STATE OF THE ENERGY MARKET 2008

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PREFACE

As the economic regulator for the Australian energy sector, the Australian Energy Regulator (AER) aims to keep stakeholders informed of policy, regulation and market developments. This is the AER's second *State of the energy market* report, which provides a high-level overview of energy market activity in Australia. The report is written in accessible language to meet the needs of a wide audience, including government, industry and the broader community. The report supplements the AER's extensive technical reporting on the energy sector.

The *State of the energy market* report consolidates information from various sources into a single user-friendly publication. In doing so, the report aims to better inform market participants and assist policy debate on energy market issues. It should be noted, however, that the AER is not a policy body. In that context, the report focuses on the presentation of facts, rather than advocating policy agendas.

This 2008 edition consists of an executive overview of the year in review, supported by 11 chapters on the electricity and natural gas sectors. The lead essay this year is an assessment by ACIL Tasman on developments and projections for the natural gas sector. There is also an appendix covering recent policy and regulatory developments in the energy sector.

The body of the report provides a more detailed survey of market activity and performance in the electricity and natural gas sectors. The chapters follow the supply chain in each industry—from electricity generation and gas production, through to energy retailing. There is also a survey of contract market activity in electricity derivatives. While the report focuses on activity in the southern and eastern jurisdictions, in which the AER has regulatory and compliance roles, there is also some coverage of market activity in Western Australia and the Northern Territory.

The *State of the energy market* report is an evolving project. Readers may notice some changes in approach to particular areas of reporting compared to the 2007 edition. For example, this year's report includes more detailed coverage of wholesale market activity in the electricity and natural gas sectors, the expansion of the wind generation sector and reliability issues in natural gas. The appendix has a stronger focus on recent policy and regulatory developments. In addition, the executive overview includes some perspectives on possible implications of climate change policies for the energy sector. More generally, the coverage of Western Australian issues has increased this year. The AER will continue to explore ways to improve the quality of information in this report over time and, as always, seeks the views of stakeholders in this regard.

In the meantime, I hope that this 2008 edition will provide a valuable resource for market participants, policymakers and the wider community.

Steve Edwell
Chairman

EXECUTIVE OVERVIEW


Mark Wilson

EXECUTIVE OVERVIEW

Australia's energy sector has faced some complex challenges in 2008, presenting both risks and opportunities for the market. Although the National Electricity Market (NEM) has returned to more stable conditions in recent months, the last two years have seen heightened volatility. South Australia experienced record prices early in 2008, triggering the unprecedented use of administered pricing. Sluggish generation investment over the last few years has raised some concerns about future supply risk, but the investment response in most regions is finally picking up. Ageing infrastructure, strong demand growth and rising costs are also driving record increases in electricity network investment.

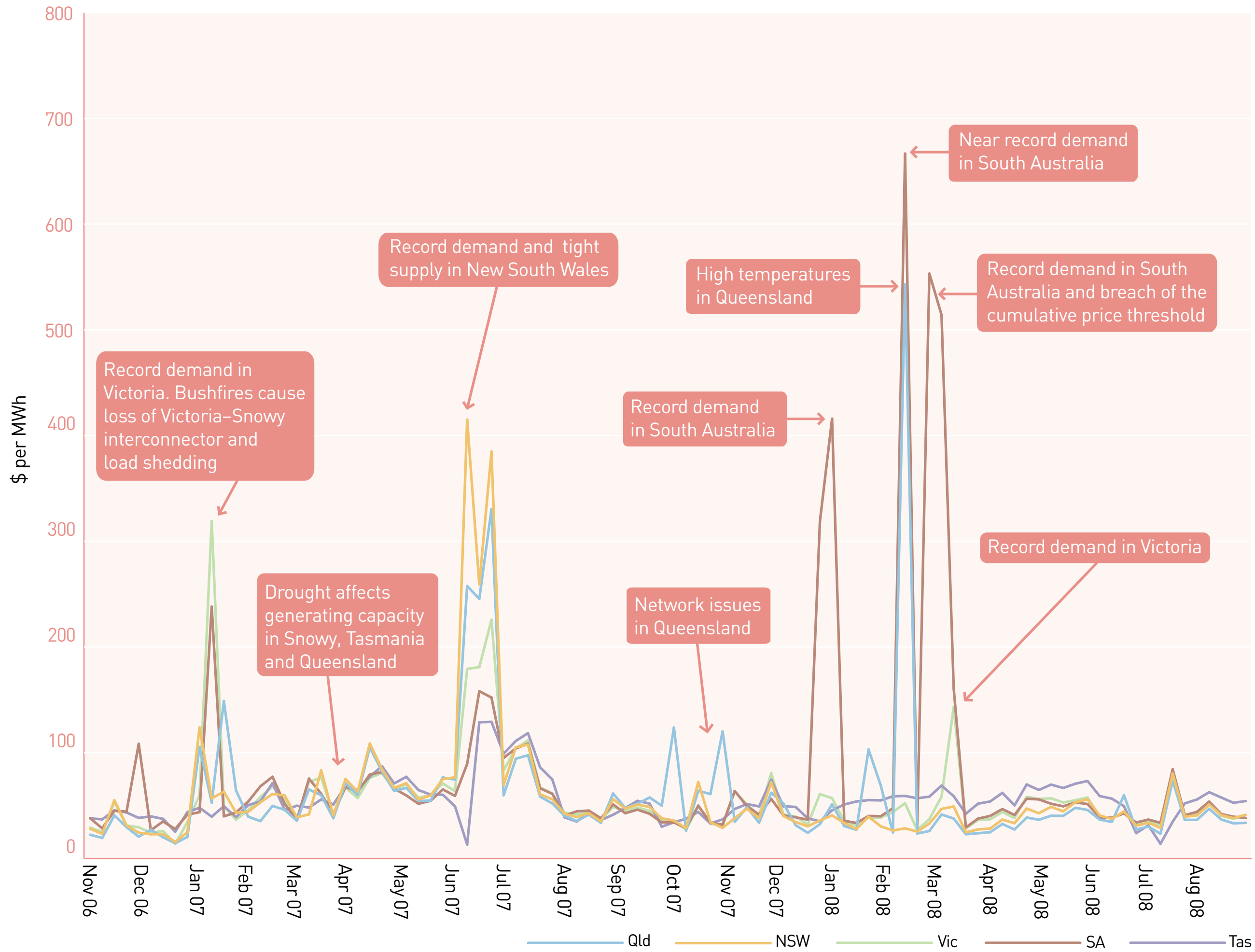
Market conditions in the natural gas sector differ between the east and west coasts. The industry is expanding rapidly on the east coast, underpinned by the burgeoning coal seam gas (CSG) sector and rising demand to supply gas-fired power stations. In the longer term, proposed liquefied natural gas (LNG) projects are likely to raise east coast prices. In contrast, in Western Australia, tight supply conditions, combined with a major plant outage, have led to record prices in 2008. Across Australia, rising wholesale prices in electricity and gas are starting to flow through to the retail sector.

At a policy level, the yet to be finalised Carbon Pollution Reduction Scheme has created some uncertainty for the market, but it will also create investment opportunities. In particular, it will add further momentum to the natural gas sector and over time will spur greater interest in clean coal and renewable generation technologies.

Against this landscape, there have been significant changes in the regulatory framework. There was further progress in 2008 towards the consolidation of economic regulation under a single agency—the Australian Energy Regulator (AER). The transfer of electricity distribution regulation from state regimes to the national framework commenced on 1 January 2008, and gas distribution followed on 1 July 2008. In addition, the regulation of gas transmission pipelines transferred from the Australian Competition and Consumer Commission (ACCC) to the AER on 1 July 2008. Moves are continuing for a transfer of non-price retail regulation.

Work is also continuing on the establishment of the Australia Energy Market Operator (AEMO) by June 2009. This new agency will have wide-ranging responsibilities in electricity and gas, including a national transmission planning role. A significant reform for the

Figure 1
National Electricity Market prices



MWh, megawatt hours.

Note: Weekly volume-weighted averages.

Source: NEMMCO; AER.

gas sector was the launch of a gas market bulletin board on 1 July 2008. In combination with a new short-term trading market in gas, scheduled for 2010, this is an important move towards enhanced transparency and efficiency in natural gas markets.

National Electricity Market

To promote market transparency, the AER reports weekly on wholesale prices in the NEM, which covers Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). The AER also publishes more detailed coverage of price events above $5000 per megawatt hour (MWh). Overall, the market exhibited more stability in 2007–08, with the notable exception of record prices for South Australia during the March quarter (figure 1). However, the market has tended to trade at higher prices in 2007 and 2008 than in previous years, which may be indicative of the exercise of market power during periods of tight supply and demand.

Wholesale electricity prices began to rise from around March 2007, when the drought constrained hydroelectric generation capacity in New South Wales, Tasmania and Victoria, and limited the availability of water for cooling in some coal-fired generators. These conditions were exacerbated in winter 2007 by strategic bidding by some New South Wales generators, which led to record prices. The drought continued to affect wholesale electricity prices in New South Wales, Victoria, Queensland and Tasmania during the September quarter of 2007. South Australia was less affected as its generators do not rely on fresh water for cooling.

Drought conditions in New South Wales and Queensland began to ease by the end of 2007, taking pressure off prices. Queensland experienced some high price events due to network outages and constraints, and aggressive bidding by a number of generators. More serious problems emerged in South Australia, where monthly prices averaged $325 per MWh in March 2008—the highest monthly price for any region since the NEM began in 1998.

A number of factors contributed to the high prices in South Australia. Adelaide experienced an unprecedented 15-day heatwave in March 2008, which led to record demand. During peak periods, a significant proportion of South Australia's electricity is sourced from Victoria. In December 2007, the South Australian transmission network owner, ElectraNet, reduced the maximum allowable flows on the Heywood interconnector by about 25 per cent. This constrained the supply of lower cost generation from Victoria. Against a backdrop of high demand and tight supply, AGL Energy—which owns 39 per cent of South Australia's generation capacity—bid a significant proportion of its capacity at close to the price cap.

In combination, these factors led to extreme prices in South Australia over 15 consecutive days in March 2008, including 26 price intervals above $5000 per MWh. For the first time in the history of the NEM, the extent and duration of extreme prices triggered an administered price cap on 17 March. This led to South Australia's spot price being capped at $100 per MWh on 11 occasions. The AER is investigating these price events and, in particular, whether generator bidding breached the National Electricity Rules. The AER is also investigating the flow limits placed on the Heywood interconnector by ElectraNet.

While NEM prices tended to stabilise over the period from April to September 2008, they nonetheless remained significantly above long-term averages. This is consistent with higher generation costs, a continuation of tight supply–demand conditions and occasional opportunistic bidding by generators. There was a significant price spike across the mainland NEM regions on 23 July, due to an unplanned outage of two transmission lines in Victoria. The AER is investigating this incident.

The general easing of NEM prices during 2007–08 was reflected in lower contract prices on the Sydney Futures Exchange. Futures prices indicate that the market is expecting higher spot prices in the short to medium-term in South Australia and Queensland—notably in the first quarter of 2009. This may reflect concerns about a recurrence of the market structure and network issues that affected these regions in the first quarter of 2008.

The NEM experienced its first regional boundary change on 1 July 2008, when the Snowy region (located in southern New South Wales) was abolished to improve pricing signals and reduce network congestion. The area formerly covered by the region is now split between the Victoria and New South Wales regions of the NEM. The other regions—Queensland, South Australia and Tasmania—continue to follow jurisdictional boundaries.

Generation investment and reliability

Over the past couple of years, some concerns have been raised about the future reliability of electricity supply in the NEM. In particular, the Australian Energy Market Commission (AEMC) Reliability Panel reported in 2007 that forecast demand is growing faster than forecast supply and that a shortfall was possible by around 2011. The panel cited stakeholder uncertainty about policy settings—including government

Table 1 Major committed generation investment in the National Electricity Market (excluding wind)

DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
NEW SOUTH WALES				
Delta Electricity (NSW Government)	Colongra	OCGT	668	2009–10
Origin Energy	Uranquinty	OCGT	640	2008–09
TRUenergy	Tallawarra	CCGT	400	2008
QUEENSLAND				
Origin Energy	Darling Downs	CCGT	630	2010
ERM Power/Arrow Energy	Braemar 2	OCGT	450	2009
Rio Tinto	Yarwun Alumina Refinery	Gas	145	2010–11
Queensland Gas Company	Condamine	CCGT	135	2009
VICTORIA				
AGL Energy	Bogong	Hydro	140	2009
Origin Energy	Mortlake	OCGT	550	2010–11
SOUTH AUSTRALIA				
Origin Energy	Quarantine	OCGT	120	2008–09
TASMANIA				
Tasmanian Government	Tamar Valley	CCGT	191	2009

OCGT, open cycle gas turbine; CCGT, combined cycle gas turbine.

Sources: NEMMCO; AER and company websites.

ownership in the generation sector and the possible effects of climate change policies—as factors that may be delaying new investment.[1]

The panel proposed a number of refinements to enhance reliability over the longer term. This included a proposal to change the National Electricity Rules to raise the NEM price cap to $12 500 per MWh from 1 July 2010, to provide greater incentives to invest in peaking generators. The panel released an exposure draft of the proposed Rule change in September 2008. In addition, the panel recommended greater flexibility for the market operator to source extra generation reserves when needed. The panel also recommended a new *energy adequacy assessment projection* to improve information about the impact of generation input constraints on energy availability.

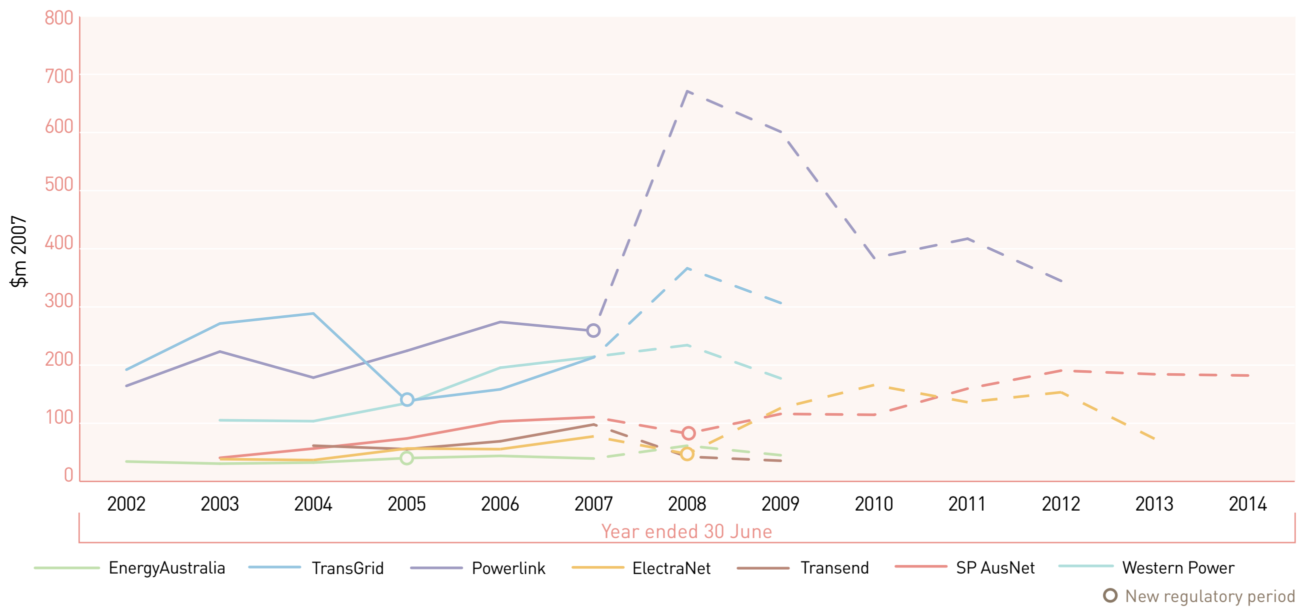
Generation investment has been slow to respond to rising demand, high prices and the need to replace some ageing plant. However, some investment response has started to emerge. The bulk of commissioned, committed and proposed new investment is in gas-fired and wind generation technologies, which are expected to become more cost competitive under climate change policies. Table 1 sets out major committed projects (excluding wind) as at September 2008.

Origin Energy has announced a number of projects, including a 630 megawatt (MW) gas-fired power station in the Darling Downs region of Queensland (scheduled to commence operation in early 2010) and a 550 MW gas-fired power station near Mortlake in Victoria (scheduled to commence operation in the summer of 2010–11).

The Darling Downs project builds on a strong investment cycle in Queensland over the past decade. Recently completed projects include the 450 MW Braemar 1 power station (owned by Babcock & Brown Power) and the 750 MW Kogan Creek power station (owned by CS Energy), which began operation in 2007. In July 2008, ERM Power and Arrow Energy reached financial closure on the 450 MW Braemar 2 power station (to commence in the first half of 2009).

1 AEMC Reliability Panel, *Comprehensive Reliability Review—Final Report*, December 2007, pp. 16, 17, 37, 43.

Figure 2
Electricity transmission investment



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.

After a long period of inactivity, the investment response in New South Wales has also picked up recently. New gas-fired projects in development include TRUenergy's 400 MW generator at Tallawarra (scheduled for late 2008), Delta Electricity's 668 MW generator at Colongra (scheduled for December 2009), and Origin Energy's 640 MW Uranquinty plant (scheduled for November 2008).

Investment in wind generation has gathered pace since 2004, especially in South Australia, where it now accounts for around 17 per cent of installed generation capacity. The extent of new investment in wind generation has led to the AEMC determining that new wind generators be classified as *semi-scheduled*, which will require them to participate in the central dispatch process.

Electricity transmission

There has been significant investment in transmission networks in the current decade and this trend is set to continue under recent AER revenue cap determinations (figure 2). Transmission investment across the NEM was forecast to exceed $1.2 billion in 2007–08. Although these outcomes are partly driven by rising labour and resource costs, they are also funding substantial upgrades and capacity expansions that should maintain the current high rates of network reliability.

Investment in the Queensland network is set to increase in the current regulatory period (2007–12) by around 80 per cent compared with the previous period, reflecting significant capital requirements and cost pressures for that network. Transmission investment will increase by around 60 per cent for the Victorian and South Australian networks over their current regulatory periods.

There have been concerns that current approaches to transmission planning focus on perspectives and priorities within individual jurisdictions, rather than on a strategic, long-term view of the efficient development of the transmission grid on a national basis. To address this, a national transmission planning function will be housed within the new AEMO from July 2009. The AEMO will develop an enhanced annual transmission plan covering long-term strategies for the transmission grid as a whole. In addition, a new regulatory investment test will provide for an assessment of wider market benefits than those that are currently considered in assessing the merits of new projects. In particular, the new test will recognise the merits of investing in excess capacity in anticipation of future demand growth.

Although the reliability of the transmission network has been consistently high since the beginning of the NEM, network congestion sometimes impedes the dispatch of the most cost-efficient generation to satisfy demand. The AER publishes data on the economic costs of network congestion, which suggest that while the costs are relatively modest, they are increasing over time. Congestion has been most prevalent around southeast Queensland, northern New South Wales, and the interconnectors linking Victoria with South Australia and Tasmania. The AEMC published a review of congestion issues in the NEM in June 2008, which recommended a number of changes to current market arrangements to reduce this problem.

The AER has undertaken a number of measures to encourage lower congestion costs. Aside from the investment allowances noted above, the AER revised its service target performance incentive scheme in 2008 to better reward network owners for cost-effective initiatives to improve operating practices (such as the scheduling and notification of network outages, live line work and equipment monitoring). The scheme permits a network 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.[2]

Climate change policies

A significant policy development over the past year has been progress towards implementation of a carbon emissions trading scheme. The Australian Government released a green paper on its approach to emissions trading in July 2008, to be known as the Carbon Pollution Reduction Scheme. The scheme is scheduled to begin in 2010. The green paper sets out the government's preferred approach to various aspects of the scheme and areas where further consideration is needed. It confirms that the scheme will be broadly based in terms of the greenhouse gases and economic sectors to be covered.

The design of the Carbon Pollution Reduction Scheme will be refined after consideration of the final report of the Garnaut Climate Change Review and Treasury modelling of the economic impacts of the scheme. The government will undertake further consultation before releasing exposure draft legislation and an associated white paper, scheduled for December 2008. The government intends to give an indication of its planned medium-term emission reduction target by the end of 2008.

The *Garnaut climate change review final report*, released in September 2008, identified an urgent need to reduce carbon emissions through a broad-based trading scheme. The report recommended a 10 per cent reduction in carbon emissions (from 2000 levels) by 2020 and an 80 per cent reduction by 2050—assuming international cooperation in the mitigation effort. In the absence of an international agreement, the review recommended a 5 per cent reduction in emissions (from 2000 levels) by 2020.

The scheme poses challenges and opportunities for the energy sector. In particular, coal-fired electricity generation, which accounts for around 83 per cent of Australia's generation capacity, is emissions-intensive. The introduction of the scheme may result in some asset write-downs and sales, and it is possible that some brown coal generating plant may be shut down.

2 The level of performance improvement required to receive the full 2 per cent bonus is probably an unrealistic aim. However, it will be difficult to determine a realistic level of performance until the scheme has operated for a period of time.

Mitigating factors such as forward market trading, vertical integration and new investment in gas-fired and wind generation are likely to ease the risk of potential supply issues.

The government is also proposing to provide some one-off assistance to existing coal-fired electricity generators. Although the Garnaut review argued that there was no economic or environmental reason for allocating free emissions permits to coal-fired electricity generators, this has been a contentious issue. The Energy Supply Association of Australia has argued that the scheme would reduce the economic lives of several coal-fired power stations, mostly in Victoria and South Australia, and substantially reduce the value of others.[3]

The AEMC Reliability Panel cited uncertainty over the details of climate change policies as one factor that may have delayed some investment in new generation capacity. As the details of climate change policies become more certain, the investment response will likely strengthen. Even so, considerable time lags between decisions to invest and the commissioning of new capacity could result in some supply issues in the short to medium term.

Climate change policies are likely to improve the competitiveness of gas-fired generation in relation to coal-fired technology. It is interesting to note that Origin Energy announced its commitment to a 550 MW plant in Victoria on the day the Garnaut review released its draft report. There will be substantial opportunities for the natural gas industry, although rising demand for gas—both for electricity generation and the likelihood of LNG exports from eastern Australia—may increase gas prices and partly neutralise its cost advantages.

There is also likely to be higher demand for renewable generation technologies. While the Carbon Pollution Reduction Scheme may not be sufficient in isolation to significantly increase renewable generation, particularly in the scheme's early years, the government has also committed to a 20 per cent mandatory renewable energy target (MRET) for Australia by 2020. The scheme obliges electricity retailers and large energy users to acquire a proportion of their electricity requirements from renewable sources. The 20 per cent target translates into around 60 000 gigawatt hours (GWh) of electricity to be generated from renewable energy sources. Currently, Australia generates around 15 000 GWh from renewable sources.[4] In July 2008, the Council of Australian Governments (COAG) released a discussion paper canvassing design options for an expanded scheme, combining the federal MRET with state and territory schemes.[5]

The intermittent nature of wind generation poses specific challenges for power system reliability and security. In particular, wind generation depends on prevailing weather conditions. In addition, momentary fluctuations in wind output raises issues for maintaining power flows within the capacity limits of transmission infrastructure. To maintain reliability and security, standby capacity is required. Typically, this must be provided by peaking plant (such as an open cycle gas turbine plant) that can respond quickly to changing market conditions.

In the longer term, there is also potential for carbon capture and storage (CCS) technologies that extract carbon dioxide (CO_2) from fossil fuel power plants and store it in deep geological formations. The permanent storage of CO_2 is a relatively untried concept. Indicative costs for coal plant with CCS vary from around US$40 to US$90 per tonne of CO_2 captured and stored. The International Energy Agency (IEA) anticipates that capture, transport and storage costs could fall below US$25 per tonne of CO_2 captured for coal-fired plants by 2030. This amounts to about US$10 to US$20 per MWh of electricity generated.[6]

3 ESAA, *Care required in setting emissions reduction targets for the energy sector*, media release, 25 July 2008.

4 COAG Working Group on Climate Change and Water, *Design Options for the Expanded National Renewable Energy Target Scheme*, 2008, p. 4.

5 COAG Working Group on Climate Change and Water, *Design Options for the Expanded National Renewable Energy Target Scheme*, 2008.

6 Betz R, School of Economics, The University of New South Wales and Owen AD, School of Economics and Finance, Curtin University of Technology, *Carbon emission reduction policies—Implications for Australia's energy market* (unpublished research for the AER), 2008; IEA, *Energy Technology Perspectives*, OECD/IEA, 2006.

In August 2008, the Ministerial Council on Energy (MCE) asked the AEMC to review the electricity and gas market frameworks to determine whether refinements are needed to accommodate climate change policies. The AER considers that, although some refinements may be needed to accommodate climate change policies, the market design of the NEM provides an efficient and robust framework for trading arrangements. In particular, the market allows price signals to be quickly transmitted to electricity users and investors, so that responses can be made on the basis of timely, transparent and market-based information. The electricity financial markets complement the physical electricity market by enabling parties to lock in price certainty into the future.

The introduction of climate change policies also raises issues for the network sector, which over time has developed around the location of coal-fired generation plant. A short to medium-term challenge will be to adapt to the increasing use of gas-fired generation. The sourcing of large volumes of electricity from new locations on the network may affect flows and create new points of congestion. This poses the risk that the output of some generators may be inefficiently constrained.

A longer term challenge relates to the increasing use of renewable generation, such as wind, geothermal and solar, in areas not presently serviced by networks. Specifically, there may be a need to augment the transmission network to deliver electricity from remote generators to load centres. Since, under current regulatory requirements, generators must pay the cost of connecting to the shared network and for related network augmentations, there may be incentives for connection investment to be scaled to accommodate only an individual generator's output. This could pose risks of inefficient augmentation that lacks regard to the longer term requirements of the power system. There may also be issues in identifying and allocating congestion costs arising from the connection of new plant.

The ability of network businesses to satisfy demand for new connections, the costs involved, and the question of who bears the associated risks may affect the feasibility, location, and timing of new investment. The establishment of a national transmission planner, a revised regulatory investment test (as noted above) and the current AEMC review of energy market frameworks provide some response to these issues and should enhance the investment climate over time.

The likelihood of greater reliance on gas-fired generation also raises issues for the adequacy of natural gas supplies and gas pipeline capacity to transport gas to power stations. As the following section notes, recently there has been a rapid expansion in gas production and reserves in eastern Australia. The gas pipeline sector has also been active in expanding pipeline capacity in response to market requirements.

The planned introduction of a carbon price is also encouraging the development of energy efficiency and demand management initiatives. Many state governments are implementing programs to promote energy efficiency via the energy retail sector. Demand management refers to strategies to address growth in demand to encourage more efficient use of existing power supply infrastructure. In some circumstances, demand management can provide an efficient alternative to network investment.

Demand management initiatives are most commonly implemented via the network sector, particularly in distribution. For example, financial incentives are offered to distribution businesses in New South Wales to undertake demand management projects that defer network investment.[7] Some jurisdictions are trialling the use of incentive payments or time-of-use tariffs to encourage small customers to reduce energy use at times of high system demand. More generally, the AEMC is reviewing whether there are barriers to effective demand management in the NEM, including in the regulation of electricity networks and network planning.[8]

7 The AER is also looking to introduce demand management incentives and related mechanisms to promote the use of demand management practices by distribution businesses.

8 AEMC, *Review of demand side participation in the National Electricity Market*, Issues Paper, 16 May 2008.

Some demand management strategies require the use of *smart meters* to enable consumers to monitor their energy use. In 2007, COAG agreed to a national implementation strategy for the progressive rollout of smart meters where the benefits outweigh costs. A cost-benefit assessment published in March 2008 found that a national rollout would deliver net benefits.[9]

Natural gas

In a commissioned essay for this report, ACIL Tasman estimated that natural gas demand in Australia will more than double to around 4300 petajoules (including exports) over the next 20 years. It forecasts that demand growth will be principally driven by rising LNG production—in western, northern and eastern Australia—and increased gas-fired electricity generation in response to climate change policies.

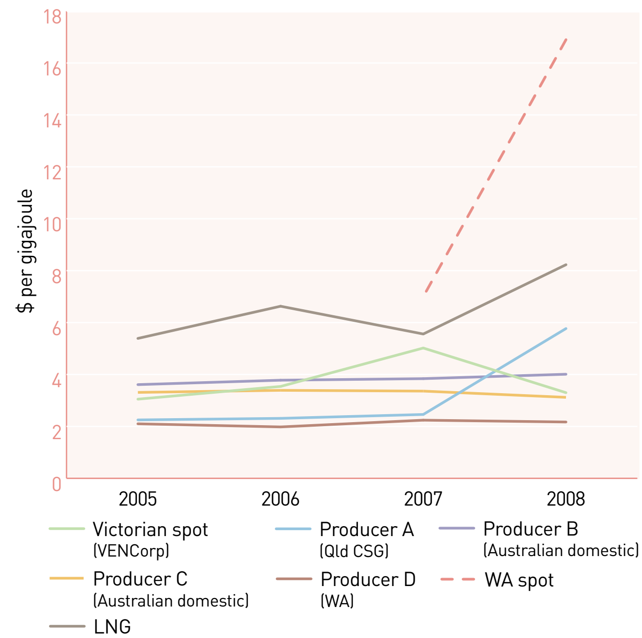
The Western Australian gas market has experienced considerable tightening since 2006, with rising production costs and strong domestic demand. At the same time, Western Australia's LNG export capacity creates exposure to international energy prices. Average LNG prices received by Australian producers rose by 48 per cent between the June quarters of 2007 and 2008.[10]

In combination, these factors have led to a substantial rise in domestic prices in Western Australia, with some gas contracts in 2007 being negotiated at around $7 per gigajoule (GJ), compared to typical prices of around $2.50 per GJ earlier in the decade. Western Australia is likely to face difficulties achieving a supply–demand balance until at least 2010.[11] In June 2008, an explosion at the Varanus Island gas facility reduced domestic gas supplies by 30 per cent for over two months and put further pressure on short-term prices (figure 3).

Gas market development on the east coast is increasingly driven by Queensland's CSG sector, which now supplies almost 20 per cent of the eastern Australian market,[12] including around 70 per cent of the Queensland market.[13] CSG reserves have continued to rise strongly,

Figure 3

Indicative wholesale natural gas prices



CSG, coal seam gas; LNG, liquefied natural gas.

Notes:

1. Western Australian spot prices are indicative only: 2007 prices are estimates for new Santos contracts signed in July; 2008 prices are based on the weighted average price of gas trades notified to Western Australia's Independent Market Operator in July 2008. Western Australian prices in July 2008 were unusually high due to a major plant outage at Varanus Island.
2. All series (except Western Australian spot) are data from the second quarter of the year.
3. Data for Producers A, B, C and D are average company realisations for specific Australian gas producers.

Sources: WA spot 2007: Department of Industry and Resources (WA), *Western Australian Oil and Gas Review*, 2008; other data: EnergyQuest, *Energy Quarterly,* August 2005, August 2006, August 2007 and August 2008; LNG data is sourced from the ABS.

9 NERA, *Cost-Benefit Analysis of Smart Metering and Direct Load Control Overview Report for Consultation*, 29 February 2008, for Smart Meter Working Group, Phase 2.

10 EnergyQuest, *Energy Quarterly*, August 2008.

11 Ministerial Council on Mineral and Petroleum Resources/Ministerial Council on Energy, *Final Report of the Joint Working Group on Natural Gas Supply*, September, 2007, p. 10.

12 EnergyQuest, *Energy Quarterly*, August 2008.

13 Wilson G, Queensland Minister for Mines and Energy, *Coal seam methane for a cleaner energy future*, press release, 13 September 2007.

and Queensland production may rise by around 60 per cent during 2008.[14] The Australian Bureau of Agricultural and Resource Economics forecasts that CSG will become the principal source of gas supply in eastern Australia by 2030.

There are several proposals to develop LNG export facilities in Queensland, based on CSG from the Surat–Bowen Basin. Although the exponential growth in reserves suggests that the domestic market is unlikely to be left short of supply, LNG exports would likely bring domestic gas prices into closer alignment with world prices, as has occurred in Western Australia.

In the short to medium-term, rising production is providing some cushioning against price increases, although Queensland prices edged higher in 2008 (figure 3). ACIL Tasman has reported that some Queensland customers are now paying prices in excess of $4 per GJ.[15] EnergyQuest reports that one CSG provider earned an average price of $7.79 per GJ for Queensland gas in the first quarter of 2008 ($5.77 in the second quarter), compared to $2.22 per GJ in the first quarter of 2006.[16] Conversely, prices in the Victorian spot market eased in 2008 following the commissioning of new transmission pipeline infrastructure that reduced capacity constraints.

Rising demand for natural gas places greater demands on gas transmission infrastructure to transport the gas to markets. Lead times for investment in transmission pipelines are around three years. The gas pipeline sector, which is privately owned, has become increasingly entrepreneurial over time. There is evidence that the sector is responding to market signals, with several new projects underway or imminent (table 2). These include Epic Energy's QSN Link from Queensland to South Australia and New South Wales, scheduled for completion by early 2009. The QSN Link will allow CSG producers in Queensland to market their gas throughout southern and eastern Australia. Other proposals include a planned pipeline from Wallumbilla (Queensland) to Newcastle.

In addition, a number of existing pipelines are being expanded to accommodate rising demand. For example, the APA Group is expanding the Moomba to Sydney Pipeline system by 20 per cent to support gas flows needed for the Uranquinty power station in New South Wales, which is scheduled for commissioning in late 2008. New pipeline investment is improving security of supply and providing improved options for gas customers to source gas from a variety of basins. Over time, rising natural gas demand is likely to lead to further meshing of the transmission pipeline network.

Significant changes have been occurring on the regulatory front in the gas sector. In July 2008, the new National Gas Law transferred the economic regulation of transmission pipelines outside Western Australia from the ACCC to the AER. However, evolving market conditions have led to the lifting of economic regulation—in whole or in part—from several major pipelines. These include the Moomba to Adelaide Pipeline and a significant portion of the Moomba to Sydney Pipeline. Most major pipelines constructed during the current decade are not regulated. The National Gas Law also introduced a *light regulation* option which avoids upfront revenue and price regulation.

In 2005, in light of rising demand for natural gas and concerns about adequacy of supply, the MCE appointed a Gas Market Leaders Group to consider the need for further market reforms.[17] In 2006, the group recommended the establishment of a gas market bulletin board and a short-term trading market in gas. It also recommended the establishment of a national gas market operator to administer these reforms and produce an annual national statement of opportunities on the gas market, covering supply–demand conditions. The reforms aim to improve transparency and efficiency in Australian gas markets, and to provide information to help manage gas emergencies.

14 ACIL Tasman, *Australia's natural gas markets: the emergence of competition?* (lead essay of this report), 2008, p. 3.
15 ACIL Tasman, *Australia's natural gas markets: the emergence of competition?* (lead essay of this report), 2008, p. 3.
16 EnergyQuest, *Energy Quarterly*, May 2008.
17 The Gas Market Leaders Group comprises 12 gas industry representatives and an independent chairperson.

Table 2 **New gas pipeline projects, 2008**

PIPELINE	LOCATION	OWNER/PROPONENT	LENGTH (KM)	COST ($ MILLION)	PROJECT COMPLETION
UNDER CONSTRUCTION					
QSN Link—Stage 1	Qld–SA and NSW	Epic Energy	180	140	2009
Eastern Gas Pipeline (addition of compressor)	Vic–NSW	Singapore Power International	Compressor (25% expansion)	n/a	2008
Bonaparte Gas Pipeline	NT	APA Group	285	150	2009
COMMITTED					
Berwyndale to Wallumbilla Pipeline	Qld	AGL Energy and Queensland Gas Company	115	70	2009
Dampier to Bunbury Stage 5B expansion	WA	DUET Group (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%)	440	690	2010
South West Queensland Pipeline—Stage 1	Qld	Epic Energy	Compressor (expansion to 170 terajoules a day)	n/a	2009
South West Queensland Pipeline—Stage 2	Qld	Epic Energy	Compressor (expansion to 220 terajoules a day)	64	2013
Queensland Gas Pipeline expansion	Qld	Singapore Power International	25 petajoules	n/a	2010
QSN link—Stage 2 expansion	Qld–SA and NSW	Epic Energy	Compressors	64	2013
Moomba to Sydney Pipeline capacity expansion	NSW	APA Group	20% capacity expansion	100	progressive from 2008

n/a, not available.

Sources: ABARE, *Energy in Australia 2008*, 2008; EnergyQuest, *Energy Quarterly Report*, August 2008; company websites and press releases.

The gas market bulletin board, which began on 1 July 2008, is a website covering major gas production fields, storage facilities, demand centres and transmission pipelines in South Australia, Victoria, New South Wales, the ACT, Queensland and Tasmania.[18] It aims to provide transparent, real-time and independent information on the state of the gas market, system constraints and market opportunities.

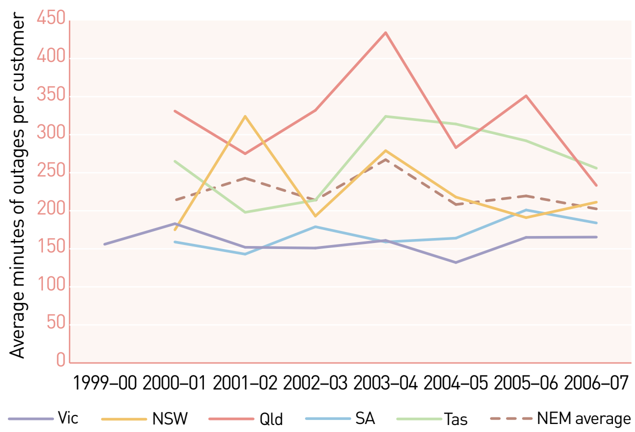
The proposed short-term trading market in gas, which is scheduled to begin by winter 2010, will be a mandatory price-based balancing mechanism at defined gas hubs in New South Wales and South Australia. Victoria has had a transparent balancing market in place since 1999. Structural and operational details of the market are undergoing further development during 2008.

Energy distribution

The regulation of the energy distribution sector has been in transition in 2008. The transfer from state-based to national regulation of electricity distribution networks began on 1 January 2008, under amendments to the National Electricity Law and Rules. The enactment of the National Gas Law and Rules commenced the transfer of gas distribution to national regulation on 1 July 2008.

18 http://www.gasbb.com.au.

Figure 4
Electricity distribution network reliability



NEM, National Electricity Market.

Notes:

1. System average interruption duration index data: the data account for all outages experienced by distribution customers, including those attributable to generation and transmission.
2. The data for Queensland in 2005-06 and New South Wales in 2006-07 have been adjusted to remove the impact of natural disasters.
3. Victorian data is for the calendar year ending in that period (for example Victoria 2005-06 is for calendar year 2005).
4. The NEM averages are weighted by customer numbers.

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

The AER's first regulatory review in electricity distribution—to set revenues for the New South Wales and ACT networks—began in May 2008. The AER began a regulatory review of the South Australian and Queensland networks in July 2008. The AER's first regulatory review in gas distribution will assess prices and other access terms and conditions for networks in New South Wales and the ACT.

The AER is working closely with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition period. Since assuming responsibility for the economic regulation of distribution networks, the AER has published a number of guidelines. These include a national service performance incentive scheme, which provides incentives to electricity distribution network businesses to improve service quality—including reliability—over time.

Annual investment in electricity distribution networks in the NEM is running at around $3 billion, primarily driven by replacement of ageing infrastructure and rising demand. Investment is contributing to stable network reliability, with recent improvements in some jurisdictions. Figure 4 indicates that the average duration of distribution outages per customer in the NEM has remained in a range of about 200–270 minutes per year since 2000–01, with some convergence in jurisdictional outcomes over time. The data should be interpreted with caution due to significant differences in network characteristics, as well as differences in information, measurement and auditing systems.

In gas, annual investment in distribution networks is running at around $400 million. At present, there is no uniform approach to the publication of service quality data for the gas distribution sector. Although Victoria, Queensland, South Australia and Western Australia publish data on a regular basis, the indicators vary between jurisdictions. The available data suggests that network reliability is generally high.

Retail

State and territory governments are currently responsible for the regulation of retail energy markets. The legislation to transfer non-price elements of retail regulation to the AEMC and AER is scheduled for introduction in the South Australian Parliament by September 2009. Under current proposals, the states and territories will retain responsibility for price regulation unless they choose to transfer those arrangements.

The reform process to date has involved the release of a series of working papers (prepared by Allens Arthur Robinson on behalf of the MCE) on the regulatory functions to be transferred to the national framework, discussions with a stakeholder reference group on the recommendations for the national framework, and consultation with interested parties. A standing committee of the MCE published a policy paper in June 2008 that will form the basis for the legislative package on the national framework.

Energy retail competition has continued to develop over the past year. With the introduction of full retail contestability in Queensland on 1 July 2007, all customers nationally are eligible to choose their natural gas supplier. Similar arrangements for electricity apply in mainland NEM jurisdictions. Tasmania extended electricity contestability on 1 July 2008 to customers using more than 750 MW per year.

The leading private sector energy retailers are AGL Energy, Origin Energy and TRUenergy, which collectively account for most market share in Victoria, South Australia and Queensland. In 2007, International Power acquired the retail partnership it formerly operated with EnergyAustralia, and now retails in its own right as Simply Energy. This relatively new retailer has acquired market share in South Australia and Victoria. There has been ongoing new entry by niche retailers, although price volatility in the electricity wholesale market has raised challenges for a number of smaller retailers.

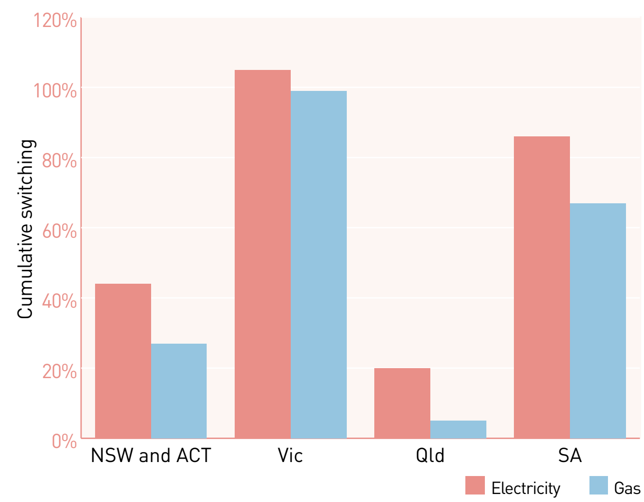
Customer switching between retailers provides one indicator of competitive activity. Switching rates in Victoria and South Australia are more than double those in New South Wales (figure 5). The low rates for Queensland reflect that small customer switching has only been possible since July 2007. Queensland nonetheless recorded a 20 per cent switching rate for electricity in the first year of full retail contestability. Across all jurisdictions, switching rates are higher in electricity than in gas, although the rates are comparable in Victoria, where gas is used widely for household purposes.

While most jurisdictions allow full customer choice, it can take time for a competitive market to develop. At August 2008, all jurisdictions applied some form of retail price regulation in electricity, and several jurisdictions applied similar arrangements in gas. Australian governments have agreed to review the continued use of retail price caps and to remove them where effective competition can be demonstrated.

The AEMC is assessing the effectiveness of energy retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps, with state and territory governments making the final decision on this matter.

Figure 5

Cumulative retail switching to 30 June 2008—small customers



Notes:

1. Cumulative switching as a percentage of the small customer base since the start of full retail contestability: Victoria and New South Wales 2002; South Australia 2003 (electricity) and 2004 (gas); Queensland 2007.
2. If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may therefore exceed 100 per cent.
3. The data may overstate the extent of customer switching due to some retailers transferring customers between different participant codes owned by the same retailer.

Sources: Electricity customer switches: NEMMCO, MSATS transfer data to June 2008; Gas customer switches: New South Wales and ACT: Gas Market Company, Market activity data from January 2002–June 2008; South Australia: REMCo, Market activity report from August 2004–June 2008; Victoria and Queensland: VENCorp, *Gas market reports: Transfer history from January 2002–June 2008*, 2008; Customer numbers: New South Wales: IPART, *NSW electricity information paper no 1–2008–Electricity retail businesses' performance against customer service indicators*, January 2008; South Australia: ESCOSA, *2006–07 Annual performance report: performance of South Australian energy retail market*, November 2007; Victoria: ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007; Queensland: QCA, *Market and non-market customers as at 31 March 2007* (available at http://www.qca.org.au).

Table 3 Electricity retail prices—recent regulatory and government decisions

JURISDICTION	PERIOD	RETAILERS	INCREASE IN REGULATED TARIFF
New South Wales	1 July 2007 to 30 June 2010	EnergyAustralia Integral Energy Country Energy	CPI + 4.1% CPI + 4.9% CPI + 3.7% (annual adjustments)
Victoria	1 January 2008 to 31 December 2008	AGL Energy Origin Energy TRUenergy	CPI + 10.7% CPI + 10.9% CPI + 15.5%
Queensland	1 July 2008 to 30 June 2009	All licensed retailers	5.40%
South Australia	1 January 2008 to 30 June 2011	AGL Energy	12.3% in 1 Jan 2008 to 30 June 2008; then CPI-only increase to July 2011
Tasmania	1 January 2008 to 30 June 2010	Aurora Energy	16.0% in 1 Jan 08 to 30 June 08, 4.0% in 2008–09 and 3.8% in 2009–10
ACT	1 July 2008 to 30 June 2009	ActewAGL Retail	7.11%
Western Australia	1 July 2009	Synergy Horizon Power	10.0%

CPI, consumer price index.

Sources: New South Wales: IPART, *Regulated electricity retail tariffs and charges for small customers 2007 to 2010* 2007; *Electricity*, final report and final determination, June 2007; Victoria: Department of Primary Industries, *Victorian Energy Prices Fact Sheet*, November 2007; Queensland: QCA, *Benchmark retail cost index for electricity 2008–09*, final decision, May 2008; South Australia: ESCOSA, *Review of retail electricity price path final inquiry report and price determination 2007*, November 2007; Tasmania: OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania*, final report and proposed maximum prices, September 2007; ACT: ICRC, *Final decision and price direction retail prices for noncontestable electricity customers*, report 4 of 2008, June 2008; Western Australia: Energy Operators (Regional Power Corporation) (charges) By-laws 2006 (WA); Premier (WA) (Hon. Alan Carpenter), *State government to phase in electricity price increases*, media statement, 4 April 2007.

The AEMC completed a review of Victoria's energy retail markets in February 2008, and found that competition is effective in both electricity and gas. In response to the review, the Victorian Government announced in September 2008 the introduction of new legislation to remove retail price caps. The legislation includes provisions for the Essential Services Commission of Victoria to undertake expanded price monitoring and report publicly on retail prices. Retailers will also be required to publish a range of their offers to assist consumers in comparing energy prices. Other obligations on retailers, including the obligation to supply and the consumer protection framework, are not affected by the removal of retail price regulation. The Victorian Government retains a reserve power to reinstate retail price regulation if competition is found in the future to be no longer effective.[19]

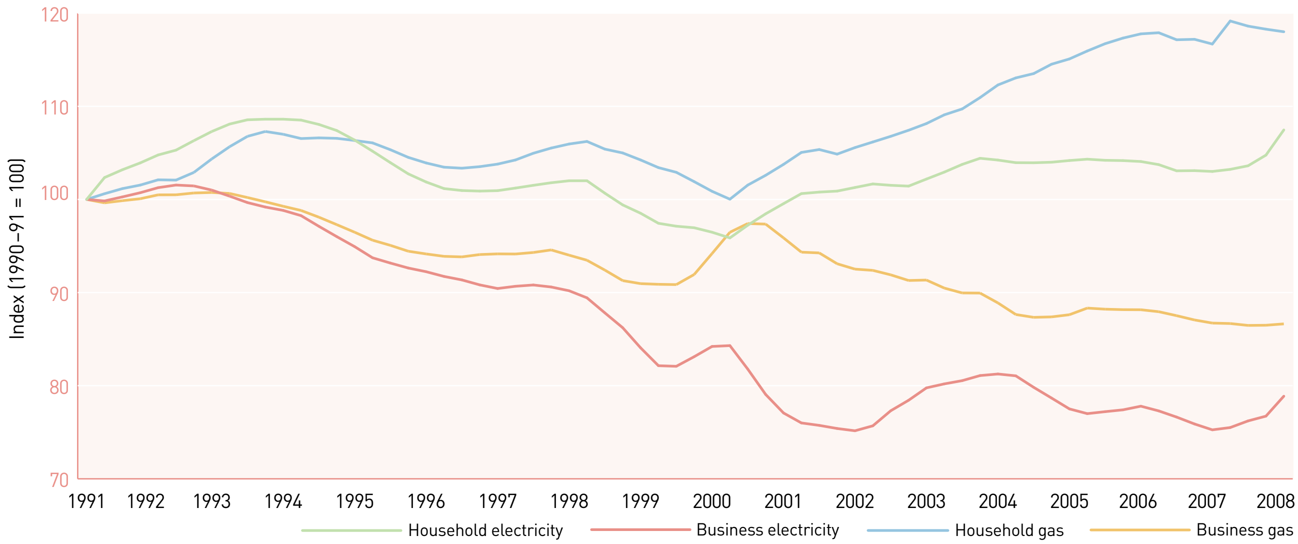
The AEMC is currently reviewing the South Australian market. The *First final report*, released in September 2008, found that competition is effective for small electricity and gas customers in South Australia, with competition being more intense in electricity than in gas. Although the AEMC considered that overall competition was effective, it noted that new entry may be limited due to rising spot prices, increased spot price volatility and increasing vertical integration in South Australia's electricity market.

Several jurisdictions have announced increases in regulated default prices in 2007 and 2008 in response to rising wholesale energy and hedging costs. Table 3 summarises recent regulated electricity price movements. In addition, several jurisdictions have allowed for further price revisions if wholesale costs continue to rise.

19 Premier of Victoria, *Brumby Government Boosts Transparency in Power Pricing*, media release, 11 September 2008.

Figure 6

Electricity and gas retail price index (real)—Australian capital cities



Source: ABS, cat. no. 6401.1 and 6427.0.

Retail price comparisons between the jurisdictions should be undertaken with care. In particular, there are differences in the operating environments of retail businesses, including the degree of retailer exposure to wholesale costs. There were also historic differences in price levels across jurisdictions. That said, several jurisdictions have agreed to significant increases in default prices. In the eastern states, these price increases have been mainly linked to the effects of drought on wholesale costs in 2007. In Western Australia, the government has announced that it will increase regulated prices after several years of declining real prices.

While price increases have been most evident for electricity, Western Australia, South Australia and—to a lesser extent—Victoria and New South Wales, have also announced significant increases in default retail prices for natural gas in response to rising wholesale costs.

Figure 6 estimates trends in average retail prices (reflecting both regulated and market contracts) over time. In the longer term, it is likely that climate change policies will add to upward pressure on retail prices. The Australian Government's green paper on the Carbon Pollution Reduction Scheme estimates that a carbon emissions price of $20 per tonne could result in household electricity prices rising by up to 16 per cent. Retail gas prices are also likely to increase as demand for gas-fired generation increases.

Asset ownership

Table 4 summarises merger and acquisition activity in the energy sector since January 2007. The trend towards greater specialisation in asset ownership has continued. Capital market drivers have led to entities specialising in either the provision of network infrastructure services or non-network (production, generation and retail) services. At the same time, there is increasing integration within each sector.

Table 4 Energy market merger activity, 1 January 2007 to 30 September 2008

DATE	PROPOSAL	SECTORS AFFECTED	STATUS
Jan 2007	AGL Energy acquisition of a 27.5% stake in Queensland Gas Company	Gas: production	Acquired
Feb 2007	AGL Energy acquisition of Powerdirect from the Qld Government	Electricity: retail	Acquired
Jul 2007	AGL Energy and TRUenergy swap of electricity generation assets in South Australia (AGL Energy acquired the Torrens Island power station in return for $300 million and the Hallett power station)	Electricity: generation	Acquired
	APA Group acquisition of Origin Energy's gas network assets, including a 33% stake in the SEA Gas Pipeline and a 17% share in Envestra	Gas: transmission, distribution	Acquired
	City Spring Infrastructure Trust (Singapore) acquisition of the Basslink interconnector from National Grid (UK)	Electricity: transmission	Acquired
Aug 2007	International Power acquisition of remaining 50% of the EA–IP Retail Partnership, to acquire full ownership	Electricity: retail Gas: retail	Acquired
Oct 2007	Babcock & Brown and Singapore Power acquisition of Alinta	Electricity: generation, transmission, distribution, retail Gas: transmission, distribution, retail	Acquired
Nov 2007	Transfield Services acquisition of Qld Government wind farm assets	Electricity: generation	Acquired
Dec 2007	AGL Energy and Arrow Energy joint venture acquisition of Enertrade's Moranbah gas assets	Electricity: generation Gas: production, transmission	Acquired
Apr 2008	BG Group acquisition of around 20% of Queensland Gas Company	Gas: production	Acquired
May 2008	BG Group acquisition of Origin Energy	Electricity: generation, retail Gas: production, transmission, retail	Proposal withdrawn 9 September 2008
	Petronas acquisition of 40% of Santos' LNG project at Gladstone (joint venture)	Gas: production	Regulatory approvals obtained
Jun 2008	Shell acquisition of 30% of Arrow Energy's upstream gas assets	Gas: production	Preliminary agreement
	BBI announces a potential sale of up to 50% of Powerco	Gas: distribution	Formal price discovery
	Victorian Funds Management Corporation acquisition of North Queensland Gas Pipeline from AGL Energy–Arrow Energy joint venture	Gas: transmission	Acquired
Jul 2008	Industry Funds Management acquisition of Babcock & Brown Power's share of Ecogen Energy (73%), to obtain full ownership (Ecogen Energy owns the Newport and Jeeralang generators)	Electricity: generation	Acquired
	Origin Energy acquisition of BBP's Uranquinty generator	Electricity: generation	Acquired
Aug 2008	APA Group acquisition of Country Pipelines (owner of the Central Ranges Pipeline)	Gas: transmission	Sales agreement entered into
	Tas Government acquisition of Babcock & Brown Power's Tamar generator	Electricity: generation	ACCC accepted Tas Government under-taking to onsell the asset to Aurora Energy
	Queensland Gas Company acquisition of Sunshine Gas	Gas: production	Shareholders proposal
	ARC Energy and Australian Worldwide Exploration merger. Demerger of Buru Energy (Canning Basin assets)	Gas: production	Completed
Sep 2008	ConocoPhillips acquisition of 50% of Origin Energy's CSG assets in Queensland (including associated LNG projects)	Gas: production	Conditional agreement
	Hydro Tasmania acquisition of Momentum Energy (51% immediately and balance in 2010)	Electricity: generation, retail	Approved by company boards
	REST acquisition of CLP Group's 33% stake in the SEA Gas Pipeline	Gas: transmission	Acquired

ACCC, Australian Competition & Consumer Commission; BBI, Babcock & Brown Infrastructure; BBP, Babcock & Brown Power; CSG, coal seam gas; EA–IP, Energy Australia–International Power; LNG, liquefied natural gas; REST, Retail Employees Superannuation Trust.

Table 5 Ownership of private network infrastructure at 1 August 2008

	ELECTRICITY DISTRIBUTION	GAS DISTRIBUTION	ELECTRICITY TRANSMISSION	GAS TRANSMISSION
Singapore Power International (includes Jemena & SP AusNet)	Vic, ACT	Vic, NSW, ACT	Vic, Basslink	Qld, Vic-NSW
APA Group		Qld	Interconnectors	NSW, Vic, Qld, WA, Vic-SA, NT
Cheung Kong Infrastructure/Spark Infrastructure	Vic, SA			
Babcock & Brown Infrastructure (some with DUET)		WA, Tas, Vic		WA, Tas
Epic Energy (Hastings)				SA, Qld, Qld-SA, WA
Envestra		Vic, Qld, SA		NT

This has seen a rationalisation of the energy networks sector (table 5), with Singapore Power International (and related entities Jemena and SP AusNet), the APA Group (formerly Australian Pipeline Trust), Cheung Kong Infrastructure/Spark Infrastructure and the Babcock & Brown group emerging as key private sector players. Epic Energy (Hastings) and Envestra focus on the gas pipeline sector. There have been moves towards further ownership consolidation over the last year. Singapore Power International and the Babcock & Brown group completed their acquisition of Alinta in October 2007, establishing these businesses among the leading network owners.

A substantially different set of entities operate private generation and retail businesses, with significant ownership consolidation occurring between these sectors in Victoria and South Australia. Two major retailers—AGL Energy and TRUenergy—have significant generation interests. In July 2007, AGL Energy and TRUenergy completed a generator swap in South Australia that moved the generation capacity of each business into closer alignment with their retail loads. While the third major retailer—Origin Energy—currently has limited generation capacity, it has several major development projects under construction (see table 1). Another major generator—International Power—has launched a retail arm called Simply Energy.

There has also been vertical integration in the public electricity sector. Snowy Hydro owns Red Energy, which has acquired some retail market share in Victoria and South Australia. In September 2008, Hydro Tasmania acquired a controlling interest in the small private retailer Momentum Energy.

Towards the middle of 2008, capital market pressures led to Babcock & Brown Power announcing the sale of several generation assets, including the Uranquinty development (to Origin Energy) and the Victorian Newport and Jeeralang generators (to Industry Funds Management). It also announced the sale of the Tamar Valley power project (to the Tasmanian Government) and of its interests in generation projects in Western Australia. In addition, Babcock & Brown Infrastructure announced a possible partial sale of Powerco, which owns the Tasmanian gas distribution network.

In June 2008, the New South Wales Government announced that it planned to privatise its electricity generation and retail assets through a combination of trade sales and share offerings. The New South Wales Auditor-General reported in August 2008 that the asset sales would raise no adverse issues for taxpayers. In September 2008, the New South Wales Premier announced that the sale of government retailers would proceed, but that the state would retain its generation assets.

There has been significant merger and acquisition activity in the gas production sector, with interest focused mainly on CSG (and associated LNG proposals) in Queensland. Queensland Gas Company, the third largest producer in the Surat–Bowen Basin, has been a focus of acquisition interest. Following an unsuccessful takeover attempt by Santos in 2006, the company formed a strategic partnership with AGL Energy in 2007, which allowed AGL Energy to acquire a 27.5 per cent stake in the business. Queensland Gas Company sold a further 20 per cent stake in its assets to BG Group (formerly British Gas) in 2008. BG Group sought to further expand its market profile in 2008 by attempting to acquire Origin Energy. The bid failed in September 2008 when Origin Energy entered an agreement to develop its CSG and LNG projects with ConocoPhillips.

The AER's role

With the transition to national regulation, the AER is now the economic regulator of all energy network assets in southern and eastern Australia, as well as gas pipeline assets in the Northern Territory. It also monitors the wholesale electricity market for compliance with the underpinning legislation, and reports on market activity. It has similar monitoring and enforcement roles in the evolving gas market structure.

As the national regulator, the AER will continue to work closely with stakeholders in these roles. It will look to apply consistent and transparent approaches to encourage efficient investment and reliable service delivery. The AER is also looking to innovate in areas where improvement might be needed. In the past year, for example, the AER has launched new schemes that provide incentives for electricity network businesses to reduce congestion and provide more reliable services.

The AER will continue to work towards best practice regulatory and enforcement outcomes, including the provision of independent and comprehensive information on market developments.


Mark Wilson

ABBREVIATIONS

1P	proved reserves
2P	proved plus probable reserves
3P	proved plus probable plus possible reserves
AASB	Australian Accounting Standards Board
ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AGA	Australian Gas Association
AMIQ	authorised maximum interval quantity
ANTS	Annual National Transmission Statement
APPEA	Australian Petroleum Production and Exploration Association
APT	Australian Pipeline Trust (part of the APA Group)
ASE	Australian Securities Exchange
B&B	Babcock & Brown
BBI	Babcock & Brown Infrastructure
BBP	Babcock & Brown Power
boe	barrel of oil equivalent
CAIDI	customer average interruption duration index
CBD	central business district
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CH_4	methane
CKI	Cheung Kong Infrastructure
CNOOC	China National Offshore Oil Company
CO_2	carbon dioxide
COAG	Council of Australian Governments
CPI	consumer price index
CPT	cumulative price threshold
CSG	coal seam gas
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DC	direct current
EAPL	East Australian Pipeline Limited
EBIT	earnings before interest and tax
EBITDA	earnings before interest, tax, depreciation and amortisation
EGP	Eastern Gas Pipeline
ERA	Economic Regulation Authority (Western Australia)
ERCOT	Electric Reliability Council of Texas
ERIG	Energy Reform Implementation Group
ESAA	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
EST	Eastern Standard Time
ETEF	Electricity Tariff Equalisation Fund
FEED	front end engineering design
FIRB	Foreign Investment Review Board
FRC	full retail contestability
Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems
GCV	gross calorific value
GEAC	Great Energy Alliance Corporation
GGP	Goldfields Gas Pipeline
GGT JV	Goldfields Gas Pipeline Joint Venture
GJ	gigajoule
GJ/a	gigajoule per annum
GMC	Gas Market Company
GMLG	Gas Market Leaders Group
GSL	guaranteed service levels
GSOO	Gas Statement of Opportunities
GWh	gigawatt hour
HKE	Hong Kong Electric Holdings

ICRC	Independent Competition and Regulatory Commission
IGCC	integrated gasification combined cycle
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal
JV	joint venture
JWG	joint working group
kcal	kilocalorie
kV	kilovolts
KW	kilowatt
KWh	kilowatt hour
LNG	liquefied natural gas
MAIFI	momentary average interruption frequency index
MAPS	Moomba to Adelaide Pipeline System
MCC	marginal cost of constraints
MCE	Ministerial Council on Energy
MCMPR	Ministerial Council on Minerals and Petroleum Resources
MSATS	Market Settlement and Transfer Solution
MSP	Moomba to Sydney Pipeline
MW	megawatt
MWh	megawatt hour
NCC	National Competition Council
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NEMO	National Electricity Market Operator
NEMS	National Electricity Market of Singapore
NER	National Electricity Rules
NGERAC	National Gas Emergency Response Advisory Committee
NGL	National Gas Law
NGMC	National Grid Management Council
NGPAC	National Gas Pipelines Advisory Committee
NGR	National Gas Rules
NGS	National Greenhouse Strategy
NGT	National Grid Transco
NPI	National Power Index
NQGP	North Queensland Gas Pipeline
NWIS	North West Interconnected System
NWSG JV	North West Shelf Gas Joint Venture
OCC	outage cost of constraints
OCGT	open cycle gas turbine
OECD	Organisation for Economic Cooperation and Development
OTC	over-the-counter
OTTER	Office of the Tasmanian Energy Regulator
PASA	projected assessment of system adequacy
PG&E	Pacific Gas and Electric
PJ	petajoule
PJ/a	petajoule per annum
PJM	Pennsylvania-New Jersey-Maryland Pool
PNG	Papua New Guinea
POE	probability of exceedence
PPA	power purchase agreement
PPI	producer price index
PV	photovoltaic
PwC	PricewaterhouseCoopers
Q	quarter
QCA	Queensland Competition Authority
QGC	Queensland Gas Company
QNI	Queensland to New South Wales interconnector
QPTC	Queensland Power Trading Corporation
RAB	regulated asset base
REMCo	Retail Energy Market Company
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCO	Standing Committee of Officials
SEA Gas	South East Australia Gas
SECWA	State Energy Commission of Western Australia
SEQ	southeast Queensland

SFE	Sydney Futures Exchange
SOO	Statement of Opportunities (published by NEMMCO)
SPCC	supercritical pulverised coal combustion
SPI	Singapore Power International
STEM	short-term energy market
STTM	short term trading market
SWIS	South West Interconnected System
SWQJV	South West Queensland Joint Venture
SWQP	South West Queensland Gas Producers
TCC	total cost of constraints
TJ	terajoule
TNSP	transmission network service provider
TW	terawatt
TWh	terawatt hour
TXU	Texas Utilities
UIWG	Upstream Issues Working Group
URF	Utility Regulators Forum
VENCorp	Victorian Energy Networks Corporation
VoLL	value of lost load
VTS	Victorian Transmission System
WAGH	WA Gas Holdings
WAPET	West Australian Petroleum
WMC	Western Mining Company

PART ONE
ESSAY

AUSTRALIA'S NATURAL GAS MARKETS: THE EMERGENCE OF COMPETITION?

A Report by ACIL Tasman Pty Ltd

ESSAY

AUSTRALIA'S NATURAL GAS MARKETS: THE EMERGENCE OF COMPETITION?

A Report by ACIL Tasman Pty Ltd July 2008

E.1 Background

The period following the first discovery of natural gas in Australia at Roma, southern Queensland, in 1900 saw decades of sporadic development activity but little real progress toward establishment of a viable natural gas industry. The inability to access mass markets meant that production was limited to small quantities for use in the local area. It was not until the 1960s and early 1970s that the foundations of the Australian natural gas industry as we now know it were laid, with the discoveries of the Cooper Basin (1963), Gippsland Basin (1967) and North West Shelf gas fields (1971).

The key to making natural gas a mainstream fuel accessible to consumers in the major population centres was the establishment of gas transmission and distribution systems. The first of these, servicing Brisbane, was commissioned in 1967, followed by those servicing Melbourne (1968), Adelaide (1969), Perth (1972) and Sydney (1976).

The early phases of the development of the Australian natural gas industry were characterised by:

- limited competitive choice for customers: population centres and industrial sites with access to natural gas generally relied on a single source of supply delivered via a single transmission pipeline

- significant government ownership of assets and businesses, particularly in gas transmission and distribution infrastructure and retailing
- underwriting of infrastructure development by state governments, notably in Western Australia, South Australia and Victoria, where the states signed long-term foundation contracts that supported private investment in upstream and midstream developments.

The Australian natural gas industry has grown considerably over the past decade, and the structure and operation of the industry has changed as a result of privatisation, corporate activity and regulatory reform. The purpose of this essay is to provide an overview of the current gas market; to document the important policy reforms, structural changes and commercial developments that have reshaped the industry; and to look at the key drivers that will determine the direction of future developments.

Structure of the gas industry in Australia

The structure of the industry can usefully be considered from three perspectives: geographic, functional and commercial. These are discussed in the following sections.

Geographic structure of the industry

Geographically, the Australian natural gas industry can be separated into three regional markets, defined by the interconnected transmission pipeline systems that link upstream producers and downstream consumers:

- eastern Australia, including Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, Tasmania and South Australia
- the Northern Territory
- Western Australia.

Each of the regional markets can be subdivided into sub-regional market areas that represent clusters of supply and demand locations linked by transmission pipelines. These regional and sub-regional market areas are illustrated in figure E.1, which also indicates the size of the markets in terms of current levels of annual gas production and consumption.

In eastern Australia, Victoria has the strongest level of gas demand, currently estimated at around 244 petajoules per year (PJ/a). Queensland is now the second largest regional market, with demand expected to reach 190 PJ/a during 2008. Unlike Victoria, where demand is dominated by small customers with low individual consumption (residential, commercial and small industrial), the Queensland market is dominated by large industrial and power generation customers—both sectors that have grown rapidly in recent years.

Total gas demand in New South Wales (including the ACT) currently stands at around 150 PJ/a, and the state's customer profile is more like Victoria than Queensland. In South Australia, gas demand currently stands at around 107 PJ/a, having declined in recent years as a result of industrial plant closures and increased electricity imports. The Tasmanian market is in its formative stages—natural gas only became available following the commissioning of the Tasmania Gas Pipeline (Longford to Bell Bay, Hobart and Port Latta) in 2002. Demand is currently estimated at 12 PJ/a, principally for electricity generation, and will grow further with additional gas-fired power plant under construction.

For many years, the most important source of gas production in eastern Australia has been the Gippsland Basin, and it continues to be the largest producer in the region, at around 250 PJ/a. Over the past five years, new gas developments in the Bass Strait region (Otway and Bass basins) have seen the productive capacity of the region rise by more than 130 PJ/a, with further growth anticipated.

The other sources of conventional gas in eastern Australia are the Cooper Basin of South Australia and southwest Queensland—now in decline, with annual production currently between 140 and 150 PJ/a—and the Surat Basin and Denison Trough regions of southern Queensland, which produce around 26 PJ/a.

Figure E.1

Geographic distribution and size of gas markets in Australia

Source: ACIL Tasman compilation of various public sources.

In recent years, a major new source of gas supply for eastern Australia has emerged in the form of coal seam gas (CSG).[1] From a virtually zero base a decade ago, CSG production has risen to over 100 PJ/a in 2007, and is expected to reach as much as 160 PJ/a in 2008, with further strong growth anticipated.

The Northern Territory market is self-contained, with the current demand of around 21 PJ/a met from fields in the Amadeus Basin in Central Australia. As these fields deplete over the next few years, domestic supply will be drawn from the offshore Bonaparte Basin: the Blacktip field and associated infrastructure are currently under development to service the domestic market. The

1 Coal seam gas, also known as coal seam methane and (particularly in the USA) as coal bed methane, is natural gas (principally methane) that occurs naturally in coal seams. Although its production characteristics differ from conventional natural gas, processed coal seam gas is effectively indistinguishable from conventional gas. Coal seam gas typically meets standard pipeline gas specifications and can be routinely co-mingled with conventional gas.

alumina refinery at Gove, on the east Arnhem Land coast of the Gulf of Carpentaria, represents an additional potential gas load of around 45 PJ/a. However, despite previous plans for gas supply from Blacktip, and subsequently from Papua New Guinea, Gove remains isolated from gas supply and continues to operate using fuel oil. In 2006, Darwin became Australia's second liquefied natural gas (LNG) production centre, with the Darwin LNG plant now producing some 3 million tonnes of LNG per year (about 165 PJ/a) from the Bayu-Undan field in the Bonaparte Basin.

The Western Australian gas market remains isolated from the rest of the country. Over the past 40 years, there has been periodic enthusiasm for the concept of a transcontinental pipeline link, tying abundant and cheap gas production in the west with large domestic markets in the east. However, in recent times it has become clear that, while Western Australia's undeveloped offshore gas resources are undoubtedly abundant, they will not be cheap to develop and there is no commercial basis for integration of the Western Australian and east coast gas markets.

Domestic gas demand in Western Australia, at around 330 PJ/a, is currently higher than in any of the eastern states. Two-thirds of this demand is located in the southwest of the state (Perth–Kwinana–Bunbury), with the balance in the northwest (Burrup Peninsula and Pilbara region) and in the central Goldfields region. With the exception of a small contribution from the Perth Basin, all gas produced in Western Australia currently comes from the offshore Carnarvon Basin. Around two-thirds of this supply comes from the domestic gas production facilities associated with the North West Shelf gas project, which also supplies gas to Australia's first and largest LNG facility. With the commissioning of a fifth LNG train during 2008, the North West Shelf LNG project will have a production capacity of 16.3 million tonnes per year—equivalent to 900 PJ/a.

Australia's total production of LNG for export now stands at 1065 PJ/a—very close to the country's total domestic gas demand.

Functional structure of the industry: the natural gas supply chain

The natural gas industry involves a supply chain that includes the following functions:

- Upstream—exploration, development, production and processing of raw gas to produce sales gas that meets established quality specifications.
- Midstream—transportation of sales gas from upstream producers to downstream customers through high- and mid-pressure transmission pipeline systems.
- Downstream—wholesale supply of gas to major industrial and power generation facilities; low pressure pipeline distribution; and retail supply of gas to smaller industrial, commercial and household customers.

Upstream industry

The upstream gas industry covers the activities associated with exploration (seismic acquisition and exploration drilling), field development, gas gathering and processing. Typically, gas produced from a number of fields within a geological basin is transported to a central processing facility that effectively forms a hub around which subsequent exploration and development is focused. Examples of these processing hubs include the Moomba facility that services fields in the Cooper Basin in Central Australia, the Longford gas plant that processes gas from fields in the Gippsland Basin in Bass Strait, and the Wallumbilla hub that serves production facilities in the Surat Basin and Denison Trough areas of southern Queensland.

In order to spread risk, upstream activities are commonly carried out under joint venture arrangements in which several parties share the costs and risks of exploration as well as production entitlements. Commercial agreements between the joint venture parties set out the rights and obligations of the parties, as well as decision-making processes.

In the past, joint venturers typically chose to market their gas on common terms and conditions, including price, and to guarantee their income streams through long-term sales contracts with gas utilities and other large customers. Nowadays, it is more common for joint venture parties to engage in separate marketing, although there may be circumstances where joint marketing is seen to be commercially desirable.[2] To ensure that such activities are not in breach of the anti-competitive conduct provisions of the *Trade Practices Act 1974*, the parties may seek authorisation from the Australian Competition and Consumer Commission (ACCC) by demonstrating that, in the circumstances applying, the public benefits of joint marketing exceed any anti-competitive costs.

In terms of regulation, the view has generally been taken that the upstream gas industry does not have high enough barriers to entry, or great enough economies of scale, to warrant regulation of third party access (or the pricing of access) to facilities. This is largely non-contentious in relation to exploration activities but less clear cut in relation to processing facilities, where there may well be benefits to be gained from at least some degree of consolidation and centralisation of activities. In the absence of regulated access, the upstream industry has established a code of practice for third party access to processing facilities. This is further discussed in section E.2.

Midstream industry

The midstream industry functions relate to gas transmission—the transportation of gas, generally at high pressure and often over long distances, from the upstream sources of production to the downstream gas consumers.

Characteristically, gas transmission pipelines exhibit significant economies of scale. It is generally cheaper to expand an existing pipeline, either through installation of additional compression or through duplication of sections of the pipeline where capacity is constrained (a process known as looping), than it is to build a new pipeline. These characteristics mean that there is rarely any incentive for pipeline owners to invest in speculative spare capacity, since additional capacity can usually be added without incremental cost penalties as and when market demand arises. Because it is generally cheaper for an existing pipeline owner to expand capacity than for a new entrant to build a second pipeline between the same producer–customer pairing, transmission pipelines have natural monopoly characteristics. For this reason, the midstream industry is subject to access regulation.[3] Upstream competition may, however, emerge where there are multiple sources of supply that could service a particular market if transport pathways are available.

The objective of access regulation is to ensure that where the pipeline service provider is not subject to effective market competition, transportation services are nevertheless available to third party users on a non-discriminatory basis and at prices that reflect the efficient cost of providing the service. Regulation therefore seeks to achieve the outcomes that effective competition in the supply of transmission services, if it existed, would be expected to deliver. As discussed in section E.2, the number of transmission pipelines subject to third party access and tariff regulation is declining as new investment leads to an increasing number of gas wholesale and retail markets being serviced by multiple pipelines.

2 For example, the proponents of the PNG Gas Project, which was to deliver gas by pipeline from PNG to eastern Australia, successfully sought authorisation for joint marketing.

3 The regulatory instrument is the National Gas Rules, which took effect on 1 July 2008, replacing the National Third Party Access Code for Natural Gas Pipeline Systems (commonly referred to within the industry as the 'National Code').

Downstream industry

The downstream industry involves the wholesale supply of gas to large consumers, including major industrial and power generation sites, and the retail supply of gas primarily to small industrial, commercial and residential customers. It includes both transportation functions (distribution and reticulation) and sales functions (retail).

Transportation

The transportation of gas from the midstream high-pressure pipeline terminus (often referred to as the city gate) to small industrial, commercial and residential customers is a key function of the downstream gas industry. Gas distribution and reticulation is a regulated business function. Regulation under the National Third Party Access Code for Natural Gas Pipeline Systems (National Code) requires separation (ring-fencing) of gas distribution businesses from gas retail sales businesses and provides for non-discriminatory third party access under standardised terms, including reference tariffs.

Gas sales: wholesale and retail

The second area of downstream activity relates to the selling of gas and associated services. Sales activities are commonly separated into wholesale and retail, although the distinction is less clear cut than might be imagined: large-scale gas users—which might be thought of as 'wholesale customers'—have the choice of purchasing gas through a retailer or contracting directly with a gas producer. Some direct contracts are for supply on a *delivered basis* (in which case the gas producer arranges for transportation) or on an *ex-plant basis* (in which case the purchaser separately arranges with the relevant pipeline service provider for the gas to be delivered). Most very large users contract for supply directly, but this is not generally a practical approach for smaller users. Even some large gas consumers prefer to have a retailer deal with the upstream and midstream issues of gas procurement and transportation. Retailers may be able to use their purchasing power to secure gas supply and transportation on better terms than individual users. They may also be better able to manage supply risk by having access to a diverse portfolio of supply options that leaves the end-user less prone to interruption as a result of disruptions to any one source of supply.

The primary functions of gas retailers are:

- the sale and marketing of gas (both pipeline natural gas and liquefied petroleum gas) to customers
- the wholesale purchase of gas for retail on-sale to customers
- the provision of billing and other information to customers
- revenue collection and credit management
- customer service and contact (including the provision of telephone call centres for customer enquiries).

Natural gas retailing differs from electricity retailing due to the physical nature of the product. Gas retailers must ensure sufficient supply and transportation capability to maintain physical delivery to customers. As a result, retailers bundle together natural gas with transportation services when selling to customers.

Another key difference for retailers in the natural gas market is the lower degree of integration across the states. There is no single market operator providing standardised market clearing and other functions (as the National Electricity Market Management Company provides in electricity), with regulation and market management being the responsibility of the various state regulators.

Emergence of retail competition

Energy retailing in eastern Australia has undergone rapid development over the past decade:

- In most states monopoly (franchise) retailers have been replaced or augmented by private retailers as markets have been progressively opened to competition.
- Significant consolidation has occurred as competitors seek to gain economies of scale and pursue growth via merger and acquisition activity.
- Major private sector retailers have diversified geographically in order to grow their businesses and to diversify sources of risk and exposure to state wholesale markets.

- Retailers have sought to further increase customer numbers and reduce risks by diversifying into both gas and electricity where possible.
- Asset intensive, highly regulated network businesses have been split off from energy retailing businesses wherever privatisation has occurred.
- The largest private sector energy retailers have developed vertical integration strategies.

Typically, smaller customers and those in more remote locations (relative to the core of the distribution networks) face higher fixed costs of service. Prior to the era of deregulation, it was common for governments to regulate prices so that residential and rural regional customers paid prices below full cost recovery, while prices for larger users were often set above efficient levels. While many jurisdictions continue to regulate default retail gas prices, regulatory reform over the past decade has been directed toward removing cross-subsidies and achieving cost-reflective pricing across the full range of users.

Retail convergence and dual fuel services

Increasingly the Australian market has seen a convergence in the retail sector between electricity and gas, with most retailers now offering both gas and electricity as part of a comprehensive energy services offering. There have even been moves—in line with trends in some overseas countries—to incorporate data and telecommunication services, although the integrated utilities retailer model has yet to find much traction here.

The primary benefits of operating as a dual fuel retailer are:

- cost savings associated with retail costs by combining separate gas and electricity retail functions such as billing systems, call centres, marketing and administration
- offering bundled dual fuel products to customers, potentially providing discounts unable to be matched by single fuel retailers.

Retail gas pricing

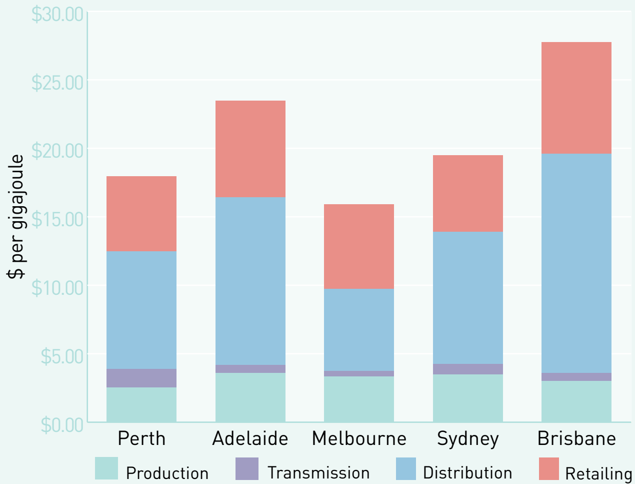
The delivered price of gas to retail consumers includes charges for each element in the supply chain: payments to the upstream producers for the gas itself; to the transmission pipeline and distribution system operators for use of their transport systems; and to the retailer for provision of retail services including gas portfolio management, meter reading, and customer account maintenance and billing.

There are significant fixed cost components in the overall service package, and those costs vary considerably depending on the geographical location of the customer. As a result, prices vary significantly for customers with different volume requirements and at different locations. Because of the many differences in costs and circumstances across regional supply chains, comparing the retail price of gas at different locations needs to be approached cautiously: 'apples with apples' comparisons are difficult. Customers vary greatly both within and between regions, and the prices they face vary accordingly. So, for example, the average residential gas customer in Victoria consumes around 65 GJ/a—more than three times the annual consumption of the average Queensland residential customer. It is nevertheless revealing to examine how indicative gas prices vary by location, and what components make up those prices. Figure E.2 illustrates the components of retail residential gas prices in the mainland state capital cities for typical residential customers in those locations. Total prices range from around $15.50 per GJ in Melbourne to almost $28 per GJ in Brisbane

Upstream costs associated with the extraction and production of the gas itself account for a relatively small proportion of total cost—between 11 and 21 per cent. Transportation through the high pressure transmission system is the smallest contributor to delivered costs for residential consumers in the capital cities (2 to 7 per cent). The total upstream and midstream costs therefore account for only around 15 per cent of delivered cost to residential consumers. For larger industrial users, this proportion rises steadily with scale as the fixed costs associated with downstream services are spread across much larger gas supply volumes.

Figure E.2

Components of retail residential gas price



Source: ACIL Tasman analysis based on wholesale gas price estimates, regulated and posted tariffs for transmission and distribution services, and published retail gas prices for residential customers.

By far the highest proportion of total cost is associated with the low pressure distribution system (38 to 58 per cent) reflecting the high capital cost to service each customer. The proportionate cost associated with distribution is greatest in Queensland, where average gas consumption per customer is lowest, and conversely, is lowest in Victoria, where average gas consumption per customer is highest. Retailing typically accounts for around 30 per cent of total costs and is relatively uniform across the regions, ranging from $5.50 to $8.00 per GJ.

Commercial structure of the industry

The final basis of characterisation of the Australian natural gas industry is in terms of the commercial relationships between the functional participants.

Historically most of the gas in Australia has been bought and sold on the basis of long-term bilateral contracts. These contracts between gas producers and wholesale gas buyers, between producers and transporters, and between transporters and wholesale consumers, have typically been for terms of 10 to 20 years. There has been a trend in recent years toward shorter term supply, but most gas supply and transportation contracts still run for at least five years. Foundation contracts underpinning new facilities development (production projects and major gas-consuming plants) are still often settled for terms of up to 20 years. Indeed, it is commonly argued that such long-term contracts are essential to the financing of new projects because they provide reasonable security of long-term gas supply as well as a degree of cost and revenue stability.

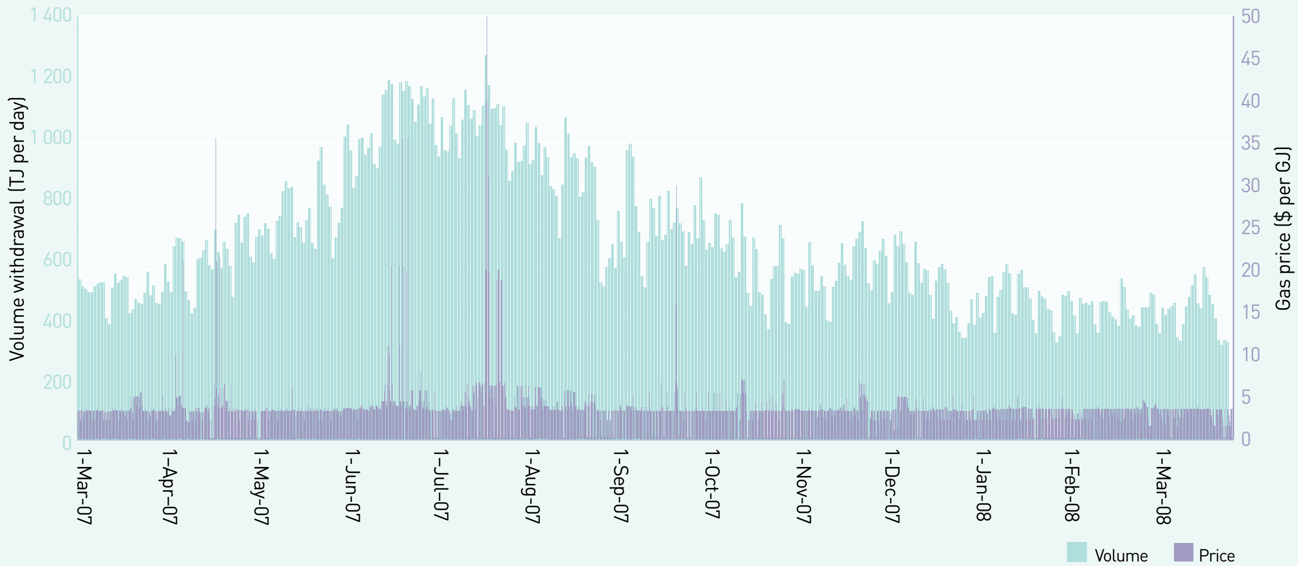
Periodic price review mechanisms, which provide some protection to both buyers and sellers against prices moving and remaining seriously 'out of market', are a feature of most long-term gas supply contracts. Between reviews, prices are typically defined according to a base price indexed regularly (most often to the consumer price index (CPI)). Contract prices therefore do not tend to fluctuate on a daily or seasonal basis. However, the many variations in detailed commercial provisions such as term, volume, volume flexibility (minimum bill or 'take-or-pay' levels; banking rights; relationships between annual contract quantities and maximum daily quantities), penalties associated with failure to supply, and so forth mean that there can be very significant price differences between contracts. Hence, the idea of a single market clearing price has little relevance in the current Australian market.

The only state where there is a formal short-term trading market is Victoria. In Victoria, a spot market has operated since privatisation of the state-owned transmission, distribution and retail gas businesses during the 1990s. As well as trading functions, the Victorian market operator (VENCorp) also provides market-based system balancing. In other jurisdictions, system balancing is physically managed by system operators (such as REMCo), but financial arrangements are otherwise undertaken by transmission and distribution system operators. The Victorian market is discussed in more detail below.

The predominance of long-term gas supply and transportation contracts, together with the lack of active spot markets (outside Victoria) has resulted in a lack of market transparency. The long-term contracts that define the market commercially are typically subject to strict confidentiality provisions. As a result, there is little public domain information regarding levels of uncontracted

Figure E.3

Victorian natural gas spot prices and volumes



Notes: Price display capped at $50 per GJ for readability; actual spot price in July 2007 reached maximum of $336 per GJ.
Source: VENCorp.

gas supply, demand, price and other commercial variables. Steps are being taken to address this lack of transparency through the Gas Market Reform initiatives currently being pursued by the Council of Australian Governments (COAG). These reforms are discussed in section E.2.

Victorian spot market

The Victorian spot market, operated by VENCorp, operates to balance daily requirements between retailers and suppliers. While the market is still underpinned by long-term bilateral contracts, the spot market provides both a balancing mechanism and a means by which sellers and buyers are able to trade contractual entitlements on a short-term basis.

Spot price volatility and volumes of natural gas sold in the Victorian pool from March 2007 to March 2008 are summarised in figure E.3.

The wide range in volume from less than 400 terajoules per day (TJ/d) to 1200 TJ/d reflects the large seasonal load swing in the Victorian market, with high demand during the cool winter months and much lower demand during summer. Significant volatility in spot prices occurred in mid-2007, partly due to water shortages curtailing electricity generation by hydro plants, which in turn drove up demand for gas for generation. While spot prices peaked at very high levels (up to $336 per GJ in July 2007), prices in the Victorian spot market mostly reflect underlying contract prices, currently ranging between $3.35 and $3.60 per GJ. The Victorian market therefore provides a clearing house in which gas can be bought and sold on an intra-daily basis, with prices reflecting the short-term supply–demand balance, while underlying long-term supply contracts insulate major buyers and sellers from price volatility in much the same way that hedge contracts operate to manage price risk for electricity generators and retailers in the National Electricity Market.

Market participants

Figure E.4 summarises the main participants in the upstream, midstream and downstream sectors of the east coast, Northern Territory and Western Australian gas markets.

Figure E.4

Gas market participants

UPSTREAM	MIDSTREAM	DOWNSTREAM
Gas exploration, production and processing	Gas transmission	Gas distribution and retail
EASTERN AUSTRALIA	EASTERN AUSTRALIA	EASTERN AUSTRALIA
PRODUCTION > Esso/BHP Billiton (46.2%) > Santos (24.7%) > Origin (10.8%) > Beach (5.0%) > AWE (2.6%) > Qld Gas (2.3%) > Arrow/AGL (1.8%) > Others (6.6%)	TRANSMISSION > **APA Group:** Roma–Brisbane, Carpentaria, Moomba–Sydney, Central West, Victoria PTS, SEA Gas [part] > **Epic Energy:** SWQP, MAPS > **SPI:** QGP, EGP/VicHub > **BBI:** Tasmania GP > **International Power:** SEA Gas [part] > **TRUenergy:** SEA Gas [part] > **AGL/Arrow:** NQGP	DISTRIBUTION > **APA Group:** Brisbane Sth/Southeast Qld, Vic United > **Envestra:** Adelaide/SA regional, Vic regional, Brisbane Nth, Central Qld (coastal) > **SPI:** NSW/ACT > **BBI:** Vic Multinet > **SP AusNet:** Vic regional RETAIL > **ActewAGL:** (NSW/ACT) > **AGL Energy:** (all except Tas) > **Aurora:** (Tas) > **Australian Power & Gas:** (Vic, NSW, Qld) > **Country Energy:** (NSW/ACT) > **EnergyAustralia:** (NSW/ACT/Vic/SA) > **Simply Energy:** (Vic/SA) > **Option One:** (Tas) > **Origin Energy:** (all except Tas, ACT) > **TRUenergy:** (Vic,NSW,SA)
NORTHERN TERRITORY	NORTHERN TERRITORY	NORTHERN TERRITORY
PRODUCTION > Santos (62%) > Magellan (38%)	TRANSMISSION > **APA Group:** Amadeus–Darwin > **Envestra:** Palm Valley–Alice Springs	RETAIL > NT Gas
WESTERN AUSTRALIA	WESTERN AUSTRALIA	WESTERN AUSTRALIA
PRODUCTION > North West Shelf JV (65.0%) > Apache (20.2%) > Santos (9.8%) > ARC Energy (1.8%) > Origin (1.5%) > Others (1.7%)	TRANSMISSION > **DUET:** Dampier Bunbury Pipeline > **APA Group:** Parmelia Pipeline Goldfields Gas Transmission, Telfer Pipeline, MidWest Pipeline > **Epic Energy:** Pilbara Energy Pipeline	DISTRIBUTION > **BBI:** Perth, SW, Geraldton, Kalgoorlie distribution RETAIL > Synergy > Perth Energy > Verve Energy

Note: Some corporate names have been abbreviated or shortened.

Source: ACIL Tasman, production data from EnergyQuest.

E.2 A decade of regulatory reform and policy development

Major regulatory reform of the Australian gas industry commenced in the mid-1990s driven by two separate but related developments:

- The Competition Policy Reform agenda of COAG following the release of the Hilmer Report on National Competition Policy. In particular, COAG drove the removal of barriers to interstate trade in gas. It oversaw the industry-led review of impediments to competition in upstream gas exploration and production, the establishment of the National Code regulating third party access to natural gas transmission and distribution systems, and the transition to full contestability in retail energy markets (gas and electricity).
- Privatisation of government-owned gas businesses (principally midstream and downstream).

As a result of these reforms, the gas industry in 2008 is vastly different from the industry a decade earlier. Ownership and operation of gas transmission pipelines is now entirely in private hands; new transmission pipelines have been built to service a greatly increased level of interstate trade in gas (Victoria to New South Wales, Victoria to South Australia, Victoria to Tasmania and, by early 2009, Queensland to New South Wales and South Australia). Government-owned gas distribution businesses have also been privatised in Western Australia, South Australia, Victoria and Queensland, as have gas retail businesses in the mainland eastern states.[4] This section discusses these reforms in more detail.

Upstream gas industry reform

A number of industry reviews have addressed potential impediments to competition in the upstream gas industry, starting with the Upstream Issues Working Group (UIWG) convened by COAG in 1998. The UIWG focused on three main issues:

- joint marketing
- third party access to production facilities
- management of exploration acreage and, in particular, administration of relinquishment requirements to ensure that prospective land is not locked up by titleholders that lack either the resources or the commercial incentives to explore for and to develop viable resources.

Subsequent consideration of upstream issues (the Parer Report, 2002;[5] the Ministerial Council on Minerals & Petroleum Resources (MCMPR) and the Ministerial Council on Energy (MCE)[6]) has focused primarily on these same issues. The current position is that the MCMPR has recommended, and the MCE has agreed, that:

- there is no case for prohibiting joint marketing of gas: applications for authorisation of joint marketing under the *Trade Practices Act 1974* should continue to be considered on a case by case basis
- there is 'no systematic problem concerning exploration effort in production licence areas' and hence no change to current administrative policy and practice for acreage management is required
- the industry code of practice governing third party access to upstream production facilities should be reviewed.

Midstream reform—the National Code

In November 1997, the Australian Government, states and territories agreed to enact legislation to apply a uniform national framework for third party access to all gas pipelines. This framework included the Gas Pipelines Access Law and the National Code. The National

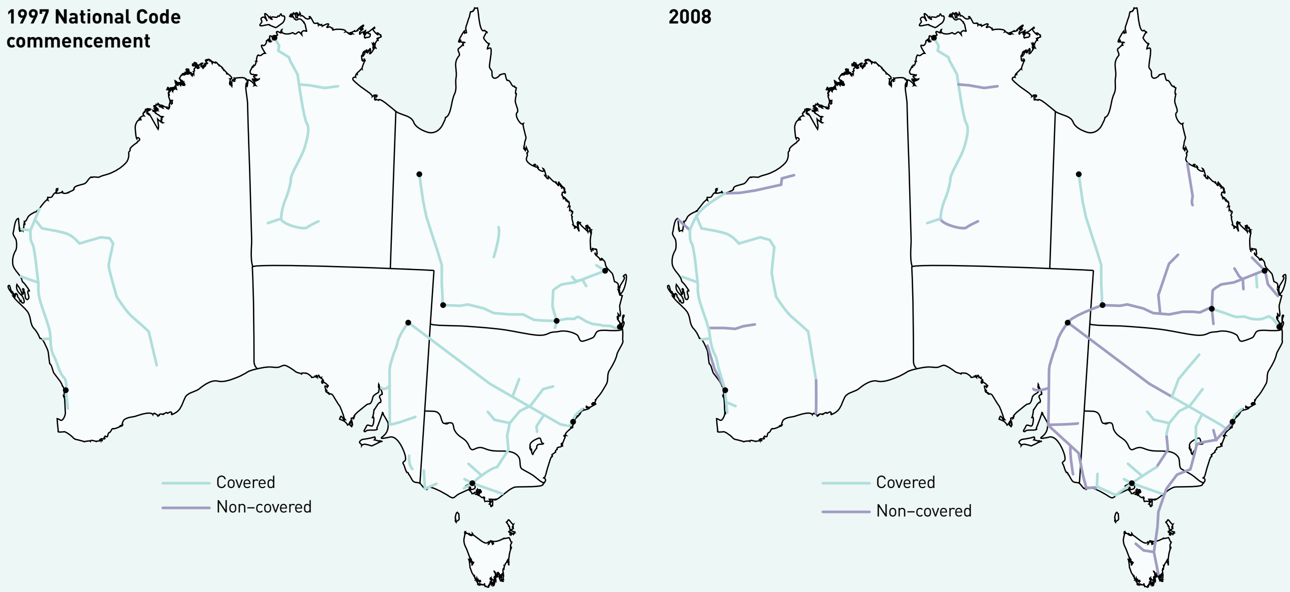
4 The New South Wales gas distribution and retail sectors have always been privately owned.

5 Parer, Warwick & others: *Towards a Truly National and Efficient Energy Market*, Commonwealth of Australia, 20 December 2002.

6 Ministerial Council on Energy (MCE) *Statement on upstream gas issues*, December 2004; Terms of Reference, MCE and MCMPR Joint Working Group on Natural Gas Supply, January 2007.

Figure E.5

Natural gas transmission pipeline developments since introduction of the National Code



Sources: ACIL Tasman; National Competition Council.

Code establishes the rights and obligations of pipeline operators and users in relation to third party access to natural gas transmission and distribution. It is designed to replicate competitive market outcomes where the monopoly characteristics of pipelines facilities might otherwise hinder third party access and the competitive supply of gas.

These regulatory arrangements recognised that transmission pipelines play a critical role in promoting effective competition in the Australian gas market. For new sources of production to enter the market, and to ensure that consumers are able to take advantage of competitive supply as those new sources emerge, access to transmission pipeline capacity on fair and reasonable terms is essential. Conversely, unregulated power to control access to transport services through transmission and distribution systems would have the potential to suppress competition by denying alternative producers a pathway to market.

Upon its introduction, the National Code applied to most of the major natural gas transmission and distribution pipeline systems. Subsequently, new pipelines meeting the coverage criteria of the National Code have also been covered. However, over the past 10 years, new pipeline interconnections and the expansion of existing pipeline systems have seen a significant increase in the level of supply-side competition in major gas markets, particularly in South Australia, New South Wales and Victoria. Major new transmission pipelines, including the Eastern Gas Pipeline (Longford–Sydney), the SEA Gas Pipeline (Western Victoria–Adelaide) and the Tasmania Gas Pipeline, are not covered under the National Code (though their operators typically offer access to uncontracted capacity under voluntarily offered standard terms and conditions). The trend to increased interconnection and reduced regulation is shown in figure E.5, which compares the extent of the transmission pipeline network and the incidence of regulatory coverage between commencement of the National Code in 1997 and the present. As shown, coverage on a number of pipelines pre-dating the National Code has been partly or fully revoked, reflecting in a number of instances the increased level of competition within the interconnected markets.

Downstream reform

In the downstream sector, the regulatory reform process can be divided into reforms to distribution and retail market reform. Distribution sector reform has largely followed the transmission sector, although given the nature of distribution there has been less activity in terms of entry of new competitors in particular distribution regions, with new investment mainly related to incremental expansion of service areas by the incumbent operators.

Within the retail sector, the key area of reform has been the move to full retail contestability (FRC), which has in effect removed the monopoly service rights and obligations under the former franchise arrangements, and replaced them with a competitive market environment in which any qualified service provider may compete for retail customers, subject to certain consumer protection arrangements. The introduction of FRC has occurred in a staged manner across each of the state jurisdictions, with larger industrial customers becoming contestable first and smaller customers later. For example, customers consuming more than 500 TJ/a became contestable in New South Wales from August 1996, whereas small residential and commercial customers (less than 1 TJ/a) did not become contestable until January 2002. The tranche definitions as well as the timing of contestability for individual tranches varied from state to state, with Queensland being the last of the eastern Australian mainland jurisdictions to move to FRC for all customer groups. Small customers (less than 1 TJ/a) became contestable in Queensland from July 2007.

Implementation of FRC in the small user segment has necessitated the introduction of retail market operators[7] to process customer transfers between retailers, to provide technical support and to administer market rules. The market operators are also responsible for daily gas usage allocation between retailers and gas balancing to maintain system security.

The retail market operators are funded by fees paid by distributors and retailers.

Regulation of transmission and distribution

The Gas Pipelines Access Law and the National Code provided, with limited amendment, the basis for regulation of gas transmission and distribution from 1997 until July 2008. Recognising the evolving requirements for regulation of the midstream gas industry, the Australian Energy Market Agreement signed by COAG in June 2004 included provisions for the development of a new national legal framework for the economic regulation of transmission and distribution pipeline assets. An independent expert panel was established to advise the MCE of issues to be addressed in implementing a national approach to energy access. The final recommendations of the expert panel were released in April 2006.[8] These recommendations, together with the conclusions reached in the Productivity Commission's earlier review of the National Code, have been incorporated into the new National Gas Law and the corresponding National Gas Rules, which effectively replaced the National Code on 1 July 2008.

The National Gas Law transfers the administration and enforcement of the existing gas access regimes from state-based regulators to the national bodies, the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). These changes are intended to provide a regulatory framework that supports efficient new pipeline investment while ensuring the interests of participants in both upstream and downstream markets, including users and customers, are appropriately considered.

7 Victoria has had a market operator (VENCorp) in place for both electricity and gas since market establishment in 1997. The retail market operator in New South Wales and the ACT is the Gas Market Company (GMC), while in South Australia this function is carried out by REMCo. Queensland has appointed VENCorp as its market operator.

8 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

Transfer of regulatory responsibilities

The National Gas Law sets out the basis for the AEMC as having responsibility for rule making and market development, and the AER as the national regulator. It provides for the AER to take on, amongst other responsibilities, the regulatory functions for gas transmission pipelines previously undertaken by the ACCC and the regulation of gas distribution, which is currently the responsibility of the various state jurisdictions. The role of gas transmission regulator transferred from the ACCC to the AER on 1 July 2008. The transfer of responsibility for regulation of gas distribution from jurisdictional regulators to the AER also occurred at that time. In Western Australia, the Economic Regulation Authority (ERA) will continue to regulate the gas pipeline sector.

Gas market reform looking forward

Despite the many changes that have occurred in the Australian gas market over the past decade, the reform agenda is by no means complete. Ongoing work is currently focused on the development of mechanisms to encourage greater transparency and efficiency in market operations; reform of transmission and distribution pipeline regulation; and long-term security of supply for domestic gas markets.

Gas market development

In December 2004, the MCE agreed to a set of principles designed to guide the future development of Australian gas markets:

- **Increased transparency:** up-to-date information on market and system operations and capabilities at all stages of the gas supply chain should be publicly available.
- **Competitive structure:** the gas market should be structured to facilitate a competitive market in all sectors and to promote further efficient investment in gas infrastructure.
- **Freedom of trade:** gas market participants should be able to freely trade between pipelines, regions and basins.
- **Clear rules:** there should be regulatory certainty and consistency across all jurisdictions, including arrangements for efficient management of supply and demand interruptions.
- **Fitness for purpose:** market design and institutional requirements should be responsive to and reflective of the needs of the market and market participants.

In November 2005, the MCE established an industry-led Gas Market Leaders Group (GMLG) to prepare a Gas Market Development Plan.

The GMLG provided its plan in June 2006 and has since been reconvened to progress two key recommendations:

- **Establishment of a bulletin board system:** the gas market bulletin board, launched on 1 July 2008, provides real time information to gas market participants and governments on the status of natural gas supplies around the country. It also supports the information requirements of the National Gas Emergency Response Protocol.
- **Design of a short term trading market:** the short-term trading market, scheduled to commence before winter 2010, will provide a mandatory price-based balancing mechanism for wholesale gas trading.

Australian Energy Market Operator

Concurrently, the MCE agreed to a detailed implementation plan for a single Australian Energy Market Operator (AEMO), responsible for the operation of both the electricity and gas industries. This AEMO would integrate the role of the National Electricity Market Management Company and existing state-based gas market operators. The timeline set by COAG for the establishment of the AEMO is June 2009.

Long-term domestic gas supply

A joint working group (JWG) established by the MCE[9] has considered how best to balance the dual objectives of building Australia's LNG export capabilities while at the same time ensuring the long-term supply of competitively priced gas for domestic users. The significance of this issue has been highlighted by recent circumstances in Western Australia, where tight supply conditions and steeply rising domestic gas prices have emerged. At the same time, record oil prices have driven international gas prices to an all-time high, and proposals for new large-scale LNG export facilities are being progressed. Rapidly growing international demand, driven by strong economic growth in China, India and elsewhere in eastern Asia, is opening unprecedented opportunities for Australian LNG exports. At the same time, Australian governments are pursuing policies to ameliorate the effects of carbon emissions on climate change. These policies will place increased demands on natural gas as a cleaner fuel alternative for power generation, providing a bridge between current coal-based technologies and low emission technologies that may provide long-term solutions, but that are unlikely to be available for large-scale commercial deployment for at least a decade.

In light of these developments, the JWG was asked to consider issues relating to the domestic gas supply and demand balance for gas; barriers to domestic supply; and strategies to ensure availability of competitively priced gas. The JWG also considered risks associated with major inter-regional projects, and policies to facilitate development of natural gas resources for both export and long-term domestic requirements.

The final report of the JWG, released in September 2007, recommended that attention be centred on the following key priorities:

- **Acreage management:** further investigation into improving current acreage management processes—in particular, the granting and renewal of retention leases to ensure that processes are transparent and that tests of commerciality are rigorously applied and enforced.
- **Improving the operation of existing market structures:** development and implementation of a short-term trading market for natural gas and a bulletin board covering all major gas production fields, major demand centres and transmission pipeline systems.
- **Developing an annual national gas statement of opportunities:** a national gas statement of opportunities (GSOO), similar to existing opportunity statements for the electricity sector, to be prepared by the AEMO with the objective of assisting existing participants and potential new entrants to identify investment opportunities and manage their positions in the market. The GSOO would also be available as an information tool for policy makers examining the projected short- and long-term reliability of the nation's gas supply.
- **Obtaining a better understanding of new market developments:** areas identified for further investigation include the likely impacts of a national emission trading scheme, east coast LNG developments, and increased use of gas in transport fuels.

E.3 Current status and future market directions

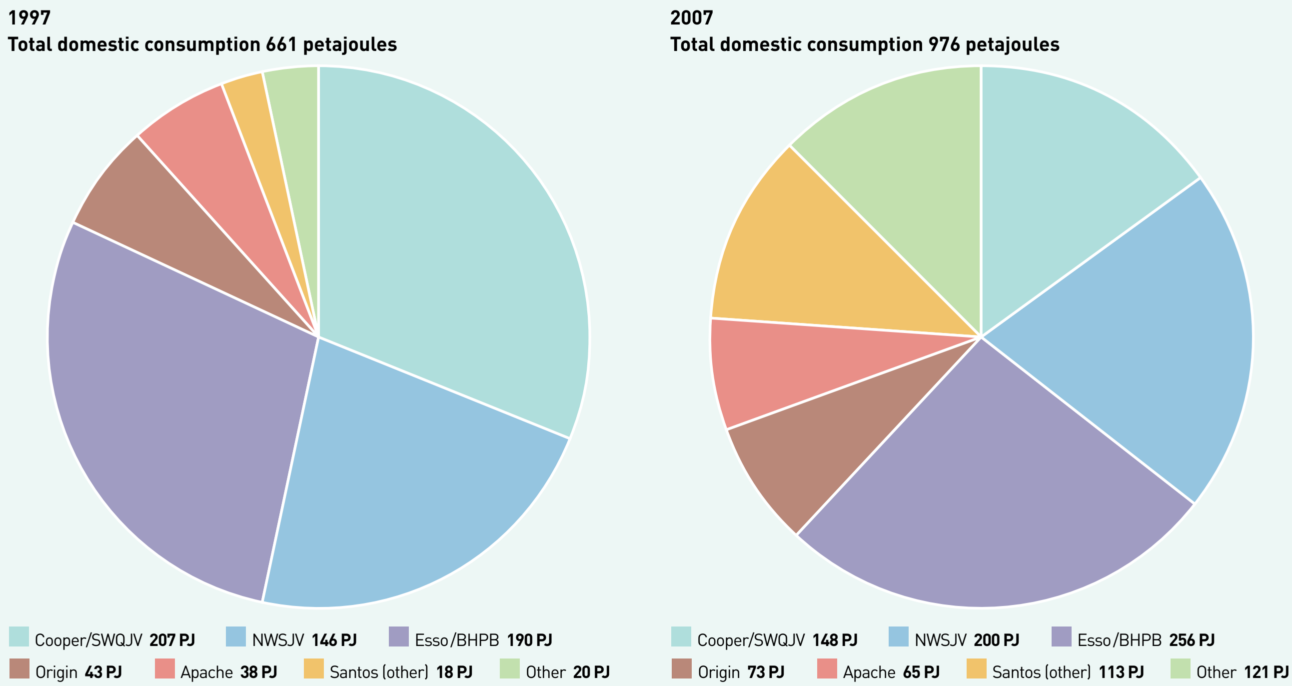
The success of competition reform in encouraging market growth and diversification in the gas industry can be gauged by comparing the patterns of production and investment prior to the commencement of the reform process with those currently prevailing.

Figure E.6 draws on statistics maintained by the Australian Petroleum Production and Exploration Association (APPEA) to compare the quantities of gas produced in Australia for domestic consumption in 1997 with 2007 data, as well as the distribution of production between different producer companies. It is evident that, across that period, there has been considerable expansion and diversification in the upstream industry as reflected in domestic gas supply. Total domestic gas consumption over that period rose from 661 petajoules to

9 MCE and MCMPR Joint Working Group on Natural Gas Supply—Terms of Reference, January 2007.

Figure E.6

Gas production for the domestic market—1997 and 2007 (petajoules)



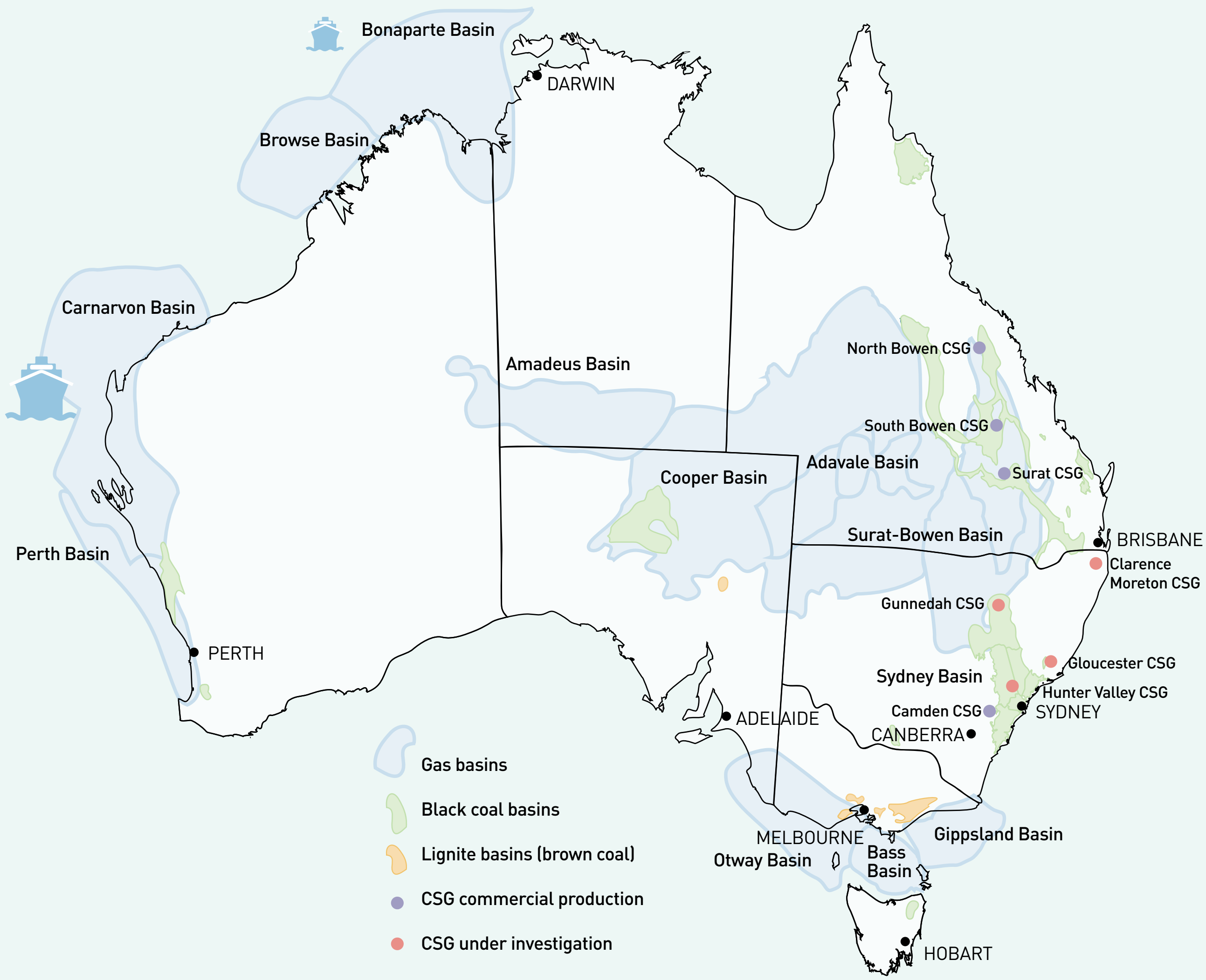
Notes: Includes coal seam gas.
Source: ACIL Tasman analysis using APPEA data.

976 petajoules, reflecting an average compound annual growth rate of 4 per cent. In terms of diversification, the three major producers in 1997—Esso/BHP Billiton from the Gippsland Basin, the Cooper Basin and South West Queensland Joint Ventures (SWQJV) in Central Australia, and the North West Shelf Joint Domestic Gas JV (NWSJV) in Western Australia—represented more than 82 per cent of the total market. In 2007, the proportion of domestic supply from these sources had fallen to under 62 per cent.

Emerging supply sources

By the late 1990s, it had become clear that the established sources of gas supply in the Gippsland and Cooper Basins would not support longer-term market growth in eastern Australia, and that alternative sources of gas would be needed. With limited expectations of new conventional gas discoveries in eastern Australia, attention increasingly turned to the north—to Papua New Guinea (PNG), to the Timor Sea, and even to the Browse Basin off the northwest coast of Western Australia—for possible new sources of supply. For much of the past decade, the PNG Gas Project was seen by many as the most likely new, long-term source of competitive gas supply for markets in eastern Australia. However, what emerged was something quite different. The local market responded to the anticipated entry of PNG gas in various ways, and the emerging market reforms supported those responses. New sources of conventional gas were identified and developed in the Bass Strait region, both in the established Gippsland Basin province and further west in the Bass and Otway basins. New producers entered the market. Long-term contracts for interstate supply were settled, with transportation of gas via new cross-border transmission pipelines occurring. Perhaps most significantly, exploration for CSG—which had enjoyed limited success in Queensland through the previous decade —began to gain real traction in terms of production and resources, and to achieve commercial acceptance. CSG won several major supply contracts that might otherwise have provided the market underpinning for the PNG Gas Project.

Figure E.7
Coal seam gas prospects in eastern Australia



Source: Base map from AER, 2007.

In the meantime, developments in world energy markets saw steep increases in the price of gas internationally, while gas prices in Australia remained low by world standards, constrained by competition from low-cost coal and cheap coal-fired electricity. By early 2007, value relativities had shifted to the point where the PNG gas proponents saw greater value in developing their resources for sale on international markets as LNG and the proposed pipeline to eastern Australia was shelved.

The emergence of coal seam gas

The extensive resources of black coal that support a world-scale export coal industry in Queensland and New South Wales also host vast quantities of gas (mainly methane) that is a close substitute for conventional natural gas. In Australia, this gas is most often referred to as coal seam gas (CSG). The key to commercial extraction of CSG lies in finding ways to extract gas from coal seams, which typically have low permeability, at sustainable rates high enough to justify the costs of drilling and production. The most prospective sites for CSG exploration and production are the Bowen and

Surat Basins in Queensland and the Sydney, Gunnedah, Gloucester and Clarence-Moreton Basins in New South Wales. The southern and central Queensland locations are now the clear leaders in terms of both reserves and production, and it is from these areas that much of the short-term supply growth is expected. However, there are good prospects also in New South Wales where coal measure sequences geologically similar to those in Queensland are now being tested in a number of locations. These locations are shown in figure E.7.

Both reserves and production of CSG have increased over the past five years, as illustrated in figure E.8.

Levels of independently certified reserves continue to grow rapidly. By the end of 2007, levels had reached around 7200 PJ of proven and probable reserves.

Production of CSG exceeded 100 PJ for the first time in calendar 2007, contributing almost 15 per cent of the total gas supply in eastern Australia. Production continues to rise and, with a number of projects ramping up to meet contractual commitments, there is no sign of a slow-down in production growth from the CSG sector.

Figure E.8

Eastern Australia coal seam gas reserves and production growth

Note: reserves include proved, plus probable reserves.

Source: ACIL Tasman compilation of various company disclosures.

Liquefied natural gas exports from eastern Australia?

Until recently, eastern Australia had not been considered a prospective location for LNG manufacturing, principally because uncommitted conventional gas resources in the region were inadequate to support a world-scale LNG facility. However, the recent surge in international energy prices, together with the identification of large resources of CSG in southern and central Queensland, has changed the prospects for east coast LNG. Since early 2007, four LNG proposals based on CSG feed from the Bowen and Surat Basins have been announced. The projects range in size from 0.5 to 4 million tonnes per year, with potential in each case for increased production with the replication of the initial liquefaction plant.

While there are technical and commercial challenges, there is a compelling logic to the attempts of the proponents to access large, high value international markets at a time of burgeoning demand and tight supply. In particular, the current oil price environment has flowed on to high prices for internationally traded LNG, which are linked formulaically to crude oil prices. With oil selling at around US$100 per barrel, the delivered price of LNG under current price arrangements can be expected to lie in the range of US$12 to $17 per GJ. After allowing for the cost of liquefaction, shipping and regasification, the netback[10] value of gas delivered to the LNG plant currently stands in excess of A$7.50 per GJ. At these prices, and based on proponent estimates of capital costs, ACIL Tasman analysis suggests that the economics of the current proposed LNG projects may well be comparable to conventional LNG projects, many of which are based on large offshore gas fields for which development costs continue to rise rapidly.

10 Netback value is the revenues from the sale of all products generated from one unit of oil/gas, less the costs associated with bringing that unit to market. The costs may include, but are not limited to, importing, transportation, production and refining costs, and royalty fees.

Whether or not any LNG proposals proceed to development, the fact that they offer a credible alternative market pathway for local gas suppliers means that they are starting to impact on domestic gas prices. Trends in pricing of domestic gas are discussed below.

Another significant issue arising from the proposed LNG developments relates to availability of gas for domestic use. A 4 million tonne per year LNG plant would require gas supply of between 225 and 250 PJ/a (after allowing for gas used in processing and transportation). In order to provide a 20-year reserve backing, such a development would therefore require dedication of up to 5000 PJ of proven and probable gas (2P) resources. Total 2P resources of CSG in eastern Australia currently stand at between 7000 and 8000 PJ. Given the rate of reserves built up over the past five years, there is every reason to believe that significantly more CSG reserves can be established. However, it is clear that the LNG proposals have the potential to divert very significant quantities of gas that might otherwise be available to domestic markets to exports. This does not necessarily mean that the domestic market will be left short of supply. However, it does mean that domestic supply will have to rely on higher-cost and less productive sources of CSG sooner than would be the case in the absence of the LNG projects, which in turn has implications for domestic gas prices.

Implications of increased pipeline interconnection

The rapid pace of development of the gas transmission pipeline system in Australia is illustrated in figure E.5. As the level of interconnection between regional markets has increased, a number of commercial and operational implications have become apparent. One important commercial opportunity afforded by interconnection of the transmission system is the potential for swap arrangements to reduce the need for physical transportation of gas. A swap involves the substitution of gas sources to meet the supply obligations under two separate contracts. So, for example, a producer with a contract to supply gas from its fields in central Australia to a customer in Brisbane might enter into a swap arrangement with a producer holding a contract to supply gas from its CSG fields in eastern Queensland to a customer in Sydney: the first producer diverts its supply to the Sydney customer, while the second producer supplies the Brisbane customer. A swap arrangement may be made between two different gas suppliers, or may be made by a single supplier within its portfolio of contracts (an internal swap). While physical interconnection of the two customer markets is not necessary for a swap to occur,[11] increased interconnection of markets increases the number of swap opportunities that can be pursued.

Swap arrangements are potentially valuable because they can minimise the amount of physical transportation required. Savings may also come from avoiding or delaying the need for construction of physical interconnections.

While swaps can increase market efficiency by minimising the physical transportation of gas, reduced payments for transportation of gas could ultimately impact on the viability of pipeline service operators and on new pipeline investment. In the extreme, a network could be envisaged in which little if any flow occurs across the system, which instead acts as a large pressure balancing vessel, with physical flow being confined largely to peripheral areas of the network. High levels of interconnection and an active swap market that minimises the need for physical transport of gas therefore imply a move toward a different system of paying for pipeline services, one with a greater focus on paying for the rights to inject or withdraw gas from the system, rather than paying for the right to transport gas through the system.

11 For example, Santos and Origin have in place a swap arrangement under which Origin meets supply obligations to Santos customers in Brisbane using eastern Queensland CSG, while Santos meets supply obligations to Origin's customers in Sydney with gas from the Moomba facility. This swap does not require physical pipeline interconnection between Queensland and New South Wales, and one of the benefits from the swap arrangement is that it allows the contract for supply into New South Wales to be settled without the need to build the dry gas connection between Ballera and Moomba. However, such interconnections ultimately increase the opportunities for swaps to occur.

Increased interconnection also raises issues in relation to system management and balancing. To date, these functions have been undertaken on an asset by asset basis by individual pipeline owners (in conjunction with system operators such as REMCo). However, with increasing integration and differing ownership across various sections of the network, the need for effective coordination between assets will become more apparent. Current initiatives to establish a bulletin board system and short-term trading market (see section E.2) are important steps in this direction.

The outlook for gas demand

Underlying gas demand in Australia could reasonably be expected to increase at an average of around 2.4 per cent per year—broadly in line with historical trends in the industry—driven by both demographic growth and industrial expansion. This would see domestic demand in eastern Australia rise from 680 PJ to 1070 PJ over the next 20 years. Similar growth in Western Australia (well below historical rates, but reflecting current tight supply and a higher price outlook) would raise domestic gas demand in the west from 350 PJ to 550 PJ by 2027.

However, two factors have the potential to push total gas demand growth much more strongly:

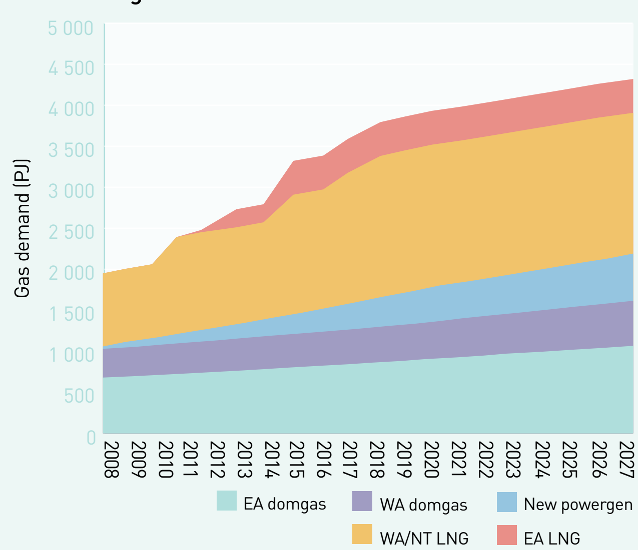
> increased reliance on gas for power generation, driven by the expected introduction of a national emission trading regime within the next two to three years
> expansion of LNG production, including establishment of an east coast LNG industry based on CSG.

The introduction of emission trading, as part of a suite of policies aimed at reducing greenhouse gas emissions, will make gas-fired electricity generation more competitive. As a result, it is likely that combined-cycle gas turbine (CCGT) plant will be the preferred new-entrant technology for bulk electricity generation, at least until low emission coal-based technologies employing carbon capture and storage become commercially available—unlikely before 2020. The required capacity of new gas-fired plant to meet demand will depend on the price of carbon under emissions trading and other factors, such as the level of uptake of renewable technologies. For purposes of illustration, we have assumed that CCGT plant accounts for the majority of new base load generation plant in both eastern and Western Australia until 2020, and continues to meet half of demand growth as new low emission technologies are introduced. On this basis, the gas requirement for incremental power generation would add around 575 PJ to domestic gas demand by 2027.

Further demand growth will be driven by expansion of LNG production. A reasonable outlook would see LNG production capacity in Western Australia and the Northern Territory increase from 16.2 million tonnes per year at present to 31 million tonnes per year by 2027, boosting feed gas requirements from 900 PJ/a to more than 1700 PJ/a. LNG developments in eastern Australia based on CSG could potentially add a further 400 PJ/a to demand, based on the development of 7.5 million tonnes per year production capacity.

Figure E.9

Australian gas demand outlook



EA, eastern Australia; WA, Western Australia; NT, Northern Territory; domgas, domestic gas; new powergen, new power generation; LNG, liquefied natural gas
Source: ACIL Tasman estimates.

Figure E.9 summarises the growth outlook for Australian gas. It provides an indication of how overall demand could develop over the next 20 years, taking into account effects of emission trading and LNG expansion.

Under this view, total gas demand will more than double, to around 4300 PJ/a, by 2027.

There is, of course, considerable scope for variation in actual outcomes given the uncertainties surrounding carbon pricing and the size, timing and location of LNG developments. However, the analysis highlights the strong growth potential for the Australian gas market, driven by domestic policies as well as international opportunities.

The outlook for gas prices

Gas prices in Australia have historically been low by international standards. They have also been stable, defined by provisions in long-term supply contracts that reflect defined base prices periodically adjusted to reflect changes in a price index such as the CPI. Rarely have Australian domestic gas prices been linked to other commodities with a more volatile price, such as crude oil.

In this regard, the Australian market is quite different from many overseas markets, including the USA, UK, Europe and many Asian countries where gas prices closely follow oil prices. The principal reason for this difference is that in Australia, natural gas has generally been seen as a substitute for coal and coal-based electricity, rather than for oil or other petroleum products. Australia's abundant, low-cost coal sources have effectively capped gas prices, limiting the prices that large-scale users in power generation and industrial applications were willing and able to pay.

Through the early 2000s, wholesale domestic gas prices throughout Australia remained low. In southern Australia, prices generally moved in line with inflation. In Queensland, where the CSG industry was emerging and new producers were keen to establish market share, new supply contracts saw significant price discounting.

Over the past two years, a number of interacting factors have brought about a major shift in the outlook for prices:

- There has been sustained upward pressure on exploration and development costs. This trend is not confined to Australia, but has been observed around the world as a result of strong global demand and capacity constraints. It has been particularly evident in the offshore oil and gas sector where upstream development cost indicators have almost doubled since 2005.[12]
- High oil prices—now standing above US$100 per barrel—have flowed on to international gas prices, including to Australian LNG exports. This has accentuated the gap between international prices and Australian domestic prices. Producers in Western Australia have responded by focussing development efforts on higher value export markets and demanding steeply increased prices for incremental domestic supply. In eastern Australia, producers have sought to establish a nexus with international prices through proposed LNG developments. The credible threat of diversion of substantial volumes of CSG from domestic markets to LNG exports is now influencing both producer and consumer price expectations.
- Electricity prices rose sharply in eastern Australia during 2007 as drought impacted on some generators —and gas prices followed. While both electricity and spot gas prices have retreated with the easing of drought conditions and relaxation of other generation constraints, the demonstrated ability of the market to absorb higher gas prices will influence near-term price settlements.
- The anticipated introduction of a national emission trading scheme would make gas a more valuable commodity in the future. Both producers and consumers are now factoring this higher anticipated demand and value into the pricing of long-term contracts that will bridge into the period when emissions trading is in place.

12 Cambridge Energy Research Associates, Upstream Capital Costs Index.

- Domestic coal prices are under sustained upward pressure as a result of the renegotiation of contracts for supply to Queensland and New South Wales generators at a time when international coal prices are very high and the range of coal qualities now being traded internationally is much wider than in the past. Higher coal prices effectively raise the cap on domestic gas prices.

The net result of these influences is that domestic gas prices are now rising. In the absence of any transparent spot market outside Victoria, and given that most prices continue to be settled in the context of long-term supply contracts, it is difficult to say exactly how far prices have risen. However, there is anecdotal evidence that in Western Australia recent sales of gas (in limited quantities, and generally to consumers in remote locations) have been settled for prices above $7 per GJ: around three times higher than the prevailing wholesale price prior to the onset of supply constraints. ACIL Tasman understands that buyers in Queensland looking to secure new gas supplies are now finding that producers are seeking significantly higher prices, reportedly in excess of $4 per GJ.

The fact that most of the major CSG producers are currently looking to boost reserves and production capacity to underpin proposed LNG facilities means that the supply surplus which had prevailed in the Queensland market for several years has now been reversed.

Higher gas prices will, of course, encourage supply side responses from new entrant producers as well as alternative energy sources. ACIL Tasman does not expect to see a sustained move, in either eastern or Western Australia, to full export parity pricing of gas. On the other hand, we consider it likely that the drivers now in play will see gas prices rise in real terms with no current prospect of a reversion to former levels.

E.4 Conclusions

Over the past 10 years, there have been profound changes in the Australian gas market across a number of dimensions. The decade has been marked by fundamental industry restructuring through privatisation of previously government-owned assets, while corporate mergers and acquisitions have seen shifting ownership and control across the supply chain. Regulatory reform has reshaped the industry. Ongoing investment in upstream exploration and production and in midstream transport infrastructure has given rise to the emergence of a much more competitive market, with greater interconnection and diversification of options for gas buyers and sellers.

While the past decade has seen profound changes in the industry, the next decade promises even greater changes. Ongoing regulatory reforms, including the development of new spot trading markets, will continue to promote competition and greater transparency in the market. This will, in turn, encourage a deeper and more liquid gas market. Meeting the challenge of climate change and emission abatement will place greater demands on gas as a cleaner source of energy for power generation and industrial purposes. Increased demand will create great opportunities, as well as pose commercial and technical challenges, for producers. Under reasonable demand projections, consumption of gas for domestic and export use will more than double over the next 20 years. This will require further investment in transport infrastructure and in facilities for peaking capacity and gas storage to manage short-term flexibility requirements.

With the introduction of emission trading in 2010 and increased integration into global energy markets, the price of gas in Australia will more closely reflect its intrinsic value as a cleaner fuel as well as its potential alternative applications, both domestically and internationally.

PART TWO ELECTRICITY


Mark Wilson

Electricity is a form of energy that is transported along a conductor, such as metal wire. Although it cannot be stored economically, it is readily converted to other forms of energy, such as heat and light, and can be used to power electrical machines. These characteristics make it a convenient and versatile source of energy that has become essential to modern life.

ELECTRICITY

The supply of electricity begins with generation in power stations. Electricity generators are usually located near fuel sources, such as coalmines, natural gas pipelines and hydroelectric water reservoirs. Most electricity customers, however, are located a long distance from electricity generators, in cities, towns and regional communities. The supply chain, therefore, requires networks to transport power from generators to customers. There are two types of network:

- high-voltage transmission lines transport electricity from generators to distribution networks in metropolitan and regional areas
- low-voltage distribution networks transport electricity from points along the transmission lines to customers in cities, towns and regional communities.

The supply chain is completed by retailers, which buy wholesale electricity and package it with transmission and distribution services for sale to residential, commercial and industrial customers.

Part Two of this report provides a chapter-by-chapter survey of each link in the supply chain. Chapter 1 considers electricity generation in the National Electricity Market (NEM), the wholesale market in which most electricity is traded in eastern and southern Australia. Chapter 2 considers activity in the wholesale market, and chapter 3 surveys the electricity derivatives markets that complement the wholesale market.

Chapters 4 and 5 provide data on the electricity transmission and distribution sectors, and chapter 6 considers retail. A survey of electricity markets in the non-NEM jurisdictions of Western Australia and the Northern Territory is provided in chapter 7.

Electricity supply chain

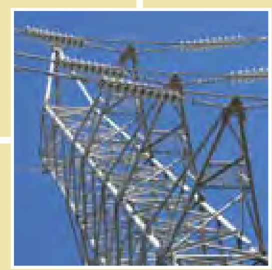
GENERATION

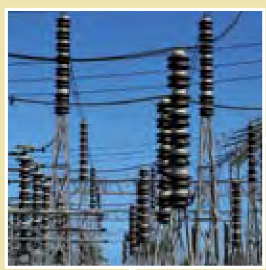
Electricity is generated at a power plant

Transformers convert low-voltage electricity to high-voltage electricity for transport

TRANSMISSION

Transmission lines carry high-voltage electricity long distances

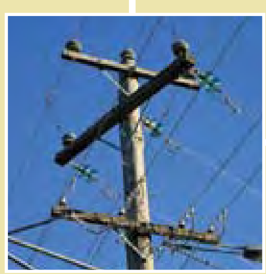


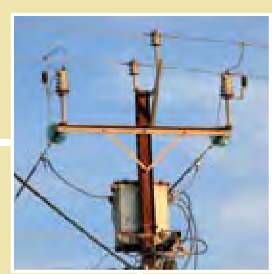


Substation transformers convert high-voltage electricity to low-voltage for distribution

DISTRIBUTION

Distribution lines carry low-voltage electricity to customers

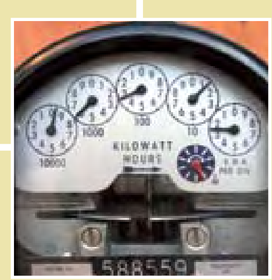




Transformers convert electricity to safe, usable levels

RETAIL

Retailers meter electricity usage



CONSUMPTION

Electricity is used for lighting and heating, and to power appliances

Image sources: *Consumption*, Jessica Shapiro (Fairfax); *Other*, Mark Wilson.

1 ELECTRICITY GENERATION

The supply of electricity begins with generation in power stations. This chapter provides a survey of electricity generation in the National Electricity Market, a wholesale market in which generators and retailers trade electricity in eastern and southern Australia. There are six participating jurisdictions, physically linked by a transmission network—Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

1 ELECTRICITY GENERATION

This chapter considers:

- electricity generation in the National Electricity Market, including geographical distribution, types of generation technology, and the lifecycle costs and greenhouse gas emissions of different generation technologies
- the ownership of generation infrastructure
- new investment in generation infrastructure
- the reliability of electricity generation in the National Electricity Market.

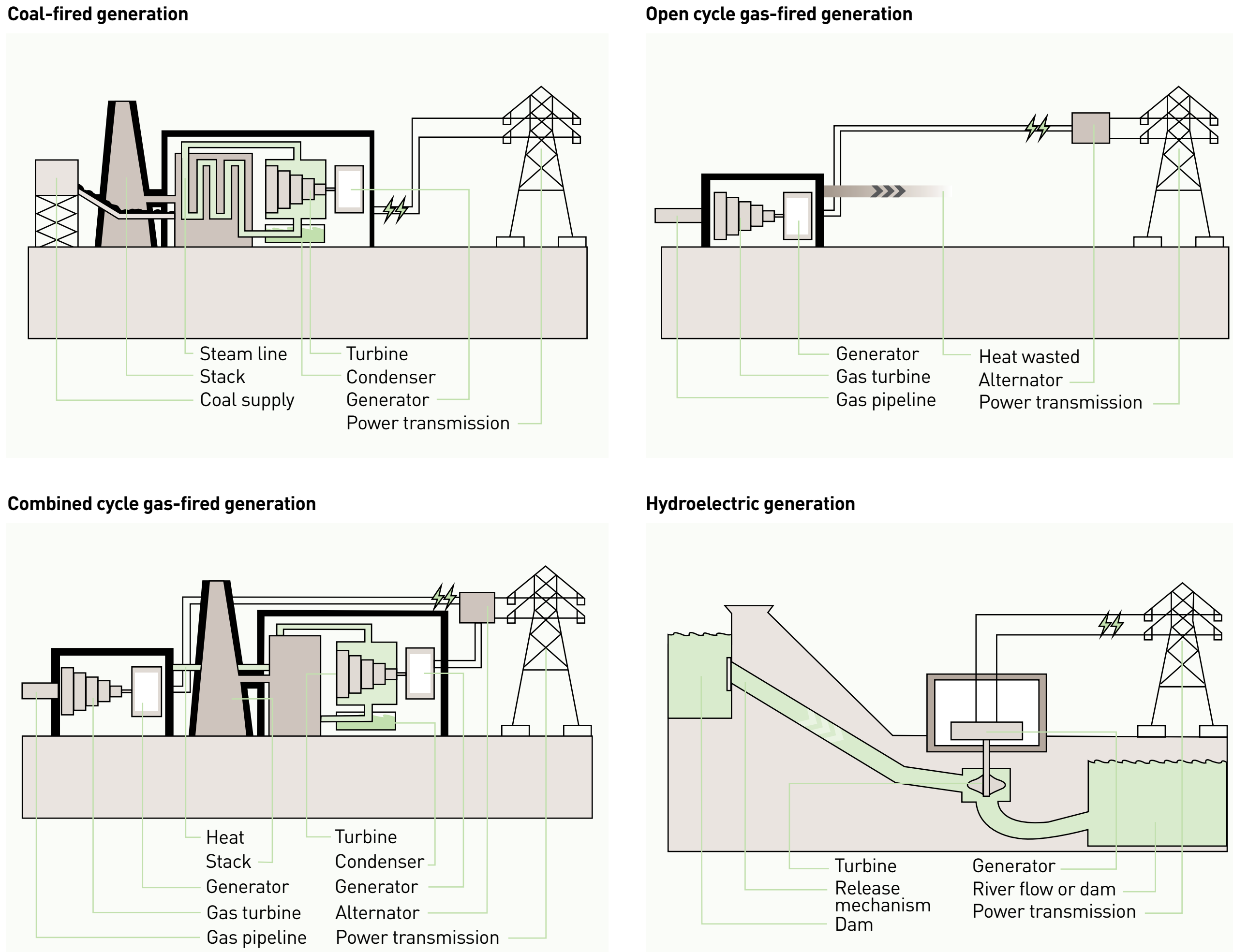
1.1 Electricity generation

A generator creates electricity by using energy to turn a turbine, which makes large magnets spin inside coils of conducting wire. In Australia, electricity is mainly produced by burning fossil fuels, such as coal and gas, to create pressurised steam. The steam is forced through a turbine at high pressure to drive the generator. Other types of generators rely on the heat emitted through a nuclear reaction, or renewable energy sources such as the sun, wind or the flow of water to generate electricity. Figure 1.1 illustrates four types of electricity generation commonly used in Australia—coal-fired, open cycle gas-fired, combined cycle gas-fired and hydroelectric generation.

The fuels that can be used to generate electricity each have distinct characteristics. Coal-fired generation, for example, has a long start-up time (8–48 hours), while hydroelectric generation can start almost instantly. Lifecycle costs and greenhouse gas emissions also vary markedly with generator type.

Figure 1.1

Electricity generation technologies



Source: Babcock & Brown.

1.1.1 Lifecycle costs

Estimates of the economic lifecycle costs of different electricity generation technologies in Australia are provided in figure 1.2. To allow comparison, the costs of each generation option have been converted to a standardised cost per unit of electricity.[1]

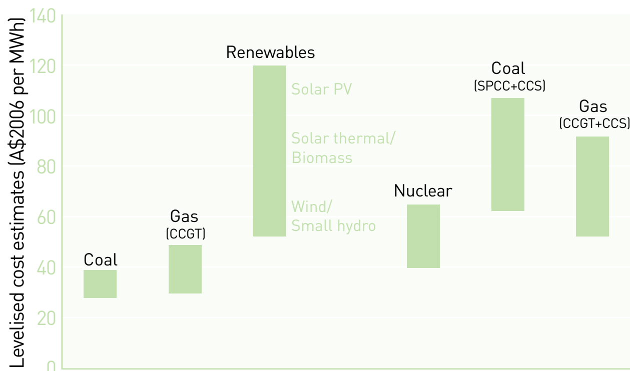
Figure 1.2 includes technologies currently in use, as well as alternatives such as nuclear energy, and fossil fuel-fired generators using carbon capture and storage (CCS) technology.[2] The cost estimates for CCS, which can be used to reduce greenhouse gas emissions from fossil fuel-fired generation (coal, gas and oil) technologies, are indicative only.

1 The levelised cost of electricity is the real wholesale price of electricity that recoups capital, operating and fuel costs. The present value of expenditures is divided by the electricity generated over the lifetime of the plant to produce a cost per unit of electricity (in $ per MWh).

2 Carbon capture and storage, also known as carbon sequestration, is an approach to mitigating carbon dioxide emissions by storing the carbon dioxide. Potential storage methods include injection into underground geological formations, injection deep into the ocean, and industrial fixation in inorganic carbonates. Some industrial processes might use and store small amounts of captured carbon dioxide in manufactured products.

Figure 1.2

Lifecycle economic costs of electricity generation



CCGT, combined cycle gas turbine; CCS, carbon capture and storage (costs are indicative only); PV, photovoltaic; SPCC, supercritical pulverised coal combustion (in which steam is created at very high temperatures and pressures).

Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?* Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, December 2006.

Developing a consistent evaluation of electricity generation costs across different technologies is difficult because of variations in the size and timing of construction costs, fuel costs, operating and maintenance costs, plant utilisation and environmental regulations. Site-specific factors can also affect electricity generation costs. Figure 1.2 therefore expresses the economic costs for each technology in wide bands.

Coal and gas are the lowest cost fuel sources for electricity generation in Australia. Of the renewable technologies currently used here, wind and hydroelectric generation are cheaper over their lifecycle than biomass and solar. It is estimated that the cost of nuclear generation would fall between that for conventional and renewable generation.

1.1.2 Greenhouse gas emissions

Greenhouse gas emissions for a range of different electricity generation technologies, based on current best practice under Australian conditions, are shown in figure 1.3. The data takes account of full lifecycle emission contributions—including from the extraction of fuels—and estimates the emissions per megawatt hour (MWh) of electricity generated.

Renewable sources of electricity (hydroelectric, wind and solar) and nuclear electricity generation have the lowest greenhouse gas emissions of the generation technologies analysed. Of the fossil fuel technologies, natural gas has the lowest emissions and brown coal, the highest. Figure 1.3 does not account for CCS technologies, which could potentially reduce emissions from gas and coal-fired generators.

1.2 Generation in the National Electricity Market

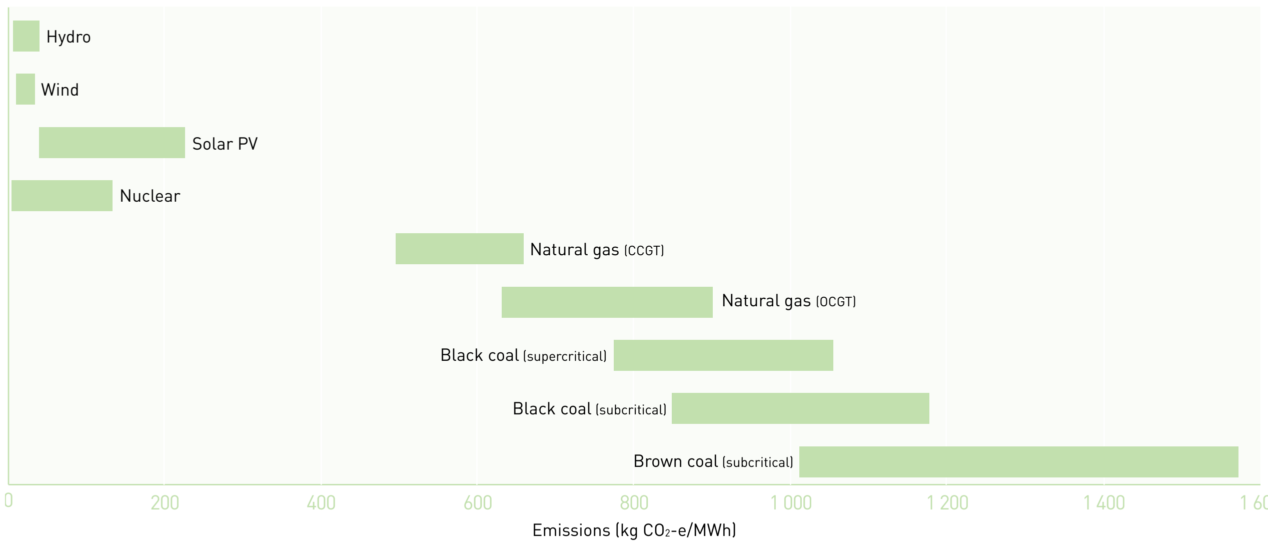
Australia has about 244 large electricity generators (figure 1.4), of which around 190 are in the National Electricity Market (NEM) jurisdictions in eastern and southern Australia.[3] The electricity produced by major generators in the NEM is sold through a central dispatch managed by the National Electricity Market Management Company (NEMMCO). Chapter 2 of this report outlines the dispatch process.

The demand for electricity is not constant, varying with time of day, day of week and ambient temperature. Demand tends to peak in summer (when hot weather drives up air conditioning loads) and winter (when cold weather increases heating requirements). A reliable power system needs sufficient capacity to meet these demand peaks. In effect, a substantial amount of capacity may be called on for only brief periods and may remain idle for most of the year.

3 This chapter has minimal coverage of Western Australia and the Northern Territory, which do not participate in the National Electricity Market. Chapter 7 provides more detailed information on the generation sectors in those jurisdictions.

Figure 1.3

Lifecycle greenhouse gas emissions from electricity generation



CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine; PV, photovoltaic.

Notes:

1. The figure shows the estimated range of emissions for each technology and highlights the most likely emissions value; includes emissions from power station construction and the extraction of fuel sources.
2. kg CO_2-e/MWh refers to the quantity of greenhouse gas emissions (in kilograms, converted to a carbon dioxide equivalent) that are produced for every megawatt hour of electricity produced.

Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?* Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, December 2006.

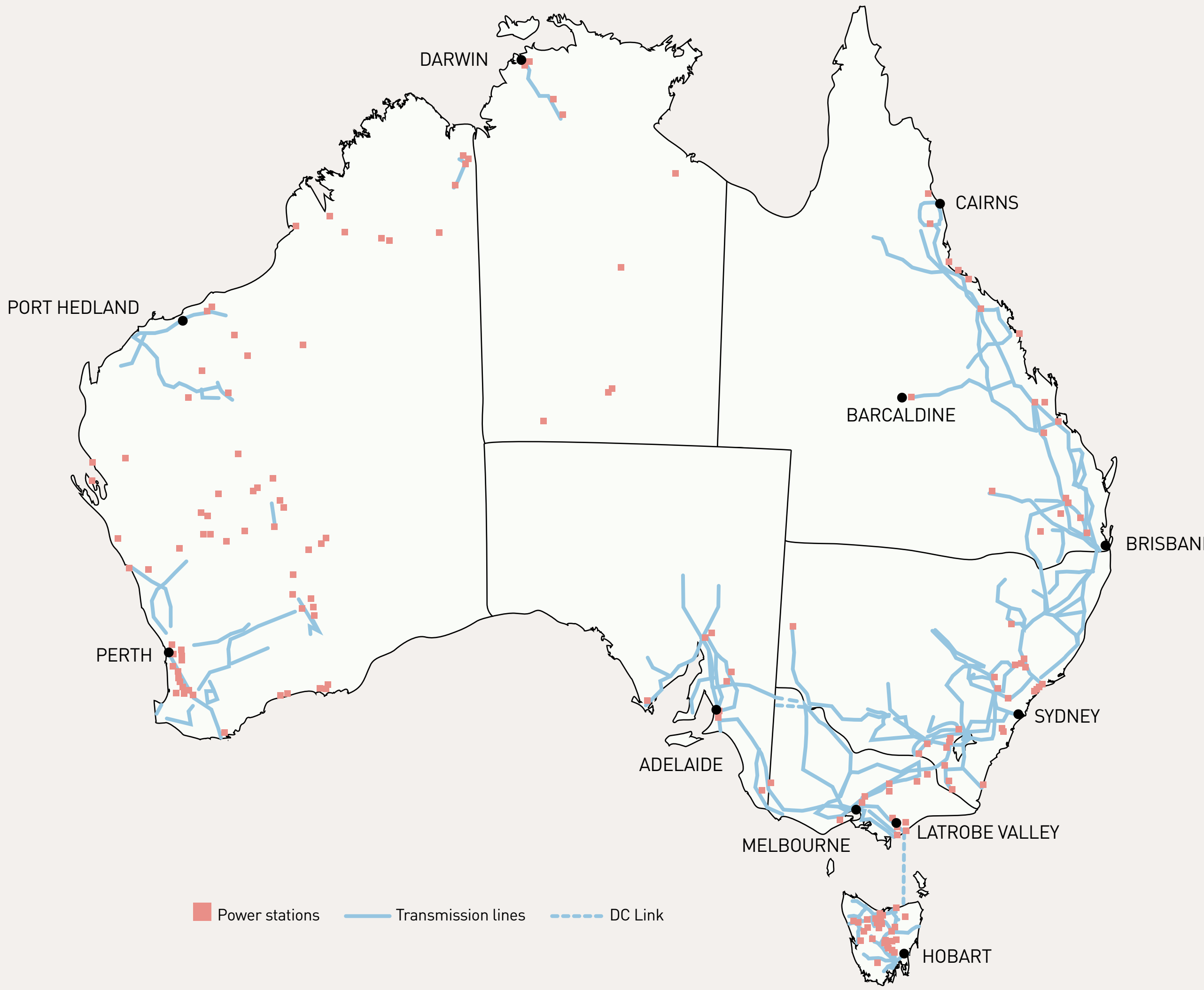
It is necessary to have a mix of generation capacity that reflects these demand patterns. The mix consists of baseload, intermediate and peaking power stations.

Baseload generators, which meet the bulk of demand, tend to have relatively low operating costs but high start-up costs, making it economical to run them continuously. *Peaking* generators have higher operating costs and are used to supplement baseload at times when prices are high. This normally occurs in periods of peak demand or when an issue such as a network outage constrains the supply of cheaper generators. While peaking generators are expensive to run, they must be capable of a reasonably quick start-up as they may be called upon to operate at short notice. There are also *intermediate* generators, which operate more frequently than peaking plants, but not continuously.

The NEM generation sector uses a variety of fuel sources to produce electricity (figure 1.5). Black and brown coal account for around two-thirds of total generation capacity across the NEM, followed by hydroelectric generation (17 per cent) and gas-fired generation (15 per cent).

Figure 1.4

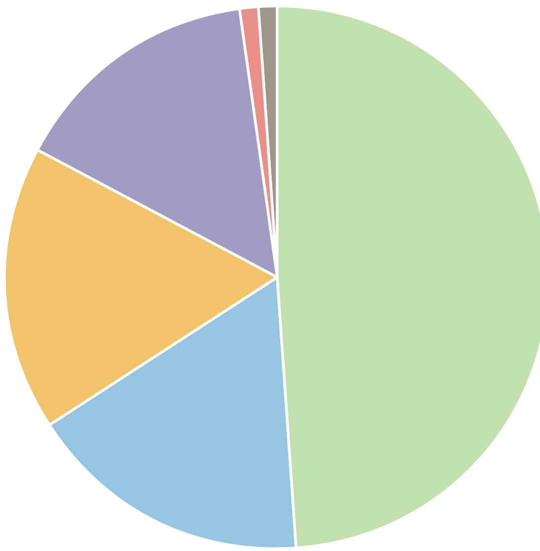
Electricity generators in Australia



Note: Locations are indicative only.

Source: ABARE, *Energy in Australia*, 2008.

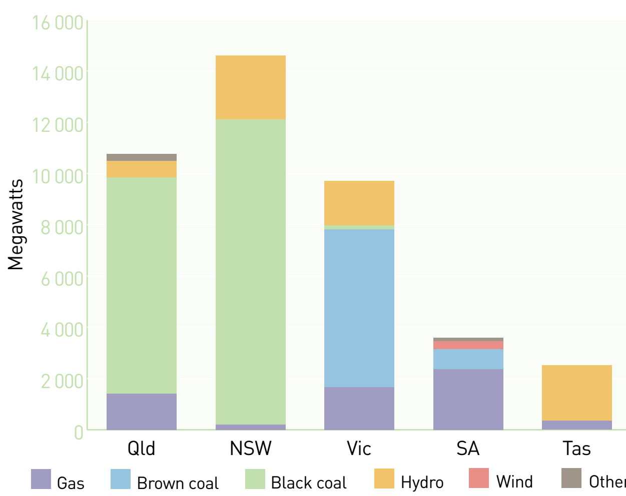
Figure 1.5
Scheduled generation capacity by fuel source—National Electricity Market, 2008



Note: Excludes power stations not managed through central dispatch

Source: NEMMCO/AER.

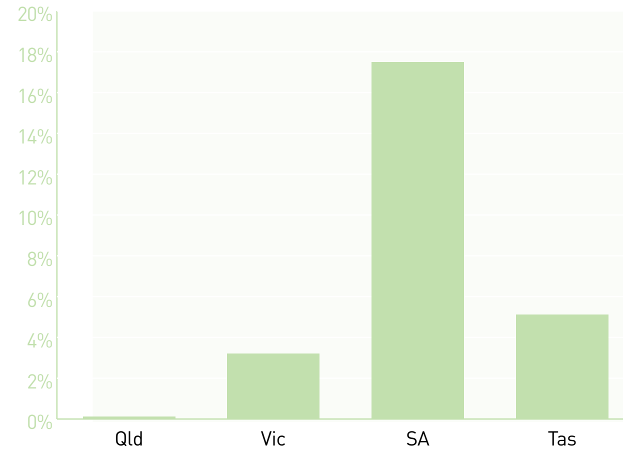
Figure 1.6
Scheduled generation capacity by fuel source—regional, 2008



Notes:
1. Excludes power stations not managed through central dispatch.
2. New South Wales and Victoria include Snowy Hydro capacity allocated to those regions.

Source: NEMMCO/AER.

Figure 1.7
Wind generation in the National Electricity Market as a percentage of registered capacity, 2008



Source: NEMMCO/AER.

Figure 1.6 sets out regional data on generation capacity by fuel source. Victoria's generation is mainly fuelled by brown coal, supplemented by gas-fired peaking generation. New South Wales and Queensland mainly rely on black coal, but there has been some recent investment in gas-fired generation. Victoria and New South Wales also have some hydroelectric generation, mainly owned by Snowy Hydro.[4] Electricity generation in Western Australia, South Australia and the Northern Territory is mainly fuelled by natural gas. Tasmania relies primarily on hydroelectric generation.

Wind generation is often reported separately from other types of generation because its capacity is dependent on the weather and cannot be relied on for generation at specified times. The extent of new investment in wind generation has led the Australian Energy Market Commission (AEMC) to determine that new wind generators be classified as *semi-scheduled*, which will require them to participate in the central dispatch process. Wind generation is the equivalent of around 2.8 per cent of registered capacity in the NEM. Wind has a significantly higher share in South Australia at 17 per cent (figure 1.7).

4 The former Snowy region was abolished on 1 July 2008. The area formerly covered by the Snowy region is now split between the Victoria and New South Wales regions of the NEM.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The pattern of generation technologies across the NEM is evolving over time. As indicated in figure 1.3, coal-fired generators produce relatively more greenhouse gas emissions than most other technologies. The Australian and state and territory governments have implemented (and are developing) initiatives to encourage the development and use of low-emission technologies.

The Australian Government has announced that it will introduce an emissions trading scheme—called the Carbon Pollution Reduction Scheme—by 2010, with a detailed design to be finalised by the end of 2008. Some Australian governments also apply targets for greenhouse gas emissions reduction, renewable energy and other low-emission generation, and provide funds for technology development.

Over time, such initiatives are likely to increase the cost competitiveness and use of low-emission technologies in the generation sector.

1.2.1 Generation ownership

Table 1.1 and figures 1.8 and 1.9 provide background on the ownership of generation businesses in Australia. Across the NEM, around two-thirds of generation capacity is government-owned or controlled.

In the 1990s, Victoria and South Australia disaggregated their generation sectors into multiple stand-alone businesses and privatised each business. Most generation capacity in these jurisdictions is now owned by International Power, AGL Energy, TRUenergy, the Great Energy Alliance Corporation (GEAC) group (in which AGL Energy holds a 32.5 per cent stake) and Snowy Hydro. Some of these businesses have invested in new generation capacity—mainly gas-fired intermediate and peaking plants—since the NEM began.

There has been a significant trend in Victoria and South Australia towards vertical integration of electricity generators with retailers. In Victoria, AGL Energy and TRUenergy are key players in both generation and retail. In South Australia, AGL Energy is both the leading generator and the leading retailer. Across Victoria and South Australia, AGL Energy and TRUenergy own around 41 per cent of registered generation capacity.[5] In July 2007, AGL Energy and TRUenergy completed a generator swap in South Australia that moved the capacity of each business into closer alignment with their respective retail loads. International Power, which controls around 26 per cent of generation capacity in Victoria and South Australia, established a retail business (Simply Energy) in 2007 and is expanding its market share in that sector. Origin Energy is currently the only major retailer with limited generation capability, but has committed to major development projects.

New South Wales and Queensland have disaggregated their generation sectors, but retain significant government ownership. Generation capacity in New South Wales is mainly split between the state-owned Macquarie Generation, Delta Electricity and Eraring Energy. Snowy Hydro, jointly owned by the New South Wales, Victorian and Australian governments also has a significant amount of hydroelectric generation capacity. Two private sector entrants, Babcock & Brown Power and the Marubeni Corporation, each own around 1.6 per cent of the generation capacity in New South Wales. The New South Wales Government announced in June 2008 its intention to privatise much of the state's generation sector, but reversed this decision in August 2008.

5 Includes AGL Energy's 32.5 per cent stake in Loy Yang A and TRUenergy's contractual arrangement for Ecogen Energy's capacity. See table 1.1.

Table 1.1 **Generation ownership in the National Electricity Market, July 2008**

GENERATION BUSINESS	POWER STATIONS	CAPACITY (MW)[1]	OWNER
NEM REGIONS			
NEW SOUTH WALES AND THE AUSTRALIAN CAPITAL TERRITORY			
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4834	NSW Government
Delta Electricity	Vales Point B; Mt Piper; Wallerawang C; Munmorah	4320	NSW Government
Eraring Energy	Eraring; Shoalhaven; Hume	2938	NSW Government
Snowy Hydro	Blowering; Tumut; Guthega	2006	NSW Govt (58%); Vic Govt (29%); Australian Govt (13%)
Marubeni Australia Power Services	Smithfield	160	Marubeni Corporation
Redbank Project	Redbank	145	Babcock & Brown Power
Various	Embedded and non-grid	514	Various
VICTORIA			
Snowy Hydro	Laverton North; Valley Power; Murray	2070	NSW Govt (58%); Vic Govt (29%); Australian Govt (13%)
Loy Yang Power	Loy Yang A	2050	GEAC (AGL Energy 32.5%; TEPCO 32.5%; Transfield Services 9.3%; others 25.7%)
Hazelwood Power	Hazelwood	1580	International Power (91.8%); Commonwealth Bank (8.2%)
TRUenergy Yallourn Pty Ltd	Yallourn	1420	TRUenergy (CLP Group)
IPM Australia	Loy Yang B	965	International Power (70%), Mitsui (30%)
Ecogen Energy	Newport; Jeeralang A and B	891	Industry Funds Management (Nominees) Ltd (all contracted to TRUenergy)
AGL Hydro Partnership	McKay Creek; Dartmouth; Somerton; Eildon; West Kiewa	477	AGL Energy
Alcoa	Anglesea	154	Alcoa
Energy Brix Australia	Energy Brix Complex	139	Energy Brix Australia
Babcock & Brown Power	Bairnsdale	70	Babcock & Brown Power
Eraring Energy	Hume Vic	58	NSW Government
Various	Embedded and non-grid	511	Various
SOUTH AUSTRALIA			
AGL	Torrens Island	1260	AGL Energy
Flinders Power	Northern; Playford B; Lake Bonney	907	Babcock & Brown Power
Pelican Point Power	Pelican Point	450	International Power
Synergen	Dry Creek; Mintaro; Snuggery; Port Lincoln	269	International Power
ATCO Power	Osborne	175	ATCO (50%); Origin Energy (50%) (all contracted to Babcock & Brown Power)
TRUenergy	Hallett	151	TRUenergy (CLP Group)
Origin Energy	Quarantine; Ladbroke Grove	146	Origin Energy
AGL Hydro Partnership	Hallet	95	AGL Energy
Infratil Energy Australia	Angaston	49	Infratil
Various	Embedded and non-grid	454	Various

GENERATION BUSINESS	POWER STATIONS	CAPACITY (MW)[1]	OWNER
QUEENSLAND			
CS Energy	Callide B; Kogan Creek; Swanbank B; Swanbank E	2254	Queensland Government
Transfield	Gladstone	1680	Rio Tinto (42.1%), Transfield Services (37.5%); others 20.4%) (all contracted to Stanwell Corporation)
Stanwell Corporation	Stanwell; Kareeya; Barron Gorge; Mackay	1580	Queensland Government
Tarong Energy	Tarong; Wivenhoe	1550	Queensland Government
Callide Power Management	Callide C	900	CS Energy (50%); InterGen (50%)
Millmerran Power Management	Millmerran	860	InterGen (50%); China Huaneng Group (50%)
Braemar Power Projects Pty Limited	Braemar 1	450	Babcock & Brown Power
Tarong Energy	Tarong North	443	Queensland Government (50%); TEPCO (25%); Mitsui (25%)
Origin Energy	Mt Stuart; Roma	314	Origin Energy
Oakey Power Holdings	Oakey	276	Babcock & Brown Power (50%); ERM Group (25%); Contact Energy (25%) (all contracted to AGL Energy)
Transfield	Yabulu	232	Transfield Services Infrastructure Fund (all contracted to AGL Energy and Arrow Energy)
Transfield	Collinsville	187	Transfield Services Infrastructure Fund (all contracted to CS Energy)
Ergon Energy	Barcaldine	49	Queensland Government
Various	Embedded and non grid	1055	Various
TASMANIA			
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; other	2172	Tasmanian Government
Bell Bay Power (Hydro Tasmania)	Bell Bay	240	Tasmanian Government
Babcock & Brown Power	Bell Bay 3	108	Babcock & Brown Power
Various	Embedded and non-grid	42	Various
NON-NEM REGIONS			
WESTERN AUSTRALIA[2]			
Verve	Maju; Kwinana WPC; Pinjar; Collie; Cockburn; other	3475	Western Australian Government
Various	Independent and remote	2642	Various
NORTHERN TERRITORY[2]			
Power and Water Corporation	Channel Island; Ron Goodin; Berrimah; Pine Creek; Katherine; other	475	Northern Territory Government
Various	Embedded and non-grid	174	Various

GEAC, Great Energy Alliance Corporation; NEM, National Energy Market.

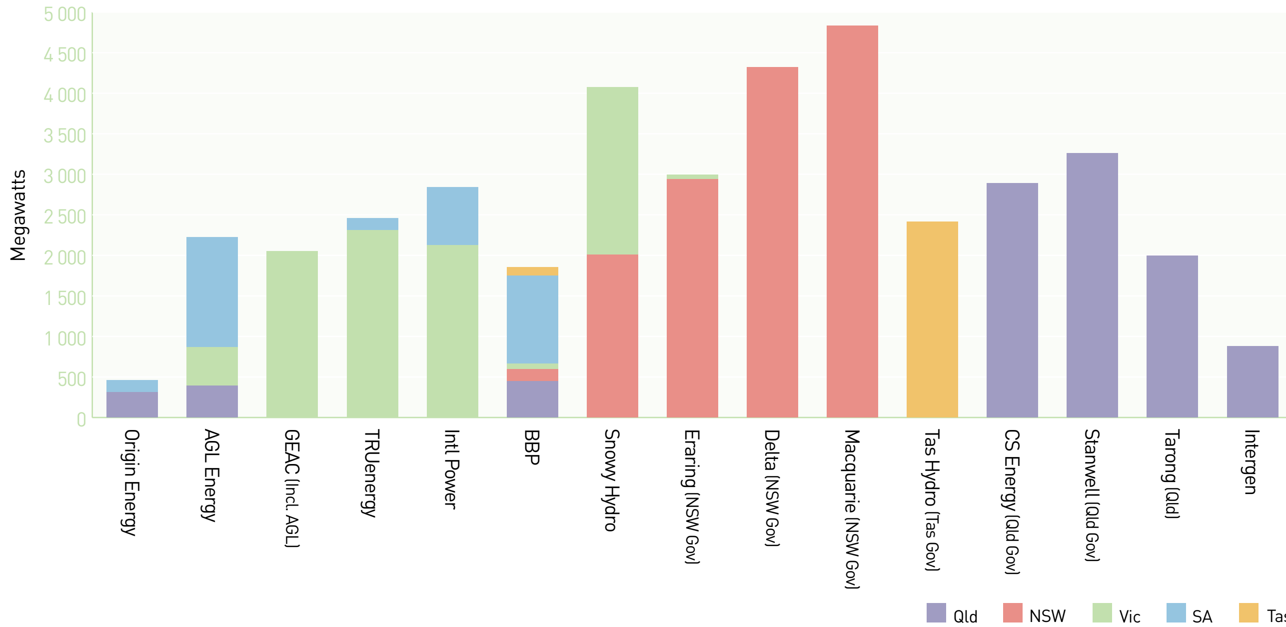
Fuel types: coal; gas; hydro; wind; diesel/fuel oil/multi-fuel; unspecified

Notes:

1. Capacity is total capacity for embedded, non-grid, Western Australian and Northern Territory generators; and summer capacity for other generators. An embedded generator is one that directly connects to a distribution network and does not have access to a transmission network.
2. Summary data only for Western Australia and Northern Territory. For more detailed information see chapter 7 of this report.

Data sources: NEMMCO; ESAA, *Electricity gas Australia*, 2008; other public sources.

Figure 1.8
Ownership of major power stations in the National Electricity Market—major stakeholders, 2008



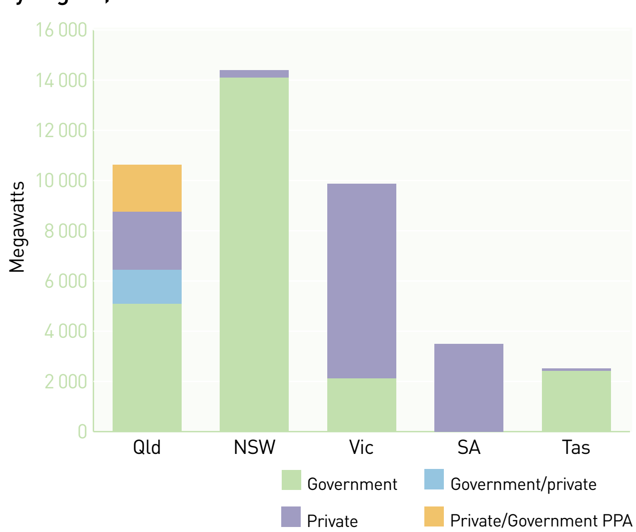
BBP, Babcock & Brown Power; GEAC, Greater Energy Alliance Corporation

Notes:

1. Excludes power stations that are not managed through central dispatch.
2. AGL ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A.
3. Ecogen Energy capacity is included for TRUenergy, which has a power purchase agreement for that capacity.
4. Does not adjust ownership shares for power purchase agreements held over the capacity of some power stations.
5. Some corporate names have been shortened or abbreviated.

Source: NEMMCO/AER.

Figure 1.9
Private and public sector generation ownership by region, 2008



Notes:

1. Excludes power stations that are not managed through central dispatch.
2. Private/government PPA refers to capacity that is privately owned but contracted under power purchase agreements to government-owned corporations. PPAs are held by government-owned corporations over the Gladstone and Collinsville generators.
3. Government/private refers to joint venture arrangements between the private and government sectors. Tarong North and Callide C generators in Queensland are government/private joint ventures.
4. New South Wales and Victoria include Snowy Hydro capacity allocated to those regions.

Source: NEMMCO/AER.

In Queensland, the state-owned Tarong Energy, Stanwell Corporation and CS Energy own around 46 per cent of generation capacity.[6] There has been considerable private investment in new capacity, including through joint ventures with state government entities—for example at Callide C and Tarong North. RioTinto, Intergen, Transfield Services Infrastructure Trust, Origin Energy and Babcock & Brown Power are among the private sector participants. Much of the privately owned capacity is contracted under power purchase agreements to state-owned wholesale energy providers.

The state-owned Hydro Tasmania owns virtually all generation capacity in Tasmania.

1.3 Investment

Investment in generation capacity is needed to meet the future growth in demand for electricity and to maintain the reliability of the power system. Investment includes the construction of new power stations and upgrades or extensions of existing power stations.

Some electricity markets (including Western Australia and most markets in the United States) use a capacity mechanism to encourage new investment in generation capacity. This may take the form of a tendering process in which capacity targets are determined by market operators and then built by the successful tenderers. Chapter 7 describes the Western Australian capacity market. By contrast, the NEM is an 'energy only' market in which investment is largely driven by price signals in the wholesale and forward markets for electricity (see section 1.4).

From the inception of the NEM in 1999 to July 2008, new investment added almost 6100 megawatts (MW) of generation capacity.[7] Figure 1.10 illustrates investment in generation capacity (excluding wind generation) since the market started, while figure 1.11 illustrates annual investment in wind capacity. Figure 1.12 illustrates cumulative investment since 1999, including wind capacity.

The investment profile has differed between regions. The strongest cumulative growth has been in Queensland and South Australia, with investment in both regions responding to high spot prices in the late 1990s. Queensland investment was mainly in baseload generation, whereas South Australian investment was mostly in intermediate and peaking generation. Investment in both regions has again accelerated since 2006.

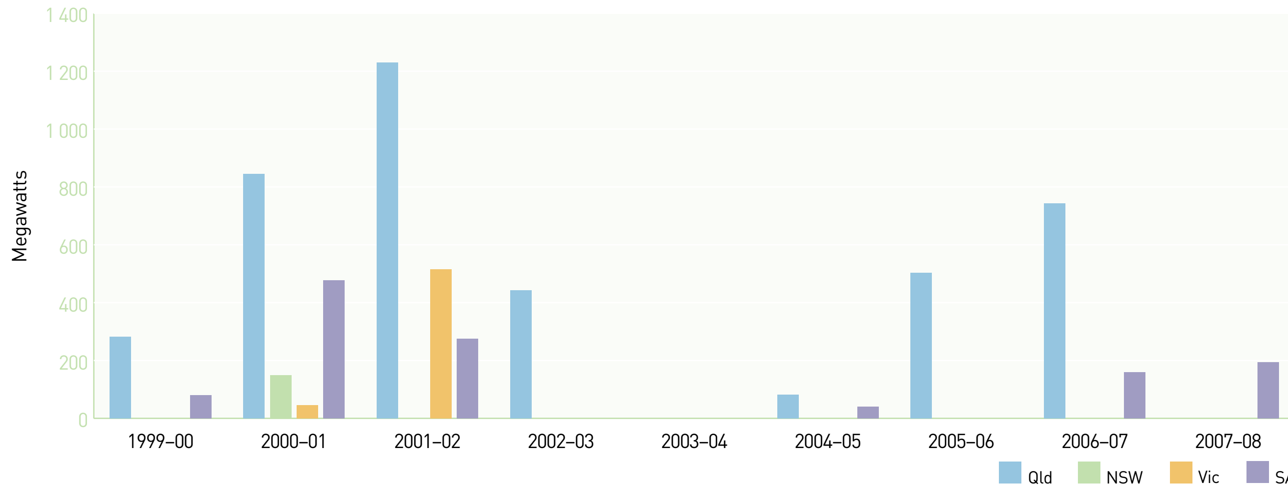
There has been less investment in New South Wales and Victoria, but tight market conditions have recently led to the announcement of new generation projects in both regions. The bulk of new investment in Victoria has been in peaking capacity to meet summer demand peaks.

6 This does not include joint ventures, such as Callide C and Tarong North, or government power purchase agreements for the capacity of privately owned generators (for example, Gladstone and Collinsville).

7 Includes only power stations that are managed by NEMMCO through central dispatch. There has also been investment in generators that bypass the central dispatch process—for example, small generators, wind generators, remote generators not connected to a transmission network, and generators that produce exclusively for self-use (such as for remote mining operations).

Figure 1.10

Annual investment in new generation capacity (excluding wind)



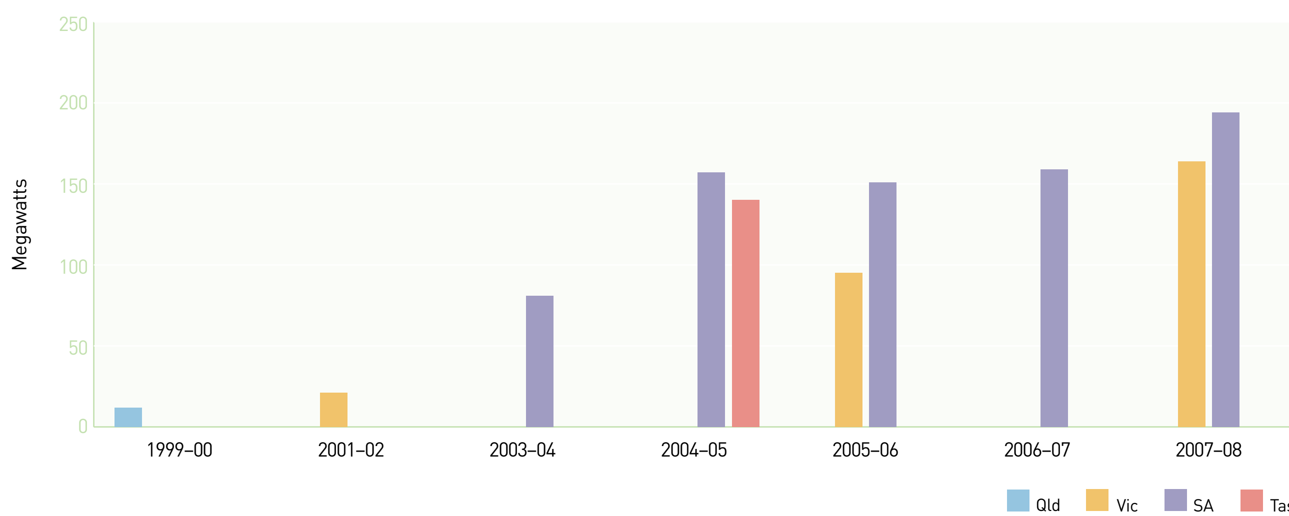
Notes:

1. These are gross investment estimates that do not account for decommissioned plant.
2. Excludes wind generation and power stations not managed through central dispatch.

Source: NEMMCO/AER.

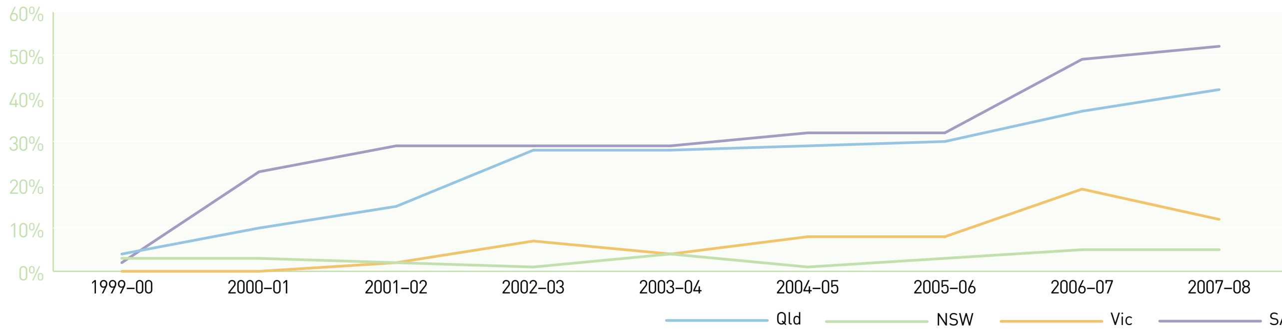
Figure 1.11

Annual investment in new wind generation capacity



Source: NEMMCO/AER.

Figure 1.12
Cumulative growth in net generation capacity since 1999–2000 (includes scheduled wind capacity)



Note: Growth is measured from market start in 1998–99. A decrease may reflect a reduction of capacity due to decommissioning or a change in the ratings of generation units.

Source: NEMMCO/AER.

Table 1.2 Generation investment in the National Electricity Market, January 2007–June 2008

REGION	POWER STATION	DATE COMMISSIONED	TECHNOLOGY	CAPACITY (MW)	ESTIMATED COST ($ MILLION)	OWNER
Qld	Daandine	Feb 2007	Biomass	33	29	APA Group
Qld	Oaky Creek	Feb 2007	Biomass	15	18	Envirogen
Qld	Kogan Creek	Apr 2007	Coal	750	1200	CS Energy
NSW	Condong	Dec 2007	CCGT	30	n/a	Delta Electricity
NSW	Eraring	Jan 2008	Gas	42	n/a	Eraring
NSW	Broadwater	Feb 2008	Biomass	30	n/a	NSW Sugar Milling Cooperative
NSW	Hunter Economic Zone	Apr 2008	Diesel	29	n/a	Infratil Energy

CCGT, combined cycle gas turbine; n/a, not available.

Note: Excludes wind generation.

Sources: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2007; EnergyQuest, *Energy Quarterly*, August 2008.

1.3.1 Recent and committed investment

Investment in generation capacity needs to respond dynamically to projected market requirements for electricity. Table 1.2 sets out major new generation investment that has come on line since 1 January 2007. New investment in the Kogan Creek power station (750 MW) continues a trend of strong investment growth in the Queensland generation sector. In addition, investors have recently committed to a number of generation projects and have proposed several others (tables 1.3 and 1.4). The majority of committed and proposed projects involve gas-fired generation, reflecting the industry's expectations in respect of government climate change policies.

Committed investment projects include those already under construction and those where developers and financiers have formally committed to construction. NEMMCO takes account of committed projects in making future projections of electricity supply and demand.

Table 1.3 **Major committed generation investment in the National Electricity Market, 2008**

DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
NEW SOUTH WALES				
Delta Electricity	Colongra	OCGT	668	2009–10
Origin Energy	Uranquinty	OCGT	640	2008–09
TRUenergy	Tallawarra	CCGT	400	2008
QUEENSLAND				
Origin Energy	Darling Downs	CCGT	630	2010
ERM Power/Arrow Energy	Braemar 2	OCGT	474	2009
Rio Tinto	Yarwun Alumina Refinery	Gas	145	2010–11
Queensland Gas Company	Condamine	CCGT	135	2009
VICTORIA				
Origin Energy	Mortlake	OCGT	550	2010–11
AGL Energy	Bogong	Hydro	140	2009
SOUTH AUSTRALIA				
Origin Energy	Quarantine	OCGT	120	2008–09
TASMANIA				
Tasmanian Government	Tamar Valley	CCGT	191	2009

CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

Note: Excludes wind generation.

Sources: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2007; EnergyQuest, *Energy Quarterly*, August 2008; company websites.

At June 2008, developers had committed to around 3900 MW of new capacity (table 1.3), of which around 45 per cent was in New South Wales. The Tallawarra and Uranquinty gas-fired power stations are major private investments in the New South Wales generation sector. TRUenergy's 400 MW Tallawarra plant is expected to become operational by summer 2008–09. Origin Energy's Uranquinty plant is expected to be able to provide 471 MW by summer 2008–09 and be fully operational (640 MW) by mid 2009.

Origin Energy has also committed to new generation capacity in other regions, including a 550 MW gas-fired power station near Mortlake in Victoria (scheduled for the summer of 2010–11) and a 630 MW gas-fired power station in the Darling Downs region of Queensland (scheduled to commence operation in early 2010). Also in Queensland, ERM Power and Arrow Energy reached financial closure in 2008 on the 474 MW Braemar 2 power station (to start in the first half of 2009).

1.3.2 Proposed projects

Proposed projects include generation capacity that is either in the early stages of development or at more advanced stages, which might include a proposed commissioning date. Such projects are not fully committed, and may be shelved in the event of a change in circumstances such as a change in demand projections or business conditions.

NEMMCO's annual Statement of Opportunities (SOO) for the NEM refers to proposed projects that are 'advanced' or publicly announced. NEMMCO does not include these projects in its supply and demand outlooks as it considers them to be too speculative. In total, the 2007 SOO referred to around 9460 MW of proposed capacity (excluding wind) in the NEM. The bulk is for New South Wales and Queensland. The significant amount of proposed capacity for New South Wales may reflect that the region is currently the highest net importer in the NEM.

Table 1.4 **Major proposed generation investment in the National Electricity Market, 2008**[1]

DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
NEW SOUTH WALES				
Wambo Power Ventures	Wellington	OCGT	628	2009–10
Macquarie Generation	Tomago	OCGT	500	n/a
Eraring Energy	Eraring upgrade	Coal	360	2009
AGL Energy	Leaf's Gully	OCGT	350	2011
Delta Electricity	Marulan	OCGT	300	2011–12
Delta Electricity	Bamarang	OCGT	300	2011–12
Delta Electricity	Mt Piper expansion	Coal	180	n/a
Wambo Power Ventures	Bega	CCGT	114	2009–10
Delta Electricity	Bamarang II	CCGT	100	2011–12
Metgasco	Richmond Valley	OCGT	30	2009
QUEENSLAND				
Origin Energy	Spring Gully	CCGT	1000	2009
CS Energy	Swanbank F	CCGT	400	2012
AGL Energy	SE Qld 1 (Ipswich)	OCGT	350	2011
AGL Energy	Townsville	OCGT	350	2012
ERM Power	Braemar 2	OCGT	290	2010–11
AGL Energy	SE Qld 2 (Kogan)	OCGT	250	2012
CS Energy/AGL	Mica Creek upgrade	CCGT	70	2010
VICTORIA				
Origin Energy	Mortlake Stage 2	CCGT	450	n/a
Snowy Hydro	Laverton North conversion	CCGT	440	2012
HRL/Harbin Power	Latrobe Valley	IDGCC	400	2011–12
Snowy Hydro	Valley Power upgrade	OCGT	100	2010
Loy Yang Power	Unit 4 upgrade	Coal	25	2008
Loy Yang Power	Unit 2 upgrade	Coal	25	2009
TASMANIA				
Gunns Ltd	Bell Bay Pulp Mill	Biomass	188	2009–10

CCGT, combined cycle gas turbine; IDGCC, integrated drying and gasification combined cycle; OCGT, open cycle gas turbine; n/a, not available.

Notes:

1. Excludes wind generation.

Sources: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2007, *EnergyQuest*, August 2008; various company websites.

1.3.4 Wind projects

Wind generation is reported separately in the SOO as non-scheduled generation because the capacity is dependent on the weather and cannot be relied on to generate at specified times.[8] Wind projects can, however, play an important role in providing electricity for future demand growth. The 2007 SOO listed about 5840 MW of committed or proposed wind capacity, predominantly in South Australia, Victoria and New South Wales.

1.4 Reliability of the generation sector

Reliability refers to the continuity of electricity supply to customers. Various factors—planned and unplanned—can lead to plant outages that interrupt power supplies. These may occur in generation or in the networks that deliver power to customers. A planned outage may occur for maintenance or construction works, and can be timed for minimal impact. Unplanned outages occur when equipment failure causes the supply of electricity to be disconnected.

The AEMC Reliability Panel reports annually on the reliability of the generation sector. The panel has set a reliability standard that requires sufficient generation and bulk transmission capacity to ensure that, in the long term, no more than 0.002 per cent of customer demand in each region of the NEM is at risk of being unserved. To ensure the standard is met, NEMMCO determines the necessary spare capacity for each region that must be available (either within the region or via transmission interconnectors). These minimum reserves provide a buffer against unexpected demand spikes and generation failure. The Reliability Panel also recommends a wholesale market price cap, which is aimed at a level to stimulate sufficient investment in generation capacity to meet the reliability standard. The panel recently completed a comprehensive review of reliability settings in the NEM and recommended a number of refinements (see box 1.1).

The AEMC Reliability Panel reports performance against the reliability standards and the minimum reserve levels set by NEMMCO. In practice, generation has proved highly reliable. Reserve levels are rarely breached and generator capacity across all regions of the market is generally sufficient to meet peak demand and allow for an acceptable reserve margin. The performance of generators in maintaining reserve levels has improved since the NEM began in 1998, most notably in South Australia and Victoria. This reflects significant generation investment and improved transmission interconnection capacity between the regions.

There were only two instances of insufficient generation capacity to meet consumer demand from the commencement of the NEM to 30 June 2007. The first occurred in Victoria in early 2000, when a coincidence of industrial action, high demand and temporary loss of generating units resulted in load shedding. The second occurred in New South Wales on 1 December 2004, when a generator failed during a period of record summer demand. The restoration of load began within ten minutes. NEMMCO has published three drought reports to assess the impact of drought on reliability. For the 2006–07 period, it found there was no unserved energy due to drought.

Table 1.5 sets out the performance of the generation sector in selected states against the reliability standard. All states now operate within the standard.

Table 1.5 Unserved energy, long-term averages to 30 June 2007

STATE	UNSERVED ENERGY
New South Wales	0.00%
Victoria	0.01%
Queensland	0.00%
South Australia	0.00%

Note: Long-term average since December 1998.

Sources: AEMC Reliability Panel, *Annual Electricity Market Performance Review: Reliability and Security 2007* (and previous years).

8 The AEMC published a final Rule determination on 1 May 2008 that requires new intermittent generators to register under the new classification of Semi-Scheduled Generator. These generators will be required to participate in the central dispatch process. Additionally, the South Australian regulator, ESCOSA, implemented licence conditions preventing wind farms from being classified as non-scheduled. Accordingly, all wind farms commissioned in South Australia since that date are currently classified as scheduled generation. Some pre-existing South Australian wind farms also have changed classification from non-scheduled to scheduled.

1.4.1 Excluded data

The power system is operated to cope with credible (foreseeable) supply interruptions. These events can be avoided through investment in generation capacity. But some power supply interruptions are caused by events that are 'non-credible'. Typically, such events occur simultaneously or in a chain reaction. For example, several generating units might fail or 'trip' at the same time, or a transmission fault might occur at the same time as a generator trips. It would not be economically efficient to operate the power system to cope with non-credible events (also called multiple contingency events). For this reason, non-credible events are excluded from reliability statistics.

Multiple contingency events caused a significant amount of unserved energy in 2006–07, including outages caused by bushfires in Victoria on 16 January 2007 and lightning storms in Tasmania on 22 February 2007. The bushfires in northern Victoria resulted in two transmission lines tripping, and the power system subsequently separating into three electrical islands. A major imbalance followed which resulted in 2490 MW of lost load. The lightning storms in Tasmania caused two 220 kV lines to trip, resulting in the power system on the west coast being islanded (disconnected from the rest of the state). A number of generating units then tripped, and the west coast transmission system eventually collapsed. The Victorian and Tasmanian incidents led to losses of consumer load but did not result in a breach of the reliability standard. The Reliability Panel noted that events such as these can seriously affect continuity of supply and that, from a consumer perspective, the effects are indistinguishable from that of reported reliability events.

1.4.2 Investment in generation and long-term reliability

The NEM combines a number of mechanisms to ensure high levels of reliability in the generation sector. In the short term, NEMMCO can manage shortfalls in reserves by directing peak generators to come on line, or by contracting for reserve capacity (which occurred for Victoria and South Australia in February 2006). In the longer term, a reliable power supply needs sufficient investment in generation to meet the needs of customers.

Price signals

A central element in the design of the NEM is that spot prices respond to a tightening in the supply–demand balance. Wholesale prices and projections in the supply–demand balance are also factored into forward prices in the contract market (see chapter 3). Regions with potential generation shortages (which could lead to reliability issues) will therefore exhibit rising prices in the spot and contract markets. High prices may help to attract investment to the areas where it is needed, and may lead to some demand-side response if suitable metering and price signals are available to end users. For example, retailers might offer a customer financial incentives to reduce consumption at times of high system demand to ease pressure on prices.

Seasonal factors (for example, summer peaks in air conditioning loads) create a need for peaking generation to cope with periods of extreme demand. The NEM price cap of $10 000 per MWh is necessarily high to encourage investment in peaking plant, which is expensive to run. Over the longer term, peaking plants play a critical role in ensuring there is adequate generation capacity (and therefore reliability) in the NEM. Victoria and South Australia have invested in significant peaking generation capacity, and investors have committed to new peaking plant in Queensland and New South Wales (see figure 1.6 and table 1.3).

Historical adequacy of generation to meet demand

Figure 1.13 compares total generation capacity with national peak demand since the NEM began. The chart shows actual demand and the demand forecasts published by NEMMCO two years in advance. The data indicates that the NEM has seen sufficient investment in new capacity over the past decade to keep pace with rising demand (both actual and forecast levels), and to provide a safety margin of capacity to maintain the reliability of the power system.

Box 1.1 Comprehensive reliability review

The AEMC Reliability Panel conducted a comprehensive review of the NEM reliability settings in 2007. It was the first review of its kind since the inception of the NEM. The panel reviewed the following reliability standards and parameters:

- *The NEM reliability standard*—currently set at 0.002 per cent.
- *Administered price mechanisms*—which aim to ensure the reliability standard is met, while avoiding unmanageable risks for market participants. These mechanisms are the market price cap (known as the value of lost load or VoLL), the market floor price, and a cap on financial exposure (the cumulative price threshold or CPT).
- *Intervention mechanisms*—which come into effect if price mechanisms fail. NEMMCO operates a reserve trader mechanism which allows it to enter into reserve contracts with generators to ensure that supply meets the reliability standard. When entering into such contracts, NEMMCO must give priority to facilities which would result in the least possible distortion to spot prices. NEMMCO can also intervene in the market by requiring generators to provide additional supply at the time of dispatch to ensure that minimum reserve levels are met.

The Reliability Panel found that the reliability standard has worked satisfactorily to date. Nevertheless, it noted that stakeholders had perceived future risks that may delay investment and impact on reliability over time. The risks identified by stakeholders included uncertainty in relation to greenhouse gas emission policies, government ownership of generation assets, the risk of investment by government-owned businesses being driven by non-commercial considerations, and inadequate long-term contracting.

The review considered a number of adjustments to the current reliability settings to maintain confidence in the NEM's ability to deliver long-term reliability. Specifically, the review considered:

- clarifying the reliability standard
- adjusting administered price mechanisms such as VoLL
- improving the reserve trader mechanism
- increasing the range and quality of information on reliability matters to assist the market in addressing potential energy constraints.

In terms of the reliability standard, the panel concluded that the existing standard of 0.002 per cent unserved energy is satisfactory. However, the panel considered that the measurement should more clearly specify its purpose. In this regard, a new version of the formal reliability standard will be published.

In relation to administered pricing, the Reliability Panel recommended raising VoLL in the medium term, and proposed to make a Rule change proposal to the AEMC to raise VoLL to $12 500 per MWh from 1 July 2010. The CPT would be similarly raised to $187 500 by specifying its value as fifteen times the value of VoLL.

The Reliability Panel also recommended a review of the VoLL price in the context of the reliability settings every two years, with at least a two-year notification period for any proposed change. It recommended that, for the VoLL to reflect its true nature as a market price cap, it should be renamed the market price limit. The market floor price should remain unchanged at –$1000 per MWh.

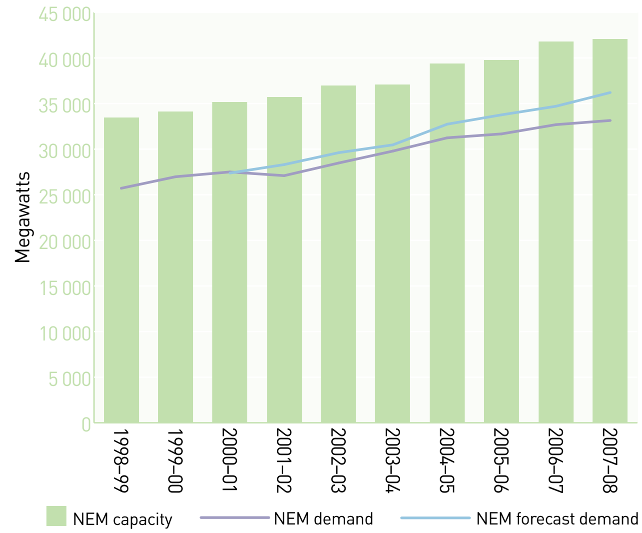
The Reliability Panel suggested that the current reserve trader mechanism be changed to a Reliability and Emergency Reserve Trader mechanism, whose operation should be reviewed as part of the regular review of reliability settings.

In terms of increasing the range and quality of information, the panel recommended a new Energy Adequacy Assessment Projection to provide information on projected response times to address energy constraints in the market that may affect reliability. The panel also recommended that, where possible, long-term contract prices such as those traded on the Sydney Futures Exchange should be published alongside spot prices to provide more balanced information about the financial exposure of market participants in extreme conditions. It considered that improved transparency would make the market more responsive to the reliability settings, particularly price mechanisms.

Further information: AEMC Reliability Panel, *Comprehensive Reliability Review, Final Report*, December 2007.

Figure 1.13

National Electricity Market peak demand and generation capacity



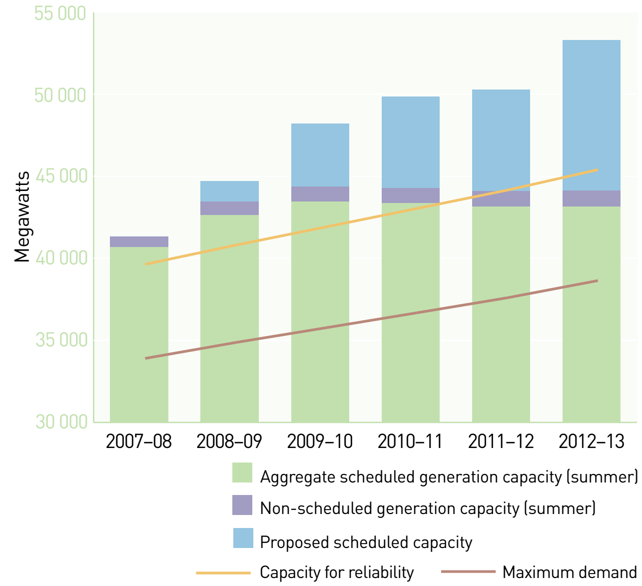
Notes:

1. Demand forecasts are taken two years in advance, based on a 50 per cent probability that the forecast will be exceeded (due, for example, to weather conditions) and a coincidence factor of 95 per cent.
2. NEM capacity excludes wind and power stations not managed through central dispatch.

Sources: NEMMCO, *Statement of opportunities for the National Electricity Market*, various years.

Figure 1.14

Demand and capacity outlook to 2012–13



Notes:

1. The maximum demand forecasts for each region in the NEM are aggregated based on a 50 per cent probability of exceedence and a 95 per cent coincidence factor.
2. Reserve levels required for reliability are based on an aggregation of minimum reserve levels for each region. Accordingly, the data cannot be taken to indicate the required timing of new generation capacity within individual NEM regions.

Data source: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2007.

Reliability outlook

The relationship between future demand and capacity determines both electricity prices and the reliability of the power system looking forward. Figure 1.14 charts forecast peak demand in the NEM against installed, committed and proposed capacity. The chart indicates the amount of capacity that NEMMCO considers would be needed to maintain reliability, given the projected rise in demand. While wind generation is not classified as installed capacity, it is included as a possible source of electricity.

Figure 1.14 indicates that current installed and committed capacity will be sufficient to meet NEMMCO's peak demand projections and reliability requirements until at least 2010–11, with a safety margin provided by wind generation.

While the uncertain nature of proposed projects means they cannot be factored into NEMMCO's reliability equations, they do provide an indicator of the market's awareness of future capacity needs. In particular, they can be seen as an indicator of the extent of competition in the market to develop electricity infrastructure. Figure 1.14 indicates the extent of proposed capacity that may need to be constructed to meet projected shortfalls beyond 2011–12. While many proposed projects may never be constructed, only a relatively small percentage would need to come to fruition to meet demand and reliability requirements into the next decade.

2 NATIONAL ELECTRICITY MARKET

Generators in the National Electricity Market sell electricity to retailers through wholesale market arrangements in which the dynamics of supply and demand determine prices and investment. The Australian Energy Regulator monitors the market to ensure that participants comply with the National Electricity Law and National Electricity Rules.

2 NATIONAL ELECTRICITY MARKET

This chapter considers:

- features of the National Electricity Market
- how the wholesale market operates
- the demand for electricity by region, and electricity trade between regions
- spot prices for electricity, including international comparisons.

2.1 Features of the National Electricity Market

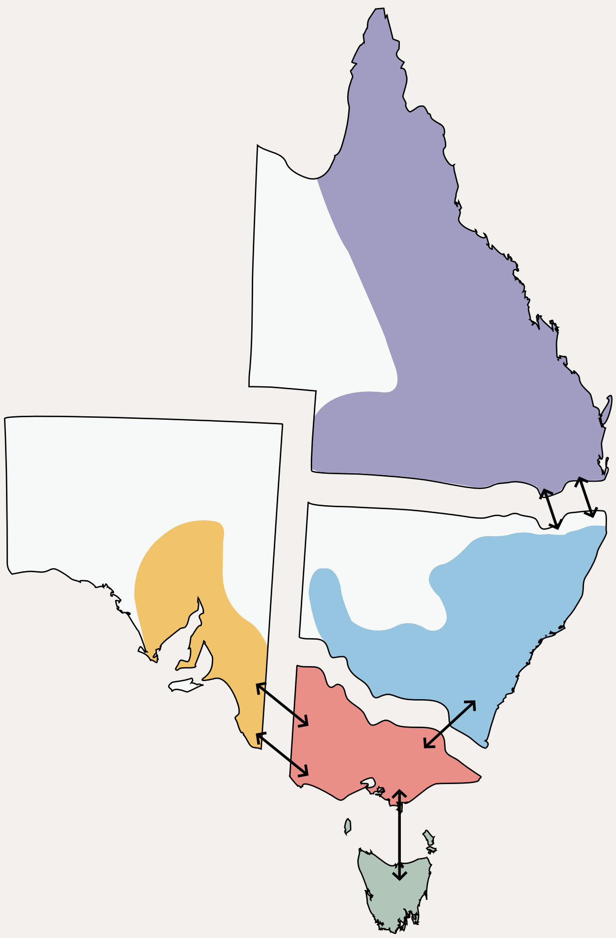
The National Electricity Market (NEM) is a wholesale market through which generators and retailers trade electricity in eastern and southern Australia. There are six participating jurisdictions—Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network.

The NEM has around 275 registered generators, six state-based transmission networks[1] (linked by cross-border interconnectors) and 13 major distribution networks that collectively supply electricity to end-use customers. In geographical span, the NEM is the largest interconnected power system in the world. It covers a distance of 4500 kilometres, from Cairns in northern Queensland to Port Lincoln in South Australia and Hobart in Tasmania. The market has five regions: New South Wales, Queensland, Victoria, South Australia and Tasmania (see figure 2.1).[2]

1 In New South Wales there are two transmission networks: TransGrid and EnergyAustralia. EnergyAustralia's transmission network assets support the TransGrid network.

2 The former Snowy region was abolished on 1 July 2008. The area formerly covered by the Snowy region is now split between the Victoria and New South Wales regions of the NEM.

Figure 2.1
Regions of the National Electricity Market



The shaded area represents the approximate geological range of the interconnected network in each National Electricity Market region

Qld NSW Vic SA Tas ⟷ Interconnectors

Source: AER.

The NEM supplies electricity to approximately 8.7 million residential and business customers. In 2007–08, the market generated around 208 terawatt hours (TWh)[3] of electricity with a turnover of almost $11.1 billion (see table 2.1).

Table 2.1 **National Electricity Market at a glance**

Participating jurisdictions	Qld, NSW, Vic, SA, ACT, Tas
NEM regions	Qld, NSW, Vic, SA, Tas
Registered capacity	44 390 MW
Number of registered generators	275
Number of customers	8.7 million
NEM turnover 2007–08	$11.1 billion
Total energy generated 2007–08	208 000 GWh
National maximum winter demand 2007–08 (18 July 2007)	34 422 MWh
National maximum summer demand 2007–08 (14 January 2008)	31 990 MWh

NEM, National Electricity Market; MW, megawatt; GWh, gigawatt hour; MWh, megawatt hour.

Sources: NEMMCO; ESAA, *Electricity Gas Australia*, 2008, p. 26.

2.2 How the National Electricity Market works

The NEM is a wholesale pool into which generators sell their electricity. The main customers are retailers, which buy electricity for resale to business and household customers. While it is also possible for an end-use customer to buy directly from the pool, few choose this option.

The market has no physical location, but is a virtual pool in which a central operator aggregates and dispatches supply bids to meet demand. The National Electricity Market Management Company (NEMMCO) has managed the operation of the NEM since 1998, but this role is scheduled to transfer to a new body, the Australian Energy Market Operator (AEMO), on 1 July 2009. The Australian Energy Regulator (AER) monitors the market to ensure that participants comply with the National Electricity Law and Rules.

3 One TWh is equivalent to 1000 gigawatt hours (GWh), 1 000 000 megawatt hours (MWh) and 1 000 000 000 kilowatt hours (KWh). One TWh is enough energy to light 10 billion light bulbs with a rating of 100 watts for one hour.

Box 2.1 Development of the National Electricity Market

Historically, governments owned and operated the electricity supply chain from generation through to retailing. There was no wholesale market because generation and retail were operated by vertically integrated state-based utilities. Typically, each jurisdiction generated its own electricity needs, with limited interstate trade.

Australian governments began to reform the electricity industry in the 1990s. The vertically integrated utilities were separated into generation, transmission, distribution and retail businesses. For the first time, generation and retail activities were exposed to competition. This created an opportunity to develop a wholesale market that extended beyond jurisdictional borders.

The Special Premiers' Conference in 1991 agreed to establish the National Grid Management Council to coordinate the development of the electricity industry in eastern and southern Australia. In early 1994, the Council of Australian Governments developed a code of conduct for the operation of a national grid, consisting of the transmission and distribution systems in Queensland, New South Wales, the ACT, Victoria and South Australia. In 1996, these jurisdictions agreed to pass the National Electricity Law, which provided the legal basis to create the NEM.

During the transition to a national market, Victoria and New South Wales trialled wholesale electricity markets that used supply and demand principles to set prices. The NEM commenced operation in December 1998, with Queensland, New South Wales, Victoria, South Australia and the ACT as participating jurisdictions.

While Queensland was part of the NEM from inception, it was not physically interconnected with the market until 2000–01 when two transmission lines (Directlink and the Queensland to New South Wales interconnector) linked the Queensland and New South Wales networks. Tasmania joined the NEM in 2005 and was physically interconnected with the market in April 2006 with the opening of Basslink, a submarine transmission cable from Tasmania to Victoria.

The NEM experienced a regional boundary change on 1 July 2008 when the Snowy region was abolished. The area formerly covered by the region is now split between the Victoria and New South Wales regions of the NEM. The other regions—Queensland, South Australia and Tasmania—follow jurisdictional boundaries.

The design of the NEM reflects the physical characteristics of electricity. This means:

> Supply must meet demand at all times because electricity cannot be economically stored. This requires coordination to avoid imbalances that could seriously damage the power system.
> One unit of electricity cannot be distinguished from another, making it impossible to determine which generator produced which unit of electricity and which market customer consumed that unit. The use of a common trading pool addresses this issue by removing any need to trace particular generation to particular customers.

The NEM is a gross pool, meaning that all sales of electricity must occur through a central trading platform. In contrast, a net pool or voluntary pool would allow generators to contract with market customers directly for the delivery of some electricity. Western Australia's electricity market uses a net pool arrangement (see chapter 7). Both market designs require the market operator to be informed of all sales so that the physical delivery of electricity can be centrally managed.

Unlike some overseas markets, the NEM does not provide additional payments to generators for capacity or availability. This characterises the NEM as an 'energy-only' market and explains the high price cap of \$10 000 per megawatt hour (MWh).[4] Generators earn their income in the NEM from market transactions,

4 The Australian Energy Market Commission's (AEMC) Reliability Panel stated in its 2007 reliability review that it intends to put forward a Rule change proposal to the AEMC to raise the market price cap to \$12 500 effective 1 July 2010. See AEMC, *Comprehensive reliability review*, Final report, December 2007, p. 51.

either in the spot or ancillary services[5] markets or by trading hedge instruments in financial markets[6] outside NEM arrangements.

2.2.1 Market operation

NEMMCO coordinates a central dispatch to manage the wholesale spot market. The process matches generator supply offers to demand in real time. NEMMCO issues instructions to each generator to produce the required quantity of electricity that will meet demand at all times at the lowest available cost, while maintaining the technical security of the power system. NEMMCO does not own any physical network or generation assets.

Some generators bypass the central dispatch process: they might only generate intermittently (such as wind generators)[7], may not be connected to a transmission network, and/or might produce exclusively for their own use (such as in remote mining operations).

2.2.2 Demand and supply forecasting

NEMMCO continuously monitors demand and capacity across the NEM and issues demand and supply forecasts to help participants respond to the market's requirements. While demand varies, industrial, commercial and household users each have relatively predictable patterns, including seasonal demand peaks related to extreme temperatures. NEMMCO uses data such as historical load (demand) patterns and weather forecasts to develop demand projections. Similarly, it estimates the adequacy of supply in its projected assessment of system adequacy (PASA) reports. It publishes a seven-day PASA report that is updated every two hours, and a two-year PASA report that is updated weekly.

2.2.3 Central dispatch and spot prices

Market supply is based on the offers of generators to produce particular quantities of electricity at various prices for each of the five-minute dispatch periods in a day. Generators must lodge offer bids ahead of each trading day.

Generator offers are affected by a range of factors, including plant technology. For example, coal-fired generators need to ensure their plants run constantly to cover their high start-up costs and may offer to generate some electricity at low or negative prices to guarantee dispatch.[8] Peaking generators face high operating costs and normally offer to supply electricity only when prices are high.

NEMMCO determines which generators are dispatched by stacking the offer bids of all generators in ascending price order for each five-minute dispatch period. NEMMCO dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to satisfy demand. This results in demand being met at the lowest possible cost. In practice, the dispatch order may be modified by a number of factors, including generator ramp rates—that is, how quickly generators can adjust their level of output—and congestion in transmission networks.

The dispatch price for a five-minute interval is the offer price of the highest (marginal) priced megawatt (MW) of generation that must be dispatched to meet demand. For example, in figure 2.2, the demand for electricity at 4.15 is about 350 MW. To meet this level of demand, the four generators offering to supply at prices up to \$37 must be dispatched. The dispatch price is therefore \$37. By 4.20, demand has risen to the point where a fifth generator needs to be dispatched. This higher cost generator has an offer price of \$38, which drives the price up to that level.

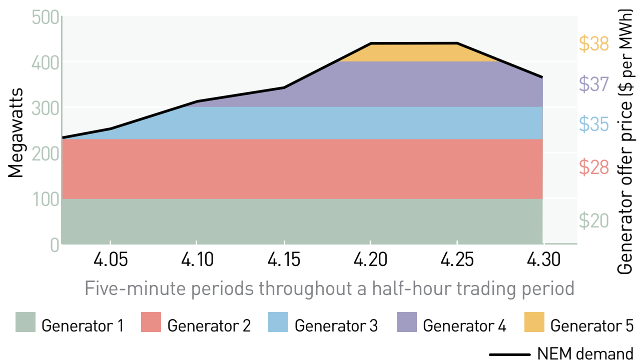
5 NEMMCO operates a market for a number of ancillary services. These include frequency control services that relate to electricity supply adjustments to maintain the power system frequency within the standard. Generators can bid offers to supply these services into spot markets that operate in a similar way to the wholesale energy market.

6 See chapter 3.

7 The AEMC published a final Rule determination on 1 May 2008 that requires new intermittent generators to register under the new classification of 'semi-scheduled generator'. These generators will be required to participate in the central dispatch process, including by submitting offers and by limiting their output whenever requested by NEMMCO.

8 The minimum allowed bid price is -\$1000 per MWh.

Figure 2.2
Illustrative generator offers (megawatts) at various prices



Source: NEMMCO.

A wholesale spot price is determined for each half-hour period (trading interval) and is the average of the five-minute dispatch prices during that interval. In figure 2.2, the spot price in the 4.00–4.30 interval is about $37 per MWh. This is the price all generators receive for their supply during this 30 minute period and the price market customers pay for the electricity they use in that period. A separate spot price is determined for each region, taking into account the physical losses in the transport of electricity over distances and transmission congestion that can sometimes isolate particular regions from the national market (see section 2.4).

The price mechanism in the NEM allows spot prices to respond to a tightening in the supply–demand balance. This creates signals for demand-side responses. For example, if suitable metering arrangements are available, some customers may be able to reduce their consumption during peak demand periods when prices are high (see section 2.6). In the longer term, price movements also create signals for new investment (see sections 1.3 and 2.6).

2.3 Demand and capacity

Annual electricity consumption in the NEM rose from under 170 000 gigawatt hours (GWh) in 1999–2000 to about 208 000 GWh in 2007–08 (see figure 2.3(a)). The entry of Tasmania in 2005 accounted for around 10 000 GWh. Demand levels fluctuate throughout the year, with peaks occurring in summer (for air conditioning) and winter (for heating). The peaks are closely related to temperature. Figure 2.3(b) shows that seasonal peaks have risen nationally from around 26 000 MW in 1999–2000 to over 33 000 MW in 2007–08. The volatility in the summer peaks reflects variations in weather conditions from year to year.

Table 2.2 sets out the demand for electricity across the NEM since 1999–2000. Reflecting its population base, New South Wales has the highest demand for electricity, followed by Victoria and Queensland. Demand is considerably lower in the less populated regions of South Australia and Tasmania.

Figure 2.4 compares seasonal demand across the regions. Victoria, South Australia and Queensland experience high demand in summer due to air conditioning loads. Tasmania tends to experience its maximum demand in winter due to heating loads. New South Wales has alternated between summer and winter peaking for several years.

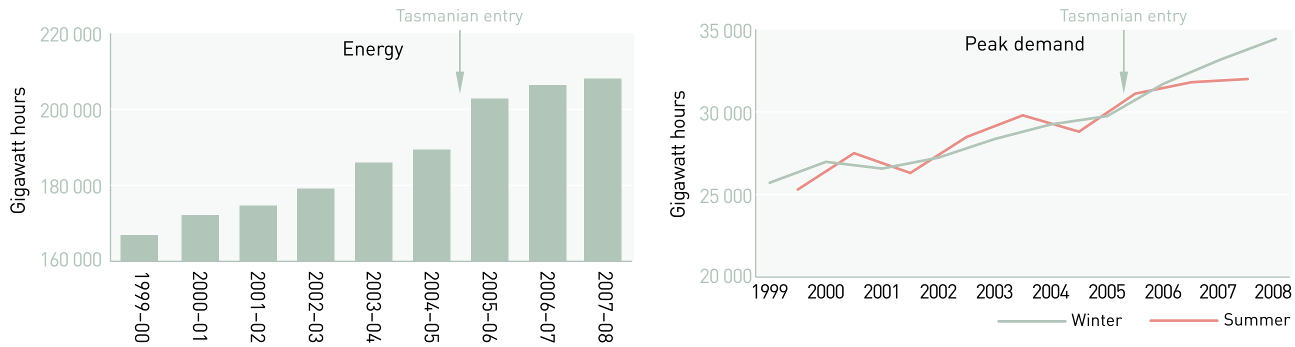
2.4 Trade between the regions

The NEM promotes efficient generator use by allowing trade in electricity between the five regions, which are linked by transmission interconnectors. Trade enhances the reliability of the power system by allowing the regions to draw on a wider pool of reserves to manage system constraints and outages.

Trade also provides economic benefits by allowing high-cost generating regions to import electricity from lower cost regions. For example, on a day of peak electricity demand in South Australia, low-cost baseload power from Victoria may provide a competitive alternative to South Australia's high-cost peaking generators. NEMMCO can dispatch electricity from lower cost regions and export it to South Australia until the technical capacity of the interconnectors is reached.

Figures 2.3a and 2.3b

National Electricity Market energy consumption and peak demand since 1999



Sources: NEMMCO; AER.

Table 2.2 Annual energy demand (terawatt hours)

	Qld	NSW	Snowy[2]	Vic	SA	Tas[1]	National
2007–08	51.5	78.8	1.6	52.3	13.3	10.3	208.0
2006–07	51.4	78.6	1.3	51.5	13.4	10.2	206.4
2005–06	51.3	77.3	0.5	50.8	12.9	10.0	202.8
2004–05	50.3	74.8	0.6	49.8	12.9		189.7
2003–04	48.9	74.0	0.7	49.4	13.0		185.3
2002–03	46.3	71.6	0.2	48.2	13.0		179.3
2001–02	45.2	70.2	0.3	46.8	12.5		175.0
2000–01	43.0	69.4	0.3	46.9	13.0		172.5
1999–00	41.0	67.6	0.2	45.8	12.4		167.1

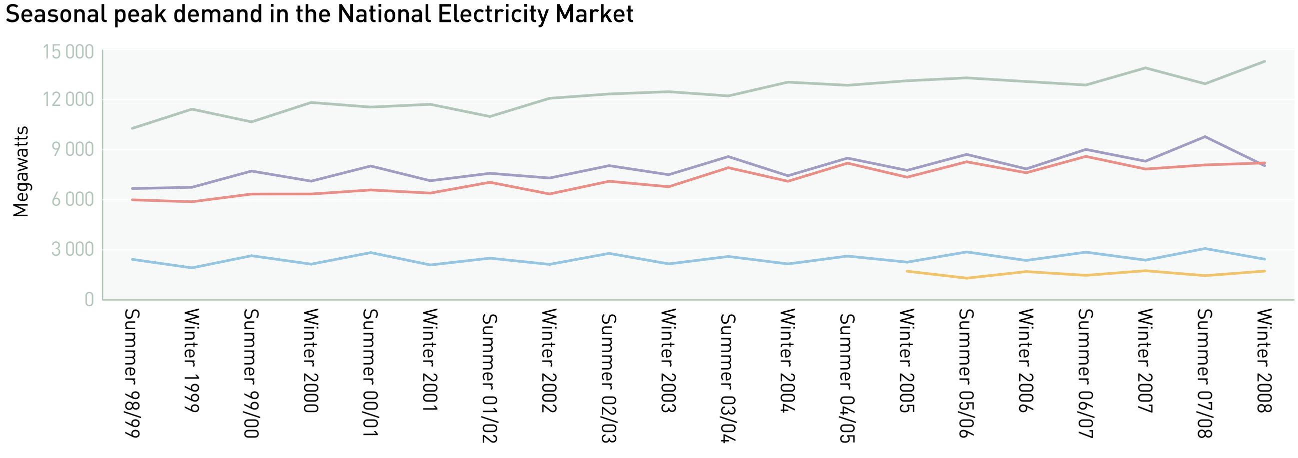
Notes:

1. Tasmania entered the market on 29 May 2005.
2. The Snowy region was abolished on 1 July 2008.

Source: NEMMCO.

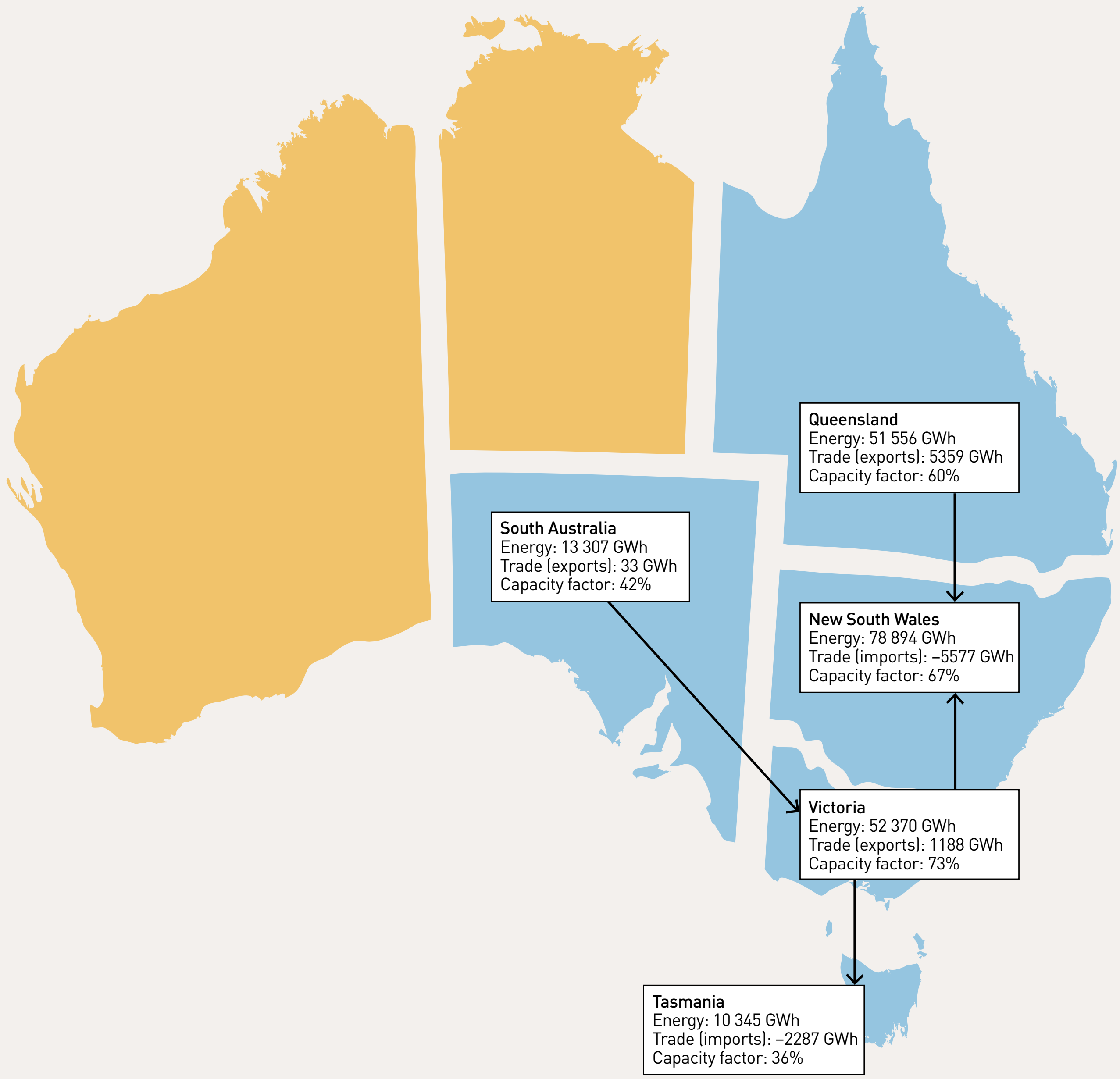
Figure 2.4

Seasonal peak demand in the National Electricity Market



Sources: NEMMCO; AER.

Figure 2.5
Trade flows across National Electricity Market regions in 2007–08



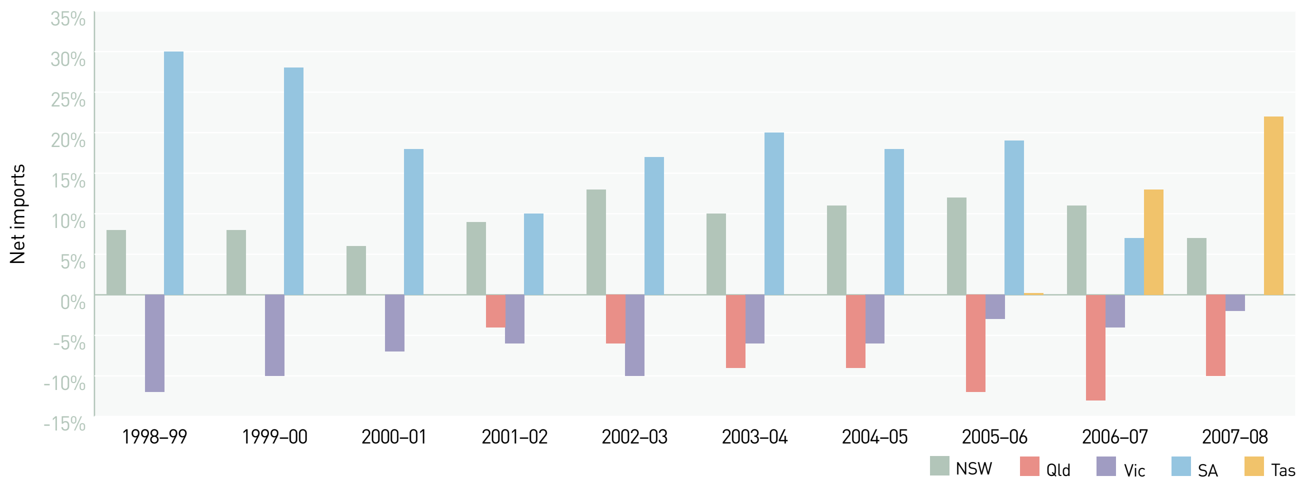
GWh, gigawatt hour.

Notes:

1. Energy refers to electricity consumption.
2. Capacity factor refers to the proportion of local generation capacity in use.
3. The Snowy region (not shown) was a net exporter of 1809 GWh in 2007–08. The region was abolished on 1 July 2008. The area formerly covered by the Snowy region is now split between the Victoria and New South Wales regions of the National Electricity Market.

Sources: NEMMCO; AER.

Figure 2.6
Inter-regional trade as percentage of regional energy consumption



Sources: NEMMCO; AER.

Figure 2.5 shows annual electricity consumption and trade between the regions in 2007–08. The figure also shows each region's generation capacity factor (the utilisation of local generation capacity). The NEM's inter-regional trade relationships are also reflected in figure 2.6, which shows the net trading position of the regions since the NEM commenced.

Figures 2.5 and 2.6 show that:

- New South Wales is a net importer of electricity. It relies on local baseload generation, but has limited peaking capacity at times of high demand.[9] This puts upward pressure on prices in peak periods, making imports a competitive alternative. New South Wales continued to be a net importer in 2007–08, although at a lesser rate than in 2006–07. Imports have accounted for between 5 and 13 per cent of the state's energy consumption since the NEM commenced.
- Victoria is a net exporter because it has substantial low-cost baseload capacity. This is reflected in the region's 73 per cent capacity factor, the highest for any region. Victoria tends to import mainly at times of peak demand when its regional capacity is stretched. While Victoria has consistently been a net exporter, its exports as a share of consumption have fallen from around 10 per cent in the early years of the NEM to about 2 per cent in 2007–08.
- Queensland's installed capacity exceeds its demand for electricity, making it a significant net exporter. Queensland exports have steadily risen since 2001–02 and have exceeded 10 per cent of the state's annual energy consumption since 2005–06.
- South Australia, historically the most trade-dependent region, imported over 25 per cent of its energy requirements in the early years of the NEM. This reflected the region's relatively higher fuel costs, resulting in high-cost generation. South Australia has significantly reduced its reliance on imports since 2005–06, and in 2007–08 it became a net exporter for the first time. The shift reflects new investment in generation since 1999, including substantial recent investment in wind capacity. South Australia was less affected by the drought than other regions as it has no hydroelectric generation and its baseload generators use cooling technologies that do not rely on fresh water.

9 The New South Wales region gained additional hydroelectric peaking capacity following the abolition of the Snowy region on 1 July 2008.

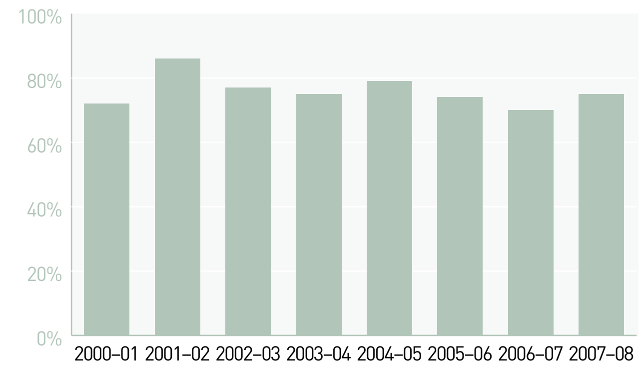
- Tasmania has been a net importer since its interconnection with the NEM in 2006. Tasmanian imports rose to over 20 per cent of its electricity requirements in 2007–08, mainly because drought has constrained its ability to generate hydroelectricity. This also contributed to Tasmania's extremely low capacity factor.

2.4.1 Market separation

The NEM central dispatch determines a separate spot price for each region of the NEM. In the absence of network constraints, interstate trade brings prices across the regions towards alignment. Due to transmission losses that occur when transporting electricity over distances, it is normal to have some disparities between regional prices. More significant price separation may occur if an interconnector is congested. For example, imports may be restricted when import requirements exceed an interconnector's design limits. Import capability may also be reduced when an interconnector is undergoing maintenance or due to an unplanned outage. The availability of generation plant and the bidding behaviour of generators can also contribute to transmission congestion.

When congestion restricts a high-demand region's ability to import electricity, prices in that region may spike. For example, if low-cost Victorian electricity is constrained from flowing into South Australia on a day of high demand, more expensive South Australian generation—for example, local peaking plant—would need to be dispatched in place of imports. This would drive South Australian prices above those in Victoria.

Figure 2.7
Regional price alignment as a percentage of trading hours

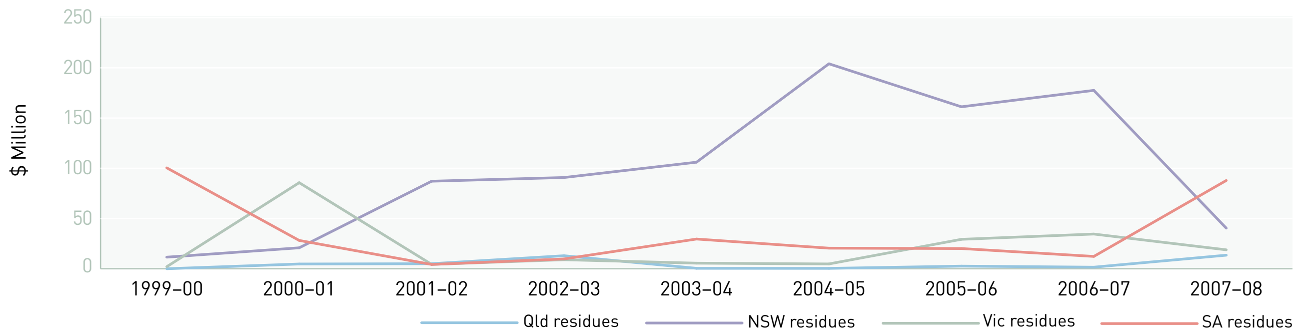


Sources: NEMMCO; AER.

Figure 2.7 indicates that the NEM operates as an 'integrated' market with price alignment across all regions for around 75 per cent of the time. The market is considered aligned when every interconnector in the NEM is unconstrained and electricity can flow freely between all regions. There may still be price differences between regions due to loss factors that occur in the transport of electricity.

While the extent of alignment is an indicator of how effectively the market is working, it should be noted that full alignment would require significant investment to remove all possible causes of congestion. AER research indicates that the economic costs of transmission congestion are relatively modest given the scale of the market, although these costs have risen since 2003–04 (see section 4.7).

Figure 2.8
Settlement residues



Sources: NEMMCO; AER.

2.4.2 Settlement residues

When there is price separation between regions, electricity tends to flow from lower priced regions to higher priced regions. The exporting generators are paid at their local regional spot price, while importing customers (usually energy retailers) must pay the higher spot price in the importing region. The difference between the price paid and the price received multiplied by the amount of electricity exported is called a settlement residue. Over time, these residues accrue to the market operator.

Figure 2.8 charts the annual accumulation of inter-regional settlement residues in each region. There is some volatility in the data, reflecting that a complex range of factors can contribute to price separation: for example, the availability of transmission interconnectors and generation plant; weather conditions; and the bidding behaviour of generators.

New South Wales recorded settlement residues ranging from around $90 million to $200 million each year from 2001–02 to 2006–07. This reflects the region's status as the largest importer of electricity (in dollar and volume terms) in the NEM, which can make it vulnerable to price separation events. In 2007–08, New South Wales settlement residues fell by around 75 per cent due to more benign market conditions. Conversely, South Australian residues increased from a low base to almost $88 million in 2007–08 due to record summer and autumn prices in the region.

As net exporters, Queensland and Victoria tend not to accumulate large settlement residue balances.

Price separation creates risks for parties that contract across regions. NEMMCO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues. An explanation of the auction process is provided in section 4.7.

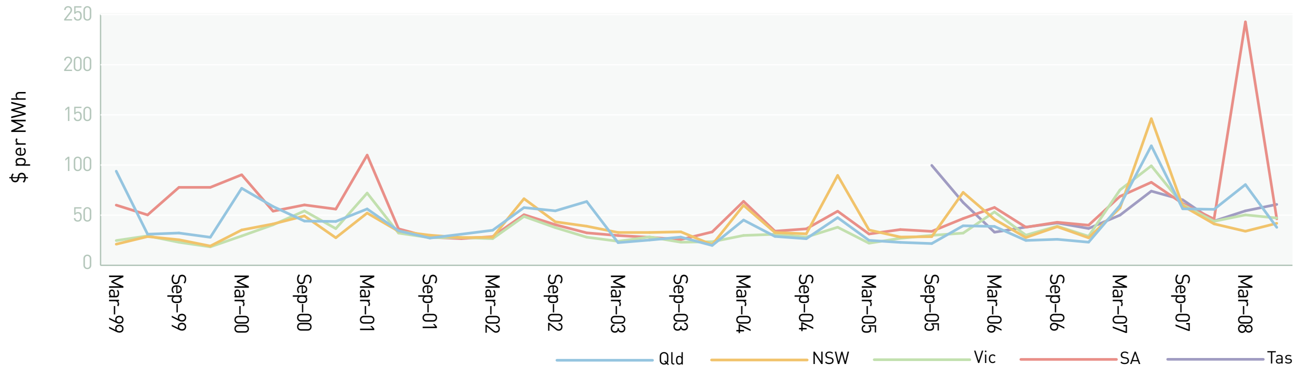
2.5 National Electricity Market prices

The central dispatch process determines a spot price for each NEM region every 30 minutes. As noted, prices can vary between regions because of losses in transportation and transmission congestion, which sometimes restricts inter-regional trade.

The AER closely monitors the market and reports weekly on wholesale and forward market activity. It also publishes more detailed analyses of extreme price events. Figure 2.9 charts quarterly volume-weighted average prices since the NEM commenced, while table 2.3 sets out annual volume-weighted prices. Figure 2.10 provides a more detailed snapshot of weekly prices since November 2006. Overall, prices tended to fall in the early years of the NEM—especially in Queensland and South Australia—following investment in new transmission and generation capacity. In the past two years, drought, record peak demands and other factors have seen prices rise to record levels.

Figure 2.9

Quarterly volume-weighted average prices—National Electricity Market



MWh, megawatt hour.

Sources: NEMMCO; AER.

Table 2.3 **Annual average National Electricity Market prices by region (dollars per megawatt hour)**

	Qld	NSW	Snowy[2]	Vic	SA	Tas[3]
2007–08	58	44	31	51	101	57
2006–07	57	67	38	61	59	51
2005–06	31	43	29	36	44	59
2004–05	31	46	26	29	39	
2003–04	31	37	22	27	39	
2002–03	41	37	27	30	33	
2001–02	38	38	27	33	34	
2000–01	45	41	35	49	67	
1999–2000	49	30	24	28	69	
1998–1999[1]	60	25	19	27	54	

Notes:

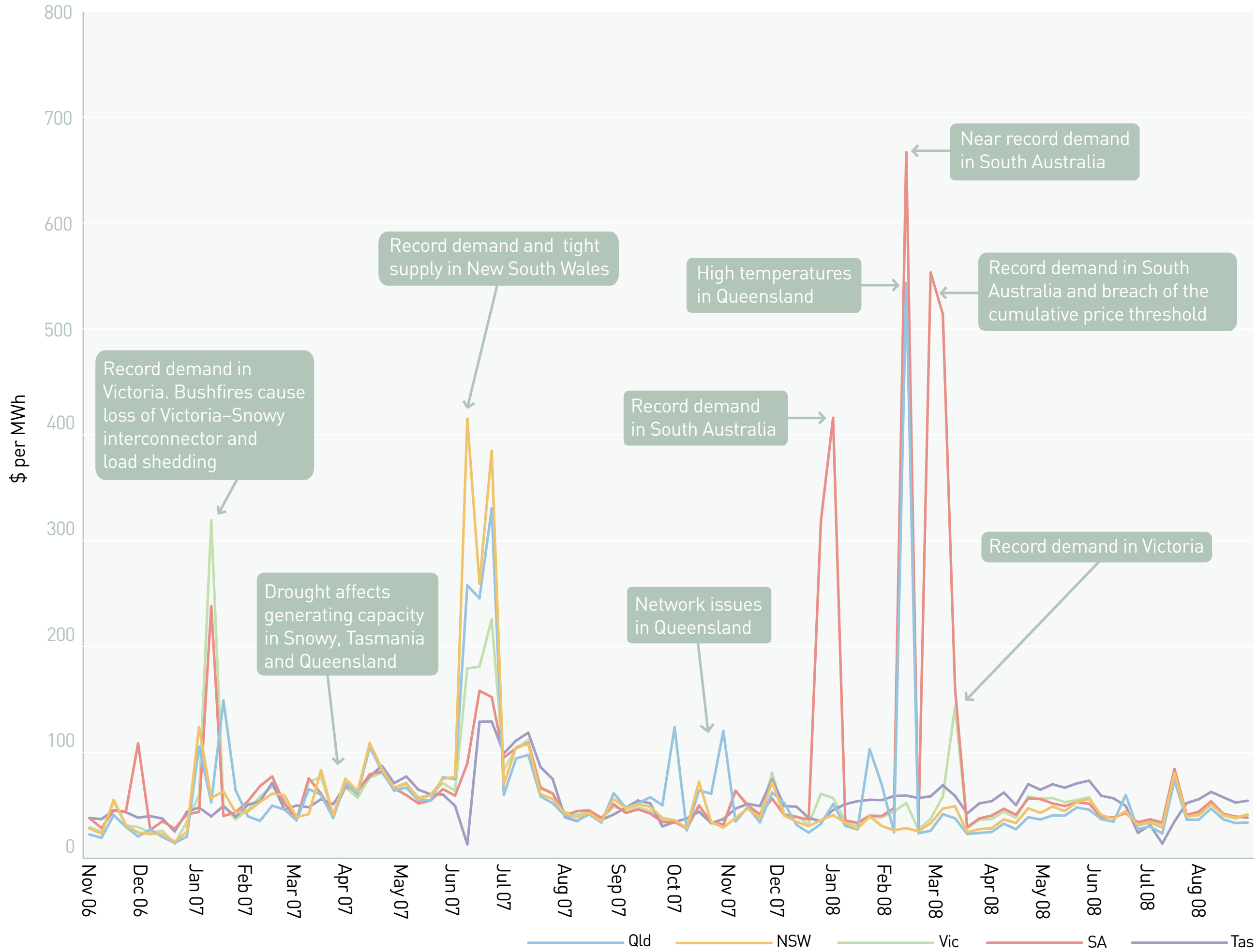
1. Six months to 30 June 1999.
2. The Snowy region was abolished on 1 July 2008.
3. Tasmania entered the market on 29 May 2005.

Source: NEMMCO.

A variety of factors led to significantly higher prices in 2006–07. In January 2007, bushfires caused an outage of the Victoria–Snowy interconnector, causing price spikes in Victoria and South Australia. Network issues in Queensland in late January also affected prices. From around March 2007, drought began to impact on prices. The drought constrained hydroelectric generating capacity in New South Wales, Tasmania and Victoria and also limited the availability of water for cooling in some coal-fired generators.

These conditions were exacerbated in winter 2007 by a number of generator outages, network outages and generator limitations. Tight supply was accompanied by record electricity demand as cold winter days increased heating requirements.

Figure 2.10
National Electricity Market prices, November 2006–September 2008



Note: Weekly volume-weighted average prices.

Sources: NEMMCO; AER.

2.5.1 Wholesale market update: 2007–2008

The drought continued to affect wholesale electricity prices in New South Wales, Victoria, Queensland and Tasmania during the September quarter of 2007. South Australia was less affected as its generators do not depend on fresh water for cooling. By the end of the quarter, drought conditions in New South Wales and Queensland had eased and prices across the NEM had fallen back towards pre-drought levels.

Wholesale prices in the December quarter were relatively subdued across most of the NEM. Queensland experienced some high-price events due to planned and unplanned network outages and aggressive bidding by a number of generators.

The March quarter of 2008 was characterised by high electricity prices in South Australia, Queensland and Victoria. South Australia experienced record high prices, averaging $243 per MWh over the quarter compared to the previous NEM record of $146 per MWh.[10]

10 The previous highest quarterly average was for New South Wales in the June quarter of 2007.

A number of factors contributed to South Australia's record high prices:

- Adelaide experienced high temperatures in January and February and an unprecedented 15-day heat wave in March 2008. The extreme temperatures led to record demand.
- A significant proportion of South Australia's electricity is sourced from Victorian generators via the Heywood and Murraylink interconnectors. In December 2007, the South Australian transmission network owner, ElectraNet, reduced the maximum allowable flows on the Heywood interconnector by about 25 per cent. This constrained the supply of low-cost generation from Victoria.
- AGL Energy, which owns about 39 per cent of South Australia's generation capacity, bid a significant proportion of its capacity at close to the price cap during the periods of high demand.

In combination, these factors led to extreme prices in South Australia in March 2008. The National Electricity Rules provide a mechanism that triggers an administered price cap during times of sustained high prices. When the sum of the prices over the previous week exceeds $150 000 (the cumulative price threshold),[11] administered pricing automatically caps the price at $300 per MWh until the end of that trading day.

On the last day of the South Australian heatwave, prices reached the cumulative price threshold and administered price caps were applied.[12] This was the first time that administered pricing had been triggered since the commencement of the NEM in 1998.

The AER is investigating the high price events in South Australia and, in particular, whether generator bidding behaviour breached the National Electricity Law and Rules.[13] The AER is also investigating the flow limits placed on the Heywood interconnector by ElectraNet.[14]

In the June quarter of 2008, prices across the NEM were relatively subdued, with no extreme price events. This is consistent with the normal historical tendency for peak demand and prices to be relatively stable during autumn. The unusually high prices in autumn 2007 mainly reflected drought conditions. More benign weather conditions in 2008 led to a return to lower prices.

The market in the third quarter of 2008 remained relatively quiet, apart from a price spike across the mainland NEM regions on 23 July due to an unplanned outage of two transmission lines in Victoria. The AER is investigating this incident.

2.6 Price volatility

Spot price volatility in the NEM reflects fluctuating supply and demand conditions. The market is sensitive to changes in these conditions, which can occur at short notice. For example, electricity demand can rise swiftly on a hot day. Similarly, a generator or network outage can quickly increase regional spot prices. The sensitivity of the market to changing supply and demand conditions can result in considerable price volatility.

While figure 2.10 provides an indicator of volatility in weekly prices, it masks more extreme spikes that can occur during half-hour trading intervals. On occasion, half-hour spot prices approach the market cap of $10 000 per MWh. Two indicators of the incidence of extreme price events are:

- the number of trading intervals where the price is above $5000 per MWh (see figures 2.11 and 2.12)
- the number of trading intervals per week where the price is more than three times the volume-weighted average price (see figure 2.13).

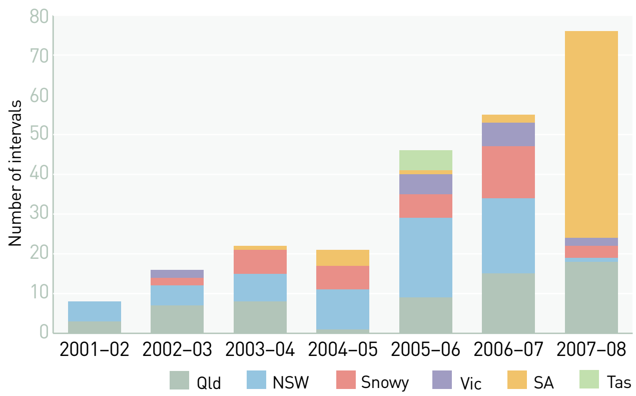
11 The AEMC Reliability Panel stated in its 2007 reliability review that it intends to put forward a Rule change proposal to the AEMC to raise the cumulative price threshold to $187 500 (being 15 times the level of the recommended market price cap) effective 1 July 2010 (See AEMC, *Comprehensive reliability review*, Final report, December 2007, p. 85).

12 In March 2008, the administered price cap was $100 per MWh during peak periods and $50 per MWh at other times. The AEMC completed a review of the administered price cap on 21 May 2008 and determined that from 25 May 2008, the administered price cap would be $300 per MWh for all regions at all times.

13 AER, *Quarterly compliance report January–March 2008*, June 2008, p. 3.

14 AER, *Quarterly compliance report April–June 2008*, August 2008, pp. 3–4.

Figure 2.11
Number of trading intervals above $5000 per megawatt hour (annual)



Note: Trading intervals are of 30 minutes duration

Sources: NEMMCO; AER.

The AER's weekly reports on wholesale market activity highlight factors contributing to spot prices that are more than three times the volume-weighted average price for the week. The AER also publishes a report on every price event above $5000 per MWh.

The incidence of trading intervals with prices above $5000 per MWh has increased since the NEM commenced (see figure 2.11). The number of events more than doubled from 2004–05 to 2005–06 and continued to rise to 76 events in 2007–08. Figure 2.12 sets out the data on a quarterly basis since January 2005 and highlights some of the factors responsible for the price spikes. Figure 2.13 indicates that trading intervals with prices three times above the volume-weighted average for the week occur most frequently in summer and winter, when peak demand is highest.

Many factors can cause price spikes. While the cause of a high-price event is not always clear, underlying causes might include:

- high demand that requires the dispatch of high-cost peaking generators
- a generator outage that affects regional supply
- transmission network outages or congestion that restricts the flow of cheaper imports into a region
- a lack of effective competition in certain market conditions
- a combination of factors.

Table 2.4 summarises key features of extreme price events in 2007–08, noting the regions in which they occurred and indicating identified causes. In many instances, the table groups multiple events based on the AER's public reporting of these events in 2007–08.

The most common causes of high-price events identified by the AER in 2007–08 were:

- extreme weather
- network availability flow limits placed on particular transmission lines and interconnectors
- generator bidding behaviour.

On two occasions, errors by NEMMCO also contributed to high spot prices.

As noted, a combination of several factors contributed to high prices in South Australia during the March quarter of 2008. South Australian spot prices exceeded $5000 per MWh on 51 occasions and, on 17 March 2008, administered pricing was triggered (see section 2.5).

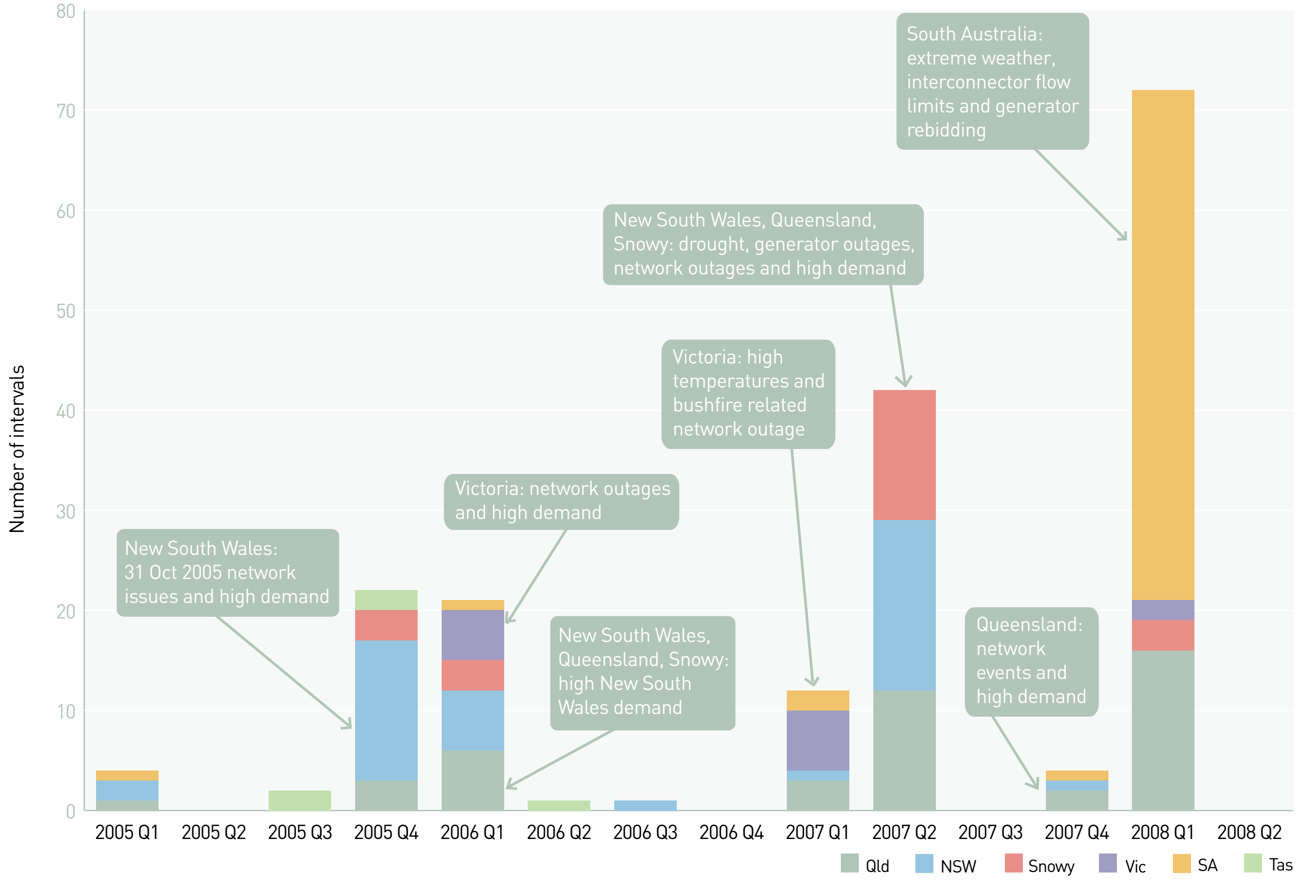
Price spikes can have a material impact on market outcomes. If prices approach $10 000 per MWh for just three hours in a year, the average annual price may rise by almost 10 per cent. Generators and retailers typically hedge against this risk by taking out contractual arrangements in financial markets (see chapter 3).

Extreme price events help to provide solutions to tight supply conditions. In particular, they create incentives to invest in peaking generation plant for operation during periods of peak demand.

Extreme price events may also create incentives for retailers to contract with customers to manage their demand in peak periods. This might involve a retailer

Figure 2.12

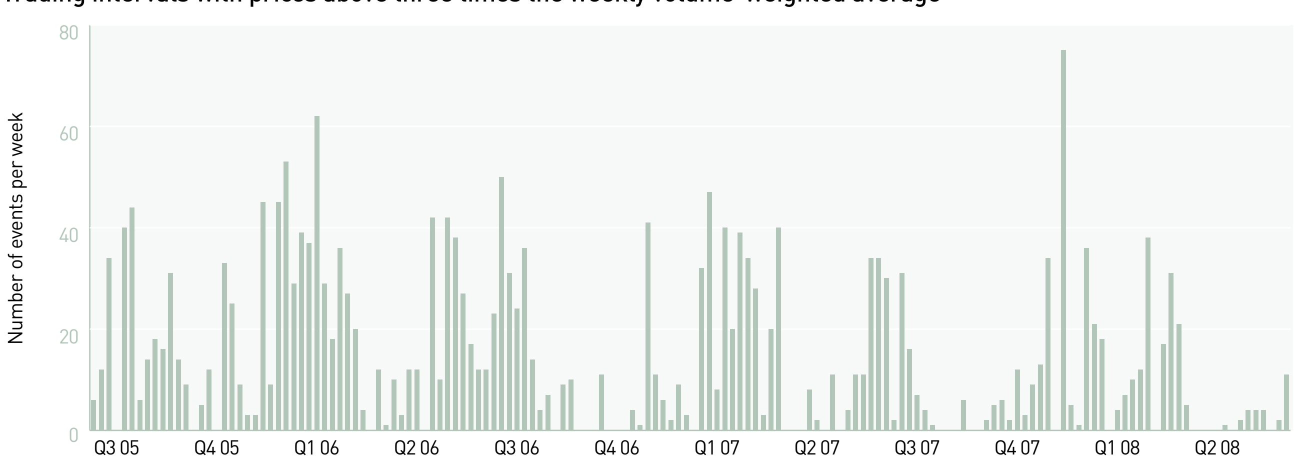
Number of trading intervals above $5000 per megawatt hour (quarterly)



Sources: NEMMCO; AER.

Figure 2.13

Trading intervals with prices above three times the weekly volume-weighted average



Sources: NEMMCO; AER.

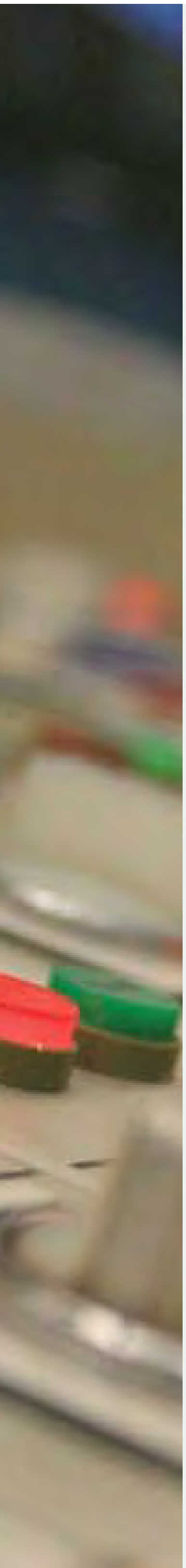
offering a customer financial incentives to reduce consumption at times of high system demand to ease price pressures. Effective demand management requires suitable metering arrangements to enable customers to manage their consumption. The Energy Reform Implementation Group noted in 2007 that demand management activity in the NEM was mainly confined to the large customer segment. It estimated that the extent of potential demand-side response in the NEM is around 700 MW across a range of energy-consuming industries.[15] At the small customer level, the Council of Australian Governments agreed in 2007 to a national implementation strategy for the progressive rollout of 'smart' electricity meters to encourage demand-side response (see section 6.6.4 of this report).

Table 2.4 **Price events above $5000 per megawatt hour in 2007–08**

DATE OR PERIOD	REGIONS	NUMBER OF EVENTS	CAUSES IDENTIFIED BY AER
17 March 2008	Victoria and Snowy	2	Extreme temperatures in Victoria and South Australia led to record high demand.
5 to 17 March 2008	South Australia	26	Extreme temperatures in Victoria and South Australia led to record high demand. AGL Energy's strategy of offering a significant proportion of generation capacity at prices above $5000 per MWh, and a limit placed on the flow of electricity on the interconnector between Victoria and South Australia, contributed to the high-price events.
22 to 23 February 2008	Queensland	14	High temperatures in Queensland led to high demand. Generator bidding—including a large proportion of capacity being priced at above $5000 per MWh and rebids by several generators—contributed to the high prices.
30 January 2008 and 7 February 2008	Queensland	2	On 30 January 2008, NEMMCO reclassified as credible the potential loss of two lines in Queensland due to lightning. This reduced the supply of generation from central and north Queensland to Brisbane. A number of generators close to Brisbane offered capacity at prices above $5000 per MWh. On 7 February 2008, lightning again led to the reclassification of the potential loss of a line. To manage the event, NEMMCO constrained off all generation in Queensland and limited flows from New South Wales. The constraints were inappropriate and caused the spot price to exceed $5000 per MWh.
26 January 2008	Snowy	1	A planned network outage in Victoria forced very large flows from Snowy to Victoria. The impact of this outage was not accurately predicted and the direction of flow between these regions was counter to normal spot price signals. Rebidding by Snowy Hydro to reallocate generation between its power stations contributed to the high-price events.
4 and 10 January 2008 and 18 and 19 February 2008	South Australia	25	Extreme temperatures in South Australia led to record high demand. AGL Energy's strategy of offering a significant proportion of generation capacity at prices above $5000 per MWh, and a limit placed on the flow of electricity on the interconnectors between Victoria and South Australia, contributed to the high-price events.
31 December 2007	South Australia	1	Extreme temperatures in South Australia led to near-record demand. A multiple unplanned network outage near Melbourne led to network constraints being invoked that forced electricity flows from Snowy and South Australia into Victoria. The forced exports from South Australia further tightened supply and raised prices in that region.
4 November 2007	Queensland	2	A planned network outage limited generation capacity in southwest Queensland. The outage, combined with rebidding by Stanwell power station and an unplanned outage at the Swanbank power station (unit E), caused high prices in Queensland.
22 October 2007	New South Wales	1	NEMMCO applied incorrect limits to manage the power system during a planned network outage in New South Wales. As a result, imports from Queensland into New South Wales and generation at several New South Wales power stations were significantly reduced.

Sources: AER, *Spot prices greater than $5000/MWh—New South Wales 22 October 2007*, 2007; AER, *Spot prices greater than $5000/MWh—Queensland 4 November 2007*, 2007; AER, *Spot prices greater than $5000/MWh—South Australia 31 December 2007*, 2008; AER, *Spot prices greater than $5000/MWh—South Australia 4 and 10 January and 18 and 19 February 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Snowy 26 January 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Queensland 30 January and 7 February 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Queensland 22 to 23 February 2008*, 2008; AER, *Spot prices greater than $5000/MWh—South Australia 15 to 17 March 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Victoria and Snowy 17 March 2008*, 2008.

15 Energy Reform Implementation Group, *Energy reform: The way forward for Australia—a report to the Council of Australian Governments*, 2007.



Box 2.2 International electricity prices

Wholesale electricity prices in Australia rose significantly during 2007 towards levels experienced in many overseas markets. However, over the longer term, electricity prices in Australia have been low relative to liberalised markets overseas. The principal reason is Australia's access to low-priced fuel such as brown and black coal.

Table 2.5 compares annual load-weighted average wholesale prices in the NEM with selected international markets on a calendar year basis. Comparisons across markets should be made with caution. Various factors can affect wholesale market outcomes, including:

- market design (for example, the use or absence of a capacity market)
- the stage of the investment cycle
- overcapacity that may be a legacy from previous regulatory regimes
- meteorological conditions
- fuel costs and availability
- exchange rates
- requirements under a carbon trading scheme
- regulatory intervention.

Prices in the Nord Pool (an electricity market linking Norway, Sweden, Finland and Denmark) increased significantly over the period from 1999 to 2006. Heavily reliant on hydroelectric power, prices in this region have a strong negative correlation with rainfall levels. The sharp price increase in 2006 resulted from a combination of factors, including increased load, rising fuel costs, low reservoir levels, unavailability of nuclear plants in Sweden and the introduction of a carbon trading scheme in Europe. In 2007, an increase in hydroelectric generation led to prices falling by almost 43 per cent.[16]

The Electric Reliability Council of Texas operates a wholesale market that supplies electricity to 75 per cent of Texas. Price fluctuations in this market—as in Canada's Alberta market—largely reflect changes in the cost of natural gas. The fall in average

Table 2.5 Average wholesale prices in selected markets ($A per megawatt hour)

	NEM				INTERNATIONAL				
YEAR	Qld	NSW	Vic	SA	Nord Pool (Scandinavia)	Alberta (Canada)	ERCOT (Texas)	NEMS (Singapore)	PJM (USA)
2007	72	76	70	65	46	75	67	73	74
2006	28	35	38	45	81	95	73	111	71
2005	27	41	28	37	48	76	95	86	83
2004	37	53	32	47	49	57	61	66	60
2003	24	30	25	29	64	69	68	82	64
2002	52	45	35	38	47	52	47	n/a	57
2001	37	36	40	52	40	92	n/a	n/a	71
2000	56	39	40	65	20	n/a	n/a	n/a	53
1999	46	24	24	60	22	n/a	n/a	n/a	53

n/a, not available.

Nord Pool, a market between Norway, Sweden, Finland and Denmark; ERCOT, Electric Reliability Council of Texas; NEMS, National Electricity Market of Singapore; PJM, Pennsylvania–New Jersey–Maryland Pool.

Notes:
1. Prices for Alberta are unweighted.
2. The PJM includes a capacity market.
3. Rounded annual volume-weighted price comparison based on calendar year data. Price conversions to Australian dollars based on average annual exchange rates.

Sources: Nord Pool; PJM; Electricity Market Company of Singapore; ERCOT; Alberta Electric System Operator.

16 Nord Pool Spot AS, *2007 Annual review*, 2008, p. 15.

prices in Alberta in 2007 was due to increased production from lower-cost generators.[17]

The Pennsylvania–New Jersey–Maryland pool (PJM) links generating facilities in 12 states in the USA. Coal is the major fuel source for electricity in the market (accounting for over 55 per cent of generation), with uranium (34 per cent) and gas (8 per cent) also being significant.[18] While PJM prices in 1999 were comparable to those in Queensland and South Australia, there was a significant increase in PJM prices to 2005. Average prices moved above $80 per MWh in 2005 following a 40 to 50 per cent increase in oil and gas costs.[19]

Unlike the NEM, the PJM operates a capacity market in conjunction with the energy market. Capacity markets provide an additional source of revenue for generators and so reduce revenue requirements in the energy market. Accordingly, spot prices in the PJM would likely be higher in the absence of a capacity market. Adjusting for this difference, table 2.5 may understate the price discount in the NEM compared to the PJM.

The National Electricity Market of Singapore (NEMS) commenced operating in January 2003. With close to 97 per cent of electricity generation fuelled by either oil or gas, prices in the NEMS have been substantially above those experienced in the NEM.[20] In 2007, average energy prices in the NEMS fell from 2006 levels, despite a 19 per cent increase in fuel oil prices. This may reflect greater competition from two new gas generators that became operational in April 2007.[21]

17 Alberta Electric System Operator, *2007 Annual report*, 2008, p. 22.

18 PJM Market Monitoring Unit, *2007 State of the market report*, 2008, p. 14.

19 PJM Market Monitoring Unit, *2005 State of the market report*, 2006.

20 Energy Market Company of Singapore, *2006 Market report to the National Electricity Market of Singapore*, 2007.

21 NEMS Market Surveillance and Compliance Panel, *Annual report 2007*, 2008, p. 10.

3 ELECTRICITY FINANCIAL MARKETS

Spot price volatility in the National Electricity Market can cause significant price risk to physical market participants. While generators face a risk of low prices impacting on earnings, retailers face a complementary risk that prices may rise to levels they cannot pass on to their customers. A common method by which market participants manage their exposure to price volatility is to enter into financial contracts that lock in firm prices for the electricity they intend to produce or buy in the future.

3 ELECTRICITY FINANCIAL MARKETS

This chapter considers:

> the structure of electricity financial markets in Australia, including over-the-counter markets and the exchange-traded market on the Sydney Futures Exchange
> financial market instruments traded in Australia
> liquidity indicators for Australia's electricity financial markets, including trading volumes, open interest, changes in the demand for particular instruments, changes in market structure and vertical integration in the underlying electricity wholesale market
> price outcomes on the Sydney Futures Exchange
> other mechanisms to manage price risk in the wholesale electricity market.

While the Australian Energy Regulator (AER) does not regulate the electricity derivatives markets, it monitors the markets because of their significant linkages with wholesale and retail activity. For example, levels of contracting and forward prices in the financial markets can affect generator bidding in the physical electricity market. Similarly, financial markets can influence retail competition by providing a means for new entrants to manage price risk. More generally, the markets create price signals for energy infrastructure investors and provide a means to secure the future earnings streams needed to underpin investment.

3.1 Financial market structure

Financial markets offer contractual instruments—called derivatives—to manage forward price risk in wholesale electricity markets.[1] While the derivatives provide a means of locking in future prices, they do not give rise to the physical delivery of electricity.

The participants in electricity derivatives markets include generators, retailers, financial intermediaries and speculators such as hedge funds. Brokers facilitate many transactions between contracting participants.

In Australia, two distinct electricity financial markets have emerged to support the wholesale electricity market:

> over-the-counter (OTC) markets, comprising direct transactions between two counterparties, often with the assistance of a broker

> the exchange-traded market on the Sydney Futures Exchange (SFE).

3.1.1 Over-the-counter markets

Over-the-counter markets allow market participants to enter into confidential contracts to manage risk. Many OTC contracts are bilateral arrangements between generators and retailers, which face opposing risks in the physical spot market. Other OTC contracts are arranged with the assistance of brokers that post bid (buy) and ask (sell) prices on behalf of their clients. In 2007–08, around 54 per cent of OTC contracts were arranged through a broker.[2] Financial intermediaries and speculators add market depth and liquidity by quoting bid and ask prices, taking trading positions and taking on market risk to facilitate transactions.

Most OTC transactions are documented under the International Swaps and Derivatives Association master agreement, which provides a template of standard terms and conditions, including terms of credit, default provisions and settlement arrangements. While the template creates considerable standardisation in OTC contracts, the terms are normally modified by market participants to suit their particular needs. This means that OTC products can provide flexible solutions through a variety of structures.

The *Financial Services Reform Act 2001* includes disclosure provisions that relate to OTC markets. In general, however, the bilateral nature of OTC markets tends to make volume and price activity less transparent than in the exchange-traded market.

3.1.2 Exchange-traded futures

Derivative products such as electricity futures and options are traded on registered exchanges. In Australia, electricity futures products developed by d-cyphaTrade are traded on the SFE.[3] Participants (licensed brokers) buy and sell contracts on behalf of clients that include generators, retailers, speculators such as hedge funds, and banks and other financial intermediaries.

There are a number of differences between OTC trading and exchange trading on the SFE:

> Exchange-traded derivatives are highly standardised in terms of contract size, minimum allowable price fluctuations, maturity dates and load profiles. The product range in OTC markets tends to be more diverse and includes 'sculpted' products.

> Exchange trades are multilateral and publicly reported, giving rise to greater market transparency and price discovery than in the OTC market.

1 Spot prices in the wholesale market can vary between –$1000 per megawatt hour (MWh) (the price floor) and $10 000 per MWh (the price cap). To manage risk resulting from volatility in the spot price, retailers can hedge their portfolios by purchasing financial derivatives that lock in firm prices for the volume of energy they expect to purchase in the future. This eliminates exposure to future price volatility for the quantity hedged and provides greater certainty on profits. Similarly, a generator can hedge against low spot prices.

2 AFMA, *2008 Australian Financial Markets Report*, 2008 and supporting 'Full report data' spreadsheet.

3 In 2006 the Sydney Futures Exchange merged with the Australian Stock Exchange. The merged company operates under the name Australian Securities Exchange.

- Unlike OTC transactions, exchange-traded derivatives are settled through a centralised clearing house, which is the central counterparty to transactions and applies daily *mark-to-market* cash margining to manage credit default risk.[4] Exchange clearing houses, such as the SFE Clearing Corporation, are regulated and are subject to prudential requirements to mitigate credit default risks. This offers an alternative to OTC trading, in which trading parties rely on the credit worthiness of electricity market counterparties. More generally, liquidity issues can arise in OTC markets if trading parties reach or breach their credit risk limits with other OTC counterparties (for example, due to revaluations of existing bilateral hedge obligations or credit downgrades of counterparties).

3.1.3 Regulatory framework

Electricity financial markets are subject to a regulatory framework that includes the *Corporations Act 2001* and the *Financial Services Reform Act 2001*. The Australian Securities and Investments Commission is the principal regulatory agency. Amendments to the Corporations Act in 2002 extended insider trading legislation and the disclosure principles expected from securities and equity-related futures to electricity derivative contracts. The Energy Reform Implementation Group (ERIG) noted in 2006 that there remains some uncertainty among market participants as to their disclosure requirements under the legislation.[5]

In 2004, the Australian Accounting Standards Board (AASB) issued new or revised standards to harmonise Australian standards with the International Financial Reporting Standards. The new standards included AASB 139, which requires companies' hedging arrangements to pass an effectiveness test to qualify for hedge accounting. The standards also outline financial reporting obligations such as mark-to-market valuation of derivative portfolios. The standards require benchmarking financial derivative revaluations to observable market prices and adjustment for embedded credit default risk.

There are a number of further regulatory overlays in electricity derivative markets. For example:

- the Corporations Act requires that OTC market participants have an Australian Financial Services licence or exemption
- exchange-based transactions are subject to the operating rules of the SFE.

3.1.4 Relationship with the National Electricity Market

Figure 3.1 illustrates the relationship between the financial markets and the physical trading of electricity in the National Electricity Market (NEM). Trading and settlement in the NEM occur independently of financial market activity, although a generator's exposure in the financial market can affect its bidding behaviour in the NEM. Similarly, a retailer's exposure to the financial market may affect the pricing and availability of supply contracts offered to customers.

3.2 Financial market instruments

The financial market instruments traded in the OTC and exchange-traded markets are called derivatives because they derive their value from an underlying asset—in this case, electricity traded in the NEM. The derivatives give rise to cash flows from the differences between the contract price of the derivative and the spot price of electricity. The prices of these instruments reflect the expected spot price, plus premiums to cover credit default risk and market risk.

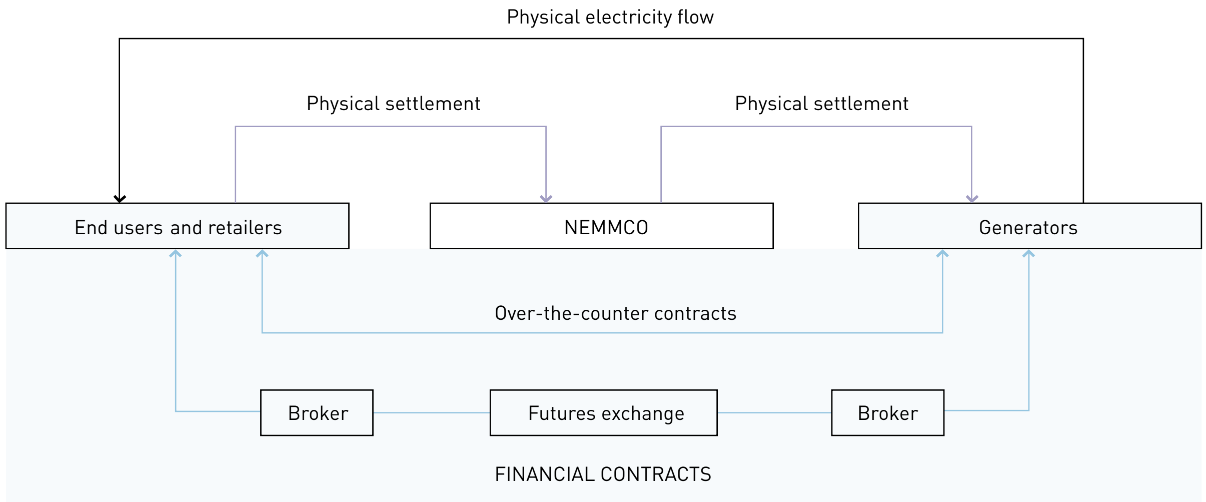
Table 3.1 lists some of the derivative instruments available in the OTC and exchange-traded markets. Common derivatives to hedge exposure to the NEM spot price are forwards (such as swaps and futures) and options (such as caps). Each provides the buyer and seller with a fixed price—and therefore a predictable future cash flow—either upon purchase/sale of the derivative or, in the case of an option, if the option is exercised. The following section describes some of the instruments in more detail.

4 Mark-to-market refers to the valuation technique whereby unrealised profit or loss associated with a derivative position is determined (and reported in financial statements) by reference to prevailing market prices.

5 ERIG, Discussion papers, November 2006.

Figure 3.1

Relationship between the National Electricity Market and financial markets



NEMMCO, National Electricity Market Management Company.

Source: Energy Reform Implementation Group.

Table 3.1 Common electricity derivatives in over-the-counter and Sydney Futures Exchange markets

INSTRUMENT	DESCRIPTION
Forward contracts	Agreement to exchange the NEM spot price in the future for an agreed fixed price. Forwards are called swaps in the OTC markets and futures on the SFE.
> swaps (OTC market)	OTC swap settlements are typically paid or received weekly in arrears (after the spot price is known) based on the difference between the spot price and the previously agreed fixed price.
> futures (SFE)	SFE electricity futures and options settlements are paid or received daily based on mark-to-market valuations. SFE futures are finally cash settled against the average spot price of the relevant quarter.
Options	A right—without obligation—to enter into a transaction at an agreed price in the future (exercisable option) or a right to receive cash flow differences between an agreed price and a floating price (cash settled option).
> cap	A contract through which the buyer earns payments when the pool price exceeds an agreed price. Caps are typically purchased by retailers to place a ceiling on their effective pool purchase price in the future.
> floor	A contract through which the buyer earns payments when the pool price is less than an agreed price. Floors are typically purchased by generators to ensure a minimum effective pool sale price in the future.
> swaptions or futures options	An option to enter into a swap or futures contract at an agreed price and time in the future.
> Asian options	An option in which the payoff is linked to the average value of an underlying benchmark (usually the NEM spot price) during a defined period.
> profiled volume options for sculpted loads	A volumetric option that gives the holder the right to purchase a flexible volume in the future at a fixed price.

NEM, National Electricity Market; OTC, over-the-counter; SFE, Sydney Futures Exchange.

3.2.1 Forward contracts

Forward contracts—called swaps in the OTC market and futures on the SFE—allow a party to buy or sell a given quantity of electricity at a fixed price over a specified time horizon in the future. Each contract relates to a nominated time of day in a particular region. On the SFE, contracts are quoted for quarterly base and peak contracts, for up to four years into the future.[6]

For example, a retailer might enter into an OTC contract to buy 10 megawatts of Victorian peak load in the third quarter of 2007 at $45 per megawatt hour (MWh). During that quarter, whenever the Victorian spot price for any interval from 7.00 am to 10.00 pm Monday to Friday settles above $45 per MWh, the seller (which might be a generator or financial intermediary) pays the difference to the retailer. Conversely, the retailer pays the difference to the seller when the price settles below $45 per MWh. In effect, the contract locks in a price of $45 per MWh for both parties.

A typical OTC swap might involve a retailer and generator contracting with one another—directly or through a broker—to exchange the NEM spot price for a fixed price that reduces market risk for both parties. On the exchange-traded market, the parties (generators, retailers, financial intermediaries and speculators) that buy and sell futures contracts through SFE brokers remain anonymous. The SFE Clearing Corporation is the central counterparty to SFE transactions. As noted, exchange trading is more transparent in terms of prices and trading volumes. While the SFE tends to offer a narrower range of instruments than the OTC market,[7] there are up to 3000 futures and options products listed on the SFE at any given time.

3.2.2 Options

While a swap or futures contract gives price certainty, it locks the parties into defined contract prices with defined volumes—without an opt-out provision if the underlying market moves adversely to the agreed contract price. An option gives the holder the right—without obligation—to enter into a contract at an agreed price, volume and term in the future. The buyer pays a premium to the option seller for this added flexibility.

An exercisable call (put) option gives the holder the right to buy (sell) a specified volume of electricity futures (or swaps) in the future at a predetermined strike price—either at any time up to the option's expiry (an 'American' option) or at expiry (a 'European' option). For example, a retailer that buys a call option to protect against a rise in NEM forward contract prices can later abandon that option if forward prices do not rise as predicted. The retailer could then take advantage of the lower prevailing forward (or NEM spot) price.

Commonly traded options in the electricity market are caps, floors and collars.[8] A cap allows the buyer—for example, a retailer with a natural *short* exposure to spot prices—to set an upper limit on the price that they will pay for electricity while still being able to benefit if NEM prices are lower than anticipated. For example, a cap at $300 per MWh—the cap most commonly traded in Australia—ensures that no matter how high the spot price may rise, a buyer using the cap to hedge a natural short retail spot market position will pay no more than $300 per MWh for the agreed volume of electricity. In Australia, a cap is typically sold for a nominated quarter; for example, July–September 2008. Base cap contracts are listed out two years ahead on a quarterly basis on the SFE and regularly trade in full year strips of quarters.

6 A peak contract relates to the hours from 7.00 am to 10.00 pm Monday to Friday, excluding public holidays. An off-peak contract relates to hours outside that period. A flat price contract covers both peak and off-peak periods.

7 The OTC market can theoretically support an unlimited range of bilaterally negotiated product types.

8 While caps and floors are technically options—they are effectively a series of half-hourly options—they are typically linked to the NEM spot price and are automatically exercised when they deliver a favourable outcome. Other options, such as swaptions, are generally linked to forward prices and the buyer must nominate whether or not the option is to be exercised.

By contrast, a floor contract struck at $40 per MWh will ensure a minimum price of $40 per MWh for a floor buyer such as a generator with a natural *long* exposure to spot prices. Retailers typically buy caps to secure firm maximum prices for future electricity purchases, while generators use floors to lock in a minimum price to cover future generation output. A collar contract combines a cap and floor to set a price band in which the parties agree to trade electricity in the future.

The range and diversity of products is expanding over time to meet the requirements of market participants.

3.2.3 Flexible volume instruments

Instruments such as swaps and options are used to manage NEM price risk for fixed quantities of electricity. But the profile of electricity loads varies according to the time of day and the weather conditions. This can result in significant volume risk in addition to price risk. In particular, it can leave a retailer over-hedged or under-hedged, depending on actual levels of electricity demand. Conversely, windfall gains can also be earned.

Structured products such as flexible volume contracts are used to manage volume risks. These sculpted products, which are traded in the OTC market, enable the buyer to vary the contracted volume on a pre-arranged basis. The buyer pays a premium for this added flexibility.

3.3 Financial market liquidity

The effectiveness of financial markets in providing risk management services depends on the extent to which they offer the products that market participants require. Adequate market liquidity is critical in this regard. In electricity financial markets, liquidity relates to the ability of participants to transact a standard order within a reasonable timeframe to manage their load and price risk, using reliable quoted prices that are resilient to large orders, and with sufficient market participants and trading volumes to ensure low transaction costs.

There are various indicators of liquidity in the electricity derivatives market, including:

- the volume and value of trade
- open interest in contracts
- transparency of pricing
- the number and diversity of market participants
- the number of market makers and the bid–ask spreads quoted by them
- the number and popularity of products traded
- the degree of vertical integration between generators and retailers
- the presence in the market of financial intermediaries.

This chapter focuses mainly on liquidity indicators relating to trading volumes, but also includes some consideration of open interest data, pricing transparency, changes in the demand for particular derivative products, changes in the financial market's structure and vertical integration.

Table 3.2 Trading volumes in electricity derivatives—Sydney Futures Exchange

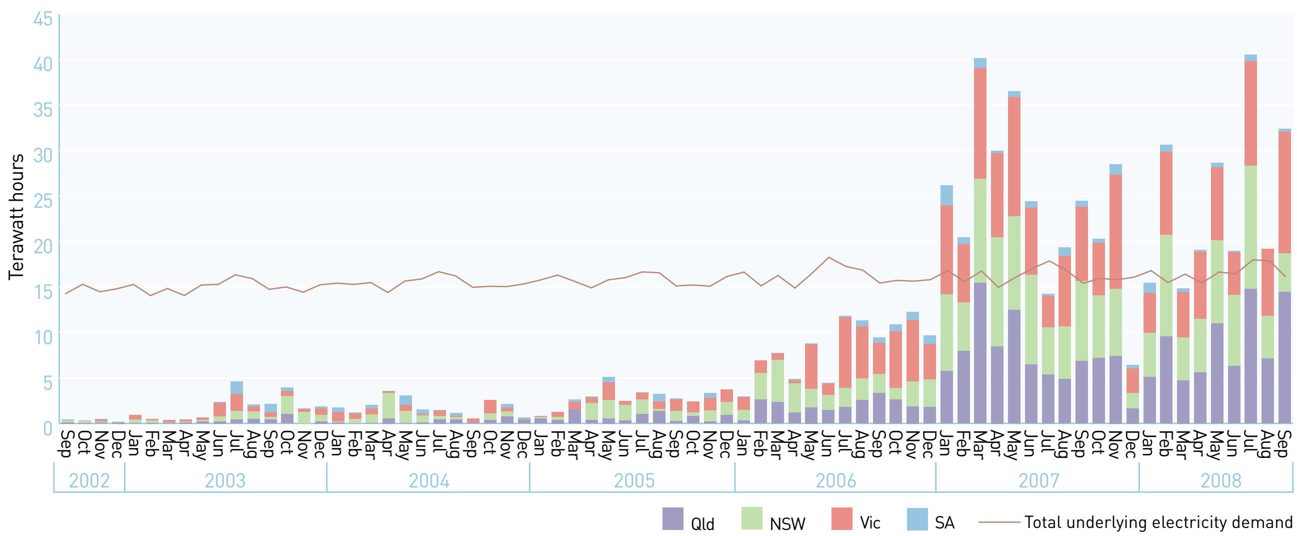
	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08
Total trade (TWh)	7	30	24	55	243	241
Increase (per cent)		341	-19	129	345	-1

TWh, terawatt hours.

Source: d-cyphaTrade.

Figure 3.2

Regional trading volumes in electricity derivatives—Sydney Futures Exchange



Source: d-cyphaTrade.

3.4 Trading volumes in Australia's electricity derivative market

There is comprehensive data on derivative trading on the SFE, which is updated on a daily and real-time basis. The OTC market is less transparent, but periodic survey data provide some indicators of trading activity.

3.4.1 Sydney Futures Exchange

Financial market vendors such as d-cyphaTrade publish data on electricity derivative trading on the SFE. Table 3.2 and figure 3.2 illustrate volume trends. Trading levels accelerated from 2005–06, with 345 per cent growth in 2006–07. In that year, volumes were equivalent to around 124 per cent of underlying NEM demand. Trade in 2007–08 was down on the high levels seen in the first half of 2007, resulting in a slight decrease in overall volumes. There are early indications of a continuation of high trading volumes in 2008–09.

In 2007–08, Victoria accounted for 38 per cent of traded volumes, followed by New South Wales and Queensland (29 per cent each). Liquidity in South Australia has remained low since 2002, accounting for around 4 per cent of volumes (figure 3.3).

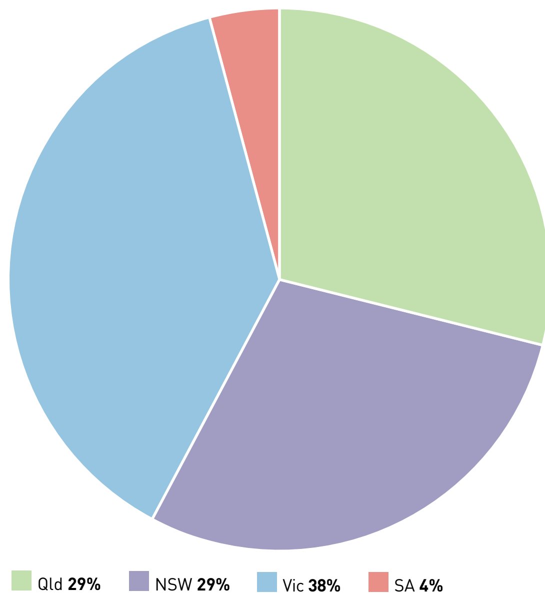
Trading on the SFE comprises a mix of futures (first listed in September 2002) and caps and other options (first listed in November 2004). Trading in options represented around 16 per cent of traded volumes in 2007–08[9] but grew exponentially in the first quarter of 2008–09, reaching 51 per cent of volumes.[10] Figure 3.4 shows that trading volumes for 2010 options

9 d-cyphaTrade, *Energy focus FY review 2007/2008*, 2008.

10 From 1 July 2008 to 12 September 2008.

Figure 3.3

Regional shares of Sydney Futures Exchange electricity derivatives trade (by volume), 2007–08



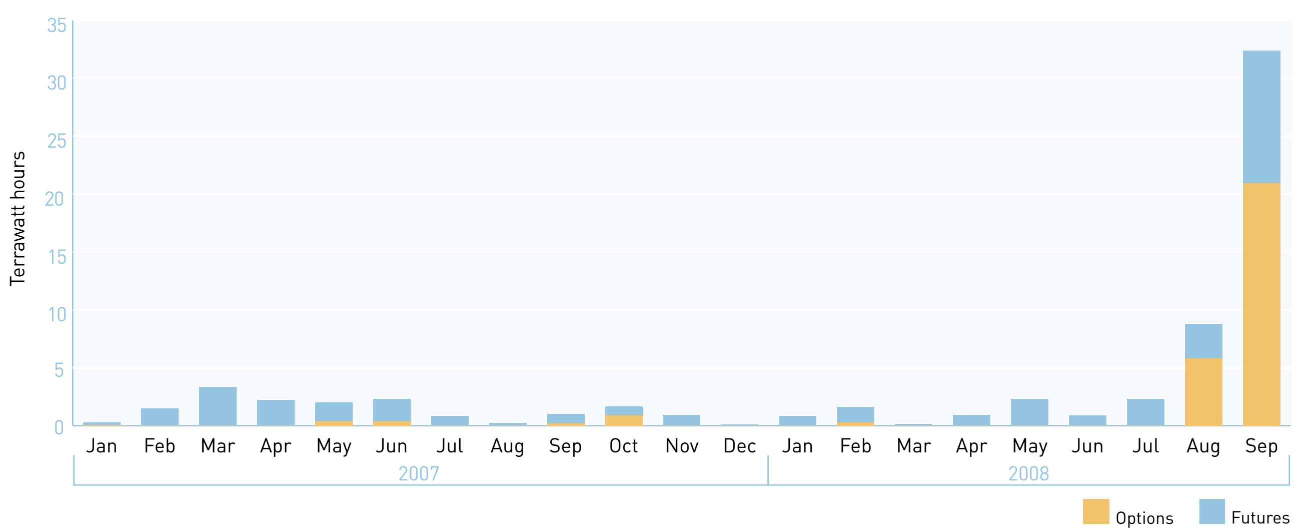
Source: d-cyphaTrade.

recorded a step increase from around August 2008, with the bulk of activity in options. This may reflect increased hedging activity associated with the planned introduction of the Carbon Pollution Reduction Scheme in 2010.

Figure 3.5 shows the composition of futures and options trade on the SFE by maturity date, based on traded volumes. The SFE trades quarterly futures and options out to four years ahead, compared to three years in many overseas markets.[11] Liquidity is highest for contracts with an end date between six months and two years out from the trade date. There are only a relatively small number of open contracts with an end date beyond 18 months. This is consistent with the trading preferences of speculators and the time horizons of electricity retail contracts, the majority of which are negotiated for one year and which rarely run beyond three years. Some retailers do not lock in forward hedges beyond the term of existing customer contracts.

Figure 3.4

Traded volumes for 2010 contracts—Sydney Futures Exchange

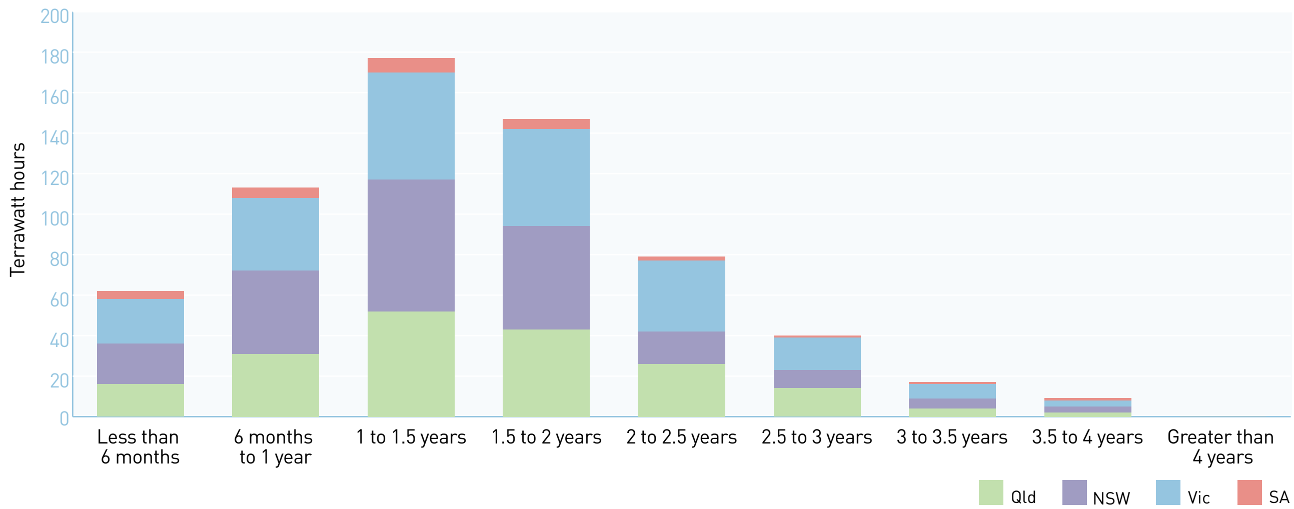


Source: d-cyphaTrade.

11 See, for example, http://www.eex.de (Germany) or http://www.powernext.fr (France).

Figure 3.5

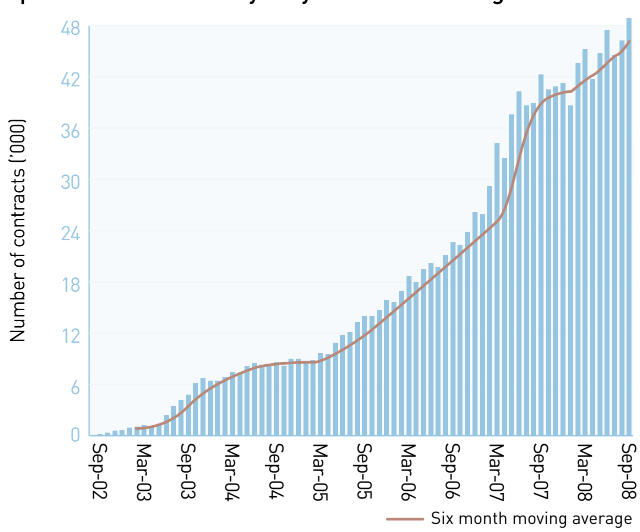
Traded volume in electricity futures contracts (by maturity date) on the Sydney Futures Exchange, September 2002 to August 2008



Source: d-cyphaTrade.

Figure 3.6

Open interest on the Sydney Futures Exchange



Source: d-cyphaTrade.

Figure 3.6 illustrates open interest in electricity futures on the SFE over time. Open interest refers to the total number of futures and option contracts that have been entered into and remain open—that is, have not been exercised, expired or closed out—at a point in time. An increase in open interest typically accompanies a rise in trading volumes and reflects underlying demand growth. As figure 3.6 illustrates, the SFE electricity futures market has experienced a steady increase in open interest since 2002. The number of open contracts rose from around zero in 2002 to over 48 000 in September 2008. It is interesting to note that although total trading volumes in 2007–08 were similar to the previous year, the level of open interest continued to rise.

3.4.2 Over-the-counter markets

There is limited data on liquidity in the OTC markets because transactions are only visible to the parties engaged in trade. The Australian Financial Markets Association (AFMA) conducts an annual survey of OTC market participants on direct bilateral and broker-assisted trade. AFMA reports that most, but not all, participants respond to the survey. A particular OTC transaction will be captured in the AFMA data if at least one party to the trade participates in the survey.

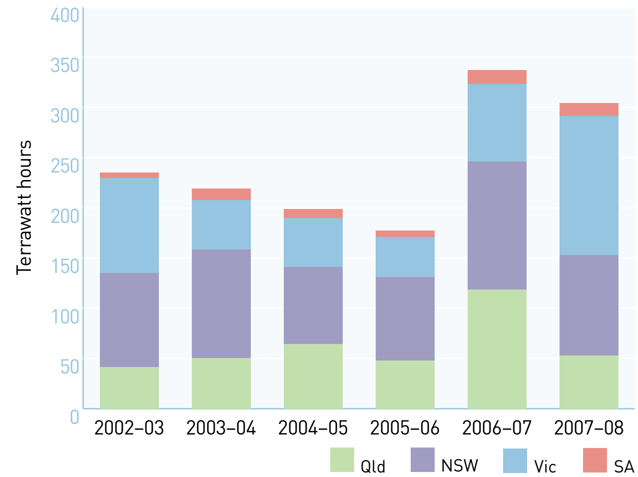
As figure 3.7 indicates, total OTC trades declined from around 235 terawatt hours (TWh) in 2002–03 to around 177 TWh in 2005–06. This trend was reversed in 2006–07, with turnover increasing by more than 90 per cent to around 337 TWh. Volumes remained above 300 TWh in 2007–08. This was consistent with significantly higher trading volumes on the SFE over the past two years.

On a regional basis, trading volumes more than doubled in 2006–07 in Queensland and South Australia. Turnover rose by around 90 per cent in Victoria and 50 per cent in New South Wales. In 2007–08, turnover continued to rise in Victoria, accounting for around 45 per cent of trade across all regions. Volumes fell in all other regions, with Queensland recording the largest fall (down 55 per cent). However, volumes in all regions remained above 2005–06 levels.

Around 67 per cent of OTC trade in 2007–08 was in swaps and around 20 per cent was in caps. Swaptions and options made up the balance (see figure 3.8).

Figure 3.7

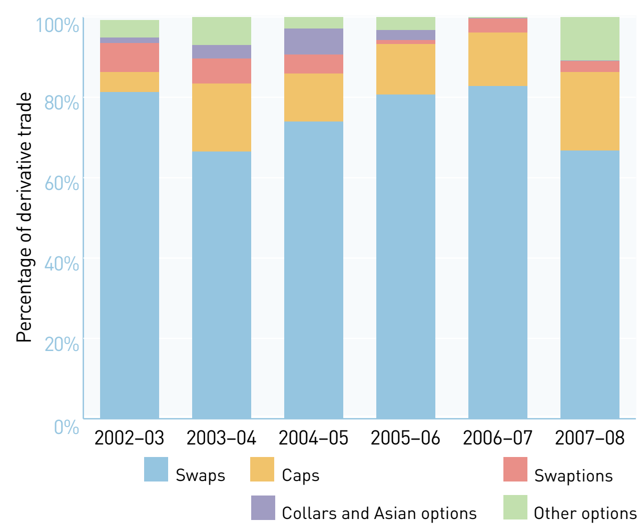
Regional trading volumes—over-the-counter market



Source: AFMA, *2008 Australian Financial Markets Report*, 2008.

Figure 3.8

Trading volumes by derivative type —over-the-counter market



Source: AFMA, *2008 Australian Financial Markets Report*, 2008.

Table 3.3 **Volumes traded in over-the-counter markets and the Sydney Futures Exchange**

	OTC (TWh)	OTC (% OF NEM DEMAND)	SFE (TWh)	SFE (% OF NEM DEMAND)	TOTAL (% OF NEM DEMAND)
2001–02	168	96	0	0	96
2002–03	235	131	7	4	135
2003–04	219	118	29	16	134
2004–05	199	106	24	13	118
2005–06	177	92	55	28	120
2006–07	337	172	243	124	296
2007–08	304	156	241	123	279

OTC, over-the-counter; SFE, Sydney Futures Exchange; NEM, National Electricity Market.; TWh, terawatt hour

Note: NEM demand excludes Tasmania, for which derivative products were not available.

Sources: d-cyphaTrade; AFMA; NEMMCO.

3.4.3 Aggregate trading volumes

Table 3.3 estimates aggregate volumes of electricity derivatives traded in OTC markets and on the SFE, and compares these volumes to underlying demand for electricity in the NEM. The data are a simple aggregation of AFMA data on OTC volumes and d-cyphaTrade data on exchange trades. The results should be interpreted with some caution, given that the AFMA data are based on a voluntary survey and are not subject to independent verification. This could result in the omission of transactions between survey non-participants. AFMA considers that the survey captures most OTC activity.

It should be noted that derivative trading volumes can exceed 100 per cent of NEM demand, as some financial market participants take positions independent of physical market volumes and regularly readjust their contracted positions over time.

Based on the available data, the majority of financial trades continue to occur in the OTC markets. However, OTC trading is declining relative to trading on the SFE. The share of derivative trades occurring in OTC markets declined from 97 per cent in 2001–02 to 56 per cent in 2007–08.

As table 3.3 indicates, OTC trades in 2007–08 were equivalent to 156 per cent of NEM demand, compared to a record 172 per cent in the previous year. Volumes on the SFE rose from near zero in 2001–02 to levels equivalent to over 120 per cent of NEM demand in 2006–07 and 2007–08. Across the combined OTC and exchange markets, trading volumes in 2007–08 were almost 280 per cent of NEM demand.

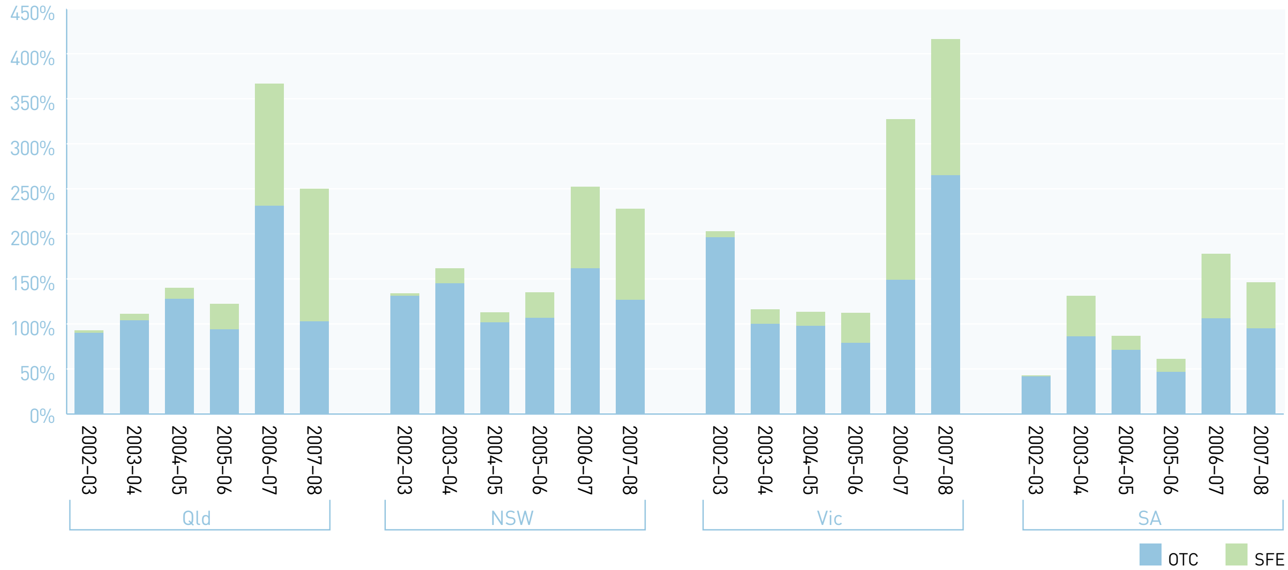
There are a number of reasons for the relatively strong growth in exchange-traded volumes. Amendments to the *Corporations Act 2001* and the introduction of international hedge accounting standards to strengthen disclosure obligations for electricity derivatives contracts may have raised confidence in exchange-based trading. In addition, d-cyphaTrade, in conjunction with the SFE, redesigned the product offerings in 2002 to tailor them more closely to market requirements. These changes have encouraged greater depth in the market, including the entry of numerous financial intermediaries.

The increase in trading volumes on the SFE has also been driven by trading parties seeking to minimise mark-to-market OTC credit exposures. A PricewaterhouseCoopers (PwC) survey of market participants also cited anonymity and credit benefits as being among the reasons for the shift away from OTC markets towards exchange trading.[12]

12 PwC, *Independent survey of contract market liquidity in the National Electricity Market*, 2006, p. 21.

Figure 3.9

Trading volumes by region as a percentage of regional National Electricity Market demand



OTC, over-the-counter; SFE, Sydney Futures Exchange.

Sources: d-cyphaTrade; AFMA; NEMMCO.

Figure 3.9 charts regional trading volumes in both the OTC and SFE sectors as a percentage of regional NEM demand. Trading volumes were generally equivalent to around 100 to 150 per cent of regional NEM demand in Queensland, New South Wales and Victoria from 2002–03 to 2005–06. Volumes rose sharply in 2006–07 to 370 per cent of NEM demand in Queensland, 330 per cent in Victoria and 250 per cent in New South Wales. South Australian volumes rose to around 180 per cent of regional NEM demand, reversing a trend of declining volumes over the three preceding years. In 2007–08, only Victoria experienced growth in trading volumes relative to regional NEM demand, reaching over 415 per cent. Volumes fell sharply in Queensland, but remained significantly above 2005–06 levels.

The composition of Queensland trade is also changing. In 2007–08, Queensland was the only region in which SFE trading volumes exceeded OTC volumes. Queensland's SFE trades accounted for almost 60 per cent of regional trading volumes. In other regions, SFE trade accounted for between 35 and 45 per cent of trading volumes.

The PwC survey of market participants raised a number of possible reasons for a lack of liquidity in South Australia's financial markets. Factors cited included the relatively small scale of the South Australian electricity market; perceptions of risk associated with network interconnection, generation capacity and extreme weather; and perceptions of high levels of vertical integration.[13] ERIG also noted gaps in the liquidity and depth of financial markets in South Australia as well as for Tasmania, which was not physically connected to the NEM until 2006. More generally, there are gaps in the market for sculpted and flexible products, which are mainly traded in the OTC market.[14]

13 PwC, *Independent survey of contract market liquidity in the National Electricity Market*, 2006, p. 28.

14 ERIG, Discussion papers, November 2006, p. 194.

3.5 Price transparency and bid–ask spread

While trading volumes and open interest provide indicators of market depth, part of the cost to market participants of transacting is reflected in the bid–ask spread (the difference between the best buy and best sell prices) quoted by market makers and brokers. A liquid market is characterised by relatively low price spreads that allow parties to transact at a nominal cost.

d-cyphaTrade and other market data providers publish bid–ask spreads for the exchange-traded market. In 2007–08, most spreads for base futures products were less than $3. Spreads are generally higher in the market for peak futures, which tends to be less liquid than the market for base futures.

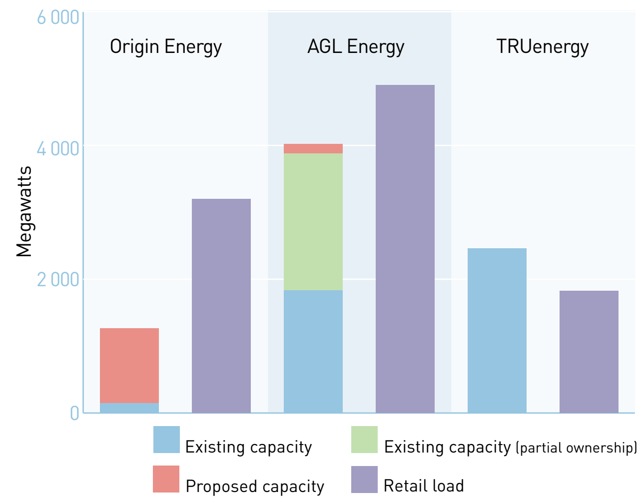
3.6 Number of market participants

Ownership consolidation, such as vertical integration across the generation and retailer sectors, can affect participation in financial markets. In particular, vertical integration can reduce a company's activity in financial markets by increasing its capacity to internally offset risk.

Figure 3.10 displays rough estimates of the current match of generation and retail load for Origin Energy, AGL Energy and TRUenergy across the Victorian and South Australian markets. All three businesses are moving over time towards more balanced portfolios between generation and retail assets. In 2007, AGL Energy acquired the 1260 megawatt (MW) Torrens Island power station in South Australia from TRUenergy in exchange for the Hallett power station (150 MW) and a cash sum. While Origin Energy's retail load exceeds its generation capacity by a significant margin, it committed in 2008 to a 550 MW power station near Mortlake in Victoria to be commissioned in the summer of 2010–11. In addition, the major generator International Power operates a retail business in Victoria and South Australia (trading as Simply Energy) and has achieved significant market penetration.

15 ERIG, Discussion papers, November 2006, pp. 195–6.

Figure 3.10
Generator capacity and retail load of vertically integrated players in Victoria and South Australia, 2007–08



Note: Average retail loads are PwC estimates for 2005–06 based on the estimated market share of each retailer as a proportion of NEM demand. Market share has been estimated from annual reports. AGL Energy's existing capacity (partial ownership) includes its 32.5 per cent share in the GEAC Group (owner of the Loy Yang A generator in Victoria). TRUenergy's existing capacity includes its contractual arrangement for Ecogen Energy capacity in Victoria (around 890 megawatts). This chart is not intended to be an accurate reflection of participants' positions, but rather provides an estimate of the possible degree of vertical integration.

Sources: PwC, *Independent survey of contract market liquidity in the National Electricity Market*, August 2006 (retail loads); NEMMCO and company websites (capacity and proposed capacity).

The United Kingdom market has significant vertical integration—six vertically-integrated firms dominate the market—and low levels of financial market liquidity. ERIG considered that if the Australian market were to evolve to a handful of balanced participants, little financial trade would be expected.[15]

While integration may have reduced the number of generators and retailers in Australia's financial markets, there has been new entry by financial intermediaries. Financial speculators that have entered the market include BP Energy Asia, ANZ, Optiver, Attunga Capital, Commonwealth Bank, Arcadia Energy, DE Shaw and Co, Electrade Derivatives, IMC Pacific, Liquid Capital, Societe General, Tibra Capital and Westpac. Other market participants remain anonymous. ERIG considered that the increasing

Figure 3.11
National Power Index 2007–2009

Source: d-cyphaTrade.

involvement of financial intermediaries is evidence of a dynamic market.

3.7 Price outcomes

Base futures account for most SFE trading volumes and open interest positions. Accordingly, the following discussion of price outcomes focuses on base futures. Prices for peak futures tend to be higher than for base futures, but follow broadly similar trends.[16]

Figure 3.11 shows average price outcomes for electricity base futures, as reflected in the National Power Index (NPI). The index is published for each calendar year and represents a basket of the electricity base futures listed on the SFE for New South Wales, Victoria, Queensland and South Australia. It is calculated as the average daily settlement price of base futures contracts across the four regions for the four quarters of the relevant calendar year. NPI data are available from June 2006 and are published daily by d-cyphaTrade.

Figure 3.11 shows that base futures prices were fairly flat throughout 2006, trading between $35 and $40 per MWh, before rising sharply in the first half of 2007. Prices for the 2007 calendar year basket peaked in June 2007 at close to $100 per MWh. This mirrored high prices in the physical electricity market, caused by tight supply–demand conditions (see section 2.5). Futures prices rose more sharply for the 2007 and 2008 calendar years than for later years. This may have reflected expectations that the tight supply–demand conditions at that time were of a relatively short-term nature.

A return to more benign conditions in the physical electricity market led to falling prices for base futures in the second half of 2007 and early 2008. The 2008 and 2009 calendar year base futures prices converged below $50 per MWh in summer 2008, but edged back towards $55 to $60 per MWh in winter 2008.

In general, contract markets often trade at a premium to the physical spot market for an underlying commodity. On average, base futures prices on the SFE have reflected a fairly constant premium over NEM spot prices of around $2 per MWh over the past three years.[17]

16 Base futures cover the hours from 0.00 to 24.00 hours, seven days per week. Peak futures relate to the hours from 7.00 am to 10.00 pm Monday to Friday, excluding public holidays.

17 Based on a comparison of time-weighted calendar year wholesale market spot prices to the average NPI value for each calendar year.

3.7.1 Future forward prices

Figure 3.12 provides a snapshot in September 2008 of forward prices for quarterly base futures on the SFE for quarters up to two years out from the trading date. These are often described as forward curves. The first four quarters of a forward curve are the prompt quarters. For comparative purposes, forward prices in June 2007—when electricity prices reached record levels in Queensland, New South Wales and Victoria—are also provided.

In September 2008, prices for the prompt quarters were generally down on the levels seen in 2007. This may reflect lower than expected wholesale market prices over summer 2007–08, new generation capacity coming on-line and the availability of previously drought-affected generators. The exception was South Australia, where futures prices were higher in 2008 than in 2007. This may indicate market concerns that high prices in South Australia's physical electricity market in early 2008—as a result of high temperatures, interconnector constraints and opportunistic bidding by generators—may recur in 2009.

Figure 3.12 also illustrates that first quarter (Q1, January to March) futures prices tend to be higher than for other quarters. This reflects the tendency for NEM spot prices to peak in summer and illustrates the linkages between derivative prices and underlying NEM wholesale prices. Box 3.1 provides a case study on the pricing of Q1 base and peak future contracts in Queensland over the past three years. Price movements in New South Wales and Victoria have followed broadly similar trends to Queensland.

While futures contracts typically relate to a specific quarter of a year, there is an increasing tendency for contracts to be traded as calendar year strips, comprising a 'bundle' of the four constituent quarters of the year. This tendency is more pronounced for contracts with a starting data at least one year out from the trade date. Figure 3.13 charts prices in September 2008 for calendar year futures strips to 2011. In September 2008, New South Wales, Queensland and Victoria had forward curves in strong contango—that is, prices are higher for contracts in the later years. This is indicative of market expectations that price risk may be greater in the medium to longer term, perhaps because

Figure 3.12
Base futures prices at September 2008

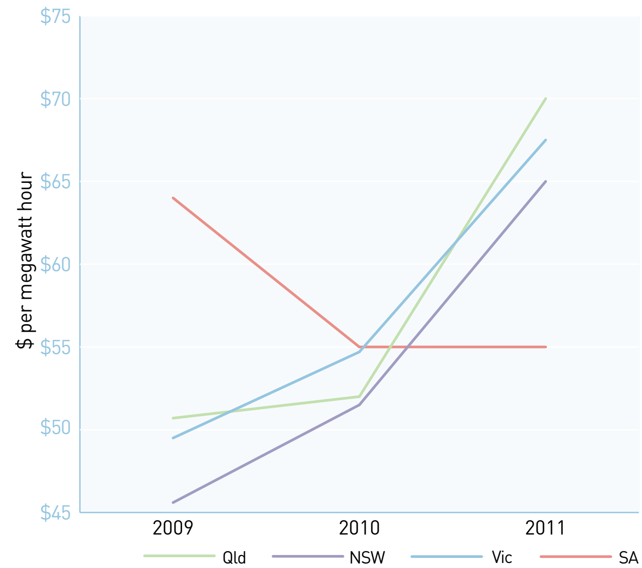
Source: d-cyphaTrade.

of concerns about the adequacy of supply and the anticipated effect of the Carbon Pollution Reduction Scheme on pool prices from 2010.

In September 2008, South Australian contracts were mostly trading flat or in backwardation—that is, prices for the nearest year (2009) were higher than for the later years. As noted, this may reflect expectations that the conditions that gave rise to record South Australian NEM prices in March 2008 may still be present in 2009, but are less likely to affect prices further into the future. Additionally, lower liquidity in South Australian contracts may result in less robust pricing in longer dated contracts.

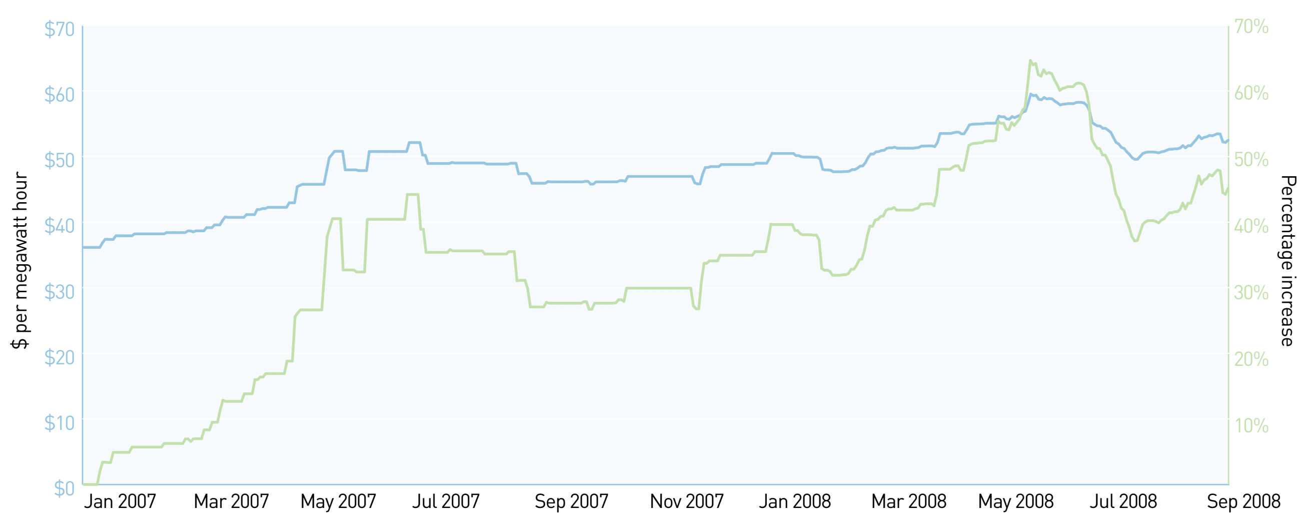
The d-cypha Eastern Power Index provides an indication of average forward prices for calendar year strips across New South Wales, Victoria and Queensland (figure 3.14). In September 2008, the Eastern Power Index for calendar year 2010 shows a trend of steadily rising prices from January 2007, increasing 45 per cent to September 2008. This is consistent with the market's anticipation that high carbon-emitting generators will face increased generation costs due to the Carbon Pollution Reduction Scheme and will attempt to recover those costs via higher pool price dispatch from July 2010 onwards.

Figure 3.13
Base calendar strip at September 2008

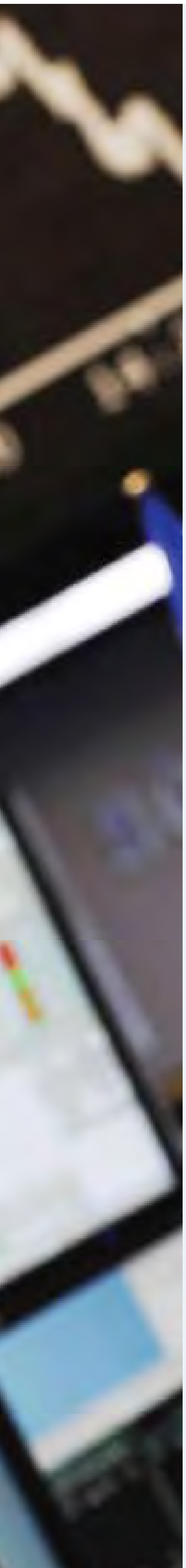


Source: d-cyphaTrade.

Figure 3.14
Eastern Power Index for 2010 contracts



Source: d-cyphaTrade.



Box 3.1 Case study—Queensland first quarter futures prices

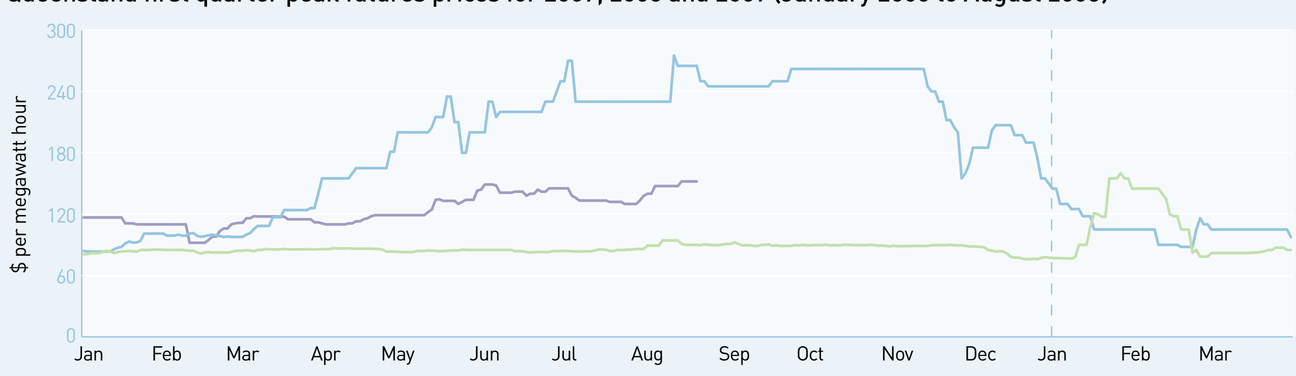
The electricity supply–demand balance in most regions is tightest in summer, with hot days leading to high demand for air conditioning. Accordingly, Q1 futures prices are higher than those for other quarters. Over the 18 months to August 2008, Q1 futures prices were especially volatile in Queensland. Figures 3.15 and 3.16 chart movements in the price of Queensland Q1 base and peak futures in 2007, 2008 and 2009, as measured in the preceding year.

- Q1 2007 prices were relatively stable throughout 2006, averaging around $50 per MWh for base futures and $85 per MWh for peak futures.
- Prices for Q1 2008 started to rise from March 2007. Between June and November 2007, base futures averaged $125 per MWh and peak futures averaged $240 per MWh. These prices reflected market concern over the availability of generation capacity (due to the drought) and the impact of congestion in the Queensland transmission network. Information available closer to Q1 2008 indicated that constraints would not be as great as expected and prices closed out at about $70 for base futures and $100 for peak futures.
- Prices in 2008 for Q1 2009 futures are below the equivalent prices in 2007 but remain well above historic levels. In August 2008, base futures prices were about $85 and peak futures prices were around $150.

Figure 3.15
Queensland first quarter base futures prices for 2007, 2008 and 2009 (January 2006 to August 2008)

Source: d-cyphaTrade.

Figure 3.16
Queensland first quarter peak futures prices for 2007, 2008 and 2009 (January 2006 to August 2008)



Source: d-cyphaTrade.

3.8 Price risk management —other mechanisms

Aside from financial contracts, there are other mechanisms to manage price risk in electricity wholesale markets. As noted, some retailers and generators have reduced their exposure to NEM spot prices through vertical integration. In addition:

- In New South Wales, the Electricity Tariff Equalisation Fund (ETEF) provides a buffer against prices spikes in the NEM for government-owned retailers that are required to sell electricity to end users at regulated prices. When spot prices are higher than the energy component of regulated retail prices, ETEF pays retailers from the fund. Conversely, retailers pay into ETEF when spot prices are below the regulated tariff. The New South Wales Government has announced that it will phase out ETEF by June 2010.
- Auctions of settlement residues allow for some financial risk management in inter-regional trade, although the effectiveness of this instrument has been the subject of some debate (see section 4.7).

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.

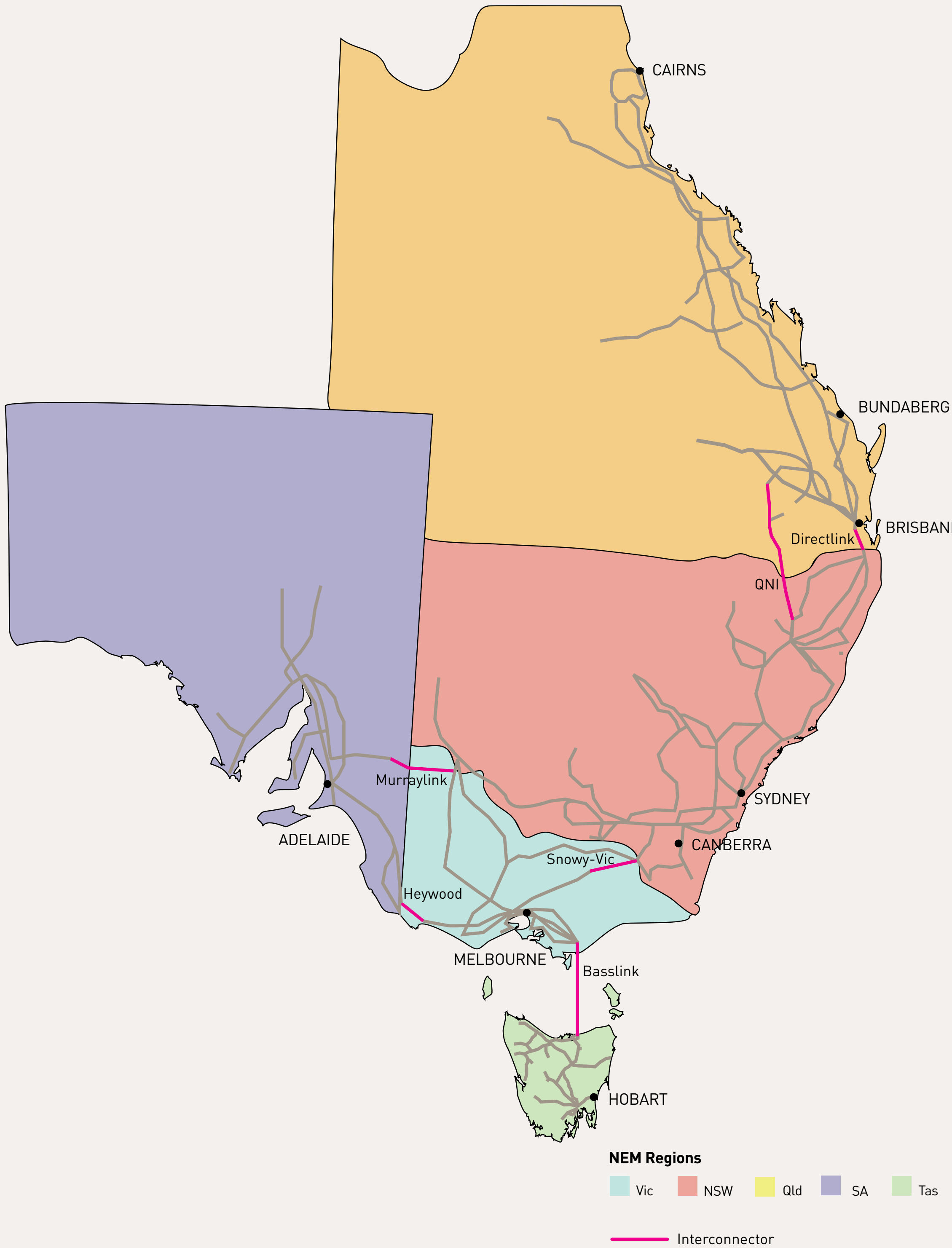
2 While transportation of electricity over long distances is efficient at high voltages, there are risks, such as flashovers. A flashover is a brief (seconds or less) instance of conduction between an energised object and the ground (or another energised object). The conduction consists of a momentary 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.

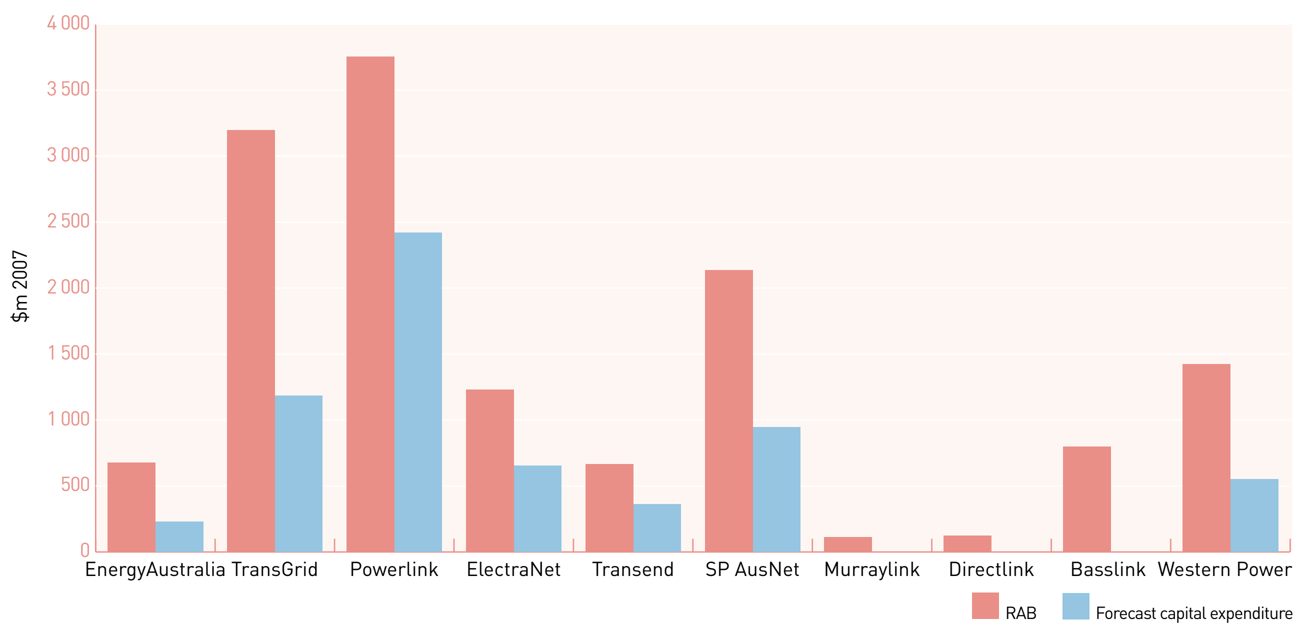
Principal sources: AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008, and previous years; AER/ACCC revenue cap decisions; company websites and press releases.

Figure 4.2
Electricity transmission network ownership

<table>
<tr><th></th><th></th><th>1994</th><th>1995</th><th>1996</th><th>1997</th><th>1998</th><th>1999</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th></tr>
<tr><td>VIC</td><td>SP AusNet</td><td colspan="3">Powernet Victoria</td><td colspan="3">GPU Powernet</td><td colspan="5">SPI Powernet (Singapore Power)</td><td colspan="4">SP AusNet (51% Singapore Power)</td></tr>
<tr><td>SA</td><td>ElectraNet</td><td colspan="6">SA Government</td><td colspan="3">Powerlink (Queensland Government), YTL</td><td colspan="6">Powerlink (Queensland Government), YTL, Hastings</td></tr>
<tr><td>NSW</td><td>TransGrid</td><td colspan="15">NSW Government</td></tr>
<tr><td></td><td>Energy-Australia</td><td colspan="15">NSW Government</td></tr>
<tr><td>QLD</td><td>Powerlink</td><td colspan="15">Qld Government</td></tr>
<tr><td>TAS</td><td>Transend</td><td colspan="15">Tas Government</td></tr>
<tr><td rowspan="3">INTER-CONN-ECTORS</td><td>Directlink</td><td colspan="6"></td><td colspan="6">Hydro-Quebec Group, NorthPower</td><td colspan="3">APA Group</td></tr>
<tr><td>Murraylink</td><td colspan="7"></td><td colspan="5">Hydro-Quebec Group, SNC-Lavalin</td><td colspan="3">APA Group</td></tr>
<tr><td>BassLink</td><td colspan="12"></td><td>NGT</td><td colspan="2">CitySpring</td></tr>
<tr><td>WA</td><td>Western Power</td><td colspan="15">WA Government</td></tr>
</table>

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:

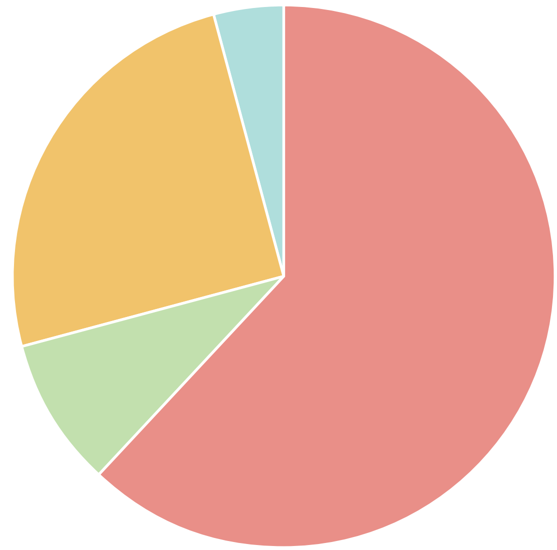
- operating costs
- asset depreciation costs
- taxation liabilities
- a commercial return on capital.

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	1 763
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	2 432
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	1 270	1 227	5 866
INTERCONNECTORS									
Murraylink	Vic—SA	113[2]							
Directlink	NSW—Qld	124[2]							
Basslink	Vic—Tas				796[3]				
NEM TOTAL									6 899

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).

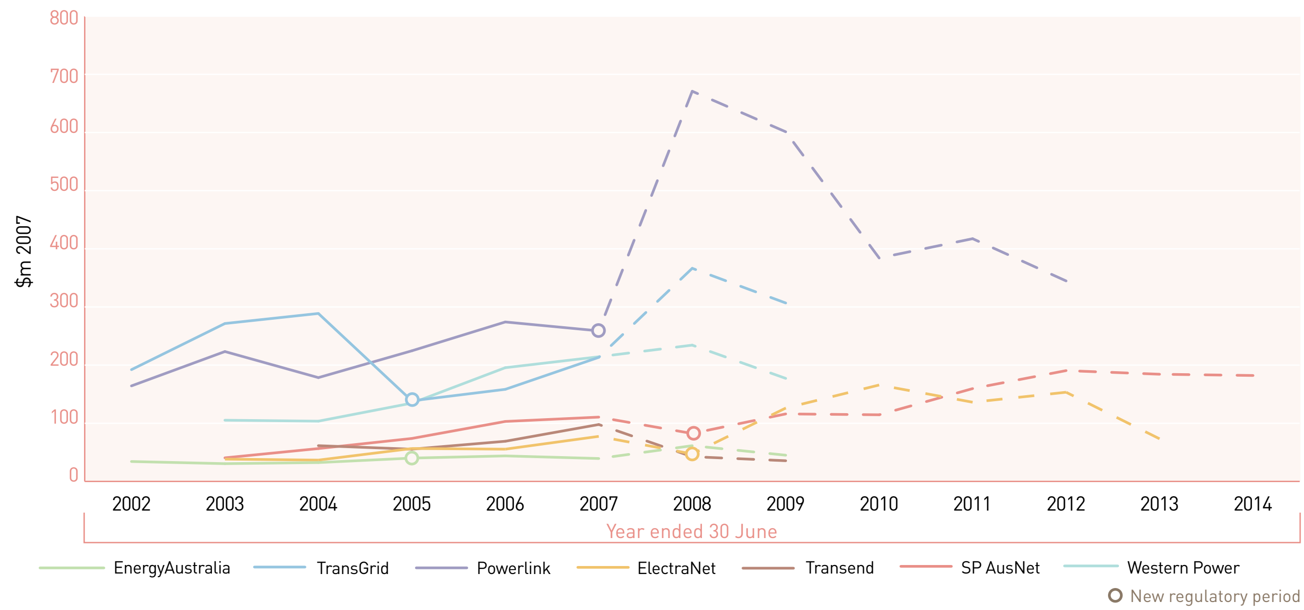
Investment levels have been highest for TransGrid and Powerlink. The other networks typically have relatively lower investment levels, reflecting the scale of the networks and differences in investment drivers, such as the age of the infrastructure and demand projections. Recent AER revenue cap decisions 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:

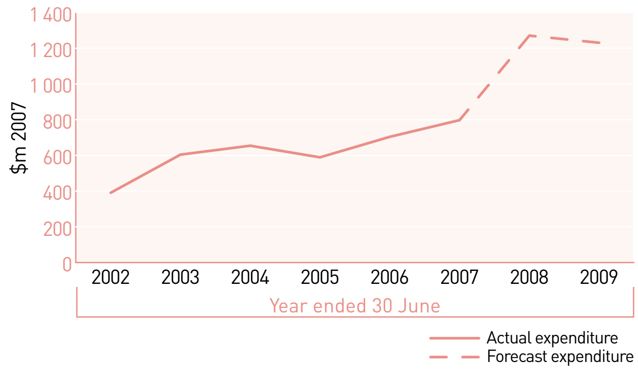
- The AER determination for Queensland's Powerlink network for 2007–12 approved investment of around $2.4 billion to meet demand growth and replace ageing assets. This is an 80 per cent increase from the previous five years. The decision increases average nominal transmission charges by around 6 per 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)



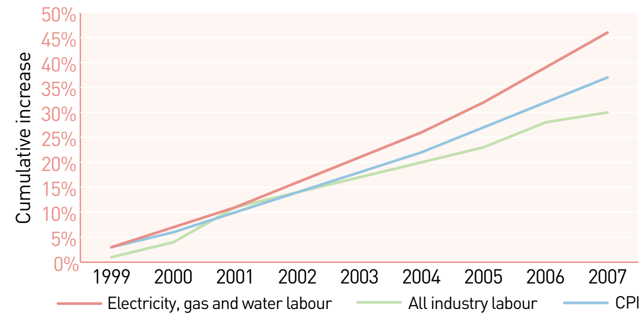
Notes:

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

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

Figure 4.7

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

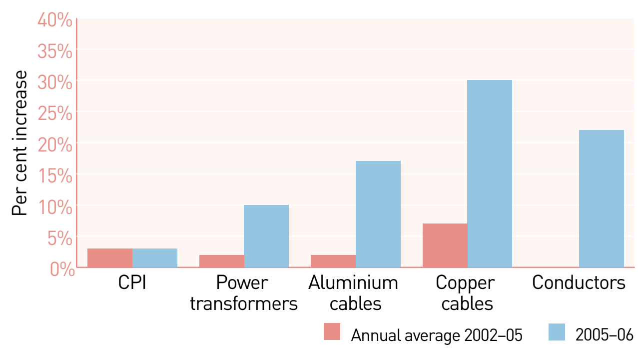


CPI, consumer price index.

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.

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]

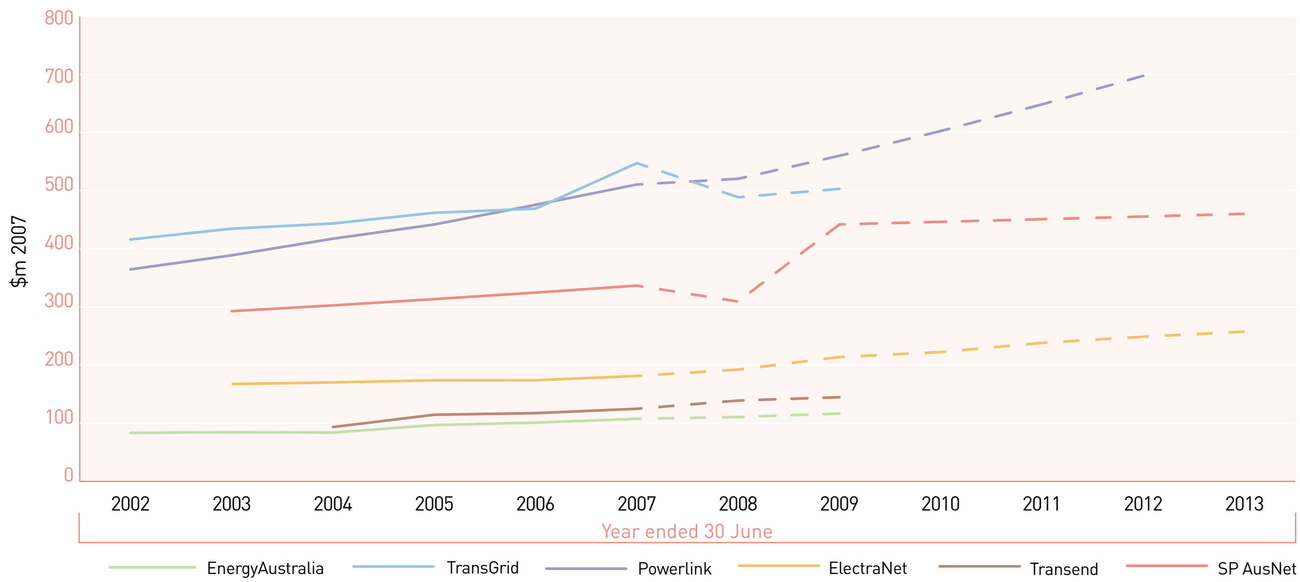
4.4.1 National transmission planning

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.

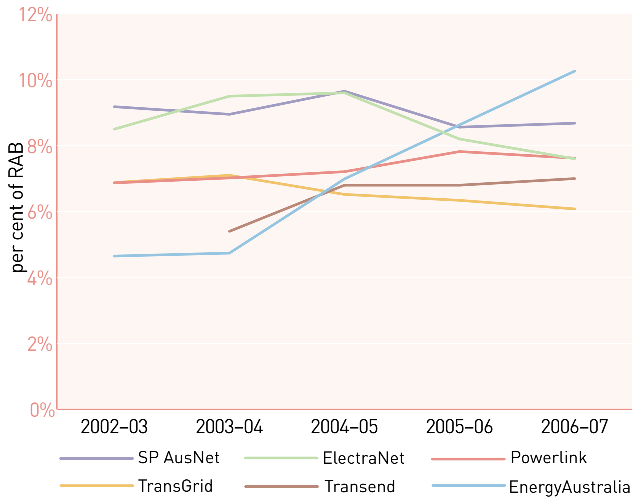
4.5.1 Revenues

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.

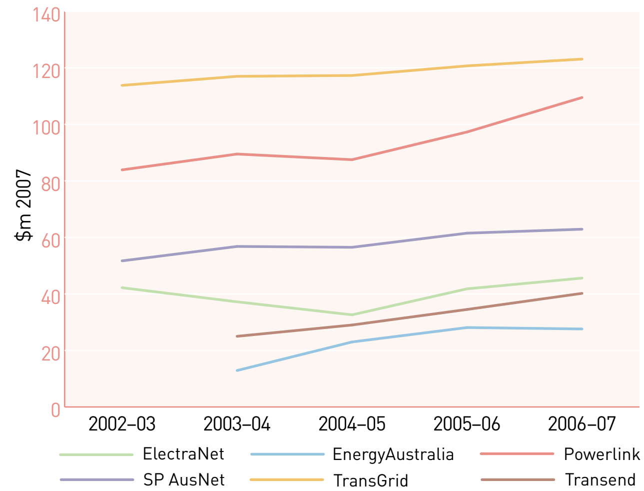
13 AER, *Transmission network service providers: Electricity regulatory report for 2006–07*, 2008.

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.

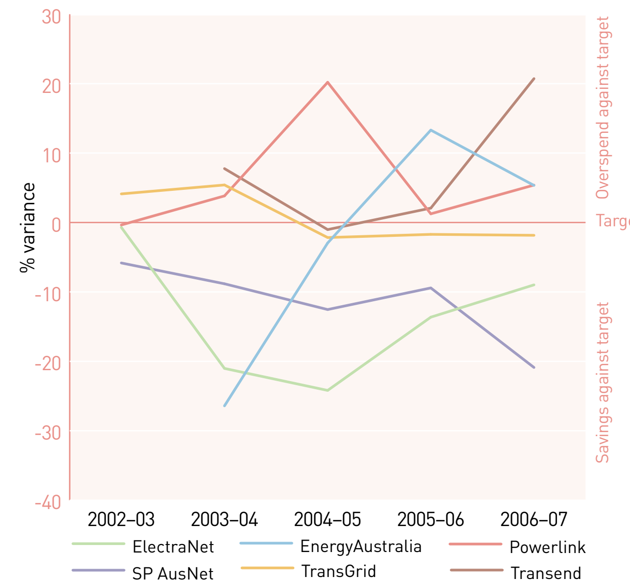
Powerlink (Queensland), which in part reflects the scale of those networks. It should be noted that several factors affect the cost structures of transmission companies. These include varying load profiles, load densities, asset age, network designs, local regulatory requirements, topography and climate.

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

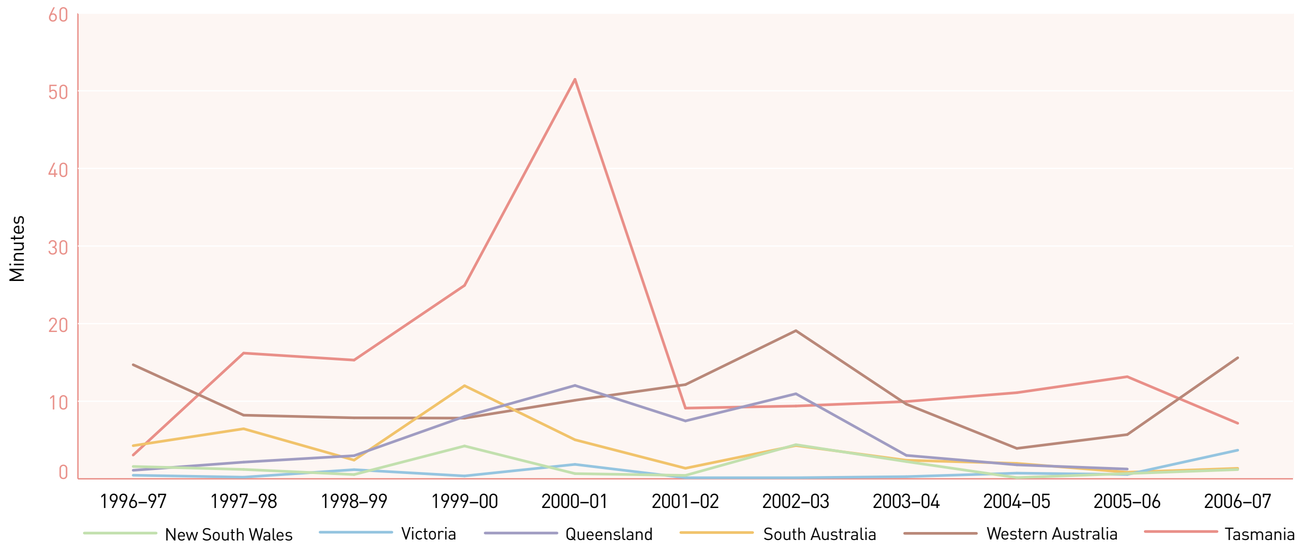
As noted, the AER has developed incentive schemes to encourage efficient transmission service quality. The schemes provide financial bonuses and penalties to network businesses that meet (or fail to meet) performance targets, which include reliability targets. Specifically, the targets relate to:

- 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**

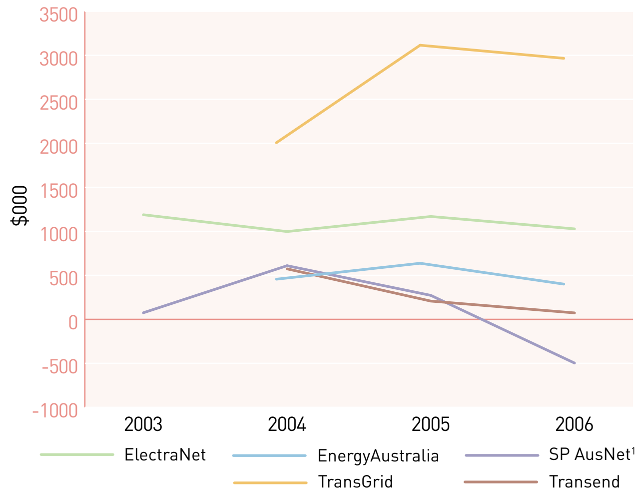
TRANSGRID (NSW)	TARGET	2003	2004	2005	2006	2007
Transmission circuit availability (%)	99.5		99.7	99.6	99.6	99.4
Transformer availability (%)	99		99.3	98.9	98.8	97.5
Reactive plant availability (%)	98.6		99.5	99.6	98.9	99.2
Frequency of lost supply events greater than 0.05 mins	5		0.0	1.0	2.0	4.0
Frequency 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:

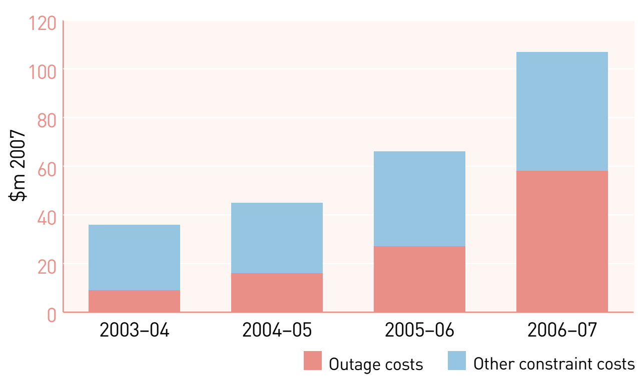
> 40 network constraints significantly affected interconnectors in 2006–07 compared to 32 in 2005–06, 15 in 2004–05 and five in 2003–04. Congestion on Basslink, which connects Victoria and Tasmania, is not included in this data.

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.

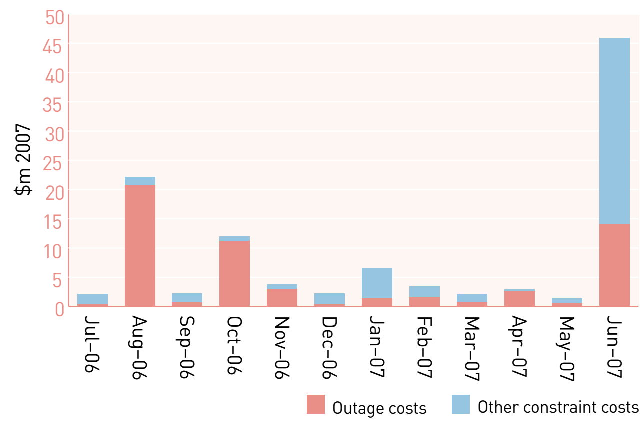
Figure 4.15
Costs of transmission congestion



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.

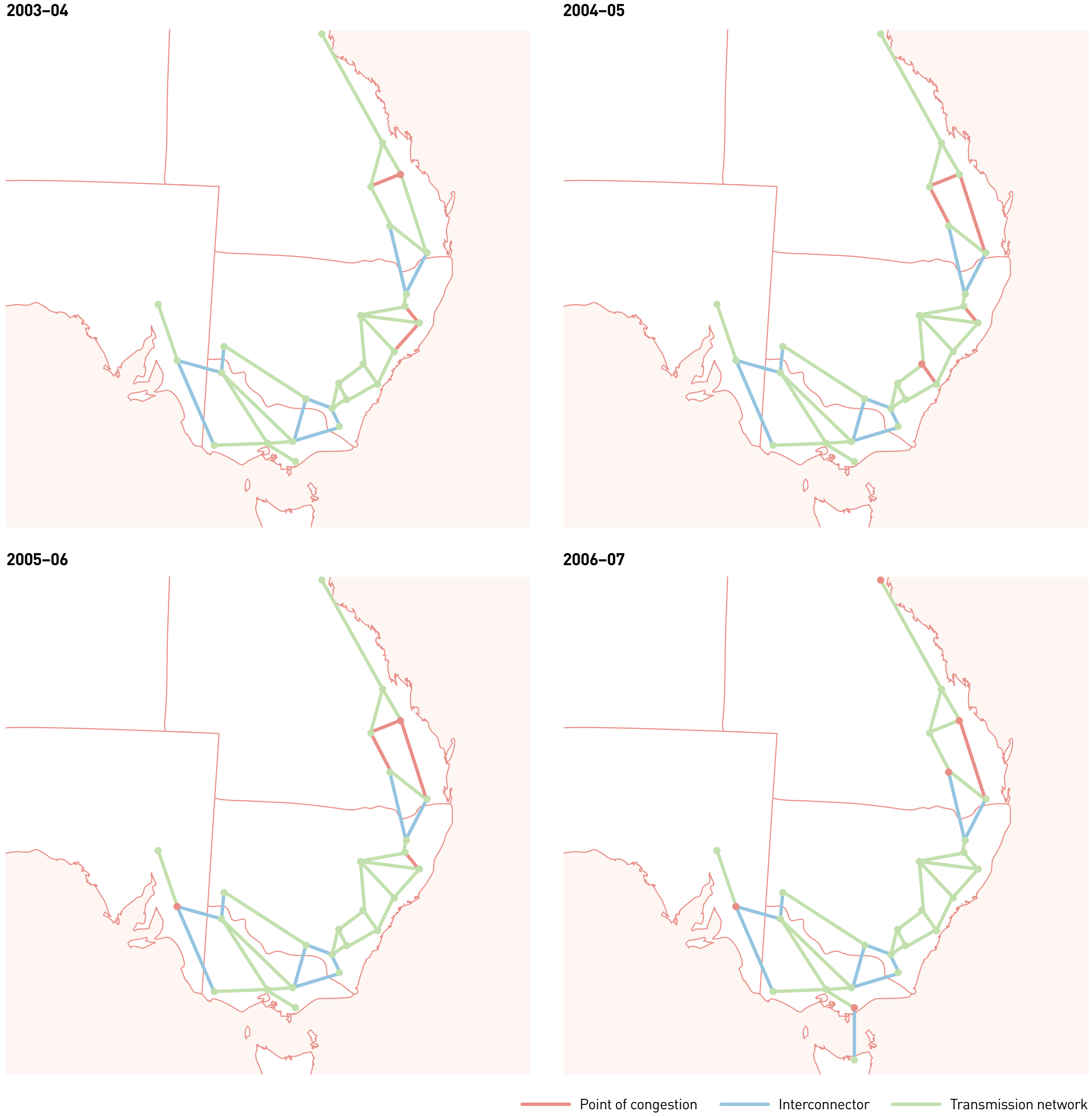
4.7.1 Geography of transmission congestion

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.

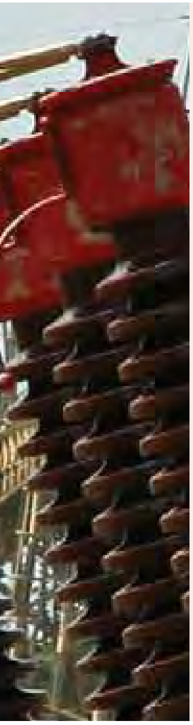
Figure 4.17 shows the locations of transmission infrastructure most affected by congestion over the past four years. Locations of congestion may change from year to year due to unique conditions such as drought, weather events and unscheduled line outages. Geographically, the impact of congestion was 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.

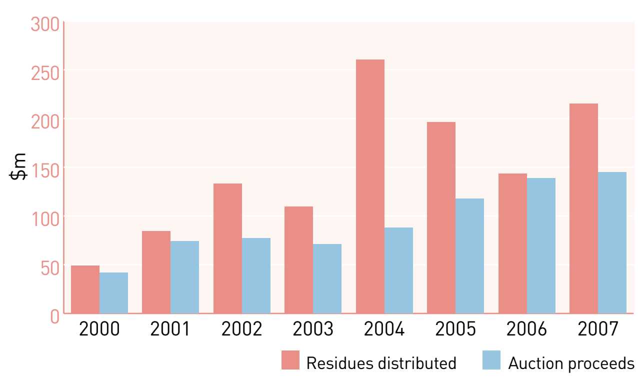
Price separation creates risks for the parties that contract across regions. NEMMCO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues up to one year in advance. Retailers, generators and other market participants may bid for a share of the residues.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

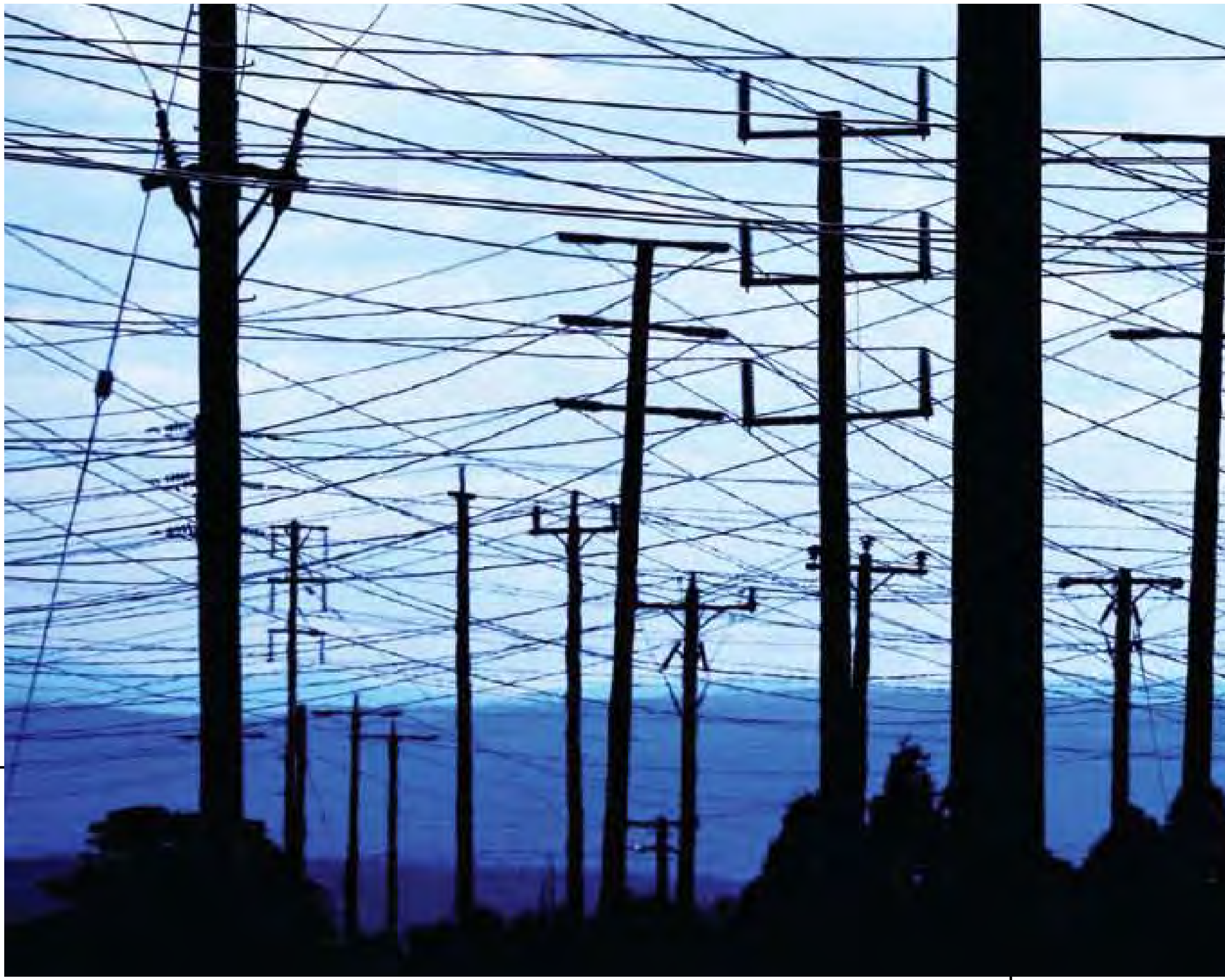
Figure 4.18
Inter-regional hedging: auction proceeds and settlement residues



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.



5 ELECTRICITY DISTRIBUTION

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

5 ELECTRICITY DISTRIBUTION

This chapter considers:

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

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

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

5.1 Role of distribution networks

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

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

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

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

5.2 Australia's distribution networks

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

5.2.1 Ownership

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

> Victoria and South Australia's networks are privately owned or leased and the ACT network has joint government and private ownership

> New South Wales, Queensland, Tasmania and the non-NEM jurisdictions of Western Australia and the Northern Territory have retained government ownership of the electricity distribution sector.

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

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

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

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

Table 5.1 Distribution networks

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

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

n/a, not available.

Notes:

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

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

Figure 5.1

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

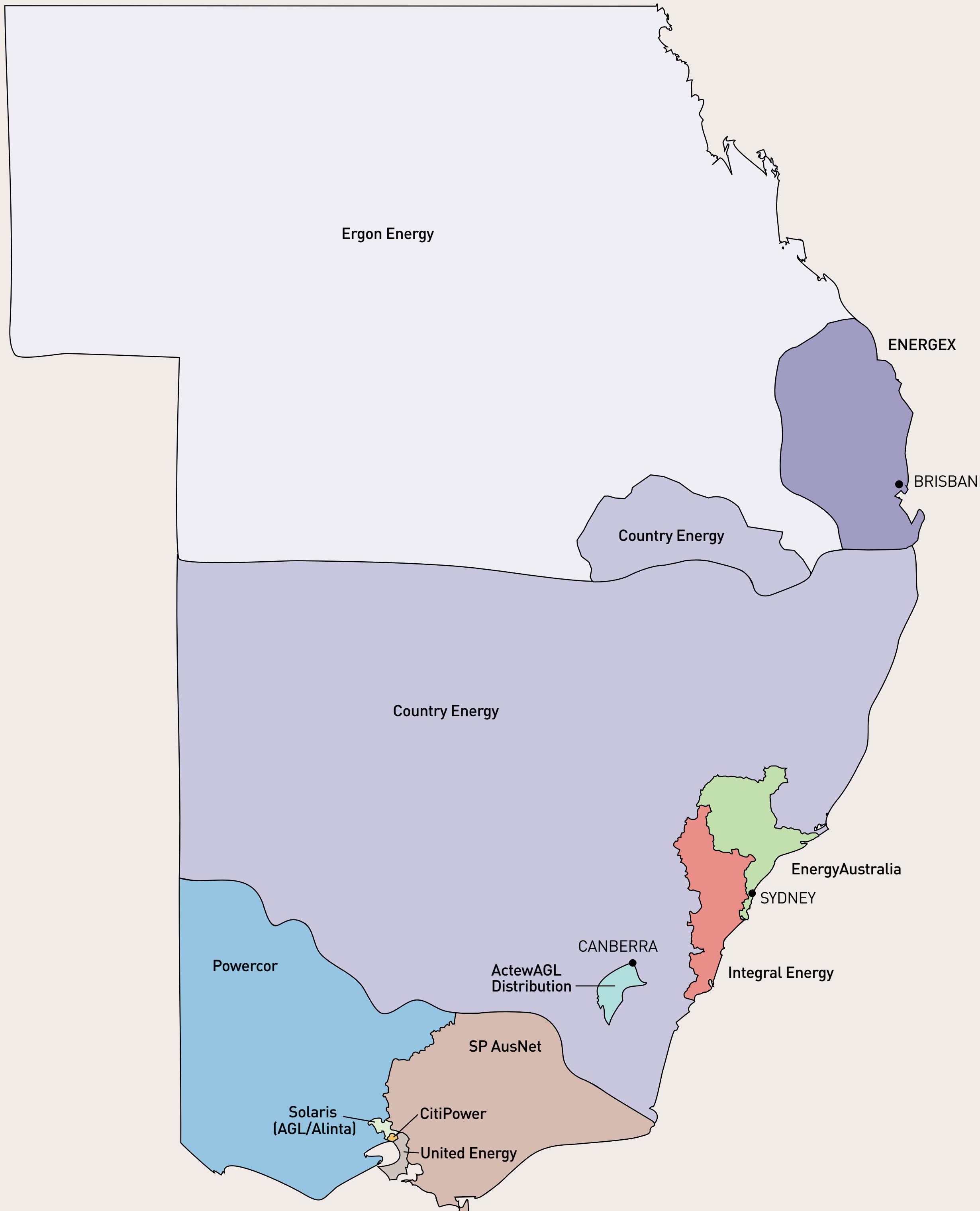
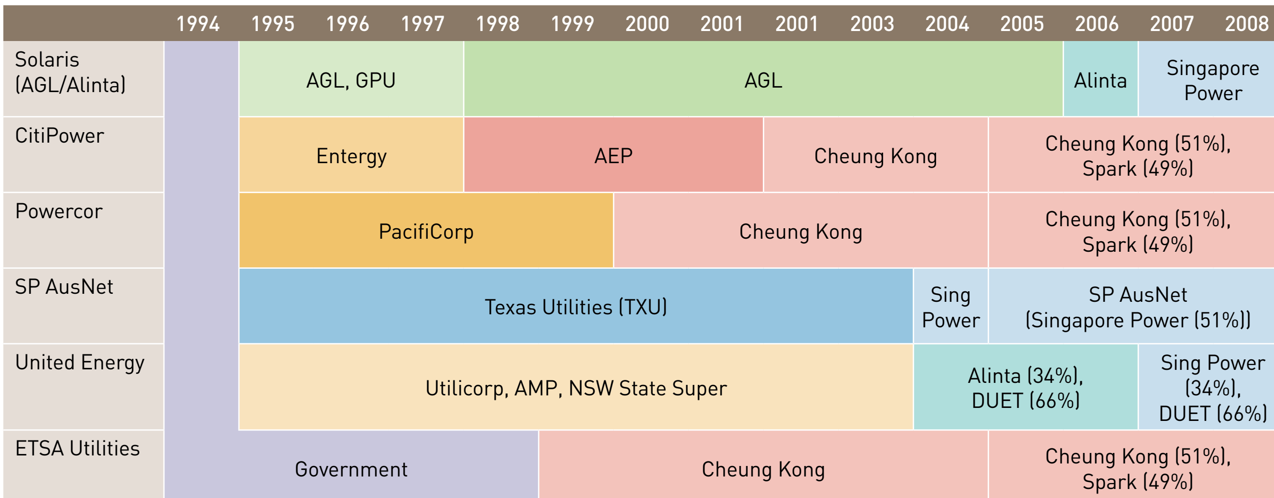


Figure 5.2

Distribution network ownership—Victoria and South Australia



Note: Some corporate names have been abbreviated or shortened.

5.2.2 Victoria and South Australia

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

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

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

5.2.3 Cross-ownership

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

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

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

Mark Wilson

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

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

Note:

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

5.3 Economic regulation of distribution services

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

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

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

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

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

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

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

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

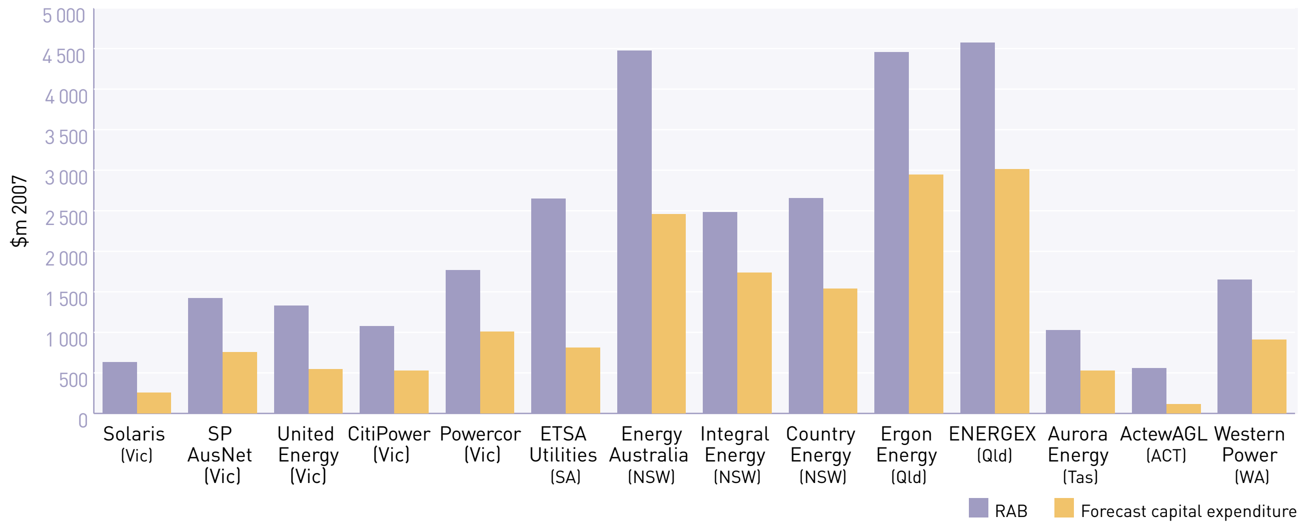
In applying any of the forms of regulation in table 5.3, a regulator must forecast the revenue requirement of a distribution business over the regulatory period. This must factor in investment forecasts and the operating expenditure allowances that a benchmark distribution business would require if operating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

6 A retrospective (after the event) assessment.

7 The RAB estimates the depreciated optimised replacement cost of an asset.

Figure 5.3

Distribution assets and investment—current regulatory period (real)



RAB, regulated asset base.

Notes:

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

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

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

> the post-tax revenue model, which is used to determine distribution businesses' annual regulated revenues

> the roll-forward model, which is used to determine the RAB for each network

> an incentive scheme which allows network businesses to retain efficiency savings in operating and maintenance expenditure for five years from the year in which the gain is made (see section 5.5)

> a service incentive scheme, to maintain and improve service performance (see section 5.6)

> cost allocation guidelines, which outline the required contents of a regulated business's cost allocation method and the basis on which the AER will assess that method for approval.

5.4 Distribution investment

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

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

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

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

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

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

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

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

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

5.5 Financial performance of distribution networks

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

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

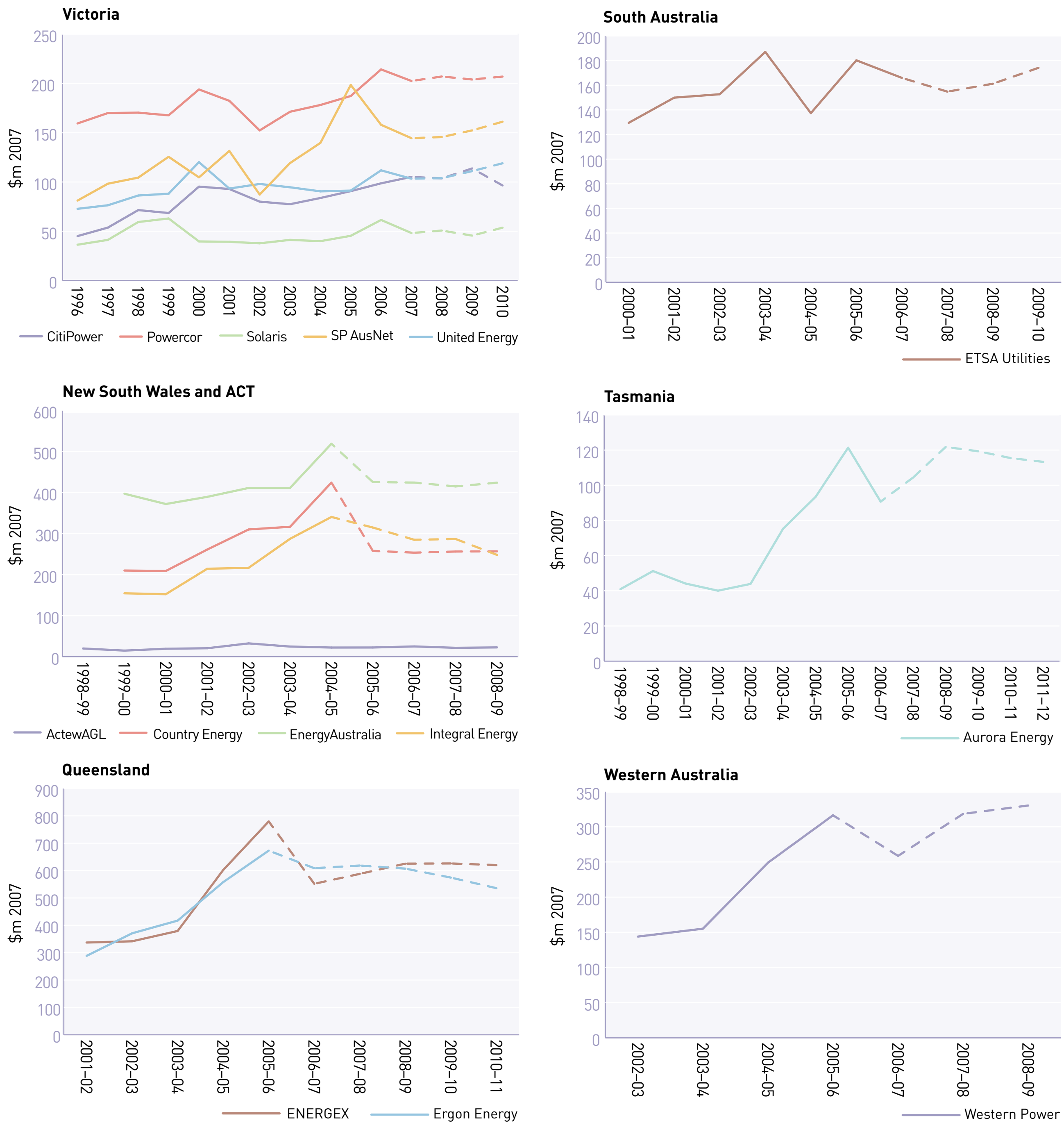
5.5.1 Revenues

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

10 See section 5.6 and figure 5.9.

Figure 5.4

Network investment (real)



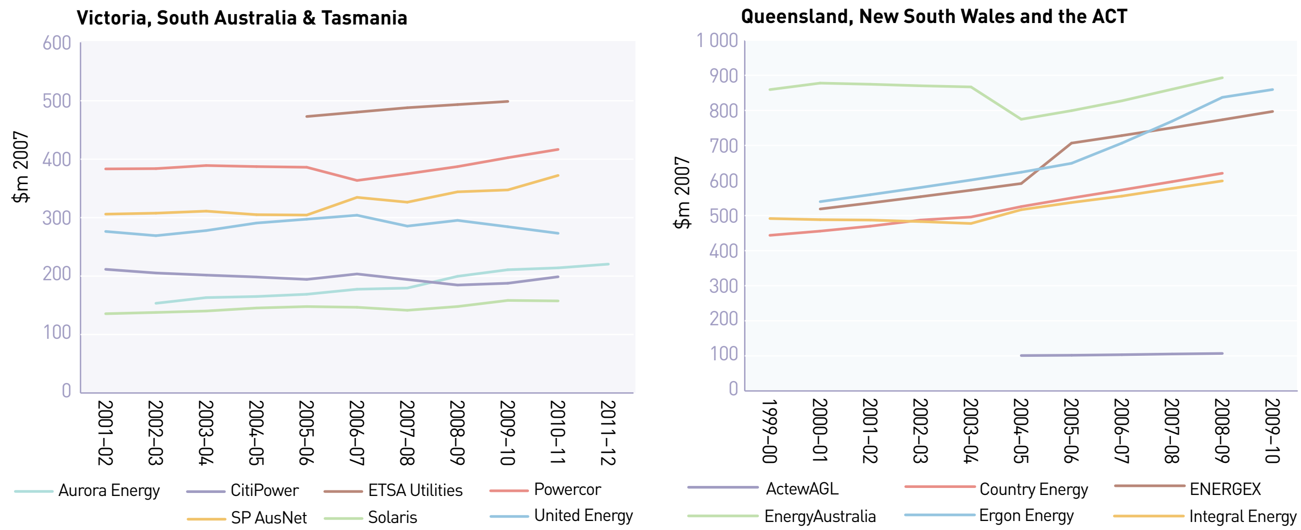
Notes:

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

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

Figure 5.5

Revenue forecasts (real)



Notes:

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

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

5.5.2 Return on assets

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

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

5.5.3 Operating and maintenance expenditure

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

Figure 5.6
Return on assets

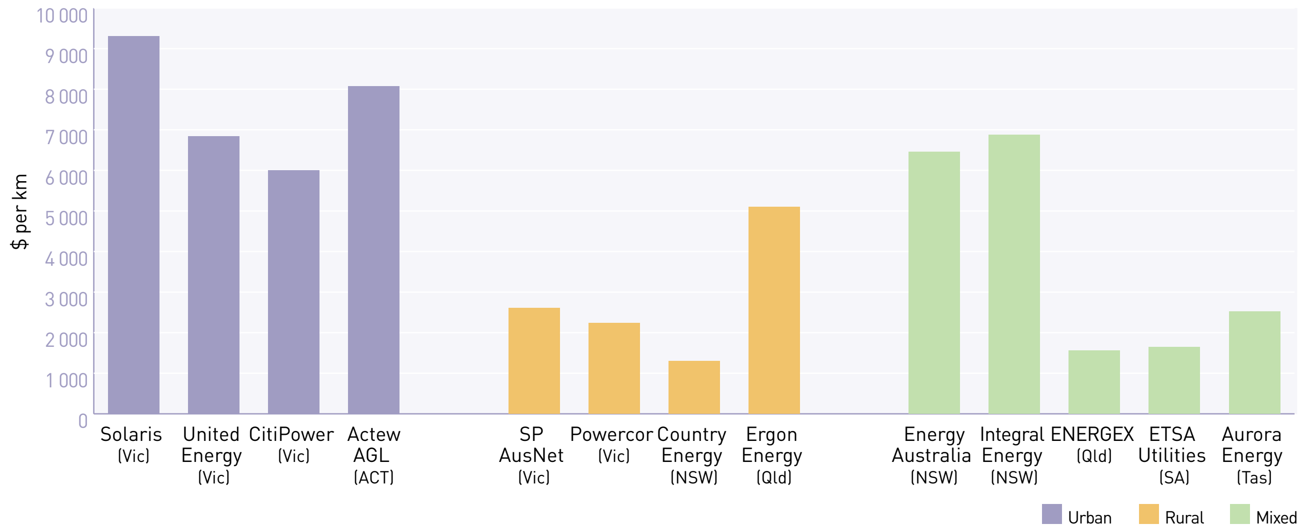
RAB, regulated asset base.

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

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

Figure 5.7

Operating and maintenance expenditure per kilometre of line length—2008



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

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

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

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

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

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

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

Figure 5.8

Operating and maintenance expenses—variances from target

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

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

5.6 Service quality and reliability

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

Quality of service monitoring for electricity distribution typically relates to:

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

All jurisdictions regulate the service performance of distribution networks through:

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

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

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

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

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

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

5.6.1 Reliability

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

12 The use of s-factor schemes is discussed in the context of electricity transmission in section 4.6 of this report.
13 AER, *Electricity distribution network service providers: Service target performance incentive scheme*, Final decision, June 2008.
14 See AER, *State of the energy market 2007*, essay B, pp. 38-53.

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

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

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

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

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

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

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

5.6.2 Reliability data

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

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

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

Table 5.4 **Reliability measures—distribution**

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 5.6 **System average interruption frequency index (SAIFI)**

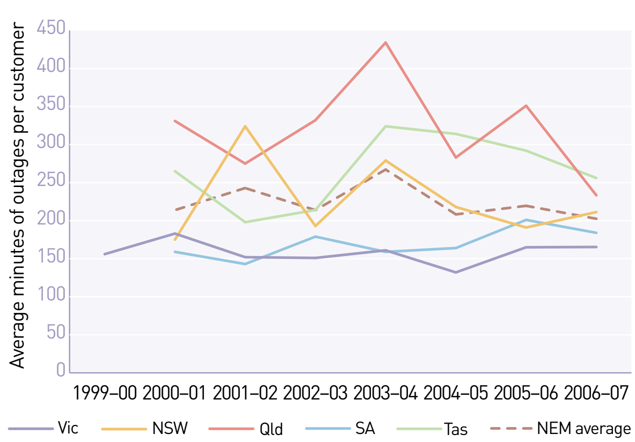
	1999–00	2000–01	2001-02	2002–03	2003–04	2004–05	2005–06	2006–07
Victoria	2.1	2.1	2.0	2.0	2.2	1.9	1.8	1.94
NSW	1.7	2.5	2.6	1.4	1.6	1.6	1.8	1.9
Queensland		3.0	2.8	3.3	3.4	2.7	2.7	2.2
South Australia		1.7	1.6	1.8	1.6	1.7	1.9	1.75
Tasmania	2.3	2.8	2.3	2.4	3.1	3.1	2.89	2.57
NEM weighted average	1.6	2.4	2.4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

Notes:

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

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

Figure 5.9
System average interruption duration index (SAIDI)



Notes and Sources: See tables 5.5 and 5.6.

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

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

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

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

5.6.3 Reliability of distribution networks by feeder

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

Table 5.7 **Feeder categories**

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

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

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

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

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

Figure 5.10a

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

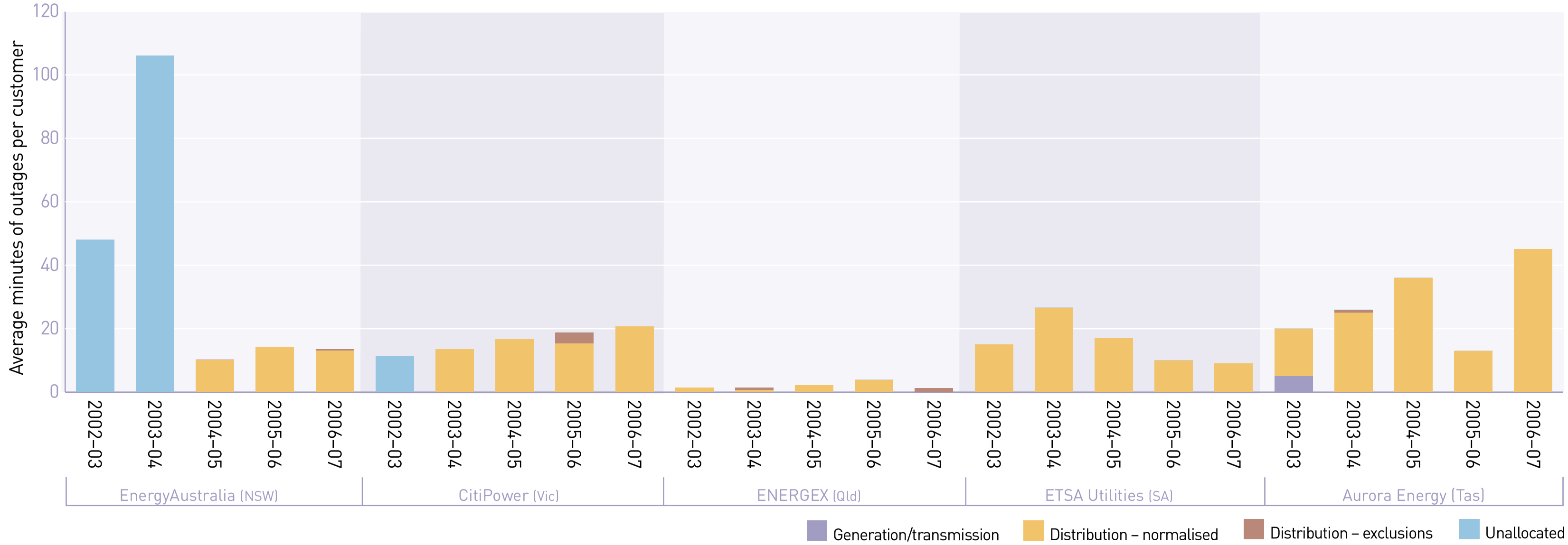


Figure 5.10b

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

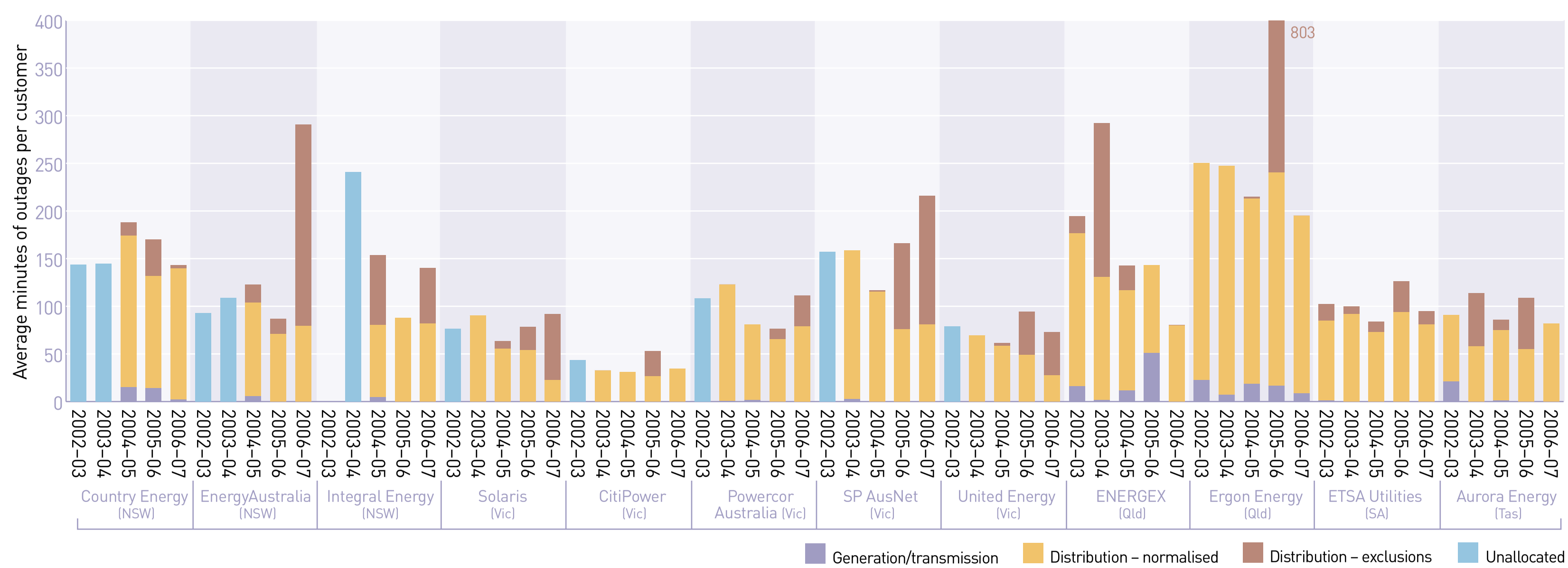


Figure 5.10c

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

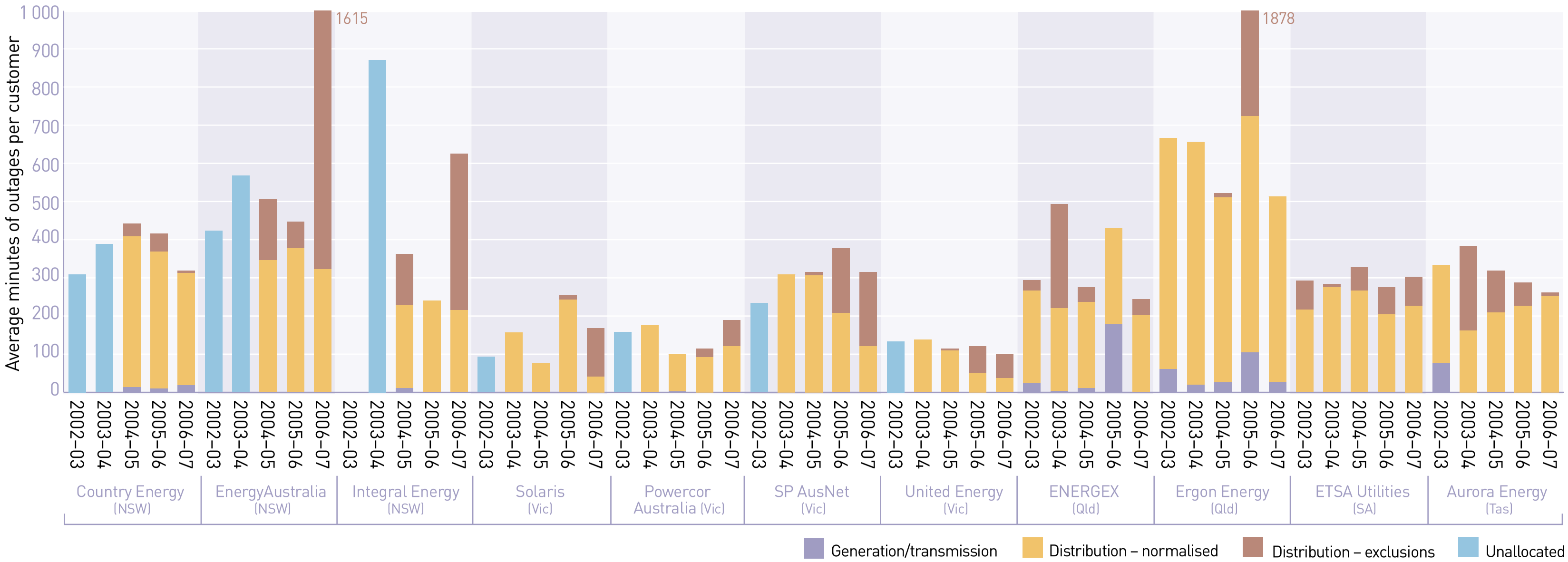
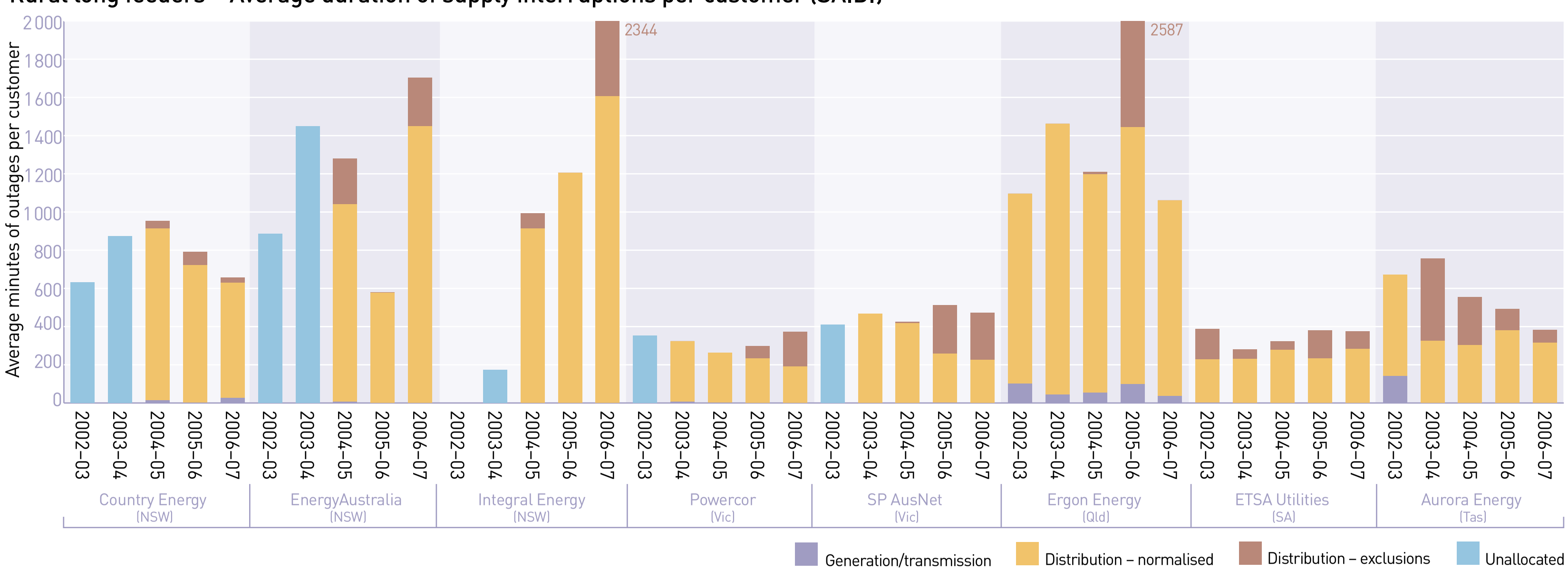


Figure 5.10d

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



Notes:

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

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

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

In summary, in the period from 2002–03:

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

5.6.4 Technical quality of supply

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

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

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

5.6.5 Customer service

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

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

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

Table 5.8 Timely provision of service

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

n/a, not available

Notes:

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

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

Table 5.9 Call centre performance

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

n/a, not available

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

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

6 ELECTRICITY RETAIL MARKETS

The retail market is the final link in the electricity supply chain. It provides the main interface between the electricity industry and customers, such as households and small businesses. Because retailers deal directly with consumers, the services they provide can significantly affect perceptions of the performance of the electricity industry.

Retailers buy electricity in the wholesale market and package it with transportation for sale to customers. Many retailers also sell 'dual fuel' products that bundle electricity and gas services. While retailers provide a convenient aggregation service for electricity consumers, they do not provide network services.

6 ELECTRICITY RETAIL MARKETS

This chapter provides a survey of electricity retail markets. It covers:

- the structure of the retail market, including industry participants and trends towards horizontal and vertical integration
- the development of retail competition
- retail market outcomes, including price and service quality
- the regulation of the retail market
- energy efficiency and demand management initiatives.

State and territory governments are responsible for the regulation of retail energy markets. Governments agreed in 2004 to transfer several non-price regulatory functions to a national framework to be administered by the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The Ministerial Council on Energy (MCE) has scheduled the regulatory package to be introduced to the South Australian Parliament in September 2009.[1]

This chapter focuses on the retailing of electricity to small customers,[2] including households and small business users. While large customers such as major industrial users buy the greatest volume of electricity, they are relatively few in number. The chapter focuses mainly on the retail sector in the National Electricity Market (NEM) jurisdictions in southern and eastern Australia, but also includes some high level information on Western Australia and the Northern Territory.[3]

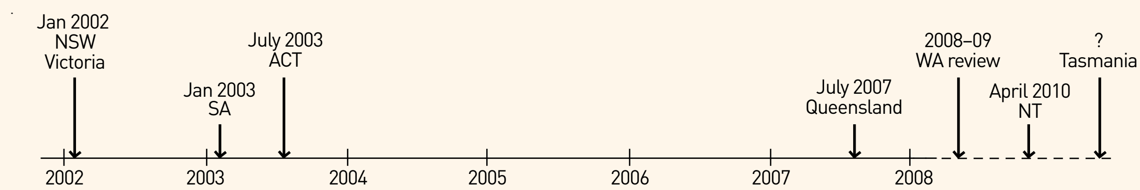
1 Section 6.11 provides an update on the transition to a national regulatory framework.

2 In Victoria, South Australia and New South Wales, small customers are those consuming less than 160 MWh per year. In Queensland and the Australian Capital Territory, small customers are those consuming less than 100 MWh per year. Small customers in Tasmania are those consuming less than 150 MWh per year.

3 Chapter 7 provides further information on the Western Australian and Northern Territory electricity sectors.

Figure 6.1

Introduction of full retail contestability



While this chapter reports some data that might enable performance comparisons to be made between retailers and jurisdictions, such analysis should note that a variety of factors can affect relative performance.

6.1 Retail market structure

The privatisation of energy retail assets is continuing. Victoria and South Australia privatised their energy retail businesses in the 1990s and Queensland privatised most of its energy retail entities in 2006–07. The Australian Capital Territory (ACT) Government operates a joint venture with the private sector to provide retail services. Western Australia, Tasmania and the Northern Territory retain government ownership in the retail sector.

New South Wales retains government ownership of its energy retail businesses, but in 2008 announced its intention to privatise electricity generation and retail. In June 2008, the New South Wales Government announced that it planned to privatise the retail businesses through a combination of trade sales and share offerings.[4] The New South Wales Auditor-General reported in August 2008 that the asset sales would raise no adverse issues for taxpayers.[5] In September 2008, the New South Wales Premier announced that the sale of government retailers would proceed, but that the state would retain its generation assets.

Alongside the privatisation of energy retail businesses, Australian governments have introduced retail contestability (customer choice). Most governments have adopted a staged timetable to introduce customer choice, beginning with large industrial customers followed by small industrial customers and finally small retail customers. Full retail contestability (FRC) is achieved when all customers are permitted to enter a supply contract with a retailer of choice.

The introduction of contestability arrangements has varied between jurisdictions (see figure 6.1):

- New South Wales, Victoria, Queensland, South Australia and the ACT have introduced FRC.
- Tasmania allows contestability for customers using at least 750 megawatt hours (MWh) per year. The Office of the Tasmanian Energy Regulator (OTTER) in 2008 conducted a public benefit assessment on the introduction of FRC for electricity customers. In May 2008, OTTER released a draft recommendation that contestability be extended to consumers using at least 50 MWh per year by 1 July 2010 and that any further extension of contestability be undertaken only once certain market conditions have been met. It found that these conditions are unlikely to be satisfied by 1 July 2010.[6]

4 Treasurer (NSW) (Hon Michael Costa), *Government announces next step in plan to secure NSW energy supplies*, media statement, 25 June 2008.

5 New South Wales Auditor-General, *Oversight of electricity industry restructuring*, August 2008.

6 Office of the Tasmanian Energy Regulator, *Public benefit assessment for electricity retail competition in Tasmania—Draft report*, May 2008, pp. 81–82.

- Western Australia allows contestability for customers using at least 50 MWh annually. The Office of Energy in 2008 conducted a review of the electricity retail market, including whether FRC should be introduced for electricity customers.[7] The Western Australian Government is also required under legislation to conduct a separate review of the benefits of FRC after April 2009.[8] The recommendations arising from the 2008 review will be re-examined in the 2009 review process.[9]
- The Northern Territory plans to introduce FRC in April 2010, subject to a public benefit test.[10]

The retail players in each jurisdiction include:

- one or more 'host' retailers that are subject to various regulatory obligations
- new entrants, including established interstate players, gas retailers branching into electricity retailing and new players in the energy retail sector.

State government-owned host retailers in New South Wales, Tasmania, Western Australia and the Northern Territory are the major players in those jurisdictions. The ACT Government operates a joint venture with a privately owned business to provide electricity retail services.

Privately owned retailers are the major players in Victoria, South Australia and Queensland. The leading private retailers are AGL Energy, Origin Energy and TRUenergy. Each has significant market share in Victoria and South Australia and is building market share in New South Wales. AGL Energy and Origin Energy entered the Queensland small customer market in 2006–07 following the privatisation of government retailers. International Power, trading as Simply Energy, has recently emerged as a significant retail business in Victoria and South Australia.

A number of niche players are active in most jurisdictions. Despite rising wholesale energy costs in 2007–08, which may reduce profit margins in the retail sector, a number of new businesses have recently obtained or are seeking retail licences. A number of businesses that held retail licences, but were not active in the market, have now commenced marketing to small customers. Table 6.1 lists licenced retailers that were active[11] in the market for residential and small business customers in June 2008.[12]

The following survey provides background on developments in each jurisdiction.[13]

6.1.1 Victoria

At June 2008, Victoria had 29 licenced retailers, 14 of which were active in the residential and small business market. These were:

- AGL Energy, Origin Energy and TRUenergy, each of which is the host retailer in designated areas of Victoria
- eleven new entrants, which were established interstate retailers (Country Energy and EnergyAustralia) and nine new players in the energy retail market (Click Energy, Jackgreen, Our Neighbourhood Energy, Powerdirect, Red Energy, Simply Energy, Victoria Electricity, Momentum Energy, and Australian Power & Gas).

Of the new entrants, Click Energy, Our Neighbourhood Energy and Simply Energy have only become active since July 2007.

Diamond Energy and Dodo Power & Gas were also granted retail licences but were not actively marketing to small customers. In response to increased wholesale electricity purchasing costs, Momentum Energy withdrew from the residential retail market in Victoria in July 2007 and its residential customers were

7 Office of Energy, *Electricity retail market review—Issues paper*, December 2007.
8 Section 55, *Electricity Corporations Act 2005* (WA).
9 Office of Energy, *Electricity retail market review—Issues paper*, December 2007, p. 37.
10 Regulation 6(4), Electricity Reform (Administration) Regulations 2008 (NT).
11 Active retailers are those retailers that are offering electricity supply contracts to customers.
12 See footnote 2 for jurisdictional classifications of 'small customers'.
13 The number of licensed retailers may not correspond with the actual number of retail licences issued as several licence holders may operate under a single trading name.

Table 6.1 Active electricity retailers: small customer market, June 2008

RETAILER[1]	OWNERSHIP	NSW	VIC	QLD	SA	TAS	ACT	WA	NT
ActewAGL Retail	ACT Government & AGL Energy	New entrant					Host		
AGL Energy	AGL Energy	New entrant	Host	New entrant	Host				
Alinta Sales	Babcock & Brown Power							New entrant	
Aurora Energy	Tasmanian Government				New entrant	Host			
Australian Power & Gas	Australian Power & Gas	New entrant	New entrant	New entrant					
Click Energy	Click Energy		New entrant						
Country Energy	NSW Government	Host	New entrant		New entrant		New entrant		
EnergyAustralia	NSW Government	Host	New entrant	New entrant			New entrant		
Ergon Energy	Queensland Government			Host					
Integral Energy	NSW Government	Host		New entrant					
Horizon Power	Western Australian Government							Host	
Jackgreen	Jackgreen Limited[2]	New entrant	New entrant	New entrant	New entrant				
Momentum Energy	Momentum Energy[3]		New entrant		New entrant				
Our Neighbourhood Energy	Our Neighbourhood Energy		New entrant						
Origin Energy	Origin Energy	New entrant	Host	Host	New entrant				
Perth Energy	Infratil							New entrant	
Power and Water Corporation	Northern Territory Government								Host
Powerdirect	AGL Energy	New entrant	New entrant	Host	New entrant				
Queensland Electricity	Infratil			New entrant					
Red Energy	Snowy Hydro[4]		New entrant		New entrant				
Simply Energy	International Power		New entrant		New entrant				
South Australia Electricity	Infratil				New entrant				
Synergy	Western Australian Government							Host	
TRUenergy	CLP Group	New entrant	Host	New entrant	New entrant		New entrant		
Victoria Electricity	Infratil		New entrant						
Active retailers		10	14	10	11	1	4	4	1
Approx. market size ('000 000 customers)		3.1	2.4	1.9	0.8	0.2	0.2	1.0	0.1

Host (incumbent) retailer New entrant

Notes:

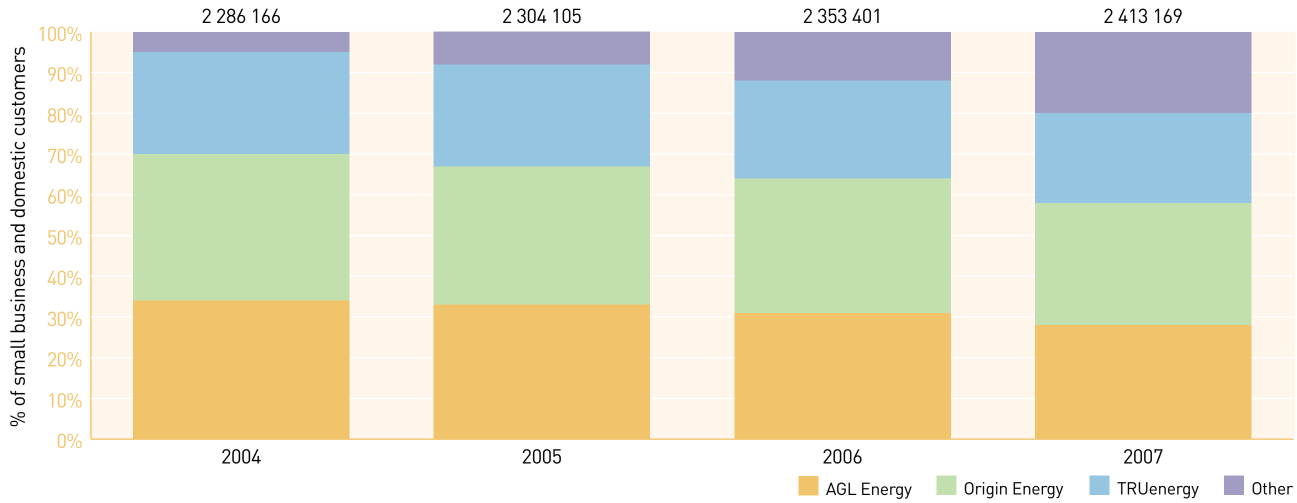
1. Not all licenced retailers are listed. Some generators are licenced retailers but are active only in the market for larger industrial users. Not all retailers listed supply electricity to all customers; for example, some retailers only market to small business users.
2. Major shareholders in Jackgreen Limited as at 1 July 2007 include Babcock & Brown Prime Broking (19.05 per cent) and Citicorp Nominees (15.89 per cent).
3. In September 2008, Hydro Tasmania acquired a controlling interest in Momentum Energy.
4. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).

Sources: Jurisdictional regulator websites, updated by information on retailer websites and other public sources.

transferred to Australian Power & Gas. Momentum Energy was actively retailing to small and medium sized businesses in June 2008.

Table 6.2 sets out the market share of Victorian retailers (by customer numbers) at 30 June 2007. The three host retailers account for about 79 per cent of the market and each has acquired market share beyond its local area. New entrant penetration in the market has increased from 13 per cent of small customers in June 2006 to almost 20 per cent in June 2007 (see figure 6.2).

Figure 6.2
Electricity retail market share (small customers)—Victoria



Note: Figures at top of columns are total small customer numbers.

Source: ESC, *Energy retail businesses comparative performance report*, various years.

Table 6.2 **Electricity retail market share (small customers)—Victoria, 30 June 2007**

RETAILER	CUSTOMERS		
	Domestic	Business	Total retail
AGL Energy	28.0%	23.4%	27.4%
Origin Energy	29.8%	34.8%	30.4%
TRUenergy	22.5%	22.3%	22.5%
Other	19.7%	19.6%	19.7%
Total customers	2 132 226	280 943	2 413 169

Source: ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007, p. 3.

6.1.2 South Australia

At June 2008, South Australia had 15 licenced electricity retailers, of which 11 were active in the small customer market. These were:

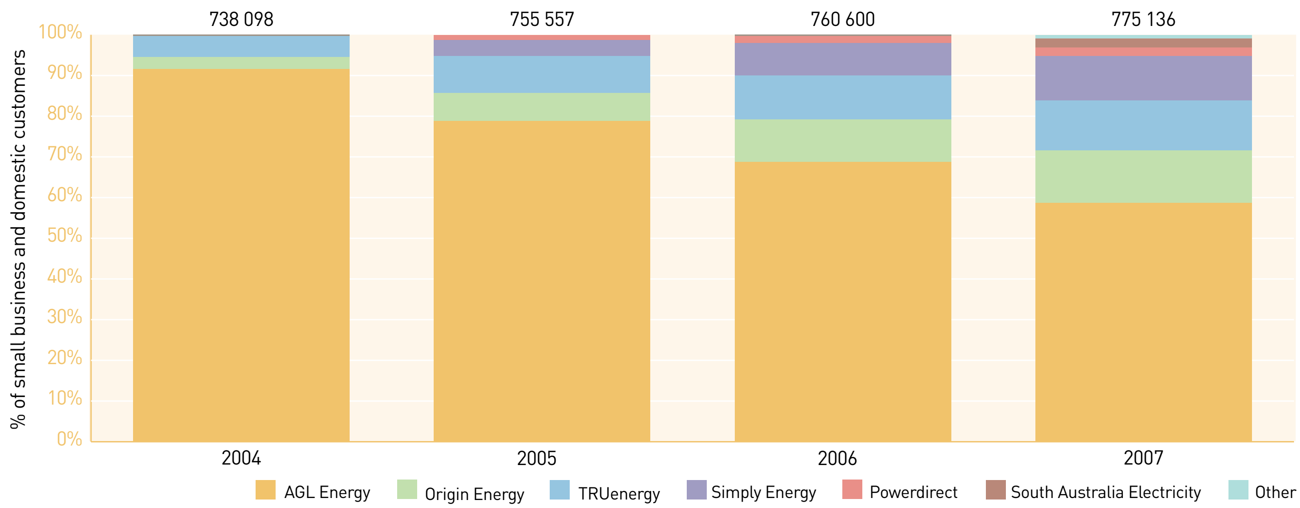
- AGL Energy, South Australia's host retailer
- ten new entrants, which were South Australia's host retailer in gas (Origin Energy), established interstate retailers (TRUenergy, Country Energy and Aurora Energy) and six new players in the energy retail market (Simply Energy, Momentum Energy, Powerdirect, South Australia Electricity, Red Energy and Jackgreen).

Of the new entrants, Red Energy and Jackgreen only became active since July 2007.

EnergyAustralia, Dodo Power & Gas, and Australian Power & Gas held retail licences but were not actively marketing to small customers.

Table 6.3 sets out the small customer market share of South Australian retailers (by customer numbers) at 30 June 2007. The host retailer—AGL Energy—supplies 59 per cent of small customers, down from 68 per cent in 2006. All other retailers have built market share, with Origin Energy, TRUenergy and Simply Energy each supplying more than 10 per cent of the small customer base. There has been only marginal penetration by niche retailers, with the four largest retailers accounting for almost 95 per cent of the market (see figure 6.3).

Figure 6.3
Electricity retail market share (small customers)—South Australia



Note: Figures at top of columns are total small customer numbers.

Source: ESCOSA, *2006–07 Annual performance report: Performance of South Australian energy retail market*, November 2007, p. 65.

Market penetration by new entrants has been more effective for large customers, with AGL Energy's market share eroding to about 40 per cent of that market (based on sales volume).[14]

Table 6.3 Electricity retail market share (small customers)—South Australia, 30 June 2007

RETAILER	CUSTOMERS		
	Domestic	Business	Total retail
AGL Energy	57.6%	67.3%	58.7%
Country Energy	0.6%	1.3%	0.6%
Origin Energy	12.7%	14.7%	12.9%
Powerdirect	1.7%	5.3%	2.2%
South Australia Electricity	2.4%	0.3%	2.2%
Simply Energy	11.8%	4.1%	10.9%
TRUenergy	13.0%	6.6%	12.3%
Other	0.3%	0.4%	0.3%
Total customers	687 826	87 310	775 136

Source: ESCOSA, *2006–07 Annual performance report: Performance of South Australian energy retail market*, November 2007, p. 65.

6.1.3 New South Wales

At June 2008, New South Wales had 25 licenced retailers, of which 10 supplied (or intended to supply) residential and/or small business customers. The active retailers were:

- EnergyAustralia, Country Energy and Integral Energy, the government-owned host retailers
- seven new entrants, which were the state's host retailer in gas (AGL Energy), established interstate players (Origin Energy, TRUenergy and ActewAGL Retail) and new players in the energy retail market (Powerdirect, Jackgreen and Australian Power & Gas).

Momentum Energy, New South Wales Electricity, Dodo Power & Gas, and Red Energy held retail licences but were not actively marketing to small customers.

New entrant retailers have acquired about 14 per cent of the small customer market (based on customer numbers) from the government-owned incumbents, with the greatest penetration occurring in the EnergyAustralia and Integral Energy local supply areas.[15]

14 ESCOSA, *2006/07 Annual performance report: Performance of South Australian energy retail market*, November 2007, Adelaide, p. 25.

15 IPART, *NSW electricity information paper no. 1/2008—Electricity retail businesses' performance against customer service indicators*, January 2008, p. 2.

6.1.4 Queensland

Until 2006, Queensland's small customer market was divided between two government owned businesses: Ergon Energy and ENERGEX. Queensland restructured its electricity retail sector in 2006 by creating two new businesses: Sun Retail and Powerdirect. Origin Energy acquired Sun Retail from the Queensland Government in January 2007 and AGL Energy acquired Powerdirect in February 2007. The Government has retained ownership of Ergon Energy's retail business, which supplies 'unprofitable' customers in rural and regional areas.

At June 2008, Queensland had 23 licenced retailers, of which 10 were active in the small customer market. These were:

- Origin Energy (previously Sun Retail) and Ergon Energy, each of which is the host retailer in designated areas of Queensland
- Powerdirect (now owned by AGL Energy)
- seven new entrants, which were established interstate retailers (EnergyAustralia, Integral Energy, AGL Energy and TRUenergy); and three new players in the energy retail market (Jackgreen, Queensland Electricity and Australian Power & Gas).

Table 6.4 sets out the estimated small customer market share of Queensland retailers (by customer numbers) at 30 June 2007. As FRC was not introduced in Queensland until July 2007, businesses could not compete for small customers. The small customer base was split between Ergon Energy (the government-owned retailer), and Origin Energy and AGL Energy, which acquired retail businesses through privatisation in 2007.

Ergon Energy is restricted to providing customer retail services to non-market customers in its designated area (predominantly rural and regional customers).

Table 6.4 Electricity retail market share (small customers)—Queensland, 30 June 2007

RETAILER	SMALL CUSTOMERS
AGL Energy	23%
Ergon Energy	33%
Origin Energy	44%
Total customers	1 890 000

Source: AER estimates.

6.1.5 The Australian Capital Territory

At June 2008, the ACT had 15 licenced retailers, of which four were active in the residential market: ActewAGL Retail (the host retailer), EnergyAustralia, Country Energy and TRUenergy. Dodo Power & Gas, Integral Energy, Jackgreen, Red Energy, Australian Power & Gas and Origin Energy held retail licences but were not actively marketing to small customers.

In 2006–07, the host retailer maintained a significant market share of around 90 per cent.[16]

6.1.6 Tasmania

Aurora Energy, the government-owned host retailer, controls the small customer market in Tasmania. Legislative restrictions prevent new entrants supplying small customers (as of June 2008).

6.1.7 Western Australia

In Western Australia, only customers consuming at least 50 MWh annually are contestable. The government-owned host retailer—Synergy—has a market share of 96 per cent in the residential market and 92.5 per cent in the non-residential market. Horizon Power services the regional areas of Western Australia and is the second largest retailer with 3.9 per cent of the residential market and 6.4 per cent of the non-residential market.[17] The remaining customers are divided between Alinta Sales (owned by Babcock & Brown Power), Perth Energy and the Rottnest Island Authority.[18]

16 Over 10 per cent of customers have switched to an alternative retailer since the introduction of FRC. ICRC, *Annual report 2006–07*, p. 14.

17 Economic Regulation Authority, *2006–07 Annual performance report—Electricity retailers*, January 2008, p. 12.

18 The Rottnest Island Authority manages the Rottnest Island Reserve and retails to customers on Rottnest Island.

6.1.8 Northern Territory

The government-owned host retailer, Power and Water Corporation, provides electricity services to customers in the Northern Territory.

6.2 Trends in market integration

Various ownership consolidation activity has occurred in the energy retail sector in recent years, including:

- retail market convergence between electricity and gas
- vertical integration between electricity retailers and generators.[19]

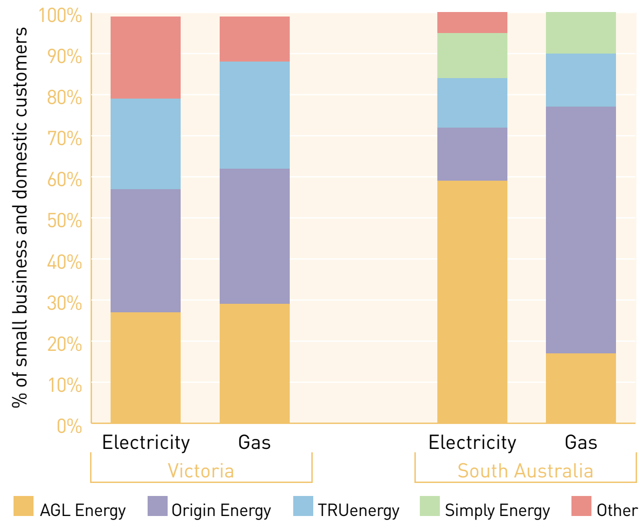
6.2.1 Energy retail market convergence

Many energy retailers offer both electricity and gas services, including 'dual fuel' retail products.[20] For example, the leading retailers in Victoria and South Australia—AGL Energy, Origin Energy and TRUenergy—jointly account for around 81 per cent of small electricity retail customers and 89 per cent of small gas retail customers (see figure 6.4). The principal difference between the two sectors is the greater penetration by niche players in electricity than in gas.

Several factors have driven retail convergence, including business cost savings and convenience for customers. At the same time, convergence can create hurdles for new entrants—especially small players—that may need to deal with different market arrangements and different risks in the provision of electricity and gas services.

Figure 6.4

Electricity and gas retail market share (small customers)—Victoria and South Australia, 30 June 2007



Sources: ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007; ESCOSA, *Annual performance report: Performance of South Australia energy retail market 2006–07*, November 2007.

6.2.2 Vertical integration in the electricity sector

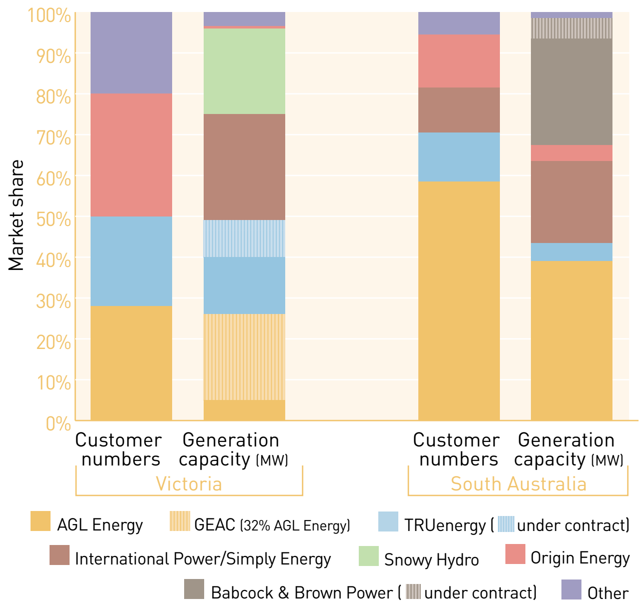
In the 1990s, governments introduced reforms to structurally separate the power supply industry into generation, transmission, distribution and retail businesses. However, some linkages between different sectors of the power supply industry remain. In particular, the New South Wales, Queensland, Tasmanian and Northern Territory governments own joint distribution–retail businesses. The ACT Government has ownership interests in both the host retailer of electricity and gas and the electricity and gas distributor. Where linkages exist between contestable and non-contestable sectors, regulators apply ring-fencing arrangements to ensure operational separation of the businesses.

19 There has been debate as to whether this form of ownership consolidation might in some contexts pose a barrier to entry for new entrant retailers. See, for example, Energy Reform Implementation Group, *Energy reform: The way forward for Australia*, A Report to COAG, January 2007, pp. 125–6.

20 In the ACT, the host retailer in electricity and gas—ActewAGL Retail—also offers contracts that 'bundle' electricity and gas retail services with telecommunications services.


Jessica Shapiro (Fairfax)

Figure 6.5
Market share in the Victorian and South Australian retail and generation sectors, 2007



Notes:

1. The figures should be interpreted with caution as market shares in each sector are based on different variables. Retail shares relate to small customer numbers, while generation shares relate to capacity.
2. In Victoria, TRUenergy holds a long-term hedge contract with Ecogen Energy (owned by Industry Funds Management).
3. In South Australia, Babcock & Brown Power bids in the facility at Osborne power station (owned by ATCO Power and Origin Energy).

Sources: ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007; ESCOSA, *SA energy retail market 06–07, November 2007* (customer numbers); NEMMCO (generation capacity and ownership); company websites.

There is also a continuing trend towards vertical integration of privately owned electricity retailers and generators. Vertical integration provides a means for retailers and generators to manage the risk of price volatility in the electricity spot market. If wholesale prices rise, the retailer can balance the increased cost against higher generator earnings.

Figure 6.5 compares generation and retail market shares in Victoria and South Australia in 2007. Two of the three major retailers—AGL Energy and TRUenergy—have significant generation interests. In July 2007, AGL Energy and TRUenergy completed a generator swap in South Australia that moved the capacity of each business into closer alignment with their retail loads. Origin Energy has limited generation capability at present but is developing new capacity. In addition, the major generator International Power operates a retail business in these jurisdictions (trading as Simply Energy) and achieved significant penetration in the South Australian market in the year to June 2007.

There has also been vertical integration in the public electricity sector. Snowy Hydro owns Red Energy, which has acquired some market share in Victoria and South Australia. In September 2008, Hydro Tasmania acquired a controlling interest in the small private retailer Momentum Energy.

6.3 Retail competition

While most jurisdictions have introduced or are introducing FRC, it can take time for a competitive market to develop. As a transitional measure, most jurisdictions require host retailers to offer to supply electricity services under a regulated standing offer (or default) contract (see section 6.4.1). Standing offer contracts cover minimum service conditions, information requirements and some form of regulated price cap or oversight. As of July 2008, all jurisdictions applied some form of retail price regulation.[21]

Australian governments have agreed to review the continued use of retail price caps and to remove them where effective competition can be demonstrated.[22] The AEMC is assessing the effectiveness of retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps.[23] The relevant state or territory government makes the final decision on this matter. Box 6.1 includes a summary of progress with the AEMC reviews.

The following provides a sample of public data that may be relevant to an assessment of the effectiveness of retail competition in Australia. In particular, it sets out data on the diversity of price and product offerings

21 See section 6.4.1 for further details.
22 Australian Energy Market Agreement 2004 (amended 2006).
23 In Western Australia, the Economic Regulation Authority is responsible for this task.

Box 6.1 Australian Energy Market Commission reviews of the effectiveness of retail competition

The AEMC completed a review of the effectiveness of competition in electricity and gas retail markets in Victoria in February 2008. It is undertaking a review of the South Australian market in 2008 and reviews are scheduled for New South Wales in 2009 and the ACT (if required) in 2010.

In undertaking these reviews, the AEMC applies the following criteria to assess the effectiveness of retail competition:

- independent rivalry within the market
- ability of suppliers to enter the market
- exercise of market choice by customers
- differentiated products and services
- prices and profit margins
- customer switching behaviour.

Victoria

The AEMC review of the Victorian electricity and gas retail markets found that competition is effective in both the electricity and the gas markets:

> The majority of energy customers are participating actively in the competitive market by exercising choice among available retailers as well as price and service offerings. There is strong rivalry between energy retailers, facilitated by the current market structures and entry conditions.[24]

Retail price regulation in Victoria currently extends only to residential customers. Standing offer retail prices are negotiated between the Victorian Government and host retailers, with the government retaining the reserve power to regulate these prices.

In response to the review, the Victorian Government announced in September 2008 the introduction of new legislation to remove retail price caps. The legislation includes provisions for the Essential Services Commission of Victoria (ESC) to undertake expanded price monitoring and report publicly on retail prices. Retailers will also be required to publish a range of their offers to assist consumers in comparing energy prices. Other obligations on retailers, including the obligation to supply and the consumer protection framework, are not affected by the removal of retail price regulation. The Victorian Government retains a reserve power to reinstate retail price regulation if competition is found in the future to no longer be effective.

South Australia

During 2008, the AEMC is reviewing the South Australian electricity and gas retail markets. In September 2008, it released a first final report on its review. The AEMC's findings were that competition is effective for small electricity and gas customers in South Australia; however, competition was more intense in electricity than in gas:[25]

> There has been strong rivalry between energy retailers as they offer customers alternative combinations of price, product and service. Large numbers of electricity and metropolitan gas customers have been willing and able to respond to competitive offers and to exercise choice between the available offers when approached by retailers and given sufficient incentive.[26]

24 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria—First final report*, December 2007.

25 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia—First final report*, September 2008, p. 19.

26 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia—First final report*, September 2008, p. 21.

27 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia—First final report*, September 2008, pp. 31–33.

28 NERA Economic Consulting, *Review of the effectiveness of energy retail market competition in South Australia—Phase 2 Report for ESCOSA*, June 2007.

While the AEMC considered that overall competition in electricity and gas markets was effective, it noted that the ease of entry for new retailers and expansions for existing retailers may be limited due to:[27]

- higher spot prices, increased spot price volatility and increased vertical integration in electricity markets
- structural limitations which restrict the ability of gas retailers to access firm transmission haulage services.

The South Australian regulator, the Essential Services Commission of South Australia (ESCOSA), undertook its own review of the effectiveness of competition in the South Australian electricity and gas retail markets in 2007. This review considered indicators that included the number of retailers, customer switching, barriers to entry and product innovation.

ESCOSA found that there appears to be effective competition in the electricity retail market, with the gas market moving towards effective competition. Customers for whom competition did not appear to be effective included small business gas customers and regional residential gas customers:

> In sum, our assessment of the conduct of market participants in both the electricity and gas retail market in South Australia suggests that both retailers and customers are acting in a manner that is broadly consistent with an effectively competitive market.[28]

of retailers; the exercise of market choice by customers, including switching behaviour; and customer perceptions of competition. There is also some consideration of regulated prices and retail profit margins. Elsewhere, this chapter touches on other barometers of competition; for example, section 6.1 considers new entry in the electricity retail market.

The information provided here does not seek to draw conclusions. More generally, the AER is not assessing or commenting on the effectiveness of retail competition in any jurisdiction.

6.3.1 Price and non price diversity of retail offers

There is evidence of retail price diversity in electricity markets that have introduced FRC (see box 6.2). In particular, both host and new entrant retailers tend to offer market contracts at discounts against the 'default' regulated terms and conditions.

There is some price diversity associated with product differentiation. For example, retailers might offer a choice of standard products, green products, 'dual fuel' contracts (for gas and electricity) and retail packages that bundle electricity and gas services with other services such as telecommunications,[29] each with different price structures.

Some product offerings bundle energy services with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. Discounts and other offers tend to vary depending on the length of a contract. Some retail products offer additional discounts for prompt payment of bills or direct debit bill payments. Many contracts carry a severance fee for early withdrawal.

29 In the ACT, the host retailer in electricity and gas—ActewAGL Retail—offers discounts on electricity services if the customer elects to 'bundle' electricity retail services with gas and telecommunications services.

Box 6.2 Case study: diversity of price and product offerings to small customers

ESCOSA and the Queensland Competition Authority (QCA) provide estimator services that allow consumers to make rough but quick comparisons of retail offers in their respective states. Table 6.5 sets out the estimated price offerings in April 2008 for customers in Queensland and South Australia using 4000 kilowatt hours (kWh) a year, based on peak usage, and not using electricity for hot water. The estimator does not account for all elements of retail offers, including some discounts. For example, some retailers were offering price and non-price bonuses on sign up, and discounts for prompt payment. Others were offering a percentage of supplied electricity from accredited renewable energy sources.

Table 6.5 indicates some price diversity in the Queensland and South Australian retail markets, with a spread across all retail offers of around $600 in South Australia and $500 in Queensland. The spreads are greater when discounts and rebates are taken into account. Discounts off the standing offer contract price are available from a number of retailers in each state, with the lowest rates attached to fixed-term contracts with termination fees. Retail offers in the upper price range generally provide customers with higher levels of accredited renewable energy.

In May 2007, the Essential Services Commission of Victoria (ESC) undertook independent research that compared electricity market contract prices with the standing offers of host retailers. This research was not intended to provide an exhaustive survey of retail market offers. Table 6.5 compares the annual electricity bill for a consumer using 4000 kWh a year in different host retailer areas in Victoria in May 2007.

The ESC found that market offers at a discount from the standing contract price were available in all host retailer areas, as well as additional monetary benefits or inducements of up to around $100 a year. Table 6.5 indicates that there was a price spread across retail offers of between $57 (in the TRUenergy host area) and $270 (in the AGL Victoria host area). The data does not account for additional benefits such as joining bonuses or discounts. Contracts varied significantly in respect of fixed terms and termination fees. The ESC also found that incentives offered by retailers under market contracts varied between host retail areas; for example, green energy products and joining bonuses were not offered by all retailers in all regions.

The AEMC also reported price information on retail market offers as part of its review of the effectiveness of competition in Victoria (see box 6.1). The AEMC found that in June 2007, five retailers were offering market contracts at a discount from the standing offer of 2–7 per cent for domestic customers and 2–10 per cent for small business customers. When direct price benefits such as prompt payment discounts and joining bonuses were taken into account, the AEMC found that discounts of 10 per cent of the regulated tariff were available to both small business and domestic customers.[30]

Market analysis in Victoria undertaken by CRA International in August 2007 also found that market contracts typically have monetary and non-monetary inducements, that contract terms vary between retailers and that some retailers allow customers to choose the source of their electricity—for example, green energy.[31] In addition, CRA found that market offers in the residential sector varied more than those offered to small businesses, although there was little innovation in market offers regarding pricing structures and levels.[32]

30 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria—First final report*, 19 December 2007, pp. 54–55.

31 CRA International, *Impact of prices and profit margins on energy retail competition in Victoria*, November 2007, p. 43.

32 CRA International, *Impact of prices and profit margins on energy retail competition in Victoria*, November 2007, p. 65.

Table 6.5 Electricity retail price offers for a customer using 4000 kWh per year in South Australia (April 2008), Queensland (April 2008) and Victoria (May 2007)

PROVIDER	Nº OF PRODUCTS	ANNUAL COST ($)[1,2] 600 700 800 900 1000 1100 1200 1300 1400 1500	ADDITIONAL BENEFITS	ACCREDITED RENEWABLE ENERGY[3]
SOUTH AUSTRALIA (AGL ENERGY)				
Regulated price			—	N
AGL Energy	7		Joining bonus	Y (10%)
Momentum Energy	1		Prompt payment discount	Y (10%)
Origin Energy	7		Joining bonus; loyalty bonus	Y (20%; 100%)
Red Energy	3		Prompt payment discount	N
Simply Energy	11		Direct debit rebate	Y (10%)
South Australia Electricity	3		Prize draws	Y (10%; 100%)
TRUenergy	3		Prompt payment discount	Y (10%)
QUEENSLAND (ORIGIN ENERGY)				
Regulated price			—	N
AGL Energy	2		Joining bonus	Y (10%)
Australian Power & Gas	5		Joining bonus; prompt payment discount	Y (10%; 50%; 100%)
EnergyAustralia	3		Joining bonus; direct debit rebate	Y (10%; 100%)
Integral Energy	2		—	Y (10%)
Jackgreen	4		—	Y (10%; 25%; 50%; 100%)
Origin Energy	4		Joining bonus; loyalty bonus	Y (20%)
Powerdirect	1		Direct debit rebate	N
Queensland Electricity	3		Prize draws; prompt payment discount	Y (10%; 100%)
TRUenergy	3		Prompt payment discount	Y (10%)
VICTORIA (AGL VICTORIA)				
Regulated price			—	N
AGL Energy	2		Joining bonus	N
Country Energy	1		Joining bonus	N
Simply Energy	2		Loyalty bonus	Y (10%)
Jackgreen	3		—	Y (10%; 25%; 50%; 100%)
Momentum Energy	1		Joining bonus	N
Origin Energy	1		—	N
Red Energy	1		Prompt payment discount	N
TRUenergy	1		Prompt payment discount	N
Victoria Electricity	1		Prompt payment discount	N
Powerdirect	1		—	N
VICTORIA (ORIGIN POWERCOR)				
Regulated price			—	N
AGL Energy	2		Joining bonus	Y (10%)
Country Energy	1		Joining bonus	N
Simply Energy	2		Loyalty bonus	Y (10%)
Jackgreen	1		Prompt payment discount	Y (10%)
Momentum Energy	1		—	N
Origin Energy	2		Joining bonus	Y (20%)
Red Energy	1		Prompt payment discount	N
TRUenergy	2		Prompt payment discount	Y (10%)
Victoria Electricity	1		Prompt payment discount	N
Powerdirect	1		—	N
VICTORIA (TRUENERGY)				
Regulated price			—	N
AGL Energy	1		—	N
Country Energy	1		Joining bonus	N
Simply Energy	2		Loyalty bonus	Y (10%)
Jackgreen	1		Prompt payment discount	Y (10%)
Momentum Energy	1		—	N
Origin Energy	2		Joining bonus	Y (20%)
Red Energy	1		Prompt payment discount	N
TRUenergy	1		Prompt payment discount	N
Victoria Electricity	1		Prompt payment discount	N
Powerdirect	1		Loyalty bonus	N

Notes:

1. Coloured bars represent the approximate range of annual charges for each retailer's products.
2. The annual costs exclude additional benefits such as prompt payment discounts, joining bonuses and loyalty bonuses.
3. Percentages represent the proportion of electricity sourced from accredited renewable generation.

Sources: ESCOSA estimator, viewed 17 April 2008, http://www.escosa.sa.gov.au; QCA estimator, viewed 17 April 2008, http://www.qca.org.au; ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007.

CHAPTER 6 ELECTRICITY RETAIL MARKETS

The variety of discounts and non-price inducements makes direct price comparisons difficult. There is also variation in the transparency of price offerings. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation. Victorian retailers are required to publish product information statements on their websites. Additionally, the Queensland and South Australian regulators and a number of private businesses operate websites that allow customers to compare their current electricity and gas retail contracts with available market offers. Box 6.2 provides case study material on the diversity of price and product offerings to small customers in South Australia, Victoria and Queensland.

Note that the price offers set out in box 6.2 are not directly comparable between jurisdictions. The offers relate to different periods and product structures in each jurisdiction, and rely on different measurement techniques. Nor should the data be taken as indicative of actual price outcomes. Section 6.4.2 of this report also considers data on retail price outcomes.

6.3.2 Customer switching

The rate at which customers switch their supply arrangements is an indicator of customer participation in the market. While switching (or churn) rates can also indicate competitive activity, they should be interpreted with care. Switching is sometimes high during the early stages of market development, when customers are first able to exercise choice. Switching rates sometimes stabilise even as a market acquires more depth. Similarly, it is possible to have low switching rates in a very competitive market if retailers are delivering good quality service that gives customers no reason to switch.

The National Electricity Market Management Company (NEMMCO) publishes churn data measuring the number of customer switches from one retailer to another. NEMMCO has published this data for New South Wales and Victoria since the introduction of FRC in 2002, for South Australia from October 2006 and for Queensland from July 2007.

The data indicate gross or cumulative switching rates and cover the total number of customer switches in a period, including switches from a host retailer to a new entrant, switches from new entrants back to a host retailer, and switches from one new entrant to another (see table 6.6 and figure 6.6). The data do not include customers who have switched from a default arrangement to a market contract with their existing retailer. This exclusion may understate the true extent of competitive activity as it does not account for the efforts of host retailers to retain market share.

Figure 6.6 illustrates that switching activity continued strongly in Victoria and South Australia throughout 2007–08. Rapid switching growth has been observed in Queensland since the commencement of FRC in July 2007. New South Wales continues to have a switching rate that is about half that of the other states.

Switches to market contracts

While NEMMCO reports on customer switching between retailers, an alternative approach is to measure customer switching from regulated 'default' contracts to market contracts. South Australia and Queensland periodically publish this data, while New South Wales and the ACT publish it on an irregular basis. In Victoria, the AEMC reported on customer switching to market contracts as part of its 2007 review of the effectiveness of retail competition.

Table 6.7 summarises the available data on switches to market contracts. The data are not directly comparable between jurisdictions because of differences in data collection methods and in the periods covered.

Table 6.6 Small customers switching retailers, 2008

INDICATOR	NEW SOUTH WALES	VICTORIA	SOUTH AUSTRALIA	QUEENSLAND
Percentage of small customers that changed retailer during 2007-08	10%	23%	18%	20%
Customer switches as a percentage of the small customer base from start of FRC to June 2008 (cumulative)	44%	105%	86%	20%

FRC, full retail contestability

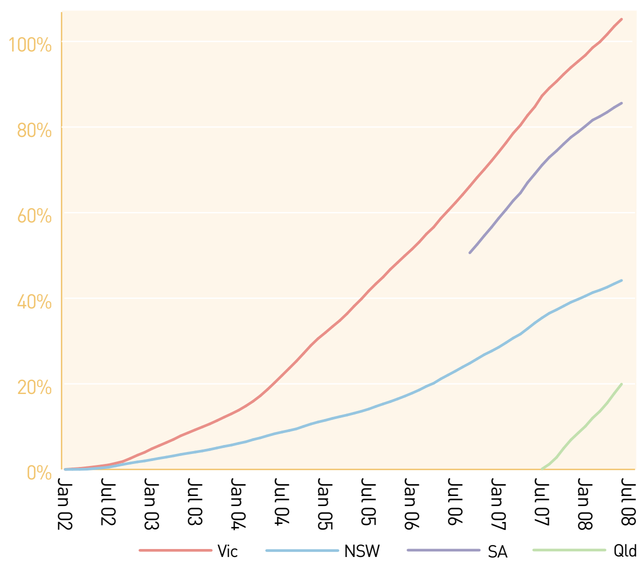
Notes:

1. If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may therefore exceed 100 per cent.
2. The customer base is estimated as of 30 June 2008.
3. The data may overstate the extent of customer switching due to some retailers transferring customers between different participant codes owned by the same retailer.

Sources: Customer switches: NEMMCO, MSATS transfer data to June 2008; Customer numbers: New South Wales: IPART, *NSW electricity information paper no 1–2008—Electricity retail businesses' performance against customer service indicators*, January 2008; South Australia: ESCOSA, *2006–07 Annual performance report: performance of South Australian energy retail market*, November 2007; Victoria: ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007; Queensland: QCA, *Market and non-market customers as at 31 March 2008*, June 2008

Figure 6.6

Cumulative monthly customer switching of retailers as a percentage of small customers, January 2002 to June 2008



Notes:

1. In November 2006, the South Australian regulator (ESOCSA) determined (in its *2005–06 Annual performance report: performance of the South Australian energy retail market*) that the electricity retail market had matured to the extent that it was appropriate for NEMMCO to publish customer transfer data comparable to that published in Victoria and NSW. There are no comparable public data for South Australia prior to June 2006.
2. The New South Wales data exclude switches in the ACT.
3. The data may overstate the extent of customer switching due to some retailers transferring customers between different participants codes owned by the same retailer.

Sources: Customer switches: NEMMCO, MSATS transfer data to June 2008; Customer numbers: New South Wales: IPART, *NSW electricity information paper no 1–2008—Electricity retail businesses' performance against customer service indicators*, January 2008; South Australia: ESCOSA, *2006–07 Annual performance report: performance of South Australian energy retail market*, November 2007; Victoria: ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007; Queensland: QCA, *Market and non-market customers as at 31 March 2007*, available at http://www.qca.org.au.

Table 6.7 Small customer transfers to market contracts

JURISDICTION	DATE	SMALL CUSTOMER ON MARKET CONTRACTS (% OF SMALL CUSTOMER BASE)
New South Wales	30 June 2006	42% of small customers in the EnergyAustralia supply area 29% of small customers in the Integral Energy supply area 5% of small customers in the Country Energy supply area
Victoria	31 December 2006	62% of residential customers 43% of small business customers
Queensland	31 March 2008	12% of all small customers
South Australia	30 June 2007	65% of residential customers (22% with the host retailer and 43% with new entrants) 38% of small business customers (5% with the host retailer and 33% with new entrants) 61% of residential and small business customers (averaged)
ACT	30 June 2007	27% of all small customers (17% with the host retailer and 10% with new entrants)

Sources: New South Wales: IPART, *Regulated electricity tariffs and charges for customers 2007–10—Electricity final report and final determination*, June 2007, p. 29; Victoria: AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria*, First Final Report, 19 December 2007, p. 89; Queensland: QCA, *Market and non-market customers as of 31 March 2008*; ACT: ICRC, *Annual report 2006–07*, pp. 14–15; South Australia: ESCOSA, *2006–07 Annual performance report: Performance of South Australian energy retail market*, November 2007, pp. iii, 21–22.

Box 6.3 The Utility Customer Switching Research Project assessment of Australian retail markets

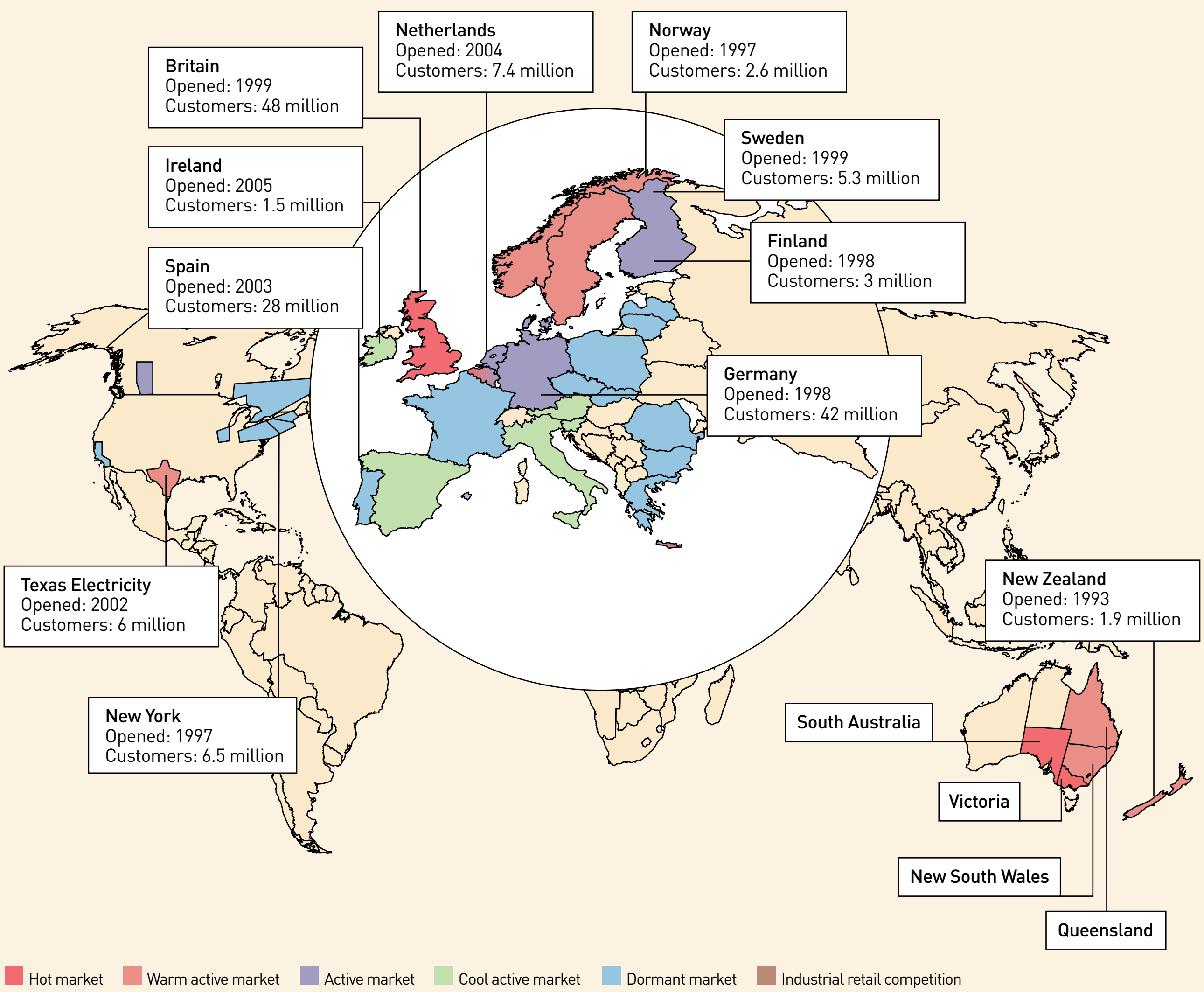
In its 2008 energy market switching report, VaasaETT noted that Australia retains its position as the most active region in the world (figure 6.7). Victoria topped the ranking, having experienced the highest level of switching ever recorded for any market. South Australia had the second highest switching levels despite the rate dropping off substantially from the middle of 2007.

The report stated that rising electricity retail prices throughout 2007–2008—resulting from drought and increased gas-fired electricity generation pushing up wholesale energy costs—contributed to the ongoing high levels of customer switching, especially in Victoria where regulated retail prices rose to the greatest extent.

In its first year of full retail contestability, Queensland was one of the most active electricity markets. New South Wales was also considered as an active market despite being described as Australia's least active market. The report states that differences betweenstates may be due to differing levels of price capping, state involvement and competitiveness within the respective markets.

Figure 6.7

Status of energy retail markets—June 2007



Source: VaasaETT Utility Customer Switching Research Project, *World retail energy market rankings*, October 2008.

The data indicate that in addition to customer movement between retailers, a significant number of small customers in several jurisdictions are choosing to move away from standing offer contracts but remain with their host retailer. South Australia and Victoria have reported relatively high rates of customer switching to market contracts compared to the other states. The relatively low rate of movement to market contracts in Queensland reflects that the state only recently introduced FRC. In New South Wales, the Independent Pricing and Regulatory Tribunal (IPART) has noted significant differences in the rate of switching to market contracts between host retail areas. For example, the switching rate of 42 per cent in EnergyAustralia supply areas compares with only 5 per cent in Country Energy areas. IPART considered this to indicate significant differences in competitive activity between metropolitan and non-metropolitan areas.[33]

International comparisons

The VaasaETT Utility Customer Switching Research Project published its fourth report on customer switching in world energy markets in 2008. The report classified competition on a scale ranging from 'hot' to 'dormant' (see box 6.3 and figure 6.7).

6.3.3 Customer perceptions of competition

Surveys on customer perceptions of retail competition are undertaken irregularly within jurisdictions. Recent surveys include:

> surveys as part of the AEMC's review of the effectiveness of retail competition in Victoria (2007) and South Australia (2008)
> IPART's survey of residential energy and water use in Sydney, the Blue Mountains and Illawarra (2006)
> surveys conducted as part of ESCOSA's monitoring of the development of energy retail competition in South Australia (2006).

Issues covered by the surveys include:

> customers' awareness of their ability to choose a retailer
> customer approaches to retailers about taking out a market contract
> retail offers received by customers
> customer understanding of retail offers.

Table 6.8 provides a summary of survey data on customer perceptions of retail competition. The surveys suggest that customer awareness of retail choice has risen over time. While it remains unusual for customers to approach retailers, there has been a steady rise in retailer approaches to customers.

Table 6.8 Residential customer perceptions of competition

	South Australia				Victoria			New South Wales	
Indicator	2003	2004	2006	2008	2002	2004	2007	2003	2006
Customers aware of choice	62%	79%	79%	82%	n/a	90%	94%	74%	92%
Customers receiving at least one retail offer	5%	44%	52%	68%	17%	33%	73%	27%[1]	53%[1]
Customers approaching retailers about taking out market contracts	3%	10%	8%	10%	3%	8%	10%	n/a	n/a

n/a, not available.

Note:

1. Does not include customers approached to switch to a market contract by their current retailer. By 2006, 44 per cent of households in New South Wales had been approached to switch to a market contract by their existing retailer.

Sources: South Australia: McGregor Tan Research, *Monitoring the development of energy retail competition—Residents*, prepared for ESCOSA, February 2006, September 2004 and November 2003; McGregor Tan Research, *Review of effectiveness of competition in electricity and gas retail markets*, prepared for AEMC, June 2008; Victoria: The Wallis Group, *Review of competition in the gas and electricity retail markets—Consumer survey*, prepared for AEMC, August 2007; New South Wales: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra—Results from the 2006 household survey*, November 2007.

33 IPART, *Regulated electricity tariffs and charges for customers 2007 to 2010—Electricity final report and final determination*, June 2007, p. 29.

6.4 Retail prices

Retail customers pay a single price for a bundled electricity product made up of electricity, transport through the transmission and distribution networks, and retail services. Data on the underlying composition of retail prices are not widely available. Figure 6.8 provides indicative data for residential customers in New South Wales and Queensland based on historical information. The charts indicate that wholesale and network costs account for the bulk of retail prices. Retail operating costs (including margins) account for around 13 per cent of retail prices in New South Wales and 10 per cent in Queensland.

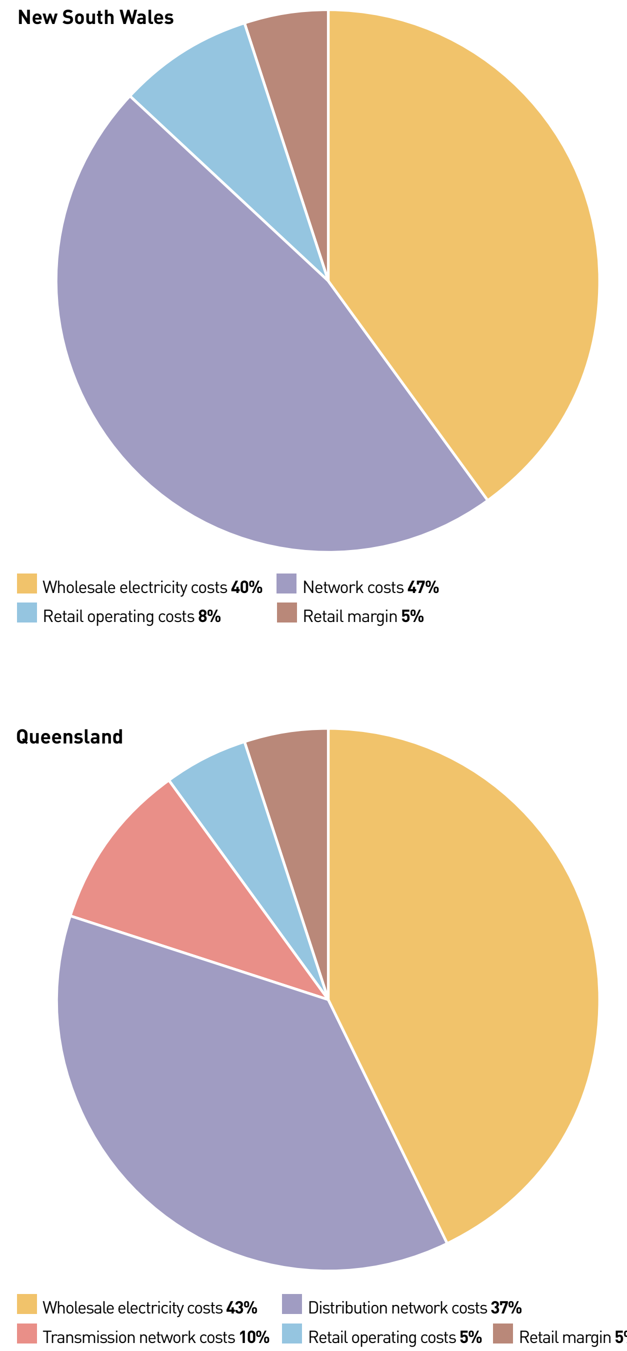
6.4.1 Regulation of retail prices

As at July 2008 all jurisdictions continue to apply retail price regulation to protect small customers. Typically, host retailers must offer to sell electricity at default prices based on some form of regulated price cap or oversight. Small customers may request a standing offer contract—with default prices—from the host retailer or choose an unregulated market contract from a licensed retailer.

Price cap regulation was intended as a transitional measure during the development phase of retail markets. To allow efficient signals for investment and consumption, governments are moving towards removing retail price caps. As noted, the AEMC (and the Economic Regulation Authority in Western Australia) is reviewing the effectiveness of competition in electricity and gas retail markets to determine an appropriate time to remove retail price caps in each jurisdiction (see box 6.1).

In setting default tariffs, jurisdictions take into consideration energy purchase costs, network charges, retailer operating costs and a retail margin. The approach varies between jurisdictions.

Figure 6.8
Composition of a residential electricity bill



Sources: New South Wales: IPART, *Regulated electricity tariffs and charges for customers 2007 to 2010—Electricity final report and final determination*, June 2007, p. 2; Queensland: QCA, *Final Decision—Benchmark Retail Cost Index for Electricity: 2008–09*, May 2008.

- The New South Wales regulator, IPART, sets a retail price cap for small customers that do not enter a market contract. IPART noted in its review of retail prices for 2007–10 that the New South Wales Government aimed to reduce customer reliance on regulated prices and had directed IPART to ensure that regulated tariffs are cost reflective by June 2010.[34]
- Since 2003, the Victorian Government has entered into agreements with host retailers on a pricing structure for default retail prices for households and small businesses. Default price arrangements ceased to apply to small businesses from 1 January 2008, and will cease for residential users from 1 January 2009.
- The South Australian regulator, ESCOSA, regulates default prices for small customers. In 2007 ESCOSA made a determination on default prices for 3.5 years commencing on 1 January 2008.
- In Queensland, the government bases annual adjustments in regulated price caps on changes in benchmark costs. In March 2007, the government delegated the calculation of benchmark costs to the QCA.
- When requested by the ACT Government, the ACT regulator (the Independent Competition and Regulatory Commission) determines the maximum prices for small customers on a standing offer contract. The regulator makes annual adjustments to the regulated tariff to reflect changes in benchmark costs.
- In Western Australia, electricity retail prices for non-contestable customers are regulated under statutory requirements and the prices for these customers are set out in by-laws. All non-contestable customers are entitled to a uniform price regardless of their geographic location. Regional customers are subsidised by the Tariff Equalisation Fund, which is administered by the Office of Energy.[35]

Table 6.9 in section 6.4.3 refers to recent retail price determinations.

6.4.2 Retail price outcomes

While retail price outcomes are of critical interest to consumers, the interpretation of retail price movements is not straightforward. Trends in retail prices may reflect movements in the cost of any one or a combination of underlying components: wholesale electricity prices, transmission and distribution charges, or retail operating costs and margins.

Particular care should be taken when interpreting retail price trends in deregulated markets. While competition tends to deliver efficient outcomes, it may sometimes give a counter-intuitive outcome of *higher* prices—especially in the early stages of competition—as in the following examples.

- Energy retail prices for some residential customers were historically subsidised by governments and other customers (usually business customers). A competitive market will unwind cross-subsidies, which may lead to price rises for some customer groups.
- Some regulated energy prices were traditionally at levels that would have been too low to attract competitive new entrants. It may sometimes be necessary for retail prices to rise to create sufficient 'headroom' for new entry.

Sources of price data

There is little systematic publication of the actual prices paid by electricity retail customers. The Energy Supply Association of Australia (ESAA) previously published annual data on retail electricity prices by customer category and region but discontinued the series in 2004.

At the state level:

- All jurisdictions publish schedules of regulated prices. The schedules are a useful guide to retail prices, but their relevance as a price barometer is reduced as more customers transfer to market contracts.
- Retailers are not required to publish the prices struck through market contracts with customers, although some states require the publication of market offers.

34 IPART, *Regulated electricity tariffs and charges for customers 2007–2010—Electricity final report and final determination*, June 2007, p. 2.
35 Office of Energy, *Electricity Retail market review—Issues paper*, December 2007, p. 7.

- The Victorian and South Australian regulators (ESC and ESCOSA) publish annual data on regulated and market prices.
- ESCOSA, QCA and ESC websites provide an estimator service that consumers can use to compare the price offerings of different retailers (see box 6.2).

Consumer Price Index and Producer Price Index

The consumer price index (CPI) and producer price index published by the Australian Bureau of Statistics track movements in household and business electricity prices.[36] The indexes are based on surveys of the prices paid by households and businesses and therefore reflect a mix of regulated and market prices.

Figure 6.9 tracks real electricity price movements for households and business customers. There is some volatility in the data for business customers, reflecting that large energy consumers are exposed to price volatility in the wholesale and contract markets for electricity (see chapters 2 and 3). In most jurisdictions, residential prices are at least partly shielded from volatility by price cap regulation and retailers' hedging arrangements.

Since 1991, real household prices have risen by 7 per cent, while business prices have fallen by 21 per cent (figure 6.10). In part, this reflects the unwinding of cross-subsidies from business to household customers that began in the 1990s. While business prices have fallen substantially since 1991, they rose in 2007 due to rising wholesale electricity costs (see section 6.4.3).

It is possible to estimate retail price outcomes for households by extrapolating from the historic ESAA data, using the CPI. Figure 6.11 estimates real electricity prices for households in Sydney, Melbourne, Adelaide, Brisbane, Hobart, Canberra and Perth since 1 July 1996. Price variations between the cities reflect a variety of factors, including differences in generation and network costs, industry scale, historical cross-subsidies, differences in regulatory arrangements and different stages of electricity reform implementation.

From 2001 to 2007, real electricity prices in Melbourne and Perth trended downwards. Sydney and Canberra prices trended upwards but remain low compared with the other capitals. In Brisbane (where small customer prices remained fully regulated until 2007) and Hobart (where small customer prices are still fully regulated), real prices have remained relatively stable since 2001. Price rebalancing to phase out cross-subsidies caused significant price rises in Melbourne and Adelaide early in the current decade.

6.4.3 Update: Retail price trends in 2007–08

Several jurisdictions announced significant increases in regulated default prices in 2007 and 2008 in response to rising wholesale energy and hedging costs. In particular, wholesale prices in the NEM reached record levels, flowing through to higher contract prices for electricity derivatives. These developments raised concerns about possible effects on retailer profitability and retail prices.

Differences in the level of default price increases between jurisdictions reflect a range of factors and should be interpreted with care. In particular, there are differences in the operating environments of retail businesses. The degree of retailer exposure to wholesale costs depends on a variety of factors, including the nature and shape of a retailer's load, the extent of hedging in financial markets to provide protection against price volatility and the strike price of financial contracts. Some retailers have vertical relationships with generators to cushion the impact of volatile wholesale costs.

There were also differences in price levels prior to the current determinations. In addition, jurisdictions adopt different approaches to determining costs and margins. For example, until 2007 the New South Wales regulator, IPART, set relatively low retail margins because the Electricity Tariff Equalisation Fund (ETEF) managed energy purchasing risks for host retailers. IPART reviewed this position in its 2007–10 determination in light of the proposed phasing out of ETEF.

36 The producer price index series tracks input costs for manufacturers.

Figure 6.9

Retail electricity price index (inflation adjusted)—Australian capital cities, June 1991 to March 2008

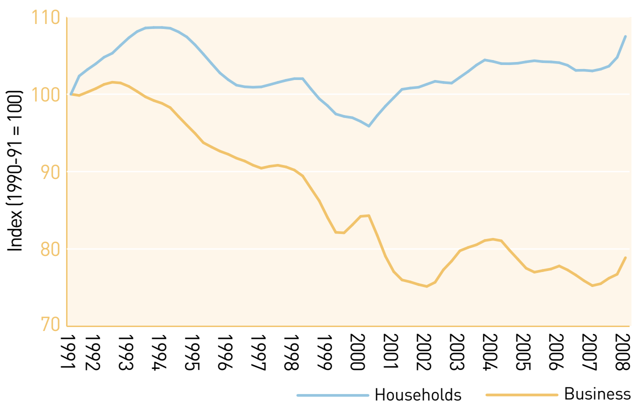
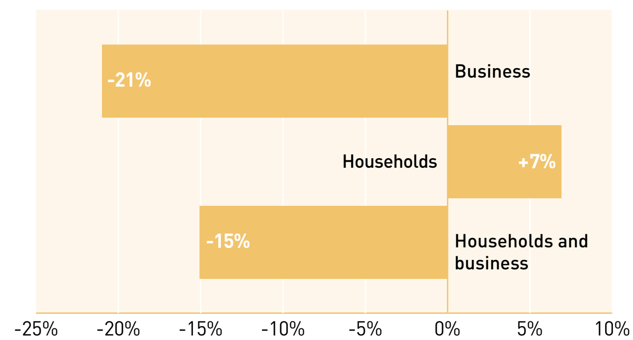


Figure 6.10

Change in the real price of electricity—Australia, June 1991 to March 2008



Note: The household index is based on the CPI for household electricity, deflated by the CPI series for all groups. The business index is based on the producer price index for electricity supply in 'Materials used in Manufacturing Industries', deflated by the CPI series for all groups.

Sources for figure 6.9 and figure 6.10: ABS, *Consumer Price Index*, March quarter 2008, cat. no. 6401.0 and 6427.0.

Figure 6.11

Real electricity prices for households—Australian capital cities, July 1996 to March 2008

KWh, kilowatt hours.

Note:

1. The dashed lines are estimates based on extrapolating ESAA data published in 2004 using the CPI series for electricity and other household fuels for each capital city.
2. 2007–08 is the three quarters to March 2008.

Sources: ABS, *Consumer Price Index*, March quarter 2008, cat no. 6401; ESAA, *Electricity prices in Australia 2003–04*, 2003.

Table 6.9 compares recent movements in regulated default prices and retail margins under regulatory or government decisions. The decisions relate to the supply of electricity by host retailers to customers on standing offer contracts. As noted, several jurisdictions have allowed significant increases in default prices. Some have also taken measures to allow further revisions to default price paths in the event of ongoing volatility in the wholesale market.

Victoria cited the effect of the drought on the cost of generating electricity as the primary reason for substantial increases in default prices. The Department of Primary Industries noted that the drought reduced the output of hydroelectric plants in favour of more

Table 6.9 **Recent regulatory decisions—electricity retail prices**

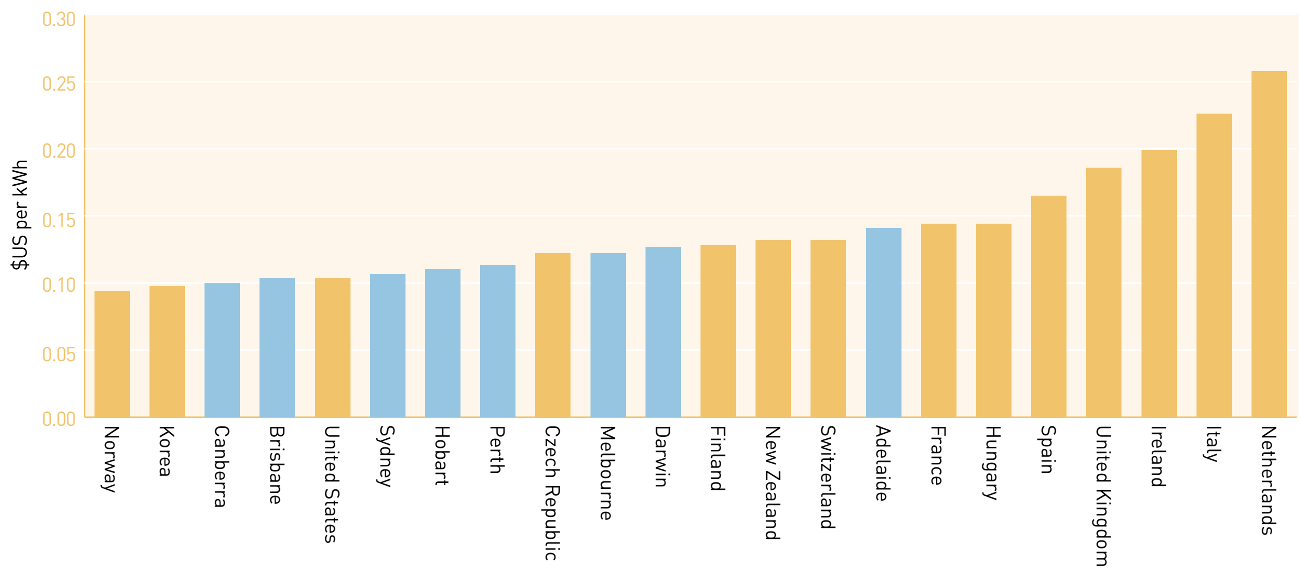
JURISDICTION	CURRENT PERIOD	RETAILERS	INCREASE IN REGULATED TARIFF	PASS-THROUGH MECHANISM FOR WHOLESALE ENERGY COSTS	RETAIL MARGIN
New South Wales	1 July 2007 to 30 June 2010	EnergyAustralia Integral Energy Country Energy	CPI + 4.1% CPI + 4.9% CPI + 3.7% (annual adjustments)	Annual review of electricity purchase costs. The retail price path will be adjusted if the review finds that forecast electricity purchase costs differ by more than 10% from the costs used to set the price path.	5% of EBITDA
Victoria	1 January 2008 to 31 December 2008	AGL Energy Origin Energy TRUenergy	CPI + 10.7% CPI + 10.9% CPI + 15.5%	Annual price determination. No adjustments permitted.	5–8% of total revenue
Queensland	1 July 2008 to 30 June 2009	All licenced retailers	5.4%	Prices are adjusted annually in accordance with a benchmark retail cost index.	5% of total revenue
South Australia	1 January 2008 to 30 June 2011	AGL Energy	12.3% in 1 Jan 08 to 30 Jun 08; and then CPI—only increase to Jul 2011	No provision to adjust price path due to changes in electricity purchase costs. However, the price determination can be reopened in circumstances where a fundamental basis of the price determination has been undermined.	10% of controllable costs (equivalent to about 5% of sales revenue)
Tasmania	1 January 2008 to 30 June 2010	Aurora Energy	16.0% in 1 Jan 08 to 30 Jun 08; 4.0% in 2008–09; and 3.8% in 2009–10	No provision to adjust price path due to changes in electricity purchase costs as the average price the regulator is to assume for each period is set out in regulations. The regulator also has limited discretion to reopen a price determination in the event of an unforeseen material change in circumstances.	3% of sales revenue
ACT	1 July 2008 to 30 June 2009	ActewAGL Retail	7.11%	Annual price determination. No adjustments permitted.	5% of sales revenue
Western Australia	1 July 2009	Synergy Horizon Power	10.0%	Government decision to be implemented through by-laws. Further price rises will be phased in over 6 to 8 years (after 30 June 2010).	n/a

n/a, not available; EBITDA, earnings before interest, tax, depreciation and amortisation; EBIT, earnings before interest and tax.

Note: Frontier Economics estimates that a 5 per cent EBITDA is equivalent to around 4 per cent on an EBIT basis.

Sources: Frontier Economics, *Mass market entrant retail costs and retail margins,* Final report, March 2007, p. 68; New South Wales: IPART, *Regulated electricity retail tariffs and charges for small customers 2007 to 2010 Electricity: Final report and final determination*, June 2007; Victoria: Department of Primary Industries, *Victorian Energy Prices Fact Sheet*, November 2007; Queensland: QCA, *Final decision: benchmark retail cost index for electricity 2008–09*, May 2008; South Australia: ESCOSA, *2007 Review of retail electricity price path final inquiry report and price determination*, November 2007; Tasmania: OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Final report and proposed maximum prices*, September 2007; ACT: ICRC, *Final decision and price direction retail prices for non-contestable electricity customers report 4 of 2008*, June 2008; Western Australia: *Energy Operators (Regional Power Corporation) (charges) By-laws 2006* (WA); Premier (WA) (Hon. Alan Carpenter), *State government to phase in electricity price increases*, media statement, 4 April 2007.

Figure 6.12
International electricity prices for households, 2006



kWh, kilowatt hours.

Note: Price data for Australia are AER estimates converted to US$. The data for each jurisdiction is for 2006 and is estimated by extrapolating the ESAA data published in 2004 using the CPI series for electricity and other household fuels for each capital city.

Sources: IEA, *Electricity information 2007*, table 3.7, Electricity prices for households in US dollars/kWh; ATO, Foreign exchange rates, End of financial year rates, US rate for 31 December 2006; ESAA, *Electricity prices in Australia 2003–04*, 2003; ABS, *Consumer price index*, cat. no. 6401.0, tables 3 and 4.

expensive gas-fired generation and that the increase in regulated electricity tariffs is an accurate reflection of increased costs incurred by retailers.[37] Similarly, the ACT has identified the lack of availability of hydroelectric power from the Snowy region and the lack of water for cooling base load generators in Queensland as driving factors behind the need to increase regulated retail tariffs by 16.7 per cent in 2007–08.[38]

In Western Australia, the Office of Energy is reviewing the electricity retail market in 2008. The Office of Energy noted in April 2008 that residential prices have not increased since June 1997 and that by June 2009 this will represent a real price reduction of about 30 per cent.[39] It also recommended that prices would need to increase by 47 per cent in 2009–10 and 15 per cent the following year to achieve cost reflective outcomes.[40] The Western Australian Government rejected the draft recommendation and announced that residential prices will increase by 10 per cent in 2009–10, with further increases to be phased in over the following 6–8 years.[41]

6.4.4 International price comparisons

Figure 6.12 compares estimated residential electricity prices in Australian capital cities with prices in selected Organisation for Economic Cooperation and Development (OECD) countries. The data indicate that average electricity prices in Australian capital cities are generally lower than in many OECD countries.

37 Minister for Energy and Resources (Victoria) (Hon Peter Batchelor), *Drought impact on power prices*, media statement, 30 November 2007; Department of Primary Industries, *Energy retail price adjustments* 2008, November 2007.

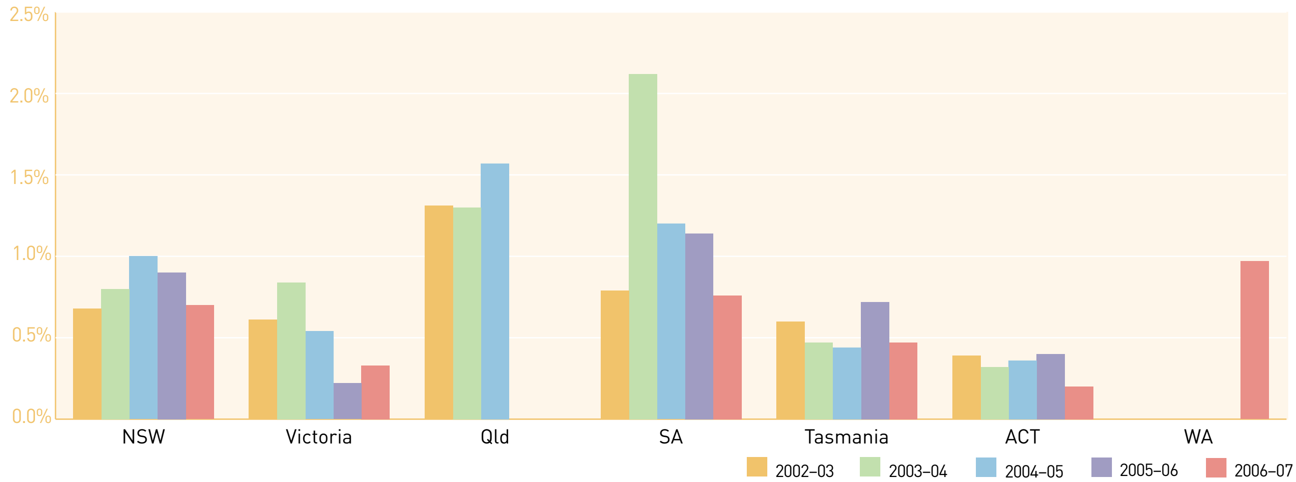
38 ICRC, *Final decision increases retail electricity tariff*, media statement, 15 June 2007.

39 Office of Energy, *Electricity Market Review draft recommendations report—Review of electricity tariff arrangements*, April 2008, p. 7.

40 Office of Energy, *Electricity Market Review draft recommendations report—Review of electricity tariff arrangements*, April 2008, p. 3.

41 Premier (WA) (Hon Alan Carpenter), *State government to phase in electricity price increases*, media statement, 4 April 2007.

Figure 6.13
Electricity residential disconnections as a percentage of small customer base

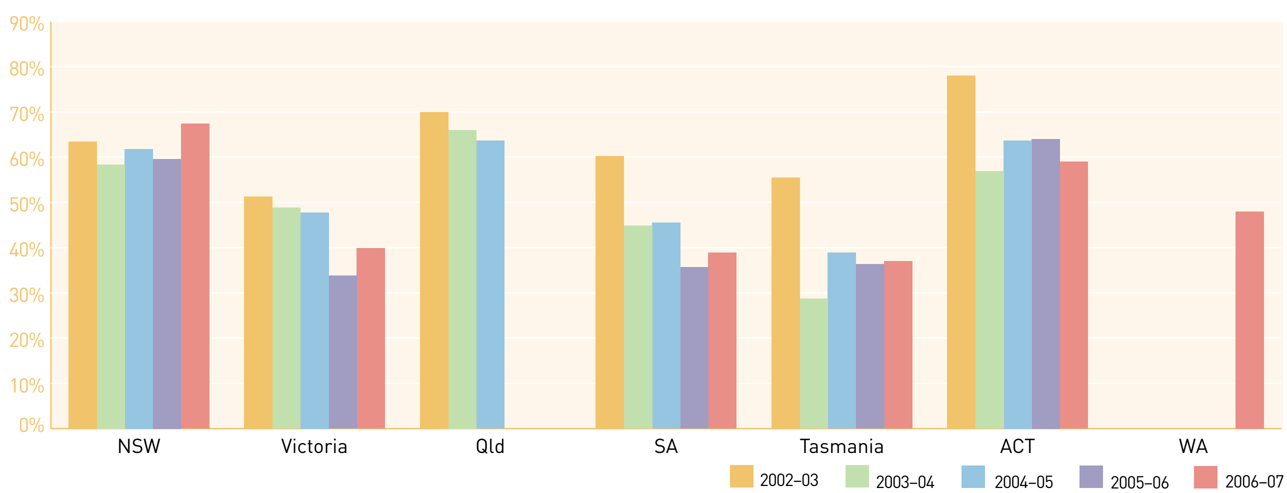


Notes:

1. Figure relates to outcomes for residential customers on a state-wide basis. State regulators also publish outcomes for particular retailers and for business customers in their jurisdiction.
2. Queensland data are only available to 2004–05. Western Australian data are available only for 2006–07.

Source: see figure 6.16.

Figure 6.14
Electricity residential reconnections within seven days as a percentage of disconnected customers



Notes:

1. New South Wales includes all reconnections (not just within seven days of disconnection)
2. Queensland data is only available to 2004–05. Western Australian data is available only for 2006–07.

Source: see figure 6.16.

For example, average prices in the United Kingdom, Italy, Spain and France are higher than in Australian capital cities. However, prices in most Australian capital cities are higher than average prices in the United States.

6.5 Quality of retail service

The jurisdictional regulators monitor and report on quality of service in the retail sector to enhance transparency and accountability, and to facilitate 'competition by comparison'.[42] The Utility Regulators Forum (URF) developed a national framework in 2002 for electricity retailers to report against common criteria on service performance.[43] The criteria address:

- access and affordability of services
- quality of customer service.

The URF measures apply to the small customer retail market.[44] All NEM jurisdictions have adopted the URF reporting template but each jurisdiction applies its own implementation framework. In addition, jurisdictions have their own monitoring and reporting requirements. This results in some differences in approach.

URF data published by jurisdictional regulators are derived from the reporting of individual retailers. The regulators consolidate and publish the data annually. It should be noted that the validity of any performance comparisons may be limited because of differences in approach between jurisdictions. In particular, measurement systems, audit procedures and classifications may differ between jurisdictions and within the same jurisdiction over time. Similarly, regulatory procedures and practices differ; for example, the procedures a retailer must follow before a customer can be disconnected.

6.5.1 Affordability and access indicators

With the introduction of retail contestability, governments have strengthened consumer protection arrangements, with a particular focus on access and affordability issues. These protections are often given effect through regulated minimum standards regimes and codes.

Retailers provide options to help customers manage their bill payments. The URF reporting template covers a number of affordability indicators, including rates of customer disconnections and reconnections.

The rate of residential customer disconnections for failure to meet bill payments (figure 6.13) and the rate of disconnected residential customers who are reconnected within seven days (figure 6.14) are key affordability and access indicators. The rate of disconnections fell in all jurisdictions other than Victoria in 2006–07, and rates are below 2002–03 levels in all jurisdictions except New South Wales and Queensland. A range of factors, varying between jurisdictions, may have contributed to these outcomes. For example, recently introduced hardship policies and the recommendations of the newly established disconnection working group in New South Wales may have contributed to the reduction in the disconnection rate of 0.2 per cent in that state since 2005–06.[45] Also, the decrease in disconnection rates in South Australia may have been assisted by an increase in the use of instalment plans.[46] More generally, the data should be considered in conjunction with reconnection data (figure 6.14).

42 See, for example, ESC, *Energy retail businesses, comparative performance report for the 2006–07 financial year*, December 2007.
43 Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, Discussion paper, March 2002.
44 See footnote 2 for jurisdictional classifications of 'small customers'.
45 IPART, *Electricity retail businesses' performance against customer service indicators 2002–2007*, 2008.
46 ESCOSA, *2006–07 Annual performance report: performance of South Australian energy retail market*, November 2007.

The rate at which disconnected residential customers are reconnected within seven days (figure 6.14) increased in most jurisdictions in 2006–07, although rates are below 2002–03 levels in all jurisdictions except New South Wales. When considered in conjunction with falling disconnection rates, the data indicate that retailers may have improved their customer management services by reducing the rate of avoidable disconnections—perhaps through better use of payment plans, as in South Australia, and through other account management options.[47]

6.5.2 Customer service indicators

There are a range of methods by which customers can seek to resolve service issues with energy retailers. In the first instance, customers can raise complaints directly with their retailer through the retailer's dispute resolution procedure. If further action is needed, they can refer complaints to their state energy ombudsman or an alternative dispute resolution body. Additionally, retail competition allows customers to transfer away from a business providing poor service.

URF monitoring in this area includes:

- customer complaints—the degree to which a retailer's services meet customers' expectations
- telephone call management—the efficiency of a retailer's call centre service.

In 2006–07, the rate of customer complaints fell slightly from the previous year in New South Wales, Tasmania and South Australia. While the rate rose in Victoria, complaints remain below 1 per cent of customers in all jurisdictions (see figure 6.15). Western Australia recorded a relatively low complaints rate for its first year of published data (2006–07).

Call centre performance varied across the jurisdictions in 2006–07 (see figure 6.16), when the percentage of customer calls answered within 30 seconds ranged from about 65 to 82 per cent. Tasmania and South Australia have recorded consistently high call centre performance results. In New South Wales and Victoria, the rate in 2006–07 was lower than the previous year, but remained higher than in 2003–04. The ACT has improved its call centre performance from 64 per cent in 2002–03 to 77 per cent in 2007–08.

6.5.3 Consumer protection

Governments regulate aspects of the electricity retail market to protect consumers and ensure they have access to sufficient information to make informed decisions. Most jurisdictions require designated host retailers to provide electricity services under a standing offer or default contract to particular customers. Most jurisdictions impose this obligation on retailers on a geographical basis. Queensland, however, requires default contracts to be offered by the financially responsible market participant—generally the current retailer—for each property. Obligations for new connections are imposed on a geographical basis.[48]

Default contracts cover minimum service conditions, billing and payment obligations, procedures for connections and disconnections, information disclosure and complaints handling. During the transition to effective competition, default contracts also include some form of regulated price cap or prices oversight (see section 6.4.1).

Some jurisdictions have established industry codes that govern the provision of electricity retail services to small customers, including under market contracts. Industry codes cover consumer protection measures, including:

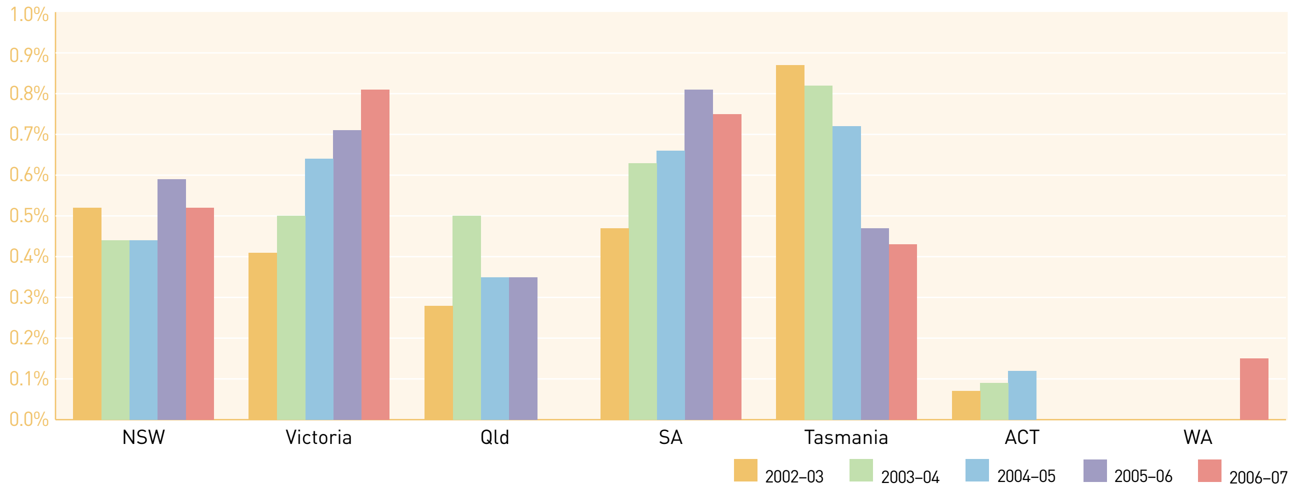
- minimum terms and conditions under which a retailer can provide electricity retail services
- standards for the marketing of energy services
- processes for the transfer of customers from one retailer to another.

Most jurisdictions have an energy ombudsman or an alternative dispute resolution body to whom consumers can refer a complaint they were unable to resolve directly with the retailer. In addition to general consumer protection measures, jurisdictions have introduced supplier of last resort arrangements to ensure customers can be transferred from a failed retailer to another.

47 ESCOSA, *2006–07 Annual performance report: performance of South Australian energy retail market*, November 2007.

48 The AEMC, in its review of the effectiveness of the Victorian energy retail market, recommended Victoria move to a financially responsible market participant model.

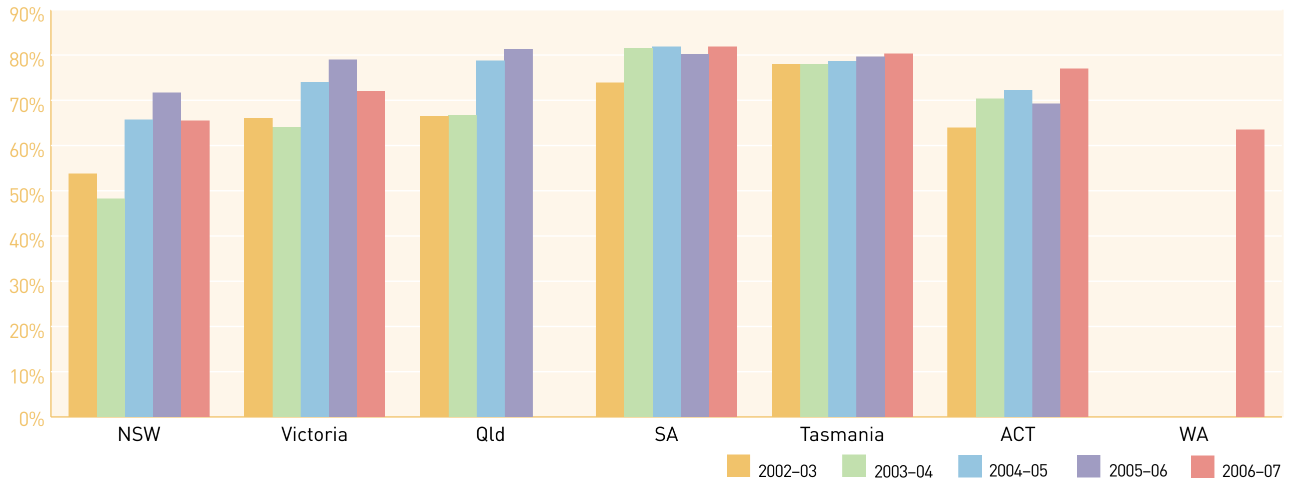
Figure 6.15
Electricity retail customer complaints as a percentage of total customers



Note: Queensland data are only available to 2004–05. Western Australian data are available only for 2006–07.

Source: see figure 6.16.

Figure 6.16
Percentage of electricity retail customer calls answered within 30 seconds



Notes:

1. South Australian data for 2005–06 and 2006–07 include electricity and gas customers. Call response rates in Tasmania are for calls answered within 20 seconds.
2. Queensland data are only available to 2004–05. Western Australian data are available only for 2006–07.

Sources for figures 6.13–6.16: Reporting against URF templates and performance reports on the retail sector by IPART (New South Wales), ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), QCA and the Department of Mines and Energy (Queensland) and ICRC (Australian Capital Territory); ERA, *2006–07 Annual performance report electricity retailers*, January 2008 (Western Australia). The 2005–06 and 2006–07 data for the ACT are preliminary data provided by the ICRC.

States and territories also provide a range of community service obligation payments to particular customer groups—often low incomes earners. Traditionally, the payments were often 'hidden' in subsidies and cross-subsidies between different customer groups, which caused distortions to pricing and investment signals. As part of the energy reform process, governments are making community service obligations more transparent and are directly funding them out of their budgets rather than using cross-subsidises.

In April 2008, the Productivity Commission recommended establishing a national consumer protection regime for energy services and a single set of consumer protection requirements in all NEM jurisdictions.[49] The commission also recommended a more consistent approach to complaint-handling and reporting processes by jurisdictional energy ombudsmen and, ultimately, the establishment of a national energy ombudsman.[50]

6.6 Demand management and energy efficiency

Energy efficiency and demand management measures are an important feature of an effective energy market. Demand management relates to strategies that address growth in demand (especially peak demand) for electricity. Energy efficiency refers to products or strategies that use less energy for the same or higher performance than an existing system or product. While energy efficiency and demand management measures can improve the efficiency of energy use, there are wider benefits. For example, the measures can help ease congestion in network infrastructure, allow the deferral of some capital expenditure, reduce the incidence of wholesale electricity price spikes (and retailers' hedging costs) and improve security of supply. A number of measures to improve energy efficiency are currently being implemented through the retail sector, as set out in the following text. Some demand management programs operate via the distribution network sector (see section 6.6.3).

6.6.1 National framework for energy efficiency

The National Framework for Energy Efficiency was launched in 2004 to better utilise energy efficient technologies to lower greenhouse gas emissions and deliver other benefits from reduced energy use. The framework is being implemented cooperatively by the Australian and state and territory governments.

Stage one of the framework focused on improved national coordination of existing energy efficiency measures. It focused on policies such as design standards for residential, commercial, industrial and government buildings; commercial and industrial efficiency; appliance and equipment efficiency; trade and professional training and accreditation; and consumer and finance sector awareness.

Stage two of the framework, agreed by the MCE in December 2007, covers schemes such as extending the Minimum Energy Performance Standards program and increasing the efficiency of heating, ventilation, air conditioning, lighting and hot water systems.[51]

6.6.2 Jurisdictional energy efficiency initiatives

Many state governments are implementing programs to promote energy efficiency:

- The Victorian Energy Efficiency Target Scheme, commencing in 2009, will set an overall target for energy savings (2.7 million tonnes annually for the first three years). The scheme will require energy retailers to meet individual targets through energy efficiency activities, such as providing householders with energy saving products and services.[52]

49 Productivity Commission, *Inquiry report: Review of Australia's consumer policy framework*, 30 April 2008, pp. 66–67.

50 Productivity Commission, *Inquiry report: Review of Australia's consumer policy framework*, 30 April 2008, p. 71.

51 MCE, *Communiqué*, 31 December 2007; The National Framework for Energy Efficiency, viewed June 2008, http://www.nfee.gov.au.

52 Victorian Department of Primary Industries, *Victorian Energy Efficiency Target Scheme fact sheet*.

- South Australian retailers will be subject to the Residential Energy Efficiency Scheme from January 2009. The scheme requires retailers to meet targets to improve household energy efficiency (for example, through the use of ceiling insulation, draught proofing and more efficient appliances) and provide energy audits to low income households. A consultation paper on the scheme was released in February 2008.[53]
- The New South Wales Energy Savings Fund is providing $200 million over five years for projects to save energy and reduce peak electricity demand. It also aims to stimulate investment in innovative measures and increase public awareness of the benefits of energy savings.

Similarly, the Queensland Sustainable Energy Innovation Fund provides grants to assist organisations with the development and commercialisation of sustainable technologies. In May 2008, Queensland also introduced the Smart Energy Savings Program. This program requires medium to large energy users to complete energy conservation audits and develop action plans to reduce their energy use. The program also includes a fund that encourages energy efficiency initiatives by encouraging investment in commercial energy saving projects.

6.6.3 Demand management

As noted, demand management relates to strategies to manage growth in demand (especially peak demand) for electricity. One strategy is to encourage customers to adjust their energy consumption in response to price signals. For example, a customer may be offered financial incentives to reduce consumption at times of high system demand.

While demand management schemes ultimately target retail customers, some measures are implemented via the network sector. In particular, some jurisdictions provide incentives to distribution businesses to undertake demand management projects:

- In New South Wales, network businesses are permitted to recover expenditure on approved demand management projects through their regulated prices.
- In South Australia, ETSA Utilities was provided with a $20 million allowance in its current determination to undertake pilot demand management initiatives—for example, load control for domestic equipment such as air conditioners and pool pumps; incentive payments to customers to reduce demand at peak times; and working with developers to encourage more sophisticated design of air conditioning and lighting control systems. Similar incentives are offered in Victoria.
- While there are currently no demand-management incentives for distribution businesses in the other NEM jurisdictions, Queensland distributors are undertaking a number of projects. For example ENERGEX is conducting a trial of the direct control of small customer air conditioner loads (known as 'Cool Change'). Under this trial, some small customers have permitted ENERGEX to connect a controlling device that cycles their air conditioner compressors on and off.

In November 2007, the AEMC published a proposal from the Total Environment Centre to amend the National Electricity Rules to improve the incentives offered to electricity network businesses to undertake demand management in preference to network expansion.[54] The AEMC is also reviewing demand management in the NEM to determine whether there are barriers to effective demand management, including in the regulation of electricity networks and network planning.[55]

In addition to the national and jurisdictional schemes, some large customers manage their demand by purchasing electricity only when it remains below a given price. Some retailers also manage demand by asking customers to load shed if the price reaches a predetermined level.

53 South Australian Department for Transport, *Energy and Infrastructure, Residential Energy Efficiency Scheme consultation paper*, February 2008.

54 AEMC, *Demand management*, viewed 11 June 2008, http://www.aemc.gov.au/electricity.php?r=20071115.124352.

55 Australian Energy Market Commission, *Review of demand side participation in the national electricity market*, viewed 11 June 2008, http://www.aemc.gov.au/electricity.php?r=20071025.174223.

6.6.4 Metering

Effective metering can encourage more active demand management by customers. Meters record the energy consumption of end-use customers at the point of connection to the distribution network. There are two main types of meters:

- The older-style 'accumulation meters' record the total consumption of electricity at a connection point, but not the time of consumption. Consumers are billed solely on the volume of electricity consumed.
- 'Interval meters' are more sophisticated and record consumption in defined time intervals (for example, half-hour periods). This allows time-of-use billing so the charge for electricity can be varied with the time of consumption. Interval meters are generally used by industry.

To provide better signals to consumers and investors on consumption, price and energy use, plans are being considered at the national and state levels to introduce 'smart meters', an advanced type of interval meter. Smart meters have remote communication capabilities between retailers and users that allow for remote meter reading, connection and disconnection of customers. They also allow retailers and distributors to manage loads to particular customers and appliances. Add-ons such as an in-house display may provide information on prices, greenhouse gas emissions and other aspects of electricity consumption. The primary benefit of smart meters is that, together with an appropriate price structure, they can help energy users self-manage their demand in response to price signals.

At June 2007, interval meters accounted for about 10 per cent of all meters in Australia. The rollout has varied among jurisdictions, with the greatest number of meters having been installed in New South Wales:

- In New South Wales, distribution businesses are rolling out interval meters for customers using more than 15 MWh of electricity a year. For smaller customers, interval meters are provided on a new and replacement basis.
- The Victorian Government has initiated a program to provide smart meters to all small customers over a four-year period from 2009.
- The Queensland Energy Competition Committee has recommended the rollout of interval meters on a new and replacement basis for small customers.
- Since 2005, the Independent Competition and Regulatory Commission (ACT) has required the installation of interval meters on a new and replacement basis and when requested by a customer.
- In Western Australia, all new meters installed must support time-of-use pricing.
- The South Australian and Tasmanian governments concluded that the rollout of interval meters to small customers is not currently justified.

In 2007, the Council of Australian Governments agreed to a national implementation strategy for the progressive rollout of smart meters where the benefits outweigh costs. A cost–benefit assessment published in March 2008 found that a national rollout would achieve a net benefit.[56] In June 2008, the MCE reviewed the cost-benefit analysis for the national smart meter rollout and estimated that a continued rollout in Victoria and New South Wales should result in more than 50 per cent of all Australian meters being replaced by 2017. It considered that other jurisdictions should progress pilot programs. The MCE will consider a timetable for any further rollout of smart meters by June 2012.[57]

56 NERA, *Cost Benefit Analysis of Smart Metering and Direct Load Control Overview Report for Consultation*, 29 February 2008, for Smart Meter Working Group, Phase 2.

57 MCE, *Communiqué*, 13 June 2008.

6.7 Future regulatory arrangements

State and territory governments are currently responsible for the regulation of retail energy markets. Governments agreed in the Australian Energy Market Agreement 2004 (amended 2006) that NEM jurisdictions would transfer non-price regulatory functions to a national framework to be administered by the AEMC and the AER. These functions include:

- the obligation on retailers to supply small customers
- small customer market contracts and marketing
- retailer business authorisations, ring-fencing and retailer failure
- balancing, settlement, customer transfer and metering arrangements
- enforcement mechanisms and statutory objectives.[58]

Under the current proposals, the states and territories will retain responsibility for price control of default tariffs unless they choose to transfer those arrangements to the AER and the AEMC.

The legislative changes required to implement the national framework are scheduled for introduction to the South Australian parliament in September 2009.[59]

The Retail Policy Working Group is developing the framework for consideration by a standing committee of the MCE.

The reform process to June 2008 involved the release of a series of working papers (prepared by Allens Arthur Robinson on behalf of the MCE), discussions with a stakeholder reference group and consultation with interested parties.

The standing committee published a policy paper in June 2008. This will form the basis for the legislative package on the national framework.

The standing committee expects to release an initial exposure draft of the legislative package in late 2008, followed by a final exposure draft in May 2009.[60]

58 Australian Energy Market Agreement 2004 (amended 2006).

59 MCE, *Energy Market Reform Bulletin No. 114*, 13 February 2008.

60 MCE Standing Committee of Officials, *A national framework for regulating electricity and gas (energy) distribution and retail services to customers—Policy response paper*, June 2008, pp. 1–5.

7 BEYOND THE NATIONAL ELECTRICITY MARKET

Two jurisdictions have electricity markets that are not interconnected with the National Electricity Market: Western Australia and the Northern Territory. Western Australia has recently introduced a number of electricity market initiatives, including a new wholesale market. The Northern Territory has introduced electricity reforms, but at present there is no competition in generation or retail markets.

7 BEYOND THE NATIONAL ELECTRICITY MARKET

7.1 Western Australia

Western Australia's electricity market is thousands of kilometres away from the National Electricity Market (NEM), which extends through eastern and southern Australia. There is neither physical interconnection nor governance linkages between the two markets.

With a customer base spread over a third of the national landmass, Western Australia's electricity industry faces some unique challenges. State-wide, around 60 per cent of installed generation capacity is fuelled by natural gas, 35 per cent by coal and 2 per cent by oil. Gas is used in base load cogeneration plants and peaking units. There has been growth in electricity generation from renewable sources, of which more than half consists of wind, with hydro and biomass comprising the balance. Renewable sources fuelled about 4 per cent of generation in 2006–07. Electricity generated from renewable energy has increased six-fold since 2003.[1]

The Western Australian Government has set a target of 6 per cent of electricity to be sourced from renewable energy by 2010. The planned development of the WA Biomass Plant in 2009–10 is expected to lift the share of renewable energy production over this target.

7.1.1 The networks

Reflecting Western Australia's geography, industry and demographics, the state's electricity infrastructure consists of several distinct systems (see figure 7.1):

- the South West Interconnected System (SWIS)
- the North West Interconnected System (NWIS)
- 29 regional, non-interconnected power systems.

The largest network, the SWIS, serves Perth and other major population centres in the south-west of the state, while the NWIS serves towns and the mining and resource industries in the north-west of the state.

1 Sustainable Energy Development Office (WA), Renewable energy, fact sheet, 2008.

The South West Interconnected System

The SWIS is the major interconnected electricity network in Western Australia, supplying the bulk of the south-west region. It extends to Kalbarri in the north, Albany in the south, and Kalgoorlie in the east. The network supplies 840 000 retail customers with 6000 kilometres of transmission lines and 64 000 kilometres of distribution lines. It comprises 4200 megawatts (MW) of installed generation capacity, of which about 75 per cent is owned by the state utility, Verve Energy. The remaining 25 per cent is privately owned, but the energy is principally dedicated to resource projects. Verve Energy's share of installed generation will fall to 66 per cent in 2008–09 as its program of retiring old plant continues.

The principal base load generators are located near Collie, about 200 kilometres south of Perth, near the state's only coal mining facilities. The majority of principal peak load (open cycle gas turbine) generators are located near the Dampier to Bunbury natural gas pipeline north of Perth. There are also plants at Kemerton and Kalgoorlie, and a large mixed fuel generation station at Kwinana, south of Perth. A 320 MW combined cycle gas turbine station is under construction at Kwinana to supply power from late 2008. Most independent power producers with plants connected to the SWIS use gas as their primary fuel (see table 7.1).[2]

Western Australia introduced a wholesale electricity market in the SWIS in September 2006 (see section 7.1.3).

Table 7.1 Installed generation capacity in the South West Interconnected System by fuel source, 2008

FUEL SOURCE	TOTAL GENERATION CAPACITY (%)
Open cycle gas turbine	40
Coal fired	38
Gas cogeneration	12
Combined cycle gas turbine	5
Renewable	5

Source: IMO.

The North West Interconnected System

The NWIS operates in the north-west of the state and centres around the industrial towns of Karratha and Port Hedland and resource centres. The network is significantly smaller than the SWIS and its purpose is to supply the resource industry's operations and associated townships in the area.

The NWIS has a generation capacity of 400 MW. The plants are mainly fuelled by natural gas, some of which is shipped on the Pilbara Energy Pipeline, which runs from Karratha to Port Hedland.

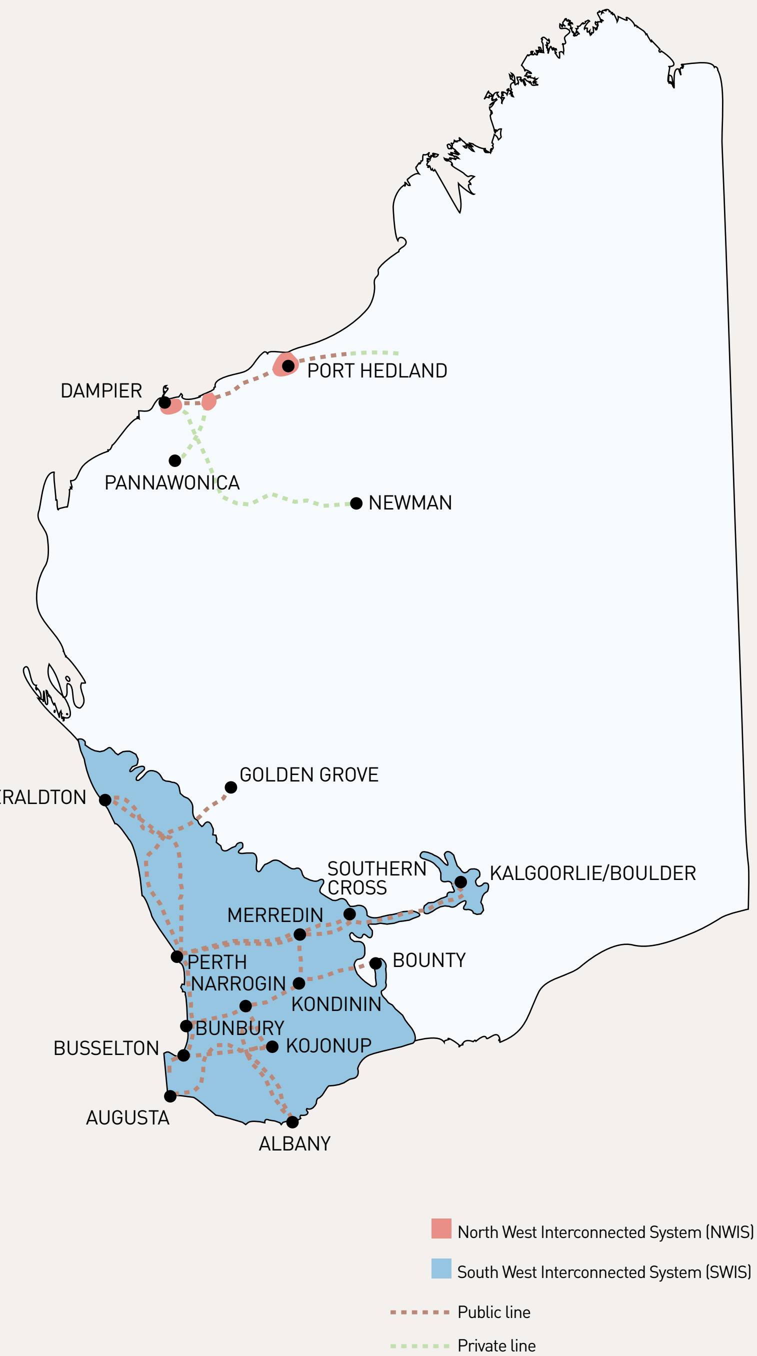
Horizon Power is responsible for the transmission, distribution, and retailing of electricity to customers through the NWIS. Horizon purchases power from private generators in the region and sells it to residential and commercial customers. Private generators serve the major resource companies in the Pilbara. These include Hamersley Iron's 120 MW generation plant at Dampier, Robe River's 105 MW plant at Cape Lambert and Alinta's 105 MW plant at Port Hedland.

Due to the small scale of this system, the NWIS will not see a wholesale market introduced in the manner of the SWIS in the foreseeable future.

2 Griffin Power is currently constructing two coal base load plants near Collie in the south-west of the state.

Figure 7.1

Electricity infrastructure map—Western Australia



Source: Economic Regulation Authority (Western Australia).

Regional non-interconnected systems

Further small, non-interconnected distribution systems operate around towns in rural and remote areas beyond the SWIS and NWIS networks.[3] Horizon Power operates the 29 distribution systems located in these regions, but independent generators supply much of the electricity.

7.1.2 Electricity market reform

In 1993, when Australian governments decided to create a national electricity market, it was impractical for Western Australia to join. Geography dictated that its networks could not be physically interconnected with the other states.

Consistent with the eastern and southern states, Western Australia's electricity industry was historically dominated by a single, vertically integrated utility under government ownership. Western Australia retained this structure for almost a decade longer than other jurisdictions. The lack of competition, in combination with relatively high generation costs (due to relatively expensive coal sources and the remoteness of major gas fields), led to high electricity prices.

The Western Australian Government began implementing a series of electricity reforms in 2003. The central reform was the disaggregation of the electricity utility Western Power Corporation into four separate, state-owned entities in April 2006. The entities are:

- Verve Energy—generation
- Western Power—transmission and distribution networks
- Synergy—retail
- Horizon Power—regional supply.

Other key reforms included:

- establishing, in 2006, a wholesale electricity market (see section 7.1.3)
- establishing, in 2004, an electricity networks access code for access to transmission and distribution networks (see section 7.1.4)
- extending, in 2005, the retail contestability threshold to all customers using more than 50 megawatt hours (MWh) per year (see section 7.1.5)
- implementing consumer protection measures, including a network reliability and quality of supply code and an energy ombudsman scheme (see section 7.1.5).

7.1.3 Wholesale electricity market

In September 2006, Western Australia launched a wholesale electricity market in the SWIS. Energy trading is facilitated through a combination of bilateral contracts, a day-ahead short-term energy market (STEM) and a balancing market. The wholesale market was designed to suit Western Australian conditions at that time and differs considerably from the NEM.

The rule development body and market operator is the Independent Market Operator (IMO), a government entity established in 2004.[4] The IMO has no commercial interest in the market and no connection with any market participant, including Western Power.

The physical system operator, System Management, is a ring-fenced entity within Western Power tasked with maintaining safe, secure and reliable operation of the power system. It is responsible for the operation and control of generator facilities, transmission and distribution networks, and large customer retailer supply management.

3 The networks are located in such areas as Broome, Gascoyne Junction, Menzies, Camballin, Halls Creek, Mount Magnet, Carnarvon, Hopetoun, Norseman, Cue, Kununurra, Nullagine, Denham, Lake Argyle Village, Sandstone, Derby, Laverton, Wiluna, Esperance, Leonora, Wittenoom, Exmouth, Marble Bar, Wyndham, Fitzroy Crossing, Meekatharra and Yalgoo.

4 Information on the market can be found on the IMO website (http://www.imowa.com.au).


Western Power

Table 7.2 **Participants in Western Australia's wholesale electricity market**

PARTICIPANT	GENERATORS 2006	GENERATORS 2008	CUSTOMERS 2006	CUSTOMERS 2008
Alcoa	■	■	■	■
Alinta Sales Pty Ltd	■	■	■	■
Barrick (Kanowna) Limited			■	■
Bioenergy Limited		■		
EDWF Manager Pty Ltd	■	■		
Eneabba Gas Limited		■		
Enebba Energy Pty Ltd		■		
Goldfields Power Pty Ltd	■	■		
Griffin Power Pty Ltd		■		■
Landfill Gas and Power Pty Ltd	■	■	■	■
Mount Herron Engineering Pty Ltd	■	■		
Namarkkon Pty Ltd		■		
NewGen Power Kwinana Pty Ltd		■		
Newmont Power Pty Ltd			■	■
Perth Energy Pty Ltd	■	■	■	■
Premier Power Sales Pty Ltd			■	■
Southern Cross Energy	■	■	■	■
South West Cogeneration Joint Venture		■		
Synergy			■	■
TransAlta Energy (Australia)				■
Transfield Services Kemerton Pty Ltd		■		
Verve Energy	■	■	■	■
Walkaway Wind Power Pty Ltd		■		
Waste Gas Resources Pty Ltd	■	■		
Water Corporation			■	■
Worsley Alumina		■		

Source: Economic Regulation Authority (Western Australia).

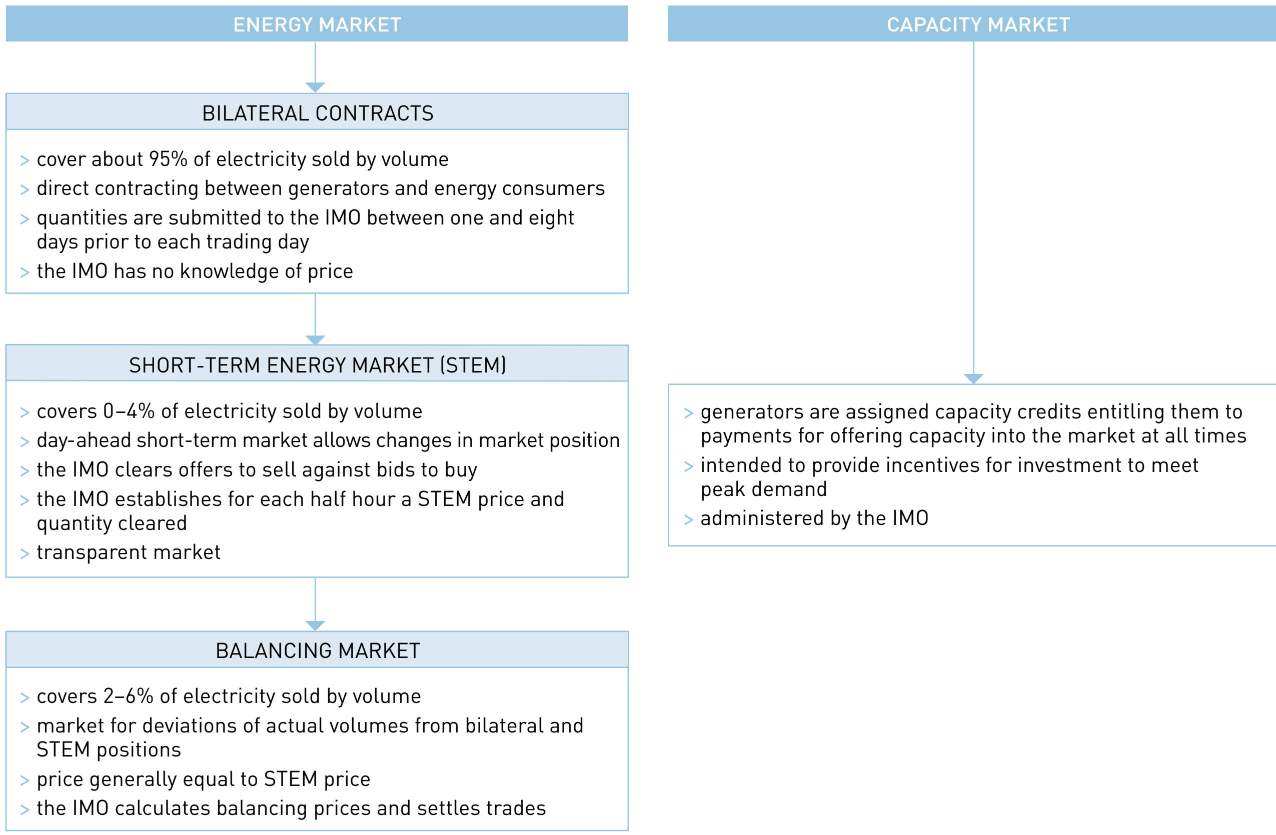
State-owned corporations will continue to dominate the market for some time for the following reasons:

- Verve Energy owns about 75 per cent of installed generation capacity in the SWIS. This will fall to 66 per cent in 2008–09. The government expects that Verve's market share will continue to fall in subsequent years with the phasing out of transitional vesting contracts implemented with the disaggregation of Western Power.[5]
- Western Power owns the bulk of the transmission and distribution systems.
- Until full retail contestability is introduced, Synergy will serve all customers using less than 50 MWh per year, including small business and residential consumers. At this stage, Western Australia has not determined a date to introduce full retail contestability. Most contestable customers still have access to gazetted tariffs, which in the current environment of rising electricity costs reduce the incentive to switch to another supplier.

5 The vesting contracts relate to the wholesale supply of electricity by Verve Energy to Synergy, the government-owned retailer. The arrangements were intended to ensure that Synergy could meet the sales obligations that it inherited from Western Power, and initially covered a substantial proportion of wholesale supply in the SWIS. The arrangements will be phased out as competition is introduced.

Figure 7.2

Western Australian wholesale electricity market



Source: Independent Market Operator (Western Australia).

However, the extent of dominance by state-owned energy corporations may reduce over time with new market entry and greater interaction between state-owned corporations and independent power producers. In particular:

- The Western Australian Government has placed a 3000 MW cap on Verve Energy's ability to invest in new generation plant to allow independent generators to increase their market share over time.
- Synergy is not permitted to own or control generation plant until the Western Australian Government is satisfied that new market entry has occurred. It is also required to conduct regular displacement tenders of energy currently sourced under transitional vesting arrangements.

It is expected that by 2009–10, Verve Energy's share of generation capacity will fall to around 60 per cent of generation capacity, with three new participants acquiring significant generation capacity (NewGen Power, Griffin Power and Alcoa).[6] Table 7.2, which sets out market participants in 2006 and 2008, indicates the extent of new entry since the market began.

Differences between the Western Australian electricity market and the National Electricity Market

Figure 7.2 illustrates the key elements of the Western Australian Wholesale Market in the SWIS. There are three main differences between the market design for the SWIS and the NEM:

- gross pool versus net pool
- capacity market arrangements
- ancillary services.

6 Economic Regulation Authority, *Annual wholesale electricity market report for the Minister for Energy*, 2007 (p. 11).

Gross pool versus net pool

The NEM is a gross pool in which the sale of all wholesale electricity occurs in a spot market. NEM participants also enter into formal hedge contracts to manage spot market risk. In contrast, energy in the SWIS is mainly traded through bilateral contracts outside the pool. These may be entered into years, weeks or days prior to supply. Before the trading day, generators must inform the IMO of the quantity of energy to be sold under bilateral contracts and to whom it will be sold so the IMO can schedule that supply.

In the lead-up to dispatch, System Management issues instructions to ensure that supply equals demand in real-time. Rather than being dispatched on a least-cost basis, dispatch mainly reflects the contract positions of participants. Generators submit daily resource plans that inform the IMO of how their facilities will be used to meet their contract positions. Generators are obliged to follow these plans, unless they are superseded by dispatch instructions. Verve Energy's facilities are scheduled around the resource plans of other generators. If it appears that supply will not equal demand, the IMO will schedule Verve Energy generation first, and then issue dispatch instructions to other market participants as necessary.

Beyond bilateral contracts, the STEM and a balancing market are used to trade wholesale electricity (see figure 7.2). The STEM supports bilateral trades by allowing market participants to trade around their net contract positions a day before energy is delivered. If, for example, a generator does not have sufficient capacity to meet its contracted position, it can bid to purchase energy in the STEM. Participation in the STEM is optional. Participating generators must offer generation plant at short run marginal cost. Each morning, market participants may submit to the IMO bids to purchase energy and/or offers to supply energy.[7] The IMO then runs an auction, in which it takes a neutral position to determine a single price for each trading interval of the day.

A market participant's actual supply or consumption of electricity during a trading interval may deviate from their net contract position (the sum of their bilateral position and STEM trades) due to unexpected deviations in demand and unplanned plant outages. The shortfall or surplus is traded on the balancing market. The IMO calculates balancing prices, which for Verve Energy plant are generally equal to the short run marginal cost of the last unit dispatched. Any independent power producer plant dispatched for balancing or ancillary service provision is 'paid as bid'.

Capacity market arrangements

The SWIS market includes both an energy market (the STEM) and a capacity market (see figure 7.2). The capacity market is intended to provide incentives for investment in generation to meet peak demand. In particular, it is intended that the capacity market will provide sufficient revenue for investment without the market experiencing high and volatile energy prices.

The IMO administers a reserve capacity mechanism to ensure that there is adequate installed capacity to meet demand. The IMO determines how much capacity is required to meet peak demand each year and allocates the costs of obtaining the necessary capacity to buyers —mostly retailers. Generators are assigned capacity credits, which entitle them to payments for offering their capacity into the market at all times. Payments of $10 625 per MW of capacity per month were provided for the period from the start of the market to 1 October 2008. For the twelve months from 1 October 2008, generators will receive $8152 per MW of capacity per month. These amounts are intended to cover the fixed costs of an open cycle peaking gas turbine and will partially cover the capital costs of base load units.

In the NEM there is no capacity market. Instead, generators are paid only for energy sent out, and a high price cap provides incentives to invest in generation and establish demand side responses. The provision of capacity payments means that wholesale spot energy

7 In order to receive reserve capacity payments, generators must offer all registered capacity into the STEM.

Table 7.3 **New entrants in the South West Interconnected System—generation and retail**

PARTICIPANT	INVESTMENT
Alinta Sales	> 80 MW wind farm at Walkaway opened in late 2005 > 130 MW cogeneration plant opened in April 2006 > 130 MW cogeneration plant commissioned in February 2007 > 350 MW open cycle plant under construction for end 2007
Stanwell/Griffin	> 80 MW wind farm at Emu Downs opened October 2006
NewGen Power Kwinana	> 320 MW Kwinana combined cycle plant under construction for end 2008
Griffin Power	> 200 MW Bluewaters 1 coal fired plant under construction for end 2008 > 200 MW Bluewaters 2 plant under construction for end 2009 > 330 MW gas-fired plant near Neerabup proposed for 2010–11
Perth Energy	> Combined cycle gas plant under consideration
Eneabba Gas	> 168 MW Centauri 1 gas-fired plant near Eneabba due to begin operation in 2009
Western Australian Biomass	> 40 MW boiler/steam turbine power station fired by biomass to begin operation in 2009–10
Western Energy	> 80 MW Kwinana combined cycle gas-fired plant due for 2010
Aviva	> 400 MW Coolimba coal-fired plant near Eneabba due for 2012
Premier Power Sales	> New retailer

Source: IMO, Office of Energy (WA).

prices in Western Australia are unlikely to need to peak as high as NEM prices to stimulate investment. The Market Rules specify that the maximum STEM price is adjusted periodically to reflect CPI changes.[8] For the year from 1 October 2006 to 30 September 2007, the STEM price cap was $159.84 per MWh. For the year from 1 November 2007 to 1 October 2008, the cap is $206 per MWh. This price is based on the marginal cost of an open cycle gas turbine using natural gas as fuel. In comparison, the NEM operates with a $10 000 per MWh price cap.[9]

The IMO determines annual reserve capacity requirements and releases an annual statement of opportunities report that covers a period of 10 years, the first having been released in 2005. Western Australia's Economic Regulation Authority (ERA) approves the maximum reserve capacity price and the energy price caps in the short-term market that are proposed by the IMO.

Ancillary services

There are eight frequency control ancillary services spot markets in the NEM in which participants may bid to provide services. Network control ancillary services are procured through long-term contracts. In contrast, there are no spot markets for ancillary services in the SWIS. System Management determines ancillary services requirements and procures them from Western Power or other participants under contract arrangements.

Energy market outcomes

While it is too early to assess the outcomes of the Western Australian energy market, a number of developments can be observed. The number of market participants is increasing, with new retailers and generators entering the market. Table 7.3 shows that Premier Power has entered the retail market and that a number of generators have been built recently or are planned for the near future.

There has been strong interest in investing in the energy market, including in renewable energy. In total, the number of generators has risen from 10 to 22 since the market began. The number of retailers has risen from 11 to 14. More varied plant sizes, technologies and fuel types are being encouraged, as are cost-efficient plant upgrades. Another outcome has been the introduction of more cost-reflective prices in the STEM, which recognise the cost of energy during system peaks and

8 The Market Rules can be found on the IMO website (http://www.imowa.com.au).
9 Information on price caps can be found on the IMO website (http://www.imowa.com.au).

short-term pressures such as fuel shortages and strong demand. However, there is less cost reflectivity in the retail market, where transitional vesting arrangements and gazetted tariffs apply.[10] To address the lack of cost reflectivity and transparency, the Western Australian Government announced in April 2008 a $780 million subsidy payment to Verve Energy over three years.[11]

The volume of energy traded in the STEM and the balancing markets has ranged from about 4.5 to 6.5 per cent of total sales, although unpublished data since late 2007 suggest it has frequently dropped below 1 per cent (see figure 7.3).

There was relatively strong trading activity in the STEM at the commencement of the market, which later declined as the market evolved. Recently, STEM trades have risen again, largely between generators seeking access to lower cost plant.

On most days the number of market participants placing STEM bids fluctuates between four and seven. Given the limited number of participants, the STEM is relatively active despite the limited quantities traded. While Verve Energy accounts for a majority of capacity in the market, figure 7.4 shows that other participants have been active in the STEM. In contrast, the level of competition in the bilateral contract market is difficult to gauge because such contracts are confidential.

The ERA has stated it is not aware of outcomes in the STEM that indicate market power is an issue. However, it has raised concerns about:

> the appropriateness of the investment signals provided by the market

> the appropriateness of the timing of the reserve capacity mechanism and whether this can create barriers to investment for facilities with long lead times

> whether the timing of planned network outages impacts on the effectiveness of the market

> whether there are barriers to the participation of consumers in demand-side management programs.[12]

According to the IMO, there have been five STEM suspensions since the market commenced. Settlement processes and participant understanding of the market systems and rules has been improving.[13]

Price outcomes

Price outcomes in the STEM and balancing markets provide transparent price signals on the cost of electricity. The mean peak STEM price from the commencement of the market until 31 July 2007 was $68.90 per MWh, while the mean off-peak price was $32.30 per MWh.[14] Figure 7.5 shows the weighted average weekly STEM prices from the commencement of the market to the end of February 2008. The early high prices were due to fuel restrictions and low generator availability. The price peaks in 2007 reflect high demand periods and fuel shortages.[15]

7.1.4 Network access

In 2004, Western Australia implemented the Electricity Networks Access Code for access to transmission and distribution network services. At present, the Code only covers Western Power's networks within the SWIS, but other networks may be covered in the future if they meet the access regime's coverage tests. In July 2006, the Commonwealth Treasurer certified the Code as an effective access regime under the *Trade Practices Act 1974*.

The ERA administers the Code, which prescribes commercial arrangements, including access charges that electricity generators and retailers must pay to use Western Power's networks. The regulatory framework sets out criteria for the ERA's acceptance or rejection of an access arrangement proposed by the service provider.

10 See also section 7.1.5.

11 Alan Carpenter, Premier, Ministerial Media Statement, *State Government to phase in electricity price increases*, 4 April 2008.

12 Economic Regulation Authority, *Annual wholesale electricity market report for the Minister for Energy*, 2007, p.viii.

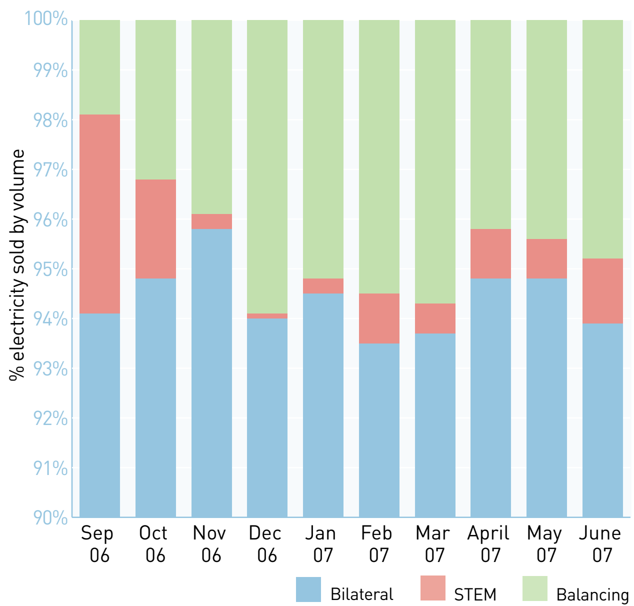
13 Independent Market Operator, *Western Australian Electricity Market*, presentation by Bill Truscott, 24 September, 2007.

14 Economic Regulation Authority, *Annual wholesale electricity market report for the Minister for Energy*, 2007, p. 12.

15 Independent Market Operator, *Western Australian electricity market*, presentation by Bill Truscott, 24 September, 2007.

Figure 7.3

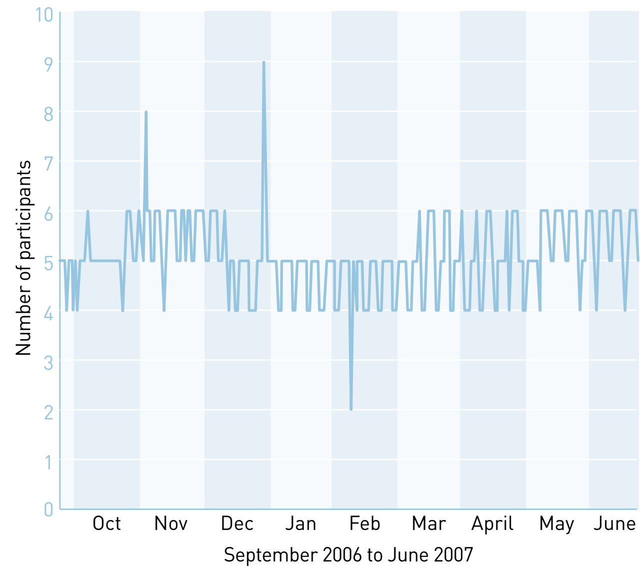
Composition of electricity trading in the South West Interconnected System



Source: IMO.

Figure 7.4

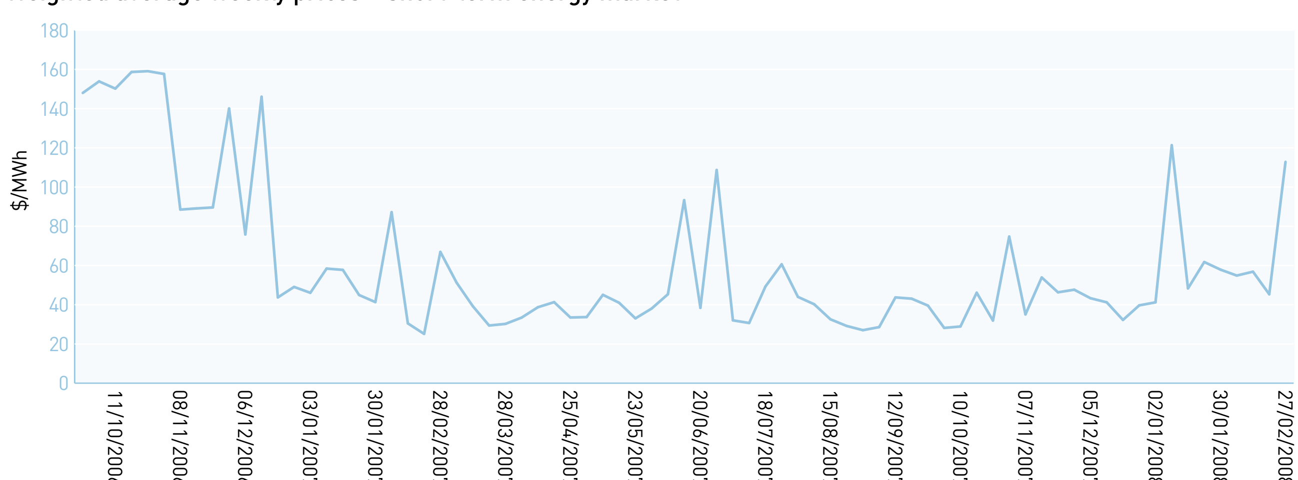
Number of active participants in short-term energy market auctions



Source: IMO.

Figure 7.5

Weighted average weekly prices—short-term energy market



MWh, megawatt hour.

Source: IMO.

The ERA released a decision in April 2007 on Western Power's access arrangement under the Code. Western Power's access tariffs under the decision are published on the ERA website. Under the access arrangement, Western Power is required to submit to the ERA, for approval, a proposed price list (to apply for the next pricing year). The 2008–09 price list was approved on 8 May 2008.[16]

7.1.5 Retail arrangements

In January 2005, Western Australia extended retail contestability to electricity customers using at least 50 MWh per year. Customers below this threshold who are connected to the SWIS are served by Synergy, the state-owned energy retailer. Most customers outside the SWIS are served by Horizon Power. Currently, around 60 per cent of the Western Australian market, by volume, is contestable.[17]

The Western Australian Government has not set an implementation date for full retail contestability in electricity. The *Electricity Corporations Act 2005* requires the Minister for Energy to undertake a review in 2009 to consider a further extension of contestability. While full contestability has not commenced, there has been some degree of retailer switching by large market customers.[18]

Companies, other than Synergy, that currently offer retail electricity products in the SWIS include Alinta Sales, Griffin Power, Landfill Gas & Power, Perth Energy, Premier Power Sales and TransAlta Energy (Australia). The ERA website publishes a list of licenced retailers.

It is Western Australian government policy that all Synergy and Horizon Power customers are entitled to a uniform tariff, irrespective of their geographic location. The Western Australian Government approves the tariff and implements the scheme through a combination of statutory requirements. Regional electricity tariffs are subsidised by the Tariff Equalisation Fund, which is administered by the Office of Energy and funded by SWIS network users.

In April 2008 the Western Australian Government announced that domestic electricity charges would increase by 10 per cent in 2009–10, with further increases to be phased in over six to eight years. It rejected an Office of Energy recommendation to increase prices by 47 per cent in 2009–10 and 15 per cent the following year—in line with substantial increases in the cost of supplying electricity. The cost pressures include higher fuel prices, infrastructure upgrades, and rising labour costs. The Western Australian Government announced a $780 million subsidy to fund the shortfall between the cost of providing electricity and the prices charged to households.[19]

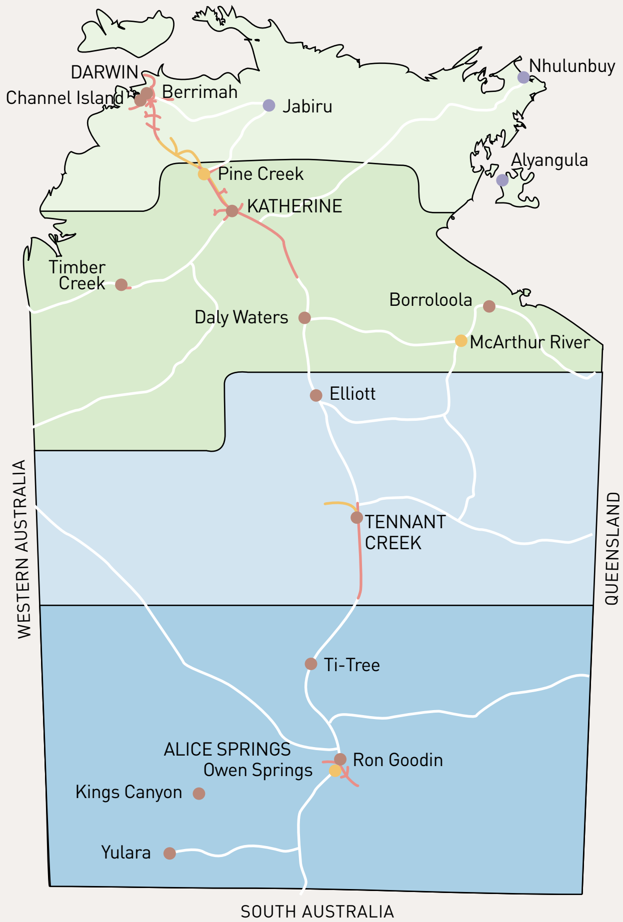
In addition to the uniform tariff, Western Australia has other consumer protection measures, including:

- an independent energy ombudsman
- a code of conduct for the supply of electricity to small-use customers
- regulations to ensure that residential and small business customers can be connected to a distribution network at the least cost to the customer
- standard form contracts for small customers
- supplier of last resort arrangements.[20]

16 Chapters 4 and 5 of this report include some data on the Western Power networks.
17 Independent Market Operator, *Annual Report 2006/07*, 2007, p. 24.
18 Independent Market Operator, *Annual Report 2006/07*, 2007, p. 24.
19 Alan Carpenter, Premier, Ministerial Media Statement, *State Government to phase in electricity price increases*, 4 April 2008.
20 For further information on the electricity retail market in Western Australia, see Chapter 6 of this report.

Figure 7.6

Northern Territory electricity system



- Power station – Power and Water Corporation
- Power station – power purchase agreement
- Retail agreement only
- Transmission lines
- Distribution lines
- Southern Region
- Barkley Region
- Katherine Region
- Northern Region

Source: Power and Water Corporation.

7.2 The Northern Territory

The Northern Territory's electricity industry is small, reflecting its population of around 215 000. There are three relatively small regulated systems,[21] of which the largest is the Darwin–Katherine system, with a capacity of around 340 MW (as at 30 June 2007) (see figure 7.6). In 2006–07, the Territory consumed around 1675 gigawatt hours of electricity. Two new generators are being constructed at Weddell, each with a capacity of 40 MW, and are expected to be operational in 2008.

The Territory uses gas-fired plants to generate public electricity, using gas sourced from the Amadeus Basin in Central Australia. However, the Amadeus fields cannot sustain increasing demand and the majority of the current contracts for gas supply are due to end in 2009. An alternative source, which will be used from 2009, is the Blacktip Field in the Joseph Bonaparte Gulf. The gas will come onshore to a processing plant near Wadeye and will then be transported by a new gas pipeline that will connect to the existing Amadeus Basin to Darwin Pipeline. It is expected that this arrangement will meet the Territory's forecast gas demand for the next 25 years.

7.2.1 Market arrangements

Given the scale of the Northern Territory market, it was not considered feasible to establish a wholesale electricity spot market. Rather, the Territory uses a 'bilateral contracting' system in which generators are responsible for dispatching the power their customers require.

The industry is dominated by a government-owned corporation, Power and Water, which owns the transmission and distribution networks. Currently, it is the monopoly retail provider and generator. Power and Water is also responsible for power system control. There are six independent power producers in the resource and processing sector that generate their own requirements and also generate electricity for the market under contract with Power and Water.

21 The Darwin–Katherine, Alice Springs and Tennant Creek systems.

From around 2000, the Territory Government introduced measures to open the electricity market to competition. It:

- commenced a phased introduction of retail contestability, originally scheduled for completion by April 2005 but rescheduled for April 2010
- corporatised the vertically integrated electricity supplier (Power and Water) and ring-fenced its generation, power system control, network and retail activities
- allowed new suppliers to enter the market
- established an independent regulator, the Utilities Commission, to regulate monopoly services and monitor the market
- introduced a regulated access regime for transmission and distribution services. In 2002, the Australian Government certified the regime as effective under the *Trade Practices Act 1974*. The Utilities Commission made its second five-year determination on network access arrangements (for 2004–05 to 2008–09) in 2004.

There has been one new entrant in generation and retail since the reforms—NT Power, which acquired some market share. However, NT Power withdrew from the market in September 2002 citing its inability to source ongoing gas supplies for electricity generation. In light of this, the government suspended the contestability timetable in January 2003. This effectively halted contestability at the 750 MW per year threshold until prospects for competition re-emerge. A single subsequent applicant was not granted an electricity retail licence due to the applicant's 'inability to meet reasonably foreseeable obligations for the sale of electricity'.[22] The introduction of full retail contestability is currently scheduled for April 2010.

When Power and Water reverted to a retail monopoly, the government approved prices oversight by the Utilities Commission of Power and Water's generation business for as long as the business is not subject to a tangible threat of competition. The government regulates tariffs for non-contestable customers via electricity pricing orders. The Utilities Commission regulates service standards, including standards for reliability and customer service.

22 Department of Business, Economic and Regional Development (NT Government), *The NT electricity, water and gas supply sector, fact sheet*, 2005.

PART THREE
NATURAL GAS

Natural gas is predominately made up of methane, a colourless and odourless gas. There are two main sources of natural gas in Australia. *Conventional natural gas* is found in underground reservoirs trapped in rock, often in association with oil. It may occur in onshore or offshore reservoirs. *Coal seam gas* is produced during the creation of coal from peat. The methane is adsorbed onto the surface of micropores in the coal. There are also renewable sources of methane, including biogas (landfill and sewage gas) and biomass, which includes wood, wood waste and sugarcane residue (bagasse). Renewable sources supply around 16 per cent of Australia's primary gas use.

NATURAL GAS

The natural gas supply chain begins with exploration and development activity, which may involve geological surveys and the drilling of wells. Exploration typically occurs in conjunction with the search for other hydrocarbon deposits, such as oil. At the commercialisation phase, the extracted gas is processed to separate the methane from the liquids and other gases that may be present, and to remove any impurities, such as water and hydrogen sulphide.

The gas extracted from a well may be used on-site as a fuel for electricity generation or for other purposes. More commonly, however, gas fields and processing facilities are located some distance from the cities, towns and regional centres where the gas is consumed. High pressure transmission pipelines are used to transport natural gas from the source over long distances. A network of distribution pipelines then delivers gas from points along the transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. Gate stations measure the natural gas leaving a transmission system for billing and gas balancing purposes, and are used to reduce the pressure of the gas before it enters the distribution network.

Retailers act as intermediaries in the supply chain. They enter into contracts for wholesale gas, transmission and distribution services, and 'package' the services together for on-sale to industrial, commercial and residential consumers.

Unlike electricity, natural gas can be stored, usually in depleted gas reservoirs, or it can be converted to a liquefied form for storage in purpose-built facilities. Liquefied natural gas is transported by ship to export markets. It is also possible to transport liquefied natural gas by road or pipeline.

Part 3 of this report provides a chapter-by-chapter survey of each link in the supply chain. Chapter 8 considers upstream gas markets, including exploration, production and wholesale trade. Chapters 9 and 10 provide data on the gas transmission and distribution sectors, and chapter 11 considers gas retailing.

Gas supply chain

PRODUCTION

Gas is extracted from wells in explored fields

PROCESSING

Extracted gas often requires processing to separate the methane and to remove impurities

DISTRIBUTION

Distribution networks are used to deliver gas to industrial customers and cities, towns and regional communities

TRANSMISSION

High pressure transmission pipelines are used to transport natural gas over long distances

RETAIL

Retailers act as intermediaries, contracting for gas with producers and pipeline operators to provide a bundled package for on-sale to customers

CONSUMPTION

Customers use gas for a number of applications, ranging from electricity generation and manufacturing to domestic use such as heating and cooking

Image sources: *Production*, Woodside; *Processing*, Origin Energy; *Transmission*, Nicholas White (supplied by KT Pty Ltd); *Retail*, Origin Energy; *Consumption*, Jupiterimages.

8 UPSTREAM GAS MARKETS

The upstream gas industry encompasses several phases, including exploration for gas resources, field development, gas gathering and, finally, the processing of natural gas to meet customer and regulatory requirements. The wholesale gas market involves sales by producers to energy retailers and other major customers. While the gas wholesale market remains characterised by confidential long-term contracts, there have been a number of recent initiatives to increase market transparency and competitive conditions.

8 UPSTREAM GAS MARKETS

This chapter considers:

- Australia's natural gas resources
- exploration and development of gas resources
- gas production and consumption, including coal seam gas and liquefied natural gas
- upstream industry structure, including participants and ownership changes
- gas wholesale markets
- gas prices
- current market developments, including a gas market bulletin board and short-term trading market
- reliability of supply.

8.1 Exploration and development

Exploration for natural gas typically occurs in conjunction with the search for other hydrocarbon deposits. The exploration process is characterised by large sunk costs and a relatively low probability of success. Activity levels are driven by a range of factors, including projected energy prices; the availability of acreage; equipment costs; perceptions of risks and rewards; and the availability of finance.

The costs incurred during this phase relate to surveying and drilling to identify possible resources and the acquisition of exploration permits. In recent years, rising equipment costs have significantly increased the cost of offshore exploration and development.[1] Given the cost and risk characteristics, exploration tends to be undertaken through joint venture arrangements to enable costs to be shared. If exploration is successful, the joint venture parties may proceed to the production phase or sell their interest to other parties.

1 ERA, *Gas issues in Western Australia*, Discussion paper, Perth, 2007.

In 2007–08, petroleum exploration expenditure in Australia was forecast to increase by around 41 per cent to $3.2 billion—the highest on record.[2] The Australian Bureau of Agricultural and Resource Economics (ABARE) has linked the sharp increase to rising global oil prices. The rise is mainly accounted for by growth in offshore exploration in Western Australia. There has also been a significant rise in exploration activity in Queensland, mostly associated with coal seam gas (CSG) (see section 8.2).[3]

The right to conduct exploration activity—including seismic acquisition and exploratory drilling—and develop gas fields is controlled by governments. In Australia, the states and territories control onshore resources and resources in coastal waters while the Australian Government has jurisdiction over resources in offshore waters outside the three nautical mile boundary. Governments release acreage each year for exploration and development.

The rights to explore, develop and produce gas and other petroleum products in a specified area or 'tenement' are documented in a lease or licence (also referred to as a 'title' or 'permit'). Licences allocated in Australia include exploration, assessment (retention) and production licences.

- An *exploration* licence provides a right to explore for petroleum, and to carry on such operations as are necessary for that purpose, in the permit area.
- An *assessment* or *retention* licence provides a right to conduct geological, geophysical and geochemical programs to evaluate the development potential of the petroleum believed to be present in the permit area.
- A *production* licence provides a right to explore for and recover petroleum, and carry on such operations as are necessary for those purposes, in the permit area.

Governments usually allocate petroleum tenements through a work program bidding process, which operates like a competitive tendering process. Under this approach, anyone may apply for a right to explore, develop or produce in a tenement based on offers to perform specified work programs. The relevant minister chooses the successful applicant by assessing the merits of the work program, the applicant's financial and technical ability to carry out the proposed work program, and any other criteria relevant to a tender. While the approach to issuing licences is relatively consistent across states and territories, there are significant differences in licence tenure and conditions.

8.2 Australia's natural gas resources

Natural gas consists mainly of methane. The two main types of natural gas in Australia are conventional natural gas and CSG. Conventional natural gas is found in underground reservoirs trapped in rock, often in association with oil. CSG is produced during the creation of coal from peat. In addition, renewable gas sources such as biogas (landfill and sewage gas) and biomass (including wood, wood waste and sugar cane residue) were forecast to supply about 4 per cent of Australia's primary energy consumption in 2007–08.[4]

Australia has abundant natural gas reserves (see table 8.1). At June 2008, total *proved and probable reserves*—those with reasonable prospects for commercialisation—stood at around 52 000 petajoules, comprising:

- 40 000 petajoules of conventional natural gas
- 12 000 petajoules of CSG.[5]

2 ABARE, *Minerals and energy: Major development projects–April 2008 listing*.

3 Australian Bureau of Statistics, *Mineral and Petroleum Exploration, ABS Cat. no. 8412.0*, March 2008; ABARE, *Minerals and energy: Major development projects–April 2008 listing*.

4 A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: National and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2007, Table A3, p. 55. 'Primary energy' refers to the use of primary fuel in the conversion and end use sectors. It includes the consumption of fuels to produce electricity.

5 EnergyQuest, *Energy Quarterly*, August 2008.

Table 8.1 Natural gas reserves and production in Australia, 2008

GAS BASIN	PRODUCTION (YEAR TO JUNE 2008)		PROVED AND PROBABLE RESERVES[2] (JUNE 2008)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
WESTERN AUSTRALIA				
Carnarvon	332	32.6	29 723	56.4
Perth	9	0.9	30	0.1
NORTHERN TERRITORY				
Amadeus	21	2.0	205	0.4
Bonaparte	0	0.0	1663	3.2
EASTERN AUSTRALIA				
Cooper (SA–Qld)	131	12.9	1129	2.1
Gippsland (Vic)	267	26.2	5602	10.6
Otway (Vic)	85	8.3	1429	2.7
Bass (Vic)	18	1.8	306	0.6
Surat–Bowen (Qld)	22	2.2	221	0.4
Total conventional natural gas	885	86.9	40 308	76.5
COAL SEAM GAS				
Surat–Bowen (Qld)	128	12.6	11 632	22.1
Sydney (NSW)	5	0.5	743	1.4
Total coal seam gas	133	13.1	12 375	23.5
DOMESTIC TOTALS	**1018**	**100.0**	**52 683**	**100.0**
LIQUIFIED NATURAL GAS (EXPORTS)				
Carnarvon (WA)	669			
Bonaparte (NT)	13			
Total liquified natural gas	682			
TOTAL PRODUCTION	**1700**			

Notes:

1. Conventional natural gas reserves include liquefied natural gas and ethane.
2. Proved reserves are those for which geological and engineering analysis suggests a 90 per cent probability of commercial recovery. Probable reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.

Source: EnergyQuest, *Energy Quarterly*, August 2008.

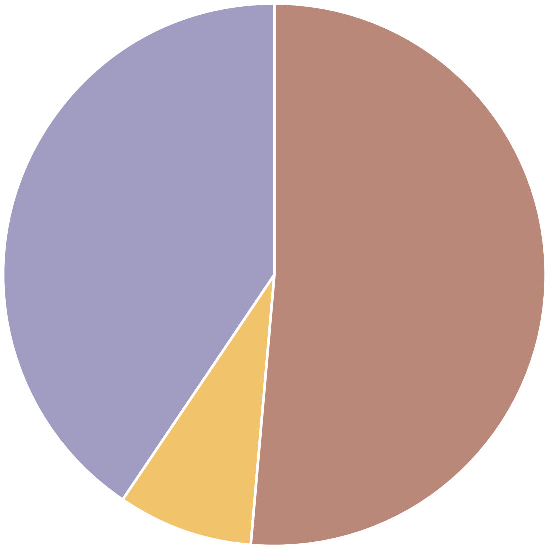
These estimates rise sharply to around 173 000 petajoules if *contingent resources*—known accumulations that are not yet commercially viable—are factored in.[6] The development of CSG has expanded rapidly in the current decade and ongoing exploration will likely add to Australia's natural gas reserves. For example, proved and probable reserves of CSG increased by around 145 per cent in the period from January 2007 to June 2008.[7]

Australia produced over 1700 petajoules of natural gas in the year to June 2008, of which around 60 per cent was for the domestic market (see figure 8.1). CSG accounts for around 8 per cent of total production,

6 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 7.

7 EnergyQuest, *Energy Quarterly*, August 2008, p. 27.

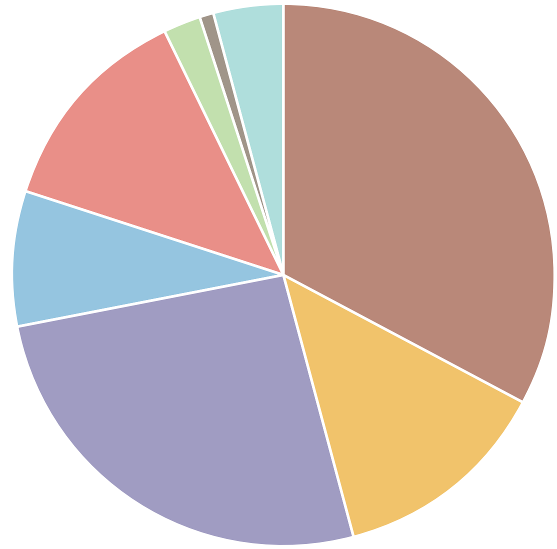
Figure 8.1
Australian natural gas production, 2007–08



CSG, coal seam gas; LNG, liquefied natural gas.

Source: EnergyQuest, *Energy Quarterly*, August 2008.

Figure 8.2
Natural gas production for domestic use by location, 2007–08



Notes: 'Other' consists of the Perth, Amadeus and Bass basins.

Source: EnergyQuest, *Energy Quarterly*, August 2008.

but its share is rising rapidly. Around 40 per cent of Australia's gas production—all currently sourced from offshore basins in Western Australia and the Northern Territory—is exported as liquefied natural gas (LNG). At current projected rates of production, Australia has sufficient proved, probable and contingent reserves to meet domestic and export demand for around 66 years.[8]

8.2.1 Geographical distribution

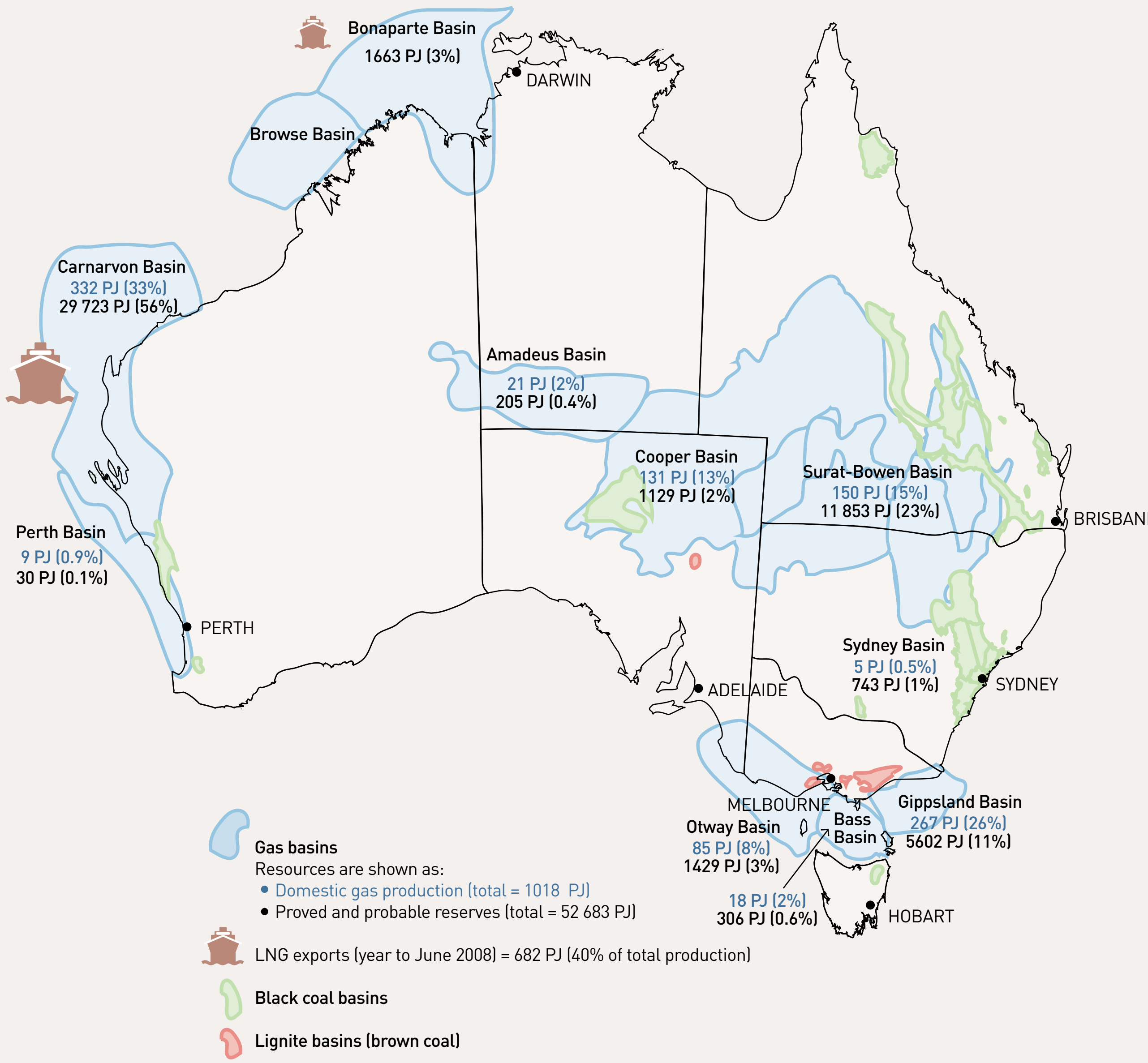
Figure 8.3 (overleaf) shows the location of Australia's major natural gas basins, including reserves and production levels. Figure 8.2 sets out the contribution of each basin to Australia's natural gas production for the domestic market. The principal sources of natural gas production are Western Australia's offshore Carnarvon Basin and Victoria's offshore Gippsland Basin. The Cooper Basin (in South Australia and Queensland) has been the principal historical source of gas for New South Wales and South Australia, but its reserves are declining. Production in Queensland's Surat–Bowen Basin and Victoria's Otway Basin has risen sharply during the current decade.

Western Australia's Carnarvon Basin holds about 56 per cent of Australia's natural gas reserves. It supplies around one-third of Australia's domestic market and 98 per cent of Australia's LNG exports. The small Perth Basin supplies about 1 per cent of the domestic market.

The Bonaparte Basin along the north-west coast contains around 3 per cent of Australia's gas reserves. The basin's development has focused on LNG for export. The first LNG exports from the basin were shipped from Darwin in 2006. The Amadeus Basin, which currently supplies gas for use within the Northern Territory, is in decline and will soon be supplemented by gas from the Bonaparte Basin.

8 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 7.

Figure 8.3
Australia's gas reserves and production, 2008



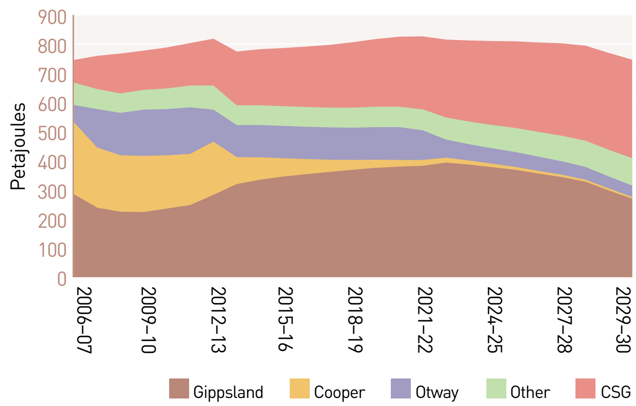
LNG, liquefied natural gas; PJ, petajoules.

Note: Production data for year ended 30 June 2008. Reserves at June 2008.

Sources: EnergyQuest, *Energy Quarterly*, August 2008; K Donaldson, *Energy in Australia 2006*, ABARE report, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2007.

Figure 8.4

Forecast sources of eastern Australia's natural gas production



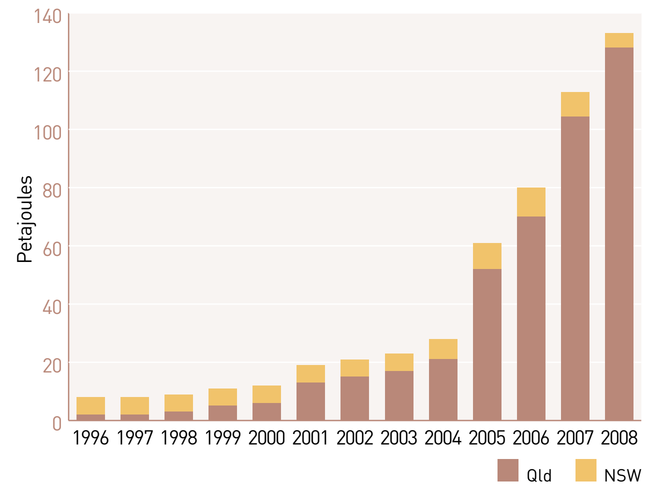
CSG, coal seam gas.

Note: 'Other' consists of conventional natural gas from the Surat–Bowen and Bass basins.

Source: C Cuevas-Cubria and D Riwoe, *Australian energy: National and state projections to 2029–30*, ABARE research report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006.

Figure 8.5

Coal seam gas production



Note: 2008 data are for the year ended 30 June. Other data are for calendar years.

Source: EnergyQuest.

Eastern Australia has around 40 per cent of Australia's natural gas reserves, the majority of which are CSG. The principal sources are the Surat–Bowen Basin in Queensland (which meets around 15 per cent of national demand), the Gippsland Basin off coastal Victoria (26 per cent) and the Cooper Basin in central Australia (13 per cent). Production in Victoria's offshore Otway (8 per cent) and Bass (2 per cent) basins has risen significantly since 2004.[9]

A number of changes are forecast in the geography of gas production in eastern and central Australia over the next 25 years (see figure 8.4). In particular, the Cooper Basin is a mature gas producing region with diminishing reserves. ABARE has predicted a rapid decline in production rates in the Cooper Basin after about 2011, to be replaced by increased supplies from the Victorian basins and CSG from Queensland.

Production of CSG has risen exponentially since 2004 (see figure 8.5), with the bulk of activity occurring in the Surat–Bowen Basin, which extends from Queensland into northern New South Wales. While the basin is an established supplier of conventional natural gas, it also contains most of Australia's proved and probable CSG reserves. There are also significant reserves of CSG in the Sydney Basin, where commercial production began in 1996.

The development of CSG stemmed initially from the Queensland Government's energy and greenhouse gas reduction policies, but recent improvements in extraction technology have spurred sustained rapid growth. Rising domestic and international gas prices have also strengthened the commercial viability of the resource.

Queensland CSG has a variety of commercial advantages, including that it is found closer to the surface and under lower pressure than conventional natural gas. It also tends to have a relatively high concentration of methane, lower levels of impurities and is closer to some markets. These features also allow for a more incremental investment in production and transport than is required when bringing a conventional natural gas development on stream.

9 Data sourced from EnergyQuest, *Energy Quarterly*, August 2008.

While CSG is produced only in Queensland and New South Wales, it is the fastest growing gas production sector: it supplied almost 20 per cent of gas produced in eastern Australia in the year to June 2008,[10] and meets around 70 per cent of the Queensland market.[11] ACIL Tasman forecasts that Queensland production may rise by around 60 per cent during 2008 to about 160 petajoules.[12]

ABARE published forecasts in 2007 that CSG production will supply around 32 per cent of the eastern Australian gas market by 2011–12. It also forecast that production will reach around 529 petajoules by 2029–30, making it the principal source of gas supply in eastern Australia (as shown in figure 8.4).[13]

8.2.2 Regional markets

The geography of Australia's gas basins and transmission networks gives rise to distinct regional markets. Market analysis often distinguishes between three regional markets—eastern Australia, Western Australia and the Northern Territory.[14]

An interconnected transmission pipeline network enables gas producers in the Cooper, Gippsland, Otway, Bass and Sydney basins to sell gas to customers across South Australia, Victoria, New South Wales, the ACT and Tasmania. The construction of a new transmission pipeline—the QSN Link—will interconnect Queensland with the south-eastern jurisdictions from 2009. This will allow gas producers in the Surat–Bowen Basin to market gas throughout southern and eastern Australia.[15] At present, there is no LNG export facility in eastern Australia.

Western Australia has no pipeline interconnection with other jurisdictions. It is the largest gas producer nationally, and supplies both the domestic market and most of Australia's LNG exports. The state's LNG export capacity creates exposure in the domestic market to international energy market conditions.

Similarly, the Northern Territory has no pipeline interconnection with other jurisdictions. It has a small domestic market and commenced LNG exports from the Bonaparte Basin in 2006.

8.3 Domestic and international demand for Australian gas

Australia consumed around 1020 petajoules of natural gas in the year to June 2008, including conventional natural gas and CSG.[16] Natural gas has a range of industrial, commercial and domestic applications within Australia. It is an input to manufacturing pulp and paper, metals, chemicals, stone, clay, glass, and certain processed foods. In particular, natural gas is a major feedstock in ammonia production for use in fertilisers and explosives. Natural gas is increasingly used for electricity generation, mainly to fuel intermediate and peaking generators. It is also used in the mining industry, to treat waste materials, and for incineration, drying, dehumidification, heating and cooling. In the transport sector, natural gas in a compressed or liquefied form is used to power vehicles. The residential sector uses natural gas mainly for heating and cooking.

10 EnergyQuest, *Energy Quarterly*, August 2008.

11 Minister for Mines and Energy (Qld) (Hon. Geoff Wilson), *Coal seam methane for a cleaner energy future*, Press Release, 13 September 2007.

12 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 3.

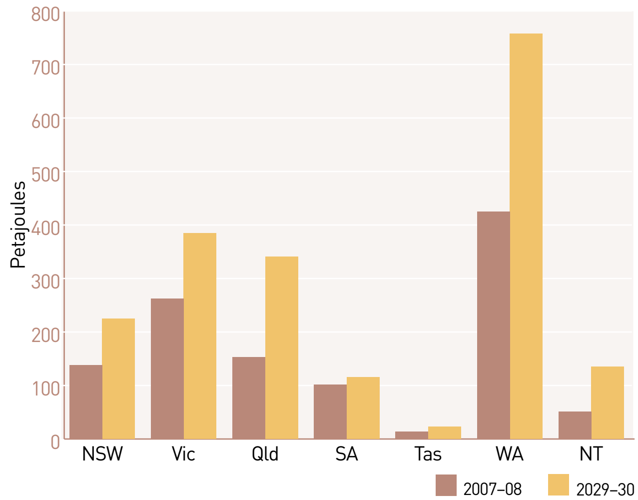
13 A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: National and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

14 See, for example, Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, pp. 7–8; ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 2.

15 For further information on the gas transmission network, see chapter 9 of this report.

16 EnergyQuest, *Energy Quarterly*, August 2008.

Figure 8.6
Primary gas consumption (forecasts)



Source: A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: National and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

Figure 8.6 sets out ABARE forecast data on primary consumption of natural gas by state and territory in 2007–08 and 2029–30. Western Australia and Victoria have the highest consumption levels, while demand growth is forecast to be strongest over the next 20 years in Queensland, Western Australia and the Northern Territory.

The consumption profile varies between the jurisdictions (see figure 8.7). Natural gas is widely used in most jurisdictions for industrial manufacturing. Western Australia, South Australia, Queensland and the Northern Territory are especially reliant on natural gas for electricity generation. In Western Australia, the mining sector is also a major user of gas, mainly for power generation. Household demand is relatively small, except in Victoria where residential demand accounts for around one-third of total consumption. This reflects the widespread use of natural gas for cooking and heating in that state.

8.3.1 Liquefied natural gas exports

LNG is produced by converting natural gas into liquid. The development of an LNG export facility requires large up-front capital investment in processing plant and port and shipping facilities. The magnitude of investment means that a commercially viable LNG project requires access to substantial reserves of natural gas. The reserves may be sourced from the LNG owner's interests in a gas field, a joint venture arrangement with a natural gas producer or through long-term gas supply contracts.[17]

Australia has LNG export projects in the North West Shelf (annual capacity of 11.9 million tonnes but scheduled to rise to over 16 million tonnes in 2008) and Darwin (annual capacity of 3.5 million tonnes). ABARE forecasts that expansion of existing projects and greenfield LNG projects will increase export capacity to around 24 million tonnes by 2011–12 and 76 million tonnes by 2029–30. This would support an annual growth in LNG exports of 7.8 per cent over the period to 2029–30.[18]

Australia is the world's fifth largest LNG exporter after Qatar, Indonesia, Malaysia and Algeria (see figure 8.8). In the year to June 2008, Australia exported around 682 petajoules of LNG, mostly from the Carnarvon Basin.[19] LNG shipments from Darwin began in February 2006. LNG accounts for around 40 per cent of Australia's natural gas production. ABARE projects that this ratio will rise to around 68 per cent by 2029–30.[20]

Rising international LNG prices together with rapidly expanding reserves of CSG in Queensland have recently improved the economics of developing LNG export facilities in eastern Australia. Several LNG proposals reliant on CSG have been announced for construction in Queensland since early 2007. The proposals range in size from 0.5 to 4 million tonnes of LNG per year. ACIL Tasman assessed in 2008 that the economics of the projects appear to be sound.[21] EnergyQuest

17 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 16.

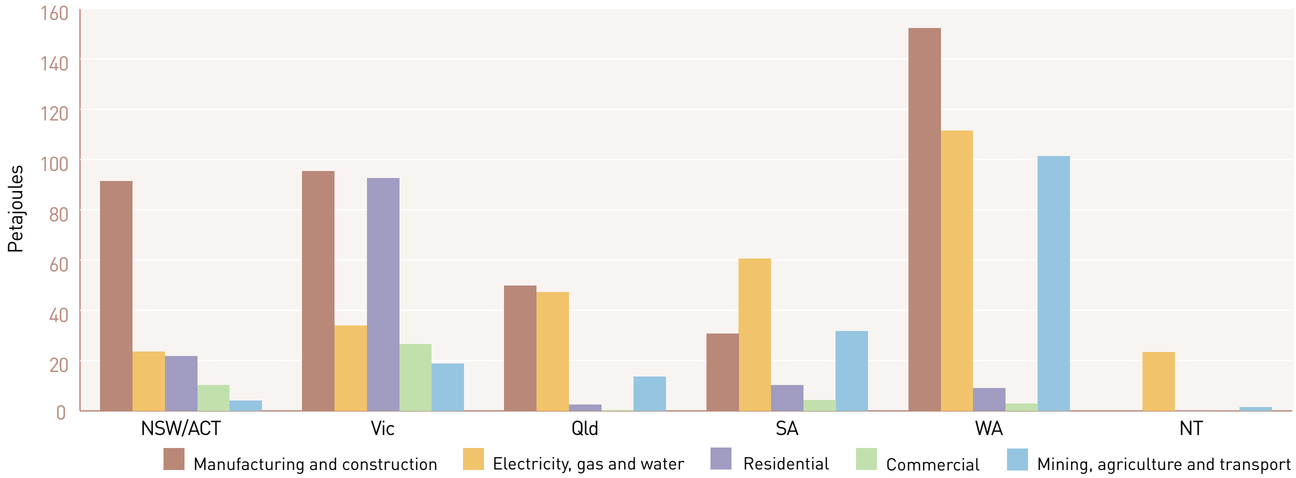
18 A Syed, R Wilson, A Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: National and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007, p. 43.

19 EnergyQuest, *Energy Quarterly*, August 2008.

20 A Syed, R Wilson, A Sandu, C Cuevas-Cubria and A Clarke. *Australian energy: National and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007, p. 44.

21 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 26.

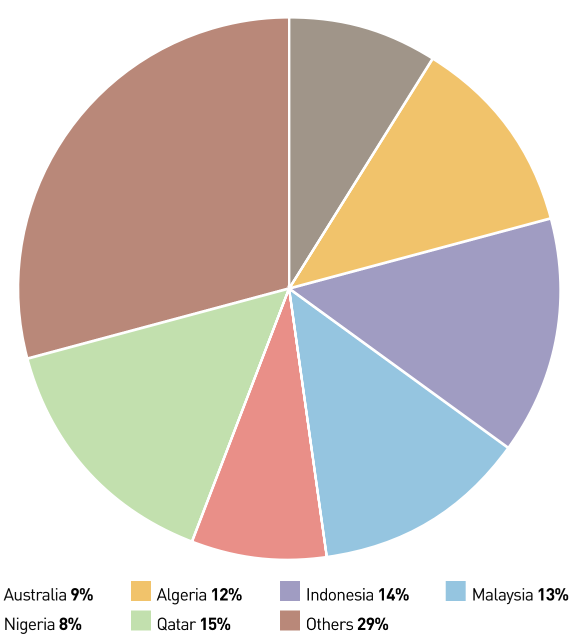
Figure 8.7
Primary natural gas consumption by industry



Note: Data for year ended 30 June 2005.

Source: ABARE.

Figure 8.8
World liquefied natural gas exports by country, 2006



Source: IEA statistics, *Natural gas information 2007*, table 19.

argued in August 2008 that the increasing involvement of major international players in east coast LNG projects makes it 'no longer a question of whether east coast LNG will proceed but rather when and how much'.[22]

8.3.2 Adequacy of supply

ACIL Tasman estimates that underlying gas demand in Australia could grow on average by around 2.4 per cent annually over the next 20 years. It also estimates that LNG exports from Western Australia and the Northern Territory could reasonably increase by around 90 per cent over this period.[23] ABARE projects that domestic demand will rise most strongly in Western Australia, Queensland and the Northern Territory (figure 8.6). Key contributors to the growth include greater use of gas in electricity generation, mining and energy-intensive refining.

There has been some debate as to the adequacy of domestic sources to satisfy Australia's natural gas demand over time. Recent assessments have highlighted contrasting conditions between Western Australia, the Northern Territory and eastern Australia.

The Western Australian gas market has experienced considerable tightening since 2006, with rising

22 EnergyQuest, *Energy Quarterly*, August 2008, p. 19.
23 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 28.

production costs and strong domestic demand occurring at a time when most producers have fully contracted their developed reserves. In addition, Western Australia's LNG export capacity makes the domestic market relatively sensitive to international energy prices, which have increased significantly since 2005.

In combination, these factors have led to a substantial rise in domestic prices in Western Australia, with some contracts in 2007 being negotiated at around $7 per gigajoule compared to typical prices of around $2.50 earlier in the decade.[24] In June 2008, an explosion at the Varanus Island gas facility reduced domestic gas supplies by 30 per cent for over two months and put further pressure on short-term prices (see section 8.6). There have been projections that Western Australia will face difficulties achieving a supply–demand balance until at least 2010.[25]

There have been some suggestions that the opening of an LNG export facility in the Northern Territory in 2006 could affect the availability of gas supplies there. While supply contracts in the Territory appear to cover the needs of existing customers for up to 15 years, competition to supply LNG exports could pose risks to the market in sourcing additional gas supplies to support major new industrial projects.[26]

In eastern Australia, an interaction of several factors will affect the supply–demand balance over the next few years. Since the 1990s, improved pipeline interconnection between the eastern gas basins has enhanced the flexibility of the market to respond to customer demand. The construction in 2008 of the QSN Link pipeline from Queensland to southern Australia will result in an interconnected pipeline network linking Queensland, New South Wales, the ACT, Victoria, South Australia and Tasmania (see chapter 9). In addition, the rapid escalation of CSG reserves in Queensland has at least delayed the need to invest in new pipelines to ship gas from sources such as Papua New Guinea.

While new pipeline investment and rising CSG reserves are strengthening the supply base, a number of factors may also put upward pressure on demand. While eastern Australia is currently insulated from global gas markets, this may change if any of several proposed LNG export projects comes to fruition.[27] The introduction of the Carbon Pollution Reduction Scheme will also likely increase reliance on natural gas as a fuel for electricity generation.

Figure 8.9 illustrates ACIL Tasman forecasts of the demand for natural gas over the next 20 years, taking into account the projected effects of the Carbon Pollution Reduction Scheme. ACIL Tasman forecasts that demand growth will be principally driven by rising LNG production—in western, northern and eastern Australia—and the increasing use of gas for electricity generation. According to this view, total gas demand would more than double to around 4300 petajoules (including exports) over the next 20 years.[28]

The net impact of rising demand for natural gas (from electricity generation and LNG exports) coupled with rising reserves (particularly from CSG) is difficult to predict. In a report published in July 2007, McLennan Magasanik Associates found that the eastern market supply outlook was relatively benign in the medium to long term, and that buyers and sellers appear willing to contract ahead to avoid supply shocks.[29]

ABARE reached similar findings in a December 2007 report, which projected that the positive outlook for

24 Department of Industry and Resources (WA), *Western Australian Oil and Gas Review*, 2008; ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.

25 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 10.

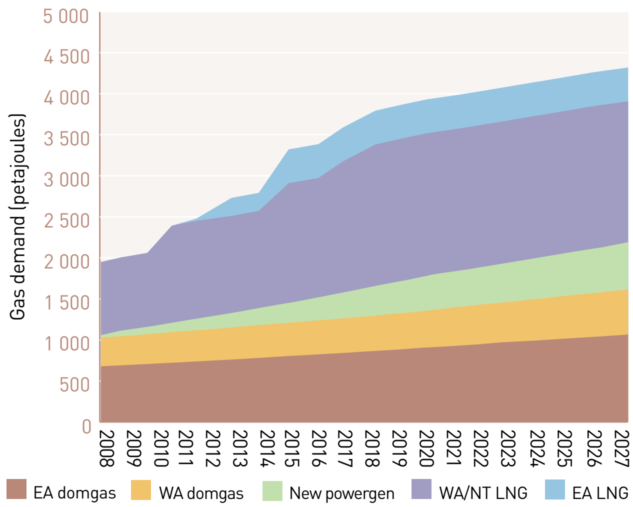
26 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 11.

27 See ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008 for a more detailed discussion of these factors.

28 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.

29 R Lewis, M Goldman and R Farmer, *Report to the Joint Working Group on Natural Gas Supply: Natural gas in Australia*, McLennan Magasanik Associates, July 2007.

Figure 8.9
Australian gas demand outlook



EA, eastern Australia; WA, Western Australia; NT, Northern Territory; domgas, domestic gas; new powergen, new power generation.

Note: Forecasts take into account the projected effects of the Carbon Pollution Reduction Scheme and LNG expansion.

Source: ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.

natural gas production from CSG would result in the eastern gas market remaining in balance over the period to 2029–30. The assessment did not account for the effects of the Carbon Pollution Reduction Scheme or LNG exports from eastern Australia.[30]

A recent ACIL Tasman assessment found that a 4 million tonne per year LNG plant (as proposed by Santos in 2007) would potentially divert very significant quantities of gas to exports. ACIL Tasman argues that while this may not leave the domestic market short of supply, it would likely require earlier reliance on higher-cost and less productive sources of CSG than in the absence of the LNG projects. This would have implications for domestic gas prices.[31]

A joint working group established by the Ministerial Council on Energy (MCE) reported in September 2007 on how best to balance the dual objectives of building Australia's LNG export capabilities while ensuring the long-term supply of competitively priced gas for domestic users.[32] The report recommended that attention be centred on:

- improving acreage management processes
- improving gas market efficiency, including through the development of a bulletin board covering major gas production fields, demand centres and transmission pipelines, and the development of a short-term trading market for natural gas (these reforms are being progressed in 2008: see section 8.7 and appendix A)
- developing an annual national gas statement of opportunities, similar to the statement currently prepared for the electricity sector (this reform is also being progressed in 2008: see section 8.7 and appendix A).

8.4 Industry structure

The prevalence of high sunk costs and the relatively small number of Australian gas fields means that the supply of natural gas is concentrated in the hands of a small number of producers.[33] It is common for oil and gas companies to establish joint ventures to help manage risk. Typically, the operator holds a substantial interest in the project. For example, the Cooper Basin partnership comprises Santos (the operator and majority owner), Beach Petroleum and Origin Energy.

There are some differences between the structure of the exploration and development sector and the gas production sector, although many participants—especially the large corporations—are active in both.

There are three main types of entities involved in gas and oil exploration. These are:

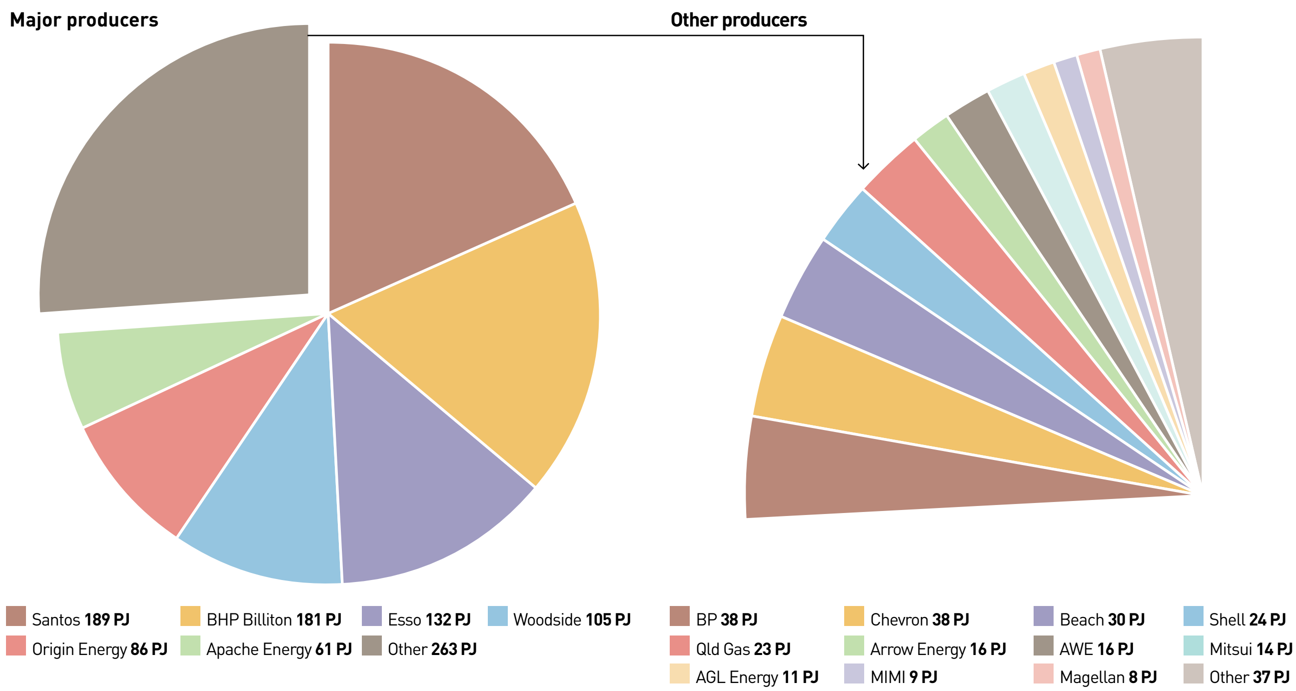
30 A Syed, R Wilson, A Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: National and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007, pp. 1, 42, 43.

31 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 26.

32 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007. The lead essay of this report considers the Joint Working Group report in more detail.

33 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 14.

Figure 8.10
Natural gas producers supplying the domestic market, 2007–08



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated.

Source: EnergyQuest, *Energy Quarterly*, August 2008.

- international majors—multinational corporations with large production interests and substantial exploration budgets (eg BP, BHP Billiton, Esso, Chevron and Apache Energy)
- Australian majors—major Australian energy companies with significant production interests and exploration budgets (eg Woodside Petroleum, Santos and Origin Energy)
- juniors—smaller exploration and production companies, that may or may not engage in gas production (eg Australian Worldwide Exploration, Arrow Energy and Queensland Gas Company).

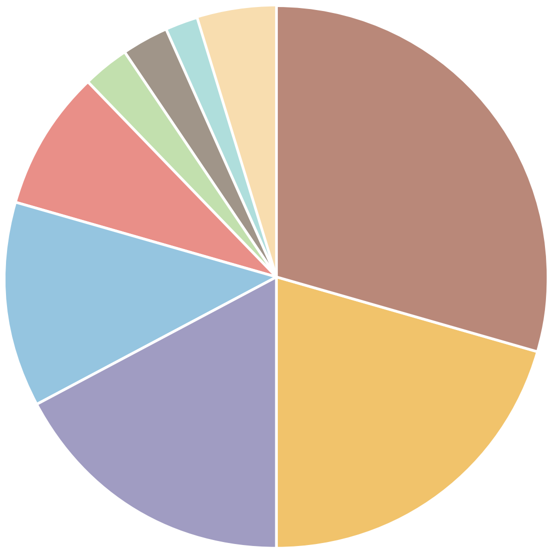
International majors tend to be involved in the larger offshore oil and LNG projects. Australian majors and smaller companies mainly focus on onshore discoveries, typically for natural gas sales to the domestic market.

Junior explorers often play a significant role in higher-risk greenfields exploration, such as the early phase of CSG developments.

Gas production in Australia is relatively concentrated. While over 100 companies are involved in gas and oil exploration, only around 30 produce gas. Six majors supplied around 77 per cent of the domestic market in 2007–08. Santos supplied around 21 per cent, followed by BHP Billiton (19 per cent), Esso (13 per cent), Woodside (10 per cent), Origin Energy (7 per cent) and Apache Energy (7 per cent). The next tier of players in terms of market share include BP, Chevron, Beach Petroleum, Shell and Queensland Gas Company (see figure 8.10).

The rise of CSG has seen the entry of several new players in both the exploration and production sectors over the past decade. New entrants include Queensland

Figure 8.11
Coal seam gas producers in Australia, 2007–08



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated.

Source: EnergyQuest, *Energy Quarterly*, August 2008.

Gas Company, Sydney Gas, Sunshine Gas and coal producers Anglo Coal and Xstrata. Smaller producers and new entrants to the production sector—including Queensland Gas Company, Sydney Gas, AGL Energy and Arrow Energy—accounted for around 50 per cent of CSG production in 2007–08 (see figure 8.11), which is considerably higher than their market share in conventional gas production.

8.4.1 Vertical integration

The increasing use of natural gas as a fuel for electricity generation creates synergies for energy retailers to manage price and supply risk through equity in gas production and gas-fired electricity generation. The energy retailers Origin Energy and AGL Energy each have substantial interests in gas production and electricity generation:

- Origin Energy has held a minority interest in gas production in the Cooper Basin for some time, but since 2000 has expanded its equity in CSG production in Queensland and in conventional gas production in Victoria's Otway and Bass basins.[34] Origin Energy is currently developing new gas-fired electricity generation capacity in Queensland, Victoria, South Australia and New South Wales. Origin Energy is a leading energy retailer in Queensland, Victoria and South Australia.
- AGL Energy, a relative newcomer to gas production, began acquiring CSG interests in Queensland and New South Wales in 2005. It has continued to expand its portfolio through mergers and acquisitions (see section 8.4.3). AGL Energy is a major electricity generator in eastern Australia (especially in Victoria and South Australia) and is a leading energy retailer in Victoria, New South Wales, South Australia and Queensland.

8.4.2 Market concentration by basin

Market concentration within particular gas basins depends on a variety of factors, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Table 8.2 and figure 8.12 set out EnergyQuest estimates of market shares in the major basins, based on production for the domestic market. Table 8.3 sets out market share data based on proved and probable gas reserves (including reserves available for export).

Several major companies have equity in Western Australia's Carnarvon Basin—Australia's largest producing basin. Woodside is the largest producer for the domestic market (around 30 per cent), but Apache Energy (19 per cent), Chevron (11 per cent), BP (11 per cent), Santos (9 per cent), BHP Billiton (7 per cent) and Shell (6 per cent) each have significant market share. Ownership of gas reserves is split between these and other entities such as MIMI (owned by Mitsubishi and Mitsui) and CNOOC (China National Offshore Oil Company). The businesses

34 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 24.

Table 8.2 Market shares in domestic gas production by basin, 2007

COMPANY	CARNARVON (WA)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
AGL					6.5%	29.3%				1.1%
Anglo Coal					3.0%					0.4%
Apache	19.3%									6.3%
ARC		57.1%							6.8%	0.7%
Arrow					10.3%					1.3%
AWE								14.2%	30.2%	1.7%
Beach				20.8%	1.1%					3.0%
Benaris								0.1%		0.0%
BHP Billiton	6.7%					41.5%	49.1%	37.9%		19.0%
BP	11.2%									3.7%
CalEnergy									15.0%	0.3%
Chevron	11.2%									3.7%
CS Energy					0.9%					0.1%
Esso	0.2%						49.1%			13.5%
Inpex	0.1%								0.8%	0.1%
Kufpec	2.3%									0.7%
Magellan			37.9%							0.8%
MIMI	1.7%									0.6%
Mitsui					2.9%			14.0%	4.8%	1.5%
Molopo					0.3%					0.0%
Mosaic					1.5%					0.2%
Origin		42.9%		15.1%	31.3%			1.3%	42.4%	7.3%
Qld Gas					14.3%					1.8%
Santos	9.2%		62.1%	64.1%	27.1%		1.7%	32.3%		19.5%
Shell	6.4%									2.1%
Sydney Gas						29.3%				0.2%
Tap	1.4%									0.5%
Woodside	30.2%							0.2%		9.9%
Other					0.7%					0.1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
TOTAL (PJ)	**331**	**9**	**21**	**137**	**129**	**9**	**277**	**79**	**19**	**1011**

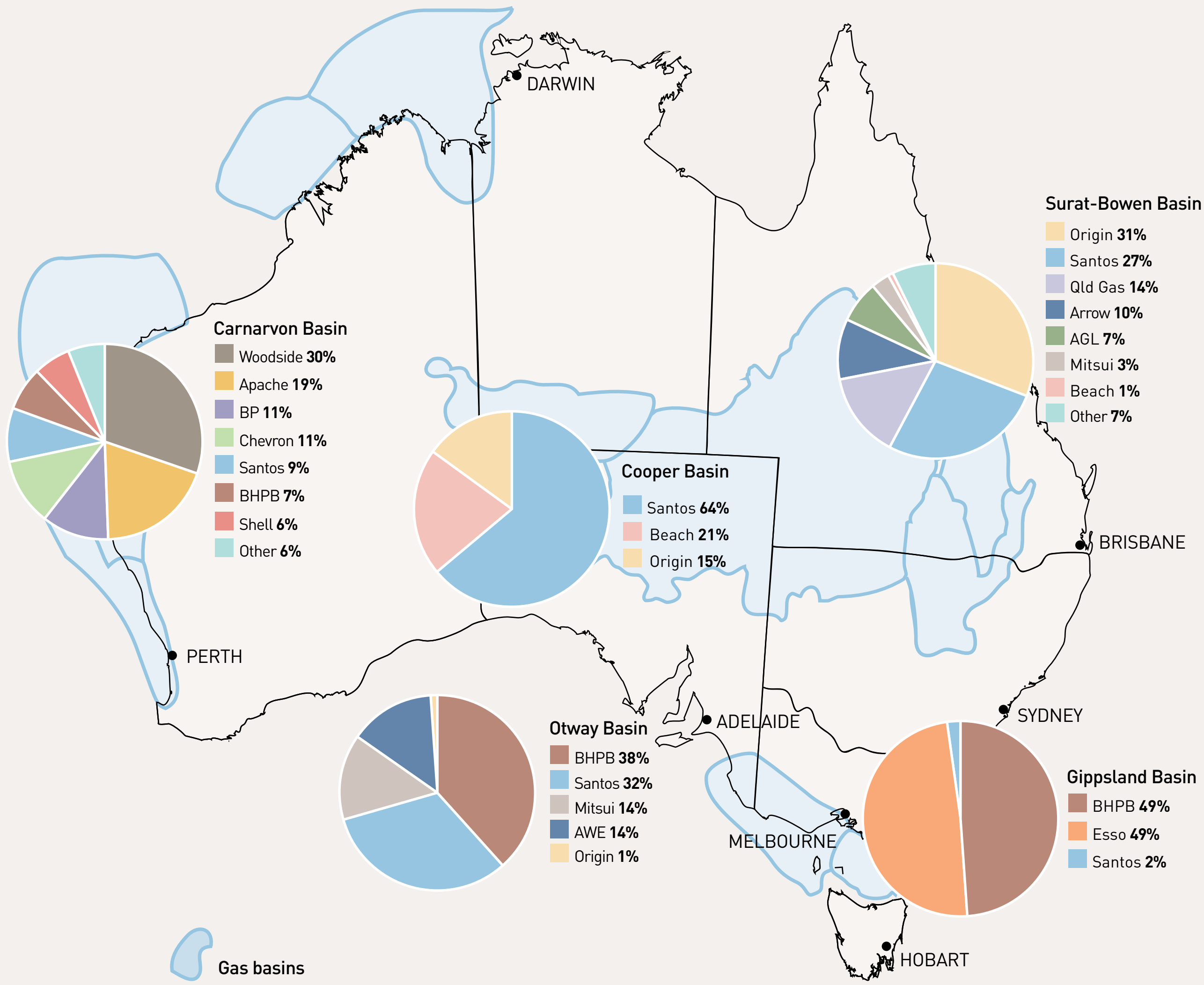
Notes:

1. Excludes liquefied natural gas.
2. Some corporate names have been shortened or abbreviated.

Source: EnergyQuest 2008 (unpublished).

Figure 8.12

Market shares in domestic gas production by basin, 2007



Notes:

1. Excludes liquefied natural gas.
2. Some corporate names have been shortened or abbreviated.

Source: EnergyQuest 2008 (unpublished).

participate in a number of joint ventures, typically with overlapping ownership interests.

Gas for the Northern Territory is currently sourced from the Amadeus Basin and produced by Santos and Magellan. The principal reserves are located in the Bonaparte Basin in the Timor Sea. The Italian energy firm ENI owns the majority of reserves in the basin.

While around 22 entities have equity in natural gas fields in eastern Australia, control of the more substantial fields in the Gippsland and Cooper basins is concentrated among the established producers Santos, Origin Energy, BHP Billiton and Esso. In 2007, these four entities accounted for around 82 per cent of production and owned around 69 per cent of proved and probable reserves in eastern Australia.[35]

A joint venture led by Santos (64 per cent) dominates production in South Australia's Cooper Basin. The other participants are Beach Petroleum (21 per cent) and Origin Energy (15 per cent). The same companies participate with slightly different shares on the Queensland side of the basin. There has been some new entry by smaller explorers in the Cooper Basin in recent years.

A joint venture between Esso and BHP Billiton accounts for around 98 per cent of production in Victoria's offshore Gippsland Basin—the largest producing basin in eastern Australia. There has been some new entry in the basin, for example, the Manta and Gummy gas project is being developed by Beach Petroleum, Anzon and Itochu.

The Otway Basin off south-western Victoria has a more diverse ownership base, with BHP Billiton (38 per cent), Santos (32 per cent), Australian Worldwide Exploration (14 per cent) and Mitsui (14 per cent) accounting for the bulk of production. Origin Energy is currently a relatively small producer but holds significant reserves.

The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration.

The growth of the CSG industry has led to considerable new entry in Queensland's Surat–Bowen Basin over the past decade and a diverse ownership profile. A number of smaller businesses such as Queensland Gas Company and Arrow Energy have developed considerable market share alongside more established entities such as Origin Energy and Santos. Overall, the largest producers in the basin are Origin Energy (31 per cent), Santos (27 per cent), Queensland Gas Company (14 per cent), Arrow Energy (10 per cent) and AGL Energy (7 per cent). These businesses also own the bulk of reserves. There has been significant ownership consolidation in the basin since 2005.

8.4.3 Mergers and acquisitions

There has been significant merger and acquisition activity in the gas production sector in recent years, with interest since 2006 focused mainly on CSG (and associated LNG proposals) in Queensland. Table 8.4 lists a number of proposed and successful acquisitions from June 2006 to September 2008.

Queensland Gas Company, the third largest producer in the Surat–Bowen Basin, has been a focus of acquisition interest. Following an unsuccessful takeover attempt by Santos in 2006, the company formed a strategic partnership with AGL Energy in 2007, which allowed AGL Energy to acquire a 27.5 per cent stake in the business. Queensland Gas Company sold a further 20 per cent stake in its assets to BG Group (formerly British Gas) in 2008. The agreement was based around the development of CSG resources for LNG exports.

BG Group sought to further expand its market profile in 2008 by attempting to acquire Origin Energy.

35 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 22.

Table 8.3 Market shares in proved and probable gas reserves by basin, 2008

COMPANY	CARNARVON (WA)	BONAPARTE (WA/NT)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	GUNNEDAH (NSW)	CLARENCE MORTON (QLD/NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
AGL Energy						3.3%				50.0%				0.6%
AJ Lucas									69.9%					0.3%
Apache Energy	3.3%													2.0%
ARC Energy			58.1%										12.4%	0.1%
Arrow Energy						10.6%								1.6%
AWE												6.0%	29.9%	0.4%
Beach					20.8%	1.6%								0.8%
Benaris												7.9%		0.2%
BHP Billiton	12.6%										44.7%	12.9%		13.2%
BP	12.8%													7.9%
Calenergy												3.1%	15.1%	0.2%
Chevron	12.8%													7.9%
CNOOC	3.4%													2.1%
Conoco–Phillips		9.8%												0.3%
CS Energy						0.6%		13.8%						0.2%
Eastern Star Gas							64.9%							0.2%
ENI		84.7%												2.9%
Esso											44.7%			5.0%
Gastar							35.1%							0.1%
Inpex		1.9%												0.1%
Kansai Electric	0.7%													0.4%
Magellan				47.6%										0.2%
Metgasco								86.2%						0.4%
MIMI	12.4%													7.7%
Mitsui						0.8%						6.0%		0.3%
Molopo						0.6%			30.1%					0.2%
Mosaic						0.7%								0.1%
Nexus											6.5%			0.7%
Origin Energy			41.9%		13.0%	34.6%						19.1%	42.6%	6.6%
Queensland Gas						17.6%								2.7%

COMPANY	CARNARVON (WA)	BONAPARTE (WA/NT)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT-BOWEN (QLD)	GUNNEDAH (NSW)	CLARENCE MORTON (QLD/NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Santos	2.4%	2.0%		52.4%	66.2%	22.3%					4.0%	13.1%		7.7%
Shell	12.6%													7.8%
Sunshine Gas						6.4%								1.0%
Sydney Gas										50.0%				0.1%
Tokyo Gas	0.7%													0.4%
Woodside	26.1%											31.9%		17.1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
TOTAL (PETAJOULES)	**29 723**	**1663**	**31**	**216**	**1183**	**7484**	**185**	**247**	**176**	**84**	**5353**	**1494**	**298**	**48 136**

Notes:
1. Based on 2P (proved and probable) reserves at 31 March 2008.
2. Some corporate names have been shortened or abbreviated. Not all minority owners are listed.

Source: EnergyQuest 2008 (unpublished).

Origin Energy rejected the offer in June 2008, and in September 2008 announced a LNG joint venture with Conoco-Phillips. BG Group subsequently announced that it would not pursue the acquisition of Origin Energy.

Further acquisitions in 2008 based around the development of CSG and LNG export facilities in Queensland included the following:

- In May 2008, Santos agreed to sell a 40 per cent stake in its proposed LNG project at Gladstone to Malaysian energy business Petronas.
- In June 2008, Arrow Energy agreed to sell 30 per cent of its CSG resources in Queensland to Shell.
- In August 2008, Queensland Gas Company reached an initial agreement to acquire Sunshine Gas.
- In August 2008, ARC Energy merged with Australian Worldwide Exploration.

8.5 Gas wholesale markets

Wholesale gas markets involve the sale of gas by producers, mainly to energy retailers that on-sell it to business and residential customers. In addition, some major industrial, mining and power generation customers buy gas directly from producers in the wholesale market.

8.5.1 Wholesale market contracts

In Australia, wholesale gas is mostly sold under confidential, long-term *take or pay* contracts. There has been a trend in recent years towards shorter-term supply, but most contracts still run for at least five years. Foundation contracts underpinning new production projects are still often struck for terms of up to 20 years. It is commonly argued that such long-term contracts are essential to the financing of new projects because they provide reasonable security of gas supply as well as a degree of cost and revenue stability.

Table 8.4 **Upstream gas merger and acquisition activity, June 2006–September 2008**

DATE	PROPOSED MERGER/ACQUISITION	GAS BASINS	STATUS AT SEPTEMBER 2008
Jun-06	Arrow Energy acquisition of CH4	Surat–Bowen (Qld)	Completed
Sep-06	Beach Petroleum acquisition of Delhi Petroleum	Cooper (Qld/SA)	Completed
Oct-06	Santos acquisition of Queensland Gas Company	Surat–Bowen (Qld)	Proposal withdrawn
Jan-07	AGL Energy and Origin Energy merger	Various	Proposal withdrawn
Jan-07	AGL Energy acquisition of a 27.5 per cent stake in Queensland Gas Company	Surat–Bowen (Qld)	Completed
Nov-07	AGL Energy–Arrow Energy joint venture acquisition of Enertrade's Moranbah gas assets	Surat–Bowen (Qld)	Completed December 2007
Apr-08	BG Group acquisition of about 20 per cent of Queensland Gas Company	Surat–Bowen (Qld)	Completed April 2008
May-08	BG Group acquisition of Origin Energy	Various	Proposal withdrawn September 2008
May-08	Petronas acquisition of 40 per cent of Santos' LNG project at Gladstone (joint venture)	Surat–Bowen (Qld)	FIRB approval July 2008
Jun-08	Shell acquisition of 30 per cent of Arrow Energy's CSG resources	Surat–Bowen (Qld)	Preliminary agreement June 2008
Aug-08	Queensland Gas Company acquisition of Sunshine Gas	Surat–Bowen (Qld)	Preliminary agreement September 2008
Aug-08	ARC Energy and Australian Worldwide Exploration merger	Perth (WA) and Bass (Vic)	Completed September 2008

FIRB, Foreign Investment Review Board.

For example, a 540 petajoule gas supply agreement between AGL Energy and Queensland Gas Company in 2006 was for supply over a period of 20 years.[36]

In Western Australia, strong domestic demand and rising LNG export prices have led to tight market conditions since 2006. The Economic Regulation Authority of Western Australia reported in 2007 that gas producers were only offering contracts with a maximum term of five years with volumes restricted to about 10 terajoules a day.[37]

Wholesale gas contracts typically include *take or pay* clauses that require the purchaser to pay for a minimum quantity of gas each year regardless of the actual quantity used. Prices may be reviewed periodically during the life of the contract. Between reviews, prices are typically indexed (often to the consumer price index). Contract prices therefore do not tend to fluctuate on a daily or seasonal basis. However, the many variations in provisions such as term, volume, volume flexibility and penalties associated with failure to supply mean that there can be significant price differences between contracts.[38]

While contracts form the basis of most gas sales arrangements, Victoria also operates a spot market to facilitate gas sales to manage system imbalances and pipeline network constraints (see box 8.1).

8.5.2 Joint marketing

Joint venture parties in gas production have to date mainly sold their gas through joint marketing arrangements under authorisation from the Australian Competition and Consumer Commission. More recently, there have been some instances of joint venture parties in new gas fields undertaking separate marketing. For example, Santos has separately marketed gas from its interest in the Casino field (Otway Basin), as has Woodside with its interest in the Geographe/Thylacine field (also in the Otway Basin).[39]

36 AGL Energy, *AGL secures cornerstone investment in QGC*, press release, 5 December 2006.
37 ERA, *Gas issues in Western Australia*, Discussion paper, Perth, 2007.
38 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.
39 NERA, *The gas supply chain in eastern Australia*, report to the AEMC, March 2008, p. 26.

8.5.3 Scheduling and balancing

Wholesale market arrangements must take account of the physical properties of natural gas and transmission pipelines:

- Unlike electricity, gas takes time to move from point to point. In Victoria, gas is typically produced and delivered within 6–8 hours because most demand centres are within 300 kilometres of gas fields. But gas delivered from the Cooper Basin into Sydney, or from the Carnarvon Basin into Perth, can take 2–3 days because the gas must be transported over much longer distances.
- Natural gas is automatically stored in pipelines (known as *linepack*). It can also be stored in depleted reservoirs or in liquefied form, which is economic only to meet peak demand or for use in emergencies.
- Natural gas pipelines are subject to pressure constraints for safety reasons. The quantity of gas that can be transported in a given period depends on the diameter and length of the pipeline, the maximum allowable operating pressure and the difference in pressure between the two ends.

These features make it essential that daily gas flows are managed. In particular, deliveries must be scheduled to ensure that gas produced and injected into a pipeline system remains in approximate balance with gas withdrawn for delivery to customers. To achieve this, gas retailers and major users must estimate requirements ahead of time and nominate these to producers and pipeline operators, subject to any pre-agreed constraints on flow rates and pipeline capacity.

Each day, producers inject the nominated quantities of gas into the transmission pipeline for delivery to customers. There are typically short-term variations between a retailer's nominated injections and their actual withdrawals from the system, creating imbalances. A variety of systems operate in Australia for dealing with physical imbalances, as well as financial settlements to address imbalances between the injections and withdrawals of particular shippers.

In most jurisdictions, physical balancing is managed by pipeline operators, while financial settlements for system imbalances are managed by independent system operators: VENCorp (Victoria and Queensland), REMCo (South Australia and Western Australia) and the Gas Market Company (New South Wales and the ACT). In Victoria, VENCorp operates a gas spot market to manage system imbalances and constraints (see box 8.1). Similar market arrangements are currently being developed for a number of major gas hubs in eastern Australia (see section 8.7).

8.5.4 Secondary trading

There is some secondary trading in gas, in which contracted bulk supplies are traded to alter delivery points and other supply arrangements. Types of secondary trades include backhaul and gas swaps.

Backhaul can be used for the notional transport of gas in the opposite direction to the physical flow in a pipeline. It is achieved by redelivering gas at a point upstream from the contracted point of receipt. Backhaul arrangements are most commonly used by gas-fired electricity generators and industrial users that can cope with intermittent supplies.

A *gas swap* is an exchange of gas at one location for an equivalent amount of gas delivered to another location. Shippers may use swaps to deal with regional mismatches in supply and demand. Swaps can also help deal with physical limitations imposed by the direction or capacity of gas pipelines and may delay the need to invest in new pipeline capacity.

Anecdotal evidence suggests that swaps are reasonably common in Australia, but are mostly conducted on a minor scale.[40] Origin Energy and the South West Queensland Gas Producers (SWQP) entered into a major swap arrangement in 2004 to enable Origin Energy to meet supply obligations in south-eastern Australia using gas produced by the SWQP. In return, Origin Energy delivered gas from its central Queensland field to meet supply obligations of the SWQP in that state.[41]

40 Firecone Ventures, *Gas swaps*, Report prepared for the National Competition Council, 2006.

41 Details of the swap arrangement are provided in AER, *State of the Energy Market 2007*, box 8.4, p. 248.

Box 8.1 The Victorian gas wholesale market

Victoria established a spot market for gas in 1999 to manage gas flows on the Victorian Transmission System (VTS). The market allows participants to trade gas supply imbalances (the difference between contracted gas supply quantities and actual requirements) on a daily basis. VENCorp operates both the wholesale market and the VTS.

Participants bid into the spot market on a daily basis via a bulletin board. Bids may range from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap).

Market participants (mostly retailers) inform VENCorp of their nominations for gas one and two days ahead of requirements. At the beginning of each day, schedules are drawn up that set out the hourly gas injections into and withdrawals from the system. The schedules rely on information from market participants and VENCorp, including demand forecasts, bids, conditions or constraints affecting bids, hedge nominations and VENCorp's modelling of system constraints.

At the beginning of each day, VENCorp stacks supply offers and selects the least cost bids to match demand across the market. This establishes a spot market clearing price. As the Victorian market is a net market, this price applies only to net injections or withdrawals (the difference between contracted and actual amounts).

Overall, gas traded at the spot price accounts for around 10–20 per cent of wholesale volumes in Victoria, with the balance sourced via bilateral contracts or vertical ownership arrangements between producers and retailers.

In effect, the spot market provides a clearing house in which prices reflect short-term supply–demand conditions, while underlying long-term contracts insulate parties from price volatility. Nevertheless, a comparison of the likely spot market price with underlying contract prices allows a retailer to choose to take a position to modify its own injections of gas and then trade gas at the spot price.

Until 2007, a single price applied in each 24-hour period without reference to system constraints or unforeseen events. Reforms to the gas market in February 2007 introduced rescheduling and rebidding at five defined time intervals over the day. The reforms aim to enhance flexibility, create incentives to respond to the spot price and provide clearer and more certain pricing signals. They also bring the gas market into closer alignment with the National Electricity Market.

Sometimes VENCorp needs to schedule additional injections of gas (typically LNG) that have been offered at above market price to alleviate short-term constraints. Market participants that inject the higher-priced gas receive ancillary payments. These are recovered from uplift charges paid, as far as practicable, by the market participants whose actions resulted in a need for injections. A user's *authorised maximum interval quantity* (AMIQ) is a key allocation factor in determining who must contribute uplift payments to pay for this gas.

In particular, market participants that exceed their AMIQ on a day when congestion occurs may face uplift charges, which provides price signals to gas users to adjust their usage patterns.

Market participants with AMIQ credits also have higher priority access to the pipeline system if congestion requires the curtailment of some users to maintain system pressure. This has not been necessary in recent years as sufficient gas (including LNG) has been available to support all users on the system. Nevertheless, in the event of severe congestion, those users without AMIQ must reduce their usage ahead of authorised users. A party can acquire AMIQ certificates by injecting gas into the Victorian system at Longford or by entering a contract with the VTS owner, GasNet.

Until winter 2007, there had been sufficient available gas and capacity on the VTS to meet customer requirements. Congestion occurred on only a few days a year, usually in winter. However, during winter 2007 there was a greater incidence of VENCorp having to inject higher-priced LNG to manage constraints and maintain minimum pressures. A key factor was that drought constrained the availability of coal-fired and hydroelectric generation, resulting in greater reliance on gas-fired generation and increased demand for natural gas.

However, with the easing of drought effects and the commissioning of new pipeline capacity in 2008, the need for high-cost injections of LNG was less evident in winter 2008.

While prices on the spot market are relatively stable, there are occasional troughs and spikes. For example, while in 2007 the average daily spot price was about $3.50 per gigajoule, it fell to close to zero on 1 May 2007, but achieved a record high on 17 July 2007 of $336 per gigajoule in the day's final trading interval. To date, VENCorp has found that price spikes in the market have been mostly due to operational and market issues, often related to severe or unpredictable weather. Further information on Victorian gas prices is set out in section 8.6 and figure 8.14.

In 2007, VENCorp engaged CRA International to undertake a strategic review of the 'top end' arrangements in the market, with particular emphasis on risk issues. The review was ongoing at August 2008.

Further information: http://www.vencorp.com.au

8.5.5 Trading hubs

A gas hub is an interconnection point between gas pipelines in which trading in gas and pipeline capacity may occur. In Australia, gas hubs include Moomba (South Australia), Wallumbilla (Queensland) and Longford (Victoria).

VicHub at Longford was established in 2003 and connects the Eastern Gas Pipeline, Tasmania Gas Pipeline and Victorian Transmission System. This connection allows for the trading of gas between New South Wales, Victoria and Tasmania. VicHub allows for the posting of public buy and sell offers, but is not a formal trading centre that provides brokering services.

The establishment of a gas market bulletin board in July 2008 and the development of a short-term trading market at defined gas hubs (scheduled to commence by winter 2010) are likely to enhance market transparency and opportunities for gas trading at the major hubs.

8.6 Gas prices

Australian gas prices have historically been low by international standards. They have also been relatively stable, defined by provisions in long-term supply contracts. In the United States and Europe, gas prices closely follow oil prices. Conversely, natural gas in Australia has generally been seen as a substitute for coal and coal-based electricity. Australia's abundant, low-cost coal sources have effectively capped gas prices.

Because gas contracts are not transparent outside Victoria, comprehensive price information is not readily available. A number of price estimates for Cooper Basin gas in 2004–05 were published during a public process on the regulation of the Moomba to Adelaide Pipeline. The estimates ranged from around $2.90 to $3.15 per gigajoule. Core Collaborative's *Australian Gas Sector Outlook* estimated that in 2005, gas prices in the Cooper and Gippsland basins were around $3.15 per gigajoule.[42]

42 Estimates published in NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, pp. 35–36.

ACIL Tasman published forecasts that in 2007–08, electricity generators in southeastern Australia would pay around $2.95 to $3.20 per gigajoule for natural gas.[43]

Since 2005, a number of interacting factors have put upward pressure on gas prices, including the following:

- A substantial rise in resource costs affecting exploration, development and production activities.
- High oil prices have flowed on to international gas prices, including for Australian LNG exports. This has put upward pressure on domestic gas prices in Western Australia, which has substantial LNG export capacity. In eastern Australia, a range of proposed LNG developments are also influencing price expectations.
- Drought led to greater demand for gas-fired generation in eastern Australia in 2007, with flow-on effects for gas prices.
- Market participants may be factoring in the effects of the Carbon Pollution Reduction Scheme into demand projections and pricing on long-term gas contracts.[44]

Figure 8.13 sets out indicative price data from 2005 to 2008 for domestic gas and LNG exports. The data relating to particular producers is based on average prices and in some cases may understate prices struck under new contracts.

8.6.1 Western Australia

Western Australia experienced low domestic gas prices for several years as a result of competition between the North West Shelf Venture and smaller producers dedicated to the domestic market. More recently, significant imbalances have arisen, with high demand for gas contracts—driven in part by the mining boom—at a time when most producers have fully contracted their developed reserves. This has been accompanied by substantial increases in gas field development costs.

At the same time, Western Australia's LNG export capacity creates exposure in the domestic market to international energy prices. Average LNG prices received by Australian producers rose by 48 per cent between the June quarters of 2007 and 2008.[45]

In combination, these factors have led to substantial price escalations in Western Australia's domestic gas market. The Western Australian Department of Industry and Resources reported that Santos secured domestic gas prices in July 2007 of more than $7 per gigajoule in two separate contracts with mining entities,[46] which is almost three times higher than the wholesale prices of around $2.50 per gigajoule that prevailed until 2006. Short-term wholesale prices averaged almost $17 per gigajoule in July 2008 following the Varanus Island incident, which cut domestic supply by around 30 per cent.[47]

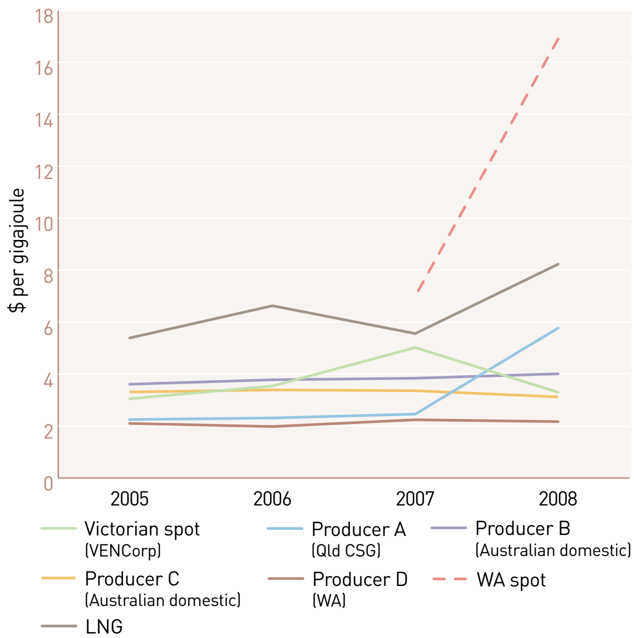
8.6.2 Eastern Australia

There is also some evidence of rising prices on the east coast. While for several years CSG prices in Queensland were typically lower than for conventional natural gas, the development of LNG proposals has raised price expectations.

Core Collaborative's *Australian Gas Sector Outlook* estimated that Queensland prices in 2006 were around $2.50 to $2.90 per gigajoule.[48] ACIL Tasman has reported that Queensland customers are now facing significantly higher prices, in excess of $4 per gigajoule.[49] EnergyQuest has reported that one CSG provider earned an average price for Queensland gas in the first quarter of 2008 of $7.79 per gigajoule ($5.77 in the second quarter), compared with $2.22 per gigajoule in the first quarter of 2006.[50] While these were significantly higher than the average prices received by other Queensland producers, they are nonetheless indicative that CSG prices may be trending higher.

43 ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, 6 June 2007.
44 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 30.
45 EnergyQuest, *Energy Quarterly*, August 2008.
46 Department of Industry and Resources (WA), *Western Australian Oil and Gas Review*, 2008.
47 EnergyQuest, *Energy Quarterly*, August 2008. See note to figure 8.13.
48 Estimates published in NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 36.
49 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.
50 EnergyQuest, *Energy Quarterly*, May 2008.

Figure 8.13
Indicative wholesale natural gas prices



CSG, coal seam gas; LNG, liquefied natural gas.

Notes:

1. Western Australian spot prices are indicative only: 2007 prices are estimates for new Santos contracts signed in July; 2008 prices are based on the weighted average price of gas trades notified to Western Australia's Independent Market Operator in July 2008. Western Australian prices in July 2008 were unusually high due to a major plant outage at Varanus Island.
2. All series (except Western Australian spot) are data from the second quarter of the year.
3. Data for Producers A, B, C and D are average company realisations for specific Australian gas producers.

Sources: WA spot 2007: Department of Industry and Resources (WA), *Western Australian Oil and Gas Review*, 2008; other data: EnergyQuest, *Energy Quarterly,* August 2005, August 2006, August 2007 and August 2008; LNG data is sourced from the ABS.

8.6.3 Victorian spot prices

The Victorian spot market (see box 8.1) provides transparent price and volume data on sales of natural gas to balance daily requirements between retailers and suppliers. Market volumes range from around 400 to 1200 terajoules per day. While the market only accounts for about 10–20 per cent of wholesale volumes in Victoria, its price outcomes are widely used as a guide to underlying contract prices.

Figure 8.14 charts price and volume activity since the market started in 1999. Despite a winter peaking demand profile, prices remained relatively stable until 2005. There has since been greater volatility, with significantly higher winter prices in 2006 and 2007. The average price for July 2007 reached a monthly record of almost $9 per gigajoule. Spot prices peaked at $336 per gigajoule on 17 July 2007, a market record. The price spikes were partly due to drought causing a shift to gas-fired electricity generation, which significantly increased demand for gas. Prices have since eased back towards trend levels. The spot price averaged $3.55 per gigajoule in the first quarter of 2008, slightly below the current contract price of about $3.59 per gigajoule.[51] An expansion of the Victorian Transmission System—the Corio Loop—eased capacity constraints on the network in winter 2008. Weighted average prices in June and July 2008 were below contract prices.

8.7 Gas market development

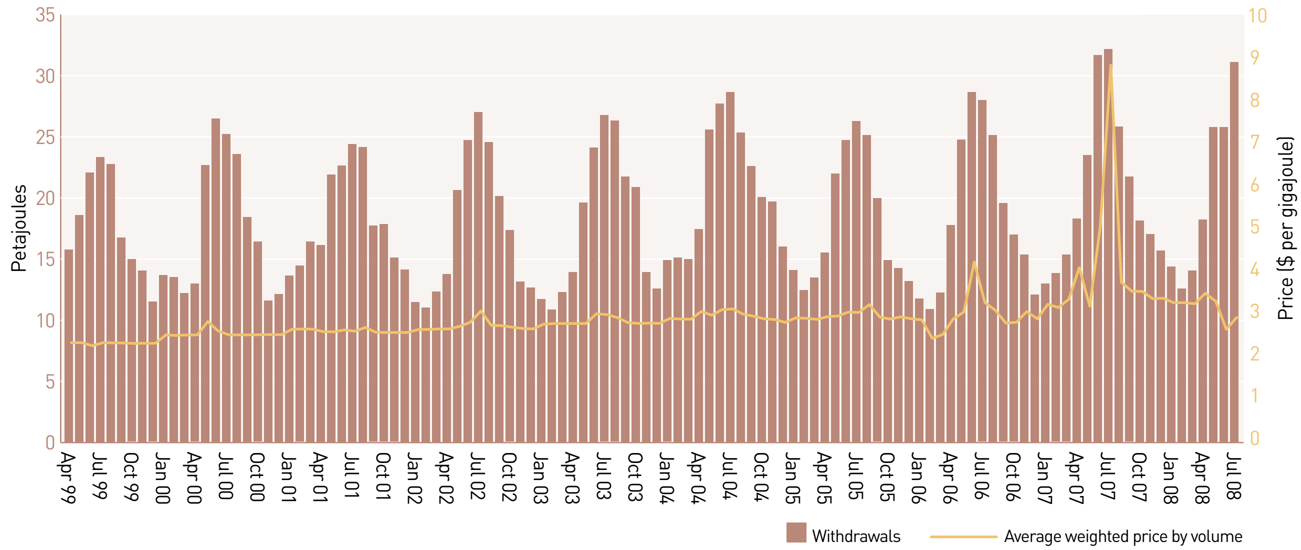
The Ministerial Council on Energy in 2005 appointed a Gas Market Leaders Group[52] to consider the need for further reform of the Australian gas market. In 2006, the Group recommended the establishment of:

> a gas market bulletin board
> a short-term trading market in gas
> a national gas market operator to administer the bulletin board and short-term trading market and to produce an annual national statement of opportunities on the gas market covering supply–demand conditions.

The bulletin board was implemented on 1 July 2008 and there has been significant progress towards implementing the other initiatives. The reforms aim to improve transparency and efficiency in Australian gas markets. They also aim to provide information to help manage gas emergencies and system constraints.

51 EnergyQuest, *Energy Quarterly*, May 2008, p. 65.
52 The group comprises 12 gas industry representatives and an independent chairperson.

Figure 8.14
Victorian gas market—monthly prices and volumes



Note: Average monthly prices (right-hand axis). Withdrawals are monthly totals (left-hand axis).

Source: VENCorp.

8.7.1 Gas market bulletin board

The gas market bulletin board, which commenced on 1 July 2008, is a website covering major gas production fields, storage facilities, demand centres and transmission pipelines, in southern and eastern Australia.[53] Provision has been made for Western Australia and the Northern Territory to participate in the future.

The bulletin board aims to provide transparent, real-time and independent information to gas customers, small market participants, potential new entrants and market observers (including governments) on the state of the gas market, system constraints and market opportunities. Information provision by relevant market participants is mandatory and covers:

> gas pipeline capacity and daily aggregated nomination data

> production capabilities (maximum daily quantities) and three-day outlooks for production facilitates

> storage capabilities and three-day outlooks for storage facilities.

Participants may also advise of spare capacity and make offers through the bulletin board.

The bulletin board facilitates trade in gas and pipeline capacity through the provision of readily available system and market information. For example, the bulletin board will provide information on outages or maintenance at production points and pipelines, including updated daily demand, actual or expected changes in supply capacity to demand centres and potentially, in the event of significant outages or system incidents, a flag indicating likely interruptions to customer supplies.

VENCorp is the interim bulletin board operator, pending the establishment of the Australian Energy Market Operator (AEMO). Under the National Gas Law, the Australian Energy Regulator monitors and enforces the compliance of market participants with the rules of the bulletin board.

Western Australia created its own limited bulletin board, run by the Independent Market Operator, to assist with the gas emergency during 2008. Though

53 http://www.gasbb.com.au

low volumes of trade were reported, the bulletin board provided some indication of prices during this period of restricted supply.

8.7.2 Short-term trading market

The MCE has approved the development, by the Gas Market Leaders Group, of a short-term trading market in gas, to commence by winter 2010. The proposed market is intended to facilitate daily trading by establishing a mandatory price-based balancing mechanism at defined gas hubs. The market would initially cover network hubs in New South Wales and South Australia, and replace existing gas balancing arrangements. Victoria has had a transparent balancing market in place since 1999 (see box 8.1).

The rationale for the market stems from concerns that the current gas balancing mechanisms in New South Wales and South Australia present barriers to retail market entry and impede gas supply efficiency. In particular, the current mechanisms create substantial financial exposures that are disproportionate to underlying costs. New entrants have faced difficulties acquiring appropriate hedging to manage these risks. The issues are especially pertinent for Sydney and Adelaide, which are sourced by multiple transmission pipelines.[54]

A daily market clearing price will be determined at each hub based on bids by gas shippers to deliver additional gas. The difference between each user's daily deliveries and withdrawals of gas will then be settled by the market operator at the clearing price. The mechanism is aimed at providing price signals to shippers and users to stimulate trading—including secondary trading—and demand-side response by users.

The short-term trading market is intended to operate in conjunction with longer-term gas supply and transportation contracts. It will provide an additional option for users to buy or sell gas on a spot basis without needing to enter delivery contracts in advance. It will also allow contracted parties to manage short-term supply and demand variations to their contracted quantities.

Structural and operational details of the market are undergoing further development during 2008.

8.7.3 Australian Energy Market Operator

The Council of Australian Governments agreed in 2007 to establish AEMO by 1 July 2009 to ultimately replace gas and electricity market operators such as VENCorp and the National Electricity Market Management Company. It is envisaged that the AEMO will operate both the gas market bulletin board and the short-term trading market. It is also envisaged that the AEMO will publish an annual Gas Statement of Opportunities (GSOO)—a national gas supply and demand statement—of a similar nature to the annual Statement of Opportunities currently published for electricity.

The GSOO is intended to provide information to assist gas industry participants in their planning and commercial decisions on infrastructure investment. The Gas Market Leaders Group commenced work on the design of the GSOO in 2008.[55]

8.7.4 Futures markets

The risk of participating in a commodity market can usually be hedged using physical or financial instruments. However, a futures gas market tends to develop only after the physical gas market reaches a certain level of maturity—with significant trading under transparent short-term contracts—as in the United States and the United Kingdom.

At present there is no futures market for gas in Australia and current opinion suggests that there is little prospect that a market will develop soon. The new gas market bulletin board and the proposed short-term trading market may facilitate future development of a formalised market for financial risk-hedging instruments (such as forward, futures, swap and option contracts).

54 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 19; McLennan Magasanik Associates, *Report to the Joint Working Group on Natural Gas Supply*, July 2007.

55 MCE, *Communiqué*, 13 June 2008.

8.8 Reliability of supply

Reliability relates to the continuity of gas supply to customers. Various factors—planned and unplanned—can lead to outages that interrupt supply. These may occur in gas production facilities or in the pipelines that deliver gas to customers.[56] A planned outage may occur for maintenance or construction works and can be timed for minimal impact. Unplanned outages occur when equipment failure causes the supply of gas to be interrupted.

A distinguishing feature of reliability issues in the gas sector compared with the electricity sector is the management of safety issues. While incidents such as gas explosions and fires at upstream facilities are rare, the risk of widespread damage and injury is serious. In extreme cases, an upstream gas incident may also lead to the load shedding of customers.

Major upstream incidents occurred at Longford (Victoria) in 1998, Moomba (South Australia) in 2004 and Varanus Island (Western Australia) in 2008. Victoria experienced a major supply outage in 1998 following gas fires at the Longford gas plant, which killed two people and shut down the state's entire gas supply for three weeks. The incident created significant economic costs. There was limited pipeline interconnection in 1998, which restricted Victoria's ability to import gas from other states to alleviate the shortage.

An explosion at South Australia's Moomba gas plant in January 2004 caused a significant loss of production capacity from the Cooper Basin, which restricted gas supplies into New South Wales. The issue was managed in part by importing gas from Victoria along the Eastern Gas Pipeline (constructed in 2000).

The incidents at Longford and Moomba led Australian governments to agree in 2005 on protocols to manage major gas supply interruptions on the interconnected networks.[57] The agreement established a government–industry National Gas Emergency Response Advisory Committee to report on the risk of gas supply shortages and options for managing potential shortages. A working group developed a communications protocol and a procedures manual which sets outs detailed instructions for officials and industry members in the event of an incident.

In the event of a major gas supply shortage, the protocol requires as far as possible that commercial arrangements operate to balance gas supply and demand and maintain system integrity. Emergency powers are available as a last resort. The gas market bulletin board includes a facility to support the emergency protocol. The bulletin board will gather emergency information, as required, from relevant market participants and jurisdictions.

There were significant reliability issues in New South Wales and the ACT in June 2007 when capacity on the Eastern Gas Pipeline and gas flows on the Moomba to Sydney Pipeline were insufficient to meet higher than expected demand. While there was no infrastructure failure by gas producers or transmission pipeline operators, the New South Wales Government established a Gas Continuity Scheme in 2008 to mitigate the risk of a recurrence. The scheme will provide commercial incentives for producers to increase supplies and customers to reduce gas usage in the event of a shortfall.

Western Australia's domestic gas supply was severely disrupted by an explosion at Varanus Island on 3 June 2008. The incident shut down Apache Energy's gas processing plant and reduced Western Australia's gas supply by around 30 per cent for over two months. Woodside Petroleum, which operates the North West Shelf joint venture, became the state's only major domestic gas supplier during this period. While it increased domestic supplies by around 150 terajoules per day, this was short of the 300 terajoules per day that Apache Energy supplied prior to the explosion.[58]

56 A discussion of reliability issues in the gas distribution sector appears in section 10.7 of this report.

57 Memorandum of Understanding in Relation to National Gas Emergency Response Protocol (Including Use of Emergency Powers), June 2005 (available at http://www.mce.gov.au).

58 Office of Energy (WA), *Gas supply disruption recovery update*, 8 July 2008.

Spot prices for gas rose sharply as a result of the explosion, with some reports of a tripling of prices.[59] The Australian and Western Australian governments cautioned that the events would cause significant economic disruption, including to mining exports.[60] Limited gas supplies forced several mining and industrial companies to scale back production, and some electricity generators switched to emergency diesel stocks. Some coal-fired power plants that had been closed were also brought back online.[61] Western Australia's Independent Market Operator (which operates the state's wholesale electricity market) established a gas bulletin board to facilitate trading during the disruption.

Apache Energy began to resume gas supply incrementally in August 2008. A resumption of full production was not expected until the end of 2008.[62]

59 J Freed, 'Spot price for gas soars after supply cut', *The Sydney Morning Herald*, 10 June 2008.
60 D Shanahan, 'Growth fears as lights start to go out', *The Australian*, 17 June 2008.
61 D Shanahan 'Growth fears as lights start to go out', *The Australian*, 17 June 2008.
62 Office of Energy (WA), *Energy Update,* 5 August 2008.

9 GAS TRANSMISSION

Nicholas White (supplied by KT Pty Ltd)

Transmission pipelines transport natural gas from production fields to major demand centres. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. They are mainly placed underground, which helps to minimise damage that could pose safety issues and interrupt gas services. In total, Australia's transmission pipeline network covers about 25 000 kilometres.

9 GAS TRANSMISSION

This chapter considers:

> Australia's gas transmission sector
> the structure of the sector, including industry participants and ownership changes over time
> the economic regulation of the gas transmission sector
> new investment in transmission pipelines
> pipeline access and tariffs
> financial indicators for the transmission pipeline sector.

9.1 Australia's gas transmission pipelines

Until the 1990s natural gas was supplied under separate state-based regimes. In all states and territories, a single transmission pipeline shipped gas to major demand centres from a single gas basin. Since the late 1990s, rising demand and regulatory reform have led to a significant rise in exploration and development activity, and rising gas production. In turn, this has stimulated investment in new gas transmission pipelines and the expansion of existing pipelines.

Australia's gas transmission pipeline network has almost trebled in length since the early 1990s. Around $3.8 billion has been invested in new gas transmission pipelines and expansions since 2000.[1] Much of this investment is in long-haul interstate pipelines that have introduced new supply sources and improved the security of gas supplies into markets in south-eastern Australia. The new cross-border infrastructure includes the 795 kilometre Eastern Gas Pipeline (Longford to Sydney, completed in 2000), the 732 kilometre Tasmanian Gas Pipeline (Longford to Hobart, 2002) and the 660 kilometre South East Australia (SEA)

1 This Australian Energy Regulator estimate is derived from regulatory determinations and other public sources. The estimate comprises around $2.1 billion investment in new pipelines and $1.7 billion capital expenditure to expand existing networks. See figure 9.5 and table 9.3.

Gas Pipeline (Port Campbell to Adelaide, 2003). The VicHub in eastern Victoria was constructed in 2002 to physically interconnect three major pipeline systems: the Victorian Transmission System, the Tasmanian Gas Pipeline and the Eastern Gas Pipeline.

New investment in the past decade has created an interconnected pipeline network covering New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). While Queensland is not yet interconnected with the southern jurisdictions, Epic Energy is constructing a new pipeline (the QSN Link) to achieve this.[2] The QSN Link, which is scheduled for completion by early 2009, will interconnect the Queensland transmission network with major pipelines in South Australia and New South Wales.

The interconnection of the eastern jurisdictions creates wider options to source gas from alternative gas basins. For example, a customer in Sydney can potentially source natural gas from the Cooper Basin or Sydney Basin (using the Moomba to Sydney pipeline) or Bass Strait (using the Eastern Gas Pipeline). The QSN Link will also provide Sydney customers with access to coal seam gas from Queensland. These developments promote a more competitive environment among gas producers, pipeline operators and gas retailers.

Transmission pipelines in Western Australia and the Northern Territory are not interconnected with other jurisdictions. The populated south-west of Western Australia is serviced by three main pipelines. The Dampier to Bunbury Pipeline and the Goldfields Pipeline deliver gas from the Carnarvon Basin, and the Parmelia Pipeline transports gas from both the Carnarvon and Perth basins. There has been substantial investment in Western Australian pipelines in the current decade, including an expansion of the Dampier to Bunbury Pipeline and new pipelines to supply gas to the mining and resources sector. In the Northern Territory, the Amadeus Basin to Darwin Pipeline transports gas from the Mereenie and Palm Valley gas fields.

Table 9.1 sets out summary details of Australia's major transmission pipelines. Figure 9.1 illustrates pipeline routes.

9.2 Ownership of transmission pipelines

Government reforms to the gas sector in the 1990s led to structural reform and significant ownership changes. In particular, vertically integrated gas utilities were disaggregated and most government-owned transmission pipelines were privatised. Figure 9.2 sets out changes in the ownership of major transmission pipelines since 1994.

Privatisation led to the entry of a number of US-based energy utilities. In the 1990s, PG&E, GPU GasNet, Tenneco and Epic Energy acquired major pipelines in Victoria, South Australia, Queensland and Western Australia, while Duke Energy—another US utility—constructed major new pipelines in eastern Australia. The principal domestic player was the New South Wales energy utility AGL, which owned or acquired major transmission assets in New South Wales and Queensland. In 2000, AGL's gas transmission assets were transferred to the Australian Pipeline Trust, which is now part of the APA Group.[3]

Over time, the US-based utilities exited the Australian market, selling their transmission assets to new entrants such as Alinta and existing players such as the APA Group. The transmission pipeline landscape experienced a major shift in 2007 with the sale of Alinta to Singapore Power International and the Babcock & Brown group. Origin Energy and the CLP Group also withdrew from the gas pipeline sector, with the sale of their network assets to the APA Group and Retail Employees Superannuation Trust respectively.[4]

2 At present, only a raw gas pipeline from Ballera to Moomba connects the Queensland and South Australian pipeline systems.

3 In 2006, the Australian Pipeline Trust began trading as part of the APA Group, which comprises Australian Pipeline Ltd, the Australian Pipeline Trust and the APT Investment Trust.

4 The AER *State of the energy market 2007* report provides a more detailed account of historical changes in the ownership of gas transmission infrastructure. See section 9.3. The report is available on the AER website.

Table 9.1 **Major transmission pipelines**

PIPELINE	LOCATION	LENGTH (KM)	YEAR CONSTRUCTED	COVERED?[1]	VALUATION[2] ($ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
NEW SOUTH WALES AND ACT								
Moomba to Sydney Pipeline	SA–NSW	2029	1974–1993	Partial	835 (2003)	2004–2009	APA Group	APA Group
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	795	2000	No	450 (2000)	n/a	Jemena (Singapore Power International (Australia))	Jemena (Singapore Power International (Australia))
Central West (Marsden to Dubbo) Pipeline	NSW	255	1998	Yes	28 (1999)	2000–2010	APA Group	APA Group
Central Ranges (Dubbo to Tamworth) Pipeline	NSW	300	2006	Yes	53 (2003)	2005–2019	APA Group	Country Energy (NSW Govt)
VICTORIA								
Victorian Transmission System (GasNet)	Vic	2035	1969–2008	Yes	524 (2007)	2008–2012	APA Group	APA Group/VENCorp
VicHub	Vic	n/a	2003	No	n/a	n/a	Jemena (Singapore Power International (Australia))	Jemena (Singapore Power International (Australia))
SOUTH AUSTRALIA								
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	680	2003	No	500 (2003)	n/a	International Power, APA Group, and REST (equal shares)	APA Group
Moomba to Adelaide Pipeline	SA	1185	1969	No	370 (2001)	n/a	Epic Energy (Hastings)	Epic Energy
TASMANIA								
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	734	2002	No	440 (2005)	n/a	Babcock & Brown Infrastructure	Babcock & Brown Infrastructure
QUEENSLAND								
QSN Link (Ballera to Moomba interconnect)	Qld–SA (and NSW)	180	2009	No	140 (2007)	n/a	Epic Energy (Hastings)	Epic Energy
South West Queensland Pipeline (Ballera to Wallumbilla)	Qld	756	1996	No	n/a	n/a	Epic Energy (Hastings)	Epic Energy
Roma (Wallumbilla) to Brisbane	Qld	440	1969	Yes	296 (2006)	2007–2011	APA Group	APA Group
Queensland Gas Pipeline (Wallumbilla to Gladstone and Rockhampton)	Qld	629	1989–1991	No	n/a	n/a	Jemena (Singapore Power International (Australia))	Jemena (Singapore Power International (Australia))
Carpentaria Pipeline (Ballera to Mount Isa)	Qld	840	1998	Yes (light regulation)	n/a	n/a	APA Group	APA Group
North Queensland Gas Pipeline	Qld	391	2004	No	160 (2005)	n/a	Victorian Funds Management Corporation	AGL Energy, Arrow Energy
Dawson Valley Pipeline	Qld	47	1996	Yes	8 (2007)	2007–2016	Anglo Coal (51%), Mitsui (49%)	Anglo Coal

PIPELINE	LOCATION	LENGTH (KM)	YEAR CONSTRUCTED	COVERED?[1]	VALUATION[2] ($ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
WESTERN AUSTRALIA								
Dampier to Bunbury Pipeline	WA	1854	1984	Yes	1618 (2004)	2005–2010	DUET Group (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%)	WestNet Energy (owned by Babcock & Brown Infrastructure)
Goldfields Gas Pipeline	WA	1427	1996	Yes	514 (1999)	2000–2009	APA Group (88.2%), Babcock & Brown Power (11.8%)	APA Group
Parmelia Pipeline	WA	445	1971	No	n/a	n/a	APA Group	APA Group
Telfer Pipeline (Port Hedland to Telfer)	WA	443	2004	No	114 (2004)	n/a	APA Group	APA Group
Midwest Pipeline	WA	353	1999	No	n/a	n/a	APA Group (50%), Horizon Power (WA Govt) (50%)	APA Group
Kambalda to Esperance Pipeline	WA	350	2004	No	45 (2004)	n/a	WorleyParsons (50%), ANZ Infrastructure Services (50%)	WorleyParsons Asset Management
Pilbara Energy Pipeline	WA	219	1995	No	n/a	n/a	Epic Energy (Hastings)	Epic Energy
Kalgoorlie to Kambalda Pipeline	WA	44	n/a	Yes	n/a	n/a	APA Group	APA Group
NORTHERN TERRITORY								
Bonaparte	NT	285	2009	No	150 (2007)	n/a	APA Group	APA Group
Amadeus Basin to Darwin Pipeline	NT	1512	1987	Yes	229 (2001)	2001–2011	Amadeus Pipeline Trust (96% APA Group)	NT Gas (APA Group)
Palm Valley to Alice Springs Pipeline	NT	140	1983	No	n/a	n/a	Envestra (APA Group 17%, CKI 17%)	APA Group
Daly Waters to McArthur River	NT	330	1994	No	n/a	n/a	APA Group, Power and Water	NT Gas (APA Group)

n/a, not available; CKI, Cheung Kong Infrastructure; REST, Retail Employees Superannuation Trust.

Notes:

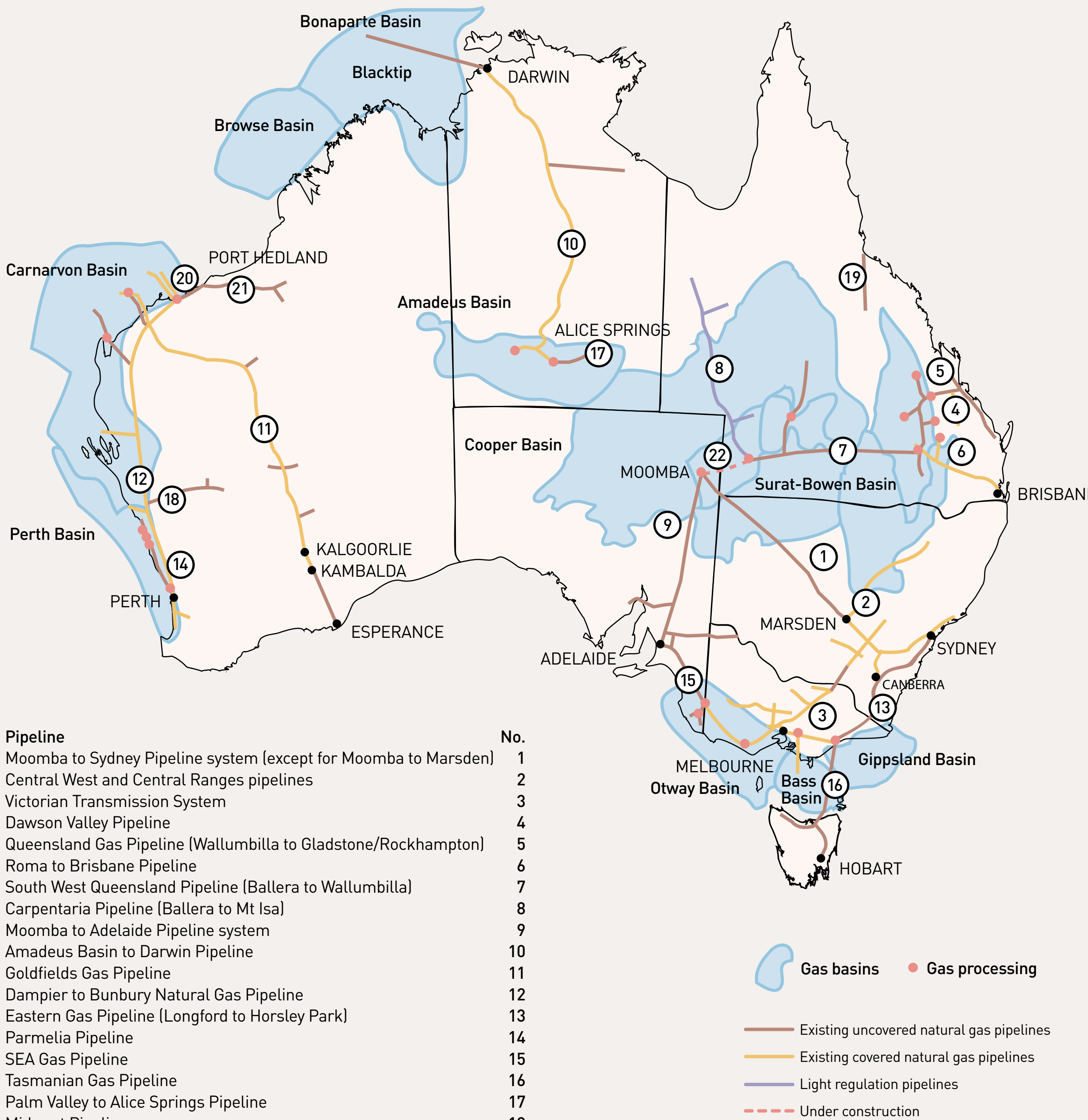
1. Covered pipelines are subject to regulatory arrangements set out in the National Gas Law and National Gas Rules.
2. For covered pipelines, valuation refers to the opening regulated asset base (RAB) for the current regulatory period. The RAB is as determined by the regulator, except for the Moomba to Sydney Pipeline, for which the RAB was determined by the Australian Competition Tribunal. For non-covered pipelines, valuation is the estimated construction cost, where data is available.

Regulatory arrangements—the Australian Energy Regulator regulates all covered pipelines outside Western Australia. In Western Australia, the Economic Regulation Authority (ERA) is the transmission regulator.

Principal sources: Access arrangements for covered pipelines; EnergyQuest, *Energy Quarterly Report, May 2008*, 2008; ABARE, *Energy in Australia 2008*, 2008; National Gas Market Bulletin Board, see http://www.gasbb.com.au (accessed 7 July 2008).

Figure 9.1

Major gas transmission pipelines



Pipeline	No.
Moomba to Sydney Pipeline system (except for Moomba to Marsden)	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mt Isa)	8
Moomba to Adelaide Pipeline system	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22

Principal sources: ABARE, *Energy in Australia 2008*, Canberra, 2007; EnergyQuest, *Energy Quarterly Report, February 2008*, 2008; NERA, *The Gas Supply Chain in Eastern Australia—A report to Australian Energy Market Commission*, 2007.

Figure 9.2

Transmission pipeline ownership

<table>
<tr><th></th><th></th><th></th><th>1994</th><th>1995</th><th>1996</th><th>1997</th><th>1998</th><th>1999</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th></tr>
<tr><td rowspan="16">Gas Transmission</td><td rowspan="6">South-east Australia</td><td>Moomba–Sydney</td><td>Govt</td><td colspan="5">AGL 51%, Gasinvest 49%</td><td colspan="9">APA Group</td></tr>
<tr><td>Eastern Gas Pipeline</td><td colspan="6"></td><td colspan="4">Duke Energy</td><td colspan="3">Alinta</td><td colspan="2">Singapore Power</td></tr>
<tr><td>Victorian Transmission System</td><td colspan="5">Govt</td><td colspan="7">GasNet</td><td colspan="3">APA Group</td></tr>
<tr><td>SEA Gas Pipeline</td><td colspan="10"></td><td colspan="3">Origin, IP, CLP 33.3% each</td><td colspan="2">APA, IP, CLP 33.3% each</td></tr>
<tr><td>Moomba–Adelaide</td><td>Govt</td><td>Tenneco</td><td colspan="8">Epic Energy</td><td colspan="5">Epic Energy (Hastings)</td></tr>
<tr><td>Tasmanian Gas Pipeline</td><td colspan="8"></td><td colspan="2">Duke Energy</td><td colspan="3">Alinta</td><td colspan="2">BBI</td></tr>
<tr><td rowspan="5">Queensland</td><td>Wallumbilla–Gladstone</td><td colspan="6">Govt</td><td colspan="4">Duke Energy</td><td colspan="3">Alinta</td><td colspan="2">Singapore Power</td></tr>
<tr><td>Gladstone–Rockhampton</td><td colspan="2">Govt</td><td>PG&E</td><td colspan="7">Duke Energy</td><td colspan="3">Alinta</td><td colspan="2">Singapore Power</td></tr>
<tr><td>Roma–Brisbane</td><td colspan="6">AGL</td><td colspan="7">APT</td><td colspan="2">APA Group</td></tr>
<tr><td>Carpentaria Gas Pipeline</td><td colspan="4"></td><td colspan="2">AGL</td><td colspan="7">APT</td><td colspan="2">APA Group</td></tr>
<tr><td>Ballera–Wallumbilla</td><td colspan="2"></td><td colspan="8">Epic Energy</td><td colspan="5">Epic Energy (Hastings)</td></tr>
<tr><td rowspan="3">Western Australia</td><td>Dampier–Bunbury</td><td colspan="4">Govt</td><td colspan="6">Epic Energy</td><td colspan="3">Alinta 20%, DUET 60%, Alcoa 20%</td><td colspan="2">BBI 20%, DUET 60%, Alcoa 20%</td></tr>
<tr><td>Goldfields Gas Pipeline</td><td colspan="4">GGT JV WMC 63%</td><td colspan="6">Southern Cross Pipelines Australia 88%</td><td colspan="3">APA Group 88.2%, Alinta 11.8%</td><td colspan="2">APA Group 88%, BBP 12%</td></tr>
<tr><td>Parmelia Pipeline</td><td colspan="3">WAPET joint venture</td><td colspan="7">CMS Gas Transmission</td><td colspan="5">APA Group</td></tr>
<tr><td rowspan="2">NT</td><td>Amadeus Basin–Darwin</td><td colspan="4">Amadeus Gas Trust</td><td colspan="2">AGL 96%</td><td colspan="9">APA Group 96%</td></tr>
<tr><td>Palm Valley–Alice Springs</td><td colspan="6">NT Gas & Holyman</td><td colspan="9">Envestra (CKI 17%, Origin 17%, other 66%)</td></tr>
</table>

APT, Australian Pipeline Trust (assets now part of the APA Group); BBI, Babcock & Brown Infrastructure; BBP, Babcock & Brown Power; CKI, Cheung Kong Infrastructure; GGT JV, Goldfields Gas Pipeline Joint Venture; IP, International Power; WMC, Western Mining Company. PG&E, Pacific Gas and Electric; WAPET, West Australian Petroleum Pty Limited joint venture (Chevron, Texaco and Shell with a two-seventh interest each, and Ampolex with a one-seventh interest).

Notes:

1. Some corporate names have been abbreviated or shortened.
2. Changes in ownership are shown in the year they occurred.
3. From 1996–2003, Epic Energy was owned by El Paso Energy (30%), CNG International (30%), Allgas Energy (10%), AMP Investments (10%), Axiom Funds Management (10%) and Hastings (10%).
4. The CLP Group sold its share in the SEA Gas Pipeline to Retail Employees Superannuation Trust in September 2008.

Principal sources: Australian Gas Association, *Gas Statistics Australia* (various years); and company websites.

A significant feature of the past few years has been the emergence of Singapore Power International and the APA Group as major owners and operators of transmission pipelines. Investment trusts such as Babcock & Brown Infrastructure, Hastings (trading as Epic Energy) and DUET Group have also acquired significant ownership profiles.[5]

In recent years, there was a tendency to separate the ownership and operation (management control) of gas transmission pipelines, but this pattern has reversed since the sale of Alinta in 2007. In particular, the APA Group, Singapore Power International and Babcock & Brown Infrastructure have moved to an integrated

5 DUET Group comprises a number of trusts, the responsible entities for which are jointly owned by Macquarie Bank (50%) and AMP Capital Holdings (50%). Hastings Diversified Utilities Fund is managed by a fund acquired by Westpac in 2005.


Babcock & Brown Infrastructure

model, in which a group entity operates and manages all pipeline assets in the group.

In the past year, the APA Group has brought its management in-house by terminating its management contract with Agility. It now operates its transmission pipeline assets internally in the group through a single management company. In August 2008, the former Alinta assets now owned by Singapore Power International were rebranded as Jemena. The new name applies to both the asset ownership and asset management entities. The Epic Energy (Hasting) pipelines continue to be operated by group management companies.

By 2008, ownership consolidation had reduced the number of principal players in the gas transmission sector to four:

- The APA Group owns the Moomba to Sydney and Central West pipelines in New South Wales; the Victorian Transmission System; two major Queensland pipelines (Carpentaria and Roma to Brisbane); four major Western Australian pipelines (Goldfields Gas, Parmelia, Telfer and Midwest); and the principal pipeline (Amadeus Basin to Darwin) in the Northern Territory. It is also a part owner of the SEA Gas Pipeline and two other Northern Territory pipelines.
- Singapore Power International acquired a portfolio of gas transmission assets from Alinta in 2007. It now owns the Eastern Gas Pipeline, VicHub, and the Queensland Gas Pipeline. In August 2008, Singapore Power International rebranded its ownership and asset management entities in the energy sector as Jemena.
- Babcock & Brown Infrastructure acquired a 20 per cent interest in the Dampier to Bunbury Pipeline from Alinta in 2007. It now operates the pipeline through its management services business WestNet Energy. It also owns the Tasmanian Gas Pipeline and has a minority interest in Western Australia's Goldfields Gas Pipeline.
- The investment fund Hastings acquired Epic Energy's gas transmission assets in 2000, including the Moomba to Adelaide Pipeline (South Australia), the Pilbara Energy Pipeline (Western Australia) and the South West Queensland Pipeline. In 2008, Epic Energy is constructing the QSN Link from Queensland to South Australia and New South Wales.

Other players include:

- DUET Group, the majority owner (60 per cent) of the Dampier to Bunbury Pipeline
- International Power and Retail Employees Superannuation Trust, which each have ownership interests in the SEA Gas Pipeline
- Cheung Kong Infrastructure, which part owns a Northern Territory pipeline via its interest in Envestra
- Anglo Coal/Mitsui has ownership interests in Queensland pipelines (see table 9.1).

9.3 Economic regulation of gas transmission pipelines

Gas pipelines are capital intensive and incur relatively low operating costs. This gives rise to economies of scale that make it cheaper to use a single pipeline than to construct multiple pipelines between a particular gas basin and a major load (demand) centre. Rising demand can usually be accommodated more cheaply by adding compressors or looping (duplicating part or all of) an existing pipeline than by constructing a second pipeline.

If a major load centre is served by only one gas basin, the transmission pipeline is likely to have significant market power, and may charge prices above underlying costs. As noted, all Australian load centres historically relied on a single gas basin and transmission pipeline to supply gas. Australian governments have tended to apply price regulation in these circumstances to address the risk of market power.

The National Gas Law and National Gas Rules (Gas Rules), which took effect on 1 July 2008, provide the overarching regulatory framework for the gas transmission sector. The law and rules replace the Gas Pipeline Access Law and National Gas Code (Gas Code), which provided the regulatory framework from 1997 to 30 June 2008.

The Gas Code initially applied to most Australian transmission pipelines, but this position has changed over the past decade. Significant new investment in gas pipelines has led to improved interconnection between gas basins and retail markets in the south-eastern states. This has improved supply options and, in some instances, may limit the ability of pipeline operators to exercise market power.

The Gas Rules (previously the Gas Code) anticipate the potential for market conditions to evolve over time, and include a coverage test to allow for an independent review of whether there is a need to regulate a particular pipeline. The National Competition Council is the coverage review body, but the final decision on coverage is made by government. Decisions are open to review by the Australian Competition Tribunal. In 2001, the tribunal reversed a ministerial decision to cover the Eastern Gas Pipeline.

The coverage process has led to the lifting of economic regulation—in whole or part—from several major pipelines, including the Eastern Gas Pipeline,[6] Western Australia's Parmelia Pipeline and a significant portion of the Moomba to Sydney pipeline. The South Australian Minister for Energy revoked coverage of the Moomba to Adelaide pipeline in 2007. The Queensland Government passed legislation in 2008 that terminated the coverage of two major Queensland pipelines—the South West Queensland and Queensland Gas pipelines.[7]

The Gas Rules include a process to cover newly constructed pipelines. Only one pipeline constructed during the current decade (the Central Ranges Pipeline in New South Wales) is currently covered. Other major pipelines—including the SEA Gas and Tasmanian Gas pipelines and several new pipelines in Western Australia —are not covered. As of July 2008, no transmission pipeline into Adelaide or Hobart was subject to economic regulation.

The service provider[8] of a covered pipeline must comply with the provisions of the National Gas Law and Gas Rules. Typically this requires submitting an access arrangement—including pipeline tariffs—to the regulator for approval. The legislation also allows for light regulation in some circumstances, in which the service provider is obliged only to publish terms and conditions of access on its website.[9]

Pipelines that are not covered are subject only to the general anti-competitive provisions of the *Trade Practices Act 1974*. Access to non-covered pipelines is a matter for the access provider and an access seeker to negotiate, without regulatory assistance.

9.3.1 Regulation of covered pipelines

As of 1 July 2008, 11 gas transmission pipelines were regulated under the Gas Rules (see table 9.2). In the southern and eastern jurisdictions, the Australian Energy Regulator (AER) replaced the Australian Competition and Consumer Commission (ACCC) as the regulator on 1 July 2008.

The Economic Regulation Authority (ERA) of Western Australia is the regulator of covered pipelines in that state, in recognition that there is no pipeline interconnection with other jurisdictions. Western Australia will implement legislation equivalent to the National Gas Law, and will review its institutional arrangements for gas within five years—or earlier, in the event of pipeline interconnection with another jurisdiction.

6 The Eastern Gas Pipeline was covered by a Ministerial decision on 16 October 2000. The Australian Competition Tribunal reversed this decision on 4 May 2001.

7 Any party may apply to the National Competition Council to consider whether a previously covered pipeline should be covered once again. The Dawson Valley Pipeline was revoked from coverage in 2000, but a later application reversed this decision in 2006. See table 9.2. The National Gas (Queensland) Regulation 2008 provides that no person may apply to reactivate coverage of the South West Queensland Pipeline for a period of one year, or the Queensland Gas Pipeline for a period of two years.

8 In accordance with the National Gas Law, the service provider may be the owner or operator of the whole pipeline or any part of the pipeline.

9 The Second Reading Speech for the National Gas (South Australian) Bill 2008 at p. 15 indicates that light regulation may be relevant for point-to-point transmission pipelines with a small number of users that each have countervailing market power.

Table 9.2 **Covered transmission pipelines at 1 March 2008**

JURISDICTION AND PIPELINE	COMMENTS
NEW SOUTH WALES	
Moomba to Sydney Pipeline	Partially covered[1]
Central West (Marsden to Dubbo)	Covered since 1998[2]
Central Ranges Pipeline	Covered in May 2004
VICTORIA	
Victorian Transmission System	Covered since 1997
QUEENSLAND	
Roma (Wallumbilla) to Brisbane Pipeline	Covered since 1997; derogations expired in 2006, enabling the regulator to set tariffs for the first time
Dawson Valley Pipeline	Coverage revoked in 2000 but reinstated in 2006
Carpentaria Pipeline (Ballera to Mt Isa)	Covered since 1997; light regulation only[3]
WESTERN AUSTRALIA[4]	
Dampier to Bunbury Pipeline	Covered since 1999
Goldfields Gas Pipeline	Covered since 1999
Kalgoorlie to Kambalda Pipeline[5]	Covered since 1999
NORTHERN TERRITORY	
Amadeus Basin to Darwin Pipeline	Covered since 1997

Notes:

1. Coverage of the Moomba to Sydney Pipeline was partially revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden. See figure 9.1.
2. Under the National Gas Law, the Central Ranges Pipeline will cease to be covered once the current access arrangement expires.
3. The service provider of a light regulation pipeline must publish the terms and conditions of access, including tariffs, on its website. There is no requirement to submit an access arrangement to the regulator for approval.
4. The Gas Code commenced in Western Australia in 1999.
5. The regulator has not approved an access arrangement for this pipeline.

9.3.2 Regulatory framework

In Australia, the providers of most transmission pipelines offer gas transportation services to third parties via access contracts. Typically, a party negotiates a long-term bilateral contract with the operator, which sets out the conditions of use. A contract typically features a maximum daily quantity allocation and sets a capacity charge, which must be paid regardless of the amount of gas a customer transports on the pipeline.

In Victoria, an independent operator (VENCorp) manages the Victorian Transmission System, and users are not required to enter into contracts. Instead a party's daily gas flow is determined by its bids into the wholesale gas market. The bids enter a market clearing engine where the lowest priced supply offers are dispatched to meet demand. Pipeline charges are based on actual gas flows following this dispatch selection process.

To assist pipeline customers, the Gas Rules require pipeline operators to develop access arrangements that set out terms and conditions of access. These typically include reference tariffs for the pipeline. Most access arrangements apply for a fixed term, after which they are subject to review.

An access arrangement must comply with the provisions of the Gas Rules and underpinning legislation, including pricing principles, ring-fencing requirements and rules for associate contracts. The regulator may require a pipeline operator to amend an access arrangement that fails to meet the code's provisions. Once approved, an access arrangement is enforceable. In particular, an access seeker may request the regulator to arbitrate a dispute and enforce the provisions of an access arrangement.[10]

10 In Western Australia a separate arbitrator hears access disputes.

The regulatory approach in gas is broadly similar to that applied to electricity networks. In particular, the regulator aims to determine revenue outcomes that cover efficient costs, including asset depreciation and a proxy for a commercial return on capital. As in electricity, the Gas Rules provide for incentive mechanisms to reward efficient operating practices.

A point of difference is that while electricity transmission regulation is based around the setting of revenue caps, the approach in the Gas Rules is to set reference (benchmark) tariffs for reference services that are commonly sought by customers. The reference tariff is intended to form a basis for negotiation between the pipeline owner and customers, but is enforceable if a party notifies the regulator of a dispute. The negotiation of tariffs may be complex if a pipeline is operating at capacity and requires an expansion to make access possible.

Typically, reference tariffs apply to firm haulage services, the most commonly sought service on most pipelines.[11] Gas users seeking short-term or interruptible supplies can try to negotiate those services with the pipeline operator or other gas shippers directly. The regulated tariffs for reference services may be of assistance in these negotiations.

The Gas Rules allow a number of options for determining regulated revenue. The two methods currently in use are the cost of service method and the net present value method:

- The cost of service method is a building block approach in which revenue is set to recover efficient costs, including operating and maintenance expenses, asset depreciation costs and a return on capital. This method, which is similar to that applied in electricity transmission, is used to set benchmark total revenues for most transmission pipelines. For example, it was recently used to set revenues for the Victorian Transmission System.
- The net present value method applies a discount rate to forecast costs and sales to set revenues that will deliver a net present value for the pipeline equal to zero. Central West is the only transmission pipeline that applies this method to set benchmark total revenue.[12]

Figures 9.3 and 9.4 show the revenue components under the access arrangements for the Victorian Transmission System for the period 2008–2012 and the Roma to Brisbane Pipeline for the period 2007–2011. The charts provide a guide to the typical composition of the revenue components in a determination. In these decisions, returns on capital and depreciation account for almost three-quarters of regulated revenue. Operating and maintenance costs account for most of the balance.

9.3.3 New regulatory framework—2008

The regulatory framework for the gas transmission sector underwent significant change in 2008, including the transfer of regulatory functions to new bodies. In 2004, the Productivity Commission completed a review of the Gas Code, which proposed several changes to address industry concerns that the regime was deterring investment. This led to the development of a new National Gas Law and Gas Rules, with new provisions to enhance regulatory certainty for investment.

The new framework commenced on 1 July 2008. While the framework mirrors its predecessor in many respects, there are a number of changes to the regulation of transmission pipelines, including the following:

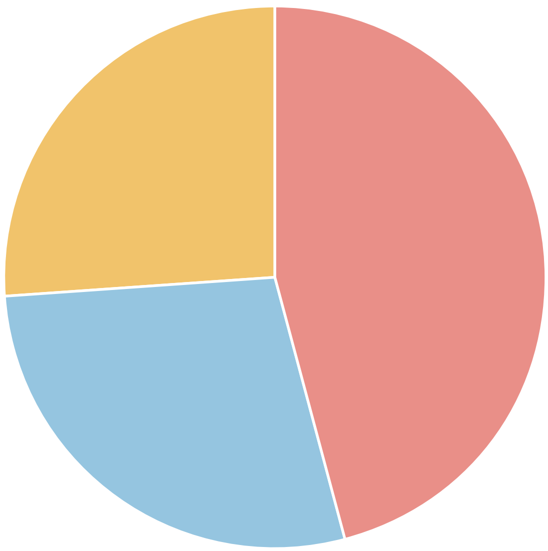
- The AER replaces the ACCC as the transmission regulator, except in Western Australia.
- For certain pipelines, 'light' regulation without upfront price and revenue regulation may apply. The National Competition Council has the role of determining whether a pipeline is subject to light regulation. The policy intent is that this form of regulation is suited to some transmission pipelines.[13] Where light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. In the event of a dispute, an access seeker may request the regulator to arbitrate.

11 Firm forward-haulage services enable the customer to reserve capacity on a pipeline and receive a high priority service. Interruptible services are sold on an 'as available' basis and may be interrupted or delayed, especially if a pipeline has capacity constraints.

12 The Gas Rules also allow for an internal rate of return approach, in which total revenues are set to provide a rate of return for the pipeline on the basis of forecast demand and costs.

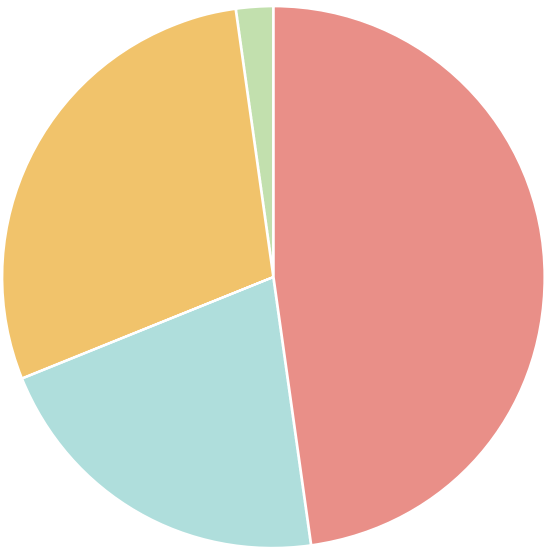
13 The Second Reading Speech for the National Gas (South Australian) Bill 2008 at p. 15 indicates that light regulation may be relevant for point-to-point transmission pipelines with a small number of users that each have countervailing market power.

Figure 9.3
Revenue composition for the Victorian Transmission System (2008–12)



Source: ACCC, *Revised Access Arrangement by GasNet Australia Ltd for the Principal Transmission System*, Final Decision, 30 April 2008.

Figure 9.4
Revenue composition for Roma to Brisbane pipeline (2007–11)



Source: ACCC, *Revised Access Arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline*, Final Decision, 20 December 2006.

> Stronger incentives apply for investment in greenfields pipelines and international pipelines to Australia. Pipeline owners can apply for a determination that provides a 15-year exemption from coverage for greenfields pipelines and a 15-year exemption from price regulation for international pipelines.

> New information-gathering powers apply in different circumstances and for different regulatory purposes and functions.

> Mandated decision-making processes and timeframes for key regulatory decisions apply.

> A new investment test that takes a cost-benefit analysis approach to assessing whether new facilities investment in existing pipelines may be rolled into the regulated asset base. The test aims to promote efficient investment in existing pipelines to meet rising demand for natural gas.[14]

14 The test allows for capital expenditure to be rolled into the regulated asset base if (1) the overall economic value is positive; or (2) the present value of incremental revenue is greater than the present value of the capital expenditure; or (3) the expenditure is necessary to maintain and improve safety of services, or maintain integrity of services or maintain a service provider's capacity to meet levels of demand for existing services.
In determining the overall economic value, only the economic value directly accruing to the service provider, gas producers, users and end users is to be considered. There are additional criteria for capital expenditure for Western Australian transmission pipelines that reflect the value that may accrue directly to electricity market participants from additional gas-fired generation capacity.
According to the Second Reading Speech, National Gas (South Australian) Bill 2008, the test is 'designed to capture net increases in producer and consumer surpluses in upstream and downstream gas markets, while also capturing the system security and reliability benefits that were considered by regulators to constitute system wide benefits. The test…unambiguously includes benefits that accrue to users and end users of gas when they are able to purchase additional quantities of gas, or to gas producers when they are able to sell additional quantities of gas' (p. 18).

9.4 Investment in transmission pipelines

Investment in the transmission sector typically involves large and lumpy capital projects to expand existing pipelines (through compression, looping and extensions) or construct new pipelines.[15] Around $3.8 billion has been invested in new transmission pipelines and expansions since 2000.[16] This represents a combination of substantial real investment in new infrastructure as well as rising resource costs in the construction sector.[17]

Figure 9.5 shows the underlying asset base and forecast investment over the current access arrangement period for a selection of pipelines where data is available.[18] The data for covered pipelines (shown as blue and pink bars in figure 9.5) is derived from regulatory determinations.

The estimates for non-covered pipelines (shown as green bars in figure 9.5) reflect initial construction costs derived from information in pipeline websites, corporate annual reports, prospectuses and media releases. While the owners of non-covered pipelines are not required to report publicly on investment data, the estimates indicate the scale of some recent investments in unregulated infrastructure.[19]

Figure 9.5 illustrates that the initial construction costs of transmission pipelines are substantial. Subsequent capital costs are relatively modest, except in the case of major capacity expansions (through the addition of compressors or duplication of sections of the pipeline through looping).

Figure 9.5 reflects significant expansion programs for the Victorian Transmission System and the Dampier to Bunbury Pipeline in Western Australia. There is little projected recurring investment for the Moomba to Sydney or Roma to Brisbane pipelines in their respective current regulatory periods. It should be noted that a major expansion may undergo a separate regulatory approval process, and may not be reflected in projected investment data.[20]

9.4.1 New pipelines and major expansions

Table 9.3 provides details of major investments since 2000, including those currently under construction. Recently completed projects include:

- the $500 million SEA Gas Pipeline from Port Campbell (Victoria) to Adelaide, completed in 2003
- the $160 million North Queensland Gas Pipeline from Moranbah to Townsville, completed in 2004
- the $430 million stage 4 expansion of the Dampier to Bunbury Pipeline (Western Australia), completed in December 2006, and the $660 million Stage 5A expansion, completed in April 2008
- the $114 million Telfer Pipeline, from Port Hedland to the Telfer Goldmine (Western Australia), completed in 2004
- the $70 million Corio Loop (Brooklyn to Lara) on the Victorian Transmission System, completed in 2008. The loop facilitates gas flow from Port Campbell (Otway Basin) to Melbourne.

15 Pipeline capacity can be increased by adding compressor stations to raise the pressure under which gas flows and by looping (duplicating) sections of the pipeline. Extending the length of the pipeline can increase line-pack (storage) capacity.

16 AER estimate derived from regulatory determinations and other public sources. The estimate comprises $2.1 billion of investment in new pipelines and $1.7 billion of capital expenditure to expand existing networks. See figure 9.5 and table 9.3.

17 Some resource costs in the energy construction sector are rising faster than general inflation, as measured by the Consumer Price Index. Chapter 4 provides data on rising costs. See section 4.4, including figures 4.7 and 4.8.

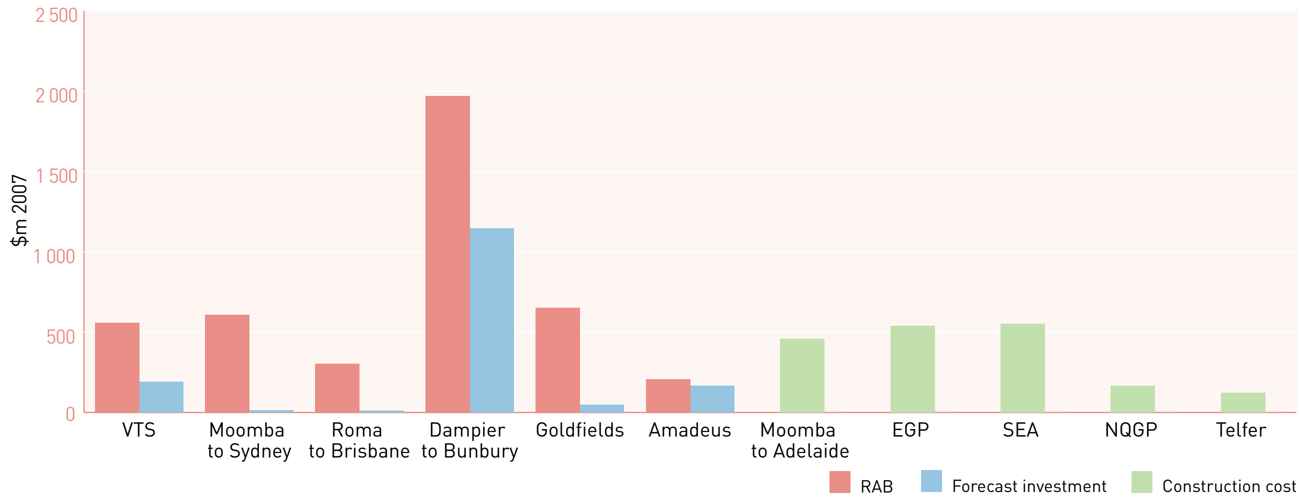
18 The data is not available for several Queensland pipelines due to historical derogations that constrained the role of the regulator in revenue determination.

19 The National Gas Law established a National Gas Market Bulletin Board on 1 July 2008. The bulletin board provides system and market information on gas transmission pipelines, including non-covered pipelines, in southern and eastern Australia. Over time this may improve public information about the non-covered pipeline sector. Chapter 8 includes background information on the bulletin board.

20 An extension or expansion that is not approved in the access arrangement cannot be rolled into the asset base until the following access arrangement review.

Figure 9.5

Transmission pipeline assets and investment (real)



VTS, Victorian Transmission System; EGP, Eastern Gas Pipeline; SEA, SEA Gas Pipeline; NQGP, North Queensland Gas Pipeline; RAB, regulated asset base.

Notes:

1. For covered pipelines, asset values are regulated asset bases as at the start of the current regulatory period. Investment is total forecast investment over the current regulatory period.
2. For non-covered pipelines, assets values are estimated construction costs.
3. All estimates are converted to June 2007 dollars.

Sources: Access arrangements for covered pipelines; company websites; press releases.

Current and planned activity suggests that the pipeline network will continue to expand at a rapid rate. The following major projects are currently under construction or advanced planning:

> Stage 1 ($140 million) of the QSN Link from Queensland to South Australia, scheduled for completion by early 2009. Epic Energy has committed to a $64 million stage 2 expansion by 2013.
> The continuing expansion of the Dampier to Bunbury Pipeline in Western Australia. The $690 million Stage 5B expansion was announced in April 2008 (subject to finance).
> A compressor to expand the capacity of the Eastern Gas Pipeline by more than 25 per cent by late 2008.
> A two-staged expansion of the South West Queensland Pipeline, announced in 2007. Stage 1 (170 terajoules a day) is to be completed by 2009 and stage 2 (220 terajoules a day) is to be completed by 2013.
> A progressive 20 per cent expansion of the Moomba to Sydney Pipeline to support the construction of the Uranquinty Power Station in New South Wales, commencing in 2008.
> The $170 million Bonaparte gas pipeline to connect the Blacktip gas field with the Amadeus Basin to Darwin Pipeline. The APA Group expects to complete the pipeline by early 2009.
> A $70 million pipeline from Berwyndale to Wallumbilla, to be operational by 2009. AGL Energy and Queensland Gas Company have agreed to develop the pipeline.[21]

21 ABARE *Energy in Australia 2008*, 2008; EnergyQuest, *Energy Quarterly Report*, November 2007 and February 2008.

Table 9.3 **Major gas pipeline investment since 2000**

PIPELINE	LOCATION	OWNER/PROPONENT	LENGTH (KM)	COST ($ MILLION)	PROJECT COMPLETION
COMPLETED					
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	Singapore Power International	795	450	2000
VicHub	Vic	Singapore Power International	n/a	n/a	2003
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	International Power, APA Group, Retail Employees Superannuation Trust	680	500	2003
Kambalda to Esperance Pipeline	WA	WorleyParsons, ANZ Infrastructure Services	350	45	2004
Telfer Pipeline (Port Hedland to Telfer Goldmine)	WA	APA Group	443	114	2004
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	Babcock & Brown Infrastructure	734	440	2002–05
North Queensland Gas Pipeline (Moranbah to Townsville)	Qld	AGL Energy/Arrow	391	160	2005
Dampier to Bunbury Stage 4 expansion	WA	DUET Group (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%)	200	430	2006
Dampier to Bunbury Stage 5A expansion	WA	DUET Group (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%)	570	660	2008
Corio Loop (expansion of Victorian Transmission System)	Vic	APA Group	57	70	2008
UNDER CONSTRUCTION					
QSN Link—Stage 1	Qld–SA and NSW	Epic Energy	180	140	2009
Eastern Gas Pipeline (addition of compressor)	Vic–NSW	Singapore Power International	Compressor (25% expansion)	n/a	2008
Bonaparte Gas Pipeline	NT	APA Group	285	170	2009
COMMITTED					
Berwyndale to Wallumbilla Pipeline	Qld	AGL Energy and Queensland Gas Company	115	70	2009
Dampier to Bunbury Stage 5B expansion	WA	DUET Group (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%)	440	690	2010
South West Queensland Pipeline—Stage 1	Qld	Epic Energy	Compressor (expansion to 170 terajoules a day)	n/a	2009
South West Queensland Pipeline—Stage 2	Qld	Epic Energy	Compressor (expansion to 220 terajoules a day)	64	2013
Queensland Gas Pipeline expansion	Qld	Singapore Power International	25 petajoules	n/a	2010
QSN link—Stage 2 expansion	Qld–SA and NSW	Epic Energy	Compressors	64	2013
Moomba to Sydney Pipeline capacity expansion	NSW	APA Group	20% capacity expansion	100	progressive from 2008

n/a, not available.

Principal sources: ABARE, *Energy in Australia 2008*, 2008; EnergyQuest, *Energy Quarterly Report*, August 2008; company websites and press releases.

9.4.2 Effects on competition

Investment over the past decade has led to the development of an interconnected gas pipeline system covering New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT. New discoveries of coal seam gas in Queensland (see chapter 8) and rising gas demand in New South Wales led to Epic Energy's decision to construct the QSN Link, which, from 2009, will connect the Queensland network via Moomba with South Australia and New South Wales. Within Queensland, customers will continue to have choice between gas from the Cooper Basin and coal seam gas from southern Queensland.

While gas tends to be purchased from the closest possible source to minimise transportation costs, the expansion of the pipeline network provides energy customers with greater choice and enhances the competitive environment. Table 9.4 lists the pipelines and gas basins serving each major Australian market. The construction of new pipelines has opened the Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition in south-eastern Australia. In some cases, it may only be possible to source gas from a particular basin using backhaul or swap arrangements (for example, such arrangements have been used to supply Sydney Basin gas into Victoria).[22]

While Santos, Origin Energy and BHP Billiton have production interests in several gas basins, the expansion of the pipeline network has provided new markets for smaller producers such as Beach Petroleum and Queensland Gas Company. The expansion of the pipeline network may also bring benefits in the wider energy sector. In particular, it may enhance competition in electricity markets by creating opportunities for further investment in gas-fired generators.

The extent to which new investment delivers competition benefits to customers depends on a range of factors, including the availability of natural gas and pipeline access from alternative sources. In particular, capacity constraints may limit access on some pipelines. For example, the SEA Gas and Roma to Brisbane pipelines have tended to operate at or near capacity in recent years. It is up to access seekers to try to negotiate an expansion of capacity. For a covered pipeline, the regulator (or in Western Australia, a separate arbitrator) may be asked to arbitrate a dispute in relation to capacity expansions.

9.5 Pipeline tariffs

The National Gas Law requires that for covered pipelines, service providers must publish reference tariffs (prices) and other conditions of access. This information must be maintained on the service provider's website —either within its approved access arrangement or separately. There is no requirement for service providers to disclose tariffs for non-covered pipelines, or negotiated tariffs for covered pipelines agreed outside the reference tariffs. Some operators publish these tariffs on a website or make them available on request to access seekers.

Figure 9.6 estimates indicative tariffs for pipeline services on a selection of routes between gas basins and Australian capital cities and gas hubs (pipeline interconnection points). The tariffs are based on rates for firm forward-haulage services, and assume a 100 per cent swing factor.[23] The tariffs are enforceable for spare capacity in covered pipelines, but are only indicative for non-covered pipelines.

Figure 9.6 allows for some comparison of transmission pipeline costs from alternative gas basins into major centres. It should be noted that while some tariffs in figure 9.6 represent alternative routes to a particular market (for example, SEA Gas and Moomba to Adelaide provide alternative services to Adelaide), others do not (for example, gas sourced from the Cooper Basin into Brisbane must travel via *both* the Ballera to Wallumbilla and the Roma to Brisbane pipelines).

22 Backhaul and swap arrangements are discussed in chapter 8, section 8.5.

23 NERA, *The Gas Supply Chain in Eastern Australia*, June 2007. In gas contracts the swing factor (or 'load factor') measures a buyer's flexibility to vary the daily quantity shipped up to a predetermined maximum. A 100 per cent swing factor means that the average daily quantity shipped equals the maximum daily quantity.

Table 9.4 **Pipeline links between major gas sources and markets**

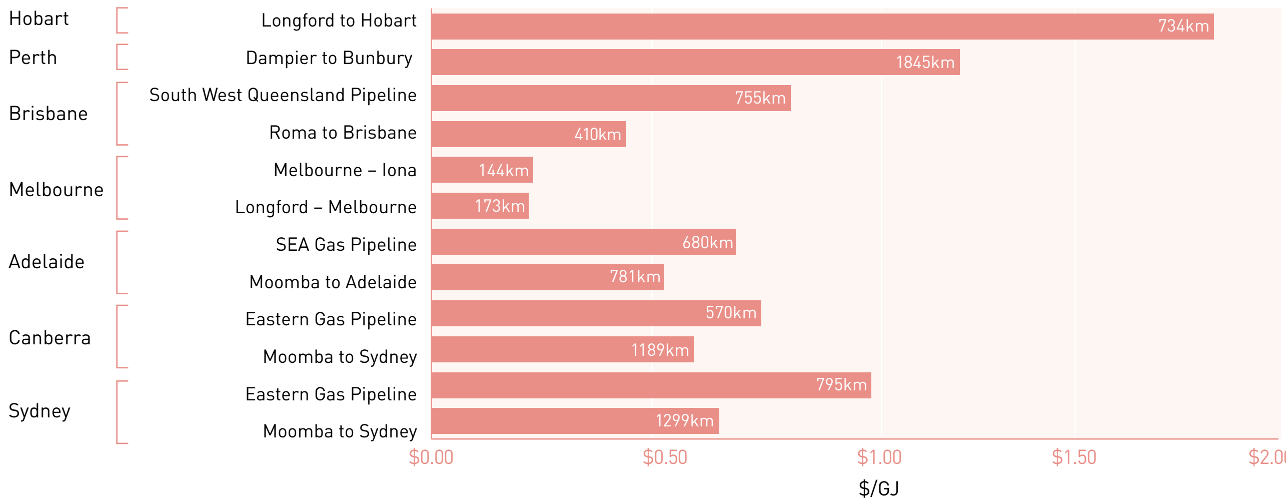
PIPELINE (OWNER)	GAS BASIN	PRODUCERS
SYDNEY AND CANBERRA		
Moomba to Sydney Pipeline (APA Group)	Cooper	Santos, Beach Petroleum, Origin Energy
	Sydney	AGL Energy, Sydney Gas
Eastern Gas Pipeline (Singapore Power International) NSW–Vic Interconnect (APA Group)	Gippsland, Otway, Bass	BHPB, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum, Mitwell
QSN Link (under construction) (Hastings)	Surat–Bowen	Mosaic, Origin Energy, Santos, Sunshine Gas, Arrow Energy, Mitsui, Molopo, Queensland Gas Company
MELBOURNE		
NSW–Vic Interconnect (APA Group)	Cooper (via MSP)	Santos, Beach Petroleum, Origin Energy
	Sydney	AGL Energy, Sydney Gas
Victorian transmission system (APA Group)	Gippsland, Bass, Otway	BHPB, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum, Mitwell
TASMANIA		
Tasmanian Gas Pipeline (Babcock & Brown Infrastructure)	Cooper (via MSP and NSW–Vic Interconnect), Gippsland, Otway, Bass	Santos, Beach Petroleum, Origin Energy
BRISBANE		
South West Queensland Pipeline (Epic Energy)	Cooper	Santos, Beach Petroleum, Origin Energy
Roma to Brisbane pipeline (APA Group)	Surat–Bowen	Mosaic, Origin Energy, Santos, Sunshine Gas, Arrow Energy, Mitsui, Molopo, Queensland Gas Company
ADELAIDE		
Moomba to Adelaide Pipeline (Epic Energy)	Cooper	Santos, Beach Petroleum, Origin Energy
SEA Gas Pipeline (APA Group, International Power, Retail Employees Superannuation Trust)	Otway and Gippsland	BHPB, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum, Mitwell
QSN Link (under construction) (Epic Energy)	Surat–Bowen	Mosaic, Origin Energy, Santos, Sunshine Gas, Arrow Energy, Mitsui, Molopo, Queensland Gas Company
DARWIN		
Amadeus Basin to Darwin (96% APA Group)	Amadeus	Magellan, Santos
PERTH		
Dampier to Bunbury Natural Gas Pipeline (DUET (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%))	Carnarvon	Apache Energy, BHPB, BP, Chevron, ExxonMobil, Inpex, Kufpec, Santos, Shell, Tap Oil, Woodside Petroleum
	Perth	ARC Energy, Origin Energy
Parmelia Pipeline (APA Group)	Perth	ARC Energy, Origin Energy

Notes:

1. In some cases, it may only be possible to source gas from a particular basin using backhaul and swap arrangements. See chapter 8.
2. Some corporate names have been abbreviated or shortened.

Principal source: EnergyQuest, *Energy Quarterly Report*, August 2008.

Figure 9.6
Indicative pipeline tariffs to major centres



Notes:
1. Tariffs are based on rates for firm forward-haulage services, and assume a 100 per cent swing factor.
2. Gas sourced from the Cooper Basin for Brisbane customers must travel via both the South West Queensland and the Roma to Brisbane pipelines.
3. Distances are indicative.

Sources: EnergyQuest, *Energy Quarterly Report*, February 2008 (Dampier to Bunbury Pipeline); NERA, *The Gas Supply Chain in Eastern Australia*, March 2008, p. 51 (other pipelines).

The significant differences between pipeline charges reflect various factors, including differences in transportation distances; differences in underlying capital costs; the age and extent of depreciation on the pipeline; technological and geographical differences; and the availability of spare pipeline capacity. In general, it is cheaper to transport gas into Sydney, Canberra and Adelaide from the Cooper Basin than it is from the Victorian coastal basins.

In practice, pipeline charges may vary considerably from the indicative rates set out in figure 9.6. In all cases it is open to an access seeker to try to negotiate discounts against published rates, including for non-standard requirements such as interruptible services.[24]

Conversely, some tariffs may be considerably higher than those set out in figure 9.6, especially if a pipeline is capacity-constrained and requires an expansion to make access possible. For example:

- limited capacity on the Eastern Gas Pipeline led to tariffs of up to $7.35 per gigajoule in 2008
- capacity issues on the SEA Gas Pipeline led to a withdrawal of all offers to sell capacity to third parties in 2008.

Tariffs for interruptible services are typically 30 per cent higher than they are for firm transportation charges, but are paid on the actual quantities shipped rather than on reserved capacity.[25]

It should be noted that the relevant consideration for customers is the cost of delivered gas—the bundled cost of gas and transportation services—from alternative sources. The lead essay of this report (*Australia's natural gas markets: The emergence of competition?*) provides ACIL Tasman estimates of the composition of delivered gas prices in mainland state capital cities. Retail prices range from around $15.50 per gigajoule in Melbourne to almost $28 per gigajoule in Brisbane. Transportation through the high pressure transmission system is the smallest contributor to delivered costs for residential consumers in the capital cities. Transmission charges range from around 2 per cent of delivered gas

24 Interruptible services are provided intermittently, depending on available pipeline capacity.
25 NERA, *The Gas Supply Chain in Eastern Australia*, June 2007, p. 42 and p. 52. Backhaul arrangements are discussed in chapter 8 of this report.

prices in Adelaide and Melbourne to 7 per cent in Perth. For larger industrial users, this proportion rises steadily with scale as the fixed costs associated with downstream services are spread across much larger gas supply volumes.

9.6 Financial indicators

There is limited performance data for the gas transmission sector. Historically, performance reports have not been published for covered pipelines, although the National Gas Law enables the AER to publish such reports in the future. Regulatory determinations include some historical performance data, as well as forward projections.

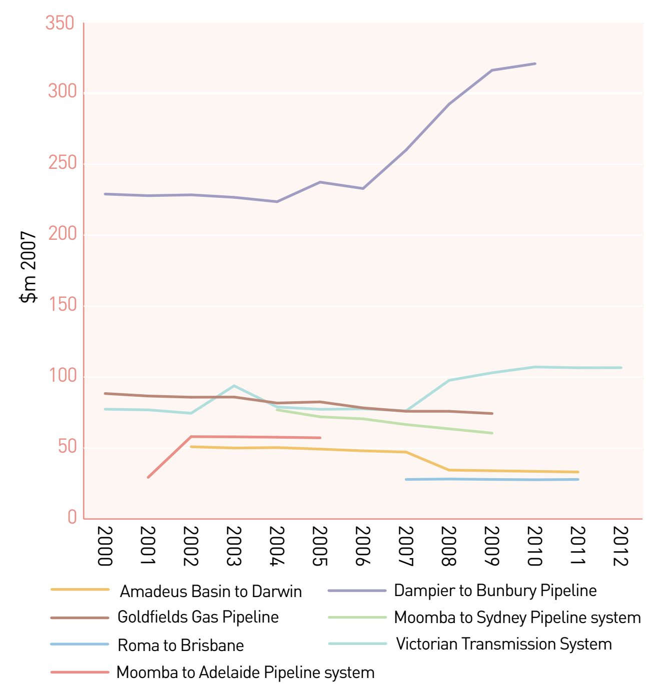
As noted, the owners of non-covered pipelines are not required to report publicly on historical performance or projected outcomes. The gas market bulletin board, which commenced in July 2008, will increase the availability of information about transmission pipelines—including capacity and supply information. The bulletin board covers most transmission pipelines in southern and eastern Australia, including non-covered pipelines.[26]

The limited financial data currently available mainly comprises financial forecasts in regulatory determinations for covered pipelines. There has been little historical reporting of service quality outcomes. The following sections set out summary data on forecast revenues and operating expenditure for covered pipelines.

9.6.1 Regulated revenues

Figure 9.7 charts annual revenues for a selection of transmission pipelines, based on forecasts in regulatory decisions. The variation in forecast revenues across pipelines reflects a range of factors, including differences in demand, age, capacity and length of the pipelines. The data indicates stable or modest revenue growth over time, consistent with rising demand and capital expenditure requirements. The data for the Dampier to Bunbury Pipeline reflects the impact of capital-related cost increases associated with the looping and extension of the pipeline.

Figure 9.7
Regulated revenue forecasts for transmission pipelines



Notes:
1. All data is converted to June 2007 dollars.
2. The data for the Moomba to Adelaide Pipeline terminates after 2004 due to a revocation of coverage.

Sources: Approved access arrangement for each pipeline.

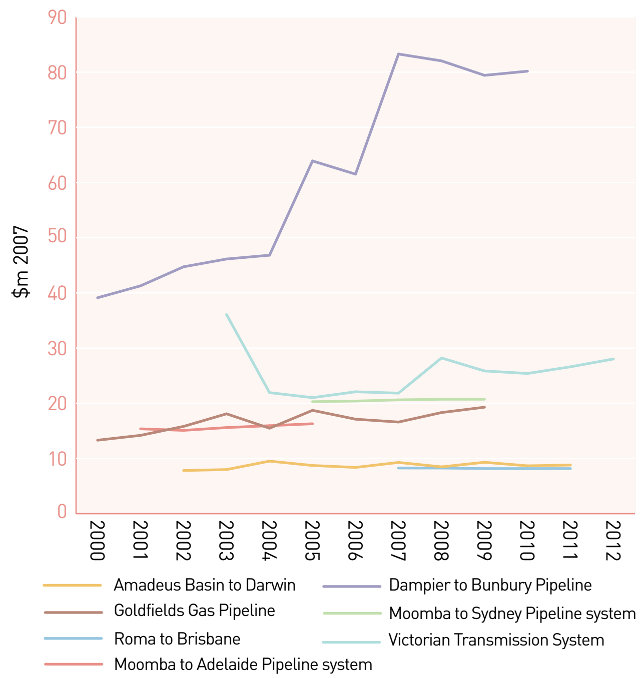
26 See chapter 8, section 8.7.

9.6.2 Operating expenses

Figure 9.8 charts the forecast operating and maintenance expenditure approved in access arrangements for major covered transmission pipelines. Consistent with the front-loaded nature of pipeline investment, the data suggests that transmission pipelines incur relatively stable and modest operating costs. The upward trend in operating expenses for the Dampier to Bunbury Pipeline reflects both the impact of a major capacity expansion (including the costs of operating new compressors) and rising resource costs in the energy construction sector.

Figure 9.8

Forecast operating and maintenance expenditure for major pipelines



Notes:

1. All data is converted to June 2007 dollars.
2. The data for the Moomba to Adelaide Pipeline terminates after 2004, due to a revocation of coverage.

Sources: Approved access arrangement for each pipeline.

10 GAS DISTRIBUTION

Natural gas distribution networks transport gas from gas transmission pipelines and reticulate it into residential houses, offices, hospitals and businesses. Their main customers are energy retailers, which aggregate loads for sale to end users. For small gas users, distribution charges for metering and transport often represent the most significant component—up to 60 per cent—of retail gas prices.

10 GAS DISTRIBUTION

This chapter considers:

- Australia's gas distribution sector
- the structure of the sector, including industry participants and ownership changes over time
- the economic regulation of distribution networks
- new investment in distribution networks
- financial indicators and service performance of the distribution sector.

10.1 Role of distribution networks

A distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers.

Gate stations (city gates) link transmission pipelines with distribution networks. The stations measure the natural gas entering a distribution system for billing and gas balancing purposes. They also adjust the pressure of the gas before it enters the distribution network.

Distributors can further adjust gas pressure at regulating stations in the network to ensure that the delivered gas is at a suitable pressure for the operation of customer equipment and appliances.

Australian laws require odorant to be added to gas that enters a distribution system. This promotes safety by making leaks easier to detect. The odorant is usually added at the gate station.

10.2 Australia's distribution networks

The total length of Australia's gas distribution networks expanded from around 67 000 kilometres in 1997 to over 81 000 kilometres in 2007. The networks deliver over 300 petajoules of gas a year and have a combined valuation of over $7 billion. Investment to augment and expand the networks is forecast at around $2 billion in the current regulatory cycle. Table 10.1 provides summary details of the major networks.

Figure 10.1 shows the location of gas distribution networks in Australia. In the past few years, new networks have been rolled out in north-western New South Wales (Central Ranges) and Tasmania following the construction of transmission pipelines into these regions. Natural gas is now reticulated to most Australian capital cities, major regional areas and towns.

10.3 Ownership of distribution networks

The major gas distribution networks in Australia are privately owned. South Australia, Victoria, Western Australia and Queensland privatised their state-owned networks in 1993, 1997, 2000 and 2006, respectively. The principal New South Wales network has always been in private hands.[1] Over time, structural reform and capital market drivers have led to specialist network businesses acquiring most assets in the sector. Figure 10.2 shows key ownership changes since 1994.

Two significant ownership changes in 2006 were the sale of AGL's New South Wales networks to Alinta and the privatisation of Queensland's Allgas network, which was sold to the APA Group. In 2007, the sale of Alinta led to Singapore Power International and Babcock & Brown Infrastructure acquiring gas distribution assets.

By 2008, ownership consolidation had reduced the number of principal players in the gas distribution sector to four:

- Singapore Power International owns the principal New South Wales gas distribution network (Alinta AGN). It has a 51 per cent share in the Victorian network (SP AusNet) and a 50 per cent share of the Australian Capital Territory (ACT) network (ActewAGL). In August 2008, Singapore Power International rebranded its gas distribution entities as Jemena.
- Envestra, a public company in which the APA Group and Cheung Kong Infrastructure each have a 17 per cent shareholding, owns networks in Victoria, South Australia and Queensland, as well as a small Northern Territory network.
- Babcock & Brown Infrastructure owns the Tasmanian distribution network (Powerco) and is the majority owner of the Western Australian network.
- The APA Group owns the Allgas network in Queensland, and has a 17 per cent stake in Envestra.

Other players include:

- DUET Group, which is the majority owner of Victoria's Multinet network and a minority owner of the Western Australian network. DUET Group contracts out the operation of its networks.
- Cheung Kong Infrastructure, which owns a 17 per cent interest in Envestra.

There are increasing ownership linkages between gas distribution and other energy networks. In particular, Singapore Power International, Babcock & Brown Infrastructure and the APA Group own and operate both gas transmission and distribution infrastructure. In addition, Singapore Power International, the APA Group, Cheung Kong Infrastructure and DUET Group all have ownership interests—in some cases, substantial interests—in the electricity network sector (see chapters 4, 5 and 9).

1 There are remnants of state-owned gas distribution networks in rural New South Wales and Queensland.
2 DUET Group comprises a number of trusts, the responsible entities for which are owned by Macquarie Bank and AMP Capital Holdings.

Table 10.1 **Australian natural gas distribution networks**

DISTRIBUTION NETWORK	LOCATION	LENGTH OF MAINS (KM)	ASSET BASE ($ MILLION 2007)	INVESTMENT —CURRENT REGULATORY PERIOD ($ MILLION 2007)	CURRENT REGULATORY PERIOD	OWNER
NEW SOUTH WALES AND ACT						
NSW Gas Networks (Alinta AGN)	Sydney, Newcastle/ Central Coast and Wollongong	23 800	2088	518	1 July 2005– 30 June 2010	Jemena (Singapore Power International (Australia))
Central Ranges System	Dubbo to Tamworth region	250	n/a	n/a	2006–2019	APA Group
Wagga Wagga distribution	Wagga Wagga and surrounding areas	622	47	8	1 July 2005– 30 June 2010	Country Energy (NSW Govt)
ActewAGL Distribution (Canberra network)	ACT and Queanbeyan	3 621	247	49	1 July 2004– 30 June 2010	ACTEW Corporation (ACT Govt) 50%; Jemena (Singapore Power International (Australia)) 50%
VICTORIA						
Multinet	Melbourne's eastern and south-eastern suburbs	9 513	888	251	1 Jan 2008– 31 Dec 2012	DUET Group 79.9%; BBI 20.1%
Envestra (Stratus)	Melbourne, north-east and central Victoria, and Albury—Wodonga region	9 350	859	394	1 Jan 2008– 31 Dec 2012	Envestra (Cheung Kong Infrastructure 17%, APA Group 17%)
SP AusNet (Westar)	Western Victoria	9 140	955	343	1 Jan 2008– 31 Dec 2012	SP AusNet (listed company: Singapore Power International 51%)
QUEENSLAND						
Allgas	South of the Brisbane River	2 515	307	155	1 July 2006– 30 June 2011	APA Group
Envestra	Brisbane, Gladstone and Rockhampton	2 261	235	100	1 July 2006– 30 June 2011	Envestra (Cheung Kong Infrastructure 17%, APA Group 17%)
SOUTH AUSTRALIA						
South Australian distribution	Adelaide and surrounds	7 377	851	204	1 July 2006– 30 June 2011	Envestra (Cheung Kong Infrastructure 17%, APA Group 17%)
WESTERN AUSTRALIA						
Alinta Gas Networks	Mid-west and south-west regions	12 157	708	157	1 Jan 2005– 31 Dec 2009	BBI 74.1%, DUET Group 25.9%. Operated by WestNet Energy (owned by BBI)
TASMANIA						
Tasmanian Gas Network	Hobart, Launceston and other towns	683	100	n/a	Not covered	Powerco (BBI)
National totals		81 289	7285	2179		

BBI, Babcock & Brown Infrastructure; n/a, not available.

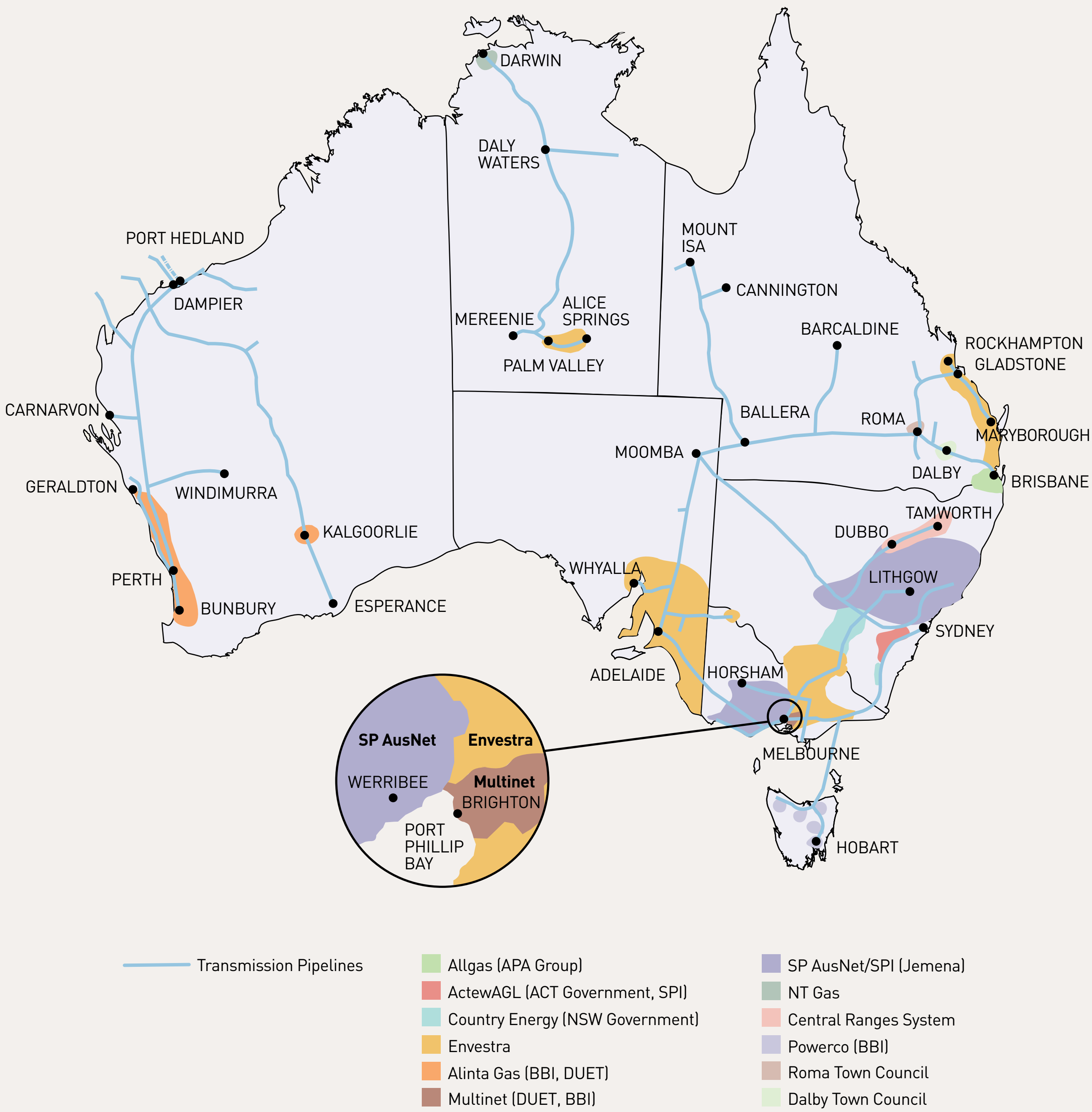
Notes:

1. For Tasmania, the asset value is an estimated construction cost. For other networks, the asset value is the opening regulated asset base for the current regulatory period, adjusted to June 2007 dollars.
2. Investment data are forecasts for the current asset arrangement period, adjusted to June 2007 dollars.
3. Some corporate names have been abbreviated or shortened.

Sources: Access arrangements for covered pipelines; company websites.

Figure 10.1

Gas distribution networks in Australia



Notes:

1. Locations of the distribution systems are indicative only.
2. Some corporate names have been abbreviated or shortened.

Source: Australian Gas Association submission to the Productivity Commission, Review of the gas access regime, August 2003, submission 13, p. 102; supplemented with additional information.

10.4 Regulation of distribution networks

Gas distribution 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.

The National Gas Law and National Gas Rules (Gas Rules), which took effect on 1 July 2008, provide the overarching regulatory framework for the gas distribution sector. These instruments replace the Gas Pipelines Access Law and the National Gas Code (Gas Code), which provided the regulatory framework from 1997 to 30 June 2008.

The Gas Rules (previously the Gas Code) include a coverage mechanism to determine which pipelines are subject to economic regulation. At July 2008, the Gas Rules covered 12 distribution networks, including all major networks in New South Wales, Victoria, Queensland, Western Australia and South Australia. The only major unregulated network is the Tasmanian distribution network, which is currently being rolled out. In addition, a number of small regional networks are not covered.[3]

The main aim of regulating a distribution network is to ensure that energy retailers and other third parties can negotiate access on reasonable terms and conditions. This may require an independent regulator to vet prices to ensure they are not set at monopolistic rates.[4]

10.4.1 Regulatory framework

The regulation of covered distribution networks was transferred from state and territory regulators to the Australian Energy Regulator (AER) on 1 July 2008.[5] In Western Australia, the local regulator—the Economic Regulation Authority—will continue to regulate covered networks.

The AER's first regulatory review in gas distribution will assess prices and other access terms and conditions from July 2010 for covered networks in New South Wales and the ACT. The AER is working closely with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition period.

The service provider[6] of a covered distribution network must comply with the provisions of the National Gas Law and Gas Rules. Typically this requires submitting an access arrangement—including pipeline tariffs—to the regulator for approval. The legislation also allows for a light regulation option in some circumstances, in which the service provider is obliged only to publish terms and conditions of access on its website.

An access arrangement must set out the terms and conditions of third party access. It must specify at least one reference service that is commonly sought by customers, and a reference (benchmark) tariff for that service. The reference service can be set for different zones (different customer locations across the network) and may comprise different components.

A reference tariff provides a benchmark for negotiating prices, but is also enforceable by the regulator. Reference tariffs may apply to one or more of the network services offered, including capacity reservation (managed capacity services), volume (throughput services), peak, off-peak and metering (data) services. A network may also deliver non-reference services.

3 A party may seek a change in the coverage status of a pipeline by applying to the National Competition Council. At present, the non-covered networks include the South West Slopes and Temora extensions of the NSW Gas Network; the Dalby and Roma town systems in Queensland; the Alice Springs network in the Northern Territory; and the Mildura system in Victoria.

4 The new gas access regime, which took effect in 2008, allows a light regulation option, without direct price control, under certain conditions. See section 9.3.

5 While the AER assumed the role of economic regulator of distribution networks on 1 July 2008, existing access arrangements will continue to be administered by the jurisdictional regulators – in Victoria, the Essential Services Commission of Victoria (ESC); in South Australia, the Essential Services Commission of South Australia (ESCOSA); in New South Wales, the Independent Pricing and Regulatory Tribunal (IPART); in Queensland, the Queensland Competition Authority (QCA); and in the Australian Capital Territory, the Independent Competition and Regulatory Commission (ICRC).

6 In accordance with the National Gas Law, the service provider may be the owner or operator of the whole pipeline or any part of the pipeline.

Figure 10.2
Distribution network ownership

<table>
<tr><th></th><th></th><th>1994</th><th>1995</th><th>1996</th><th>1997</th><th>1998</th><th>1999</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th></tr>
<tr><td rowspan="3">NSW and the ACT</td><td>NSW Gas Networks</td><td colspan="12">AGL</td><td>Alinta</td><td colspan="2">Singapore Power</td></tr>
<tr><td>Wagga Wagga</td><td colspan="15">Country Energy (NSW Government)</td></tr>
<tr><td>Canberra Distribution</td><td colspan="6">AGL</td><td colspan="7">ActewAGL (ACT Government, AGL)</td><td colspan="2">ACT Govt, Singapore Power</td></tr>
<tr><td rowspan="3">Vic</td><td rowspan="3">GasCor</td><td colspan="3" rowspan="3">Government</td><td colspan="2">Stratus</td><td colspan="10">Envestra</td></tr>
<tr><td colspan="2">Multinet</td><td colspan="4">AMP Soc & Utilicorp</td><td colspan="4">DUET (79.9%), Alinta (20.1%)</td><td colspan="2">DUET (80%), BBI (20%)</td></tr>
<tr><td colspan="2">Westar</td><td colspan="5">TXU</td><td colspan="5">SP AusNet (SPI 51%)</td></tr>
<tr><td>Tas</td><td>Tasmanian Distribution</td><td colspan="9"></td><td colspan="6">Babcock & Brown Infrastructure</td></tr>
<tr><td rowspan="2">Qld</td><td>Allgas</td><td colspan="12">Government</td><td colspan="3">APA Group</td></tr>
<tr><td>Gas Corp of Qld</td><td colspan="3" rowspan="2">Boral</td><td colspan="12" rowspan="3">Envestra</td></tr>
<tr><td>SA</td><td>SAGASCO</td></tr>
<tr><td rowspan="2">NT</td><td>Centre Gas Systems</td><td colspan="3">Boral</td></tr>
<tr><td>NT Gas</td><td colspan="6">Amadeus Gas Trust</td><td colspan="9">Amadeus Gas Trust (96% APT)</td></tr>
<tr><td>WA</td><td>SECWA</td><td>Govt</td><td colspan="5">AlintaGas</td><td colspan="3">WAGH (45%)</td><td colspan="4">Alinta (74%), DUET (26%)</td><td colspan="2">BBI (74%), DUET (26%)</td></tr>
</table>

BBI, Babcock & Brown Infrastructure; SECWA, State Energy Commission of Western Australia; WAGH, WA Gas Holdings.
Note: Some corporate names have been abbreviated or shortened.

Most network providers use a building block approach to determine total revenues. Under the Gas Rules, total revenues should reflect efficient costs, recover depreciation and operating expenditure, and provide a return on capital. Reference tariffs are set by dividing total revenue by forecast sales volumes for the relevant reference services. Tariffs are typically adjusted annually for inflation and other approved factors.[7]

While the new regulatory framework—which commenced on 1 July 2008—makes some changes to the decision-making process and the timing of regulatory decisions, the approach to assessing reference tariffs remains largely unchanged. Chapter 9 provides a summary of key changes affecting regulatory decision making under the new legislation.

Figure 10.3 shows the revenue components in the latest access arrangement for Multinet in Victoria (owned by DUET Group and Babcock & Brown Infrastructure). It illustrates the relative importance of the building block components in a typical reference tariff determination. Returns on assets and depreciation account for around two-thirds of the revenue determination. Operating and maintenance costs; tax; and efficiency carry-overs account for the balance.

7 See also chapter 9 for background on the regulatory framework for gas transmission. The frameworks for gas transmission and distribution are similar.

Construction of the South Gippsland Natural Gas Pipeline (Multinet)

10.5 Investment in distribution networks

Investment in gas distribution typically involves capital works to upgrade and expand the capacity of existing networks and extend the networks into new residential and commercial developments, regional centres and towns. While most major centres already have a distribution network in place, there are also recent examples of new networks being constructed —for example, the Central Ranges (New South Wales) and Tasmanian networks. Mostly, however, distribution investment relates to discrete development and upgrade projects that are relatively small compared to capital projects in gas transmission. This tends to result in distribution investment recording relatively stable trends over time, compared to the 'lumpy' investment cycles often seen for gas transmission.

The cost of distribution investment depends on a range of factors, including:

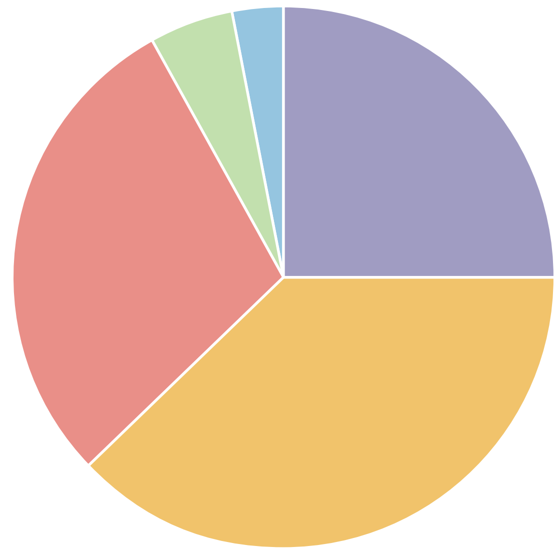
> the distance of new infrastructure from access points on gas transmission lines or gas distribution mains
> the density of housing and the presence of other industrial and commercial users in the area.

Figure 10.4 shows the opening regulated asset bases (RABs)[8] and forecast investment over the current regulatory period (typically five years) for the major networks. Figure 10.5 shows annual investment in each network in the current decade, based on actual data where available, and forecast data for other years. The forecast data relates to proposed investment that the regulator has approved as efficient. The chart excludes the Tasmanian distribution network, which is not covered by the Gas Rules. The graphs depict real data in June 2007 dollars.

Investment in gas distribution networks has grown steadily in recent years:

> Investment was forecast at around $400 million in 2007–08, and grew on average, by around 8 per cent annually over the preceding five years.

Figure 10.3
Revenue components for Victoria's Multinet gas network, 2008–12



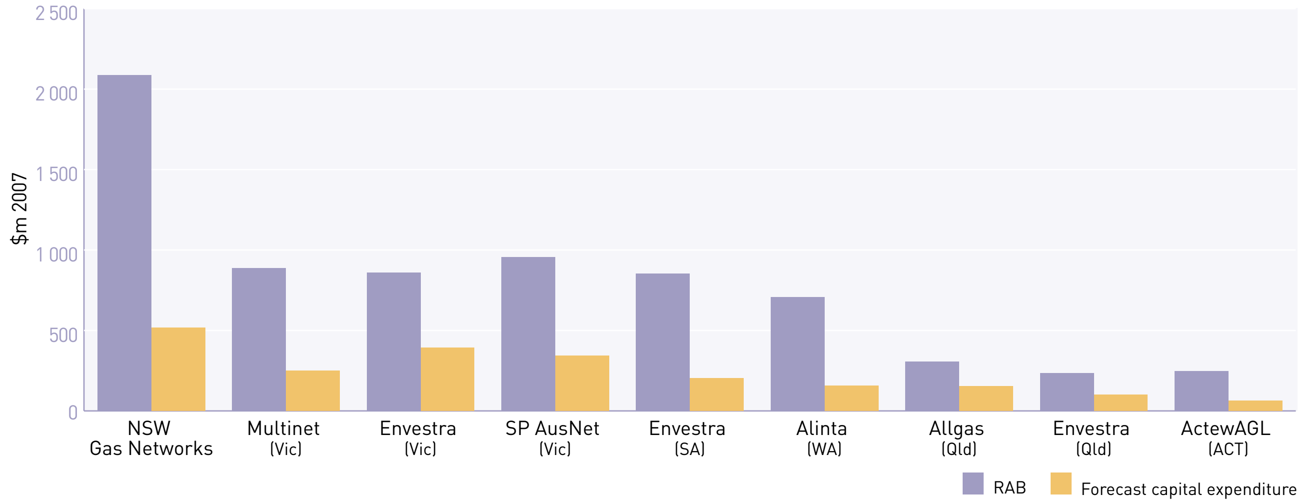
Source: ESC, *Gas access arrangement review 2008–2012, Final decision*, 2008.

> Over the longer term, real investment of around $2 billion is forecast during the current regulatory periods for the major networks. This represents both substantial real investment in new infrastructure as well as rising resource costs in the construction sector.[9]
> Investment over the current regulatory cycle is running at around 25 per cent of the underlying asset base in most networks, but around 35 per cent for SP AusNet (Victoria) and 40–50 per cent for Envestra (Victoria) and the Queensland networks.
> The combined Victorian networks attract significantly higher investment than New South Wales, in part reflecting the penetration of natural gas as a major heating source in Victoria. More generally, different outcomes between jurisdictions reflect a range of variables, including development activity; incentives or policies that encourage gas supply; market conditions; and investment drivers such as the scale and age of the networks.

8 The regulated asset base estimates the depreciated optimised replacement cost of an asset.

9 Some resource costs in the energy construction sector are rising faster than general inflation, as measured by the Consumer Price Index. Chapter 4 provides data on rising costs. See section 4.4, including figures 4.7 and 4.8.

Figure 10.4
Gas distribution assets and investment—current regulatory period (real)



Notes:
1. The asset valuation for each pipeline is the RAB published in a regulator-approved access arrangement.
2. Investment data represents forecast capital expenditure over the current regulatory period (see table 10.1).
3. All estimates are converted to June 2007 dollars.

Sources: Access arrangements and regulatory determinations published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); ERA (WA); and ICRC (ACT).

- Investment is forecast to rise strongly during the current decade in Queensland, South Australia and Victoria. Recent regulatory determinations for these jurisdictions reflect a significant step-increase in forecast investment in the current regulatory cycle. Looking forward, the introduction of carbon emission reduction policies may further accelerate the development of natural gas as an energy source, and influence investment.
- The investment data mostly reflects the incremental expansion of existing networks. For example, Envestra began a $3.7 million project in 2005 to upgrade and extend its Queensland network. The construction of new transmission pipelines also provides opportunities to develop new distribution networks. For example, the Tasmanian distribution network is being rolled out in major cities and towns following the construction of a transmission pipeline from Victoria to Tasmania.
- Gas distribution investment tends to reflect more stable trends over time than gas transmission. This reflects the nature of gas distribution investment, which typically focuses on roll-out and upgrade projects. There is some volatility due to factors such as timing differences between the commissioning and completion of projects. More generally, the network businesses have some flexibility to manage and reprioritise the timing of capital expenditure over the regulatory period. Transitions between regulatory periods, and from actual to forecast data, also cause some data volatility.

10.6 Financial indicators

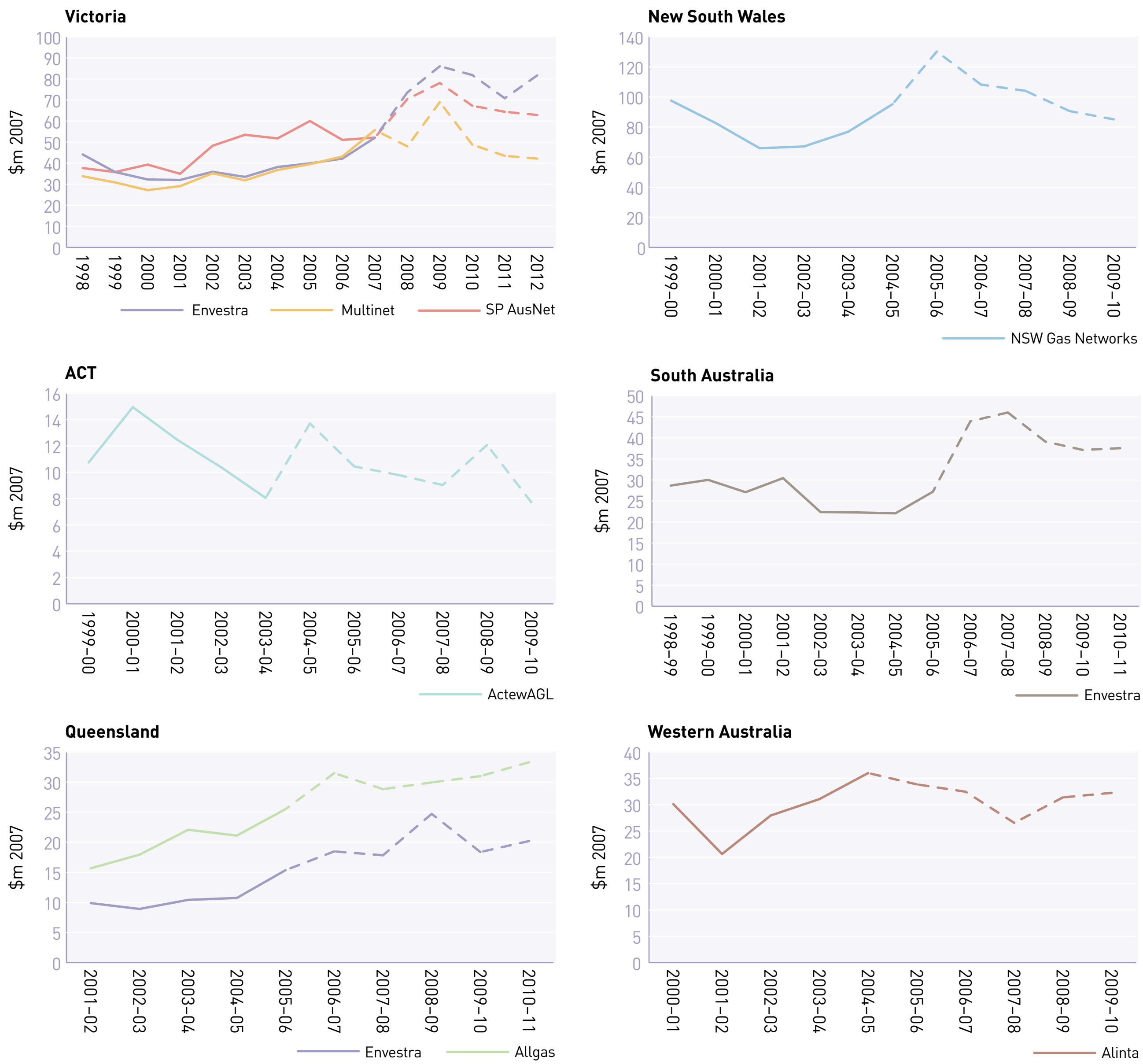
Some jurisdictional regulators have published annual performance reports on gas distribution networks. The reports reflect the dual roles of some jurisdictional agencies as technical and economic regulators. In addition, regulatory determinations include both historical performance data for the preceding regulatory period and forecasts of future outcomes. The data set out in section 10.6 are derived from regulatory forecasts.

10.6.1 Revenues

Figure 10.6 charts real revenues for the major networks, based on forecasts in regulatory decisions. Real revenues have remained stable over time, with modest growth—reflecting rising demand—in some instances.

Figure 10.5

Network investment (real)



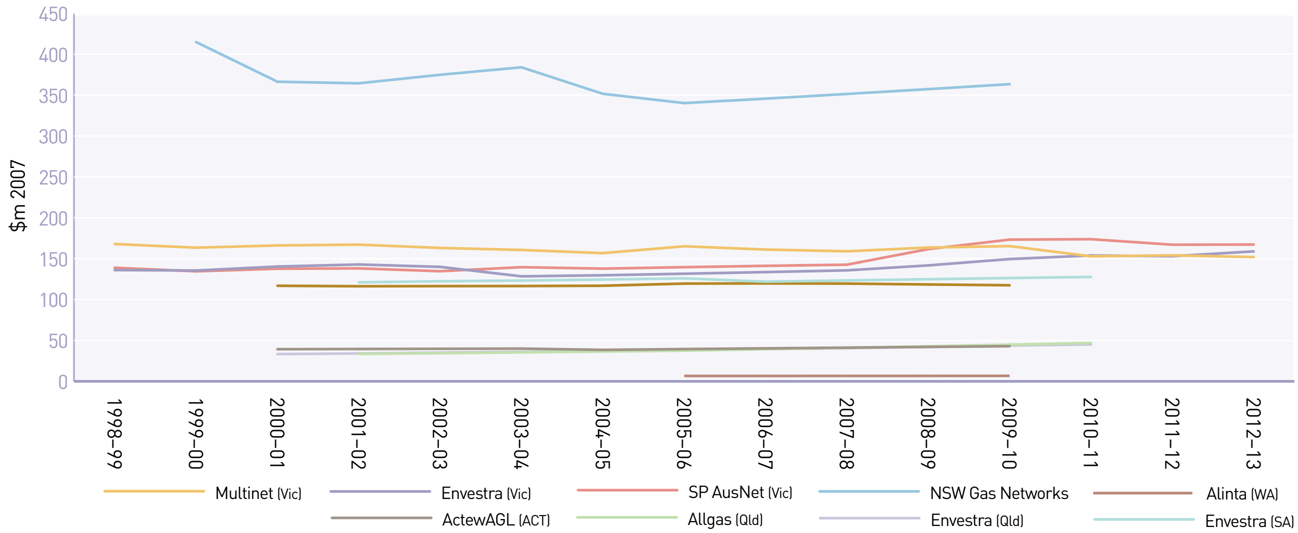
Notes:

1. The asset valuation for each pipeline is the RAB published in a regulator-approved access arrangement.
2. Actual data (unbroken lines) used when available and forecasts (broken lines) for other years.

Sources: Access arrangements, regulatory determinations and network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); ERA (WA); and ICRC (ACT).

Figure 10.6

Revenue forecasts (real)



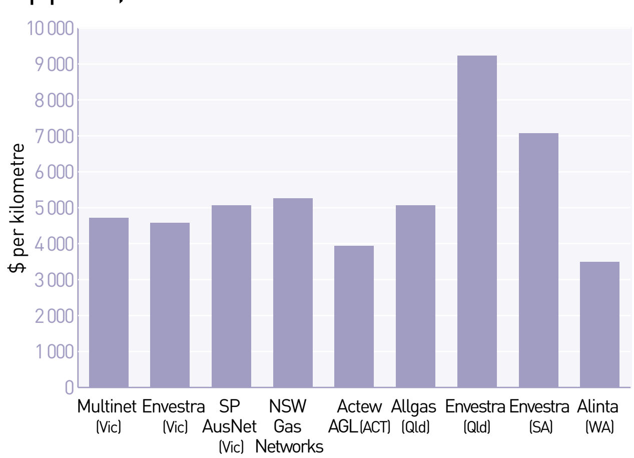
Notes:

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

Source: Approved access arrangement for each pipeline.

Figure 10.7

Operating and maintenance expenditure per kilometre of pipeline, 2007



Notes:

1. Forecast data for year ended 30 June. Victorian data are for 2006 calendar year.
2. All data converted to 2007 dollars.

Sources: Approved access arrangement for each pipeline; network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); ERA (WA); and ICRC (ACT).

The variations between networks reflect differences in market conditions and cost drivers such as the scale and age of the networks. For example, the relatively high revenues for NSW Gas Networks in part reflects that the network covers most of the state. In comparison, Victoria has three major networks.

10.6.2 Operating and maintenance expenditure

Figure 10.7 compares forecast operating and maintenance expenditure for the networks on a per kilometre basis. Most networks have expenses ranging from about $4000 to $7000 per kilometre of network line length. Differences may arise for a number of reasons, including the age and condition of the networks and geographical factors. Normalising on a per kilometre basis may bias against high-density urban networks with relatively short line lengths. Envestra, which has been expanding its Queensland network, recorded higher per kilometre costs than the other networks.

Table 10.2 Gas distribution performance: reporting arrangements

JURISDICTION	REPORTING ARRANGEMENTS
New South Wales	Distribution businesses report annually to the Department of Water and Energy on network integrity and safety information, network reliability and consumer-related matters. As of 1 March 2008, the most recent published data was for 2001–02.
Victoria	The Essential Services Commission publishes annual performance reports for the three gas distribution businesses, covering financial performance, reliability of supply, network integrity, and customer service.
Queensland	The Queensland Competition Authority publishes annual performance reports for the two distribution businesses, covering unaccounted-for gas, reliability of supply and customer service.
South Australia	The Essential Services Commission of South Australia publishes annual performance reports, covering financial performance, reliability of supply, network integrity and customer service.
Western Australia	The Economic Regulation Authority published its first compliance report for gas distribution in 2007, covering reliability of supply and network integrity. New licensing arrangements will widen the range of published data over time, including performance indicators based on the Victorian model.
Tasmania	The Office of the Tasmanian Energy Regulator publishes annual performance reports, covering reliability of supply, network integrity, and customer service.
ACT	The Independent Competition and Regulatory Commission publishes annual performance reports, covering network performance and consumer protection. As of 1 March 2008, the most recent published data was for 2004–05.

10.7 Quality of service

Quality of service monitoring for gas distribution services typically relates to:

- reliability of gas supply (the provision of a continuous gas supply to customers)
- network integrity (gas leaks; the effectiveness of operational and maintenance activities)
- customer service (responsiveness to issues such as complaints and reported gas leaks).

While the Utility Regulators Forum established national reporting indicators on service quality for electricity distribution and energy retailing, there are no equivalent indicators for gas distribution. Instead, the practice has been to develop jurisdiction-specific service standards and reporting arrangements. Some of these technical and service standards are connected with jurisdictional licensing requirements. The jurisdictional reporting arrangements are outlined in table 10.2.

As noted, the monitoring and reporting of service quality is less comprehensive in the natural gas sector than in the electricity sector. This reflects:

- different approaches to reporting across jurisdictions
- the greater reliance on electricity than natural gas as a major energy source for most end-users
- technical characteristics inherent in the distribution of gas.

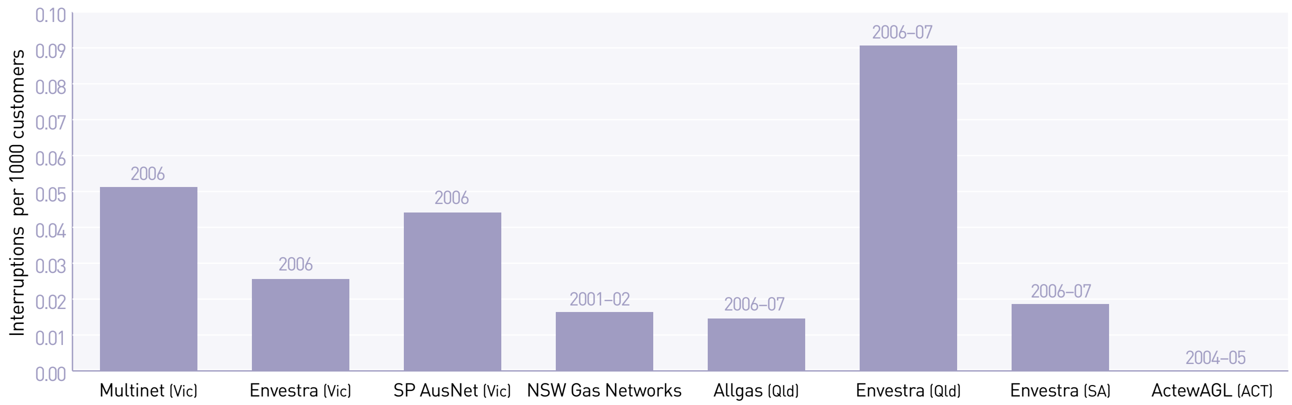
A distinguishing feature of reliability and network integrity issues in the gas sector compared with the electricity sector is the management of safety issues and the scope for widespread damage and injury from incidents such as gas explosions. The oversight of these gas network integrity and safety issues is undertaken by technical jurisdictional regulators, and is generally administered through licensing requirements.

10.7.1 Reliability of supply

The reliability of gas supply refers to the continuity of supply to customers. Most jurisdictions impose reliability requirements on gas distributors as part of their licence conditions and publish performance data. In some cases, jurisdictions impose statutory obligations for network operators and owners, relating to the continuity of gas supply.

From a reliability perspective, gas distribution networks can maintain continuous gas flow to most customers in the event of a disruption to part of the network. In the case of planned renewals, or unplanned incidents such as gas explosions, third party damage, water entering the mains or directions from the technical regulator, customers in the vicinity of the incident or those affected by the technical direction of the regulator may experience a loss of gas flow. However, even if a gas

Figure 10.8
Significant unplanned interruptions per 1000 customers



Notes: Latest year of available data. Includes only interruptions affecting five or more customers.
Sources: Network performance reports published by ESC (Vic); QCA (Qld); ESCOSA (SA); ICRC (ACT); and Department of Water and Energy (NSW).

main is damaged, the gas can usually still flow across the distribution network, leaving supply to most customers unaffected. If necessary, a distribution network operator can load-shed some customers to manage a more serious supply interruption (as will be discussed later in the chapter).

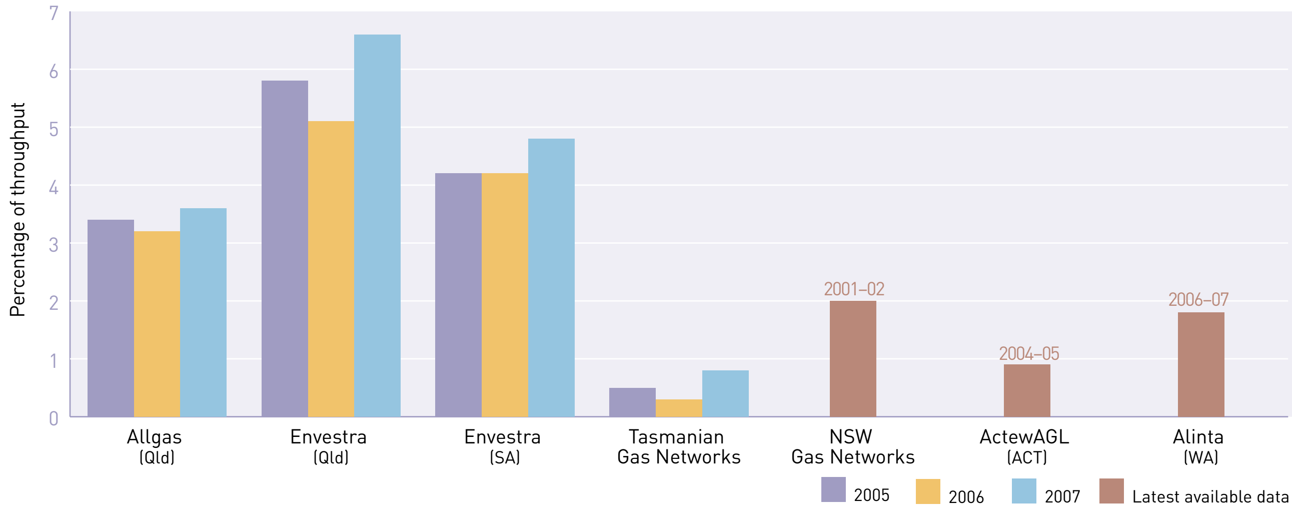
Figure 10.8 shows the most recent data for each jurisdiction on the number of significant[10] unplanned supply interruptions per 1000 customers. The Victorian, Queensland and South Australian regulators publish these data annually. Tasmania also publishes annual data, but not on a comparable basis to the mainland networks. The Tasmanian data are likely to record volatility while the state's distribution network is being rolled out. The ACT recorded negligible interruptions in the only year of published data. The New South Wales Department of Water and Energy collects annual reliability data from network businesses, but the latest published data are for 2001–02.

Figure 10.8 indicates that the rate of interruptions is low for all networks, with most recording fewer than 0.05 events per 1000 customers. The Essential Services Commission (ESC) reported in 2007 that the average Victorian customer may expect to lose supply about once every 40 years.[11] In part, these outcomes reflect the inherently reliable nature of gas distribution networks. Envestra's Queensland network, which recorded a higher rate of interruptions than other networks, received a significant increase in investment allowances in the current regulatory period. This may improve the network's reliability performance over time.

There were significant reliability issues in New South Wales and the ACT from 22–24 June 2007 when capacity on the Eastern Gas Pipeline and gas flows on the Moomba to Sydney Pipeline were insufficient to meet higher than expected demand. The distribution network operator was able to manage this issue by load-shedding large industrial and commercial customers, resulting in interruptions to their gas supplies. This enabled gas flows to continue without interruption to smaller retail customers. While there was no underlying infrastructure failure in this instance, the New South Wales Government established a *Gas Continuity Scheme* in 2008 to mitigate the risk of a recurrence. The scheme will provide commercial incentives for producers to increase supplies and customers to reduce gas usage in the event of a shortfall event.

10 Affecting five or more customers.
11 ESC, *Gas Distribution Businesses, Comparative Performance Report 2006*, 2007, p. 2.

Figure 10.9
Unaccounted-for gas



Note: Limited data available for New South Wales, Western Australia and the ACT.
Sources: Network performance reports published by ESC (Vic); QCA (Qld); ESCOSA (SA); ICRC (ACT); and Department of Water and Energy (NSW)

10.7.2 Network integrity

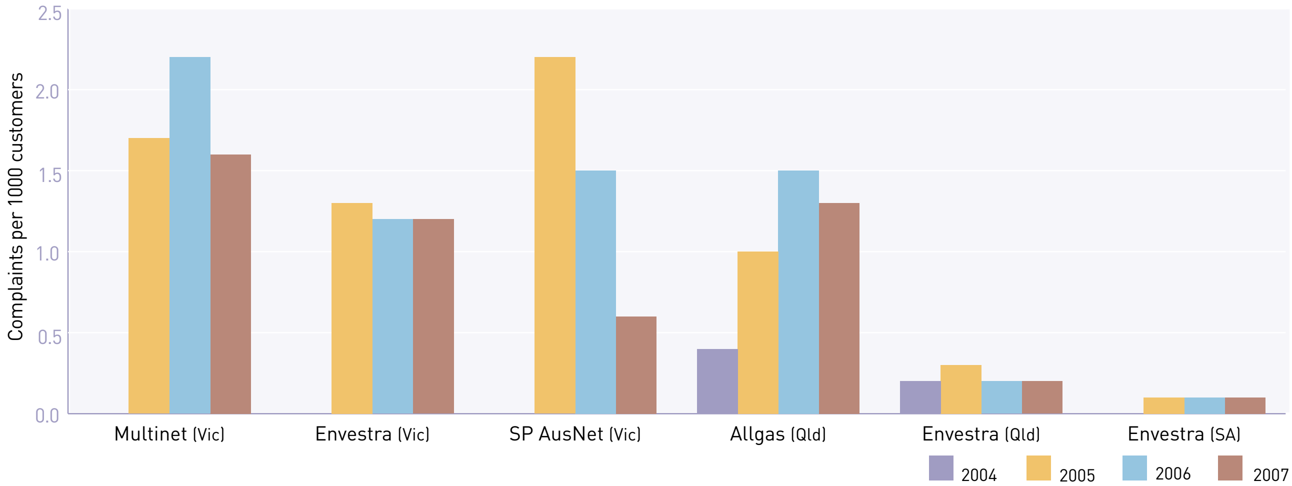
Network integrity issues relate to matters such as the frequency of gas leaks and the amount of unaccounted-for gas. Victoria, Queensland, Western Australia and the ACT publish data on gas leaks, but the indicators differ between jurisdictions. Victoria and the ACT publish annual data on the number of gas leaks per kilometre of pipe. The Victorian networks typically record around 1.3 gas leaks per kilometre each year, but most leaks affect few customers. In 2007, Western Australia began publishing data on the number of reported gas leaks occurring in public areas. Queensland reports a separate data series on the response time to repair gas leaks. The data indicate a typical response time of just under one hour for a network business to secure the site of a leak.

Unaccounted-for gas refers to the difference between the amount of gas injected into a distribution network and the amount of gas ultimately delivered to customers. Losses can occur for a number of reasons, including gas leaks, meter reading errors and theft. Queensland, South Australia, Western Australia and Tasmania report annually on this data. The Western Australian regulator published these data for the first time in 2007. The ACT last published data on unaccounted-for gas in 2004–05. The latest reported New South Wales data are for 2001–02. Figure 10.9 sets out the latest three years of data for Queensland, South Australia and Tasmania, and the limited data available for Western Australia, New South Wales and the ACT.

Figure 10.9 indicates that up to 7 per cent of gas injected into a pipeline may be unaccounted for. The Essential Services Commission of South Australia noted in its 2006–2007 performance report that unaccounted-for gas had almost doubled in the Envestra network since 2002–03. The issue may be linked to the existence of older cast iron pipelines in parts of network. Envestra is undertaking a capital works program to replace around 100 kilometres of cast iron pipes a year.[12] In 2007, the Queensland Competition Authority also noted a high rate of unaccounted-for gas in Envestra's Queensland network. Envestra reported that infrastructure replacement programs would likely reduce unaccounted-for gas over time.[13] Conversely, the low

12 ESCOSA, *2006–07 Annual performance report: Performance of South Australian energy networks*, 2007, p. 77.
13 Queensland Competition Authority, *Gas Distribution—Service Quality Performance for the Year Ending 30 June 2007*, 2007, p. 7.

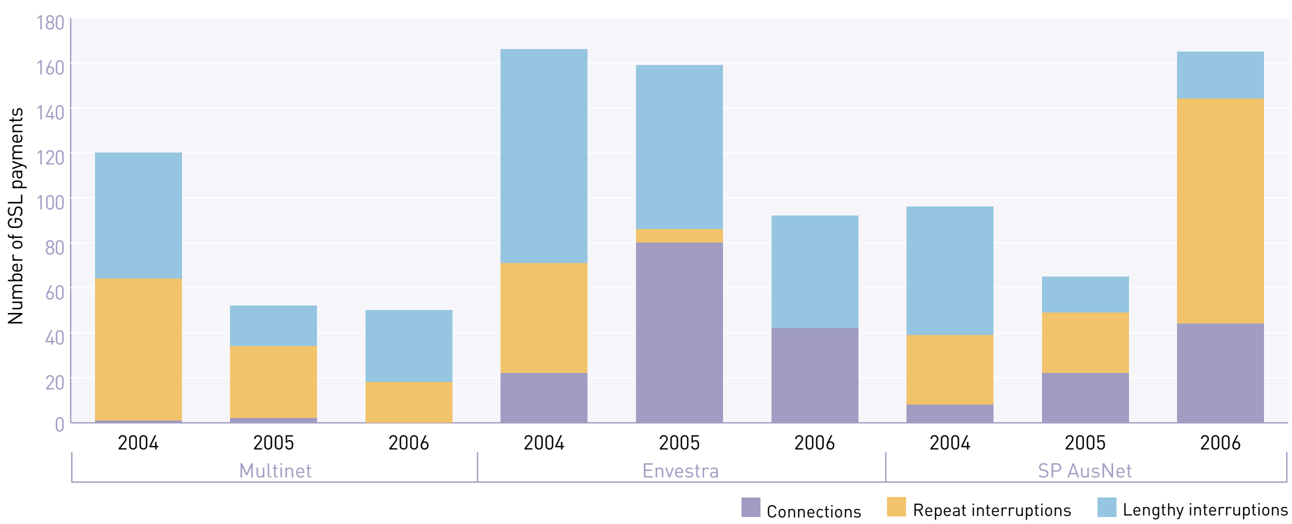
Figure 10.10
Customer complaints per 1000 customers



Notes:
1. Data for year ended 30 June. Victorian data are for preceding calendar year (for example, 2006–07 refers to calendar year 2006).
2. Victorian and South Australian data only available from 2004–05.

Sources: Network performance reports published by ESC (Vic), QCA (Qld); and ESCOSA (SA).

Figure 10.11
Guaranteed service level payments—Victoria



Sources: Essential Services Commission (ESC), Victoria, *Gas distribution businesses—comparative performance report 2006*, 2007.

rate of unaccounted-for gas in Tasmania may in part reflect the fact that the distribution network is relatively new and embodies more recent technology than some other networks.

10.7.3 Customer service

The level of customer service achieved by a distributor can be measured in terms of timeliness and responsiveness across a range of customer interactions, including customer calls, arranging new connections, keeping appointments, and the number and nature of complaints made about service providers. Victoria, Queensland and South Australia report annually on this information (figure 10.10). The latest reported New South Wales data is for 2001–02. As of 1 March 2008, the latest data for the ACT were for 2004–05.

The number of customer complaints has tended to lie in a range of 0.5 to 2 complaints per 1000 customers. Envestra achieved a significantly lower rate of complaints in both Queensland and South Australia. The complaints rate has tended to fall in Victoria over the past three years. A number of factors may limit the validity of comparisons between the networks, including differences in measurement and auditing systems.

Victoria applies guaranteed service levels that distributors must meet, or pay penalties for breaches. Figure 10.11 sets the number of payments made by each distributor for failures to meet target service levels over a three-year period. The ESC reported that, in 2006, distributors made 307 payments worth almost $30 000. The number of payments declined by 12 per cent and their total value by 8 per cent from 2005, although performance levels varied between networks.[14]

14 Essential Services Commission (ESC), Victoria, *Gas distribution businesses—comparative performance report 2006*, 2007.

11 GAS RETAIL MARKETS

The retail market is the final link in the gas supply chain. It provides the main interface between the gas industry and customers, such as households and small business. Retailers enter into contracts with producers and pipeline operators and package these together as an aggregated service for sale to consumers. Because retailers deal directly with consumers, the services they provide significantly affect perceptions of the performance of the gas industry.

11 GAS RETAIL MARKETS

This chapter provides a survey of gas retail markets. It covers:

- the structure of the retail market, including industry participants and trends towards vertical integration
- the development of retail competition
- retail market outcomes, including price, affordability and service quality
- the regulation of the retail market.

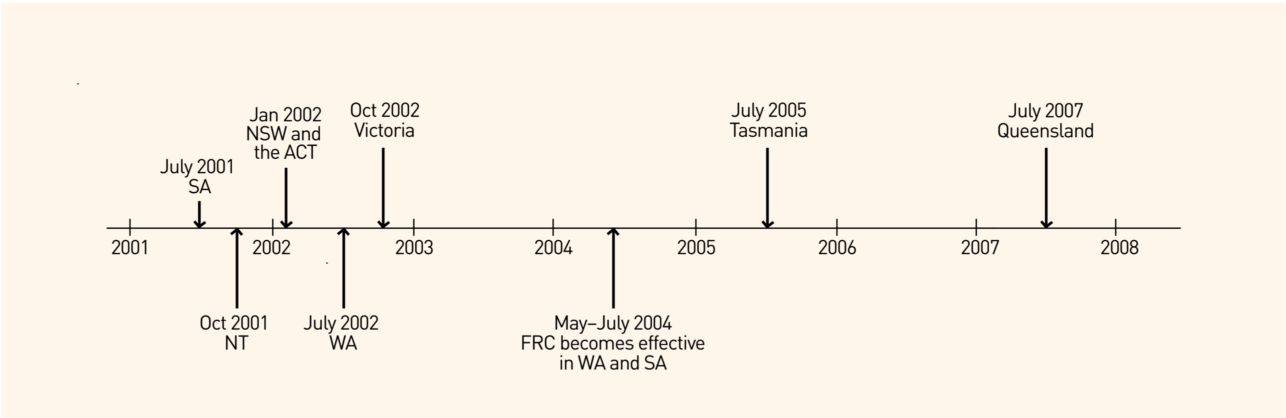
State and territory governments are responsible for the regulation of retail energy markets. Governments agreed in 2004 to transfer non-price regulatory functions to a national framework to be administered by the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The Ministerial Council on Energy (MCE) has scheduled the regulatory package to be introduced to the South Australian parliament in September 2009.[1]

Retail customers include residential, business and industrial gas users. This chapter focuses on the retailing of gas to small customers,[2] including households and small business users. Many energy retailers are active in both gas and electricity markets and offer *dual fuel* products. This chapter should therefore be read in conjunction with Chapter 6, 'Electricity retail markets'.

1 Sections 11.6 and 6.7 provide an update on the transition to future regulatory arrangements.

2 Small customers are defined as those using less than 1 terajoule of gas a year.

Figure 11.1
Introduction of full retail contestability



FRC, full retail contestability.

While this chapter reports some data that might enable performance comparisons to be made between retailers and jurisdictions, such analysis should note that a variety of factors can affect relative performance.

11.1 Retail market structure

Historically, gas retailers in Australia were integrated with gas distributors and operated essentially as monopoly providers in their state or region. In the 1990s, governments began to reform the industry through restructuring, privatisation and the introduction of competition.

South Australia (in 1993), Victoria (in the late 1990s), Western Australia (in 2000) and Queensland[3] (in 2007) have privatised their state-owned gas retailers. While New South Wales has some government ownership, its gas retail sector has always been mainly in private hands.[4] The Australian Capital Territory (ACT) Government operates a joint venture with the private sector to provide gas retail services. Before the formation of the joint venture in 2000, the ACT gas retailer was privately owned. One of the two active retailers in the relatively new Tasmanian gas retail sector is state-owned.

All state and territory governments have introduced full retail contestability (FRC) for gas customers, meaning that customers can enter a supply contract with a retailer of their choice (see figure 11.1). Most governments chose to phase in retail contestability by introducing competition for large industrial customers, followed by small industrial customers and, finally, small business and household customers.

The retail players in most jurisdictions include one or more *host* retailers, that are subject to various regulatory obligations, and new entrants. New entrants include new players in the gas retail sector, established interstate gas retailers, and electricity retailers branching into gas retailing.

Table 11.1 lists licensed gas retailers that are currently active in the market for residential and small business customers.[5] Privately owned retailers are the major players in most jurisdictions.

- In the eastern states, the leading retailers are AGL Energy, Origin Energy and TRUenergy. Each has significant market share in Victoria and South Australia. AGL Energy is the leading gas retailer in New South Wales and jointly owns (with the ACT Government) the leading ACT retailer. AGL Energy

3 In Dalby and Roma the local councils operate distribution and retail services in their local areas.
4 The New South Wales Government owns EnergyAustralia and Country Energy.
5 Active retailers are those retailers that are offering gas supply to new small customers.

Table 11.1 Active gas retailers: small customer market, May 2008

RETAILER[1]	OWNERSHIP	VIC	NSW	QLD	SA	TAS[2]	ACT	WA	NT
ActewAGL Retail	ACT Government and AGL Energy		Host				Host		
AGL Energy	AGL Energy	Host	Host	Host	New entrant				
Alinta	Babcock & Brown Power							Host	
Aurora Energy	Tasmanian Government					New entrant			
Australian Power & Gas	Australian Power & Gas	New entrant	New entrant						
Country Energy	NSW Government		Host				New entrant		
EnergyAustralia	NSW Government		New entrant				New entrant		
Red Energy	Snowy Hydro[3]	New entrant							
Simply Energy	International Power	New entrant			New entrant				
Option One	Babcock & Brown Infrastructure					New entrant			
Origin Energy	Origin Energy	Host		Host	Host				Host
TRUenergy	CLP Group	Host	New entrant		New entrant		New entrant		
Victoria Electricity	Infratil	New entrant							
Active retailers		7	6	2	4	2	4	1	1
Approx. market size ('000 000 customers)[4]		1.68	1.02	0.15	0.37	0.003	0.09	0.57	0.001

Host (incumbent) retailer New entrant

Notes:

1. Not all licensed retailers are listed. Some of the retailers listed only offer gas services as part of a gas and electricity contract. The list also excludes three small retailers (BRW Power Generation (Esperance), Dalby Town Council and Roma Town Council).
2. There is no host retailer in Tasmania as gas distribution and retail services have only been available for a short time and FRC existed from market start.
3. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).
4. Customer numbers for Queensland, Western Australia and the Northern Territory are based on ESAA data on the number of residential and small commercial and industrial connections to the distribution network, consuming less than 10 terajoules a year (at 30 June 2007).

Source: Jurisdictional regulator websites; ESAA *Electricity Gas Australia* 2008; updated by information on retailer websites and other public sources.

acquired significant market share in Queensland via the 2006–07 privatisation process, while Origin Energy was already an established retailer in that state.

- In Western Australia, Alinta (owned by Babcock & Brown Power) is the leading retailer and is the only retailer licensed to retail to customers consuming less than 0.18 terajoules a year.
- In Tasmania, Option One competes with the state-owned Aurora Energy.
- Government-owned retailers account for a significant minority of the New South Wales market.
- Various niche players are active in most jurisdictions.

The following survey provides background on developments in each jurisdiction.

11.1.1 Victoria

At May 2008, Victoria had 12 licensed retailers, seven of which were active in the residential and small business market. These were:

- TRUenergy, AGL Energy and Origin Energy, each of which is the host retailer in designated areas of Victoria[6]
- four new players in the gas retail market, which were Australian Power & Gas, Red Energy, Simply Energy and Victoria Electricity.

Momentum Energy and Dodo Power & Gas held retail licences but were not actively marketing to small customers in May 2008.

6 In the late 1990s, Victoria split the Gas and Fuel Corporation into multiple retail businesses, each linked to a distribution network area, and sold each to different interests: Utilicorp and AMP Society (operating as United Energy and Pulse Energy), TXU, and Origin Energy. AGL acquired the former United Energy business in 2002 and TXU sold its retail interests to Singapore Power in 2004, which in turn sold the business to China Light and Power (now CLP Group) in 2005. The new owners rebadged TXU as TRUenergy.

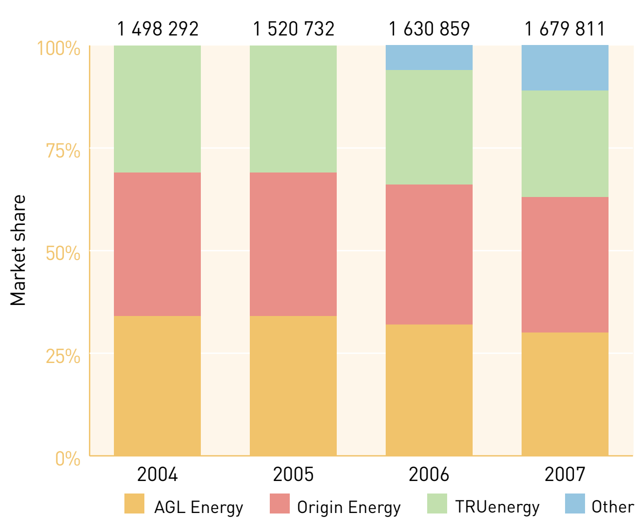
Table 11.2 and figure 11.2 set out the market share of Victorian retailers (by customer numbers) at 30 June 2007. The three host retailers (TRUenergy, AGL Energy and Origin Energy) account for about 89 per cent of the market and each retails beyond its 'local' area. While the market share of new entrants is small, new entrant penetration increased from 6 per cent of small customers in June 2006 to over 11 per cent in 2007.

Table 11.2 Gas retail market share (small customers)—Victoria, 30 June 2007

RETAILER	CUSTOMERS		
	Domestic	Business	Total retail
AGL Energy	29.6%	25.5%	29.4%
Origin Energy	33.4%	29.6%	33.3%
TRUenergy	25.7%	39.0%	26.0%
Other	11.4%	5.9%	11.2%
Total customers	1 634 871	44 940	1 679 811

Source: ESC, *Energy retail businesses comparative performance report for the 2006/07 financial year*, December 2007, p. 3.

Figure 11.2
Gas retail market share (small customers)—Victoria



Note: figures at top of columns are total small customer numbers.

Source: ESC, *Energy retail businesses comparative performance report*, various years.

11.1.2 South Australia

At May 2008, South Australia had 12 licensed retailers, four of which were active in the residential and small business market. These were:

- the host retailer, Origin Energy
- three new entrants, which were South Australia's host retailer in electricity (AGL Energy), an established interstate retailer (TRUenergy) and Simply Energy (a relatively new player in the retail market).

Country Energy, EnergyAustralia, Australian Power & Gas, Dodo Power & Gas, Jackgreen, Momentum Energy and South Australian Electricity held retail licences but were not actively marketing to small customers in May 2008. Several of these businesses are active in the South Australian electricity retail market.

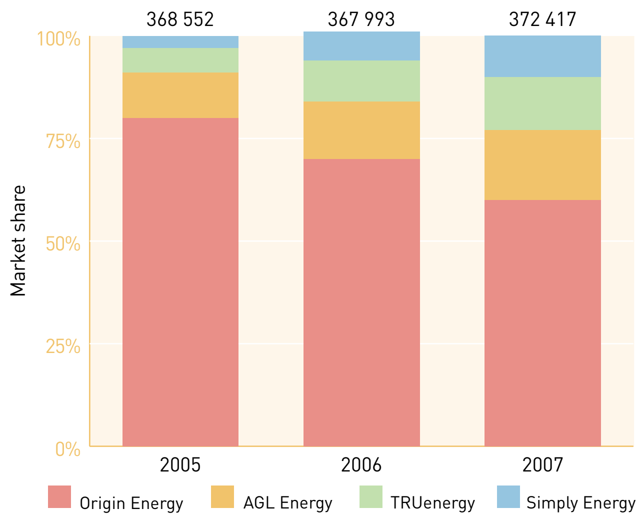
Table 11.3 sets out the market share of South Australian retailers (by customer numbers) at June 2007. New entrants account for about 40 per cent of the small customer market—up from 30 per cent in 2006 and 20 per cent in 2005 (see figure 11.3).

Table 11.3 Gas retail market share (small customers)—South Australia, 30 June 2007

RETAILER	CUSTOMERS		
	Domestic	Business	Total retail
Origin Energy	59.3%	88.7%	59.9%
AGL Energy	17.3%	3.4%	17.0%
TRUenergy	13.1%	5.6%	13.0%
Simply Energy	10.3%	2.3%	10.1%
Total customers	365 077	7340	372 417

Source: ESCOSA, *2006–07 Annual performance report: Performance of the South Australian energy retail market*, November 2007, p. 66.

Figure 11.3
Gas retail market share (small customers)—South Australia



Note: figures at top of columns are total small customer numbers.

Source: ESCOSA, *Annual performance report: Performance of the South Australian energy retail market*, various years.

11.1.3 New South Wales

At May 2008, New South Wales had 13 licensed retailers, six of which were active in the residential and small business market. These were:

- the host retailers, AGL Energy, Country Energy and ActewAGL Retail
- three new entrants, which were electricity retailer EnergyAustralia, established interstate retailer TRUenergy and Australian Power & Gas (a new player in the energy retail market).

Integral Energy and Jackgreen held retail licences but were not actively marketing to small customers in May 2008.

NERA Economic Consulting reported that at June 2007, AGL Energy continued to supply the majority of the Sydney retail gas market and had a market share of 79 per cent, while the other significant gas retailer, EnergyAustralia, had a market share of around 16 per cent.[7]

11.1.4 Queensland

At May 2008, Queensland had seven licensed retailers, two of which were active in the residential and small business market. These were the host retailers, AGL Energy (previously Sun Gas Retail)[8] and Origin Energy.

In addition, the local councils in Dalby and Roma provide gas services in their local government areas. In June 2008, Australian Power & Gas withdrew from actively retailing in the gas retail market. EnergyAustralia obtained a retail licence in July 2007 and Dodo Power & Gas in March 2008, but neither were actively retailing to small customers in May 2008.

11.1.5 Australian Capital Territory

At May 2008, the ACT had seven licensed retailers, four of which were active in the residential and small business market. The active retailers include the host retailer, ActewAGL Retail, and three new entrants, which were established interstate retailers EnergyAustralia, Country Energy and TRUenergy.

Dodo Power & Gas and Jackgreen held retail licences but were not actively marketing to small customers in May 2008.

NERA Economic Consulting reported that at June 2007, ActewAGL Retail had a market share of 92 per cent.[9] EnergyAustralia and Country Energy held the remaining 8 per cent.

7 NERA Economic Consulting, *The gas supply chain in eastern Australia—A report to the Australian Energy Market Commission*, March 2008, p. 89.
8 AGL Energy acquired the government-owned Sun Gas Retail in 2006.
9 NERA Economic Consulting, *The gas supply chain in eastern Australia—A report to the Australian Energy Market Commission*, March 2008, p. 91.

11.1.6 Tasmania

At May 2008, Tasmania had two gas retailers active in the small customer market: the state-owned Aurora Energy and Option One (owned by Babcock & Brown Infrastructure through Powerco, the Tasmanian distribution network business). TRUenergy and Country Energy obtained retail licences in 2008 but were not actively marketing to small customers in May 2008.

11.1.7 Western Australia

Although the Western Australian retail market is open to retail competition, Alinta is the only active retailer for customers using less than 0.18 terajoules of gas a year. In May 2007, Babcock & Brown Power acquired Alinta's Western Australian gas retail business.

The state's host retailer in electricity, Synergy, applied for a gas trading licence in April 2007 to sell gas to small customers. However, restrictions imposed by the Western Australian Government prevent Synergy from supplying gas to customers using less than 0.18 terajoules a year.[10]

11.1.8 The Northern Territory

In the Northern Territory, gas is mainly used for electricity generation. Origin Energy retails gas to small customers in Alice Springs, and NT Gas supplies a small quantity of gas to commercial and industrial customers in Darwin.

11.2 Trends in market integration

There has been considerable ownership consolidation in the energy retail sector, including:

- retail market convergence between electricity and gas
- vertical integration between gas production and gas retail.

Efficiencies in the joint provision of electricity and gas services have encouraged retailers to be active in both markets, and offer *dual fuel* retail products. The convergence between the gas and electricity retail markets is considered in section 6.2.1 of this report.

There is a continuing trend towards vertical integration between privately owned gas retailers and gas producers. Investment in gas production provides gas retailers with a natural hedge against rising wholesale gas prices and enhances security of supply. The retailers AGL Energy, Origin Energy and TRUenergy each have interests in gas production and/or gas storage. Origin Energy is a gas producer in Queensland, Western Australia, South Australia and Victoria. AGL Energy has become a producer of coal seam gas in Queensland and New South Wales. TRUenergy has gas storage facilities in Victoria. AGL Energy, Origin Energy and TRUenergy are also major electricity generators.

In addition, there are some ownership linkages between the gas pipeline and gas retail sectors. For example, the retailers TRUenergy and Simply Energy (owned by International Power) have ownership shares in the SEA Gas Pipeline from Victoria to South Australia.

10 ERA, *Decision on gas trading licence application for Synergy (Electricity Retail Corporation)*, 26 June 2007.

11.3 Retail competition

While most jurisdictions have introduced FRC in gas, it can take time for a competitive market to develop. As a transitional measure, some jurisdictions require host retailers to supply small customers in nominated geographical areas under a regulated standing offer (or default) contract (see section 11.4.1). Standing offer contracts often cover minimum terms and conditions and include a regulated price that is subject to some form of cap or oversight. These contracts apply to all customers who do not have a market contract. At July 2008, four jurisdictions—New South Wales, Victoria, South Australia and Western Australia—applied some form of retail price regulation.

Australian governments have agreed to review the continued use of retail price caps and remove them where effective competition can be demonstrated.[11] The AEMC is assessing the effectiveness of retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps. The relevant state or territory government makes the final decision on this matter. The AEMC conducted a review of the Victorian market in 2007 and is reviewing the South Australian market in 2008. In response to the review, the Victorian Government announced in September 2008 the introduction of new legislation to remove retail price caps. Further information on the AEMC reviews is provided in box 6.1 in chapter 6 of this report.

The following is a sample of public data that may be relevant to an assessment of the effectiveness of retail competition in Australia. The data show the diversity of price and product offerings of retailers; the exercise of market choice by customers, including switching behaviour; and customer perceptions of competition. Elsewhere, this chapter touches on other barometers of competition: for example, section 11.1 considers new entry in the gas retail market. The AER does not seek to draw conclusions on the information provided and does not attempt to assess the effectiveness of retail competition in any jurisdiction.

11.3.1 Price and non-price diversity of retail offers

There is some evidence of price and product diversity in gas retail markets in Australia. Under market contracts, retailers generally offer a rebate and/or discount from the terms of a standing offer contract. Often discounts are tied to the term of the contract; for example, longer-term contracts typically attract larger discounts than more flexible arrangements. Discounts may also be available for prompt payment of bills and payments by direct debit.

Some product offerings bundle gas services with inducements such as loyalty bonuses, competitions, membership discounts, shopper cards and free products. Some retailers also offer discounts for contracting jointly for gas and electricity services.

In assessing the effectiveness of competition in gas retail markets in Victoria, the AEMC noted:[12]

> Retailers offer non-price benefits in an effort to differentiate their offers from those of their rivals and to attract those customers for whom a price discount is not sufficient encouragement to switch. For some customers, the offer of physical products or other less tangible benefits such as improved environmental outcomes or community support may be greater, or an additional, inducement for switching to a market contract with a different retailer than simple discounts from the standing offer price.

The AEMC also reported that nine of 13 Victorian retailers surveyed had offered at least one non-price benefit in conjunction with market offers over the past five years. The most common non-price benefits were magazine subscriptions and vouchers.[13]

The variety of discounts and non-price inducements makes direct price comparisons between retail offers difficult. There is also variation in the transparency

11 Australian Energy Market Agreement 2004 (amended 2006), p. 28.

12 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria—First final report*, 19 December 2007, p. 60.

13 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria—First final report*, 19 December 2007, p. 62.

of price offerings. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation. Box 11.1 provides case study material on the diversity of price and product offerings in South Australia, Queensland and Victoria.

Note that the price offers set out in box 11.1 relate to a variety of time periods and product structures, and rely on different measurement techniques. The price offers are therefore not directly comparable between jurisdictions. Section 11.4 of this report also considers data on retail price outcomes.

11.3.2 Customer switching

The rate at which customers switch their supply arrangements (or churn) is an indicator of customer participation in the market. Switching rates can also indicate competitive activity. High rates of switching can reflect the availability of cheaper and/or better offers from competing retailers, successful marketing by retailers, and customer dissatisfaction with some service providers.

However, switching rates should be interpreted with care. Switching is sometimes high during the early stages of market development when customers are first able to exercise choice. Switching rates sometimes stabilise even as the market acquires more depth. Similarly, it is possible to have low switching rates in a competitive market if retailers are delivering good quality service that gives customers no reason to switch.

Switching rates may also be affected by factors such as the number of competitors in the market, customer experience with competition, demographics, demand and the cost of the service in relation to household budgets. For example, consumers are more likely to be responsive to energy offers and actively seek out cheaper services if the cost of gas services represents a relatively high proportion of their budget.

Gas churn data is published by independent market operators: the Gas Market Company (New South Wales and the ACT), VENCorp (Victoria and Queensland) and REMCo (South Australia). For each, churn is measured as the number of switches by gas customers from one retailer to another in a period, including switches from a host retailer to a new entrant, switches from new entrants back to a host retailer, and switches from one new entrant to another (see table 11.5 and figure 11.4).[17]

The data do not include customers who have switched from a standing offer contract to a market contract with their existing retailer. This exclusion may understate the true extent of competitive activity as it does not account for the efforts of host retailers to maintain market share.

Figure 11.4 illustrates that switching activity continued strongly in Victoria and South Australia in 2007–08. Queensland, New South Wales and the ACT had switching rates of less than half those recorded in the other states. Table 11.5 shows that only 5 per cent of small customers in Queensland, New South Wales and the ACT changed gas retailer in 2007–08, compared to 23 per cent in Victoria and 13 per cent in South Australia. At June 2008, cumulative switching rates in Victoria (99 per cent) and South Australia (67 per cent) were more than double the New South Wales and ACT rate (27 per cent). The relatively low rate of customer switching in Queensland reflects the recent introduction of FRC in that state (1 July 2007). The gas retail switching rates in each jurisdiction were lower than switching rates in electricity.

17 The New South Wales, ACT, Queensland and Victorian data are based on transfers at delivery points. As most residential customers receive gas from only one delivery point, the data approximates the number of customers transferring to another retailer.

Box 11.1 Case study—diversity of price and product offerings to small customers

Information is available in South Australia, Queensland and Victoria on the price and product offerings of gas retailers.

The Essential Services Commission of South Australia (ESCOSA) and the Queensland Competition Authority (QCA) provide online estimator services that allow consumers to make rough but quick comparisons of retail offers.[14] The estimators do not account for all elements of retail offers, such as sign-up bonuses. Table 11.4 sets out the estimated annual gas bill in April 2008 for customers in South Australia and Queensland using 60 gigajoules of gas per year, based on peak usage and not using gas for hot water.

Victoria's Essential Services Commission (ESC) undertakes annual independent research that compares some gas market contract prices in different host retailer areas.[15] The ESC found that market offers at a discount from the standing contract price were available in all host retailer areas, as well as additional monetary inducements of up to $50 a year. Table 11.4 sets out results of the ESC research from May 2007.

Table 11.4 indicates that there is some price diversity in the gas retail markets, though often less so than for electricity (see box 6.2 in chapter 6 of this report). The price spread in Victoria was about $200, and just over $100 in South Australia. In Queensland the price spread was just under $80. Discounts off the regulated retail price of up to 14 per cent were available in Victoria (compared with 10 per cent for electricity), and of up to 7 per cent in South Australia (consistent with electricity). Retail gas prices in Queensland are not regulated.

Market analysis in Victoria undertaken by CRA International in August 2007 found that market contracts typically have a range of monetary and non-monetary inducements. Variable-term contracts tended to offer smaller discounts and fewer non-monetary benefits than fixed-term contracts.[16]

14. The estimators are available at http://www.escosa.sa.gov.au and http://www.qca.org.au.
15. ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007.
16. CRA International, *Impact of prices and profit margins on energy retail competition in Victoria*, November 2007, pp. 65-66.

Table 11.4 Gas retail price offers for a customer using 60 GJ per year in South Australia (April 2008), Queensland (April 2008) and Victoria (May 2007)

PROVIDER	Nº OF PRODUCTS	ANNUAL COST ($)[1,2] 600–1500	ADDITIONAL BENEFITS
SOUTH AUSTRALIA (ORIGIN ENERGY)			
Regulated price			—
AGL Energy	4		Joining bonus
Origin Energy	3		Prompt payment discount
TRUenergy	2		Joining bonus; loyalty bonus
QUEENSLAND (NO REGULATED PRICE)			
AGL Energy	2		—
Australian Power & Gas	4		Joining bonus; prompt payment discount
Origin Energy	2		—
VICTORIA (AGL SOUTH)			
Regulated price			—
AGL Energy	1		Joining bonus
Origin Energy	1		Joining bonus
EnergyAustralia[3]	2		Loyalty bonus
TRUenergy	1		Prompt payment discount
Victoria Electricity	1		Prompt payment discount
VICTORIA (AGL NORTH)			
Regulated price			—
AGL Energy	1		Joining bonus
TRUenergy	1		Prompt payment discount
Victoria Electricity	1		Prompt payment discount
VICTORIA (ORIGIN METRO)			
Regulated price			—
AGL Energy	1		Joining bonus
EnergyAustralia[3]	2		Loyalty bonus
Origin Energy	1		Loyalty bonus
TRUenergy	1		Prompt payment discount
Victoria Electricity	1		Prompt payment discount
VICTORIA (ORIGIN SOUTH EAST)			
Regulated price			—
EnergyAustralia[3]	2		Loyalty bonus
Origin Energy	1		Loyalty bonus
TRUenergy	1		Prompt payment discount
Victoria Electricity	1		Prompt payment discount
VICTORIA (ORIGIN NORTH)			
Regulated price			—
AGL Energy	1		Joining bonus
EnergyAustralia[3]	2		Loyalty bonus
TRUenergy	1		Prompt payment discount
Victoria Electricity	1		Prompt payment discount
VICTORIA (TRU EAST)			
Regulated price			—
AGL Energy	1		Joining bonus
EnergyAustralia[3]	2		Loyalty bonus
TRUenergy	1		Prompt payment discount
Origin Energy	1		Loyalty bonus
Victoria Electricity	1		Prompt payment discount
VICTORIA (TRU CENTRAL)			
Regulated price			Prompt payment discount
AGL Energy	1		Joining bonus
EnergyAustralia[3]	2		Loyalty bonus
TRUenergy	1		Prompt payment discount
Origin Energy	1		Loyalty bonus
Victoria Electricity	1		Prompt payment discount

Notes:

1. Coloured bars represent the approximate range of annual charges for each retailer's products.
2. The annual costs exclude additional benefits such as prompt payment discounts, and joining and loyalty bonuses.
3. In July 2007 International Power announced its acquisition of the Energy Australia–International Power Retail Partnership. This partnership retailed gas services in Victoria under the Energy Australia trading name. International Power has since rebadged the retail business as Simply Energy.

Sources: South Australia: ESCOSA estimator, viewed 17 April 2008, http://www.escosa.sa.gov.au; Queensland: QCA estimator, viewed 17 April 2008, http://www.qca.org.au; Victoria: ESC, *Energy retail businesses comparative performance report for the 2006–07 financial year*, December 2007.

Table 11.5 **Small customers switching retailers, 2008**

INDICATOR	NSW AND ACT	VICTORIA	QUEENSLAND	SOUTH AUSTRALIA
Percentage of small customers that changed gas retailer during 2007–08	5%	23%	5%	13%
Customer switches as a percentage of the small customer base from FRC start to June 2008 (cumulative)—Gas	27%	99%	5%	67%
Customer switches as a percentage of the small customer base from FRC start to June 2008 (cumulative)—Electricity	44%	105%	20%	86%

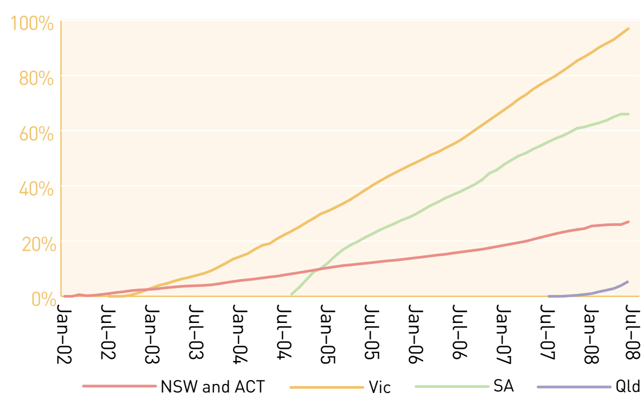
Note:

1. If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may therefore exceed 100 per cent.
2. The customer base is estimated at 30 June 2008.

Sources: New South Wales and ACT: Gas Market Company, Market activity data January 2002–June 2008; South Australia: REMCo, Market activity reports August 2004–June 2008; Victoria and Queensland: VENCorp, Gas market reports: Transfer history January 2002–June 2008.

Figure 11.4

Cumulative monthly customer switching of retailers as a percentage of small gas customers, to June 2008



Sources: New South Wales and ACT: Gas Market Company, Market activity data January 2002–June 2008; South Australia: REMCo, Market activity reports August 2004–June 2008; Victoria and Queensland: VENCorp, Gas market reports: Transfer history January 2002–June 2008.

Switches to market contracts

An alternative approach to measuring customer churn is to measure switching from standing offer contracts to market contracts. In June 2008, South Australia was the only jurisdiction that periodically published this data. In Victoria, the AEMC reported on customer switching to market contracts as part of its 2007 review of the effectiveness of retail competition.[18]

Table 11.6 summarises available data on switches to market contracts in South Australia and Victoria. The data are not directly comparable because of differences in data collection methods and the periods covered.

The data indicate that in addition to customer movement between retailers, a significant number of residential customers in Victoria and South Australia are choosing to move away from standing offer contracts but remain with their host retailer. Once again, switching rates are lower than for electricity (see table 6.7 in chapter 6).

International comparisons

The VaasaETT Utility Customer Switching Research Project published its fourth report on customer switching in world energy markets in 2008. VaasaETT classified the Victorian and South Australian energy retail markets as 'hot' and the New South Wales and Queensland retail energy markets as 'warm active'. Box 6.3 in chapter 6 of this report provides further details.

11.3.3 Customer perceptions of competition

Surveys on customer perceptions of retail competition are undertaken from time to time. Recent reviews include:

18 AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria—First final report*, 19 December 2007.

Table 11.6 Small customer transfers to market contracts

JURISDICTION	DATE	SMALL CUSTOMERS ON MARKET CONTRACTS (% OF SMALL CUSTOMER BASE)
Victoria	31 December 2006	60% of residential customers
		31% of small business customers
South Australia	30 June 2007	56% of residential customers (16% with the host retailer and 40% with new entrants)
		14% of small business customers (3% with the host retailer and 11% with new entrants)

Sources: Victoria: AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in Victoria—First final report*, 19 December 2007, p. 89; South Australia: ESCOCA, *2006–07 Annual performance report: Performance of South Australian energy retail market*, November 2007, pp. iii and 23.

- surveys as part of the AEMC reviews of the effectiveness of retail competition in Victoria (2007) and South Australia (2008)
- the Independent Pricing and Regulatory Tribunal's (IPART's) survey of residential energy and water use in Sydney, the Blue Mountains and Illawarra (2006)
- surveys conducted as part of ESCOSA's monitoring of the development of energy retail competition in South Australia.

Issues covered by the surveys include:

- customer awareness of their ability to choose a retailer
- customer approaches to retailers about taking out a market contract
- retailer offers received by customers
- customer understanding of retail offers.

Table 11.7 provides summary data. The surveys suggest that customer awareness of retail choice has risen over time to high levels, particularly in New South Wales and Victoria. It remains unusual for customers to approach retailers about taking out a market contract. However, increasing numbers of customers are being approached by retailers.

Table 11.7 Residential customer perceptions of competition

	SOUTH AUSTRALIA			VICTORIA		NEW SOUTH WALES	
INDICATOR	2004	2006	2008	2004	2007	2003	2006
Customers aware of choice	78%	79%	84%	83%	91%	92%	93%
Customers receiving at least one retail offer	20%	34%	20%	22%	45%	29%[1]	36%[1]
Customers approaching retailers about taking out market contracts	8%	6%	5%	6%	6%	n/a	n/a

n/a, not available.

Note:

1. Does not include customers approached to switch to a market contract by their current retailer. By 2006, 43 per cent of households had been approached to switch to a market contract by their existing retailer.

Sources: South Australia: McGregor Tan Research, *Monitoring the development of energy retail competition—residents*, prepared for ESCOSA, February 2006, September 2004 and November 2003; McGregor Tan Research, *Review of effectiveness of competition in electricity and gas retail markets*, prepared for AEMC, June 2008; Victoria: The Wallis Group, *Review of competition in the gas and electricity retail markets—consumer survey*, prepared for AEMC, August 2007; New South Wales: IPART, *Residential energy and water use in Sydney, the Blue Mountains and Illawarra–Results from the 2006 household survey*, November 2007.

11.4 Retail prices

Gas retail prices paid by customers cover the costs of a bundled product made up of gas, transport through transmission and distribution pipelines, and retail services.

Figure 11.5 provides an indication of the typical make-up of a residential gas bill in Victoria and South Australia in 2007. Wholesale gas costs and pipeline (transmission and distribution) charges account for the bulk of retail gas prices. Retail operating costs and retail margins account for around 16 per cent of retail prices in Victoria and 19 per cent in South Australia.

The lead essay of this report sets out ACIL Tasman estimates of the composition of residential gas prices in five mainland capital cities (see figure E.2). The analysis notes that prices vary significantly for customers with different volume requirements and at different locations.

By far the highest proportion of total cost is associated with the distribution system, reflecting the high capital cost of servicing each customer.

11.4.1 Regulation of retail prices

While all jurisdictions have introduced FRC, at July 2008 New South Wales, Victoria, South Australia and Western Australia continued to regulate gas retail prices for small customers. Typically, host retailers must offer standing offer contracts to sell gas at default prices based on some form of regulated price cap or oversight. These contracts apply to customers who have not switched to a market contract. Retail gas prices are not regulated in Queensland, Tasmania, the ACT or the Northern Territory.

Price cap regulation was intended as a transitional measure during the development phase of retail markets. To allow efficient signals for investment and consumption, governments are moving towards removing retail price caps. As noted, the AEMC is reviewing the effectiveness of competition in electricity and gas retail markets to determine an appropriate time to remove retail price caps in each jurisdiction (see box 6.1 in chapter 6).

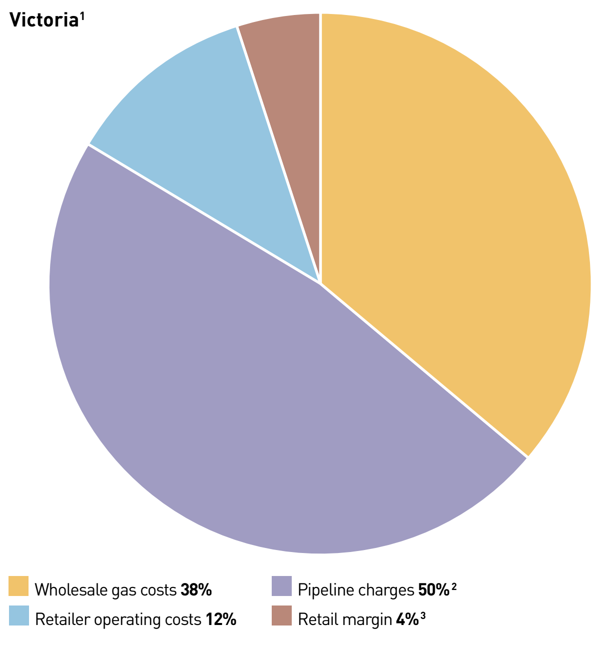
In setting default prices, jurisdictions take into consideration gas purchase costs, pipeline charges, retailer operating costs and a retail margin. The approach varies between jurisdictions:

- In New South Wales, prices under standing offer contracts are controlled through voluntary agreements with host retailers that limit annual price increases.
- Since 2003, the Victorian Government has entered into agreements with host retailers on a pricing structure for default retail prices for households and small businesses. Default arrangements ceased to apply to small businesses from 1 January 2008 and will cease for residential customers from 1 January 2009.
- The South Australian regulator (ESCOSA) sets default prices for the host retailer by considering the costs that a prudent retailer would incur in delivering the services.
- In Western Australia, gas retail prices for the major distribution systems are capped by regulations. During 2008, the Office of Energy is reviewing the level and structure of regulated retail prices.

Section 11.4.3 considers recent retail price determinations and provides detail on the progress of the Western Australian review of regulated retail prices.

Figure 11.5

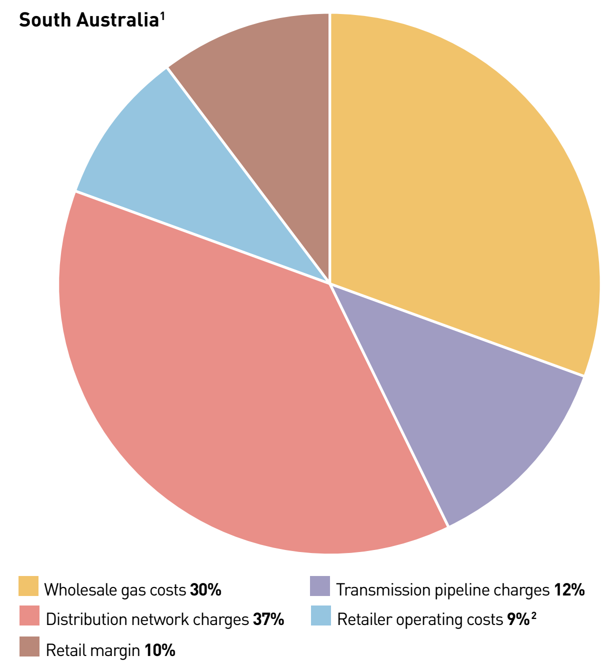
Indicative composition of a residential gas bill—Victoria and South Australia, 2007



Notes:

1. Based on 2007 prices and average annual residential consumption of 60 gigajoules.
2. Pipeline charges are an average for the three Victorian host retailers—Origin Energy, AGL Energy and TRUenergy.
3. Retail margin based on standing offer contracts.

Source: CRA International, *Final report: Impact of prices and profit margins on energy retail competition in Victoria*, November 2007, Prepared for AEMC review of effectiveness of competition in the electricity and gas retail markets—Victoria.



Notes:

1. Based on 2007–08 prices and average annual residential consumption of 60 gigajoules.
2. Retailer operating costs are exclusive of full retail competition costs.

Source: ESCOSA, *2008 gas standing contract price path inquiry draft inquiry report and draft price determination*, April 2008; ESCOSA, *gas standing contract price path final inquiry report and final price determination*, June 2005.

11.4.2 Retail price outcomes

Retail price outcomes should be interpreted with care. Trends in retail prices may reflect movements in the cost of any one or a combination of the bundled components in a retail product—for example, movements in wholesale gas prices, transmission and distribution pipeline charges or retail operating costs. In addition, retail price movements are affected by regulatory arrangements. As noted in section 6.4.2, while competition tends to deliver efficient outcomes, it may sometimes give a counter intuitive outcome of higher prices—especially in the early stages of competition as historical cross-subsidies are phased out.

Sources of price data

There is little systematic publication of actual gas retail prices in Australia. The Australian Gas Association (AGA) previously published data on retail gas prices but discontinued the series after 1998. Some jurisdictions publish price information:

- Jurisdictions that regulate prices publish schedules of default prices. The schedules are a useful guide to retail prices but their relevance as a price barometer is reduced as more customers transfer to market contracts.
- The South Australian regulator (ESCOSA) publishes annual data on default and market prices.

- ESCOSA and the Queensland and Victorian regulators (QCA and ESC) provide an estimator service on their websites that can be used to compare the price offerings of different retailers (see box 11.1).
- Retailers are not required to publish the prices struck through market contracts with customers.

Consumer Price Index and Producer Price Index

The consumer price index (CPI) and producer price index, published by the Australian Bureau of Statistics, track movements in gas retail prices paid by households and businesses.[19] The indexes are based on customer surveys and therefore reflect both market and regulated prices.

Figure 11.6 tracks real gas price movements for households and business customers since 1991. There is considerable disparity between the movement of real retail gas prices for households and businesses. The real price of gas for businesses has fallen 13 per cent since 1991, while the real gas price for households has increased by 18 per cent (see figure 11.7). In part, the disparity may reflect the rebalancing of retail prices to remove cross-subsidies from business to household consumers.

It is possible to estimate retail price outcomes for households by using CPI data to extrapolate from the historic AGA price data. Figure 11.8 applies this method to estimate real gas prices for households in the major capital cities since July 1996. Real household gas prices have risen since 1996 in all states except Victoria, but the pattern and rate of adjustment has varied. Customers in New South Wales and South Australia have experienced moderate real price increases from 2000–01 to 2007–08 of 24 per cent and 22 per cent, respectively, while real prices in Western Australia, Victoria and the ACT have remained relatively stable. Prices in Queensland were relatively stable from 2000–01 to 2004–05 but have since risen sharply.

ACIL Tasman has developed estimates of gas retail prices in mainland capital cities (published in the lead essay of this report; see figure E.2). The data indicate that gas retail prices range from around $15.50 per gigajoule in Melbourne to almost $28 per gigajoule in Brisbane.

Caution should be exercised when making price comparisons. Price variation between the cities (and between individual customers) reflects a variety of factors, including variations in the wholesale price of gas and the distances over which gas must be transported, and differences in regulatory arrangements. Consumption patterns and industry scale also play a role. For example:

- Victoria has a relatively large residential consumer base with consumers located close to the gas fields.
- Western Australia traditionally has relatively low wholesale gas prices but high transport costs as most residential consumers are located a long distance from gas basins. Volumes are also relatively low.
- Queensland prices reflect a small residential customer base and low rates of residential consumption because of that state's warm climate.

11.4.3 Update: retail price trends in 2007–08

Several jurisdictions have experienced rising gas wholesale and transportation costs in 2007 and 2008. These developments have raised concerns about possible effects on retailer profitability and retail prices.

Several of the jurisdictions that continue to regulate retail gas prices have taken measures to allow pass-through of rising costs into retail prices. Table 11.8 compares recent movements in regulated tariffs in Victoria, New South Wales, South Australia and Western Australia and the mechanisms to allow further tariff revision. The decisions relate to the supply of gas by host retailers to customers on default arrangements. Different approaches between jurisdictions reflect a range of factors and should be interpreted with care. In particular, there are differences in the operating environments of retail businesses.

19 The producer price index series tracks input costs for manufacturers.

Figure 11.6

Retail gas price index (inflation adjusted)—Australian capital cities, June 1991–March 2008

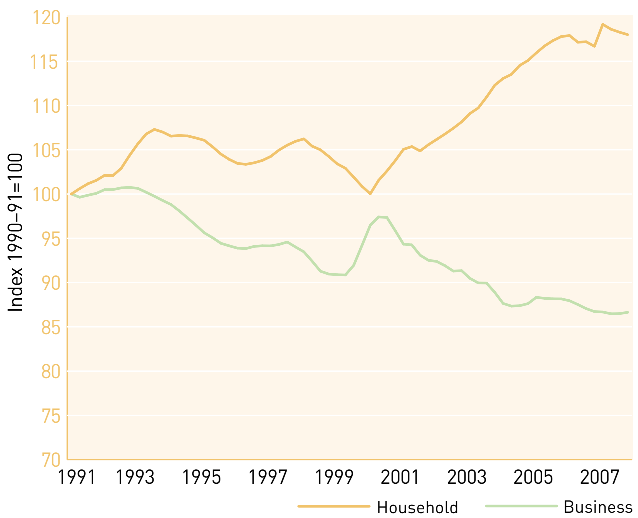
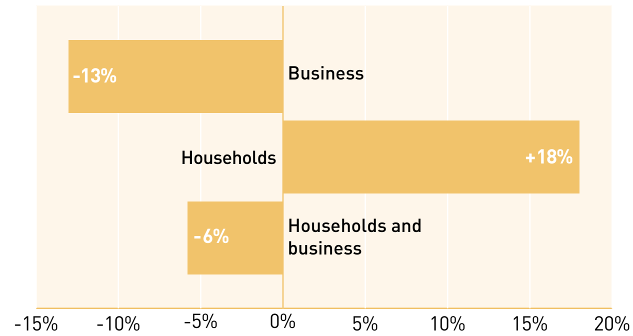


Figure 11.7

Change in the real price of gas—Australia, June 1991–March 2008

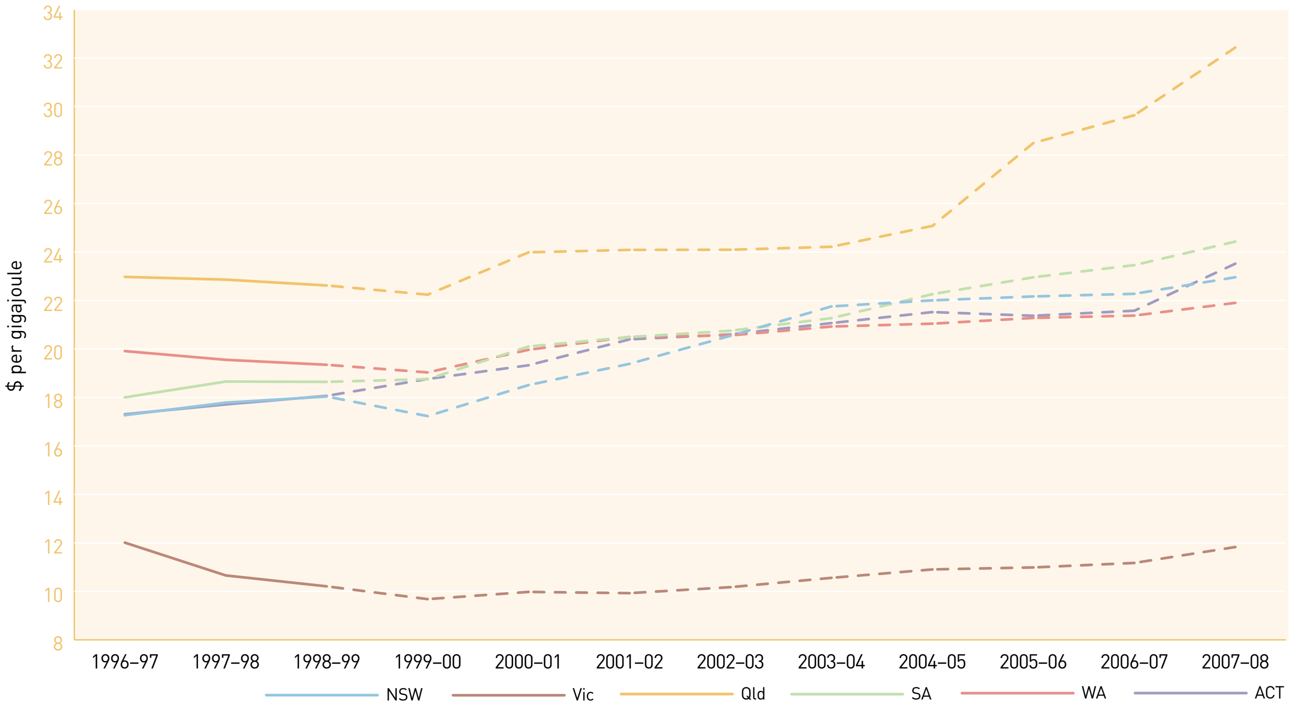


Note: The households index is based on capital city consumer price indexes for 'gas and other household fuels' deflated by the capital city consumer price index (CPI) series for all groups. The business index is based on the producer price index for gas supply in 'Materials used in Manufacturing Industries' deflated by the CPI series for all groups. The household index was affected by the introduction of the GST on 1 July 2000, which increased prices paid by households for gas services.

Sources for figures 11.6 and 11.7: ABS cat. no. 6401.0 and 6427.0.

Figure 11.8

Real retail gas prices—state and territory, July 1996–June 2008



Note: The dashed lines are estimates based on inflating 1998–99 AGA data by the CPI series for gas and other household fuels for the capital city in that state.

Sources: AGA, *Gas statistics Australia*, Canberra, August 2000, p. 73; ABS, *Consumer price index, Australia*, March quarter 2008, Canberra, cat. no. 6401.0.

Table 11.8 **Recent changes in regulated gas retail prices**

JURISDICTION	CURRENT PERIOD	RELEVANT RETAILERS	INCREASE IN REGULATED TARIFF	PASS THROUGH MECHANISM FOR WHOLESALE ENERGY COSTS
Victoria	1 January 2008–31 December 2008	TRUenergy Origin Energy AGL Energy	CPI + 3.1% CPI + 5.3% CPI + 5.4%	Annual price determination. No further adjustment permitted.
New South Wales	1 July 2007–30 June 2010	Origin Energy ActewAGL Retail AGL Energy Country Energy	CPI annually in all areas except the Murray Valley district (Origin), which increases by CPI + 2% annually	Retailers can apply to IPART in special circumstances to vary prices outside the limit. In 2008, IPART made a determination under these provisions to increase tariffs for Country Energy (by 12.2%), ActewAGL Retail (by 5.8–6.1%) and AGL Energy (by 5.24%).[1]
South Australia	1 July 2008–30 June 2011	Origin Energy	2008–09: 8.25% 2009–10 to 2010–11: CPI + 1% annually	Increased costs incurred from prescribed events can be recovered through tariff increases and the determination may be reopened.
Western Australia	1 July 2008–30 June 2009	Alinta	5.4 to 16.5%	Government decision to be implemented through regulations.

CPI, Consumer Price Index; IPART, Independent Pricing and Regulatory Tribunal.

Note:

1. Estimated increase for a typical retail customer in each of the Country Energy, ActewAGL Retail and AGL Energy supply areas.

Sources: Victoria: Department of Primary Industries, *Victorian energy prices factsheet,* p. 2; New South Wales: IPART, *Regulated gas retail tariffs and charges for small customers 2007–10: Gas Final report and voluntary transitional pricing arrangements June 2007,* p. 2; South Australia: ESCOSA, *2008 Gas standing contract price path inquiry: Final inquiry report and final price determination*, June 2008; Western Australia: *Energy Coordination (Gas Tariffs) Regulations 2000;* Office of Energy, *Gas tariffs review—Interim Report*, June 2008.

In 2008, the New South Wales regulator (IPART) approved special retail price increases of between 5.24 and 12.2 per cent[20] for the host retailers AGL Energy, ActewAGL Retail and Country Energy because of rising wholesale gas and transmission costs:

> AGL Energy and ActewAGL Retail were unable to secure sufficient transmission on the Eastern Gas Pipeline for gas required for peak winter usage and incurred additional costs in sourcing gas from the Cooper Basin via the Moomba to Sydney Pipeline. There were also significant changes to the contractual arrangements for transport of gas on the Moomba to Sydney Pipeline.

> Following compression issues in the Victorian transmission system during winter 2007, Country Energy incurred additional costs in securing alternative gas supply arrangements.

In Western Australia, wholesale gas prices rose sharply in 2007 to levels of up to three times those experienced earlier in the decade. The Office of Energy expressed concern that these increases could act as a barrier to entry in the gas retail market and could affect retail margins in the future—particularly for new entrant retailers needing to secure wholesale gas supplies.[21] In 2008, the Office of Energy reviewed the level and structure of gas tariffs and in June 2008 made an interim recommendation to increase regulated tariffs by between 5.4 per cent and 16.5 per cent (depending on the customers' geographic location and the level of their gas consumption).[22] The Minister for Energy confirmed that the Western Australian Government will accept this interim recommendation.[23]

The South Australian regulator (ESCOSA) has indicated that an increase in the regulated tariff of 8.25 per cent in 2008–09 largely reflects an increase in wholesale gas supply costs and an increase in the retail margin.[24]

20 Estimated increase for a typical retail customer.

21 Office of Energy, *Gas Tariffs Regulations review report*, October 2007, pp. 9, 15–17, 20.

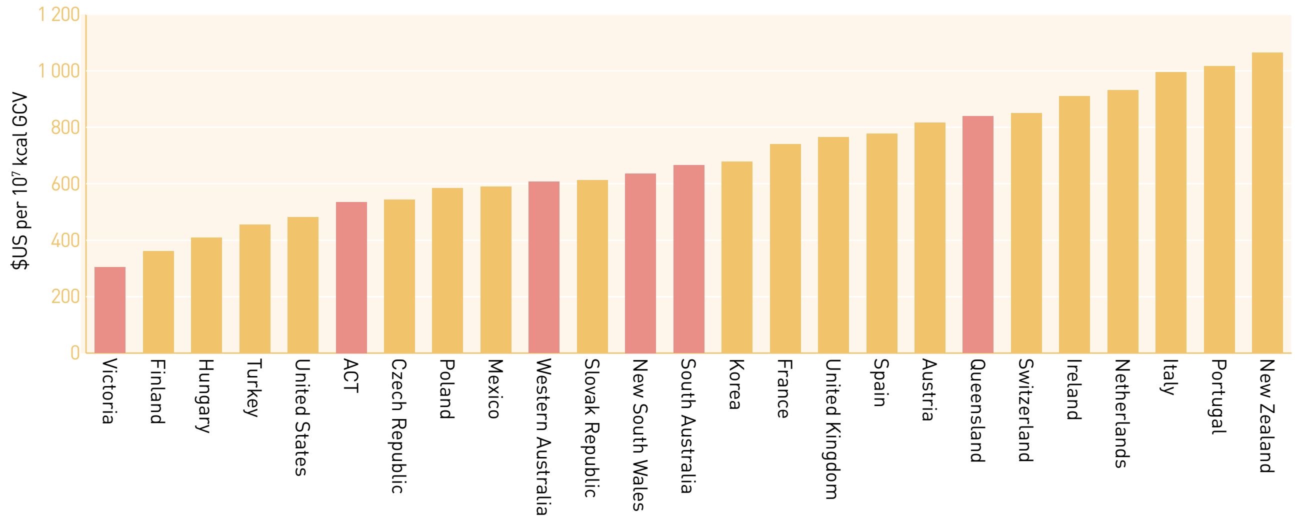
22 Office of Energy, *Gas tariffs review—Interim report*, June 2008.

23 Minister for Energy (WA) (Hon. Francis Logan), *Review of gas tariff cap*, media statement, 20 June 2008.

24 ESCOSA, *2008 Gas standing contract price path inquiry: Final inquiry report and final price determination*, June 2008.

Figure 11.9

International gas prices for households, 2006



kcal, kilocalorie; GCV, gross calorific value.

Notes:

1. Latest data available December 2006.
2. Price data for Australia is based on AER estimates benchmarked against the US average. The data for each jurisdiction is for 2006 and is estimated by inflating 2000 AGA data by the capital city consumer price index series for gas and other household fuels.

Sources: AGA, *Gas statistics Australia 2000*, Canberra, August 2000, p. 118; ABS, *Consumer price index, Australia*, March quarter 2008, Canberra, cat. no. 6401.0; IEA, *Natural gas information*, table 20, Natural gas price for households in $US, Q4 2006, published 2007; ATO, *Foreign exchange rates: End of financial year rates*, US rate for 31 December 2006; Energy Administration Information, *Official energy statistics from the US Government*, Natural gas prices from 2006.

Queensland does not regulate retail prices but has recently experienced significant retail price increases (see figure 11.8). In 2008, the Queensland Minister for Mines and Energy directed the Queensland regulator (QCA) to review small customer prices and competition in the gas retail market to determine whether additional measures are required to encourage competitive outcomes for customers, existing retailers and new entrants.[25] The QCA released an issues paper for the review in May 2008.[26]

11.4.4 International price comparisons

Figure 11.9 compares estimated residential gas prices in six Australian states and territories with selected Organisation for Economic Cooperation and Development (OECD) countries. The data indicate that Australian gas retail prices are generally lower than in many OECD countries. For example, retail prices in most Australian states are lower than in New Zealand, Italy, the United Kingdom, France and Korea. However, Australian retail prices are generally higher than prices in the United States. Only Victoria—with among the world's lowest gas retail prices—has lower prices than the United States.

11.5 Quality of retail services

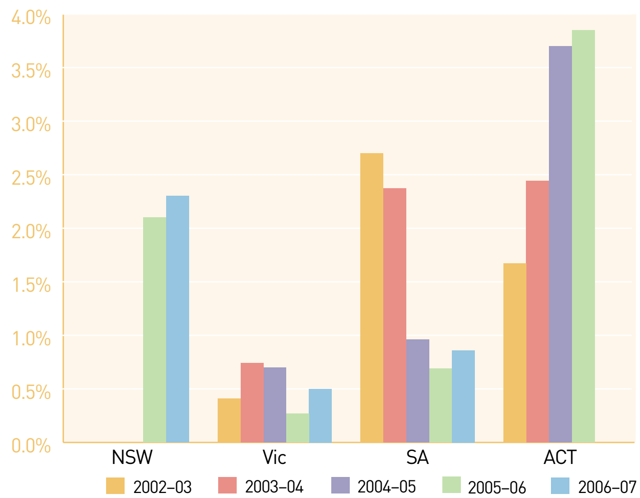
Competition provides incentives for retailers to improve performance and quality of service as a means of maintaining or increasing market share. In addition, governments have established regulations and codes on minimum terms and conditions, information disclosure and complaints handling requirements that retailers must meet when supplying gas to small retail customers. As discussed in section 6.5, jurisdictional regulators monitor and report on quality of service in the retail sector to enhance transparency and accountability.

25 Minister for Mines and Energy (Qld) (Hon. Geoff Wilson), *Minister directs review of gas market pricing*, media statement, 2 May 2008.

26 QCA, *Review of small customer gas pricing and competition in Queensland—Issues Paper*, May 2008.

Figure 11.10

Gas residential disconnections as a percentage of the customer base



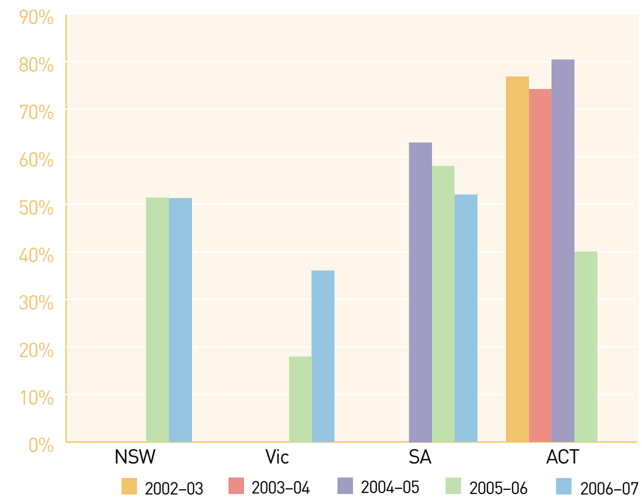
Notes:

1. ACT figures include residential and non-residential customers but exclude disconnections by EnergyAustralia.
2. New South Wales data is only available from 2005–06. ACT data is only available to 2005–06.

Source: See figure 11.13.

Figure 11.11

Residential gas customers reconnected within seven days as a percentage of customers disconnected



Notes:

1. Victorian data for 2005–06 only includes six months of data from January–June 2006.
2. New South Wales and Victorian data is only available from 2005–06. South Australian data is only available from 2004–04. ACT data is only available to 2005–06.

Source: See figure 11.13.

Most jurisdictions also have an ombudsman who investigates and reports on complaints.

In May 2007, the Utility Regulators Forum (URF) recommended an extension of national reporting arrangements for electricity retail businesses to include the gas retail sector from 2007–08.[27] The URF reporting criteria address:

> customer affordability and access to services
> quality of customer services.

New South Wales, Victoria, South Australia and the ACT have reported performance against the URF indicators but each jurisdiction applies different methodologies and assumptions. The validity of any national performance comparisons may be limited by differences in approach between the jurisdictions.

11.5.1 Affordability and access indicators

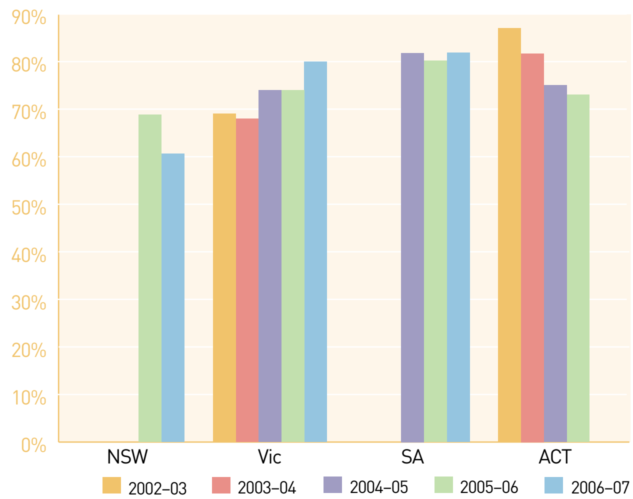
The rate of residential customer disconnections for failure to meet bill payments (see figure 11.10) and the rate of disconnected customers reconnected within seven days (see figure 11.11) are key affordability and access indicators.

In 2006–07, the rate of residential customer disconnections rose from the previous year in New South Wales, Victoria and South Australia. Disconnection rates in Victoria and South Australia remained below 1 per cent, but exceeded 2 per cent in New South Wales. The ACT has recorded rising disconnection rates since 2002–03.

27 Utility Regulator Forum, *National energy retail performance indicators*, Final paper, May 2007, p. ii.

Figure 11.12

Percentage of gas retail customer calls answered within 30 seconds



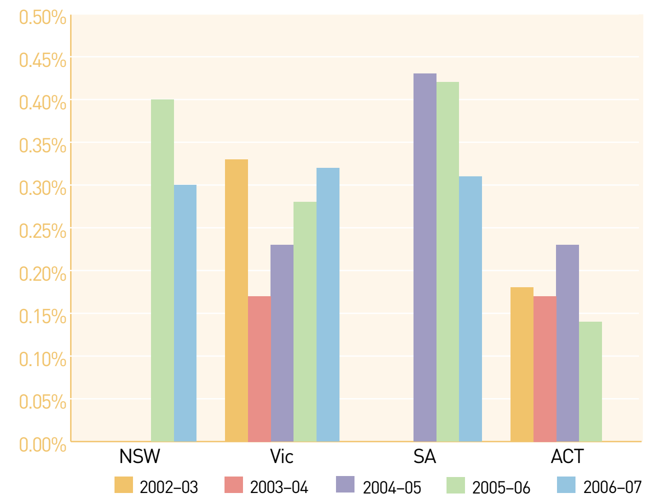
Notes:

1. South Australian statistics include data for gas and electricity.
2. New South Wales data is only available from 2005–06. South Australian data is only available from 2004–05. ACT data is only available to 2005–06.

Source: See figure 11.13.

Figure 11.13

Retail gas customer complaints as a percentage of total customers



Note: New South Wales data is only available from 2005–06. South Australian data is only available from 2004–05. ACT data is only available to 2005–06.

Sources for figures 11.10, 11.11, 11.12 and 11.13: New South Wales: IPART, *Gas retail businesses' performance against customer service indicators for the period of 1 July 2005 – 30 June 2007*, 2008. Victoria: ESC, *Energy retail businesses comparative performance report 2006 – 07*, December 2007; South Australia: ESCOSA, *2006 – 07 Annual performance report: Performance of South Australian energy retail market*, November 2007; ACT: ICRC, *Licensed electricity, gas and water and sewerage utilities performance report*, various years.

A number of factors may have contributed to these outcomes. For example, the ESC noted that 2005–06 rates were very low in Victoria following the introduction of legislation to compensate customers for wrongful disconnection. The ESC observed that the increase in rates since 2005–06 may indicate that rates are returning to average historical levels.[28]

The rate at which disconnected customers were reconnected in 2006–07 (figure 11.11) fell slightly from the previous year in South Australia but improved sharply in Victoria to around 36 per cent. The rate was around 50 per cent in New South Wales and South Australia.

11.5.2 Customer service indicators

Customer service measures provide an indication of customer satisfaction with the quality of retailer service. Indicators include:

- the percentage of customer calls answered within 30 seconds (see figure 11.12)
- retail customer complaints as a percentage of total customers (see figure 11.13).

Call centre performance varied across the jurisdictions in 2006–07 (figure 11.12). In Victoria and South Australia, around 80 per cent of customer calls were answered within thirty seconds. New South Wales recorded a lower rate of about 60 per cent.

28 ESC, *Energy retail businesses comparative performance report 2006–07*, December 2007, p. 39.

The rate of gas complaints by residential customers was around 0.3 per cent of the customer base in New South Wales, Victoria and South Australia in 2006–07. The rate has increased in Victoria since 2003–04, but fallen in New South Wales since 2005–06 and South Australia since 2004–05. The ACT tends to have a lower complaints rate than the other jurisdictions shown in figure 11.13. The ESC noted that the increase in the number of Victorian complaints in 2006–07 was mainly associated with issues other than affordability.[29]

As noted in section 6.4.2, customers have a range of options to redress customer service issues: customers can raise complaints directly with their retailer, refer complaints to their state energy ombudsman or transfer away from a business providing poor service.

11.5.3 Consumer protection

Governments regulate aspects of the energy retail market to protect consumers' rights and ensure they have access to sufficient information to make informed decisions. Victoria, New South Wales, South Australia and Western Australia require designated host retailers to provide gas services under a standard contract to nominated customers. Standard contracts cover minimum service conditions relating to billing; procedures for connections and disconnections; information disclosure; and complaints handling. During the transition to effective competition, default contracts also include regulated retail tariffs (see section 11.4.1). While prices in Queensland are not regulated, there is still a requirement for host retailers to offer small customers a standard contract. This contract must be published on the retailers' website and notified to the Queensland regulator (QCA).

Some jurisdictions have established industry codes that apply to all retail gas services, including those sold under market contracts. The codes govern market conduct and establish minimum terms and conditions under which a retailer can sell gas to small retail customers.

The codes may:

> constrain how retailers may contact potential customers
> require precontract disclosure of information, including commissions for market contracts
> provide for cooling-off periods
> provide rules for the conduct of door-to-door sales, telemarketing and direct marketing.

Most jurisdictions also have an energy ombudsman or alternative dispute resolution body to whom consumers can refer a complaint they were unable to resolve directly with the retailer. In addition to general consumer protection measures, jurisdictions have introduced supplier of last resort arrangements to ensure customers can be transferred from a failed or failing retailer to another. Section 6.5.3 provides further background on consumer protection arrangements for energy retail customers.

11.6 Future regulatory arrangements

State and territory governments are currently responsible for the regulation of retail energy markets. Governments agreed in the Australian Energy Market Agreement 2004 (amended 2006) to transfer non-price regulatory functions to the national framework.[30] These functions include:

> the obligation on retailers to supply customers at a default tariff with minimum terms and conditions
> arrangements to ensure customer supply continuity and wholesale market financial integrity in the event of a retailer failure
> minimum contract terms and conditions applying to small customer market contracts
> small customer marketing conduct obligations
> retailer general business authorisations (where necessary for matters other than technical capability and safety).

This framework will be administered by the AEMC and AER. Further information on the transfer of regulatory arrangements is set out in section 6.7 of this report.

29 ESC, *Energy retail businesses comparative performance report 2006–07*, December 2007, p. 59.
30 This commitment did not cover the Northern Territory or Western Australia.

PART FOUR
APPENDIXES

A ENERGY MARKET REFORM

The process of energy market reform has been steadily unfolding since the early 1990s. In 2004, the Australian, state and territory governments set the agenda for a transition to national energy regulation in the Australian Energy Market Agreement. The most recent wave of reform is underpinned by revisions to that agreement in 2006. The revisions include streamlined regulatory, planning, governance and institutional arrangements for the National Energy Market (NEM).

Reform activity since 2006 has focused on a number of key areas, including:

> transition to a national energy framework
> effect of climate change policies on the energy sector
> electricity market reform, covering the wholesale market and networks
> development of an open and transparent gas wholesale sector
> removal of retail price regulation.

A.1 National institutional framework

At the national level, two intergovernmental bodies determine the direction of Australia's energy policy—the Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE).

COAG is the peak intergovernmental forum in Australia. The council comprises the Prime Minister, state premiers, territory chief ministers and the president of the Australian Local Government Association. The role of COAG is to initiate, develop and monitor the implementation of policy reforms that are of national significance and that require cooperative action by Australian governments. This includes energy market reform.

The MCE comprises Australian, state and territory energy ministers. Ministers from New Zealand and Papua New Guinea have observer status. The MCE's role is to initiate and develop energy policy reforms for consideration by COAG. It also monitors and oversees implementation of energy policy reforms agreed by COAG.

Special-purpose bodies have been created to develop and implement specific reform packages for the energy sector:

- In 2006, COAG established an Energy Reform Implementation Group (ERIG) to report on measures that may be necessary to achieve a fully national electricity transmission grid. ERIG also addressed industry structure and financial market issues that may affect the ongoing efficiency and competitiveness of the energy sector.
- The MCE has established:
  - the Retail Policy Working Group to oversee the transfer of energy distribution (non-economic) and retail regulation functions to the national legislative framework
  - an industry-led Gas Market Leaders Group to produce a market development plan for the gas wholesale sector.

There are several other key agencies in the national energy framework:

- The Australian Energy Regulator (AER), which is the national energy regulator.
- The Australian Energy Market Commission (AEMC), which is responsible for rule making and market development in the NEM. The AEMC also undertakes reviews of the energy market framework and provides policy advice to the MCE.
- Market operators, such as the National Electricity Market Management Company (NEMMCO), which is responsible for the day-to-day operation and administration of the power system and electricity wholesale spot market in the NEM.

Although the AER, AEMC and market operators are not policy bodies, each participates in energy market reform processes. Figure A.1 outlines the roles and responsibilities of key bodies involved in national energy policy, regulation and market operation.

A.2 Transition to a national energy framework

Transfer of regulatory functions

The AER and AEMC were established under the Australian Energy Market Agreement in 2004. However, the transfer of functions from other Australian, state and territory regulators is still in progress. Table A.1 sets out the institutional arrangements that will apply once the transfer of functions is complete.

Electricity networks

The AER has been responsible for the regulation of electricity transmission networks since 1 July 2005. This role was previously undertaken by the Australian Competition and Consumer Commission (ACCC).

On 1 January 2008, revisions to the National Electricity Law and Rules refined the regulatory process for electricity networks. The new framework also established the AER as the economic regulator of electricity distribution networks in the NEM jurisdictions.[1]

In 2008, the AER released guidelines to assist electricity distribution businesses and their customers to understand the AER's approach to distribution network regulation. It also released details of the incentive schemes that will apply to electricity distribution businesses.

Gas networks

The National Gas Law and Rules, which took effect on 1 July 2008, provide the overarching regulatory framework for the gas transmission and distribution sectors. These instruments replace the Gas Pipelines Access Law and the National Gas Code (Gas Code), which had provided the regulatory framework since 1997.

1. The regulation of distribution networks in Western Australia and the Northern Territory remain under state and territory jurisdiction.

Figure A.1

National energy market—institutional framework

POLICY

Council of Australian Governments

COAG is the peak intergovernmental forum in Australia. The council comprises the Prime Minister, state premiers, territory chief ministers and the president of the Australian Local Government Association. The role of COAG is to initiate, develop and monitor the implementation of policy reforms that are of national significance and that require cooperative action by Australian governments, including National Competition Policy and related energy market reforms.

Ministerial Council on Energy

The MCE comprises Australian, state and territory energy ministers. Ministers from New Zealand and Papua New Guinea have observer status.

The MCE is the sole governance body for Australian energy market policy. Its role is to initiate and develop energy policy reforms for consideration by COAG. It also monitors and oversees implementation of energy policy reforms agreed by COAG.

Energy Reform Implementation Group

ERIG was created by COAG in 2006 to review certain elements of the operation of Australia's energy sector. In particular, ERIG provided advice on achieving a fully national transmission grid, structural issues affecting the competitiveness and efficiency of the electricity sector, and ensuring there are transparent and effective financial markets to support energy markets.

Retail Policy Working Group

The Retail Policy Working Group was established by the MCE in 2006 to develop recommendations on the energy distribution and retail regulation functions to be transferred to national regulation in accordance with the Australian Energy Market Agreement.

Gas Market Leaders Group

The Gas Market Leaders Group is an industry-led body established by the MCE in 2005 to develop and implement a gas market development plan to accelerate the development of a reliable, competitive and secure natural gas market.

RULES DEVELOPMENT

Australian Energy Market Commission

The AEMC has responsibility for the rule-making process under the National Electricity Law and National Gas Law, and making determinations on proposed rules. The AEMC also undertakes reviews on its own initiative or as directed by the MCE, and provides policy advice to the MCE on electricity and gas market issues.

REGULATOR AND MARKET OPERATORS

Australian Energy Regulator

Electricity: The AER enforces the National Electricity Law and Rules, monitors the wholesale electricity market and regulates electricity transmission and distribution networks in the NEM.

Gas: The AER enforces the National Gas Law and Rules, and regulates covered gas transmission and distribution pipelines in all states and territories (except Western Australia).

National Electricity Market Management Company

NEMMCO administers and operates the wholesale NEM and is responsible for the registration of participants, the scheduling and dispatch of generators, the management of transmission constraints and the financial settlement of trades in the market. In addition, NEMMCO is required to publish each year electricity demand and energy projections for the next 10 years (SOO), including a statement on the national transmission flow paths (ANTS).

VENCorp

VENCorp manages and plans Victoria's gas and electricity transmission networks and operates the gas wholesale spot market. VENCorp also operates the national gas market bulletin board pending the creation of the Australian Energy Market Operator.

Australian Energy Market Operator
(beginning 1 July 2009)

AEMO is planned as a single, industry-funded national energy market operator for both electricity and gas.

AEMO will merge the roles of the current national electricity market operator (NEMMCO) with the gas market operators in New South Wales, the Australian Capital Territory, Queensland, Victoria and South Australia.

AEMC, Australian Energy Market Commission; AEMO, Australian Energy Market Operator; AER, Australian Energy Regulator; ANTS, Annual National Transmission Statement; COAG, Council of Australia Governments; ERIG, Energy Reform Implementation Group; MCE, Ministerial Council on Energy; NEM, National Energy Market; NEMMCO, National Energy Market Management Company; SOO, Statement of Opportunities.

Table A.1 **Energy regulation after implementation of national framework**

<table>
<tr><th></th><th>Qld</th><th>NSW</th><th>ACT</th><th>Vic</th><th>SA</th><th>Tas</th><th>NT</th><th>WA</th></tr>
<tr><td>Gas transmission</td><td colspan="7">Australian Energy Regulator</td><td rowspan="7">Economic Regulation Authority</td></tr>
<tr><td>Gas distribution</td><td colspan="7">Australian Energy Regulator</td></tr>
<tr><td>Electricity wholesale</td><td colspan="6">Australian Energy Regulator</td><td rowspan="5">Utilities Commission</td></tr>
<tr><td>Electricity transmission</td><td colspan="6">Australian Energy Regulator</td></tr>
<tr><td>Electricity distribution</td><td colspan="6">Australian Energy Regulator</td></tr>
<tr><td>Retail (non-price)</td><td colspan="6">Australian Energy Regulator</td></tr>
<tr><td>Retail (pricing)</td><td>QCA</td><td>IPART</td><td>ICRC</td><td>ESC</td><td>ESCOSA</td><td>OTTER and GPOC</td></tr>
<tr><td></td><td colspan="8"></td></tr>
<tr><td>Rule changes</td><td colspan="8">Australian Energy Market Commission</td></tr>
<tr><td></td><td colspan="8"></td></tr>
<tr><td>Competition regulation</td><td colspan="8">Australian Competition and Consumer Commission</td></tr>
</table>

ESC, Victorian Essential Services Commission; ESCOSA, Essential Services Commission of South Australia; GPOC, Government Prices Oversight Commission; ICRC, Independent Competition and Regulatory Commission; IPART, Independent Pricing and Regulatory Tribunal; QCA, Queensland Competition Authority; OTTER, Office of the Tasmanian Energy Regulator.

The new legislation transferred the regulation of covered distribution networks outside Western Australia from state and territory regulators to the AER. It also transferred the regulation of covered transmission pipelines outside Western Australia from the ACCC to the AER. As of July 2008, the AER regulated eight covered transmission pipelines and 11 covered distribution networks.[2]

The AER is working closely with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition to the national framework. In September 2008, the AER released guidelines to assist gas network businesses and their customers to understand the AER's approach to the regulation of gas distribution businesses.

Retail

The Retail Policy Working Group has been developing recommendations to the MCE Standing Committee of Officials on retail functions for transfer to national regulation.

The areas under review include:[3]

- retailer obligations for supply to small customers
- customer market contracts
- marketing
- business authorisations
- ring-fencing
- retailer failure arrangements (retailer of last resort).

The Standing Committee of Officials published its final recommendations on the transfer of retail functions to the AER in June 2008.[4] Under the current proposals, the AER will:

- be a gatekeeper for authorisation and exemptions
- publish standing tariffs
- undertake monitoring and enforcement in the areas of:
  - customer financial hardship
  - compliance with terms of regulated contracts and rules
  - marketing conduct
- issue guidance to market participants on the application of the new framework and the AER's enforcement strategy.

2. There are three covered transmission pipelines and one covered distribution network in Western Australia. These assets are regulated by the Economic Regulation Authority.
3. MCE, *Communiqué*, 19 May 2006.
4. MCE Standing Committee of Officials, *A National Framework for Regulating Electricity and Gas (Energy) Distribution and Retail Services to Customers*, 2008.

It is expected that the legislative package will be introduced into the South Australian Parliament by September 2009, after which the states and territories will transition to the national framework.

Establishing the Australian Energy Market Operator

In April 2007, COAG agreed to establish an Australian Energy Market Operator (AEMO) as a single, industry-funded national energy market operator for both electricity and gas.[5] The AEMO is scheduled to begin by 1 July 2009.[6]

The AEMO will merge the roles of the current national electricity market operator (NEMMCO) with gas market operators in New South Wales, the Australian Capital Territory, Queensland, Victoria and South Australia.

Impact of climate change policies on the energy sector

The Australian government is committed to reducing carbon emissions by 60 per cent of 2000 levels by 2050. Policy measures that have been announced to assist in the achievement of this target include a Carbon Pollution Reduction Scheme, involving the trading of emissions rights,[7] and a 20 per cent mandatory renewable energy target for Australia, to be reached by 2020.[8]

Recognising the potential for significant impacts on the energy sector as a result of these climate change policies, the MCE requested that the AEMC review the energy market frameworks. The review is to consider both the electricity and gas markets in all states and territories. The AEMC is to identify potential market risks arising from climate change policies and present options to refine the energy market frameworks to mitigate those risks. The review is scheduled for completion by September 2009.[9]

One likely outcome of the introduction of climate change policies is an increasing reliance on intermittent generation (such as wind farms), which can raise reliability and security issues for the power system.[10] To manage these issues, NEMMCO submitted a Rule change proposal to the AEMC that would require significant intermittent generators to participate in the central dispatch process and to limit their output at times when that output would otherwise violate secure network limits.

The AEMC published a Rule determination on 1 May 2008 that requires new intermittent generators to register under the new classification of *semi-scheduled generator*. These generators will be required to participate in the central dispatch process, including submitting offers and limiting their output when requested by NEMMCO. This Rule will take effect on 31 March 2009.[11]

A.3 National Electricity Market reform

National transmission planner and regulatory investment test

In 2007, ERIG reported that there was a need to strengthen transmission planning arrangements in the NEM. In particular, it found that current approaches focused on priorities within individual jurisdictions, rather than on the national grid as a whole. It recommended that a national planning body be established and housed within a reformed market operator body.[12] In addition, it recommended that the

5. COAG, *Communiqué*, 13 April 2007.
6. MCE, *Communiqué*, 13 December 2007.
7. Australian Government Department of Climate Change, *Carbon Pollution Reduction Scheme Green Paper*, July 2008.
8. COAG Working Group on Climate Change and Water, *Design options for the expanded national renewable energy target scheme*, July 2008.
9. MCE, *Terms of reference—AEMC review of energy market framework in light of climate change policies*, 2008.
10. See discussion in Executive overview.
11. AEMC, *Rule determination—National Electricity Amendment (central dispatch and integration of wind and other intermittent generation) Rule 2008*, May 2008.
12. ERIG, *Energy Reform—the way forward for Australia—A report to the Council of Australian Governments by the Energy Reform Implementation Group*, January 2007.

regulatory test for transmission investment be reformed to enable consideration of reliability and market benefits within one process.[13]

COAG adopted the ERIG recommendations in April 2007.[14] The MCE subsequently directed the AEMC to develop a detailed implementation plan for a national transmission planning function, and to advise on a project assessment and consultation process to replace the current regulatory test.

The AEMC released its final report in June 2008, which recommended the development of a national transmission planner within the AEMO.[15] The planning body would publish an annual national transmission network development plan outlining the efficient development of the power system. The plan would provide a long-term strategic outlook (minimum 20 years), focusing on national transmission flow paths.

The development plan would not replace local planning and would not be binding on transmission businesses or the AER. Rather, the plan would complement shorter-term investment planning by transmission businesses.

With respect to the regulatory test, the AEMC recommended the removal of the current distinction between reliability-driven projects and projects driven by the delivery of market benefits. All projects would be assessed through a single consultation and assessment framework, which aims to identify investments that maximise net economic benefits and, where applicable, meet reliability standards. The revised assessment process would be more comprehensive than the current test, and would apply to a wider range of investment projects.

The AEMC also released a report by Frontier Economics, which assesses various models of interregional transmission charging.[16] Under current arrangements, customers in an importing region of the NEM do not pay a charge to transmission network providers in the exporting region to cover the costs incurred to serve their load. The AEMC has recommended that a more detailed review be carried out on the appropriate mechanism for implementing a formal interregional transmission charging arrangement.

Jurisdictional reliability standards

ERIG reported in 2007 that the current transmission reliability standards need greater clarity and transparency. In particular, it formed a view that clause 5.1 of the National Electricity Rules and the majority of jurisdictional reliability obligations require significant interpretation.[17]

In April 2007, COAG accepted ERIG's recommendations for a nationally consistent framework for setting transmission reliability standards.[18] The AEMC Reliability Panel is undertaking a review of jurisdictional transmission reliability standards. An interim report in August 2008 set out the panel's preferred option for a nationally consistent framework.[19] Key features include:

> economically derived and deterministically expressed standards set on a jurisdictional basis by an independent jurisdictional authority
> the introduction of a national reference standard
> a clear and transparent standard setting process.

13. The regulatory test is an analysis tool used by transmission and distribution businesses in the NEM to assess the efficiency of network investment.
14. COAG, *Communiqué*, 13 April 2007.
15. AEMC, *National transmission planning arrangements—final report to MCE*, 30 June 2008.
16. Frontier Economics, *Advice on the application of AEMC options for an inter-regional charging mechanism in the NEM—A report prepared for the Australian Energy Market Commission*, April 2008.
17. ERIG, *Energy Reform—the way forward for Australia—A report to the Council of Australian Governments by the Energy Reform Implementation Group*, January 2007.
18. COAG, *Communiqué*, 13 April 2007.
19. AEMC Reliability Panel, *Towards a nationally consistent framework for transmission reliability standards review—Interim report*, 5 August 2008.

Congestion management review

Although the reliability of transmission networks in the NEM is consistently high, network congestion sometimes impedes the dispatch of the most cost-efficient generation to satisfy demand. In October 2005, the MCE directed the AEMC to review congestion management issues in the NEM and, in particular, to consider the scope for enhanced market-based solutions to manage trading risks.

The AEMC released the *Final report: congestion management review* in June 2008.[20] It recommended a number of changes to current market arrangements to reduce network congestion and better manage the effects of this problem. The recommendations included:

> formalisation in the National Electricity Rules of NEMMCO's current process for determining which generators to dispatch in the market
> amendment of the National Electricity Rules in respect of settlement residues to reduce uncertainty for holders of settlement residue units—in particular, it was recommended that new arrangements be introduced for the management and funding of negative settlement residues
> publication of a *congestion information resource* by NEMMCO to consolidate and enhance information on network congestion
> clarification and strengthening of the rights of generators that fund transmission augmentations to manage congestion risk—in particular, ensuring that future network users contribute to investment costs where they benefit from them.

In 2008, the AER launched a scheme that provides incentives for network businesses to better manage factors within their control that can lead to transmission congestion—for example, the scheduling of outages.[21]

Abolition of the Snowy region

In late 2006 and early 2007, the AEMC received five Rule change proposals on the ineffective management of network congestion in the NEM. In August 2007, the AEMC found that abolishing the Snowy region of the NEM would improve incentives for generators to bid in a competitive way, improve dispatch efficiency and result in more cost-reflective spot prices. The AEMC also found that this would provide clearer signals for efficient investment and electricity use.[22]

The Snowy region of the NEM was abolished on 1 July 2008. The areas previously covered by the region are now located in the New South Wales and Victoria regions.

Comprehensive Reliability Review

Over the past couple of years some concerns have been raised about the future reliability of electricity supply in the NEM. This led to the AEMC Reliability Panel conducting a review of reliability settings in the NEM, the Comprehensive Reliability Review.

The panel's report, published in 2007, recommended an increase in the wholesale market price cap (VoLL) from \$10 000 to \$12 500, effective from 1 July 2010.[23] It also recommended an increase in the *cumulative price threshold* (which triggers administered wholesale pricing) to \$187 500, or fifteen times the value of VoLL.

The review also recommended that the current reserve trader mechanism be changed to a *Reliability and Emergency Reserve Trader*. The revised mechanism would provide NEMMCO with greater flexibility in sourcing reserve capacity. Changes from the current mechanism include an extended timeframe for contracting with reserve providers and the introduction of multiple rounds of tendering.

20. AEMC, *Final report: Congestion management review*, June 2008.
21. AER, *Final decision—Service target performance incentive scheme version 2*, March 2008.
22. AEMC, *Rule determination—National Electricity Amendment (abolition of Snowy region) Rule*, August 2007.
23. AEMC Reliability Panel, *Final report—Comprehensive reliability review*, 2007.

Another significant recommendation was for a new *energy adequacy assessment projection*. This mechanism would improve market participants' ability to forecast and respond in times where there may be energy constraints that would affect reliability.

Review of demand-side participation in the National Electricity Market

An increasing focus of reform has been to increase the responsiveness of electricity demand to price signals. In particular, the AEMC is reviewing options to better facilitate demand-side participation in the NEM. The review consists of three stages:[24]

- stage 1—investigating demand-side participation issues in the context of the current AEMC work program
- stage 2—reviewing the National Electricity Rules to identify barriers to efficient demand-side participation and to develop proposals to reduce or remove those barriers
- stage 3—identifying any additional barriers to efficient demand-side participation.

The AEMC published a report by NERA[25] on stage 1 and released an issues paper[26] on stage 2 in May 2008. The issues paper focused on:

- the economic regulation of networks
- network planning
- network access and connection arrangements
- wholesale markets and financial contracting
- the use of demand-side participation for reliability purposes.

In August 2008, the AEMC released a report by CRA International on ways in which electricity customers can participate in the wholesale market, elements of the National Electricity Rules that may limit demand-side participation, and options for reform.[27]

Demand management activities aimed at energy customers require *smart meters* to record patterns of energy use. In 2007, COAG agreed to a national implementation strategy for the progressive rollout of smart meters where the benefits outweigh costs.[28] A cost-benefit assessment published in March 2008 found that a national rollout would achieve a net benefit.[29]

A.4 Gas wholesale market reform

In 2005, the MCE established the Gas Market Leaders Group to accelerate the development of a competitive, reliable and secure natural gas market, that promotes efficient investment and provides efficient management of supply interruptions.[30] The MCE has endorsed several of the group's recommendations, including the development of the gas market bulletin board, a short-term trading market in gas and an annual national statement of opportunities on the gas market covering supply–demand conditions.

The bulletin board, which started on 1 July 2008, is a transparent, real-time and independent information source for gas market participants and market observers on the status of natural gas supplies around the country. Industry participants must publish three days ahead information on production and storage capabilities and pipeline capacity, to provide a snapshot for gas users.

24. AEMC, *Statement of approach—review of demand side participation in the National Electricity Market*, March 2008.
25. NERA, *Stage one final report—review of demand side participation in the National Electricity Market*, May 2008.
26. AEMC, *Stage two issues paper—review of demand side participation in the National Electricity Market*, August 2008.
27. CRA International, *Final report—the wholesale market and financial contracting: AEMC review of demand side participation in the NEM*, August 2008.
28. COAG, *Communiqué*, 13 April 2007.
29. NERA, *Cost-Benefit Analysis of Smart Metering and Direct Load Control Overview Report for Consultation*, 29 February 2008, for Smart Meter working Group, Phase 2.
30. MCE, *Energy reform market bulletin no. 55*, 7 December 2005.

The short-term trading market in gas is scheduled to begin by winter 2010. The proposed market will establish a mandatory price-based balancing mechanism at gas hubs in New South Wales and South Australia. Victoria already has a transparent balancing market in place. Structural and operational details of the market are undergoing further development during 2008.

An annual *Gas Statement of Opportunities*—similar to the annual *Statement of Opportunities* currently published for electricity—is intended to provide information to assist gas industry participants in their planning and commercial decisions on infrastructure investment. The Gas Market Leaders Group began work on the design of the publication in 2008.[31]

In 2006, the MCE and Ministerial Council on Mineral and Petroleum Resources created a Joint Working Group on Natural Gas Supply to consider the adequacy of domestic gas supplies and related infrastructure. A particular focus of the review was to look at balancing the exploitation of resources for export with ensuring sufficiency of gas supplies for domestic use. The final report of the Joint Working Group was released in September 2007.[32]

Further details on the reforms to the gas wholesale sector are set out in chapter 8, section 8.7.

A.5 Review of the effectiveness of retail competition

In line with the Australian Energy Market Agreement, all jurisdictions have agreed to remove energy market retail price caps where it can be shown that effective competition exists. The AEMC is reviewing the effectiveness of retail competition in jurisdictions to inform these decisions.

In May 2007, the MCE requested that the AEMC provide advice on the state of energy retail competition in Victoria. The AEMC found that competition is effective in both electricity and gas retail markets.[33] In response to the review, the Victorian Government announced in September 2008 the introduction of new legislation to remove retail price caps. The legislation includes provisions for the Essential Services Commission of Victoria to undertake expanded price monitoring and report publicly on retail prices. Retailers will also be required to publish a range of their offers to assist consumers in comparing energy prices.[34] Other obligations on retailers, including the obligation to supply and the consumer protection framework, will not be affected by the removal of retail price regulation. The Victorian Government will retain a reserve power to reinstate retail price regulation if competition is found to be no longer effective in the future.

In 2008, the AEMC reviewed the South Australian electricity and gas retail markets. The AEMC's first final report, released in September 2008, found that retail competition in both markets was effective.[35]

The next scheduled reviews are for New South Wales (2009) and the ACT (if required; 2010).[36] Further details of the AEMC review process are provided in chapter 6, box 6.1.

31. MCE, *Communiqué*, 13 June 2008.
32. Ministerial Council on Mineral and Petroleum Resources/Ministerial Council on Energy Joint Working Group on Natural Gas Supply, *Final Report*, September 2007.
33. AEMC, *Review of Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria—First Final Report*, December 2007.
34. Premier of Victoria, *Brumby Government Boosts Transparency in Power Pricing*, media release, 11 September 2008.
35. AEMC, *Review of Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia—First Final Report*, September 2007.
36. MCE, *Communiqué*, 25 May 2007.

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