnergyAustralia. The Tribunal will also consider alternative depreciation profiles submitted by stakeholders, provided net present value neutrality is maintained and where significant benefits over the straight line approach can be demonstrated.

The depreciation amounts included in the DNSPs building block revenue requirements are set out in Table A8.1 below.

Table A8.1 Return of capital building block components 2004-05 to 2008-09 ($m)

DNSP	2004/05	2005/06	2006/07	2007/08	2008/09
EnergyAustralia	170	189	209	229	247
Integral Energy	127	139	152	164	178
Country Energy	132	147	163	179	196
Australian Inland	3	3	4	4	4

Depreciation or 'return of capital' is a key component of the DNSPs' revenue requirement as and is a critical determinant of financial and operational capacity.

Depreciation is the mechanism by which invested capital is returned to the DNSPs over the anticipated economic life of depreciable assets. As a major non-cash item, depreciation can provide an important source of funding for new investment. Consequently, the DNSPs require that depreciation will provide for the return of past investment, except where the value of an investment has been unexpectedly stranded through optimisation. Customers also require assurance that depreciation over the life of an asset will not recover more than the cost of past investments. These concerns may arise where there are changes in the calculation of asset lives.

The Tribunal's consideration of depreciation policy inextricably links assessments of recoverable costs and asset replacement decisions. In addition to cost of capital considerations, the application of depreciation policy must give the DNSPs confidence that the return of the asset base provided by depreciation charges will return capital equivalent to the cost of the investment.

A central issue is the profile of depreciation, ie the pattern of and period over which invested capital should be returned. The profile of depreciation will invariably affect the profile of prices over time, and the allocation of stranding risks between customers and the DNSPs. However, it should not affect the expected net present value of future revenue streams.

A8.1 Issues/options considered

In September 2003, the Allen Consulting Group delivered to the Tribunal a paper entitled *Principles for determining regulatory depreciation allowances*. The paper contends that in most cases, the most appropriate measure of depreciation is economic depreciation, based on the change in market value of an asset between two points in time; and, where monopoly assets are regulated, economic depreciation is a circular concept, since the value of the asset is affected by the depreciation allowed by the regulator.[261]

This implies that regulators have discretion in selecting rates of depreciation, since most methods will, by definition, be aligned with market values (unlike competitive industries, where an inappropriate depreciation method could send wrong signals to corporate decision makers).

The Tribunal recognises that there is no one 'best' approach to calculating depreciation and that under particular circumstances one depreciation profile might be preferred to another.

The Tribunal's presumption of the continuation of the straight line approach is on the basis of administrative simplicity, consistency and transparency. For the Tribunal to consider alternatives to straight line depreciation, stakeholders will need to detail the specific depreciation they are proposing and explain how this will lead to a superior outcome—in terms of market risk and price variations and in relation to the principles and objectives of the Code—than the straight line approach.

For the reasons outlined above, the DNSPs support the use of the existing straight-line depreciation methodology. In support of this methodology, the DNSPs pointed out that the straight line approach is used for financial accounting purposes and the fact that that most regulators and electricity distributors throughout Australia have also adopted this approach.

Given the complexities inherent in other depreciation methodologies[262] and in the absence of compelling arguments to the contrary, the Tribunal believes there is little reason to move away from a straight-line approach at this point in time.

A8.1.1 Alternative depreciation profiles

As acknowledged by the Tribunal in its 1999 section 12A report, no single depreciation profile is consistently the most appropriate, particularly in the context of technological change and the differential impact on assets. Mindful of this, the Tribunal stated in its 1999 determination that it would be willing to consider alternative depreciation schedules where these better reflect economic risks and market values.

261 The Allen Consulting Group, *Principles for determining regulatory depreciation allowances*, September 2003, p 5.

262 Discussed in detail in the Tribunal's section 12A report, *Pricing for Electricity Networks and Retail Supply*, June 1999, Volume I, pp 93-95.

The Tribunal's 2004 electricity network review Issues Paper, raised the possibility of alternative depreciation profiles in the future, where these can assist in managing market risks and managing variations in the prices of new investment. In doing so, the Tribunal stated that the key proviso is that alternative depreciation profiles must yield an aggregate allowance that is the same in net present value terms as the straight line approach—that is, the alternative depreciation profile is 'net present value neutral'.[263]

In the lead up to its final decision, the Tribunal will consider the interaction of alternative depreciation profiles and the methodology for setting the X-factor. Where a net present value (NPV) approach[264] is used to determine the X-factor, then an NPV neutral depreciation profile will have the same impact on revenue over the life of the asset as a straight line approach. However, an approach to setting the X-factor such as the straight line revenue smoothing approach would be sensitive to the building block costs at the end of the regulatory period. Front-loading or back-loading depreciation would likely lead to a different level of revenue recovery than straight line depreciation.

Any proposed alternative depreciation profiles where the objective of NPV neutrality is maintained would need to be explained in relation to the principles and objectives of the Code, including price stability.[265]

Integral Energy has submitted that in circumstances where consumers are exposed to the possibility of substantial price increases, a deferred depreciation methodology could achieve NPV neutrality without impacting on regulatory returns over the standard lives of the relevant assets. Integral Energy believes that such an alternative would be revenue neutral over the standard life of the relevant assets.[266]

A8.2 Analysis and Tribunal's rationale

A8.2.1 1999 section 12A report

In its 1999 section 12A report on electricity pricing, the Tribunal discussed the importance to DNSPs of matching depreciation allowances and the cash flow required to replace existing network assets.[267] In theory, investors are not affected by a change in asset lives which is NPV-neutral. As long as the appropriate discount rate is used in calculating the NPV, investors can use capital markets to neutralise any mismatch between depreciation allowances and investment requirements. However, in practice, there is a degree of uncertainty about the accuracy of the discount rate used to address any mismatch, and regulator should avoid large mismatches where possible. Where a DNSP proposes a change in depreciation profile, the Tribunal will assume that it will not be disadvantaged on an NPV basis, because the DNSP itself has the best knowledge about its own business. The Tribunal can be less certain whether the DNSP will not in fact be over-recovering at some point.

263 IPART, *Regulation of New South Wales Distribution Networks, Determination and Rules under the National Electricity Code*, NCDet99-1, December 1999, p 61.

264 That is, where the net present value of revenue recovered from tariffs is equal to the net present value of building block costs.

265 Chapter 6, clause 6.1.1(c)(3). Price stability is also a relevant factor in setting the regulatory cap under clause 6.10.5(d)(3).

266 Integral Energy submission to 2004 electricity network review, April 2003, p 146.

267 IPART, *Pricing for Electricity Networks and Retail Supply*, June 1999, Report Volume I, p 92.

A8.2.2 1999 network determination

In the 1999 network determination, the Tribunal calculated an allowance for depreciation assuming straight line depreciation. This allowance was based on a categorisation of assets and separate asset life assumptions for these categories established in the GHD/Worley/Arthur Andersen asset valuation.[268]

A8.2.3 Asset lives

In the process leading up to the Tribunal's 1999 electricity determination, the New South Wales Treasury commissioned the GHD/Arthur Andersen/Worley International consortium to provide a study of the ODRC value and asset lives of the DNSP networks. The Tribunal engaged its own consultant, PB Power, to review the valuations derived by the consortium. PB Power reported that the asset lives used by the consortium were reasonable, and that in some cases equipment would survive longer than suggested by the consortium. In its final decision, the Tribunal adopted a refined version of the asset lives suggested by the consortium in order to more accurately reflect where each DNSP was in its asset life cycle.[269]

In its submission to the Tribunal's current network review, EnergyAustralia has supplied asset lives that differ from those used for the 1999 determination. In general, the proposed revised asset lives are longer than the previously adopted estimates, leading to a lower depreciation component for EnergyAustralia's network cost building blocks for the 2004-2009 regulatory period. The Tribunal notes however, that these changes have been made with minimal explanation of how the new asset lives are derived.

Table A8.2. shows that on average, for the four DNSPs, depreciation accounts for about 26 per cent of building block revenue and 5.6 per cent of the RAB over 2004-2009.

Table A8.2 Depreciation as a proportion of building block revenue and RAB, 2004-2009 (average)

DNSP	Building block revenue (%)	RAB (%)
EnergyAustralia	25	4.4
Integral Energy	29	6.0
Country Energy	31	6.3
Australian Inland	19	5.6

268 IPART, *Regulation of NSW Electricity Distribution Networks: Determination and Rules under the National Electricity Code*, December 1999, p 61.

269 IPART, *Regulation of NSW Electricity Distribution Networks: Determination and Rules under the National Electricity Code*, December 1999, pp 63-64.

APPENDIX 9 RESOLVING THE CLOSING UNDERS AND OVERS ACCOUNT BALANCE

The Tribunal has decided to incorporate the outstanding unders and overs account balances in the revenue requirements for the 2004 regulatory period.

The Tribunal has made a Rule under Clause 6.10.1(f) of the Code governing the operation of the unders and overs account (Rule 2001/3). That rule sets out:

- the requirements for notifying balances
- the calculation of the account balance
- processes for adjusting the balances when the balances exceed certain limits.

The Rule does not specify a process for resolving outstanding balances at the end of the regulatory period.

A9.1 Options and issues considered

The current revenue cap form of regulation has required the operation of an unders and overs account that records any over or under-recovery of the DNSP Aggregate Annual Revenue Requirement (AARR). None of the DNSPs are expecting to have a zero balance by the end of the current regulatory period on 30 June 2004.

The Tribunal wrote to the businesses in mid-October asking for the DNSPs to update their forecasts of their closing balances for June 30, 2004. The new forecasts are:

- Country Energy forecasts **under**-recovery balance of $1.7 million
- Australian Inland forecasts **under**-recovery balance $3.2 million
- EnergyAustralia forecasts **over**-recovery balance of $99 million
- Integral Energy forecasts **over**-recovery balance of $73 million.

Under the weighted average price cap form of regulation, revenue is not capped and so an unders and overs account arrangement will not be required for DUOS tariffs.[270] The Tribunal has considered how it should resolve the outstanding balances over the next or future regulatory periods. In making its draft decision, it is aware that the final values for the outstanding balance at 30 June 2004 will not be known at the time it makes its determination. The final outcomes for 2004 will depend on the impact of the 1 July 2003 price changes and the actual sales by DNSPs during 2003/04 at these higher prices.

The Tribunal therefore has to address two issues in this draft decision:

- how to treat the expected unders and overs account balance in the 2004 determination
- how to treat any difference between the expected unders and overs account balance and the final realised value.

[270] The Tribunal has, however, adopted an unders and overs account for transmission revenue which will be treated as a pass-through amount, to account for differences in forecast and realised values each year.

All four DNSPs requested that the Tribunal make arrangements for the closing balances to be resolved during the 2004 regulatory period. They proposed different methods for resolving these balances, although all aim to minimise price impacts on customers, to differing degrees.

Country Energy proposed introducing a correction factor in the weighted average price cap formula. This process would involve:

- calculating a CPI-X smoothed revenue path based upon the relevant 'core' cost components of the building block revenue
- adding an annual adjustment factor to the CPI-X price path to recover the unders and overs balance on an NPV basis.

The correction factor would be a specific percentage adjustment factor calculated as the ratio of the under-recovery balance to total required revenue over the regulatory period. The factor would be adjusted following the release of audited data on the under and over recovery balance. This approach would mean the under-recovery balance is recovered during the next regulatory period.

Faced with potentially substantial increases in prices due to higher operating costs, Australian Inland proposed that its under-recovery balance be added to its RAB. This would return the under-recovery balance over the next regulatory period and beyond and have a lower impact on prices.

EnergyAustralia proposed that its over-recovery balance be added to its RAB. More specifically, it proposed that its over-recovery balance be deducted from the $575 million in additional capital expenditure and $113 million in holding costs that it requested the Tribunal roll into its RAB. The over-recovery balance would therefore offset this addition to the RAB, and would be equivalent to simply deducting the balance off the RAB.

On the assumption that the Tribunal applies an NPV neutral price smoothing mechanism (X-factor), Integral Energy proposed that its over-recovery balance be deducted from its revenue requirement in 2004/05. The objective of this approach is to reduce the extent of the P-nought adjustment and the price shock to customers.

Origin Energy and EMRF both argued that the outstanding balances should be incorporated into the revenue requirements for the current period. Origin Energy argued that this is an appropriate treatment since it is current customers that have contributed to the outstanding balance. AGL Energy Sales and Marketing submitted that the treatment of the residual under and overs account balance should not result in unreasonable price increases to customers.

A9.2 Tribunal's analysis and rationale

Like the DNSPs and other stakeholders, the Tribunal believes it is appropriate for the outstanding unders and overs account balances to be resolved during the 2004 regulatory period. Based on the views put forward in submissions, there are two broad approaches to dealing with the residual unders and overs account balances:

- incorporating the outstanding balances into the regulated revenues in the next regulatory period
- rolling the outstanding balance into the regulatory asset base for recovery over a longer period of time.

In undertaking its analysis of the proposals, the Tribunal has considered the principles and objectives of chapter 6 of the Code and in particular has had regard to:

- Price stability — to what extent does the approach decrease/increase price shocks to customers?
- Intergenerational equity — to what extent do current customers bear the cost of or benefit from the resolution of the outstanding balance?

A9.2.1 Resolving over-recovery balances

In the case of an over-recovery balance, both price stability and intergenerational equity suggest that the over-recovery balance should be incorporated into the regulated revenues in the next regulatory period. Returning the balance during the 2004 regulatory period would involve a larger price offset for a shorter period of time (the 2004-09 regulatory period) than incorporation in the regulatory asset base which would have a lower annual offset that persists for a longer period. The time frame for the regulatory asset base approach would depend on how the outstanding balance is incorporated in the regulatory asset base. For example, if it were pro-rated across the full asset base, then the balance would be returned over a period matching the DNSP's average remaining asset life.

From an intergenerational equity perspective, returning the over-recovery in the next regulatory period would also be preferred as current customers, who have paid the higher than required prices, are more likely to benefit from the lower prices.[271]

On balance, the draft determination is to resolve over-recovery balances during the 2004-09 regulatory period by deducting the outstanding balance from revenue requirements.

A9.2.2 Under-recovering businesses

An under-recovery balance means that prices on average have been below the level required to recover DNSP's required revenues. In this situation, the case for recovering the under-recovery balance during the next regulatory period is less clear cut. In principle, price stability and intergenerational equity become competing objectives.

271 In the case of EnergyAustralia, because it had a substantial opening asset balance in 1999, it is likely that its customers paid more than efficient costs during the 1996-99 regulatory period. This would suggest for EnergyAustralia, at least, there is a stronger imperative for the over-recovery amount to be returned sooner rather than later.

Intergenerational equity arguments for incorporation of the under recovery amount during the 2004 regulatory period are similar as for the over recovery amount. However, in this situation incorporation of the under recovery amount will increase prices during the 2004 regulatory period compared to what they would otherwise have been. The Tribunal believes there is then, in-principle, a trade off between intergenerational equity and limiting price impacts on customers during the next regulatory period — particularly in the face of expected significant increases in notional revenue requirements for the coming regulatory period.

For Country Energy, however, the Tribunal's analysis indicates that the impact on prices is negligible, reflecting the forecast small under-recovery balance. For Australian Inland, the impact on prices of incorporating its under-recovery balance during the next regulatory period is greater since their under-recovery balance represents a greater share of expected revenue requirements in 2004/05 (18 per cent).

Stakeholder submissions argued strongly for the Tribunal to place a greater weight on intergenerational equity. In response to the Secretariat's initial proposal in the discussion paper to incorporate under-recovery balances in the regulatory asset base, Country Energy argued that:

> We believe the key issue in relation to the treatment of unders and overs is cost reflectivity where costs should be paid for at the time when the services are used and assets consumed.
>
> When structuring the cost recovery of service provision it is necessary for the regulator to ensure that the cost of investment is recovered and paid for by customers that receive and enjoy the economic benefits from that investment. The majority of Country Energy's unders balance can be attributed to under-recovered FRC related costs, the majority of which are associated with capital investments in IT systems. Current customers are enjoying these FRC related investments and services. The economic decline of FRC investments will also occur during the current and forthcoming regulatory periods due to their short-lived nature. Future generations will not benefit from these capital investments. Therefore it is current customers that have contributed to the unders balance and it is these customers that should bear the cost, not future generations. We consider it unfair that future customers should be required to contribute a higher proportion of the current economic costs of service provision.[272]

The Tribunal agrees that intergenerational equity considerations would suggest that the under-recovery balance should be returned during the next regulatory period. In light of the negligible price impacts for Country Energy and the strong arguments that have been advanced for placing greater weight on intergenerational equity, the Tribunal has decided for this draft report to add the under-recovery balances to the notional revenue requirements for the 2004 regulatory period.

The Tribunal recognises that its draft decision will mean that Australian Inland's revenue requirements and price path are increased. Practically, the Tribunal's decision on Australian Inland's price path (see chapter 5) means that it will lose much of the benefit of the under-recovery account balance — with much or all of the under-recovery balance simply adding to the revenue shortfall. The Tribunal believes that is justified in Australian Inland's

272 Country Energy submission to IPART on Secretariat Discussion Paper, 20 October 2003, p 51.

situation in which it has indicated that that it is prepared to accept a lower rate of return as it transitions to more sustainable prices by foregoing some revenue.

Country Energy submitted that the under-recovery balance be incorporated in the next regulatory period via a percentage adjustment factor in the price cap formula. In proposing the correction factor approach, Country Energy's submission indicates that it is seeking to retain the value of the under recovery amount. Country Energy is concerned that simply adding the under-recovery amount to the notional revenue requirement in the 2004 regulatory period would mean that it would simply lose the amount as unrecovered revenue under its proposed price path (Country Energy's standardised proposed price path of a P-nought of 13.2 per cent real and followed by 5.7 per cent real increases does not recover its proposed total costs).

However, it is difficult to see how Country Energy's correction factor approach addresses this problem. Under its proposal, there is a maximum total price to consumers that it believes would generate an acceptable price impact on customers. This represents an absolute constraint on what revenue can be recovered. Incorporation of an explicit correction factor for the under-recovery balance would simply reduce the amount that can be recovered against notional revenue requirements — the composition of revenue (in terms of how it is notionally mapped against costs) would change but not the total amount collected. While Country Energy would be recouping the under-recovery amount, it would be foregoing other notional required revenue. For this reason, the Tribunal has decided not to follow Country Energy's correction factor approach.

A9.2.3 Treatment of the forecast error

In terms of handling the forecast error associated with using the forecast closing 2004 balance, the Tribunal has decided that the difference between the forecast balance and the actual closing balance ('the forecast error') is to be added to the Transmission unders and overs account that it is implementing for the recovery of transmission revenues. The Tribunal believes this is a simple and practical approach that guarantees that the closing unders and overs account balance will be fully reflected in the DNSPs' revenue requirement.

The Tribunal considered other options including making no adjustment for the error and incorporating into weighted average price cap formula via a correction factor. It does not believe there was any justification for making no adjustment. It considers that adding a correction factor to the weighted average price cap formula would increase the complexity of the formula. In addition, because it would calibrated on the basis of projected volumes each year, this approach would likely over or under recover the amount associated with the forecast error.

APPENDIX 10 APPROACH TO DETERMINING THE X-FACTOR

This Appendix provides an evaluation of each method's outcomes, the issues considered by the Tribunal, and an additional explanation of the different methods of calculating X-factors. The Code does not have any specific requirements relating to the appropriate path for calculating X-factors. The Tribunal has had regard to the general provisions of the Code outlining the key objectives and principles for the regulation of network prices.

A10.1 Options considered

The Tribunal's issues paper and financial modelling contained three broad approaches to calculating the amount by which prices need to move to deliver the notional revenue requirement to DNSPs over the regulatory period. These were:

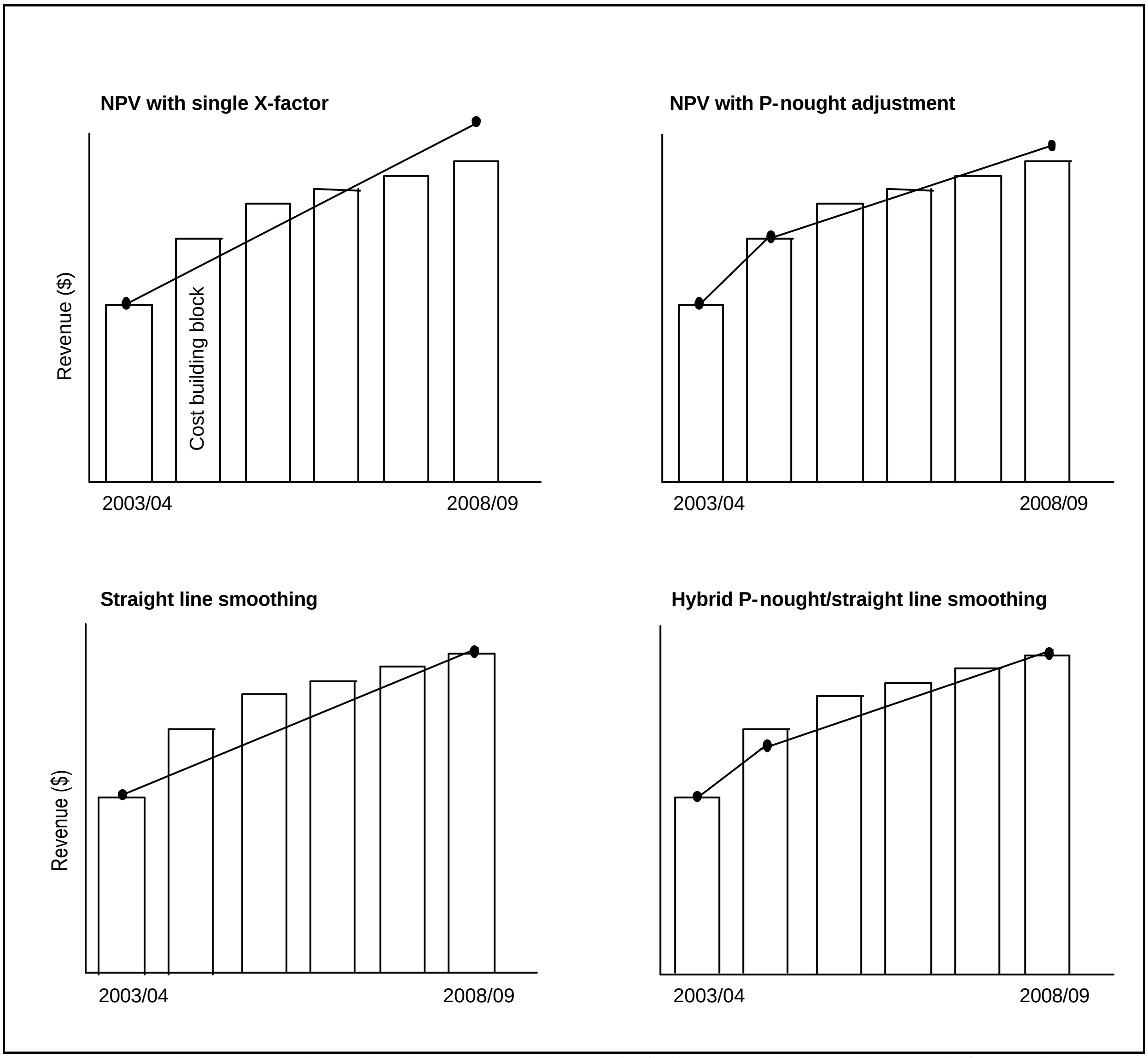
- **Net Present Value (NPV) approach with single X-factor** — a single X-factor is set to ensure expected revenue equals expected notional revenue requirements (in NPV terms).
- **NPV approach with P-nought adjustment** — an initial X-factor (P-nought) allows prices to rise sufficiently to ensure expected revenue is equal to notional revenue requirements in the first year, with a second X-factor, to apply over the remainder of the regulatory period, set at a level that ensures expected revenue equals expected notional revenue requirements over the life of the regulatory period.
- **Straight line revenue smoothing (glide path)**— a single X-factor is set such that prices change smoothly over the regulatory period in real terms to ensure that the expected revenue in the final year of the regulatory period equals the notional revenue requirements in that year.[273]

In addition to these three approaches, Country Energy and Australian Inland have proposed a hybrid approach combining a P-nought adjustment with straight line revenue smoothing. This approach involves two X-factors. An initial X-factor is set to deliver a desired P-nought adjustment to prices. A second X-factor determines a constant real price path that would ensure expected revenue in the final year of the regulatory period is equal to the expected notional revenue requirement in that year (as under the straight line approach).

Figure A10.1 illustrates the approximate revenue paths under these approaches.

[273] The Tribunal also considered a 'fixed term' form of efficiency carryover mechanism, where the price path is set so that DNSPs can retain the benefits of any out performance (or, potentially, underperformance) for a fixed number of years, irrespective of when they occur in the regulatory period. This is discussed further in Chapter 5, section 5.4.

Figure A10.1 Revenue paths under alternate approaches



Note: The actual revenue paths under these approaches might be less smooth than illustrated if annual volume growth is volatile.

Each of these approaches has different implications for:

- **Price stability.** How volatile will the price path be under this approach? Will customers face large jumps in prices and/or changes in direction (increases followed by falls) during the regulatory period?
- **Revenue recovery.** Does the option allow for recovery of notional revenue requirements? Does it allow a reasonable return on investment?
- **Transitional issues into the regulatory period commencing 2009.** What does the option imply for revenue in the final year of the 2004-09 regulatory period? Is the notional revenue requirement for the final year (2008/09) over or under recovered, potentially requiring a realignment of revenues going into the next regulatory period?
- **Implications for incentives.** What implications are there for incentives for efficient operation and investment? Does the approach allow businesses some form of efficiency carryover?

- **Regulatory consistency.** How does the option compare with the approach in the 1999 determination? What are the implications for the 2009 determination?

A10.1.1 Analysis

The four options for setting the price path were evaluated by the Tribunal in terms of the above five criteria below.

Table A10.1 below summarises how each of the proposed X-factor methodologies rate against the abovementioned criteria and shows that each option rates differently against each of the above criteria.

Given the current circumstances, the straight line smoothing is likely to have least impact on prices faced by customers. It also offers the greatest level of incentives for efficiency gains but at a cost in terms of the amount of revenue raised by the DNSPs. The single X-factor NPV approach offers a smooth price path with higher annual price increases but has weak incentives for cost efficiencies. The NPV P-nought approach also offers weak incentives for efficiency improvements but offers the option of a higher initial price increase with lower annual rises thereafter, while fully recovering revenue. The Tribunal has had to consider whether stakeholders are likely to prefer larger ongoing annual increases over a more significant initial increase followed by smaller annual price increases or vice versa.

The trade-off among options between the incentives offered and the level of revenue recovery is readily apparent. The options that have the greatest incentive properties are likely to under-recover expected costs in the 2004-09 regulatory period.

Under the straight line approach efficiency 'losses' (that is, the difference between expected and actual costs) from the 1999-2004 regulatory period would be carried forward in to the 2004-09 regulatory period. This negative carryover would reduce the expected rates of return for the DNSPs. A key issue is what impact these lower rates of return would have on incentives for investment. One view of this is that the revenue outcomes under the glide path approach would simply be an outcome of incentive based regulation. If the straight line approach were seen as a form of efficiency carryover that has been and will be applied across past and future regulatory periods, then this disincentive to investment would be reduced. In this situation, the lower returns would reflect the context of a wider picture across a number of regulatory periods whereby the glide path offers expected rates of return that in some periods are higher than the WACC and in some periods are lower but on average deliver a prospective return on investment equal to the WACC.

Table A10.1 Summary of approaches

Approach	Price path	Revenue recovery	Incentives for efficiency	Transition to 2009 regulatory period	Consistency with 1999 determination
NPV with single X factor	Stable price increases in 2004-09	NPV neutral	No additional incentives beyond CPI –X regulation. Lower than straight line/glide path approach, unless intro-ducing ECM[274]	Likely to over-recover final year revenues	Inconsistent with 1999 determination
NPV with P-nought adjustment	Initial price shock followed by stable price increases	NPV neutral	No additional incentives beyond CPI –X regulation. Lower than straight line approach, unless intro-ducing ECM	Could over or under recover final year revenues. Less than single X-factor approach	Inconsistent with 1999 determination
Straight line smoothing	Stable price increases. Likely lowest average price increase in 2004-09	Likely to under-recover in 2004-09 period	Stronger incentives as form of efficiency carryover mechanism	No transition issues	Consistent with 1999 determination
Hybrid straight line smoothing/P-nought approach	Initial price shock (smaller than pure P-nought approach) followed by stable prices	Likely to under-recover in 2004-09 period	Lower incentives than straight line approach but stronger than NPV neutral approaches	No transition issues	Partially consistent with 1999 determination.

274 Efficiency carry-over mechanism.

APPENDIX 11 RECOMMENDATIONS RELATING TO NETWORK DEMAND MANAGEMENT (DM) FROM TRIBUNAL'S SECTION 12A INQUIRY[275]

A11.1 Recommendations (5-9) from Section 12A Inquiry to encourage network driven DM

Recommendation 5

The Tribunal confirms its existing commitment to the recovery of prudent expenditures on network capex, loss reduction and DM payments and proposes that during the 2004 network review process, it will work with:

- *the DNSPs and other stakeholders to develop network planning processes that provide greater clarity to the treatment of investment in non-network projects and DM*
- *the DNSPs to develop a framework for assessing the economic prudence of loss management investments.*

Recommendation 6

That DNSPs undertake trials of localised congestion pricing in regions of emerging constraint of the distribution network. Such trials should:

- *be integrated with network planning processes and standard offer programs*
- *have regard to retail market design and the provision of time of use meters*
- *be carefully designed to manage the impacts on customers through: the use of rebates as well as positive price signals; optional tariff structures; and market segmentation to focus on customers most able to respond to price signals.*

The Tribunal confirms that rebates on network charges or DNSP payments for load reductions should be included as negative revenue in calculating regulated revenue and compliance with side-constraints on changes in network charges.

Recommendation 7

The Tribunal proposes to:

- *formally set out its methodology for calculation of avoided TUOS in a Schedule to the Pricing Principles and Methodologies, taking into account any adjustments required by the application of Chapter 6 of the National Electricity Code to Transmission pricing from 2002/03*
- *Consult further with stakeholders in establishing guidelines in the PPM on the treatment of avoided DUOS.*

Recommendation 8

That negotiation guidelines and streamlined connection agreements be developed under the framework of the National Electricity Code, and in doing so:

275 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, October 2002.

- *consideration be given to the UK proposal that distributed generators be given the choice of paying deep connection fees up-front or paying shallow connection fees initially, with the balance paid through an annualised connection charge*
- *standard connection agreements be developed for small DG projects (up to 1MW initially) of installed capacity.*

Alternatively, if appropriate, this initiative could be undertaken in NSW as part of a review of the NSW Demand Management Code of Practice.

Recommendation 9

That an industry-based working group develop Standard Offer contracts for demand management as part of the review of the NSW Demand Management Code of Practice.

APPENDIX 12 PRICING ISSUES CONSULTATION GROUP (PICG) STAKEHOLDERS REPRESENTED

ORGANISATION	(where two or more meetings were attended)
1	AGL Sales & Marketing
2	Australian Inland
3	Business Council for Sustainable Energy
4	Country Energy
5	Energy & Management Services Consultancy
6	EnergyAustralia Network
7	EnergyAustralia Retail
8	Energy Users Association of Australia
9	Energy Reform Forum
10	Essential Services Commission Victoria
11	Independent Competition and Regulatory Commission
12	Integral Energy
13	Independent Pricing and Regulatory Tribunal
14	Ministry of Energy and Utilities
15	National Retailers Forum
16	NSW Treasury
17	Origin Energy
18	Public Interest Advocacy Centre
19	Sustainable Energy Development Authority
20	TransGrid

PICG MEETINGS HELD	
1	30 January 2003
2	6 March 2003
3	7 May 2003
4	18 June 2003
5	23 July 2003
6	25 September 2003 (combined with Energy Industry Consultation Group)

APPENDIX 13 ENERGYAUSTRALIA OPERATING AND FINANCIAL INFORMATION

A13.1 Corporate and operating information

Head Office: 570 George Street Sydney, NSW 2000
Network Service Area: 22,275 square kilometres
Major Towns / Cities: Sydney, Barry, Merriwa, Nelson Bay, Scone, Waterfall
Employee Numbers: 2,738

Source: EnergyAustralia's Price and Service Report 2002.

A13.2 Network demand profile

Table A13.1 Historical demand 1999/00 to 2003/04[1]

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered	24,364	25,276	25,402	26,948	29,709
Peak demand (MW)[2]	4,983	4,696	5,003	5,090	5,190
Total Customers:					
Residential	1,260,714	1,300,446	1,314,973	1,330,800	1,358,200
Non-residential	143,026	144,906	149,305	150,608	152,805

1. From 2003/04, demand based on EnergyAustralia's 'high growth' scenario submitted to the 2004 Electricity Review and EnergyAustralia's submission to the 2004 Electricity Network Review.
2. Source: Prices and Services Report.

Table A13.2 Forecast demand 2004/05 to 2008/09[1]

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered	30,423	31,051	31,669	32,424	33,202
Peak demand (MW)	5,290	5,380	5,460	5,570	np
Total Customers:					
Residential	1,377,900	1,392,900	1,409,600	1,424,400	1,441,600
Non-residential	155,305	157,405	159,505	161,605	164,405

1. Demand based on EnergyAustralia's 'high growth' scenario submitted to the 2004 Electricity Review.
np = not provided

Table A13.3 Maximum demand

Historical	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	np	np	2004/05	5,310	5,400
2000/01	np	np	2005/06	5,400	5,600
2001/02	5,003	4,824	2006/07	5,500	5,800
2002/03	5,080	4,950	2007/08	5,590	5,990
2003/04f	5,190	5,170	2008/09	5,710	6,220

Source: EnergyAustralia's submission to the 2004 Electricity Network Review, Attachment 3. All forecasts from 2003/04 are based on EnergyAustralia's 'high growth' scenario. (np = not provided).

A13.3 Reliability

Table A13.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	90	118	175
	Standard		101	102
	MS	84	96	96
SAIFI	Raw	2.3	2.5	2.5
	Standard		1.2	1.3
	MS	1.2	1.2	1.3
CAIDI	Raw	39	47	69
	Standard		80	80
	MS	70	79	77

Source: Network Price and Service Report 2001 and 2002.

Table A13.5 Forecast reliability

		2002/03 A	2003/04 F	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall Distn Normalised	102	EnergyAustralia chose not to provide information					101
SAIFI	Overall Distn Normalised	1.2						1.2
CAIDI	Overall Distn Normalised							

Source: EnergyAustralia's submission to the 2004 Electricity Network Review, April 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.

A13.4 Distribution revenue forecast 2004/05 to 2008/09

Table A13.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB [1]	4,103,549	4,467,593	4,829,573	5,181,661	5,513,986
Operating Costs	290,281	305,483	313,730	320,889	326,980
Capital Expenditure	443,629	452,275	453,720	446,073	467,627
Forecast Network Sales (GWh)	30,423	31,051	31,669	32,424	33,202
Forecast Sales Growth (%)	2.4%	2.1%	2.0%	2.4%	2.4%

Note:

1. Opening balance adjusted to exclude transmission assets and street lighting and to include capex over and above what was provided for in the 1999 Determination at its undepreciated value.

Table A13.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04[1]

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004f
Opening value		3,766,320	3,788,805	3,943,051	4,244,573	4,420,331	4,605,443
Capex/Additions [2]		140,600	256,200	272,300	293,000	293,800	330,318
Depreciation		169,693	183,596	207,996	226,210	244,122	261,354
Disposals		12,000	11,444	6,127	16,383	5,607	1,970
Indexation		63,579	93,086	243,345	125,350	141,041	143,088
Closing value	**3,766,320**	**3,788,805**	**3,943,051**	**4,244,573**	**4,420,331**	**4,605,443**	**4,815,525**

Notes:
1. Includes transmission assets.
2. Net of capital contributions.
Columns may not add due to rounding.

Table A13.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Opening value	4,815,525	4,467,593	4,829,573	5,181,661	5,513,986
Adjustment [1]	-711,976				
Capex/Additions [2]	443,629	452,275	453,720	446,073	467,627
Depreciation	178,179	198,097	218,502	239,324	258,081
Disposals	9,423	9,423	9,423	9,423	9,423
Indexation	108,016	117,225	126,293	135,000	143,577
Closing value	**4,467,593**	**4,829,573**	**5,181,661**	**5,513,986**	**5,857,686**

Notes:
1. In the 1999 determination, EnergyAustralia's regulatory asset base was presented including transmission assets (which are regulated by the ACCC). This draft determination will not include tranmission assets in the regulatory asset base. In addition, street lighting assets are an excluded distribution service, so these assets are also deducted from the regulatory asset base. The capex over and above what was provided for in the 1999 determination has been included at its undepreciated value.
2. Net of capital contributions.
3. Transmission assets have been excluded from 2003/04 closing value to ensure consistent calculation.
Columns may not add due to rounding.

A13.5 Notional revenue requirements

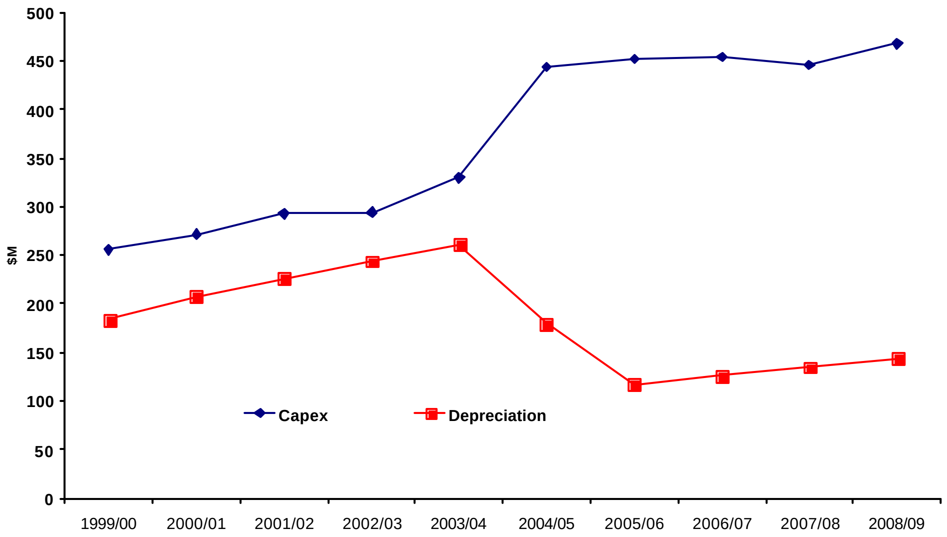
Table A13.9 Notional revenue requirement 2004/05 to 2008/09

Financial year ending 30 June	2005	2006	2007	2008	2009
$'000 $ of the year					
Operating expenditure [1]	290,281	305,483	313,730	320,889	326,980
Depreciation	170,298	189,335	208,837	228,738	246,666
Return on fixed assets	287,829	312,368	336,531	359,731	382,587
Return on working capital	6,188	5,799	5,901	6,440	6,993
Unsmoothed Base Revenue	**754,595**	**812,984**	**864,999**	**915,798**	**963,226**
less correction for previous over/under recovery	20,758	22,724	24,876	27,232	29,811
less revenue from non-tariff sources	5,003	5,345	5,712	6,106	6,529
Unsmoothed Base Revenue from tariffs [3]	**728,834**	**784,915**	**834,411**	**882,461**	**926,886**
Smoothed Revenue Base [3]	**725,811**	**771,013**	**818,492**	**872,007**	**928,508**
Return on fixed assets (real pre-tax)	**6.7%**	**6.5%**	**6.5%**	**6.6%**	**6.8%**
NPV of revenue foregone	**34,259**				
Average distribution price (nominal c/kWh)	2.38	2.47	2.57	2.67	2.78
Cumulative average real price change	**6.5%**	**8.0%**	**9.5%**	**11.0%**	**12.6%**

Notes:
1. Excludes line costs and Electricity Distribution Levy.
2. Depreciation calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation for the revenue requirement is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
3. Unsmoothed base revenue from tariffs is different from smoothed base revenue in 2009 as the IPART financial model calculates an X-factor to several decimal places, whereas the Tribunal's decision is to determine the X-factor to one decimal place. The smoothed revenue base reflects the revenue requirement using an X-factor to one decimal place.

Columns may not add due to rounding.

Figure A13.1 Return of capital (depreciation) versus capex profile



A13.6 Financial performance ratios

Table A13.10 Financial ratio analysis - actual gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	3.54	3.43	3.39	3.41	3.50
NSW Treasury rating (2002)	**AA**	**A+**	**A+**	**A+**	**AA**
- EBITDA + interest earnings / interest expense	3.56	3.45	3.40	3.42	3.51
NSW Treasury rating (2002)	**AA**	**A+**	**A+**	**A+**	**AA**
- Pre tax interest cover (EBIT + interest earnings) / interest expense)	2.12	2.00	1.95	1.96	2.03
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
- Funds flow interest cover	3.75	3.61	3.49	3.50	3.59
S&P - US Utilities (1995)	**A**	**A**	**A**	**A**	**A**
Ability to repay debt					
- Funds flow net debt payback	7.81	7.86	7.85	7.62	7.33
NSW Treasury rating (2002)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
- Funds from operations/Total debt	0.14	0.13	0.13	0.13	0.14
S&P - US Utilities (1995)	**BBB**	**BB**	**BB**	**BB**	**BB**
Debt to Equity Ratio	47%	47%	48%	48%	47%
- (Debt-cash assets)/(RAB)	0.47	0.47	0.48	0.48	0.47
NSW Treasury rating (2002)	**A+**	**A**	**A**	**A**	**A**
S&P - US Utilities (1995)	**AA**	**A**	**A**	**A**	**A**
Ability to finance investment from internal sources					
- Internal financing ratio	0.47	0.50	0.55	0.61	0.63
NSW Treasury rating (2002)	**BB**	**BBB**	**BBB**	**BBB+**	**BBB+**
- Net cash flow / net Capex	0.59	0.55	0.58	0.65	0.68
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
- Cash flow before Capex / Capex	0.66	0.70	0.73	0.81	0.85
Funds flow adequacy					
Funds from operations/(dividends + capex)	0.62	0.61	0.64	0.70	0.73
NSW Treasury total score					
- EBITDA + interest earnings / interest expense	8.00	7.00	7.00	7.00	8.00
- Funds flow net debt payback	4.00	4.00	4.00	4.00	4.00
- (Debt-cash assets)/(RAB)	7.00	6.00	6.00	6.00	6.00
Internal financing ratio	2.00	4.00	4.00	5.00	5.00
Total score	**4.67**	**5.00**	**5.00**	**5.33**	**5.67**
Overall rating	**BBB**	**BBB+**	**BBB+**	**BBB+**	**BBB+**
Net Debt	2,109,733	2,314,180	2,503,220	2,657,659	2,805,495

1. Weightings for NSW Treasury Score: 33 per cent EBIT DA interest cover, funds flow and internal financing ratio.

Table A13.11 Financial ratio analysis - notional 60 per cent gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	2.68	2.65	2.66	2.72	2.82
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**BBB+**	**BBB+**	**BBB+**
- EBITDA + interest earnings / interest expense	2.69	2.66	2.67	2.73	2.83
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**BBB+**	**BBB+**	**BBB+**
- Pre tax interest	1.61	1.55	1.53	1.56	1.63
S&P - US Utilities (1995)	**BB**	**BB**	**BB**	**BB**	**BB**
- Funds flow interest cover	2.84	2.79	2.74	2.79	2.89
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Ability to repay debt					
- Funds flow net debt payback	11.11	11.03	10.80	10.30	9.77
NSW Treasury rating (2002)	**BB**	**BB**	**BB**	**BB**	**BB**
- Funds from operations/Total debt	0.10	0.10	0.10	0.10	0.11
S&P - US Utilities (1995)	**<BB**	**<BB**	**<BB**	**<BB**	**<BB**
Debt to Equity Ratio	60%	60%	60%	59%	58%
- (Debt-cash assets)/(RAB)	0.60	0.60	0.60	0.59	0.58
NSW Treasury rating (2002)	**BB**	**BB+**	**BB+**	**BB+**	**BB+**
S&P - US Utilities (1995)	**BB**	**BB**	**BB**	**BBB**	**BBB**
Ability to finance investment from internal sources					
- Internal financing ratio	0.45	0.48	0.53	0.59	0.61
NSW Treasury rating (2002)	**B+**	**BB+**	**BBB**	**BBB**	**BBB+**
- Net cash flow / net Capex	0.57	0.53	0.56	0.63	0.66
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
- Cash flow before Capex / Capex	0.61	0.64	0.67	0.75	0.78
Funds flow adequacy					
Funds from operations/(dividends + capex)	0.59	0.57	0.61	0.67	0.70
NSW Treasury total score					
- EBITDA + interest earnings / interest expense	5.00	5.00	5.00	5.00	5.00
- Funds flow net debt payback	2.00	2.00	2.00	2.00	2.00
- (Debt-cash assets)/(RAB)	2.00	3.00	3.00	3.00	3.00
Internal financing ratio	1.00	3.00	4.00	4.00	5.00
Total score	**2.67**	**3.33**	**3.67**	**3.67**	**4.00**
Overall rating	**BB**	**BB+**	**BB+**	**BB+**	**BBB**
Net Debt	2,721,063	2,934,157	3,132,069	3,295,511	3,452,479

1. Weightings for NSW Treasury Score: 33 per cent EBIT DA interest cover, funds flow and internal financing ratio.

A13.7 Distribution financial performance statement

Table A13.12 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Revenue from tariffs (excl GST and EDL)	725,811	771,013	818,492	872,007	928,508
Other 'building block' revenue (incl IDT receipts)	5,003	5,345	5,712	6,106	6,529
Transmission charges (including IDT payments)	166,237	177,056	188,572	200,830	213,590
Other revenue	0	0	0	0	0
Total revenue	**897,052**	**953,414**	**1,012,776**	**1,078,944**	**1,148,626**
Network operating expenditure	290,281	305,483	313,730	320,889	326,980
Transmission charges (including IDT payments)	166,237	177,056	188,572	200,830	213,590
Total costs	456,518	482,538	502,302	521,720	540,570
EBITDA	**440,534**	**470,876**	**510,474**	**557,224**	**608,057**
EBIT	**262,355**	**272,779**	**291,972**	**317,900**	**349,976**
Interest/investment income	1,769	1,818	1,922	2,000	2,078
Interest expenses	124,356	137,141	150,779	163,317	173,606
Operating profit before cap cons and abnormals	139,768	137,456	143,114	156,583	178,447
Abnormal items					
Profit before tax	**139,768**	**137,456**	**143,114**	**156,583**	**178,447**
Tax equivalent	41,930	41,237	42,934	46,975	53,534
Profit after tax	**97,837**	**96,219**	**100,180**	**109,608**	**124,913**
Retained profits at beginning of year	211,012	240,363	269,228	299,282	332,165
Adjustments/transfers	0	0	0	0	0
Total available for appropriation	308,849	336,582	369,409	408,891	457,078
Dividends	68,486	67,353	70,126	76,726	87,439
Retained profit at year end	**240,363**	**269,228**	**299,282**	**332,165**	**369,639**

Columns may not add due to rounding.

A13.8 Summary of rolled forward RAB

Table A13.13 Summary of rolled forward RAB

$'000 $ of the year	2005	2006	2007	2008	2009
Total system assets					
Opening value	3,822,158	4,174,583	4,532,141	4,889,782	5,232,700
Capex/Additions	398,156	406,715	410,524	399,863	420,261
depreciation	143,275	155,619	168,331	181,201	194,443
disposals	2,950	2,950	2,950	2,950	2,950
Indexation	100,494	109,412	118,398	127,206	136,034
Closing value	**4,174,583**	**4,532,141**	4,889,782	5,232,700	5,591,602
Total non-system assets					
Opening value	281,391	293,009	297,432	291,879	281,287
Capex/Additions	45,473	45,559	43,196	46,210	47,365
depreciation	34,904	42,478	50,171	58,123	63,638
disposals	6,473	6,473	6,473	6,473	6,473
Indexation	7,522	7,814	7,895	7,794	7,543
Closing value	**293,009**	**297,432**	**291,879**	**281,287**	**266,084**
Total RAB					
Opening value	4,103,549	4,467,593	4,829,573	5,181,661	5,513,986
Capex/Additions	443,629	452,275	453,720	446,073	467,627
depreciation	178,179	198,097	218,502	239,324	258,081
disposals	9,423	9,423	9,423	9,423	9,423
Indexation	108,016	117,225	126,293	135,000	143,577
Closing value	**4,467,593**	**4,829,573**	**5,181,661**	**5,513,986**	**5,857,686**

Notes:
All capex / additions are net of capital contributions.
Columns may not add due to rounding.

APPENDIX 14 INTEGRAL ENERGY OPERATING AND FINANCIAL INFORMATION

A14.1 Corporate and operating information

Head Office: 51 Huntingwood Drive Huntingwood, NSW 2148
Network Service Area: 24,500 square kilometres
Major Towns / Cities: Blacktown, Campbelltown, Liverpool, Parramatta, Penrith, Wollongong
Employee Numbers: 1,353

Source: Integral Energy's submission to IPART – 10 April 2003 and Price and Service Report 2002.

A14.2 Network demand profile

Table A14.1 Historical demand 1999/00 to 2003/04

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered[1]	12,784	13,890	13,864	14,721	14,722
Peak demand (MW)[1]	2,858	2,966	2,994	3,122	3,231
Total Customers:					
Residential	679,445	691,561	705,950	726,609	736,075
Non-residential	63,711	69,387	70,371	72,287	70,063

1. Source: Prices and Services Report 2002.

Table A14.2 Forecast demand 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered	15,072	15,433	15,762	15,966	16,281
Peak demand (MW)	3,326	3,406	3,491	3,574	np
Total Customers:					
Residential	751,075	769,575	788,075	806,575	825,075
Non-residential	70,417	72,218	73,999	75,300	76,101

np = not provided.

Table A14.3 Maximum demand

Historical	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	-	-	2004/05	2,808	3,321
2000/01	-	-	2005/06	2,874	3,425
2001/02	2,555	2,994	2006/07	2,935	3,524
2002/03	2,672	3,114	2007/08	2,975	3,599
2003/04f	2,743	3,222	2008/09	3,033	3,698

Source: Integral Energy, *Prices and Service Report 2002*.

A14.3 Reliability

Table A14.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	124	217	738
	Standard		136	134
	MS	84	96	99
SAIFI	Raw		2.95	3.55
	Standard		1.30	1.26
	MS	1.1	1.16	1.14
CAIDI	Raw		74	208
	Standard		105	107
	MS	75	83	87

Source: Draft Electricity Network Performance Report 2002/03.

Table A14.5 Forecast reliability

		2002/03a	2003/04f	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall	217	np	374	354	338	318	302
	Distn	155	np	np	np	np	np	np
	Normalised	120	199	114	108	103	97	92
SAIFI	Overall	2.74	np	2.91	2.76	2.63	2.48	2.35
	Distn	1.42	np	np	np	np	np	np
	Normalised	1.3	np	1.21	1.15	1.09	1.02	0.97
CAIDI	Overall	79	np	128	128	128	128	128
	Distn	109	np	np	np	np	np	np
	Normalised	92	np	94	94	94	94	94

Source: Integral Energy's submission to the 2004 Electricity Network Review, September 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.
np = numbers not currently available.

A14.4 Distribution revenue forecast 2004/05 to 2008/09

Table A14.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB [1]	2,211,599	2,396,941	2,567,683	2,710,298	2,865,640
Operating Costs	206,933	212,224	219,700	227,309	234,808
Capital Expenditure	259,467	253,533	234,314	256,307	265,149
Forecast Network Sales (GWh)	15,072	15,433	15,762	15,966	16,281
Forecast Sales Growth (%)	2.4%	2.4%	2.1%	1.3%	2.0%

1. Opening balance adjusted to exclude street lighting and to include capex over and above what was provided for in the 1999 Determination at its undepreciated value.

Table A14.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004
Total value of assets							
Opening value		1,731,735	1,761,115	1,782,320	1,863,940	1,941,346	2,019,338
Capex/Additions [1]		98,265	98,406	96,679	146,587	147,793	227,502
Depreciation		94,409	104,687	115,199	124,561	131,834	139,235
Disposals		4,000	15,417	8,885	24	235	-
Indexation		29,525	42,902	109,025	55,405	62,267	63,993
Closing value	**1,731,735**	**1,761,115**	**1,782,320**	**1,863,940**	**1,941,346**	**2,019,338**	**2,171,597**

Notes:

1. Net of capital contributions.

Columns may not add due to rounding.

Table A14.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Total RAB					
Opening value	2,171,597	2,396,941	2,567,683	2,710,298	2,865,640
Adustment [1]	40,002				
Capex/Additions [2]	259,467	253,533	234,314	256,307	265,149
Depreciation	132,657	145,884	158,820	171,927	186,031
Disposals	0	0	0	0	0
Indexation	58,533	63,093	67,121	70,961	74,955
Closing value	**2,396,941**	**2,567,683**	**2,710,298**	**2,865,640**	**3,019,713**

Notes:

1. Street lighting is proposed to be an excluded distribution service. Capex over and above what was provided for in the 1999 determination has been included at its undepreciated value.
2. Net of capital contributions.

Columns may not add due to rounding.

A14.5 Notional revenue requirements

Table A14.9 Notional revenue requirement 2004/05 to 2008/09

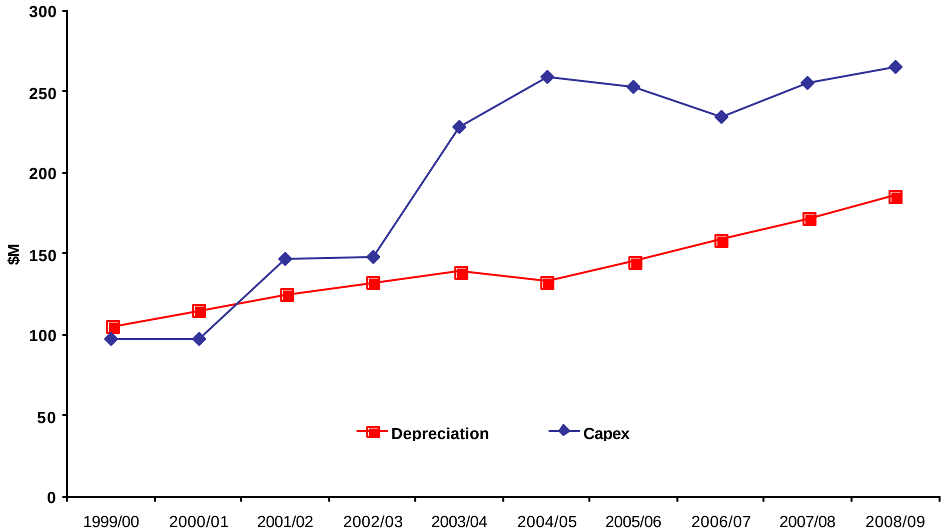
Financial year ending 30 June	2005	2006	2007	2008	2009
$'000 $ of the year					
Operating expenditure [1]	206,933	212,224	219,700	227,309	234,808
Depreciation	126,790	139,431	151,795	164,322	177,802
Return on fixed assets	155,973	168,122	178,856	189,089	199,732
Return on working capital	2,663	2,816	3,085	3,384	3,594
Unsmoothed Base Revenue	**492,358**	**522,593**	**553,436**	**584,104**	**615,936**
less correction for previous d recovery	15,276	16,722	18,306	20,039	21,937
less revenue from non-tariff sources	4,772	5,031	5,276	5,459	5,694
Unsmoothed Base Revenue from tariffs [3]	**472,310**	**500,840**	**529,854**	**558,605**	**588,305**
Smoothed Revenue Base [3]	**465,978**	**495,125**	**525,494**	**555,403**	**588,598**
Return on fixed assets (real pre-tax)	**6.5%**	**6.6%**	**6.6%**	**6.7%**	**6.8%**
NPV of revenue foregone	**16,656**				
Average distribution price (nominal c/kWh)	3.09	3.20	3.32	3.44	3.56
Cumulative average real price change	**1.1%**	**2.2%**	**3.3%**	**4.5%**	**5.6%**

Notes:

1. Excludes line costs and Electricity Distribution Levy.
2. Depreciation calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation for the revenue requirement is calculated in the middle of the year whereas depreciation for the asset base is calculated at the end of the year.
3. Unsmoothed base revenue from tariffs is different from smoothed base revenue in 2009 as the IPART financial model calculates an X-factor to several decimal places, whereas the Tribunal's decision is to determine the X-factor to one decimal place. The smoothed revenue base reflects the revenue requirement using an X-factor to one decimal place.

Columns may not add due to rounding.

Figure A14.1 Return of capital (depreciation) Versus capex profile



A14.6 Financial performance ratios

Table A14.10 Financial ratio analysis - actual gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	3.73	3.83	3.58	3.70	3.70
NSW Treasury rating (2002)	**AA**	**AA**	**AA**	**AA**	**AA**
- EBITDA + interest earnings / interest expense	3.80	3.90	3.64	3.76	3.75
NSW Treasury rating (2002)	**AA**	**AA+**	**AA**	**AA**	**AA**
- Pre tax interest cover (EBIT + interest earnings) / interest expense)	1.94	1.97	1.82	1.86	1.85
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
- Funds flow interest cover	3.77	3.88	3.59	3.74	3.73
S&P - US Utilities (1995)	**A**	**A**	**A**	**A**	**A**
Ability to repay debt					
- Funds flow net debt payback	6.53	6.40	6.37	6.16	5.97
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**BBB+**	**BBB+**	**A**
- Funds from operations/Total debt	0.14	0.15	0.14	0.15	0.16
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Debt to Equity Ratio	48%	49%	48%	48%	48%
- (Debt-cash assets)/(RAB)	0.48	0.49	0.48	0.48	0.48
NSW Treasury rating (2002)	**A**	**A**	**A**	**A**	**A**
S&P - US Utilities (1995)	**A**	**A**	**A**	**A**	**A**
Ability to finance investment from internal sources					
- Internal financing ratio	0.57	0.64	0.74	0.73	0.77
NSW Treasury rating (2002)	**BBB**	**BBB+**	**A**	**A**	**A+**
- Net cash flow / net Capex	0.57	0.64	0.72	0.74	0.77
S&P - US Utilities (1995)	**BBB**	**BBB**	**A**	**A**	**A**
- Cash flow before Capex / Capex	0.69	0.77	0.87	0.88	0.91
Funds flow adequacy					
Funds from operations/(dividends + capex)	0.61	0.68	0.76	0.77	0.80
NSW Treasury total scc lower risk					
- EBITDA + interest earnings / interest expense	8.00	9.00	8.00	8.00	8.00
- Funds flow net debt payback	5.00	5.00	5.00	5.00	6.00
- Total Debt/ (Debt + Equity)	4.00	5.00	5.00	5.00	5.00
Internal financing ratio	4.00	5.00	6.00	6.00	7.00
Total score	**5.67**	**6.33**	**6.33**	**6.33**	**7.00**
Overall rating	**BBB+**	**A**	**A**	**A**	**A+**
Net Debt	1,174,387	1,264,670	1,330,441	1,397,022	1,458,741

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBITDA interest cover, funds flow and internal financing ratio.

Table A14.11 Financial ratio analysis - notional 60 per cent gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	2.96	3.07	2.95	3.06	3.09
NSW Treasury rating (2002)	**BBB+**	**A**	**BBB+**	**A**	**A**
- EBITDA + interest earnings / interest expense	3.02	3.13	3.00	3.11	3.13
NSW Treasury rating (2002)	**A**	**A**	**BBB+**	**A**	**A**
- Pre tax interest cover (EBIT + interest earnings) / interest expense)	1.54	1.58	1.50	1.54	1.54
S&P - US Utilities (1995)	**BB**	**BB**	**BB**	**BB**	**BB**
- Funds flow interest cover	3.00	3.11	2.95	3.09	3.11
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Ability to repay debt					
- Funds flow net debt payback	8.70	8.40	8.28	7.92	7.62
NSW Treasury rating (2002)	**BB+**	**BB+**	**BB+**	**BBB**	**BBB**
- Funds from operations/Total debt	0.11	0.11	0.11	0.12	0.12
S&P - US Utilities (1995)	**<BB**	**BB**	**BB**	**BB**	**BB**
Debt to Equity Ratio	60%	60%	59%	58%	57%
- (Debt-cash assets)/(RAB)	0.60	0.60	0.59	0.58	0.57
NSW Treasury rating (2002)	**BB+**	**BB+**	**BB+**	**BB+**	**BBB**
S&P - US Utilities (1995)	**BB**	**BB**	**BBB**	**BBB**	**BBB**
Ability to finance investment from internal sources					
- Internal financing ratio	0.55	0.62	0.73	0.72	0.75
NSW Treasury rating (2002)	**BBB**	**BBB+**	**A**	**A**	**A+**
- Net cash flow / net Capex	0.56	0.63	0.70	0.72	0.75
S&P - US Utilities (1995)	**BBB**	**BBB**	**A**	**A**	**A**
- Cash flow before Capex / Capex	0.64	0.72	0.82	0.83	0.86
Funds flow adequacy					
Funds from operations/(dividends + capex)	0.59	0.66	0.73	0.75	0.77
NSW Treasury total score (0 - 10)					
- EBITDA + interest earnings / interest expense	6.00	6.00	5.00	6.00	6.00
- Funds flow net debt payback	3.00	3.00	3.00	4.00	4.00
- Total Debt/ (Debt + Equity)	3.00	3.00	3.00	3.00	4.00
Internal financing ratio	4.00	5.00	6.00	6.00	7.00
Total score	**4.33**	**4.67**	**4.67**	**5.33**	**5.67**
Overall rating	**BBB**	**BBB**	**BBB**	**BBB+**	**BBB+**
Net Debt	1,455,912	1,550,156	1,620,032	1,690,780	1,756,726

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBITDA interest cover, funds flow and internal financing ratio.

A14.7 Distribution financial performance statement

Table A14.12 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Revenue from tariffs (excl GST and EDL)	465,978	495,125	525,494	555,403	588,598
Other "building block" revenue (incl IDT receipts)	4,772	5,031	5,276	5,459	5,694
Transmission charges (including IDT payments)	106,838	110,440	113,561	116,073	120,130
Other revenue	1,837	1,272	1,291	1,305	1,321
Total revenue	**579,426**	**611,869**	**645,622**	**678,241**	**715,744**
Network operating expenditure	206,933	212,224	219,700	227,309	234,808
Transmission charges (including IDT payments)	106,838	110,440	113,561	116,073	120,130
Total costs	313,771	322,664	333,261	343,382	354,939
EBITDA	**265,655**	**289,205**	**312,361**	**334,859**	**360,805**
EBIT	**132,997**	**143,321**	**153,541**	**162,932**	**174,775**
Interest/investment income	5,358	5,358	5,358	5,358	5,358
Interest expenses	71,272	75,601	87,170	90,420	97,529
Operating profit before cap cons and abnormals	67,084	73,078	71,729	77,871	82,604
Abnormal items	0	0	0	0	0
Profit before tax	**67,084**	**73,078**	**71,729**	**77,871**	**82,604**
Tax equivalent	20,125	21,923	21,519	23,361	24,781
Profit after tax	**46,959**	**51,154**	**50,210**	**54,509**	**57,823**
Retained profits at beginning of year	160,357	174,445	189,791	204,854	221,207
Adjustments/transfers	0	0	0	0	0
Total available for appropriation	207,316	225,599	240,001	259,364	279,030
Dividends	32,871	35,808	35,147	38,157	40,476
Retained profit at year end	**174,445**	**189,791**	**204,854**	**221,207**	**238,554**

Notes: Columns may not add due to rounding.

A14.8 Summary of rolled forward RAB

Table A14.13 Summary of rolled forward RAB

$'000 $ of the year	2005	2006	2007	2008	2009
Total system assets					
Opening value	1,959,724	2,139,650	2,312,535	2,468,553	2,641,206
Capex/Additions	227,795	224,965	212,574	234,023	240,210
Depreciation	99,709	108,383	117,027	126,009	135,679
Disposals	0	0	0	0	0
Indexation	51,841	56,303	60,471	64,639	69,033
Closing value	**2,139,650**	2,312,535	2,468,553	2,641,206	2,814,770
Opening value	251,874	257,291	255,149	241,746	224,434
Capex/Additions	31,673	28,569	21,740	22,284	24,938
Depreciation	32,948	37,501	41,793	45,918	50,352
Disposals	0	0	0	0	0
Indexation	6,693	6,789	6,650	6,322	5,923
Closing value	257,291	255,149	241,746	224,434	204,943
Total RAB					
Opening value	2,211,598	2,396,941	2,567,683	2,710,298	2,865,640
Capex/Additions	259,467	253,533	234,314	256,307	265,149
Depreciation	132,657	145,884	158,820	171,927	186,031
Disposals	0	0	0	0	0
Indexation	58,533	63,093	67,121	70,961	74,955
Closing value	2,396,941	2,567,683	2,710,298	2,865,640	3,019,713

Notes:
All capex / additions are net of capital contributions.
Columns may not add due to rounding.

APPENDIX 15 COUNTRY ENERGY OPERATING AND FINANCIAL INFORMATION

A15.1 Corporate and operating information

Head Office: Cnr Littlebourne Street and Hampden Park Road, Kelso NSW 2795
Network Service Area: 582,000 square kilometres
Major Towns / Cities: Albury, Bathurst, Dubbo, Grafton, Port Macquarie, Queanbeyan, Tamworth, Wagga Wagga
Employee Numbers: 2,345

Sources: Country Energy, *Submission to 2004 Distribution Review,* April 2003, and Country Energy, *Prices and Services Report*, November 2002, and Country Energy, *2002 Annual Report.*

A15.2 Network demand profile

Table A15.1 Historical demand 1999/00 to 2003/04

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered [1]	9,648 [2]	10,007	9,965	10,387	10,307
Peak demand (MW)[1]	np	1,950	1,909	2,021	2,082
Total Customers:	716,578 [2]				
Residential		595,675	628,422	622,045	646,141
Non-residential		110,865	87,808	90,164	90,284

1. Source: Country Energy Prices and Services Report 2002.
2. Includes North Power, Great Southern Energy and Advance Energy.
np = not provided.

Table A15.2 Forecast demand 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered	10,482	10,660	10,841	11,026	11,213
Peak demand (MW)[1]	2,122	2,166	2,204	np	np
Total Customers:					
Residential	655,187	664,360	673,661	683,092	692,655
Non-residential	91,548	92,829	94,129	95,447	96,783

1. Source: Country Energy 2003 Price and Services Report. (np = not provided).

Table A15.3 Maximum demand

Historical	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	np	Np	2004/05	2,122	1,745
2000/01	1,820	1,659	2005/06	2,191	1,806
2001/02	1,909	1,549	2006/07	2,244	1,853
2002/03	1,990	1,628	2007/08	2,290	1,895
2003/04f	2,068	1,697	2008/09	2,334	1,935

Source: Country Energy, submission to the 2004 Network Review, Attachment C, April 2003. (np = not provided.)

A15.3 Reliability

Table A15.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	169	242	178
	Standard		173	167
	MS	131	138	137
SAIFI	Raw		2.0	1.9
	Standard		1.5	1.5
	MS	1.4	1.3	1.4
CAIDI	Raw		121	95
	Standard		116	109
	MS	91	110	98

Source: Draft Electricity Network Performance Report 2002/03.

Table A15.5 Forecast reliability

		2002/03a	2003/04f	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall	308	336	403	484	484	474	465
	Distn	287	313	376	451	451	442	433
	Normalised	230	251	301	361	361	354	347
SAIFI	Overall	2.72	2.97	3.56	4.27	4.27	4.19	4.11
	Distn	2.39	2.61	3.13	3.76	3.76	3.68	3.61
	Normalised	2.16	2.36	2.83	3.39	3.39	3.33	3.26
CAIDI	Overall	113	113	113	113	113	113	113
	Distn	120	120	120	120	120	120	120
	Normalised	106	106	106	106	106	106	106

Source: Integral Energy's submission to the 2004 Electricity Network Review, September 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.

A15.4 Distribution revenue forecast 2004/05 to 2008/09

Table A15.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB	2,368,609[1]	2,522, 669	2,669,560	2,806,945	2,940,037
Operating Costs	209,852	217,995	226,452	235,237	244,362
Capital Expenditure	237,115	242,217	245,487	254,690	261,099
Forecast Network Sales (GWh)	10,482	10,660	10,841	11,026	11,213
Forecast Sales Growth (%)	1.7%	1.7%	1.7%	1.7%	1.7%

1. Opening balance adjusted to exclude street lighting and to include capex over and above what was provided for in the 1999 Determination at its undepreciated value.

Table A15.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004f
Opening value		1,675,524	1,743,885	1,776,365	1,921,766	2,041,891	2,197,220
Capex/Additions [1]		146,956	123,762	141,609	180,999	220,983	228,872
Depreciation		89,422	93,350	101,925	110,970	122,747	135,556
Disposals		18,053	40,428	4,427	7,350	9,272	9,550
Indexation		28,879	42,496	110,144	57,446	66,365	69,206
Closing value	**1,675,524**	**1,743,885**	**1,776,365**	**1,921,766**	**2,041,891**	**2,197,220**	**2,350,192**

Notes:

1. Net of capital contributions.

Columns may not add due to rounding.

Table A15.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Total RAB					
Opening value	2,350,192	2,522,669	2,669,560	2,806,945	2,940,037
Adustment [1]	18,417				
Capex/Additions [2]	237,115	242,217	245,487	254,690	261,099
Depreciation	137,641	153,826	170,316	187,362	205,117
Disposals	7,500	7,500	7,500	7,500	7,500
Indexation	62,085	66,001	69,714	73,264	76,671
Closing value	**2,522,669**	**2,669, 560**	**2,806,945**	**2,940,037**	**3,065,191**

Notes

1. Street lighting is proposed to be an excluded distribution service. Capex over and above what was provided for in the 1999 determination has been included at its undepreciated value.
2. Net of capital contributions.

Columns may not add due to rounding.

A15.5 Notional revenue requirements

Table A15.9 Notional revenue requirement 2004/05 to 2008/09

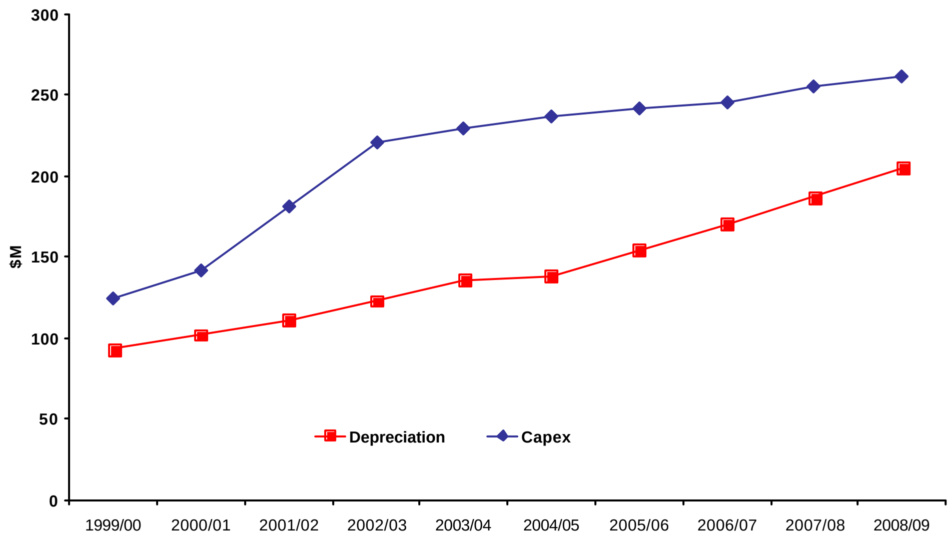
Financial year ending 30 June	2005	2006	2007	2008	2009
$'000 $ of the year					
Operating expenditure [1]	209,852	217,995	226,452	235,237	244,362
Depreciation	131,553	147,022	162,783	179,074	196,044
Return on fixed assets	165,438	175,871	185,765	195,224	204,304
Return on working capital	3,728	3,959	4,275	4,610	4,966
Unsmoothed Base Revenue	**510,571**	**544,846**	**579,275**	**614,146**	**649,675**
less correction for previous over/under recovery	-356	-389	-426	-467	-511
less revenue from non-tariff sources	6,046	6,271	6,500	6,735	6,974
Unsmoothed Base Revenue from tariffs	**504,880**	**538,965**	**573,201**	**607,877**	**643,211**
Smoothed Revenue Base	**461,916**	**492,900**	**525,963**	**561,247**	**598,901**
Return on fixed assets (real pre-tax)	**5.0%**	**5.0%**	**5.1%**	**5.2%**	**5.3%**
NPV of revenue foregone	**182,421**				
Average distribution price (nominal c/kWh)	4.42	4.64	4.87	5.12	5.38
Cumulative average real price change	**6.5%**	**9.2%**	**11.9%**	**14.7%**	**17.6%**

Notes:

1. Excludes line costs and Electricity Distribution Levy.
2. Depreciation calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation for the revenue requirement is calcualted in the middle of the year whereas depreication for the asset base is calcualted at the end of the year.

Columns may not add due to rounding.

Figure A15.1 Return of capital (depreciation) versus capex profile



A15.6 Financial performance ratios

Table A15.10 Financial ratio analysis - actual gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	2.82	2.92	3.02	3.16	3.32
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**A**	**A**	**A+**
- EBITDA + interest earnings / interest expense	2.82	2.92	3.02	3.16	3.32
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**A**	**A**	**A+**
- Pre tax interest cover (EBIT + interest earnings) / interest expense)	1.32	1.32	1.34	1.38	1.44
S&P - US Utilities (1995)	**BB**	**BB**	**BB**	**BB**	**BB**
- Funds flow interest cover	2.88	2.97	3.06	3.19	3.35
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**A**
Ability to repay debt					
- Funds flow net debt payback	9.09	8.72	8.20	7.64	7.06
NSW Treasury rating (2002)	**BB**	**BB+**	**BB+**	**BBB**	**BBB**
- Funds from operations/Total debt	0.11	0.12	0.12	0.13	0.14
S&P - US Utilities (1995)	**BB**	**BB**	**BB**	**BB**	**BBB**
Debt to Equity Ratio	57%	57%	56%	55%	54%
- (Debt-cash assets)/(RAB)	0.57	0.57	0.56	0.55	0.54
NSW Treasury rating (2002)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB+**
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Ability to finance investment from internal sources					
- Internal financing ratio	0.61	0.66	0.72	0.77	0.82
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**A**	**A+**	**AA**
- Net cash flow / net Capex	0.69	0.68	0.75	0.79	0.85
S&P - US Utilities (1995)	**BBB**	**BBB**	**A**	**A**	**A**
- Cash flow before Capex / Capex	0.70	0.74	0.81	0.86	0.93
Funds flow adequacy					
Funds from operations/(dividends + capex)	0.69	0.70	0.76	0.81	0.86
NSW Treasury total score (0 - 10)					
- EBITDA + interest earnings / interest expense	5.00	5.00	6.00	6.00	7.00
- Funds flow net debt payback	2.00	3.00	3.00	4.00	4.00
- Total Debt/ (Debt + Equity)	4.00	4.00	4.00	4.00	5.00
Internal financing ratio	5.00	5.00	6.00	7.00	8.00
Total score	**4.00**	**4.33**	**5.00**	**5.67**	**6.33**
Overall rating	**BBB**	**BBB**	**BBB+**	**BBB+**	**A**
Net Debt	1,457,571	1,534,124	1,596,398	1,648,381	1,686,729

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBITDA interest cover, funds flow and internal financing ratio.

Table A15.11 Financial ratio analysis – notional 60 per cent gearing

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	2.68	2.78	2.88	3.01	3.17
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**BBB+**	**A**	**A**
- EBITDA + interest earnings / interest expense	2.68	2.78	2.88	3.01	3.17
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**BBB+**	**A**	**A**
- Pre tax interest	1.25	1.26	1.28	1.32	1.37
S&P - US Utilities (1995)	**BB**	**BB**	**BB**	**BB**	**BB**
- Funds flow interest cover	2.74	2.82	2.92	3.05	3.20
S&P - US Utilities (1995)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Ability to repay debt					
- Funds flow net debt payback	9.71	9.32	8.76	8.14	7.50
NSW Treasury rating (2002)	**BB**	**BB**	**BB+**	**BB+**	**BBB**
- Funds from operations/Total debt	0.11	0.11	0.12	0.12	0.13
S&P - US Utilities (1995)	**<BB**	**<BB**	**BB**	**BB**	**BB**
Debt to Equity Ratio	60%	59%	59%	58%	57%
- (Debt-cash assets)/(RAB)	0.60	0.59	0.59	0.58	0.57
NSW Treasury rating (2002)	**BB+**	**BB+**	**BB+**	**BB+**	**BBB**
S&P - US Utilities (1995)	**BB**	**BB**	**BBB**	**BBB**	**BBB**
Ability to finance investment from internal sources					
- Internal financing ratio	0.60	0.66	0.72	0.76	0.82
NSW Treasury rating (2002)	**BBB+**	**BBB+**	**A**	**A+**	**AA**
- Net cash flow / net Capex	0.68	0.67	0.74	0.79	0.85
S&P - US Utilities (1995)	**BBB**	**BBB**	**A**	**A**	**A**
- Cash flow before Capex / Capex	0.69	0.73	0.79	0.85	0.91
Funds flow adequacy					
Funds from operations/(dividends + capex)	0.68	0.69	0.75	0.80	0.86
NSW Treasury total score (0 - 10)					
- EBITDA + interest earnings / interest expense	5.00	5.00	5.00	6.00	6.00
- Funds flow net debt payback	2.00	2.00	3.00	3.00	4.00
- Total Debt/ (Debt + Equity)	3.00	3.00	3.00	3.00	4.00
Internal financing ratio	5.00	5.00	6.00	7.00	8.00
Total score	**4.00**	**4.00**	**4.67**	**5.33**	**6.00**
Overall rating	**BBB**	**BBB**	**BBB**	**BBB+**	**A**
Net Debt	1,531,889	1,610,207	1,673,602	1,726,697	1,766,172

Notes:

1. Weightings for NSW Treasury Score: 33 per cent EBITDA interest cover, funds flow and internal financing ratio.

A15.7 Distribution financial performance statement

Table A15.12 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Revenue from tariffs (excl GST and EDL)	461,916	492,900	525,963	561,247	598,901
Other "building block" revenue (incl IDT receipts)	6,046	6,271	6,500	6,735	6,974
Transmission charges (including IDT payments)	117,875	125,219	132,936	141,440	150,229
Other revenue	0	0	0	0	0
Total revenue	**585,837**	**624,389**	**665,400**	**709,422**	**756,104**
Network operating expenditure	209,852	217,995	226,452	235,237	244,362
Transmission charges (including IDT payments)	117,875	125,219	132,936	141,440	150,229
Total costs	327,727	343,213	359,388	376,677	394,590
EBITDA	**258,110**	**281,176**	**306,011**	**332,745**	**361,513**
EBIT	**120,469**	**127,349**	**135,695**	**145,383**	**156,397**
Interest/investment income	0	0	0	0	0
Interest expenses	91,507	96,200	101,252	105,362	108,793
Operating profit before cap cons and abnormals	28,961	31,150	34,443	40,021	47,604
Abnormal items	0	0	0	0	0
Profit before tax	**28,961**	**31,150**	**34,443**	**40,021**	**47,604**
Tax equivalent	8,373	9,345	10,333	12,006	14,281
Profit after tax	**20,588**	**21,805**	**24,110**	**28,015**	**33,323**
Retained profits at beginning of year	351,260	357,436	363,978	371,211	379,615
Adjustments/transfers					
Total available for appropriation	371,848	379,241	388,088	399,226	412,938
Dividends	14,412	15,263	16,877	19,610	23,326
Retained profit at year end	**357,436**	**363,978**	**371,211**	**379,615**	**389,612**

Columns may not add due to rounding.

A15.8 Summary of rolled forward RAB

Table A15.13 Summary of rolled forward RAB

$'000 $ of the year	2005	2006	2007	2008	2009
Total system assets					
Opening value	2,125,149	2,248,955	2,373,927	2,499,769	2,627,010
Capex/Additions	168,928	173,639	178,301	183,754	188,669
Depreciation	100,363	107,061	114,036	121,304	128,874
Disposals	-	-	-	-	-
Indexation	55,240	58,394	61,577	64,791	68,034
Closing value	**2,248,955**	**2,373,927**	**2,499,769**	**2,627,010**	**2,754,839**
Total non-system assets					
Opening value	243,460	273,713	295,633	307,176	313,027
Capex/Additions	68,187	68,578	67,186	70,936	72,430
Depreciation	37,278	46,765	56,280	66,058	76,243
Disposals	7,500	7,500	7,500	7,500	7,500
Indexation	6,845	7,606	8,137	8,472	8,637
Closing value	**273,713**	**295,633**	**307,176**	**313,027**	**310,352**
Total RAB					
Opening value	2,368,609	2,522,669	2,669,560	2,806,945	2,940,037
Capex/Additions	237,115	242,217	245,487	254,690	261,099
Depreciation	137,641	153,826	170,316	187,362	205,117
Disposals	7,500	7,500	7,500	7,500	7,500
Indexation	62,085	66,001	69,714	73,264	76,671
Closing value	**2,522,669**	**2,669,560**	**2,806,945**	**2,940,037**	**3,065,191**

Notes:
All capex / additions are net of capital contributions.
Columns may not add due to rounding.

APPENDIX 16 AUSTRALIAN INLAND OPERATING AND FINANCIAL INFORMATION

A16.1 Corporate and operating information

Head Office: 160-162 Beryl Street, Broken Hill, NSW 2880
Network Service Area: 155,000 square kilometres
Major Towns / Areas: Area from the Queensland to Victorian borders, South Australian border in the west to WhiteCliffs, Wilcannia, Balrandald and Moulamein in the east
Employee Numbers: 74

Source : Australian Inland's submission to IPART – 10 April 2003, *Price and Service Report 2002,* and 2002 Annual Report and website.

A16.2 Network demand profile

Table A16.1 Historical demand 1999/00 to 2003/04

	1999/00	2000/01	2001/02	2002/03	2003/04f
Total GWh delivered [1]	409	415	402	401	427
Peak demand (MW)[1]	57	59	59	60	61
Total Customers:					
Residential	15,473	15,469	15,511	15,557	15,547
Non-residential	3,389	3,400	3,396	3,375	3,400

1. Source: *Australian Inland Prices and Services Report 2002.*

Table A16.2 Forecast demand 2004/05 to 2008/09

	2004/05	2005/06	2006/07	2007/08	2008/09
Total GWh delivered	433	440	447	453	461
Peak demand (MW) [1]	62	63	64	np	np
Total Customers:					
Residential	15,547	15,547	15,547	15,547	15,547
Non-residential	3,400	3,400	3,400	3,400	3,400

1. Source: Australian Inland 2003 Price and Services Report.
np = not provided.

Table A16.3 Maximum demand

Historical [1]	Winter (MW)	Summer (MW)	Forecast	Winter (MW)	Summer (MW)
1999/00	np	np	2004/05	np	np
2000/01	np	np	2005/06	np	np
2001/02	np	np	2006/07	np	np
2002/03	np	np	2007/08	np	np
2003/04f	np	np	2008/09	np	np

1. Source:Australian Inland submission to the 2004 Network Review, Attachment C.
np = not provided.

A16.3 Reliability

Table A16.4 Historical reliability

		1999/00	2000/01	2001/02
SAIDI	Raw	203	364	358
	Standard	203	351	354
	MS	140	246	269
SAIFI	Raw	3.2	3.3	2.8
	Standard	3.2	3.1	2.8
	MS	2.9	2.7	2.3
CAIDI	Raw	64	108	126
	Standard	64	112	128
	MS	49	91	115

Source: Network Price and Service Report 2002

Table A16.5 Forecast reliability

		2002/03a	2003/04f	2004/05	2005/06	2006/07	2007/08	2008/09
SAIDI	Overall	336	320	302	303	295	295	295
	Distn	274	292	275	275	267	267	267
	Normalised	157	175	158	158	150	150	150
SAIFI	Overall	2.9	1.8	1.7	1.7	1.5	1.5	1.5
	Distn	2.0	1.8	1.6	1.6	1.5	1.5	1.5
	Normalised	1.6	1.4	1.3	1.3	1.1	1.1	1.1
CAIDI	Overall	116	178	182	182	195	195	195
	Distn	137	165	168	168	180	180	180
	Normalised	98	126	126	120	136	136	136

Source: Australian Inland's submission to the 2004 Electricity Network Review, September 2003.
Note: Definition of reliability categories changed between 2001/02 and 2002/03.
np = numbers not currently available.

A16.4 Distribution revenue forecast 2004/05 to 2008/09

Table A16.6 Building block core assumptions

$'000 $ of the year	2004/05	2005/06	2006/07	2007/08	2008/09
Opening RAB [1]	64,872	66,739	67,952	68,704	69,113
Operating Costs	10,188	10,114	10,042	9,971	9,902
Capital Expenditure	3,493	3,090	2,859	2,735	2,855
Forecast Network Sales (GWh)	433	440	447	453	461
Forecast Sales Growth (%)	1.4%	1.6%	1.6%	1.3%	1.8%

1. Includes adjustment to exclude street lighting and 1999-2004 capex underspend.

Table A16.7 Regulated distribution asset rolled forward from 1998/99 to 2003/04

$'000 $ of year	1998	1999	2000	2001	2002	2003	2004f
Total value of assets							
Opening value		49,801	52,096	53,898	57,607	61,021	62,956
Capex/Additions [1]		3,358	2,705	3,036	4,316	3,183	5,095
Depreciation		1,917	2,175	2,342	2,556	2,947	3,253
Disposals		-	-	285	55	232	-
Indexation		854	1,272	3,300	1,709	1,931	1,965
Closing value	**49,801**	**52,096**	**53,898**	**57,607**	**61,021**	**62,956**	**66,763**

Notes:
1. Net of capital contributions.
Columns may not add due to rounding.

Table A16.8 Regulated distribution asset rolled forward from 2004/05 to 2008/09

$'000 $ of year	2005	2006	2007	2008	2009
Total RAB					
Opening value	66,763	66,739	67,952	68,704	69,113
Adustment [1]	-1,891				
Capex/Additions [2]	3,493	3,090	2,859	2,735	2,855
Depreciation	3,291	3,584	3,841	4,077	4,321
Disposals	-	-	-	-	-
Indexation	1,665	1,707	1,735	1,752	1,764
Closing value	**66,739**	**67,952**	**68,704**	**69,113**	**69,410**

Notes
1. Street lighting is proposed to be an excluded distribution service. Any capex underspend from the 1999 determination has been excluded.
2. Net of capital contributions.
Columns may not add due to rounding.

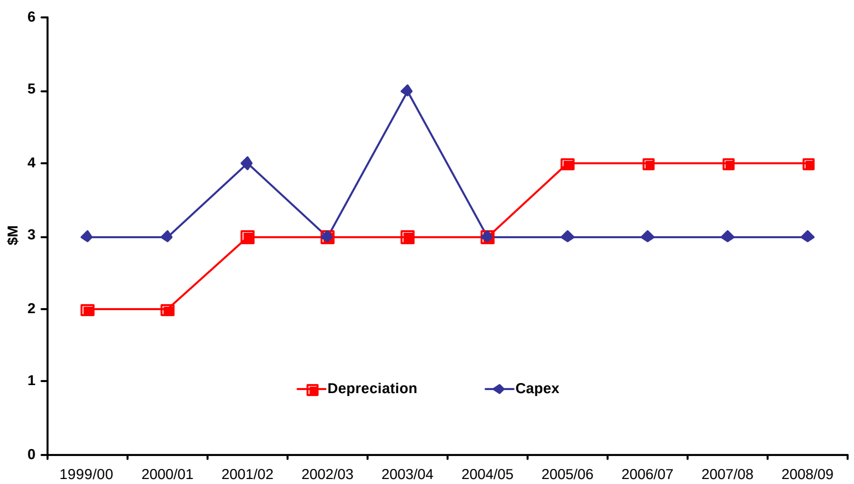
A16.5 Notional revenue requirements

Table A16.9 Notional revenue requirement 2004/05 to 2008/09

Financial year ending 30 June	2005	2006	2007	2008	2009
$'000 $ of the year					
Operating expenditure [1]	10,188	10,114	10,042	9,971	9,902
Depreciation	3,145	3,426	3,671	3,897	4,130
Return on fixed assets	4,438	4,549	4,622	4,668	4,699
Return on working capital	250	248	257	265	275
Unsmoothed Base Revenue	**18,021**	**18,336**	**18,592**	**18,801**	**19,006**
less correction for previous over/under recovery	(676)	(740)	(810)	(887)	(971)
less revenue from non-tariff sources	19	19	19	19	19
Unsmoothed Base Revenue from tariffs	**18,678**	**19,058**	**19,384**	**19,669**	**19,958**
Smoothed Revenue Base	**12,446**	**13,276**	**14,162**	**15,110**	**6,122**
Return on fixed assets (real pre-tax)	**-2.3%**	**-1.5%**	**-0.6%**	**0.4%**	**1.4%**
NPV of revenue foregone	**21,043**				
Average distribution price (nominal c/kWh)	2.75	2.89	3.04	3.19	3.35
Cumulative average real price change	**6.50%**	**9.20%**	**11.90%**	**14.70%**	**17.60%**

Notes:
1. Excludes line costs and Electricity Distribution Levy.
2. Depreciation calculated for the revenue requirement differs from the depreciation calculated for the asset base due to timing differences. Depreciation for the revenue requirement is calcualted in the middle of the year whereas depreication for the asset base is calcualted at the end of the year.
Columns may not add due to rounding.

Figure A16.1 Return of capital (depreciation) versus capex profile



A16.6 Financial performance ratios

Table A16.10 Financial ratio analysis - actual net cash

	2005	2006	2007	2008	2009
Ability to service debt					
- EBITDA / interest expense	10.84	15.11	27.90	121.45	0.00
NSW Treasury rating (2002)	**AAA**	**AAA**	**AAA**	**AAA**	**0.00**
- EBITDA + interest earnings / interest expense	19.62	23.88	40.14	163.95	NA
NSW Treasury rating (2002)	**AAA**	**AAA**	**AAA**	**AAA**	NA
- Pre tax interest cover (EBIT + interest earnings) / interest expense)	3.95	6.84	14.25	67.93	0.00
S&P - US Utilities (1995)	**AA**	**AA**	**AA**	**AA**	**0.00**
- Funds flow interest cover	19.91	22.81	38.90	161.63	0.00
S&P - US Utilities (1995)	**AA**	**AA**	**AA**	**AA**	**0.00**
Ability to repay debt					
- Funds flow net debt payback	-6.70	-5.73	-5.12	-4.70	-4.39
NSW Treasury rating (2002)	NA	NA	NA	NA	NA
- Funds from operations/Total debt	1.19	1.88	7.82	0.00	0.00
S&P - US Utilities (1995)	**AA**	**AA**	**AA**	**0.00**	**0.00**
Debt to Equity Ratio	0.04	0.03	0.01	0.00	0.00
- (Debt-cash assets)/(RAB)	-0.36	-0.36	-0.37	-0.40	-0.42
NSW Treasury rating (2002)	NA	NA	NA	NA	NA
S&P - US Utilities (1995)	NA	NA	NA	NA	NA
Ability to finance investment from internal sources					
- Internal financing ratio	0.98	1.24	1.49	1.71	1.79
NSW Treasury rating (2002)	**AA+**	**AAA**	**AAA**	**AAA**	**AAA**
- Net cash flow / net Capex	1.00	1.17	1.42	1.67	1.75
S&P - US Utilities (1995)	**AA**	**AA**	**AA**	**AA**	**AA**
- Cash flow before Capex / Capex	1.08	1.37	1.76	2.18	2.40
Funds flow adequacy					
Funds from operations/(dividends + capex)	1.00	1.14	1.32	1.45	1.45
NSW Treasury total sc lower risk					
- EBITDA + interest earnings / interest expense	10.00	10.00	10.00	10.00	NA
- Funds flow net debt payback	NA	NA	NA	NA	NA
- Total Debt/ (Debt + Equity)	9.00	9.00	9.00	NA	NA
Internal financing ratio	9.00	10.00	10.00	10.00	10.00
Total score	NA	NA	NA	NA	NA
Overall rating	NA	NA	NA	NA	NA
Net Debt	-24,957	-25,486	-26,697	-28,538	-30,679

1. Weightings for NSW Treasury Score: 33 per cent EBIT DA interest cover, funds flow and internal financing ratio.
2. As Australian Inland is in a net cash position, any debt ratios are not applicable. All above ratios are based on actual expected net cash.

No notional gearing table has been included as Australian inland is in a net cash position.

A16.7 Distribution financial performance statement

Table A16.11 Distribution financial performance statement

$'000 $ of year	2005	2006	2007	2008	2009
Revenue from tariffs (excl GST and EDL)	12,446	13,276	14,162	15,110	16,122
Other "building block" revenue (incl IDT receipts)	19	19	19	19	19
Transmission charges (incl IDT payments)	7,518	7,596	7,674	7,755	7,836
Other revenue	0	0	0	0	0
Total revenue	19,984	20,891	21,855	22,883	23,976
Network operating expenditure	10,188	10,114	10,042	9,971	9,902
Transmission charges (incl IDT payments)	7,518	7,596	7,674	7,755	7,836
Total costs	17,706	17,710	17,716	17,726	17,738
EBITDA	2,277	3,181	4,139	5,157	6,238
EBIT	(1,013)	(404)	298	1,080	1,917
Interest/investment income	1,844	1,844	1,817	1,804	1,884
Interest expenses	210	210	148	42	-
Operating profit before cap cons and abnormals	620	1,230	1,967	2,842	3,801
Abnormal items					
Profit before tax	620	1,230	1,967	2,842	3,801
Tax equivalent	186	369	590	853	1,140
Profit after tax	434	861	1,377	1,989	2,660
Retained profits at beginning of year	19,638	19,769	20,027	20,440	21,037
Adjustments/transfets	0	0	0	0	0
Total available for appropriation	20,073	20,630	21,404	22,429	23,697
Dividends	304	603	964	1,392	1,862
Retained profit at year end	**19,769**	**20,027**	**20,440**	**21,037**	**21,835**

Columns may not add due to rounding.

A16.8 Summary of rolled forward RAB

Table A16.12 Summary of rolled forward RAB

$'000 $ of the year	2005	2006	2007	2008	2009
Total system assets					
Opening value	57,044	58,713	59,983	61,372	62,539
Capex/Additions	2,307	1,985	2,178	2,034	2,137
depreciation	2,093	2,207	2,316	2,426	2,539
disposals	-	-	-	-	-
Indexation	1,455	1,493	1,527	1,560	1,590
Closing value	**58,713**	**59,983**	**61,372**	**62,539**	**63,726**
Total non-system assets					
Opening value	7,828	8,027	7,969	7,332	6,574
Capex/Additions	1,186	1,105	681	701	718
depreciation	1,198	1,377	1,525	1,651	1,782
disposals	-	-	-	-	-
Indexation	211	214	208	192	173
Closing value	8,027	7,969	7,332	6,574	5,684
Total RAB					
Opening value	64,872	66,739	67,952	68,704	69,113
Capex/Additions	3,493	3,090	2,859	2,735	2,855
depreciation	3,291	3,584	3,841	4,077	4,321
disposals	-	-	-	-	-
Indexation	1,665	1,707	1,735	1,752	1,764
Closing value	**66,739**	**67,952**	**68,704**	**69,113**	**69,410**

Notes:
All capex is net of capital contributions.
Columns may not add due to rounding.

LIST OF ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
ASP	Accredited Service Provider
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
COAG	Council of Australian Governments
Code	National Electricity Code
CPI	Consumer Price Index
CRNP	Cost Reflective Network Pricing
DM	Demand Management
DNSP	Distribution Network Service Provider
DORC	Depreciated Optimised Replacement Cost
DUOS	Distribution Use of System
EDL	Electricity Distributor Levy
ESC of Victoria	Essential Services Commission of Victoria
EWON	Energy and Water Ombudsman of NSW
FRC	Full Retail Contestability
Gross State Product	Gross State Product
GWh	Gigawatt hour = 1,000,000 kilowatt hours or 1,000 MWh
HV	High Voltage – normally refers to voltages greater than 22kV
IDT	Inter distributor transfers
IPART	Independent Pricing and Regulatory Tribunal (also (represented as the Tribunal)
kV	Kilovolt = 1,000 volts
kVA	Kilovolt Amp = 1,000 volt-amperes
kW	Kilowatt = 1,000 watts
KWh	Kilowatt hours
LV	Low voltage, normally refers to 240/415 volt distribution for customer installations
MAIFI	Momentary Average Interruption Frequency Index
MEU	Ministry of Energy and Utilities
MRP	Market Risk Premium

MS	Modified Standard measure which excludes major natural events and planned interruptions
MW	Megawatt
MWh	Megawatt hour = 1,000 kilowatt hours
NECA	National Electricity Code Authority
NECA	National Electrical Contractors Association
NEMMCO	National Electricity Market Management Company
NRGP	Network Region Gross Product
NUOS	Network Use of System
ODRC	Optimised Depreciated Cost (also known as DORC)
OPEX	Operating Expenditure
OPV	Optimised Deprival Valuation
PIAC	Public Interest Advocacy Centre
PICG	Pricing Issues Consultation Group
PPM	IPART, *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services,* March 2001
RAB	Regulatory Asset Base
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCNRRR	Steering Committee on National Regulatory Reporting Requirements
TNSP	Transmission Network Service Provider
Tribunal	Independent Pricing and Regulatory Tribunal
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap