REGULATION OF NEW SOUTH WALES ELECTRICITY DISTRIBUTION NETWORKS

Determination and Rules Under the National Electricity Code

December 1999

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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December 1999

The Tribunal members for this review are:

Dr Thomas G Parry, Chairman
Mr James Cox, Full time member

This publication comprises two documents:

The Tribunal's determination on
Regulation of New South Wales Electricity Distribution Networks
under the National Electricity Code

Rules made by the Tribunal under clause 9.10.1(f) of the National Electricity Code

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Determination
Under the National Electricity Code

December 1999

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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FOREWORD

The Tribunal has issued this determination under the National Electricity Code (the Code). The Code became effective in December 1998, facilitating the introduction of the national electricity market. The Tribunal is the first regulator to issue a determination for distribution network service providers (DNSPs) under the Code. This has not been an easy task. The Code is riddled with inconsistencies and deficiencies that made our task far more difficult than it should have been.

In this determination the Tribunal establishes the annual revenue requirements for the six electricity DNSPs in New South Wales for the period from 1 February 2000 until 30 June 2004.

The Tribunal's determination will result in real price reductions for distribution service charges of 16 per cent on average over the next five years. Reflecting the benefits of greater volumes and rapid growth, customers of Integral Energy and EnergyAustralia, on average, will benefit from real reductions of around 27 per cent and 16 per cent, respectively. Because of the higher cost environment within which rural DNSPs operate, their customers will not enjoy the same level of price reductions as the metropolitan DNSPs. Average price movements will be limited to inflation or reducing in real terms.

The six distribution network service providers are public utilities owned and operated on behalf of the residents of NSW by the State Government. In protecting the value of the DNSPs, the Tribunal has had regard to the interest of the owners for the benefit of the taxpayers and residents of the State.

NSW taxpayers will benefit from the profits and tax equivalent payments made by the DNSPs. At the same time, the Tribunal has considered electricity customers, whose interests are best served by long-term, sustainable and efficient cost-reflective network prices.

In its deliberations, the Tribunal has attempted to seek an appropriate balance of the interests of both the owners and the users of electricity services in NSW. The outcomes determined in this report are very much underpinned by robust growth projections (particularly in the metropolitan areas) and a declining rate of return, offset by an increase in the value of the businesses' regulatory asset base.

The Tribunal has established four sets of rules under clause 6.10.1(f) of the Code that DNSPs must comply with. The rules relate to:

- unders and overs accounts
- pricing notification and information disclosure
- charges for miscellaneous services
- charges for monopoly services to support contestable works.

I would like to thank the organisations and individuals that contributed to this review process.

Thomas G Parry
Chairman
December 1999

EXECUTIVE SUMMARY

Background and legislative basis for determination (chapters 1 & 3)

The Independent Pricing and Regulatory Tribunal (the Tribunal) issues this determination under the National Electricity Code (the Code). The Code became effective in December 1998, facilitating the introduction of the national electricity market.

The Tribunal is the first regulator to issue a determination for distribution network service providers under the Code. This has not been an easy task. The Code is riddled with inconsistencies and deficiencies. The Tribunal is concerned that the Code may inhibit the development of better regulatory outcomes.

The Tribunal was granted a derogation from part E of chapter 6 of the Code. Part E of chapter 6 relates to pricing principles, but the Tribunal felt that the guidelines had undesirable outcomes.

This Tribunal had regard to analysis presented in its June 1999 report addressing the reference issued by the Premier under section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992* (IPART Act).

In making this determination, the Tribunal has considered numerous objectives and principles outlined in various clauses under the Code.

The outcomes of this determination are underpinned by:

- robust growth projections (particularly for metropolitan areas)
- a declining rate of return
- increasing regulatory asset values.

Pricing outcomes (chapter 9)

The Tribunal establishes the base revenue requirements for each of the six electricity distribution network service providers (DNSPs) in New South Wales for the period from 1 February 2000 until 30 June 2004. Distribution services constitute around 40 per cent of a typical electricity account.

Table 1 Base revenue requirements ($m)

	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
EnergyAustralia[1]					
Building Block	674	692	710	730	752
Smoothed	691	706	721	736	752
Integral Energy					
Building Block	388	398	407	415	419
Smoothed	395	401	407	413	419
NorthPower					
Building Block	186	194	200	208	215
Smoothed	170	180	191	203	215
Great Southern Energy					
Building Block	117	122	126	129	132
Smoothed	113	117	122	127	132
Advance Energy					
Building Block	87	90	92	95	97
Smoothed	74	78	82	87	92
Australian Inland Energy					
Building Block	14	14	15	15	16
Smoothed	11	12	12	13	13
Industry Total					
Building Block	1466	1510	1550	1592	1631
Smoothed	1454	1494	1535	1579	1623

Table 2 Cumulative real reductions in network prices, 1999/00 to 2003/04

DNSP	Real reductions, 1999/2000 to 2003/04 (%)
EnergyAustralia[1]	16
Integral Energy	27
NorthPower	0
Great Southern Energy	6
Advance Energy	0
Australian Inland Energy	0
DNSP total	**16**

1 Includes costs and revenues for transmission services as determined by the ACCC.

Asset values (chapter 6)

The six DNSPs are public utilities owned and operated by the NSW Government on behalf of the residents of NSW. In balancing the interests of stakeholders, the Tribunal has had regard to:

- the value of the business for the benefit of the tax payers and residents of the state
- pricing outcomes for electricity users.

The regulatory asset base includes the initial capital bases and working capital. The regulatory asset bases at 30 June 1998 are as follows:[2]

Table 3 Initial capital bases as at 30 June 1998

DNSP	Initial capital base ($m) [3]
EnergyAustralia[1]	3,767
Integral Energy	1,732
NorthPower	858
Great Southern Energy	515
Advance Energy	303
Australian Inland Energy	50
DNSP total	**7,225**

1: EnergyAustralia's initial capital base includes its transmission assets.

The Tribunal wishes to emphasise that in its deliberations on the initial capital base it considered, among other issues, the government ownership of the DNSPs. This accords with the requirement of the Code that provides for the regulator to have regard to the pre-existing asset valuation policies for government-owned DNSPs. This decision does not bind the Tribunal's future regulatory decisions on initial capital bases for the electricity industry or any other industry.

Rate of return (chapter 5)

The cost of capital is an important ingredient in determining revenue streams. It is applied to the entire capital base of each utility and to new investment throughout the regulatory period.

For the purposes of calculating base revenues for the NSW DNSPs over the regulatory period, the Tribunal has determined that a real, **pre-tax rate for return of 7.5 per cent** is appropriate. This is consistent with a nominal post tax return on equity of approximately **11 to 12 per cent.**

[2] Financial modelling is based on 1998/99 figures.
[3] Includes streetlighting assets.

In its June 1999 s12A report the Tribunal states that the rate of return for Advance Energy and Australian Inland Energy should have a 25 basis point premium over the rate of return for the other DNSPs. Having reconsidered the associated risks. The Tribunal can no longer justify the premium, especially in the context of the straight revenue cap, now to be applied.

The Tribunal has applied a pre-tax nominal rate of return of 7.6 per cent to working capital.

Regulatory framework issues (chapter 3)

Form of regulation

The Tribunal has adopted a straight revenue cap, supported by a glide path, which allows the DNSPs to share the benefits of out-performance with customers over time.

Limits on price movements

The Tribunal has protected customers from large increases in the network component of their electricity accounts. Average prices across the network must not increase by more than CPI. To allow price restructuring, a residential customer's network bill cannot increase by the greater of CPI plus 2 per cent or $30 if that customer consumes the same amount of energy in the same pattern as in the corresponding period the previous year.

Standards of service

The Tribunal has not included a service reliability incentive mechanism in this determination due to a lack of adequate data. However, the Tribunal intends to work with stakeholders to develop its treatment of standards of service.

Capital contributions

The customer capital contributions issue is contentious. The Tribunal has been working with stakeholders to develop a workable solution. Unfortunately, the issue has not been resolved in this determination's timeframe and the Tribunal has made no decision on capital contributions in this determination. When this issue is resolved the Tribunal will issue a decision on capital contributions.

Rules under clause 6.10.1(f) of the Code

As part of a separate document, the Tribunal has established four sets of rules under clause 6.10.1(f) of the Code. The rules relate to:

- unders and overs accounts
- pricing notification and information disclosure
- charges relating to miscellaneous services
- charges relating to monopoly services.

DNSPs must comply with these rules.

SUMMARY OF DETERMINATION

What follows is a summary of the Tribunal's determination. It should be used and relied on only in conjunction with the full determination that follows.

Definition of prescribed services

It is the Tribunal's determination that, for the purpose of clause 6.10.4, 'prescribed distribution services' are those services performed by each DNSP that are associated with or ancillary to access to that DNSP's network for the supply of electricity within that DNSP's service area.

Length of regulatory period

The Tribunal has determined a revenue path for the NSW DNSPs effective from 1 February 2000 until 30 June 2004.

For the 1999/2000 financial year the revenue will comprise the (rolled forward) 1997 determination pro-rated for the period from 1 July 1999 to 31 January 2000, and this determination, pro-rated for the period from 1 February 2000 until 30 June 2000. Pro-rating will be on the basis of calendar days covered by each determination.

If a new determination is not issued to take effect from 1 July 2004, all charges for prescribed services must continue unchanged from the level at 30 June 2004 until a new determination takes effect.

Approach to setting revenue

The Tribunal has adopted a building block approach to determining base revenue requirements, supplemented by analysis of pricing outcomes and a range of financial indicators. The building block approach sets the base revenue requirement as the sum of estimated efficient operating costs, depreciation (return of capital) and a risk adjusted return on capital.

In this determination the Tribunal has adopted a fixed revenue cap and allows a glide-path[4] of base revenue gains and losses using 1998/99 as a base year. The base revenue set in this determination covers the efficient costs of providing prescribed distribution services.

The annual aggregate revenue requirement (AARR) that the DNSPs can collect will include the glide-pathed base revenue as established by the building blocks, together with:

- transmission charges and payments for network services made to other DNSPs. These payments may be subject to a prudency test if payments are not between unrelated parties at published regulated charges
- avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through an examination of avoided network costs
- payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.

[4] A glide path allows a company to retain some of the benefits of its additional efficiency gains over the subsequent regulatory period(s).

- contestability costs as determined by the Tribunal
- an amount to rectify unders and overs account balances
- the net impact of the GST.

The AARR is not subject to glide pathing. Rather, the base revenues are glide-pathed.

EnergyAustralia's base revenue includes incomes received under the ACCC determination for transmission services.

Contestability costs

Once the framework for contestability is known and the Tribunal can estimate the costs with reasonable certainty, it will publish a decision on the reasonable costs of contestability and add these costs to the AARR set in this determination. The Tribunal will index contestability costs by CPI-X in subsequent years.

Indexation of revenues and GST pass through

To derive the base revenue throughout the regulatory control period the Tribunal will apply the percentage change CPI figure (defined below) to the regulated revenues.

The Tribunal will incorporate the effect of the GST through a one-off indexation of revenues by the Goods and Services Tax (GST) as defined in *A New Tax System (Goods and Services Tax) Act 1999*. This indexation will exclude the economy-wide impact of the GST but include an estimate of the specific impact of the GST on each DNSP.

This can be expressed as:

$$\text{Base revenue}^{00/01} = \text{base year}^{5} \text{ base revenue}^{99/00} * (1+CPI - X) + \text{net GST}^{\text{ util.}}$$
$$\text{Base revenue}^{01/02} = \text{base revenue}^{00/01} * (1+CPI^{-GST} - X)$$
$$\text{Base revenue}^{02/03} = \text{base revenue}^{01/02} * (1+CPI - X)$$
$$\text{Base revenue}^{03/04} = \text{base revenue}^{02/03} * (1+CPI - X)$$

where

CPI^{-GST}	=	CPI minus the estimated impact of GST package on the CPI
$netGST^{\text{ util}}$	=	net $ change in tax position by the utility under the GST package
CPI	=	year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter (retrospectively).

The revenue rolled forward is the revenue resulting from the building blocks (and published in this determination), not the actual revenue collected in the previous year.

The Tribunal will require an audit of the changes in costs under the GST package, at the expense of the DNSPs. In consultation with the industry, the Tribunal will establish procedures for this audit. Each DNSP will be required to obtain the Tribunal's agreement on the consultant to be appointed.

5 The base year base revenue is the 1999/2000 base revenue as determined by the building blocks in this determination. It is not the pro-rated revenue cap for 1999/2000.

Unders and overs account balances

The DNSPs are required to comply with 'Unders and overs accounts, Rule 99/1', which sets out provisions and requirements for unders and overs accounts. The Tribunal issued this Rule under clause 6.10.1(f) of the Code.

Limits on price movements

Average prices across the network[6] must not increase by more than CPI. To allow restructuring, increases in the standard periodic bills[7] of any residential customers (including rural residential customers) for the same pattern and volume of electricity consumption must not exceed the bill for the corresponding period of the preceding year by more than the greater of CPI plus 2 per cent or $30. Network prices for the same pattern and volume of electricity consumption for residential customers (including rural residential customers), must not exceed the CPI plus 2 per cent, exclusive of the impact of the GST plus net GST impact (expressed as a percentage of the pre-GST total costs) on each DNSP in 2000/01. To illustrate the CPI limitation:

$\text{residential network tariffs}^{99/00} \leq \text{residential network tariffs}^{98/99} * (1+\text{CPI})*1.02$
$\text{residential network tariffs}^{00/01} \leq \text{residential network tariffs}^{99/00} * (1+\text{CPI})*1.02 + \text{net GST}^{\text{util.}}$
$\text{residential network tariffs}^{01/02} \leq \text{residential network tariffs}^{00/01} * (1+\text{CPI}^{-\text{GST}})*1.02$
$\text{residential network tariffs}^{02/03} \leq \text{residential network tariffs}^{01/02} * (1+\text{CPI})*1.02$
$\text{residential network tariffs}^{03/04} \leq \text{residential network tariffs}^{02/03} * (1+\text{CPI})*1.02$

where

CPI	=	year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter
$\text{CPI}^{-\text{GST}}$	=	CPI minus estimated impact of GST package on the CPI (in percentage terms)
$\text{netGST}^{\text{util}}$	=	net change in tax paid by the utility under the GST package, expressed as a percentage of total pre-GST costs
residential network tariffs	=	DNSP-specific average residential network tariffs as at 30 June of the relevant year.

These price limits are to apply to all DNSPs, except where the DNSP can demonstrate to the Tribunal that changes to transmission prices resulting from the expiration of the derogation on transmission prices prevent DNSPs from recovering transmission charges from their customers.

Compliance with rules

Each DNSP must comply with this determination and any rules issued by the Tribunal under clause 6.10.1(f) of the Code.

6 Based on the AARR.

7 A standard periodic bill excludes fees for miscellaneous or monopoly services and charges for higher services standards available at the discretion of the user.

Pricing guidelines and disclosure requirements

The DNSPs are required to comply with clause 9.16.3(c) of the Code and the 'Pricing guidelines and information disclosure, Rule 99/2', which sets out pricing guidelines and disclosure requirements. The Tribunal issued this Rule under clause 6.10.1(f) of the Code.

Unless a DNSP has published a current pricing information package that meets the 'Pricing notification and information disclosure Rule 99/2', the DNSP may not increase its charge for any prescribed service. Under these circumstances, if actual revenue from the existing charges is projected to exceed the AARR, the DNSP must lower all its charges for prescribed services by a uniform percentage to reduce its revenues to the regulated levels.

Rate of return

The Tribunal has determined that an appropriate rate of return (real, pre tax) for the electricity distribution networks lies within the range, 5 to 8.5 per cent.

For the purpose of calculating regulated revenues for NSW DNSPs over the regulatory control period, the Tribunal has decided that a real, pre-tax rate of return of 7.5 per cent is appropriate. This is consistent with a nominal post tax return on equity of approximately 11-12 per cent.

The Tribunal has applied a pre-tax nominal return of 7.65 per cent to working capital.

Capital base

Regulatory asset base

The initial capital bases at 30 June 1998 are as follows:[8]

Table 4 Initial capital base as at 30 June 1998

DNSP	Initial capital base ($m) [9]
EnergyAustralia[1]	3,767
Integral Energy	1,732
NorthPower	858
Great Southern Energy	515
Advance Energy	303
Australian Inland Energy	50
DNSP total	**7,225**

1: EnergyAustralia's initial capital base includes its transmission assets.

8 The financial modelling is based on 1998/99 figures.

9 Includes streetlighting assets.

Rolling forward the capital base

The initial capital base as at 30 June 1999 is determined as follows:

- initial capital base as at 30 June 1998 indexed by the CPI[10]
- plus capital expenditure for 1998/99 indexed by half the CPI percentage change
- less depreciation (as calculated in Attachment 3)
- less asset disposals.

Capital expenditure

The Tribunal has incorporated capital expenditure projections illustrated in Table 5 into the building block analysis.

Table 5 Capital expenditure projections ($1999)[11]

	1999/00 ($m)	2000/01 ($m)	2001/02 ($m)	2002/03 ($m)	2003/04 ($m)
EnergyAustralia	143.4	147.5	149.5	168.0	178.0
Integral Energy	102.0	78.7	62.9	64.0	60.5
NorthPower	68.0	65.2	68.9	61.6	58.3
Great Southern Energy	38.6	42.6	36.1	36.0	32.5
Advance Energy	27.4	26.3	26.4	28.7	26.0
Australian Inland Energy	3.1	3.1	3.1	3.1	3.1
Total	**382.5**	**363.4**	**346.9**	**361.4**	**358.4**

Source: Worley capital expenditure review report. Excludes retail and retail IT related capital expenditure, recoverable works and capital contribution works. Revised capital expenditure estimates were submitted by Great Southern Energy and Australian Inland Energy. These revisions were reviewed by Worley.

Operating and maintenance expenditure

The Tribunal has determined the following efficiency gains in operating and maintenance expenditure for the NSW DNSPs over the regulatory period (using 1997/98 as the base year, rolled forward):[12]

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10 See chapter 3 for an explanation of the treatment of the GST.

11 It should be noted that the DNSPs' capital expenditure forecasts include street lighting capital expenditure. This is consistent with the Tribunal's decision to include the street lighting business in the DNSPs' revenue cap.

12 The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

Table 6 Cumulative real reductions in operating and maintenance figures

	Cumulative real reduction over 5 years before allowance for growth (%)
EnergyAustralia	10
Integral Energy	15
NorthPower	15
Great Southern Energy	15
Advance Energy	15
Australian Inland Energy	5

These efficiency targets are based on 1997/98 operating and maintenance expenditures.[13]

The Tribunal allows for operating and maintenance expenditure (after applying inflation and the cumulative real reduction outlined in Table 6 to grow by one half of the percentage growth in MWh sales. The resulting operating and maintenance expenditures (excluding TUOS), incorporated in the building blocks, are outlined in Table 7.

Table 7 Operating and maintenance building block components, 1999-2000 to 2003-2004 ($'000)

	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	205,562	209,673	213,866	218,144	222,507
Integral Energy	157,174	159,924	162,723	165,570	168,468
NorthPower	70,687	71,747	72,824	73,916	75,025
Great Southern Energy	47,648	48,125	48,606	49,092	49,583
Advance Energy	43,826	44,374	44,929	45,491	46,059
Australian Inland Energy	6,861	7,033	7,208	7,389	7,573

Depreciation

The Tribunal has determined to:

- allow depreciation on the initial capital base established for regulatory purposes
- adopt the asset lives established in the GHD/Worley/Arthur Andersen asset valuation
- adopt depreciation schedules based on straight line depreciation methodology
- provide scope for alternative depreciation profiles in the future where these can assist in managing market risks and managing variations in the prices of new investment

13 The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

- establish net present value neutrality as an essential condition for alternative depreciation profiles.

The depreciation amounts included in the AARR are as set out in the table below:

Table 8 Return of capital building block components, 1999-2000 to 2003-2004[14] ($'000)

DNSP	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	174,399	182,496	190,906	199,810	209,332
Integral Energy	94,779	98,476	103,099	106,695	106,892
NorthPower	44,991	47,869	49,480	52,459	55,379
Great Southern Energy	29,199	31,064	32,177	33,486	33,631
Advance Energy	18,890	20,051	19,630	20,396	20,586
Australian Inland Energy	2,606	2,752	2,906	3,068	3,237

14 Nominal dollars. Includes depreciation on Streetlighting assets.

Total revenue requirements

The following table illustrates the base revenue requirements for the NSW DNSPs for the period from 1 February 2000 to 30 June 2004:

Table 9 Base revenue requirements ($ million)

	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
EnergyAustralia[15]					
Building Block	674	692	710	730	752
Smoothed	691	706	721	736	752
Integral Energy					
Building Block	388	398	407	415	419
Smoothed	395	401	407	413	419
NorthPower					
Building Block	186	194	200	208	215
Smoothed	170	180	191	203	215
Great Southern Energy					
Building Block	117	122	126	129	132
Smoothed	113	117	122	127	132
Advance Energy					
Building Block	87	90	92	95	97
Smoothed	74	78	82	87	92
Australian Inland Energy					
Building Block	14	14	15	15	16
Smoothed	11	12	12	13	13
Industry Total					
Building Block	1466	1510	1550	1592	1631
Smoothed	1454	1494	1535	1579	1623

Charges for miscellaneous and monopoly services

Charges for miscellaneous services

The Tribunal has determined an exhaustive list of miscellaneous charges. This establishes the maximum amount that may be charged for the provision of the relevant miscellaneous service. No new charges may be levied by a DNSP during the regulatory control period. The list of approved maximum charges for miscellaneous services is shown in Table 10.

15 Includes costs and revenues for transmission services as determined by the ACCC.

Table 10 Maximum charges for miscellaneous services

Miscellaneous Service		Maximum allowable charges	
		Normal business hours maximum allowable ($)	Outside normal business hours maximum allowable ($)
Provision of time-of-use or half hourly metering data: per half hour		25.00	N/A*
Special meter reading		30.00	75.00
Meter test		50.00	125.00
Conveyancing inquiry:	desk inquiry	25.00	N/A*
	field visit	50.00	N/A*
	total	75.00	N/A*
Account establishment		35.00	87.50
Off-peak conversion		40.00	100.00
Disconnection visit:			
	if no disconnection (acceptable payment received)	30.00	N/A*
	disconnection (acceptable payment not received)	60.00	N/A*
	pole top/pillar box disconnection	100.00	N/A*
	Maximum total (pole top/pillar box & meter disconnection)	160.00	N/A*
Rectification of illegal connection		150.00	475.00

*N/A = Not applicable.

These charges must be levied in accordance with 'Charges for miscellaneous services, Rule 99/3'. The DNSPs must also ensure that they conduct an adequate customer information program as required by the Rule.

Revenue from charges levied for the provision of miscellaneous services is included in the base revenue of each DNSP.

Charges for monopoly services

The Tribunal has determined an exhaustive list of charges for monopoly services associated with contestable work.[16] This establishes the prescribed amount or where specified the maximum amount to be charged for the provision of the relevant monopoly service. No

16 'Contestable work' is work relating to the distribution network system that can be performed by an accredited service provider. A ring-fenced arm of the DNSPs business may compete for this work. The DNSP needs to inspect the work for security and safety reasons regardless of whether the ring-fenced arm or an external accredited service provider performs the work.

new charges may be levied by a DNSP during the regulatory control period. The list of prescribed charges for miscellaneous services is shown in Table 11.

Table 11 Charges for monopoly services associated with contestable work

	Underground urban residential subdivision (vacant lots)	Rural Overhead Subdivisions and Rural Extensions	Underground Commercial and Industrial or Rural Subdivisions (vacant lots - no development)	Commercial and Industrial Developments	Asset Relocation Or Street Lighting
Design Information (Minimum 1 Hr)	Up to 5 lots 2 Hrs @ R2 6 to 10 lots 3 Hrs @ R2 11 - 40 lots 5 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (See Note 5)
Design Certification (Minimum 1 Hr)	Up to 5 lots 1 Hr @ R2 6 to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 4 Hrs @ R2	1 - 5 poles 1 Hr @ R2 6 -10 poles 2 Hrs @ R2 11 or more poles 3 Hrs @ R2	Up to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R3 per hour	R2 or R3 per hour (See Note 5)
Design Rechecking (Minimum 1 Hr)	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (See Note 5)
Inspection Fee (Minimum 2 Hrs @ R2)	Grade: / A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.3xR2 / 0.7xR2 / 1.5xR2 Remainder: 0.1xR2 / 0.4xR2 / 0.7xR2	Grade: / A per pole / B per pole / C per pole 1-5 poles: 0.6xR2 / 1.2xR2 / 2.2xR2 6-10 poles: 0.5xR2 / 1.0xR2 / 2.0xR2 11+ poles: (see Note 4) 0.4xR2 / 0.7xR2 / 1.5xR2	Grade: / A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Remainder: 0.5xR2 / 1.2xR2 / 2.5xR2	R2 or R3 per hour (see Note 1)	R2 or R3 per hour (see Note 1)
Access Permit	Residential Subdivisions: $18.00 per lot combined fee	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit
Substation Commissioning		$600 per substation (See Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)
Administration	Up to 5 lots 3 hours @ R1 6 - 10 lots 4 hours @ R1 11 - 40 lots 5 hours @ R1 Over 40 lots 6 hours @ R1	Up to 5 poles: 3 Hrs @ R1 6-10 poles: 4 Hrs @ R1 11 or more poles 6 Hrs @ R1	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of Arrangement	3 hours @ R1				
Re-Inspection	R2 per hour (max 1 hour per level 2 reinspection)				
Access	R1 per hour (see narrative)				
Authorisation	2 hours @ R2				
Inspection of Service Work (Level 2 work)	All Service connections: A Grade : $14 per NOSW B Grade: $22 per NOSW C Grade: $65 per NOSW (NOSW = Notification of Service Work)				

Notes:

1. Level of inspection determined prior to commencement of job & based on grade of accredited service provider.
2. $600 for a simple substation (single transformer/RMI unit) other at hourly rate including setting/re-setting protection equipment.
3. Where individual service connections are required for multiple dwelling subdivisions the per lot fee should be applied per service connection.
4. Inspections are based on 3 visits. Substation poles are not included. The inspection for substation poles is A Grade – 3.5Hrs @ R2; B Grade – 7Hrs @ R2; C Grade 9 Hrs @ R2.
5. Hourly rate to be determined based on complexity of the job.

Table 12 Hourly labour rates applicable to monopoly services

Labour class	Hourly rate
Admin R1	$44
Design R2a	$54
Inspector R2b	$54
Engineer R3	$65

These charges must be levied in accordance with 'Charges for monopoly services, Rule 99/4'.

Revenue from charges levied for the provision of monopoly services is to be included in the base revenue of each DNSP.

Embedded generation and avoided TUOS

With respect to Integral Energy's submission to the Tribunal regarding avoided TUOS payments, the Tribunal has decided that:

- as a matter of principle, it is appropriate for avoided TUOS payments paid to an embedded generator to be recovered in network revenues, to the extent that these payments reflect the actual TUOS charges avoided by the DNSP as a consequence of the embedded generator
- on a forward looking basis, it is appropriate that Integral's payments to Smithfield and Tower/Appin for the purposes of 'avoided TUOS' to be recovered in Integral's revenue requirement, to the extent that these payments reflect the actual TUOS charges that Integral avoids as a consequence of the embedded generators; and consequently
- for the period from 1 February 2000 to 30 June 2004, Integral's payments to Smithfield and Tower/Appin for avoided TUOS are to be passed through to customers to the extent that the payments reflect the actual avoided TUOS charges. The pass through amount in each year will be subject to the approval of the Tribunal.

GLOSSARY OF ACRONYMS AND TERMS

AARR	Aggregate annual revenue requirement determined under the National Electricity Code.
ACCC	Australian Competition and Consumer Commission
ACTEW	ACT Electricity and Water
AGL	The Australian Gas Light Company
AGSM	Australian Graduate School of Management
AIE	Australian Inland Energy
ASX	Australian Stock Exchange
Base revenue	The sum of operating costs and return of and return on capital.
CAIDI	Customer average interruption duration index
CAIFI	Customer average interruption frequency index
Capex	Capital expenditure
CAPM	Capital asset pricing model
CEGB	Central Electricity Generating Board (UK)
CIPSE	Community Information Project on Sustainable Energy
Code	National Electricity Code
COAG	Council of Australian Governments
CPI	Consumer price index, as defined in the Code glossary.
CPI-X	CPI minus a distributor indexation factor
CRNP	Cost reflective network pricing: a cost allocation method which reflects the value of assets used to provide transmission or distribution services to network users.
CSO	Community service obligation: a government subsidy for activities undertaken by a government enterprise which would not be undertaken as a commercial activity or would require higher prices to be commercial
CWWG	Contestable Works Working Group
DEA	Data envelopment analysis
Deprival value	A value ascribed to assets which is the lower of economic value or optimised depreciated replacement value.
Derogation	Modification, variation or exemption to one or more provisions of the Code.
DGM	Dividend growth model
DLF	Distribution loss factor, as calculated according to the Code in clause 3.6.3.
DNSP	Distribution network service provider: a person who engages in the activity of owning, controlling, or operating a distribution system.

DORC/ODRC	Depreciated optimised replacement cost (see definition under ODRC)
DSM	Demand side management
DUOS	Distribution use of system: a service provided to a Distribution Network User for use of the distribution network for the conveyance of electricity that can be reasonably allocated on a locational and/or voltage basis.
EAPA	Energy Accounts Payments Assistance (Scheme)
EBIT	Earning before interest and tax
EGWG	Embedded Generation Working Group
EICG	Electricity Industry Consultation Group
EION	Energy Industry Ombudsman, NSW
EPD	Energy Project Division, Victoria
ESI	Electricity Supply Industry
ETR	Effective tax rate
EUG	Energy Users Group
FDC	Fully distributed costs
γ	Franking credit gamma
Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems
GSN	Great Southern Energy Gas Networks Pty Ltd
GWh	Gigawatt hour (one GWh=1000 megawatt hours or one million kilowatt hours)
IPART	The New South Wales Independent Pricing and Regulatory Tribunal established under the *Independent Pricing and Regulatory Tribunal Act 1992 (NSW).*
kWh	Kilowatt hour (the standard unit of energy which represents the consumption of electrical energy at the rate of one kilowatt over a period of one hour)
LCAB	Licence Compliance Advisory Board
MAR	Maximum allowable revenue, not to be confused with maximum allowed revenue as defined in the Code.
MCWG	Miscellaneous Charges Working Group
MMC	Monopolies and Mergers Commission (UK)
MoEU	Ministry of Energy and Utilities
MRP	Market risk premium for equity
MWh	Megawatt hour (one MWh=1000 kilowatt hours)
NCOSS	NSW Council of Social Services

NECA	National Electricity Code Administrator Limited A.C.N. 073 942 775, the company responsible for administering the Code.
NEMMCO	National Electricity Market Management Company Limited, the company which operates and administers the market in accordance with the Code.
NPV	Net present value
NSP	Network service provider: a person who engages in the activity of owning, controlling, or operating a transmission or distribution system and who is registered in that capacity with NEMMCO.
ODRC	Optimised depreciated replacement cost: the ODRC calculation is based on the gross replacement cost of modern equivalent network assets, adjusted for overdesign, overcapacity and redundant assets, less an appropriate allowance for depreciation. It measures the minimum cost of replicating the system in the most efficient way possible, given its service requirements and the age of the existing assets.
ODV	Optimised deprival value
OFFER	Office of the Electricity Regulator (UK)
OFGAS	Office of the Gas Regulator (UK)
OFWAT	Office of Water Regulator (UK)
Opex	Operating expenditure
ORC	Optimised replacement cost
ORG	Office of the Regulator General, Victoria
P/E	Price/earnings ratio
PIAC	Public Interest Advocacy Centre
QCA	Queensland Competition Authority
RAB	Regulatory asset base
Ring fencing	The clear separation of subsidiaries or divisions of a company that may have competitive advantages in dealing with each other.
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SEDA	Sustainable Energy Development Authority
SLUOS	Streetlighting use of system
TUOS	Transmission use of system
v	Volt (the unit of electric potential or electromotive force)
w	Watt (a measure of the power present when a current of one ampere flows under a pressure of one volt)

WACC	Weighted average cost of capital: a "forward looking" weighted average cost of debt and equity for a commercial business entity. The network owner's WACC will represent the shadow price or social opportunity cost of capital as measured by the rate of return required by investors in a privately-owned company with a risk profile similar to that of the network company.

1 INTRODUCTION

This determination is made under the National Electricity Code ('the Code'). In 1998 the Premier gave the Tribunal a reference under section 12A of the *Independent Pricing and Regulatory Tribunal Act 1992* ('the IPART Act') to investigate the pricing for electricity networks in NSW. The Tribunal's report, *Pricing for Electricity Networks and Retail Supply* ('the section 12A report'), provides useful information which the Tribunal has referred to in this determination.

1.1 The review process

On 21 August 1999 the Tribunal advertised in *The Sydney Morning Herald* seeking submissions to its determination under the Code. The Tribunal received 53 submissions from various stakeholders.

The Tribunal held public hearings on 14 and 15 October 1999 in IPART's meeting rooms on Level 2, 44 Market Street, Sydney. Twelve organisations presented information to the Tribunal.

Copies of all public submissions and a transcript of the hearings are available for inspection at the Tribunal's offices or on the Tribunal's website.

In 1998 the Tribunal established an electricity industry consultation group (EICG), comprising representatives of the DNSPs, the retailers, large customers and consumer and community groups. The EICG continued to meet throughout the preparation of this determination and provided valuable input to the determination. Additionally, working groups were established to consider the following specific issues:

- contestable works and monopoly fees
- miscellaneous charges
- capital contributions
- service standards
- embedded generation
- the form of regulation
- pricing principles.

The Tribunal members who conducted this inquiry are:

Dr Thomas Parry, Chairman
Mr James Cox, Full-time Member.

1.2 The National Electricity Code

The Code provides a framework for the national wholesale electricity market. The Tribunal is the Jurisdictional Regulator for distribution service pricing in New South Wales.[17]

1.2.1 Requirements of the Code

Chapters 5 and 6 of the Code establish an access regime within the national electricity market for distribution and transmission networks. Chapter 5 details access arrangements, network planning and technical requirements. Chapter 6 sets out the principles for distribution and transmission service pricing.

The Code requires that the distribution service pricing regime to be administered under part D of chapter 6 achieve the following outcomes:

- provide an equitable allocation of efficiency gains (clause 6.10.2(b)(1))
- provide a fair and reasonable return on efficient investment, given efficient operating and maintenance practices (clause 6.10.2(b)(2))
- prevent the extraction of monopoly rents (clause 6.10.2(c))
- foster efficient operating and maintenance practices (clause 6.10.2(e))
- foster efficient use of existing infrastructure (clause 6.10.2(f))
- permit the balancing of interests of owners, users and the public (clause 6.10.2(k)).

In making a determination under the Code, the Tribunal is required to comply with clause 6.10.7, by publishing full and reasonable details of the basis and rationale of the decision including:

- reasonable details of the qualitative and quantitative methodologies applied
- full reasons for material judgements and quantitative decisions made, options considered, and discretions exercised which have a material bearing on the outcome of the decision.

Clause 9.16.3(c) of the Code gives the Tribunal the discretion not to apply part E of chapter 6 of the Code. Part E deals with price structures. The Tribunal believes that the guidelines set out in part E are inappropriate and would deliver incorrect pricing signals. It has, therefore, exercised its discretion not to apply part E. However, the Tribunal has exercised its powers under clause 6.10.1(f) of the Code to develop 'Pricing notification and information disclosure Rule 99/2'.

17 Clause 9.16.3(b) of the Code provides that "IPART is and will always be taken to have been the Jurisdictional Regulator for the purposes of clause 6.10.1(b) of the Code and will continue to be the Jurisdictional Regulator until the Minister appoints another body."

2 THE NSW ELECTRICITY INDUSTRY

2.1 Reforms to the industry

Over the past five years 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 network service providers and retail supply businesses
- separating the transmission and generation functions, and establishing TransGrid
- splitting the generation sector into three companies: Pacific Power, Delta Electricity and Macquarie Generation.[18]

In addition to these structural changes, competition in the generation sector has been introduced. This competition arises from the electricity industries of New South Wales, Victoria, Australian Capital Territory and South Australia operating in a competitive wholesale market, which is underpinned by harmonisation of the NSW and Victorian markets.

The NSW Government is introducing competition in the retail market. Large customers are now able to choose their electricity retailer, and competition has been introduced progressively to smaller customers. The NSW Government has convened the Market Implementation Group (MIG) to oversee and direct electricity reform in NSW. MIG's responsibilities include guiding the transition to full retail competition.

This determination relates to distribution services. Distribution services primarily involve electricity wires. Because there is no competition on the wires business, it will continue to be regulated. The Tribunal is concurrently issuing a determination under the IPART Act that relates to franchise retail service providers.

2.2 Characteristics of DNSPs

Each distribution network service provider (DNSP) has individual customer and load characteristics, as illustrated in Table 2.1.

[18] Generation and transmission assets are also provided by the Snowy Mountains Hydro Electric Authority.

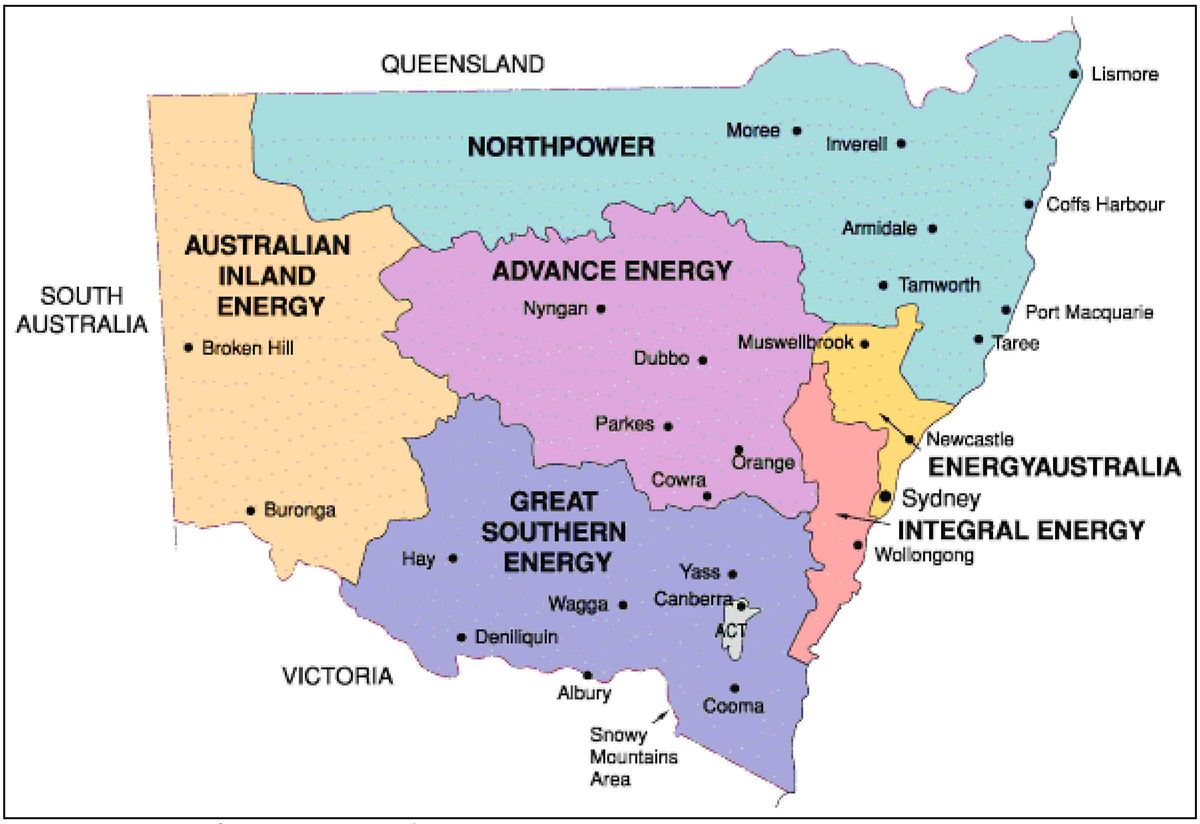
Table 2.1 NSW DNSP customer and load profiles, 1998/99

Distributor	Number of network customers	Total network load (MWh)	Network service area (sq. km)
EnergyAustralia	1,386,640	22,978,445	22,000
Integral Energy	751,028	14,002,026	24,500
NorthPower	362,522	3,878,134	230,000
Great Southern Energy	227,795	3,047,739	176,000
Advance Energy	119,982	2,636,787	167,000
Australian Inland Energy	21,410	417,786	155,000

Source: 1998-99 regulatory accounts for customer numbers and load, area from the Boundary Review Committee's final report.

Figure 2.1 illustrates the service territories for the New South Wales distribution network service providers.

Figure 2.1 Distribution network service provider boundaries



Source: Ministry for Energy & Utilities.

2.2.1 An average electricity bill

An electricity bill comprises distribution and transmission costs and energy costs plus a retail margin.

The Australian Competition and Consumer Commission (ACCC) regulates the transmission component. The energy costs comprise a mixture of contracts and pool prices.

Table 2.2 provides a summary of average network and franchise retail prices for each distributor.

Table 2.2 Average electricity prices, 1998/99

Distributor	Average retail price c/kWh	Average network price (DUOS + TUOS) c/kWh[19]
EnergyAustralia		3.56
Residential	9.8	
Business	10.3	
Integral Energy		3.33
Residential	9.4	
Business	9.8	
NorthPower		4.90
Residential	10.4	
Business	11.4	
Great South Energy		4.33
Residential	9.6	
Business	8.4	
Advance Energy		3.21
Residential	10.6	
Business	10.4	
Australian Inland Energy		3.36
Residential	9.5	
Business	6.4	

Source: 1998/99 regulatory accounts.

19 Actual average network price.

3 REGULATORY FRAMEWORK

3.1 Regulation of distribution services

3.1.1 Determination of 'prescribed distribution services'

It is the Tribunal's determination that, for the purpose of clause 6.10.4, 'prescribed distribution services' are those services performed by each DNSP that are associated with or ancillary to access to that DNSP's network for the supply of electricity within that DNSP's service area.

Code requirements

Clause 6.10.4 of the Code requires the Tribunal, as the jurisdictional regulator, to determine which services are 'prescribed distribution services' and therefore subject to economic regulation under the Code. Services which are not 'prescribed distribution services' are deemed to be 'excluded distribution services'. 'Excluded distribution services' may attract a light-handed regulatory approach.

In deciding which distribution services are prescribed distribution services, the Tribunal is required to have regard to:

- the principles contained in clause 6.10.3
- the extent of effective competition in the provision of that service and whether sufficient competition exists to warrant light-handed regulation
- the effectiveness of the form of economic regulation specified under clause 6.10.5.

3.1.2 Retailer of last resort

'Retailer of last resort' provisions are not part of this determination for two reasons: firstly, retailer of last resort provisions are licence requirements, which the Ministry of Energy and Utilities administers. Secondly, the Tribunal has issued this determination under the Code, which provides powers to regulate prescribed distribution services. Provisions for retailer of last resort do not fall into the prescribed distribution services category.

3.1.3 Determination on regulatory control period

For NSW DNSPs the annual aggregate revenue requirement (AARR) determined by the Tribunal will apply for the regulatory control period from 1 February 2000 until 30 June 2004.

If a new determination is not issued to take effect from 1 July 2004, all charges for prescribed distribution services are to continue unchanged from the level at 30 June 2004 until a new determination takes effect.

For the 1999/2000 financial year the AARR will comprise the (rolled forward) 1997 determination revenue pro-rated for the period from 1 July 1999 to 31 January 2000, and this determination, pro-rated for the period from 1 February 2000 until 30 June 2000. Pro-rating will be on the basis of calendar days covered by each determination.

3.1.4 Code requirements

This four year and five month regulatory control period complies with clause 6.10.5(c) of the Code, which requires that the regulatory control period for distribution be no less than three years.

3.2 Building block approach to pricing and financial analysis

3.2.1 Determination on approach to setting base revenue

The Tribunal has adopted a building block approach to determining base revenue requirements, supplemented by analysis of pricing outcomes and a range of financial indicators. The building block approach sets the base revenue requirement as the sum of estimated efficient operating costs, depreciation (return of capital) and a risk adjusted return on capital.

3.2.2 Code requirements

The Tribunal must determine the AARR in accordance with part D of chapter 6 of the Code. Part D does not expressly refer to the AARR. However, it does require the Tribunal to:

- adopt a form of economic regulation that is of the prospective CPI minus X form or other incentive-based variant of the CPI minus X form, consistent with the objectives and principles outlined in clauses 6.10.2 and 6.10.3
- specify a form of economic regulation to be applied to the DNSP in the form of a revenue cap, a weighted average price cap or a combination
- take into account each DNSP's revenue requirement during the regulatory control period having regard to the factors in clause 6.10.5(d)
- have regard to objectives in clause 6.10.2 and the principles in clause 6.10.3 of the Code.

3.2.3 Tribunal assessment

The Tribunal considers the building block approach, supplemented by pricing and financial analysis, to be a reasonable method of meeting the Code requirements. The analysis of pricing outcomes and financial indicators tests the reasonableness of the outcomes of the building block approach.

3.3 Form of economic regulation

3.3.1 Determination on revenue cap

In this determination the Tribunal has adopted a fixed revenue cap under clause 6.10.5(b) of the Code as the form of economic regulation to be applied to the DNSPs in NSW.

3.3.2 Code requirements

Section 6.10.5 (b) of the Code allows the Tribunal to regulate under a revenue cap, a weighted average price cap or a combined revenue/price cap. Under section 6.10.3(d) of the Code, the Tribunal is required to give two years' notice to DNSPs before amending the form of economic regulation set out in section 6.10.5 of the Code. There has been no prior determination under the Code and, therefore, no existing form of economic regulation under the Code.

3.3.3 Public consultation

The Tribunal's s12A report

The Tribunal held a public forum in February 1999 to discuss the industry's cost drivers. In the s12A report the Tribunal presented stakeholders comments, the DNSPs' reported cost drivers, and the following proposed maximum allowable revenue (MAR) formula:

$$MAR = [[a + bN + cM + dL] * (1 + (CPI\text{-}X))] + Y + GST$$

where

N = customer numbers
M = MWh sales
L = circuit kilometres (rural distributors only)
Y = Y2K costs, NEMMCO fees and costs of moving to full contestability ($)
GST = the net impact of the GST on the business[20]

a = residual fixed term capturing other costs ($'000)
b = dollars per customer
c = dollars per MWh
d = dollars per circuit kilometre

CPI = the ABS December year-on-year percentage change for all-groups all capitals

Public consultation for this determiantion

As part of the review process for this determination, the Tribunal consulted further with stakeholders and refined the MAR equation.

EnergyAustralia provided the Tribunal with modelling that estimated EnergyAustralia's marginal cost drivers. The Tribunal conducted further modelling based on EnergyAustralia's cost drivers and distributed the following revised MAR formula to stakeholders:

$$MAR = [(a + b(N^t\text{-}N^0) + c(M^t - M^0)) * (1 + CPI - X)] + Y + GST$$

where

N^t = Customer numbers in year t
N^0 = Customer numbers in year 0 (1998-1999)

M^t = MWh sold in year t
M^0 = MWh sold in year 0 (1998-1999)

CPI = the ABS December year-on-year percentage change for all-groups all capitals

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20 The Tribunal will engage an auditor (at the DNSPs' expense) to verify the DNSPs' calculation of the net impact of the GST.

Y = Y2K costs, NEMMCO fees and costs of moving to full contestability ($)
GST = net impact of the GST and other concurrent tax changes on the business

a = revenue for year 0 of the review period (1998-1999)
b = customer billing, call centres and the low voltage network
c = dollars per MWh

Table 3.1 shows the coefficients distributed with the revised revenue formula for comment. Each set of coefficients produces a different 'X' factor for each DNSP (see section 3.4).

Table 3.1 Revenue formula coefficients distributed for comment

DNSP	Customer number (b) coefficient ($ per customer)	Energy (c) coefficient ($ per MWh)
EnergyAustralia & Integral Energy	120	6.25
	145	5.50
	180	5.00
	200	5.00
Great Southern Energy, NorthPower,	120	6.25
Advance Energy & Australian Inland Energy	200	5.50
	300	5.25
	400	5.25

The Tribunal held a forum in October 1999 to discuss the revised MAR formula and other regulatory options.

There was strong support for a revenue cap at the public forum, in submissions and at the public hearings. Strongly advocating a revenue cap, NorthPower states in its submission:

> The real revenues projected by the Tribunal under a smoothed transition to full cost recovery for NorthPower should be adopted as the actual allowable revenue caps and indexed by CPI over the regulatory period. There is no need for the development of a MAR equation.[21]

At the forum, Australian Inland Energy and Great Southern Energy indicated strong support for a revenue cap. Other DNSPs generally supported a revenue cap. SEDA added its support for a revenue cap.

Subsequent to the public forum, EnergyAustralia altered its position on the form of regulation, stating:[22]

> EnergyAustralia has critically assessed the current form of price control for the NSW electricity distribution and franchise retail businesses and proposed in the paper that the Tribunal adopt a "tariff basket" approach to price regulation. …

21 NorthPower submission, p 2, 10 September 1999.
22 EnergyAustralia submission, p 1, 25 November 1999.

> EnergyAustralia is committed to pursuing a price cap approach as the form of economic regulation. I understand from your officers that the Tribunal may have difficulties in implementing such a change in methodology in its entirety in the upcoming December 1999 determination. I do not believe, however, that this should prevent the form of economic regulation being addressed for another five years.

Demand management issues raised in public consultation

Demand management shifts or reduces demand for energy wherever it is more economic to do so than to provide supply capacity. Allowing demand management options to compete against supply side (or 'build' options) reduces the environmental impacts of energy supply.

Section 6.10.3(e)(2) of the Code requires the jurisdictional regulator to:

> … create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration.

A number of stakeholders raised issues relating to the level of the 'c' factor in the proposed revenue formula. They expressed concern that even at $9.50/MWh (the level set in the 1997 determination), the MAR formula introduces an artificial bias against demand management. For instance, in its submission, SEDA states:

> The 'c' factor in the current revenue cap formula is $9.50/MWh. This 'c' factor effectively penalises the network business $9.50 of every MWh of energy a customer conserves.
>
> … SEDA strongly supports the removal of the volume related 'c' factor from the revenue cap. [23]

Some stakeholders argue that the 'c' factor should be very close to zero, reflecting their estimates of the marginal cost of transporting an additional kWh over the network. [24] Further, SEDA argues that if the Tribunal was to adopt a revenue formula with a 'c' factor, the Tribunal would need to include a 'f' factor to represent foregone revenue (from demand management initiatives). Under this scenario, SEDA also called for an 'e' factor representing embedded generation.

As previously mentioned, at the public forum on the MAR formula SEDA expressed support for a revenue cap.

Incentive mechanisms in the revenue formula

The Tribunal has considered using the MAR formula to provide DNSPs with incentives for certain activities. In its 1996 determination the Tribunal included a factor in the MAR formula to provide an incentive to invest in loss reduction projects. However, stakeholders argued that this loss factor mechanism was not effective. Nevertheless, industry participants support including a similar coefficient for service standard incentives (see section 3.9 for a discussion of service standards). [25]

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23 SEDA submission, p 2, 11 October 1999.

24 The Tribunal recognises that the marginal cost of transporting an addition kWh vastly increases as capacity becomes constrained.

25 The Tribunal has indicated that capital expenditure related to service reliability will be included in the regulated asset base at the next review, subject to a prudency test (see Chapter 3).

The Tribunal questions whether adding a coefficient to the revenue stream is the most appropriate method of providing incentives. Setting a coefficient for an incentive mechanism is highly subjective and may lead to inappropriate signals. Therefore, the Tribunal wishes to explore other incentive mechanisms.

The Tribunal supports and the Code requires incentive-based regulation. The Tribunal will continue to work with industry to develop appropriate and effective incentive mechanisms.

3.3.4 Tribunal's assessment of revenue cap

The Tribunal, therefore, specifies a revenue cap as the form of economic regulation under clause 6.10.5(b) of the Code. In adopting a revenue cap, the Tribunal has departed from the approach it recommended in the s12A report. After publishing that report, the Tribunal further analysed the form of regulation and considered the views put forward in public consultation. The Tribunal has decided to adopt a revenue cap in this determination because:

- there is industry and stakeholder support for a revenue cap
- revenue caps do not create a bias against demand management
- revenue caps are simpler to understand and administer than a revenue formula
- revenue caps provide flexibility in offering services and pricing options
- revenue caps provide equally strong incentives for DNSPs to pursue efficiency gains
- revenue caps are cost reflective.

3.4 Revenues, glide paths and X factors

3.4.1 Determination on revenues, glide paths and X factors

The base revenue requirements[26] determined allows a glide-path[27] of gains and losses using 1998/99 as a base year. The base revenue set in this determination covers the efficient costs of providing prescribed distribution services.

The AARR that the DNSPs can collect will be the glide-pathed base revenue, as established by the building blocks, together with:

- ***transmission charges and payments for network services made to other DNSPs. These payments may be subject to a prudency test if payments are between related parties at levels different to the published regulated charges***
- ***avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through and examination of avoided network costs***
- ***payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.***
- ***contestability costs as determined by the Tribunal (added to the base revenues)***
- ***Y2K costs as approved by the Tribunal (added to the base revenues)***

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26 Base revenue is the revenue determined by the building block analysis and includes operating costs, a return on capital and a return of capital.

27 A glide path allows a company to retain some of the benefits of its additional efficiency gains over the subsequent regulatory period(s).

- ***an amount to rectify unders and overs account balances***
- ***the net impact of the GST.***

The AARR is not subject to glide pathing. Rather, the base revenues are glide-pathed.

EnergyAustralia's base revenue includes incomes received under the ACCC determination for transmission services.

3.4.2 Tribunal's assessment of glide paths, revenue streams and X factors

By allowing a company to retain some of the benefits of its additional efficiency gains over the subsequent regulatory period(s), a glide path provides an incentive to pursue additional efficiency gains. A glide path also allows for a smoother transition to new price levels.

As outlined above, the base revenue for each DNSP is based on a building block analysis supported by pricing and financial analysis, and is subject to glide pathing. The resulting base revenues are set out in chapter 9. The AARR that the DNSPs can collect will be the base revenue as established by the building blocks, together with:

- transmission charges and payments for network services made to other DNSPs. This is consistent with 6.10.5.(7) (ii) of the Code. These payments may be subject to a prudency test if payments are not between unrelated parties at published regulated charges
- avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through and examination of avoided network costs
- payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.
- contestability costs as determined by the Tribunal
- Y2K costs as approved by the Tribunal
- an amount to rectify unders and overs account balances
- the net impact of the GST.

The 'CPI-X' component does not represent the impact of inflation and efficiency gains. The CPI-X factor is used to achieve the desired revenue path, resulting in end-year revenues consistent with the building block/pricing and financial analysis/glide path outcomes. The building block components are indexed and the efficiency gains are built into the operating and maintenance expenditure – see chapter 8.

The X factors determined for each DNSP are set out in Table 3.2. The X factor is applied in indexing revenues for each year after the base revenue year. It is not an efficiency factor.

Table 3.2 X factors used to index revenues (%)

EnergyAustralia	0.86
Integral Energy	1.47
NorthPower	-3.16
Great Southern Energy	-0.89
Advance Energy	-2.57
Australian Inland Energy	1.03

3.5 Contestability costs, Y2K costs and NEMMCO fees

In its s12A report, the Tribunal indicated that it would allow a pass through of costs associated with Y2K and contestability, and National Electricity Market Management Company (NEMMCO) fees. The Tribunal has further considered this matter and this section outlines the treatment of these costs.

3.5.1 Determination on contestability costs

Once the framework for contestability is known and the Tribunal can estimate the costs with reasonable certainty, it will publish its decision on the reasonable costs of contestability and add these costs to the base revenue requirements set in this determination. The Tribunal will index contestability costs by CPI-X in subsequent years.

3.5.2 Tribunal's assessment of contestability costs

Since 1996 the NSW retail electricity market has been opened progressively to competition. Introducing contestability requires consideration of a range of issues, including metering technology, data collection and aggregation systems, a wholesale settlements system, and industry codes, standards and regulation.

The Tribunal commissioned SRC International to explore a range of issues surrounding the introduction of competition into the electricity market for residential and other low-use electricity consumers.

The costs of implementing retail contestability will depend upon the model adopted. Further, the proportion of those costs that DNSPs will need to pass-through will depend upon the allocation of those costs (eg whether customers, retailers or DNSPs are responsible for owning and/or maintaining meters).

The principal costs that will arise when implementing retail contestability will include:

- costs relating to metering or profiling arrangements
- data collection
- data aggregation and wholesale settlement
- billing and processing
- customer register and customer churn processes and systems and processes.

SRCI estimated that the total cost of implementing retail contestability in NSW will be $35m with ongoing annual costs of $27m. These estimates assume second-tier metering[28] with manual meter reading. The actual costs could vary significantly depending upon the model eventually chosen. It is likely that some of these costs will be borne by the DNSPs although both the overall level of costs and the allocation of those costs are currently unknown.

The Market Implementation Group (MIG) has been established to, among other issues, resolve retail contestability issues in New South Wales. Until the MIG determines the framework for introducing full contestability, the Tribunal will not know the level of associated costs. This puts the Tribunal in a very difficult position in relation to its regulatory treatment of contestability costs.

In its s12A report, the Tribunal indicates that it will allow DNSPs to pass through the cost of moving to full contestability. Having further considered this issue, the Tribunal is concerned that such an approach may pre-empt government policy. Furthermore, the Tribunal believes the costs associated with moving to full contestability should be treated in a similar manner to any other capital and/or operating costs. As these costs are unknown, it is not possible to include them in the current analysis.

Once the framework for contestability is known and the Tribunal can estimate the costs with reasonable certainty, it will publish its decision on the reasonable costs of contestability and add these costs to the AARR set in this determination. The Tribunal will index contestability costs by CPI-X in subsequent years.

3.5.3 Tribunal's assessment of Y2K costs

In the s12A report the Tribunal indicated it would pass through certain costs in the MAR formula, including Y2K costs. Having further considered this issue, the Tribunal believes that Y2K costs should be treated in the same manner as other operating expenditure.

The DNSPs have reported Y2K expenditures set out in Table 3.3. These figures have not been tested for prudency.

Table 3.3 Reported Y2K expenditure

DNSP	1997/98	1998/99
EnergyAustralia	none reported	$8,900,000
Integral Energy	none reported	none reported
NorthPower	none reported	$1,113,000
Great Southern Energy	none reported	$99,000
Advance Energy	$194,000	$190,000
Australian Inland Energy	none reported	$40,000

Source: 1997/98 and 1998/99 regulatory accounts.

28 'Second tier' customers are customers that change from their incumbent retailer. These customers would require a half hour meter.

The DNSPs should finalise their Y2K expenditure in 1999/2000. Before adding Y2K costs to the AARR set in this determination, the Tribunal will have these costs verified and tested for prudency by a consultant, at the expense of the DNSPs.

3.5.4 Tribunal's assessment of NEMMCO fees

Currently the DNSPs do not pay any fees to NEMMCO and the Tribunal is not aware of any new NEMMCO fees that will be imposed on DNSPs. Therefore, there is no need to provide for NEMMCO fees in this determination. If NEMMCO fees are imposed on DNSPs, the Tribunal will consider the issue in the next determination.

3.6 Indexation of revenues and GST pass through

3.6.1 Determination on indexation of revenues and GST pass through

To derive the base revenue for each year throughout the regulatory control period, the Tribunal will apply the percentage change CPI figure (defined below) to the base revenue of the previous year.

The Tribunal will incorporate the effect of the GST through a one-off indexation of base revenues by the Goods and Services Tax (GST) as defined in A New Tax System (Goods and Services Tax) Act 1999. This indexation will be exclusive of the economy-wide impact of the GST but including an estimate of the specific impact of the GST on the DNSP.

This can be expressed as:

$$\text{Base revenue}^{00/01} = \text{base year}^{29}\ \text{base revenue}^{99/00} * (1+CPI - X) + \text{net GST}^{util}$$
$$\text{Base revenue}^{01/02} = \text{base revenue}^{00/01} * (1+CPI^{-GST} - X)$$
$$\text{Base revenue}^{02/03} = \text{base revenue}^{01/02} * (1+CPI - X)$$
$$\text{Base revenue}^{03/04} = \text{base revenue}^{02/03} * (1+CPI - X)$$

where

CPI^{-GST}	=	***CPI minus the estimated impact of GST package on the CPI***
$netGST^{util}$	=	***net $ change in tax position of the utility under the GST package***
CPI	=	***year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter.[30]***

The base revenue rolled forward is the base revenue resulting from the building blocks (and published in this determination), not the actual revenue collected by the DNSPs in the previous year.

The Tribunal will require an audit of the changes in costs under the GST package, at the expense of the DNSPs. In consultation with the industry, the Tribunal will establish procedures for this audit. Each DNSP will be required to obtain the Tribunal's agreement on the consultant to be appointed.

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29 The base year base revenue is the 1999/2000 base revenue as determined by the building blocks in this determination. It is not the pro-rated revenue cap for 1999/2000.

30 The CPI is a retrospective CPI.

3.6.2 Tribunal's assessment of GST issues

A New Tax System is due to commence on 1 July 2000 and will:

- introduce a 10 per cent GST
- remove the wholesale sales tax and make changes to the excise on petrol and diesel and some other indirect taxes.

In addition to the GST, changes to the taxation system include reducing the rate of corporate income tax and abolishing accelerated depreciation. For a discussion of the impact of these changes on the rate of return, see chapter 5.

The package of taxation changes will affect the prices of all goods and services, including lowering those where the wholesale sales tax is higher than the GST. This will affect the economy-wide CPI calculated by the Australian Bureau of Statistics (ABS). The impact on individual businesses will reflect their operating and capital costs and revenue structure.

The Tribunal uses the CPI figure to:

- index revenues during the regulatory period
- index the regulated capital base until the start of the next regulatory period
- set limits on price movements (see section 3.8).

The Tribunal is aware that there is likely to be substantial changes in the DNSPs' costs and that these changes will differ substantially from the economy-wide impact reflected in the CPI.

The Tribunal's treatment of GST impacts involves no 'windfall' loss or gain for the utility owner. The impact on the consumer will equal the net impact of the GST package[31] on the industry. To implement this method, the Tribunal requires the DNSPs to provide more information.

3.7 Unders and overs account balances

An unders and overs account will apply to each DNSP in NSW. Any variation between the aggregate annual revenue requirement (AARR), as determined by the Tribunal, and actual revenue collected is to be monitored in the unders and overs accounts. The unders and overs account is cumulative from year to year.

For any year that a variance occurs between the AARR and the actual revenue collected in that year, an interest charge or an interest credit will apply, as appropriate. The interest adjustment will be applied on the cumulative balance at year-end. The total cumulative balance in the unders and overs account includes any prior year interest adjustments.

Interest will be pegged at the 3-year Commonwealth Bond rate as at the first Monday following the financial year-end. The Australian Financial Review will be the reference source for this rate.

31 The net impact may include incremental compliance costs.

DNSPs must provide annual returns to the Tribunal by 30 October each year. The annual returns must disclose account balances as a contingent item. These returns must demonstrate that the unders and overs account balances result from actual demand deviating from forecast demand. The Tribunal will allow the following tolerance margins for deviations from the related AARR and will require the following action on an annual basis[32] as a result of these deviations:

Table 3.4 Tolerance margins and actions that the Tribunal will require for unders and overs account balances

Tolerance	DNSP action required
less than +/- 2 per cent	Must notify the Tribunal within 30 days of year end with action plan[33] to resolve balance within the term of the price path.
between +/-2 per cent and +/- 5 per cent	Must notify the Tribunal within 30 days of year end with action plan[34] for rectifying the balance at the first subsequent changes to network tariffs.
over recovery of more than 5 per cent	Must provide a rebate to retailers on the first bill of the subsequent year to reduce the unders and overs account balance to zero.[35]
(under) recovery of more than 5 per cent	Unders and overs account balance will be reduced to under recovery of 5 per cent.[36]

Approved unders and overs account balances as at 31 January 2000 (accrued under determinations made by the Tribunal under the IPART Act) will carry forward into a determination made under the National Electricity Code effective from 1 February 2000. Each DNSP will be required to submit its unders and overs account balance for approval by the Tribunal as soon as practicable after 31 January 2000.

These requirements comply with 'Unders and overs accounts, Rule 99/1', which sets out provisions and requirements for unders and overs accounts. The Tribunal issued this Rule under clause 6.10.1(f) of the Code.

Any rectification of unders and overs account balances must comply with the limits on price movements imposed by the Tribunal.

32 The Tribunal will require the specified actions to commence on 1 July 2001.

33 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

34 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

35 The Tribunal intends to exercise its powers under state legislation to require retailers to pass on rebates to end-use customers.
The Tribunal recognises that issues may arise when customers disconnect from the system in the time between the period of over-collection and the payment of the rebate. The refund should be made to customers connected to the distribution network system on 30 June on the year that over recovery breaches the 5 per cent tolerance.

36 If, for example, at 30 June 2002 a DNSP has an under recovery of 8 per cent, the Tribunal will reduce the account balance to 5 per cent under recovered for the 2001/2002 financial year. The DNSP will lose the 3 per cent difference.

3.7.1 Tribunal's assessment of unders and overs account balances

In its 1996 determination, the Tribunal introduced unders and overs accounts. The purpose of an unders and overs account is to cater for variance between the allowable regulated revenue for a year and the actual revenue earned in that year.

The Tribunal's 1997 determination set out the following tolerance margins for deviations from the regulated revenue cap and required the following action on an annual basis as a result of deviations:

Table 3.5 Tolerance margins and actions required in 1997 determination for unders and overs account balances

Tolerance	Action
less than +/- 2 per cent	As part of on-going compliance, must notify IPART within 30 days of year end.
between +/-2 per cent and +/- 5 per cent	Notify IPART within 30 days of year end with action plan to resolve balance within the term of the price path.
greater than +/- 5 per cent	Notify IPART within 30 days of year end. Following consultation, immediate action by the distributor required.

As illustrated in Table 3.5, EnergyAustralia has substantially over recovered its allowed revenues. This has resulted from a $50 million over recovery in 1997/98 and a $25 million over recovery in 1998/99. Clearly, this level of over recovery breaches the tolerance levels set out in the 1997 determination. Advance Energy has under collected by 6 per cent.

The actions undertaken to rectify these balances have not been effective in dealing with under and/or over recovery.

Table 3.6 Network over/(under) recovery, 30 June 1999

	DNSP's reported over/(under) recovery	Adjustment	Balance to be carried forward	Balance carried forward as % of 1998/99 revenue
EnergyAustralia	96,503		96,503	12
Integral Energy	10,782		10,782	2
NorthPower	(8,765)	13,187[37]	4,422	2
Great Southern Energy	952[38]		952	1
Advance Energy	(8,280)	3,142[39]	(5,138)	-6
Australian Inland Energy	691	(934)[40]	(243)	-2

Note: NorthPower's balance will be reduced by a maximum of $1,509,256, representing payment to Advance Energy for electricity transportation from Wellington to Nyngan from 1996 to January 2000.

These balances were accrued under determinations made by the Tribunal under the IPART Act. The Tribunal intends to carry forward approved balances as at 31 January 2000 into the Code-based determination effective from 1 February 2000. Each DNSP will be required to submit its unders and overs account balance for approval by the Tribunal as soon as practicable after 31 January 2000.

As stated above, the intended purpose of the unders and overs account is to cater for differences between forecast demand and actual demand. The under/over account balances of some DNSPs do not result purely from differences between forecast and actual demand.

The Tribunal considered the issue of unders and overs accounts for this determination. It has concluded that there are compelling reasons for continuing unders and overs accounts.

To ensure that DNSPs are using the unders and overs accounts as the Tribunal intends, the Tribunal requires each DNSP to demonstrate each year that its unders and overs account balances result from actual demand deviating from forecast demand. The Tribunal recognises that there could be difficulties in forecasting network demand charges where there are large price increases on time of use tariffs (for example, when the system is constrained). However, the Tribunal expects that each DNSP will demonstrate to the Tribunal that the variations result from that class of customers.

In 'Unders and overs accounts, Rule 99/1' the Tribunal set tolerance margins (outlined in Table 3.6) to allow for deviations from the AARR. The Tribunal requires the respective action (from 1 July 2001) on an annual basis as a result of these deviations.

37 Transitional funding from Treasury.
38 Already includes transitional funding from Treasury.
39 Transitional funding from Treasury.
40 Includes $498,000 transitional funding from Treasury and a $1,432,000 payment to Powercor for transmission services.

Table 3.7 Tolerance margins and actions that the Tribunal will require for unders and overs account balances

Tolerance	DNSP action required
less than +/- 2 per cent	Must notify the Tribunal within 30 days of year end with action plan[41] to resolve balance within the term of the price path.
between +/-2 per cent and +/- 5 per cent	Must notify the Tribunal within 30 days of year end with action plan[42] for rectifying the balance at the first subsequent changes to network tariffs.
over recovery of more than 5 per cent	Must provide a rebate to retailers on the first bill of the subsequent year to reduce the unders and overs account balance to zero. [43]
(under) recovery of more than 5 per cent	Unders and overs account balance will be reduced to under recovery of 5 per cent. [44]

Any rectification of the unders and overs account balances must comply with the limitations on price movements imposed by the Tribunal.

3.8 Limits on price movements

3.8.1 Determination on limits on price movements

Average prices across the network must not increase by more than CPI. Increases in the standard periodic bills[45] of any residential customers (including rural residential customers) for the same pattern and volume of electricity consumption must not exceed the bill for the corresponding period of the preceding year by more than the greater of CPI plus 2 per cent or $30. Network prices for the same pattern and volume of electricity consumption for residential customers (including rural residential customers), must not exceed the CPI plus 2 per cent, exclusive of the impact of the GST plus net GST impact (expressed as a percentage of the pre-GST total costs) on each DNSP in 2000/01. To illustrate the CPI limitation:

41 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

42 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

43 The Tribunal intends to exercise its powers under state legislation to require retailers to pass on rebates to end-use customers.
The Tribunal recognises that issues may arise when customers disconnect from the system in the time between the period of over-collection and the payment of the rebate. The refund should be made to customers connected to the distribution network system on 30 June on the year that over recovery breaches the 5 per cent tolerance.

44 If, for example, at 30 June 2002 a DNSP has an under recovery of 8 per cent, the Tribunal will reduce the account balance to 5 per cent under recovered for the 2001/2002 financial year. The DNSP will lose the 3 per cent difference.

45 A standard periodic bill excludes fees for miscellaneous or monopoly services and charges for higher services standards available at the discretion of the user.

$$\textit{residential network tariffs}^{99/00} \le \textit{residential network tariffs}^{98/99} * (1+CPI)*1.02$$
$$\textit{residential network tariffs}^{00/01} \le \textit{residential network tariffs}^{99/00} * (1+CPI)*1.02 + \textit{net } GST^{util.}$$
$$\textit{residential network tariffs}^{01/02} \le \textit{residential network tariffs}^{00/01} * (1+CPI^{-GST})*1.02$$
$$\textit{residential network tariffs}^{02/03} \le \textit{residential network tariffs}^{01/02} * (1+CPI)*1.02$$
$$\textit{residential network tariffs}^{03/04} \le \textit{residential network tariffs}^{02/03} * (1+CPI)*1.02$$

where

CPI	=	***year-on-year percentage change in the consumer price index, weighted average of eight capital cities, published by the Australian Bureau of Statistics relating to the December quarter (retrospectively)***
CPI^{-GST}	=	***CPI minus estimated impact of GST package on the CPI (in percentage terms)***
$netGST^{util}$	=	***net change in tax position of the utility under the GST package, expressed as a percentage of total pre-GST costs***
residential network tariffs	=	***DNSP-specific average residential network tariffs as at 30 June of the relevant year.***

These limits on price movements apply to each DNSPs' total AARR.

These price limits are to apply to all DNSPs, except where the DNSP can demonstrate to the Tribunal that changes to transmission prices resulting from the expiration of the derogation on transmission prices prevent DNSPs from recovering transmission charges from their customers.

3.8.2 Tribunal's assessment of limits on price movements

As it indicated in its s12A report, the Tribunal is adopting controls on price movements for both network prices (in this determination) and retail prices for residential customers (in its separate retail determination). The purpose of the limits on price movements is to avoid price shocks to residential customers.

The GST and associated changes in prices will impact on the application of the limits on price movements. The Tribunal has accounted for this in specifying the limits.

3.9 Service standards

3.9.1 Determination on service standards incentive mechanism

The Tribunal has not included a service reliability incentive mechanism in this determination. DNSPs must comply with the service standards and reporting requirements under the Code and any applicable law.

3.9.2 Public consultation

In its s12A report the Tribunal considers ways of introducing an incentive mechanism for improved service reliability. In public consultation following the s12A report, stakeholders repeatedly brought service standards to the Tribunal's attention.

In its submission, Advance Energy states its support for including a service reliability incentive in the regulatory framework:

> Advance Energy would welcome the inclusion of service standards in the regulation of network prices. ... Advance Energy believes that a regulatory focus encompassing the standards of service expected by customers is also required. A regulatory framework that concentrates on both efficiency and standards of service is more consistent with market-based outcomes. …[46]

The Tribunal's main concern with including a service reliability incentive in the regulatory framework is the lack of adequate, consistent and comparable data. Advance Energy notes the scarcity of data problem in its submission:

> Advance Energy shares the view of the Tribunal that the inclusion of service standards should be based on verifiable and meaningful data. It is however important for the Tribunal to allow sufficient time in order to develop the reporting systems required to compile the data and indicators which would form part of the service standards regulatory regime. As indicated above, this process is occurring through the Licence Compliance reporting regime. [47]

In the s12A report, the Tribunal states that unless reporting on the technical regulation of distribution service standards yields verifiable and meaningful data, it may adopt an asymmetric service standards incentive mechanism. This would impose penalties for failing to deliver specified service standards, without providing rewards for out-performing the specified standards. Asymmetric treatment of service standards concerned several stakeholders, including NSW Treasury:

> NSW Treasury is concerned that an 'asymmetric form of standards regulation' which includes financial penalties for failing to meet standards without matching rewards for exceeding standards would create an asymmetric risk profile for the distributors. IPART may wish to consider awarding a 'premium' above regulated revenue to distributors that consistently outperform agreed standards. [48]

3.9.3 Tribunal's assessment of service standards issues

The Tribunal has decided not to introduce the asymmetric incentive mechanism it proposed in the s12A report.

The Tribunal is aware that the industry supports an incentive mechanism for service reliability. It also recognises the potential merits of incorporating this sort of incentive mechanism into the economic regulatory framework. However, the framework for measuring service standards and targets is not developed to a level that the Tribunal believes adequate to enable it to incorporate an incentive mechanism based on those measures.

At this stage, the Tribunal is reluctant to include a service reliability incentive mechanism that is based on measured data. However, the Tribunal does not wish to hinder efficient provision of enhanced service standards. The Tribunal reaffirms that efficient, prudent costs

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46 Advance Energy submission, 30 September 1999, p 8.
47 Advance Energy submission, 30 September 1999, p 11.
48 NSW Treasury submission, November 1999.

associated with service reliability improvements will be considered in the operating and/or capital expenditure components of the AARR.

The Tribunal will continue to work with stakeholders to consider the treatment of improved service reliability within the regulatory framework.

3.10 Compliance with Rules

Each DNSP must comply with this determination and any rules issued by the Tribunal under clause 6.10.1(f) of the Code.

4 PRICING PRINCIPLES AND DISCLOSURE REQUIREMENTS

The Tribunal believes that clear requirements for disclosing the basis of pricing and for notifying price changes will improve the regulatory arrangements for DNSPs and electricity users. This section sets out the Tribunal's determination on these matters.

4.1 Determination on disclosure of information on pricing structures and future directions

Each DNSP will be required to comply with the provisions outlined in 'Pricing notification and information disclosure Rule 99/2', issued by the Tribunal under clause 6.10.1(f) of the Code.

Unless a DNSP has published a current pricing information package that meets the 'Pricing notification and information disclosure Rule 99/2', the DNSP may not increase its charge for any prescribed service. Under these circumstances, if actual revenue from the existing charges is projected to exceed the AARR, the DNSP must lower all its charges for prescribed services by a uniform percentage to reduce its revenues to the regulated levels.

4.2 Pricing guidelines

As indicated in chapter 1, the Tribunal has exercised its discretion in clause 9.16.3(c) of the Code, not to apply part E of chapter 6 of the Code. Pending the development of guidelines, clause 9.16.3 requires that prices are to be determined 'in accordance with the methodology applied by that Distribution Network Service Provider to derive prices for similar services under the [pre-existing] IPART Determinations … or such other methodology approved in writing by IPART'.

This provides an opportunity for the Tribunal to develop pricing principles and guidelines in consultation with other stakeholders and regulators, and for those measures to be recognised under parts D & E of the Code.

Further, DNSPs must comply with 'Pricing notification and information disclosure Rule 99/2' issued by the Tribunal under clause 6.10.1(f) of the Code.

4.3 Code requirements

Part E of chapter 6 of the Code sets out a method for calculating charges for prescribed distribution services. It details the steps involved, prescribes aspects of the classification of services and allocation of costs to services, and requires the jurisdictional regulator to agree to various aspects of the allocation procedures.

However, clause 6.11(e) provides that:

> The *Jurisdictional Regulator* may, in consultation with *Code Participants*, develop alternative pricing methodologies to the approach set out in Part E. Any new pricing methodology so developed must conform to any jurisdictional rules, principles, or guidelines for the regulation of *distribution* pricing formulated under clause 6.10.1(f).

Clause 6.10.1(f) requires that such guidelines be consistent with the objectives for pricing and any national guidelines:

> Subject to any provision relating to cross-border networks in Chapter 9, each *jurisdictional regulator* may formulate guidelines and rules to apply to *distribution service* pricing within that *Jurisdictional Regulator's* jurisdiction and any guidelines so formulated must:
>
> (1) not be inconsistent with the objectives and principles for *distribution service* pricing set out in clauses 6.10.2 and 6.10.3;
>
> (2) not be inconsistent with any national guidelines for *distribution service* pricing formulated by the *Jurisdictional Regulators* under clause 6.10.1(c)
>
> (3) not purport to regulate matters to which any national guidelines formulated by the *Jurisdictional Regulators* under clause 6.10.1(c) apply.

The Code provides for the development of over-arching national guidelines through clause 6.10.1(c):

> With the consent of each *participating jurisdiction*, the *Jurisdictional Regulators* may together formulate and agree national guidelines to apply to national *distribution service* pricing.

4.4 Section 12A report

4.4.1 Application of the Code

The Tribunal has harboured concerns about the practicality of Part E of the Code for some time. In its s12A report the Tribunal states:

> … chapter 6 of the Code is poorly drafted, has many ambiguities, and does not provide an ideal regulatory framework. Considerable work is required by all state-based regulators, in consultation with the ACCC and other stakeholders, before a determination can be made under the Code.
>
> Yet a determination is required to be released by December 1999. A way forward is for the Tribunal to issue a determination covering distribution under the IPART Act but at the same time endeavouring to comply with Parts D and E of chapter 6 of the Code. It may be necessary for a transitional regulation to be passed deeming the IPART Act determination to have been made under the Code. (Volume 1, Chapter 3 of the s12A report)

The Tribunal maintains its concerns.

4.4.2 Pricing guidelines

In its s12A report the Tribunal states its intention to:

> … work with the DNSPs and other stakeholders to establish agreed guidelines for pricing which can supplement the provisions in chapter 6 of the Code and reduce or streamline the requirements for approval of individual elements in the cost allocation and pricing process. The Tribunal wishes to work with ORG and other jurisdictional regulators to develop such guidelines.

In volume 2, chapter 2 of the s12A report, the Tribunal discusses the objectives for pricing at some length. In summary prices should:

- reflect economic costs by:
  - reflecting the level of available capacity
  - signalling future investment costs
  - discouraging uneconomic bypass
  - allowing negotiation to better reflect the economic costs of specific services
- provide a commercially sustainable revenue stream while recovering the gap between marginal and average costs in the least distorting manner possible
- reduce regulatory burdens by being:
  - simple
  - transparent
  - stable
  - predictable.

Except where there is network congestion, the marginal costs of transmission and distribution are likely to be less than average costs. This creates a tension between economically efficient prices and prices necessary for commercial sustainability. The gap between marginal and average costs should be recovered in the least distortionary manner possible. A practical approach to minimising distortions would recover the gap between marginal and average costs in a manner which:

- does not vary between locations
- contains a fixed component
- to the extent a variable component is necessary, includes both energy and demand components.

4.4.3 Disclosure of pricing methodology

In the s12A report the Tribunal proposes that, as far as possible, the DNSPs should bear responsibility for determining the structure of their network prices. However, the Tribunal considers that the freedom for a monopoly to determine its price structure should be accompanied by the responsibility to disclose medium term pricing strategies and information concerning the basis for determining prices. Such an obligation already exists, but it has not been included in a determination and the requirements have not been identified. In order to clarify the requirements and strengthen compliance the Tribunal plans to:

- work with the DNSPs and other stakeholders to refine existing rules or establish new rules or guidelines for information to be disclosed in pricing information booklets
- require DNSPs to publish such booklets
- require that if a DNSP has not published a complying booklet, that all DNSP’s network charges should be decreased or increased by a uniform percentage consistent with the DNSP’s overall CPI-X cap (see the discussion in volume 2, chapter 2 of the s12A report).

4.5 Development of workable regulatory arrangements

In a review commissioned by the Tribunal, DGJ Projects found that:

> The many ambiguities and conflicts that exist within Part E are likely to seriously compromise its effectiveness as a workable regulatory instrument and the ability of NECA's proposed code changes to achieve their intended purpose.[49]

This advice is consistent with the views expressed in the Tribunal's 12A report. Hence, the Tribunal proposes to work with stakeholders and other regulators to develop guidelines under the Code. These guidelines could provide a basis for redrafting part E of chapter 6.

4.5.1 Findings of the Pricing Principles Working Group

In order to achieve these goals, the Tribunal established the Pricing Principles Working Group (PPWG) to consider and report on:

a) the translation of the pricing principles in the 12A report into practical guidelines on cost allocation and compliance procedures

b) the requirement to publish information on pricing strategies

c) the requirement to notify the Tribunal and customers of network price changes.

The PPWG comprises representatives of the DNSPs, independent retailers, end-use customers, embedded generators and regulators other than the Tribunal. To date the PPWG has focused on items (b) and (c) above. The Tribunal considered the views expressed in its deliberations on these matters. Minutes of the meetings of the PPWG are available on the Tribunal's website (www.ipart.nsw.gov.au).

Requirement to publish a pricing information package

The PPWG reviewed the information disclosed in the current pricing booklets, the information disclosed under gas access arrangements, and the disclosure regime in New Zealand. The PPWG emphasised the importance of disclosing the basis of current prices and the directions for future price changes. The proposals discussed by the PPWG are based upon NZ disclosure requirements. In discussing these proposals, the PPWG noted that considerable information on the DNSPs' operations is, or will be, disclosed through the Tribunal's regulatory processes, the asset management plans and the reports of the Licence Compliance Advisory Board. Hence, the pricing information package could refer to information contained in other reports.

Having considered the proposals discussed by the PPWG, the Tribunal has concluded that they provide a sound basis for providing clear guidance to the DNSPs for the preparation of the required pricing information package. These proposals are reflected in 'Pricing notification and information disclosure Rule 99/2'.

Requirement to notify price changes

The PPWG considered the period established for notification of price changes and the timing of price changes.

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[49] DGJ Projects, *Review of Changes to Chapter 6, Part E of the National Electricity Code*, October 1999, pp 1-2.

The PPWG proposes that there should normally be only one change in network prices during a year and that this change should occur on 1 July.

The PPWG is also of the view that DNSPs should provide network users with a minimum of 30 days' notice prior to any changes taking effect. The Tribunal has endorsed this view and incorporated it in 'Pricing notification and information disclosure Rule 99/2'.

Whilst the Tribunal considers DNSPs should continue to be responsible for setting prices, it needs to be:

- adequately informed in advance of changes and potential impacts
- assured that the proposals comply with the Tribunal's determinations
- have an opportunity to raise any concerns it may have about the proposals.

In order to meet these needs, the 'Pricing notification and information disclosure Rule 99/2' requires DNSPs to notify the Tribunal of proposed price changes 30 days in advance of the changes taking effect. This notification must be supported by the information package required in 'Pricing notification and information disclosure Rule 99/2'.

5 RATE OF RETURN

The rate of return is applied to the regulatory asset base to yield a return on assets. The return on capital and return of capital (or depreciation) components constitute over 70 per cent of the base revenue requirement.

Much controversy has surrounded the determination of an appropriate asset base and rate of return for the DNSPs. As it has often signalled, the Tribunal is concerned that an approach, which places undue emphasis on the asset value and rate of return, may not produce appropriate outcomes and may counter the goals of incentive regulation.

5.1 Determination on rate of return

The Tribunal has determined that an appropriate weighted average cost of capital (WACC) (real, pre tax) for the electricity distribution networks lies within the range, 5.0 to 8.5 per cent.

For the purpose of calculating the AARR for NSW DNSPs over the regulatory control period, the Tribunal has decided that a real, pre-tax rate of return of 7.5 per cent is appropriate. This is consistent with a nominal post tax return on equity of approximately 11-12 per cent.

The Tribunal has applied a pre-tax nominal rate of return of 7.6 per cent to working capital.

5.2 Code requirements

The rate of return adopted for the purpose of calculating recommended revenue paths should take account of the outcomes in clause 6.10.2, the principles in clause 6.10.3, and the matters in clause 6.10.5 of the Code.

In particular, the Code requires that the distribution service pricing regulatory regime seek to achieve several outcomes:

Clause 6.10.2(b) states:

> … an incentive-based regulatory regime which: …
>
> (2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Network Owners on efficient investment …; [emphasis added].

Clause 6.10.5 (5) states:

> The distribution network owner's weighted average cost of capital 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 owner in the provision of that network service.

The definition of 'weighted average cost of capital' in chapter 10 of the Code, refers to "an amount determined in a manner consistent with schedule 6.1". Schedule 6.1 defines weighted average cost of capital (WACC) as:

> The weighted average cost of capital is a 'forward looking' weighted average cost of debt and equity for a commercial business entity. Accordingly, the network owner's weighted average cost of capital will represent the shadow price or social opportunity cost of capital as measured by the rate of return required by investors in a privately owned company with a risk profile similar to that of the network company.

The Code provides guidance for the use of the capital asset pricing model (CAPM) and WACC. However, in assessing and applying the model's parameters, issues arise which reveal considerable differences of opinion. The Tribunal notes that CAPM is only one approach to setting a rate of return.

5.3 Public consultation

The Tribunal's s12A review provided useful information to be considered by the Tribunal in making this determination.

The WACC parameters and matters that received primary attention in submissions in response to the Tribunal's analysis for the section 12A review include:

- the risk free rate and the inflation rate
- the market risk premium
- the asset beta
- debt gearing
- the treatment of tax and WACC conversion formulae.

In its submission in response to the Tribunal's section 12A review, NSW Treasury concludes:

> Given recent regulatory determinations on cost of capital and uncertainty relating to the real pre-tax transformation and future tax reform, NSW Treasury proposes that a real pre-tax WACC of 8.0% for NSW distributors be adopted ... [50]

Some DNSPs have suggested that for this determination, a rate of return less than they had initially proposed is appropriate.[51] For example, Great Southern Energy[52] and EnergyAustralia[53] contend that a real pre-tax WACC of 8 per cent is appropriate for their network businesses.

On the basis of advice from KPMG Corporate Finance, Advance Energy notes the appropriate real pre tax WACC for its distribution business is 8.7 per cent in view of its size and inherent business risks borne by its network business. [54]

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50 NSW Treasury, Pricing for Electricity Networks and Retail Supply – NSW Treasury Response, November 1999, p 29.

51 In an initial joint proposal to the Tribunal the DNSPs suggest that a 9.5 per cent real pre tax WACC is appropriate for the NSW electricity network businesses.

52 Great Southern Energy Networks, submission to IPART, September 1999, p 9.

53 EnergyAustralia, submission to IPART, September 1999, p 9.

54 Advance Energy, submission to IPART, September 1999.

NorthPower notes:

> It is NorthPower's position that for this review, the asset value and associated valuation methodology is a more critical issue to be resolved that the precise level of cost of capital for NorthPower. As such, we would not propose a rate of return higher than that, which allows for full ODRC and CPI average price increases. [55]

5.4 Tribunal's analysis and assessment

Cost of capital is a significant element in determining revenues and prices. Economic regulation aims to reflect efficient costs and provide a commercially sustainable revenue stream for the DNSPs. An appropriate rate of return on investment, ie, one that enables owners of regulated businesses to finance their regulated undertakings and obtain reasonable returns in accordance with the risks involved, is an essential component of the rate of return.

If the rate of return is set too low, prices will be distorted and the regulated businesses could become capital constrained or face financial distress. They would then have to reduce their maintenance and capital expenditure to below optimum levels. This would degrade the level of service, resulting in increased costs to consumers.

On the other hand, if the rate of return is set too high, this will be reflected in higher prices. This would provide inappropriate incentives to investors, which may lead to over investment in electricity network assets. This could also result in distorted pricing signals to consumers, and is likely to lead to inefficient outcomes. High prices could distort the apparent economics of network bypass options, demand side management, or the use of alternative energy sources.

In making its assessment on the rate of return, the Tribunal considered:

- submissions made in response to the Tribunal's report for the section 12A review
- the latest market conditions, including advice from Dr Garry Twite and Baring Brothers Burrows
- the principles and requirements of the Code
- the risks faced by the DNSPs, and the risks inherent in the regulatory system
- the impact on end-users and investors/utilities.

In its recent decision on gas arrangements,[56] the Tribunal determined that net working capital should be treated differently in calculating return on capital assets. A nominal return will be allowed on a forecast working capital level. This contrasts with the real return on capital assets (ie system and non-system assets), which will be indexed by CPI over time. The Tribunal notes that in the above and other access decisions, the issue of working capital is insignificant as the return on working capital represents a very small percentage of the total revenue requirement.

55 NorthPower, response to the Pricing Tribunal's Report to the Premier of NSW, October 1999, p 14.

56 For example, IPART, Final Decision on Access Arrangement for Great Southern Energy Networks Pty Ltd, March 1999 and Draft Decision on Access Arrangement for Albury Gas Company Limited, July 1999.

Key issues considered by the Tribunal in making its determination are summarised below.

5.4.1 Approaches to rate of return

There are many approaches that can be taken to estimate an appropriate rate of return. These are set out in more detail in the Tribunal's section 12A report.

Schedule 6.1 of the Code promotes the use of the capital asset pricing model (CAPM) and the weighted average cost of capital (WACC). However, CAPM is just one way of estimating the cost of equity. Other methods that can be used include price/earnings (P/E) ratio, dividend growth model, and arbitrage pricing theory. These alternative models are generally hampered by implementation problems. Given the lack of data, they are impractical at this stage. Thus, at present, CAPM is the most widely accepted procedure for estimating the cost of capital. CAPM has been applied by regulatory agencies to estimate the cost of capital for regulated industries in the USA, UK and Australia. The industry and market participants support the use of CAPM.

As set out in the section 12A report, recent research and studies have revealed problems inherent in applying CAPM, particularly in respect of individual component parameters. [57] One of the most topical issues in relation to the application of CAPM is the treatment of tax.

CAPM expresses the rate of return as post tax nominal WACC. Traditionally, Australian regulators have used a pre-tax WACC formulation - primarily to avoid the complexity of undertaking tax forecasts. However, the debate surrounding the Victorian gas access arrangements last year revealed that none of the formulae available to convert the post-tax WACC to an equivalent pre-tax WACC is sufficiently complex to account for all the relevant factors. The debate revealed that calculations to estimate the effective tax rate were still required under the pre-tax WACC approach.

For this determination, the Tribunal has decided to continue to adopt a pre-tax WACC formulation. However, in doing so, the Tribunal has derived a WACC range using alternative transformation methods, including 'market practice', the approaches suggested by Professor Davis,[58] and a study by Macquarie Risk Advisory Services. [59] The Tribunal notes that is consistent with the approach used in other regulatory contexts, eg Envestra used an average of the two approaches in the access arrangement submitted for the South Australian distribution system.

The conventional market practice conversion sequence involves adjusting first for tax and then for inflation. This is consistent with the approach outlined in schedule 6.1 of the Code.[60] However, the Tribunal is of the view that schedule 6.1 provides a guide, but does not prescribe a mandatory approach for use in regulating electricity networks.

57 The practical difficulties were discussed at the Public Forum on WACC in relation to gas access undertakings which was jointly held by ACCC and ORG on 3 July 1998.

58 *Access Arrangements and Discount Rates: Real Pre Tax and Nominal Post Tax Relationship*, K Davis, 19 May 1998.

59 Macquarie Risk Advisory Services Limited, *Weighted Average Cost of Capital for Victorian Gas Distribution Access Arrangements, July 1998*, p 30. The study models the 50 year financial position, suggesting that under the 'market practice' transformation methods actual returns are higher than expected returns.

60 The conversion method reflects the fact that taxable income is calculated on nominal, rather than real profits. The DNSPs contend that this approach is the most appropriate.

The Tribunal wishes to foreshadow its intention to consider the merits of moving to a post tax rate of return, and thus treating tax as an explicit component of the cost of service in subsequent determinations. For this reason the Tribunal will be seeking more detailed information relating to tax from the NSW DNSPs in the lead up to the next determination.

Attachment 3 of the Tribunal's section 12A report provides a summary of the Tribunal's analysis and consideration of the application of CAPM and WACC. The Tribunal considers that its analysis in the section 12A report is appropriate for regulation under the Code and has, therefore, adopted it in this determination.

5.4.2 Tribunal's assessment of WACC parameters

Risk free rate and inflation

In accordance with the CAPM principles, the risk free rate of return should be assessed on a forward-looking basis. In theory, an 'on-the-day' rate should be used in the CAPM model. However, the use of a relatively short averaging period is considered to be reasonable by the market and academics. Thus, the Tribunal considers that it is most appropriate to derive the risk free rate from a 20 day average of the bond yield. For the reasons given in the s12A report, the Tribunal is of the view that it is most appropriate to use the 10 year Australian Commonwealth bond rate (as opposed to the 5 year rate) to derive the risk free rate.

The 10 year Commonwealth bond rate has moved up by approximately 40 basis points since the release of the section 12A report. The 20 day average of the nominal rates (20 days to 16 December 1999) is 6.62 per cent. This compares with an average (2010) indexed bond rate of 3.52 per cent over the same period. This implies an inflation expectation of 3.0 per cent.

Table 5.1 Risk free rates (%)

	10 year bond	2010 indexed bond	implied inflation
s12A review - 20 day average to 9 June 1999	6.02	3.65	2.30
20 day average to 16 December 1999	6.62	3.52	3.00

Despite the recent increase in the nominal bond yield, the observed real bond yield has been relatively stable over the past 12 months. In effect, the upward movement in the nominal rate is predominantly due to an increase in inflation expectation. For this reason, the increase in the nominal rate has had virtually no impact on the average cost of capital in real terms.

On the basis of this information, for the purpose of this determination the Tribunal has chosen to adopt a nominal risk free rate of 6.6 per cent, and an inflation rate of 3 per cent.

Market risk premium

The market risk premium (MRP) is the margin above the risk-free rate that investors can expect to earn from a well-diversified portfolio of equities. In the section 12A report, the Tribunal recommends a market risk premium range of 5 to 6 per cent for establishing the

WACC for the DNSPs. This figure was based on recent studies that suggest market risk premiums are trending downwards.[61]

NSW Treasury in its submission to the Tribunal has argued that a range of 6 to 7 per cent for the MRP is more acceptable, with the use of a 6 per cent margin for establishing the WACC. Advance Energy, on the advice of KPMG Corporate Finance, states that 5 to 7 per cent is a more appropriate range for its distribution business, given the historical wide fluctuations in risk premium from one period to the next.

The Tribunal has examined a number of more recent studies in considering the appropriate level for the market risk premium for this determination.

A study undertaken by the Centre for Research in Finance at the Australian Graduate School of Management (AGSM) shows a wide range of risk premium.

Table 5.2 Average equity risk premium

Method	Period	Risk premium (%)
Including October 1987		
Arithmetic average	1964-95	6.2
Geometric average	1964-95	4.1
Excluding October 1987[62]		
Arithmetic average	1964-95	8.1
Geometric average	1964-95	6.6

Source: Discussion paper by Dr Gary Twite, prepared for IPART, based on data from the Centre for Research in Finance for 1974-1998.

As shown above, there are significant fluctuations in the measure of market premium. Measures of risk premium are also influenced by the measurement period.

Ibbotson Associates have measured the MRP for various countries, including the USA. The longer term equity risk premium (from 1970-1998) is estimated to be 6.4 per cent.[63] Ibbotson

61 Kortian, T (1998), *Australian Sharemarket Valuation and the Equity Premium*, Department of Finance, University of Sydney. As well as the decline in inflation and the increasing importance of institutional investors which have exerted downward pressure on the Australian equity premium, Kortian (1998) argues that demographic changes due to an increased number of younger savers in Australia's population are important in underpinning the decline of the Australian equity premium.

In addition, in his advice to the ACCC and ORG, Professor Kevin Davis estimates a range of 4.5 to 7.0 per cent for the market risk premium.

The Tribunal also notes that OFWAT considers a more appropriate range for the equity risk premium is 2.75 - 3.75 per cent. In arriving at this range, OFWAT has considered the results of the survey of institutional investors carried out by Credit Lyonnaise Securities Europe (CLSE), recent research published by equity analysts, academic studies, and a Price Waterhouse survey.

62 Exclusion of the October 1987: reduction in share prices increases the market risk premium. However, exclusion of such one off adjustments is controversial and may well bias the estimates upwards.

63 IbbotsonAssociates, *International Equity Risk Premia Report*, 1999.

Associates estimated the market risk premium for Australia to be 3.4 per cent for the period 1970-1998.[64]

Cornell Hirshleifer and James (1997) and Goyal & Welch (1999) have estimated the market risk premium in the US to be 5.6 per cent and 5 per cent respectively.[65]

CSFB Equity Research values AGL at a risk premium of 5.5 per cent.[66]

In its most recent draft decision on the Central West Transmission Pipeline, ACCC adopted a value of 5.5 per cent. This is consistent with Arthur Andersen's comment for AGLGN. In its earlier draft regulatory principles for electricity, ACCC comments that it is probable that a 5.0 per cent market risk premium is more appropriate than the 6.0 per cent allowed in the Victorian decisions.[67]

Recent regulatory decisions and academic advice establish the following risk premium range:

Table 5.3 Market risk premium

Regulatory decision	Date of release	Market risk premium (%)
Officer (according to ORG) [68]	March 1998	6.0
Davis[69]	March 1998	4.5 - 7.0[70]
ACCC (Gas final decision) [71]	October 1998	6.0
ORG Victoria[72]	October 1998	6.0
ACCC Electricity Transmission (draft)	May 1999	6.0
ACCC Central West (draft)	September 1999	5.5
Davis advice to SAIPAR[73]	October 1999	6.0
IPART AGLGN (draft)	October 1999	5.0-6.0

64 IbbotsonAssociates, *International Equity Risk Premia Report*, 1999.

65 Advice from Dr Garry Twite AGSM UNSW.

66 Credit Suisse First Boston, The Australian Gas Light Company, May 1999.

67 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenue*, 27 May 1999, p 79.

68 See Office of the Regulator-General, *Weighted Average Cost of Capital for Revenue Determination: Gas Distribution*, 27 March 1998, p ii.

69 Kevin Davis, *The Weighted Average Cost of Capital for the Gas Industry*, Report Prepared for the Australian Competition and Consumer Commission and Office of the Regulator General, March 18 1998, p 13-4.

70 With a preference towards the lower end of this range.

71 Australian Competition and Consumer Commission, *Victorian Gas Transmission Access Arrangements Final Decision*, 6 October 1998, p 53.

72 Office of the Regulator-General, *Weighted Average Cost of Capital for Revenue Determination: Gas Distribution*, 27 March 1998, p ii.

73 Davis, K, The Weighted Average Cost of Capital for Access Arrangements for Envestra, Draft, prepared for the South Australian Independent Pricing and Access Regulator (SAIPAR), October 1999.

In the light of the above information and given the continued low inflation environment,[74] the Tribunal considers that the market risk premium of 5 to 6 per cent recommended in the section 12A report should be used in establishing the WACC range for the purpose of this determination.

Asset beta

The Tribunal recommends an asset beta of 0.35 to 0.50 for the WACC for the NSW DNSPs. NSW Treasury notes in its submission to the Tribunal that this asset beta range is low relative to "both relevant industry benchmarks and the recent Victorian gas decisions".[75] The Treasury provides a selection of asset betas to support its case.

In their draft decision for the Victorian gas network, the ACCC and ORG used a range of 0.35 to 0.40. They then adjusted the asset beta upward to 0.55 to allow for company-specific risks in the final decision. This practice is inconsistent with CAPM,[76] as recently noted by Professor Kevin Davis in his report to the South Australian Independent Pricing and Access Regulator (SAIPAR) regarding its decision on Envestra's proposed access arrangement. Thus the asset beta assumption for the decision is artificially high, and is not an appropriate benchmark.

Recent regulatory decisions in relation to electricity utilities have applied asset betas as low as 0.3 and as high as 0.5 (see table below). The Tribunal's proposed asset beta assumption appears to be consistent with recent regulatory decisions.

Table 5.4 Asset betas used in regulatory decisions

Regulator	Decision	Asset beta
ACCC	Victoria Gas (draft)	0.35
ACCC	Victoria Gas (final)	0.55
ORG	Victoria Gas (draft)	0.40
ORG	Victoria Gas (final)	0.55
IPARC	ACTEW electricity (draft)	0.35 - 0.45
ACCC	TransGrid (draft)	0.45
ACCC	Central West Pipeline (draft)	0.60
IPART	Wagga Wagga gas network (final)	0.4 – 0.5
IPARC	ACTEW electricity (final)	0.3 – 0.5
IPART	Albury gas network (draft)	0.4 – 0.5
IPART	AGLGN (draft decision)	0.4 - 0.5
OTTER	Tasmania electricity (final)	0.42[77]

74 Recent surveys of indicators of prices have shown that inflationary pressures remain subdued. Separating out the impact of the GST, it is expected only modest upward pressure on the underlying CPI will occur during the next year or so.

75 NSW Treasury, NSW Treasury Response, November 1999, p 24.

76 The purpose of an asset or equity beta is to capture the systematic risk of a company, which may not align with the company's total risk.

77 This asset beta is implied by OTTER's equity beta assumption of 0.95 and its debt gearing assumption of 50-70 per cent, assuming a debt beta of 0.06, and using the Monkhouse delivering formula.

According to a World Bank policy research working paper, firms regulated under the rate of return regulation have lower asset beta than a comparable firm operating under a price cap mechanism. Thus, electricity utilities tend to have relatively lower asset betas than their counterparts in the gas monopoly.

Table 5.5 Asset betas of utilities

Type of regulatory regime	Gas	Electricity	All
High power incentives, eg price cap regime	0.84	0.57	0.71
Intermediate	0.57	0.41	0.60
Lower powered incentives, eg rate of return regime	0.20	0.35	0.32

Source: Regulatory Structure and Risk of Infrastructure Firms: An International Comparison, Alexander, Mayer and Weeds, World Bank Policy Research Working Paper 1998.

The building block approach applied by the Tribunal in this determination in determining the base revenue requirements for NSW DNSPs is similar to the rate of return regulatory regime. Arguably, the asset beta applicable to an electricity network business should not be as high as that borne by the utilities operating under a 'high powered' incentive regime, particularly when the regulatory approach is moving toward a fixed revenue cap. This suggests that the asset beta assumption for the NSW DNSPs should be lower than the asset beta assumptions used for the gas regulatory decisions noted above. [78]

This analysis is supported by the National Economic Research Associates (NERA) in its recent critique of the WACC parameters proposed by the ACCC for TransGrid:

> … we would expect the fact that TransGrid is to be regulated by means of a revenue cap (as opposed to the `revenue yield' form of price control applied to the Victorian gas businesses) to cause its beta to lie towards the bottom of the range for network service providers. All else equal, a revenue cap is more likely to shield a regulated business from swings in the economic cycle than other forms of price control which allow revenue to move in relation to energy transported. [79]

Furthermore, arguments that the distribution businesses face significant demand risk are not relevant for the asset beta estimate. Volatility of demand is a firm specific risk and as such, is diversifiable by investors. To the extent that this risk can be recovered, it should be reflected in the cashflow estimation rather than in the required rate of return.

In addition, various 'industry benchmarks' can be used to support the Tribunal's asset beta assumption, such as those for Australian industry groups:

78 The Tribunal recognises that care should be taken when reviewing overseas companies to derive beta assumptions, particularly in respect of the adjustments for gearing and the implicit assumption that the risk of the market portfolio is the same in each country.

79 NERA, A *Critique of the WACC Parameters Proposed for TransGrid*, May 1999, p 13.

Table 5.6 Asset beta assumptions for selected Australian industry groups

ASX industry group	Geared beta	Asset beta[80]
Telecommunications	0.70	0.41
Infrastructure & utilities	0.61	0.46

Source: Risk Management Service, Centre for Research in Finance, AGSM.

In light of above, the Tribunal does not see merit in revising its asset beta assumption of 0.35 to 0.50 (with a midpoint of 0.425) as recommended in the section 12A review. The Tribunal has therefore used this assumption to establish the WACC for the DNSPs.

Gearing

In the section 12A review the Tribunal concludes that a gearing of 60 per cent is appropriate for establishing the WACC for the DNSPs.

Drawing on advice from KPMG, Advance Energy in its submission to the final review argues for a lower gearing because of the small size of Advance relative to other DNSPs, and its concentrated industrial customer base. These customers' businesses (principally mining and agriculture) are by nature more subject to variable business cycles. It is argued that a gearing assumption of 40 to 45 per cent is more appropriate for Advance Energy.

However, Advance's arguments are not in accordance with the CAPM theory. Volatility of demand and hence earnings is categorised as firm specific risk and as such, is diversifiable by investors. To the extent that this risk can be insured against, it should be reflected in the cashflow estimation rather than in the required rate of return. For example, the expected cashflow of Advance could be adjusted to incorporate an allowance for a fair cost of insurance against such risks or a faster rate of depreciation.

The size of a firm does not impact directly on its capital structure. Gearing depends more on the capacity of a firm to repay debt and interest. This capacity depends on the sustainability of cashflows from its operations.

Advance Energy argues that generally, smaller firms have higher expected returns because they have higher risk, in keeping with the 'small company' theory. Whilst the small company theory is well documented and researched in the field of finance, the debate continues. A recent UK study[81] documents the long term performance of smaller companies, as compared to large capitalisation equities in the UK. The study reveals that the historical size premium of small cap companies (for 1955 to 1988) went into reverse during the last decade (1989 to 1997). The study concludes that the 'size effect' causes small cap stocks to perform differently from large caps, but does not necessarily manifest itself through a 'size premium'.

The gearing of 60 per cent was determined on the basis of an efficient, typical network business rather than the specific circumstances of a particular business. There appears to be

80 Delivered by the Monkhouse formula used by ACCC.

81 *Murphy's Law and Market Anomalies*, Elroy Dimson and Paul Marsh, Professors of Finance at London Business School, August 1998.

no theoretically good reason for adjusting the gearing of Advance Energy on the basis of its size and variability of demand.

NSW Treasury proposes a gearing of 50 per cent, arguing that a high gearing level is unsustainable given the possibility that accelerated depreciation will be abolished following a recent recommendation by the Ralph Business Tax Review. This would have the effect of increasing the tax charge and reducing the after tax cashflow of the DNSPs.

However, the Ralph Business Tax Review also proposes reducing the capital gains and company tax from 36 to 34 per cent and then 30 per cent in two steps. This would reduce the tax paid by businesses and increase the after tax cashflows. The impact of the tax review on the distributors cannot be known until a thorough assessment of the total tax package is undertaken.

It should be noted that ACCC in its draft decision on TransGrid uses 60 per cent gearing to establish the WACC. In his report to SAIPAR regarding a suitable WACC for access arrangements for Envestra, Kevin Davis concurs that 60 per cent is a reasonable gearing assumption for a typical utility.

The latest financial position of the listed utilities shows the following debt to debt and equity ratio:

Table 5.7 Gearing of Australian listed utilities

$ million	Debt	Market capitalisation	Debt/(Debt+Market capitalisation %))
United Energy	1,228	832	59
Envestra	1,228	899	69
AGL group	1,316	3,614	27

Having regard to the above evidence and information, a gearing assumption of 60 per cent is considered appropriate for the electricity network businesses, given the stability and sustainability of their operating cashflows.

Cost of equity

On the basis of the parameters noted above, ie:

- a nominal risk free rate of 6.6 per cent
- a risk premium on equity in the range 5.0-6.0 per cent
- a range for the asset beta of 0.35-0.50
- an equity beta of 0.78-1.14 derived assuming 60 per cent debt gearing and a debt beta of 0.06,[82]

the Tribunal has derived a nominal post tax return on equity of 10.5 to 13.5 per cent.

[82] The equity beta is converted from the asset beta using the Monkhouse formula: Be=Ba+(Ba-Bd(1-rd)/(1+rd)T)D/E.

Cost of debt

In the section 12A report, the Tribunal concluded that the cost of debt appropriate for the electricity utilities is 1.0 per cent above the 10 year Commonwealth bond rate.

The cost of debt varies, depending on the gearing of the business and the terms of the debts. The cost of debt is established by the WACC calculation by adding a margin to the risk free rate.

Debt margins used in regulatory decisions and advised by academics are as follows:

Table 5.8 Debt margin

	Debt margin (%)
ACCC Victoria gas (draft)	0.80
ACCC Victoria gas (final)	1.00
ACCC TransGrid (draft)	0.80 – 1.20[83]
IPART section 12A report	1.00
ACCC Central West Pipeline (draft)	0.80 – 1.20[84]
Davis (advice on Envestra gas access)	1.2[85]
IPART- AGLGN (draft decision)	0.90 – 1.10[86]

Since the release of the Victorian gas final decision the uncertainty in global financial markets has reduced. [87]

In the financial year to 30 June 1998, the NSW distributors reported the following interest rate risk exposure:

83 but use 1.00 for calculation.
84 but use 1.00 for calculation.
85 based on a BBB rating.
86 As proposed by Arthur Andersen.
87 As proposed by Arthur Andersen.

Table 5.9 Effective interest rates of NSW distributors ($'000, except where otherwise indicated)

	Floating interest rate	Maturing 1 year or less	Maturing 1 to 5 years	Maturing more than 5 years	Total borrowings	Weighted average EIR[88] (%)
EnergyAustralia	296	3	620	386	1,305	6.66
Integral	-	11	214	595	820	5.67
NorthPower	60	2	40	36	139	7.58
Great Southern Energy	1	0	91	0	91	6.85
Advance Energy	-	6	6	28	40	7.82
Australian Inland Energy	-	-	-	-	-	-
Total	357	22	970	1,045	2,395	6.40
Portfolio weighting	15%	1%	41%	44%		

The weighted average effective interest rate borne by the distributors varies from 5.7 per cent to 7.8 per cent based on a portfolio of short and long term borrowings. The overall weighted average for the industry is 6.4 per cent with 44 per cent of the loans maturing after more than five years.

As at 30 June 1998, the 10 year bond rate was 5.58 per cent. This indicates that the distributors' aggregate borrowings were exposed to a margin of 0.82 per cent over the 10 year Commonwealth bond rate at 30 June 1998.

In the light of the distributors' weighted average effective interest rate, recent regulatory decisions, and other information detailed above, the Tribunal is of the view that it is more appropriate to use a debt margin range of 0.80 to 1.00 per cent to establish the WACC for the network businesses. However, it is worth noting that adopting this range for the debt premium, relative to using a point estimate of 1 per cent, only results in a marginal change in the WACC range. All else equal, it reduces the mid-point of the range by 0.06 per cent.

Tax assumptions

As set out in section 5.4.1, CAPM provides a basis for calculating the post tax cost of equity, ie an after tax return to equity investors. The required post tax rate of return is then translated to a pre tax return by reference to a tax rate. At issue is whether the effective tax rate or statutory tax rate should be assumed for this purpose. In line with the initial proposals by the DNSPs and the government shareholder, the Tribunal assumes a statutory tax rate of 36 per cent in the section 12A review.

Government owned enterprises (and therefore the NSW DNSPs) do not pay income tax to the Australian Taxation Office. Instead it is calculated under the NSW tax equivalent

88 Effective interest rate.

regime.[89] Until recently, the NSW Treasury adopted a financial distribution policy based on pre tax profits. However, its current policy has been negotiated and set on a post tax basis. NSW Government trading enterprises (GTEs) are required to adopt tax effect accounting and tax planning. It appears GTEs are in the early years of the tax equivalent regime. If fully applied, the depreciation deduction for tax purposes is likely to be greater than accounting depreciation. As a result, the effective tax rate is likely to be less than 36 per cent. In a recent discussion paper, the Tribunal's notes its analysis suggests that the effective rate for the six NSW distribution network businesses in the next ten years is likely to average 27 per cent.[90]

The Tribunal believes the utilities should manage their own tax affairs. Applying the effective tax rate would pass some of the tax benefits on to end-users.

The benefits of accelerated depreciation and the tax shield provided by debt defer tax liabilities. As a result, the effective tax rate will vary over time. Initially, it will be below the statutory rate. In later years it will be above the statutory rate. Given current depreciation and inflation rates, the long term average rate is likely to be below the statutory rate.[91]

The difference between the statutory and effective tax rates raises risks if the statutory rate is used in establishing the regulated revenue path.[92] For instance, the varying effective rates of return may encourage gold-plating in the early years and under-investment later.

At this stage further work is required to estimate the effective tax rate and consider how this can be incorporated into the regulatory regime.

As a consequence of the Ralph Business Tax Review, there is likely to be a change in the corporate statutory tax rate from 36 to 34 per cent and then 30 per cent in two steps. These changes will affect the value of imputation credits and will abolish accelerated depreciation for tax purposes. All else being equal, adopting a tax rate assumption of 34 or 30 per cent will have little impact on the WACC.[93] However, changes that affect the value of imputation credits are likely to have a more substantial impact on the WACC. The exact magnitude is difficult to quantify at this stage. Further, the changes in the effective tax rate as a result of the changes in the tax depreciation rules are not relevant while the Tribunal continues to use the statutory tax rate. For these reasons, the Tribunal has calculated the WACC at both the existing and proposed statutory tax rates, and had regard to the impact on a range for WACC.

The Tribunal recognises that a key question that remains is the difference in net present value terms between actual tax paid over the life of an asset, and tax allowed using the statutory rate. As signalled in section 5.4.1, the treatment of taxation will be examined further in future reviews and determinations.

89 Effective interest rate.

90 IPART, *The Rate of Return for Electricity Distribution Networks*, A Discussion Paper, November 1998, p 9.

91 See ORG, *Cost of Capital Financing*, May 1999, p 43.

92 Ibid, p 46.

93 Changing the tax assumption from 36 per cent to 34 or 30 per cent reduces the WACC (real, pre tax) by between 0.1 and 0.3 per cent.

5.4.3 A feasible range for the rate of return

Given the inherent conversion problems and the arbitrariness of the combined effects of different inputs to CAPM, the Tribunal has adopted a feasible range for the cost of capital.

As detailed above, the Tribunal has revised a number of parameters used in the section 12A report. These revisions have been made in light of prevailing market conditions and methodologies currently followed by market practitioners and other regulators. The changes involve:

- an increase in the nominal risk free rate by 0.6 per cent
- an increase in the inflation assumption from 2.29 per cent to 3.00 per cent
- a decrease in the real risk free rate by 0.13 per cent
- a change in the debt premium from 1 per cent to consideration of a range of 0.8 to 1 per cent
- a range for the tax rate assumption of 30 to 36 per cent, instead of 36 per cent.

Using these parameters, the application of the CAPM/WACC model results in a rate of return in the range of either:

- 10.5 - 13.5 per cent nominal post tax return on equity
- 5.0 - 8.5 per cent pre tax real rate of return on capital. [94]

Table 5.10 presents the results of the parameters adopted by the Tribunal for the purposes of this determination:

Table 5.10 WACC parameters adopted by IPART

	Section 12A review	This determination
Risk free rate	6.02%	6.62%
CPI	2.29%	3.00%
Real risk free rate	3.65%	3.52%
Market risk premium	5.0 - 6.0%	5.0 – 6.0%
Debt margin	1.0%	0.8 - 1.0%
Debt to total assets	60%	60%
Gamma	0.5 - 0.3	0.5 - 0.3
Tax rate	36%	30 – 36%
Asset beta	0.35 - 0.50	0.35 - 0.50
Debt beta	0.06	0.06
Equity beta	0.77 - 1.14	0.78 - 1.14
Cost of equity (nominal post tax)	9.9 - 12.9%	10.5 – 13.5%
Cost of debt (nominal pre tax)	7.0%	7.4 – 7.6%
WACC (nominal post tax)	5.8 - 7.1%	6.6 – 7.5%
WACC (real pre tax)	5.3 - 8.6%	5.0 – 8.5%

94 The lower and upper range are the real pre tax WACC derived using the two alternative conversion methods from nominal post tax WACC to real pre tax WACC.

5.4.4 Other evidence and considerations

As set out in the Tribunal's section 12A report there are a number of other considerations relevant to the decision of an appropriate rate of return. In the report the Tribunal notes that market expectations and the decisions of overseas regulators[95] are both relevant to the Tribunal's decisions. Since the release of the Tribunal's section 12A report, a number of UK regulators have released their decisions.

OFWAT recently made a decision in which a range of 4.25-5.25 per cent was adopted for the post-tax real cost of capital for "an efficiently financed water company". [96] This range was derived using:

- a risk free rate of 2.5 – 3 per cent
- a debt premium of 1.5 to 2 per cent
- an equity risk premium of 3 to 4 per cent
- an equity beta of 0.7 to 0.8
- gearing of 'around' 50 per cent.

OFGEM recently decided that a real pre-tax WACC range of 6 to 6.9 percent was applicable, and that a rate of 6.5 per cent should be adopted for the purpose of calculating the price controls of the UK electricity distribution business. [97] OFGEM bases this decision on:

- a risk free rate of 2.5 per cent
- a debt premium of 1.4 per cent
- a cost of debt of 4.3 per cent
- an equity risk premium of 3.5 per cent
- an equity beta of 1.0
- gearing of 50 per cent
- a post tax cost of equity of 6 per cent
- a 'taxation adjustment' of 1.429.

5.4.5 Conclusions

As established above, the use of CAPM/WACC means the rate of return for the electricity distribution networks should be within the range 5.0 - 8.5 per cent (real, pre tax). Within this range, a single rate of return must be used to calculate the regulated revenue for each DNSP.

The Tribunal is required to arrive at a rate of return having regard to all the objectives and requirements of the Code. Important considerations include the impact on end-users and investors/utilities. If returns are set too high, they will impact adversely on the competitiveness of end-users and may encourage inefficient bypass. If returns are set too low, there will be an equally undesirable outcome - investors/utilities may be reluctant to

[95] While these estimates are of interest, the Tribunal recognises that care should be taken when comparing rates.

[96] OFWAT, Final Determination Future Water and Sewerage Charges 2000-2005.

[97] OFGEM, Distribution Price Control Review, Final Proposals, December 1999.

invest in the industry, resulting in a degradation of service standards. A return on new investment should be sufficient to satisfy capital providers, lenders and investors operating in the market. However, given the differences of opinion about how WACC should be calculated under a CAPM framework, the regulator's judgement is critical in arriving at an appropriate point estimate for the rate of return.

In the section 12A report, the Tribunal proposed that a rate of return towards the higher end of the range under the CAPM framework, is appropriate for the DNSPs. This was proposed by the Tribunal once it had considered the risks facing the DNSPs, evidence on market expectations of the rate of return, risks inherent in the regulatory system, and other economic considerations. The Tribunal proposed that a real pre tax rate of return of 7.5 per cent should apply to EnergyAustralia, Integral Energy, NorthPower and Great Southern Energy, and that a real pre tax rate of return of 7.75 per cent should apply to Advance Energy and Australian Inland Energy. This conclusion was in line with a nominal post tax return on equity of approximately 11-12 per cent.

A higher rate of return for Advance Energy and Australian Inland Energy was proposed by the Tribunal in the section 12A report to account for the DNSPs' higher proportion of industrial customers, and thus exposure to revenue risk due to the potential closure of any of these large businesses. [98]

On balance, the Tribunal considers that a rate of return within the range 7-8 per cent (real pre tax) is appropriate for the DNSPs. Changes in market conditions since the section 12A report, has had little impact on the range under the CAPM framework. Indeed, the midpoint of the return range derived under CAPM has only fallen marginally by 0.2 per cent.

However the Tribunal no longer considers it appropriate for Advance Energy and Australian Inland Energy to earn a higher rate of return. In contrast to the MAR formula used in the section 12A report, the Tribunal has adopted a pure revenue cap approach for this determination. Under a revenue cap, the DNSPs are sheltered from the revenue risks arising from a high industrial customer base, and therefore should not be compensated for these risks.

Having considered the matters described above, the Tribunal determines that a real pre tax rate of return of 7.5 per cent should apply to all DNSPs, EnergyAustralia, Integral Energy, NorthPower, Great Southern Energy, Advance Energy and Australian Inland Energy. This conclusion is consistent with a nominal post tax return on equity of approximately 11-12 per cent.

This determination should not be seen as binding the Tribunal's future regulatory decisions on rates of return for this or other industries.

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98 It should be noted that the Tribunal recognises, as detailed in the section 12A report, that business risk of this type is diversifiable and therefore not captured by CAPM. Under the CAPM model, these risks should be included in the cash flow rather than the WACC. However, a similar effect can be achieved by adopting the common practice of including a loading on the rate of return.

6 CAPITAL BASE

6.1 Initial capital base

Together with operating and maintenance expenditure, return on capital and return of capital constitute the building blocks used to determine base revenue requirements. Return on and return of capital constitute over 70 per cent of the base revenue requirement.

As is noted in Chapter 5, the Tribunal is concerned that an approach that places too much emphasis on the asset value and rate of return may not produce appropriate outcomes and may counter the goals of incentive regulation.

6.1.1 Determination on regulatory capital base

The DNSPs' initial capital base for each DNSP as at 30 June 1998 is as follows:

Table 6.1 Initial capital base at 30 June 1998

DNSP	Initial capital base ($m)[99]
EnergyAustralia[1]	3,767
Integral Energy	1,732
NorthPower	858
Great Southern Energy	515
Advance Energy	303
Australian Inland Energy	50
DNSP total	**7,225**

1: EnergyAustralia's initial capital base includes its transmission assets.

See Attachment 2 for information on working capital.

6.1.2 Code requirements

Clause 6.10.3 of the Code sets out the requirements for valuing the initial capital base. In particular, clause 6.10.3(e)(5)(iii) states that:

> … valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the Jurisdictional Regulator. In determining the basis of asset valuation to be used, the Jurisdictional Regulator must have regard to:
>
> A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;
>
> B any subsequent relevant decisions of the Council of Australian Governments; and
>
> C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2

99 Includes streetlighting assets.

6.1.3 Public consultation

Throughout the s12A review and subsequent public consultation, much attention has focused on the initial capital base. As mentioned above, the Tribunal is concerned that stakeholders place too much emphasis on issues surrounding the asset base. Doing this deflects attention from the regulatory framework and its ability to provide incentives for efficient performance.

Nevertheless, the Tribunal notes the healthy debate surrounding the proposed asset values set out in the s12A report. Those asset values are close to the depreciated optimised replacement cost (DORC) valuations. Stakeholders were clearly divided into two positions: those supporting a DORC valuation and those opposing a DORC valuation.

The DNSPs and Treasury support the use of DORC. For example, in its submission, EnergyAustralia states:

> EnergyAustralia supports the Tribunal's use of ODRC as a means to provide an appropriate base for regulated assets.
>
> EnergyAustralia requests the Tribunal establish guidelines on ODRC valuation and optimisation in consultation with network service providers.

Advance Energy also supports the use of DORC, stating:

> Advance Energy strongly supports the first main principle in this report which is the ODRC approach for valuation of assets as it provides for transparent and repeatable network asset valuations. It is also economically efficient by replicating asset valuations under market conditions, meets the objectives of the National Electricity Code (the Code), has no revenue circularity problems, is independently verifiable and is consistent with the building block approach.

The NSW Treasury position is summarised as:

> NSW Treasury endorses the asset values for DNSPs proposed by IPART for the following reasons:
> - The values are based on independently determined professional valuations
> - The valuations were confirmed by an independent IPART review
> - The values were determined following the ODRC approach
> - The values are consistent with an appropriate balancing of the interests of owner and customer.

On the other hand, the Business Council of Australia object to the use of DORC, stating:

> The late intervention of the government, by requiring the Tribunal to adopt the inflated DORC asset valuation is regrettable, as it will mean electricity prices to consumers and downstream industries that are higher than otherwise might be the case.
>
> We consider that the justification for intervention (viz "reasonable recognition of pre-existing policies of the government") cannot be supported if the Tribunal is seeking "to balance the interests of the owners and users of NSW electricity services."

Likewise, in its submission, the Energy Markets Reform Forum states its opposition to DORC:

> We are strongly opposed to the intervention by the NSW Government, which has resulted in IPART adopting the inflated DORC asset valuation. This action raises the asset value of the Distribution Businesses by some $2.2 billion, and will in effect over-recover some $160 million to $170 million in revenue per year from electricity users in this State. This will deliver an economically sub-optimal outcome for the NSW economy and the people in this State.

6.1.4 Tribunal's assessment

The Tribunal has considered the principles and matters set out in the Code including clauses 6.10.2 and 6.10.3.

Clause 6.10.2(e) of the Code requires the Tribunal to give reasonable recognition to the pre-existing policies regarding asset values, revenue paths and prices where the assets are government-owned. The s12A report notes that the Premier wrote to the Chairman of IPART in June 1999, confirming the Government's pre-existing policies, which include:

- independently determined ODRC valuations of the physical assets of the NSW distributors (incorporating revisions to Treasury guidelines as recommended by the independent consultants); and
- replacement cost valuations of easements prepared by independent consultants.

Having considered all information presented to the Tribunal, it has balanced the interests of stakeholders and determined that the position on the initial capital base in Table 6.1 is appropriate in this determination. The initial capital base illustrated in Table 6.1 is consistent with the proposed valuations in the s12A report. These values are expected to deliver revenue streams and network prices sufficient to finance network functions, maintain service standards and earn reasonable returns.

The Tribunal's determination does not bind future regulatory decisions on initial capital bases for the electricity industry or any other industry.

6.1.5 Easements

The Tribunal included in the initial capital base at historical costs easements in existence at 1 July 1999, as specified in table 6.2.

Table 6.2 Easement values as at 30 June 1998, ($'000)

DNSP	Value of easements
EnergyAustralia	9,797
Integral Energy	2,916
NorthPower	205
Great Southern Energy	987
Advance Energy	nil
Australian Inland Energy	nil

Source: GHD/Worley/Arthur Andersen asset valuation report.

To include a market value for existing easements in the initial asset base would be of no economic benefit. If new easements need to be acquired, the expenditure will be considered on the same basis as the other elements of capital expenditure (see section 6.3).

The Tribunal recognises that easements are required by the DNSP to provide prescribed distribution services. Electricity easements generally apply in perpetuity. Gradual growth in load, and the difficulty and expense of negotiating a new easement means that they are rarely replaced. Indeed, a network is far more likely to seek to alter the terms of an existing easement to allow a different sized wire to be erected than to extinguish an easement and negotiate a new one. The restrictive nature of easements (ie being an easement for electricity distribution lines only) may mean that they have no value to any other entity.

6.1.6 Working capital

The Tribunal considers that any business must maintain an investment in working capital to allow it to manage the lag between payments to suppliers and receipts from customers. Also, many businesses maintain an investment in spares inventory. The Tribunal considers that an investment in working capital is a necessary part of conducting a network business, and should earn a return in a manner similar to investment in physical assets.

In its recent decisions on access arrangements[100], the Tribunal determined that net working capital should be treated differently in calculating return on capital assets. A nominal return of 7.6 per cent (the pre-tax nominal cost of debt per Table 5.11) will be allowed on a forecast working capital level. This contrasts with the real return on capital assets (ie system and non-system assets), to which the Tribunal has applied CPI indexation over time. The Tribunal notes that in many cases, the issue of working capital is insignificant as the return on working capital represents a very small percentage of the total revenue requirement. In some cases (eg Albury Gas Company), net working capital is assumed to be zero.

In this determination, the Tribunal assessed the reasonableness of working capital based on a balance sheet approach. This analysis was distorted by a number of one-off adjustments and prepayments, and also by inconsistent reporting by the DNSPs from year to year. This led to significant variability in the relative amounts of working capital among the DNSPs.

In order to determine a reasonable level of working capital for each of the DNSPs, the Tribunal adopted a simplified payment cycle approach. Generally, this approach allows for the amount of working capital to be estimated based on the amount of time payments and receipts are outstanding. For the purposes of this determination, the Tribunal has assessed the level of working capital assuming that payments from customers are outstanding for 45 days from the date of service delivery, and that suppliers (for both operating and capital expenditures) are paid 30 days after service delivery. The Tribunal also added an allowance for inventory.

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100 See for example, IPART, *Final Decision on Access Arrangement for Great Southern Energy Networks Pty Ltd*, March 1999, *Draft Decision on Access Arrangement for Albury Gas Company Limited*, July 1999, and *Draft Decision*, *Access Arrangement for AGL Gas Networks Limited Natural Gas System in NSW*, October 1999.

This can be expressed as follows:

	Total network revenue (DUoS + TUoS)	* 45/365
less	Operating costs (including TUoS costs)	* 30/365
less	Capital expenditure	* 30/365
plus	Inventory ($).	
Equals	Working capital	

The return on working capital is included in the building block analyses shown in Attachment 2.

6.2 Rolling forward the capital base

6.2.1 Determination on rolling forward the capital base

The initial capital base at 30 June 1999 is determined as follows:

- ***initial capital base as at 30 June 1998 (listed in Table 6.1) indexed by the CPI***
- ***capital expenditure for 1998/99 indexed by half the CPI percentage***[101]
- ***depreciation as calculated in Attachment 3 deducted***
- ***asset disposals deducted.***

6.2.2 Future treatment of the initial capital base

In respect of regulatory assets in existence at 1 July 1999, the Tribunal is of the view that:

- stranded or redundant assets should be dealt with via the calculation of optimised deprival value (ODV) for each DNSP at 30 June 2003
- in calculating ODV the economic value of the assets should be compared to the then current estimate of DORC, on an asset class by asset class basis.

For assets brought into existence after 1 July 1999:

- subject to a prudency test, the asset base should be rolled forward based on forecast capital expenditure until 30 June 2003. After 30 June 2003 this capital expenditure will be tested for prudency and the regulatory capital base will be adjusted to take account of actual capital expenditure. The service provider will retain the return on the difference between projected and actual expenditure during the period
- prudent investment in demand management should be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure.

For the purposes of determining the AARR until 30 June 2004:

- the initial capital base at the start of each year is indexed by the CPI
- projected capital expenditure (excluding capital contributions) is added and indexed by half the CPI percentage for the year in which the expenditure has been incurred[102]

101 Capital expenditure occurs throughout the year. Half the percentage change in CPI is used because, on average, the capital expenditure would be incurred half way through the year.

- depreciation and asset disposal are subtracted.

6.2.3 Code requirements

The Code does not explicitly specify an asset roll forward methodology. However, the principles in clauses 6.10.2 and 6.10.3 of the Code apply. As noted above, clause 6.10.3(e)(5)(iii) of the Code provides guidance on any valuations of new or revaluations of existing assets. The Code requires the Tribunal and the jurisdictional regulator to have regard to the Council of Australian Governments agreement of 19 August 1994, that deprival value is the preferred approach to valuing network assets.

Clause 6.10.2(b)(2) requires that the jurisdictional regulator seek to achieve a sustainable commercial revenue stream which provides distribution network owners with a fair and reasonable rate of return on efficient investment:

> 6.10.2 Objectives of the distribution service pricing regulatory regime to be administered by the Jurisdictional Regulators
>
> The distribution service pricing regulatory regime to be administered under Part D of the Code must seek to achieve the following outcomes: …
>
> (b) an incentive-based regulatory regime which: …
>
> (2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Network Owners on efficient investment, given efficient operating and maintenance practices of the Distribution Network Owners;

It is reasonable to regard 'efficient investment' as including efficient capital investment between regulatory reviews. This reading suggests that DNSPs should receive a return of capital and a return on capital on efficient capital investment at the time that the investment is made. Efficient capital investment should be rolled into the regulatory asset base when it is commissioned, rather than requiring DNSPs to wait until the following regulatory review before a return on the new capital expenditure is granted.

Clause 6.10.2 appears to recognise that a balance is required between investment in the industry, and the efficient use of existing infrastructure:

> (d) an environment which fosters an efficient level of investment within the distribution sector, and upstream and downstream of the distribution sector;
>
> …
>
> (f) an environment which fosters efficient use of existing infrastructure;

6.2.4 Public consultation

Several DNSPs have expressed concern about the Tribunal's proposal to calculate an ODV for each DNSP as part of the next regulatory review. For example, EnergyAustralia states:

> EnergyAustralia does not support the Tribunal's proposal to adopt the Optimised Deprival Value by asset class at the next regulatory review. There are a number of flaws with this method if applied to the electricity industry. EnergyAustralia supports all asset

102 Capital expenditure occurs throughout the year. Half the percentage change in CPI is used because, on average, the capital expenditure would be incurred half way through the year.

> values to be valued consistently by ODRC and trusts that the Tribunal will adequately consult with the industry before the next review about this issue.

NorthPower expresses similar reservations:

> NorthPower is concerned by IPART's reference to conducting an ODV of this nature for pre 1 July 1999 assets as it reintroduces the inherent circularity problems of prices linked to asset values linked to prices.

SEDA is concerned that the proposed process for rolling in new assets may encourage DNSPs to focus on supply side options only. In order to align DNSPs' incentives with broader economic efficiency objectives, SEDA recommends:

> … that IPART state explicitly that prudent investment in DM [demand management] may be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure

6.2.5 Tribunal's assessment

The Tribunal acknowledges that an ODV valuation depends on cost allocation methodology and costs and revenue assumptions. As stated in section 6.1, the Tribunal has determined a write up in asset values to DORC from their 1996 value rolled forward, while at the same time delivering network price reductions. This has been facilitated by the reduction in the cost of capital since the 1996 review.

The Code does not 'lock in' asset values. Rather, the Code allows regulators scope to revalue existing assets and new assets (clause 6.10.3(5)). The Tribunal proposes to split the asset base into sunk and new assets. Consistent with the intention in clause 6.10.3(e)(5) of the Code, the Tribunal requires DNSPs to keep two separate pools of assets:

- assets in existence and in service at 1 July 1999
- assets brought into existence after 1 July 1999.

In its next determination, the Tribunal may consider calculating an ODV value for each DNSP for pre-1999 assets.

Capital related costs are the major portion of costs in infrastructure industries. Any improvements in the efficiency of capital expenditure may provide cost savings in the long term. The Tribunal is mindful that it must provide the appropriate signals to regulated entities to encourage efficient investment. Such incentives are in the long term interests of customers.

Before rolling into the initial capital asset base actual capital expenditure for the period 1 July 1999 to 30 June 2003, the Tribunal will have a prudency review conducted. Prudent investment in demand management may be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure.

6.3 Capital expenditure

In determining the AARR, the Tribunal must ensure that each DNSP has sufficient capacity (either debt or equity) to fund prudent and efficient investments in its network, having regard to future demand and service standards. In making this assessment, the Tribunal is mindful of the relationship between capital expenditure, operating expenditure, demand management and distributed generation.

6.3.1 Determination on capital expenditure

The Tribunal has incorporated the capital expenditure projections illustrated in Table 6.3 into the building block analysis.

Table 6.3 Capital expenditure projections ($1999)

	1999/00 ($m)	2000/01 ($m)	2001/02 ($m)	2002/03 ($m)	2003/04 ($m)
EnergyAustralia	143.4	147.5	149.5	168.0	178.0
Integral Energy	102.0	78.7	62.9	64.0	60.5
NorthPower	68.0	65.2	68.9	61.6	58.3
Great Southern Energy	38.6	42.6	36.1	36.0	32.5
Advance Energy	27.4	26.3	26.4	28.7	26.0
Australian Inland Energy	3.1	3.1	3.1	3.1	3.1
Total	**382.5**	**363.4**	**346.9**	**361.4**	**358.4**

Source: Worley capital expenditure review report, adjusted for inflation of 3 per cent. Excludes retail and retail IT related capital expenditure, recoverable works and capital contribution works. Revised capital expenditure estimates have been submitted by Great Southern Energy and Australian Inland Energy. These revisions have been reviewed by Worley.

The Tribunal wishes to stress that these capital expenditure forecasts are derived for the purpose of determining the base revenue requirements. This procedure is by no means a direction to the DNSPs on the amount of capital expenditure they should incur in any given year.

6.3.2 Code requirements

The Code does not contain any provisions relating specifically to capital expenditure. However, the principles in clause 6.10.2 and 6.10.3 of the Code make references to 'new assets', suggesting that it contemplates expenditure on new assets.

6.3.3 Public consultation

As noted in the s12A report, the Tribunal engaged Worley International to review the capital expenditure forecasts of the DNSPs. In the public consultation that followed that review, the DNSPs reiterated their support for the Worley process. For instance, EnergyAustralia states:

> EnergyAustralia supports the capital expenditure review process outlined by the Tribunal and undertaken by Worley's.

6.3.4 Revised forecasts for Great Southern Energy

In their report to the Tribunal as part of the section 12A review, Worley stated that Great Southern Energy did not have adequate information for a full assessment of its capital expenditure. In early 1999 Great Southern Energy engaged Worley to re-run the capital expenditure review of the network based on additional information that had become available. The revised capital expenditure forecasts (see Table 6.4) were included in the section 12A report and subject to public consultation. The Tribunal considers it relevant and appropriate that these forecasts be included in its building block analysis in this determination.

Table 6.4 Capital expenditure forecasts for Great Southern Energy

	1999/00	2000/01	2001/02	2002/03	2003/04
Original IPART/Worley capital expenditure review ($mill)	22.3	22.3	22.3	22.3	22.3
GSE/Worley revised capital expenditure review ($mill)	38.0	41.9	35.5	35.4	32.0
Change in capital expenditure projections ($ mill)	15.7	19.6	13.2	13.1	9.7
Change in capital expenditure projections (%)	71	88	59	59	43

6.3.5 Revised forecasts for Australian Inland Energy

Capital expenditure projected for Australian Inland Energy in the 12A report was based on the initial Worley review. Projected expenditure declined rapidly during the forecast period (see Table 6.5). In part, this reflected the constraints of the available data. However, Worley notes:

- Australian Inland Energy's capital expenditure is driven primarily by new connections or augmentation funded by capital contributions
- age profiles show that the network is relatively new
- the network is characterised by low load growth and low load density
- although there are no set targets, reliability is the main driver of network design.

Table 6.5 Capital expenditure forecasts for Australian Inland Energy

	1999/00	2000/01	2001/02	2002/03	2003/04
Original IPART/Worley capital expenditure review ($m)	2.8	2.4	0.4	0.4	0.4
Revised AIE/Worley capital expenditure review ($m)	5.6	4.4	3.3	5.5	2.9
Difference between capital expenditure projections ($ m)	2.8	2.0	2.9	5.1	2.5
Difference between capital expenditure projections (%)	100	83	725	1275	625

AIE subsequently commissioned Worley to undertake a further review of the capital expenditure requirements. Projected capital expenditure over the next five years more than trebles from $6.4m to $21.7m. The increase reflects:

- increased growth related expenditure
- increased expenditure to meet higher, but undefined, reliability standards
- increased capital expenditure on non-network assets.

The magnitude of the increase over a very short period raises questions about the robustness of current and previous estimates.

Expenditure relating to the planned substation at Balranald has is not included in these projections as Government is funding the project.

Unlike the projections in the 12A review, these revised projections have not been subject to disclosure and stakeholder review. In view of this, the Tribunal does not consider it appropriate to incorporate the revised projections in calculating revenues for the period of this determination. However, the Tribunal accepts that the previous projections were too low in the later years. Consequently, the Tribunal has decided to incorporate annual capital expenditure of $3.1m annually (ie the same level of expenditure as for 1997/98). Total capital expenditure included for revenue setting purposes over the five years is $15.5m.

The Tribunal wishes to stress that AIE is not obliged to spend this amount nor constrained from spending more. If AIE is confident that the captial expenditure is economic, it should be confident that it will be rolled into the asset base at the next review.

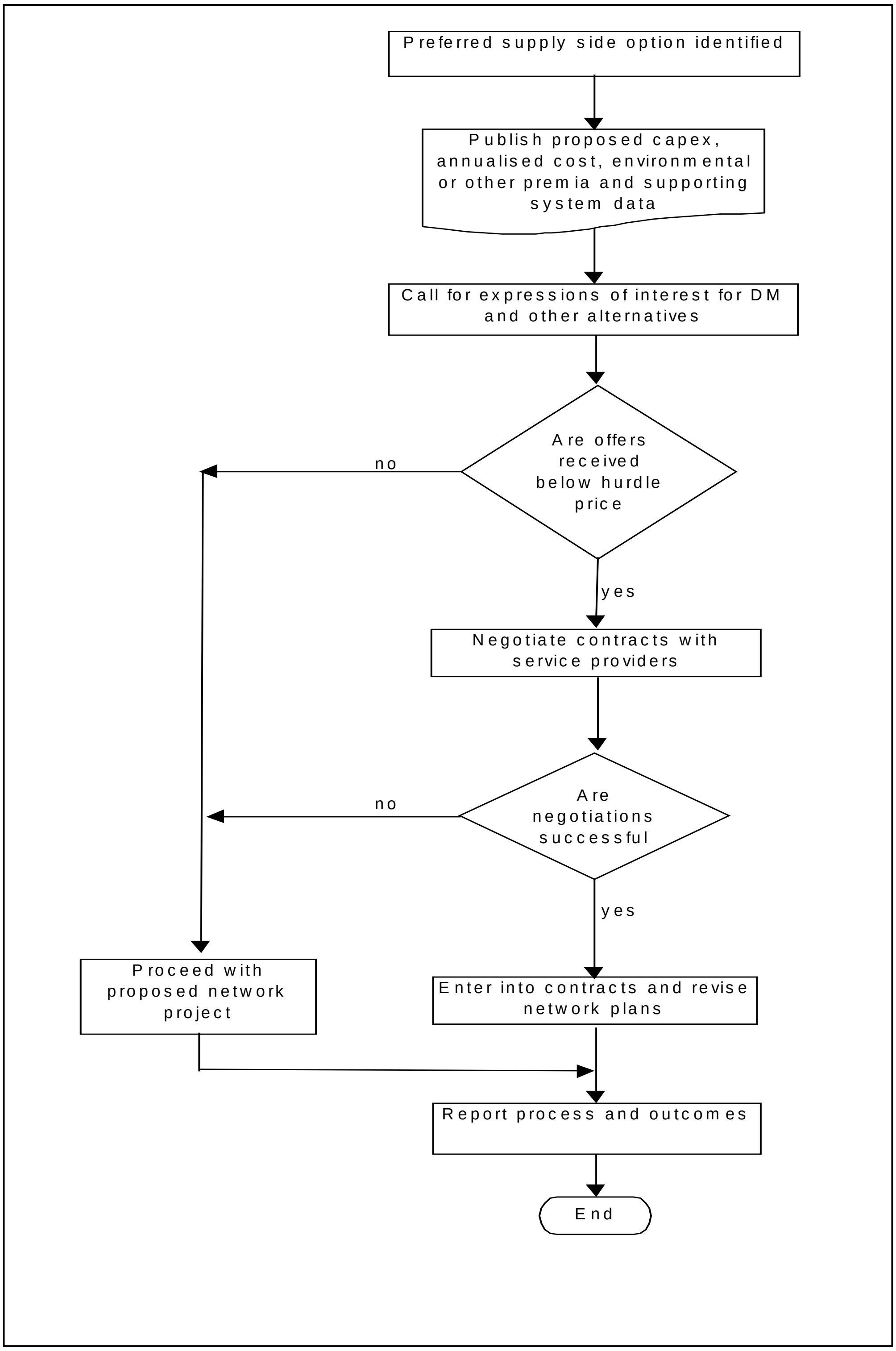
6.4 Demand management and other strategies

The Code requires that the regulatory regime 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'.

An essential feature of the Tribunal's assessment of the prudence of a DNSP's capital expenditure is clear evidence that the DNSP has investigated demand management and distributed resource options as a crucial part of its network planning function. See volume 2, chapter 7 of the s12A report for a discussion on demand management strategies.

The Tribunal supports the framework illustrated in Figure 6.1 as a method for DNSPs to investigate demand management strategies and other alternatives. This framework involves public disclosure of planning criteria and capital expenditure proposals together with a call for expressions of interest in alternatives. Implementation of this approach may allow competition to disclose the best alternative and reduce the risk that the investment may be disallowed under the prudency review at the next determination.

Figure 6.1 Demand Management Investigation Flowchart



7 DEPRECIATION

Depreciation policy or 'return of capital' is crucial to the determination of the DNSPs' financial and operational capacity. In providing for the return of capital previously invested, depreciation accounts for about 30 per cent of total network costs and revenues.

7.1 Determination on depreciation

The Tribunal has determined to:

- ***allow depreciation on the initial capital base established for regulatory purposes***
- ***adopt the asset lives established in the GHD/Worley/Arthur Andersen asset valuation***
- ***adopt depreciation schedules based on straight line depreciation methodology***
- ***provide scope for alternative depreciation profiles in the future where these can assist in managing market risks and managing variations in the prices of new investment***
- ***establish net present value neutrality as an essential condition for alternative depreciation profiles.***

The depreciation amounts included in the AARR are as set out in the table below:

Table 7.1 Return of capital building block components, 1999-2000 to 2003-2004[103] ($'000)

DNSP	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	174,399	182,496	190,906	199,810	209,332
Integral Energy	93,467	98,476	103,099	106,695	106,892
NorthPower	44,991	47,869	49,480	52,459	55,379
Great Southern Energy	29,199	31,064	32,177	33,486	33,631
Advance Energy	18,890	20,051	19,630	20,396	20,586
Australian Inland Energy	2,606	2,752	2,906	3,068	3,237

7.2 Code requirements

The Code provides no specific guidance on depreciation. However, the principles in clauses 6.10.2 and 6.10.3 are relevant. Depreciation is also a crucial component in determining the AARR specified under clause 6.10.5.

7.3 Public consultation

There has been little debate on depreciation following the release of the Tribunal's section 12A report. Overall, there has been general agreement that a straight line approach is appropriate. For example, Advance Energy notes that:

103 Nominal dollars. Includes depreciation on streetlighting assets.

> For the sake of simplicity and transparency a straight-line approach is supported. [104]

However, there are two areas in which interested parties have raised concerns. Namely, the need to consider alternate depreciation methods in specific situations, and the Tribunal's choice of asset life assumptions.

With respect to alternative methods, several points have been raised. Whilst EnergyAustralia supports a straight line depreciation approach "at the present time", in its submission to the Tribunal, EnergyAustralia notes:

> EnergyAustralia supports further investigation into an annuity approach and economic forms of depreciation.[105]

In relation to asset lives, NSW Treasury states:[106]

> NSW Treasury supports the Tribunal's recommendations on depreciation with the exception that asset lives should be consistent with that used in the ODRC valuation undertaken by the GHD, Worley and Arthur Andersen consortium.

This is consistent with the comments made by the DNSPs. For example, Advance Energy argues:[107]

> To ensure consistency between the ODRC valuation and the depreciation allowance reflected in the calculation of the revenue requirement, the asset lives established in the GHD asset valuation review should be adopted.

Furthermore Great Southern Energy Networks has raised a concern in relation to the aggregated nature of the asset lives: [108]

> Great Southern Energy is concerned at the significant gap between the capex allowance ($37.75m) and depreciation estimate of IPART ($23.942m). Whilst in the short term this gap can be covered with debt finance, this gap needs to be eliminated in the longer term. Great Southern Energy has used a more sophisticated individual asset useful life approach to estimating depreciation which flags the need for an allowance exceeding that provided by IPART.

These issues are addressed below.

7.4 Tribunal's assessment

Depreciation provides for the return of capital previously invested. As a major non-cash item, depreciation can also provide an important source of funding for new investment. For this reason, the DNSPs require certainty that depreciation will provide for the return of past investment, except where the value of an investment has been unexpectedly stranded through optimisation.

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104 Advance Energy, Submission to IPART, 30 September 1999, p 21.

105 *Submission to the Independent Pricing and Regulatory Tribunal of NSW concerning Pricing for Electricity Networks and Retail supply*, EnergyAustralia September 1999, p 27.

106 NSW Treasury, *Pricing for Networks and Retail Supply – NSW Treasury Response*, November 1999, p 17.

107 Advance Energy, Submission to IPART, 30 September 1999, p 22.

108 Great Southern Energy Networks, Submission to IPART, 30 September 1999, p 5.

Customers require assurance that the depreciation over the life of the asset will not recover more than the cost of past investments. These concerns may arise where there are changes in the calculation of asset lives.

The profile of depreciation will affect the profile of prices over time, and the allocation of stranding risks between customers and the DNSPs. However, it should not affect the expected net present value of future streams of revenues.

7.4.1 Methodology

The Tribunal has adopted straight line depreciation in this determination. It has done so in view of the submissions it has received and the reasons expressed in its section 12A report[109] which it considers relevant to this determination. However, the Tribunal acknowledges, as it did in the section 12A report, that no single depreciation profile is consistently the most appropriate. This is particularly the case in the context of technological change and its differential impact on assets.

Mindful of these limitations, the Tribunal believes the regulatory regime should provide flexibility for alternative depreciation schedules where these better reflect economic risks and market values. On this basis, and consistent with the comments raised in submissions, the Tribunal will continue to investigate alternative approaches, and may consider adjusting depreciation profiles in its next determination.

7.4.2 Asset lives

In the section 12A report, the Tribunal applied a weighted average remaining asset life for each DNSP to the (depreciated) initial capital base rolled forward over time. This included system and non-system assets. Weighted average lives were calculated on the basis of the asset lives used in the GHD/Arthur Andersen/Worley International consortium asset valuation studies, weighted by the replacement cost of assets.[110]

The Tribunal adopted these asset lives to ensure consistency between the determination of the regulatory asset base, ie, the ODRC valuation, and the determination of regulatory depreciation. Furthermore, these asset lives had been reaffirmed by the PB Power review.[111] PB Power had reported that the asset lives used by the consortium were reasonable and even conservative in some cases.[112]

> Provided that adequate controls are instituted to ensure that the condition of equipment and quality of maintenance are regularly monitored, we believe that in general a substantial proportion of equipment will survive longer than the asset lives adopted by the Consortium.[113]

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109 See Chapter 8 of the Tribunal's section 12A report, p91-103.

110 The section 12A report states that the asset lives contained in Worley's capital expenditure review had been adopted by the Tribunal. However, the report should have noted that the asset lives used were those by the GHD/Arthur Andersen/Worley International consortium.

111 NSW Treasury engaged a consortium comprised of Arthur Andersen, GHD and Worley International to carry out a DORC valuation of the network assets of the DNSPs. The Tribunal engaged PB Power to review the valuations conducted by the consortium.

112 PB Power, *NSW Distribution Companies Asset Valuation Review*, April 1999, p 5.

113 PB Power, *NSW Distribution Companies Asset Valuation Review*, April 1999, p 20.

Since the release of the section 12A report, the Tribunal has obtained further information from the GHD/Arthur Andersen/Worley International consortium and has refined the asset lives adopted for each DNSP in order to more accurately reflect where each DNSP is in its asset life cycle.

For this determination, the Tribunal has calculated depreciation rates for system assets on the basis of the effective lives of asset classes assumed in the GHD/Arthur Andersen/Worley International studies, and applied these to the optimised replacement cost of those assets. Non-system assets have been depreciated on the basis of information contained in each DNSP's regulatory accounts at a weighted-average rate based on each DNSPs' non-system assets.[114]

Capital contributions are excluded from the asset base for the purposes of return of capital and return on capital calculations.[115] Depreciation of capital additions and disposals to the asset base has been calculated on the basis of the depreciation rate for system assets. Implicit in this treatment is the assumption that capital expenditure, capital contributions and asset disposals comprise existing[116] system assets. Further information on the asset composition of capital works, capital contributions and asset disposals will be obtained by the Tribunal for use in subsequent determinations.

This approach addresses the concerns raised by interested parties.

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114 as at 30 June 1998.

115 The value of capital contributions identified by GHD/Worley/Arthur Andersen has been assumed in this analysis. For a discussion of why capital contributions have been excluded for the purposes of calculating return of and return on capital, see chapter 11 of volume 2 of the Tribunal's section 12A report.

116 ie, as at 30 June 1998.

8 EFFICIENCY TARGETS FOR OPERATING AND MAINTENANCE EXPENDITURE

Operating and maintenance expenditure constitutes part of the building block used to set base revenues. Together with return on capital and return of capital, operating and maintenance expenditure constitutes the total base revenue.

8.1 Determination on operating and maintenance expenditure

The Tribunal has determined the following efficiency gains in operating and maintenance expenditure for the NSW DNSPs over the regulatory control period (using 1997/98 as the base year and rolled forward): [117]

Table 8.1 Cumulative real reductions in operating and maintenance figures

	Cumulative real reduction over 5 years before allowance for growth (%)
EnergyAustralia	10
Integral Energy	15
NorthPower	15
Great Southern Energy	15
Advance Energy	15
Australian Inland Energy	5

These efficiency targets are based on 1997/98 operating and maintenance expenditures.

After applying inflation and the cumulative real reduction outlined in Table 8.1, the Tribunal will allow operating and maintenance expenditure to grow by half the percentage growth in MWh sales. The resulting operating and maintenance expenditures (excluding TUOS), incorporated in the building blocks, are outlined in Table 8.2.

Table 8.2 Operating and maintenance building block components, 1999-2000 to 2003-2004[118] ($'000)

	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004
EnergyAustralia	205,562	209,673	213,866	218,144	222,507
Integral Energy	157,174	159,924	162,723	165,570	168,468
NorthPower	70,687	71,747	72,824	73,916	75,025
Great Southern Energy	47,648	48,125	48,606	49,092	49,583
Advance Energy	43,826	44,374	44,929	45,491	46,059
Australian Inland Energy	6,861	7,033	7,208	7,389	7,573

117 The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

118 Nominal dollars. Includes streetlighting operating expenses.

8.2 Code requirements

The objectives of the Code include adopting an incentive-based regulatory regime which:

- provides an equitable allocation of efficiency gains (clause 6.10.2(b)(1))
- provides a sustainable commercial revenue stream which includes a fair and reasonable return on efficient investment given efficient operating and maintenance practices (clause 6.10.2(b)(2))
- fosters efficient operating and maintenance practices (clause 6.10.2(e))
- fosters efficient use of existing infrastructure (clause 6.10.2(f)).

The Code requires the regulatory regime for DNSP's to be administered according to a number of *principles*, including providing distribution network owners with:

- incentives and reasonable opportunities to increase efficiency (clause 6.10.3 (e) (1))
- a fair and reasonable risk-adjusted cashflow rate of return on efficient investment, given efficient operating and maintenance practices on the part of distribution network owners (clause 6.10.3(e)(5)).

The Tribunal must take into account each DNSP's requirements during the regulatory control period, having regard to a number of factors, including:

> Clause 6.10.5(d)(4) – Distribution network service pricing – potential for efficiency gains
> … the Jurisdictional Regulator's reasonable judgment of the potential for efficiency gains to be realised by the Network Owner in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards …

8.3 Public consultation

This section briefly summarises the issues raised in submissions or at public hearings.

8.3.1 The level of efficiency gains

Several DNSPs raise concerns about the level of efficiency gains the Tribunal has recommended in its section 12A review. For example, the then Chief Executive Officer of Integral Energy, commented:

> … if we invested more in the past in underground networks we would end up with a much better revenue capital and we would have in fact lower operating costs. So we were certainly annoyed, miffed, disappointed, when EnergyAustralia was given a 10 per cent operating cost reduction, but we were in fact given 15 per cent.
>
> We would assert, again, that with a more modest operating cost reduction, and we argued for a 9 per cent operating cost reduction from 1998-99, we will still continue to have a significant reduction in the real network prices paid by our customers as long as the Tribunal continues to use the current revenue formula and the basis by which it is so developed. [119]

[119] Transcript of public hearings, 14 October 1999.

In its submission, NSW Treasury states:

> NSW Treasury does not object to IPART's [efficiency target] proposals. [120]

The Tribunal has maintained its position on efficiency targets, given the lack of substantial evidence to justify the DNSPs claims that the efficiency targets are too high.

8.3.2 The trade off between capital expenditure, operating expenditure and service reliability

The review process for this determination has largely examined operating and capital expenditure separately. However, the London Economics data envelopment analysis (DEA) study (which assessed the overall efficiency of the DNSPs), jointly assessed operating and capital costs.

The DNSPs called for capital and operating expenditures to be considered together. Indicative of other DNSPs' comments, EnergyAustralia states:

> During the course of the present review, the Tribunal separately assessed capital and operating expenditure. Consequently, there has been insufficient recognition of the continual tradeoff that is made between capital expenditure, operating expenditure and service levels. [121]

The Tribunal recognises there is a trade off between capital expenditure and operating expenditure. This can impact on service reliability. The Tribunal also recognises the trade off between demand management/energy efficiency and capital expenditure. In its next review, the Tribunal will consider the merits of jointly assessing operating and capital expenditure and demand management.

Comments relating to service reliability and capital expenditure are discussed in chapters 3 and 6, respectively, of this determination.

8.3.3 Productivity indicators

In the section 12A review, stakeholders vigorously debated the productivity measures the Tribunal considered. Whilst some stakeholders support the London Economics and/or UMS studies, others argue that the methodologies adopted are flawed or irrelevant. In public consultation following the section 12A report, stakeholders have continued to raise concerns relating to these studies.

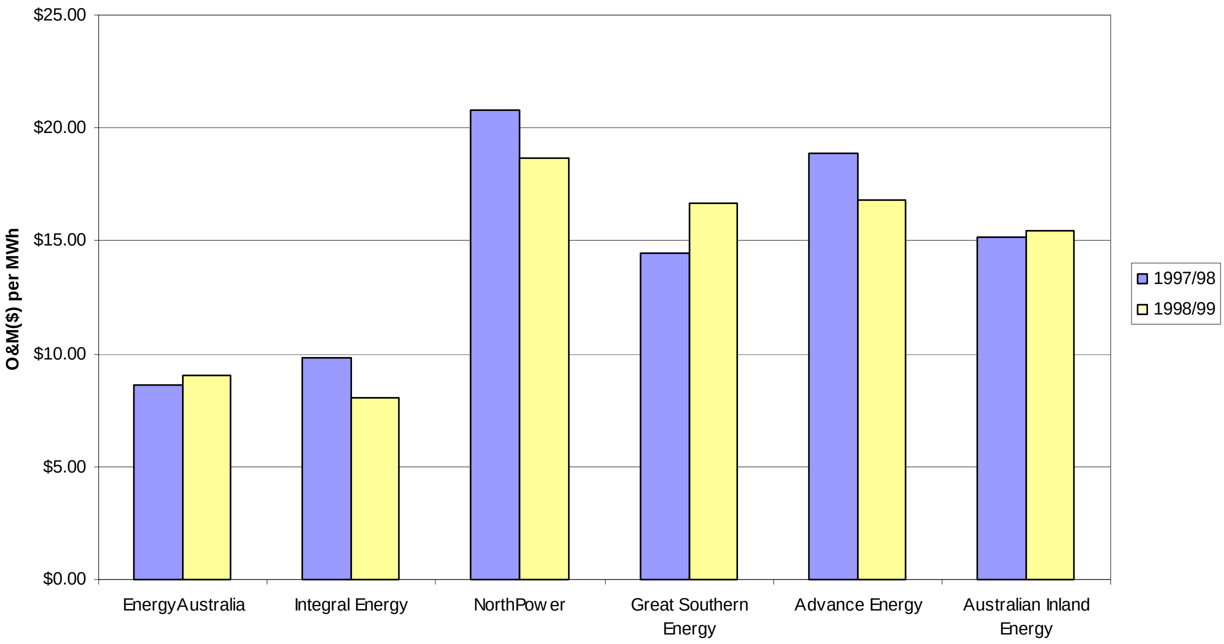
After further consideration and review of the submissions made to it, the Tribunal is satisfied of its view in relation to the London Economics or UMS studies. As stated in the section 12A report, the Tribunal is mindful of the limitations of each of those benchmarking studies when assessing the scope for productivity gains. Further, the Tribunal also considered a range of indicators, without relying on any one study.

Although the DNSPs consider that there are flaws in the current benchmarking studies, some have indicated a preference for an unlinked form of benchmarking. An unlinked approach would involve the Tribunal setting efficiency targets based on the DNSP' relative

120 NSW Treasury submission, November 1999, p 30.
121 Submission from EnergyAustralia, 30 September 1999, p 40.

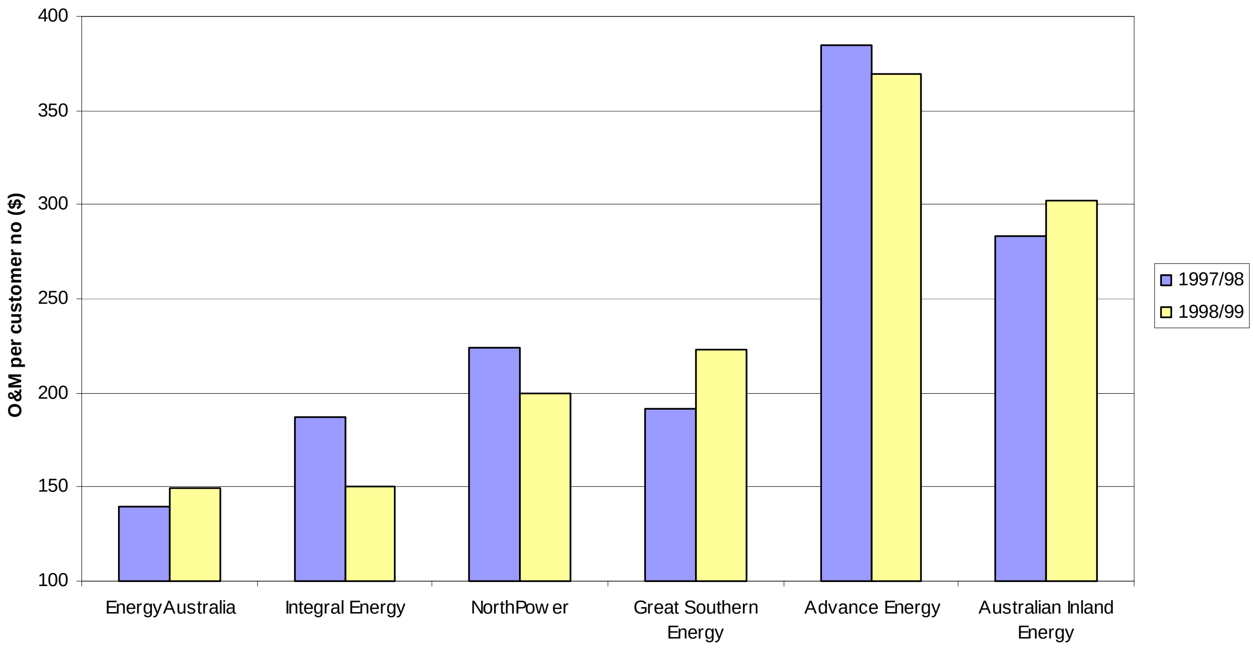
performances, without examining the underlying cost structures. The Tribunal recognises that before it can consider adopting such a regulatory framework, it must have a robust benchmarking framework. The Tribunal is willing to work with stakeholders, including other regulators, to develop appropriate performance measures.

Figure 8.1 Operating and maintenance expenditure per MWh distributed,



1997/98 – 1998/99

Figure 8.2 Operating and maintenance expenditure per customer, 1997/98 – 1998/99



Advance Energy raised concerns regarding the partial productivity indicators the s12A report. These partial productivity indicators are based on franchise customer load. As Advance Energy has a relatively high proportion of contestable customer load, it is disadvantaged relative to the other DNSPs. The Tribunal again considered and re-analysed the partial indicators, based on total load, and incorporated information from the 1998/99 Regulatory Accounts (see figure 8.1 and figure 8.2). The Tribunal acknowledges the improved relative performance of Advance Energy, but maintains that a 15 per cent reduction over five years is appropriate.

These partial productivity measures are based on data from the DNSPs' regulatory accounts.[122] This data includes any Y2K and contestability operating costs already incurred by the DNSPs.

According to the regulatory accounts, some DNSPs substantially increased their operating and maintenance expenditure in 1998/99, while others substantially decreased their expenditure. In the timeframe available, the Tribunal has not been able to fully analyse these movements. They may partly result from changes to the cost allocation policies of the DNSPs.

8.4 Tribunal's assessment

In making its determination relating to efficient operating and maintenance costs, the Tribunal has had regard to the analysis presented in the s12A report, ensuing public consultation (including public hearings and submissions), and further analysis of partial productivity indicators.

Throughout the public consultation process, there has been a lack of substantial evidence to justify the DNSPs' claims that the efficiency targets set out in the s12A report are too high. The Tribunal has again considered those efficiency targets to be appropriate. It has, therefore, applied them in this determination.

The Tribunal has determined the following efficiency gains in operating and maintenance expenditure for the NSW DNSPs over the regulatory period (using 1997/98 as the base year, rolled forward)[123]

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122 Excluding avoided TUOS reported in Integral Energy's 1997/98 regulatory accounts.

123 The operating and maintenance projections are based on 1997/98 figures, plus streetlighting operating expenses. These figures were rolled forward to 1998/99 by inflation minus the annual efficiency target plus half the growth estimate. The cumulative real reductions will apply to this amended 1998/99 operating and maintenance figure.

Table 8.3 Cumulative real reductions in operating and maintenance figures

	Cumulative real reduction over 5 years before allowance for growth (%)
EnergyAustralia	10
Integral Energy	15
NorthPower	15
Great Southern Energy	15
Advance Energy	15
Australian Inland Energy	5

These efficiency targets are based on 1997/98 operating and maintenance expenditures because the benchmarking studies and partial productivity indicators were based on those figures. Therefore, the efficiency targets established in the section 12A report were determined on 1997/98 figures.

After applying the cumulative real reduction outlined in Table 8.1, operating and maintenance expenditure will grow by half the percentage growth in MWh sales.

9 TOTAL REVENUE REQUIREMENTS

The previous chapters have examined each of the cost-based 'building blocks' for the DNSPs. This chapter outlines the construction of the annual revenue requirements for the DNSPs from these building blocks.

Two key 'building blocks' are the return of and return on capital. Each of these is crucially dependent on the initial capital base, yet as indicated there is no one method of asset valuation which is always appropriate. The regulator faces a range of possible asset valuations with different strength and weaknesses. In light of this the Tribunal has tempered the use of the strict 'building block' approach through a consideration of a range of indicators. The indicators used, and the manner of their consideration, are outlined in this chapter.

9.1 Determination on total revenue requirements

The Tribunal has determined the following total revenue requirements for the NSW DNSPs for the period from 1 February 2000 to 30 June 2004:

Table 9.1 Total Revenue Requirements ($ million)

	1999/2000	2000/2001	2001/2002	2002/2003	2003/2004
EnergyAustralia[124]					
Building Block	674	692	710	730	752
Smoothed	691	706	721	736	752
Integral Energy					
Building Block	388	398	407	415	419
Smoothed	395	401	407	413	419
NorthPower					
Building Block	186	194	200	208	215
Smoothed	170	180	191	203	215
Great Southern Energy					
Building Block	117	122	126	129	132
Smoothed	113	117	122	127	132
Advance Energy					
Building Block	87	90	92	95	97
Smoothed	74	78	82	87	92
Australian Inland Energy					
Building Block	14	14	15	15	16
Smoothed	11	12	12	13	13
Industry Total					
Building Block	1,466	1,510	1,550	1,592	1,631
Smoothed	1,454	1,494	1,535	1,579	1,623

124 Includes costs and revenues for transmission services as determined by the ACCC.

The annual aggregate revenue requirement for the fiscal year 1999/2000 is to be determined by pro-rating and adding:

- the revenue cap as determined under IPART Act Determination 5.3 of 1997 (as continued to 31 January 2000 by regulation) for the period from 1 July 1999 to 31 January 2000
- the annual aggregate revenue requirement as determined in this Determination, pro-rated for the period from 1 February 2000 to 30 June 2000.

This can be illustrated as:

$$\boxed{\text{1999/2000 Revenue Cap per determination 5.3, 1997} \times \frac{215}{366}} + \boxed{\text{1999/2000 Revenue Cap per this determination} \times \frac{151}{366}}$$

9.2 Code requirements

The Tribunal must determine the AARR in accordance with part D of chapter 6 of the Code. Part D does not expressly refer to the AARR. However, it does require the Tribunal to:

- adopt a form of economic regulation that is of the prospective CPI minus X form or other incentive-based variant of the CPI minus X form, consistent with the objectives and principles outlined in clauses 6.10.2 and 6.10.3
- specify a form of economic regulation to be applied to the DNSP in the form of a revenue cap, a weighted average price cap or a combination
- take into account each DNSP's revenue requirement during the regulatory control period having regard to the factors in clause 6.10.5(d)
- have regard to objectives in clause 6.10.2 and the principles in clause 6.10.3 of the Code.

9.3 Public consultation

The DNSPs propose a price path based on accrual building block approach.

> Revenues for network monopolies should be based on a building block approach which provides for:
> - Efficient operating costs.
> - Depreciation expenses.
> - An adequate return for funds invested.

There were no submissions on the use of the 'building block' approach from other interested parties.

9.4 Summary of approach

9.4.1 The 'building block' approach

In general, the 'building block' approach builds up the base revenue from three major components:

- return on capital
- return of capital
- efficient operating costs.

Under this approach, the jurisdictional regulator would make a separate decision on each 'building block'. The Tribunal has long been concerned about such an approach, in that it can lead to a procedure-bound methodology in which key decisions on major components of the base revenue requirement are made in isolation of other key components. The Tribunal prefers an approach which has regard to the interaction of key components, and also the impact on the firm's prices and profitability. Hence, the building block analysis is supplemented by a consideration of the overall implication, and outcomes of the resulting price paths.

The components of return on capital, namely the initial capital base, the treatment of capital expenditure, depreciation and the rate of return, are discussed in chapters 6, 7 and 5 respectively.

9.4.2 Financial indicator analysis

The Code permits a regulator to assess financial performance in order to establish the initial capital base and determine an appropriate rate of return.

> 6.10.5 Form and mechanism of economic regulation
> In respect of distribution services subject to economic regulation pursuant to clause 6.10.4(a): …
>
> (d) In setting a separate regulatory cap to be applied to each Network Owner in accordance with clause 6.10.5(b), the Jurisdictional Regulator must take into account each Distribution Network Owner's revenue requirements during the regulatory control period, having regard for: …
>
> (11) any other relevant financial indicators.

The Tribunal favours an approach to initial asset valuation and the ongoing determination of revenue requirement that has regard to a broader range of financial indicators. The Tribunal rejects strict reliance on 'return on rate base' as the driving determinant of asset valuation and the revenue requirement of the network.

The Tribunal recognises the circularity inherent in determining revenues dependent on the value of an asset base whose value is in turn reliant on the revenue stream. There is a wide range of price and asset value combinations consistent with the efficient, commercial operation of the utilities and the ongoing provision of services. The difficulty facing the regulator is to determine an initial capital base and price path that provides an appropriate balance of stakeholder interests.

The use of indicators based on publicly available or easily accessible information reduces the problems of information asymmetry prevalent in regulatory regimes around the world. The Tribunal has taken the view that reliance on any single indicator may distort the regulatory framework by encouraging inappropriate behaviour. A broader focus reduces the incentive for an infrastructure owner to enter into gaming behaviour in order to influence one particular revenue driver.

The financial indicators applied in the Tribunal's determination have been chosen on the basis of relevance, availability of information, and common usage in the financial community. Attention was given to cash based measures (particularly where the objective is to determine the appropriate opening asset valuation) and, where possible, indicators in wide use in the financial markets.

In order to develop a robust conclusion, the regulator must be able to cross-check revenue scenarios against a range of financial indicators.

The Tribunal considers that a cross-check approach is appropriate both in determining the opening regulatory value of the existing assets, and as a means of assessing the reasonableness of the network operator's revenue requirement on an ongoing basis. The Tribunal does not consider that it will necessarily be appropriate to set the opening regulatory asset valuation and revenue requirement at a level that maintains the historical level of the performance indicators. This is particularly true where the level of those indicators reflects excess profits or cash flows within the network system. This consideration must be balanced with the regulator's responsibility not to jeopardise the financial integrity of the infrastructure owner.

9.4.3 Integration of analysis

The Tribunal's financial models are structured in a 'building block' design, with inputs on such factors as the value of the regulatory asset base, forecast capital expenditure, the rate of return, depreciation and operating costs. Given these inputs, the models produce a forecast revenue path and report the results against a range of financial indicators.

The DNSPs' performance against this range of indicators is then used to guide the Tribunal's assessment of the sustainable revenue stream. This involves an iterative process, testing the sensitivity of the financial indicators to different forecast revenue or price paths and initial capital bases. It should be noted that, in determining the reasonableness of that revenue stream, the Tribunal will be required to make assumptions about the future revenue path and load growth beyond the current review period. In proposing the base revenue the Tribunal must also consider the relevant Code requirements.

The selection of the appropriate price path takes into account a reasonable sharing of costs and efficiency gains between the network owner and customers.

This revenue path will then be translated into a maximum allowable revenue path, which will reflect the Tribunal's decision on glide paths. Subsequent to this report, the DNSPs will then allocate this revenue requirement to different services based on the cost drivers of the system and pricing principles developed by the Tribunal. The DNSP will then design tariffs to respond to the cost drivers for the service. A final check will then completed to ensure that the tariffs will generate the revenue requirement at the forecast customer and volume levels. These tariffs, and a guide to explain the procedures and allocations used in their development, will be published jointly by the DNSP and the jurisdictional regulator.

9.5 Tribunal's assessment

9.5.1 Network financial projections and modelling

In conducting its analysis, the Tribunal assessed the proposals of the DNSPs and other parties, and its own analysis, on such matters as the cost of capital, necessary capital expenditure levels, the scope for efficiency gains in operating costs, and the amount of load growth expected to be experienced by the network. These forecasts are summarised in Table 9.2.

Table 9.2 Summary of modelling inputs

Distributor	WACC (pre tax real)	Capital expenditure	Operating cost reduction 2000-2004	Load Growth
EnergyAustralia	7.5%	per Worley	10%	2.0%
Integral Energy	7.5%	per Worley	15%	3.5%
NorthPower	7.5%	per Worley	15%	3.0%
Great Southern Energy	7.5%	per Worley	15%	2.0%
Advance Energy	7.5%	per Worley	15%	2.5%
Australian Inland Energy	7.5%	trend line[125]	5%	1.0%

9.5.2 Revenue glide path

In order to reduce volatility in annual revenues, reduce the potential for price shocks to customers and provide stronger incentives for the future, the Tribunal has applied a mechanism to smooth the DNSPs' revenue paths. In the absence of smoothing, the Tribunal's proposals could result in a significant reduction in average prices for the metropolitan DNSPs in the first year followed by increases in subsequent years. This would result in greater volatility in earnings. The Tribunal has decided to smooth the revenue path over the entire period so that price changes can be phased in.

The revenue path modelled is 'smoothed' to reach the revenue target at the end point in a straight line from 1998/99.

The Tribunal's analysis indicates that under this scenario, DNSPs will benefit from a slight improvement in cashflow and financial performance, as compared with the 'unsmoothed' scenario.

9.5.3 Scenario testing

In its section 12A report to the Premier, the Tribunal tested the outcomes of a number of capital base and rate of return combinations, assessing the reasonableness of the range of financial indicators of each scenario. This scenario analysis was used to assist the Tribunal in reaching its decisions in this Determination. This process, and the results of the scenario analysis, is described in some detail in Volume 1, chapter 11 of the section 12A report.

9.5.4 Financial indicator analysis

The Tribunal recognises that comparisons of forecast financial results are difficult. This is not to suggest that such comparisons should not be performed. Rather, it means that the results of such comparisons must be interpreted with caution.

[125] See section 6.3.5.

Choice of financial indicators

As discussed above, the Tribunal has used a series of financial indicators. The definition of the ratios used is shown in Attachment 6 of the s12A report to the Premier. The Tribunal has also used a set of indicators used by debt rating agency Standard & Poor's and NSW Treasury. These ratios derived under this Determination are presented in Table 9.4.

Rating agencies commonly assess an organisation's financial capacity and ability to service debt using ratios such as:

- funds flow interest cover - to assess a utility's ability to service debt
- net cashflow/capital expenditure - to assess internal financing capacity
- net debt/funds from operation - to assess ability to repay debt.

Although the ratios are useful, the Tribunal recognises that it would be dangerous to use them without some judgement of the appropriateness of financial outcomes.

S&P has recently published the financial ratio medians for energy utilities including overseas utilities. It appears that the median numbers for the cash flow ratios are broadly within the ranges for a utility with average and above average business risk profile. The Tribunal considers that the rating ratios in Table 9.4 remain a useful guide in its financial indicators analysis and that a business profile between excellent and above average is appropriate.

9.5.5 Summary

The Tribunal has considered a number of revenue path scenarios. It has assessed the results for each of the DNSPs and for industry as a whole. The end points for the range of asset values, being the rolled-forward 1996 value and the latest DORC estimates were modelled for each of the DNSPs. Much of the analysis involved running alternative values for each of the DNSPs within this range. Each of the scenarios was also examined in terms of the overall results for the DNSPs. This aggregate analysis is made more relevant by the fact that the DNSPs share a common owner - the NSW Government. Each scenario was also assessed in terms of complying with this reviews terms of reference.

9.6 Conclusions

Following consideration of the submissions from stakeholders and interested parties, the requirements of the terms of reference and the Premier's letter of 18 June 1999, the Tribunal concludes that an initial capital base in aggregate of $7.2bn as at 30 June 1998, revenue requirement in 1999/2000 of $1,453m, real reductions in distribution prices on average of 16.0 per cent per cent, in all circumstances balances the interest of owners and customers.

The Tribunal proposes the annual aggregate revenue requirements of the DNSPs as shown in Table 9.3:

Table 9.3 DNSPs nominal annual revenue requirements and projected distribution prices ($mill)

Industry Total	1999/00	2000/01	2001/02	2002/03	2003/04
Regulatory asset value[1]	7,433	7,651	7,850	8,050	8,258
Capital expenditure	394	386	379	407	416
Depreciation	365	383	398	416	429
Return on capital base (%)	7.3	7.3	7.3	7.3	7.4
Operating costs	532	541	550	560	569
Total revenue (unsmoothed)	1,453	1,497	1,540	1,584	1,626
Smoothed allowed revenue	1,453	1,493	1,535	1,578	1,622
Average distribution price (c/kWh)	3.02	3.02	3.03	3.04	3.05
Cumulative real reduction in distribution prices	-6.4%	-8.9%	-11.4%	-13.7%	-16.0%

1) Representing average of opening and closing regulatory asset base and comprising system and non-system assets.

The initial capital base at 30 June 1998 is made up of system assets of $6.7bn and non system assets of $0.5bn. This yields an aggregate initial capital base of $7.2bn for the NSW distribution networks as at 30 June 1998. The adoption of the $7.2bn asset valuation as the initial capital base is expected to deliver a revenue stream sufficient for DNSPs to finance their network functions, maintain an adequate service, and earn reasonable returns. Table 9.4 provides the forecast financial indicators.

Attachments 2.1 through 2.6 provide financial profiles of each DNSP. Included in these profiles are the building block components of the revenue requirements for each of the five years 1999/00 to 2003/4 and financial indicators. A brief summary for each DNSP is as follows.

9.6.1 Financial profiles

The financial indicators in attachments 2.1 through 2.6 are based on actual capital structure, ie relatively low gearing. The level of gearing is a matter for Government. However the Tribunal has also calculated the financial indicators based on a commercial gearing level. The results indicate that the DNSPs are forecast to have relatively strong financial outcomes.

Energy Australia

The revenue requirements proposed for EnergyAustralia cover both transmission (regulated by the ACCC) and distribution. When the transmission revenue requirements are finalised by the ACCC the revenue requirements for distribution will be the difference between the total proposed and the ACCC determined amount.

The five year financial projections to 2003/04 (covering both transmission and distribution) indicate that EnergyAustralia has a very strong profile, with funds flow interest cover of 8.1 times in fiscal year 1999/2000, and forecast to remain above that level in the following four years. The gearing level (total debt to total capital) is at 31 per cent in 1999/2000, declining to 23 per cent at the close of the regulatory period. Net debt payback is forecast to remain around 1.8 to 2.8 years over the next five years. The internal financing ratio at well over 100 per cent indicates that EnergyAustralia is capable of financing its capital expenditure without any apparent difficulty. Together, these indicate that the regulated revenue path provides sufficient cashflow for Energy Australia to fund its operations, repay debt and meet capital expenditure forecasts.

The operating margin (EBITD/revenue) remains at above 60 per cent with EBIT averaging 37 per cent over the period. Anticipated annual growth is 2 per cent. Operating cost per kWh is projected to reduce in real terms by 10 per cent over the 5 year period. This is before an allowance for growth.

The strong cashflow from operations enables the distributor to provide a constant tax and dividend stream to its owner, the Government, over the next five years. This is forecast to average $230m per annum over the next 5 years. The proposed revenue requirements result in average distribution price reductions of 16 per cent in real terms for EnergyAustralia's customers over the five year period.

Integral Energy

The proposed distribution network revenue for Integral Energy is around $407m for the next five years with operating margin (EBITD/revenue) projected to remain at 51 per cent. Integral Energy is provided with strong operating cashflow which will enable the DNSP to fund its capex, repay debt and interest and provide tax and dividend to its Government owner. As a result of its strong financial position, gearing is forecast to decrease from 38 per cent in 1999/00 to 27 per cent in 2003/04.

As indicated by its robust fund flow interest cover, net debt payback and internal financing ratio, Integral Energy is projected to have a strong financial profile over the next five years. This is achieved at the same time as average distribution real price reductions of 27 per cent are forecast.

NorthPower

The proposed network revenue for NorthPower is forecast to increase by approximately 16 per cent in real terms over the next 5 years. However, network prices on average are forecast to remain constant in real terms over the same period. Profitability is forecast to improve over this period with the operating margin increasing from 50 per cent to 56 per cent and EBIT from 28 per cent to 34 per cent. Tax and dividend payments to its owner, the Government is forecast to be between $50m to $74m. These represent 85 per cent of the profit before tax. Rate of return on assets (real pre tax) improves from 5.7 per cent in 1999/00 to 7.5 per cent in 2003/04.

NorthPower has forecast a relatively large capital expenditure program. The funding of this capital expenditure impacts measures such as fund flow interest cover, net debt payback and the internal financing ratio. By the end of the 5 years, NorthPower's lending ratios are forecast to be heading towards the AA credit rating. NorthPower's gearing remains at around 20 per cent over the period.

Great Southern Energy

Great Southern Energy's proposed revenue requirement is forecast to put them in a very strong financial position over the 5 years. This strong financial position facilitates forecast distribution network charges reducing over the period by 6 per cent in real terms. Fund flows from operations grow from $65m in 1999/00 to $80m in 2003/04. Fund flow interest cover stays well above the AAA benchmark and so is the net debt payback ratio. Although the debt level is anticipated to increase, the gearing remains between 17 per cent to 19 per cent over the period.

Its high operating margin, between 49 and 54 per cent provides GSE with strong cashflow. The profit margin over the period enables GSE to maintain a market return and the level of tax and dividend payments to its owner.

Advance Energy

The proposed network revenue for Advance Energy is forecast to increase by approximately 13 per cent in real terms over the next 5 years. However, network prices on average are forecast to remain constant in real terms over the same period with forecast load growth of 2.5 per cent and operating cost per kWh is projected to reduce in real terms by 19 per cent over the 5 year period.

Operating margin and profit margin compare favourably with industry average. The proposed revenues enables Advance Energy to service its debts, fund the projected capital expenditures and maintain a stable tax and dividend stream to its owner.

Advance Energy's financial profile compares favourably with other DNSPs as indicated by the credit rating ratios of fund flow interest cover, net debt payback and internal financing ratio. Although these ratios are anticipated to weaken over the period these still remain at above the A to AAA benchmark. Debt level is expected to increase toward the close of the period but remains low. Gearing increases from 19 per cent in 1999/00 to 23 per cent in 2003/04.

Australian Inland Energy

Underpinning Australian Inland Energy's forecast financial position over the next five years is stable cashflow from operations. Operating margin and profitability is projected to be relatively strong with EBITD remaining at around $7m from 1999/00 to 2003/04. Given the negligible debt level and modest capital expenditure program, the credit rating ratios remain robust at above AAA level. Annual tax and dividend payments to its shareholder stay at around $5m to $5.8m. Average distribution network prices are forecast to remain constant in real terms.

Table 9.4 Credit rating ratios

Rating	AAA	AA	A	BBB	BB
Funds flow interest cover (times)					
Utility business risk profile					
Excellent	4.00	3.25	2.75	1.50	<1.0
Above average	4.25	3.50	3.00	2.0	1.5
Average	5.00	4.00	3.25	2.5	2.0
Below average	X	4.25	3.50	3.0	2.5
Vulnerable	X	X	4.00	3.5	3.0
Net debt/Fund flow from operation (times)					
Utility business risk profile					
Excellent	4.0	6.0	9.0	12	20
Above average	3.5	5.0	7.0	9.0	>15
Average	3.0	4.0	5.5	7.0	>10
Below average	X	4.0	5.5	7.0	>9
Vulnerable	X	X	4.0	6.0	>8
Internal financing ratio (per cent)					
Utility business risk profile					
Excellent	100	70	60	40	>35
Above average	100	80	70	50	>45
Average	100	100	90	55	<55
Below average	X	100	100	75	<60
Vulnerable	X	X	100+	90	<70

Source: Capital Structure Policy for NSW Government Trading Enterprises, Appendix 1, August 1994.

10 CHARGES FOR MISCELLANEOUS AND MONOPOLY SERVICES

10.1 Determination

10.1.1 Determination on charges for miscellaneous services

The Tribunal has determined an exhaustive list of miscellaneous charges. This establishes the maximum amount that may be charged for the provision of the relevant miscellaneous service. No new charges may be levied by a DNSP during the regulatory control period. The list of approved maximum charges for miscellaneous services is shown in Table 10.1.

The circumstances under which these charges may be levied are listed in 'Charges for Miscellaneous Services Rule 99/3', issued by the Tribunal. The DNSPs must also ensure that they conduct an adequate customer information program as outlined in 'Charges for Miscellaneous Services Rule 99/3'.

Revenue from charges levied for the provision of miscellaneous services is included in the AARR of each DNSP.

10.1.2 Determination on charges for monopoly services

The Tribunal has determined an exhaustive list of charges for monopoly services associated with contestable work. This establishes the prescribed amount to be charged for the provision of the relevant monopoly service. No new charges may be levied by a DNSP during the regulatory control period. The list of prescribed charges for monopoly services is shown in Table 10.2.

The circumstances under which these charges are to be levied are listed in 'Charges for Monopoly Services Rule 99/4', issued by the Tribunal.

Revenue from charges levied for the provision of monopoly services is to be included in the AARR of each DNSP.

10.2 Public consultation

10.2.1 Charges for miscellaneous services

To assist this review, the Electricity Industry Consultation Group (EICG) established a Miscellaneous Charges Working Group (MCWG) to investigate, discuss, and make recommendations on aspects of miscellaneous charges which members believed to be pertinent to their respective constituents. The MCWG comprises representatives of: EnergyAustralia, Integral Energy, Advance Energy, the Energy Industry Ombudsman NSW, the NSW Department of Community Services, the NSW Council of Social Services (NCOSS), and the Public Interest Advocacy Centre (PIAC).

The MCWG reported to the EICG in May 1999. Following the Tribunal's s12A report, the MCWG was reconvened and issued its final report on 30 September 1999. The report was distributed to the EICG, made available to interested parties, and placed on the Tribunal's website.

Submissions from the DNSPs tend to concentrate on two proposals discussed in the section 12A Report: the exhaustive list of miscellaneous charges, and the inclusion of miscellaneous charge revenues in the DNSP revenue cap.[126] Some submissions recommended refinements to the regime proposed in the s12A report.[127]

10.2.2 Charges for monopoly services associated with contestable works

Established by the EICG, the Contestable Works and Monopoly Fees Working Group (CW&MFWG) comprises representatives of the DNSPs, Department of Energy, Energy Industry Ombudsman, NSW (EION), the National Electrical Contractors Association, UDIA, developers and design and construction service providers. Having reviewed all charges for monopoly services associated with contestable works, the CW&MFWG has produced a report with recommendations.

The CW&MFWG first reported to the EICG on 17 March 1999. An amended report was filed on 21 April 1999. Following the Tribunal's s12A report, the CW&MFWG was reconvened and an amended report was provided on 29 September 1999. That report was distributed to the EICG, made available to interested parties, and placed on the Tribunal's website. A significant proportion of the CW&MFWG's discussion is devoted to the critical, very contentious issue of ring fencing.[128]

Submissions from the DNSPs identify contestable works as difficult to manage. While supporting the work of the CW&MFWG, Advance Energy comments that there are few accredited service providers in the rural areas, and it is costly for the DNSP to appoint dedicated inspection staff.[129] EnergyAustralia supports the development of a simpler fee structure which ensures an adequate return to the DNSPs.[130]

10.3 Charges for miscellaneous services

In addition to their core charges, the DNSPs levy a suite of charges for services relating indirectly to the conveyance of electricity. In this sense, the provision of miscellaneous services is incidental to the provision of the core service of electricity distribution.

Charges for miscellaneous services are applied in various forms. The most frequently applied charges by DNSPs include personal disconnection visit charges and application fees. The Tribunal published a list of permissible miscellaneous charges in its Determination 5.3 of July 1997. However, a wide disparity remains in the type and application of these charges across the DNSPs. The Tribunal's concern about miscellaneous charges is highlighted by complaints made to EION. Although miscellaneous charges do not collectively account for a material proportion of total DNSP revenue, they can be individually significant, particularly for low income consumers.

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126 See, for example, Great Southern Energy submission p28, Integral Energy submission p 27.

127 See Advance Energy submission, pp71-73, EnergyAustralia submission, pp 54-55.

128 Generally, independent contractors were concerned that the incumbent contracting departments were filling the inconsistent roles of approving contestable works and competing to perform the work themselves.

129 Advance Energy submission, p 74.

130 EnergyAustralia submission, p 62.

10.3.1 Exhaustive list of charges for miscellaneous services

To address the complaints in this area, the Tribunal has determined an exhaustive list of charges for miscellaneous services, as shown in Table 10.1. Each miscellaneous service is a prescribed distribution service. The DNSPs are not to levy any charges not shown on the list, and they are authorised to levy the approved charges only in the circumstances outlined in 'Charges for Miscellaneous Services Rule 99/3' issued by the Tribunal. It should be noted that these charges for miscellaneous services are maximum charges, exclusive of the GST and the DNSPs are at liberty to reduce or waive these charges as may be appropriate in the circumstances.

Submissions from the electricity DNSPs and retailers indicate a clear preference for flexibility in determining the suite of miscellaneous charges to be levied. The DNSPs and retailers argue that this flexibility is required to address the changes being introduced with full contestability. The Tribunal is sympathetic to the DNSPs' desire to maintain flexibility in the face of changes to the industry. However, the Tribunal does not consider it appropriate or desirable to amend the schedule of charges for miscellaneous services without a public consultation process. Nor in the Tribunal's view does the Code permit an amendment to the Tribunal's determination during the regulatory control period, except in very limited circumstances. For these reasons, it is not possible for the Tribunal to give the DNSPs the flexibility they desire.

10.3.2 Separation into charges for network and retail services

The MCWG was asked to separate the recommended list of charges for miscellaneous services into network and retail lists. Given the diverse internal structures of the DNSPs, the working group was unable to arrive at an agreed view. The Tribunal has had regard to the recommendations of the MCWG in approving the suite of charges for miscellaneous services in this Determination. The Tribunal considers some charges are more clearly retail charges than network charges. The suite of miscellaneous charges will not fit each DNSP's business objectives exactly. In reaching this distinction, the Tribunal has considered that the retailer will be the entity with the ongoing customer service relationship. Accordingly, those charges relating to physical network operation have been assigned to the DNSP.

The Tribunal considers the DNSP may not have a direct financial relationship with the end use customers. Therefore, approved charges for miscellaneous services levied by the DNSP must be levied on the retailer having the financial relationship with the particular end use customer. The retailer will make a decision as to whether to absorb the charge or pass it through to the end use customer.

Table 10.1 Maximum charges for miscellaneous services

Miscellaneous Service		Maximum allowable charges	
		Normal business hours maximum allowable ($)	Outside normal business hours maximum allowable ($)
Provision of time-of-use or half hourly metering data: per half hour		25.00	N/A*
Special meter reading		30.00	75.00
Meter test		50.00	125.00
Conveyancing inquiry:	desk inquiry	25.00	N/A*
	field visit	50.00	N/A*
	total	75.00	N/A*
Account establishment		35.00	87.50
Off-peak conversion		40.00	100.00
Disconnection visit:			
	if no disconnection (acceptable payment received)	30.00	N/A*
	disconnection (acceptable payment not received)	60.00	N/A*
	pole top/pillar box disconnection	100.00	N/A*
	Maximum total (pole top/pillar box & meter disconnection)	160.00	N/A*
Rectification of illegal connection		150.00	475.00

*N/A = Not applicable.

10.4 Charges for monopoly services associated with contestable works

The Electricity Supply (Customer Contracts) Regulations require the DNSPs to compete with private entities to provide many former monopoly services. In particular, the provision of customer connection services is an area where customer choice must evolve as a means of ensuring efficient costs and prices. However, although competition is developing in this area, DNSPs still retain ownership of networks and must maintain the reliability, safety standards and quality of supply of their networks.

In order to safeguard these standards, distributors have developed an accreditation process whereby persons or companies seeking to undertake connection work are graded as to their competency. Additionally, in line with the requirements of safety and reliability, distributors need to inspect the work of accredited persons, to examine and certify electrical designs submitted by external contractors, and to provide information in regard to electrical designs.[131]

Distributors view these as monopoly services, and for the purposes of this report, these services are accepted as monopoly services.

131 Electricity Association of NSW, Code of Practice – Contestable Works, section 2(d).

Charges for monopoly services associated with contestable works do not represent a significant proportion of a DNSP's AARR. Nevertheless, the Tribunal must ensure these charges for monopoly services relating to contestable works are competitively neutral and that the methodology by which they are applied does not restrict entry of non-DNSP contractors engaging in contestable works by increasing the cost of development.

Consistent with its decisions on miscellaneous charges and streetlighting, the Tribunal has determined that revenues from charges for monopoly services should be included in the AARR for each DNSP. The Tribunal considers that the charges for monopoly services should be set on the basis of incremental costs, given that the other 'overhead costs' will be recovered through charges for network services.

The key pricing recommendations of the CW&MFWG are to:

- provide revised hourly rates for some services (see Table 10.3)
- introduce a fee to authorise accredited service providers to work on or near a distributor's network
- rename and restructure the administrative overhead fee
- revise inspection rates
- change the narrative and level of the access permit fee.

The CW&MFWG made many valuable recommendations for the conduct of contestable works. The Tribunal considers these recommendations are best dealt with in an industry code of practice. The Tribunal encourages industry participants to convene a group to agree on such a code of practice.

Perceived failure to ring fence remains the most contentious issue facing the CW&MFWG. The Tribunal considers ring fencing to be a larger issue, of which the contestable works area is a subset. The Tribunal is working with industry participants and other regulators to develop ring fencing guidelines under the Code, and expects that these matters will be largely resolved through that process.

10.4.1 Exhaustive list of charges for monopoly services associated with contestable works

Similar to its experience with miscellaneous services, the Tribunal has experienced considerable complaint activity in this area. However, the complaints tend to focus on the consistent application of charges for monopoly services, rather than the level of charges. The contestable contractors argue that the inconsistent application of monopoly charges creates a perception of an uneven playing field, and concern that the fees may not be applied consistently to the incumbent DNSPs' contracting arms.

This is largely a ring fencing and competitive neutrality issue. The ring fencing aspects will be considered as part of the broader work on ring fencing guidelines to be established under the Code. Competitive neutrality complaints will need to be addressed by each jurisdiction's competitive neutrality body.

Although the Tribunal has approved an exhaustive list of *maximum* charges to be applied to miscellaneous services, the Tribunal considers that, for most monopoly services, any perceived scope for the DNSP to reduce charges to the incumbent contracting arm should be removed. Subject to one qualification, a DNSP must not charge more or less than the charges listed in Table 10.2. The qualification is that if a charge in Table 10.2 is listed as a maximum charge, a DNSP may charges less than the maximum. That is, the DNSP must not charge more or less than the prescribed charge. Each monopoly service is a prescribed distribution service. Charges for monopoly services are to be levied in accordance with the conditions set out in 'Charges for Monopoly Services Rule 99/4', issued by the Tribunal.

The Tribunal considers that it is important the DNSP be able to demonstrate clearly that charges for monopoly services have been levied consistently on the incumbent DNSP contracting arm and any independent contractors.

Amendments to the working group's recommendations

The CW&MFWG has recommended that the previous fee for travel time be removed, and that inspection fees include a component for average travel time. In making this recommendation, the working group notes that in Integral Energy's case, an inspector would rarely travel more than two hours to a site. This recommendation has the effect of charging for travel in the EnergyAustralia and Integral Energy service territories, where the travel time may not be incurred. The Tribunal is of the view that a reasonable amount of travel is consistent with the operation of a DNSP's business. However, the Tribunal is concerned that for the rural distributors, significant travel times can be necessary. The Tribunal prefers to determine a charge for travel time where incurred, rather than to increase fees across the board to include an average element for travel time. The Tribunal has therefore reduced those charges for monopoly services with an embedded travel time component as recommended in the working group report, and retained the specific charge for travel time.

Similarly, some recommended fees include an administration component. As stated above, the Tribunal believes that charges for monopoly services should be calculated on an incremental basis. The Tribunal is of the view that it is inappropriate to levy an 'administration fee' and to include administration charges within the various monopoly fees. The Tribunal has therefore reduced those charges containing an administrative component by the amount of the embedded administration.

Table 10.2 Charges for monopoly services associated with contestable work

Monopoly Service	Underground urban residential subdivision (vacant lots)	Rural Overhead Subdivisions and Rural Extensions	Underground Commercial and Industrial or Rural Subdivisions (vacant lots - no development)	Commercial and Industrial Developments	Asset Relocation Or Street Lighting
Design Information (Minimum 1 Hr)	Up to 5 lots 2 Hrs @ R2 6 to 10 lots 3 Hrs @ R2 11 - 40 lots 5 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (See Note 5)
Design Certification (Minimum 1 Hr)	Up to 5 lots 1 Hr @ R2 6 to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 4 Hrs @ R2	1 - 5 poles 1 Hr @ R2 6 -10 poles 2 Hrs @ R2 11 or more poles 3 Hrs @ R2	Up to 10 lots 2 Hrs @ R2 11 - 40 lots 3 Hrs @ R2 Over 40 lots 6 Hrs @ R2	R3 per hour	R2 or R3 per hour (See Note 5)
Design Rechecking (Minimum 1 Hr)	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (See Note 5)
Inspection Fee (Minimum 2 Hrs @ R2)	Grade: A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.3xR2 / 0.7xR2 / 1.5xR2 Remainder: 0.1xR2 / 0.4xR2 / 0.7xR2	Grade: A per pole / B per pole / C per pole 1-5 poles: 0.6xR2 / 1.2xR2 / 2.2xR2 6-10 poles: 0.5xR2 / 1.0xR2 / 2.0xR2 11+ poles: 0.4xR2 / 0.7xR2 / 1.5xR2 (see Note 4)	Grade: A per lot / B per lot / C per lot First 10 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Next 40 lots: 0.5xR2 / 1.2xR2 / 2.5xR2 Remainder: 0.5xR2 / 1.2xR2 / 2.5xR2	R2 or R3 per hour (see Note 1)	R2 or R3 per hour (see Note 1)
Access Permit	Residential Subdivisions: $18.00 per lot combined fee	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit	$800 max. per access permit
Substation Commissioning		$600 per substation (See Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)	$600 per substation (see Note 2)
Administration	Up to 5 lots 3 hours @ R1 6 - 10 lots 4 hours @ R1 11 - 40 lots 5 hours @ R1 Over 40 lots 6 hours @ R1	Up to 5 poles: 3 Hrs @ R1 6-10 poles: 4 Hrs @ R1 11 or more poles 6 Hrs @ R1	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of Arrangement	3 hours @ R1				
Re-Inspection	R2 per hour (max 1 hour per level 2 reinspection)				
Access	R1 per hour (see narrative)				
Authorisation	2 hours @ R2				
Inspection of Service Work (Level 2 work)	All Service connections: A Grade : $14 per NOSW B Grade: $22 per NOSW C Grade: $65 per NOSW (NOSW = Notification of Service Work)				

Notes:

1. Level of inspection determined prior to commencement of job & based on grade of accredited service provider.
2. $600 for a simple substation (single transformer/RMI unit) other at hourly rate including setting/re-setting protection equipment.
3. Where individual service connections are required for multiple dwelling subdivisions the per lot fee should be applied per service connection.
4. Inspections are based on 3 visits. Substation poles are not included. The inspection for substation poles is A Grade – 3.5Hrs @ R2; B Grade – 7Hrs @ R2; C Grade 9 Hrs @ R2.
5. Hourly rate to be determined based on complexity of the job.

Table 10.3 Hourly labour rates applicable to monopoly services

Labour class	Hourly rate
Admin R1	$44
Design R2a	$54
Inspector R2b	$54
Engineer R3	$65

11 CAPITAL CONTRIBUTIONS

In December 1996, the Tribunal issued Determination 10, Pricing for Capital Contributions and Recoverable Works. This Determination, as amended and supplemented by the capital contribution guidelines in Determination No. 5.4 of 1997 sets out the current arrangements under which customers are required to contribute to the costs of connecting to the distribution system, and the basis for determining the amount of such costs.

Key elements of these arrangements are:

- DNSPs are responsible for funding all shared parts of the network upstream from the point of customer connection
- customers are responsible for the cost of all non-shared assets required for their connection to the distribution system downstream from the point of connection
- where economically and environmentally superior alternatives to system connection are available, and the customer (or group of customers) decides to connect, the customer is required to meet the full cost of connection, including the cost of any augmentation required upstream from the point of connection
- at their discretion, customers may either retain or hand over to the DNSP any assets they have fully funded.

In response to industry and customer concerns regarding the effect of Determination 10, the Electricity Industry Consultation Group (EICG) formed the Capital Contributions Working Group (CCWG). The CCWG comprises industry, customer, government, and community representatives.[132] The CCWG examined capital contributions issues and developed proposals for the Tribunal's consideration. The CCWG completed an initial report in April 1999. This was distributed to interested parties and placed on the Tribunal's web site. However, the CCWG had foreshadowed further examination of the implementation issues associated with its recommendations. The Tribunal discussed the issues and provided comments in its Section 12A report of July 1999.[133]

The CCWG identified the capital contributions area as very complex, with significant government policy implications. In particular, the capital contributions issue highlights the tensions felt by the DNSPs in meeting the sometimes conflicting 'successful business', 'social responsibility' and 'regional development' requirements of the State Owned Corporations Act.[134]

The CCWG was not able to produce a final report in time for an adequate public consultation process to be completed before the release of this determination. ***Accordingly, this determination reaches no conclusions on the treatment of capital contributions.*** Determination No. 10 of 1996, as amended by determination No. 5.4 of 1997, will remain in effect until 31 January 2000 under clause 9.16.3(a) of the Code. The Tribunal will endeavour to hold a public consultation process on the working group's report, and will publish a decision on capital contributions as soon as practicable.

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132 A full list of working group participants is appended to the report.

133 *Pricing for Electricity Networks and Retail Supply*, Volume 2 Chapter 11.

134 See *State Owned Corporations Act 1989* - Sect 20E.

11.1 Determination on capital contributions

This determination makes no decision on capital contributions. The Tribunal will publish a decision on capital contributions as soon as practicable.

11.2 Code requirements

Capital contributions are considered under Part E of Chapter 6 of the Code. Consistent with the NSW derogation under clause 9.16.3(c) of the Code, the Tribunal has not applied the provision of part 6E in this determination. However, the Tribunal considers that it should have some regard to the Code provisions regarding capital contributions:

> **6.15.2 Capital contributions, pre-payments and financial guarantees**
>
> The principles to be applied to capital contributions, pre-payments and financial guarantees are:
>
> (a) the *Distribution Network Service Provider* is not entitled to receive any asset related cost component of *annual revenue requirement* for assets provided by *Network Users*;
>
> (b) the *Distribution Network Service Provider* may receive a capital contribution, pre-payment and/or financial guarantee up to the future *annual revenue requirement* for any new assets installed as part of a new *connection* or modification to an existing *connection*, including any *augmentation* to the *distribution network*;
>
> (c) where assets have been the subject of a contribution or prepayment, the *Distribution Network Service Provider* must amend the *aggregate annual revenue requirement*; and
>
> (d) the asset categories referred to in clause 6.13.3 must not incorporate the asset related cost components of the *annual revenue requirement* for any asset category covered by clause 6.15.2 and the *Network Users* who use any such asset together as a group are to pay less for the ongoing use of that asset category than they otherwise would have paid.

The Tribunal considers that consistency with the Code's requirements relating to capital contributions will not affect the Tribunal's decisions on total revenue requirements under this Determination. While there may be secondary implications for the DNSPs' forecast capital expenditure, the Tribunal does not expect these impacts to affect the total revenue requirements.

11.3 Public Consultation

In submissions made to the Tribunal, and discussions held by the CCWG, several issues are raised by industry and customers. These issues may be grouped into two broad categories:

- those associated with the clarity, workability and coverage of determination No. 10 of 1996 and determination 5.4 of 1997 and its guidelines. Some DNSPs have reported difficulty in applying the specified approach due to ambiguities in the terms used, and the inadequacy of the guidance provided to deal with common circumstances. This has been a cause of frustration and confusion for DNSPs and customers alike.

- those associated with the identification and treatment of uneconomic connections. From the DNSPs' perspective, there is concern that the current approach will stimulate requests for connections which will require substantial and continued funding support from other customers. From the customers' perspective, there is concern that any increased application of a user pays approach to connection will disregard the broader social and regional considerations involved. Both groups are concerned at the prospect that DNSPs may, de facto, be required to arbitrate between economic and social objectives.

In the relatively short time available to it, the CCWG has made valuable progress in identifying the key concerns of the interested parties. The CCWG has endeavoured to relate these concerns to the principal underlying economic and social issues. Arising in the provision and funding of infrastructure, these may combine individual, shared, private and external benefits. From this analysis, initial proposals for an alternative approach have been developed. However, the CCWG has indicated that considerable further work on implementation is required before substantial changes to the current arrangements can be recommended.

11.4 Tribunal's consideration

One of the CCWG's major tasks has been to define what constitutes an 'uneconomic' (as opposed to economic) connection. Where connections are uneconomic, the working group has proposed approaches may be used to assess the appropriate level of customer contribution and recover any shortfall that may be assessed as reasonable.

The issue of uneconomic connections raises many of the conceptual difficulties of establishing a uniform capital contributions policy. For example:

- the revenues contributed by a new customer will normally be based on average uniform tariffs and may make varying contributions to fixed costs
- whether an extension is economic depends on the comparison of revenues to marginal costs, not average costs[135]
- the level of asset utilisation is unknown at the time of connection
- the potential for additional customers to connect to the new extension assets under consideration is often uncertain at the time of construction.

A key recommendation of the CCWG's April 1999 report is:

> Distributors should undertake an 'economic' assessment of proposed new connections. To the extent that Network revenues from new connections will provide more than their associated costs of supply, distributors should contribute to the costs of connections. A practical method of implementing this recommendation may be for specific distributor contribution levels to be determined for defined customer classes.[136]

The CCWG has made the following draft final recommendations:[137]

> 1. Many issues associated with the recommendations of this report require further consideration. The EICG should establish a working group to develop an implementation plan for submission to the Independent Pricing and Regulatory Tribunal of NSW and the NSW Government.
> 2. Distributors should undertake an "economic" assessment of proposed new connections. To the extent that Network revenues from new connections will

135 However, marginal costs are more difficult to measure and are likely to be substantially different from average costs.
136 Report of the Capital Contributions Working Group, April 1999, p 2.
137 Draft final report of the Capital Contributions Working Group, December 1999, p 3.

provide more than their associated costs of supply, distributors should contribute to the costs of connections. A practical method of implementing this recommendation may be for specific distributor contribution levels to be determined for defined customer classes. [Implementation issues will need to be addressed as per recommendation 1.]

3. After allowing for distributors' contributions to new connections, customers would be responsible for all additional connection costs relating to dedicated connection assets and shared line extensions.
4. System augmentation costs on existing lines would be the responsibility of distributors unless a customer requires a load of more than 100 amps single phase. The customer shall be responsible for augmentation costs in those instances.
5. A scheme to reimburse previous customers where new customers are connecting to assets that were previously funded by customer contributions should be reintroduced. New customers would be responsible for their proportion of line extensions constructed within the previous six years.
6. An agency should be appointed to assess the merits for funding assistance to customers subject to capital contributions. This agency would consider the social, environmental and extrinsic commercial impacts of new connections to establish whether funding assistance is appropriate. Funding options that the agency may consider could include:
   - increasing tariffs and revenues in that distributor's geographic area
   - increasing tariffs and distribution revenues across all customers in NSW
   - an industry fund which could include retailers
   - explicit taxpayer funding through NSW consolidated revenue.
7. Distribution system assets on public property (or subject to easements) should generally be owned by the franchise area distributor. Customers should own and have responsibility for consumer mains. No recommendation is offered in this report relating to responsibility for other assets on customer premises (excluding consumer mains).
8. Connection assets funded by distributors should derive appropriate returns and associated operating cost recovery through regulated revenues. Contributions received from customers should not provide returns to distributors, however, associated operating and maintenance costs incurred by distributors should be recovered through regulated revenues.

The Tribunal will consider these recommendations as part of its intended public consultation process on capital contribution issues.

The CCWG estimates the indicative DNSP contribution levels as follows:

Table 13 Distributor contributions (indicative)

	Below 100 amps single phase	Above 100 amps single phase
Residential (including Off peak) ($/Customer)	$1,500	$150 / MWh
Rural/farm (excluding irrigation) ($/Customer)	200	$20 / MWh
Business low voltage ($/MWh)	250	320
Business high voltage ($/MWh)	*	*
Business subtransmission ($/MWh)	*	*

Source: Draft final report of the Capital Contributions Working Group, December 1999, p 15.
Notes:
Threshold as specified under Recommendation 4.
Low voltage = (240 and 415 Volt), high voltage = (> 415 volt & < 33 kV), Subtransmission = (33 kV – 132 kV)
Subtransmission rates are normally calculated on an individual customer basis rather than using standard rates.
* = Highly variable – Not possible to give an indicative figure

The Tribunal has not endorsed the CCWG's recommendations. Following a public consultation process, the Tribunal will publish a decision on capital contributions.

12 EMBEDDED GENERATION

This chapter sets out the Tribunal's intentions with respect to embedded generation issues, and also addresses the Tribunal's assessment of a specific matter relating to avoided transmission use of system (TUOS) payments made by a DNSP to an embedded generator.

12.1 Determination on embedded generation and avoided TUOS

The Tribunal will continue to work with the embedded generation working group and other regulators to develop a framework within which parties can negotiate agreements for embedded generation. It is envisaged that the framework will include:

- ***procedural guidelines***
- ***agreed methodologies***
- ***dispute resolution processes and***
- ***standardised contract documentation.***

With respect to Integral Energy's submission to the Tribunal regarding avoided TUOS payments made to embedded generators, the Tribunal determines that:

- ***on a forward looking basis, it is appropriate that Integral's payments to Smithfield and Tower/Appin for the purposes of 'avoided TUOS' to be recovered in Integral's AARR, to the extent that these payments reflect the actual TUOS charges that Integral avoids as a consequence of the embedded generators; and consequently***
- ***for the period from 1 February 2000 to 30 June 2004, Integral's payments to Smithfield and Tower/Appin for avoided TUOS are to be passed through to customers to the extent that the payments reflect the actual avoided TUOS charges. The pass through amount in each year will be calculated by Integral, and submitted to the Tribunal for approval. The payments will not form part of the Integral's AARR unless the pass through amount has been approved by the Tribunal.***

With respect to avoided TUOS payments made by a DNSP to embedded generators more generally, the Tribunal determines that:

- ***as a matter of principle, it is appropriate for avoided TUOS payments paid to an embedded generator to be recovered in the AARR, to the extent that these payments reflect the actual TUOS charges avoided by the DNSP as a consequence of the embedded generator; and***
- ***if a DNSP begins to make payments to an embedded generator for the purposes of avoided TUOS within this regulatory control period, then these payments are to be passed through to customers to the extent that the payments reflect the actual avoided TUOS charges. The pass through amount in each year will be calculated by the DNSP, and submitted to the Tribunal for approval. The payments will not form part of the DNSP's AARR unless the pass through amount has been approved by the Tribunal.***

12.2 Code requirements

The Code establishes arrangements and procedures for generators to access the transmission and distribution networks, the basis for determining access charges, and procedures governing network planning and augmentation. Of special relevance to embedded generation are references to:

- the need to pass through avoided transmission use of system (TUOS) charges
- payments that may be made to or received from embedded generators for distribution network services
- the inclusion of embedded generation as a possible option for addressing projected network limitations.

12.2.1 Avoided TUOS payments

The Code is explicit with regard to the pass through of avoided TUOS to embedded generators. Clause 5.5 (which deals with connection agreements) permits transmission costs avoided by a DNSP to be passed through to the embedded generator, funded out of the DNSP's AARR:

> (f) The Network Service Provider and the Generator shall negotiate in good faith to reach agreement as appropriate on the: …
>
> (3) amount to be passed through to the Generator (where the Generator is an Embedded Generator) for avoided transmission use of system charges that would otherwise be payable by the Network Service Provider as a result of the Generator not being connected to its distribution network; …
>
> (h) Any payments to Embedded Generators under clause 5.5(f)(3) are to be included as part of the AARR of the Network Service Provider and are to be recovered in the same manner as payments to Embedded Generators under clause 6.13.3(d).

This reflects the position of the ACCC in its final decision on the Code access arrangements. The ACCC regarded the pass through of TUOS (based on the Tribunal's 'with and without' basis) as a means of restoring competitive neutrality with generators that were not paying TUOS.

> .... as generators will be dispatched into the wholesale market largely on the basis of generation and connection asset costs, the incidence of network charges appears to disadvantage embedded generation which competes on a delivered cost basis. [p 62]

12.2.2 Network support payments

Chapter 6 of the Code recognises that the DNSPs may pay embedded generators for the contribution they make to network support.

Clause 6.10.5 requires that payments to embedded generators be included in the DNSP's revenue cap:

> (d) In setting a separate regulatory cap to be applied to each Network Owner …, the Jurisdictional Regulator must take into account each Distribution

> Network Owner's revenue requirements during the regulatory control period, having regard for: …
>
> (7) the right of the Distribution Network Owner… to recover reasonable costs arising from: …
>
> (iii) payments made to Embedded Generators for demand side management programs and local energy storage facilities which provide distribution service… where the Jurisdictional Regulator determines that this is appropriate;

For instance, Chapter 6, Part E of the Code also deals with payments to embedded generators. Clause 6.13.3 requires that payments received from or made to embedded generators to be included in the AARR for the appropriate DNSP asset category:

> (c) Payments to and from Embedded Generators are to be determined up to an amount of the long run marginal cost of augmenting the distribution network….
>
> (d) Any payments made under clause 6.13.3(c):
>
> (1) to Embedded Generators must be added to: and
>
> (2) from Embedded Generators must be deducted from,
>
> the AARR for the relevant asset category…

Clause 6.14.1, recognises that in converting DNSP costs into prices:

> (e) There may be situations where the DNSP is prepared to pay for equivalent network service by Embedded Generators…. prices for such equivalent network services are to be agreed between the relevant DNSP and Jurisdictional Regulator.

This point is discussed further in part 4.5 of schedule 6.6:

> Embedded generators can in some circumstances provide significant benefits in certain parts of a distribution network….Distribution service charges are negotiable between the Network Owner and the Generator. The charges (or payment) need to reflect the benefit available to the Network Owner from the embedded generation. This will depend on — the degree to which any benefits to the network that might accrue from the generation are shared between the NSP, the Generator and other Network Users. … The long run marginal cost (benefit) of the shared network reinforcement represents the upper limit of payment to the Generator.

Part 5 of this schedule also provides discretion for the regulator to treat services provided to embedded generators for reserve (or standby) capacity, other distribution services and access as, effectively, competitive services that can be excluded from the revenue or price cap.

However chapter 6, Part E does not apply expressly to this determination as the Tribunal has exercised its discretion not to apply Part E (see chapter 10 of this report). Nevertheless the principles in Part E provides useful guidance to the Tribunal's approach to embedded generation under Part D.

12.2.3 Network planning

By offering ways of addressing future network limitations, particularly within regions, embedded generation offers benefits. The Code assigns responsibility for network planning within regions to the relevant NSP. Clause 5.6.2 requires NSPs to select options which maintain the operating standards of their networks while maximising the net benefit to customers. NSPs are required to consult with participants and interested parties to identify these options:

> (f) … the Network Service Provider must consult with affected Code Participants and interested parties on the possible options, including but not limited to demand side and generation options, to address the projected limitations of the relevant transmission system or distribution system.
>
> (g) Network Service Providers must carry out cost effectiveness analysis of possible options to identify the option that maximises the net benefit to customers …

Part 4.5 of schedule 6.6 briefly discusses the competitive process that NSPs may use to ensure that the most cost effective option is identified correctly:

> As a general principle, commercial arrangements shall be made with Generators and this may include a competitive tendering process to ensure equal opportunity for other Generators. For example, a statement of opportunity for the area concerned could be issued with an invitation to bid for generation capacity in the area. This would facilitate free market forces providing the optimum outcome for the network business and existing network customers.

12.2.4 Other matters

In addition, and as set out in the Tribunal's section 12A report, other matters may impact on the issue of embedded generation. The NECA review, which is directed at improving the network pricing sections of the Code, addresses a number of issues of direct relevance to embedded generation. These include TUOS pass through, standby charges and network bypass, as well as more fundamental principles of network access, and pricing affecting the development of the electricity market. If changes are made to the Code as a consequence of the review they may affect the requirements guiding the Tribunal.

12.3 General Principles

Embedded generation may take the form of a local generator or a combined generator and load, and can offer a number of advantages. Namely, 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 its location and energy source, it may also offer environmental advantages.
- where networks are congested, embedded generation may reduce costs by avoiding or deferring capital expenditure on the network.

The commercial viability of embedded generation is influenced by the availability and conditions of network connections, the use for exporting and importing energy, and the recognition and sharing of relevant network cost savings. On this basis, network pricing and its regulation can significantly affect incentives to establish embedded generation (ie local generation and cogeneration).

Recognising this, the Code establishes arrangements and procedures for generators to access the transmission and distribution networks, the basis for determining access charges, and procedures governing network planning and augmentation (as set out above). Nevertheless, proponents of embedded generation have raised concerns regarding difficulties encountered in negotiating network access, use and benefit sharing with DNSPs.

The Tribunal wishes to ensure that price regulation encourages efficient decision making concerning the establishment of embedded generation rather than other forms of generation, load management, and network investment. The Tribunal's preferred approach to network access is to encourage negotiation among the involved parties within a framework of established pricing principles. However the Tribunal recognises that to facilitate this negotiation, clear signals with respect to future regulatory treatment are required, and on this basis supports the development of a framework within which the parties can negotiate agreements.

In developing this regulatory framework, the Tribunal recognises that consultation is essential for the development of a workable approach that addresses the concerns of affected parties. Consequently, the Tribunal envisages that the Tribunal's Electricity Industry Consultation Group, and in particular the Embedded Generation Working Group will continue to make a valuable contribution to the development and documentation of the framework. The Tribunal also recognises that it is essential that the framework developed is consistent among jurisdictions, and other regulatory requirements such as the NSW demand management code of practice.

12.4 Integral Energy and Avoided TUOS

Integral Energy has two agreements with embedded generators. The Smithfield Power Purchase Agreement was made in June 1995, and the Appin Tower Colliery Power Purchase Agreement was made in May 1995.

Integral has submitted to the Tribunal that both agreements allow for a pass through of avoided TUOS charges to the embedded generator. On this basis Integral argues that:[138]

- in principle, the avoided TUOS payments should be recovered in Integral's AARR
- a pro-rata of TUOS charges paid by Integral on the basis of the embedded generators' relative peak and shoulder energy output provides an appropriate basis for calculating 'avoided TUOS'
- the 'avoided TUOS' is about $9 million per annum
- Integral's network revenue for 1997/98, 1998/99 and 1999/00 should be increased by $9 million.

These issues were not addressed in the Tribunal's section 12A report.

138 This is based on information provided to the Tribunal by Integral Energy in its confidential submission dated 30 April 1999, and subsequent confidential submission dated 27 August 1999.

12.4.1 Tribunal's analysis and assessment

Should payments to embedded generators be recovered in network revenue?

As set out in the Tribunal's guidelines on embedded generation, sound economic and equity arguments support the case for a DNSP to pass on the benefits of avoided TUOS charges to an embedded generator, and for the DNSP to recover these payments from customers, albeit for a short period. In line with these arguments, and as set out in section 12.2 of this report, section 5.5 of the Code deals explicitly with the pass through of avoided TUOS charges to embedded generators.

The Tribunal is of the view that the reference to "any payment" in section 5.5 means all amounts "passed through to the Generator (where the Generator is an Embedded Generator) for avoided transmission use of system charges that would otherwise have been payable by the Network Service Provider as a result of the Generator not being connected to its distribution network". Hence, to be included in the DNSP's AARR under the Code, the payments recovered in network revenues must truly answer this description.[139]

On this basis amounts to be passed through from Integral to the embedded generators, Smithfield and Appin during this regulatory control period which are amounts truly representing avoided TUOS charges must (by virtue of clause 5.5 (h)):

- be *included* as part of the AARR; and
- are to be *recovered* in the same manner as payments to embedded generators under clause 6.13.3(d).

This is consistent with the economic and equity arguments for a DNSP to pass on the benefits of avoided TUOS charges to an embedded generator and for the DNSP to recover these payments.[140]

Should retrospective payments to embedded generators be recovered?

Integral has also sought to recover payments on a retrospective basis, ie, in 1997/98 and 1998/99. However the principles relating to the recovery of payments described above apply only after the Code commenced, ie, after December 1998, not retrospectively. No determinations of the Tribunal under the IPART Act expressly permit the recovery of Integral's payments to an embedded generator for avoided TUOS. Accordingly there is no support for Integral's request for the inclusion of payments on a retrospective basis.

However, the Tribunal must determine the avoided TUOS charges, that would otherwise have been payable by Integral, as a result of the embedded generators for this regulatory control period, ie, from 1 February 2000. This is discussed below.

139 This does not in any way affect the obligation on the DNSP to make or receive payments made under agreements between a DNSP and an embedded generator. The obligation to make payments and the right to receive payments for avoided TUOS are governed by the terms of the relevant agreement. However, the payments made under the agreements may not necessarily equate to the payments that may be properly included for the purpose of the AARR under the Code, as indicated.

140 If the Tribunal were to allow a DNSP to recover an amount that is greater than the actual avoided TUOS charges, then this would merely serve to 'over signal' the benefits of embedded generation. This would promote inefficient investment in embedded generation, and raise network charges to non-embedded generation customers to inefficient levels.

What TUOS charges will a DNSP avoid as a consequence of an embedded generator?

Local or embedded generation essentially serves as a substitute for an electricity transmission network. Therefore, the connection of an embedded generator, which reduces the load on the network, may result in a reduction in transmission costs incurred by the TNSP. A reduction in costs should be reflected in TUOS charges.[141]

The amount of the avoided TUOS charge can be determined by what is generally known as the "with and without" test. That is, the avoided TUOS charge will be the difference between the TUOS charge payable with the embedded generator and the TUOS charge payable without the embedded generator. The "with or without" concept sounds simple, however in practice it is quite difficult to apply.

Current TUOS charges are calculated on the basis of the Tribunal's March 1996 determination. From March 1996 to 30 June 1997, the determination sets out energy, demand and fixed TUOS charges payable by each DNSP.[142] From 1 July 1997 to 30 June 1999, the determination sets out that these energy, demand and fixed TUOS charges are to be rolled forward annually by CPI-3%.[143]

Clause 9.16.2 of the Code establishes that TUOS charges, from 1 July 1999 to 30 June 2002, will be calculated on the basis of the Tribunal's March 1996 determination. This means that charges over this period will be calculated by adjusting the energy, demand and fixed TUOS charges in place at 30 June 1999 to reflect the difference between TransGrid's 1998/99 allowable revenue and the ACCC's determination on transmission revenues. TransGrid is also required to collect EnergyAustralia's transmission revenue, payable by the NSW DNSPs.[144]

Hence, if an embedded generator connects to a distribution network over this period, it will reduce the load (energy and maximum demand) on the transmission network, and hence the amount of TUOS payable by the DNSP. The DNSP's TUOS payments will reduce by:

- energy TUOS charge * the energy generated by the embedded generator; and
- demand TUOS charge * the reduction in the DNSP's overall maximum demand attributable to the embedded generator (if any).[145]

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141 The remainder of the discussion assumes that TUOS charges are set to reflect transmission costs.

142 See Tribunal's Determination 2.1 March 1996 p 13.

143 In 1997/98 a one-off adjustment for actual 1996/97 loads was to be made.

144 It is to be collected from the DNSPs on the basis of their relative peak and shoulder energy load.

145 This holds as long as there are no adjustments for under/over recoveries of transmission revenues. If there are adjustments for under/over recoveries of transmission revenues, the DNSP will avoid TUOS charges in the year that the embedded generator connects to the system by the amount detailed above. In the next year the amount of avoided TUOS will be recovered by the TNSP from all of its customers – and thus the DNSP will only avoid a proportion of:

- energy TUOS charge * the energy generated by the embedded generator; and
- demand TUOS charge * the reduction in the DNSP's overall max demand attributable to the embedded generator.

Nevertheless, the DNSP serving the region where the embedded generator is located will still avoid some TUOS charges. Although, some may argue that there is no 'avoided TUOS' at all, as other transmission customers pay for the TUOS charges the DNSP avoids.

This outcome, that is that the TNSP recovers its revenue cap irrespective of changes in load, signals that all transmission costs are fixed. As such, it signals that no transmission costs can be avoided as a consequence of a change in load, including due to the connection of an embedded generator. This is not

While transmission revenues post 30 June 2002 will be revealed shortly in the ACCC's forthcoming decision on NSW transmission revenues, the specific TUOS charges payable by the DNSPs is uncertain at this stage. Indeed the methodology for their calculation will remain uncertain until the outcome of the NECA review is finalised. As such, avoided TUOS post 30 June 2002 can not be calculated at this time. In principle however, if the load in the DNSP's area falls due to an embedded generator, all else equal, the amount of transmission revenue allocated to the DNSP post 30 June 2002 will be smaller relative to the March 1996 determination.

What TUOS charges will Integral Energy avoid as a consequence of Smithfield and Tower Appin?

Integral has submitted to the Tribunal that a proportion of the TUOS fixed, demand and energy charge is currently being passed to the embedded generators, and that this is reflective of 'avoided TUOS'. However, applying the relevant principles as discussed above, the Integral estimates are likely to be considerably more than the actual avoided TUOS charges.

The principles discussed above suggest that for the period to 30 June 2002:

1. There will be no reduction in the fixed TUOS charge payable by Integral as a consequence of the embedded generation.
2. There will be a reduction in the TUOS demand charges payable by Integral as a consequence of the embedded generators – by the amount that the embedded generators reduce maximum chargeable demand.
3. There will be a reduction in the TUOS energy charges payable as a consequence of the embedded generators – by the amount that the embedded generators reduce total peak and shoulder load.

The amount of TUOS charges avoided from 1 July 2002 is uncertain at this time, for the reasons indicated above. The Tribunal however acknowledges that it is appropriate for Integral to continue to recover payments to embedded generators for the entire regulatory control period.

Specific TUOS charges over the entire regulatory control period are unknown at this time. For this reason the Tribunal is of the view that payments to embedded generators should be treated as a pass-through, subject to the approval by the Tribunal. In addition, pass through arrangements means that the DNSPs have an incentive to ensure that payments to embedded generators for the purposes of avoided TUOS do not exceed actual 'avoided TUOS'.

In principle:

- in the period from 1 February 2000 to 2001/02, payments should be calculated as the:
  - energy TUOS charge * the peak and shoulder energy generated by the embedded generators in the relevant year; and
  - demand TUOS charge * the reduction in Integral's overall maximum demand attributable to the embedded generators in the relevant year.

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consistent with the actual structure of transmission costs. As such, a pure revenue cap approach is problematic.

- in the period 2002/03 through to 2003/04, payments should be calculated as the reduction in allocated transmission revenue to Integral as a consequence of the embedded generator.

The exact amount will be calculated by Integral in each year once TUOS charges are known, and submitted to the Tribunal for approval (prior to a price change).

ATTACHMENT 1 NSW TRANSITIONAL PROVISIONS

9.16 Transitional Arrangements for Chapter 6 - Network Pricing

9.16.3 Distribution Network Service Pricing - IPART Determinations to prevail to the exclusion of Parts D and E in Chapter 6

(a) Until the end of 31 January 2000, *Distribution network service* pricing for *distribution networks* situated in New South Wales will be regulated by *IPART* under the *IPART Act* and the following determinations made by *IPAR*T, to the exclusion of Parts D and E of Chapter 6 of the *Cod*e:

(1) Determination No. 2.2 of 1996 published in Gazette No. 43 of 4 April 1996 at pages 1616-1623, as modified by the Determination referred to in paragraph (3);

(2) Determination No. 10 of 1996 published in Gazette No. 1 of 3 January 1997 at pages 29-34 as modified by the Determination referred to in paragraph (4);

(3) Determination No. 5.3 of 1997 published in Gazette No. 93 of 22 August 1997 at pages 6609-6621;

(4) Determination No. 5.4 of 1997 published in Gazette No. 93 of 22 August 19997 at pages 6622-6628;

(5) Determination No. 6 of 1998 published in Gazette No. 171 of 11 December 1998 at pages 9681-9662

(b) *IPART* is and will always be taken to have been the *Jurisdictional Regulator* for the purposes of clause 6.10.1(b) of the *Code* and will continue to be the *Jurisdictional Regulator* until the *Minister* appoints another body.

(c) Notwithstanding clauses 6.11 to 6.16 of this *Cod*e, the prices for *prescribed distribution services* provided by means of *distribution networks* and associated *connection assets* located in New South Wales applying to individual *connection points* located in New South Wales in the period commencing on 1 February 2000 until the end of 30 June 2000 and in the years commencing on 1 July 2000 and 1 July 2001 will, unless no later than 3 months prior to the start of the relevant year the *Jurisdictional Regulator* determines that such prices should be determined on the basis of Part E of Chapter 6 of the *Cod*e, be determined on the following basis:

(1) subject to clause 9.16.3(c)(2), the prices for *prescribed distribution services* provided by a *Distribution Network Service Provider* will be the prices determined in accordance with the methodology applied by that *Distribution Network Service Provider* to derive prices for similar services under the IPART Determinations set out in clause 9.16.3(a) or such other methodology approved in writing by IPART (an "alternate methodology") provided that, references in any such determination to a "network revenue cap" in respect of a *Distribution Network Service Provider* will be deemed to be a reference to the *aggregate annual revenue requirement* determined for that *Distribution Network Service Provider* in respect of the year commencing on 1 July 1999 or the years commencing on 1 July 2000 or 1 July 2001 (as the case may be) in accordance with clause 6.12 of the *Cod*e; and

(2) the price to apply at any *connection point* on any *distribution network* which became a *connection point* after 30 June 1999 will be:

(i) if IPART has not approved an alternate methodology, the price reasonably determined by the *Distribution Network Service Provider* for the *distribution network* on which the *connection point* is located which would have applied at that *connection point* in the year commencing on 1 July 1999 or the year commencing on 1 July 2000 and 1 July 2001 (as the case may be) if that *connection point* had been a *connection point* on or before 30 June 1999; and

(ii) if IPART has approved an alternate methodology, the price reasonably determined in accordance with the alternate methodology.

(d) For the purposes of clauses 6.10 to 6.18 and clause 6.20 of the Code, any amounts paid to a *Distribution Network Service Provider* to reflect the increase in price provided for by section 43B of the *ES Act* are deemed to not be paid in respect of the provision of *distribution services* by that *Distribution Network Service Provide*r.

(e) This clause 9.16.3 is a specific derogation for the purposes of clause 6.10.1(f) of the *Cod*e.

(f) Clause 9.16.3(a) will cease to apply on and from 1 February 2000 and clauses 9.16.3(c), (d) and (f) will cease to apply on and from 1 July 2002.

ATTACHMENT 2 FINANCIAL INFORMATION

A2.1 EnergyAustralia profile

A2.1.1 Background

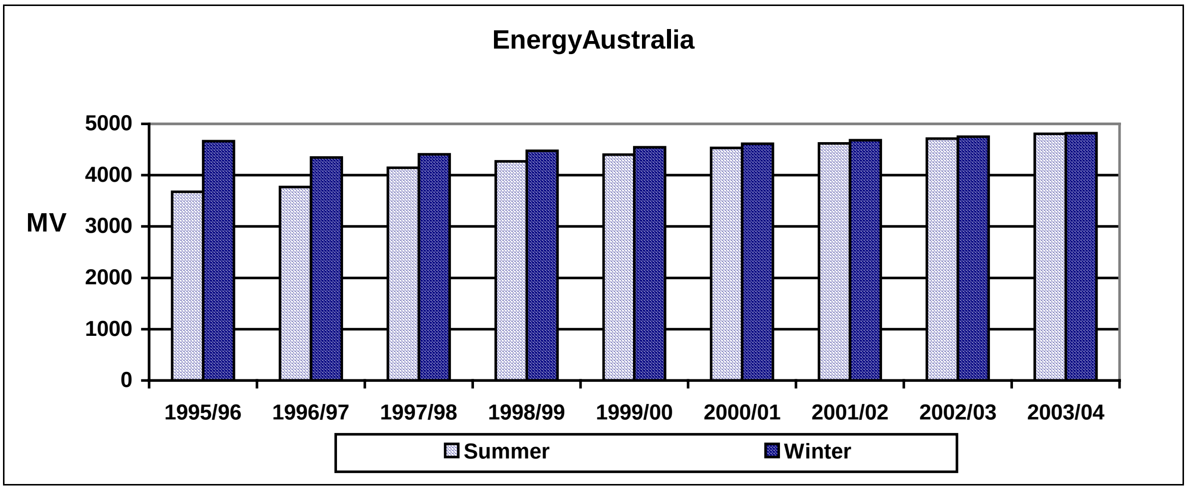
Head Office	570 George Street, Sydney NSW 2000
Major Towns/Cities[1]	Cessnock, Gosford, Maitland, Muswellbrook, Newcastle, Singleton, Sydney
Network Service Area (sq. km)[1]	22,275
Employee Numbers[2]	3,017

Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.1.2 Network Demand Profile

EnergyAustralia	1995/96	1996/97	1997/98
Total GWh delivered	21,035	21,212	22,067
Peak Demand (MW)	4,563	4,660	4,481
Total Customers	1,330,099	1,347,295	1,370,000
Residential	1,191,955	1,208,037	1,225,000
Non-Residential	138,144	139,258	145,000
Total Route km	28,670	28,818	29,956

A2.1.3 Maximum Demands



Source: Worley (1998).

A2.1.4 EnergyAustralia Distribution Revenue Path Forecasts 1999/2000 – 2003/04

EnergyAustralia Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base[1] ($000)	3,837,028	3,913,611	3,992,069	4,080,544	4,183,937
Operating Costs ($000)	205,562	209,673	213,866	218,144	222,507
Capital Expenditure per Worley review ($000)	147,745	156,492	163,408	189,135	206,358
Depreciation ($000)	174,399	182,496	190,906	199,810	209,332
Network Sales (GWh)	23,438	23,907	24,385	24,873	25,370
Sales Growth (%)	2.00%	2.00%	2.00%	2.00%	2.00%

1 Includes transmission assets

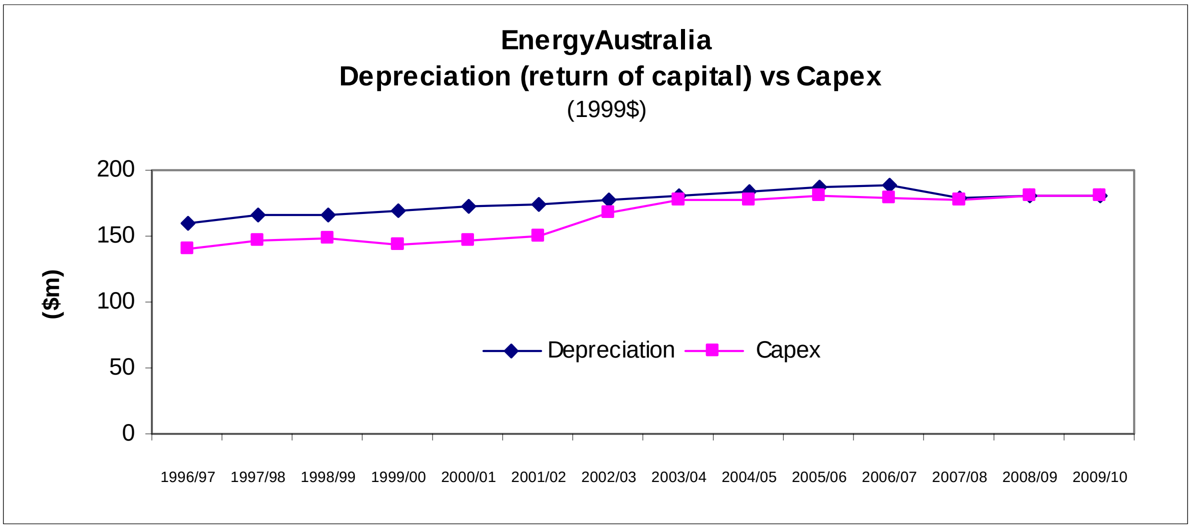
EnergyAustralia Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	205,562	209,673	213,866	218,144	222,507
Return of Capital (depreciation)	174,399	182,496	190,906	199,810	209,332
Return on Capital	287,777	293,521	299,405	306,041	313,795
Return on Working Capital	6,165	6,214	6,276	6,222	6,224
Total Base Revenue (duos)	673,903	691,903	710,454	730,217	751,858
Smoothed Base Revenue	690,892	705,653	720,731	736,130	751,858
Regulated Return on Assets	7.9%	7.9%	7.8%	7.6%	7.5%
Network Price (nominal c/kWh)	2.95	2.95	2.96	2.96	2.96
Network Price (real c/kWh)	2.86	2.78	2.70	2.63	2.56
Cumulative Real Network Price Change	-6.3%	-8.9%	-11.5%	-13.9%	-16.3%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

EnergyAustralia Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	3,799,463	3,874,593	3,952,628	4,031,509	4,129,580
Add: Revaluation of Assets	113,984	116,238	118,579	120,945	123,887
Add: Capital Expenditure	147,745	156,492	163,408	189,135	206,358
Less: Depreciation	174,399	182,496	190,906	199,810	209,332
Less: Disposals	12,199	12,199	12,199	12,199	12,199
Closing Balance	3,874,593	3,952,628	4,031,509	4,129,580	4,238,293
Average Regulated Fixed Assets	3,837,028	3,913,611	3,992,069	4,080,544	4,183,937

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.1.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

EnergyAustralia Financial Performance Ratios	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Operating costs as % of base revenue	36%	35%	35%	35%	35%
EBIT margin on sales (EBIT/revenue)	38%	38%	37%	37%	36%
EBITDA margin on sales (EBITDA/revenue)	60%	60%	61%	61%	61%
NPAT/Shareholders Funds	6%	6%	5%	5%	5%
EBIT/(Total Assets - cash & investments)	7%	7%	7%	7%	7%
EBIT/(Borrowings + Equity)	8%	7%	7%	7%	7%
EBITDA/(Equity - revaluation)					
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

EnergyAustralia Ratio Analysis	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Ability to service debt					
(a) Funds flow interest cover (using net interest)	9.93	10.61	11.57	12.78	13.92
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	8.06	8.52	9.15	9.92	10.62
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	4.61	4.87	5.23	5.68	6.09
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	3.86	4.03	4.26	4.55	4.79
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	7.25	7.78	8.50	9.38	10.23

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	2.78	2.49	2.21	1.99	1.81
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.27	0.29	0.32	0.35	0.38
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	31%	28%	26%	24%	23%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.36	0.40	0.45	0.50	0.55
Cash flow before capex/Total debt	16%	18%	21%	23%	25%
EBIT/(total debt + total equity)	10%	11%	11%	12%	12%
Total Debt / Total assets	27%	25%	23%	22%	20%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	1.35	1.40	1.42	1.28	1.22
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Net cash flow/Capex	1.18	1.26	1.29	1.18	1.13
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Cash flow before Capex and cap cons/net Capex	1.33	1.40	1.42	1.28	1.22
Cash flow before Capex/Capex	1.29	1.36	1.38	1.26	1.21
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	1.18	1.22	1.23	1.16	1.13
Funds from operations/ (dividends + capex) including cap cons	1.36	1.36	1.36	1.28	1.24

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. EnergyAustralia is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

EnergyAustralia	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	690,892	705,653	720,731	736,130	751,858
Transmission Revenue	114,151	114,670	115,192	115,716	116,242
Other Income	-	-	-	-	-
Total Income	805,043	820,324	835,922	851,845	868,100
Operating Expenditure					
Operating Costs	205,562	209,673	213,866	218,144	222,507
Transmission Charges	114,151	114,670	115,192	115,716	116,242
Total Operating Expenditure	319,713	324,343	329,058	333,859	338,748
EBITDA	485,330	495,981	506,864	517,986	529,351
Depreciation	176,549	185,555	194,636	204,133	214,238
EBIT	308,781	310,426	312,228	313,853	315,113
Interest and financing charges	66,960	63,761	59,658	55,211	51,749
Profit Before Tax and Abnormal Items	241,821	246,664	252,570	258,642	263,364
Plus: Capital Contributions	21,341	17,226	16,232	16,622	17,021
Profit Before Tax	263,162	263,890	268,802	275,264	280,385
Tax expense	94,738	95,000	96,769	99,095	100,939
Net Profit After Tax	168,424	168,890	172,033	176,169	179,446
Dividends declared	128,949	129,306	131,713	134,879	137,389

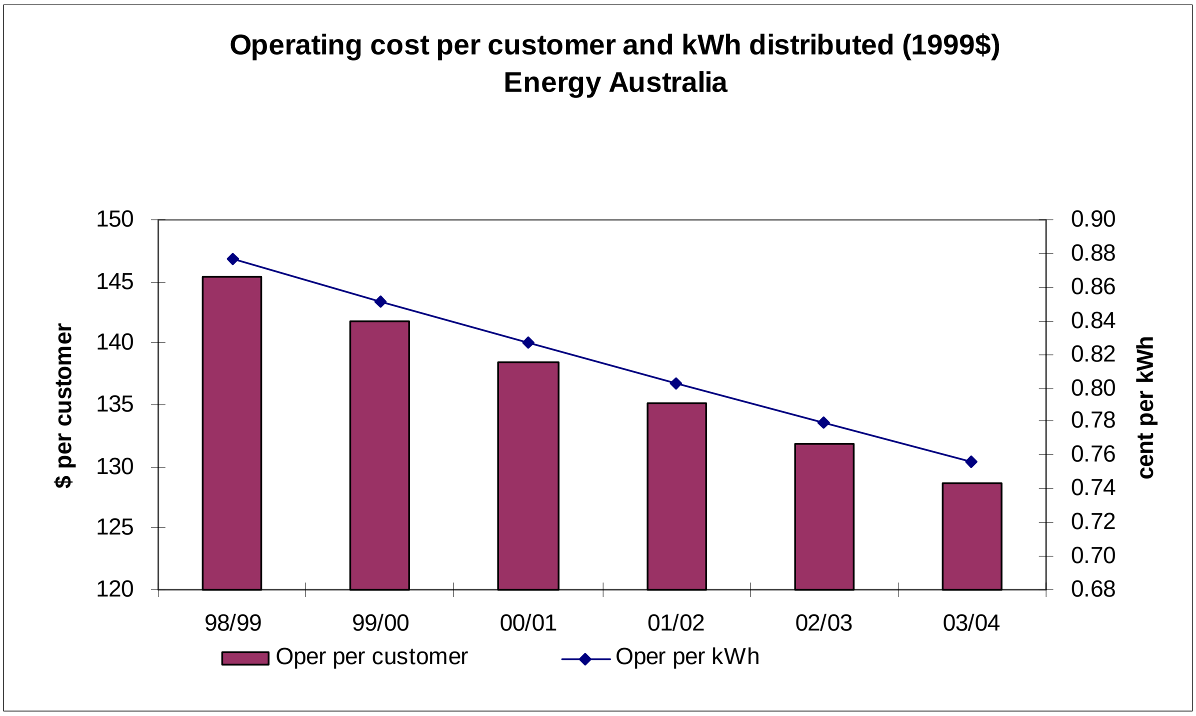
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

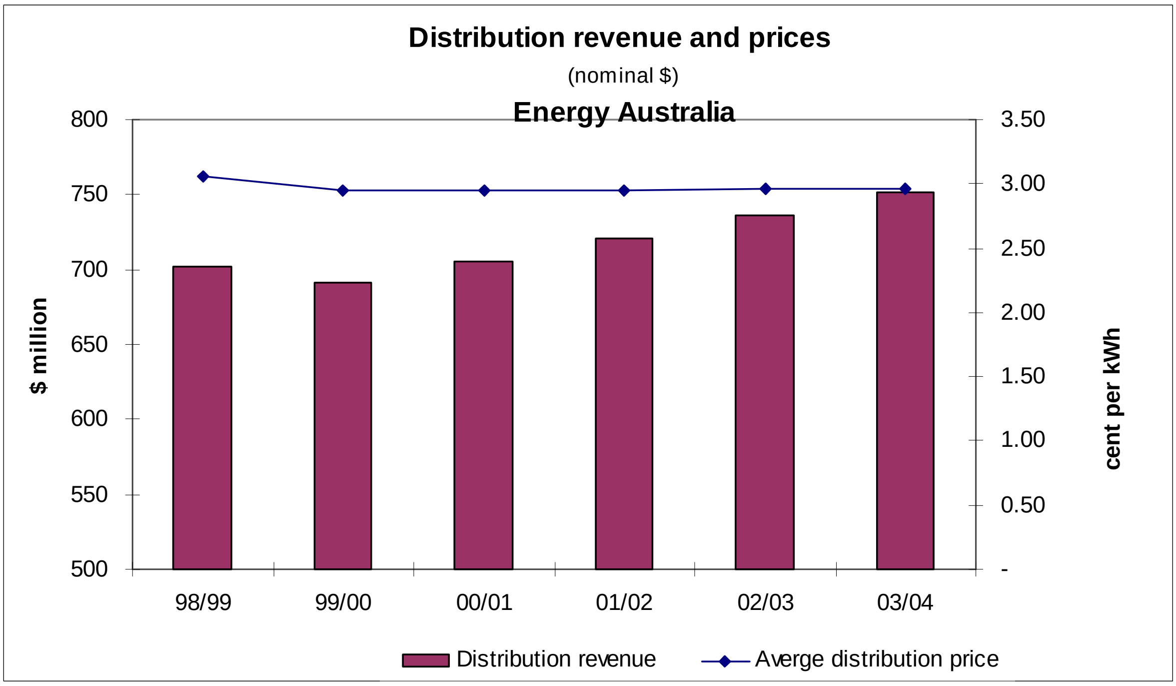
EnergyAustralia	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	89,775	91,694	93,653	95,654	97,697
Inventories	19,900	19,900	19,900	19,900	19,900
Investments	322,400	322,400	322,400	322,400	322,400
Prepayments	14,354	14,354	14,354	14,354	14,354
Accrued Revenue	91,700	91,700	91,700	91,700	91,700
FITB	54,300	54,300	54,300	54,300	54,300
Property, Plant and Equipment	3,939,137	4,031,338	4,122,722	4,233,091	4,353,920
Other assets	57,846	57,846	57,846	57,846	57,846
Total assets	4,589,413	4,683,532	4,776,874	4,889,245	5,012,117
Bank overdraft	-	-	-	-	-
Creditors	82,037	83,225	84,435	85,667	86,922
Accruals	-	-	-	-	-
Borrowings	1,253,743	1,190,609	1,122,197	1,068,936	1,022,893
Customer deposits	400	400	400	400	400
Provision for Income Tax	23,685	23,750	24,192	24,774	25,235
PDIT	120,600	120,600	120,600	120,600	120,600
Provision for dividend	64,475	64,653	65,857	67,440	68,694
Other provisions (employee etc)	138,600	138,600	138,600	138,600	138,600
Other liabilities (provisions per 98 reg accounts)	66,100	66,100	66,100	66,100	66,100
Total liabilities	1,749,640	1,687,938	1,622,381	1,572,516	1,529,443
Share Capital	1,480,000	1,480,000	1,480,000	1,480,000	1,480,000
Asset Revaluation Reserve	1,243,839	1,360,077	1,478,656	1,599,601	1,723,489
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	76,459	115,934	155,517	195,838	237,127
This year's profits retained	39,474	39,583	40,320	41,290	42,058
Shareholders' funds	2,839,773	2,995,594	3,154,494	3,316,728	3,482,674
Total Liabilities and Shareholder's funds	4,589,413	4,683,532	4,776,874	4,889,245	5,012,117

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.1.6 Projected operating costs efficiency



A2.1.7 Regulated distribution revenue and price movements



A2.2 Integral Energy profile

A2.2.1 Background

Head Office	51 Huntingwood Drive, Huntingwood NSW 2148
Major Towns/Cities[1]	Lithgow, Katoomba, Nowra, Wollongong
Network Service Area (sq. km)[1]	24,602
Employee Numbers[2]	2,039

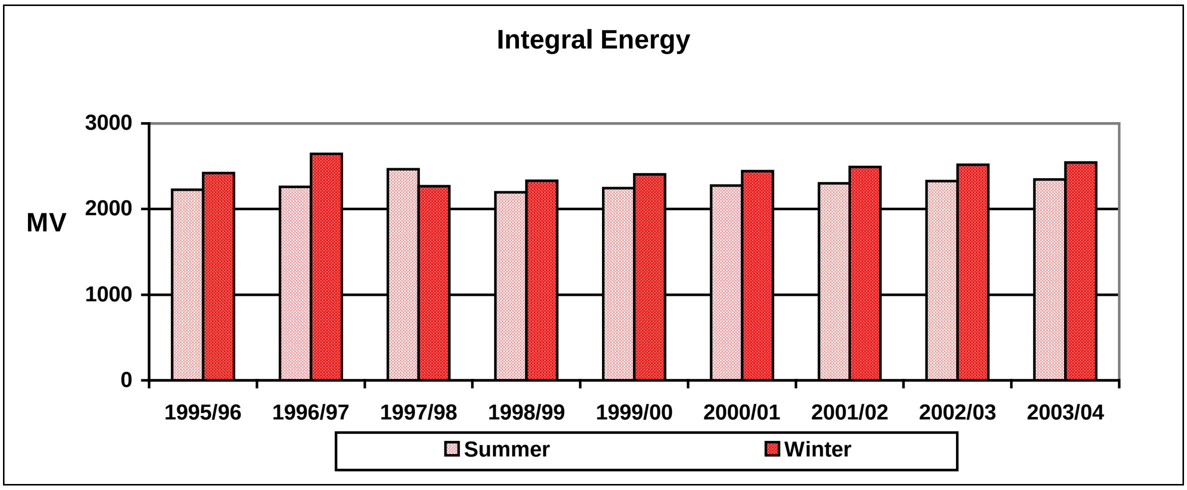
Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.2.2 Network Demand Profile

Integral Energy	1995/96	1996/97	1997/98
Total GWh delivered	12,092	12,669	14,005
Peak Demand (MW)	2,421	2,643	2,642
Total Customers	691,359	735,364	739,322
Residential	628,459	658,642	661,472
Non-Residential	62,900	76,722	77,850
Total Route km	25,836	25,680	27,134

Source: London Economics (1999), Final Annex 2.

A2.2.3 Maximum Demands



Source: Worley (1998).

A2.2.4 Integral Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Integral Energy Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	1,773,722	1,821,198	1,847,099	1,863,971	1,880,133
Operating Costs ($000)	157,174	159,924	162,723	165,570	168,468
Capital Expenditure per Worley review ($000)	105,128	83,477	68,762	72,084	70,122
Depreciation ($000)	93,467	98,476	103,099	106,695	106,892
Network Sales (GWh)	14,492	14,999	15,524	16,068	16,630
Sales Growth (%)	3.5%	3.5%	3.5%	3.5%	3.5%

Integral Energy Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	157,174	159,924	162,723	165,570	168,468
Return of Capital (depreciation)	93,467	98,476	103,099	106,695	106,892
Return on Capital	133,029	136,590	138,532	139,798	141,010
Return on Working Capital	2,710	2,884	3,016	3,034	3,087
Total Base Revenue (duos)	386,380	397,874	407,370	415,098	419,457
Smoothed Base Revenue	394,719	400,763	406,900	413,131	419,457
Regulated Return on Assets	7.90%	7.66%	7.47%	7.39%	7.50%
Network Price (nominal c/kWh)	2.72	2.67	2.62	2.57	2.52
Network Price (real c/kWh)	2.64	2.52	2.40	2.28	2.18
Cumulative Real Network Price Change	-11.3%	-15.5%	-19.5%	-23.3%	-27.0%

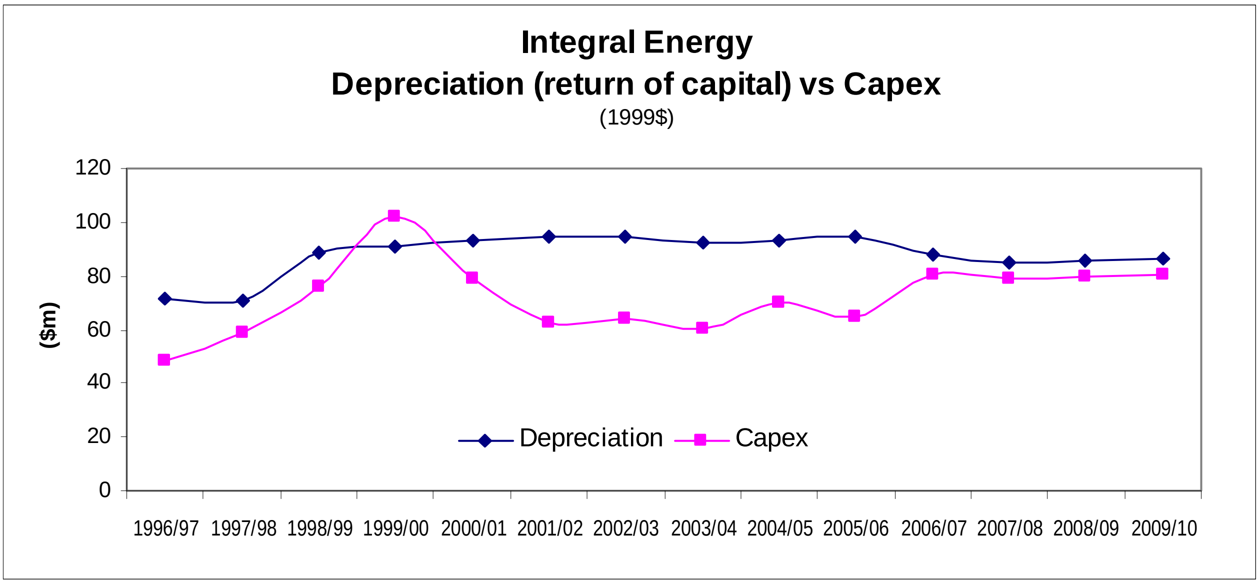
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Integral Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	1,743,768	1,803,676	1,838,720	1,855,478	1,872,464
Add: Revaluation of Assets	52,313	54,110	55,162	55,664	56,174
Add: Capital Expenditure	105,128	83,477	68,762	72,084	70,122
Less: Depreciation	93,467	98,476	103,099	106,695	106,892
Less: Disposals	4,066	4,066	4,066	4,066	4,066
Closing Balance	1,803,676	1,838,720	1,855,478	1,872,464	1,887,801
Average Regulated Fixed Assets	1,773,722	1,821,198	1,847,099	1,863,971	1,880,133

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.2.5 Return of Capital (depreciation) Versus Capex Profile

Source: Worley (1998).



Integral Energy Financial Performance Ratios	1999/00	2000/01	2001/02	2002/03	2003/04
Operating costs as % of base revenue	0.49	0.49	0.49	0.49	0.49
EBIT margin on sales (EBIT/revenue)	0.31	0.30	0.29	0.29	0.29
EBITDA margin on sales (EBITDA/revenue)	0.51	0.51	0.51	0.51	0.51
NPAT/Shareholders Funds	0.05	0.05	0.04	0.04	0.04
EBIT/(Total Assets - cash & investments)	0.07	0.07	0.07	0.07	0.07
EBIT/(Borrowings + Equity)	0.07	0.07	0.07	0.07	0.07
EBITDA/(Equity - revaluation)	0.34	0.34	0.34	0.33	0.33
Effective tax rate	0.36	0.36	0.36	0.36	0.36
Dividend cover	0.77	0.77	0.77	0.77	0.77

Integral Energy Ratio Analysis	1999/00	2000/01	2001/02	2002/03	2003/04
Ability to service debt					
(a) Funds flow interest cover (using net interest)	6.60	6.73	7.15	7.91	8.89
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	6.17	6.29	6.66	7.31	8.15
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	3.11	3.10	3.22	3.49	3.92
S&P - US Utilities (1995)	A	A	A	A	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	2.95	2.94	3.04	3.28	3.65
S&P - US Utilities (1995)	A	A	A	A	AA
EBITDA / net interest	5.17	5.28	5.62	6.19	6.89
Ability to repay debt					

Funds flow net debt payback (Net debt/Funds from operations)	4.34	4.00	3.57	3.14	2.73
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.21	0.23	0.25	0.28	0.32
S&P - US Utilities (1995)	A	A	A	AA	AA
Total Debt/Total capital	38%	35%	32%	30%	27%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.23	0.25	0.28	0.32	0.37
Cash flow before capex/Total debt	15%	16%	18%	20%	23%
EBIT/(total debt + total equity)	9%	9%	10%	10%	12%
Total Debt / Total assets	36%	34%	31%	28%	25%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	1.06	1.40	1.77	1.76	1.83
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Net cash flow/Capex	1.04	1.38	1.74	1.72	1.80
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Cash flow before Capex and cap cons/net Capex	1.06	1.40	1.77	1.76	1.84
Cash flow before Capex/Capex	1.05	1.39	1.76	1.75	1.83
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	1.04	1.25	1.46	1.45	1.48
Funds from operations/ (dividends + capex) including cap cons	1.06	1.27	1.48	1.48	1.51

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Integral Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Integral Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	394,719	400,763	406,900	413,131	419,457
Transmission Revenue	71,279	72,672	74,092	75,541	77,017
Other Income	157	161	166	171	176
Total Income	466,154	473,596	481,158	488,842	496,650
Operating Expenditure					
Operating Costs	157,174	159,924	162,723	165,570	168,468
Transmission Charges	71,279	72,672	74,092	75,541	77,017
Total Operating Expenditure	228,452	232,596	236,815	241,111	245,485
EBITDA	237,702	241,000	244,343	247,731	251,165
Depreciation	94,779	99,787	104,410	108,006	108,202
EBIT	142,923	141,213	139,934	139,726	142,963
Interest and financing charges	45,979	45,603	43,457	39,999	36,439
Profit Before Tax and Abnormal Items	96,944	95,610	96,476	99,727	106,524
Plus: Capital Contributions	1,296	1,296	1,296	1,296	1,296
Profit Before Tax	98,240	96,906	97,772	101,023	107,820
Tax expense	35,366	34,886	35,198	36,368	38,815
Net Profit After Tax	62,874	62,020	62,574	64,655	69,005
Dividends declared	48,138	47,484	47,908	49,501	52,832

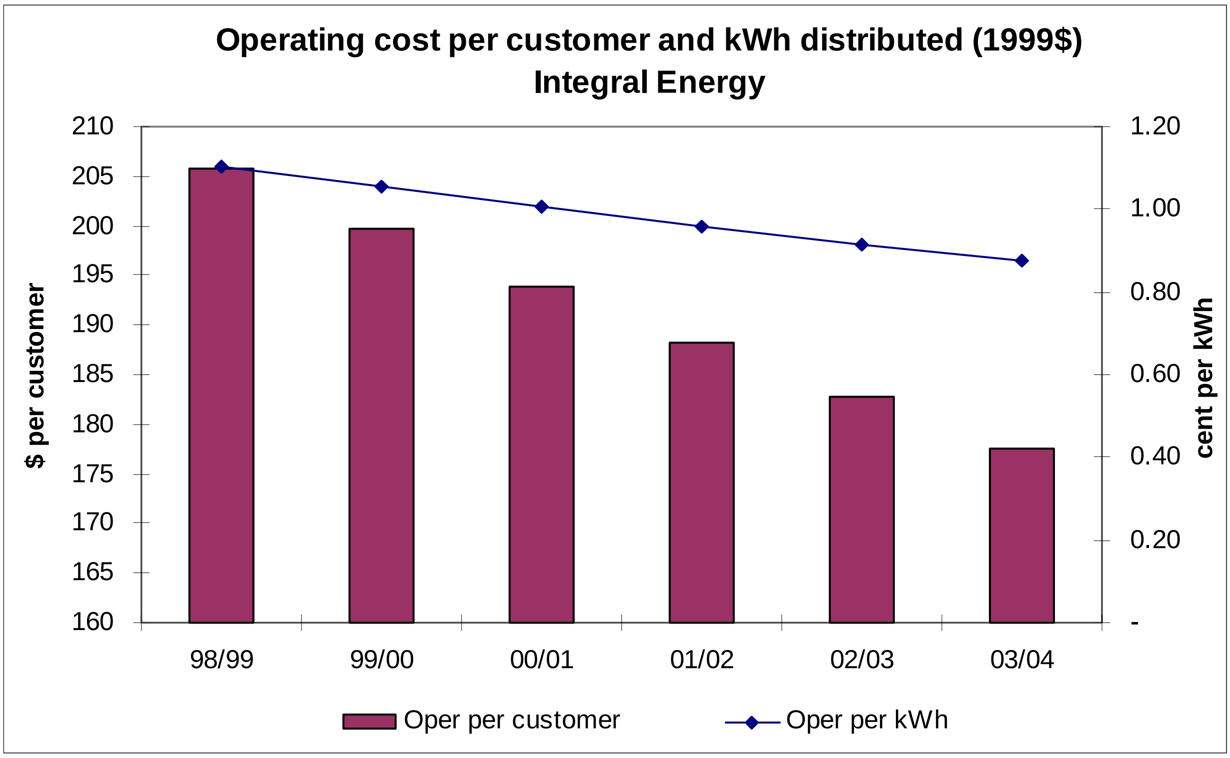
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

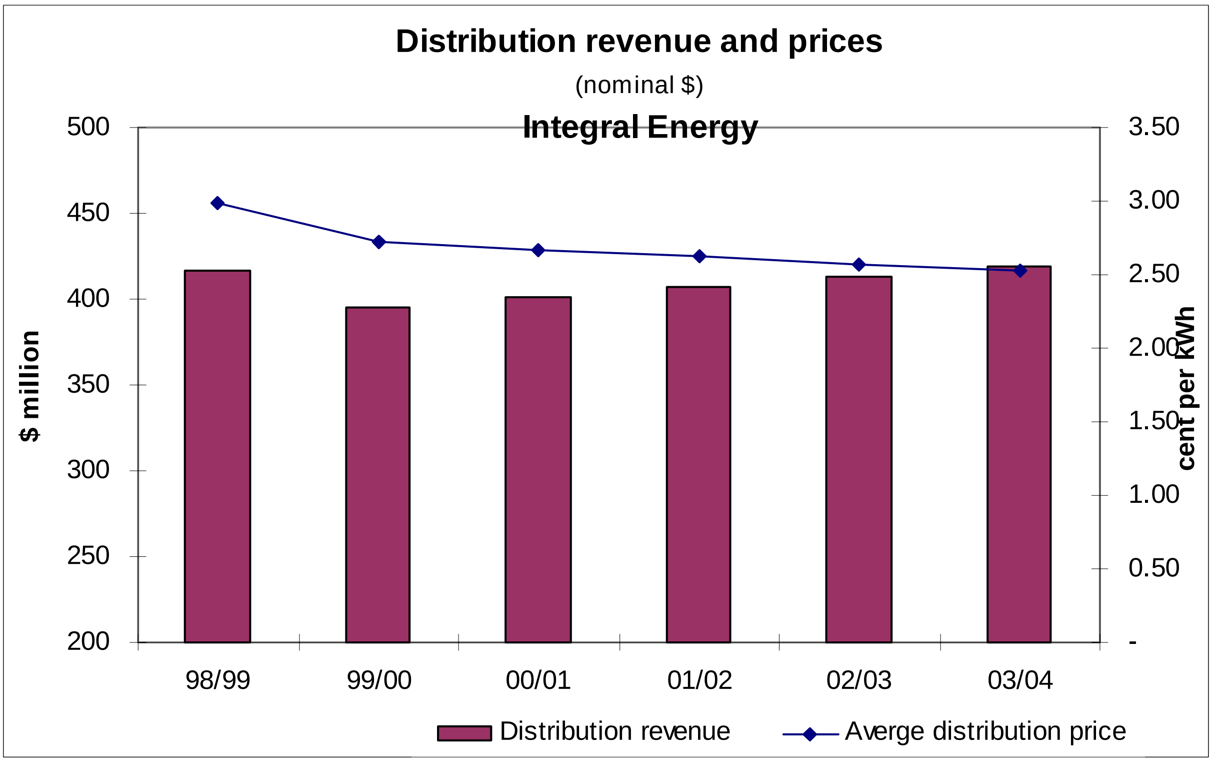
Integral Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	51,313	52,099	52,897	53,707	54,529
Inventories	5,460	5,460	5,460	5,460	5,460
Investments	68,796	68,796	68,796	68,796	68,796
Prepayments	1,136	1,136	1,136	1,136	1,136
Accrued Revenue	26,000	26,000	26,000	26,000	26,000
FITB	-	-	-	-	-
Property, Plant and Equipment	1,833,960	1,868,989	1,885,733	1,902,705	1,918,029
Other assets	137,370	137,370	137,370	137,370	137,370
Total assets	2,124,035	2,159,850	2,177,392	2,195,174	2,211,320
Bank overdraft	-	-	-	-	-
Creditors	34,268	34,889	35,522	36,167	36,823
Accruals	-	-	-	-	-
Borrowings	759,790	726,784	673,576	618,807	559,672
Customer deposits	1,034	1,034	1,034	1,034	1,034
Provision for Income Tax	8,842	8,722	8,800	9,092	9,704
PDIT	-	-	-	-	-
Provision for dividend	24,069	23,742	23,954	24,751	26,416
Other provisions (employee etc)	19,629	19,629	19,629	19,629	19,629
Other liabilities (provisions per 98 reg accounts)	10,703	10,703	10,703	10,703	10,703
Total liabilities	858,335	825,503	773,218	720,182	663,981
Share Capital	1,086,748	1,086,748	1,086,748	1,086,748	1,086,748
Asset Revaluation Reserve	570,285	624,395	679,557	735,221	791,395
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	-406,068	-391,332	-376,796	-362,130	-346,977
This year's profits retained	14,736	14,536	14,666	15,153	16,173
Shareholders' funds	1,265,700	1,334,347	1,404,174	1,474,992	1,547,339
Total Liabilities and Shareholder's funds	2,124,035	2,159,850	2,177,392	2,195,174	2,211,320

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.2.6 Projected operating costs efficiency



A2.2.7 Regulated distribution revenue and price movements



A2.3 NorthPower profile

A2.3.1 Background

Head Office	NorthPower House, 9 Short Street, Port Macquarie NSW 2444
Major Towns/Cities[1]	Armidale, Bourke, Casino, Coffs Harbour, Glen Innes, Grafton, Gunnedah, Inverell, Kempsey, Lismore, Moree, Murwillumbah, Narrabri, Port Macquarie, Taree, Tenterfield
Network Service Area (sq. km)[1]	230,000
Employee Numbers[2]	1,127

Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.3.2 Network Demand Profile

NorthPower	1995/96	1996/97	1997/98
Total GWh delivered	3,285	3,552	3,720
Peak Demand (MW)	683	771	800
Total Customers	330,043	340,189	350,798
Residential	261,035	269,544	278,517
Non-Residential	69,008	70,645	72,281
Total Route km	66,830	67,281	67,841

Source: London Economics (1999), Final Annex 2.

A2.3.3 Maximum Demands

Not available from NorthPower

A2.3.4 NorthPower Distribution Revenue Path Forecasts 1999/2000 – 2003/04

NorthPower Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	917,925	965,574	1,015,041	1,063,800	1,107,178
Operating Costs ($000)	70,687	71,747	72,824	73,916	75,025
Capital Expenditure per Worley review ($000)	70,051	69,132	75,317	69,338	67,529
Depreciation ($000)	44,991	47,869	49,480	52,459	55,379
Network Sales (GWh)	3,994	4,114	4,238	4,365	4,496
Sales Growth (%)	3%	3%	3%	3%	3%

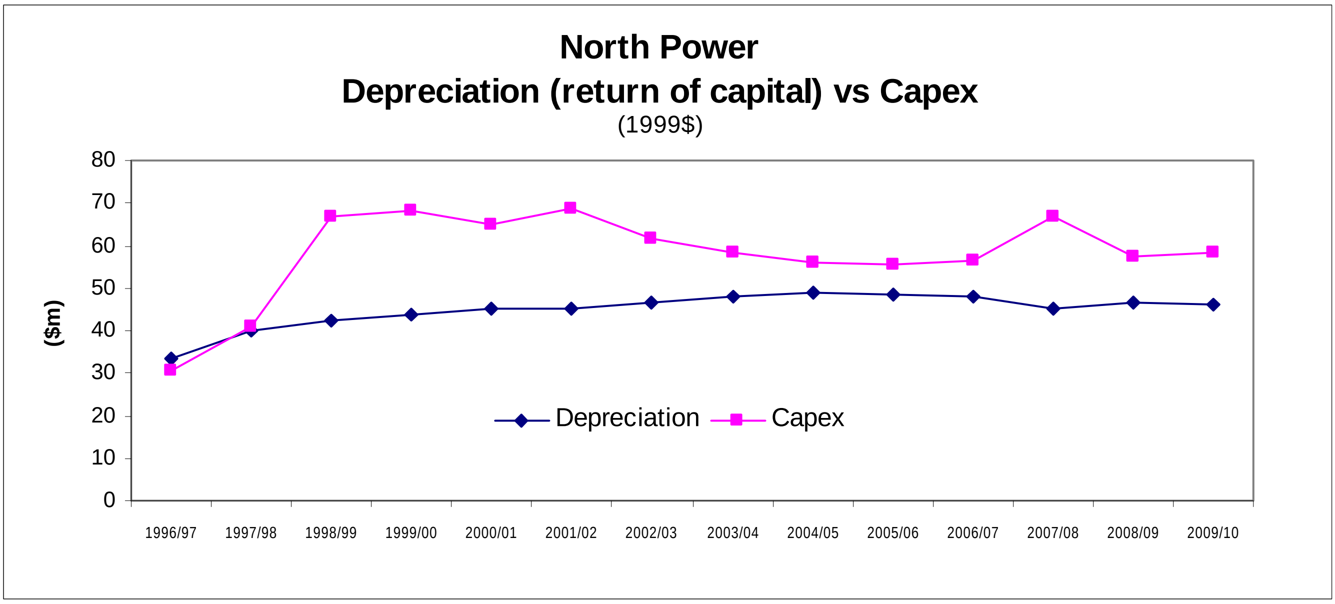
NorthPower Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	70,687	71,747	72,824	73,916	75,025
Return of Capital (depreciation)	44,991	47,869	49,480	52,459	55,379
Return on Capital	68,844	72,418	76,128	79,785	83,038
Return on Working Capital	1,536	1,632	1,688	1,828	1,947
Total Base Revenue (duos)	186,058	193,666	200,120	207,988	215,390
Smoothed Base Revenue	169,597	180,041	191,127	202,896	215,390
Regulated Return on Assets	5.71%	6.09%	6.61%	7.02%	7.50%
Network Price (nominal c/kWh)	4.26	4.38	4.52	4.65	4.79
Network Price (real c/kWh)	4.13	4.13	4.13	4.13	4.13
Cumulative Real Network Price Change		0%	0%	0%	0%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

NorthPower **Regulated Fixed Assets($'000)**	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Opening Balance	893,517	942,332	988,815	1,041,266	1,086,334
Add: Revaluation of Assets	26,806	28,270	29,664	31,238	32,590
Add: Capital Expenditure	70,051	69,132	75,317	69,338	67,529
Less: Depreciation	44,991	47,869	49,480	52,459	55,379
Less: Disposals	3,050	3,050	3,050	3,050	3,050
Closing Balance	942,332	988,815	1,041,266	1,086,334	1,128,023
Average Regulated Fixed Assets	917,925	965,574	1,015,041	1,063,800	1,107,178

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.3.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

NorthPower Financial Performance Ratios	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Operating costs as % of base revenue	53%	50%	47%	45%	42%
EBIT margin on sales (EBIT/revenue)	28%	29%	31%	33%	34%
EBITDA margin on sales (EBITDA/revenue)	50%	51%	53%	55%	56%
NPAT/Shareholders Funds	5%	5%	5%	5%	6%
EBIT/(Total Assets - cash & investments)	6%	6%	6%	7%	7%
EBIT/(Borrowings + Equity)	6%	6%	6%	7%	7%
EBITDA/(Equity - revaluation)	21%	22%	24%	25%	27%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

NorthPower Ratio Analysis	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Ability to service debt					
(a) Funds flow interest cover (using net interest)	20.32	18.64	18.35	17.79	18.46
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	13.31	12.93	13.13	13.14	13.79
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	8.30	7.72	7.82	7.69	8.07
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	5.65	5.55	5.77	5.83	6.18
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	14.82	13.57	13.28	12.86	13.29

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	1.52	1.57	1.66	1.62	1.52
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.41	0.41	0.41	0.42	0.45
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	0.19	0.19	0.20	0.20	0.19
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.66	0.64	0.60	0.62	0.66
Cash flow before capex/Total debt	26%	27%	26%	27%	28%
EBIT/(total debt + total equity)	13%	14%	14%	15%	16%
Total Debt / Total assets	18%	18%	19%	18%	18%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.70	0.78	0.76	0.88	0.96
NSW Treasury rating (1994)	A	A	A	AAA	AAA
S&P - US Utilities (1995)	A	A	A	A	AA
Net cash flow/Capex	0.64	0.71	0.69	0.78	0.85
S&P - US Utilities (1995)	BBB	A	BBB	A	A
Cash flow before Capex and cap cons/net Capex	0.70	0.79	0.77	0.88	0.97
Cash flow before Capex/Capex	0.73	0.81	0.79	0.90	0.97
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.79	0.85	0.83	0.92	0.98
Funds from operations/ (dividends + capex) including cap cons	0.93	1.00	0.98	1.08	1.15

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. NorthPower is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

NorthPower	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	170,022	180,376	191,361	203,015	215,379
Transmission Revenue	35,644	36,163	36,689	37,223	37,764
Other Income	4,981	5,131	5,285	5,443	5,607
Total Income	210,648	221,670	233,335	245,681	258,749
Operating Expenditure					
Operating Costs	70,687	71,747	72,824	73,916	75,025
Transmission Charges	35,644	36,163	36,689	37,223	37,764
Total Operating Expenditure	106,331	107,910	109,512	111,138	112,789
EBITDA	104,316	113,760	123,822	134,542	145,961
Depreciation	45,930	49,049	50,908	54,139	57,322
EBIT	58,386	64,711	72,914	80,403	88,639
Interest and financing charges	7,037	8,382	9,326	10,459	10,982
Profit Before Tax and Abnormal Items	51,350	56,329	63,588	69,944	77,657
Plus: Capital Contributions	7,038	7,491	7,853	8,335	8,833
Profit Before Tax	58,388	63,820	71,441	78,278	86,490
Tax expense	21,020	22,975	25,719	28,180	31,136
Net Profit After Tax	37,368	40,845	45,722	50,098	55,353
Dividends declared	28,610	31,272	35,006	38,356	42,380

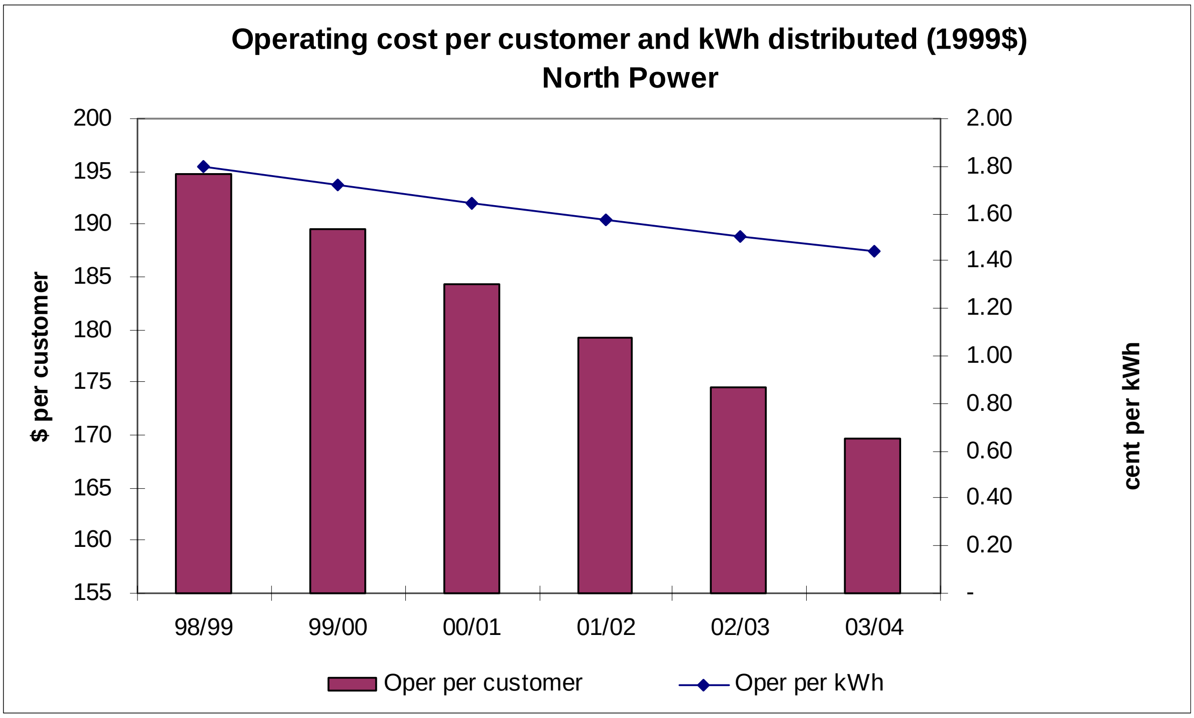
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

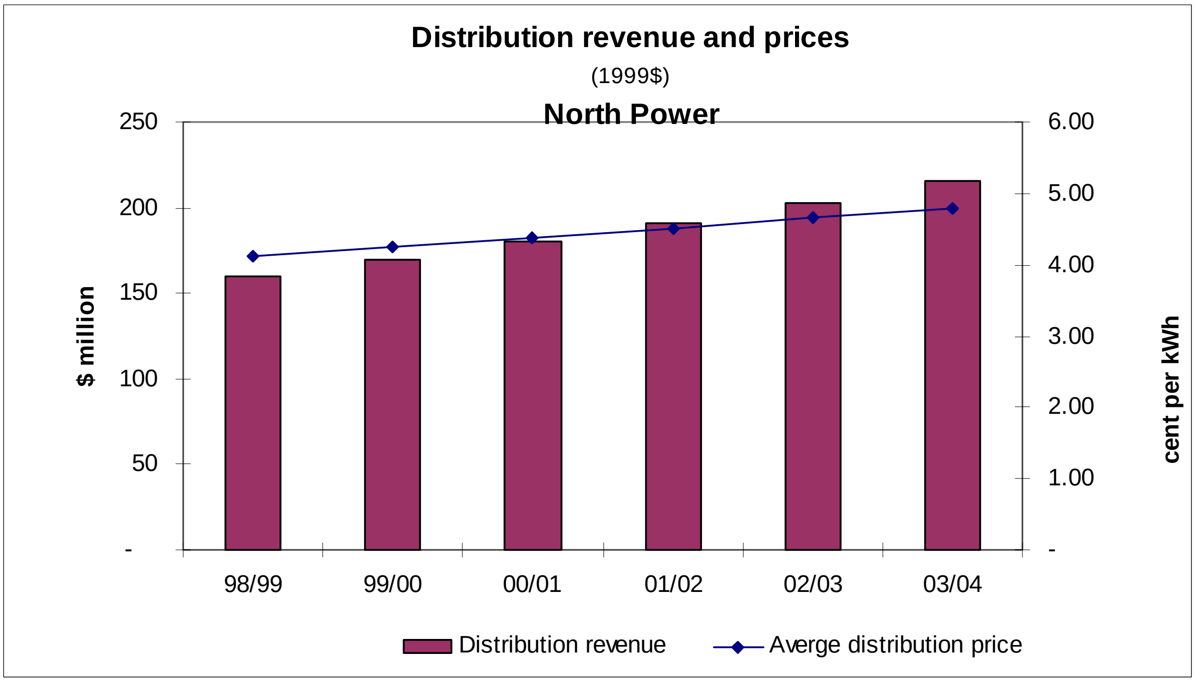
NorthPower	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	25,503	27,056	28,704	30,452	32,307
Inventories	9,304	9,304	9,304	9,304	9,304
Investments	72,934	72,934	72,934	72,934	72,934
Prepayments	115	115	115	115	115
Accrued Revenue	-	-	-	-	-
FITB	-	-	-	-	-
Property, Plant and Equipment	972,281	1,025,076	1,083,952	1,135,674	1,184,254
Other assets	61	61	61	61	61
Total assets	1,080,198	1,134,547	1,195,071	1,248,540	1,298,974
Bank overdraft	-	-	-	-	-
Creditors	10,633	10,791	10,951	11,114	11,279
Accruals	-	-	-	-	-
Borrowings	190,668	205,196	222,626	230,662	232,618
Customer deposits	1	1	1	1	1
Provision for Income Tax	5,255	5,744	6,430	7,045	7,784
PDIT	-	-	-	-	-
Provision for dividend	14,305	15,636	17,503	19,178	21,190
Other provisions (employee etc)	32,673	32,673	32,673	32,673	32,673
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	253,535	270,041	290,184	300,674	305,545
Share Capital	95,910	95,910	95,910	95,910	95,910
Asset Revaluation Reserve	322,879	351,149	380,813	412,051	444,641
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	399,116	407,875	417,448	428,164	439,905
This year's profits retained	8,758	9,573	10,716	11,742	12,973
Shareholders' funds	826,663	864,506	904,887	947,867	993,430
Total Liabilities and Shareholder's funds	1,080,199	1,134,547	1,195,071	1,248,540	1,298,975

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.3.6 Projected operating costs efficiency



A2.3.7 Regulated distribution revenue and price movements[146]



146 Nominal $.

A2.4 Great Southern Energy profile

A2.4.1 Background

Head Office	Level 1, CityLink Plaza, 30 Morisset Street, Queanbeyan NSW 2620
Major Towns/Cities[1]	Albury, Bega, Cooma, Cootamundra, Deniliquin, Eden, Griffith, Hay, Junee, Leeton, Queanbeyan, Temora, Wagga Wagga, Yass, Young
Network Service Area (sq. km)[1]	176,000
Employee Numbers[2]	901

Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.4.2 Network Demand Profile

Great Southern Energy	1995/96	1996/97	1997/98
Total GWh delivered	3,159	3,018	2,999
Peak Demand (MW)	576	576	576
Total Customers	219,512	223,303	225,841
Residential	185,693	188,378	191,248
Non-Residential	33,819	34,925	34,593
Total Route km	52,191	53,544	54,896

Source: London Economics (1999), Final Annex 2.

A2.4.3 Maximum Demands

Not supplied by Great Southern Energy

A2.4.4 Great Southern Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Great Southern Energy Core Assumptions	1999/00	2000/01	2001/02	2002/03	2003/04
Regulatory Asset Base ($000)	529,694	556,926	583,309	606,930	629,672
Operating Costs ($000)	47,648	48,125	48,606	49,092	49,583
Capital Expenditure per Worley review ($000)	39,790	45,189	39,436	40,504	37,712
Depreciation ($000)	29,199	31,064	32,177	33,486	33,631
Network Sales (GWh)	3,109	3,171	3,234	3,299	3,365
Sales Growth (%)	2%	2%	2%	2%	2%

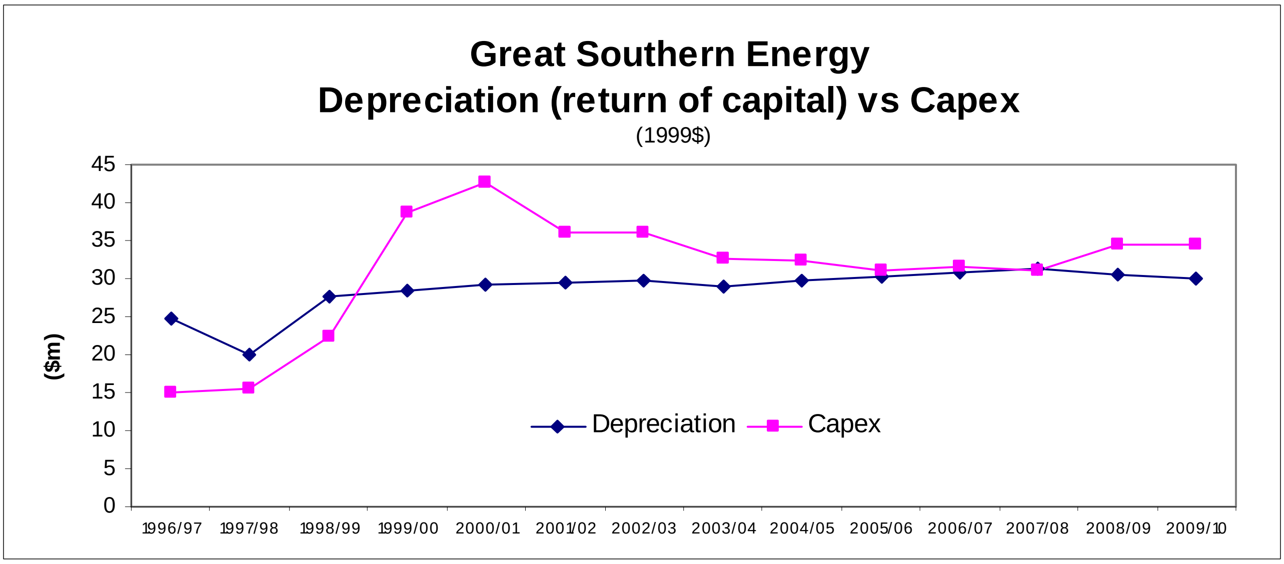
Great Southern Energy Output Summary ($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Building Block Revenue Requirement					
Operating Costs	47,648	48,125	48,606	49,092	49,583
Return of Capital (depreciation)	29,199	31,064	32,177	33,486	33,631
Return on Capital	39,727	41,769	43,748	45,520	47,225
Return on Working Capital	905	908	983	1,016	1,075
Total Base Revenue (duos)	117,479	121,867	125,514	129,113	131,514
Smoothed Base Revenue	112,884	117,278	121,843	126,587	131,514
Regulated Return on Assets	6.63%	6.68%	6.87%	7.08%	7.50%
Network Price (nominal c/kWh)	3.63	3.70	3.77	3.84	3.91
Network Price (real c/kWh)	3.53	3.49	3.45	3.41	3.37
Cumulative Real Network Price Change	-1.1%	-2.2%	-3.3%	-4.4%	-5.4%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

Great Southern Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	517,150	542,239	571,614	595,004	618,857
Add: Revaluation of Assets	15,514	16,267	17,148	17,850	18,566
Add: Capital Expenditure	39,790	45,189	39,436	40,504	37,712
Less: Depreciation	29,199	31,064	32,177	33,486	33,631
Less: Disposals	1,017	1,017	1,017	1,017	1,017
Closing Balance	542,239	571,614	595,004	618,857	640,487
Average Regulated Fixed Assets	529,694	556,926	583,309	606,930	629,672

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.4.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

Great Southern Energy Financial Performance Ratios	1999/00	2000/01	2001/02	2002/03	2003/04
Operating costs as % of base revenue	53%	51%	50%	48%	46%
EBIT margin on sales (EBIT/revenue)	27%	28%	29%	29%	31%
EBITDA margin on sales (EBITDA/revenue)	49%	50%	51%	52%	54%
NPAT/Shareholders Funds	6%	5%	5%	5%	6%
EBIT/(Total Assets - cash & investments)	6%	6%	6%	6%	7%
EBIT/(Borrowings + Equity)	6%	6%	6%	6%	7%
EBITDA/(Equity - revaluation)	19%	20%	20%	21%	22%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

Great Southern Energy Ratio Analysis	1999/00	2000/01	2001/02	2002/03	2003/04
Ability to service debt					
(a) Funds flow interest cover (using net interest)	40.64	31.38	25.38	24.10	23.61
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	16.65	15.30	14.07	13.98	14.15
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	16.13	12.38	10.16	9.74	9.79
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	6.97	6.35	5.91	5.91	6.11
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	28.73	22.32	18.17	17.31	16.87

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	0.80	1.04	1.12	1.16	1.14
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.47	0.44	0.43	0.44	0.45
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	0.17	0.18	0.19	0.19	0.18
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	1.24	0.97	0.90	0.86	0.88
Cash flow before capex/Total debt	25%	25%	25%	26%	27%
EBIT/(total debt + total equity)	14%	13%	13%	14%	15%
Total Debt / Total assets	16%	17%	17%	17%	17%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.67	0.67	0.82	0.85	0.94
NSW Treasury rating (1994)	BBB	BBB	AAA	AAA	AAA
S&P - US Utilities (1995)	BBB	BBB	A	A	AA
Net cash flow/Capex	0.55	0.56	0.67	0.70	0.76
S&P - US Utilities (1995)	BBB	BBB	BBB	BBB	A
Cash flow before Capex and cap cons/net Capex	0.67	0.67	0.82	0.85	0.95
Cash flow before Capex/Capex	0.73	0.72	0.85	0.88	0.96
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.79	0.78	0.88	0.90	0.97
Funds from operations/ (dividends + capex) including cap cons	1.09	1.05	1.19	1.20	1.29

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Great Southern Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Great Southern Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	112,884	117,278	121,843	126,587	131,514
Transmission Revenue	23,664	23,772	23,880	23,989	24,098
Other Income	2,552	2,628	2,707	2,789	2,872
Total Income	139,100	143,678	148,431	153,364	158,484
Operating Expenditure					
Operating Costs	47,648	48,125	48,606	49,092	49,583
Transmission Charges	23,664	23,772	23,880	23,989	24,098
Total Operating Expenditure	71,312	71,897	72,486	73,081	73,681
EBITDA	67,787	71,782	75,945	80,283	84,804
Depreciation	29,736	31,989	33,464	35,116	35,588
EBIT	38,051	39,793	42,481	45,167	49,215
Interest and financing charges	2,360	3,215	4,180	4,639	5,028
Profit Before Tax and Abnormal Items	35,691	36,577	38,300	40,528	44,187
Plus: Capital Contributions	8,930	8,778	8,749	8,724	8,898
Profit Before Tax	44,621	45,355	47,049	49,252	53,086
Tax expense	16,064	16,328	16,938	17,731	19,111
Net Profit After Tax	28,558	29,027	30,112	31,521	33,975
Dividends declared	21,865	22,224	23,054	24,134	26,012

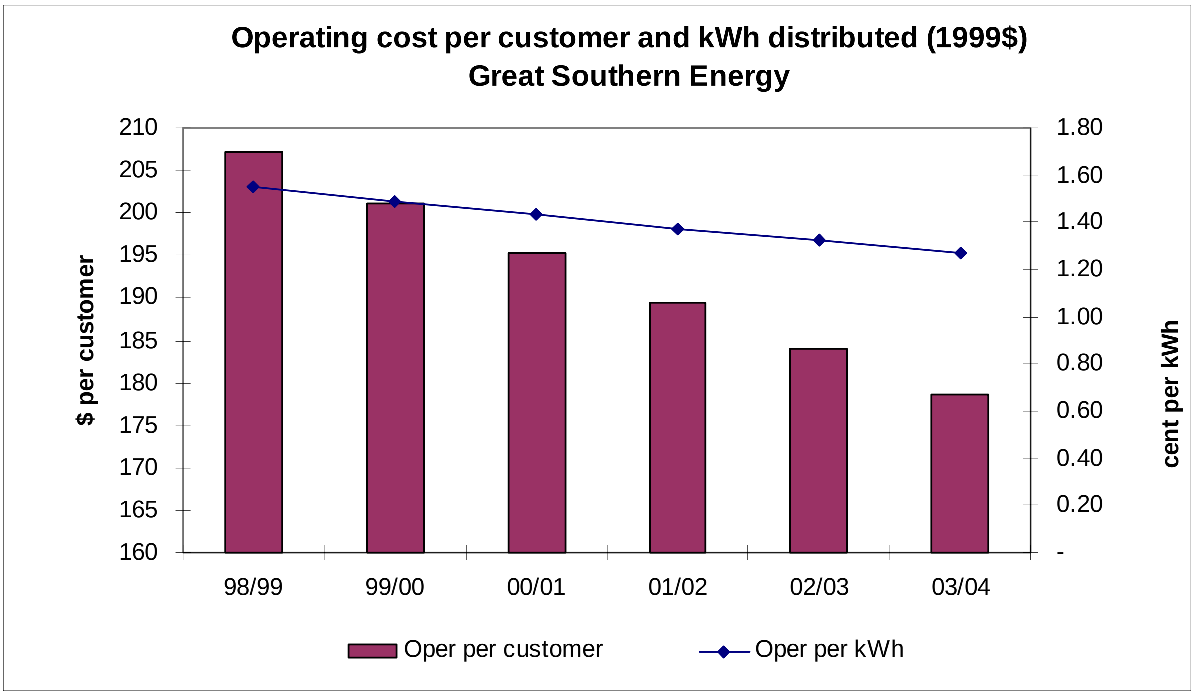
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

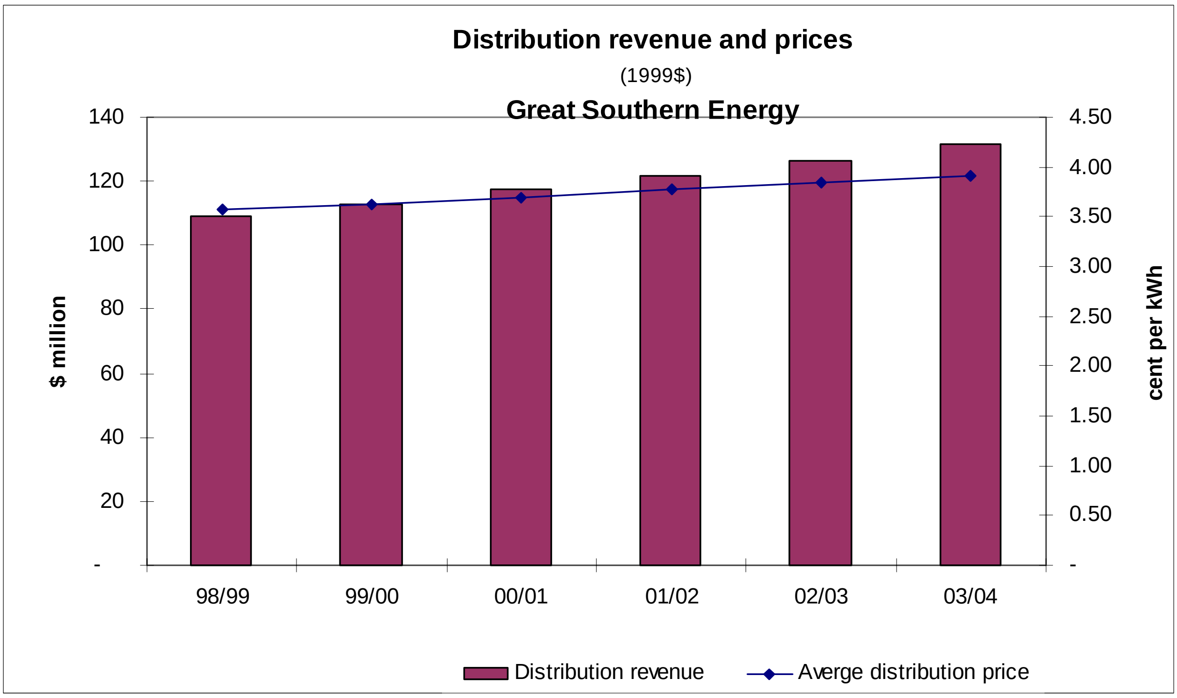
Great Southern Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	27,057	28,110	29,204	30,341	31,522
Inventories	4,156	4,156	4,156	4,156	4,156
Investments	65,754	65,754	65,754	65,754	65,754
Prepayments	3,451	3,451	3,451	3,451	3,451
Accrued Revenue	-	-	-	-	-
FITB	-	-	-	-	-
Property, Plant and Equipment	562,304	599,533	630,386	661,332	689,903
Other assets	13,532	13,532	13,532	13,532	13,532
Total assets	676,254	714,536	746,483	778,566	808,318
Bank overdraft	-	-	-	-	-
Creditors	14,486	14,604	14,724	14,845	14,967
Accruals	-	-	-	-	-
Borrowings	105,106	119,953	127,007	132,993	134,811
Customer deposits	22	22	22	22	22
Provision for Income Tax	4,016	4,082	4,234	4,433	4,778
PDIT	-	-	-	-	-
Provision for dividend	10,932	11,112	11,527	12,067	13,006
Other provisions (employee etc)	30,458	30,458	30,458	30,458	30,458
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	165,020	180,232	187,972	194,817	198,041
Share Capital	253,154	253,154	253,154	253,154	253,154
Asset Revaluation Reserve	150,955	167,222	184,371	202,221	220,787
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	100,432	107,125	113,928	120,986	128,374
This year's profits retained	6,693	6,803	7,057	7,388	7,963
Shareholders' funds	511,234	534,305	558,511	583,749	610,277
Total Liabilities and Shareholder's funds	676,254	714,536	746,483	778,566	808,318

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.4.6 Projected operating costs efficiency



A2.4.7 Regulated distribution revenue and price movements[147]



147 Nominal $.

A2.5 Advance Energy profile

A2.5.1 Background

Head Office	Crn Littlebourne Street and Hampden Park Road KELSO NSW 2795
Major Towns/Cities[1]	Bathurst, Cobar, Coonamble, Dubbo, Forbes, Gilgandra, Mudgee, Nyngan, Parkes, Orange, Wellington
Network Service Area (sq. km)[1]	167,272
Employee Numbers[2]	547

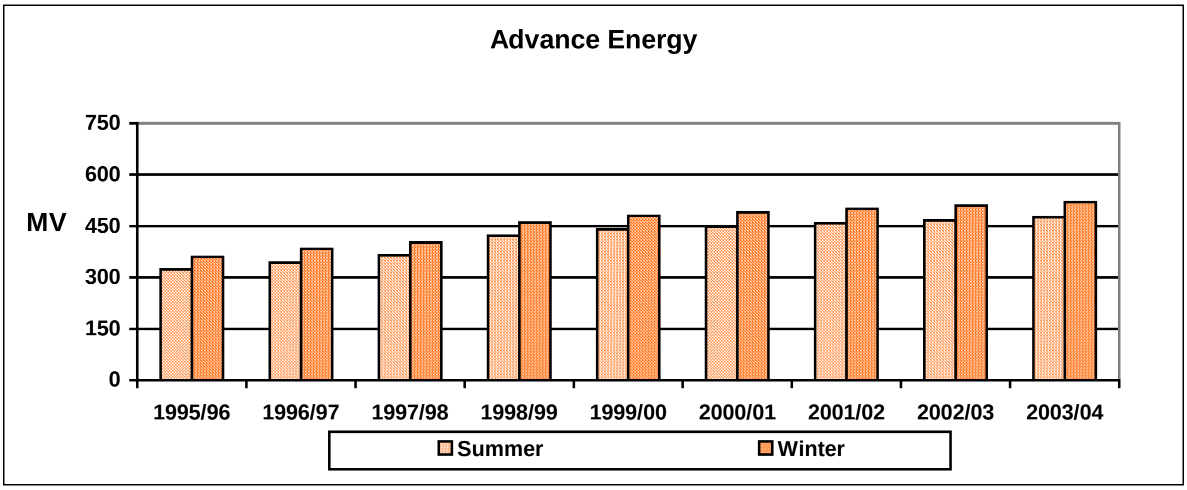
Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.5.2 Demand Growth Profile

Advance Energy	**1995/96**	**1996/97**	**1997/98**
Total GWh delivered	1,995	2,368	2,393
Peak Demand (MW)	360	383	402
Total Customers	116,156	116,537	117,613
Residential	100,307	97,970	98,653
Non-Residential	15,849	18,567	18,960
Total Route km	41,858	41,985	42,231

Source: London Economics (1999), Final Annex 2.

A2.5.3 Maximum Demands



Source: Worley (1998).

A2.5.4 Advance Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Advance Energy Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	322,641	339,198	356,188	375,681	395,925
Operating Costs ($000)	43,826	44,374	44,929	45,491	46,059
Capital Expenditure per Worley review ($000)	28,272	27,933	28,882	32,266	30,170
Depreciation ($000)	18,890	20,051	19,630	20,396	20,586
Network Sales (GWh)	2,703	2,770	2,840	2,911	2,983
Sales Growth (%)	2.5%	2.5%	2.5%	2.5%	2.5%

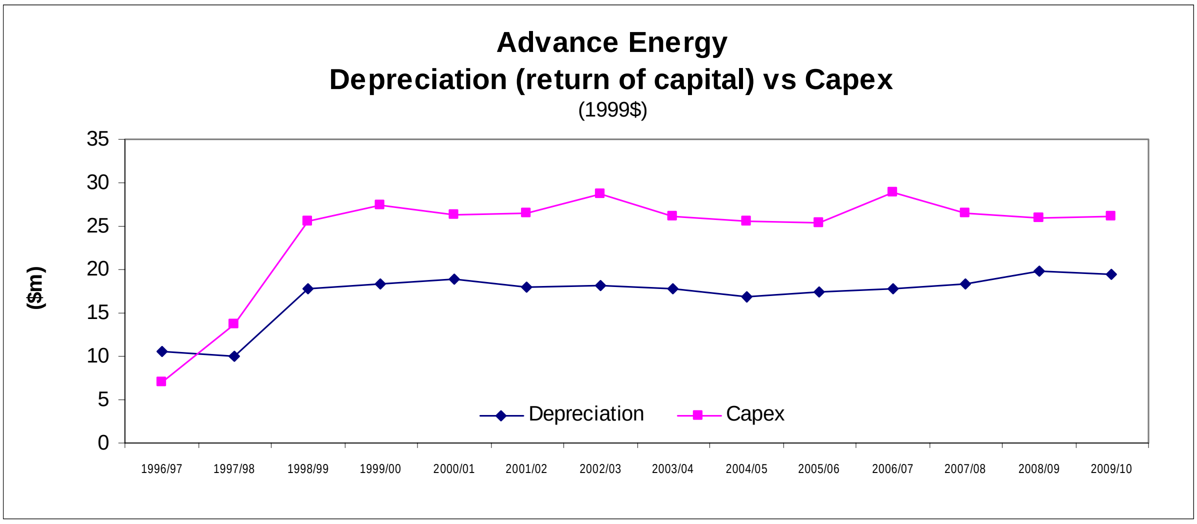
Advance Energy Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	43,826	44,374	44,929	45,491	46,059
Return of Capital (depreciation)	18,890	20,051	19,630	20,396	20,586
Return on Capital	24,198	25,440	26,714	28,176	29,694
Return on Working Capital	551	589	621	640	695
Total Base Revenue (duos)	87,465	90,454	91,893	94,702	97,035
Smoothed Base Revenue	73,924	78,045	82,396	86,989	91,839
Regulated Return on Assets	3.26%	3.76%	4.71%	5.28%	5.98%
Network Price (nominal c/kWh)	2.74	2.82	2.90	2.99	3.08
Network Price (real c/kWh)	2.66	2.66	2.66	2.66	2.66
Cumulative Real Network Price Change	0%	0%	0%	0%	0%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

Advance Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	314,115	331,166	347,230	365,146	386,217
Add: Revaluation of Assets	9,423	9,935	10,417	10,954	11,587
Add: Capital Expenditure	28,272	27,933	28,882	32,266	30,170
Less: Depreciation	18,890	20,051	19,630	20,396	20,586
Less: Disposals	1,754	1,754	1,754	1,754	1,754
Closing Balance	331,166	347,230	365,146	386,217	405,634
Average Regulated Fixed Assets	322,641	339,198	356,188	375,681	395,925

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.5.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

Advance Energy Financial Performance Ratios	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Operating costs as % of base revenue	75%	71%	67%	64%	60%
EBIT margin on sales (EBIT/revenue)	17%	19%	22%	24%	26%
EBITDA margin on sales (EBITDA/revenue)	38%	40%	42%	44%	46%
NPAT/Shareholders Funds	5%	5%	5%	6%	6%
EBIT/(Total Assets - cash & investments)	4%	5%	5%	6%	6%
EBIT/(Borrowings + Equity)	5%	5%	6%	6%	7%
EBITDA/(Equity - revaluation)	14%	16%	17%	18%	20%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

Advance Energy Ratio Analysis	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Ability to service debt					
(a) Funds flow interest cover (using net interest)	18.86	16.16	15.27	14.50	13.62
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Funds flow interest cover (using interest expense)	14.44	13.08	12.73	12.36	11.87
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	6.23	5.49	5.67	5.59	5.51
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	4.93	4.58	4.84	4.86	4.89
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	13.53	11.60	10.82	10.28	9.62

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	1.90	2.05	2.23	2.42	2.50
NSW Treasury rating (1994)	AA	AA	AA	AA	AA
Funds from operations/Total debt	0.40	0.38	0.36	0.35	0.34
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	19%	20%	21%	23%	23%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	0.52	0.49	0.45	0.41	0.40
Cash flow before capex/Total debt	25%	24%	23%	21%	20%
EBIT/(total debt + total equity)	10%	10%	11%	11%	12%
Total Debt / Total assets	17%	18%	19%	21%	21%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.58	0.66	0.66	0.62	0.69
NSW Treasury rating (1994)	BBB	BBB	BBB	BBB	BBB
S&P - US Utilities (1995)	BBB	BBB	BBB	BBB	BBB
Net cash flow/Capex	0.46	0.52	0.52	0.50	0.55
S&P - US Utilities (1995)	BBB	BBB	BBB	BBB	BBB
Cash flow before Capex and cap cons/net Capex	0.58	0.66	0.67	0.63	0.70
Cash flow before Capex/Capex	0.67	0.73	0.74	0.70	0.77
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.69	0.75	0.76	0.73	0.80
Funds from operations/ (dividends + capex) including cap cons	1.08	1.17	1.16	1.09	1.18

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Advance Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Advance Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	73,924	78,045	82,396	86,989	91,839
Transmission Revenue	15,135	15,274	15,414	15,555	15,698
Other Income	5,870	6,046	6,227	6,414	6,606
Total Income	94,929	99,365	104,037	108,958	114,143
Operating Expenditure					
Operating Costs	43,826	44,374	44,929	45,491	46,059
Transmission Charges	15,135	15,274	15,414	15,555	15,698
Total Operating Expenditure	58,962	59,648	60,343	61,046	61,757
EBITDA	35,967	39,716	43,694	47,913	52,386
Depreciation	19,414	20,899	20,795	21,876	22,375
EBIT	16,553	18,818	22,899	26,037	30,011
Interest and financing charges	2,659	3,425	4,039	4,661	5,444
Profit Before Tax and Abnormal Items	13,894	15,393	18,860	21,376	24,567
Plus: Capital Contributions	7,226	7,428	7,688	7,880	8,077
Profit Before Tax	21,120	22,821	26,548	29,256	32,644
Tax expense	7,603	8,215	9,557	10,532	11,752
Net Profit After Tax	13,517	14,605	16,991	18,724	20,892
Dividends declared	10,349	11,182	13,008	14,335	15,995

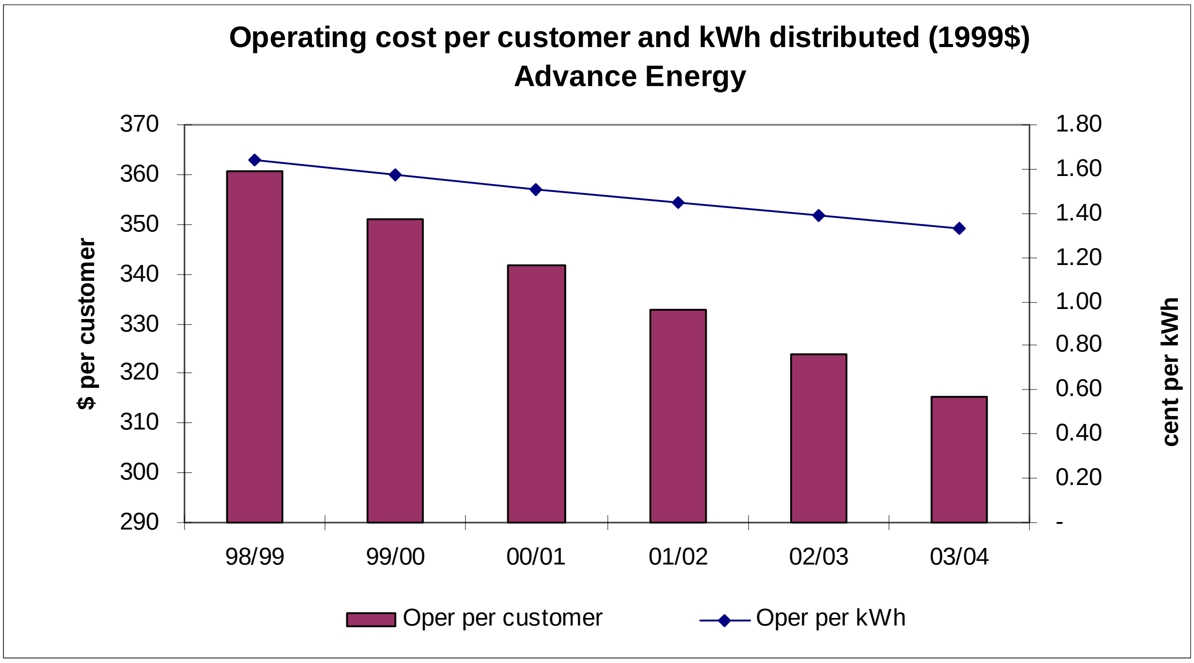
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

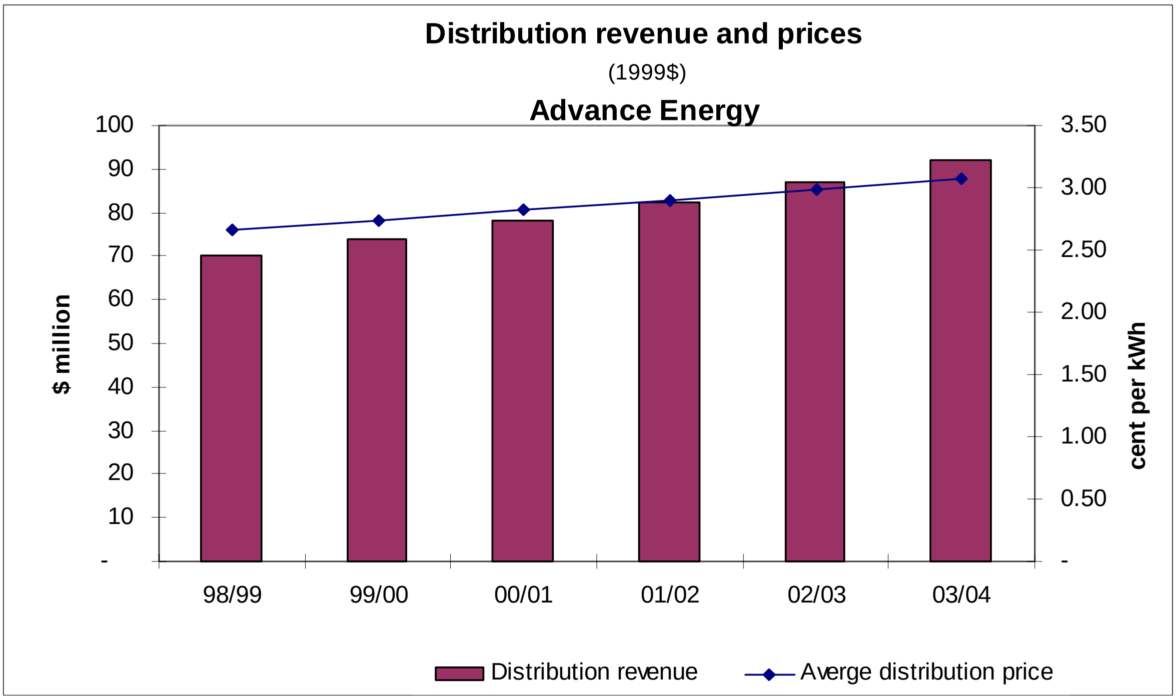
Advance Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	15,814	16,696	17,627	18,609	19,647
Inventories	3,387	3,387	3,387	3,387	3,387
Investments	15,902	15,902	15,902	15,902	15,902
Prepayments	309	309	309	309	309
Accrued Revenue	8,432	8,432	8,432	8,432	8,432
FITB	-	-	-	-	-
Property, Plant and Equipment	348,710	371,354	395,792	423,263	448,967
Other assets	-	-	-	-	-
Total assets	392,554	416,080	441,449	469,902	496,644
Bank overdraft	-	-	-	-	-
Creditors	12,972	13,123	13,275	13,430	13,586
Accruals	-	-	-	-	-
Borrowings	66,147	75,594	85,163	97,211	106,179
Customer deposits	-	-	-	-	-
Provision for Income Tax	1,901	2,054	2,389	2,633	2,938
PDIT	-	-	-	-	-
Provision for dividend	5,174	5,591	6,504	7,168	7,998
Other provisions (employee etc)	18,996	18,996	18,996	18,996	18,996
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	105,190	115,357	126,328	139,438	149,697
Share Capital	-2,004	-2,004	-2,004	-2,004	-2,004
Asset Revaluation Reserve	35,961	45,896	56,313	67,267	78,854
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	250,239	253,407	256,830	260,812	265,201
This year's profits retained	3,168	3,423	3,982	4,388	4,897
Shareholders' funds	287,364	300,722	315,121	330,464	346,947
Total Liabilities and Shareholder's funds	392,554	416,080	441,449	469,902	496,644

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.5.6 Projected operating costs efficiency



A2.5.7 Regulated distribution revenue and price movements[148]



148 Nominal $.

A2.6 Australian Inland Energy profile

A2.6.1 Background

Head Office	160-162 Beryl Street, Broken Hill NSW 2880
Major Towns/Cities[1]	Broken Hill, Menindee, Mildura, Wilcannia, Tibooburra
Network Service Area (sq. km)[1]	155,100
Employee Numbers[2]	98

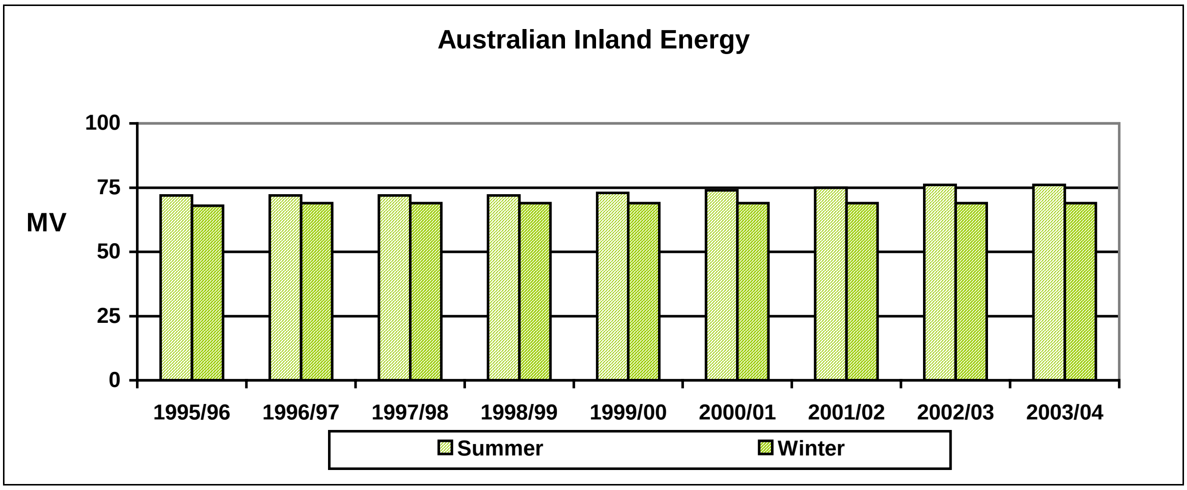
Sources: [1] Distribution Boundary Review Committee (1998); [2] 1997/98 Regulatory Accounts.

A2.6.2 Demand Growth Profile

Australian Inland Energy	1995/96	1996/97	1997/98
Total GWh delivered	361	383	393
Peak Demand (MW)	72	72	73
Total Customers	18,923	19,127	19,046
Residential	15,622	15,836	15,836
Non-Residential	3,301	3,291	3,210
Total Route km	8,993	9,048	9,096

Source: London Economics (1999), Final Annex 2.

A2.6.3 Maximum Demands



Source: Worley (1998).

A2.6.4 Australian Inland Energy Distribution Revenue Path Forecasts 1999/2000 – 2003/04

Australian Inland Energy Core Assumptions	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Regulatory Asset Base ($000)	52,351	54,537	56,738	58,949	61,165
Operating Costs ($000)	6,861	7,033	7,208	7,389	7,573
Capital Expenditure per Worley review ($000)	3,246	3,343	3,444	3,547	3,653
Depreciation ($000)	2,606	2,752	2,906	3,068	3,237
Network Sales (MWh)	421,964	426,183	430,445	434,750	439,097
Sales Growth (%)	1.0%	1.0%	1.0%	1.0%	1.0%

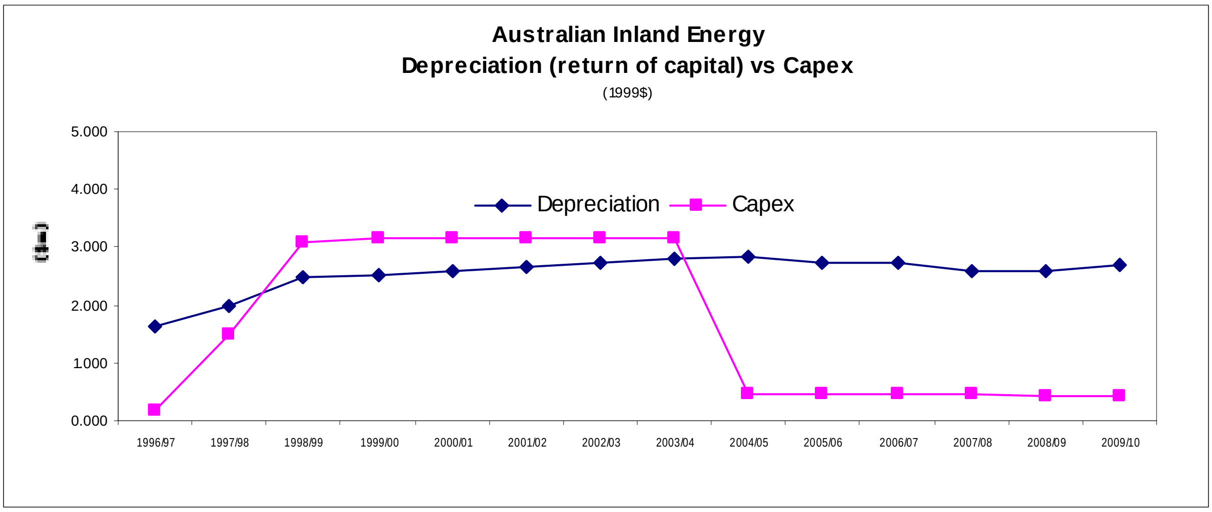
Australian Inland Energy Output Summary ($'000)	**1999/00**	**2000/01**	**2001/02**	**2002/03**	**2003/04**
Building Block Revenue Requirement					
Operating Costs	6,861	7,033	7,208	7,389	7,573
Return of Capital (depreciation)	2,606	2,752	2,906	3,068	3,237
Return on Capital	3,926	4,090	4,255	4,421	4,587
Return on Working Capital	182	185	188	190	193
Total Base Revenue (duos)	13,576	14,059	14,557	15,068	15,591
Smoothed Base Revenue	11,322	11,778	12,252	12,746	13,260
Regulated Return on Assets	3.19%	3.32%	3.44%	3.56%	3.69%
Network Price (nominal c/kWh)	2.68	2.76	2.85	2.93	3.02
Network Price (real c/kWh)	2.60	2.60	2.60	2.60	2.60
Cumulative Real Network Price Change	0.00%	0.00%	0.00%	0.00%	0.00%

Note: Amounts in nominal dollars. Columns may not add due to rounding.

Australian Inland Energy Regulated Fixed Assets($'000)	1999/00	2000/01	2001/02	2002/03	2003/04
Opening Balance	51,262	53,440	55,635	57,842	60,056
Add: Revaluation of Assets	1,538	1,603	1,669	1,735	1,802
Add: Capital Expenditure	3,246	3,343	3,444	3,547	3,653
Less: Depreciation	2,606	2,752	2,906	3,068	3,237
Less: Disposals	-	-	-	-	-
Closing Balance	53,440	55,635	57,842	60,056	62,274
Average Regulated Fixed Assets	52,351	54,537	56,738	58,949	61,165

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.6.5 Return of Capital (depreciation) Versus Capex Profile



Source: Worley (1998).

Australian Inland Energy Financial Performance Ratios	1999/00	2000/01	2001/02	2002/03	2003/04
Operating costs as % of base revenue	86%	83%	81%	78%	76%
EBIT margin on sales (EBIT/revenue)	27%	26%	24%	23%	22%
EBITDA margin on sales (EBITDA/revenue)	45%	45%	44%	43%	43%
NPAT/Shareholders Funds	7%	6%	6%	5%	5%
EBIT/(Total Assets - cash & investments)	6%	6%	5%	5%	5%
EBIT/(Borrowings + Equity)	6%	5%	5%	5%	4%
EBITDA/(Equity - revaluation)	15%	15%	15%	15%	15%
Effective tax rate	36%	36%	36%	36%	36%
Dividend cover	77%	77%	77%	77%	77%

Australian Inland Energy Ratio Analysis	1999/00	2000/01	2001/02	2002/03	2003/04
Ability to service debt					
(a) Funds flow interest cover (using net interest)	-13.54	-16.75	-19.85	-24.12	-30.46
NSW Treasury rating (1994)	>AAA	>AAA	>AAA	>AAA	>AAA
S&P - US Utilities (1995)	>AA	>AA	>AA	>AA	>AA
(b) Funds flow interest cover (using interest expense)	120.29	46.55	33.02	25.93	21.61
NSW Treasury rating (1994)	AAA	AAA	AAA	AAA	AAA
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
(a) Pre tax interest cover (EBIT/net interest)	-4.94	-5.94	-6.87	-8.13	-9.98
S&P - US Utilities (1995)	>AA	>AA	>AA	>AA	>AA
(b) Pre tax interest cover (EBIT + interest earnings) / interest expense)	49.73	18.82	13.08	10.06	8.20
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
EBITDA / net interest	-8.25	-10.35	-12.48	-15.42	-19.76

Ability to repay debt					
Funds flow net debt payback (Net debt/Funds from operations)	-2.54	-2.18	-1.85	-1.55	-1.27
NSW Treasury rating (1994)	>AAA	>AAA	>AAA	>AAA	>AAA
Funds from operations/Total debt	1.27	0.92	0.73	0.62	0.54
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Total Debt/Total capital	6%	7%	9%	10%	11%
S&P - US Utilities (1995)	AA	AA	AA	AA	AA
Funds from operations/Net debt	-0.39	-0.46	-0.54	-0.65	-0.79
Cash flow before capex/Total debt	22%	32%	28%	25%	23%
EBIT/(total debt + total equity)	22%	18%	16%	14%	12%
Total Debt / Total assets	5%	7%	8%	9%	10%
Reliance on debt					
Internal financing ratio (Net cash flow/net Capex)	0.33	0.53	0.57	0.60	0.63
NSW Treasury rating (1994)	<BB	BBB	BBB	BBB	BBB
S&P - US Utilities (1995)	BB	BBB	BBB	BBB	BBB
Net cash flow/Capex	0.20	0.33	0.36	0.38	0.40
S&P - US Utilities (1995)	<BB	BB	BB	BB	BB
Cash flow before Capex and cap cons/net Capex	0.26	0.53	0.56	0.60	0.63
Cash flow before Capex/Capex	0.54	0.70	0.73	0.74	0.76
Funds flow adequacy					
Funds from operations/ (dividends + capex) excl cap cons	0.69	0.76	0.78	0.79	0.80
Funds from operations/ (dividends + capex) including cap cons	1.35	1.53	1.55	1.57	1.61

The credit rating ratios as shown above are based on actual capital structure, which is relatively conservatively geared. The level of gearing is a matter for the Government. The Tribunal has also tested the financial strength of DNSPs using a hypothetical gearing commensurate with the private utilities. Australian Inland Energy is forecast to have a strong financial outcome.

Income & Expenditure Statement ($'000)

Australian Inland Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Income					
Regulated Revenue Cap	11,322	11,778	12,252	12,746	13,260
Transmission Revenue	3,359	3,341	3,323	3,305	3,287
Other Income					
Total Income	14,681	15,119	15,575	16,051	16,546
Operating Expenditure					
Operating Costs	6,861	7,033	7,208	7,389	7,573
Transmission Charges	3,359	3,341	3,323	3,305	3,287
Total Operating Expenditure	10,220	10,374	10,531	10,693	10,860
CSOs and Grants	2,200	2,000	1,800	1,600	1,400
EBITDA	6,660	6,745	6,844	6,958	7,087
Depreciation	2,672	2,871	3,077	3,289	3,508
EBIT	3,988	3,874	3,767	3,668	3,579
Interest and financing charges	(807)	(652)	(549)	(451)	(359)
Profit Before Tax and Abnormal Items	4,795	4,526	4,316	4,119	3,938
Plus: Capital Contributions	2,000	2,000	2,010	2,020	2,060
Profit Before Tax	6,795	6,526	6,326	6,139	5,998
Tax expense	2,446	2,349	2,277	2,210	2,159
Net Profit After Tax	4,349	4,177	4,049	3,929	3,839
Dividends declared	3,330	3,198	3,100	3,008	2,939

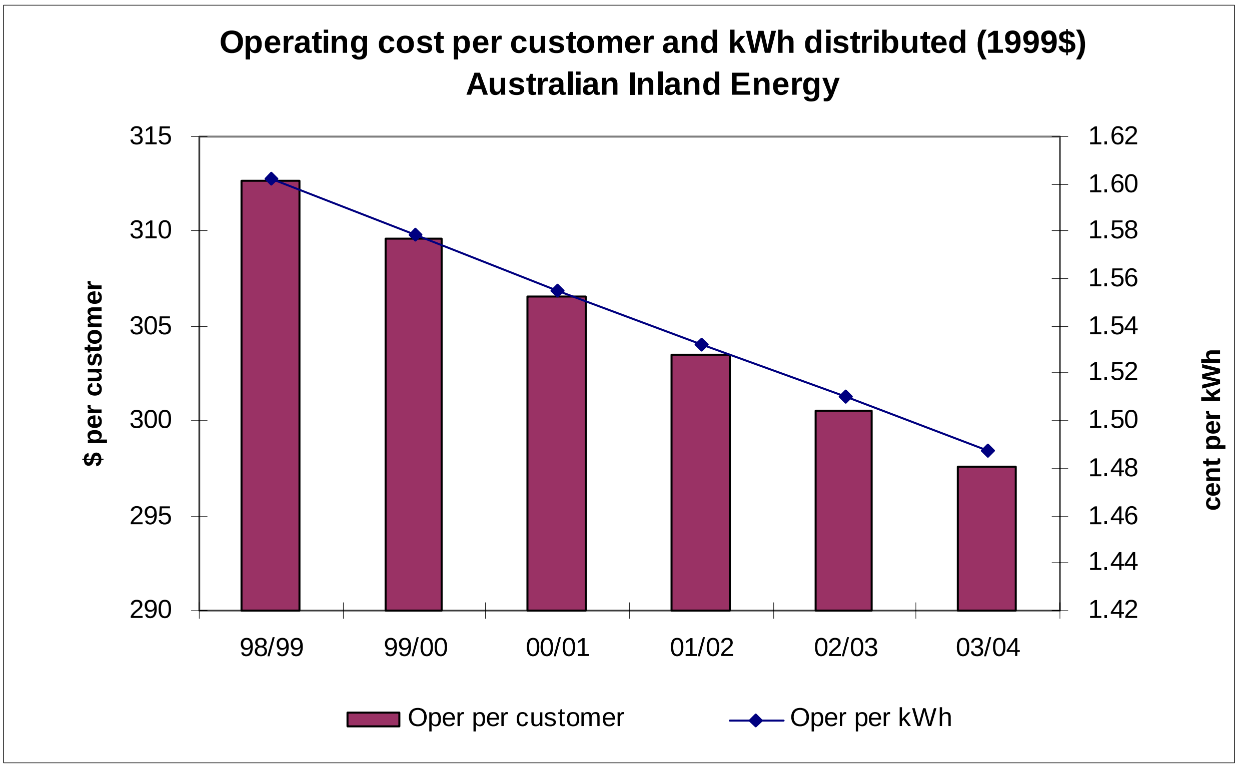
Note: Amounts in nominal dollars. Columns may not add due to rounding.

Balance Sheet ($000)

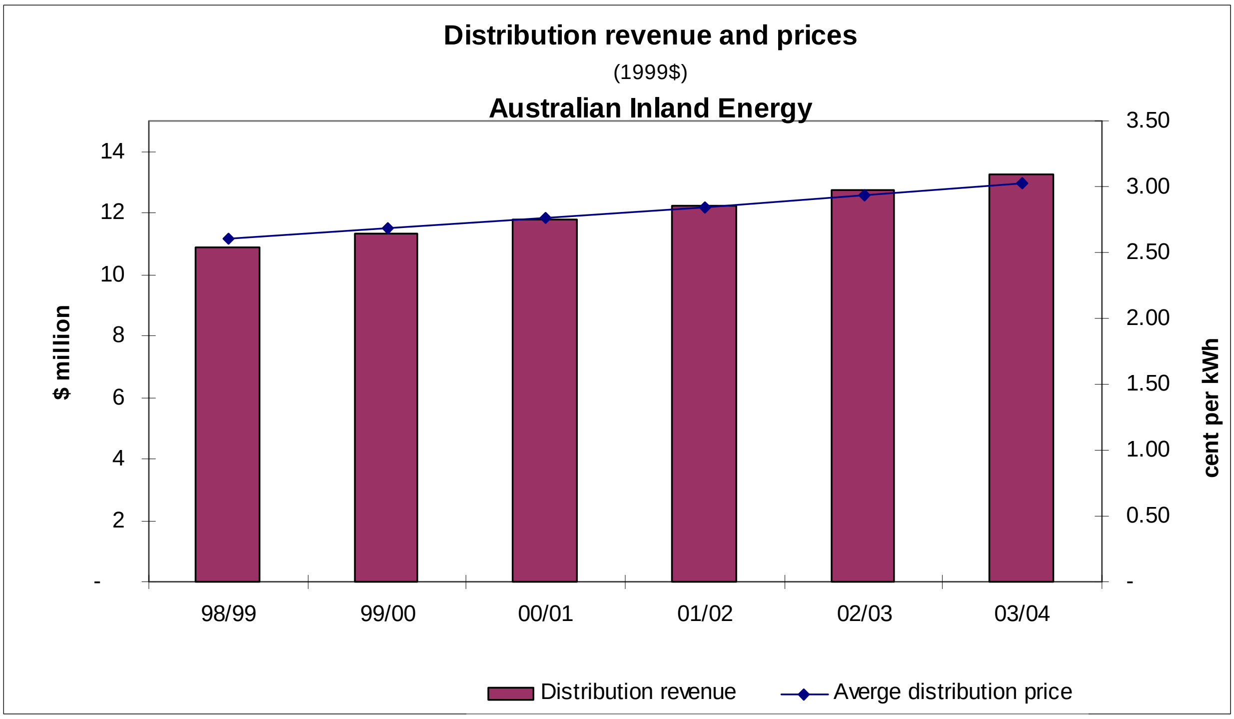
Australian Inland Energy	1999/00	2000/01	2001/02	2002/03	2003/04
Cash	-	-	-	-	-
Receivables	793	824	858	892	928
Inventories	1,680	1,680	1,680	1,680	1,680
Investments	16,467	16,467	16,467	16,467	16,467
Prepayments	291	291	291	291	291
Accrued Revenue	-	-	-	-	-
FITB	1,039	1,039	1,039	1,039	1,039
Property, Plant and Equipment	57,799	61,875	65,921	69,934	73,942
Other assets	1,103	1,103	1,103	1,103	1,103
Total assets	79,172	83,279	87,359	91,406	95,450
Bank overdraft	-	-	-	-	-
Creditors	1,902	1,930	1,960	1,990	2,021
Accruals	-	-	-	-	-
Borrowings	3,908	5,495	6,994	8,417	9,776
Customer deposits	327	327	327	327	327
Provision for Income Tax	612	587	569	553	540
PDIT	2,671	2,671	2,671	2,671	2,671
Provision for dividend	1,665	1,599	1,550	1,504	1,469
Other provisions (employee etc)	2,857	2,857	2,857	2,857	2,857
Other liabilities (provisions per 98 reg accounts)	-	-	-	-	-
Total liabilities	13,941	15,466	16,928	18,319	19,662
Share Capital	34,922	34,922	34,922	34,922	34,922
Asset Revaluation Reserve	20,710	22,313	23,982	25,718	27,519
Other reserves	-	-	-	-	-
Accumulated Profits/Losses	8,579	9,599	10,577	11,526	12,447
This year's profits retained	1,019	979	949	921	900
Shareholders' funds	65,231	67,813	70,431	73,087	75,788
Total Liabilities and Shareholder's funds	79,172	83,279	87,359	91,406	95,450

Note: Amounts in nominal dollars. Columns may not add due to rounding.

A2.6.6 Projected operating costs efficiency



A2.6.7 Regulated distribution revenue and price movements[149]



149 Nominal $.

ATTACHMENT 3 DEPRECIATION

As discussed in chapter 7, since the release of the section 12A report, the Tribunal has obtained further information from the GHD/Arthur Andersen/Worley International consortium and has refined the asset lives adopted for each DNSP in order to more accurately reflect where each DNSP is in its asset life cycle.

For this determination, the Tribunal has calculated depreciation rates for system assets on the basis of the effective lives of asset classes assumed in the GHD/Arthur Andersen/Worley International studies, and applied these to the optimised replacement cost of those assets. Non-system assets have been depreciated on the basis of information contained in each DNSP's regulatory accounts at a weighted-average rate based on each DNSPs' non-system assets.[150]

This attachment details the ORC values and asset lives supporting the depreciation of system assets. It also provides the total depreciation on system assets for the 1999/2000 year as a guide. To arrive at the total depreciation used in the financial modelling, as discussed in chapter 7 this total must be adjusted by adding the depreciation on non-system assets and on capital additions in the year, and deducting depreciation on capital contributions and assets disposed during the year.

150 as at 30 June 1998.

Depreciation	EnergyAustralia			Integral Energy		
Description of Asset	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**
132 kV Tower Lines	$69,191	50.0	1,449	$27,137	50.0	2,186
132 kV Concrete and Steel Pole Lines	$65,010	45.0	1,513	$2,179	45.0	113
132 kV Other Lines	$0	0.0	-	$21,483	45.0	1,101
132 kV Underground Cable	$772,040	45.0	17,964	$22,150	45.0	1,364
66 kV Concrete Pole Lines	$29,915	45.0	696	$1,188	45.0	48
66 kV Other Lines		0.0	-	$20,129	45.0	811
33 kV Concrete and Steel Pole Lines	$100,252	45.0	2,333	$182,677	45.0	155
33 kV Other Lines	$288	35.0	9	$53,310	45.0	2,541
66 kV Underground Cable	$612	60.0	11	$3,569	60.0	78
33 kV Underground Cables (Gas Type)		0.0	-	$0	0.0	-
33 kV Underground Cables (Solid Type)	$248,654	60.0	4,339	$23,644	60.0	635
22 kV Distribution Overhead Lines	$1,301	45.0	30	$2,408	44.3	109
11 kV Distribution Overhead Lines	$228,065	43.7	5,461	$94,814	43.7	6,154
LV Distribution Overhead Lines (Including Services)	$566,955	38.4	15,455	$121,731	42.6	7,179
SWER Lines	$1,488	45.0	35	$779	45.0	45
22 kV Underground Cable		0.0	-	$4,970	60.0	98
11 kV Underground Cable	$1,277,823	70.0	19,114		60.0	4,251
LV Underground Cable	$460,503	59.0	8,173	$441,423	60.0	10,271
Sub -Transmission Substations (132/66/33 kV Includes Building Excludes Land)	$413,080	46.6	9,276	$35,818	40.0	4,234
Zone Substations (Includes Building, Excludes Land)	$881,467	47.1	19,603	$204,412	40.0	13,144
132/66/33/22/11 kV Transformers	$283,207	50.0	5,931	$85,493	50.0	3,840
Pole Substations (Excluding Transformers)	$61,805	40.5	1,596	$29,648	40.5	1,691
Pole Transformers	$75,822	35.0	2,268	$36,711	36.9	2,429
Group/Kiosk/Chamber/Ground Substations (Excluding Transformers)	$516,265	40.0	13,514	$104,472	40.0	4,374
Group/Kiosk/Chamber/Ground Transformers	$259,091	44.9	6,043	$66,632	45.0	2,245
HV Customers Subs/Tap changing/Misc Subs (incl TXs)	$25,512	39.9	669		0.0	-
Pilots	$11,019	60.0	192		0.0	-
Customer Metering and Load Control	$315,769	25.4	13,036	$123,537	25.0	11,180
Street Lighting Overhead (Including Mains)	$245,000	20.0	12,827	$13,026	20.0	1,868
Street Lighting Underground (Including Mains)		0.0	-	$47,357	20.0	6,793
SCADA and Central Control Facilities	$57,496	37.7	1,596	$17,152	9.4	3,935
Communication Bearer Systems (Excludes Mobile)		0.0	-	$3,339	7.0	874
Easements	$9,797	0.0	-	$2,916	0.0	-
Land	$292,617	0.0	-	$35,503	0.0	-
Emergency Spares (Major Plant, Excludes Inventory)	$9,797	0.0	-	$11,195	30.1	-
Work In Progress	$191,600	0.0	-	$39,983	0.0	-
Total	**$7,471,441**		**$163,133**	**$1,884,045**		**$93,746**

Depreciation	NorthPower			Great Southern Energy		
Description of Asset	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**
132 kV Tower Lines	$3,020	50.0	63	$2,144	50.0	45
132 kV Concrete and Steel Pole Lines	$2,122	55.0	40		0.0	-
132 kV Other Lines		0.0	-	$48,655	53.5	952
132 kV Underground Cable		0.0	-		0.0	-
66 kV Concrete Pole Lines	$10,507	55.0	200		0.0	-
66 kV Other Lines	$125,351	51.4	2,555	$98,081	53.5	1,920
33 kV Concrete and Steel Pole Lines		0.0	-	$12,098	53.5	237
33 kV Other Lines	$83,533	52.0	1,682	$83,037	53.2	1,635
66 kV Underground Cable	$549	60.0	10	$100	60.0	2
33 kV Underground Cables (Gas Type)		0.0	-		0.0	-
33 kV Underground Cables (Solid Type)	$350	60.0	6	$5,428	60.0	95
22 kV Distribution Overhead Lines	$149,935	53.8	2,916		0.0	-
11 kV Distribution Overhead Lines	$322,690	47.4	7,135	$342,552	52.4	6,846
LV Distribution Overhead Lines (Including Services)	$305,661	46.2	6,929	$162,906	49.3	3,457
SWER Lines	$35,103	54.0	680	$31,692	53.4	621
22 kV Underground Cable	$1,854	60.0	32		0.0	-
11 kV Underground Cable	$41,200	60.0	719	$17,593	60.0	307
LV Underground Cable	$89,736	60.0	1,566	$35,403	60.0	618
Sub -Transmission Substations (132/66/33 kV Includes Building Excludes Land)	$4,860	40.0	127	$2,540	40.0	66
Zone Substations (Includes Building, Excludes Land)	$135,115	40.0	3,537	$108,058	40.0	2,829
132/66/33/22/11 kV Transformers	$78,196	50.1	1,633	$63,280	50.0	1,324
Pole Substations (Excluding Transformers)	$138,639	40.0	3,629	$109,778	40.0	2,874
Pole Transformers	$88,578	39.8	2,330	$81,985	43.5	1,973
Group/Kiosk/Chamber/Ground Substations (Excluding Transformers)	$31,043	40.0	813	$23,828	40.0	624
Group/Kiosk/Chamber/Ground Transformers	$13,061	45.0	304	$10,226	45.0	238
HV Customers Subs/Tap changing/Misc Subs (incl TXs)	$0	0.0	-		0.0	-
Pilots	$0	0.0	-		0.0	-
Customer Metering and Load Control	$89,544	25.0	3,750	$97,017	25.0	4,062
Street Lighting Overhead (Including Mains)	$20,619	20.0	1,080	$9,644	21.7	466
Street Lighting Underground (Including Mains)	$26,521	20.0	1,388	$27,639	20.4	1,420
SCADA and Central Control Facilities	$5,700	4.6	1,286	$580	4.4	138
Communication Bearer Systems (Excludes Mobile)	$5,319	12.1	461	$4,026	7.3	576
Easements	$205	0.0	-	$987	0.0	-
Land	$5,059	0.0	-	$1,247	0.0	-
Emergency Spares (Major Plant, Excludes Inventory)	$1,270	0.0	-	$835	0.0	-
Work In Progress	$20,230	0.0	-	$5,344	0.0	-
Total	$1,835,570		$44,872	$1,386,703		$33,325

Depreciation	Advance Energy			Australian Inland Energy		
Description of Asset	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**	**ORC ($000)**	**Effective Life**	**1999/2000 Depreciation**
132 kV Tower Lines		0.0	-	$267	50.0	6
132 kV Concrete and Steel Pole Lines	$26,093	55.0	497		0.0	-
132 kV Other Lines	$21,725	55.0	414		0.0	-
132 kV Underground Cable	$1,580	60.0	28		0.0	-
66 kV Concrete Pole Lines		0.0	-	$8,497	55.0	162
66 kV Other Lines	$66,821	55.0	1,272	$4,761	54.9	91
33 kV Concrete and Steel Pole Lines	$2,016	55.0	38	$32,868	54.9	627
33 kV Other Lines	$6,690	55.0	127		0.0	-
66 kV Underground Cable		0.0	-		0.0	-
33 kV Underground Cables (Gas Type)		0.0	-		0.0	-
33 kV Underground Cables (Solid Type)		0.0	-		60.0	-
22 kV Distribution Overhead Lines	$135,647	52.9	2,683	$31,678	53.0	626
11 kV Distribution Overhead Lines	$143,986	52.7	2,863	$415	52.0	8
LV Distribution Overhead Lines (Including Services)	$119,720	51.4	2,438	$16,535	51.0	339
SWER Lines	$41,437	54.6	795	$22,481	54.8	430
22 kV Underground Cable	$417	60.0	7	$435	60.0	8
11 kV Underground Cable	$10,575	60.0	185		0.0	-
LV Underground Cable	$25,094	60.0	438		0.0	-
Sub -Transmission Substations (132/66/33 kV Includes Building Excludes Land)	$10,155	40.0	266		0.0	-
Zone Substations (Includes Building, Excludes Land)	$57,498	37.9	1,588	$3,991	40.0	104
132/66/33/22/11 kV Transformers	$35,270	49.4	747	$5,660	50.0	119
Pole Substations (Excluding Transformers)	$77,602	40.0	2,031	$9,484	40.0	248
Pole Transformers	$44,959	45.0	1,046	$10,418	45.0	242
Group/Kiosk/Chamber/Ground Substations (Excluding Transformers)	$14,913	40.0	390	$1,346	40.0	35
Group/Kiosk/Chamber/Ground Transformers	$8,276	45.0	193	$790	45.0	18
HV Customers Subs/Tap changing/Misc Subs (incl TXs)		0.0	-		0.0	-
Pilots		0.0	-		0.0	-
Customer Metering and Load Control	$31,692	25.0	1,327	$3,216	24.0	140
Street Lighting Overhead (Including Mains)	$8,132	28.0	304	$2,169	21.1	108
Street Lighting Underground (Including Mains)	$12,387	20.0	649		0.0	-
SCADA and Central Control Facilities	$4,779	4.1	1,208		0.0	-
Communication Bearer Systems (Excludes Mobile)	$2,659	7.0	398		0.0	-
Easements		0.0	-		0.0	-
Land	$1,339	0.0	-	$340	0.0	-
Emergency Spares (Major Plant, Excludes Inventory)	$1,500	0.0	-	$518	0.0	-
Work In Progress	$1,440	0.0	-		0.0	-
Total	$914,402		$21,932	$155,869		$3,311

ATTACHMENT 4 SUBMISSION LIST

Organisation	Name
	G. McDonell
Advance Energy	M. Coble
Australian Baldor Motors and Drivers	K. Limly
Australian Business	P. Orton
Australian Cogeneration Association	R. Brazzale
Australian Conservation Foundation	S. van Rood
Bathurst City Council	P. Perram
BB Water Saver Syste	B. Hibberd
BCA Energy Task Force	P. Weickhardt
Canterbury City Council	R. Davidson
Centron ToughGuard	J. Brady
Cessnock City Council	M. Alexander
Copmanhurst Shire Council	G. Cowan
Dynamic Synergies International Pty Ltd	D. Willis
Ecopower	B. Ellul
Energy Engineering of Australia Pty Ltd	J. Wyer
Energy Industry Ombudsman NSW	C. Petre
Energy Markets Reform Forum	W. Martin
EnergyAustralia	P. Broad
EnergyAustralia	M. Davies
Environmental Law & Policy Consultants	M. Mobbs
Gloucester Shire Council	N. McLeod
Great Southern Energy	L. Elder
Great Southern Energy	P. Hoogland
Harris Energy Solutions Pty Ltd	G. Harris
Ilum-a-Lite Pty Ltd	J. Rutherford
Institute for Sustainable Futures	G. Milne
Integral Energy Australia	J. Allen
Integral Energy Australia	J. Allen
Integral Energy Australia	R. Thorn
Lane Cove Council	R. Selleck
Manly Council	J. Thompson
National Farmers Federation	

NCON Corporation Pty Limited	D. Barnes
NorthPower	P. Topfer
NSW Treasury	B. Hartnell
Port Stephens Council	R. Bowen
Power Visions	I. Lawrence
Public Interest Advocacy Centre	T. Benson
PV Solar Energy Pty Ltd	P. Erling
Quantum energy syste Pty Ltd	S. Harmon
Riverina Wool Combing Pty Ltd	B. Hamilton
Riverina Wool Combing Pty Ltd	B. Hamilton
Robert Turner Consulting Pty Ltd	R. Turner
SEDA	B. Precious
Singleton Shire Council	B. Carter
Sustainable Technologies Australia Limited	S. Tulloch
Sutherland Shire Council	G. Smith
Sydney Airports Corporation	N. Westnedge
TD International Pty Ltd	L. Taylor
Total Environment Centre	S. Crawford
Track Electrics	W. Allwood
Wagga Wagga City Council	C. Earnshaw
Waverley Council	M. McMahon
Wingecarribee Shire Council	D. McGowan

Rules made by the Tribunal under clause 6.10.1(f) of the National Electricity Code

December 1999

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

Clause 6.10.1(f) National Electricity Code

Rule 99/1
Unders And Overs Accounts

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Unders and overs accounts, Rule 99/1'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Unders and overs accounts to apply

Each DNSP must maintain an unders and overs account in a manner consistent with any relevant determination or direction by the Tribunal. Any variation between the aggregate annual revenue requirement (AARR), as determined by the Tribunal, and actual revenue collected is to be monitored in the unders and overs accounts. The unders and overs account is cumulative from year to year.

For any year that a variance occurs between the AARR and the actual revenue collected in that year, an interest charge or an interest credit will apply, as appropriate. The interest adjustment will be applied on the cumulative balance at year-end. The total cumulative balance in the unders and overs account includes any prior year interest adjustments.

Interest will be pegged at the 3-year Commonwealth Bond rate as at the first Monday following the financial year-end. The Australian Financial Review will be the reference source for this rate.

Annual returns and tolerances

DNSPs must provide annual returns to the Tribunal by 30 October each year. The annual returns must disclose account balances as a contingent item. These returns must demonstrate that the unders and overs account balances result from actual demand deviating from forecast demand. The Tribunal will allow the following tolerance margins for deviations from the related AARR and will require the following action on an annual basis[151] as a result of these deviations:

Table 1 Tolerance margins and actions that the Tribunal will require for unders and overs account balances

Tolerance	DNSP action required
less than +/- 2 per cent	Must notify the Tribunal within 30 days of year end with action plan[152] to resolve balance within the term of the price path.
between +/-2 per cent and +/- 5 per cent	Must notify the Tribunal within 30 days of year end with action plan[153] for rectifying the balance at the first subsequent changes to network tariffs.
over recovery of more than 5 per cent	Must provide a rebate to retailers on the first bill of the subsequent year to reduce the unders and overs account balance to zero.[154]
(under) recovery of more than 5 per cent	Unders and overs account balance will be reduced to under recovery of 5 per cent.[155]

Approved unders and overs account balances as at 31 January 2000 (accrued under determinations made by the Tribunal under the IPART Act) will carry forward into a determination made under the National Electricity Code effective from 1 February 2000. Each DNSP will be required to submit its unders and overs account balance for approval by the Tribunal as soon as practicable after 31 January 2000.

151 The Tribunal will require the specified actions to commence on 1 July 2001.

152 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

153 An action plan must include the calculation of network prices (for each tariff class) based on maximum allowable revenues, demand forecasts and unders and overs balance rectification.

154 The Tribunal intends to exercise its powers under state legislation to require retailers to pass on rebates to end-use customers.
The Tribunal recognises that issues may arise when customers disconnect from the system in the time between the period of over-collection and the payment of the rebate. The refund should be made to customers connected to the distribution network system on 30 June on the year that over recovery breaches the 5 per cent tolerance.

155 If, for example, at 30 June 2002 a DNSP has an under recovery of 8 per cent, the Tribunal will reduce the account balance to 5 per cent under recovered for the 2001/2002 financial year. The DNSP will lose the 3 per cent difference.

Clause 6.10.1(f) National Electricity Code

Rule 99/2
Pricing notification and information disclosure

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Pricing notification and information disclosure Rule 99/2'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Disclosure of information on pricing structures and future directions

By 30 November each year[156], DNSPs must publish a pricing information package that discloses:

a) the methodology used to derive prices for prescribed distribution services

b) medium term directions for prices for prescribed distribution services.

For the pricing information package due on 30 November 2000 and subsequent years, the information disclosed must include, but is not limited to:

a) a list of the cost components for providing prescribed distribution services. This must include the definition of the costs, the total of each cost for the network business, and the basis for allocating costs shared with other activities of the network owner and/or operator. The costs for the preceding year must reconcile with the regulatory accounts as specified by the Tribunal. Projected costs for the current year must be provided.

156 Except for 1999/2000, when the due date is 30 April 2000.

b) a statement of the basis for valuing assets and calculating depreciation. If the depreciated optimised replacement cost (DORC) approach is adopted, the extent of optimisation and relevant unit rates must be provided or referenced. Assumed asset lives and other assumptions in the calculation of depreciation must be described or referenced.

c) an explanation and quantification of the methodology used to calculate current prices from the costs identified under (a) & (b), including:
   - definition of the prescribed distribution services, customer classes and regions for pricing, and the components of charges such as the demand, energy and fixed components
   - allocation of costs to prescribed distribution services, customer classes, and/or regions used for pricing purposes
   - allocation of costs to, and calculation of, the various components of charges such as the demand, energy and fixed components.

d) identification of forecast demand and load factors used in calculating charges for prescribed distribution services

e) data on performance measured against a range of key indicators, including:
   - summary indicators of reliability and quality of service drawn from the reporting requirements determined by the Ministry of Energy and Utilities
   - other indicators as may be determined by the Tribunal

f) an outline of future pricing strategies, specifying proposed changes to the prescribed distribution services, charging options offered, structure of charges and/or allocation of costs, and quantifying potential impact on prices

g) a summary of the DNSP's asset management and development plans, identifying potential impacts on pricing

h) a summary of any other industry or company developments that may affect pricing.

Where it believes there is a net public benefit, the Tribunal may waive any of the above requirements on the request of a DNSP.

The pricing information package may be published electronically as well as in hard copy and may include supplements and appendices. Paper copies must be available on request. Some of the requirements may be met through reference to other documents, such as asset management reviews and asset valuation studies. However, the information package must contain sufficient information to enable the user to understand the information package without referring to these documents.

Notification of price changes

Except with the Tribunal's prior approval, charges for prescribed distribution services may be changed annually only on 1 July, or as near as practicable to that date, consistent with any applicable determination of the Tribunal.

Unless a DNSP has published a current pricing information package that meets the 'Pricing notification and information disclosure Rule 99/2', the DNSP may not increase its charge for any prescribed distribution service. Under these circumstances, if actual revenue from the existing charges is projected to exceed the AARR, the DNSP must lower all its charges for prescribed distribution services by a uniform percentage to reduce its revenues to the regulated levels.

DNSPs are to give network users and the Tribunal 30 days' notice of proposed changes to charges for prescribed distribution services. DNSPs should publish existing and proposed charges, and any changes in the associated terms and conditions.

Notification of price changes to the Tribunal must be accompanied by supporting material that:

a) indicates the percentage and absolute change in the charges or average bills for each customer class

b) demonstrates that revenues are projected to recover no more than the sum of the base revenue as established by the glide path, together with:
   - transmission charges and payments for network services made to other DNSPs. This is consistent with 6.10.5.(7) (ii) of the Code. These payments may be subject to a prudency test if payments are not between unrelated parties at published regulated charges
   - avoided transmission use of system (TUOS) payments to embedded generators, up to an amount determined by the Tribunal through and examination of avoided network costs
   - payments for demand management and other network support services, up to an amount determined by the Tribunal through an examination of avoided network costs.
   - contestability costs as determined by the Tribunal
   - Y2K costs as approved by the Tribunal
   - an amount to rectify unders and overs account balances
   - the net impact of the GST.

c) demonstrates compliance with side constraints on maximum increases in charges for prescribed distribution services

d) provides the cost of supply modelling that underpins the proposed charges

e) notification to the Tribunal should be accompanied by a statement signed by the Chairman and Chief Executive Officer, undertaking that the above requirements have been met.

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

Clause 6.10.1(f) National Electricity Code

Rule 99/3
Charges for Miscellaneous services

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Charges for miscellaneous network services Rule 99/3'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Levying charges for miscellaneous services

Outside normal business hours fees

For those charges which allow for an after hours fee to be charged, the 'outside normal business hours' fee may be charged only:

- where the customer has been informed of the additional cost before work commences
- the customer is advised of the times during which the work can be carried out at normal rates
- after receiving this information the customer requests that the work be carried out outside normal business hours.

Provision of time-of-use or half-hourly metering data

This charge applies to cover the cost of obtaining and providing historical metering data on a half hourly or time of use basis to non-contestable customers where such data is not available from the customer's normal meter readings. The charge is intended to cover the cost of installing and removing recording instruments to obtain the half-hourly or time of use metering data. The charge is $25.00 per half-hour (or part thereof) of staff time required to make the information available.

Special meter reading

This charge applies to cover the costs of a special meter reading either at the customer's explicit request or because the meter is inaccessible at the normal reading time and an estimated reading has been offered to the customer and the customer does not accept that offer and insists on an actual meter reading being carried out.

The charge is not to be applied for:

- a reading associated with a final account; or
- for a check of a disputed reading carried out at the customer's request if the original reading is subsequently found to be incorrect.

Meter test

This charge applies to cover the cost of testing a meter for accuracy when requested by the customer. The customer may be present at any field test conducted by the DNSP. The fee is to be charged to the customers next account if the meter is found to be reading correctly as defined in clause 21(3) of Schedule 2 of the Electricity Supply (General) Regulation 1996.

While a customer's meter is being tested at the request of the customer, the DNSP must give the customer an extension to the due date for payment of their electricity account. No late fees are to be levied while such an extension is in effect.

It should be noted that under the Code of Practice for Franchise Customer Metering a customer is entitled to request a test from another body having qualifications acceptable to the DNSP. This test is at the customer's expense. The DNSP is entitled to be present at this test.

The Code of Practice also requires the DNSP to establish a maintenance plan for maintenance testing of their franchise meters. Details of this plan must be communicated to customers on request.

Conveyancing inquiry

This charge applies for the supply of information regarding the availability of supply, presence of DNSP's equipment, power lines etc for property conveyancing. Freedom of information (FOI) inquiries are excluded.

Account establishment

This charge applies to cover the DNSP's costs of establishing a new customer in its records, recording the meter reading for the new customer. The fee applies to both new and existing premises and excludes all charges by way of capital contribution. This fee is not to be applied in the case of reconnecting power following an involuntary disconnection, but may be charged to effect reconnection following disconnection at the customer's request.

Off-peak conversion

Customers will be allowed to change their off-peak pricing option once in a 12 month period at no cost. Should the customer request a further change in off-peak pricing option within that 12 month period then this fee will apply.

This charge does not cover repairs to damaged metering or time control equipment.

Disconnection Visit

This charge applies to the cost of a visit by DNSP staff with the specific intent to disconnect a customer at the time of the visit.

The visit to the customer with the intent of disconnection can only occur once the provisions of the Electricity Supply (General) Regulation 1996 (Schedule 2, Part 4, Division 2, Clause 40) with respect to the disconnection of customers have been completed in full.

The Personal Visit fee may be levied only in circumstances where:

1. The customer has been warned of impending disconnection by issue of a late payment reminder notice. This notice must clearly provide information to customers regarding financial assistance available, particularly through the Energy Account Payment Assistance (EAPA) scheme. Subject to the rules applicable to Late Payment charges, the $5.00 Late Payment charge may be levied for this notice.
2. The DNSP has sent to the customer at least 2 written notices of the DNSP's intention to disconnect, the second notice to be sent no earlier than one week after the first notice.
3. The DNSP has made and documented reasonable attempts to deal with the customer in person or by telephone, whether before or after sending any disconnection notice, for the purpose of assisting the customer to do whatever is necessary to remove the grounds referred to in that notice.
4. Having completed this process, a DNSP's representative visits the customer personally with an intention to disconnect. The Tribunal considers it important that the customer be given the opportunity to make an acceptable payment on the account before a Personal Visit fee is levied. At the time of the personal visit, the customer may avoid disconnection by making an acceptable payment on the account (not necessarily the full outstanding balance).

If an acceptable payment is received, and the DNSP's representative does not proceed with disconnection, the DNSP may charge the $30 Personal Visit fee. DNSPs are encouraged to waive this fee where the customer can provide evidence that a payment has been made but not recorded, such as where a payment was made at a collection outlet such as a post office, or payment has been mailed.

In cases where the customer does not make an acceptable payment and disconnection proceeds, the DNSP may charge the $60 Personal Visit fee. This also covers the cost of a second visit to reconnect the customer. If the customer makes an acceptable payment on the overdue account, and pays the $60 disconnection visit charge, during normal business hours, then the customer is entitled to be reconnected that day at no extra cost; that is, no after hours fees can be charged for the reconnection.

Where disconnection is to be effected, and the customer denies access for disconnection, or there is evidence that the customer has reconnected supply illegally after an earlier disconnection, the customer may be disconnected at the pillar box or pole top and the $100 Pillar Box/Pole Top Disconnection fee may be levied. The maximum charge for a disconnection visit will be $160 (ie $60 for the visit plus $100 to make a disconnection at a pole top or pillar box should such a disconnection be necessary).

The customer would be reconnected after making an acceptable payment on the account (not necessarily the full outstanding balance) or acceptable payment arrangements. No fee is chargeable for reconnection.

It should be noted that the personal visit is considered to be the culmination of this process. Once a Personal Visit is effected, the entire process described above must be repeated before another charge for a personal visit can be made. The DNSP or retailer are encouraged to visit the customer to discuss payment arrangements, but they cannot impose the $30 fee before the entire process described above is repeated. Considering the complaint activity in this area, the Tribunal will seek evidence that this process has been followed in response to future complaints.

Rectification of illegal connection

This charge applies when a customer connects the electricity supply by interfering with property belonging to the electricity distributor in an unauthorised manner and without the distributor's permission.

Informing Customers

End use customers must be informed of the charges for miscellaneous services that may be levied by the DNSP and passed through the retailer. The Tribunal considers this information will help reduce the level of complaint activity in this area.

Information should be provided to customers:

- in advance of any fees being charged
- in plain language
- in a physical form on bills and notices so that it is accessible to customers
- in a way which makes clear when the fees are applied.

DNSPs should also clarify to end use customers:

- the internal and external dispute resolution mechanisms available if they query or dispute any of the charges
- the times during which 'normal business hours' fees apply and beyond which 'outside business hours' fees may apply
- the normal business hours of the network business.

This information should be provided by DNSPs and retailers to:

- new customers at the time of connection
- existing customers in advance of fees being charged for the first time
- all customers from time to time as part of general customer information.

Clause 6.10.1(f) National Electricity Code

Rule 99/4
Charges For Monopoly Services

Interpretation

This rule is made by the Independent Pricing and Regulatory Tribunal of NSW (the Tribunal) as the jurisdictional regulator under clause 6.10.1(f) of the National Electricity Code.

This rule is to be referred to as the 'Charges for monopoly services Rule 99/4'.

This rule applies to DNSPs in New South Wales.

This rule commences on 30 December 1999 and will remain in force until revoked by the Tribunal. This rule may be amended or supplemented by the Tribunal from time to time.

Except where indicated, expressions used in this rule have the same meaning as in the National Electricity Code (approved for the purpose of National Electricity (NSW) Law) and any determination of the Tribunal under the National Electricity Code.

Rule provisions

The following provisions apply:

Levying charges for monopoly services

Access

Providing access to switchrooms, substations etc for accredited meter and service providers. The fee for this service should be based on an hourly rate as the time taken to provide access will vary considerably from one location to the next, as will the time required to be on site (depending on whether it is inspection only or for the duration of the work).

DNSPs are encouraged to offer an alternative to paying this charge by arranging for the authorised person to have a key. If keys are provided, this fee would cease to apply.

Authorisation

When an employee or sub-contractor of an accredited service provider is required to work on or near a DNSP's network such persons must be individually authorised to do so every 12 months. An authorisation charge may be levied at rate 2 for a maximum of 2 hours.

Travel Time

$50 per hour for travel in excess of two hours (one way) for work associated with contestability, such as inspection of private contractor's work.

Administration

The administrative overhead charge is designed to cover the cost that a DNSP incurs because of the contestable development. It includes not only the work carried out by the contestable works administrator but such things as legal, accounting, records (both administration and technical) survey, corporate overheads etc.