5 ELECTRICITY DISTRIBUTION

Jessica Shapiro (Fairfax)

Most electricity customers are located a long distance from generators. The electricity supply chain therefore requires networks to transport power from generators to customers. Chapter 4 provides a survey of high-voltage transmission networks that move electricity over long distances from generators to distribution networks in metropolitan and regional areas. This chapter focuses on the lower voltage distribution networks that move electricity from points along the transmission line to customers in cities, towns and regional communities.

5 ELECTRICITY DISTRIBUTION

This chapter considers:

- the role of the electricity distribution network sector
- the structure of the sector, including industry participants and ownership changes over time
- the economic regulation of the distribution network sector
- financial outcomes, including revenues and returns on assets
- new investment in distribution networks
- quality of service, including reliability and customer service performance.

There are a number of possible ways to present and analyse data on Australia's distribution networks. This chapter mostly adopts a convenient classification of the networks based on jurisdiction and ownership criteria. Other possible ways to analyse the data include by feeder —for example, a rural/urban classification. Section 5.6 includes analysis based on a feeder classification.

While this chapter includes data that might enable performance comparisons to be made between networks, such analysis should note that geographical, environmental and other differences can affect relative performance. These factors are noted, where appropriate, in the chapter.

5.1 Role of distribution networks

Distribution networks move electricity from transmission networks to residential and business customers.[1] A distribution network consists of the poles, underground channels and wires that carry electricity, as well as substations, transformers, switching equipment, and monitoring and signalling equipment. While electricity moves along transmission networks at high voltages to minimise energy losses, it must be stepped down to lower voltages in a distribution network for safe use by customers. Most customers in the National Electricity Market (NEM) require delivery at around 230–240 volts.

Distribution networks criss-cross urban and regional areas to provide electricity to every customer. This requires substantial investment in infrastructure. The total length of distribution infrastructure in the NEM is around 700 000 kilometres—16 times greater than for transmission infrastructure.

In Australia, electricity distributors provide the infrastructure to transport electricity to household and business customers, but do not sell electricity. Instead, retailers bundle electricity generation with transmission and distribution services and sell them as a package (see chapter 6). In some jurisdictions, there is common ownership of distributors and retailers, which are ring-fenced (operationally separated) from one another.

The contribution of distribution costs to final retail prices varies between jurisdictions, customer types and locations. The Queensland Competition Authority (QCA) reported in 2008 that distribution services account for about 37 per cent of a typical residential electricity bill.[2] The Essential Services Commission (ESC) of Victoria reported in 2004 that distribution can account for 30 to 50 per cent of retail prices, depending on customer type, energy consumption, location and other factors.[3]

5.2 Australia's distribution networks

Australia has 15 major electricity distribution networks, 13 of which are located in the NEM. Table 5.1 provides summary details.[4] New South Wales, Victoria and Queensland have multiple networks, each of which is a monopoly provider in a designated area. In the other jurisdictions, there is one major network. There are also small regional networks with separate ownership in some jurisdictions. Figure 5.1 illustrates the distribution network areas for Queensland, New South Wales, the Australian Capital Territory (ACT) and Victoria.

5.2.1 Ownership

Table 5.1 sets out ownership arrangements for Australian distribution networks. At June 2008:

- Victoria and South Australia's networks are privately owned or leased and the ACT network has joint government and private ownership
- New South Wales, Queensland, Tasmania and the non-NEM jurisdictions of Western Australia and the Northern Territory have retained government ownership of the electricity distribution sector.

1 There are exceptions. For example, some large businesses such as aluminium smelters can bypass the distribution network and source electricity directly from the transmission network. Conversely, embedded generators have no physical connection with the transmission network and dispatch electricity directly into a distribution network.

2 QCA, *Draft decision—benchmark retail cost index for electricity: 2008–09*, May 2008.

3 ESC, *Electricity distribution price review 2006-10*, Issues paper, December 2004, p. 5.

4 This chapter includes some high level information on Western Australia and Northern Territory, but focuses mainly on the NEM jurisdictions. Chapter 7 provides further information on Western Australian and Northern Territory electricity markets.

Table 5.1 Distribution networks

NETWORK	LOCATION	LINE LENGTH (KM)	CUSTOMER NUMBERS	ASSET BASE ($ MILLION, NOMINAL)	INVESTMENT— CURRENT PERIOD ($ MILLION 2007)	CURRENT REGULATORY PERIOD	OWNER
NEM REGIONS							
NEW SOUTH WALES AND ACT							
EnergyAustralia	Inner, northern and eastern metropolitan Sydney and surrounds	47 144	1 539 030	4116	2455	1 Jul 2004–30 Jun 2009	NSW Government
Integral Energy	Southern and western metropolitan Sydney and surrounds	33 863	822 446	2283	1733	1 Jul 2004–30 Jun 2009	NSW Government
Country Energy	Country and regional NSW; southern regional Queensland	182 023	734 071	2375	1539	1 Jul 2004–30 Jun 2009	NSW Government
ActewAGL	All of ACT	4623	146 556	510	115	1 Jul 2004–30 Jun 2009	ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International (Australia)) 50%
VICTORIA							
Solaris (formerly AGL/Alinta)	Western metropolitan Melbourne	5579	286 085	578	253	1 Jan 2006–31 Dec 2010	Jemena (Singapore Power International (Australia))
SP AusNet (Eastern Energy)	Eastern Victoria	29 397	573 766	1307	755	1 Jan 2006–31 Dec 2010	SP AusNet (listed company; Singapore Power International 51%)
United Energy	South-eastern metropolitan Melbourne	12 308	609 585	1220	547	1 Jan 2006–31 Dec 2010	Jemena (Singapore Power International (Australia)) 34%; DUET Group 66%
CitiPower	Inner metropolitan Melbourne	6488	286 107	991	529	1 Jan 2006–31 Dec 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
Powercor	Western Victoria	80 577	644 113	1626	1008	1 Jan 2006–31 Dec 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
SOUTH AUSTRALIA							
ETSA Utilities	All of South Australia	80 644	781 881	2468	810	1 Jul 2005–30 Jun 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%

NETWORK	LOCATION	LINE LENGTH (KM)	CUSTOMER NUMBERS	ASSET BASE ($ MILLION, NOMINAL)	INVESTMENT—CURRENT PERIOD ($ MILLION 2007)	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
ENERGEX	Brisbane, Gold Coast, Sunshine Coast and surrounds	48 115	1 217 193	4308	3011	1 Jul 2005–30 Jun 2010	Qld Government
Ergon Energy	Country and regional Queensland	142 793	736 710	4198	2945	1 Jul 2005–30 Jun 2010	Qld Government
TASMANIA							
Aurora Energy	All of Tasmania	24 400	259 600	981	575	1 Jan 2008–30 Jun 2012	Tas Government
NEM totals		697 954	8 637 143	26 961	16 275		
NON-NEM REGIONS							
WESTERN AUSTRALIA							
Western Power	All of Western Australia	69 083	925 000	1595	907	1 Jul 2006–30 Jun 2009	WA Government
NORTHERN TERRITORY							
Power and Water	All of Northern Territory	6619	82 022	432	n/a	1 Jul 2004–30 Jun 2009	NT Government

n/a, not available.

Notes:

1. Asset valuation is the opening regulated asset base for the current regulatory period (nominal values). Investment data is forecast capital expenditure over the current regulatory period, converted to June 2007 dollars. The regulatory period is 4.5 years for Aurora Energy (Tasmania), 3 years for Western Power (Western Australia) and 5 years for other networks. Northern Territory data includes transmission networks.
2. While the Australian Energy Regulator (AER) assumed the role of economic regulator of distribution networks in the NEM on 1 January 2008, existing regulatory determinations will continue to be administered by the jurisdictional regulators—in Victoria, the Essential Services Commission of Victoria (ESC); in South Australia, the Essential Services Commission of South Australia (ESCOSA); in New South Wales, the Independent Pricing and Regulatory Tribunal (IPART); in the ACT, the Independent Competition and Regulatory Commission (ICRC); in Queensland, the Queensland Competition Authority (QCA); and in Tasmania, the Office of the Tasmanian Energy Regulator (OTTER). The AER will assume responsibility for administering the Victorian regulatory determination from 1 January 2009. The Economic Regulation Authority (ERA) of Western Australia and the Northern Territory's Utilities Commission will continue to regulate distribution networks in those jurisdictions.

Principal sources: regulatory determinations published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ICRC (ACT), ERA (WA) and Utilities Commission (NT); ESAA, *Electricity Gas Australia*, 2008.

Figure 5.1

Electricity distribution network areas—Queensland, New South Wales, ACT and Victoria

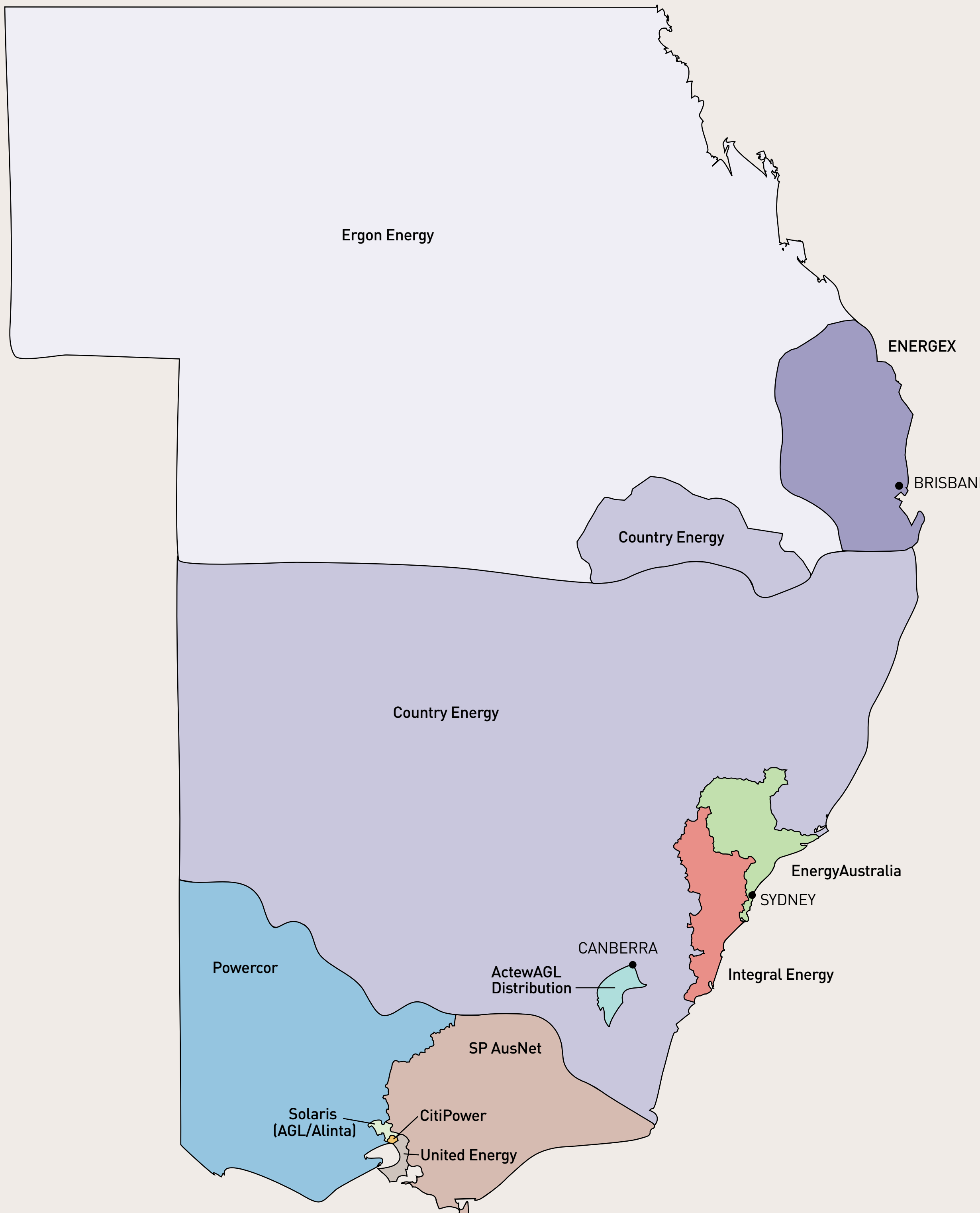
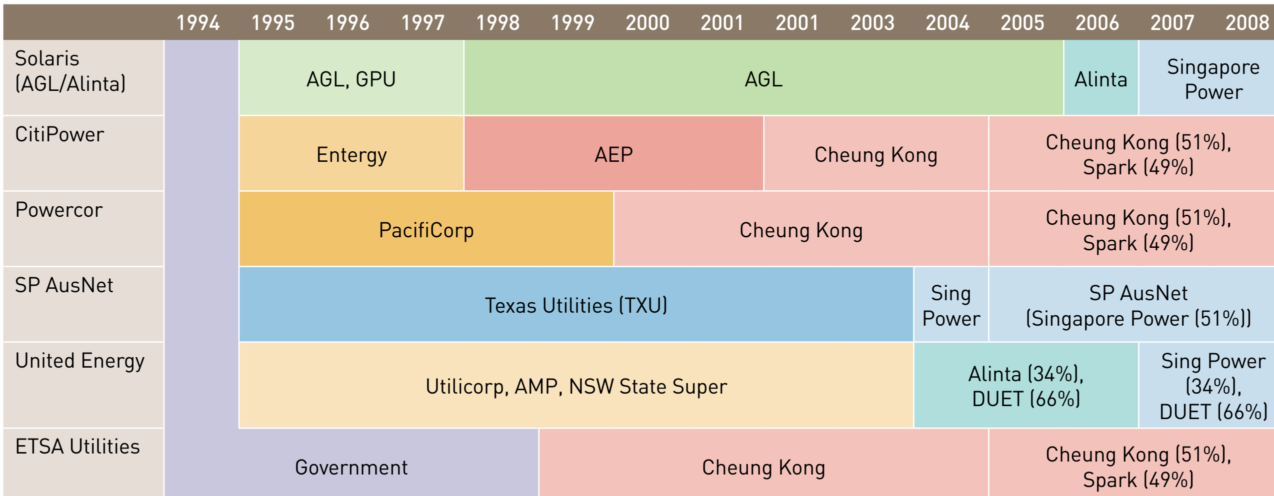


Figure 5.2

Distribution network ownership—Victoria and South Australia



Note: Some corporate names have been abbreviated or shortened.

5.2.2 Victoria and South Australia

Victoria's five distribution networks—CitiPower, Solaris, United Energy, SP AusNet and Powercor—are privately owned. The South Australian network (ETSA Utilities) is leased to private interests. Figure 5.2 tracks ownership changes since privatisation. At June 2008, there are two principal network owners:

- Cheung Kong Infrastructure and Hongkong Electric Holdings have a 51 per cent stake in two Victorian networks (Powercor and CitiPower) and a 200-year lease of the South Australian distribution network (ETSA Utilities). The remaining 49 per cent in each network is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a direct interest.
- Singapore Power International owns a 51 per cent stake in SP AusNet, which owns Victoria's SP AusNet network. Singapore Power International acquired a second Victorian network (Solaris) and part ownership of a third network (United Energy) from Alinta in 2007. It also owns a 50 per cent share in the ACT distribution network (ActewAGL). In August 2008, Singapore Power International rebranded its energy business as Jemena.

DUET Group has a majority interest in Victoria's United Energy network. The minority owner, Singapore Power International, operates the network.[5]

5.2.3 Cross-ownership

In some jurisdictions, there are ownership linkages between electricity distribution and other segments of the energy sector (see table 5.2). New South Wales and Tasmania have common ownership in electricity distribution and retailing, with ring-fencing arrangements for operational separation. Queensland privatised most of its energy retail sector in 2006–07, but Ergon Energy continues to provide distribution and retail services to some customers.

A number of electricity distributors also provide other energy network services. The most significant is Singapore Power International, which owns electricity transmission and distribution networks, and gas transmission and distribution pipelines.

5 DUET Group comprises a number of trusts, the responsible entities for which are jointly owned by Macquarie Bank and AMP Capital Holdings.


Mark Wilson

Table 5.2 **Ownership linkages between electricity distribution and other energy sectors**

OWNERSHIP LINKAGE	DISTRIBUTION BUSINESS
Electricity distribution and transmission	Singapore Power International (Vic)
	EnergyAustralia (NSW)
	Western Power (WA)
Electricity distribution and gas transportation	Singapore Power International (Vic)
	Cheung Kong Infrastructure (via equity in Envestra) (Vic and SA)
Electricity distribution and retail	ActewAGL (ACT)[1]
	EnergyAustralia, Integral Energy and Country Energy (NSW)
	Aurora Energy (Tas)
	Ergon Energy (Qld)

Note:

1. ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. The remaining shares are owned by AGL Energy and Singapore Power International respectively.

5.3 Economic regulation of distribution services

Electricity distribution networks are capital intensive and incur declining costs as output rises. This gives rise to a natural monopoly industry structure. In Australia, the networks are regulated under the National Electricity Law and National Electricity Rules (Electricity Rules) to manage the risk of monopoly pricing.

On 1 January 2008, the Australian Energy Regulator (AER) became responsible for the economic regulation of electricity distribution following the transfer of functions from state and territory regulators. The AER's first regulatory review in electricity distribution—to set revenues for the New South Wales and ACT networks—began in May 2008. The AER commenced a regulatory review of the South Australian and Queensland distribution networks in July 2008. The amended Electricity Rules contain transitional arrangements for the ongoing administration of existing distribution determinations by jurisdictional regulators. The AER is working closely with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition period. The regulation of distribution networks in Western Australia and the Northern Territory remain under state and territory jurisdiction.

The Electricity Rules set out the framework for regulating distribution networks. The Electricity Rules require the use of an incentive-based approach, but allow the regulator to choose the form of price or revenue control. Regulatory frameworks currently applied in the NEM states include revenue yield models that control the average revenue per unit sold, based on volumes or revenue drivers; and weighted average price caps, which allow flexibility in individual tariffs within an overall ceiling. In South Australia, an electricity pricing order sets some elements of the regulatory framework. As table 5.3 illustrates, there are a range of approaches in the regulatory decisions currently in place.

In essence, each approach involves the setting of a ceiling on the revenues or prices that a distribution business is allowed to earn or charge during a regulatory period —typically five years. A building block model is generally applied to determine the revenue or price ceiling. The building blocks factor in a network's operating costs, asset depreciation costs, taxation liabilities and a commercial return on capital. The setting of these elements has regard to various factors, including projected demand growth; price stability; the potential for efficiency gains in cost and capital expenditure management; service standards; and the provision of a fair and reasonable risk-adjusted rate of return on efficient investment.

Table 5.3 **Current forms of incentive regulation in the National Electricity Market**

FORM OF REGULATION	HOW IT WORKS	REGULATOR	NETWORK(S)
Weighted average price cap	Sets a ceiling on a weighted average of distribution tariffs (prices). The distribution business is free to adjust its individual tariffs as long as the weighted average remains within the ceiling. There is no cap on the total revenue a distribution business may earn. Revenues can vary depending on tariff structures and the volume of electricity sales.	Essential Services Commission (Vic) Independent Pricing and Regulatory Tribunal (NSW)	Solaris CitiPower Powercor SP AusNet United Energy EnergyAustralia Integral Energy Country Energy
Revenue cap	Sets the maximum revenue a distribution network may earn during a regulatory period. It effectively caps total earnings. This mirrors the approach used to regulate transmission networks. The distribution business is free to determine individual tariffs provided that total revenues do not exceed the cap.	Queensland Competition Authority (Qld) Office of the Tasmanian Energy Regulator (Tas)	ENERGEX Ergon Energy Aurora Energy
Maximum average revenue cap	Sets a ceiling on average revenues during a regulatory period. Total prescribed distribution service revenues are capped each year at the average revenue allowance for a year multiplied by actual energy sales. Tariffs must be set to comply with this constraint.	Independent Competition and Regulatory Commission (ACT)	ActewAGL
Revenue yield (average revenue control)	Links the amount of revenue a distribution business may earn to the volume of electricity sold. Total revenues are not capped and may vary in proportion to the volume of electricity sales. The distribution business is free to determine individual tariffs—subject to tariff principles and side constraints—provided that total revenues do not exceed the average.	Essential Services Commission of South Australia (SA)	ETSA Utilities

There have been variations between regulatory approaches to the treatment of specific building block components. Incentive schemes attached to some elements of the blocks also vary between jurisdictions. For example, in current determinations:

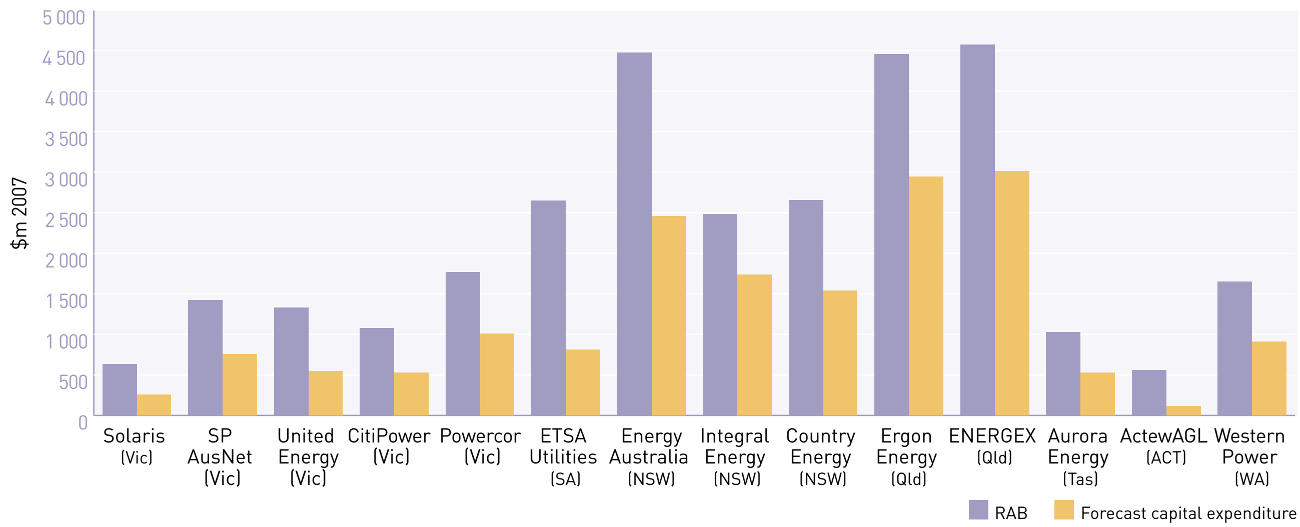
- There are differences between jurisdictions in the treatment of taxation in determining returns on capital.
- Jurisdictions applied different types of incentive mechanisms to encourage distribution businesses to manage their operating and capital expenditure efficiently.
- Some jurisdictions have conducted an ex post[6] review of whether past investment was prudent when determining the amount of capital expenditure to be rolled into the regulated asset base (RAB).[7]
- Some jurisdictions have provided financial incentives for networks to improve service standards over time, while others have not applied such schemes (see section 5.6).

In applying any of the forms of regulation in table 5.3, a regulator must forecast the revenue requirement of a distribution business over the regulatory period. This must factor in investment forecasts and the operating expenditure allowances that a benchmark distribution business would require if operating efficiently. The aim is to provide incentives for the distribution business to reduce costs through efficient management and spend less than its forecast allowance. As will be discussed in section 5.6, these incentives should be balanced against a service standards regime to ensure any expenditure savings are not at the expense of network reliability and performance.

6 A retrospective (after the event) assessment.
7 The RAB estimates the depreciated optimised replacement cost of an asset.

Figure 5.3

Distribution assets and investment—current regulatory period (real)



RAB, regulated asset base.

Notes:

1. Asset valuation is the opening RAB for the current regulatory period. Investment is forecast capital expenditure over the current regulatory period.
2. The regulatory period is 4.5 years for Aurora Energy (Tasmania), 3 years for Western Power (Western Australia) and 5 years for other networks.
3. All estimates are converted to June 2007 dollars.

Source: Regulatory determinations published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ERA (WA) and ICRC (ACT).

Since assuming responsibility in 2008 for the economic regulation of distribution networks, the AER has published a number of guidelines on regulatory arrangements, including on:

- the post-tax revenue model, which is used to determine distribution businesses' annual regulated revenues
- the roll-forward model, which is used to determine the RAB for each network
- an incentive scheme which allows network businesses to retain efficiency savings in operating and maintenance expenditure for five years from the year in which the gain is made (see section 5.5)
- a service incentive scheme, to maintain and improve service performance (see section 5.6)
- cost allocation guidelines, which outline the required contents of a regulated business's cost allocation method and the basis on which the AER will assess that method for approval.

5.4 Distribution investment

New investment in distribution infrastructure is needed to maintain and, where appropriate, improve network performance over time. Investment covers network augmentations to meet rising demand and expand into new regional centres and towns; and upgrades to improve the quality of existing networks by replacing ageing assets. Some investment is driven by regulatory requirements on matters such as network reliability.

Figure 5.3 shows the opening RABs and forecast investment over the current regulatory period for the major networks.[8] In the NEM, the combined opening RABs of distribution networks is around $27 billion, more than double the valuation for transmission infrastructure. Investment over the current regulatory cycle for the NEM networks is running at around $16 billion.[9]

8 At the end of the regulatory period, the RAB is adjusted to reflect new investment that has occurred.

9 Investment estimates are for the current—typically five year—regulatory periods. The RAB and investment estimates are in June 2007 dollars.

Many factors can affect the value of RABs, including the basis of original valuation, network investment, the age of a network, geographical scale, the distances required to transport electricity from transmission connection points to demand centres, population dispersion and forecast demand profiles.

Figure 5.4 charts annual investment in each network, using actual data where available and forecast data for other years. The forecast data relates to proposed investment that the regulator has approved as efficient at the beginning of the regulatory period. The charts depict real data in June 2007 dollars.

In summary, investment in the NEM jurisdictions was forecast at over $3 billion in 2007–08, in addition to around $318 million forecast for Western Australia. Investment has risen steadily during the current decade in most networks. This appears to be reflected in stable or improving reliability outcomes in several jurisdictions.[10]

On average, investment during the current regulatory cycle is running at over 40 per cent of the underlying asset base in most networks, and over 60 per cent in Queensland and parts of New South Wales. Different outcomes between jurisdictions reflect a range of variables, including forecast demand, the scale and age of the networks, and investment allowances in historical regulatory determinations.

There is some volatility in the data, reflecting a number of factors. In particular, there is some lumpiness in investment because of the one-off nature of some capital programs. More generally, the network businesses have some flexibility to manage and reprioritise their capital expenditure over the regulatory period. Transitions between regulatory periods, and from actual to forecast data, also result in some data volatility. For example, network businesses tend to schedule a significant portion of investment in the early stages of a regulatory period —although some projects are ultimately delayed.

5.5 Financial performance of distribution networks

The jurisdictional regulators have published annual performance reports on electricity distribution networks. In addition, new regulatory determinations include both historical performance data for the preceding regulatory period and forecasts of future outcomes.

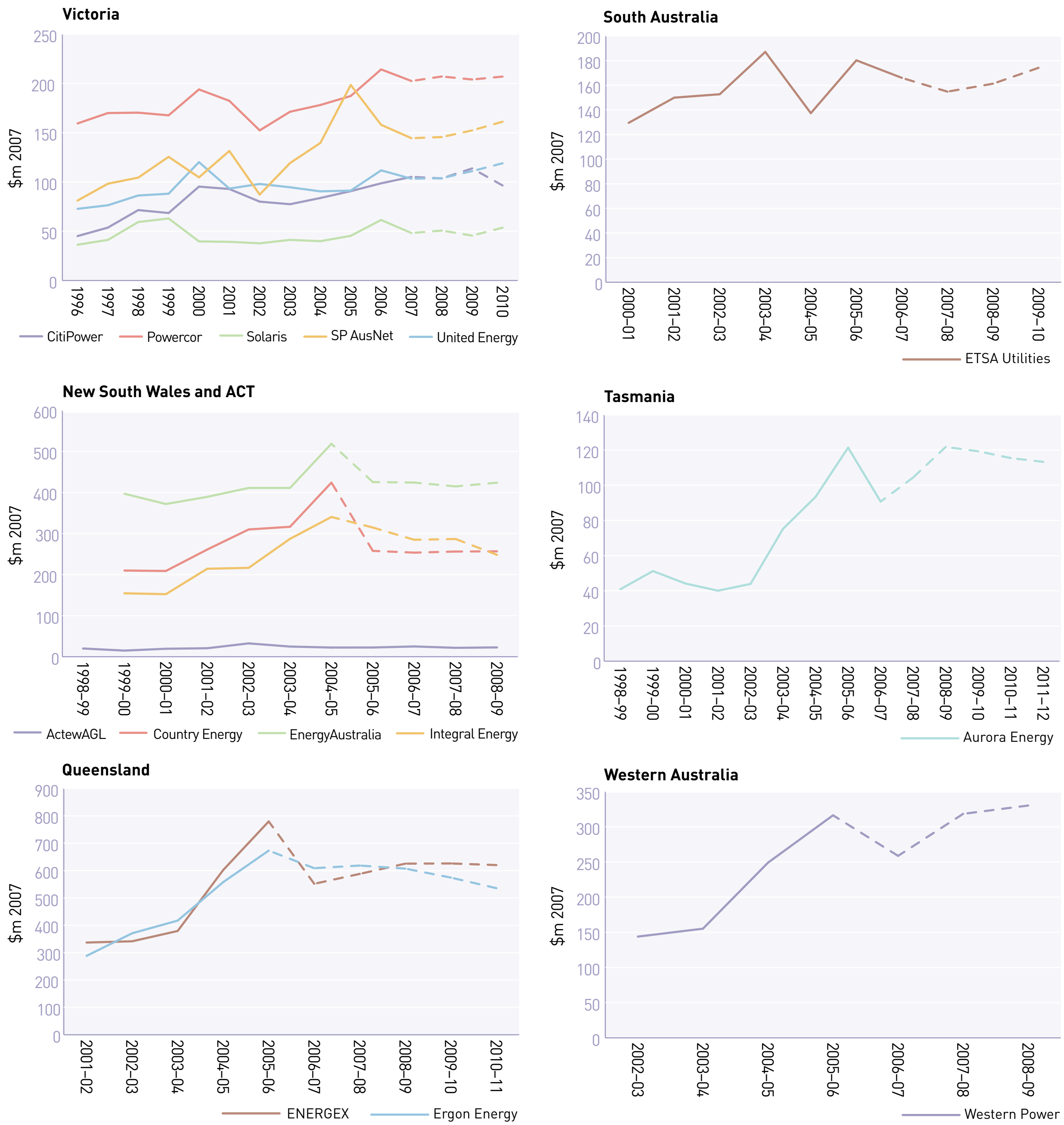
Following the transfer to national regulation in 2008, the AER will publicly report on the financial performance of distribution networks in the future. The AER will consult with stakeholders on reporting arrangements, including appropriate measures.

5.5.1 Revenues

Figure 5.5 charts real revenues for distribution networks in the NEM, based on forecasts in regulatory decisions. Allowed revenues are tending to rise over time as underlying asset bases expand to meet rising demand. The combined revenue of the NEM's 13 major distribution networks was forecast at around $5.6 billion in 2007–08, a rise of about 2.6 per cent in real terms over the previous year.

10 See section 5.6 and figure 5.9.

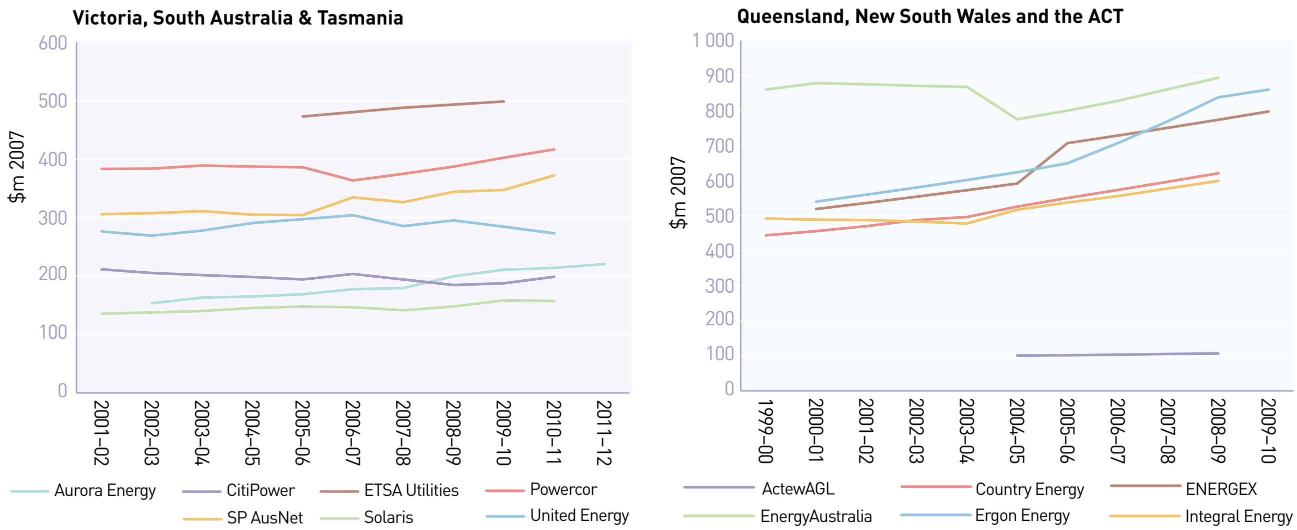
Figure 5.4
Network investment (real)



Notes:
1. Actual data (unbroken lines) used where available and forecasts (broken lines) for other years.
2. All data has been converted to June 2007 dollars.

Source: Regulatory determinations published by ESC (Vic); IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas) and ICRC (ACT).

Figure 5.5
Revenue forecasts (real)



Notes:

1. Data for year ended 30 June. Victorian data is for previous calendar year (for example, 2006–07 refers to calendar year 2006).
2. All data converted to 2007 dollars.

Sources: Regulatory determinations published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas) and ICRC (ACT).

5.5.2 Return on assets

A commonly used financial indicator to assess the performance of a business is the return on assets. The ratio is calculated as operating profits (net profit before interest and taxation) as a percentage of the average RAB. Figure 5.6 sets out the returns on assets for distribution networks in the NEM, where data is available. Over the past five years, the privately-owned distribution businesses in Victoria and South Australia tended to yield returns of about 8 to 12 per cent. The government-owned distribution businesses in New South Wales, Queensland and Tasmania achieved returns ranging from 4 to 10 per cent.

A variety of factors can affect performance in this area. These might include differences in the demand and cost environments faced by each business and variances in demand and costs outcomes compared to those forecasted in the regulatory process.

5.5.3 Operating and maintenance expenditure

Figure 5.7 charts forecast operating and maintenance expenditure for each network on a per kilometre basis in 2007–08. The forecasts reflect regulatory allowances for each network to cover efficient operating and maintenance expenditure. There is a range of outcomes in this area, reflecting differences in customer and load densities, the scale and condition of the networks, geographical factors and reliability requirements. Normalising on a per kilometre basis tends to bias against high-density urban networks with relatively short line lengths. This is reflected in the high outcomes for the three Victorian urban networks and the ACT network.

Figure 5.6
Return on assets

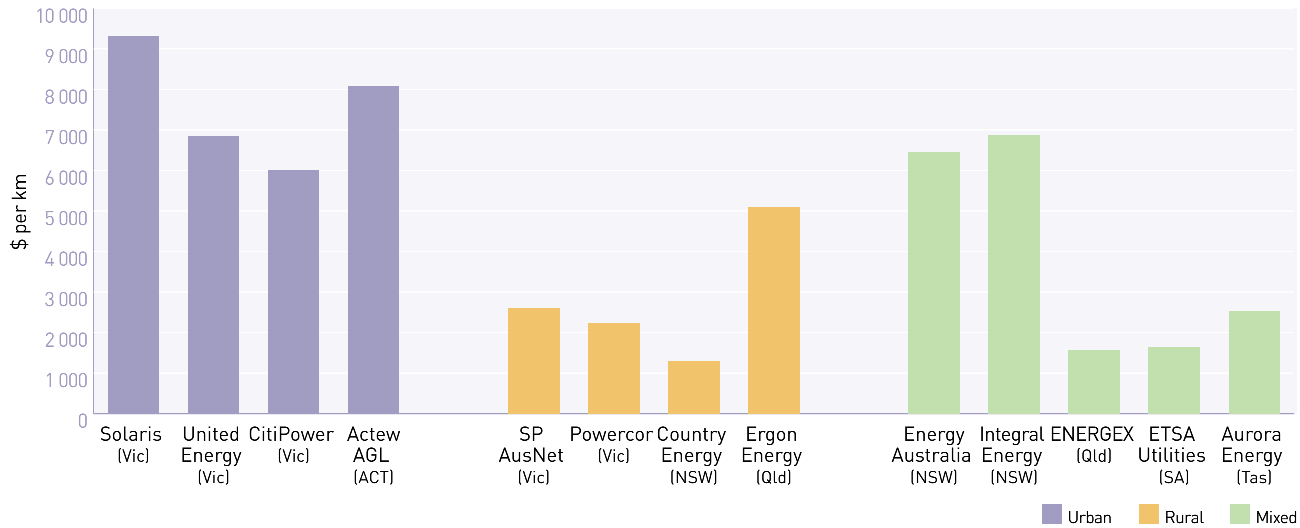
RAB, regulated asset base.

Note: Data for year ended 30 June. Victorian data are for previous calendar year (for example, 2006–07 refers to calendar year 2006).

Sources: Regulatory determinations published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas) and ICRC (ACT).

Figure 5.7

Operating and maintenance expenditure per kilometre of line length—2008



Note: Forecast data for 2007–08 converted to June 2007 dollars. The Victorian data is for calendar year 2007.

Sources: Regulatory determinations published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas) and ICRC (ACT).

The AER published details in June 2008 of a national efficiency benefit sharing scheme as part of the national framework for distribution regulation.[11] The scheme provides incentives for distribution businesses to reduce their spending against forecast targets through efficient operating practices. It allows the businesses to retain some or all of their underspending against target in the current regulatory period. The national scheme is designed to apply uniformly to all distribution businesses. The AER will first apply the scheme in its current price reviews of the Queensland and South Australian distribution networks, scheduled to take effect in July 2010.

Over time, the national scheme will replace the current state-based incentive schemes that jurisdictional regulators administer. Figure 5.8 compares actual expenditure against target expenditure for each network under the state-based schemes. A positive variance indicates that actual expenditure exceeded target in that year—that is, the distribution business overspent. A negative variance indicates underspending against target.

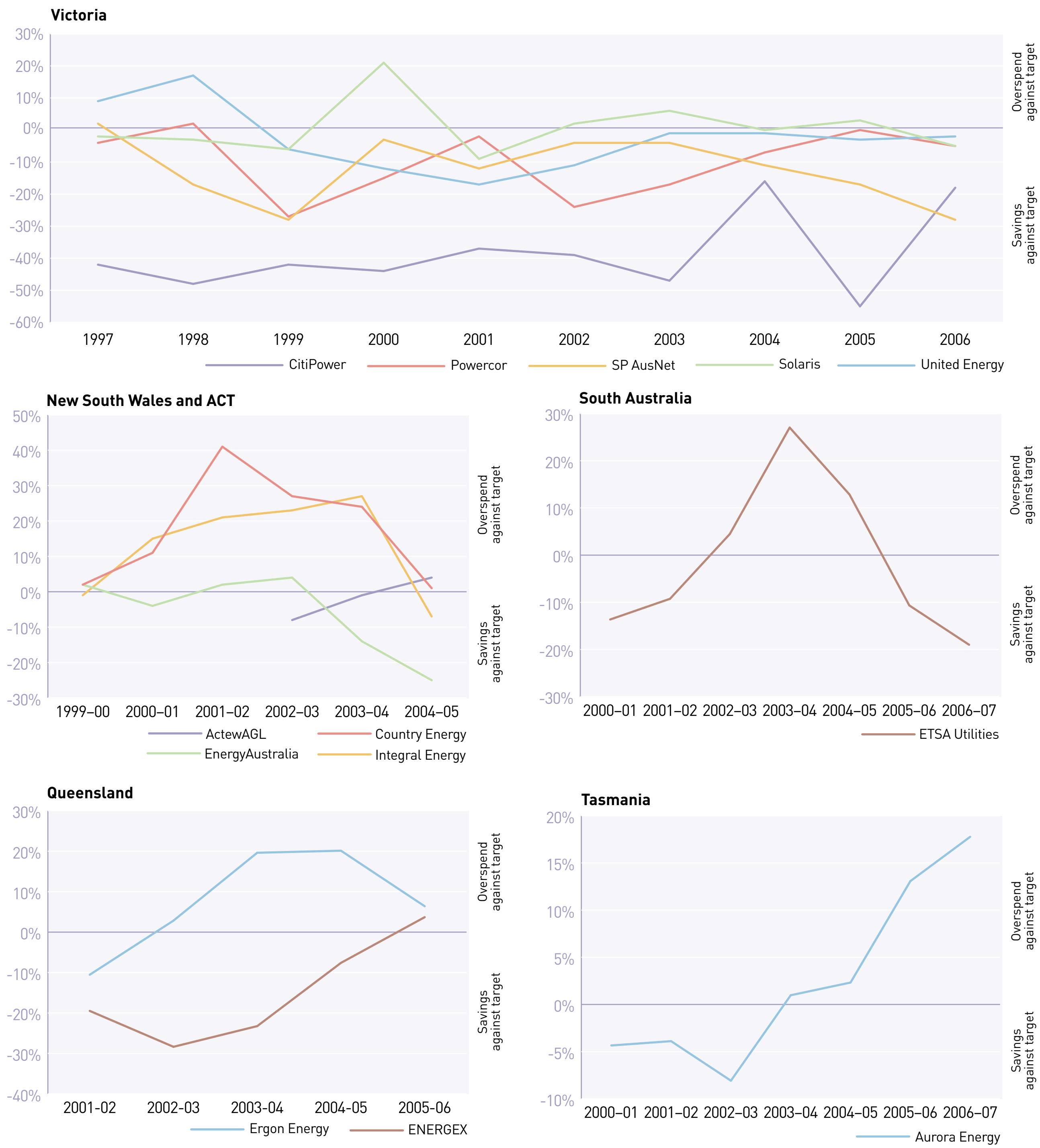
A trend of negative variances over time may suggest a positive response to efficiency incentives. More generally, care should be taken in interpreting year-to-year changes in operating expenditure. As the network businesses have some flexibility to manage their expenditure over the regulatory period, timing considerations may affect the data. Delays in completing a project may also affect expenditure.

Figure 5.8 indicates that most Victorian networks and ENERGEX (Queensland) have underspent against their forecast allowances for most or all of the charted period. The New South Wales and South Australian networks and Ergon Energy (Queensland) have recorded sharply improved performance in this area since 2003–04.

11 AER, *Electricity distribution network service providers: Efficiency benefit sharing scheme*, Final decision, June 2008.

Figure 5.8

Operating and maintenance expenses—variances from target



Note: Positive variances (above zero) reflect overspending against target. Negative variances (below zero) reflect underspending against target.

Sources: Performance reports published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas) and ICRC (ACT).

5.6 Service quality and reliability

Electricity distribution networks are monopolies that face little risk of losing customers if they provide poor service. In addition, regulatory incentive schemes for efficient cost management might encourage a business to sacrifice service performance to reduce costs. In recognition of these risks, governments and regulators monitor the performance of distribution businesses to ensure they provide acceptable levels of service.

Quality of service monitoring for electricity distribution typically relates to:

- reliability (the continuity of electricity supply through the network)
- technical quality (for example, voltage stability)
- customer service (for example, on-time provision of services and the adequacy of call centre performance).

All jurisdictions regulate the service performance of distribution networks through:

- the monitoring and reporting of reliability, technical quality and customer service outcomes against standards set out in legislation, regulations, licences and codes; there may be sanctions for non-compliance
- guaranteed service levels (GSLs) that, if not met, require a network business to make payments to affected customers; the guarantees relate to network reliability, technical quality of service and customer service; each of the NEM jurisdictions implements a GSL scheme.

In addition, some jurisdictions have applied financial incentive schemes for distribution businesses to maintain and improve service performance over time. The Victorian and South Australian networks are currently subject to an 's-factor' incentive scheme.[12] The South Australian scheme focuses on customers with poor reliability outcomes. Service incentive schemes do not currently apply to other networks.

The AER published details in June 2008 of a national service performance incentive scheme as part of the national framework for distribution regulation.[13]

The scheme provides financial bonuses and penalties to network businesses that meet (or fail to meet) performance targets. The targets relate to reliability of supply and customer service and include a GSL component. The results are standardised for each network to derive an 's-factor' which reflects whether service performance has improved over past average performance levels. A distribution business can earn an annual bonus of up to 3 per cent of its revenue if it meets all performance targets.

The national scheme is based on existing state-based incentive schemes in Victoria and South Australia and therefore has regard to industry and community expectations. Over time, the national scheme will replace the state-based schemes. The AER will first apply the national scheme in its current price reviews of the Queensland and South Australian distribution networks, scheduled to take effect in July 2010. While the AER considers that the scheme should apply on a consistent basis nationally where this is practical, there is some flexibility to allow for transitional issues and the differing circumstances and operating environments of particular businesses. The AER has also noted that the scheme will need to evolve over time to allow for such factors as changes in energy industry technology, climate change policies and other issues affecting customer expectations of service performance and the operating environment for the distribution sector.

The AER will publicly report on the service performance of distribution businesses in the future. It will consult with stakeholders on the reporting measures and future reporting arrangements.

5.6.1 Reliability

Reliability refers to the continuity of electricity supply to customers, and is a key performance indicator that impacts on customers. Distribution outages account for over 90 per cent of the duration of all electricity outages in the NEM. Relatively few outages originate in the generation and transmission sectors.[14]

12 The use of s-factor schemes is discussed in the context of electricity transmission in section 4.6 of this report.

13 AER, *Electricity distribution network service providers: Service target performance incentive scheme*, Final decision, June 2008.

14 See AER, *State of the energy market 2007*, essay B, pp. 38-53.

A reliable distribution network keeps interruptions or outages in the transport of electricity down to efficient levels. It would be inefficient to try to eliminate every possible interruption. Rather, an efficient outcome would reflect the level of service that customers are willing to pay for. There has been some research on the willingness of electricity customers to pay higher prices for a reliable electricity supply. For example, a 1999 Victorian study found that more than 50 per cent of customers were willing to pay a higher price to improve or maintain their level of supply reliability.[15] However, a 2003 South Australian survey indicated that customers were willing to pay for improvements in service only to poorly serviced customer areas.[16]

Various factors, both planned and unplanned, can impede network reliability.

- A planned interruption occurs when a distributor needs to disconnect supply to undertake maintenance or construction works. Such interruptions can be timed for minimal impact.
- Unplanned outages occur when equipment failure causes the supply of electricity to be disconnected unexpectedly. There are often routine external causes, such as damage caused by trees, birds, possums, vehicle impacts or vandalism. Networks can also be vulnerable to extreme weather, such as bushfires or storms. There may be ongoing reliability issues if part of a network has inadequate maintenance or is utilised near its capacity limits at times of peak demand. Sometimes these factors occur in combination.

The impact of an outage depends on customer load, the design of the network, maintenance practices and the time taken by a distributor to restore supply after an interruption. The impact of a distribution outage tends to be localised to a part of the network.

Jurisdictions track the reliability of distribution networks against performance standards to assess whether they are operating at a satisfactory level. The standards take into account the trade-off between improved reliability and cost. Ultimately, customers must pay for the cost of investment, maintenance and other solutions needed to deliver a reliable power system.

The trade-offs between improved reliability and cost have resulted in standards for distribution networks being less stringent than for generation and transmission. These less stringent standards also reflect the localised effects of distribution outages, compared with the potentially widespread geographical impact of a generation or transmission outage. The capital intensive nature of distribution networks makes it very expensive to build in high levels of redundancy (spare capacity) to improve reliability. These factors help to explain why distribution outages account for such a high proportion of electricity outages in the NEM.

For similar reasons, there tend to be different reliability standards for different feeders (parts) of a distribution network. For example, a higher reliability standard is usually required for a central business district (CBD) network with a large customer base and a concentrated load density than for a highly dispersed rural network with a small customer base and a low load density. While the unit costs of improving reliability in a dispersed rural network are relatively high, few customers are likely to be affected by an outage. Conversely, the unit costs of improving reliability in a high density urban network are relatively low, and many customers are likely to be affected by an outage.

5.6.2 Reliability data

All jurisdictions have their own monitoring and reporting frameworks for reliability. In addition, the Utility Regulators Forum (URF) has adopted four indicators of distribution network reliability that are widely used in Australia and overseas. The indicators relate to the average frequency and duration of network interruptions or outages (see table 5.4). The indicators do not distinguish between the nature and size of loads that are affected by supply interruptions.

15 KBA and Powercor, *Understanding customers' willingness to pay: Components of customer value in electricity supply*, 1999.

16 The survey found that 85 per cent of consumers were satisfied with their existing level of service and were generally unwilling to pay for improvements in these levels. It found that there was a willingness to pay for improvements in service only to poorly served consumers. On this basis, ESCOSA has focused on providing incentives to improve the reliability performance for the 15 per cent of worst served consumers, while maintaining average reliability levels for all other customers. See ESCOSA, *2005–2010 Electricity distribution price determination*, part A, April 2005; and KPMG, *Consumer preferences for electricity service standards*, March 2003.

Table 5.4 **Reliability measures—distribution**

INDEX	NAME	DESCRIPTION
SAIDI	System average interruption duration index	Average total number of minutes that a distribution network customer is without electricity in a year (excludes interruptions of one minute or less)
SAIFI	System average interruption frequency index	Average number of times a customer's supply is interrupted per year
CAIDI	Customer average interruption duration index	Average duration of each interruption (minutes)
MAIFI	Momentary average interruption frequency index	Average number of momentary interruptions (of one minute or less) per customer per year

Source: URF, *National regulatory reporting for electricity distribution and retailing businesses*, 2002.

In most jurisdictions, distribution businesses are required to report performance against the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI) indicators. The national service performance incentive scheme, published in June 2008, includes the SAIDI and SAIFI indicators.[17]

Jurisdictional regulators audit, analyse and publish reliability outcomes, typically down to feeder level (CBD, urban and rural) for each network.[18] Tables 5.5 and 5.6 and figure 5.9 estimate historical SAIDI and SAIFI data for NEM jurisdictions. In the future, the AER will report on reliability outcomes as part of its performance reporting on the distribution sector.

The data in tables 5.5, 5.6 and figure 5.9 reflect and total outages experienced by distribution customers. In general, the data has not been normalised to exclude distribution outages that are beyond the reasonable control of the network operator—for example, outages that originate in the generation and transmission sectors, and outages caused by external factors such as extreme weather. However, the data for Queensland in 2005–06 and New South Wales in 2006–07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

From a customer perspective, the unadjusted data presented here is relevant, but an assessment of distribution network performance should normalise data to exclude external sources of interruption. At present, there is no consistent approach to determining exclusions. The impact of excluded events is considered later in this chapter in relation to reliability at the feeder level.[19]

A number of issues limit the validity of performance comparisons between the networks. In particular, the data currently relies on the accuracy of the network businesses' information systems, which may vary considerably. There are also differences in design, geographical conditions and historical investment between the networks. As noted, differences in customer density and load density can affect the costs and benefits of achieving high reliability. In addition, there are differences in the approach of each jurisdiction to excluded events. The URF agreed that in some circumstances, reliability data should be normalised to exclude interruptions that are beyond the control of a network business.[20] In practice, there are differences between jurisdictions in the approval and reporting of exclusions. More generally, there is no consistent approach to auditing performance outcomes.

17 AER, *Electricity distribution network service providers: Service target performance incentive scheme*, Final decision, June 2008

18 In New South Wales the distribution businesses publish this data in the first instance. The regulator (IPART) periodically publishes summary data.

19 The national service performance incentive scheme, published in June 2008, adopts a consistent approach to determine exclusions, based on a standard set by the Institute of Electrical and Electronics Engineers. The standard is currently in use in a number of Australian jurisdictions. In addition, the scheme identifies specific events, for which the impact would be excluded (see: AER, *Electricity distribution network service providers: Service target performance incentive scheme*, Final decision, June 2008, section 6.7).

20 The URF definitions of SAIDI and SAIFI exclude outages that exceed a threshold SAIDI impact of three minutes; outages that are caused by exceptional natural or third party events; and outages for which the distribution business cannot reasonably be expected to mitigate the effect of by prudent asset management.

Table 5.5 System average interruption duration index (SAIDI) (minutes)

	1999–00	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07
Victoria	156	183	152	151	161	132	165	165
NSW		175	324	193	279	218	191	211
Queensland		331	275	332	434	283	351	233
South Australia		159	143	179	159	164	201	184
Tasmania		265	198	214	324	314	292	256
NEM weighted average		211	245	211	267	201	221	202

Table 5.6 System average interruption frequency index (SAIFI)

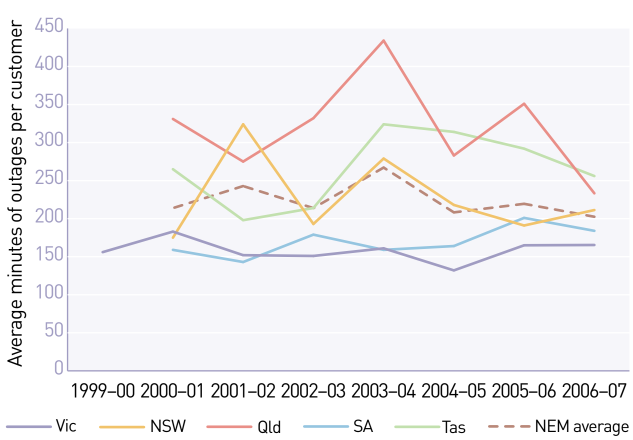
	1999–00	2000–01	2001-02	2002–03	2003–04	2004–05	2005–06	2006–07
Victoria	2.1	2.1	2.0	2.0	2.2	1.9	1.8	1.94
NSW	1.7	2.5	2.6	1.4	1.6	1.6	1.8	1.9
Queensland		3.0	2.8	3.3	3.4	2.7	2.7	2.2
South Australia		1.7	1.6	1.8	1.6	1.7	1.9	1.75
Tasmania	2.3	2.8	2.3	2.4	3.1	3.1	2.89	2.57
NEM weighted average	1.6	2.4	2.4	2.1	2.2	1.9	2.0	2.0

Notes:

1. The data reflects total outages experienced by distribution customers. In some instances, this may include outages resulting from issues in the generation and transmission sectors. In general, the data has not been normalised to exclude distribution network issues beyond the reasonable control of the network operator. The data for Queensland in 2005–06 and New South Wales in 2006–07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.
2. Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005).
3. The NEM averages are weighted by customer numbers.

Sources: Performance reports published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. The AER consulted with PB Associates in the development of historical data.

Figure 5.9
System average interruption duration index (SAIDI)



Notes and Sources: See tables 5.5 and 5.6.

Noting these caveats, the SAIDI data indicates that distribution networks in the NEM have delivered reasonably stable reliability outcomes over the past few years, with recent improvements in some jurisdictions. The NEM-wide SAIDI remained in a range of about 200–270 minutes from 2000–01 to 2006–07. While there are regional variations, some convergence is evident in 2006–07.

The average duration of outages per customer has tended to be lower in Victoria and South Australia than in other jurisdictions, despite some community concerns that privatisation might adversely affect service quality. The average duration of outages has tended to fall in New South Wales since 2003–04, despite a slight deterioration in 2006–07. Average reliability (as measured by SAIDI) is lower in Queensland than in other mainland jurisdictions. It should be noted that Queensland is subject to significant variations in performance, in part because of its large and widely dispersed rural networks, and extreme weather events. These characteristics make it more vulnerable to outages than some other jurisdictions. Queensland recorded improved reliability from 2003–04. This is particularly evident for 2006–07, when outage time fell considerably.

The SAIFI data appears to show an improvement in the average frequency of outages across the NEM since 2000. The average frequency of outages is higher in Queensland than in other jurisdictions, although in 2006–07, the state achieved its best performance in this area, moving closer to the results of the other mainland jurisdictions. On average, distribution customers in the mainland NEM regions experience outages around twice a year. The rate is a little higher in Tasmania.

The recent improvements in reliability in New South Wales and Queensland are consistent with the rising investment trends noted in section 5.4. In Queensland, the government took action to improve reliability when a 2004 review (the Somerville review) found that distribution service performance was unsatisfactory. The government introduced performance requirements aimed at improving reliability by 25 per cent by 2010. There was also a significant step-increase in investment allowances for Queensland's distribution networks (see figure 5.4).[21]

5.6.3 Reliability of distribution networks by feeder

Given the diversity of network characteristics, it may be more meaningful to compare network reliability on a feeder category basis than on a statewide basis. There are four categories of feeder based on geographical location (see table 5.7).

Figures 5.10a–d set out the average duration of supply interruptions per customer (SAIDI) for each feeder type, subject to data availability.[22] The charts distinguish between outages that are deemed within the reasonable control of the networks (normalised outages) and outages deemed beyond their control. The latter exclusions cover outages that originate in the generation and transmission sectors, and outages caused by external events such as extreme weather. As a general principle, it would be unreasonable to assess distribution performance unless the impact of these external factors is excluded. Total network outages in a period are the sum of the normalised and excluded data.

Table 5.7 Feeder categories

FEEDER CATEGORY	DESCRIPTION
Central business district	Predominately supplies commercial, high-rise buildings through an underground distribution network containing significant interconnection and redundancy when compared to urban areas
Urban	A feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km
Rural short	A feeder, which is not a CBD or urban feeder, with a total feeder route length less than 200 km
Rural long	A feeder, which is not a CBD or urban feeder, with a total feeder route length greater than 200 km

Source: Utilities Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, 2002.

As noted, it is difficult to make meaningful comparisons between jurisdictions—even based on the normalised data—because of differences in approach to exclusions and auditing practices. Any attempt to compare performance should also take account of geographical, environmental and other differences between the networks. That said, it is apparent that CBD and urban customers tend to experience better network reliability than rural customers. This reflects that reliability standards take into account the differing cost-benefit reliability trade-offs in each part of a network. To illustrate, there are likely to be more severe economic consequences from a network outage on a CBD feeder compared to a similar outage on a remote rural feeder where customer bases and loads are more dispersed.

21 For background on the Somerville review and Queensland reliability issues, see AER *State of the Energy Market 2007*, p. 53.
22 As of March 2008, the most recent published data for the ACT was for 2002–03.

Figure 5.10a
CBD feeders—Average duration of supply interruptions per customer (SAIDI)

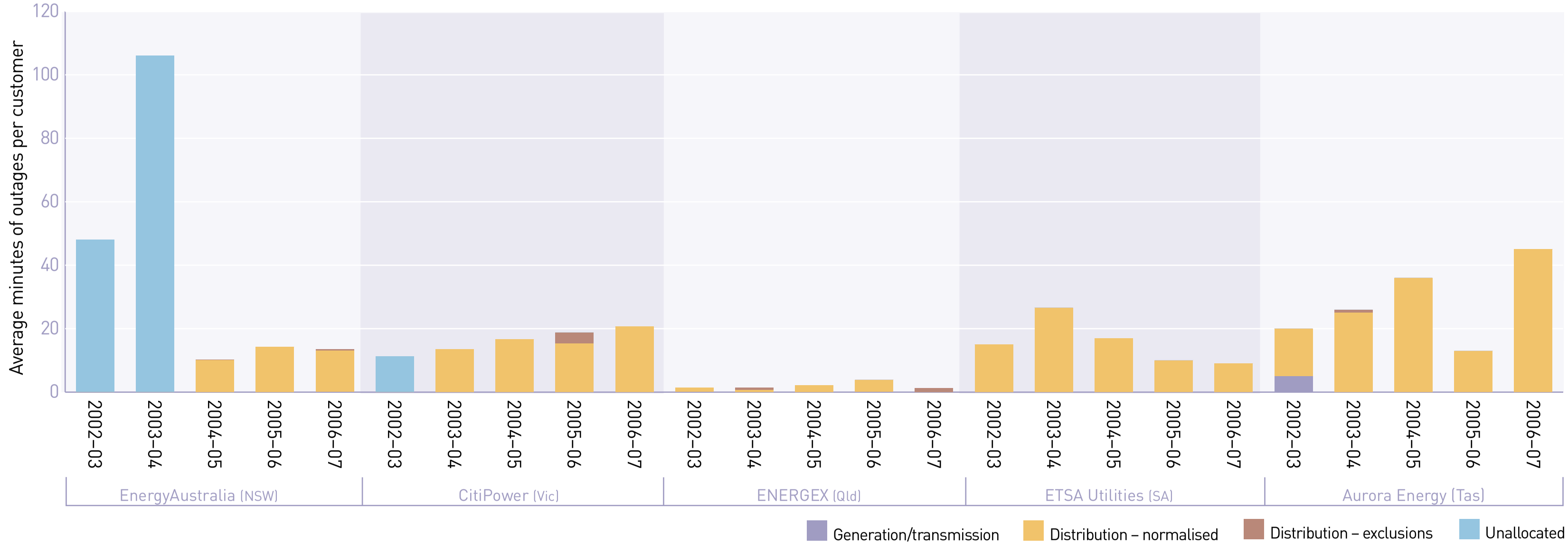


Figure 5.10b
Urban feeders—Average duration of supply interruptions per customer (SAIDI)

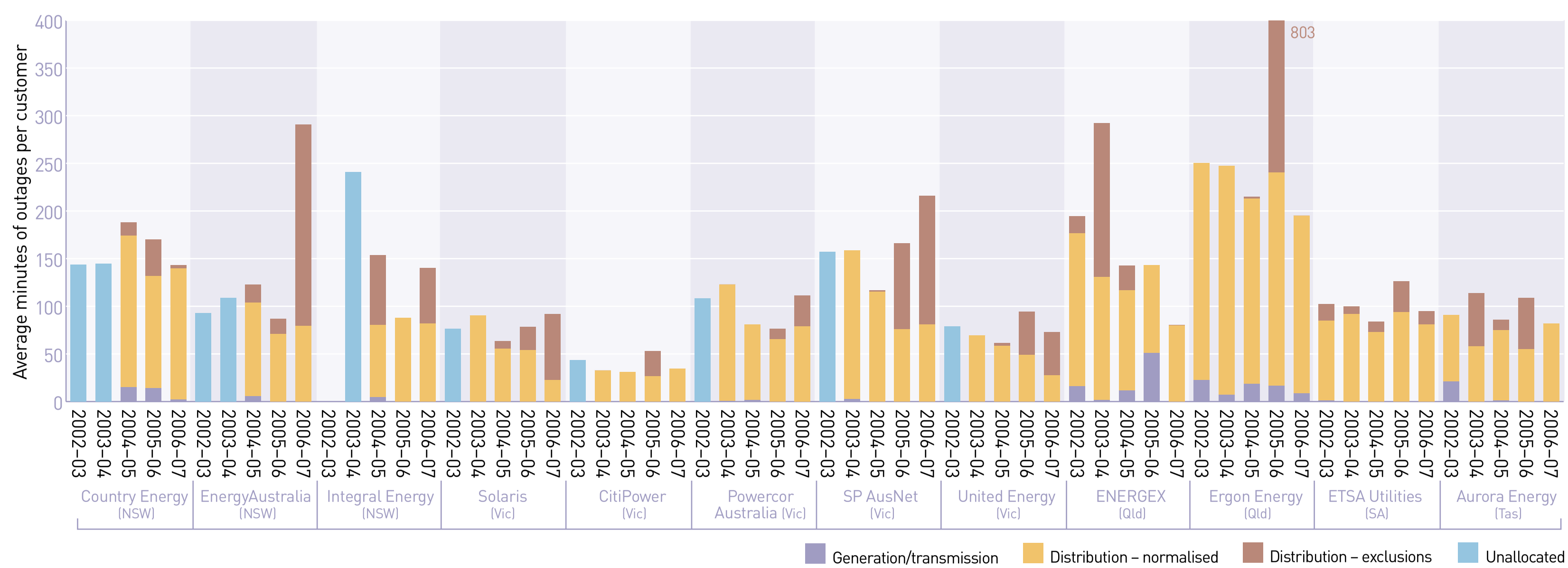


Figure 5.10c

Rural short feeders—Average duration of supply interruptions per customer (SAIDI)

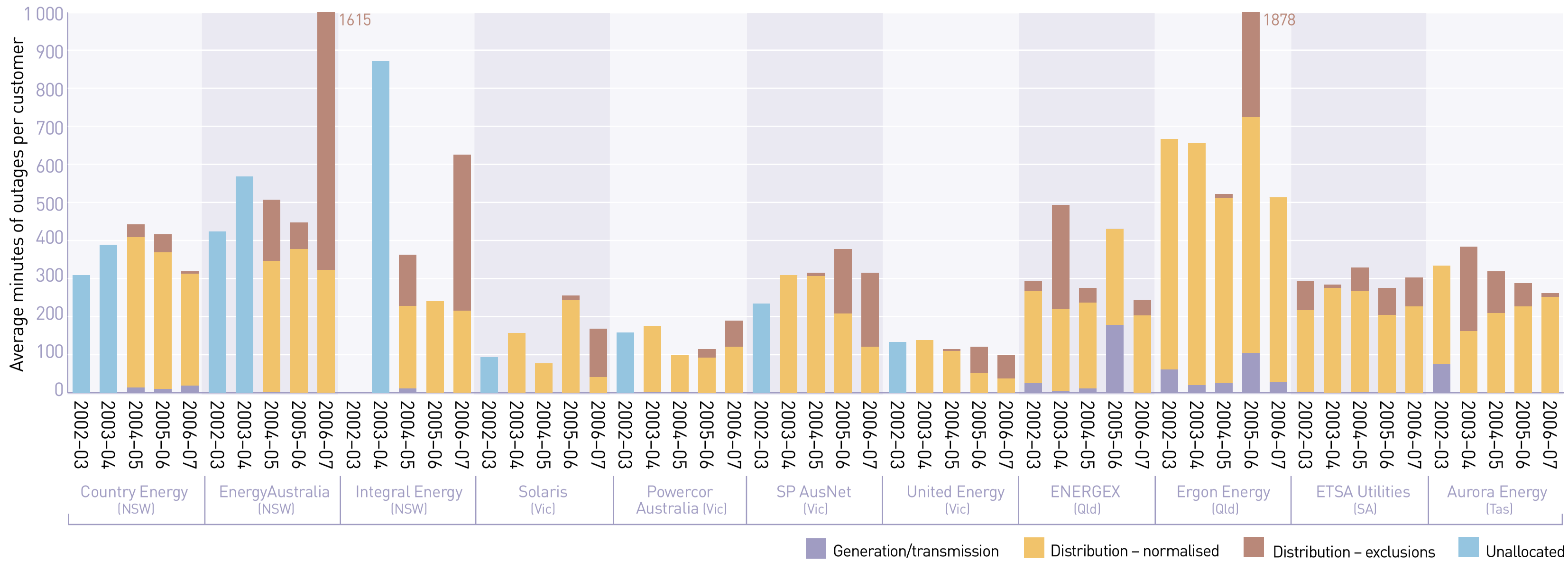
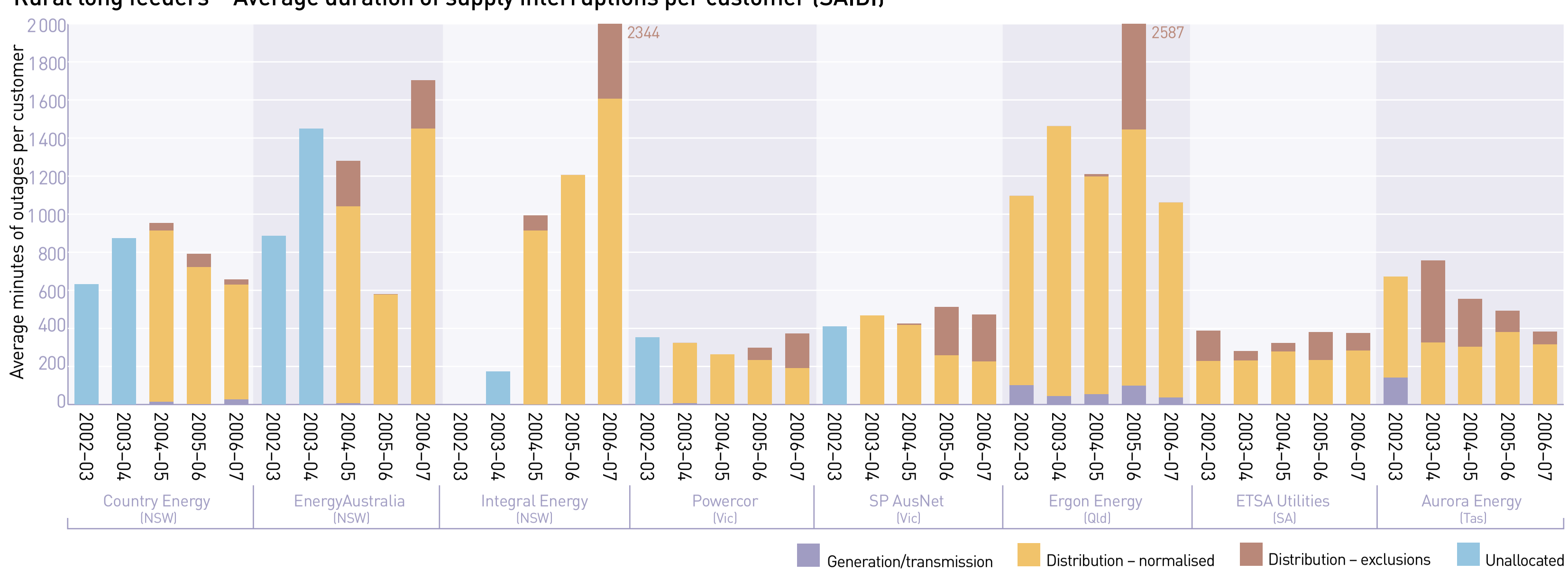


Figure 5.10d

Rural long feeders—Average duration of supply interruptions per customer (SAIDI)



Notes:

1. Victorian data is for the calendar year ending in that period (for example, 2005–06 data is for calendar year 2005).
2. Unallocated data does not provide a breakdown between categories.

Sources: Distribution network performance reports published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy.

Similarly, the unit costs of improving reliability in a high density urban network will be lower than in a dispersed rural network. For these reasons, CBD networks are designed for higher reliability than other feeders, and include the use of underground feeders, which are less vulnerable to outages.

In summary, in the period from 2002–03:

- CBD feeders were more reliable than other feeders. Most CBD customers experienced outages totalling less than 20 minutes per year.
- Urban customers typically experienced outages totalling around 50 to 150 minutes per year. Normalised outage time tends to be lowest for Victorian customers, and highest for Ergon Energy (Queensland) customers. Networks in several jurisdictions experienced significant interruptions that were excluded from the normalised data. Extreme weather caused significant exclusions for Queensland in 2005–06 and New South Wales in 2006–07. The normalised data indicates that reliability is reasonably stable or improving over time in most networks.
- Rural short customers typically experienced normalised outages of around 100 to 300 minutes per year, with outages tending to be highest in New South Wales and Queensland. Ergon Energy (Queensland) customers typically experienced over 500 minutes of normalised outages. Weather-related factors led to major exclusions in Queensland in 2005–06 and New South Wales in 2006–07.
- With a feeder route length of more than 200 kilometres, rural long customers experienced the least reliable electricity supply. Rural long customers in Victoria, South Australia and Tasmania experienced outages of around 200 to 400 minutes per year on average. The Victorian networks recorded the lowest rate of outages, and have improved their performance over time. In 2006–07, a typical customer in two New South Wales networks and the Ergon Energy network (Queensland) experienced over 1000 minutes of normalised outages, with additional substantial outages attributed to external factors.

5.6.4 Technical quality of supply

The technical quality of electricity supply in a distribution network can be affected by issues such as voltage dips, swells and spikes, and television or radio interference. Some problems are network-related (for example, the result of a network limit or fault), but others may be traced to an environmental issue or to a network customer.

Network businesses report on technical quality of supply by disaggregating complaints into their underlying causes and categorising them. There are a number of issues in making performance comparisons between jurisdictions. In particular, the definition of 'complaint' adopted by each business may vary widely.

The complaint rate for technical quality of supply issues since 2004–05 is less than 0.1 per cent of customers for most distribution networks in the NEM.

5.6.5 Customer service

Network businesses report on their responsiveness to a range of customer service issues, including:

- timely connection of services
- timely repair of faulty street lights
- call centre performance
- customer complaints.

Tables 5.8 and 5.9 provide a selection of customer service data published by state and territory regulators. As noted, it is difficult to make performance comparisons due to the significant differences between networks, as well as possible differences in definitions and in information, measurement and auditing systems.

Table 5.8 Timely provision of service

NETWORK	PERCENTAGE OF CONNECTIONS COMPLETED AFTER AGREED DATE			PERCENTAGE OF STREETLIGHT REPAIRS COMPLETED AFTER AGREED DATE			AVERAGE NUMBER OF DAYS TO REPAIR FAULTY STREETLIGHT		
	2005	2006	2007	2005	2006	2007	2005	2006	2007
VICTORIA									
Solaris (AGL/Alinta)	0.14	0.12	0.09	6.1	6.9	1.1	2.0	3.0	2.4
SP AusNet	0.03	0.21	2.40	1.0	0.8	0.1	2.0	2.0	1.4
United Energy	0.12	0.05	0.29	0.8	0.2	0.4	1.4	1.0	1.0
CitiPower	0.00	0.02	0.03	7.8	11.4	5.8	2.3	3.0	2.2
Powercor	0.13	0.12	0.06	0.3	0.1	3.4	2.0	2.0	2.2
NEW SOUTH WALES									
EnergyAustralia	0.01	0.02	n/a	6.6	6.0	n/a	8.0	9.0	n/a
Integral Energy	0.01	0.02	n/a	5.5	0.9	n/a	2.0	2.0	n/a
Country Energy	0.02	0.02	n/a	1.3	1.0	n/a	9.0	8.0	n/a
QUEENSLAND									
Ergon Energy	6.62	0.84	0.48	9.7	21.5	17.9	2.8	3.9	3.5
ENERGEX	3.98	0.62	0.54	5.4	4.8	0.6	3.5	4.5	4.0
SOUTH AUSTRALIA									
ETSA Utilities	0.91	1.33	0.51	4.5	5.5	2.6	3.8	3.6	2.6
TASMANIA									
Aurora Energy	n/a	0.15	0.14	10.5	12.3	14.0	n/a	n/a	n/a

n/a, not available

Notes:

1. Victorian data is in calendar years. Data for other jurisdictions is for year ended June 30.
2. Completed connections data for Queensland and South Australia includes new connections only.

Source: Distribution network performance reports published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy.

Table 5.9 Call centre performance

NETWORK	PERCENTAGE OF ABANDONED CALLS BEFORE REACHING HUMAN OPERATOR			PERCENTAGE OF CALLS ANSWERED BY HUMAN OPERATOR WITHIN 30 SECONDS		
	2005	2006	2007	2005	2006	2007
VICTORIA						
Solaris (AGL/Alinta)	0.9	5.0	7.0	73.8	75.2	77.4
SP AusNet	8.8	6.0	9.0	79.8	82.7	92.3
United Energy	7.7	24.0	18.0	75.6	73.8	72.9
CitiPower	10.8	10.0	5.0	88.2	89.2	85.7
Powercor	5.9	7.0	7.0	90.9	88.7	86.7
NEW SOUTH WALES AND ACT						
EnergyAustralia	10.5	10.5	n/a	44.6	81.3	n/a
Integral Energy	6.0	3.2	n/a	81.0	89.0	n/a
Country Energy	41.2	42.6	n/a	48.4	47.2	n/a
ActewAGL	16.9	22.5	n/a	65.6	39.7	n/a
QUEENSLAND						
Ergon Energy	2.7	3.5	2.3	77.3	85.1	87.0
ENERGEX	4.1	3.9	3.0	80.6	89.4	79.1
SOUTH AUSTRALIA						
ETSA Utilities	4.4	4.0	3.0	86.9	85.2	89.3
TASMANIA						
Aurora Energy	1.0	9.3	5.6	n/a	n/a	n/a

n/a, not available

Note: Victorian data is in calendar years. Data for other jurisdictions is for year ended June 30.

Source: Distribution network performance reports published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy.