PRICING FOR ELECTRICITY NETWORKS AND RETAIL SUPPLY

ISSUES PAPER

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

PRICING FOR ELECTRICITY NETWORKS AND RETAIL SUPPLY

ISSUES PAPER

Discussion Paper DP-25 **September 1998**

Submissions

Public involvement is an important element of the Tribunal's processes. The Tribunal therefore invites submissions from interested parties to all of its investigations.

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. Unless otherwise stated, all submissions will be made available to the ACCC to assist in its investigation of transmission pricing.

Confidentiality

Special reference must be made to any issues in submissions for which confidential treatment is sought and all confidential parts of submissions must be clearly marked. *However, it is important to note that confidentiality cannot be guaranteed as the Freedom of Information Act and section 22A of the Independent Pricing and Regulatory Tribunal Act provide measures for possible public access to certain documents.*

Public access to submissions

All submissions that are not subject to confidentiality will be made available for public inspection at the Tribunal's offices immediately after registration, by the Tribunal and also via the Tribunal's web site. Transcriptions of public hearings held by IPART will also be available.

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.

Submissions concerning the issues raised in this paper should be received from the subject utilities no later than 25 September 1998, and from other interested parties no later than 30 October 1998.

Comments or inquiries regarding this issues paper should be directed to:
Scott Young ☎(02) 9290 8404 fax (02) 9290 2061 or e-mail scott_young@ipart.nsw.gov.au

INDEPENDENT PRICING AND REGULATORY TRIBUNAL OF NEW SOUTH WALES
Level 2, 44 Market Street, Sydney. Tel: (02) 9290 8400, Fax: (02) 9290 2061.
E-mail ipart@ipart.nsw.gov.au

All correspondence to: PO Box Q290, QVB Post Office, Sydney NSW 1230

TABLE OF CONTENTS

1 INTRODUCTION

On 16 June 1998, Bob Carr, Premier of New South Wales, issued a Special Reference on Electricity to the Tribunal under Section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992*. The Tribunal advertised the draft Terms of Reference for the review in *The Sydney Morning Herald* of Friday, 19 June 1998 and sought comments. This Issues Paper addresses the Premier's draft Terms of Reference. Following the Premier's settling advice, the final Terms of Reference will be publicly available from the Tribunal or on the Tribunal's website.

The draft Terms of Reference for the Special Reference on Electricity cover transmission, distribution, and franchise retail electricity services in New South Wales.

Under the Special Reference on Electricity draft Terms of Reference, the Tribunal is to report on appropriate pricing of:

a) government monopoly electricity transmission and distribution services (provided by TransGrid and energy distributors) for the five year period from 1 July 1999; and

b) government monopoly electricity services to be provided to franchise customers (by energy distributors) for the period from July 1999.

The draft Terms of Reference for this review are reproduced with the investigation advertisement in Appendix 1 to this Issues Paper.

In undertaking this report, the Tribunal will be working closely with the Australian Competition and Consumer Commission (ACCC) on appropriate pricing of electricity network services provided by TransGrid. References in this Issues Paper to questions on which the Tribunal seeks comments should also be read as issues on which the ACCC wishes to be informed with respect to transmission pricing.

Background

The NSW electricity industry commenced a period of major restructuring in 1995. This restructuring included amalgamation of the then 25 electricity distribution businesses (DBs[1]) to today's six, separation of the generation and high voltage transmission functions, and commencement of the separation of the network distribution services from the retail trading function within the DBs. The former monopoly generation function has also been divided into three competitive generation entities and removed from price regulation.

The restructuring of the NSW electricity industry has taken place alongside major national industry reforms prompted by the Hilmer Report and the national Competition Principles Agreement. Among other things, these reforms provide for third party access to essential infrastructure systems.

In October 1994, the Tribunal[2] issued an Interim Report which proposed medium term price/revenue paths. The finalisation of this report was postponed pending industry reforms, and the Tribunal issued its medium term revenue path Determinations on Electricity Prices in March 1996. In its July 1997 Determination, the Tribunal made minor

---

1 In this paper, the term "distribution business" or "DB" refers to the network infrastructure business and the franchise retail business as a combined entity.

2 Then the Government Pricing Tribunal.

adjustments to the calculations of the revenue caps for TransGrid and the six electricity distributors. The medium term revenue paths determined in 1996 run to 30 June 1999.

The result of this review will be a report to the Premier on appropriate pricing for the six DBs, their franchise retail suppliers, and TransGrid, to take effect from 1 July 1999. This review is expected to provide the basis for determining the price path. The review will be a *de novo* review, in which all electricity related matters subject to the Tribunal's jurisdiction will be subject to review. While stressing that this is a *de novo* review, the Tribunal is keenly aware of the substantial benefits of consistency over time and between regulatory jurisdictions. This Issues Paper serves as a guide to assist all participants in the review process.

Purpose of this review

The primary purpose of this review is to advise on the medium term revenue or average price paths for TransGrid and the six NSW DBs from 1 July 1999. This review will also examine the form of regulation appropriate for the future (see section 4.3.1), and discuss technical, operational, customer related and environmental issues relevant to the pricing of the regulated services of TransGrid and the DBs.

With the introduction of competition in the electricity industry, the Tribunal is required to regulate the residual monopoly elements of the industry. The Tribunal is also concerned to ensure that competition in electricity markets is effective, providing all customers with the opportunity to benefit from wholesale or retail competition.

A key function of the Tribunal is to ensure non-discriminatory access to the electricity networks. This requires the Tribunal to:

- regulate the natural monopoly distribution component of the distributors' businesses separately from the retail supply component
- ensure strong separation or 'ring fencing' of the retail and distribution components
- publish prices and terms and conditions for access to the network which do not discriminate between potential retail supplies
- establish procedures for the resolution of access disputes.

As more customers are permitted to enter the market and select their suppliers, retail prices will continue to be deregulated. Initially, not all customers will have a choice of supplier. Under the current schedule, residential customers, which are the last group to become contestable, will be able to choose their supplier according to a transitional timetable to commence 1 January 2001. In this review, the Tribunal will consider whether the possible advantage held by the incumbent suppliers requires interim regulatory measures.

Purpose of this Issues Paper

This Issues Paper:

- provides a brief overview of the electricity industry and its regulatory environment
- identifies and discusses relevant ongoing industry reforms
- provides background to the review and outlines the review process
- advises of consultancies and analysis to be conducted by the Tribunal

- indicates the Tribunal's expectations in regard to the submissions from the utilities
- identifies particular areas of interest to the Tribunal and invites comments on these issues from the utility companies and other interested parties.

2 ELECTRICITY INDUSTRY OVERVIEW

In the past five years, with the introduction of generation and retail sales competition, the NSW electricity industry has undergone major structural change. This has involved:

- amalgamating the previous 25 distributors into two large metropolitan and four rural distribution businesses, six in all
- separating the transmission and generation functions, and establishing TransGrid
- splitting the generation sector into three companies: Pacific Power, Delta Electricity, and Macquarie Generation.[3]

In parallel with these structural changes, the Government has introduced retail and wholesale competition into the electricity industry. A National Electricity Market and national electricity regulation are to be introduced. Currently, the NSW, Victoria, ACT and South Australian industries operate in a competitive environment underpinned by harmonisation of the NSW and Victorian markets.

With the introduction of competition and the convergence of the gas and electricity markets, consumers are increasingly being allowed to choose the retail supplier of their electricity. Some may choose to purchase their energy directly on the wholesale market. Energy retailers' success will depend on how well, and at what price, they can meet consumers' energy requirements. Retail competition will provide a keener focus for competition in the wholesale market.

The six electricity distributors have considerably different customer and load characteristics, as follows:

Table 2.1 NSW Electricity Distributors

Distributor	Number of Network Customers	Total Network Load (MWh)	Network Service Area (sq. km)
EnergyAustralia	1,319,000	21,477,000	22,000
Integral Energy	719,000	11,360,000	24,500
NorthPower	335,000	3,576,000	264,000
Great Southern Energy	223,000	3,412,000	176,000
Advance Energy	116,500	2,361,000	167,000
Australian Inland Energy	19,000	386,000	155,000

Industry financial information is included in section 2.3 of this Issues Paper.

3 Generation and transmission services are also provided by the Snowy Mountains Hydro Electric Authority (the Snowy). The Tribunal is cognisant that its findings in relation to TransGrid's interconnection assets may have an effect on the future regulatory regime for the Snowy Scheme.

At present, the Tribunal regulates the total revenue earned by distribution businesses (DBs) through a revenue cap. The Tribunal has also placed constraints on maximum increases in customer prices tor educe rate shock concerns. For TransGrid, the form of regulation is essentially a price cap, recognising the fewer customers and the lower sensitivity to marginal changes in demand and throughput.

The Tribunal also regulates the price of retail electricity to the (non-contestable) franchise market. This is accomplished firstly, by regulating the retail gross margin which may be earned by the franchise retail businesses, and secondly, through a set of 'side constraints' which limit changes in retail electricity prices to franchise customers. On the current timetable, all customers will be eligible for contestability according to a transitional timetable to commence 1 January 2001. A key issue for this review is whether any regulation of retail prices will be required beyond that date.

2.1 The scope of the review

The generation sector of the NSW electricity industry includes three companies: Delta Electricity, Macquarie Generation, and Pacific Power.[4] Although all three companies are currently government owned, they compete amongst themselves for load and dispatch priority. Furthermore, since the introduction of the National Electricity Market, these generators have been competing with interstate generators from Victoria and, to some extent, South Australia. Aggressive bidding strategies have driven the pool price and associated hedging contracts down to very low levels.

Whilst vesting contracts for franchise load remain in place, competition in generation means there is no longer a need for price regulation of the wholesale electricity market. Prices in that part of the market are no longer regulated by IPART. Thus, the generation sector is not part of this review. If concerns about the competitiveness of the wholesale market arise, they will be referred to the ACCC.

Connecting the generators to distribution networks and some large end users is the high voltage transmission network owned and operated by TransGrid. TransGrid's transmission charges are currently regulated by the Tribunal under Determination 5.1 dated July 1997,[5] which is effective until 30 June 1999. Under the NSW derogations to the National Electricity Code, TransGrid will be regulated by the ACCC from 1 July 1999. The current reference is provided by the Premier of NSW, but the Tribunal expects to work closely with the ACCC throughout this next review of TransGrid. The ACCC will reach its own views on appropriate pricing for electricity network services provided by TransGrid.

In addition to TransGrid, this review will focus on the six electricity distribution networks owned and operated by EnergyAustralia, Integral Energy, Advance Energy, NorthPower, Great Southern Energy and Australian Inland Energy, and their related franchise retail arms. The revenue caps for the electricity distributors and the retail margin cap for the associated franchise retailers are currently regulated under the Tribunal's Determination 5.3, dated July 1997. This Determination runs to 30 June 1999.

The draft Terms of Reference of this review are outlined in section 3.3, and reproduced with the investigation advertisement in Appendix 1 to this Issues Paper.

[4] In addition, the Snowy generates electricity into the SE Australia grid. The Snowy is owned by NSW, Victoria and the Commonwealth. It is not yet corporatised.

[5] Determination 5.1 dated July 1997 modifies Determination 2.1 dated March 1996.

2.2 Ongoing industry reforms

In 1994, the Council of Australian Governments (CoAG) agreed to industry reforms. Amongst other reforms, the Competition Principles Agreement introduced Section IIIA of the *Trade Practices Act* which requires open access to essential infrastructure facilities. This necessitates the unbundling of supply and transport components in such industries as electricity and natural gas. The purpose of these reforms is to give customers choice in the supply of the commodity, and access to the transportation infrastructure which transports the commodity for their use.

Consistent with the CoAG reforms, the electricity industry has worked to develop an industry access code. The National Electricity Code (the 'Code') has been presented to the ACCC for authorisation under Part VII of the *Trade Practices Act*, in regard to potential breaches of Part IV (anti-competitive practices). The ACCC has signalled its authorisation of the Code, subject to various amendments including:

- strengthened requirements for ring fencing[6] the network and retail supply functions of the distribution businesses
- strengthened information collection and disclosure powers for ACCC and jurisdictional regulators.

The National Electricity Code has also been submitted to the ACCC as an industry access code under Part IIIA of the *Trade Practices Act*.[7] The ACCC has indicated that it will approve the National Electricity Code as an access undertaking subject to various amendments.

NECA (Network Pricing) Review

During the development of the Code, various stakeholders expressed concern about the proposed approach to transmission pricing. As a result, the National Electricity Code Administrator (NECA) is undertaking a review of the transmission and distribution network pricing sections of the Code.

NECA is to consider current pricing arrangements as outlined in chapter 6 of the Code. In consultation with various parties, NECA will consider the merits, and, if any, the net benefit of modifying:

- the pricing requirements set out in Part C of chapter 6 of the Code
- the methodologies and regulatory principles set out in Part E of chapter 6 of the Code.

The NECA network pricing review is currently scheduled for completion in late 1998. At that time, subject to agreement with ACCC, the recommended changes will be incorporated into the Code. The progress of the NECA review and the resulting possible changes to the Code provide a degree of uncertainty for TransGrid and the DBs. Aware of that uncertainty, the Tribunal will adjust the parameters of this review as necessary.

---

6 Ring fencing is the clear separation of subsidiaries or divisions of a company that may have competitive advantages in dealing with each other. See section 7.9 for further discussion.

7 Clause 1.12 of the Code defines the National Electricity Market "Access Code" to be chapters 4 through 9 of the Code.

Boundary Review

In 1997, the NSW Government announced that it would undertake a review of the service territory boundaries of the six DBs. The electricity distributors and retailers were concerned that the outcome of the boundary review would cause some uncertainty.

The Distribution Boundary Review Committee reported to the Minister for Energy on 30 June 1998.[8] Among other things, the Committee recommended the merging of the service territories of Advance Energy and Great Southern Energy. However, the Government decided not to change the existing boundaries at that time. For the purposes of this review, the service territories of the six DBs will remain unchanged.

The Distribution Boundary Review Committee also examined the appropriateness of ring fencing requirements in relation to the retail and network elements of the DBs. In particular, the Committee considered the requirement contained in the National Electricity Code that Jurisdictional Regulators and the ACCC develop ring fencing guidelines for the distribution and transmission networks respectively. The Committee's consideration of ring fencing is discussed in section 7.9.

National Electricity Market

The National Electricity Market is currently scheduled to commence operations in November 1998. This market will allow the trading of electricity between New South Wales, Victoria, and South Australia. Queensland will operate a separate market, using the same rules, until completion of the interconnector between NSW and Queensland.

Ahead of the commencement of the National Electricity Market, NSW and Victoria have been trading electricity across the state border under the terms of the NEM1 market. Victoria also exports electricity to South Australia.

Under the National Electricity Market, generators will bid supply volumes and prices into a pool. Market participants will then purchase supplies from the pool. The market and system operator will dispatch generators in ascending bid price order until supply equals demand. The price at which the marginal generator is dispatched will then be paid to all dispatched generators through the pool settlements mechanism. Generators will bid supply and price levels in half hourly increments and the market and system operator will adjust dispatch levels every five minutes. Under NEM1, this mechanism is already operational. TransGrid is acting as the market and system operator, a role which will pass to NEMMCO[9] upon commencement of the National Electricity Market in November 1998.

Many issues surround the National Electricity Market. Of these, some are beyond the scope of this review. Others will affect the regulation of TransGrid particularly, as the owner of assets which connect the NSW market to those in Victoria and Queensland.

Retail contestability

Retail contestability refers to the ability of an electricity consumer to enter a contract for supply from the retailer of its choice, rather than being restricted to purchasing electricity

[8] Terms of reference for the boundary review are available on the Department of Energy's web site, www.doe.nsw.gov.au/Electricity/dbr/dbrc2.htm. A summary of the recommendations, and a downloadable version of the report, are also available.

[9] National Electricity Market and Management Company.

supply from the network owner. This is a key aspect of the Competition Principles Agreement.

Access to electricity network infrastructure is increasing in NSW. Customer loads between 750 MWh and 160 MWh pa became contestable from 1 July 1998. A year from that date, on 1 July 1999, customers with individual loads over 100 MWh pa will be allowed to aggregate their loads to meet the contestability threshold, subject to eligibility requirements. All other customers are scheduled to become contestable from 1 January 2001, subject to the announcement of a transitional timetable.

Table 2.2 Contestability Timetable

Site Thresholds	Approximate Annual Electricity Bill	Date for Eligibility	Date for Mandated[10] Contestability	Approximate Number of Eligible Sites	Example
>40 GWh pa	>$2,000,000	1 October 1996	1 October 1997	47	Large hospital, heavy manufacturing
>4 GWh pa	>$250,000	1 April 1997	1 October 1997	660	Multi-storey office block
>750 MWh pa	>$75,000	1 July 1997	1 July 1998	3,500	Supermarket
>160 MWh pa[11]	>$16,000	1 July 1998	1 July 1999	10,800	Fast food restaurant
<160 MWh pa	<$16,000	1 January 2001	(Note 1)	2,700,000	Service station, household

Note 1: Retail contestability for all customers below 160 MWh pa will commence from 1 January 2001 with detailed transitional arrangements to be developed and announced at a later date. See section 4.3.1, Future role of retail regulation.

Vesting contracts

While part of the electricity market is not yet contestable, contracts for the supply of electricity to the franchise market remain in place. These 'vesting' contracts require the franchise retailer to purchase a specified quantity of electricity from NSW generators at a specified price. These contracts provide financial cover for the purchase of electricity for the franchise market. Because vesting contracts do not cover the contestable market, the proportion of total load covered by vesting contracts will decline as the contestability timetable progresses.

For the purposes of this review, vesting contracts will affect the cost of electricity included in franchise tariffs. The current 'pass through price' is based on approximately 85 per cent of the franchise market load's being covered by vesting contracts priced at $44.50 per MWh. The remaining 15 per cent is considered as passed through to franchise customers at $38.00

[10] Under the contestability transitional arrangements, customers are allocated a defined period during which they may choose a retailer, or may avail themselves of the published tariffs of the incumbent retailer.

[11] Aggregation for customers below 160 MWh pa will be permitted from 1 July 1999 subject to certain criteria including a minimum site threshold of 100 MWh pa.

per MWh. This is consistent with the financial modelling underpinning the Tribunal's 1996 Determination.

To the extent that franchise retailers are able to purchase the non-vested portion of their load at a price less than that assumed in the ‘pass through price’ calculation, they will be able to enhance their profitability. Recent experience in the electricity generation market indicates that all franchise retailers should have been able to generate additional profits and cash flows by purchasing the non-vested portion of their franchise load from the electricity pool. The Tribunal considers that the disposition of any additional profits accruing to the franchise retailers which purchase franchise customers’ electricity from the pool is a matter for Government, as owner of the franchise retailers, to consider. The Tribunal has not sought to review the pass through price, which will operate until June 30 1999. However, this review will consider all pricing matters post 1999.

2.3 Industry financial performance

2.3.1 Introduction

The Tribunal's review of industry financial performance must be considered in light of the considerable restructuring of the industry. The vertically integrated utilities have been disaggregated and replaced by businesses representing the three separate functions of generation, transmission and distribution. Changes in ownership structures resulted in the corporatisation of TransGrid, and the former 25 distributors were merged to form six new distributors. Prior to 1996, the distribution sector, as a whole, had not been placed on a fully commercial basis. This required an increase in debt levels within the sector, and improved profitability. The financial projections supporting the Tribunal's 1996 Determination provided for this.

On 1 October 1996 the 50 largest customers in NSW were given a choice of electricity supplier. By July 1997 a further 4,000 large electricity users were eligible for contestability. Together, this represents 40 per cent of the NSW State market by volume. In May 1997 direct competition in the National Electricity Market was introduced between NSW and Victoria.

Electricity prices

Average electricity prices[12] in NSW have fallen by 22 per cent in real terms since 1992/93. While residential prices of electricity have fallen by 10 per cent, business prices have dropped by 30 per cent. The relative movements of residential and business electricity prices in the past five years are shown in Figure 2.1 below.

The extent of price reduction varies across the six distribution areas. Decreases in residential prices between 1992/93 and 1996/97 ranged from 10 per cent to 14 per cent while decreases in business prices ranged from 10 per cent to 36 per cent over the period. In real terms, electricity bills for residential and business customers have been reduced by $180m and $900m respectively compared with 1992/93.

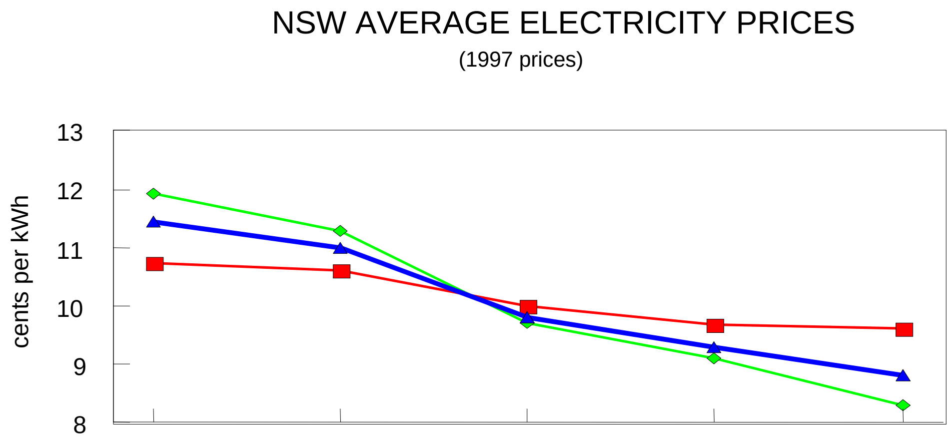
In 1996/97, the distributors continued to rationalise and unify their tariff structures. Residential prices were largely maintained at the 1995/96 levels. Retail competition was

[12] The average price of electricity depends on the tariff and customer mix of the distribution area. Prices for industrial customers vary across user categories depending on their particular load characteristics. To facilitate comparison with previous years, the 1996/97 business prices cover franchise and contestable customers.

introduced in 1996/97 for the very large electricity users. Sites using more than 40 GWh and 4 GWh were eligible for contestability on 1 October 1996 and 1 April 1997 respectively. Recent customer surveys indicated that significant savings have been secured by these contestable customers since contestability was introduced.

As shown in Figure 2.1, since 1992/93 electricity prices have been realigned in favour of business customers. They dropped below residential prices for the first time in 1994/95. Business prices, which were on average 11 per cent higher than residential prices five years ago, are now 14 per cent lower than residential prices. This indicates that cross subsidies borne historically by the business sector have been substantially removed. This has been achieved without raising residential prices in real terms.

Figure 2.1 Movement of residential and business electricity prices[13]



	1993	1994	1995	1996	1997
Residential	10.75	10.62	10.02	9.68	9.63
Business	11.93	11.28	9.70	9.09	8.29
All customers	11.44	11.00	9.82	9.31	8.82

2.3.2 Financial performance of the electricity supply industry in NSW

Although falling electricity wholesale and retail prices have meant that revenue has dropped, the electricity supply industry continued to improve its profit and returns in 1996/97 through substantial cost reductions. This underpinned the 11.5 per cent (in real terms) improvement in the industry's operating margin.[14] However, underlying the apparent increase in overall profitability and returns was the shifting of profit from the generation to the distribution sector as a result of falling electricity wholesale prices.

Recapitalisation of the distributors in 1996 has resulted in higher debt levels. In 1995/96 aggregate financing charges rose by almost 15 per cent in real terms compared with 1994/95. A recent asset write-down in the industry caused depreciation charges to fall. However, increased profit lifted the industry returns as well as tax and dividend returned to the

---

13 The average prices for 1992/93 to 1994/95 were calculated using sales statistics contained in the "Engineering & Financial Statistics of Electricity Supply Authorities in NSW" published by Department of Energy. The average prices for subsequent years are calculated from sales statistics provided by distributors with their 1996/97 regulatory accounts.

14 Represented by the ratio of earnings before interest, tax and depreciation to operating revenue.

Government shareholder. The Tribunal's 1996 Determination provided quite explicitly for the shift in profitability, and the recapitalisation of the distributors.

Tabulated below are the key financial performance indicators of the industry:

Table 2.3 Key Financial Data and Performance Indicators Electricity Supply Industry

KEY FINANCIAL DATA		1994/95	1995/96	1996/97
Sales of electricity[15]	$m	4,507	4,493	3,944
Operating expenses (excl. depreciation and Interest)	$m	2,609	2,557	2,190
EBITD	$m	2,146	2,179	2,395
EBIT	$m	1,402	1,507	1,782
Property, plant and equipment	$m	15,506	12,838	12,538
Loans	$m	4,224	5,869	5,442
Total assets	$m	17,883	15,975	15,207
Equity	$m	10,729	6,861	7,004

FINANCIAL PERFORMANCE		1994/95	1995/96	1996/97
EBITD/Total revenue	%	48	48	55
EBIT/Total revenue	%	31	34	40
Return on assets	%	7.5	9.4	10.6
Debt to equity plus debt	%	28	46	44
Tax equivalent and dividends	$m	734	828	1,417

2.3.3 TransGrid

TransGrid reported transmission revenue of $342m in 1996/97, compared with IPART's determination (March 1996) of $355m. The difference largely represents net revenue transferred to distributors when 132kV assets were transferred to the distributors during the year. Average transmission charge fell from $6.63 per MWh in 1994/95 to $5.59 in 1996/97. This is a **real** reduction of 19 per cent.

In comparison, network operating costs per MWh sent out fell further over the period. Cost savings amounted to 24 per cent in real terms. Group operating costs have been budgeted to fall by a further 4 per cent in 1997/98. Over the three years to 1996/97 staff numbers fell by 18 per cent. There was also a 10 per cent reduction in debt level, resulting in a reduction of the debt/equity ratio from 50 per cent in 1994/95 to 44 per cent in 1996/97.

15 Purchases of electricity by the distributors from the NSW generators is essentially an inter-sectoral transfer. Therefore they are eliminated from the total revenue. This amount includes direct sales from the generators to large end users.

Table 2.4 Key Financial and Operating Performance TransGrid [16]

KEY FINANCIAL DATA		1994/95 (5 months[17])	1995/96	1996/97
Transmission of electricity	$m	160	376	342
Operating expenses (excl. depreciation)	$m	53	130	119
EBITD	$m	112	267	250
EBIT	$m	85	195	176
Property, plant and equipment[18]	$m	1,941	2,037	2,008
Cash & Investments	$m	5	36	22
Debts	$m	948	893	852
Total assets	$m	2,021	2,166	2,115
Equity	$m	950	1,072	1,069

FINANCIAL PERFORMANCE		1994/95 (5 months)	1995/96	1996/97
EBITD/Total revenue	%	68	67	68
EBIT/Total revenue	%	51	49	48
Return on assets	%	10	9	8
Return on equity	%	5	6	4
Debt to equity plus debt	%	50	45	44
Capital expenditure	$m	(5 months) 12	49	53

OPERATING PERFORMANCE		1994/95 (5 months)	1995/96	1996/97
No of employees	No.	1,325	1,265	1,083
Energy sent out (GWh)	GWh	58,091	59,885	61,254
Transmission line (circuit km)	Km	'na	11,527	11,507
Underground cable (km)	Km	'na	20	20
Average unit charge (nominal)	$/MWh	6.63	6.28	5.59
Network operating cost	$m	83	73	70
Network operating cost/MWh delivered (nominal)	$/MWh	1.44	1.23	1.14

Investments in the transmission system rose modestly from $49m to $53m during the year. The current capital program projects a total investment of $250m over the next four years. The capex program comprises the following projects:

[16] Source of information includes TransGrid Annual Reports and 1996/97 regulatory accounts (unaudited).
[17] TransGrid was incorporated on 1 February 1995.
[18] This is the book value of TransGrid network assets valued on an optimised replacement cost methodology. This is not the regulatory asset base used by the Tribunal in determining the regulated revenue for TransGrid.

Table 2.5 TransGrid Capital Expenditure Program

CAPITAL PROJECT	STATUS
Regentville Substation (Western Sydney)	Completed in late 1997.
Inverell-Moree 132 kV transmission line	To be completed by 1999.
Lismore-Mullumbimby 132kV transmission line	Completed in late 1997.
Coffs Harbour-Kempsey 132 kV line	To be completed by 2001.
Queensland Interconnector (330kV line from Armidale to Tarong)	Plan endorsed by the respective Ministers in May 1997.

2.3.4 Electricity distributors

Overall, the distribution sector[19] reported stronger cash flows and higher operating margins in the 1996/97 financial year relative to the previous year. This was achieved largely through substantial cost cutting by distributors and lower wholesale electricity prices. However, with the opening up of the market for electricity users above 4 GWh during 1996/97, NSW distributors were under price pressure to retain contestable customers. This resulted in a 3 per cent fall in electricity revenue in 1996/97. The reduction in electricity revenue was partially offset by increases in non-core business income.

Despite lower electricity revenues, distributors were able to improve their profitability, due largely to reductions in purchased electricity costs. This resulted in higher returns and increases in tax and dividends returned to the Government shareholder in 1996/97. Capital expenditure has been trending downwards in the past three years. The possible impact of lower capital expenditure on the quality and reliability of service is an issue for consideration in this review.

As part of the restructuring of the distribution industry, distribution assets were written down by around 15 per cent of their pre-merger value, [20] while the gearing of distributors was raised to private sector levels in 1996/97.

Tabulated below is the consolidated financial and operating performance of the NSW distributors from 1994/95 to 1996/97. For comparability, the financial results include the electricity distribution business, and both the franchise and contestable retail activities.

The results of the industry restructure should be borne in mind when making comparisons between 1994/95 and 1996/97 financial results. The industry restructure reallocated revenues and returns to reflect the underlying economics of the industry, and provided commercial returns to the distribution sector. Higher returns in the distribution sector, as well as increased cash flows and dividends, reflect this restructure and application of Treasury's financial distribution policy.

19 Including franchise retail suppliers.

20 Rural distribution assets were written down in accordance with the Recoverable Amount Test.

Table 2.6 Key Financial and Operating Performance NSW Electricity Distributors

KEY FINANCIAL DATA[21]		1994/95[22]	1995/96[23]	1996/97
Sale of electricity	$m	3,862	3,876	3,762
Purchase of electricity	$m	2,603	2,540	2,211
Operating and maintenance costs[24]	$m	630	650	640[25]
EBITD	$m	700	778	1,069
EBIT	$m	356	447	740
Property, plant and equipment	$m	6,619	5,594	5,556
Cash and investments	$m	395	458	426
Total assets	$m	7,751	7,122	7,197
Loans	$m	888	2,396	2,387
Equity	$m	5,759	3,294	3,268
Tax and dividend payments	$m	108	152	555
Capital expenditure	$m	494	429	357

FINANCIAL PERFORMANCE		1994/95	1995/96	1996/97
EBITD/total revenue	%	17.8	19.6	26.5
EBIT/total revenue	%	9.1	11.3	18.3
Return on assets	%	4.6	6.3	10.3
Return on equity	%	4.2	-2.9[26]	9.3
Debt to equity plus debt	%	13.4	42.1	42.2

OPERATING PERFORMANCE		1994/95	1995/96	1996/97
No. of employees	No	10,248	9,140	8,061
Customer number	No	2,693,607	2,746,459	2,773,050
Customers per employee	No	263	300	344
Electricity sales	GWh	40,954	41,722	42,686
Nominal average electricity prices	c/kWh	9.43	9.29	8.82
Real average electricity prices	c/kWh	9.82	9.31	8.82
Nominal operating cost per customer	$	234	236	231
Real operating cost per customer	$	246	237	231
Nominal operating cost per circuit km	$/km	2,324	2,398	2,363
Real operating cost per circuit km	$/km	2,422	2,405	2,362
Nominal operating costs per MWh sales	$/MWh	15.23	15.37	15.31
Real operating costs per MWh sales	$/MWh	15.86	15.41	15.31

---

21 The key financial data is extracted from the audited consolidated financial statements of the distributors.

22 Figures are based on the notional consolidated results and financial position of the distributors constituting the newly formed distributors.

23 Notional consolidated figures as disclosed in distributors' 1995/96 annual reports. The consolidated results of the first 3 months prior to merger on 1 October 1995 are based on the aggregation of the predecessor distributors which amalgamated to form the six new distributors.

24 The operating and maintenance costs cover network and retail business of the distributors. Non-core business costs are excluded in the 1996/97 amount. It should be noted that since 1994/95 operating costs have been affected by changes to accounting policy on pole capitalisation and introduction of sales tax.

25 The introduction of competition in the retail market imposes additional retail operating costs on distributors.

26 The negative return was primarily attributable to provisions for restructuring costs being brought to account by distributors in 1995/96.

Distributor network charges

In 1996/97, the network use of system charges (NUOS) collected by the distributors amounted to $1,636m from their 'wires' business. This is 0.85 per cent short of the revenue cap of $1,650m for 1996/97.

The *average* network price[27] paid by NSW customers was around 3.82 cents per kWh in 1996/97. This is 13 per cent lower than the average price of 4.32 cents per kWh charged by the Victorian distribution businesses.

A comparison of the NSW and Victorian tariffs reveals the following four differences and one similarity:[28]

- In general, NSW network tariffs for domestic and small business customers are lower than those charged by the Victorian distributors.
- The low voltage demand time of use charges of Victorian distributors are within the range of similar charges in NSW.
- At the high voltage demand time of use level, Victorian charges are lower than in NSW.
- At the subtransmission level, the Victorian distributors have lower network charges relative to NSW.
- Overall average network charges in NSW are lower than the Victorian charges.

Capital expenditure

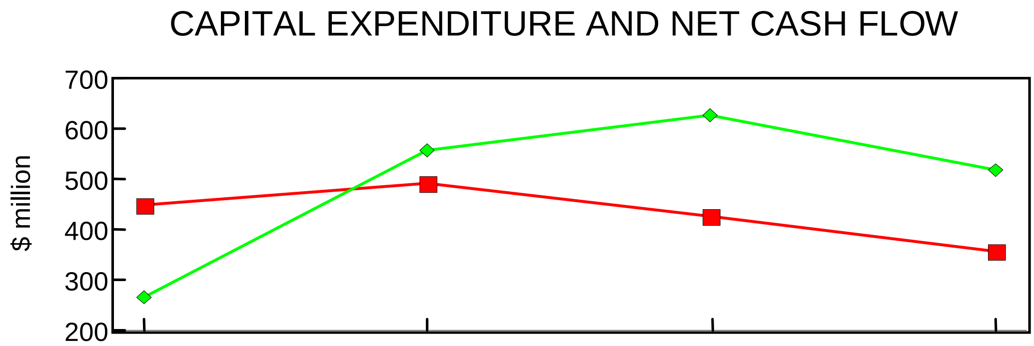
Expenditure on capital works has been falling since 1994/95. The 1996/97 aggregate capital expenditure totalled $357m, a reduction of 21 per cent compared with spending in 1995/96.

The reduction in capital expenditure did not, however, reflect a reduction in the distributors' ability to fund capital programs. Indeed, funds available to fund capital expenditure or shareholder returns increased. As shown in Figure 2.2 below, capital expenditure in the past three years was well covered by the net cash flow generated by the distribution operations. This was a reversal of the trend prior to 1994/95. The net cash flow to capex ratio was maintained at around 1.4 to 1.5 times in the past two years, indicating that the industry was capable of funding the current capital programs – or more - internally.

[27] Excluding the 0.55 cent State Distribution Levy applicable to contestable customers.

[28] The NSW electricity distribution levy was introduced effective 1 July 1997, and therefore is not reflected in these results.

Figure 2.2 Capital expenditure and net cash flow



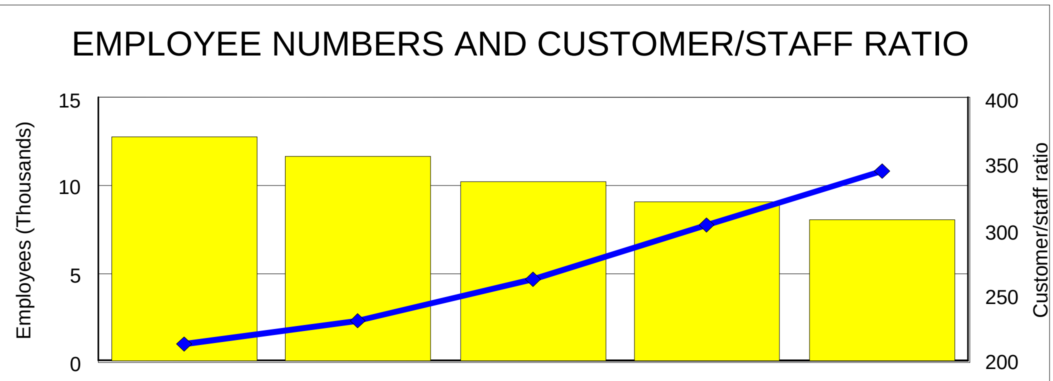
	1994	1995	1996	1997
capex	452	494	429	357
Net cash flow	269	557	630	519

Note 1: The fall in the net cash flow in 1997 is due to the substantial dividend payout to the Government shareholder.

Operating costs and productivity

Aggregate employment continued to fall in 1996/97, mostly at a similar rate to 1995/96. Total employment by the distributors was reduced by around 11 per cent to 8,061 in 1996/97, bringing the cumulative reduction in the past five years to 36.8 per cent. As a result, the customer/staff ratio rose from 213 in 1992/93 to 344 in 1996/97, an improvement of 62 per cent as shown in Figure 2.3 below.

Figure 2.3 Employment and customer/staff ratio



	1993	1994	1995	1996	1997
Staff no. (left scale)	12,752	11,651	10,248	9,050	8,061
Customer/staff ratio	213	231	263	303	344

Source: Distributors' annual reports.

As shown in Table 2.7 below, labour productivity (calculated as real revenue per employee) improved by 39 per cent in real terms over the same period. The increase was higher in 1996/97, up 14 per cent compared with 10 per cent in 1995/96. This was mainly attributable to the continued fall in employment levels in 1996/97 and the rise in operating revenue (including core and non-core business revenue). Due to the effect of contracting-out, the trends in labour productivity should be interpreted with caution.

Table 2.7 Efficiency and productivity measures (1997 prices)

		1993	1994	1995	1996	1997	% change 1993-1997
Labour productivity (note 1)	$	358	382	400	439	499	+39%
Operating and maintenance cost (note 3)	$m	738	717	656	652	640 (note 2)	-13%
Operating costs per customer (note 3)	$	287	273	246	237	231	-20%
Operating costs per circuit km (note 3)	$	2,826	2,769	2,422	2,405	2,362	-16%
Operating costs per MWh sold (note 3)	$	19	18	16	15	15	-19%

Note 1: Labour productivity is calculated as real revenue per full time equivalent employee.
Note 2: 1996/97 operating expenses include network and retail business expenses but exclude costs incurred by non-core businesses of the distributors as disclosed in the regulatory accounts returned to IPART.
Note 3: Operating and maintenance costs exclude depreciation and interest expenses.

Excluding operating expenses relating to the distributors' non-regulated businesses,[29] the operational efficiency of the distributors also improved over the same period as reflected in lower operating costs per customer, circuit km and MWh sales. These are shown in Table 2.7.

[29] Based on the 1996/97 regulatory accounts of the distributors, operating expenses relating to non-core businesses amounted to around $118 million. These expenses were excluded in calculating the efficiency measures in Table 2.6 to facilitate comparisons over time.

3 THE REVIEW PROCESS

3.1 Legislative basis for this review

The Tribunal derives its powers to conduct this review from section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992 (IPART Act).* Section 12A of the *IPART Act* provides that the Tribunal is to conduct investigations and make reports on any matter with respect to pricing, industry or competition that is referred to the Tribunal by the Premier.

The Tribunal received a section 12A reference from the Premier on 16 June 1998, requiring the Tribunal to report on the appropriate pricing of:

a) government monopoly electricity transmission and distribution services (provided by TransGrid and energy distributors) for the five year period from 1 July 1999; and

b) government monopoly electricity services to be provided to franchise customers (by energy distributors) for the period from July 1999.

Basis for the 1996 and 1997 Determinations

Unlike IPART's current review, the March 1996 and July 1997 electricity pricing determinations were made under section 11 of the *IPART Act*. Section 11 of the *IPART Act* allows the Tribunal to conduct investigations and to report on the pricing of a government monopoly service where that service:

- is supplied by a government agency specified in Schedule 1 of the *IPART Act;* and
- has been declared to be a 'government monopoly service' under s4 of the *IPART Act*.

The Electricity Transmission Authority (TransGrid) and the six NSW electricity distribution businesses (DBs) are currently listed in Schedule 1 of the *IPART Act*. The , transmission and distribution of electricity (and certain ancillary services such as connection, disconnection, and inspection) have been declared 'government monopoly services' under section 4 of the *IPART Act*.

Section 12 Determinations

Section 12 of the *IPART Act* requires that the Tribunal conduct investigations and make reports to the Premier on:

- a determination of the pricing for a specified government monopoly service; or
- a periodic review of pricing policies in respect of a specified government monopoly service.

As noted below, the Tribunal must consider the matters listed in section 15(1) of the *IPART Act* when conducting an inquiry under section 11 or 12 of the *IPART Act*. Determinations made under section 11 or section 12 are enforceable.

Matters to be considered under section 15(1)

The Tribunal is not automatically required to consider the matters listed in section 15(1) in all section 12A references. However, one or more of the matters listed in section 15(1) may be included by the Premier in the issues to be considered in a section 12A review. Conversely, the Tribunal is required to consider the matters listed in section 15(1) in **all** section 11 and section 12 inquiries.

Matters listed in section 15(1) of the *IPART Act* include: the efficient cost of providing services, the protection of consumers from the abuses of monopoly power, the appropriate rate of return on assets, standards of quality, reliability and safety, the need to maintain ecologically sustainable development, and the social impact of determinations.

Enforceability of report

The report that the Tribunal makes under a section 12A reference is a report to the Premier. A section 12A report is not enforceable, whereas determinations made by the Tribunal under section 11 and section 12 are enforceable under the *IPART Act*. However, it is possible for the findings of a report made under section 12A to be enforced by subsequent legislative enactment of some or all of the report's findings or the inclusion of some or all of the report's findings in a section 11 or section 12 determination.

Once the National Electricity Law has been passed, IPART, as jurisdictional regulator, will be able to put in place a price path for distribution network services under the National Electricity Code (the 'Code'). Alternatively, there is a derogation in the Code which allows IPART to regulate distribution network services under the *IPART Act* until as late as 1 January 2001 (ie by way of a section 11 or section 12 determination).

3.2 The National Electricity Code

Changes are planned for the way in which TransGrid and the DBs' monopoly services will be regulated.

The *National Electricity (NSW) Act 1997* is currently awaiting proclamation. Some sections have been proclaimed, which have removed the six NSW electricity distribution businesses from Schedule 1 of the *IPART Act*, but will allow IPART to continue to regulate those businesses as if they were listed in Schedule 1 of the *IPART Act* until 31 December 2000. Concurrently, the National Electricity Code (the 'Code') contains a derogation that allows IPART to regulate the prices of distribution network service under the *IPART Act* until 31 December 2000, after which time IPART must regulate these services under the provisions of chapter 6 of the Code as the appointed jurisdictional regulator.

The proclaimed sections of the *National Electricity (NSW) Act* have also removed TransGrid from Schedule 1 of the *IPART Act* but will allow IPART to continue to regulate TransGrid as if it was listed in Schedule 1 of the *IPART Act* until 30 June 1999. After that date, the NSW derogations from the Code provide for regulation to pass to the ACCC under the National Electricity Code.

NSW derogations from the Code

The NSW derogations from the National Electricity Code introduce some uncertainty for NSW DBs. The NSW derogation in relation to distribution network pricing provides that regulation of the DBs under chapter 6 of the Code will commence as late as 1 January 2001. However, under that derogation, IPART could start regulating the DBs under chapter 6 of the Code from 1 July 1999 in the absence of a determination under the *IPART Act*.

It is expected that the recommendations of the Report to the Premier resulting from the current section 12A review will be implemented on 1 July 1999. If the Tribunal issued a Determination under the *IPART Act* effective 1 July 1999, this could effectively impose an 18 month regulatory period on the NSW DBs. The Tribunal is of the view that such a short regulatory period would cause considerable price uncertainty for customers, significant uncertainty for the DBs, and uncertainty for the Government, as owner. The Tribunal recognises that longer regulatory periods are required if incentive based regulation is to be effective. The Tribunal is of the view that an 18 month regulatory period is unreasonably short. However, changes to the NSW derogations from the Code are a matter for government to consider.

The status of this review and the current derogations also present some uncertainty for TransGrid. The current reference on TransGrid has been provided by the NSW Premier. Yet under the current NSW derogations from the National Code, TransGrid's revenue will to be regulated by the ACCC from 1 July 1999. In the absence of a co-operative approach by the ACCC and IPART, TransGrid could be faced with overlapping regulatory pressures. Further, there may be uncertainty whether the findings of the ACCC would take precedence over those of the Tribunal in the determination of revenues and prices effective 1 July 1999. The Tribunal considers that close coordination with the ACCC is essential. This will lead to a reduction in duplication, and also enhance consistency between regulatory jurisdictions.

3.3 Terms of Reference

The Tribunal advertised the draft Terms of Reference for this review on 19 June 1998. That advertisement requested interested parties to comment on the draft Terms of Reference by 6 July 1998. In making its recommendations to the Premier to settle the final Terms of Reference, the Tribunal considered the comments it received. The draft Terms of Reference are reproduced with the investigation advertisement in Appendix 1 to this Issues Paper. Final terms of Reference, when settled by the Premier, will be advertised and publicly available from the Tribunal and on the Tribunal's website.

In conducting this review, the Tribunal will have regard to all the matters listed in the final Terms of Reference. Under the draft Terms of Reference, the Tribunal is to base its recommendations upon the National Electricity Code and the National Electricity Law with the objectives of protecting the long term commercial value of the affected businesses for the benefit of the State's taxpayers, and the long term interests of the customers of these businesses.

In accordance with the draft Terms of Reference, the Tribunal will seek to ensure the review is consistent with the objectives and principles for pricing outlined in the Code and the outcomes of the NECA review of the network pricing requirements of the Code.

The Tribunal notes that there is some overlapping of matters to be considered under the Special Reference and under section 15 of the *IPART Act*. For completeness, section 15 of the *IPART Act* requires the Tribunal to consider:

- the efficient costs of providing the relevant services
- the protection of consumers from the abuse of monopoly power
- the appropriate rate of return and payment of dividends to the owner

- the impact of pricing policies and the need to renew or increase relevant assets on the capital structure and funding requirements of the distribution businesses’ funding of new assets or increased capacity
- the promotion of competition in the supply of electricity services
- standards of quality, reliability and safety of services
- social impacts of its determinations and recommendations
- the impact of pricing policies on ecologically sustainable development and considerations of demand management and least cost planning.

3.4 Process

Under its Act, the Tribunal’s review must include a public consultation process. This generally involves inviting submissions from the utility companies, and from other interested parties. The Tribunal is of the view that the utility companies have a clear responsibility to demonstrate the appropriateness of any proposed revenue or prices. Therefore, the Tribunal's procedures in this matter have been to require the utility companies to file submissions some weeks in advance of those filed by other interested parties. The Tribunal plans to continue this procedure in this review.

The field of utility regulation suffers from information asymmetry. The Tribunal maintains that the quality of submissions from interested parties will be enhanced by its receiving the utility companies' submissions early. The quality and content of the utility companies' submissions will affect the quality of response. In order to balance the information received and to improve the quality of participant submissions, the Tribunal has provided guidelines for the utility companies’ submissions. See section 8.1.1 below. Unless otherwise stated, all submissions will be made available to the ACCC to assist in its investigation of transmission pricing.

The Tribunal encourages participants to make submissions on the public record. Although the Tribunal will accept submissions on a confidential basis, it considers that public submissions add considerably to the quality of debate. The Tribunal may place greater weight on information which is on the public record and which has been subject to review and testing by other stakeholders. Information marked confidential is subject to the provisions of the *IPART Act* and the *Freedom of Information Act*.

After the Tribunal has received submissions, participants may still file additional commentary, rebuttal or additional information. However, it must be stressed that submissions to the Tribunal must be complete at time of filing. The Tribunal's acceptance of additional comments should not be regarded as an opportunity to file a brief or incomplete submission, with augmentation following just prior the hearing date.

At the public hearing the Tribunal will invite key participants who have filed submissions to clarify their submissions. Presenters are also welcome to rebut commentary made in any other submission. Participants speaking at the public hearing may be subject to questioning by the Tribunal.

Following the public hearing, the Tribunal, directly or through the Secretariat, will undertake further consultation and analysis. During this period, the Tribunal or the Secretariat may issue additional consultation papers, or seek the advice of consultants. Wherever possible, consultant reports will be a matter of public record.

The Tribunal will issue a public Report to the Premier. This Report will state the Tribunal's advice on the final Terms of Reference.

3.4.1 Summary timetable

The Tribunal proposes to conduct its review of pricing for electricity networks and retail supply in accordance with the following timetable:

19 June 1998	IPART advertises draft Terms of Reference
September 1998	Release of Issues Paper
25 September 1998	Submissions from utility companies due
30 October 1998	Submissions from interested parties due
10, 11 December 1998	IPART Public Hearings (to be confirmed)
30 April 1999	Publication of IPART Report to Premier

During this process, the Tribunal will issue a number of consultancy reports and discussion papers. IPART and the ACCC are working to release a joint process paper, which will outline the release dates for consultancy reports and discussion papers, and also set a timetable for industry round table discussions.

3.4.2 Studies and discussion papers

The Tribunal has engaged consultants to examine various issues. The reports of these consultants will be public documents. These documents will be available electronically from the Tribunal's web site when published, and paper copies will be made available on request.

Capital expenditure review

The Tribunal has engaged Worley International to review the reasonableness of the networks' capital expenditure forecasts. The study will involve an assessment of the current condition of the network, and analysis of the reasonableness and adequacy of forecast capital expenditure. This report is scheduled for completion in late August for the DBs and in late September for TransGrid.

In conjunction with the Worley study, the Tribunal will release a discussion paper on asset related issues, seeking comments on such matters as the opening capital base, the ongoing valuation of that capital base with inflation over time, depreciation issues, optimisation and redundant capital.

Asset base roll forward

The Tribunal is conscious that it must be consistent in its treatment of utility companies within a given industry, and across industries. Therefore, the Tribunal will issue a cross-industry generic discussion paper on the roll forward of utilities' capital bases over time. This discussion will take place within the context of the differing legislative environments for the various industries.

This discussion paper will canvass such matters as indexation of the capital base, the treatment of depreciation, and the prudence of capital expenditure. Whilst this discussion paper will survey issues across industries, it is expected that the discussion will be relevant to this review.

Regulatory approaches

There is considerable debate in the field of infrastructure regulation regarding the form of regulation and what regulatory approaches should be adopted. This debate is not unique to the electricity industry, but is common to all infrastructure industries, from airports to water distribution systems.

The Tribunal will issue a discussion paper seeking comments on appropriate approaches to regulation. This paper will canvass such matters as the legislative requirements currently in place, overseas experiences in various industries, and the pros and cons of the various approaches.

Whilst this discussion paper will survey regulatory approaches across industries, it is expected that the discussion will be relevant to this review.

Efficiency and benchmarking

The Tribunal has engaged London Economics to undertake an efficiency and benchmarking study of the DBs. This study will involve a comparison of the relative efficiency of the NSW distributors relative to a number of overseas comparators. The report from this study is expected to be released in early October.

In conjunction with the London Economics study, the Tribunal will release a discussion paper on efficiency comparisons, the strengths and limitations of benchmarking, and other related issues.

Retail contestability

The Tribunal has engaged SRC International to conduct a study of contestability aspects for low use customers in the market. This study will investigate whether contestability will be effective for low use and domestic customers, considering such matters as metering requirements, customer inertia, and the extent to which the incumbent distributor retailers will have significant market power after the contestability timetable has run its course. Release of this report is expected in late 1998.

Service standards

The draft Terms of Reference require the Tribunal to consider service quality, including reliability, standards, taking into account the potential for network service providers to offer price/quality trade offs above minimum standards. The Tribunal plans to release a discussion paper jointly with the Department of Energy, the technical regulator.

The Tribunal may also undertake further studies, or produce consultants' reports as issues arise. The Tribunal may also hold round table discussion groups on various topics over the course of the review.

4 FORM OF REGULATION

The Tribunal considers that the form of regulation is critical to ensuring the benefits of regulation are achieved. As mentioned above, the Tribunal will issue a discussion paper on the various forms of regulation, and their pros and cons. Industry participants are encouraged to comment on approaches to regulation as part of their submission to this Issues Paper.

The draft Terms of Reference require the Report's recommendations to be based on the National Electricity Law and the National Electricity Code. The National Code addresses matters to be considered in the regulation of transmission and distribution network services in separate sections, but the matters to be considered are broadly similar. A summary of the objectives the National Code seeks to achieve is included in Discussion Box 4.1.

4.1 Incentive regulation

The National Code espouses an incentive regulation model. The key characteristics of 'incentive regulation' are:

- regulation of prices or revenues, rather than profits
- use of medium term price or revenue controls, rather than annual reviews
- incentives for the utility to pursue efficiency gains by providing an opportunity for the utilities to retain the benefits of improved profitability for a period of time.

In general terms, this means that the network revenues are set by regulator at a level which reflects the efficient costs of providing the network services. This allows for a sustainable commercial revenue stream which includes a fair and reasonable rate of return to network owners on efficient investment in the system.

The accepted level of network revenue is then projected forward over the regulatory period. The forward projection often reflects changes in the general level of prices, as measured by the Consumer Price Index or a similar measure. The projection also reflects the regulator's assessment of reasonably achievable efficiency gains over the period. Other factors which may be considered are transition paths for prices and industry returns and the financial requirements of the utilities. Together, these are expressed in the 'X' factor in 'CPI-X' regulation.

The management of the network is encouraged to achieve greater efficiencies than reflected in the revenue requirement determination and the X factor. Incentive regulation provides for a reasonable sharing of efficiencies over time between the owners of the network and the users of the network.

The clarity of the regulatory arrangements will be important for the success of the regime and the strength of the incentives. Equally important is the commitment of both the regulator and the utility to the words and spirit of the regime.

DISCUSSION BOX 4.1
Objectives of National Code regulatory regime[30]

The revenue regulatory regime under the National Code seeks to achieve the following outcomes (summarised from section 6.2.2 of the National Code):

a) an efficient and cost-effective regulatory environment;

b) an incentive-based regulatory regime which:
   (1) provides an equitable allocation between Network Users and Network Owners of efficiency gains reasonably expected to be achievable by the Network Owners; and
   (2) provides for a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Network Owners on efficient investment, given efficient operating and maintenance practices;

c) prevention of monopoly rent extraction by Network Owners;

d) an environment which fosters an efficient level of investment within the network sector, and upstream and downstream of the network sector;

e) an environment which fosters efficient operating and maintenance practices;

f) an environment which fosters efficient use of existing infrastructure;

g) reasonable recognition of pre-existing policies of governments regarding network 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 network assets;

k) reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of Transmission Network Owners.

Achieving the benefits of incentive regulation

The fundamental purpose of an incentive regulation mechanism is to encourage utility companies to improve the efficiency of their business. Over time, improved efficiency will be translated into lower prices to system users. However, during the regulatory period, efficiency gains will translate into greater returns to shareholders. An important balance must be struck to share any gains in a way that continues to provide appropriate incentives to management to improve performance, yet allows customers to benefit from reduced prices.

In order to achieve efficiency gains, the regulatory period must be long enough for management initiatives to be implemented and take effect. The period must also be long enough to discourage measures to improve the profitability of the business in the short term

[30] The following discussion provides a general indication of matters to be considered in the regulation of transmission and distribution networks under the National Electricity Code. Readers are directed to Chapter 6 of the Code for the exact requirements.

at the expense of longer term considerations. For example, sharp reductions in system maintenance would increase the profitability of the network business in the short term, but at the expense of system degradation and risk of failure. Longer term objectives, such as more efficient network operation and utilisation, must be allowed a sufficiently long period to return benefits during the regulatory period. The extent to which benefits are rolled into the next regulatory period through benchmarking or 'glide paths' in price adjustments will have an important impact on incentives and risks.

The management of a utility business must have sufficient confidence in the regulatory regime to trust that all the benefits of efficiency initiatives will not be 'clawed back' by the regulator. Management's ability to retain the benefits of efficiency gains in the business during the regulatory period will be a critical factor in providing the incentive to undertake efficiency initiatives. A perceived risk of retrospective adjustments ('clawbacks') would seriously undermine these incentives, ultimately at the risk of efficiency gains being achieved at all.

It should be recognised that in an incentive regulation regime, it is entirely likely, and indeed encouraged, that a utility could and should earn a higher return on its investment in the system than was considered reasonable by the regulator in setting the initial revenue cap. This contrasts with a price control regime with frequent profitability resets, in which management is not provided strong incentives to pursue efficiency gains.

Against this encouragement to achieve greater profitability through efficiency measures, the regulator must balance the interests of users of the system. An example of this balancing act is in the selection of the period of the revenue cap. If the utility company experiences long periods of high profits, users will begin to apply pressure for regulatory intervention, which could potentially undermine the incentive mechanism. The regulator must remain committed to a fixed regulatory term in order for the incentive mechanism to have the desired effect.

However, the regulator recognises that it is making decisions in an environment of information asymmetry, in which the regulated utility will always have more information about its cost structures. It is not uncommon in regulatory regimes for every factor resulting in higher costs to be brought to the regulator's attention, while additional revenues or cost reductions are not reported by the utility company.

A regulatory regime operating in an environment of information asymmetry will invariably base its decisions on forecasts which differ from actual results. The UK Department of Trade and Industry[31] has suggested greater use of 'Error Correction Mechanisms' as a supplement to a CPI-X regime. In principle, these mechanisms would provide a clear and in-built means of promptly sharing the benefits when financial and operating results differ from those envisaged when the revenue cap was set. The difficulty is in the design and implementation of such mechanisms so as to distinguish factors beyond the control of the utility, and assess their impact.

In recognition of the information asymmetry issue, the National Code allows the regulator to revoke a determination based on false or materially misleading information, or if there was a material error in the setting of the revenue cap, and consent has been received from parties

[31] Department of Trade and Industry, *A Fair Deal for Consumers – Modernising the Framework for Utility Regulation*, March 1998. This paper is available on the DTI web site at www.dti.gov.uk (Search: Utilities Review).

affected by the re-opening of the revenue cap. Further, the Code allows the regulator to revoke a determination for transmission networks, where there has been a substantial change in ownership.[32]

Sharing the benefits of incentive regulation

Whilst the achievement of efficiency gains is important, it is equally important for the regulatory regime to provide for those gains to be shared between network owners and network system users. An incentive regulation mechanism may focus on three levels of gains: those reasonably expected and reflected in the X factor, those arising from management's 'out-performance' of those reasonably expected efficiency gains, and 'windfall gains', arising from occurrences beyond management's control.

Reasonably achievable efficiency gains are shared through the projection of revenue requirements and incorporated in the X factor in the 'CPI-X' formula. Choosing the level of the X factor is an important feature in the effectiveness of the regime. Setting the X factor too high could provide for inadequate returns to the network owner, particularly if it is operating at high levels of efficiency at the start of the regulatory period. In contrast, setting the X factor too low could result in excessive returns to the owner, and demands by customers to reopen the regulatory investigation. The appropriate level for the X factor is an important matter for the regulator's judgement.

Achieved efficiency gains are shared by owners and users at the end of the regulatory period, or during the following period. Again, the nature of the sharing mechanism will affect the amount of incentive provided to achieve efficiency gains, particularly those gains arising from 'out-performance' of the regulatory incentive regime. Generally, the longer management is able to retain the benefits of increased efficiency in the business through higher profits, the greater the incentive to pursue those initiatives.

A sharing mechanism which delivers all the benefits of efficiency initiatives to customers through lower prices immediately at the end of the regulatory period (such as a P_0 adjustment) will provide less incentive than a 'glide path' regime which allows some of the gains to be retained in the business over a longer time. A P_0 adjustment regime will also provide a sharp disincentive to implementing efficiency initiatives toward the end of the regulatory period.

One way of achieving an extended sharing of efficiency gains is to phase out benefits over a period extending into the next regulatory period. This may be reflected by a greater X factor in the regulatory period following the efficiency gains. The greater incentive to achieve efficiency improvements that this mechanism provides would be translated into lower prices to customers in the longer term.

A sharing mechanism may also recognise that some gains may accrue to the company which are neither the result of management action, nor within the control of management. How these 'windfall gains' are to be treated at the end of the regulatory period should also be considered. In particular, a sharing mechanism must consider whether these 'windfall gains' should be passed back to customers through an immediate adjustment to the regulated revenue cap (as part of a P_0 adjustment), or phased out in a similar way to 'out-performance' gains. This approach faces the practical difficulty of defining and distinguishing windfall gains.

---

[32] See section 6.2.4 and 6.10.5(5) of the National Electricity Code.

In summary, the need to share the benefits of efficiency improvements between owners and users will affect management’s incentives to initiate efficiencies. Generally, the greater proportion of the benefits that management may retain in the business during the regulatory period, and the longer the period over which management may retain some proportion of those gains, the stronger the incentives for efficiency improvements.

The Tribunal seeks comments on appropriate sharing mechanisms for incentive regulation, including mechanisms to share the benefits of reasonable efficiency gains achieved within the regulatory period, gains arising from ‘out-performance’ of the regulatory mechanism, and ‘windfall gains’. The Tribunal also seeks comments on the role of ‘error correction mechanisms’ in the regulatory model.

4.2 Determination of network caps

Under the current regulatory approach, DBs' regulated revenues or average prices are determined with reference to efficient costs and a reasonable return on investment. This revenue requirement is then expressed in terms of a formula designed to reflect the impact on costs of additional customers of varying size, additional load, and the sharing of efficiency gains through a CPI-X factor.[33] A similar approach has been taken by the UK electricity regulator, OFFER. The parameters adopted by OFFER were based on the cost of supply modelling undertaken on behalf of the distributors, and subsequent consultation with the distributors. Importantly, the parameters were intended to reflect the average impact on costs across broad customer classes rather than the impact on any one customer.

The formula used to regulate overall revenues or prices for the network businesses reduces the sensitivity of the utilities’ revenues to the volume of electricity sold. Under a simple price cap, a 10 per cent increase in volumes increases revenues by 10 per cent. Under the current formula, a 10 per cent increase in the volume of electricity sold would increase revenues by approximately 2.5 per cent, more in line with increases in costs. The parameters in the current formula reflect previous cost modelling by the DBs and were set following extensive consultation with the DBs.

This approach, which has been referred to as ‘revenue regulation’, was adopted because it was considered to:

- better reflect the industry’s cost drivers. The fixed costs within networks mean that, with the exception of areas of congestion, additional costs caused by increases in the volume of electricity transmitted are much lower than average costs. By better matching the cost drivers, the risks from variations in volumes and the incentives for gaming forecasts of future volumes are reduced.
- reduce the bias against demand management under price regulation. Due to the sensitivity of revenues to volumes, price regulation creates a disincentive for the networks to contract for demand management services, even where this is a lower cost way of meeting users’ energy needs.
- better mirror the incentives in a competitive market to adopt a mix of options which meets customers’ needs most cost effectively, and to match the incentives for the retail arm of the DB with those of external, independent retailers.

33 For further information on the approach and the formula adopted see *Electricity Prices March 1996* and *Electricity Prices July 1997.*

Some distributors have indicated a preference for placing a cap on individual prices or the average price. They argue that this would provide a stronger commercial focus on the 'core' business of the distribution of electricity.

Under TransGrid's cap, a 10 per cent increase in the volume of electricity transported could translate into an increase in revenue of up to 5 per cent, depending on the maximum demand of the additional load. However, this has been achieved through the regulation of a price structure which includes a fixed component that accounts for 50 per cent of revenue, rather than the use of a revenue control formula.

The Tribunal seeks comments on the approach to regulation of revenues or average prices, and the methodology for determining the value of the revenue formula drivers. In particular, the Tribunal seeks comments on the nature of the signals for new investment, load growth and energy efficiency under the various approaches.

4.3 Determination of retail caps

Currently the regulated retail revenue cap is determined with reference to a sustainable gross retail margin[34] that will allow retailers to participate effectively in the market. Similar to the network revenue cap, this margin is expressed as a formula used to estimate the margin attributable to additional customers or additional load, and a CPI-X factor. Franchise retailers have been responsible for setting retail tariffs for franchise customers within this cap. Tariffs must also comply with side constraints set by the Tribunal on the maximum increase for individual customers or classes of customer.

The Tribunal seeks comments on the effectiveness of the retail gross margin approach, the price signals this approach provides, and the appropriateness of this approach. The Tribunal also seeks comments on the sustainable size of the retail gross margin.

As customers have become contestable, they have generally had been allowed a 12 month period in which to exercise their choice of a future supplier. During this period, customers have been able to elect to remain on a regulated franchise tariff. This has provided a residual degree of regulatory protection and price certainty during the transition period.

The scope of the regulated retail margin has been 'rolled back' as groups of customers have become contestable. This has been a complex process. From July 1998 only one group of franchise customers remains (ie those with loads below 160 MWh).[35]

Options available are to set a retail margin cap for those customers below 160 MWh or to set an average price cap. In either case, a mechanism is required to adjust for customers who become contestable through load aggregation. Another issue is whether wholesale purchase costs should be passed through at actual costs or at benchmark costs, and if the latter, how should benchmark costs be set. The choice of approach may also affect the incentives for energy efficiency and the retailers' risks.

The Tribunal seeks comments on the appropriate form of regulation for franchise retail customers.

---

34 Gross margins are retail revenues less the purchase costs of electricity and network use of system charges. Hence gross margins include the costs of retailing electricity and a profit margin.

35 Some loads greater than 100 MWh per year, which are eligible for aggregation, could become contestable from 1 July 1999.

4.3.1 Future role of retail regulation

Customer loads between 750 MWh and 160 MWh pa became contestable on 1 July 1998. Customers with individual loads over 100 MWh pa will be allowed to aggregate their loads to meet the contestability threshold, effective 1 July 1999, subject to eligibility requirements. All other customers are scheduled to become contestable from 1 January 2001, subject to a transitional timetable to be announced. Some stakeholders have expressed concern about the effectiveness of competition and contestability for residential and other low use customers. Relevant issues include:

- the potential advantages to the incumbent supplier and the cost and effectiveness of contestability for the smallest users of electricity
- the need for and capacity to provide default regulatory protection in this market.

An issue for consideration is whether any default regulatory protection is required for residential or small business customers.

Once the contestability timetable has run its course, and all customers are free to choose a retailer, the first question to consider will be whether the existing suppliers have significant market power. If it is judged that they do, the second question is whether interim regulatory measures are an appropriate response.

Clearly, competition for medium to large customers has been aggressive, and margins are small or possibly negative. However, relative to small users' energy bills, the costs of introducing contestability through metering or load deeming may be quite high. Depending on how these costs are allocated, this could give the existing supplier significant market power. The other potential advantages for the existing supplier, such as customer inertia and access to customer lists and load information,[36] may be more significant in the residential and small business markets.

If a form of transitional regulation is judged to be necessary, it must be designed and implemented with care. Poorly designed mechanisms could hamper the development of the competitive market, to the long term detriment of customers. The Tribunal notes that in the UK, OFFER has proposed transitional ceiling prices for residential customers during the early stages of the introduction of contestability.

Care must be exercised, as interim regulatory mechanisms may inhibit the market’s development, having a negative impact on customers in the medium term. Issues of providing a safety net and a retailer of last resort for low use customers must also be considered.

The Tribunal seeks comments regarding the options for introducing contestability, and on whether there is a need for interim regulation particularly for low volume users.

[36] London Economics, *Distributor Market Power*, November 1995.

5 AGGREGATE ANNUAL REVENUE REQUIREMENT

To establish an incentive based regulatory regime, the first step is determining the base level of revenue or average prices on which incentive regulation is to apply.

Parts B and D of Chapter 6 of the National Electricity Code provide for the calculation of the 'aggregate annual revenue requirement' (AARR) for transmission and distribution network service providers respectively. The glossary of the Code defines the AARR to be the "calculated total annual revenue earned by an entity for a defined class of service."

The Tribunal considers that the AARR can be calculated using a 'building block' approach, which constructs the revenue requirement from the costs that should be recovered from system users. However, the Tribunal wishes to emphasise that it does not favour a strict application of a rate base/rate of return model. Indeed, the Tribunal is of the view that the results of the 'building block' approach must include an assessment of the sustainable cash flows and profitability of the entity. Thus the Tribunal does not see cash flow or financial indicator analysis as an alternative to 'building block' analysis. Rather, these are an adjunct to the 'building block' analysis. They help to determine the capital costs incorporated in the building blocks.

5.1 Non-capital costs

Measurement of non-capital costs is essential to the regulator's assessment of cost recovery and cross subsidies. The draft Terms of Reference clearly require the Tribunal to have regard to the efficient costs of providing the relevant services.

Clause 6.10.5(d) requires that, in setting each network owner's regulatory cap, the Jurisdictional Regulator must take into account a number of financial indicators, including:

> the Jurisdictional Regulator's reasonable judgement of the potential for efficiency gains to be realised by the Network Owner in expected operating, maintenance and capital costs ….[37]

Operating and maintenance costs

The Code provides that one of the objectives which the distribution service pricing regulatory regime must seek to achieve is "an environment which fosters efficient operating and maintenance practices within the distribution sector."[38] The Code also sets out equivalent requirements for transmission service pricing.

Operating and maintenance (O&M) costs are often considered the 'cash outlay' costs of an infrastructure business. Recovery of these costs does not provide any return to the infrastructure owner, as they are paid out in the form of salaries, ongoing operating and maintenance costs, emergency service costs, etc. These costs allow the business to provide and maintain service.

The Tribunal recognises the importance to the utility owner of recovering O&M costs. However, it is important that the utility not incur excessive or unnecessary costs in providing service. It is in the interests of all concerned that the regulator and interested parties be able

[37] Clause 6.10.5(d)(4).

[38] See Clause 6.10.2(e), which is contained in Part D of Chapter 6. Clause 6.2.2(e), which is contained in Part B of Chapter 6, sets out the equivalent requirement in relation to transmission service pricing.

to examine the level of current and forecast operating costs, and be able to compare those costs with other similar entities, both in Australia and overseas. The Tribunal notes that it is important for network companies to be explicit in stating the classification and level of their operating and maintenance costs. This is essential to allow meaningful comparisons with other similar service providers. The Tribunal asks that TransGrid and the DBs provide relevant system design and performance characteristics, customer and load information, and other information which will allow for meaningful comparisons.

Administrative and general costs

Administrative and General (A&G) costs are often likened to O&M costs, in that they are ‘cash outlay’ costs. However, the Tribunal recognises an important difference. Whereas O&M costs are generally expended by the regulated entity, many utility companies achieve significant synergies and economies of scale in their A&G costs by sharing these costs with other related entities. While some of the A&G costs will be incurred directly by the utility, the bulk of these costs are often incurred by a head office group, and then allocated or ‘mirrored down’ to operating companies.

The Tribunal is concerned to ensure that the amount of A&G costs borne by the regulated entity is not unreasonable relative to the functions performed, and the total level of A&G costs incurred by the entity as a whole. In particular, the Tribunal is concerned to ensure that the utility company not bear too large a share of the corporate A&G costs, particularly if that allocation results in related competitive entities bearing an inappropriately low share of those common costs. The Tribunal regards as important that network companies be explicit in their submissions regarding the total amount of common A&G and overhead costs borne by the corporate entity as a whole, the amount of such costs allocated to the operating utility, and the basis and calculation of that allocation.

As with O&M costs, the Tribunal considers it important that the utility not incur excessive or unnecessary costs in providing service. In the interests of all concerned, the regulator and interested parties should be able to examine the level of current and forecast A&G costs, and to compare those costs with those of similar entities, in Australia and overseas. It is important for network companies to be explicit in their submissions regarding the classification and level of A&G costs, to allow meaningful comparisons with other similar network service providers.

The Tribunal seeks comments on the level of non-capital costs, comparability with domestic and international benchmarks, and the scope for efficiency improvements.

5.2 Capital costs

The inclusion of capital costs in the revenue requirement formula recognises the owner’s investment in the regulated utility and the capital intensive nature of infrastructure businesses. Failure to include adequate capital related costs as part of the revenue requirement of the utility business risks a reduction in investment in the industry. This could ultimately lead to reductions in coverage, service levels and dependability. Under both the National Electricity Code and the *IPART Act*, the Tribunal is required to have regard to the appropriate rate of return and payment of dividends to the owner.

Fundamental to the measurement of capital costs in the revenue requirement is an assessment of the utility’s capital investment in the system. Arguments about asset valuation vary from insisting ownership rights be recognised, to questioning whether any value should be attributed to sunk investment.

The Tribunal has not endorsed any particular asset valuation methodology. This is because the Tribunal is of the view that asset valuation issues must be considered with regard to the overall profitability of the infrastructure business, sustainable cash flows of the business, as shown by the use of a range of cash-based financial indicators, and equity considerations. Any overbuilding of assets, or ‘gold plating’, should also be considered. On a number of occasions, the Tribunal has reiterated that it does not endorse any particular asset valuation methodology, including Depreciated Optimised Replacement Cost (DORC), for the purpose of determining the sustainable revenue requirement of a regulated utility.

The Tribunal is conscious of the principles for regulation of distribution service pricing, as included in Clause 6.10.3 of the National Code. This section indicates that “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”. Clause 6.10.3(e)(5) provides some indication as to the matters to be considered by the Jurisdictional Regulator in reaching a decision on any subsequent distribution network asset revaluations:[39]

> 6.10.3 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:
>
> (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:
>
> (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: …
>
> (iii) … 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;
>
> (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.

The asset valuation used in the 1996 Electricity Pricing Determination was based on a present value analysis of revenues, which in turn was based on a 20 per cent reduction in revenues derived from the Tribunal's 1994 Determination, and an exchange of correspondence with the Premier in 1995. Combining the above with assumptions about wholesale prices and retail margins, the Tribunal derived revenue caps for the DBs. From these revenue caps, the Tribunal conducted a present value analysis, (the recoverable amount test, or ‘RAT’ test) and cross-checked the results against a DORC valuation. This result was then used to form a

---

39 National Electricity Code, Version 2.2. A similar clause relates to revaluation of transmission assets. See Clause 6.2.3(d)(4)(iv)(A).

view as to the approximate value of the infrastructure assets. This value, together with an estimate of the value of past capital contributions by customers, was used to derive the initial regulatory asset base.

A key issue to be decided in assessing assets is the method of rolling the base asset value forward through time. Issues to be considered include: the use of forecast or actual capital expenditures, the effects of assets that are no longer required to provide service (stranded assets), the extent of any future optimisation of the existing asset base or future capital additions, and the depreciation methodology associated with the existing asset base and any future assets. The Tribunal is planning to issue a generic discussion paper on asset roll forward issues.

The Tribunal seeks comment on the components of an asset roll forward methodology, and their application.

A major topic of debate is whether the value of the existing asset base should remain constant in nominal terms, or be indexed by some measure of inflation (ie remain constant in real terms). This issue triggers further debate regarding the rate of return that a utility company may earn on its asset base.

The Tribunal recognises that return and performance targets for company management are often set in relation to return on asset figures. The Tribunal acknowledges that utility owners and management will be faced with uncertainty until regulatory asset values and ongoing asset valuation techniques are determined. In this review, the Tribunal will endeavour to provide clear messages to industry participants about this issue.

The Tribunal considers that it is important for network companies to be explicit in their submissions on the matter of the valuation of assets currently in service.

The Tribunal seeks comment on asset valuation and revaluation issues.

Capital expenditure

Discussions regarding asset valuation are not complete without consideration of the treatment of future capital expenditure. The Code provides that one of the objectives which the distribution service pricing regulatory regime must seek to achieve is “an environment which fosters an efficient level of investment within the distribution sector, and upstream and downstream of the distribution sector”[40] The Code contains an equivalent objective for the regulation of transmission service pricing.

Capital expenditure in the infrastructure utilities tends to be ‘lumpy’, that is, service capacity tends to be constructed in waves of asset replacement and renewal, or large increments to new capacity. This is characteristic of capital intensive businesses.

Capital expenditure is an important element in this review. Capital expenditure since the last review may be an important part of a utility’s asset base. During the period of the review, prudent future capital expenditure will be added to the utility’s asset base. It may also affect a range of other financial indicators through its effect on utilities’ cash flows and

[40] Clause 6.10.2(d). Clause 6.2.2(d) sets out an equivalent objective in relation to the regulation of transmission service pricing.

debt structures. Capital expenditure on renewals and replacement can also provide a useful cross-check on the provisions for depreciation.

It is important that network companies be explicit in their submissions regarding how future capital expenditures are reflected in their revenue path requests.

The Tribunal has commissioned an independent review of the networks' capital expenditure programs. The purpose of the review is to better ascertain the capital expenditure necessary to ensure users' energy requirements are met at least cost, and consistent with appropriate service standards. This review will examine past investment and the adequacy of existing networks. The study will also consider the adequacy of past and proposed maintenance and the impact on reliability and quality of supply. The Tribunal is conscious of the inextricable link between adequacy of capital expenditure and maintenance on one hand, and reliability, quality of supply and cost of service on the other.

The Tribunal is concerned that the regulatory framework should encourage TransGrid and the DBs to consider all options, including local generation and contracting for energy management services, and to choose the least cost option for meeting customer requirements. The framework should discourage TransGrid and the DBs from over-investing in the network, (ie gold plating) and, on the other hand, from deferring investment essential to maintaining adequate service standards. The Tribunal recognises that alternatives to capital expenditure may include increased operating expenditures on maintenance or on demand side management options, and the need for a capital expenditure policy to recognise the tradeoff between capex, opex, and reliability. Clause 6.10.3 provides that the regulation of distribution network services should be consistent with a number of principles. One of these principles is that the Jurisdictional Regulator must have regard to the need to "create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration."[41]

This can be supplemented, if necessary, with investment planning protocols or requirements additional to the current capital planning requirements in the DBs' licences.[42] Options could include a requirement that major capital expenditure programs and underlying analysis or requirements be published to seek expressions of interest for alternatives to substantial network augmentations.

The Tribunal seeks comments on incentives for appropriate capital expenditure that could be built into the regulatory regime.

Return on capital

Industry participants tend to emphasise the return on capital invested as part of the regulatory model. The Tribunal considers that utilities should have the opportunity to earn a commensurate return on their investment. The valuation of that investment remains a major issue. A fundamental question is whether the rate of return should be a real rate (consistent with a revaluing asset base) or a nominal rate (consistent with a nominal fixed asset base). The Tribunal considers that the valuation of the assets, a reasonable rate of return on efficient capital investment, and the sustainable cash flows of the business, are

---

41 Clause 6.10.3(e)(2). Clause 6.2.3(d)(2) outlines the equivalent obligation for the regulation of transmission service pricing.

42 See New South Wales *Electricity Supply Act 1995*, Electricity Distributors' & Retail Suppliers' Licences, Guidelines and Requirements Policy on the Department of Energy website, www.doe.nsw.gov.au /Electricity/guidelines/guide.html#Chapter 4.

intricately linked. Ultimately the valuation of the business will depend upon the present value of the sustainable cash flows as discounted using a reasonable rate of return.

Failure to determine an appropriate rate of return will distort investment signals in the marketplace. An excessive rate of return will cause funds to flow to the utility. This may encourage over building and gold plating. On the other hand, an insufficient rate of return may starve the utility of capital, resulting in reduced capital expenditure, and potentially in reductions in service levels or degradation of the system.

The Weighted Average Cost of Capital (WACC) is based on a weighted average of the utility's cost of debt and cost of equity. The utility's cost of debt can be readily determined by reviewing outstanding debt and any discount or premium on its issue. Several models are available to estimate the appropriate rate of return on equity in a business. These include: the Capital Asset Pricing Model (CAPM), the discounted cash flow model, and a comparable earnings test.

As is noted above, Clause 6.10.5(d) requires that, in setting each network owner's regulatory cap, the Jurisdictional Regulator must have regard to a number of financial indicators. One of these financial indicators is "the Distribution Network Operator's WACC applicable to the relevant network service, having regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to those faced by the Distribution Network Operator in the provision of that network service".

The term 'weighted average cost of capital' is defined in the Code as meaning "an amount determined in a manner consistent with Schedule 6.1." Schedule 6.1 sets out the procedure for calculating WACC. Clause 3 of Schedule 6.1 states that "The Network Owner's required rate of return on equity is estimated using the CAPM." Schedule 6.1 of the National Code also indicates that the limitations of the CAPM model should be recognised. It should be regarded as providing an indication of the cost of equity, rather than a firm or precise measurement.

As well as requiring the regulator to have regard to the network owner's WACC, the National Code requires the regulator to have regard to the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investments (including sunk assets). In particular, the National Electricity Code requires that the regulation of distribution network service pricing be conducted by the Jurisdictional Regulator according to a number of principles. One of these principles is that the Jurisdictional Regulator must have regard to need to "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 …"[43]

Also relevant is Clause 6.10.5(d), which requires that in setting each network owner's regulatory cap, the Jurisdictional Regulator must have regard to "the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets subject to the provisions of clause 6.10.3(e)(5) [noted above]."[44]

The appropriate return to the capital provider should be commensurate with the risk associated with that capital. CAPM relates the required return of the asset to the risks

[43] Clause 6.10.3(e)(5) – see Clause 6.2.3(d)(4) for the equivalent requirement in relation to the transmission sector. Clause 6.10.3(e)(5) also deals with asset valuation.

[44] See Clause 6.10.5(d)(6).

associated with that asset. This approach requires several inputs to the model to be determined: the rate of return on a risk free asset (eg Commonwealth bonds), the rate of return on the equities market as a whole, and a measure of the riskiness of the utility, relative to that of the equities market. It should be kept in mind that CAPM should not reward investors for company specific risks, as these can be eliminated in principle by holding a diversified portfolio.

Presented in Table 4.1 is a comparison of the WACC variables proposed by gas utilities currently involved in investigations, as well as those proposed by the Tribunal's Secretariat as a feasible range consistent with current market conditions.

Table 4.1 Comparison of WACC calculations

	EPD Gas Transmission proposal (Nov. 1997)	ACCC Gas Transmission draft Determination (midpoint)[45] (May 1998)	Great Southern Energy Gas proposed (range) (March 1998)	EPD Gas Distribution proposal (Nov. 1997)	ORG Gas Distribution draft Determination (May 1998)	IPART Secretariat Albury Gas Company Discussion Paper (range) (March 1998)
Nominal risk free rate	8.00%	5.4%	8.00 - 8.30%	8.00%	5.1 - 6.1%	5.8 - 7.4%
Market risk premium	6.50%	6.0%	6.50 - 7.00%	6.50%	6.0%	5 - 7%
Equity beta	0.95	0.85	1.13 - 1.01	1.08	0.85	0.66 - 0.88
Nominal cost of debt	8.75%	Premium of 80 points	8.80 - 9.00%	8.75%	Premium of 75 points	Premium of 80 points
Gearing ratio	60%	60%	60%	60%	60%	60%
Tax rate	36%	25%	36%	36%	15 - 25%	36%
Imputation utilisation rate	25%	50%	21 - 15%	25%	40 - 60%	20 - 50%
Real pre-tax WACC	9.73%	6.7%	11.1%	10.16%	5.5% - 7.5%	7.5 - 9.5%
Nominal pre-tax WACC	13.02%		13.90 - 14.30%	13.47%		9 - 12%

Notes:
1. The EPD proposals have yet to be approved by the regulators.
2. The Great Southern Energy proposal refers to the gas business and has yet to be approved by the regulator.
3. The ACCC and ORG ranges are derived from draft determinations, and have yet to be finalised.

The Tribunal considers that it is important for network companies to be explicit in their submissions concerning their assessment of the risks associated with owning and operating an electricity network business, the appropriate rate of return required to compensate for those risks, and the derivation of the rate of return reflected in their revenue path requests.

[45] ACCC, Draft Decision on Access Arrangement by Transmission Pipelines Australia, May 1998, pp 58-59.

In practice, the Tribunal's task is to determine a reasonable commercial rate of return for the utilities that can be used as a component within its Determinations. It expects to consider a range of models for assessing the cost of capital, and a range of assumptions for these models. Technical models can provide a guide for the feasible range for the rate of return. However, the debate prompted by the draft Determinations on the Victoria gas arrangements has highlighted that the exercise of judgement is inevitable.

The Tribunal seeks comments on the factors to be considered in assessing an appropriate return or profit margin, the means of valuing the assets, the role of asset valuation in determining regulated prices, and an appropriate range for the cost of capital.

Taxes and equivalents

The Tribunal recognises that any return on capital provided will attract corporate income taxes or tax equivalents. Recognition of such taxes or tax equivalents is necessary to ensure that infrastructure investors are compensated adequately for their investment in infrastructure networks.

The Tribunal considers that taxes or equivalents can be recognised in either of two ways, using the 'building block' approach. First, they can be recognised by adjusting the required debt and equity rates of return, and applying a pre-tax WACC to the asset base. Alternatively, income taxes and equivalents can be calculated explicitly and included in other recoverable costs, with an after tax WACC applied to the asset base. The Tribunal considers that it is important for network companies to be explicit in their submissions regarding the treatment of taxes or equivalents, and to illustrate this treatment through accompanying calculations.

The Code provides that in setting a regulatory cap to apply to each Network Owner, the Jurisdictional Regulator must have regard for any State and Commonwealth taxes which the Network Owner has paid in connection with the operation of its business as a provider of distribution services.[46]

Return of capital

As well as achieving a return *on* capital invested, it is also important for investors to ultimately receive a return *of* capital invested. This is often accomplished by including depreciation as a recoverable cost in the revenue requirement determination.

The debates surrounding depreciation are as varied and complex as those surrounding asset valuation. The Tribunal considers that it is important to encourage informed debate on this issue; debate which recognises the judgemental impacts of depreciation and other similar costs, and the major effect these costs can have on the total utility revenue requirement.

Another major issue is the appropriate base for depreciation. Many market participants argue that to allow depreciation on a written up asset base is tantamount to returning capital that was never invested. Against this, other stakeholders (notably the utilities) argue that depreciation on the historic cost asset base does not provide for the maintenance of the operating capacity of the network. If a written up asset base is to be used, the Tribunal questions whether it should expect to see, over a number of years, a rough equivalence of depreciation expense and replacement or renewal related capital expenditure. It is

[46] Clause 6.10.5(d)(7)(i). See Clause 6.2.4(c)(6) in relation to transmission services.

important for network companies to be explicit in their submissions regarding the asset base on which depreciation is calculated. This information should also specify the depreciation treatment afforded to customer or developer funded or contributed assets.

A further debate focuses on the useful life of assets. Questions arise as to whether assets should be depreciated according to a measure of economic life or technical life. The pattern of depreciation expense (eg straight line depreciation or amortisation based depreciation) is another point of debate. The Tribunal considers it is important for network companies to be explicit in their submissions regarding the patterns of depreciation applied to major asset groups.

An alternative to calculating accounting depreciation for assets with very long lives is to adopt a renewal annuity approach. Under this approach, an amount is charged to the operating statement each year, sufficient to maintain the entire system of infrastructure operating at the same level of effectiveness in perpetuity. The level of the annuity payment is determined with reference to the current condition of the assets, and the future expenditure necessary to maintain the assets' operating capability.

The key to adopting a renewals annuity approach is the development of detailed asset management plans for infrastructure networks. The renewals annuity calculation depends largely on the availability of quality information, and on the condition and performance of the assets.

Proponents of the renewal annuity approach contend that it is a more tangible reflection of the consumption of the assets' service potential than a depreciation charge. Opponents argue that the task of assessing the probable course of renewal or repair work in the future introduces a degree of arbitrariness that renders the approach no more useful than standard methods of estimating accounting depreciation.

The Tribunal seeks comments on appropriate ways of reflecting reductions in service potential, or returns of capital to investors, in determining the revenue requirement.

6 PRICING ISSUES

6.1 Current structure of transmission network prices

The Tribunal's March 1996 Determination prescribed the structure of the charges which may be levied by TransGrid on the DBs. The revenue required from each distributor was calculated using the averaged Cost Reflective Network Pricing (CRNP) approach (see discussion of CRNP below). The transmission price to each distributor was structured to reflect the cost drivers. The DBs need not apply the same pricing structure as TransGrid when passing on transmission charges.

The structure of transmission prices has an impact on the incentives for demand management and embedded generation. A high fixed component will discourage users from implementing demand management initiatives. However, a high proportion of variable costs may encourage an inefficient level of embedded generation and limit the extent to which the network operator can recoup fixed costs.

Following discussions with TransGrid and the DBs, the Tribunal endorsed a in its 1996 Determination network pricing structure to DBs based on:

- fixed charge (50 per cent)
- demand charge (25 per cent)
- energy charge (25 per cent).

Cost reflective network pricing (CRNP)

The method of transmission pricing has been one of the more controversial aspects of the National Electricity Code. At present, the Code proposes a mixture of 'postage stamping' and cost reflective network pricing (CRNP). However, as required by the Code, NECA is currently reviewing these transmission pricing arrangements.

CRNP allocates the revenues based on the optimised deprival value of each asset and the modelled flow of electricity. As electricity flow varies from instant to instant, the modelling is based upon an engineering load flow algorithm. The load flow calculation is done for each of the connection points to the transmission system and each connection point would have a unique price. In its essence, CRNP is a sunk cost allocation model.

NECA has recently issued an options paper on network pricing which highlights the economic efficiency criteria for network pricing and assesses network pricing options against these criteria. Accompanying the options paper is a discussion paper which summarises more recent developments in transmission pricing overseas.

In its options paper, NECA notes that the current CRNP methodology possesses few of the main theoretical characteristics of efficient locational and congestion signals.

> CRNP looks backwards to the sunk cost of assets required to serve particular regions as a whole. It does not reflect the future costs of serving increments to load. This may provide a reasonable proxy for long-run average costs. Long-run average costs, however, are not relevant to efficient locational pricing within a network monopoly.

The outcome of the NECA review will be a critical input to the Tribunal's report.

Key issues in reviewing the current transmission pricing arrangements are:

- the relative weight to be given to the postage stamp and CRNP components – or alternative approaches to transmission pricing
- whether separate prices should be calculated for individual connections points and passed on to end-users.

The Tribunal previously expressed concerns that a strict application of the CRNP approach will often result in very high prices in areas with under-utilised assets, and low prices in areas with highly utilised assets, where congestion constraints may be imminent. If these prices were adopted, they would send perverse economic signals: consumption and additional connections would be encouraged in areas where the system is in urgent need of expansion, while in areas where there are under-utilised assets, users would be discouraged from increasing their consumption or connecting to the network. Congestion pricing, either for generation or transmission, would remedy this somewhat. However, concerns have been raised about the complexity of such approaches, especially if congestion pricing was added on to CRNP.

In its March 1996 Electricity Price Determination, the Tribunal considered the principles in the draft National Electricity Code, before adopting an averaged CRNP approach to determine the price of transmission. This was because a pure CRNP allocation would result in significant price disparities at each bulk supply point. The Tribunal was concerned that such variations could have significant effects in some communities (particularly those in remote areas or served by under-utilised assets) with little benefit, or possibly no benefit, to economic efficiency. As a result, the Tribunal required TransGrid to average the prices for connection points within each DB region. This was considered to reduce the variability in prices within regions. In addition, the Tribunal capped the price for Australian Inland Energy at the highest of the other DBs.

The Tribunal's experience in gas and electricity shows that there is a danger in applying a prescriptive fully distributed cost approach, such as CRNP, in the belief that it will deliver economically efficient prices.

The Tribunal's consideration of transmission pricing will have close regard to the outcome of the NECA review.

The Tribunal seeks comments on TransGrid's approach to price setting, the adequacy of the current disclosure mechanisms, and the appropriate involvement of the regulator.

6.2 Current structure of distribution network prices

The revenue cap limits total revenue, but does not determine prices to be charged to individual customers for use of the network. Within certain side constraints, the Tribunal has left responsibility for rate design and implementation largely to the DBs. Together with the responsibility for the monopoly to design its own price structures goes a responsibility to disclose information to the regulator and customers regarding the basis for setting prices.

The DBs have been required to advise the Tribunal of the cost of supply modelling underpinning the prices set. This information provides an opportunity for the Tribunal's Secretariat to raise any concerns with regard to the pricing approach. The DBs have also been required to provide the Tribunal with a medium term pricing strategy and to publish a booklet outlining to customers the basis of their pricing structures.

Fulfilment of the latter two requirements has not met the Tribunal's expectations. In several cases the medium term strategies supplied to the Tribunal have been quite perfunctory. With one exception, there have been lengthy delays in the preparation of information booklets by the DBs and the extent of disclosure varies.

As part of this review, the Tribunal requires the DBs to indicate in their submissions, their medium term pricing approaches, their revenue/cost assessments, and price levels that are proposed to apply over the term of this review.

Ensuring the DBs retain responsibility for pricing structures has a number of potential advantages. It increases the accountability of each DB and enables its pricing structures to better reflect its operating environment. The DBs have exercised this autonomy within broadly similar parameters for pricing.

However, the DBs' reluctance to provide supporting information on price structures raises the question of whether the regulator should become more involved in price determination. Options for the regulator could include strengthened requirements for public disclosure (including disclosure of the cost of supply modelling) and the establishment of parameters for pricing structures to ensure greater consistency in network pricing. The Tribunal is hesitant to determine individual customer prices. However, the Tribunal recognises the possible incentive for a DB to determine prices in a way that may not appropriately reflect the balance of interests of all its customers.

Another question in the marketplace concerns the appropriateness of demand-based tariffs for all contestable customers.[47] Particularly for low use and poor load factor customers, a move to a demand based tariff can result in sharp increases in the annual cost of electricity supply.

The Tribunal seeks comments on the extent to which demand-based pricing has given appropriate price signals to customers, and the extent to which these price signals have been effective in achieving their desired goals.

The Tribunal seeks comments on the DBs' approach to price setting, the adequacy of the current disclosure mechanisms, and the appropriate involvement of the regulator.

6.3 Current structure of franchise retail prices

As is the case for the distribution prices, the level and structure of franchise retail prices are largely under the control of each DB, but are subject to side constraints. As discussed in section 4.3, the retail revenue cap is reduced to reflect the number of customers eligible for contestability within each tranche. As with distribution prices, the franchise retailer must demonstrate to the Tribunal that the scheduled prices do not over-recover the regulated gross margin cap.

The 1995 restructuring of the electricity industry and amalgamation of the DBs meant the six DBs inherited a wide variety of tariffs and charges. In some cases, this diversity of tariffs remains, so that similar customers in a given distribution area pay significantly different prices for a similar service than is paid by others in the same franchise area. This has caused confusion among customers, and administrative complexity for the DBs. While some DBs

[47] That is, tariffs based largely on maximum demand, with little or no component of the charge varying with actual consumption.

want to standardise prices, others may prefer to offer a wide range of prices to reflect differing levels of service, between customers and between areas within the service territory.

The structure of prices can have a considerable effect on customers. Although current prices are predominantly consumption based, some DBs are progressively introducing demand-based tariffs to commercial customers. It is open to question whether very heavy reliance on a demand component may 'over-signal' the marginal network costs of higher demand levels. For customers with a poor load factor,[48] a demand-based tariff can result in sharp increases in the annual cost of electricity service, raising rate shock issues. Demand-based tariffs tend to disadvantage smaller customers, and those who cannot, for a variety of reasons, alter their consumption patterns.

The Tribunal seeks comments on the extent to which it should become involved in determining individual prices for franchise retail customers.

6.3.1 Side constraints

In order to reduce the incidence of rate shock to customers, the Tribunal imposes side constraints to limit the annual movement of distribution prices. For example, the franchise retail side constraints provide that no residential tariff can be increased by more than the greater of CPI or $5.00[49] per quarter.

Since the last review, the Tribunal has received complaints that the current side constraints are too restrictive to permit DBs to restructure tariffs to a 'cost-reflective' level. The Tribunal is concerned about tariff restructuring for several reasons. First, to the extent that a cross subsidy exists in the network tariffs, the time required to unwind that cross subsidy will be greater with more restrictive side constraints. On the other hand, the Tribunal is concerned to avoid excessive price shocks to customers. It also notes that the extent of cross subsidisation, if any, may be overstated by the use of fully distributed cost of supply models.

The Tribunal seeks comments on the appropriateness of the current side constraints, and whether any changes in their levels are required.

6.4 Other pricing issues

6.4.1 Unbundling of TUOS and DUOS

Several stakeholders have commented that Transmission Use Of System (TUOS) charges should not be recovered through the distribution network revenue cap, but should act as a 'pass through' cost, appearing separately on a customer's bill. The NECA network pricing review options paper has suggested that TUOS charges should be unbundled.

Unbundled transmission charges may signal more clearly to retailers and end users the costs of transmission. Currently, TransGrid's charges comprise a 50 per cent weighted fixed component, a 25 per cent weighted demand component, and a 25 per cent weighted throughput component. Several customers have commented that the translation of the

---

48 The load factor is a measure of the variability in the level of a customer's load over the course of a year, measured as average daily demand over maximum daily demand. A load factor close to 1 indicates that the customer uses approximately the same amount of electricity every day.

49 $7.00 for customers on off-peak tariffs.

multi-faceted transmission charge to a demand-based distribution tariff has inappropriately penalised low load factor customers.[50]

The Tribunal expects that this issue will be resolved through the NECA transmission pricing review. ***However, it seeks comments on the approach of passing transmission charges through to the customer, including suggestions regarding the mechanics of how such an approach might be implemented.***

6.4.2 Distributor-owned transmission assets

The definition of ‘transmission network’ in Chapter 10 of the National Electricity Code includes some assets owned by the NSW distribution businesses. Transmission network is defined in the Code to include:

a) any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network (‘parallel assets’);

b) any part of a network operating at nominal voltages between 66 kV and 220 kV that does not operate in parallel to and provide support to the higher voltage transmission network but is deemed by the Regulator to be part of the transmission network (‘non-parallel assets’).

The pricing of transmission network services is to be regulated under Parts B and C of Chapter 6 of the National Code. The pricing of distribution network services is to be regulated according to Parts D and E of Chapter 6.

It is possible for certain transmission assets to be regulated according to Parts D and E of Chapter 6. Clause 6.2.1(d) provides that, subject to the agreement of the ACCC and the relevant jurisdictional regulator, those portions of the transmission network operating at voltages of between 132 kV and 66 kV that do **not** operate in parallel with and provide support to the higher voltage network (ie, non-parallel assets as defined above) may be deemed to be subject to Parts D and E of Chapter 6 of the Code. In deciding which assets are to be covered by distribution service pricing regulation, consideration must be given to the practical desirability of aligning changes in regulatory coverage to changes in asset ownership wherever feasible. This should be considered in respect of transmission assets owned by distribution businesses.

As currently worded, clause 6.2.1(d) does not provide for parallel assets to be deemed to be subject to Parts D and E of Chapter 6. Instead, any parallel assets owned by the distribution businesses will be subject to regulation by the ACCC under Parts B and C of Chapter 6 (while the rest of the network is regulated by IPART under Parts D and E of Chapter 6). Potentially, a number of NSW distribution businesses will be subject to joint regulation by the ACCC and IPART.

A change to clause 6.2.1(d) has been proposed by EnergyAustralia. This change that would allow parallel assets to be deemed to be subject to:

- part D of Chapter 6 for the purposes of calculating the annual aggregate revenue requirement of the distribution business that owns the parallel transmission assets; and

---

[50] This may be an example of the problem of ‘double marginalisation’ which can lead to inefficient price signals with usage-related prices overstating marginal costs.

- part C of Chapter 6 for purposes of calculating prices in relation to parallel transmission assets.

In addition to the potential for inefficiency and problems relating to dual reporting obligations, the duplication of regulatory functions increases the potential for a utility company to game the regulatory regime to its advantage. Further, if DBs own transmission assets, the Tribunal will be concerned to ensure there is adequate ring fencing between the two segments of the DBs.

The Tribunal seeks comments on appropriate mechanisms for regulating transmission assets within distribution systems.

6.4.3 Network prices and cross subsidies

In the past, the Tribunal has allowed the network companies considerable freedom in the design of individual tariffs. The Tribunal has analysed those tariffs to ensure that they do not over-recover the approved revenue cap, and to ensure that cross subsidies are phased out while avoiding excessive rate shocks.

'Cross subsidy' is a frequently used, but often poorly defined term. Generally, a cross subsidy exists where one group of customers pays greater than its stand alone costs of supply, while another group of customers pays less than its incremental[51] cost of supply.

The cost of supply is the key issue. It is often difficult to assign costs to an individual group of customers, particularly as many of the costs are incurred in serving customers together. Joint and common costs are significant in network industries such as electricity distribution. The treatment of joint and common costs is relevant to the measurement of cross subsidies.

The Tribunal considers that care needs to be taken when defining cross subsidies. Fully distributed modelling of sunk costs does not provide a sound basis for determining cross subsidies and may overstate the extent of cross subsidies.[52]

There is increasing agreement that it is the avoidable, or incremental, costs that are most relevant to the economic measurement of a cross subsidy. Prices below incremental costs suggest an under-recovery of the economic costs of providing the service.[53] This is discussed in Baumol and Sidak:[54]

> A cross subsidy is present when the average incremental revenue contributed by a product of a firm is insufficient to cover its average incremental cost, but the firm nevertheless earns sufficient revenue from all its products to cover its cost of capital together with its other outlays.

---

51 Long run avoidable cost is often used as a proxy for incremental or marginal cost.

52 For fuller analysis, refer to Independent Pricing and Regulatory Tribunal, *Determination on Access Undertaking (as varied) of AGL Gas Networks Limited*, Report Gas 97-2, July 1997.

53 Changing market pressures can hold long-run prices below long-run incremental costs. In this case it is not efficient to attempt to lift prices to long-run incremental levels. However, while the service may continue to be offered in this short term, its long-run provision would not be commercially viable.

54 Baumol, W J and Sidak, J G (1994), *Toward Competition in a Local Telephony,* Cambridge, p 62.

Whilst the incremental cost approach is preferred in theory as "it assesses subsidies relative to a benchmark which would encourage efficient production and consumption decisions,"[55] it can be difficult to apply in practice.

Estimation of incremental costs requires extensive information that is not generally available from standard accounts. An alternative approach seeks to identify customer groups which may be funding a cross subsidy to other customer groups by paying prices which exceed the stand alone cost of supply. In the context of a customer's right to bypass, such information is of considerable commercial importance.

This raises to the concept of a range of prices that are subsidy free. A set of prices is said to be subsidy free if the price for each service is above average long run incremental costs and below the average stand alone cost.[56] The basis for these limits is usually discussed in terms of competitive pressures. Prices above the stand alone costs can be sustained in the long run only through the existence of entry barriers or other restrictions that prevent bypass. Thus prices above stand alone costs require the exercise of market power. With open entry, a customer cannot be charged more than the stand alone cost of supply, otherwise another business could enter the market and provide the service at a cheaper price.[57] Conversely, the incremental costs represent a minimum, since a business would not supply a customer that could not pay at least the incremental cost of supply. Otherwise, the business would improve its profitability by not supplying that customer.[58]

As part of its investigation into whether cross subsidies exist, the Tribunal will request and/or develop cost of supply models to determine the extent, if any, to which the revenues generated from any class of customers vary from the incremental, stand alone, or fully distributed costs attributable to that class.

The Tribunal seeks comments on approaches to assessing cross subsidies and to identify the possible magnitude of cross subsidies.

6.4.4 Negotiation of network prices

The 1994 Hilmer report envisioned a 'negotiate and arbitrate' regime. Negotiation of access prices plays an integral role in that regime. However, the Tribunal has received comments from industry participants regarding the network DBs' reluctance to negotiate access prices. The DBs have expressed concern at the potential loss of revenue through negotiation. The NECA review is considering this issue and its recommendations are expected to help the Tribunal improve the framework for negotiation.

The Tribunal seeks comments on the extent to which negotiation of network prices has been undertaken, and the extent to which specialist intermediaries have been involved in the negotiation process. The Tribunal also seeks comments on the extent of any further incentives or direction that may be required to encourage effective negotiation.

---

55 Australian and New Zealand Minerals and Energy and Council (1995), *Subsidies, Cross Subsidies and Community Service Obligations in the Public Electricity and Gas Utilities – Methods for identifying and measuring the costs*, Report No.95.04, Canberra, p 18.

56 Baumol, WJ, Koehn, MF, Willig, RD (1987), *How Arbitrary is Arbitrary?*, Public Utilities Fortnightly, Volume 120, No. 5.

57 This assumes easy market entry.

58 It is worth noting that Baumol, WJ and Sidak, JG, 1994, apply the stand-alone/incremental cost distinction to final prices, while in this case it is applied to the prices of an intermediate product.

6.4.5 Coverage of the network caps

Network caps were established in 1996 to provide for the costs (including a reasonable return) of the monopoly function of the networks at that time. In some cases, competition has been introduced (eg contestable capital works, section 7.6), or has not been introduced as quickly as anticipated (eg street lighting, section 7.1). This has necessitated some adjustment to the initial determination. Apparent inconsistencies in the practices of DBs have also become apparent (eg maintenance of connection assets, section 7.7).

It is anticipated that the scope of the monopoly network businesses will continue to narrow. Hence, it is important that the forthcoming determination be based on a clear and consistent definition of the monopoly network services. At the same time, it must provide a mechanism to adjust the cap to reflect changes in the scope of the monopoly businesses.

The Tribunal seeks comments on methods of improving clarity and flexibility in the coverage of the network caps.

7 OTHER MATTERS

7.1 Street lighting

In October 1997, the Tribunal engaged Coopers & Lybrand to examine the reasonable costs for street lighting services.[59] The C&L report recommends that the cost of using street lighting system assets be recovered through the network revenue cap. It also recommends a price freeze on street lighting charges in 1998/99 pending the longer term review. The Tribunal's preferred approach to street lighting services is outlined in a Tribunal paper released on 16 April 1998.

The Tribunal's current Determination on street lighting charges expires on 30 June 1998. The Tribunal will hold public hearings on street lighting issues on 20 August 1998.

The Tribunal seeks comments on the C&L report and its findings, and on street lighting matters under the Tribunal's purview.

7.2 Metering

A key issue for metering is contestability issues. As noted above, the 1996 Determination provided for metering to be included in the activities of the networks at that time. This meant the metering of customers was included as part of the network revenue cap. Contestability of metering services means that DBs, along with others, recover the costs for metering contestable customers from market determined prices.

The Tribunal seeks comments on whether the network caps should be adjusted to exclude the now contestable metering function, and if so, how. The Tribunal also asks the DBs to provide relevant data on the number and value of meters by customer class.

In establishing contestability for metering, separate roles have been established for metering providers, and metering data agents. These are distinct from the roles of the network and the retailer. The contestability of metering providers and metering data agents has the potential to provide competitive benefits. However, concerns about the complexity of these arrangements have been expressed to the Tribunal.

In regard to the contestability issue for low use customers, the Tribunal is interested in developments in metering and SCADA technology and cost. The Tribunal seeks information on the current limitations of metering technology, and questions whether time of use metering will be cost effective for low use customers in the near future. These issues are discussed in the SRCI report on Contestability.[60]

The Tribunal seeks comments on the implementation and effectiveness of metering contestability.

---

[59] The report of this consultancy is available electronically on the Tribunal's website, or on request from the Secretariat.

[60] Discussed in section 3.4.2.

7.3 Inset network regulation

An inset network (or inset appointment) is a distribution network that is provided with electricity from another distribution network, rather than from the high voltage transmission system. Since the last review, the Tribunal has fielded a number of requests regarding ways of regulating inset appointments. The proposals have raised concerns as to the price charged by the host network and any changes to the regulatory arrangements for the host which may be required. Licence conditions and prices charged by the inset networks are also issues of concern. Another issue is to ascertain the basis of retail contestability and pricing for customers served from an inset network.

Victoria’s Office of the Regulator-General (ORG) is currently investigating inset network issues. Interested parties are encouraged to review the ORG’s commentary on Powercor's application for a variation to its distribution licence to include the Docklands area. A discussion paper is available on the ORG website at www.reggen.vic.gov.au/docs/electric/docdis.pdf.

The Tribunal seeks comments on the regulatory approaches to inset networks.

7.4 Embedded generation

Embedded generation (ie local generation and cogeneration) can offer a number of advantages. It can increase the level of competition in the wholesale electricity market. Because it can displace the use of parts of the networks, it can also introduce competitive pressures on network pricing. Depending on location and energy source, it may also offer environmental advantages.

For these reasons, the Tribunal has the objective that, as far as possible, network regulation and pricing should not discourage local generation compared with other forms of generation or load management. In view of the variations in individual circumstances of embedded generation projects, the Tribunal has taken the view it is not possible to set standardised network tariffs. Hence, current arrangements rely on negotiated network access. The Tribunal has published *Guidelines for the Treatment of Embedded Generation* to assist the process of negotiating network access. The ACCC has proposed that this approach be incorporated in the Code. NECA will address this matter as part of its network pricing review.

The principle underpinning the guidelines is that any savings in transmission and distribution charges are available to be shared by the embedded generator and the host distributor for a fixed period rather than being automatically passed through to other network users. This is intended to provide a financial incentive for the DB to negotiate. The guidelines also foreshadow possible sanctions if negotiations fail, resulting in uneconomic bypass or higher net costs for customers. Protracted negotiations over access for some major embedded generation projects are a matter of concern. These guidelines have been supplemented by discussion papers on two sub-components of the network access charges: standby charges and connection charges.

The NECA review may have a substantial impact on the economics of embedded generation, affecting decisions on the sharing of transmission costs between loads and generation and the unbundling of transmission costs. The review discusses issues of standby charges, connection charges and negotiation. The outcomes of the NECA review will be an important element in the Tribunal's considerations.

The Tribunal seeks comments on the framework established for negotiating network access for embedded generation. In particular, it seeks comments on steps which could help promote the successful resolution of negotiations and/or alternative regulatory approaches.

7.5 Capital contributions

In its December 1996 Determination on capital contributions, the Tribunal stated that the customer requesting connection to the network should fund the connection assets used solely by that customer. Such assets are described as customer-dedicated assets.

Connection of a new customer may require augmentation of the existing network. Augmentation happens when the existing network system is expanded or its capacity is increased. Augmentation works usually benefit more than one user or customer of that distribution network. The Tribunal concluded in its December 1996 Determination that augmentation works should be funded by the distributor.

Distributors have expressed concern that the scope of the connection works which can be charged to customers under the Tribunal's capital contributions policy is too 'shallow'. Other customers have to fund upstream augmentations or the 'deeper' connection works required to service new loads.[61] Capital contributions to TransGrid are currently not regulated.

The Tribunal seeks comments on the reasonable allocation to the connecting customer/s and the network owner of costs arising from connection applications. The Tribunal also seeks comments on how capital contributions to TransGrid should be dealt with in the period from 1 July 1999.

7.6 Contestable works and monopoly fees

Contestability for customer connection works is scheduled under the Electricity Supply (Customer Contracts) Regulations, with implementation dates ranging from February 1997 to June 1998. Some questions have been raised about the effectiveness of the contestability of works. Customers and contractors have complained to the Tribunal that there is not equal competition, and have questioned whether the spirit of the Tribunal's determinations has been met.[62] Contractors and customers are also concerned to ensure that there is competitive neutrality. To achieve this, DBs must explicitly charge the various monopoly fees to their contracting arms and quote on an arm's length basis. The DBs have provided assurances that all contractors are treated equally. Notwithstanding this, the reservations expressed by the Tribunal in the December 1996 Determination have been brought to the fore.

The number and level of monopoly fees associated with contestable works levied by the network operators has also caused concern. These include fees for inspection, certification, and access. The Tribunal contends that these charges should not form barriers to entry for contractors, thus undermining the competition objective. The Tribunal is also concerned that these charges may offset the benefits of contestability to customers. This was the basis on which the Tribunal rejected requests for increases in such fees in the July 1997 review. On the other hand, the DBs have expressed concern that the current charges are not adequate to recover the costs of services necessary to support contestability.

---

[61] The Tribunal has determined that in exceptional circumstances, the customer may be required to fund augmentation costs. See page 16 of the 1996 Capital Contributions Determination.

[62] Determination 10, 1996 and Determination 5.4, 1997.

The Tribunal seeks comments from interested parties on the contestability of connection works, the appropriateness of monopoly services associated with contestable works, and the level of monopoly fees for such services.

7.7 Maintenance of connection assets

Since the release of its 1996 Determination, it has become clear to the Tribunal that there is considerable diversity in the application of policies for the maintenance of connection assets, both among distributors and within the service territories of individual DBs. The Tribunal believes that consistency of approach will be important to reducing customer misunderstanding and complaint.

In its 1994 Interim Report, the Tribunal raised the option of defining the point of customer connection more closely to the property boundary. It was expected that this would reduce the problems of under-recovery of rural tariffs. Through competitive pressure, it was also expected to reduce maintenance costs. This recommendation was largely opposed by the DBs of that time as being contrary to existing practice and, perhaps, leading to lower safety and reliability.

The Tribunal notes that some of the current six DBs have proposed that the customer be responsible for inspecting, maintaining and replacing customer-dedicated connection assets beyond the 'customer's terminals', as defined in the industry Service and Installation Rules.[63] This redefinition of maintenance boundaries would increase the maintenance responsibilities of the customer. It will therefore be necessary, to clarify the extent of the regulated network and the point of demarcation between the regulated assets and those falling within customers' responsibility.

In making its 1996 Determinations, the Tribunal provided for the pre-existing maintenance policies of each distributor in that distributor's network revenue caps. A change in the maintenance practices of the distributors would necessarily involve adjustments to the respective revenue caps to avoid the customer's paying twice. This would be achieved through normal network charges and through explicit maintenance charges.

The Tribunal seeks comments on these issues. Where changes to the scope of the regulated networks are proposed, it seeks comments and information on the consequent adjustment to network revenue caps and pricing policies.

7.8 Customer issues

7.8.1 Customer service standards

The Tribunal is concerned to ensure that adequate standards of service are established and maintained. The Tribunal believes it is appropriate to strive for some alignment among the DBs and also between electricity and gas distributors, so the electricity and gas distribution businesses are required to meet similar standards for similar responsibilities. The Tribunal recognises that there may be differences in the standards of service to allow for differing circumstances. For example, fault correction times may be shorter in urban areas than in rural areas.

[63] A current version of the Service and Installation Rules is available from the Electricity Association of NSW.

It should be noted that under the regulatory arrangements in place, the Tribunal does not set customer or service standards. However, the Tribunal needs to ensure that appropriate standards are set and enforced, and that the DBs have sufficient resources to meet the standards. Essential to this are adequate monitoring, reporting and public disclosure requirements supported by appropriate sanctions. Disclosure of maintenance and planning standards could contribute to a clearer understanding of customer service standards.

There is a clear relationship between standards of services and cost of service. Invariably, higher standards of service can be provided only at higher cost. While this trade off is keenly understood by network infrastructure owners and operators, it is often less appreciated by customers. Indeed, customers' appreciation has been hampered by a lack of clear indication regarding the 'standard' service, and the additional costs at which superior service may be provided.

The Tribunal considers that a clear definition of the basic service to be provided is essential to determining the appropriate level of revenue required to provide that level of service. In this regard, the Tribunal seeks comments on measures of service standards, and the level of service currently provided to customers. This will be a feature of the joint IPART/ Department of Energy Discussion Paper on Service Standards, discussed in section 3.4.2. This paper will focus on technical standards of electricity supply service, rather than on customer service standards.

The Government has implemented arrangements that will provide NSW electricity customers with a range of customer protection measures. The electricity consumer protection package consists of four key components to provide greater security for residential electricity consumers:

- guaranteed minimum standards of service, with rebates where standards are not met
- compulsory participation in the NSW Energy Industry Ombudsman Scheme for all licensed retailers and distributors
- mandatory disconnection procedures
- mandatory provision of social programs.

The Tribunal also wishes to investigate the possibility of guarantees of customer service, similar to those for the UK water utilities regulated by OFWAT and also for Sydney Water. The guarantees set customer service oriented standards, eg meter reading appointments kept on time. Performance of these standards would be benchmarked against other DBs and self benchmarked over time. The Tribunal is interested in comments regarding imposing financial penalties for failure to meet these standards.

The Tribunal seeks comments on the adequacy of the current performance standards and the processes by which standards are set and enforced.

7.8.2 Miscellaneous charges

The area of miscellaneous charges has been a matter of considerable customer complaints to the Tribunal. Complaints tend to focus on two issues: the introduction of new charges, and the level of charges.

Some distributors have claimed that as electricity services become unbundled and cost information becomes more accurate, the pricing of various components of electricity services have reflected this progress. For example, the supply availability fee may be 'new' to some customers. This fixed charge has been used as a means of recognising the fixed cost component in maintaining a customer's connection to the electricity supply, regardless of energy consumption. The use of electricity is charged separately according to the appropriate tariffs.

As discussed above, there has also been considerable confusion surrounding the 'monopoly charges' levied by network businesses for contestable connection works. These fees, such as safety inspection and contractor accreditation fees, will also be subject to review.

As part of this review, the Tribunal will undertake a thorough analysis of all miscellaneous charges.

The Tribunal seeks comments on the types and levels of miscellaneous charges that are appropriate for networks and franchise retailers to charge. The Tribunal also seeks comments on an appropriate suite of miscellaneous charges once the contestability timetable for retail energy, metering and customer connection works has run its course.

7.9 Separation of activities

The monopoly electricity distribution function is the major component, in terms of assets and profits, of the DBs' present activities. Stakeholders have stressed the importance of the regulator's ensuring that firstly, there are no monopoly rents in the distribution infrastructure business and secondly, that this major monopoly function does not give the DBs an advantage over competitors in their competitive activities. The robustness of the regulatory regime will depend, in part, on the adequacy of ring fencing provisions and of information collection and disclosure powers.

Ring fencing

Ring fencing is the clear separation of subsidiaries or divisions of a company that may have competitive advantages in dealing with each other. Strong ring fencing requirements may help ensure more effective on-going competition. The cost of this may be that the distributors are less able to achieve synergies from the integration of their business activities for the benefit of customers. These forces need to be balanced carefully. Especially in the early stages of the market, it may be appropriate to err on the side of protecting the integrity of the competitive framework.

The Tribunal is concerned to ensure that adequate ring fencing arrangements are in place to separate the monopoly business from any related contestable business. Accounting separation is insufficient; significant personnel and corporate culture changes may be required to implement an effective ring fencing regimen. The Tribunal is also conscious that compliance with ring fencing requirements may need to be monitored, and seeks comment on the form that compliance monitoring might take.

The Tribunal notes that the ACCC has requested modifications to the Code to strengthen the ring fencing provisions. It further notes that provisions in the National Gas Third Party Access Code are considerably stronger than the current electricity requirements. The Tribunal also notes that the NSW distribution licences include ring fencing provisions that empower the Minister for Energy to require legal separation of entities.

The NSW Distribution Boundary Review Committee examined the ring fencing of DBs' network and retail functions and considered a range of ring fencing options: accounting separation, organisational separation, legal separation and structural separation (ie cross-ownership restrictions). The ring fencing regime currently in force in NSW requires accounting separation.

The Committee noted that the introduction of ring fencing arrangements in the electricity industry similar to those contained in the Gas Code is supported by the ACCC and others on the grounds of competitive neutrality and the increasing convergence of the gas and electricity industries (as is noted above). The ring fencing arrangements contained in the Gas Code require legal separation. The Committee noted that, in the electricity industry, the retailer of last resort requirements oblige the network distributors to undertake retail functions whereas such a provision does not exist in the gas industry. Further, the Committee considered that "the commercial incentives for preferential dealing, information sharing, transfer pricing and distortions in cost allocation will be the same irrespective of whether the regulated and non-regulated businesses are carried out within the same organisation or by related but legally separated corporations."[64]

The Committee stated that effective ring fencing requirements should be established and should include:

- rules for the accounting separation of separately regulated activities and non-regulated activities
- rules in respect of the methodologies by which common and shared costs are allocated between regulated and non-regulated activities
- rules requiring non-discriminatory treatment of related and third-party businesses by the regulated network businesses.

The Tribunal seeks comments on ring fencing requirements.

7.10 Environmental issues

Parts B and D of Chapter 6 of the National Electricity Code contain a number of requirements relevant to environmental issues. The Code provides that the regulation of distribution service pricing is to be administered according to a set of principles, one of which is that the Jurisdictional Regulator is to have regard to the need to "create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration"[65].

The Code also requires that the distribution service pricing regulatory regime must seek to achieve a number of outcomes, which include "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."[66] This clause would appear to be broad enough to allow the regulator to consider environmental issues.

The draft Terms of Reference of the major electricity review being conducted under section 12A of the *IPART Act* require that IPART report on the impact of the proposed regulatory regime on the factors listed in section 15 of the *IPART Act*. These factors include:

---

64 Distribution Boundary Review Committee, Final Report, June 1998, p 4 and 68.

65 Clause 6.10.3(e)(2). Clause 6.2.3(d)(2) contains the equivalent objective in relation to the regulation of transmission aggregate revenue.

66 Clause 6.10.2(k). See Clause 6.2.2(k) for the equivalent requirement in relation to the transmission network regulatory regime.

- s15(1)(f) "the need to maintain ecologically sustainable development (within the meaning of section 6 of the *Protection of the Environment Administration Act 1991*) by appropriate pricing policies that take account of all feasible options available to protect the environment"; and
- s15(1)(j) "considerations of demand management (including levels of demand) and least cost planning".

Distribution and retail licences[67] impose environmental conditions. Distribution licence conditions require distributors to carry out investigations to ascertain whether it will be cost effective to avoid or postpone proposed network expansion by implementing demand management strategies. The retail licence conditions require retailers to develop strategies for greenhouse gas reduction, energy efficiency, demand management and purchases from sustainable energy sources.

As part of its March 1996 Electricity Pricing Determination, the Tribunal introduced revenue regulation for the distribution and retail supply industries. Price regulation creates a disincentive for DBs to contract for energy efficient services, even where this is a lower cost way of meeting users' energy needs. By greatly reducing the link between electricity sold and revenue, revenue regulation also reduces the bias against energy efficiency under price regulation. The form of regulation is discussed more fully in section 4.

As part of the March 1996 Determination, the Tribunal also provided that the premium paid by customers for 'green power' would not form part of DBs' retail margin caps. Green pricing in electricity supply involves a DB offering its customers an opportunity to buy 'green electrons'. If a customer agrees to pay an additional amount on his or her bill, the DB will in turn invest in renewable energy technologies and meet a proportion of the customer's demand using these technologies.

Depending on its location and energy source, embedded generation may offer environmental benefits. Consequently, it is important that price regulation not hinder the establishment of economic generation. Equally, regulation should not be used to prop up uneconomic generation. For a further discussion on embedded generation pricing issues, see section 7.4.

Issues associated with least cost planning[68] by DBs will be considered by the Tribunal when it reviews past and future capital expenditures. The Licence Compliance Advisory Board will also address least cost planning when assessing whether distributors comply with licence conditions. A code of practice regarding network investment and demand management is currently being developed by the industry under the auspices of the Department of Energy, the license regulator.

The Tribunal seeks comments on environmental and least cost planning issues.

67 Licences are issued and administered by the Minister for Energy.

68 Least cost planning is a process of examining all energy saving/energy providing options to select a mixture of options that minimises total distributor costs.

8 INFORMATION GATHERING AND DISCLOSURE

8.1 Information gathering

In the past, the Tribunal has identified issues and left the substance of the DBs' submissions largely to the judgement of each DB's management. This philosophy remains in place, but the Tribunal has found that this approach has resulted in its receiving inadequate and inconsistent information. In this review, the Tribunal plans to provide clear guidelines to the DBs regarding the types of information it requires a DB to submit in order for the Tribunal to carry out its tasks.

The Tribunal has been examining regulatory information requirements in other jurisdictions. Whilst there is some disparity between regulators, it is clear that a standard set of regulatory accounts is an important tool for many regulators. While the Tribunal currently receives a standard set of regulatory accounts from the DBs, these accounts are aggregated at a high level, and are also of a historical, rather than forecast nature. The Tribunal is currently investigating the costs and benefits associated with providing a more detailed suite of regulatory accounts that includes forecast data.

The Tribunal seeks comments from interested parties on the costs and benefits associated with a standard set of regulatory accounts for the electricity DBs, and on what form those accounts might take.

8.1.1 The Tribunal's requirements of the utilities' submissions

In the past, the Tribunal has accepted submissions from the DBs that have not provided complete or comparable sets of information. For example, not all the DBs have provided information about pricing structures and approaches in their submissions. The Tribunal asked the DBs to produce information booklets outlining the derivation of their individual tariffs. The DBs' response to this request was, with one exception, disappointing. In this Issues Paper, the Tribunal lists expectations of the DBs' submissions.

The Tribunal encourages the DBs to file this information on the public record. As with submissions from interested parties, the Tribunal may give greater weight to information placed on the public record which has been subjected to review and testing by other stakeholders.

8.2 Information disclosure

Just as important as information gathering, is the question of information disclosure. Generally, the companies regulated by the Tribunal are comfortable with providing the regulator with most types of information requested. However, the regulated entities are very reticent about providing information to the public in general, and to users in particular. The Tribunal is of the view that the regulatory process can be aided by informed analysis and comment from industry participants. However, this must be balanced by the regulated entities' need to operate as commercial organisations and their need to protect certain valuable information.

For the purposes of conducting the section 12A reference, IPART's information gathering and disclosure powers will be governed by the *IPART Act*. Section 22(1) of the IPART Act requires the Tribunal to make a document available for inspection on request by any person, unless the document is an exempt document within the meaning of the *Freedom of Information Act 1989*.

Section 22(2) of the *IPART Act* provides that the Tribunal may “make a document available for inspection on request by any person who the Tribunal considers has an interest in the investigation to which the document relates, despite the fact that the document is an exempt document within the meaning of the Freedom of Information Act 1989…” However, s22(2)(c) provides that the Tribunal may only do this if it “is satisfied that making the document available could not reasonably be expected to damage the commercial or other interests of the State or of the person that gave it to the Tribunal …”.

The Tribunal may, in making a document available under s22, make only parts of the document available, delete parts of the document before release or impose conditions on the availability of part or all of the document.

The Tribunal seeks comments on an appropriate level of information disclosure by TransGrid and the DBs under its jurisdiction.

APPENDIX 1 - INVESTIGATION ADVERTISEMENT

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

Special Reference on Electricity

The Tribunal has been given a Special Reference on Electricity by the Premier under Section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992*.

Draft Terms of Reference

Having regard to the need to effect a smooth and reasonable transition to a national electricity market and the following developments affecting the State's electricity industry:

- Any changes to the boundaries of the State's electricity supply businesses;
- Delays in the commencement of the national market;
- Issues raised by the NECA network pricing review and the ACCC Statement of Regulatory Intent on transmission pricing under the National Electricity Code;
- The jurisdictional regulators review of distribution pricing under the National Electricity Code;
- The timetable for retail contestability in NSW; and
- The State based regulatory arrangements for the electricity industry, including any reset principles advised by the Government;

the Tribunal is to report on appropriate pricing of:

(a) Government monopoly electricity transmission and distribution services (provided by TransGrid and energy distributors) for the five year period from 1 July 1999; and

(b) Government monopoly electricity services provided to franchise customers (by energy distributors) for the period from July 1999.

The report's recommendations are to be based on the National Electricity Law and National Electricity Code with the objectives of protecting the long term commercial value of the affected businesses for the benefit of the State's taxpayers and the long term interests of the customers of these businesses. The report is to have regard to:

1. The State's obligations under national competition policy;
2. The efficient cost of supplying the relevant services and future capital expenditure requirements;
3. Transitional arrangements for any price changes;
4. Service quality (including reliability) taking into account the potential for network service providers to offer price / quality trade offs above minimum standards;
5. The Government's targeted average 20% real price reduction target for the industry as a whole;
6. The form of the regulatory arrangements including the incentive structures established by the existing and alternative arrangements;
7. The ACCC's Statement of Regulatory Intent for the Regulation of Transmission Revenues;
8. Comparable interstate arrangements; and
9. The matters set out in Section 15(1) of the *Independent Pricing and Regulatory Tribunal Act 1992*.

The Tribunal is to investigate and report no later than 30 April 1999.

Comments on the Draft Terms of Reference

Comments on the draft terms of reference should be received by the Tribunal by 6 July 1998 (Ref 98 / 144).

For information please contact Mr Scott Young, Program Manager Electricity; tel:(02) 9290-8404, fax 9290 2061, email - *scott_young@ipart.nsw.gov.au*.

Thomas G Parry	National Mutual Centre	P.O. Box Q290
Chairman	44 Market Street	QVB Post Office
19 June 1998	SYDNEY NSW 2000	NSW 1230

Appeared in the *Sydney Morning Herald* on Friday 19 June 1998

Note: these terms of reference are to be finalised upon settling advice from the Premier.

APPENDIX 2 - INFORMATION REQUIREMENTS

The following information must be supplied for each business segment within the regulated company as well as for the company as a whole, with regulated and unregulated businesses separated. For example, information must be shown for the distribution company as a whole, for the network regulated business, network unregulated business, retail supply (franchise business), and the retail supply (unregulated business). The disaggregrated accounts must reconcile with the audited statutory accounts. Any required reconciliation is to be provided with the accounts. A substantial amount of the financial information could be sourced from the audited regulatory accounts.

General company information

- List of all associated / affiliated companies with a description of the scope of their activities (regulated and unregulated).
- Description of how ring fencing works within the organisation.
- Current organisation chart.
- Description of how services are charged between related business units, ie transfer prices.
- Schedule of related party transactions, identifying the nature of transactions, amount, basis of determining amount, and related entity.
- Corporate plan.
- Performance agreement with shareholders or statement of corporate intent.
- Description of asset valuation methodology used for financial reporting and regulatory purposes, if different.
- Description of cost allocation methodology.
- Cost of supply methodology.

General financial information

- Profit and loss account – current year plus 5 year forecasts.
- Balance sheet – current year plus 5 year forecasts.
- Cash flow – current year plus 5 year forecasts.
- Capital expenditure forecasts – 20 years.
- Debt and interest profiles – plus 10 year forecast

Information in support of the level of the network revenue or price cap

Asset valuation

The valuation of the DB's assets, by major voltage and function class, indicating:

- The historical cost of the assets, and the depreciation taken on those assets to date

- The valuation of the assets at the last review, rolled forward by year to reflect capital expenditures, depreciation, and adjustments to derive the asset valuation in the current submission
- Details of contributions for capital works – past and future
- Committed capital works and capital investment
- Description of the nature and justification for planned capital investment
- The level of capital contributions and treatment of assets funded by customer and developer contributions
- Assets previously included as monopoly network assets (eg meters) which are now part of the DB’s contestable business
- Identification of any assets which are shared between the monopoly network business and other business units, and the basis of that allocation.

Rate of return

- The requested Weighted Average Cost of Capital (WACC), and supporting information for that WACC, including the Capital Asset Pricing Model inputs of risk free rate, beta value, and market risk premium, the DB's capital structure, the DB's cost of debt, and other supporting information.

Depreciation

- Depreciation expense by major voltage and function class, indicating the method of depreciation, average asset life, and a comparison of depreciation expense for tax or tax equivalent purposes.
- Assumptions on the economic life of assets for depreciation.

Operating costs

- Details of the cost of goods/services sold.
- Operating costs by major function (distribution maintenance, transformer maintenance, metering, billing, administration) by year, indicating the amounts at the last review and the amounts for each year between reviews.
- Staff numbers.
- Wages and salaries – by major function (distribution maintenance, transformer maintenance, metering, billing, administration) by year, indicating the amounts at the last review and the amounts for each year between reviews.
- Marketing costs.
- Total overhead costs.
- Assigned corporate overheads, indicating the total amount of the corporate overhead, the amount assigned to each operating business, and the basis and calculation of that allocation (the amounts allocated to each operating business may be included in a commercial in confidence appendix to the submission).

Requested revenue or average price cap

- The DB's requested revenue or average price cap, as developed from these inputs, reflecting the effects of any under/over adjustments, and calculation of the under/over amount.

Translation of revenue or average price cap to tariffs

- A revenue analysis, indicating the amounts and proportions of revenues derived from each customer class (domestic general, domestic hot water, etc) and each type of charge (fixed, demand, volumetric).
- Description of methodology applied to derive tariffs, major drivers in the application of that methodology - level of tariffs that would result from applying that methodology to the requested revenue cap.
- The DB's proposed medium term price path, clearly indicating the current level of tariffs, and proposed structure and level changes for the next five years.

Operating statistics

Relevant operating statistics by year since the last review and forecast as appropriate, including:

- description of system capabilities
- map of network
- a customer profile, indicating the number of customers of each class and the contribution of each customer class to system peak, total load, etc by calendar month
- km of lines in service, by type
- km of lines constructed, by type
- load by peak/shoulder/off peak by month
- description of service territory, including information on customer density, urban/rural make up.

Performance statistics

Relevant performance statistics by year since the last review, including:

- number of outages by duration - planned vs unplanned
- average duration of outages - urban vs rural
- new customer connection time
- contestable customer transfer time
- other relevant performance statistics
- number of customer complaints by year since the last review, by major category (eg service quality, metering problems, bill too high, tariff structure, contestable works, maintenance charges on assets on private land, contestable works, capital contributions)
- copy of current customer satisfaction survey.

Miscellaneous charges

- A schedule listing the miscellaneous charges levied by the network since the last review.
- Revenues raised from each of those miscellaneous charges, by year.

Information in support of the level of the retail gross margin or average retail prices for franchise customers

Revenue cap and tariffs

Cost, revenue cap and tariff information consistent with that requested above for the network business.

Customer information

- Number of customers and related load in the franchise area scheduled to become contestable on 1 July 1998 and 1 July 1999, by tranche.

Retail cost information

Additional information supporting the calculation of the RGM cap, including, for each tranche of franchise customers:

- Electricity purchase cost
- Cost of losses
- NUOS charges
- Market fees
- Method of allocating these costs among the customer groups
- Retail price (ie the price applicable to the customer prior to contestability.

Requested revenue or average price cap

Description and quantification of capital costs associated with the retail business, including:

- any asset related costs and working capital costs
- description of assets and basis of asset valuation, rate of return, depreciation, useful life of assets, etc.

The DB's requested revenue or average price cap, as developed from these inputs, reflecting the effects of any under/over adjustments, and calculation of the under/over amount.

An assessment of the sustainable level of competitive margins in the electricity retail business, or an assessment of the required returns on capital invested.

Translation of revenue or average price cap to tariffs

- A revenue analysis, indicating the amounts and proportions of revenues derived from each customer class (domestic general, domestic hot water, etc) and each type of charge (fixed, demand, volumetric).
- A customer profile, indicating the number of customers of each class and the contribution of each customer class to system peak, total load, etc.

- Description of the methodology applied to derive tariffs, major drivers in the application of that methodology - level of tariffs that would result from applying that methodology to the requested revenue cap.
- The DB's proposed medium term price path, clearly indicating the current level of tariffs, and proposed structure and level changes for the next five years.

Operating statistics

Relevant operating statistics by year since the last review and forecast as appropriate, including total load by peak / shoulder / off peak by month.

Customer complaints

Number of customer complaints by year since the last review, by major category (eg service quality, metering problems, bill too high, tariff structure, contestable works).

Miscellaneous Charges

A schedule listing any miscellaneous charges levied by the retailer since the last review, the number of occasions on which each charge has been levied, and the revenues raised from each of those miscellaneous charges, by year.