4 ELECTRICITY TRANSMISSION

Electricity generators are usually located close to fuel sources such as natural gas pipelines, coal mines and hydroelectric 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 diverse range 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]

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 between them, underground cables, transformers, switching equipment, reactive power devices, and monitoring and telecommunications equipment.

1 AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008.

Electricity must be converted to high voltages for efficient transport over long distances. This minimises the loss of electrical energy that naturally occurs.[2] 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 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 instantaneously, it reduces the amount of spare generation capacity that must be provided at each town or city to ensure a reliable electrical supply. This reduces inefficient investment in generation.

4.2 Australia's transmission network

In Australia there are transmission networks in each state and territory, with cross-border interconnectors that connect some networks. The NEM in eastern and southern Australia 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 4.1. The transmission networks in Western Australia and the Northern Territory are not connected to the NEM (see chapter 7).

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 kilometre link between Victoria and Tasmania is the longest submarine power cable in the world. By contrast, transmission networks in the United States and in many European countries tend to be meshed and of a higher density. These differences result in transmission charges being a more significant contributor to end prices in Australia than they are in many other countries. For example, transmission charges comprise about 10 per cent of retail prices in the NEM[3] compared to 4 per cent in the United Kingdom.[4]

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 in other parts of the network. Australia also has three DC networks, all of which are cross-border interconnectors.

4.2.1 Interconnection

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. In 1990, more than 30 years after the inception of the Snowy scheme, the Heywood interconnector between Victoria and South Australia commenced operation.

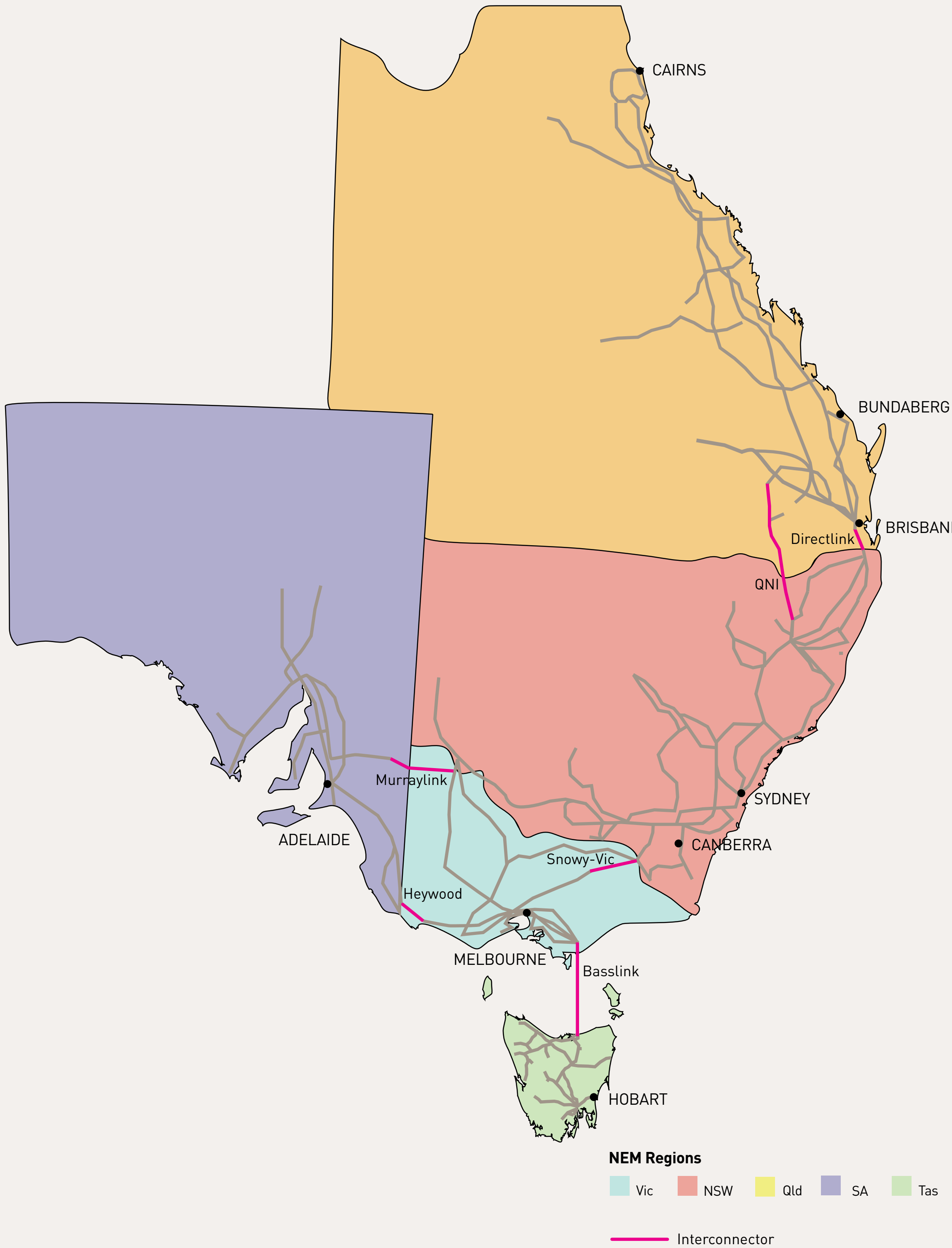
2 While transportation of electricity over long distances is efficient at high voltages, there are risks, such as flashovers. A flashover is a brief (seconds or less) instance of conduction between an energised object and the ground (or another energised object). The conduction consists of a momentary flow of electricity between the objects, and is usually accompanied by a show of light and possibly a cracking or loud exploding noise. High towers, insulation and wide spacing between the conductors help to control this risk.

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

4 Source: ofgem, *Factsheet 66*, January 2008 (available at www.ofgem.gov.uk).

Figure 4.1

Transmission networks in the National Electricity Market



QNI, Queensland–New South Wales Interconnector; NEM, National Electricity Market.

The construction of new interconnectors gathered pace with the commencement of the NEM in 1998. Two interconnectors between Queensland and New South Wales (Directlink[5] and the Queensland–New South Wales Interconnector) commenced operation in 2000, followed by a second interconnector between Victoria and South Australia (Murraylink) in 2002. Murraylink is the world's longest underground power cable. The construction of a submarine transmission cable (Basslink) from Victoria to Tasmania in 2006 completed the interconnection of all transmission networks in eastern and southern Australia. Figure 4.1 shows the interconnectors in the NEM.

4.2.2 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 separate the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition, but this was not appropriate for the transmission and distribution networks, which became regulated monopolies.

Figure 4.2 illustrates ownership changes in the NEM jurisdictions since 1995. Victoria and South Australia privatised their transmission networks, but other jurisdictions retained government ownership:

- Singapore Power International acquired Victoria's state transmission network in 2000 following the network's original sale to GPU Powernet in 1997. Singapore Power International floated its Australian assets as SP AusNet in 2005, but retained a 51 per cent stake.
- 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.

5 Directlink is also known as the Terranora interconnector.

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 VENCorp plans and directs network augmentation. VENCorp also buys bulk network services from SP AusNet for sale to customers.

Private investors have constructed three interconnectors —Murraylink, Directlink and Basslink—since the commencement of the NEM. All have since changed ownership. As of March 2008 the APA Group owned Murraylink and Directlink. A Singapore-based trust with links to Singapore Power International acquired Basslink in 2007.

4.2.3 Scale of the networks

Figure 4.3 compares asset values and capital expenditure in the current regulatory period for transmission networks in the NEM. Western Power (Western Australia) is included for comparative purposes. The chart reflects asset values as measured by the regulated asset base (RAB) for each network. The RAB is the asset valuation that regulators use 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.

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 RAB of all transmission networks in the NEM is around $12.4 billion. This will continue to rise over time with ongoing investment (see section 4.4).

Investment levels are relatively high in relation to the underlying RAB for Powerlink and SP AusNet. This reflects new investment programs approved under recent Australian Energy Regulator (AER) regulatory decisions.

Table 4.1 Transmission networks in Australia

NETWORK	LOCATION	LINE LENGTH (KM) 2006–07	MAX DEMAND (MW) 2006–07	CURRENT REGULATORY PERIOD[1]	REGULATED ASSET BASE ($ MILLION NOMINAL)[2]	INVESTMENT —CURRENT PERIOD ($MILLION 2007)[3]	OWNER
NEM REGIONS							
NETWORKS							
TransGrid	NSW	12 489	13 458	2004–05 to 2008–09	3 013	1 184	New South Wales Government
Energy Australia	NSW	1 040	5 484	2004–05 to 2008–09	636	230	New South Wales Government
SP AusNet	Vic	6 500	9 062	2008–09 to 2013–14	2 191	947[4]	Listed company (Singapore Power International 51%)
Powerlink	Qld	12 000	8 589	2007–08 to 2011–12	3 753	2 418	Queensland Government
ElectraNet	SA	5 611	2 942	2008–09 to 2012–13	1 251	655	Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust
Transend	Tas	3 645	2 415	2004 to 2008–09	604	362	Tasmanian Government
NEM TOTAL		41 285	41 950		11 462	5 796	
INTERCONNECTORS[5]							
Murraylink	Vic–SA	180		2003 to 2012	103		APA Group
Directlink	Qld–NSW	63		2006 to 2015	117		APA Group
Basslink	Vic–Tas	375		Unregulated	780[6]		CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)
NON-NEM REGIONS							
Western Power	WA	6 623		2007 to 2009	1 387	626	Western Australian Government

Notes:

1. The AER regulates all networks and interconnectors in the NEM except for Basslink. Western Power is regulated by the Economic Regulation Authority of Western Australia. Power and Water is regulated by the Northern Territory Utilities Commission.
2. The RABs are as set at the beginning of the current regulatory period for each network. Values sourced from the National Electricity Rules, schedule 6A.2.1(c)(1); AER, *Powerlink Queensland Transmission Network Revenue Cap 2007–08 to 2011–12, Final Decision*, June 2007; *SP AusNet Transmission Revenue Determination 2008–09 to 2012–13, Final Decision*, January 2008; *ElectraNet Transmission Revenue Determination 2008–09 to 2012–13, Final Decision*, April 2008. Western Power's RAB is as specified in the ERA's *Further Final Decision on the Proposed Access Arrangement for the South West Interconnected Network*, April 2007.
3. Investment data is for the current regulatory period (typically five years). The data is based on reported actual expenditure where available and forecast expenditure in other years.
4. SP AusNet's investment data includes forecast investment by VENCorp.
5. 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.
6. As Basslink is not regulated there is no RAB. $780 million is the estimated construction cost.
7. There are no electricity transmission networks in the Northern Territory.

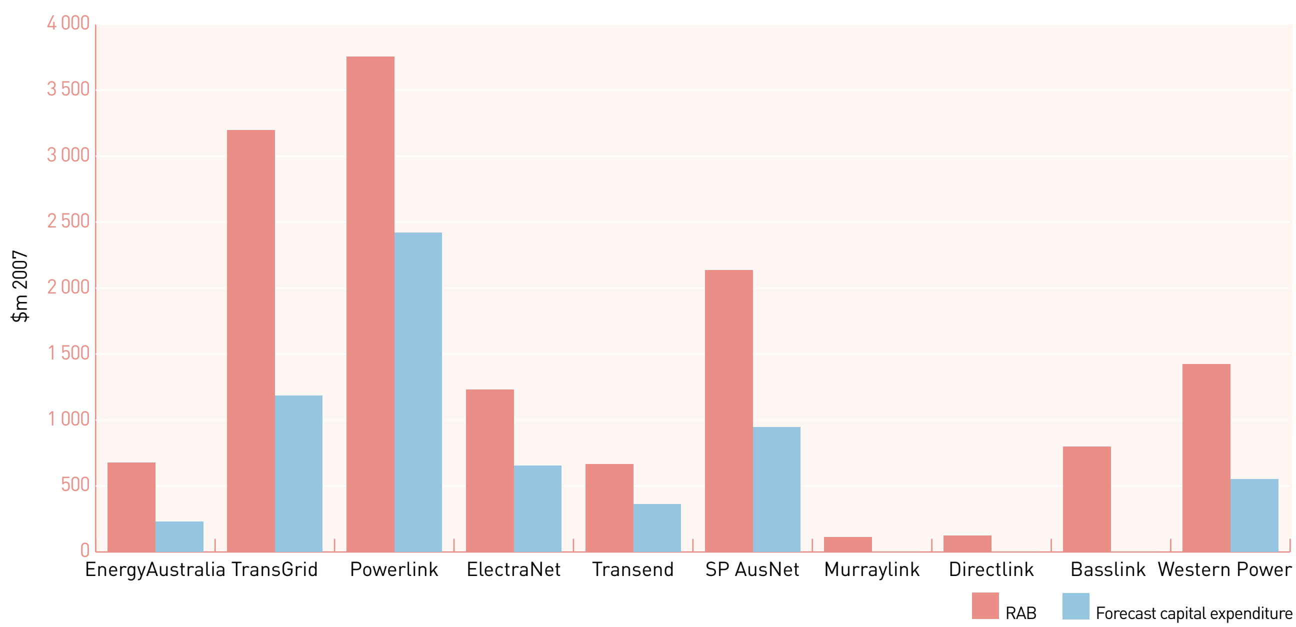
Principal sources: AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008, and previous years; AER/ACCC revenue cap decisions; company websites and press releases.

Figure 4.2
Electricity transmission network ownership

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
VIC	SP AusNet	Powernet Victoria			GPU Powernet			SPI Powernet (Singapore Power)					SP AusNet (51% Singapore Power)			
SA	ElectraNet	SA Government						Powerlink (Queensland Government), YTL			Powerlink (Queensland Government), YTL, Hastings					
NSW	TransGrid	NSW Government														
	Energy-Australia	NSW Government														
QLD	Powerlink	Qld Government														
TAS	Transend	Tas Government														
INTER-CONN-ECTORS	Directlink							Hydro-Quebec Group, NorthPower						APA Group		
	Murraylink								Hydro-Quebec Group, SNC-Lavalin					APA Group		
	BassLink													NGT	CitySpring	
WA	Western Power	WA Government														

NGT, National Grid Transco.

Figure 4.3
Transmission network assets and investment (real)



Note:

1. Network asset values are RABs at the beginning of the current regulatory period (See table 4.1). Basslink is estimated construction cost.
2. Investment data is forecast capital expenditure for the current regulatory period (typically five years).
3. SP AusNet includes augmentation investment by VENCorp.
4. Values are in real 2007 dollars.

Sources: National Electricity Rules, schedule 6A.2.1(c)(1); AER, *Powerlink Queensland Transmission Network Revenue Cap 2007–08 to 2011–12, Final Decision*, June 2007; AER, *SP AusNet Transmission Revenue Determination 2008–09 to 2012–13, Final Decision*, January 2008; AER, *ElectraNet Transmission Revenue Determination 2008–09 to 2012–13, Final Decision*, April 2008; ERA, *Further Final Decision on the Proposed Access Arrangement for the South West Interconnected Network*, April 2007.

4.3 Regulation of transmission services

Electricity transmission networks are capital intensive and incur declining costs as output increases. This gives rise to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing.[6] The Australian Competition and Consumer Commission (ACCC) was the industry regulator until this role transferred to the AER in 2005.

The AER regulates transmission networks under a framework set out in the National Electricity Rules. The approach is to determine a revenue cap for each network, which sets the maximum allowable revenue a network can earn during a regulatory period—at least 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. The component building blocks cover:

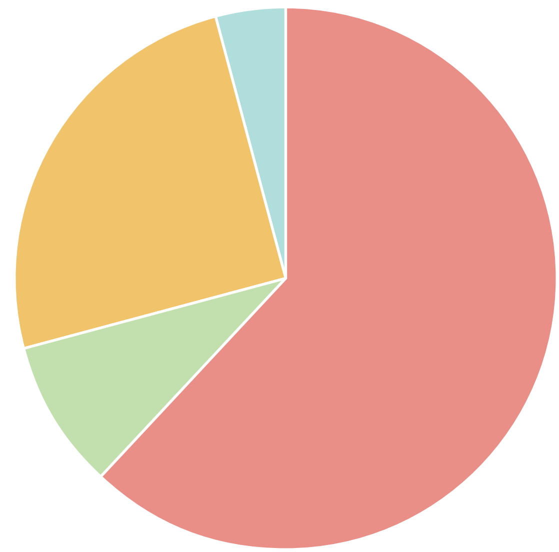
- operating costs
- asset depreciation costs
- taxation liabilities
- a commercial return on capital.

To illustrate, figure 4.4 shows the components of the revenue cap for ElectraNet (South Australia) for the period 2008–09 to 2012–13. For most networks:

- over 60 per cent of the revenue cap consists of the return on capital invested in the network
- around 70 per cent of the cap consists 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 (see sections 4.6 and 4.7).

Figure 4.4
Composition of ElectraNet revenue cap 2008–09 to 2012–13



Sources: AER, Powerlink Queensland Transmission Network Revenue Cap 2007–08 to 2011–12, Final Decision, June 2007, AER; ElectraNet Transmission Revenue Determination 2008–09 to 2012–13, Final Decision, April 2008.

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 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 The Murraylink, Directlink and Basslink interconnectors were constructed as unregulated infrastructure that aimed to earn revenue through arbitrage. That is, they profited by purchasing electricity in low-price NEM regions and selling it into higher-price regions. Murraylink and Directlink converted to regulated networks in 2003 and 2006, respectively. Basslink is currently the only unregulated transmission network in the NEM.

Table 4.2 **Transmission investment in the National Electricity Market (NEM) (real)**

NETWORK	LOCATION	2003	2004	2005	2006	2007	2008	2009	7 YEAR TOTAL
		ACTUAL INVESTMENT					FORECAST INVESTMENT		
NETWORK									
TransGrid	NSW	272	289	139	158	232	366	307	1763
EnergyAustralia	NSW	31	32	40	44	39	61	45	293
SP AusNet	Vic	41	57	74	103	111	81	116[1]	583
Powerlink	Qld	223	178	225	274	259	671	601	2432
ElectraNet	SA	38	37	57	55	77	47	126	438
Transend	Tas		62	55	69	98	43	36	362
Total networks		604	654	590	704	816	1270	1227	5866
INTERCONNECTORS									
Murraylink	Vic—SA	113[2]							
Directlink	NSW—Qld	124[2]							
Basslink	Vic—Tas				796[3]				
NEM TOTAL									6899

Note: Data is for years ended 30 June. Values are in real 2007 dollars.

1. Includes forecast investment by VENCorp.
2. Regulated value at conversion.
3. Estimated construction cost.

The regulatory process also requires a regulatory test assessment for individual projects. The regulatory test is a decision-making tool used to assess proposed augmentation projects for economic efficiency. Under the two limbs of the regulatory test, a network business must ensure a proposed augmentation passes a cost-benefit analysis or provides a least-cost solution.[7]

In determinations made since 2005, the AER has allowed network businesses discretion over how and when to spend their 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.

There has been significant investment in transmission infrastructure in the NEM since the shift to national regulation (see table 4.2 and figures 4.5 and 4.6).[8]

Transmission investment in the major NEM networks exceeded $800 million in 2006–07, equal to around 6 per cent of the combined RABs. Investment is forecast to rise to around $1270 million in 2007–08. Investment over the seven years to 2008–09 is forecast at around $6.9 billion, including the Basslink interconnector. Rising investment outcomes reflect both substantial real investment in new infrastructure as well as rising resource costs in the energy construction sector (see figures 4.7 and 4.8).

Investment levels have been highest for TransGrid and Powerlink. The other networks typically have relatively lower investment levels, reflecting the scale of the networks and differences in investment drivers, such as the age of the infrastructure and demand projections. Recent AER revenue cap decisions project significantly higher investment into the next decade.[9] Forecast investment indicates that a step-change increase in investment levels is taking place across the NEM.

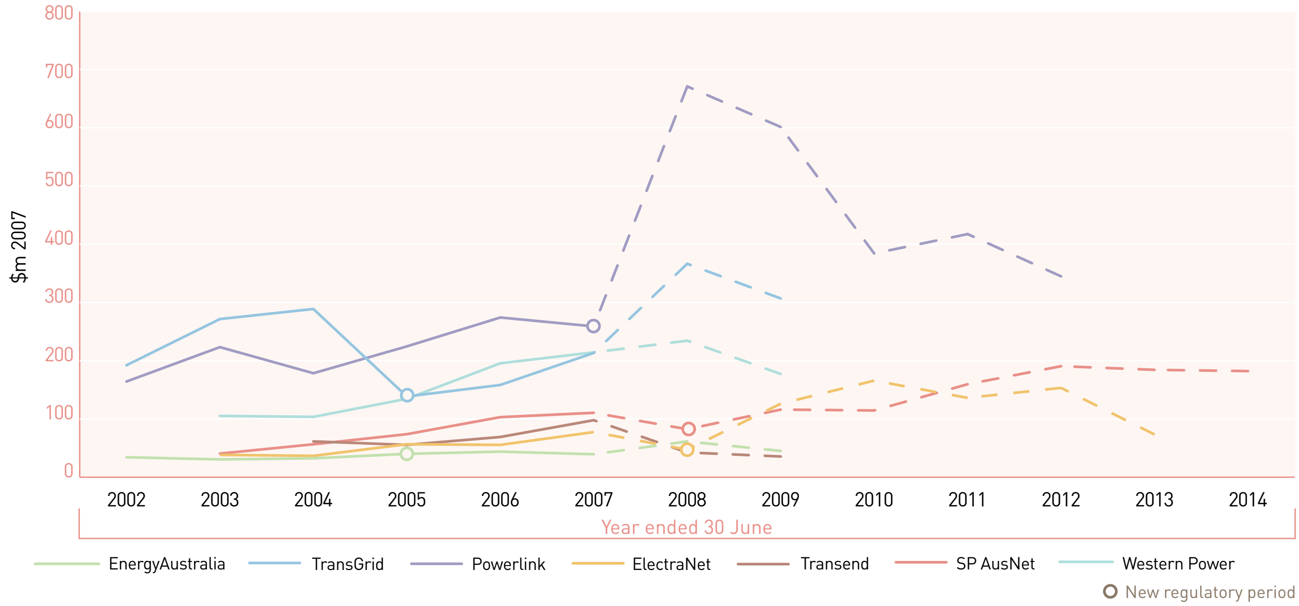
7 The test comprises a reliability limb (a least cost test for reliability projects) and a market benefits limb (a cost benefit test for all other projects). See AER, *Regulatory test for network augmentations*—Version 3, November 2007.

8 Figure 4.5 includes Western Power for comparative purposes.

9 AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008.

Figure 4.5

Transmission investment by network (real)



Notes:

1. Actual data (unbroken lines) used where available and forecasts (broken lines) for other years.
2. Forecast capital investment is as approved by the regulator through revenue cap determinations.
3. Values are in real 2007 dollars.
4. For SP AusNet, actual expenditure is replacement expenditure only; forecast expenditure includes network augmentation by VENCorp.
5. Data series terminate in different years due to differing regulatory periods.

Source: ACCC/AER Annual Regulatory Reports and revenue cap decisions; ERA access arrangement decisions.

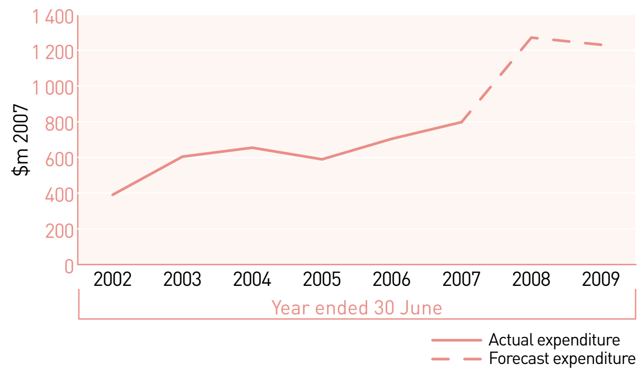
For example:

- The AER determination for Queensland's Powerlink network for 2007–12 approved investment of around $2.4 billion to meet demand growth and replace ageing assets. This is an 80 per cent increase from the previous five years. The decision increases average nominal transmission charges by around 6 per cent.
- In Victoria the AER supported investment of around $750 million in SP AusNet's network over the six years to 2013–14, a 60 per cent increase over the previous regulatory period. The decision increases average nominal transmission charges by around 5 per cent annually. In addition, the AER supported network augmentation investment by VENCorp of around $200 million.
- In South Australia the AER approved investment of around $650 million for the ElectraNet network over the five years to 2012–13. This represents a 60 per cent increase over the previous regulatory period and will increase nominal transmission charges by about 8 per cent.

These recent AER decisions continue a trend of rising investment over the current decade (see figure 4.6). Care should be taken in interpreting year-to-year changes in the data. Timing differences between the commissioning of some projects and their completion creates some volatility. In addition, transmission infrastructure investment can be 'lumpy' because of the one-off nature of very large capital programs. More generally, as regulated revenues are set for three to seven year periods, the network businesses have flexibility to manage and reprioritise their capital expenditure during these periods.

As noted, rising values for transmission investment reflect both real investment as well as higher real input costs. In particular, some resource costs have risen faster than general inflation as measured by the Consumer

Figure 4.6
National Electricity Market transmission investment (real)



Notes:
1. Excludes private interconnectors.
2. Values are in real 2007 dollars.

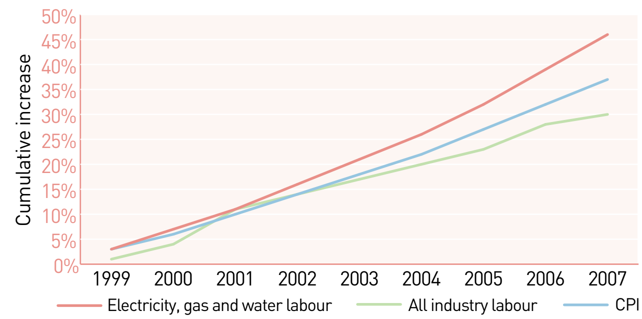
Source: ACCC/AER Annual Regulatory Reports and revenue cap decisions.

Price Index (CPI). The Australian Bureau of Statistics wage index for the electricity, gas and water sectors shows that labour costs in the sector have risen faster over the past decade than both the CPI and the all-industry average (see figure 4.7). The data reflects engineering and trades skills shortages in the sector.

In addition to cost pressures from rising labour costs, network service providers have experienced rising costs of materials. A report for the AER's 2008 regulatory determination for SP AusNet found that costs of materials and equipment had risen substantially over the past few years. Figure 4.8 sets out average annual cost increases for materials and equipment between 2002 and 2006. The data illustrates a sharp rise in costs. In part, this reflects demand pressures from Australia's resource and mining boom and from industrial growth in China and other parts of Asia.[10]

Capital expenditure forecasts in recent AER determinations take account of the increased costs faced by electricity transmission businesses. Escalation factors used in recent regulatory decisions indicate that cost increases for materials may have peaked, while labour costs will continue to rise over the next few years.[11]

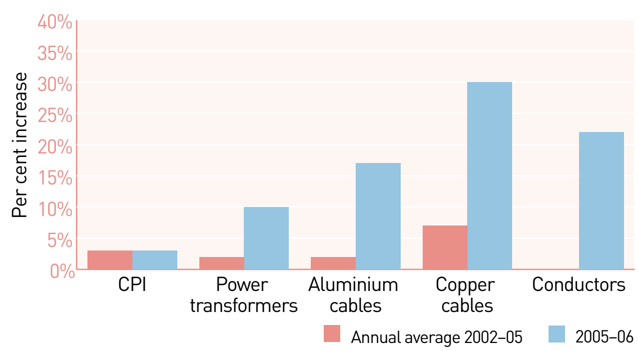
Figure 4.7
Australian Bureau of Statistics wage index for electricity, gas and water supply sector



CPI, consumer price index.

Source: ABS, *6345.0 Labour Price Index, Australia*, December 2007.

Figure 4.8
Materials and equipment costs



CPI, consumer price index.

Source: SKM, *Escalation factors affecting capital expenditure forecasts* (Appendix C to SP AusNet Electricity Transmission Revenue Cap), February 2007.

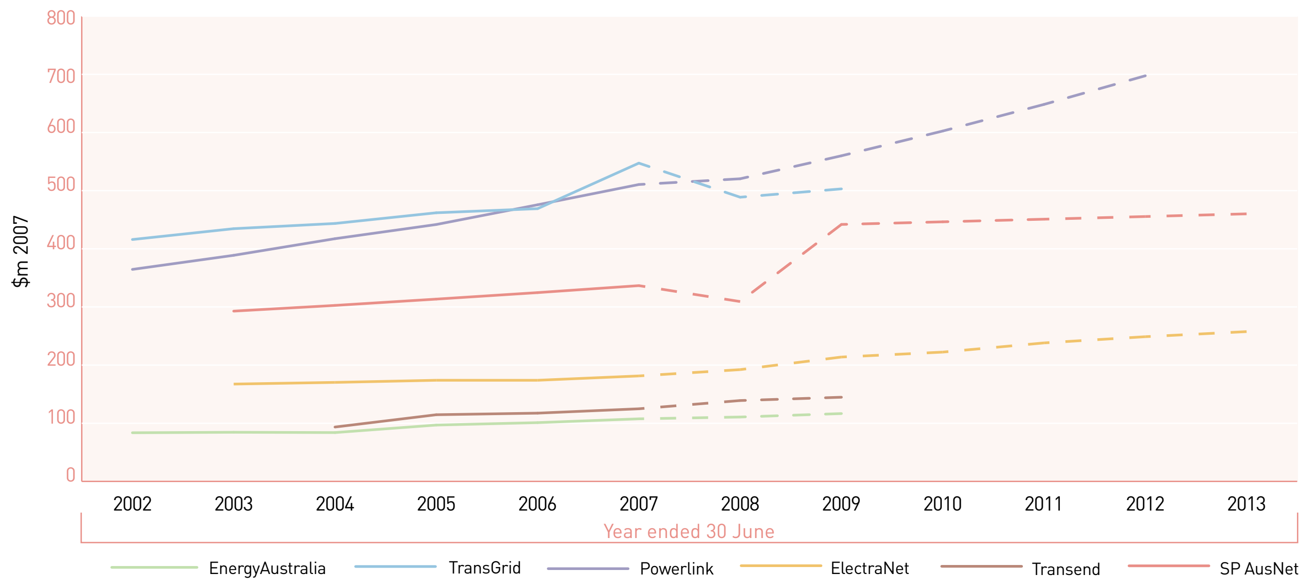
4.4.1 National transmission planning

There have been some concerns that the current jurisdiction-by-jurisdiction approach to transmission planning might not adequately reflect a national perspective on new investment requirements. To address this, the Council of Australian Governments (COAG) agreed in 2007 to enhance planning arrangements. The reforms include establishing the Australian Energy Market Operator (AEMO) to house a national transmission planning function. The AEMO will also replace the National Electricity Market Management

10 SKM, *Escalation factors affecting capital expenditure forecasts* (Appendix C to SP AusNet Electricity Transmission Revenue Cap), February 2007, p. 19. AER. *ElectraNet Transmission Revenue Determination 2008–09 to 2012–13*, May 2008, p. 110.

11 AER, *SP AusNet Transmission Revenue Determination 2008–09 to 2012–13, Final Decision*, January 2008.

Figure 4.9
Transmission revenue forecasts (real)



Notes:
1. Actual data (unbroken lines) is used where available, forecast data (broken lines) is used for other years.
2. Values are in real 2007 dollars.

Source: AER/ACCC Regulatory Reports and final and draft revenue cap decisions.

Company (NEMMCO) as the operator and administrator of the power system and wholesale market.

The Ministerial Council on Energy (MCE) has agreed to establish a national transmission planner by July 2009. It is expected that the national transmission planner will publish an annual national transmission network development plan to replace NEMMCO's current annual national transmission statement. Part of the national planning arrangements will include revisions to the regulatory test to integrate its two limbs.[12]

4.5 Financial performance

The AER publishes an annual performance report on the electricity transmission network sector.[13] In addition, new regulatory determinations include both historical performance data for the preceding regulatory period and forecasts of future outcomes.

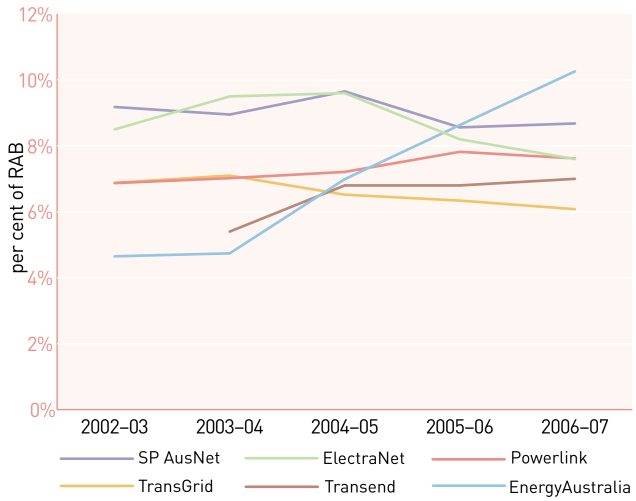
4.5.1 Revenues

Figure 4.9 charts the 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. 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 NEM's transmission networks is forecast to reach around $1725 million in 2007–08, representing a real increase of about 16 per cent over five years.

12 See also Appendix A of this report. The current test comprises a reliability limb (a least-cost test for reliability projects) and a market benefits limb (a cost-benefit test for all other projects). See AER, *Regulatory test for network augmentations—Version 3*, November 2007.

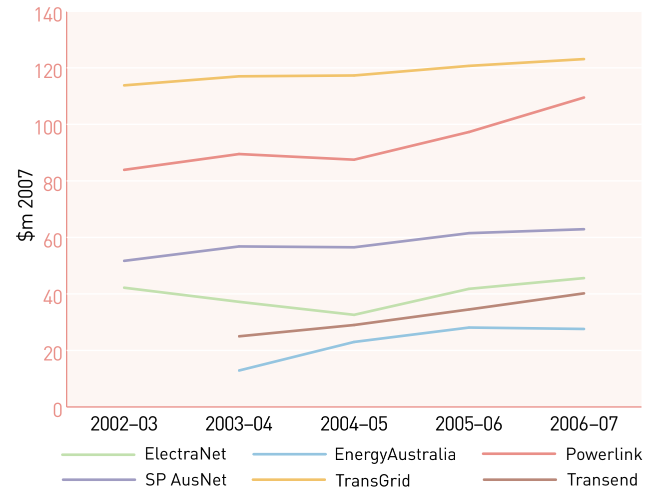
13 AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008.

Figure 4.10
Return on assets



Source: AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008.

Figure 4.11
Operating and maintenance expenditure (real)



Note: Values are in real 2007 dollars.

Source: ACCC/AER Annual Regulatory Reports.

Some networks experienced a significant rise in revenues in their first revenue determination under national regulation. For example, in 2003–04 the ACCC allowed revenues for Transend (Tasmania) which were 28 per cent higher than those provided in its previous regulatory period. In addition, the start of a new regulatory period sometimes provides a sharp increase in revenues, reflecting a step-change in capital expenditure. For example, SP AusNet's forecast revenue for 2008–09 (the first year of the new regulatory period) represents a 40 per cent increase in real revenues over the previous year.

4.5.2 Return on assets

The AER's annual regulatory reports contain a range of profitability and efficiency indicators for transmission network businesses in the NEM.[14] Of these, the return on assets is a widely used indicator of performance.

The return on assets is based on operating profits (net profit before interest and taxation) as a percentage of the RAB.[15] Figure 4.10 shows the return on assets for transmission networks over the five years to 2006–07. In this period, government-owned network businesses typically 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 returns in the range of 7 to 10 per cent. There is some convergence of outcomes from 2005–06, including a sharp rise in returns for the small EnergyAustralia network.

A variety of factors can affect performance in this area, including differences in the demand and cost environments faced by each business, the regulated rate of return provided by the regulator, and variances in demand and costs outcomes compared to those forecasted in the regulatory process.

4.5.3 Operating and maintenance expenditure

In setting a revenue cap, the AER factors in an allowance to cover efficient operating and maintenance costs. In 2006–07, transmission network businesses spent about $400 million on operating and maintenance costs, about $8 million below regulatory forecasts. Real expenditure allowances are rising over time in line with rising demand and costs (see figure 4.11). Spending is highest for TransGrid (New South Wales) and

14 AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008. See also previous years.
15 The RAB is recalculated annually (with new investment rolled in) for the purposes of this measure.

Powerlink (Queensland), which 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.

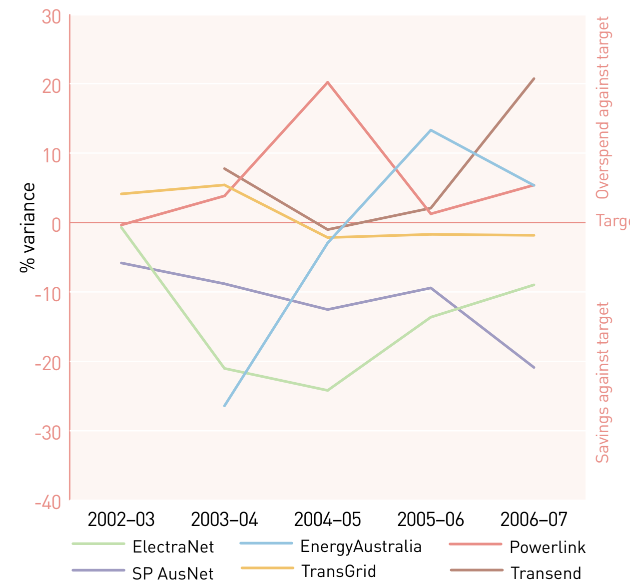
The regulatory scheme provides incentives for network businesses to reduce their spending through efficient operating practices. The AER sets expenditure targets and allows a business to retain any underspend in the current regulatory period—and retain some savings into the next period. The AER also applies a service standards incentive scheme to ensure that cost savings are not achieved at the expense of network performance (see section 4.6).

The AER's 2006–07 regulatory report[16] compares 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. However, it may be that delays in undertaking some projects deferred the need to operate and maintain those assets. 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.

On average operating and maintenance expenditure outcomes have been about 1.5–2.0 per cent below forecasts since 2003–04. SP AusNet (Victoria) and ElectraNet (South Australia) have spent below their target levels since the incentive scheme began in 2002–03 (see figure 4.12). These businesses have reported that they actively pursue cost efficiencies in response to the scheme.[17] The other networks have tended to spend above target, with TransGrid tracking close to its forecasts in most years.

Figure 4.12

Operating and maintenance expenditure —variances from target



Source: AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008.

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 (see section 4.6).

4.6 Reliability of transmission networks

Reliability refers to the continuity of electricity supply to customers. 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.

16 AER, *Transmission network service providers: Electricity regulatory report 2006–07*, 2008.

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

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 capital expenditure allowances that network businesses 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 this, a service quality incentive scheme rewards network businesses for maintaining or improving service quality. In combination, 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 NEMMCO. There is considerable variation in the approaches of state governments to planning, and in the standards applied by each jurisdiction. The Australian Energy Market Commission (AEMC) is currently completing a review of national reliability standards with the aim of developing a nationally consistent framework. The review involves examining existing transmission reliability standards (which are established within the National Electricity Rules and jurisdictional instruments) and options to establish nationally consistent reliability standards.

4.6.1 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.[18]

The data (see figure 4.13) indicates that the NEM jurisdictions have generally achieved high rates of transmission reliability. In 2006–07, unsupplied energy across New South Wales, Victoria and South Australia totalled only 6.2 minutes. Victoria and Western Australia recorded higher outage time than usual in 2006–07, although the Victorian data remained below the national average.

Australian Energy Regulator data

As noted, the AER has developed incentive schemes to encourage efficient 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:

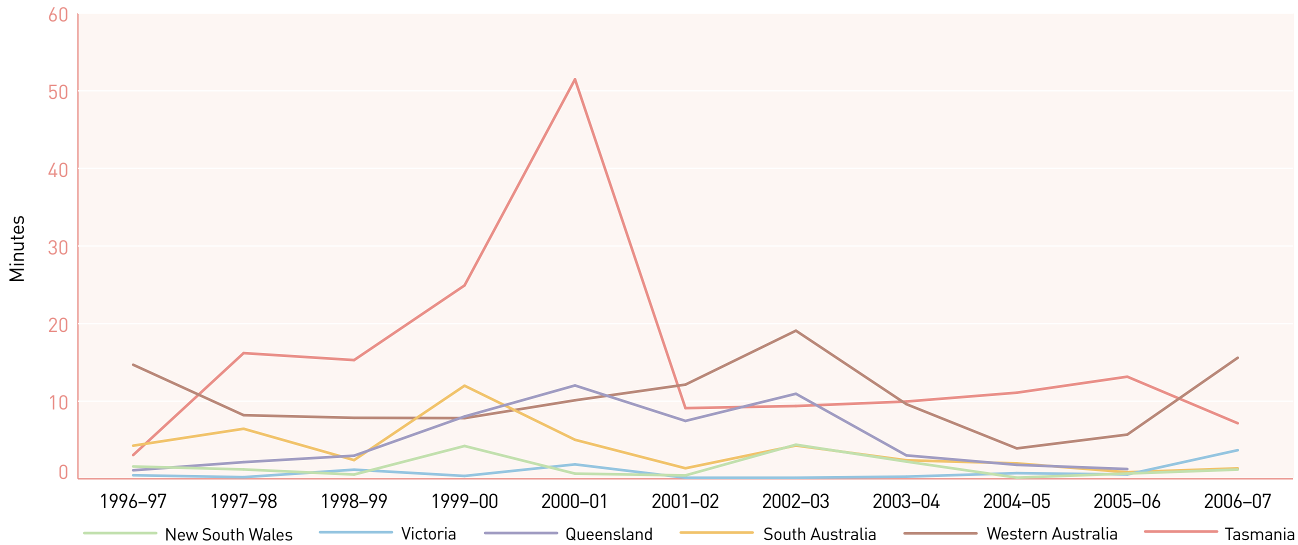
> transmission circuit availability
> average duration of transmission outages
> frequency of 'off supply' events.

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.

18 System minutes unsupplied calculated as megawatt hours of unsupplied energy divided by maximum regional demand.

Figure 4.13

Transmission outages—system minutes unsupplied



Note: Data not available for Queensland in 2006–07.

Source: ESAA, *Electricity Gas Australia* 2008.

Table 4.4 sets out performance data for the major networks against their individual targets. While caution must be taken in drawing conclusions from short data series, it is apparent 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. The major networks in eastern and southern Australia have generally outperformed their s-factor targets. In 2007, Energy Australia, Murraylink and Directlink performed below their targets.

Table 4.3 s-factor values

TRANSMISSION BUSINESS	2003	2004	2005	2006	2007
TransGrid		0.93	0.70	0.63	0.12
EnergyAustralia		1.00	0.67	0.39	−0.14
SP AusNet[1]	−0.03	0.22	0.09	−0.17	0.06
ElectraNet	0.74	0.63	0.71	0.59	0.28
Powerlink					0.82
Transend		0.55	0.19	0.06	0.56
Directlink				−0.54	−0.62
Murraylink				0.21	−0.32

Note:

1. SP AusNet's financial incentive is capped at +0.5% of its maximum allowable revenue, as SP AusNet is also required to comply with the Victorian Government's performance incentive regime administered by VENCorp.

Source: AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008; and reports for previous years.

Figure 4.14 illustrates the net financial reward or penalty from the scheme for each major network. While the scheme encourages network businesses to improve their performance over time, it should be noted that the financial outcomes relate to individual targets for each network and are not a comprehensive indicator of service quality. For example, while SP AusNet was penalised in 2006, it has one of the lowest rates of transmission outages in the NEM (see figure 4.13).

Table 4.4 **Performance against service targets—major networks**

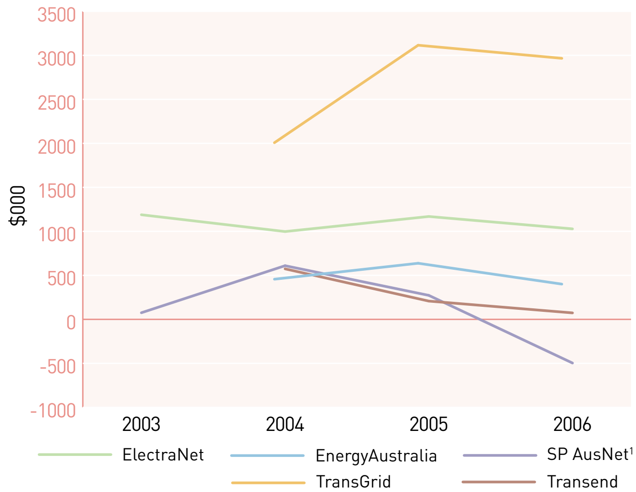
TRANSGRID (NSW)	TARGET	2003	2004	2005	2006	2007
Transmission circuit availability (%)	99.5		99.7	99.6	99.6	99.4
Transformer availability (%)	99		99.3	98.9	98.8	97.5
Reactive plant availability (%)	98.6		99.5	99.6	98.9	99.2
Frequency of lost supply events greater than 0.05 mins	5		0.0	1.0	2.0	4.0
Frequency of lost supply events greater than 0.40 mins	1		0.0	0.0	0.0	1.0
Average outage duration (minutes)	1500		936.8	716.7	812.0	788
ENERGY AUSTRALIA (NSW)	**TARGET**	**2003**	**2004**	**2005**	**2006**	**2007**
Transmission feeder availability (%)	96.96		98.6	98.3	97.7	96.6
SP AUSNET (VIC)	**TARGET**	**2003**	**2004**	**2005**	**2006**	**2007**
Total circuit availability (%)	99.2	99.3	99.3	99.3	99.3	99.1
Peak critical circuit availability (%)	99.9	99.8	100.0	99.9	99.9	99.8
Peak non-critical circuit availability (%)	99.85	99.8	99.6	99.9	99.8	99.9
Intermediate critical circuit availability (%)	99.85	99.5	99.8	99.8	99.5	99.3
Intermediate non-critical circuit availability (%)	99.75	99.3	99.4	98.2	99.0	95.8
Frequency of lost supply events greater than 0.05 mins	2	3.0	2.0	5.0	5.0	n/a
Frequency of lost supply events greater than 0.30 mins	1	0.0	0.0	2.0	2.0	n/a
Average outage duration—lines (hours)	10	10.0	2.7	7.5	30.9	1.6
Average outage duration—transformers (hours)	10	7.7	4.9	6.6	7.2	5.4
ELECTRANET (SA)	**TARGET**	**2003**	**2004**	**2005**	**2006**	**2007**
Transmission line availability (%)	99.25		99.4	99.6	99.4	99.4
Frequency of lost supply events greater than 0.2 mins	5		7.0	0.0	4.0	1.0
Frequency of lost supply events greater than 1 min	2		0.0	0.0	0.0	0.0
Average outage duration (minutes)	100		48.9	114.1	88.5	269.9
POWERLINK (QLD)	**TARGET**	**2003**	**2004**	**2005**	**2006**	**2007**
Transmission circuit availability—critical elements (%)	99.07					99.44
Transmission circuit availability—non-critical elements (%)	98.40					98.70
Transmission circuit availability—peak hours (%)	98.16					98.60
Frequency of lost supply events greater than 0.2 mins	5					1.0
Frequency of lost supply events greater than 1 min	1					0.0
Average outage duration (minutes)	1033					612
TRANSEND (TAS)	**TARGET**	**2003**	**2004**	**2005**	**2006**	**2007**
Transmission line availability (%)	99.10		99.3	98.7	99.2	99.0
Transformer circuit availability (%)	99		99.3	99.2	98.8	99.6
Frequency of lost supply events greater than 0.1 mins	16		18.0	13.0	16.0	10.0
Frequency of lost supply events greater than 2 mins	3		0.0	0.0	1.0	0.0

Met target Below target

n/a, not available

Source: AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008.

Figure 4.14
Incentive scheme outcomes—service performance



Note:
1. SP AusNet's financial incentive is capped at +0.5% of its maximum allowable revenue, as SP AusNet is also required to comply with the Victorian Government's performance incentive regime administered by VENCorp.

Source: AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008; 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 constrained 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. Factors beyond the control of the service provider include extreme weather. For example, hot weather can result in high air-conditioning loads that push a network towards its pre-determined limits, which are set by the network business. To protect system security, NEMMCO may then invoke network constraints. Similarly, line maintenance may limit available capacity. The potential for network congestion is magnified if these events occur simultaneously.

If a major transmission outage occurs in combination with other generation or demand events, it can sometimes cause the load shedding of some consumers. However, this is rare in the NEM. Instead, the main impact of congestion is on the cost of electricity. In particular, transmission congestion increases the total cost of electricity by displacing low-cost generation with more expensive generation. For example, 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.

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, which is likely to result in increased electricity prices.

Not all constraints have the same market impact. Most do not force more expensive generation to be dispatched. For example, congestion which 'constrains off'[19] a coal-fired plant and requires the dispatch of another coal-fired plant may have little net 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 project in 2006 to measure the impact of transmission congestion in the NEM. The AER measures the cost of transmission congestion by comparing dispatch costs with and without congestion. The AER has developed

19 Under the National Electricity Rules, 'constrained off' means: 'in respect of a generating unit, the state where, due to a constraint on a network, the output of that generating unit is limited below the level to which it would otherwise have been dispatched by NEMMCO on the basis of its dispatch offer'.

Table 4.5 **Market impact of transmission constraints—Australian Energy Regulator 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 Victoria –Snowy interconnector 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 > outages may be planned (e.g. scheduled maintenance) or unplanned (e.g. equipment failure). > excludes other causes, such as network design limits.	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 measure 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.

three measures of the impact of congestion on the cost of electricity (see table 4.5). 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.[20]

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, then the measures will reflect a mix of economic costs and monopoly rents.

The AER assesses the impact of major constraints in its weekly market reports and in annual congestion reports. The AER has published four years' data on the costs of congestion. This data (see figure 4.15) indicates that the annual cost of congestion has risen from around $36 million in 2003–04 to $107 million in 2006–07. Typically, most congestion costs accumulate on just a handful of days. Around two-thirds of the total cost for 2006–07 accrued on just 16 days. Around half of total costs are attributable to network outages.

In addition:

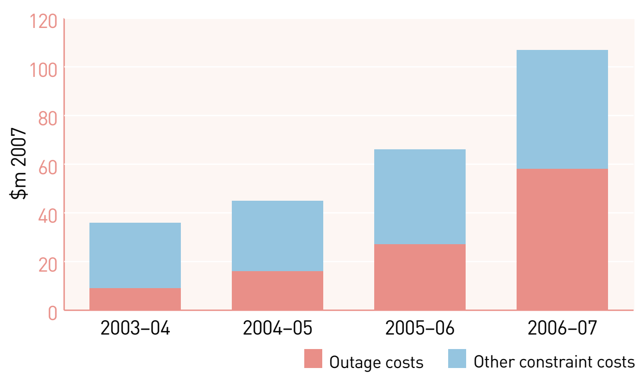
> 40 network constraints significantly affected interconnectors in 2006–07 compared to 32 in 2005–06, 15 in 2004–05 and five in 2003–04. Congestion on Basslink, which connects Victoria and Tasmania, is not included in this data.

20 A more detailed discussion of this appears in: AER, indicators of the market impact of transmission congestion—decision, 9 June 2006; AER, annual congestion reports for 2003–04, 2004–05, 2005–06 and 2006–07.

> 14 network constraints in the NEM (mainland) caused congestion for 10 hours or more in 2006–07 compared to nine constraints in the two previous years and seven in 2003–04. There were four constraints in Tasmania which caused congestion for 10 hours or more in 2006–07.

While the data outlines results for only four years, it is apparent 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 market. Recent regulatory decisions have provided for increased transmission investment that may help to address capacity issues and reduce congestion costs over time. The significant capital expenditure programs of transmission businesses suggest that the transmission sector as a whole is generally responding well to the needs of the market.

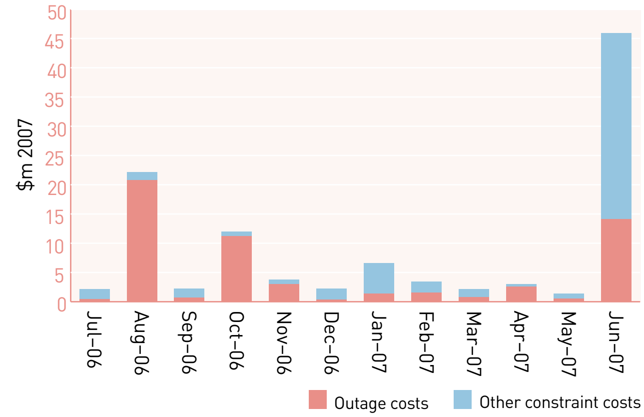
Figure 4.15
Costs of transmission congestion



Source: AER.

Figure 4.16 shows that when the data is broken down into months, the bulk of congestion costs in 2006–07 occurred in August, October, and June—in contrast to the previous year when congestion was concentrated in late spring and summer. The significant congestion costs in June 2007 reflect line outages and generator constraints (due to water shortages) at times of very high electricity demand. To manage transmission congestion on some lines, NEMMCO was obliged to constrain off some low-cost generation, which led to the dispatch of higher-cost plant (in some cases, gas peaking plant).

Figure 4.16
Monthly costs of transmission congestion for 2006–07



Source: AER.

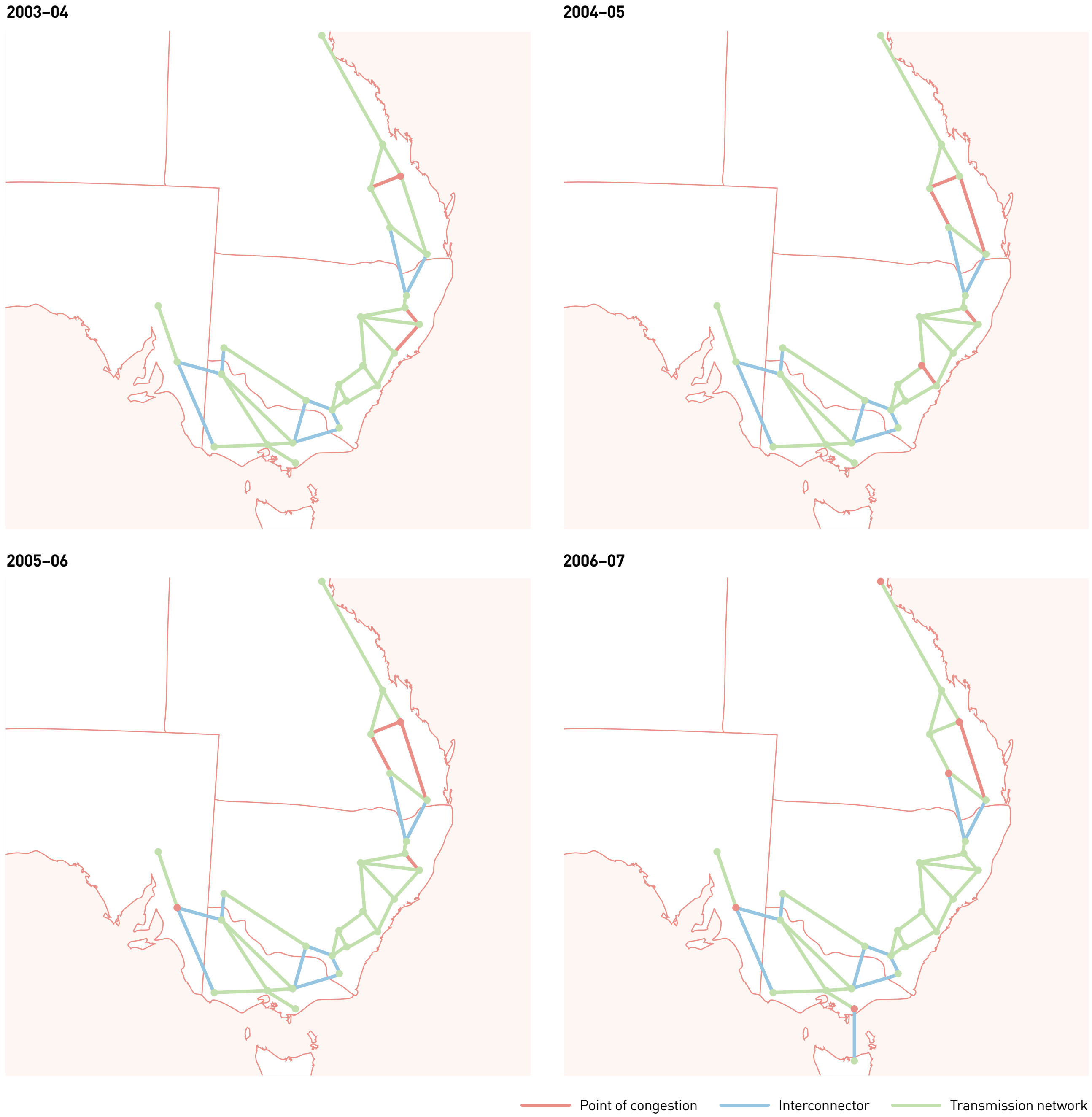
4.7.1 Geography of transmission congestion

The MCC data, which identifies particular constraints with a significant impact, showed that around 750 network constraints affected the market at least once in 2006–07. At any one time, between 350 and 450 constraints were typically in place. Congestion may be significant in a particular area for only a few days a year, but this is sometimes sufficient to have a significant impact on congestion costs.

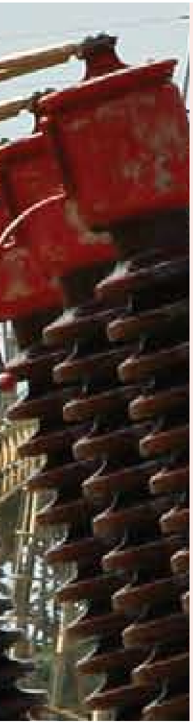
Figure 4.17 shows the locations of transmission infrastructure most affected by congestion over the past four years. Locations of congestion may change from year to year due to unique conditions such as drought, weather events and unscheduled line outages. Geographically, the impact of congestion was most evident in south-east Queensland and at interconnection points between regions. The duration of congestion within Queensland increased from 375 hours in 2005–06 to 773 hours in 2006–07. A significant proportion of this related to flows between central Queensland and the load centre in Brisbane (see Queensland case study in box 4.1). Other recurring locations of significant congestion include the Heywood interconnector (Victoria–South Australia border), northern New South Wales and Basslink (Victoria–Tasmania).

Figure 4.17

Congestion locations in the National Electricity Market



Source: AER.



Box 4.1 Case study—Transmission outages in Queensland

An example of the effects of transmission constraints on energy market outcomes occurred on Wednesday 13 June 2007 on the 814 line between Gladstone and Gin Gin in Queensland.

On this day, the NEM experienced very high New South Wales demand. In addition, a number of generators were out of service. Drought had constrained the availability of water for cooling in some coal-fired generators—especially at Tarong and Swanbank in Queensland and in some New South Wales and Victorian generators.

These conditions led to a very tight demand–supply balance, causing high prices across the NEM. Prices reached $6951 per MWh in Queensland at 6 pm, mostly driven by peak New South Wales demand. In this period, outages on the Gladstone–Gin Gin line also reduced transfer capability between central and south Queensland. To manage this issue, NEMMCO was obliged to invoke a constraint to reflect the network's reduced capability. The limit on flows meant that generators in northern Queensland that rely on the network were 'constrained off', reducing the amount of electricity they could supply. This led to NEMMCO dispatching higher-cost generators when lower-cost generation would otherwise have been available. The outage cost of constraints on this day was estimated to be $2.5 million.

Long-term outages on the Gladstone–Gin Gin line accounted for a significant amount of the congestion in Queensland for 2006–07. The NEMMCO constraints invoked to manage this congestion limited the dispatch of central and northern Queensland generators. In June 2007, the constraints restricted their output by as much as 550 MW.

4.7.2 Measures to reduce congestion costs

The AER recognises the significance of congestion costs and has responded to the issue by:

- developing measures of the market impact of transmission constraints and publishing data against these measures (as outlined)
- implementing an incentive scheme to reduce transmission constraints
- providing for rising transmission investment in regulatory decisions (for example, the AER has approved a significant capital expenditure program for Powerlink over the next five years; Powerlink is the transmission provider in Queensland, a region that has experienced recurring congestion issues).

Other responses include the AEMC congestion management review, which aims to enhance mechanisms to manage congestion in the NEM. The review considers options such as congestion pricing, changes to regional pricing structures and deeper connection charges. In addition, the MCE is implementing national transmission planning arrangements which are expected to reduce congestion through enhanced whole-of-NEM network planning.

Congestion management incentive scheme

The AER introduced a new incentive mechanism in 2008 to reduce the effects of transmission congestion. The mechanism forms part of the service performance incentive scheme to encourage network owners to take account of the impact of their behaviour on the electricity market.[21] This new mechanism operates as a bonus-only scheme. The incentive aims to reward network owners for improving operating practices in areas such as outage timing, outage notification, live line work and equipment monitoring. In some cases, these may be more cost-efficient measures to reduce congestion than solutions that require investment in infrastructure.

21 AER, *Electricity transmission network service providers: Service target performance incentive scheme*, March 2008.

The mechanism permits a transmission business to earn an annual bonus of up to 2 per cent of its revenue if it can eliminate all outage events with a market impact of over $10 per MWh.[22]

4.7.3 Settlement residue auctions

Congestion in transmission interconnectors can cause prices to differ across regions of the NEM (see 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 will 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.

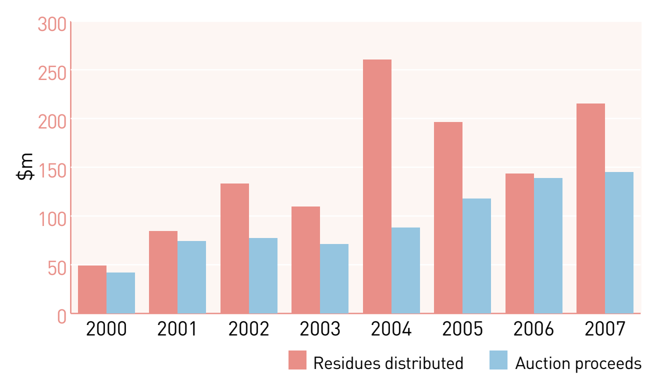
Price separation creates risks for the parties that contract across regions. NEMMCO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues up to one year in advance. Retailers, generators and other market participants may bid for a share of the residues. 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.

Figure 4.18 charts the amount of settlement residues that accrued each year against the proceeds of residue auctions from 2000 to 2007. 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 figure illustrates that the residues are frequently auctioned for less than their ultimate value. On average, the actual residues have been around 60 per cent higher than the auction proceeds.

Market participants tend to discount the value of settlement residues because they are not a firm hedging instrument.[23] 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 (see chapter 3).

Figure 4.18
Inter-regional hedging: auction proceeds and settlement residues



Source: NEMMCO.

22 The AER decision to introduce the scheme noted that the level of performance improvement required to receive the full 2 per cent bonus is probably an unrealistic aim. However, it is difficult to determine what a realistic level of performance is at this time because the scheme is untried.

23 Energy Reform Implementation Group, *Discussion papers*, November 2006, p .177.