Price and Service Report for 2000/01

NSW Distribution Network Service Providers

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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1 INTRODUCTION

This report provides information on the performance of the distribution network service providers in NSW (DNSPs) for the financial year 1 July 2000 to 30 June 2001. Its aim is to provide customers and other stakeholders with comparative data on prices and service levels of the DNSPs. For this purpose, where possible, data prior to 2000/01 and forecast data have been included.

The Independent Pricing and Regulatory Tribunal (the Tribunal) is responsible for regulating the prices DNSPs charge for access to their networks.[1] In December 1999, the Tribunal issued a network determination[2] (1999 Network Determination) for the period 1 February 2000 to 30 June 2004. The determination sets the total revenue that each DNSP may recover through its network pricing.

Under the 1999 Network Determination, DNSPs are responsible for determining their own prices. However, the revenue generated must not be more than that set by the Tribunal, and the prices must be prepared in accordance with the *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services* (PPM).[3]

This Tribunal report is based on information that each DNSP has provided in its Price and Service Report[4] and its annual Regulatory Accounts (2000/01). The system performance information in Chapter 5 has been drawn from data each DNSP provides to the Ministry of Energy and Utilities (MEU) for its Electricity Network Performance Report and from the DNSPs' websites.

This report summarises and compares the DNSPs in five categories:

- general operating background
- pricing framework
- average prices and typical bills
- standards of service
- financial performance.

This is the second Price and Service Report the Tribunal has published. The Tribunal welcomes any feedback on this report and its usefulness.

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1 Under the provisions of the National Electricity Code (the Code).

2 IPART, *Regulation of New South Wales Electricity Distribution Networks: Determination and Rules under the National Electricity Code*, December 1999.

3 IPART, *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services*, March 2001. Developed as the alternative pricing methodology to the approach in Part E under clause 6.11(e) of the National Electricity Code with effect on and from 1 July 2001.

4 Under the PPM, each DNSP must publish and make publicly available an annual Price and Service Report by 30 November. The specific information to be included in the Price and Service Reports is attached at Appendix 1.

2 GENERAL OPERATING BACKGROUND

This report provides information for the financial year 2000/01 on the distribution network service providers (DNSPs) of NSW – EnergyAustralia, Integral Energy, Australian Inland Energy & Water, Advance Energy, Great Southern Energy and NorthPower. On 1 July 2001, Advance Energy, Great Southern Energy and NorthPower merged to form Country Energy. Where possible, the Tribunal has presented information on the new entity Country Energy, otherwise, data for the 2000/01 financial period is presented separately for each DNSP.

The DNSPs are provided with transmission services from the transmission network service providers (TNSPs) – TransGrid, EnergyAustralia or Powerlink. The TNSPs transport energy from the generator to a number of points in each DNSP's area and charge the DNSPs the cost of transmission. The DNSPs then pass these costs through to customers.

The Australian Competition and Consumer Commission (ACCC) regulates transmission revenues and prices are established in accordance with the National Electricity Code. The impact transmission charges have on network prices are briefly outlined in Chapter 3.

2.1 Area of operations

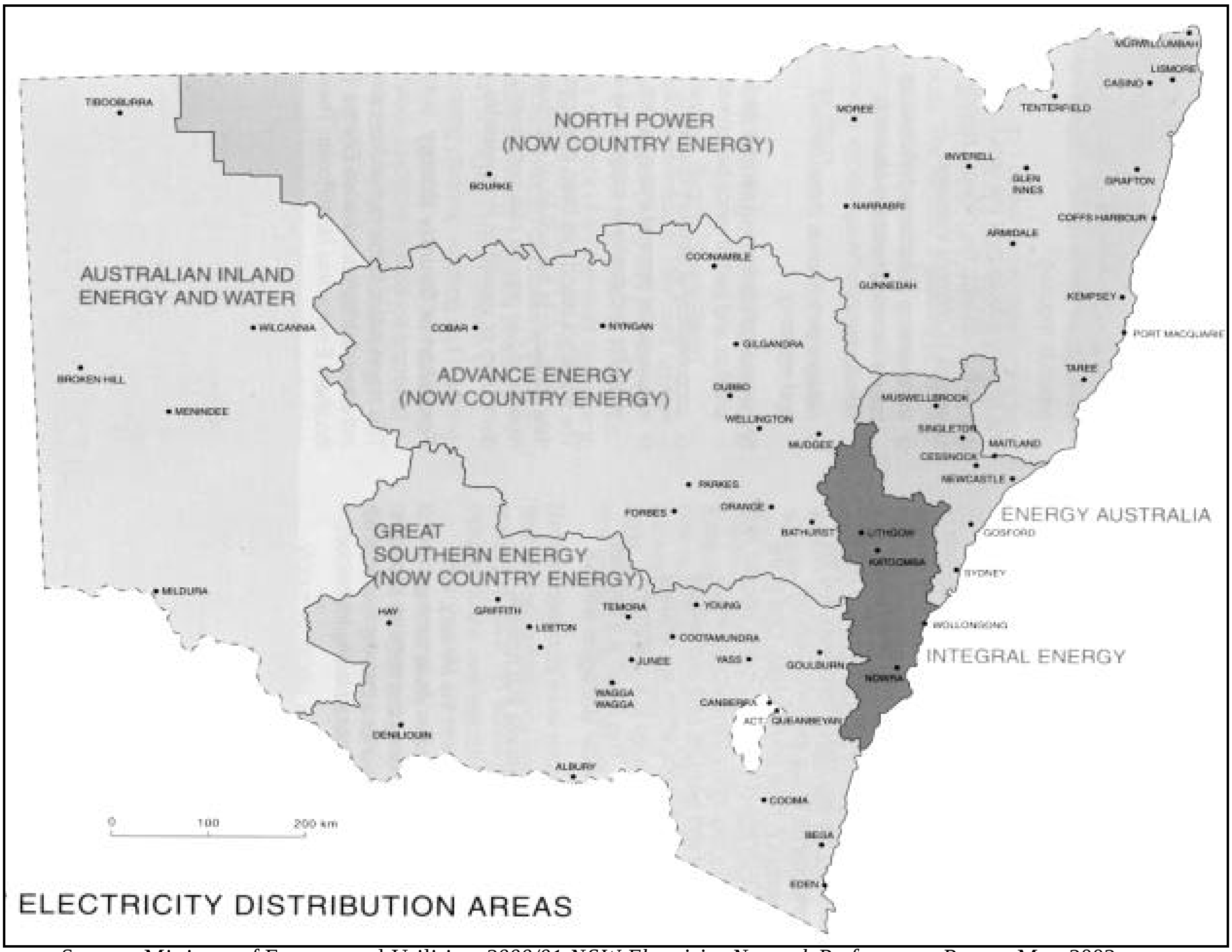
The areas of operation of the DNSPs vary widely (see Table 2.1 and Figure 2.1). EnergyAustralia and Integral Energy operate predominantly in densely populated urban districts, with a larger number of customers over relatively small geographic areas. AIEW and Country Energy cover sparsely populated rural regions over a larger geographical area.

Table 2.1 Operating statistics 2000/01

		Energy Australia	Integral Energy	Country Energy	AIEW
Operating area	km^2	22,275	24,500	582,000	155,000
Network customers ('000)	no.	1,441	761	729	19
Maximum demand	MW	4,696	2,966	1,950	59
Distribution network					
-underground	km	12,611	8,612	3,806	31
-overground	km	39,267	24,640	173,887	9,426
-total	km	51,878	33,252	177,693	9,458
Electricity distributed					
-residential	GWh	9,394	5,635	4,508	108
-non residential	GWh	15,881	8,255	5,500	308
-total	GWh	25,276	13,890	10,007	415
Employee number					
- network	no.	2,498	1,229	1,913	83
- retail	no.	389	246	424	25
- non-regulated businesses	no.	497	291	-	-
- total	no.	3,384	1,766	2,337	108
Customers per employee (network)	no.	577	619	381	228
Customer density	per 1,000 k	64,693	31,063	1,253	122
Circuit km per 1000 km2	km	2,329	1,357	305	61

Source: DNSPs' Price and Service Reports, 2000/2001.

Figure 2.1 Operating areas of NSW DNSPs



Source: Ministry of Energy and Utilities, *2000/01 NSW Electricity Network Performance Report,* May 2002.

2.2 Consumption and growth factors

Significant increases in energy sales have occurred in the Sydney metropolitan region. This has been driven in part by strong residential and commercial development, urban consolidation and population growth. As a result, higher than forecast revenue has been collected by the DNSPs (discussed in section 3.2).

Table 2.2 illustrates the actual growth in energy sales that has occurred and provides a comparison with the energy sales growth assumption used in the 1999 Network Determination (a constant growth factor was assumed for each year of the regulatory period (1999-2004)). Table 2.3 lists the number of customers connected to each DNSP since 1997/98.

The maximum demand per annum is illustrated in Table 2.4. Maximum demand is a significant driver of costs as DNSPs must design the network to service this capacity. There is a noticeable shift occurring in the timing and level of peak demand, from winter to summer, with longer peaks,[5] which can partially be attributed to increased penetration and use of commercial and residential air conditioning.[6]

5 EnergyAustralia, *Price and Service Report 2001,* November 2001, p 28, and Integral Energy *Network Price and Service Report*, January 2002, p 30.

6 EnergyAustralia, *Price and Service Report 2001,* November 2001, p 24.

DNSPs have responded to the change in demand, with increases in actual and forecast capital expenditure and operating costs (discussed in chapter 6). Medium-term pricing strategies are also undergoing review by the DNSPs as a result of the shift in timing and level of the peak demand.[7]

Table 2.2 Growth in energy sales in GWh and percentage change

	1999 Network Determination[1]	1997/98 actual	1998/99 actual	1999/00 actual	2000/01 actual	2001/02 forecast
EnergyAustralia						
actual		22,151	23,064	24,364	25,276	26,000
% change	**2.0%**		4.1%	5.6%	3.7%	2.9%
Integral Energy						
actual		13,988	14,812	15,048	15,956	16,211
% change	**3.5%**		5.9%	1.6%	6.0%	1.6%
Country Energy						
actual		9,183	9,452	9,740	9,935	10,150
% change	**2.6%**		2.9%	3.0%	2.0%	2.2%
AIEW						
actual		400	418	413	415	423
% change	**1.0%**		4.3%	-1.2%	0.6%	1.8%

Note 1: constant growth factor assumed per annum for 2000-2004.
Source: DNSPs' Price and Service Reports, 2000/01.

DNSP	1997/98 actual	1998/99 actual	1999/00 actual	2000/01 actual
EnergyAustralia	1,366	1,387	1,399	1,441
Integral Energy	737	751	760	761
Country Energy	695	705	717	729
AIEW	22	21	21	19

Table 2.3 Number of network customers (000s)

Source: DNSPs' Regulatory Accounts.

Table 2.4 Maximum Demand MW

DNSP	1997/98 actual	1998/99 actual	1999/00 actual	2000/01 actual	2001/02 forecast
EnergyAustralia	4,481	4,618	4,983	4,696	4,934
Integral Energy	2,642	2,801	2,858	2,966	3,117
Country Energy	np	1,767	1,906	1,950	1,996
AIEW	np	59	57	59	60

Source: DNSPs' Price and Service Reports, 2000/01.
np: not provided.

[7] For more information on the pricing strategies, refer to the DNSPs' individual price and service reports.

3 PRICING FRAMEWORK

The Tribunal regulates DNSPs' network prices in the form of a revenue cap. DNSPs must structure their prices to raise network revenue that matches the annual aggregate revenue requirement (AARR) determined by the Tribunal.

DNSPs determine their own prices (or tariffs) within the bounds of the revenue cap (AARR). However, they are subject to certain limits on price movements and must demonstrate compliance with IPART's *Pricing Principles & Methodologies for Prescribed Distribution Services* (PPM). The price limits in the 1999 Network Determination are:[8]

- average prices across the network must not increase by more than the change in the Consumer Price Index (CPI), and
- a residential customer's network bill must not increase by more than the greater of the change in CPI plus 2 per cent, or $30 per annum, for the same quantity and pattern of consumption as in the previous year.

These price limits apply to all DNSPs. A DNSP may increase average prices by more than the change in CPI if it can demonstrate to the Tribunal that changes to transmission prices[9] from the TNSPs prevent the DNSP from recovering transmission charges from its customers.

Each DNSP must publish the methodology it uses to derive the prices in its annual Price and Service Report.[10] These reports explain the relationship between prices and costs - how costs are allocated between distribution services and customer classes and how tariffs have been structured. The pricing structure must have regard to principles in the PPM (see Appendix 1). The broad aim of the principles is to ensure that prices signal the economic costs of service provision.

3.1 Annual Aggregate Revenue Requirement

The Tribunal sets a base revenue allowance for each year of the regulatory period[11] for each DNSP. The base revenue allowance plus pass-through costs make up the DNSPs' Annual Aggregate Revenue Requirement (AARR), or revenue cap. The base revenue allowance is made up of forecast costs of supply – operating costs, depreciation and a return on assets. The pass-through costs are determined separately each year as they are more volatile in nature and in most cases are not known until the year they are incurred. They include: transmission use of system charges (TUOS), avoided TUOS payments to embedded generators, payments for network services to and from other distributors for inter-distributor electricity transfers, contestability costs and the net impact of the GST.[12]

8 As defined in Schedule 1 of the 1999 Network Determination.

9 DNSPs are charged transmission use of system charges (TUOS) by the TNSPs. TUOS charges are subject to endorsement by ACCC, and have been structured according to IPART Determination 5.1, TransGrid's Prices (1997), as a derogation under the Code. With the expiration of the derogation on 30 June 2002, TUOS charges are now calculated in accordance with the Code. This has affected the method of calculation of TUOS to network users.

10 A requirement under the PPM.

11 1 February 2000 to 30 June 2004.

12 Details on the base revenue and pass-through costs are found in the 1999 Network Determination.

Table 3.1 shows the actual AARR for each DNSP for 1999/2000 and 2000/01, and forecast for 2001/02.

Table 3.1 Aggregate Annual Revenue Requirement (AARR)[1]

DNSP	1999/00 actual	2000/01 actual	2001/02 forecast
EnergyAustralia	832	828	791
Integral Energy	485	489	504
Country Energy	435	465	495
AIEW	16	16	17

Source: DNSPs' Price and Service Reports for 2000/01.
Note 1: forecasts of AARR made prior to the recovery of contestability costs.

3.1.1 Transmission cost component

Transmission network service providers (TNSPs) charge the DNSPs for use of the transmission system. These charges are a cost component of the DNSPs' AARR.

The ACCC regulates transmission prices under the National Electricity Code (the Code) which requires the form of regulation to be a revenue cap. TransGrid's, EnergyAustralia's and Powerlink's annual transmission revenues may increase each year by up to CPI + 1.3%, CPI – 1.4% and CPI + 6.4% respectively. The determination expires on 30 June 2004.

The Code also requires that transmission charges be based on cost reflective network pricing (CRNP) principles. This means that the distance over which the energy is being transmitted is a significant driver of charges. However, until 30 June 2002, a Code derogation maintained the pricing structure in the Tribunal's determination on TransGrid's prices.[13] The Tribunal determination had the effect of averaging transmission charges within each distribution region.[14]

The change in pricing structure resulting from the expiration of the derogation will have significant impacts on the charges for the DNSPs. For 2002/03 it is expected that there will be higher total charges in rural and remote areas. This will be reflected in the DNSPs AARR and flow into the network prices the DNSPs charge.[15]

3.2 Unders and overs account

Under the 1999 Network Determination, DNSPs must maintain an *Unders and Overs Account* to record the difference between actual revenue collected during the financial year and the AARR (target revenue). The intention of the account is to cater for the differences between forecast energy sales and actual sales.

Rule 2001/03[16] lists the actions the DNSP must take if a significant balance in the unders and over account accumulates. For example, the Tribunal required EnergyAustralia to reduce

13 IPART, *Electricity Prices - July 1997*, Determination 5.1 – TransGrid's Prices, 1997.

14 Country Energy, *Electricity Network Services Pricing and Service Information Package,* November 2001.

15 The new pricing structure can be viewed on TransGrid's website. www.transgrid.com.au

16 Issued under the 1999 Network Determination. Prior to 2001/02, Rule 99/1 applied.

network prices by an average of 8 per cent in 2001/02 to reduce their level of over-recovery. An under-recovery is reduced via an increase in prices. However it may not be completely removed as the increase is limited by the price-constraints. Table 3.2 shows the amount of network revenue over- or under-recovered by DNSPs in 2000/01 and the cumulative balance of the account at the close of the financial year.[17]

Table 3.2 Under and over recovery of regulated network revenue 2000/01

$ million (nominal)	Energy Australia	Integral Energy	Country Energy	AIEW
Total regulated network revenue	863.5	488.8	467.1	15.4
Annual Aggregate Revenue Requirement	827.6	488.6	465.0	16.4
Over/(under) recovery of network revenue	35.9	0.1	1.8	(1.0)
% Deviation from AAR	4%	0%	0.4%	-6%
Network over- and under-recovery account				
Opening balance	213.6	4.8	1.0	(0.3)
Over/(under) recovery for financial year	35.9	0.1	1.8	(1.0)
Interest charge/credit	12.9	0.3	0.1	(0.0)
Closing balance	262.5	5.2	2.9	(1.3)
Closing balance as % AARR	32%	1%	0.6%	-8%

Source: DNSPs' Price and Services Reports for 2000/01.

As a result of the 8 per cent reduction in average network prices, EnergyAustralia's over-recovery is expected to be substantially reduced. The Tribunal expects that approximately $130 million will have been returned to customers by 30 June 2003.

3.3 Pricing strategies and cost allocation

Network charges aim to reflect the cost of providing the electricity service. The general approach that DNSPs use when setting prices is to allocate the allowable revenue (AARR) to cost pools using a fully distributed cost approach. Most DNSPs allocate the network costs to customer classes based on usage of assets.[18] A general summary of the cost allocation process is provided in Appendix 2, Table A2.1. Allocation of costs by network segment will assist in developing the relationship with reliability and supply quality indicies in the future.

Each DNSP must set out their medium-term network pricing strategies in their annual Price and Service Report. In summary, each DNSP's current pricing direction is as follows.

Australian Inland Energy & Water (AIEW)

AIEW is continuing with a strategy to simplify tariffs and improve cost-reflectivity of existing pricing arrangements as, in most cases, the network prices do not recover costs.[19] This strategy will include reducing cross-subsidies and providing equity within customer

17 Country Energy was not officially formed until 1 July 2001, however, for comparison purposes, the over and under recoveries of the DNSPs, NorthPower, Great Southern Energy and Advance Energy, have been aggregated here. The aggregate balance on 1 July 2001 will form the opening balance for Country Energy.

18 AIEW intends to implement a comprehensive network pricing model by 1 July 2002, which will incorporate cost allocation by asset category by determining unit costs per asset segment.

19 AIEW, *Network Price and Service Report,* November 2001, p 41.

and geographic classifications. The increase in average prices for AIEW reflects the move towards cost-reflectivity.

Country Energy

Country Energy, in the medium term, aims to merge some of the network prices in the northern and central networks, particularly the urban residential, rural residential and business general supply prices. The fixed component will gradually be standardised where possible, with adjustment to the variable components of the network price to ensure revenue neutrality. It is anticipated, however, that differences between average network prices across Country Energy within the same customer class will continue to exist for some time into the future due to the significant price discrepancy in the northern and central regions, as compared to the southern region.[20]

EnergyAustralia

In 2001/02 EnergyAustralia will progress with its medium term pricing strategy set in 2000/01 of refining the price structure to improve economic signals. These refinements include:[21]

- introducing price incentives to encourage large customers to implement load factor improvements
- progressively increasing the kW capacity charge for business customers to provide incentives to alter consumption patterns
- rollout of type 5 meters to appropriate customers to extend the use of the low voltage time-of-use tariff.

Integral Energy

Integral Energy intend to move further towards demand based tariffs to provide more appropriate price signals to customers.[22] Specific tariff changes will include structural reforms to existing tariffs and the introduction of new – cost reflective – network tariffs which will inevitably change the component mix of tariffs between fixed, energy and demand charges. A main feature of the 2002 tariffs design process includes the development of peak usage charges for medium and large customers, and consideration of time-of-use tariffs for small and medium sized customers.[23]

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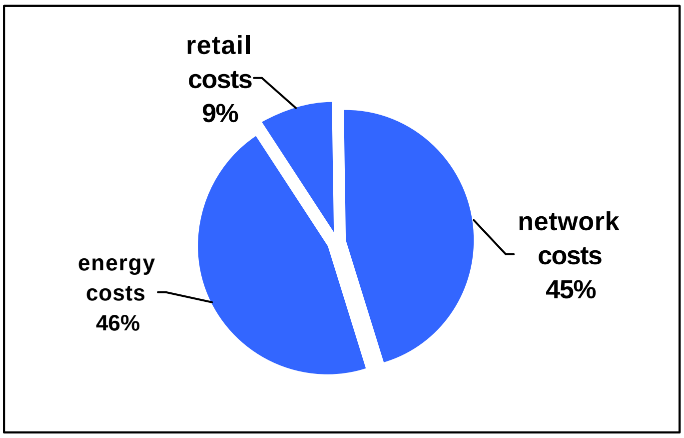
20 Country Energy, *Electricity Network Services Pricing and Service Information Package*, November 2001, p 68.
21 EnergyAustralia, *Price and Service Report 2001*, November 2001, p 32.
22 Integral Energy, *Network Price and Service Report*, January 2002, p 30.
23 Integral Energy, *Network Price and Service Report*, January 2002, p 34.

4 PRICES

This chapter considers average network prices and the impact on bills for retail customers across NSW. A typical customer's electricity bill comprises of approximately 45 per cent network costs, as illustrated in Figure 4.1. Network costs include the transmission use of system (TUOS) costs as well as all specific distribution network costs.

Figure 4.1 Composition of a typical electricity bill



Source: Regulatory Accounts 2000/01.

It is important to note that no end-use customer receives a bill from a DNSP – retailers incorporate the generation, transmission and distribution costs into the final retail price, where contestable customers' bills can have network charges separately itemised if they choose.

4.1 Average network prices

4.1.1 Historical performance

Figure 4.2 demonstrates that there has been a general decrease in average network prices (ie transmission and distribution) over the past five years.[24] This is in line with the Tribunal's estimates in its 1999 Network Determination, despite the increase in transmission charges.

Table 4.1[25] and Figures 4.3-4.6 present the actual average network prices for residential and non-residential customers separately. Average network prices are based on actual customer numbers, actual revenue and actual consumption at the end of each financial year. Note that actual figures for 2001/2002 were not available at the time of compiling this report. However, the actual tariffs charged for 2001/2002 and the impact on a typical bill is illustrated in section 4.2.

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24 The graph is also presented in 2001 dollars (ie adjusted for inflation) in Appendix 3, Figure A3.1.

25 Table 4.1 is in nominal terms. A comparison of average prices adjusted for inflation (2001 dollars) is provided in Appendix 3, Table A3.1.

Table 4.1 Average network prices 1996/97 to 2000/01 (nominal, cents per kWh) [1]

DNSP	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001
EnergyAustralia					
Residential	np	np	np	4.84	3.91
Non residential	np	np	np	3.17	3.09
All customers	3.90	3.84	3.56	3.76	3.40
Integral Energy					
Residential	4.66	4.74	4.74	4.41	4.40
Non residential	2.59	2.48	2.62	3.04	2.53
All customers	3.38	3.30	3.40	3.64	3.29
Country Energy [2]					
Residential (inc rural)	np	np	np	4.45	4.67
Non residential	np	np	np	4.59	4.31
All customers	4.28	4.56	4.33	4.53	4.47
AIEW					
Residential (inc rural)	3.16	3.48	3.63	3.79	3.84
Non residential	3.07	3.36	3.26	3.28	3.50
All customers	3.09	3.39	3.36	3.42	3.59

Notes
1 The average price is calculated as: actual energy delivered to customers / revenue received in that year.
2 Country Energy figures are the addition of revenues and MWh of the three separate entities as represented in their 2000/01 Price and Service Information Package.
Source: Regulatory Accounts.

Figure 4.2 Average network prices for DNSPs (nominal)

Source: Table 4.1

Figure 4.3 EnergyAustralia average prices (nominal)

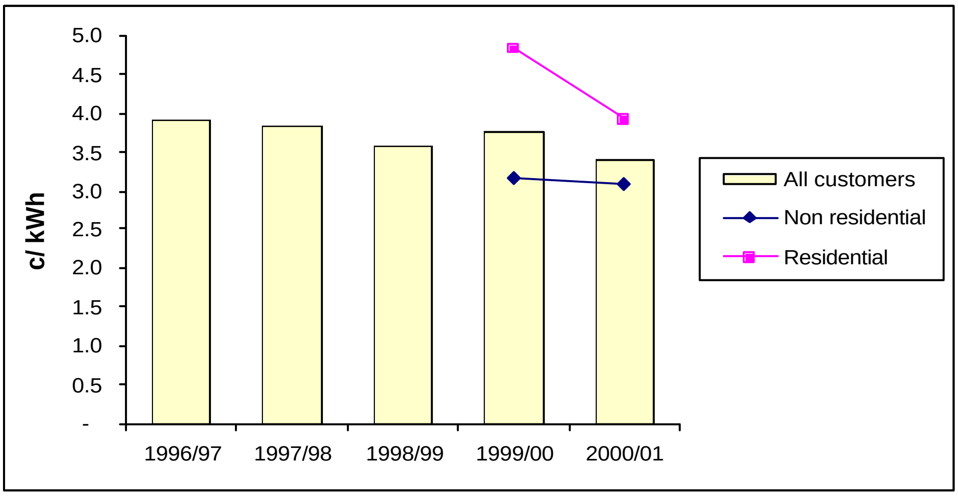


Figure 4.4 Integral Energy average prices (nominal)

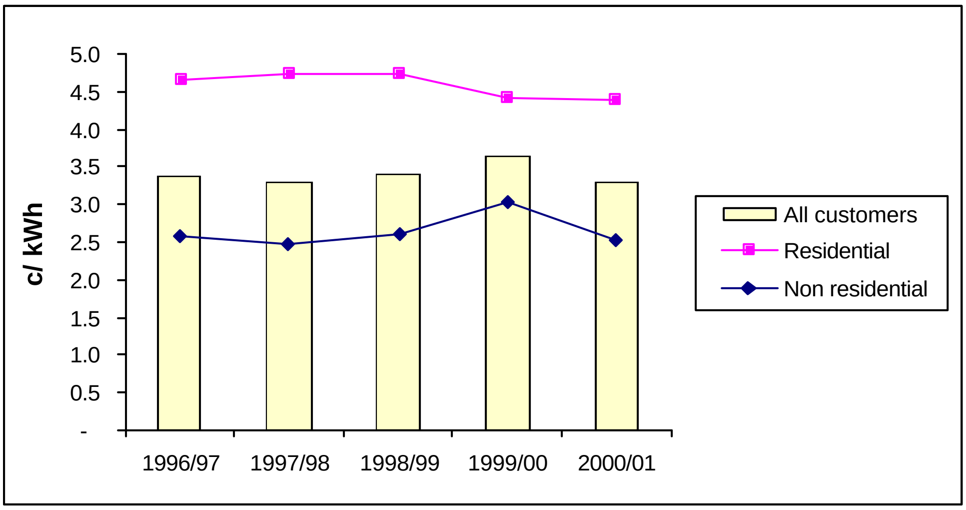


Figure 4.5 AIEW average prices (nominal)

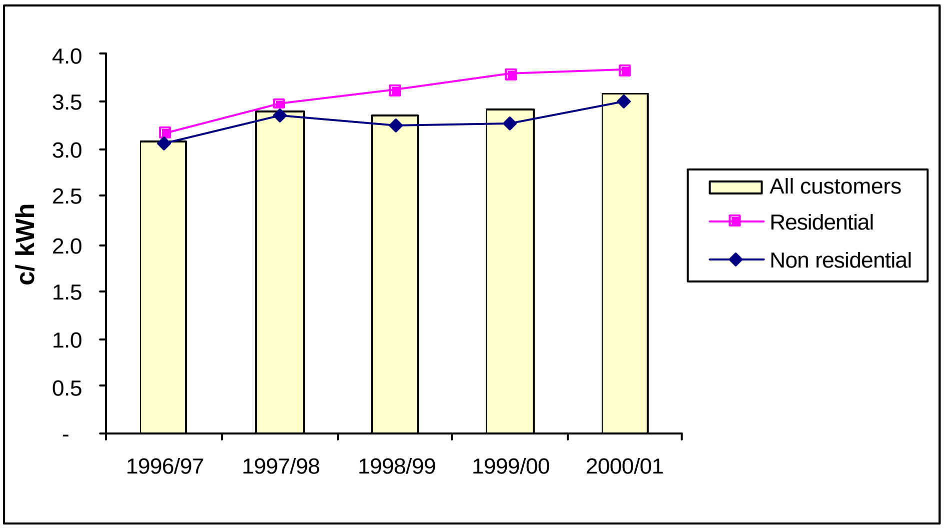
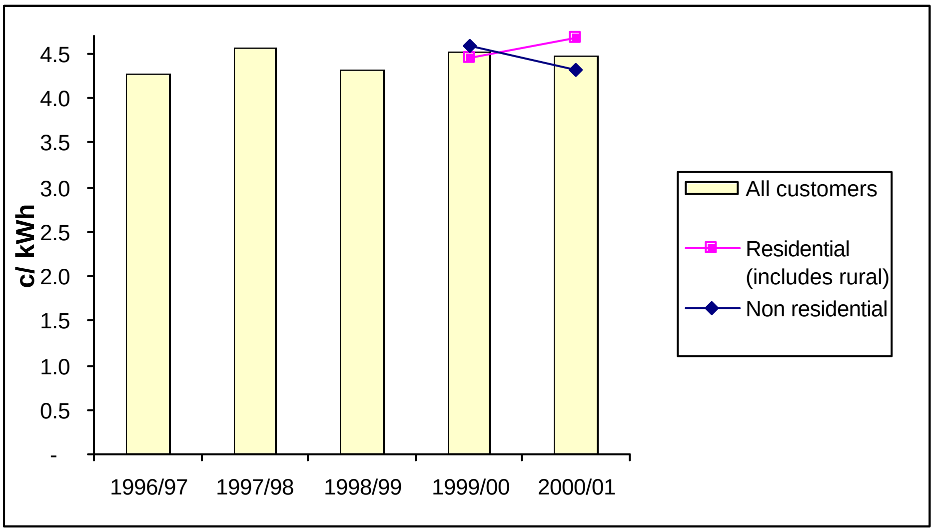


Figure 4.6 Country Energy average prices (nominal)



4.1.2 2002/03 average network price forecasts

All DNSPs have forecast an increase in average prices for 2002/03. For AIEW and Country Energy, the increases are larger than the change in CPI due to the increase in transmission charges. The average price increases are:

Table 4.2 Average network price increase 2002/03 (nominal)

DNSP	%
EnergyAustralia	3
Country Energy	6
Integral Energy	2.8
AIEW[26]	11

4.2 Network component of customer bills

In any one year, the change in a typical bill may be more or less than the average price change and will differ between DNSPs. This is because the individual network tariffs are determined according to the cost-reflective pricing strategies outlined in section 3.3.

Tables 4.3–4.6[27] show actual bills for typical customers from 1999/00 (the start of the regulatory period) until 2001/02. Expected bills for 2002/03 have been calculated for domestic and general supply (business) customers. The 'typical' consumption levels are from the standard range presented in the Electricity Supply Association of Australia's publication, *Electricity Prices in Australia 2000/2001*.[28]

26 This price increase calculation excludes one large customer.

27 The tables are presented in nominal terms. A comparison of typical bills adjusted for inflation (2001 dollars) and GST is provided in Appendix 5, Tables A5.1-A5.4.

28 The 'typical bill' assumptions are produced in Appendix 4.

Note that the bills incorporate the Goods and Services Tax (GST) of 10 per cent, which came into effect from 1 July 2000.

4.2.1 Urban and rural effects

The tables below illustrate that network charges within a tariff category vary widely across NSW. In general, business charges from the urban DNSPs (EnergyAustralia and Integral Energy) are lower than those of the rural DNSPs (Country Energy and AIEW). This is to be expected as there is a higher cost of supply for rural DNSP business customers, reflecting the lower density of business customers in urban centres and the cost of the rural networks. However, comparing rural DNSPs with urban DNSPs should be done cautiously. The costs of supply vary greatly due to the different operating environments, diverse capacity and network sizes, and impact on energy losses.[29]

Network prices have generally decreased for urban DNSP customers and increased slightly for rural DNSP customers. Since the 1999 Network Determination, the emphasis on cost reflectivity in prices has highlighted the fact that services in some country areas have been provided at less than the cost of supply. The increases to customers have been maintained at a reasonable level however, by the price-constraints which limit the impact of increases in individual bills.

Table 4.3 EnergyAustralia typical bills (nominal dollars, including GST)

Customer class	1999/00	2000/01	2001/02	2002/03	%[1]
Domestic					
Domestic	202	202	186	192	-5
Domestic with controlled load hot water	280	277	247	255	-9
Rural Domestic	na	na	na	na	na
General supply					
Business non-TOU, 18 MWh cons. pa	892	922	857	887	-4
Business non-TOU, 60 MWh cons. pa	2,698	2,784	2,566	2,638	-5
Low Voltage TOU					
Business TOU with 30% lf.	10,616	10,998	10,647	na	0
Business TOU with 60% lf.	15,632	16,463	15,601	na	0
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	56,705	49,314	43,751	na	-23
LVD TOU (kVA), with 40% lf.	65,060	61,598	55,495	na	-15
LVD TOU (kVA), with 60% lf.	70,079	71,459	65,042	na	-7
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	238,240	228,824	212,486	na	-11
HVD TOU (kVA), with 60% lf.	263,610	264,303	247,231	na	-6
HVD TOU (kVA), with 80% lf.	272,300	89,266	272,011	na	0

Note 1 for each tariff, the percentage change has been calculated between the earliest data presented in the table to the last year of data presented in the table.
na: not available.
lf: load factor.

[29] For further information on the cost drivers of each DNSP, refer to the individual 2000/01 Price and Service Report of the DNSP.

Table 4.4 Integral Energy typical bills (nominal dollars, including GST)

Customer class	1999/00	2000/01	2001/02	2002/03	%[1]
Domestic					
Domestic	217	230	246	256	18
Domestic with controlled load hot water	286	302	316	333	17
Rural Domestic	600	660	692	na	15
General supply					
Business non-TOU, 18 MWh cons. pa	822	898	914	935	4
Business non-TOU, 60 MWh cons. pa	2,628	2,870	2,919	2,956	3
Low Voltage TOU					
Business TOU with 30% lf.	9,921	10,913	12,038	na	21
Business TOU with 60% lf.	13,860	15,246	16,805	na	21
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	46,635	51,299	53,387	na	14
LVD TOU (kVA), with 40% lf.	55,386	60,925	63,920	na	15
LVD TOU (kVA), with 60% lf.	61,175	67,293	70,852	na	16
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	197,769	217,546	231,989	na	17
HVD TOU (kVA), with 60% lf.	227,390	250,129	268,227	na	18
HVD TOU (kVA), with 80% lf.	241,010	265,111	284,396	na	18

Note 1 for each tariff, the percentage change has been calculated between the earliest data presented in the table to the last year of data presented in the table.

na: not available.

lf: load factor.

Table 4.5 AIEW typical bills (nominal dollars, including GST)

Customer class	1999/00	2000/01	2001/02	2002/03	%[1]
Domestic					
Domestic	190	190	199	224	18
Domestic with controlled load hot water	261	266	281	316	19
Rural Domestic	744	892	919	na	3
General supply					
Business non-TOU, 18 MWh cons. pa	1,145	1,128	1,285	1,443	28
Business non-TOU, 60 MWh cons. pa	3,648	3,577	4,094	4,598	29
Low Voltage TOU					
Business TOU with 30% lf.	22,728	27,251	28,031	na	23
Business TOU with 60% lf.	15,979	19,162	19,712	na	23
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	82,364	98,750	101,634	na	23
LVD TOU (kVA), with 40% lf.	110,360	132,326	136,169	na	23
LVD TOU (kVA), with 60% lf.	132,702	159,129	163,738	na	23
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	327,223	392,379	403,211	na	23
HVD TOU (kVA), with 60% lf.	393,708	472,174	484,950	na	23
HVD TOU (kVA), with 80% lf.	441,185	529,257	543,204	na	23

Note 1 for each tariff, the percentage change has been calculated between the earliest data presented in the table to the last year of data presented in the table.

na: not available.

If: load factor.

Table 4.6 Country Energy typical bills (nominal dollars, including GST)[30]

Customer class	1999/00[1]	2000/01	2001/02	2002/03	%[2]
Domestic					
Domestic	na	268	274	300	12
Domestic with controlled load hot water	na	366	374	398	9
Rural Domestic	na	934	953	972	4
General supply					
Business non-TOU, 18 MWh cons. pa	na	1,346	1,373	1,455	8
Business non-TOU, 60 MWh cons. pa	na	4,320	4,407	4,554	5
Low Voltage TOU					
Business TOU with 30% lf.	na	12,387	12,621	na	2
Business TOU with 60% lf.	na	20,237	20,620	na	2
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	na	54,205	55,229	na	2
LVD TOU (kVA), with 40% lf.	na	107,346	109,374	na	2
LVD TOU (kVA), with 60% lf.	na	160,486	163,518	na	2
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	na	214,620	218,677	na	2
HVD TOU (kVA), with 60% lf.	na	321,010	327,077	na	2
HVD TOU (kVA), with 80% lf.	na	427,400	435,477	na	2

Notes

1 Country Energy was formed on 1 July 2001.

2 for each tariff, the percentage change has been calculated between the earliest data presented in the table to the last year of data presented in the table.

na: not available.

lf: load factor.

30 Corresponds to tariffs for the Northern Region (previously a NorthPower tariff).

5 STANDARDS OF SERVICE

Under the current electricity licensing regime, there are no mandatory service standards that the DNSPs are required to meet. However, the DNSPs must nominate performance targets in their licence plans and provide data to the Tribunal on their compliance with these targets.[31]

The DNSPs also provide comprehensive data to the Ministry of Energy and Utilities (MEU) under the *Electricity Supply (Safety Plans) Regulation 1997*, on network safety, network planning and adequacy, demand management, and supply reliability and quality. The MEU assesses this data and publishes it in an annual Electricity Network Performance Report. The majority of the information in this section is sourced from the *2000/01 NSW Electricity Network Performance Report* produced in May 2002 by MEU (MEU Report).

The Tribunal will be reviewing expected standards of service as part of the 2004 Network Determination. The review will be conducted in two stages. The first stage will involve defining reliability measures and establishing performance targets. The second stage will address the form of the mechanism to link service quality and price through DNSP revenue during the regulatory period. The progression of the second stage however, will depend on the availability of robust and reliable data.

Performance measures for electricity distribution service typically fall into three categories which are discussed in more detail below:

- network reliability measures, which indicate how often and for how long customers lose their electricity supply
- technical or service quality measures, which relate to the quality of the electricity supply received by customers (eg voltage levels)
- customer service measures, which relate to a DNSP's responsiveness and timeliness in their interactions with customers.

5.1 Rural DNSPs and urban DNSPs[32]

Rural DNSPs have networks characterised by very long feeders servicing a small number of isolated customers and a few small towns and villages. Having very long feeders significantly increases the risk of failure and there is usually no alternative source to restore supply if a fault occurs. In addition, staff response times to faults on the network can be longer due to the distance between the location of the fault and the nearest service facility.

Customers in city and major urban areas have shorter feeders due to the higher load density, and when there is a problem with their supply, they are often able to be supplied from an alternative source while repairs are done.

Performance of DNSPs is also influenced by factors such as historical capital expenditure decisions, geography, demographics, storm frequency, the extent of undergrounding of the network, and the level of redundancy in the network. These factors should be borne in mind when comparing DNSPs as direct comparisons are not always appropriate.

31 Established under the *Electricity Supply Act 1995*.

32 Information in this section is sourced from the *2000/01 NSW Electricity Network Performance Report, May 2002,* Ministry of Energy and Utilities, p 33.

5.2 Network reliability

Table 5.1 defines the indices commonly used to measure the duration and frequency of supply interruptions, and Table 5.2 lists the different measures of each index. The measures are averages across each DNSP's region, hence it is likely that there are individual areas within the regions which have results significantly different from the average. For the individual customer, actual local reliability is of more concern than the regional average. In recognition of this, the MEU monitors individual feeders which have unsatisfactory reliability and the DNSPs set objectives based on local regions (illustrated in Appendix 6, Tables A6.1-A6.3).

Table 5.1 Supply interruption indices

Index	Measure	Description
System Average Interruption Duration Index (**SAIDI**)	Average number of minutes of no supply per customer, per year	Total customer minutes, on average, that a customer could expect to be without electricity during the year. Calculated as the sum of the duration of each interruption (in minutes), divided by the total number of customers averaged over the year.
System Average Interruption Frequency Index (**SAIFI**)	Average number of interruptions per customer, per year	The number of occasions per year when each customer could, on average, expect to experience an interruption. Calculated as the total number of customer interruptions, divided by the total number of customers averaged over the year.
Customer Average Interruption Duration Index (**CAIDI**)	Average duration, in minutes, of each interruption	The average time taken for supply to be restored to a customer when an interruption has occurred. Calculated as the sum of the duration of each customer interruption (in minutes), divided by the total number of customer interruptions ie SAIDI divided by SAIFI.

Table 5.2 Data sets for index measurement

Measure	Description
Overall	All interruptions, including transmission interruptions
Raw	All interruptions less transmission interruptions
Standard	Raw less interruptions due to major natural events and less than one minute interruptions
Modified Standard	Standard, less all planned interruptions for which the customer has been notified

5.2.1 Performance in 2000/01

Tables 5.3-5.5 present each DNSPs average performance in SAIDI, SAIFI and CAIDI from 1998/99 - 2000/01, using the raw data measure (planned and unplanned interruptions, including those caused by major natural events).

In 2000/01, for most DNSPs, the supply interruption indices — using the raw data — have increased when compared to the previous year. The individual DNSP network management reports for 2000/01 reveal that major natural events had a significant impact on the number and duration of interruptions per customer in 2000/01, except for AIEW which experienced problems unique to its network. In addition, EnergyAustralia's high average outage times were influenced by a major fire incident in the Paddington Zone substation and Integral Energy's number and length of planned interruptions increased due to heavy maintenance and upgrading works.

Table 5.3 SAIDI (raw) – average annual minutes of interruption per customer

DNSP	1998/99	1999/00	2000/01
EnergyAustralia	115	90	118
Integral Energy	138	124	218
NorthPower	na	129	220
Great Southern Energy	214	221	231
Advance Energy	na	196	327
AIEW	na	203	364

Table 5.4 SAIFI (raw) – average number of interruptions per customer

DNSP	1998/99	1999/00	2000/01
EnergyAustralia	2.4	2.3	2.5
Integral Energy	2.2	2.1	3.0
NorthPower	na	1.6	1.8
Great Southern Energy	2.3	2.3	2.2
Advance Energy	na	1.7	2.2
AIEW	na	3.2	3.3

Table 5.5 CAIDI (raw) – average length of time of each interruption (minutes)

DNSP	1998/99	1999/00	2000/01
EnergyAustralia	48	39	47
Integral Energy	62	58	74
NorthPower	na	83	125
Great Southern Energy	na	97	106
Advance Energy	na	117	146
AIEW	na	64	108

The majority of DNSPs set objectives based on the modified standard (MS) data set which excludes interruptions caused by major natural events and planned interruptions. Appendix 6 illustrates performance and objectives based on the MS data. Table A6.1 lists individual region performance for 2000/01 against the objectives set by the DNSPs, and Figures A6.1-A6.3 illustrate the average modified standard performance since 1995/96 for each DNSP.

The MEU report states that the supply reliability statistics — based on MS data — do not show any clear trend in performance since 1998/99, and that a longer period may be required to identify whether specific works to improve reliability are effective. MEU have also stated that as data gathering becomes more accurate, the resulting performance may actually appear worse.[33]

5.3 Technical or service quality

Technical quality can be measured by supply voltage quality and frequency of supply. From the DNSP's point of view, measuring quality of supply is expensive and problems are often temporary, being region or feeder specific. Hence, in general, DNSPs undertake very little measurement of a technical nature, although this area of performance is a major customer concern.

The DNSPs have published some supply service standards for reliability and quality based on the *Code of Practice – Electricity Service Standards*.[34] The code describes the various technical descriptors of supply reliability and quality that NSW DNSPs should use as a basis for developing and publishing their own standards. These measures include:

- frequency of supply
- range of supply voltage
- voltage fluctuations, dips and unbalance
- neutral to earth voltages
- lightning surges
- direct current levels
- harmonic content of voltage and current waveforms
- audible and electronic noise
- electromagnetic fields.

To facilitate the reporting process, MEU intends to implement a new reporting framework based on the outcomes from the Utility Regulators' Forum on standardising quality and reliability reporting nationally.[35] The national reliability reporting framework is expected to be implemented for the 2002/03 reporting year and the DNSPs will incorporate the new framework into their next revision of their safety plans.[36] The outcomes from the forum include recommendations from the MEU working group report in January 2001.

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33 Ministry of Energy and Utilities, *2000/01, NSW Electricity Network Performance Report,* p 35.

34 The Code was published by the Electricity Association of NSW which ceased operation in December 2001.

35 To be managed by the Steering Committee of National Regulatory Reporting Requirements (SCNRRR).

36 Under the *Electricity Supply (Safety Plans) Regulation 1997.*

5.4 Customer service

DNSPs have a range of customer service measures required under the *Electricity Supply (General) Regulation 1996*.[37] These include guaranteed service levels, which require compensation payments to be made to a customer if the standard is not met. The guaranteed customer service standards cover:

a) telephone hotline services

b) timely provision of connection services

c) timely notice of planned interruptions to supply

d) repair of faulty street lights

e) punctuality in keeping appointments

f) disconnection of services.

In total, across the six DNSPs, the following results were highlighted when comparing 2000/01 with 1999/2000:

- the number of reported street light faults increased
- the number of customers disconnected for not paying their bill decreased by approximately 30 per cent
- the amount of compensation paid out to customers for not meeting guaranteed customer service standards increased by approximately 11 per cent
- of the total amount of compensation paid, 85 per cent was paid in relation to the standards on planned service interruptions.

It must be noted that these figures provide an indicative level of service only. Actual breaches may in fact be higher than those reported as a breach is only recorded when a complaint is received from a customer.

For more details of the DNSPs' performance against these standards, see Appendix 5 of the Tribunal's 2000/01 Licence Compliance Report.[38]

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37 Clause 35, Schedule 2.

38 IPART, *Electricity Distribution and Retail Licences: Compliance Report for 2000/01 – Report to the Minister for Energy*, Compliance Report No 5, October 2001.

6 FINANCIAL PERFORMANCE OF DNSPS

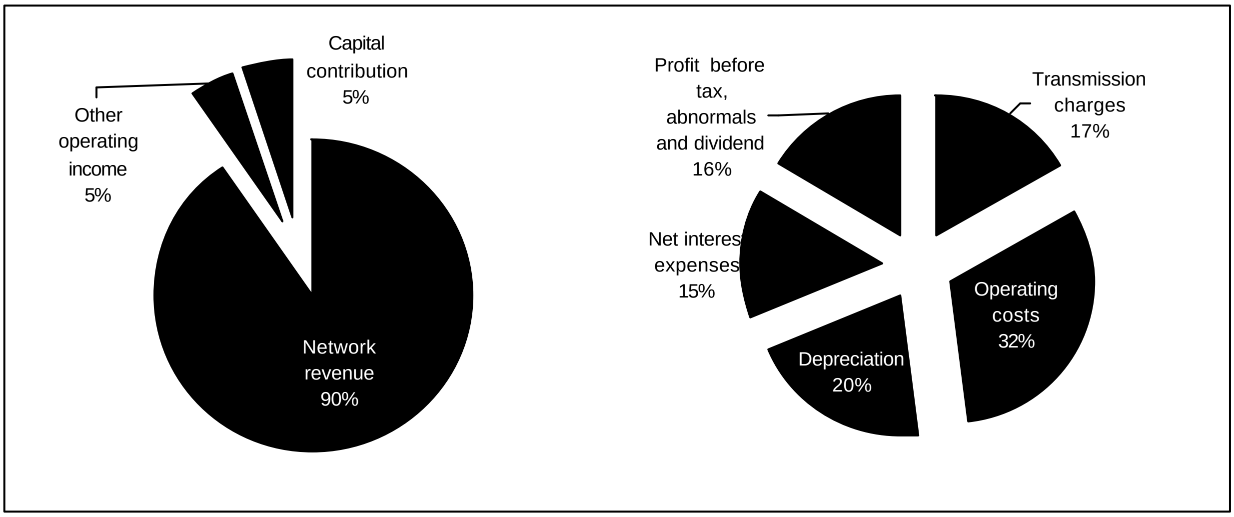
Economic regulation aims to reflect efficient costs and provide a commercially sustainable revenue stream for DNSPs. Despite the real reduction in prices,[39] the 1999 Network Determination forecast relatively strong financial outcomes for the DNSPs.

This chapter summarises the 2000/01 financial performance of the NSW DNSPs.[40] Detailed financial statistics for each DNSP for 1999/2000 and 2000/01 are set out in Appendix 7.

Figure 6.1 presents the components of the income and expenditure of the DNSPs in 2000/01. In aggregate, DNSPs derive 90 per cent of their revenue from network revenue. From total revenue, they spent 32 per cent on operating and maintenance, 17 per cent on payments to the transmission network service provider (TNSP) and 15 per cent on interest payments, with the remainder on depreciation and profits.

Figure 6.1 Aggregate income and expenditure of DNSPs in 2000/01

Income **Expenditure**



Source: 2000/01 Regulatory Accounts.

6.1 Revenue and profitability

For 2000/01, network revenue remained relatively stable across the DNSPs, with an overall nominal increase of 2 per cent. EnergyAustralia was the only DNSP that experienced a decline in revenue as a result of the decrease in prices charged. This had a significant, negative impact on their EBIT and EBITD figures and depressed the total figure taken across all DNSPs. Table 6.1 aggregates the performance of the DNSPs and provides a comparison with 1999/00. Appendix 7 lists each DNSPs financial performance separately, and compares it to their performance in 1999/00.

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[39] Refer to Appendix 3, Table A3.1 for average prices in 2001 dollars.

[40] The data used in the analysis has been drawn mainly from the audited Regulatory Accounts 2000/01.

Table 6.1 Aggregate financial performance of DNSPs (nominal)

Year ended 30 June		1999/00	2000/01	%
Financial performance				
Use of system charge	$m	1,728	1,754	2%
Other operating income	$m	86	89	4%
Transmission charges paid	$m	-324	-331	2%
Operating and maintenance expenses	$m	-536	-603	12%
EBITD	$m	953	910	-5%
Depreciation	$m	-373	-390	5%
EBIT	$m	580	520	-10%
Net interest expenses	$m	145	293	102%
Capital contributions	$m	133	98	-27%
Financial position				
Cash and investments	$m	268	329	23%
Property plant and equipment	$m	7,679	7,958	4%
Other assets	$m	662	665	0%
Total assets	**$m**	**8,609**	**8,952**	**4%**
Borrowings	$m	2,019	4,108	103%
Common equity	$m	5,559	3,742	-33%
Total capitalisation (borrowing + equity)	$m	7,578	7,849	4%
Profitability				
EBITDA margin on sales (EBITDA/revenue)	%	53%	49%	
EBIT margin on sales (EBIT/revenue)	%	32%	28%	
EBIT/(Total Assets - cash & investments)	%	7%	6%	
EBIT/(Borrowings + Equity)	%	8%	7%	
Income protection				
Pretax interest coverage (EBIT/Interest)	times	4.0	1.8	
EBITD/Interest coverage	times	6.6	3.1	
Total debt/EBITD	times	2.1	4.5	
Capital structure				
Gearing (total debt/total capitalisation)	%	27%	52%	

Sources: 1999/2000 Price and Service Reports and 2000/01 Regulatory Accounts using Regulatory Asset Base.

6.2 Network costs

6.2.1 Operating costs

Table 6.2 looks at the actual network operating costs incurred by the DNSPs in 2000/01, and compares it with the target operating costs allowed for in the 1999 Network Determination for 2000/01. The revenue requirements in the determination factored in efficiency targets of between 5 and 15 per cent adjusted to growth. As a whole, higher operating costs were incurred over that provided for in the 1999 Network Determination for 2000/01. There was a decline in profitability (EBIT), nevertheless, this was partly offset by an increase in revenue resulting from increased energy sales during the period.

NorthPower incurred significant operating costs in 2000/01 due to restructuring expenses incurred for the merger with Great Southern Energy and Advance Energy at the start of 2001/02 financial year.

Table 6.2 also provides a comparison with operating expense in 1996/97 in nominal terms.

Table 6.2 DNSPs' 2000/01 actual operating costs and target

$ million (nominal)	Opex allowed in 2000/01 AARR	Actual opex incurred 2000/01	Actual exceeds Determ. (%)	1996/97 opex incurred (nominal)	2000/01 actual exceeds 1996/97 (%)
EnergyAustralia	210	249	19%	230	8%
Integral Energy	160	156	-3%	147	6%
NorthPower	72	98	36%	83	17%
Great Southern Energy	48	53	10%	57	-7%
Advance Energy	44	39	-12%	39	1%
AIEW	7	8	14%	7	23%
DNSPs total	**541**	**603**	**11%**	**564**	**7%**

Source: DNSPs' regulatory accounts, 2000/2001 and 1999 Network Determination for DNSPs.

Appendix 8, Tables A8.1 and A8.2 illustrate the performance of DNSPs in operating costs per MWh distributed and operating costs per customer for 1996/97 and 2000/01 (in 2001 dollars). Typically, the regional DNSPs (Country Energy and AIEW) who supply in sparsely populated areas, have higher than average operating costs per MWh and per customer as the customer density and supply of electricity in these areas are well below their urban counterparts.

6.2.2 Interest expense, debt and recapitalisation

During 2000/01 a re-capitalisation of the DNSPs took place. Table 6.3 below lists the capital repayments made by the DNSPs to the NSW Government.

Table 6.3 Capital repayments 1 July 2000

DNSP	$ million
EnergyAustralia	1,130
Integral Energy	200
NorthPower	320
Great Southern Energy	300
Advance Energy	190
AIEW	-
Total	**2,140**

Source: 1999/2000 Annual Reports of Distributors.

The debt level of the industry increased significantly in 2000/01 due to the recapitalisation, and interest expense across the six DNSPs almost doubled to $293m from $145m in 1999/2000 (Table 6.1).

Industry–wide gearing rose from 27 per cent in 1999/2000 to 52 per cent in 2000/01 (Table 6.1). The industry debt/EBITD ratio however, indicates that all the DNSPs are able to repay all debts in less than five years.

6.3 Tax and dividends

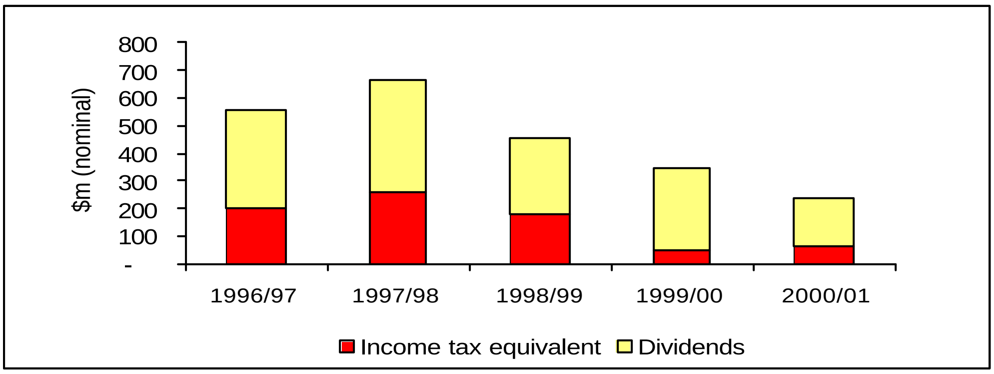
Tax and dividends paid are based on profits of the aggregate regulated and unregulated businesses of the utilities (networks, retail and other). These payments are at their lowest level since 1996/97, decreasing to $235m in 2000/01, shown in Table 6.4 and Figure 6.2.

Table 6.4 Tax and dividends – 1996/97 to 2000/01

$ million (nominal)	1996/97	1997/98	1998/99	1999/00	2000/01
Income tax equivalent	199	258	179	49	**65**
Dividends	362	412	271	295	**169**
Total	**561**	**670**	**450**	**344**	**235**
Group profit before tax	516	823	487	670	**351**
Tax & dividends as % of profit before tax	109%	81%	92%	51%	**67%**

Source: DNSPs' regulatory accounts, 2000/01.

Figure 6.2 Tax and dividends – 1996/97 to 2000/01



A breakdown of taxes and dividends paid individually by DNSPs in 2000/01 is shown in Table 6.5.

Table 6.5 Tax and dividends for each DNSP – 2000/01

$ million	Tax	Dividend
EnergyAustralia	57.8	92.5
Integral Energy	33.6	52.8
NorthPower	(5.6)	12.0
Great Southern Energy	(21.7)	10.0
Advance Energy	0.4	0.6
AIEW	0.9	1.2
Total	**65.5**	**169.1**

Source: 2000/2001 Regulatory Accounts.
Note: Taxes and dividends are paid on the consolidated profits of distributors' regulated and non-regulated businesses.

6.4 Network capital expenditure

As part of the 2000/01 regulatory accounts, the DNSPs report actual capital expenditure and projections by asset category, as shown in aggregate in Table 6.6. In 2000/01, the industry incurred capital expenditure of $595m. Of this, 22 per cent was deemed replacement capital expenditure, 57 per cent new capital expenditure and 4 per cent reliability enhancement expenditure.

The actual 2000/01 capital expenditure incurred is compared with the capital expenditure forecasts used in the 1999 Network Determination. Worley International was engaged in 1999 to review capital expenditure forecasts of the DNSPs during the regulatory period, 1999/2000 to 2003/04, the outcomes of which were incorporated in the DNSPs individual AARRs.

In aggregate, network system capital expenditure in 2000/01 is 54 per cent higher than that projected in the 1999 Network Determination.

EnergyAustralia

EnergyAustralia's capital expenditure was almost double the 1999 Network Determination projection for 2000/01. EnergyAustralia reported that it began a major network capacity augmentation program with the start of the Sydney CBD upgrade project and upgrades to 14 zone substations that supply 20 per cent of customers. Major capital works of $900 million have been planned for the next five years.[41] Table 6.6 demonstrates that the majority of the increase in expenditure is associated with growth – growth which EnergyAustralia did not foresee at the time of setting the 1999 Network Determination.

Integral Energy

Integral Energy has incurred capital expenditure of 43 per cent above the level projected in the 1999 Network Determination for 2000/01. This is largely a result of significant increases in zone substation construction and refurbishment due to high load growth in the Western Sydney area. The present trend is forecast to continue into 2001/02, to accommodate the larger than forecast growth in demand.[42]

Country Energy (NorthPower, Advance Energy, Great Southern Energy)

In aggregate, NorthPower, Great Southern Energy and Advance Energy reported capital expenditure of $166 million in 2000/01. This is 16 per cent higher than that projected in the 1999 Network Determination. Country Energy’s projections for capital expenditure over the next five years are generally comparable to the projections by Worley International.[43] This does not include however costs associated with contestability and associated information technology expenses.

Australian Inland Energy & Water (AIEW)

AIEW have performed relatively in line with the 2000/01 capital expenditure predictions in the 1999 Network Determination. They have however forecast a considerable increase in capital expenditure, with a budget for 2001/02 of $11 million and for 2002/03 $18 million. This is more than double the level presented in the determination.

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41 EnergyAustralia, *Annual Report 2000/01*, p 6 and p 12.

42 Integral Energy, *Network Price and Service Report,* November 2001, p 14.

43 Country Energy, *Electricity Network Services Pricing and Service Information Package,* November 2001, p 22.

AIEW's 2000/01 Price and Service Report indicates that the major network capital projects over the next five years will be related to new mining developments, however the scope of work, timing and overall cost is dependent on feasibility studies currently being undertaken.[44]

6.4.1 Capital contributions

Capital contributions are up-front payments by customers to fund assets. The cost of these assets are excluded from the DNSPs regulatory asset base, however, the DNSPs take ownership of the assets and recover the maintenance costs through network tariffs. The Tribunal has issued a new determination for DNSPs on capital contributions,[45] which takes effect from 1 July 2002.

The DNSPs received $98 million in capital contributions from their network customers in 2000/01. This represents a decrease from $141 million in 1999/2000, mainly attributable to an exceptional year for EnergyAustralia where $66 million was collected. In comparison, total capital contributions for 1998/99 were $75 million.

44 AIEW, *Network Price and Service Report,* November 2001, p 32.

45 IPART, *Capital Contributions and Repayments For Connections To Electricity Distribution Networks in New South Wales,* April 2002.

Table 6.6 Network capital expenditure actual and projections 2000-2004[1]

$ million (nominal)	2000/01 EnergyAust	2000/01 Integral	2000/01 AIEW	2000/01 CE	2000/01 Total	DNSPs projection 2001/02	DNSPs projection 2002/03	DNSPs projection 2003/04
Actual Expenditure								
Net system capital expenditure								
Renewal	67	31	0	31	**129**	190	209	214
Reliability	9	1	0	13	**24**	23	13	12
Growth	183	65	2	91	**341**	353	386	383
Non system capital expenditure	48	22	1	30	**101**	100	87	83
Total actual capital expenditure	**307**	**119**	**4**	**166**	**595**	**666**	**695**	**692**
Forecast in 1999 Network Determination	**2000/01 EnergyAust**	**2000/01 Integral**	**2000/01 AIEW**	**2000/01 CE**	**2000/01 Total**			
Net system capital expenditure								
Renewal	54	34	0	27	**115**			
Reliability	11	1	1	20	**33**			
Growth	55	28	1	59	**143**			
Non system capital expenditure	37	20	1	37	**94**			
Total capex projections in Determination	**156**	**83**	**3**	**142**	**386**	**379**	**407**	**416**
DNSPs' capex exceeds Determination projections by	**96%**	**43%**	**6%**	**16%**	**54%**	**76%**	**71%**	**67%**

Note 1: capital expenditure excludes customer capital contributions.
Source: DNSP regulatory accounts 2000/01.

APPENDIX 1 PPM INFORMATION DISCLOSURE REQUIREMENTS

Extract from the Pricing Principles and Methodologies for Prescribed Electricity Distribution Services (PPM)

[Schedule 3]

1. A DNSP's Price and Service Report will provide information on customer class price levels and structures, service standards, underlying costs, price derivation methods and rationale and medium term price and service strategies in order to allow:

   (a) current and potential users to understand the basis for prices and to take account of prices and service standards in their consumption, investment and location decisions

   (b) interested parties to better assess the range of economic opportunities for meeting user requirements, including through services associated with embedded generation, demand management and other options that may reduce users' costs and lead to more efficient outcomes.

2. A DNSP's Price and Service Report will clearly document, describe and explain:

   (a) the level and structure of prices

   (b) the standard of service provided

   (c) the methodology used to derive prices and their cost basis, and

   (d) medium term directions for prices and standards of service.

3. DNSPs are required to address the following broad questions in their Price and Service Reports.

   (a) Are the prices subsidy free? The test for this is whether the prices for individual customers are between the stand-alone and incremental costs of supply. DNSPs must demonstrate that prices lie within this range and explain how they determine the range.

   (b) Do prices have regard to an acceptable cost of supply model? The cost modelling referred to in the development of the Proposed Prices should be disclosed. This should include an explanation of the basis for the allocation of TUOS charges to distribution network prices.

   (c) Do prices reflect the future need for augmentation of the network? Prices may be expected to be higher in locations where the system is closer to capacity. DNSPs should report on the significance of locational congestion and related capex requirements across their network. DNSPs should explain their decision to use or avoid locational price signals in the context of the congestion costs they face.

   (d) Does the structure of prices reflect marginal economic costs? DNSPs should explain the extent to which prices signal marginal costs and the basis for their decisions on the weights applied to the fixed and variable price components.

   (e) Are the prices consistent with allowed revenues? DNSPs should report the level of their overs and unders account and explain the means by which they intend to maintain consistency between prices and allowed revenues.

(f) What is the impact of the DNSP's price strategies on price stability in the short term? The impact of price changes introduced for the current year on representative user profiles (to be provided by the Tribunal) should be described and the reasons for the changes explained.

(g) What is the impact of the DNSP's price strategies on price stability in the medium term? The DNSP's medium term price strategies and the expected impact on price outcomes for customer classes should be described. DNSPs should indicate whether the strategies are likely to create material adjustment costs for some users and if so the management options available to users and transitional measures that the DNSP may adopt.

(h) What level of service performance is provided for the prices charged? DNSPs should report and explain the level of reliability and quality of service they provide to localities across their service areas. Variations in service levels should be explained and expected medium term trends described.

4. In responding to the requirements of paragraphs 2 and 3, the information disclosed must include, but is not limited to:

(a) cost information provided in a form consistent with the Tribunal's pro forma information template

(b) the basis for allocating shared costs

(c) an explanation and quantification of the methodology used to calculate current prices from the costs identified under (a)

(d) unders and overs account balance, tolerance margin and action plan

(e) forecast demand and load factors used in calculating current prices

(f) a summary of asset management and development plans and their relationship to prices

(g) data on performance measured against key service standard indicators; and

(h) an outline of future strategies for pricing and standards of service.

APPENDIX 2 COST ALLOCATION METHODOLOGIES

Table A2.1 Cost allocation, customer classification and tariff structure approaches

DNSP	Cost Allocation	Customer Classification	Tariff Structures
Energy Australia	• Allocates AARR to asset categories or 'cost pools' • Allocates cost pools to customer classes based on usage of network assets	• voltage level • type of meter or type of usage • location (for large customers)	• fixed network access charge plus • energy charge (can be TOU*) plus in some instances • demand charge[46] (TOU) plus in some instances • capacity charge (TOU)
Integral Energy	• Allocates AARR (costs) to asset classes (network components) • The 'cost pools' are determined using customer classifications • Convert 'cost pools' to variable usage based prices (kWhs, kVA) and tariff rates	• voltage level • location • load shape • type of meter	• fixed network access charge plus • energy charge (can be TOU) plus in some instances • demand charge (can be TOU) plus in some instances • controlled load (mainly domestic customers)
Country Energy	• AARR allocated as a cost to customers based on their use of the distribution system • Conversion of cost pools to usage-based network prices based on customer classification	• voltage level • location • load shape • type of meter	• fixed access charge plus • energy charge (network usage) plus in some instances • demand time of use and in some instances • controlled load
Australian Inland Energy & Water	• Allocates AARR to assets within classes of distribution services • Then allocates costs to the nine cost pools • Allocates costs by kWh to each tariff in direct kWh ratio[47]	• voltage level • location and • load shape	• fixed component plus • energy component plus in some instances • time of use component (where metering permits) plus in some instances • demand component (where metering permits)

46 All DNSPs generally apply a demand charge in $/kVA.

47 AIEW, *Network Price and Service Report November 2001*, p 17, states that the AARR has not been apportioned amongst the various asset categories of the network using a building block method, but rather derived from former franchise tariffs discounted by energy costs and adjusted within side constraints.

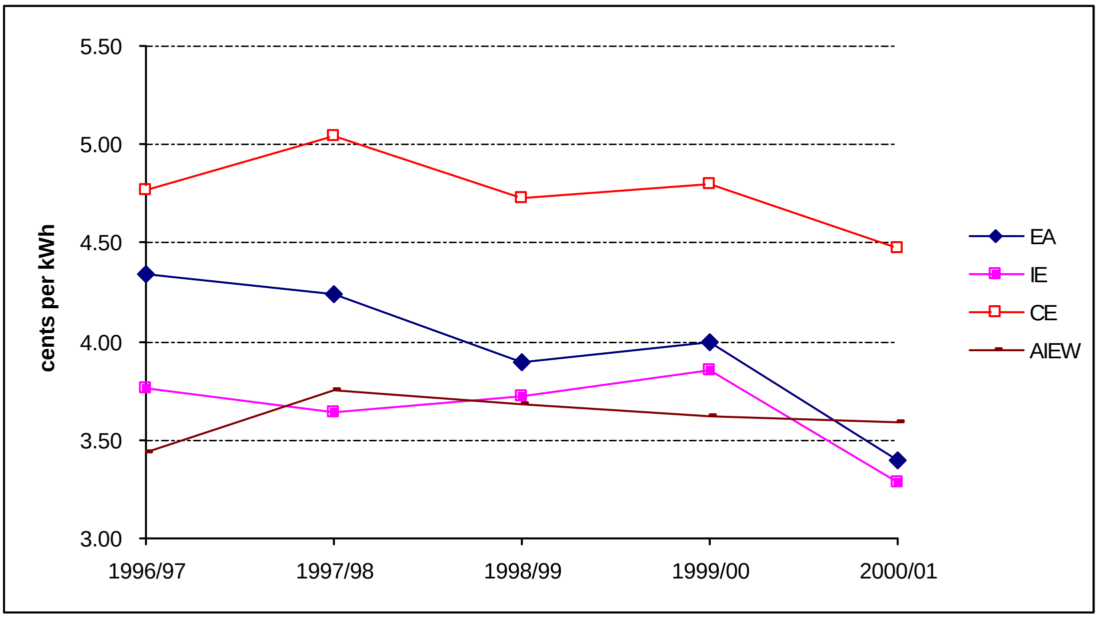
APPENDIX 3 AVERAGE PRICES ADJUSTED FOR INFLATION

Table A3.1 Average network prices (2001 dollars, cents per kWh)

DNSP	1996/1997	1997/1998	1998/1999	1999/2000	2000/2001
EnergyAustralia					
Residential	np	np	np	5.13	3.91
Non residential	np	np	np	3.36	3.09
All customers	4.35	4.24	3.89	3.99	3.40
Integral Energy					
Residential	5.19	5.24	5.18	4.68	4.40
Non residential	2.88	2.75	2.86	3.23	2.53
All customers	3.76	3.64	3.72	3.85	3.29
Country Energy[2]					
Residential (inc rural)	np	np	np	4.72	4.67
Non residential	np	np	np	4.86	4.31
All customers	4.76	5.05	4.73	4.80	4.47
AIEW					
Residential (inc rural)	3.52	3.85	3.97	4.02	3.84
Non residential	3.41	3.72	3.56	3.47	3.50
All customers	3.44	3.75	3.68	3.62	3.59

Notes
1 the average price is calculated as: energy delivered to customers / revenue received in that year adjusted by the change in CPI.
2 Country Energy figures are the addition of revenues and MWh of the three separate entities as represented in their 2000/01 Price and Service Information Package.
Source: Regulatory Accounts.

Figure A3.1 Average network prices for DNSPs (2001 dollars)



APPENDIX 4 ASSUMPTIONS IN TYPICAL BILL CALCULATIONS

Table A4.1 Assumptions in typical bill calculations

	Cons kWh/pa	Load Factor	Demand kW	Demand kVA	Energy Consumption peak	shoulder	off-peak
DOMESTIC							
Domestic	3,500	na	na	na	na	na	na
Domestic With Controlled Load Hot Water	7,500	na	na	na	na	na	40%
Rural	12,000	na	na	na	na	na	na
GENERAL SUPPLY							
Business non-TOU, 18MWh consumption pa	18,000	na	na	na	na	na	na
Business non-TOU, 60MWh consumption pa	60,000	na	na	na	na	na	na
LOW VOLTAGE TOU							
Business ToU, LF 30%	262,800	30%	100	na	23.8%	47.7%	28.5%
Business ToU, LF 50%	438,000	50%	100	na	17.8%	35.7%	46.5%
LOW VOLTAGE DEMAND (LVD)							
LV Demand TOU (KVA), LF 20%	876,000	20%	500	513	26.7%	53.5%	19.80%
LV Demand TOU (KVA), LF 40%	1,752,000	40%	500	556	21.4%	42.9%	35.70%
LV Demand TOU (KVA), LF 60%	2,628,000	60%	500	581	17.8%	35.7%	46.50%
HIGH VOLTAGE DEMAND (LVD)							
HV Demand TOU, LF 40%	8,760,000	40%	2,500	2,472	19.8%	39.6%	40.60%
HV Demand TOU, LF 60%	13,140,000	60%	2,500	2,583	17.7%	35.4%	46.90%
HV Demand TOU, LF 80%	17,520,000	80%	2,500	2,611	14.6%	29.3%	56.10%

na: not applicable.

APPENDIX 5 TYPICAL BILLS ADJUSTED FOR INFLATION AND GST[48]

Table A5.1 EnergyAustralia typical bills (2001 dollars, excluding GST)

Customer class	1999/00	2000/01	2001/02	2002/03	%
Domestic					
Domestic	215	184	164	164	-23
Domestic with controlled load hot water	297	252	218	218	-26
Rural Domestic	na	na	na	na	na
General supply					
Business non-TOU, 18 MWh cons. pa	946	839	756	760	-20
Business non-TOU, 60 MWh cons. pa	2,860	2,531	2,265	2,260	-21
Low Voltage TOU					
Business TOU with 30% lf.	11,255	9,998	9,397	na	-17
Business TOU with 60% lf.	16,573	14,966	13,770	na	-17
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	60,120	44,831	38,616	na	-36
LVD TOU (kVA), with 40% lf.	68,978	55,998	48,981	na	-29
LVD TOU (kVA), with 60% lf.	74,299	64,963	57,407	na	-23
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	252,587	208,022	187,543	na	-26
HVD TOU (kVA), with 60% lf.	279,485	240,275	218,209	na	-22
HVD TOU (kVA), with 80% lf.	288,698	262,969	240,081	na	-17

Table A5.2 Integral Energy typical bills (2001 dollars, excluding GST)

Customer class	1999/00	2000/01	2001/02	2002/03	%
Domestic					
Domestic	230	209	217	220	-5
Domestic with controlled load hot water	303	275	279	285	-6
Rural Domestic	636	600	611	na	-4
General supply					
Business non-TOU, 18 MWh cons. pa	872	816	807	802	-8
Business non-TOU, 60 MWh cons. pa	2,786	2,609	2,576	2,533	-9
Low Voltage TOU					
Business TOU with 30% lf.	10,518	9,921	10,625	na	1
Business TOU with 60% lf.	14,695	13,860	14,832	na	1
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	49,443	46,635	47,120	na	-5
LVD TOU (kVA), with 40% lf.	58,721	55,386	56,417	na	-4
LVD TOU (kVA), with 60% lf.	64,859	61,175	62,535	na	-4
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	209,679	197,769	204,756	na	-2
HVD TOU (kVA), with 60% lf.	241,084	227,390	236,741	na	-2
HVD TOU (kVA), with 80% lf.	255,524	241,010	251,012	na	-2

48 In all tables, for each tariff, the percentage change has been calculated between the earliest data presented in the table to the last year of data presented in the table. Inflation rate of 3 per cent assumed for 01/02 and 02/03. na means not available, lf means load factor.

Table A5.3 AIEW typical bills (2001 dollars, excluding GST)

Customer class	1999/00	2000/01	2001/02	2002/03	%
Domestic					
Domestic	201	173	176	192	-5
Domestic with controlled load hot water	277	242	248	271	-2
Rural Domestic	789	811	811	na	3
General supply					
Business non-TOU, 18 MWh cons.pa	1,214	1,026	1,134	1,237	2
Business non-TOU, 60 MWh cons.pa	3,868	3,252	3,613	3,940	2
Low Voltage TOU					
Business TOU with 30% lf.	24,097	24,774	24,740	na	3
Business TOU with 60% lf.	16,941	17,420	17,398	na	3
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	87,324	89,772	89,704	na	3
LVD TOU (kVA), with 40% lf.	117,006	120,296	120,185	na	3
LVD TOU (kVA), with 60% lf.	140,694	144,663	144,517	na	3
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	346,929	356,708	355,879	na	3
HVD TOU (kVA), with 60% lf.	417,418	429,249	428,023	na	3
HVD TOU (kVA), with 80% lf.	467,754	481,143	479,438	na	2

Table A5.4 Country Energy typical bills (2001 dollars, excluding GST)

Customer class	1999/00[1]	2000/01	2001/02	2002/03	%
Domestic					
Domestic	na	244	242	257	5
Domestic with controlled load hot water	na	333	330	341	2
Rural Domestic	na	849	841	833	-2
General supply					
Business non-TOU, 18 MWh cons. pa	na	1,224	1,212	1,247	2
Business non-TOU, 60 MWh cons. pa	na	3,927	3,889	3,902	-1
Low Voltage TOU					
Business TOU with 30% lf.	na	11,261	11,140	na	-1
Business TOU with 60% lf.	na	18,397	18,199	na	-1
Low Voltage Demand (LVD)					
LVD TOU (kVA), with 20% lf.	na	49,277	48,746	na	-1
LVD TOU (kVA), with 40% lf.	na	97,587	96,535	na	-1
LVD TOU (kVA), with 60% lf.	na	145,896	144,323	na	-1
High Voltage Demand (HVD)					
HVD TOU (kVA), with 40% lf.	na	195,109	193,007	na	-1
HVD TOU (kVA), with 60% lf.	na	291,827	288,683	na	-1
HVD TOU (kVA), with 80% lf.	na	388,545	384,357	na	-1

Note 1: Country Energy was formed on 1 July 2001.

APPENDIX 6 NETWORK RELIABILITY SERVICE STANDARDS[49]

Table A6.1 2000/01 Regional SAIDI (MS) Performance and Objectives[1 2]

Duration (min) of unplanned interruptions per customer (excluding major natural events)			
Region	**DNSP**	**Objective**	**Actual**
GSE - CBD –underground	Great Southern Energy	15	4
Balranald area	AIEW	30	508
Lake Macquarie	EnergyAustralia	30	74
Sydney (CBD & several inner suburbs)	EnergyAustralia	30	218
Newcastle	EnergyAustralia	40	96
GSE - Urban – General	Great Southern Energy	45	52
Sydney Eastern suburbs	EnergyAustralia	50	102
Parramatta	Integral Energy	50	89
Camden, Campbelltown	Integral Energy	60	48
NP - Urban	NorthPower	80	90
Wentworth supply	AIEW	90	106
Baulkham Hills, Blacktown	Integral Energy	90	70
Fairfield, Holroyd	Integral Energy	90	98
Euston	AIEW	100	275
Moulamein-Koraleigh	AIEW	100	567
Southern suburbs of Sydney	EnergyAustralia	110	42
Liverpool	Integral Energy	110	66
Northern suburbs of Sydney	EnergyAustralia	120	93
Maitland	EnergyAustralia	130	170
Penrith/Blue Mountains	Integral Energy	130	62
Wollongong (Bellambi)	Integral Energy	140	95
AE - Urban General	Advance Energy	150	144
Broken Hill (& immediate rural)	AIEW	160	165
Blue Mountains (upper)	Integral Energy	160	182
GSE - Rural – High or Medium Density	Great Southern Energy	180	332
NP - Rural	NorthPower	180	192
Central Coast	EnergyAustralia	200	185
Shellharbour, Kiama, Wollongong	Integral Energy	210	132
GSE - Rural – Low Density	Great Southern Energy	220	583
Menindee	AIEW	230	303
AE - Rural General	Advance Energy	250	216
Muswellbrook	EnergyAustralia	270	222
Greater Lithgow, Rylstone	Integral Energy	270	185
Hawkesbury	Integral Energy	270	252
Shoalhaven	Integral Energy	300	110
Wollondilly, Wingecarribee	Integral Energy	310	201
Tibooburra line	AIEW	320	2082
Wilcannia/White Cliffs	AIEW	340	279
AE - Rural Remote	Advance Energy	350	376
Gol Gol – Monak	AIEW	380	49
NP – Remote	NorthPower	500	577

Note 1: EnergyAustralia have not publicly set an objective, however have provided figures which indicate what may be expected.

Note 2: Integral Energy's objectives are based on the RAW measure ie. include planned interruptions and major natural events. The actual performance in this table is based on unplanned interruptions only.

49 Source: *2000/01 NSW Electricity Network Performance Report, May 2002*, MEU. MS: Modified Standard measure excludes major natural events and planned interruptions.

Table A6.2 2000/01 Regional SAIFI (MS) Performance and Objectives[1 2]

Number of unplanned interruptions per customer (excluding major natural events)			
Region	**DNSP**	**Objective**	**Actual**
GSE - CBD –Underground	Great Southern Energy	0.3	0.1
GSE - Urban – General	Great Southern Energy	0.6	0.6
Balranald area	AIEW	1	2.3
Moulamein-Koraleigh	AIEW	1	3.1
Camden, Campbelltown	Integral Energy	1	0.7
Fairfield, Holroyd	Integral Energy	1	1.0
Euston	AIEW	1.5	1.8
Wentworth supply	AIEW	1.5	1.5
NP - Urban	NorthPower	1.5	1.2
GSE - Rural – High or Medium Density	Great Southern Energy	1.9	2.6
Baulkham Hills, Blacktown	Integral Energy	2	1.0
Liverpool	Integral Energy	2	0.9
Parramatta	Integral Energy	2	0.9
Penrith/Blue Mountains	Integral Energy	2	0.9
GSE - Rural – Low Density	Great Southern Energy	2.2	4.8
Gol Gol – Monak	AIEW	2.5	0.4
Tibooburra line	AIEW	2.5	8.5
NP - Rural	NorthPower	2.5	1.3
Broken Hill (& immediate rural)	AIEW	3	3.0
Hawkesbury	Integral Energy	3	2.1
Shoalhaven	Integral Energy	3	1.3
Wollongong (Bellambi)	Integral Energy	3	1.5
Blue Mountains (upper)	Integral Energy	4	2.5
Greater Lithgow, Rylstone	Integral Energy	4	1.7
Wollondilly, Wingecarribee	Integral Energy	4	2.0
Shellharbour, Kiama, Wollongong	Integral Energy	5	1.6
NP – Remote	NorthPower	5	3.0
Menindee	AIEW	6	2.4
Lake Macquarie	EnergyAustralia	6	1.1
Sydney Eastern suburbs	EnergyAustralia	6	0.6
Sydney (CBD & several inner suburbs)	EnergyAustralia	6	0.6
Wilcannia/White Cliffs	AIEW	7.5	3.9
AE - Urban General	Advance Energy	10	1.5
Northern suburbs of Sydney	EnergyAustralia	10	1.6
Southern suburbs of Sydney	EnergyAustralia	10	0.6
Central Coast	EnergyAustralia	12	2.5
AE - Rural General	Advance Energy	15	2.0
Maitland	EnergyAustralia	15	2.6
AE - Rural Remote	Advance Energy	20	3.2
Muswellbrook	EnergyAustralia	20	2.5
Newcastle	EnergyAustralia	20	2.6

Note 1: EnergyAustralia have not publicly set an objective, however have provided figures which indicate what may be expected.

Note 2: Integral Energy's objectives are based on the RAW measure, ie include planned interruptions and major natural events. The actual performance in this table is based on unplanned interruptions only.

Figure A6.1 SAIDI (MS) – average annual duration of interruptions per customer

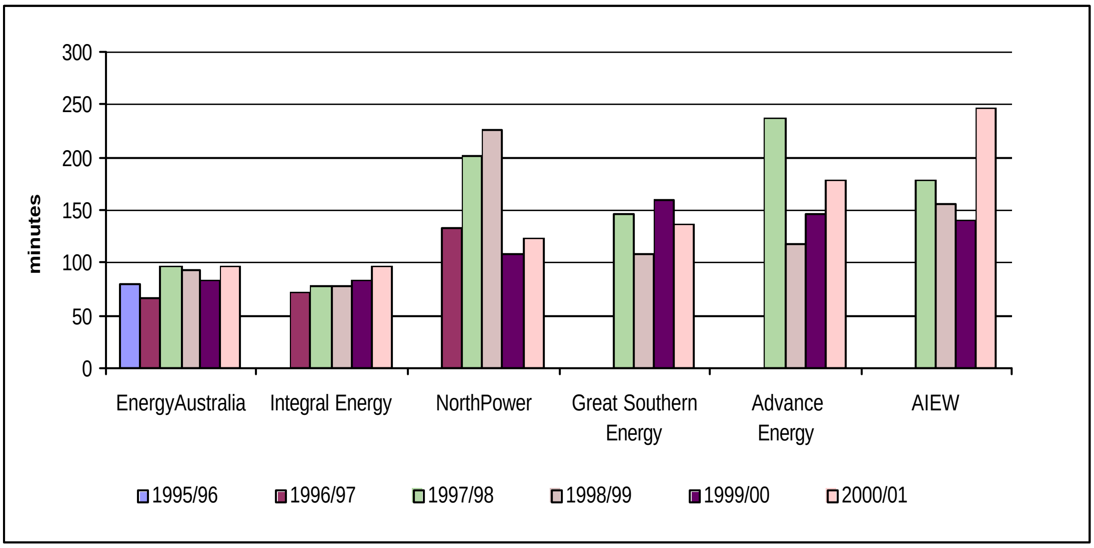


Figure A6.2 SAIFI (MS) – average number of interruptions per customer pa

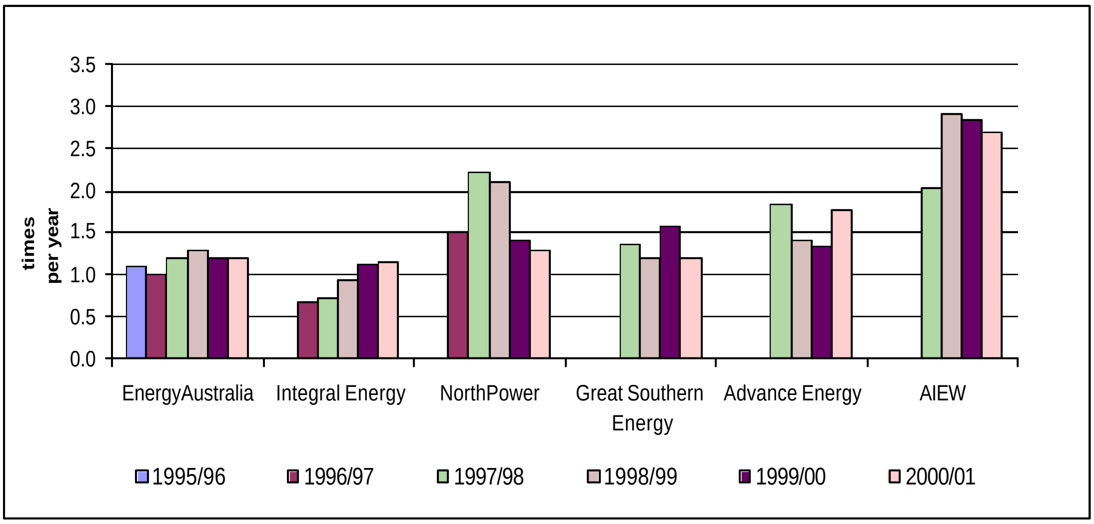
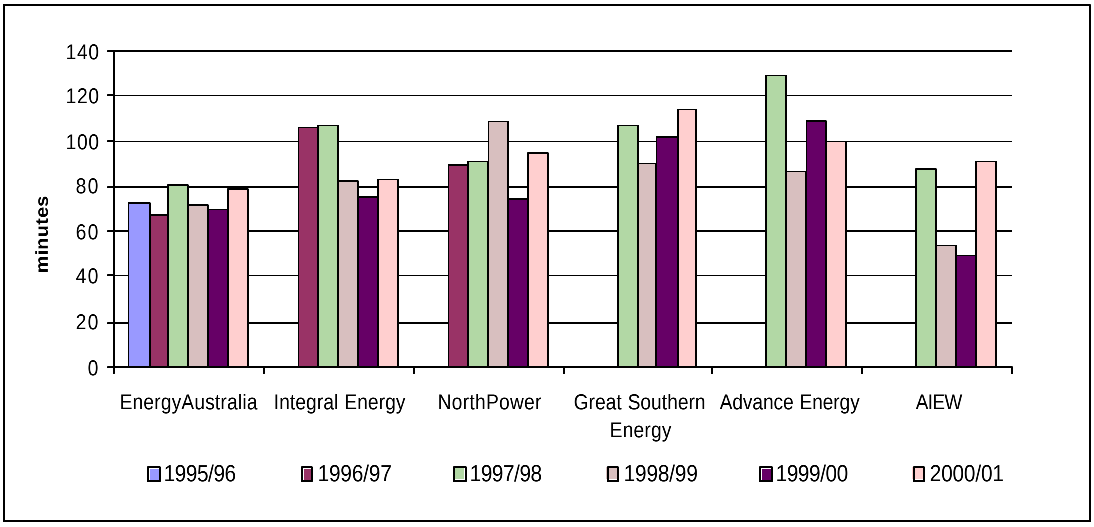


Figure A6.3 CAIDI (MS) – average duration of each interruption



APPENDIX 7 FINANCIAL PERFORMANCE OF DNSPS [50]

Table A7.1 EnergyAustralia financial performance

Year ended 30 June ($ nominal)		1999/00	2000/01	%
Financial performance				
Use of system charge	$m	833	816	-2%
Other operating income	$m	25	26	4%
Transmission charges paid	$m	(142)	(137)	-4%
Operating and maintenance expenses	$m	(209)	(249)	19%
EBITD	$m	506	456	-10%
Depreciation	$m	(182)	(186)	2%
EBIT	$m	324	270	-17%
Net interest expenses	$m	77	153	99%
Capital contributions	$m	63	35	-44%
Financial position				
Cash and investments	$m	126	73	-42%
Property plant and equipment	$m	4,027	4,031	0%
Other Assets	$m	344	352	2%
Total assets	$m	4,497	4,456	-1%
Borrowings	$m	1,044	2,140	105%
Common equity	$m	2,759	1,682	-39%
Total capitalisation (borrowing + equity)	$m	3,803	3,822	0%
Profitability				
EBITDA margin on sales (EBITDA/revenue)	%	59%	54%	
EBIT margin on sales (EBIT/revenue)	%	38%	32%	
NPAT/Shareholders Funds	%	7%	6%	
EBIT/(Total Assets - cash & investments)	%	7%	6%	
EBIT/(Borrowings + Equity)	%	9%	7%	
Income protection				
Pretax interest coverage (EBIT/Interest)	times	4.2	1.8	
S&P indicative ratings		**AA**	**BBB**	
EBITD/Interest coverage	times	6.6	3.0	
Total debt/EBITD	times	2.1	4.7	
Capital structure				
Gearing (total debt/total capitalisation)	%	27%	56%	
S&P indicative ratings		**AA**	**BB**	

50 Information is sourced from the Regulatory Accounts using the Regulatory Asset Base (RAB). Columns may not add due to rounding.

Table A7.2 Integral Energy financial performance

Year ended 30 June ($ nominal)		1999/00	2000/01	%
Financial performance				
Use of system charge	$m	459	474	3%
Other operating income	$m	32	30	-6%
Transmission charges paid	$m	(88)	(95)	8%
Operating and maintenance expenses	$m	(160)	(156)	-3%
EBITD	$m	243	253	4%
Depreciation	$m	(94)	(100)	6%
EBIT	$m	149	153	3%
Net interest expenses	$m	59	72	22%
Capital contributions	$m	25	30	20%
Financial position				
Cash and investments	$m	31	195	528%
Property plant and equipment	$m	1,800	1,869	4%
Other Assets	$m	150	86	-42%
Total assets	$m	1,981	2,150	9%
Borrowings	$m	701	908	30%
Common equity	$m	1,130	1,055	-7%
Total capitalisation (borrowing + equity)	$m	1,831	1,963	7%
Profitability				
EBITDA margin on sales (EBITDA/revenue)	%	50%	50%	
EBIT margin on sales (EBIT/revenue)	%	30%	30%	
NPAT/Shareholders Funds	%	8%	7%	
EBIT/(Total Assets - cash & investments)	%	8%	8%	
EBIT/(Borrowings + Equity)	%	8%	8%	
Income protection				
Pretax interest coverage (EBIT/Interest)	times	2.6	2.1	
S&P indicative ratings		**BBB**	**BBB**	
EBITD/Interest coverage	times	4.2	3.5	
Total debt/EBITD	times	2.9	3.6	
Capital structure				
Gearing (total debt/total capitalisation)	%	38%	46%	
S&P indicative ratings		**AA**	**BB**	

Table A7.3 AIEW financial performance

Year ended 30 June ($ nominal)		1999/00	2000/01	%
Financial performance				
Use of system charge	$m	14	15	6%
Other operating income	$m	4	4	9%
Transmission charges paid	$m	(5)	(5)	-6%
Operating and maintenance expenses	$m	(7)	(8)	15%
EBITD	$m	7	7	-7%
Depreciation	$m	(3)	(3)	-4%
EBIT	$m	4	4	-9%
Net interest expenses	$m	(1)	(1)	10%
Capital contributions	$m	1	1	-31%
Financial position				
Cash and investments	$m	18	17	-5%
Property plant and equipment	$m	53	62	17%
Other assets	$m	6	6	-7%
Total assets	$m	77	85	10%
Borrowings	$m	-	-	
Common equity	$m	68	74	9%
Total capitalisation (borrowing + equity)	$m	68	74	9%
Profitability				
EBITDA margin on sales (EBITDA/revenue)	%	35%	34%	
EBIT margin on sales (EBIT/revenue)	%	22%	19%	
NPAT/Shareholders Funds	%	7%	5%	
EBIT/(Total Assets - cash & investments)	%	7%	5%	
EBIT/(Borrowings + Equity)	%	6%	5%	
Income protection[1]				
Pretax interest coverage (EBIT/Interest)	times	na	na	
S&P indicative ratings		na	na	
EBITD/Interest coverage	times	na	na	
Total debt/EBITD	times	na	na	
Capital structure				
Gearing (total debt/total capitalisation)	%	na	na	
S&P indicative ratings		na	na	

Note 1: AIEW does not hold any debt nor pay any interest.

Table A7.4 Advance Energy financial performance

Year ended 30 June ($ nominal)		1999/00	2000/01	%
Financial performance				
Use of system charge	$m	88	96	9%
Other operating income	$m	6	17	185%
Transmission charges paid	$m	(20)	(20)	1%
Operating and maintenance expenses	$m	(36)	(39)	9%
EBITD	$m	39	53	37%
Depreciation	$m	(19)	(21)	10%
EBIT	$m	19	33	71%
Net interest expenses	$m	1	17	1594%
Capital contributions	$m	8	6	-29%
Financial position				
Cash and investments	$m	0	3	na
Property plant and equipment	$m	336	371	11%
Other assets	$m	24	52	117%
Total assets	$m	360	426	18%
Borrowings	$m	45	247	450%
Common equity	$m	285	117	-59%
Total capitalisation (borrowing + equity)	$m	330	365	11%
Profitability				
EBITDA margin on sales (EBITDA/revenue)	%	41%	47%	
EBIT margin on sales (EBIT/revenue)	%	21%	29%	
NPAT/Shareholders Funds	%	6%	12%	
EBIT/(Total Assets - cash & investments)	%	5%	8%	
EBIT/(Borrowings + Equity)	%	6%	9%	
Income protection				
Pretax interest coverage (EBIT/Interest)	times	14.4	1.9	
S&P indicative ratings		**AA**	**BBB**	
EBITD/Interest coverage	times	24.6	3.2	
Total debt/EBITD	times	1.2	4.6	
Capital structure				
Gearing (total debt/total capitalisation)	%	14%	68%	
S&P indicative ratings		**AA**	**BB**	

Table A7.5 Great Southern Energy financial performance

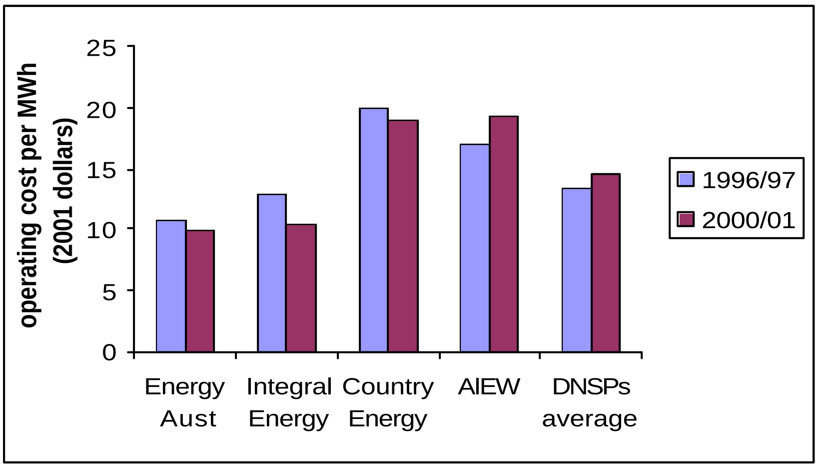
Year ended 30 June ($ nominal)		1999/00	2000/01	%
Financial performance				
Use of system charge	$m	130	137	6%
Other operating income	$m	5	4	-26%
Transmission charges paid	$m	(27)	(29)	6%
Operating and maintenance expenses	$m	(50)	(53)	6%
EBITD	$m	59	59	1%
Depreciation	$m	(29)	(32)	10%
EBIT	$m	30	27	-8%
Net interest expenses	$m	0	24	na
Capital contributions	$m	13	13	-3%
Financial position				
Cash and investments	$m	46	26	-44%
Property plant and equipment	$m	516	600	16%
Other assets	$m	64	100	56%
Total assets	$m	626	725	16%
Borrowings	$m	56	358	540%
Common equity	$m	521	260	-50%
Total capitalisation (borrowing + equity)	$m	577	619	7%
Profitability				
EBITDA margin on sales (EBITDA/revenue)	%	43%	42%	
EBIT margin on sales (EBIT/revenue)	%	22%	20%	
NPAT/Shareholders Funds	%	6%	4%	
EBIT/(Total Assets - cash & investments)	%	5%	4%	
EBIT/(Borrowings + Equity)	%	5%	4%	
Income protection				
Pretax interest coverage (EBIT/Interest)	times	113.8	1.2	
S&P indicative ratings		**>AA**	**<BB**	
EBITD/Interest coverage	times	226.0	2.5	
Total debt/EBITD	times	1.0	6.0	
Capital structure				
Gearing (total debt/total capitalisation)	%	10%	58%	
S&P indicative ratings		**AA**	**BB**	

Table A7.6 NorthPower financial performance

Year ended 30 June ($ nominal)		1999/00	2000/01	%
Financial performance				
Use of system charge	$m	203	217	7%
Other operating income	$m	13	8	-41%
Transmission charges paid	$m	(43)	(45)	6%
Operating and maintenance expenses	$m	(74)	(98)	32%
EBITD	$m	100	81	-19%
Depreciation	$m	(46)	(49)	7%
EBIT	$m	54	32	-40%
Net interest expenses	$m	9	29	218%
Capital contributions	$m	23	14	-41%
Financial position				
Cash and investments	$m	47	16	-66%
Property plant and equipment	$m	947	1,025	8%
Other Assets	$m	74	69	-6%
Total assets	$m	1,068	1,110	4%
Borrowings	$m	173	454	163%
Common equity	$m	796	553	-31%
Total capitalisation (borrowing + equity)	$m	969	1,007	4%
Profitability				
EBITDA margin on sales (EBITDA/revenue)	%	46%	36%	
EBIT margin on sales (EBIT/revenue)	%	25%	14%	
NPAT/Shareholders Funds	%	7%	2%	
EBIT/(Total Assets - cash & investments)	%	5%	3%	
EBIT/(Borrowings + Equity)	%	6%	3%	
Income protection				
Pretax interest coverage (EBIT/Interest)	times	6.1	1.1	
S&P indicative ratings		**AA**	**<BB**	
EBITD/Interest coverage	times	11.3	2.8	
Total debt/EBITD	times	1.7	5.6	
Capital structure				
Gearing (total debt/total capitalisation)	%	18%	45%	
S&P indicative ratings		**AA**	**BB**	

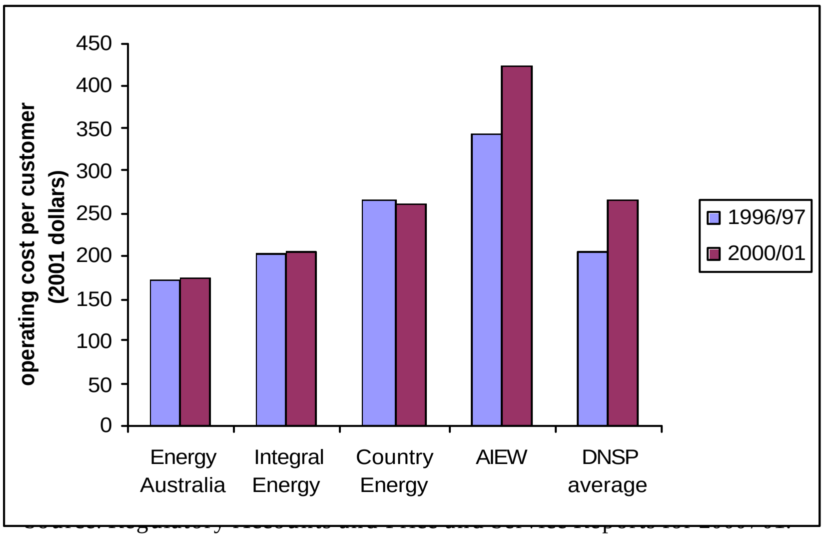
APPENDIX 8 OPERATING COST ANALYSIS ADJUSTED FOR INFLATION[51]

Figure A8.1 Operating cost per MWh



Source: Regulatory Accounts and Price and Service Reports for 2000/01.

Figure A8.2 Operating cost per customer



Source: Regulatory Accounts and Price and Service Reports for 2000/01.

51 The ratios for Country Energy are notionally derived by aggregating its constituent DNSPs' operating data in 1996/97 and 2000/01.

ABBREVIATIONS

1999 Network Determination	IPART, *Regulation of New South Wales Electricity Distribution Networks: Determination and Rules under the National Electricity Code*, December 1999
ACCC	Australian Competition and Consumer Commission
AE	Advance Energy
AIEW	Australian Inland Energy & Water
CAIDI	Customer Average Interruption Duration Index
CE	Country Energy
Code	National Electricity Code (also represented as NEC)
CPI	Consumer Price Index
CRNP	Cost Reflective Network Pricing
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System Charge
EDL	Electricity Distributor Levy
EA	EnergyAustralia
GSE	Great Southern Energy
GWh	Gigawatt hour = 1,000,000 kilowatt hours or 1,000 MWh
HV	High Voltage – normally refers to voltages greater than 22kV
IE	Integral Energy
IPART	Independent Pricing and Regulatory Tribunal (also represented as the Tribunal)
kV	kV = 1,000 volts
kVA	kVA = 1,000 volt-amperes
kW	Kilowatt = 1,000 watts
KWh	Kilowatt hours
LF	Load factor (average load divided by the peak load)
LV	Low voltage, normally refers to 240/415 volt distribution for customer installations
MEU	Ministry of Energy and Utilities

MEU Report	*2000/01 NSW Electricity Network Performance Report*, Ministry of Energy & Utilities, May 2002
MS	Modified Standard measure which excludes major natural events and planned interruptions
MW	Megawatt
MWh	Megawatt hour = 1,000 kilowatt hours
NEC	National Electricity Code (also represented as the Code)
NECA	National Electricity Code Authority
NEMMCO	National Electricity Market Management Company
NP	NorthPower
NUOS	Network Use of System Charge (NUOS = TUOS + DUOS)
PPM	IPART, *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services,* March 2001
RAB	Regulatory Asset Base
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TLF	Transmission Loss Factor
TNSP	Transmission Network Service Provider
TOU	Time of Use
Tribunal	Independent Pricing and Regulatory Tribunal (also represented as IPART)
TUOS	Transmission Use of System Charge