4 ELECTRICITY TRANSMISSION

Mark Wilson

Electricity generators are usually located close to fuel sources such as natural gas pipelines, coalmines and hydro-electric water reservoirs. Most electricity customers, however, are located a long distance from these generators in cities, towns and regional communities. The electricity supply chain therefore requires networks to transport power from generators to customers. The networks also enhance the reliability of electricity supply by allowing a diversity of generators to supply electricity to end markets. In effect, the networks provide a mix of capacity that can be drawn on to help manage the risk of a power system failure.

4 ELECTRICITY TRANSMISSION

This chapter considers:

- the role of the electricity transmission network sector
- the structure of the sector, including industry participants and ownership changes over time
- the economic regulation of the transmission network sector by the Australian Energy Regulator
- revenues and rates of return in the transmission network sector
- new investment in transmission networks
- operating and maintenance costs of running transmission networks
- quality of service, including transmission reliability and the market impacts of congestion.

Some of the matters canvassed in this chapter are addressed in more detail in the Australian Energy Regulator's annual report on the transmission sector.[1]

There are two types of electricity network:

- high-voltage transmission lines that move electricity over long distances from generators to distribution networks in metropolitan and regional areas
- low-voltage distribution networks that move electricity from points along the transmission line to customers in cities, towns and regional communities (see chapter 5).

4.1 Role of transmission networks

Transmission networks transport electricity from generators to distribution networks, which in turn transport electricity to customers. In a few cases, large businesses such as aluminium smelters are directly connected to the transmission network. A transmission network consists of towers and the wires that run

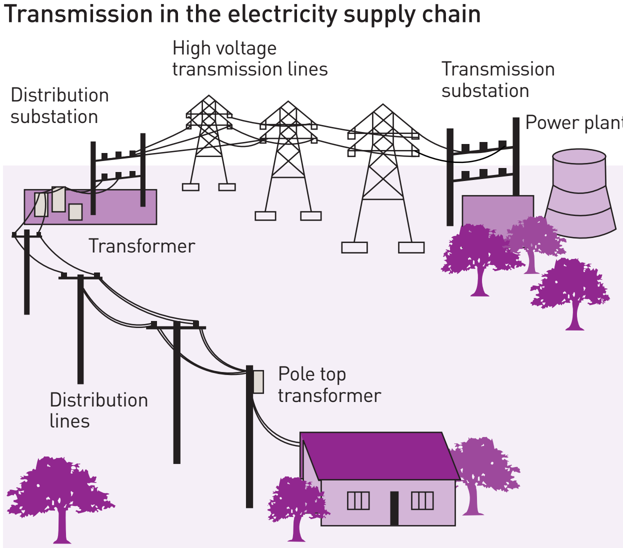
1 AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007.

between them, underground cables, transformers, switching equipment, reactive power devices, monitoring and telecommunications equipment. In the National Electricity Market (NEM), transmission networks consist of equipment that transmits electricity at or above 220 kilovolts (kV) and assets that operate between 66 kV and 220 kV, which are parallel to, and provide support to, the higher voltage transmission network.

The physics of electricity means that it must be converted to high voltages for efficient transport along a transmission network. This minimises the loss of electrical energy that naturally occurs when transmitting electricity over long distances. However, high voltages also increase the risk of flashover.[2] High towers, better insulation and wide spacing between the conductors help to control this risk.

Figure 4.1

Transmission in the electricity supply chain



The high-voltage transmission network strengthens the performance of the electricity industry in three ways:

- First, it gives customers access to large, efficient generators that may be located hundreds of kilometres away. Without transmission, customers would have to rely on generators in their local area, which may be more expensive than remote generators.
- Second, by allowing many generators to compete in the electricity market, it helps reduce the risk of market power.
- Third, by allowing electricity to move over long distances at a moment's notice, it reduces the amount of spare generation capacity that must be carried by each town or city to ensure a reliable electrical supply. This reduces the amount of investment that needs to be tied up in generators.

4.2 Australia's transmission network

The NEM in eastern and southern Australia has a combination of state-based transmission networks and cross-border interconnectors that connect the networks together. This arrangement provides a fully interconnected transmission network from Queensland through to New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania, as shown in figure 4.2. The transmission networks in Western Australia and the Northern Territory are not interconnected with the NEM (see chapter 7).

Aside from the Snowy Mountains Hydro-Electric Scheme, which has supplied electricity to New South Wales and Victoria since 1959, transmission lines that cross state and territory boundaries are relatively new. More than 30 years after the inception of the Snowy scheme, the Heywood interconnector between Victoria and South Australia was opened in 1990.

The construction of new interconnectors gathered pace with the commencement of the NEM in 1998. Two interconnectors between Queensland and New South Wales (Directlink and the Queensland–New South Wales Interconnector (QNI)) commenced in 2000, followed by a second interconnector between Victoria and South Australia (Murraylink) in 2002. The construction of Basslink between Victoria and Tasmania in 2006 completed the interconnection of all transmission networks in eastern and southern Australia. Figure 4.3 depicts the interconnectors in the NEM.

2 A flashover is a brief (seconds or less) instance of conduction between an energised object and the ground (or other energised object). The conduction consists of a momentary flow of electricity between the objects, which is usually accompanied by a show of light and possibly a cracking or loud exploding noise.

Figure 4.2
Transmission networks in the National Electricity Market

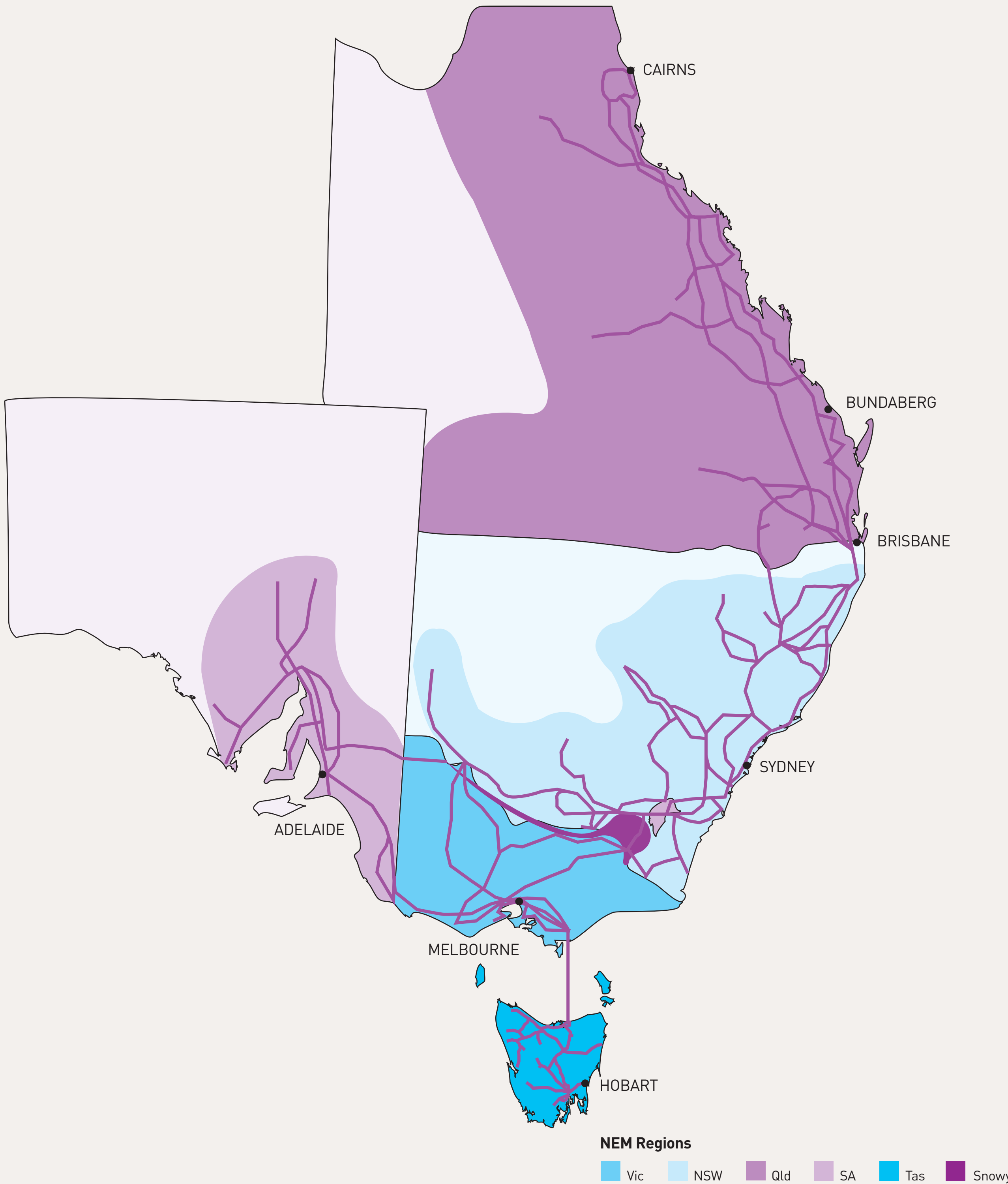
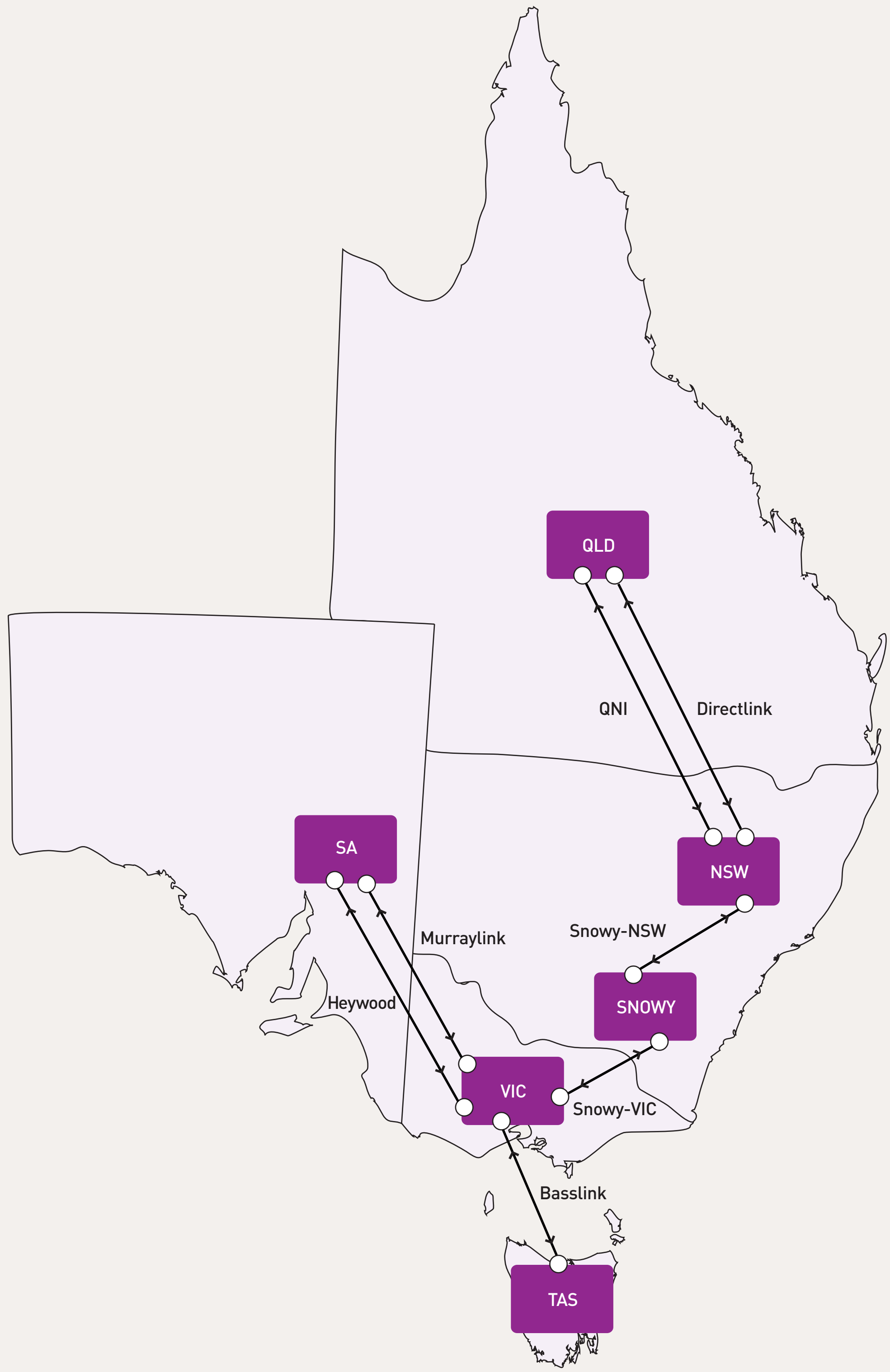


Figure 4.3

Transmission interconnectors in Australia



The NEM transmission network is unique in the developed world in terms of its long distances, low density and long, thin structure. This reflects that there are often long distances between demand centres and fuel sources for generation. For example, the 290 km link between Victoria and Tasmania is the longest submarine power cable in the world. By contrast, transmission networks in the USA and many European countries tend to be higher density and meshed. These differences result in transmission charges being a more significant contributor to end prices in Australia than in many other countries. For example, transmission charges comprise about 10 per cent of retail prices in the NEM,[3] compared to 5 per cent in the United Kingdom.

Electricity can be transported over alternating current (AC) or direct current (DC) networks. Most of Australia's transmission network is AC, in which the power flow over individual elements of the network cannot be directly controlled. Instead, electrical power, which is injected at one point and withdrawn at another, flows over all possible paths between the two points. As a result, decisions on how much electricity is produced or consumed at one point on the network can affect power flows on network elements in other parts of the network. Australia also has three DC networks, all of which are cross-border interconnectors (table 4.1).

Ownership

Table 4.1 lists Australia's transmission networks and their current ownership arrangements. Historically, government utilities ran the entire electricity supply chain in all states and territories. In the 1990s, governments began to carve out the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition, but this was not feasible for the networks, which became regulated monopolies (section 4.3).

Victoria and South Australia privatised their transmission networks, but other jurisdictions retained government ownership.

- Victoria sold the state transmission network (Powernet Victoria) to GPU Powernet in 1997, which in turn sold the business to Singapore Power in 2000. Singapore Power sold 49 per cent of its Australian electricity assets through its partial float of SP AusNet in November 2005.
- South Australia sold the state transmission network (ElectraNet) in 2000 to a consortium of interests led by Powerlink, which is owned by the Queensland Government. YTL Power Investments, part of a Malaysian conglomerate, is a minority owner. Hastings Fund Management acquired a stake in ElectraNet in 2003.

Victoria has a unique transmission network structure in which network asset ownership is separated from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Victorian Energy Networks Corporation (VENCorp) plans and directs network augmentation. VENCorp also buys bulk network services from SP AusNet for sale to customers.

3 The contribution of transmission to final retail prices varies between jurisdictions, customer types and locations.

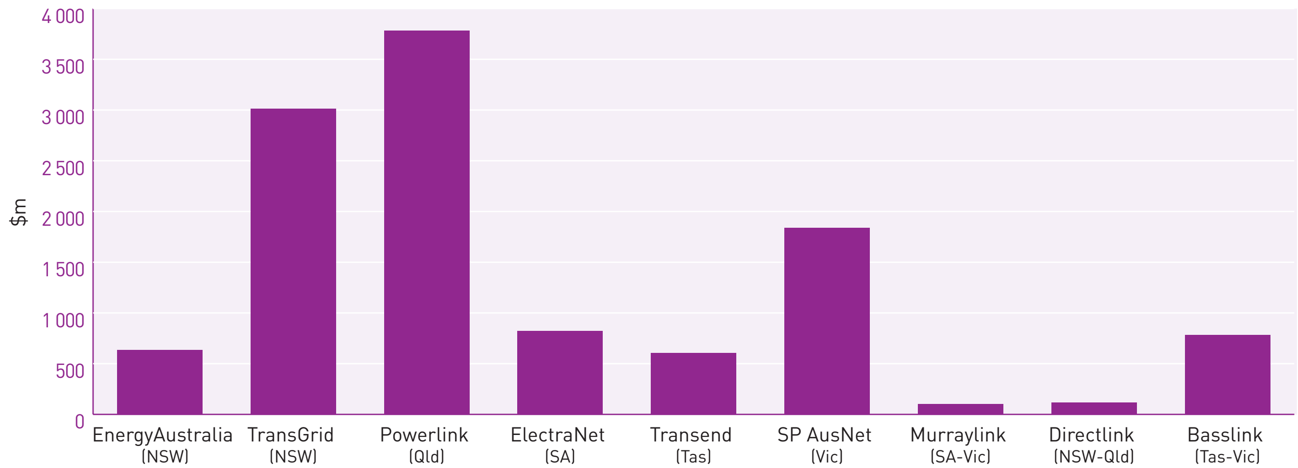
Table 4.1 Transmission networks in Australia

NETWORK	LOCATION	LINE LENGTH (KM) IN 2005–06	MAX DEMAND (MW) IN 2005–06	CURRENT	REGULATED ASSET[1] BASE ($ MILLION)	OWNER
NEM REGIONS[2]						
NETWORKS						
TransGrid	NSW	12 485	13 126	AC	3 013 (1 July 2004)	New South Wales Government
Energy Australia	NSW	1 040	5 165	AC	636 (1 July 2004)	New South Wales Government
SP AusNet	Vic	6 553	8 535	AC	1 836 (1 January 2003)	Singapore Power International 51%
VENCorp[3]	Vic	–	–	–	–	Victorian Government
Powerlink	Qld	11 902	8 232	AC	3 753 (1 July 2007)	Queensland Government
ElectraNet	SA	5 663	2 659	AC	824 (1 January 2003)	Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust
Transend	Tas	3 580	1 780	AC	604 (31 December 2003)	Tasmanian Government
INTERCONNECTORS[4]						
Murraylink	Vic–SA	180		DC	103 (1 October 2003)	APA Group (35% Alinta)[5]
Directlink	Qld–NSW	63		DC	117 (1 July 2005)	APA Group (35% Alinta)[5]
Basslink	Vic–Tas	375		DC	780[6]	National Grid Transco (United Kingdom)
NON-NEM REGIONS						
NETWORKS						
Western Power	WA	6 623		AC	1 387 (1 July 2006)	Western Australian Government
Power and Water	NT	671		AC	–	Northern Territory Government

1. Regulated asset base is an asset valuation applied by the economic regulator. The RABs are as at the beginning of the current regulatory period for each network, as specified in the National Electricity Rules, schedule 6A.2.1(c)(1). Powerlink's RAB is as determined in the AER's 2007–08 to 2011–12 revenue cap decision, June 2007. Western Power's RAB is current as specified in the Economic Regulation Authority of Western Australia's *Further Final Decision on the Proposed Access Arrangement for the South West Interconnected Network*, 2007.
2. All networks and interconnectors in the NEM except for Basslink are regulated by the Australian Energy Regulator; Western Power is regulated by the Economic Regulation Authority of Western Australia and Power and Water is regulated by the Utilities Commission (Northern Territory).
3. VENCorp acquires bulk transmission services in Victoria from SP AusNet under a network agreement and provides them to customers. It plans and directs augmentation of the network but does not own network assets.
4. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state-based networks, are Heywood (Vic-SA), QNI (Qld-NSW), Snowy-NSW and Snowy-Vic.
5. A Babcock & Brown/Singapore Power consortium acquired Alinta under a conditional agreement in May 2007. As a consequence, the ownership of APA Group is likely to change.
6. As Basslink is not regulated there is no RAB. $780 million is the estimated construction cost.

Figure 4.4

Regulated asset bases of transmission networks



Note: The RABs are as at the beginning of the current regulatory period for each network. See table 4.1.

Sources: National Electricity Rules, schedule 6A.2.1(c)(1); AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Decision, June 2007.

Private investors have constructed three interconnectors since the commencement of the NEM:

> Murraylink, which runs between Victoria and South Australia, is the world's longest underground power cable. It was developed by TransÉnergie Australia, a member of the Hydro-Quebec group, and SNC-Lavalin, and commenced operations in 2002. Murraylink was sold to APA Group (formerly Australian Pipeline Trust)[4] in 2006.

> Directlink is an underground interconnector between Queensland and New South Wales that was developed by TransÉnergie Australia and the New South Wales distributor NorthPower (now Country Energy). It commenced operations in 2000.

> Basslink, which connects Victoria and Tasmania, is the longest submarine power cable in the world and commenced operation in 2006. National Grid Transco, one of the largest private transmission companies in the world, owns Basslink.

The three interconnectors were originally constructed as unregulated infrastructure that aimed to earn revenue by arbitraging the difference between spot prices in adjacent regions of the NEM—that is, the interconnectors profited by purchasing electricity in low-price markets and selling it into high-price markets. However, Murraylink and Directlink applied to convert to regulated networks in 2003 and 2006 respectively. This means that their revenues are now set by regulatory determinations. Basslink is currently the only unregulated transmission network in the NEM.

Scale of the networks

Figure 4.4 compares the value of transmission networks in the NEM as reflected in their regulated asset bases (RABs). This is the asset valuation that regulators apply in conjunction with rates of return to set returns on capital to infrastructure owners. In general, it is set by estimating the replacement cost of an asset at the time it was first regulated, plus subsequent new investment, less depreciation. More generally, it provides an indication of relative scale.

4 As at November 2006 the Australian Pipeline Trust began trading as part of the APA Group, which comprises the Australian Pipeline Ltd, Australian Pipeline Trust and APT Investment Trust.

Powerlink (Queensland) and TransGrid (New South Wales) have significantly higher RABs than other networks. Many factors can affect the size of the RAB, including the basis of original valuation, network investment, the age of a network, geographical scale, the distances required to transport electricity from generators to demand centres, population dispersion and forecast demand profiles. The combined RABs of all transmission networks in the NEM is around $11.7 billion. This will continue to rise over time with ongoing investment (section 4.4).

4.3 Regulation of transmission services

While wholesale electricity is traded in a competitive market, this is not the case for transmission services. Electricity transmission networks are highly capital intensive and incur relatively low operating costs. These conditions give rise to economies of scale that make it cheaper to meet rising demand by expanding an existing network than building additional networks. As a result, the efficient market structure is to have one firm operate a transmission network without competition. This situation is described as a natural monopoly.

Given the dependence of generators and retailers on the networks to transport electricity to customers, there are incentives for a network service provider to exercise market power. The structural separation of the networks from generators and retailers means that network owners have no incentive to protect affiliated businesses by denying third-party access to the networks. However, a monopolist typically has incentives to charge a price that exceeds the cost of supply. This is in contrast to a competitive market, where rivalry between firms drives prices towards cost. For this reason, independent price regulation has been introduced.

There was a shift from state-based determination of transmission prices to national regulation with the commencement of the NEM in 1998. The Australian Competition and Consumer Commission (ACCC) commenced regulation of the networks on a progressive basis, depending on the timing of the expiry of state-based regulatory arrangements. The first networks to move to national regulation were TransGrid and EnergyAustralia (New South Wales) in 1999, followed by Powerlink (Queensland) in 2002, SP AusNet and VENCorp (Victoria) in 2003, Electranet (South Australia) in 2003 and Transend (Tasmania) in 2004. The regulation of transmission networks in Western Australia and the Northern Territory remains under state and territory jurisdiction. The National Electricity Law transferred national transmission regulation from the ACCC to the Australian Energy Regulator (AER) on 1 July 2005.[5]

The AER regulates transmission networks under a framework set out in the National Electricity Rules. The rules require the AER to determine a revenue cap for each network, which sets the maximum allowable revenue a network can earn during a regulatory period—typically five years. In setting the cap, the AER applies a building block model to determine the amount of revenue needed by a transmission company to cover its efficient costs while providing for a commercial return to the owner. Specifically, the component building blocks cover:

- operating costs
- asset depreciation costs
- taxation liabilities
- a commercial return on capital.

5 Section 15 of the *National Electricity (South Australia) (New National Electricity Law) Amendment Act 2005*.

To illustrate, figure 4.5 shows the components of the revenue caps for TransGrid for the period 2004–05 to 2008–09 and Transend for the period 2004 to 2008–09. For each network:

- over 50 per cent of the revenue cap consisted of the return on capital invested in the network
- around 70 per cent of the cap consisted of the return on capital plus the return of capital (depreciation).

The regulatory process includes incentives for efficient transmission investment and operating expenditure. There is also a service standards incentive scheme to ensure that efficiencies are not achieved at the expense of service quality (sections 4.4 to 4.6).

Revenues

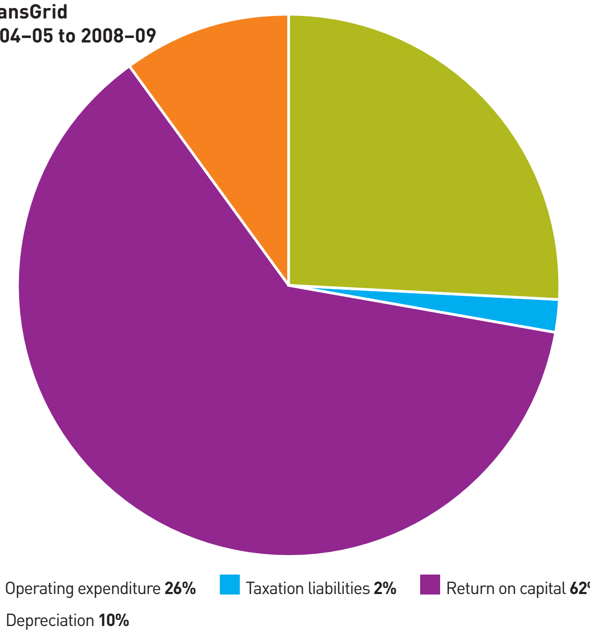
Figure 4.6 charts the capped revenues allowed under national regulation for major transmission networks in the NEM. The year in which the data commences varies between networks, reflecting that the transfer to national regulation occurred in progressive stages. The step movements in the data—for example, TransGrid in 2004–05—usually reflect a transition from one five-year regulatory period to another. The first plot points for Electranet (2001–02) and Transend (2002–03) represent the final revenue determination under state regulation.

Different outcomes between the networks reflect differences in scale and market conditions. However, the revenues of all networks are increasing to meet rising demand over time. The combined revenue of the networks is forecast to reach around $1660 million in 2006–07, representing a real increase of about 6 per cent over two years.

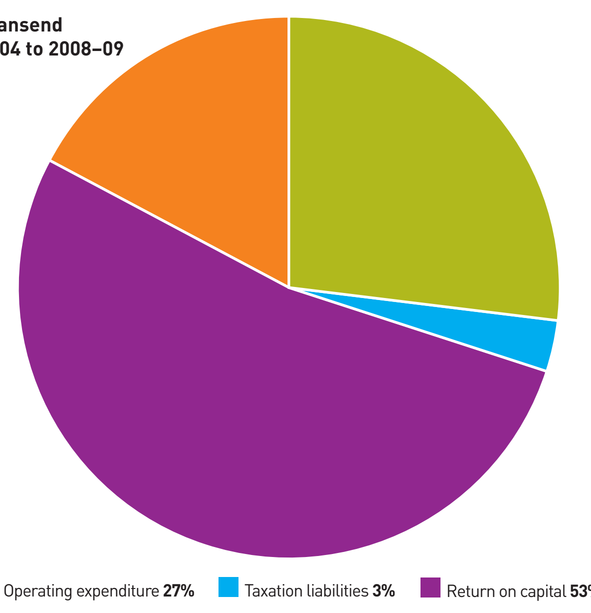
Some networks experienced a significant rise in revenues in their first revenue determination under national regulation. For example, the ACCC allowed Transend (Tasmania) a 28 per cent increase in revenue in 2003–04 above its earnings under previous regulatory arrangements.

Figure 4.5
Composition of the TransGrid and Transend revenue caps

TransGrid
2004–05 to 2008–09

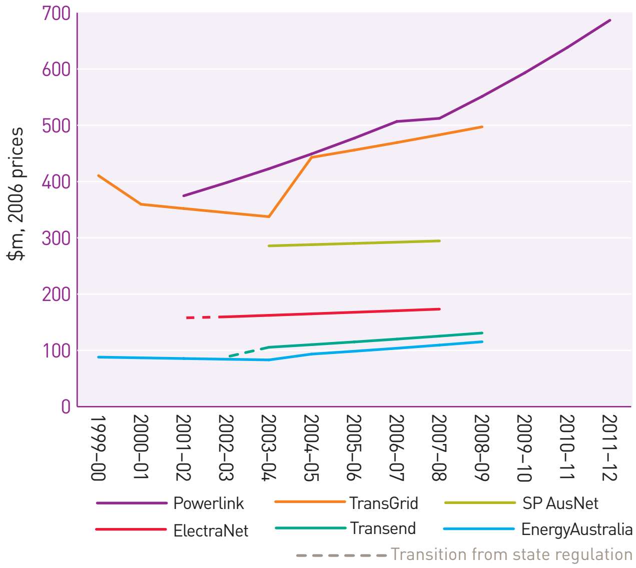


Transend
2004 to 2008–09



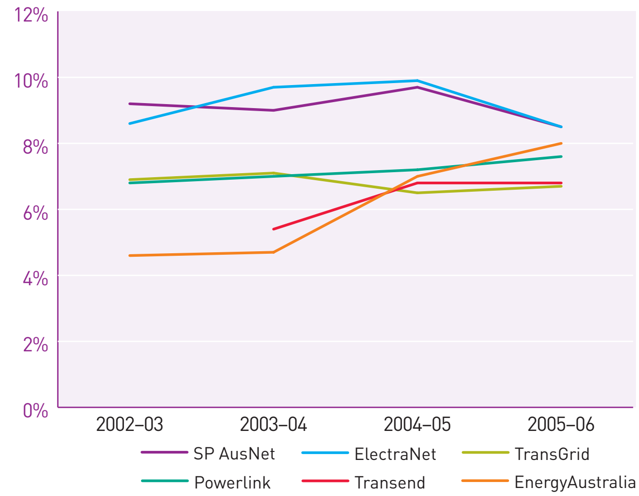
Source: ACCC revenue cap decisions

Figure 4.6
Real maximum revenues



Source: AER final revenue cap decisions.

Figure 4.7
Return on assets



Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007.

Return on assets

The AER's annual regulatory reports publish a range of profitability and efficiency indicators for transmission network businesses in the NEM.[6] Of these, the return on assets is a widely used indicator of performance.

The return on assets is calculated as operating profits (net profit before interest and taxation) as a percentage of the RAB. Figure 4.7 sets out the return on assets for transmission networks over the four years to 2005–06. In this period, government-owned network businesses achieved annual returns on assets ranging from 5 to 8 per cent. The privately owned networks in Victoria and South Australia (SP AusNet and ElectraNet) yielded higher returns in the range of 8 to 10 per cent, although there was some convergence in 2005–06 outcomes.

A variety of factors can affect performance in this area, including 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. In order to draw firm conclusions, a longer time series of data would be necessary.

4.4 Transmission investment

New investment in transmission infrastructure is needed to maintain or improve network performance over time. Investment covers network augmentations (expansions) to meet rising demand and the replacement of depreciated and ageing assets. Some investment is driven by technological innovations that can improve network performance.

The regulatory process aims to create incentives for efficient transmission investment. At the start of a regulatory period an investment (capital expenditure) allowance is set for each network. The process also allows for a contingent allowance for large investment projects that are foreseen at the time of the revenue determination, but where there is significant uncertainty about timing or costs of the project.

6 AER, *Transmission network service providers: Electricity regulatory report for 2005-06*, 2007. See also reports from previous years.

Table 4.2 **Real transmission investment in the NEM ($m, 2006 prices)**

NETWORK	LOCATION	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	SIX YEAR TOTAL
		ACTUAL INVESTMENT				FORECAST INVESTMENT		
NETWORKS								
TransGrid	NSW	234	235	138	156	230	364	1 357
EnergyAustralia	NSW	34	37	40	43	65	61	280
SP AusNet	Vic	40	57	74	102	82	83	438
Powerlink	Qld	224	179	226	271	258	515	1 673
ElectraNet	SA	37	36	57	55	74	45	304
Transend	Tas	…	61	55	68	92	43	319
Total		569	605	590	695	801	1 111	4 371
INTERCONNECTORS								
Murraylink (2000)	Vic–SA							102
Directlink (2002)	NSW–Qld							117
Basslink (2006)	Vic–Tas							780
NEM total								5 370

Note: Annual data for interconnectors is not available. Data refers to RAB (Murraylink and Directlink) and estimated construction cost (Basslink).

In determinations made since 2005, the AER has allowed network businesses discretion over how and when to spend its investment allowance, without the risk of future review. To encourage efficient network spending, network businesses retain a share of the savings (including the depreciation that would have accrued) against their investment allowance. There is a service standards incentive scheme to ensure that cost savings are not achieved at the expense of network performance (section 4.6).

There has been significant investment in transmission infrastructure in the NEM since the shift to national regulation (table 4.2 and figures 4.8 and 4.9). Transmission investment in the major networks reached almost $700 million in 2005–06, equal to around 6 per cent of the combined RAB, and is forecast to rise to around $1100 million by 2007–08. Investment over the six years to 2007–08 is forecast at around $4.3 billion. There has also been over $700 million in private investment in interconnectors since 2002–03, giving a NEM-wide investment total of around $5 billion. This is equal to around 40 per cent of the combined network RAB.

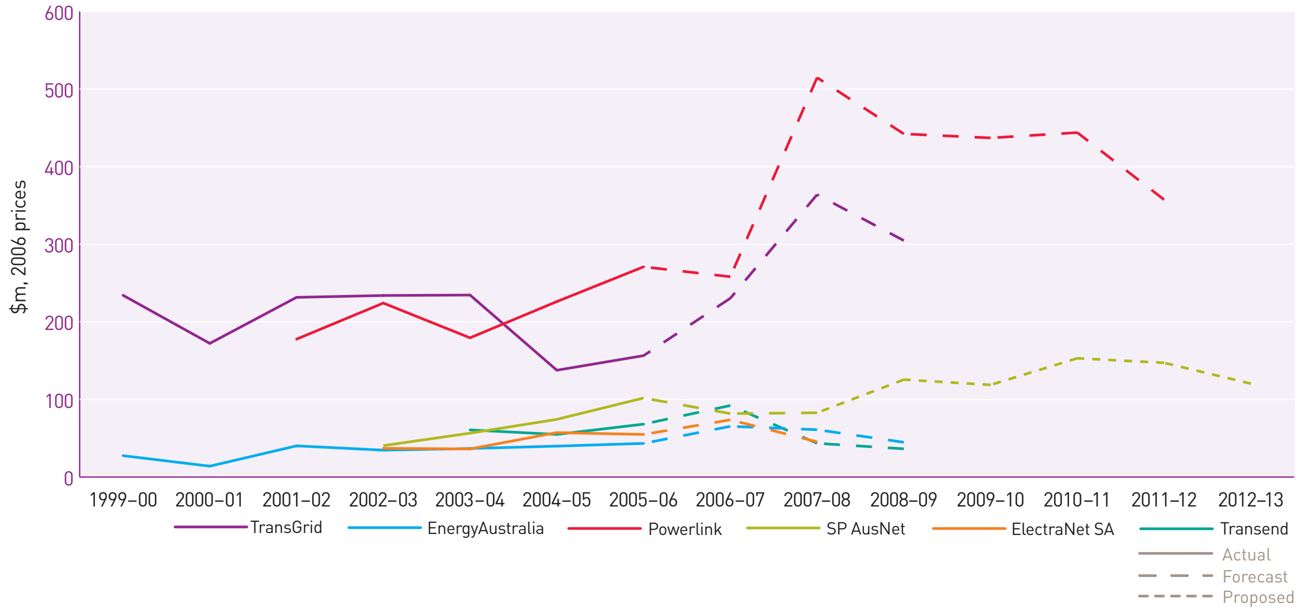
Investment levels have been highest in New South Wales and Queensland. Differences in investment levels between the states reflect the relative scale of the networks and investment drivers such as the age of the networks and demand projections.

> In New South Wales, TransGrid invested almost $1 billion in the 1999–2004 regulatory period, and anticipates investment of around $1.2 billion during the 2005–09 regulatory period.

> In Queensland, Powerlink's capital expenditure in the 2002–06 regulatory period was around $1.1 billion. The AER's final determination for 2007–12 supports investment of over $2.6 billion.

> SP AusNet (Victoria), ElectraNet (South Australia), Transend (Victoria) and EnergyAustralia (New South Wales) have relatively lower investment levels, reflecting the scale of the networks (table 4.1). It may also reflect differences in investment drivers.

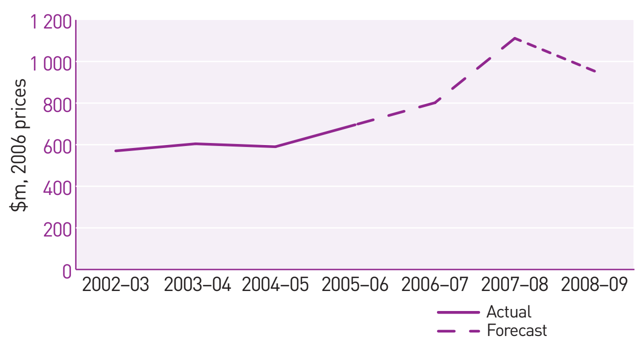
Figure 4.8
Transmission investment by network



Note: Forecast capital investment is as approved by the regulator through revenue cap determinations. Proposed capital investment is subject to regulatory approval.

Sources: ACCC and AER revenue cap decisions and proposals by transmission network businesses.

Figure 4.9
NEM-wide transmission investment



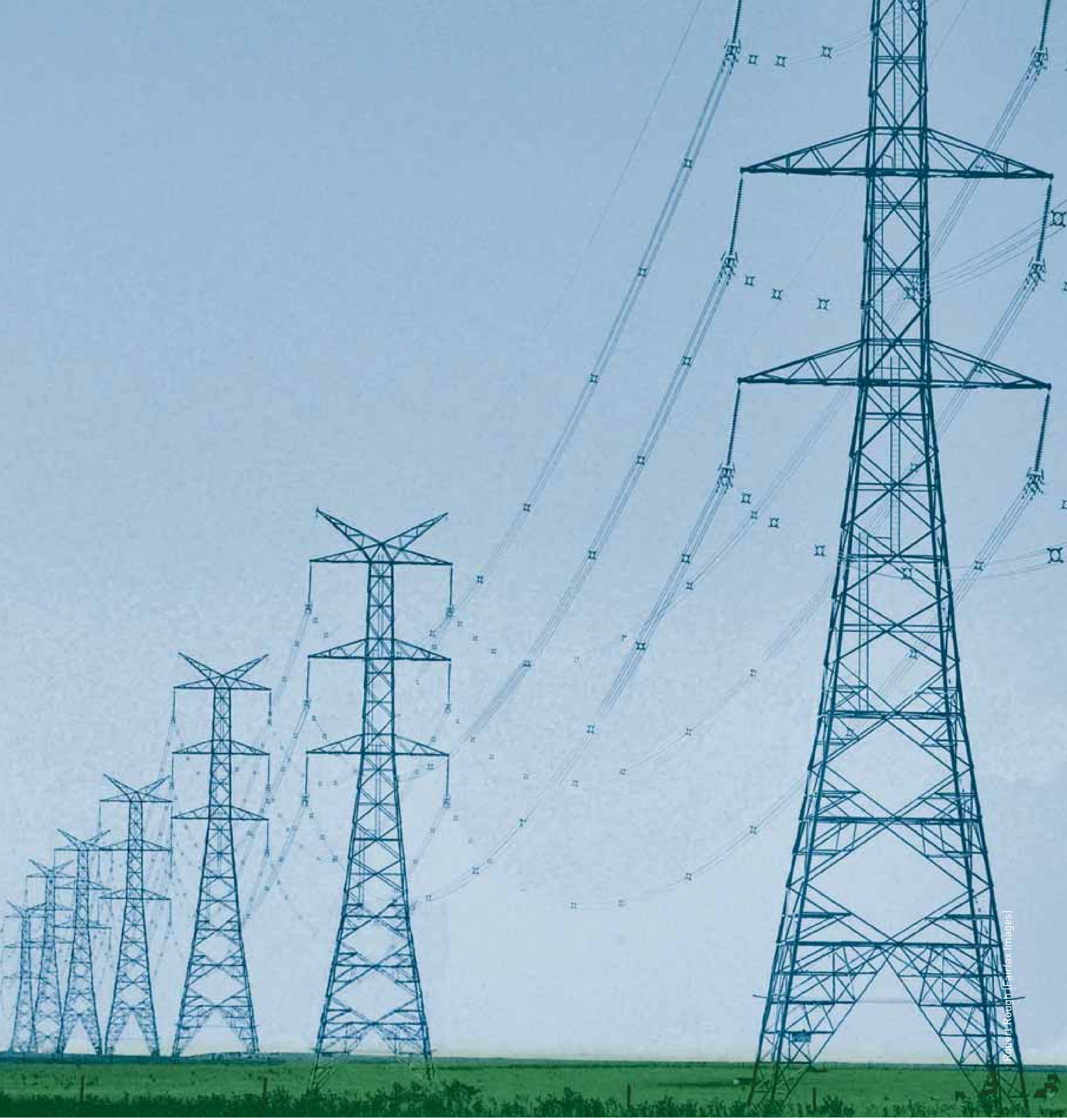
Note: Excludes private interconnectors.

Sources: ACCC and AER revenue cap decisions and proposals by transmission network businesses.

There has been a trend of rising investment in most networks (figures 4.8 and 4.9), although timing differences between the commissioning of some projects and their completion creates some volatility in the data. Transmission infrastructure investment can be 'lumpy' because of the one-off nature of large capital programs. More generally, care should be taken in interpreting year-to-year changes in capital expenditure. As regulated revenues are set for five-year periods, the network businesses have flexibility to manage and reprioritise their capital expenditure over this period. The analysis of investment data should therefore focus on longer term trends rather than short-term fluctuations.

In recent and current revenue cap applications, TransGrid, Powerlink and SP AusNet have projected a significant rise in investment into the next decade (figure 4.8).[7]

7 AER, *Transmission network service providers: Electricity regulatory report for 2004–05*, 2006, ch. 5.



Power cables in rural Victoria

4.5 Operating and maintenance expenditure

In setting a revenue cap for a transmission network, the AER factors in the amount of revenue needed to cover efficient operating and maintenance costs. A target level of expenditure is set and an incentive scheme encourages the transmission business to reduce its spending through efficient operating practices. The scheme allows the business to retain any underspend against target in the current regulatory period, and also retain some of those savings into the next period. The AER also applies a service standards incentive scheme to ensure that cost savings are not achieved at the expense of network performance (section 4.6).

The AER's annual regulatory report[8] compiles data on target and actual levels of operating and maintenance expenditure. A trend of negative variances between these data sets may suggest a positive response to efficiency incentives. Conversely, it would be possible that the original targets were too generous. 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. This suggests that analysis should focus on longer term trends.

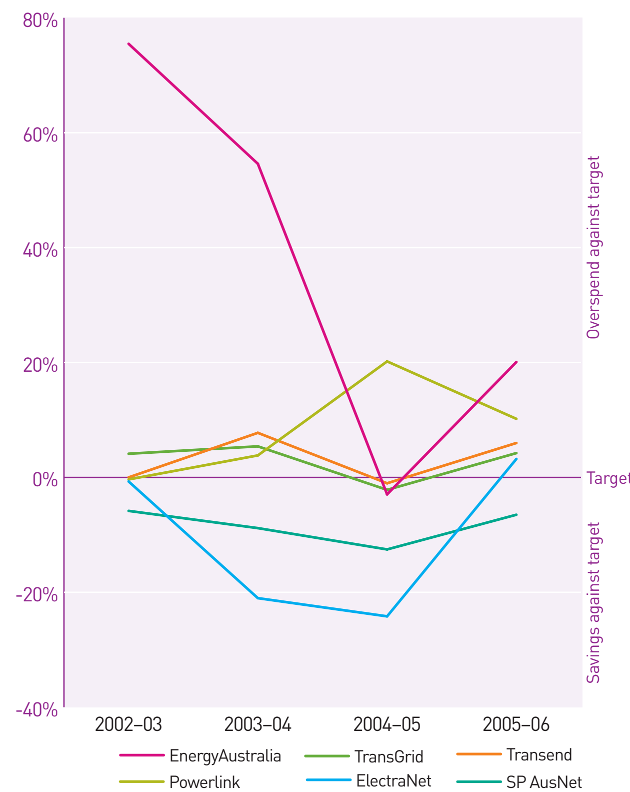
In 2004–05 network businesses spent about $354 million on operating and maintenance costs, about $8 million below forecast. In comparison, 2005–06 expenditure ($387 million) was about $17.5 million above forecast. Network spending was highest for TransGrid (New South Wales) and Powerlink (Queensland), which at least in part reflects the scale of those networks. It should be noted that several factors affect the cost structures of transmission companies. These include varying load profiles, load densities, asset age, network designs, local regulatory requirements, topography and climate.

SP AusNet (Victoria) has spent below its target level every year since the incentive scheme began in 2002–03 (figure 4.10). ElectraNet (South Australia) has generally spent below target, except in 2005–06 when it slightly overspent. SP AusNet and ElectraNet have reported that they actively pursue cost efficiencies in response to the incentive scheme.[9] The other networks have tended to spend above target.

As noted, it is important that cost savings are not achieved at the expense of service quality. AER data indicates that all major networks in eastern and southern Australia have performed well against target levels of service quality (section 4.6).

Figure 4.10

Operating and maintenance expenditure—variances from target



Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06, 2007.*

8 AER, *Transmission network service providers: Electricity regulatory report 2005-06*, 2007. See also reports from previous years.

9 AER, *Transmission network service providers: Electricity regulatory report 2004-05*, 2006, pp. 59 and 63.

4.6 Reliability of transmission networks

Reliability refers to the continuity of electricity supply to customers. The reliability of a transmission network depends on the extent to which it can deliver the electricity required by users. There are many factors that can interrupt the flow of electricity on a transmission network. Interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, lightning strikes or the impact of hot weather raising air-conditioning loads above the capability of a network). A serious network failure might require the power system operator to disconnect some customers, otherwise known as load-shedding.

As in other segments of the power system, there is a trade-off between the price and reliability of transmission services. While there are differences in the reliability standards applied by each jurisdiction, all transmission networks are designed to deliver high rates of reliability. They are engineered with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. More generally, the networks enhance the reliability of the power supply as a whole by allowing a diversity of generators to supply electricity to end markets. In effect, the networks provide a mix of capacity that can be drawn on to help manage the risk of a power system failure.

Regulatory and planning frameworks aim to ensure that, in the longer term, there is efficient investment in transmission infrastructure to avoid potential reliability issues. In regulating the networks, the AER provides investment allowances that network business can spend at their discretion. To encourage efficient investment, the AER uses incentive schemes that permit network businesses to retain the returns on any 'underspend' against their allowance. To balance the scheme, service quality incentive schemes reward network businesses for maintaining or improving service quality. In combination, the capital expenditure allowances and incentive schemes encourage efficient investment in transmission infrastructure to maintain reliability over time.

Investment decisions are also guided by planning requirements set by state governments in conjunction with standards set by the National Electricity Market Management Company (NEMMCO). There is considerable variation in the approaches of state governments to planning and in the standards applied by each jurisdiction (essay B).

To address concerns that jurisdiction-by-jurisdiction planning might not adequately reflect a national perspective, NEMMCO commenced publication in 2004 of an annual national transmission statement (ANTS) to provide a wider focus. It aims, at a high level, to identify future transmission requirements to meet reliability needs.

Acting on the recommendations of the Energy Reform Implementation Group (ERIG), the Council of Australian Governments agreed in 2007 to establish the National Energy Market Operator (NEMO) by June 2009. NEMO will become the operator of the power system and wholesale market, and will be responsible for national transmission planning. As one of its functions it will release an annual national transmission network development plan to replace the current ANTS process.

Transmission reliability data

The Energy Supply Association of Australia (ESAA) and the AER report on the reliability of Australia's transmission networks.

Energy Supply Association of Australia data

The ESAA collects survey data from transmission network businesses on reliability, based on system minutes of unsupplied energy to customers. The data is normalised in relation to maximum regional demand to allow comparability.

The data indicates that NEM jurisdictions have generally achieved high rates of transmission reliability. In 2003–04, there were fewer than 10 minutes of unsupplied energy in each jurisdiction due to transmission faults and outages with New South Wales, Victoria and South Australia each losing fewer than three minutes. The networks again delivered high rates of reliability in 2004–05. Essay B of this report charts the ESAA data (figure B.1).

Australian Energy Regulator data

As noted, the AER has developed incentive schemes to encourage high transmission service quality. The schemes provide financial bonuses and penalties to network businesses that meet (or fail to meet) performance targets, which include reliability targets. Specifically, the targets relate to:

> transmission circuit availability
> average duration of transmission outages
> frequency of 'off supply' events.

Rather than impose a common benchmark target for all transmission networks, the AER sets separate standards that reflect the individual circumstances of each network based on its past performance. Under the scheme, the over- or under-performance of a network against its targets results in a gain (or loss) of up to 1 per cent of its regulated revenue. The amount of revenue-at-risk may be increased to a maximum of 5 per cent in future regulatory decisions.

Table 4.4 sets out the performance data for each network business against its individual target. The data reveals trends in the performance of particular networks over time. While caution must be taken in drawing conclusions from two or three years of data, it can be noted that the major networks have generally performed well against their targets.

The results are standardised for each network to derive an 's-factor' that can range between –1 and +1. This measure determines financial penalties and bonuses. An s factor of –1 represents the maximum penalty, while +1 represents the maximum bonus. Zero represents a revenue neutral outcome. Table 4.3 sets out the s-factors for each network since the scheme began in 2003. All major networks in eastern and southern Australia have outperformed their s-factor targets. As the targets are based on past performance, these outcomes indicate that service quality is improving over time.

Table 4.3 AER s-factor values 2003–05

TNSP	2003	2004	2005
ElectraNet (SA)	0.74	0.63	0.71
SP AusNet (Vic)	(0.03)	0.22	0.09
Murraylink (interconnector) (Vic–SA)	na	(0.80)	0.15
Transend (Tas)	na	0.55	0.19
TransGrid (NSW)	na	0.93	0.70
EnergyAustralia (NSW)	na	1.00	1.00

na not applicable

Note: An incentive scheme for Powerlink (Queensland) commenced in July 2007.

Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007.

Table 4.4 Performance of Transmission Networks against AER targets

TRANSGRID (NSW)	TARGET	2003	2004	2005
Transmission circuit availability (%)	99.5		99.72	99.57
Transformer availability (%)	99.0		99.30	98.90
Reactive plant availability (%)	98.5		99.47	99.64
Frequency of lost supply events greater than 0.05 mins	6		0	1
Frequency of lost supply events greater than 0.40 mins	1		0	0
Average outage duration (minutes)	1500		936.84	716.73
ENERGYAUSTRALIA (NSW)				
Transmission feeder availability (%)	96.96		98.57	98.30
SP AUSNET (VIC)				
Total circuit availability (%)	99.2	99.32	99.27	99.34
Peak critical circuit availability (%)	99.6	99.79	99.97	99.94
Peak non-critical circuit availability (%)	99.85	99.84	99.57	99.86
Intermediate critical circuit availability (%)	99.85	99.48	99.80	99.75
Intermediate non-critical circuit availability (%)	99.75	99.34	99.39	98.21
Frequency of lost supply events greater than 0.05 mins	2	3	2	5
Frequency of lost supply events greater than 0.30 mins	1	0	0	2
Average outage duration–lines (hours)	10	9.98	2.73	7.54
Average outage duration–transformers (hours)	10	7.76	4.86	6.64
ELECTRANET (SA)				
Transmission line availability (%)	99.25		99.38	99.57
Frequency of lost supply events greater than 0.2 mins (number)	5–6		7	0
Frequency of lost supply events greater than 1 min	2		0	0
Average outage duration (minutes)	100–110		48.92	114.11
TRANSEND (TAS)				
Transmission line availability (%)	99.10–99.20		99.34	98.67
Transformer circuit availability (%)	99–99.10		99.31	99.20
Frequency of lost supply events greater than 0.1 mins	13–16		18	13
Frequency of lost supply events greater than 2 mins	2–3		0	0
MURRAYLINK				
Planned circuit energy availability (%)	99.45	99.27	99.27	98.18
Forced outage circuit availability in peak period (%)	99.38	99.68	98.88	99.63
Forced outage circuit availability in off-peak period (%)	99.4	99.55	99.38	99.72

Met target Failed to meet target

Note: An incentive scheme for Powerlink (Queensland) commences in July 2007

Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007; and reports for previous years.

4.7 Transmission congestion

Transmission networks do not have unlimited ability to carry electricity from one location to another. Rather, there are physical limits on the amount of power that can flow over any one part or region of the network. These physical limits arise from the need to prevent damage to the network and ensure stability in the face of small disturbances.

A transmission line can become congested, or 'blocked', due to events and conditions on a particular day. Some congestion is caused by factors within the control of a service provider—for example, through the way they schedule outages, their maintenance and operating procedures, their standards for network capability (such as thermal, voltage or stability limits), changes in network monitoring procedures and decisions on equipment upgrades. Conversely, service providers are not responsible for all transmission congestion. Other contributing factors include extreme weather and constraints imposed by NEMMCO to manage issues in the power system.

For example, hot weather can cause high air conditioning loads that may push a network towards its pre-determined limits set by NEMMCO. Similarly, line maintenance may limit available capacity. The potential for network congestion would be magnified if these events occur simultaneously.

If a major transmission outage occurs in combination with other generation or demand events, it can sometimes cause users to be blacked out. However, this is rare in the NEM. Instead the main impact of congestion is on the cost of electricity. If a particular transmission line is congested, it can prevent a low-cost generator that uses the line from being dispatched to satisfy demand. Instead, generators that do not require the constrained line will be used. If this requires the use of higher cost generators, it ultimately raises the cost of producing electricity. The market impact of transmission congestion is therefore the cost of using expensive generators when low-cost generation could have been used instead.

Congestion can also create opportunities for the exercise of market power. If a network constraint prevents low-cost generators from moving electricity to customers, there is less competition in the market. This can allow the remaining generators to adjust their bidding to capitalise on their position. Ultimately this is likely to raise electricity prices.

Not all constraints have the same market impact. Most do not cause blackouts or force more expensive generation to be dispatched. For example, congestion which 'constrains off' a coal-fired plant and requires the dispatch of another coal-fired plant may have little impact. But the costs may be substantial if cheap coal fired generation needs to be replaced by a high-cost peaking plant such as a gas-fired generator.

With the assistance of NEMMCO, the AER completed a two-year project in 2006 to measure the impact of transmission congestion in the NEM. The following is a non-technical discussion of the results of this research. A more detailed discussion appears in the AER June 2006 decision on the market impact of transmission congestion and in the AER annual reports on congestion.[10]

The AER has developed three measures of the impact of congestion on the cost of electricity (table 4.5). The measures relate to the cost of using more expensive plant than would be used in the absence of congestion. Two measures (the total cost of constraints, TCC, and the outage cost of constraints, OCC) focus on the overall impact of constraints on electricity costs, while the third measure (the marginal cost of constraints, MCC) identifies which particular constraints have the greatest impact.

10 AER, *Indicators of the market impact of transmission congestion—decision*, 9 June 2006; AER, annual congestion reports for 2003–04, 2004–05 and 2005–06.

Table 4.5 **Market impact of transmission constraints—the AER measures**

MEASURE	DEFINITION	EXAMPLE
Total cost of constraints (TCC)	The total increase in the cost of producing electricity due to transmission congestion (includes outages and network design limits). > Measures the total savings if all constraints were eliminated.	Hot weather in New South Wales causes a surge in demand for electricity, raising the price. The line between Victoria and the Snowy reaches capacity, preventing the flow of lower cost electricity into New South Wales to meet the demand. Higher cost generators in New South Wales must be used instead. > TCC measures the increase in the cost of electricity caused by the blocked transmission line.
Outage cost of constraints (OCC)	The total increase in the cost of producing electricity due to outages on transmission networks. > Only looks at congestion caused by network outages. > Excludes other causes, such as network design limits. > Outages may be planned (e.g. scheduled maintenance) or unplanned (eg equipment failure).	Maintenance on a transmission line prevents the dispatch of a coal-fired generator that requires the use of the line. A higher cost gas-fired peaking generator (that uses a different transmission line) has to be dispatched instead. > OCC measures the increase in the cost of electricity caused by line maintenance.
Marginal cost of constraints (MCC)	The saving in the cost of producing electricity if the capacity on a congested transmission line is increased by 1 MW, added over a year. > Identifies which constraints have a significant impact on prices. > Does not measure the actual impact.	> See TCC example (above). > MCC measures the saving in the cost of producing electricity in New South Wales if one additional MW of capacity was available on the congested line. At any time several lines may be congested. The MCC identifies each network element while the TCC and OCC aggregate the impact of all congestion—and do not discriminate between individual elements.
Qualitative impact statements	A description of major congestion events identified by the TCC, OCC and MCC data. > Analyses the causes of particular constraints, for example, network design limits, outages, weather, demand spikes.	Lightning in the vicinity of the Heywood interconnector between Victoria and South Australia led to reduced electricity flows for 33 hours in 2003–04.

The measures estimate the impact of congestion on generation costs rather than spot prices. In particular, the measures reflect how congestion raises the cost of producing electricity, taking account of the costs of individual generators. If the bidding of generators reflects their true cost position, the measures will be an accurate measure of the economic cost of congestion. They therefore reflect the negative efficiency effects of congestion and make an appropriate basis to develop incentives to mitigate this cost. However, if market power allows a generator to bid above its true cost structure, the measures will reflect a mix of economic costs and monopoly rents.

The AER has published three years data on the costs of transmission congestion (figure 4.11). This data indicates that the annual cost of congestion has risen from around $36 million in 2003–04 to $66 million in 2005–06. Typically, most congestion costs accumulate on just a handful of days. Around 66 per cent of the total cost for 2005–06 accrued on just 10 days. Around 40 per cent of total costs are attributable to network outages. Breaking down the data by month, the bulk of congestion costs in 2005–06 occurred in late spring and summer (figure 4.12).

Figure 4.11
Costs of transmission congestion

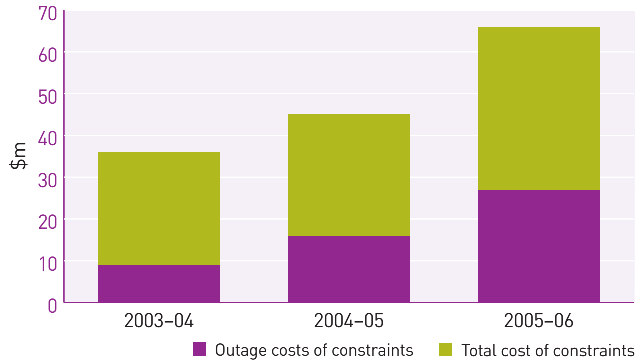
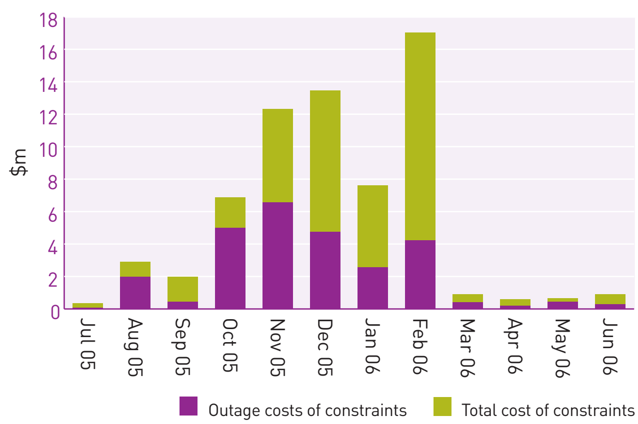


Figure 4.12
Monthly congestion costs, 2005–06



Source: AER

The MCC data, which identifies particular constraints with a significant impact, showed that in 2005–06 around 800 network constraints affected the market at least once. At any one time between 150 and 250 constraints were typically in place. Of these:

> 32 network constraints significantly affected interconnectors, compared to 15 in 2004–05 and five in 2003–04. Congestion on Basslink, which connects Victoria and Tasmania, is not included in this data.

> Nine network constraints within particular regions of the NEM caused congestion for 10 hours or more, compared to nine constraints in 2004–05 and seven in 2003–04. There were also 13 constraints in Tasmania in this category.

The AER plans to assess the impact of major constraints in its weekly market reports. The data will provide information to industry and policy makers on the costs of congestion and will help identify measures to reduce those costs.

In June 2007, the AER released an issues paper on the development of a new incentive scheme to reward transmission companies for reducing the number and duration of outages with a market impact, and for providing more advanced notice of outages.

To date, network service providers have had little incentive to minimise congestion costs as they must bear the costs of network improvements, while retailers, generators and customers gain the benefits. A well-designed incentive scheme would reward network owners for improving operating practices in areas such as outage timing, outage notification, live line work and equipment monitoring. These may be more cost-efficient measures to reduce congestion than solutions that require investment in infrastructure.

More generally, the congestion data should be treated with caution as it outlines results for only three years. Longer term trends may become apparent with the publication of more data over time. The preliminary outcomes suggest that there are some significant constraints and that their impact has risen since 2003–04. Total costs are nonetheless relatively modest given the scale of the electricity market, suggesting that the transmission sector as a whole is responding well to the market's needs.

Transmission tower

Settlement residue auctions

Congestion in transmission interconnectors can cause prices to differ across regions of the NEM (section 2.4). In particular, prices may spike in a region that is constrained in its ability to import electricity. To the extent that trade remains possible, electricity should flow from lower price to higher price regions. Consistent with the regional design of the NEM, the exporting generators are paid at their local regional spot price, while importing retailers must pay the higher spot price in their region. The difference between the price paid in the importing region and the price received in the generating region, multiplied by the amount of flow, is called a settlement residue. Figure 2.8 (chapter 2) charts the annual accumulation of settlement residues in each region of the NEM.

Price separation creates risks for the parties that contract across regions. NEMMCO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues up to one year in advance. Retailers, generators and other market participants may bid for a share of the residues. For example, a Queensland generator, trading in New South Wales, may bid for residues between those regions if it expects New South Wales prices to settle above Queensland prices. As New South Wales is a significant importer of electricity, it can be vulnerable to price separation and often accrues high settlement residue balances.

Table 4.6 shows the amount of settlement residues that accrued each year against the proceeds of residue auctions. The total value of residues represents the net difference between the prices paid by retailers and the prices received by generators across the NEM. It therefore gives an approximation of the risk faced by market participants from inter-regional trade. The table illustrates that the residues are frequently auctioned for less than their ultimate value. On average, the actual residues have been around 75 per cent higher than the auction proceeds.

Table 4.6 Inter-regional hedging: auction proceeds and settlement residues

YEAR	PREMIUM (AUCTION PROCEEDS)	ACTUAL SETTLEMENT RESIDUE DISTRIBUTED	EXCESS OF ACTUAL OVER PREMIUM	
	$ MILLION	$ MILLION	$ MILLION	%
1999–00	41	60	19	46%
2000–01	64	99	35	55%
2001–02	87	98	11	13%
2002–03	62	120	58	94%
2003–04	81	141	60	74%
2004–05	98	230	132	135%
2005–06	118	220	102	86%
Total	558	974	416	75%

Source: ERIG, *Discussion papers*, November 2006.

ERIG considered that market participants discount the value of settlement residues because they are not a firm hedging instrument.[11] In particular, a reduction in the capability of an interconnector—for example, due to an outage—reduces the cover that the hedge provides. This makes it difficult for parties to assess the amount of hedging they are bidding for at the residue auctions. The auction units are therefore a less reliable risk management tool than some other financial risk instruments, such as those traded in over-the-counter and futures markets (chapter 3).

11 ERIG, *Discussion papers*, November 2006, p. 177.