STATE OF THE ENERGY MARKET 2010

AER
AUSTRALIAN
ENERGY
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PREFACE

The Australian Energy Regulator's (AER) fourth *State of the energy market* report provides a high level overview of energy market activity in Australia. The report is intended to meet the needs of a wide audience, including government, industry and the broader community. It supplements the AER's extensive technical and compliance reporting on the energy sector.

The *State of the energy market* consolidates information from various sources into one user friendly publication. The aim is to better inform market participants and assist policy debate on energy market issues.

The 2010 report consists of a market overview, supported by four chapters on the electricity and natural gas sectors. It is more concise than previous editions, and focuses on activity over the past 12–18 months in those jurisdictions and areas in which the AER has regulatory responsibilities. Much of the material excluded from this edition is contextual, and cross-references to the 2009 edition will help readers who require that material.

The *State of the energy market* is an evolving project, and the AER will continue to review its approach. As always, we hope to hear the views of readers. In the meantime, I hope this 2010 edition will provide a valuable resource for market participants, policy makers and the wider community.

Andrew Reeves
Chairman

MARKET OVERVIEW

Getty Images

A feature of energy market reporting in the media in 2010 has been concerns about rising energy charges. While some reporting in this area fails to adequately distinguish between volume and price changes, retail energy charges have risen significantly in most jurisdictions. The increases have been mostly attributed to rising network charges and wholesale energy costs, but retailer costs and climate change policies (including renewable energy targets, incentives for small scale solar generation and energy efficiency schemes) have also contributed.

Recent regulatory decisions have allowed significant increases in capital investment and operating expenditure to enable energy networks to reliably meet greater demand. With network costs accounting for around 50 per cent of a typical electricity bill, rising capital and operating expenditure is flowing through to energy customers.

The continued growth in peak electricity demand, combined with the twin pressures of customer expectations for reliable supply and rising costs of service provision, pose increasingly complex dilemmas for energy customers, network businesses, governments and regulators. This environment presents important responsibilities for ensuring efficient service delivery and customer confidence to participate in the market.

With the transfer of a range of retail regulatory functions to a national framework expected between 2011 and 2013, the Australian Energy Regulator (AER) is consulting with energy customers, consumer advocacy groups, energy retailers, jurisdictional regulators and ombudsmen and government departments to ensure an efficient transition and continuing protections for energy customers.

1 Energy networks

The AER regulates electricity networks and gas pipelines in southern and eastern Australia (and gas pipelines in the Northern Territory). In electricity, this involves the assessment and approval of revenues that network businesses may earn from transporting electricity to customers. The regulatory framework for gas pipelines is similar, but derives prices for reference services set out in access arrangements.

In 2010 the AER completed electricity distribution reviews for the Queensland and South Australian networks (released May 2010) and the Victorian networks (released October 2010). It also approved access arrangements for the Australian Capital Territory (ACT) and New South Wales gas distribution networks (released April and June 2010 respectively).

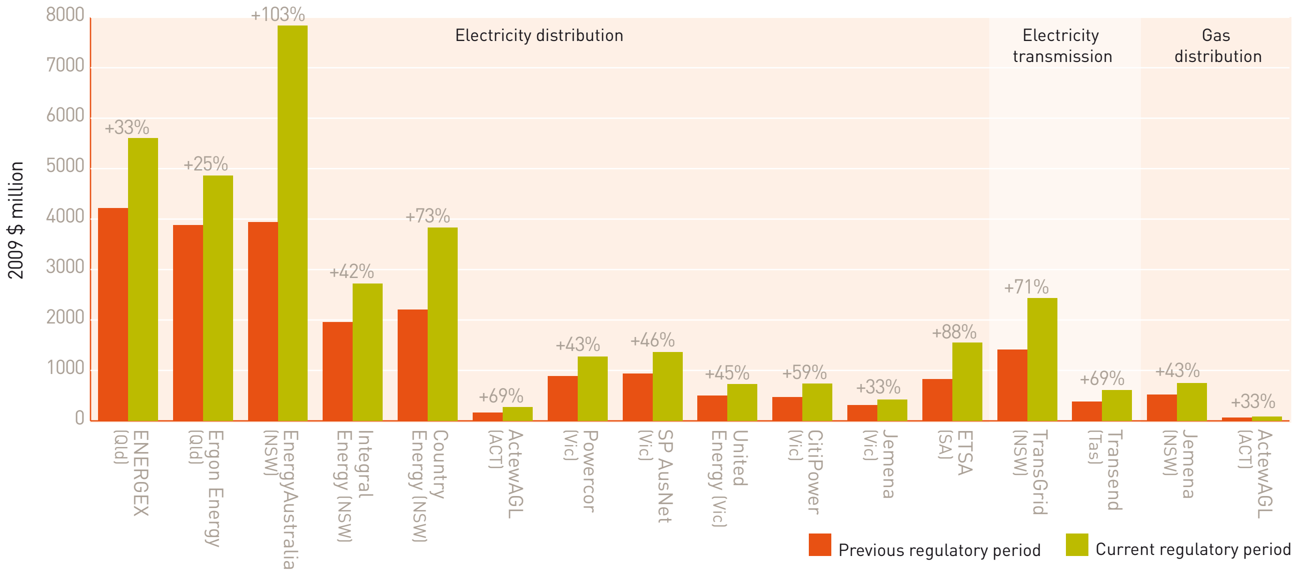
The AER's recent regulatory decisions have allowed significant increases in capital investment in some networks (figure 1). Key drivers of these increases include:

- more rigorous licensing conditions and other obligations for network security, safety and reliability
- load growth and rising peak demand
- new connections
- the need to replace ageing assets, given much of the networks were developed between the 1950s and 1970s.

Other drivers include changes to system operation due to climate change policies and the introduction of smart meters and grids.

While these factors are driving higher levels of investment, each network faces a different blend of challenges—for example, each network has unique issues relating to its age and technology, its load characteristics, the costs of meeting the demand for new connections, and its licensing, reliability and safety requirements. Other issues are common to all network businesses—for example, rising input and finance costs.

Figure 1
Network investment—AER determinations since 2009



Source: AER.

As required by the regulatory regime, the AER accounts for these factors when assessing the needs of each network. Electricity distribution determinations in 2010 reflected that:

- the Queensland networks have pressing capital requirements associated with population growth, new connections and industrial demand, as well as rising demand per customer. The networks are also obliged to improve performance in response to stricter reliability standards
- the South Australian network requires significant investment to meet rising load growth and peak demand driven by the use of air conditioners during summer heatwaves. The network also needs to address reliability risks from ageing assets and new reliability standards for the Adelaide central business district (involving complementary upgrades to transmission and distribution systems). Investment costs in Queensland and South Australia have also been rising as a result of real increases in the cost of labour and materials
- the Victorian distributors operate mostly mature and comparatively reliable networks. While the AER considers past expenditure (in what has been a relatively stable operating environment) provides a good starting point for assessing future needs, it also accounted for the need to replace ageing infrastructure, address Victoria's new bushfire safety standards, and maintain reliability in the face of growing costs and demand. While these considerations led it to approve higher levels of investment, the AER did not accept the full extent of the increases proposed by distribution businesses
- the global financial crisis has significantly increased debt financing costs for all networks. The rate of return on capital in the next regulatory periods has thus increased by more than 100 basis points compared with the rate in previous periods. Recent AER determinations reflected that higher debt costs increased the revenue requirements of distribution businesses by 5–9 per cent from requirements in previous regulatory periods.

The capital drivers for gas distribution networks are broadly similar to those for electricity distribution. The AER's recent determination for the New South Wales gas networks approved higher capital expenditure to meet demand growth and maintain network capacity. The underlying investment drivers included rising connection numbers, the development of renewal and replacement infrastructure to maintain the capacity of ageing networks, and the development of infrastructure to support changes in market operations.

Differences in operating environments can result in significant variations in capital investment requirements. Electricity distribution investment over the current five year regulatory periods is expected to exceed investment in the previous regulatory periods by around 25–33 per cent in Queensland, 42–103 per cent in New South Wales, 33–59 per cent in Victoria, 88 per cent in South Australia and 69 per cent in the ACT (in real terms). Gas distribution investment will increase by around 43 per cent in New South Wales and 33 per cent in the ACT.

Differences in the networks' operating environments also affect operating and maintenance expenditure allowances. In assessing this area, the AER considers relevant cost drivers, including load growth, expected productivity improvements and input costs for labour and materials. The recent Victorian electricity determinations, for example, accounted for an expected increase in regulatory compliance costs for electrical safety, network planning and customer communications, largely stemming from changes associated with the 2009 Victorian bushfires.

With network costs accounting for around 50 per cent of a typical electricity bill, rising capital and operating expenditure are flowing through to energy customers (table 1 and section 3). The retail impacts are greater in networks with substantial capital requirements.

Under the propose–respond model, the AER must accept a regulatory proposal for higher levels of capital and operating expenditure when it represents a reasonable estimate of the efficient costs of a prudent operator. The AER may amend a proposal only to conform with a reasonable estimate. The regulator thus has a substantial evidentiary burden if challenging a proposal.

The AER's decisions are also subject to a merits review by the Australian Competition Tribunal. Since January 2008 network businesses have appealed the determinations on three electricity transmission networks, eight electricity distribution networks and two gas distribution networks (table 2). The decisions on these appeals have increased allowable network revenues by around $2 billion, with substantial flow-on impacts on retail energy charges. Two appeals were continuing in late 2010.

Electricity customers will look to network businesses to make sustained efforts to translate rising investment and operating costs into stable or improving network performance. In light of this, the AER is developing an enhanced national information framework to facilitate its regulatory oversight of network businesses. The framework aims to make the businesses more publicly accountable for the way they spend their regulatory allowances and enhance the transparency of regulated outcomes.

A key performance indicator is network reliability. The average duration of outages per customer in the National Electricity Market (NEM) has generally been 200–250 minutes per year, allowing for regional variations (figure 2). The average duration of outages per customer rose in all mainland jurisdictions in 2008–09. Queensland customers experienced the largest increase, with the average outage duration rising by more than 100 minutes. Annual fluctuations in the data are due largely to climatic variability—for example, tropical storm activity.

Australia' energy markets are operating in an increasingly challenging environment that may impact on network operation and performance. For example, government policy to mitigate climate change may lead to an influx of new low carbon generation plant. The connection framework supporting remote generators—and the transmission network framework more generally—is being reviewed to ensure future network investment is efficient. The issues include how to best coordinate the connection of clusters of new generators (such as wind generators) to the networks.

Table 1 Recent AER decisions—energy networks

SECTOR	LOCATION	ANNOUNCED	PERIOD COVERED (5 YRS TO)	% CHANGE FROM PREVIOUS 5 YEAR PERIOD		ESTIMATED IMPACT ON RETAIL BILL FOR TYPICAL HOUSEHOLD
				CAPEX	OPEX	
Electricity (D)	Vic	October 2010	31 Dec 2015	33–59	8–46	1.8% rise (year 1), then 2.6% per year
Gas (D)	NSW	June 2010	30 Jun 2015	43	8.6	5% rise (year 1), then 2.3% per year
Electricity (D)	SA	May 2010	30 Jun 2015	88	41	6% rise (year 1), then 3.4% per year
Electricity (D)	Qld	May 2010	30 Jun 2015	25–33	19–20	9.2% rise (year 1), then 2.3% per year
Electricity (D)	ACT	April 2009	30 Jun 2014	69	43	4.1% rise (year 1), then 1.3% per year
Electricity (D)	NSW	April 2009	30 Jun 2014	42–103	34–38	9.3–10.4% rise (year 1), then cumulative 16–35% rise (years 2–4)
Electricity (T)	NSW	April 2009	30 Jun 2014	71	23	
Electricity (T)	Tas	April 2009	30 Jun 2014	69	31	2.3% rise (year 1), then 1% per year

Capex, capital expenditure; D, distribution; Opex, operating expenditure; T, transmission.

Notes:

The range of data for some jurisdictions reflects different outcomes across networks.

The Victorian retail impacts are averages across the networks. The range is -1.6 to 5.1 per cent (year 1), then 2.3 to 2.9 per cent per year.

The South Australian retail impact in year 1 will be revised down to reverse over recovery of revenue by the network in 2009–10.

The New South Wales retail impacts cover transmission and distribution. Retail impacts for years 2–4 account for adjustments resulting from a merits review decision.

Capex and opex growth rates are real. Retail impacts are nominal and include inflationary price impacts.

Sources: Regulatory determinations by AER and IPART.

Table 2 Australian Competition Tribunal decisions on AER determinations, June 2008 – November 2010

DECISION DATE	TYPE OF REVIEW	SECTOR	OUTCOME	NETWORKS	REVENUE IMPACT
30 Sep 08	Merits	ET	Increased the opening RAB by $36.1 million	ElectraNet (SA)	$51 million
25 Nov 09	Merits	ET, ED	Nominal vanilla weighted WACC increased from around 8.8% to 10%; EnergyAustralia's controllable operating expenditure allowance increased by $4.5 million; definition of general nominated pass through event amended; AER decision on EnergyAustralia public lighting remitted for redetermination; TransGrid's controllable operating expenditure allowance increased by $14 million	EnergyAustralia (NSW) Integral Energy (NSW) Country Energy (NSW) TransGrid (NSW) Transend (Tas)	$818 million $321 million $411 million $381 million $80 million
18 Jan 10	Merits	ED	Expenditure for related party margins and management fees to be included in budgets for Victorian advanced metering review	Jemena (Vic) United Energy (Vic)	$8.4 million $13.1 million
17 Sep 10	Merits	GD	Debt risk premium calculation method	ActewAGL (ACT)	$5 million
Continuing	Merits	ED	Treatment of imputation credits; opening RAB (ETSA only); capital expenditure allowance, customer service costs, demand forecasts, street lighting, service incentive scheme, labour cost escalators (Ergon only)	ENERGEX (Qld) Ergon Energy (Qld) ETSA (SA)	
Continuing	Merits	GD	Gamma value, DRP value, indemnity clauses in reference services agreement, opening capital base and capital expenditure	Jemena Gas Networks (NSW)	

D, distribution; DRP, debt risk premium; E, electricity; G, gas; T, transmission; WACC, weighted average cost of capital.

Notes:

The 18 January 2010 decision on Victorian advanced metering covers a two year period; other revenue impacts are for five year regulatory control periods.

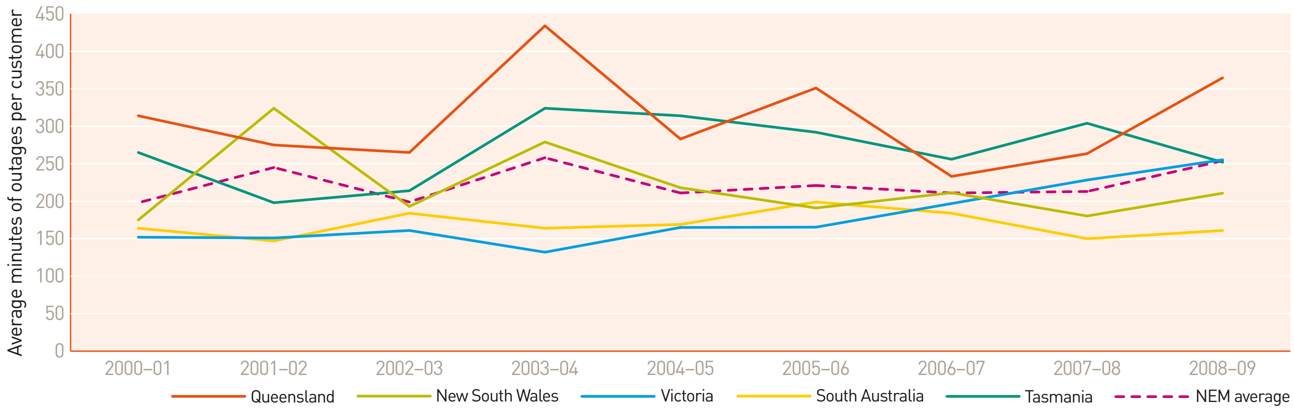
The EnergyAustralia decision (25 November 2009) does not account for increased revenues from public lighting.

The impact of the ElectraNet decision (30 September 2008) accounts for a $30 million increase in revenues from contingent projects.

All data are nominal.

Figure 2

Electricity distribution—reliability of supply



Notes:

The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator's reasonable control. Some data have been adjusted to remove the impact of natural disasters (for example, Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year beginning in that period.

Data sources: Performance reports by the AER (Victoria), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates when developing historical data.

Another challenge is finding innovative ways of responding to rising peak demand. When combined with appropriate tariff structures and communications technologies, smart meters are one way to reduce peak and overall demand by giving customers the information needed to manage their consumption more efficiently. Victoria began a rollout of smart meters in 2009.

Smart grids take the concept of smart meters further towards direct control of load, the use of communications technology to rapidly detect and switch around faults to minimise supply disruptions, and the integration of local generation to support the network. The Australian Government has committed $100 million for a trial of smart grid technologies. Ultimately, these innovations should lead to better use and operation of the networks to meet increasingly complex needs.

Regulatory and policy reforms are underway to encourage greater efficiency in network investment. In July 2009 the Australian Energy Market Operator (AEMO) began operating as a single, industry funded national energy market operator for both electricity and gas. It has a National Transmission Planner role, which overlays the traditional jurisdiction based approach to network planning with a more strategic, long term focus on efficiently developing the transmission grid from a national perspective. AEMO expected to publish its first annual national transmission network development plan in December 2010, outlining its view of the efficient development of the power system over the next 20 years.

The AER published a new regulatory investment test in 2010 to require that transmission businesses evaluate the most efficient methods—for example, network augmentation or alternatives such as generation investment—to respond to rising demand for electricity services.

The AER reviewed the compliance of TransGrid (New South Wales) with the regulatory test in relation to a proposed 330 kilovolt (kV) transmission line from Dumaresq to Lismore. It found shortcomings in TransGrid's analysis and decision making process.[1] TransGrid subsequently committed to the AER to improve future processes.

The Australian Energy Market Commission (AEMC) began a comprehensive review in 2010 of the electricity transmission sector. It will consider arrangements for the provision and use of transmission services and implications for the frameworks governing transmission investment. This will include identifying any weaknesses or inefficiencies in how the networks coordinate with generation investment. The final report is expected by November 2011.

2 National Electricity Market

The AER monitors activity in the NEM, which is the wholesale spot market covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. It publishes reports on market activity and the compliance of participants with the National Electricity Rules.

Figure 3 tracks weighted annual average spot electricity prices in the NEM. Average spot prices in 2009–10 rose significantly in South Australia, to $82 per megawatt hour (MWh), and New South Wales, to $52 per MWh. Strategic generator bidding and rebidding to take advantage of opportunities for exceptional prices contributed to these outcomes.

Tasmania recorded its lowest average spot price ($30 per MWh) since joining the NEM in 2005. This reflected more favourable conditions for hydroelectric generation and less evidence of the opportunistic bidding that caused record high prices in 2008–09. Queensland ($37 per MWh) recorded its second consecutive year of average spot prices below $40 per MWh. Victoria ($42 per MWh) was the only mainland region to record a reduction in spot prices in 2009–10.

While conditions were generally benign in most regions in 2009–10, the spot price exceeded $300 per MWh in 330 trading intervals (figure 4) and exceeded $5000 per MWh in 95 intervals (figure 1.9, chapter 1).[2]

Price spikes can have a material impact on market outcomes. If prices approach the market cap of $12 500 per MWh for just three hours in a year, then the average annual spot price may rise by almost 10 per cent.

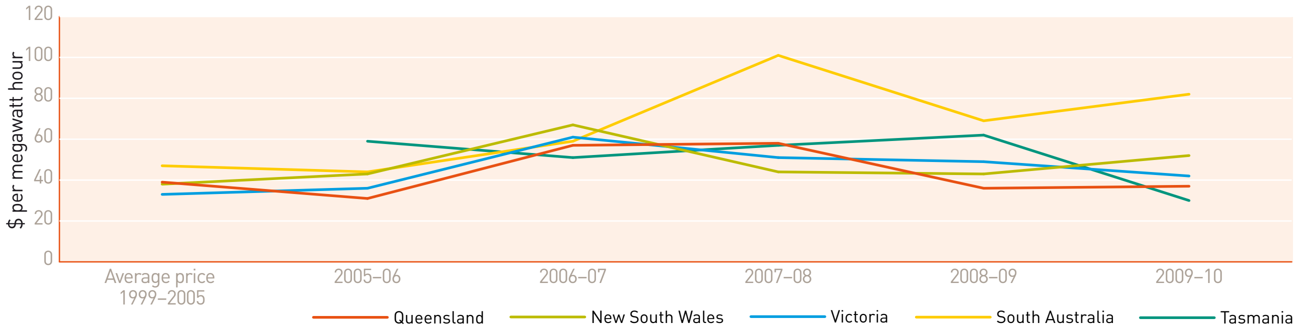
The bulk of extreme price events in 2009–10 occurred in South Australia and New South Wales. These regions jointly accounted for over 62 per cent of spot prices above $300 per MWh and 71 per cent of spot prices above $5000 per MWh:

- Spot prices in *South Australia* rose by 20 per cent to $82 per MWh in 2009–10, which was the second highest price for any region since the NEM commenced. Around 50 per cent of NEM prices above $5000 per MWh in 2009–10 occurred in South Australia. Most of the events were associated with opportunistic bidding by AGL Energy, owner of the Torrens Island power station, which accounts for 40 per cent of statewide generation capacity. Transmission limits on importing electricity from Victoria mean AGL Energy can, on days of high electricity demand, bid a significant proportion of its capacity at prices around the market cap and drive up spot prices. A period of prolonged opportunistic bidding and high prices in November 2009 triggered wholesale market controls that capped prices at $300 per MWh.
- Spot prices in *New South Wales* rose by 23 per cent to $52 per MWh in 2009–10, which was the largest regional price increase in that year in the NEM. New South Wales recorded 21 price events above $5000 per MWh. At least 11 of these events featured an interplay of factors in which Delta Electricity and other generators rebid capacity to higher prices to take advantage of a tight market. Generators also rebid their ramp rates, reducing the rates at which plant can vary output in response to dispatch instructions, to prolong the impact. This behaviour caused prices to stay above $300 per MWh for up to eight hours at a time.

1 AER, *Investigation report, Compliance with the planning and network development provisions of the National Electricity Rules—TransGrid*, 2010.

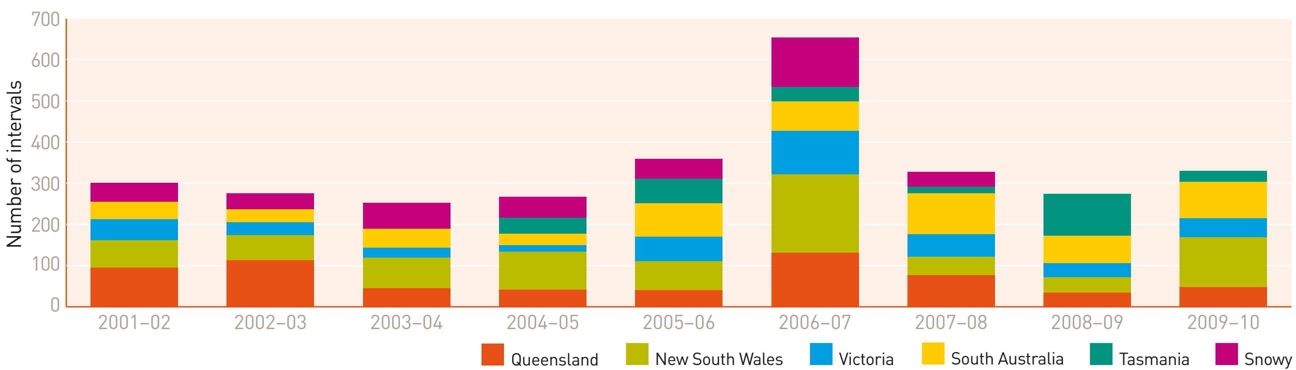
2 A trading interval is 30 minutes. The trading interval price is the average of the five minute dispatch prices during that interval.

Figure 3
Weighted average spot prices—electricity



Source: AER.

Figure 4
Trading intervals above $300 per megawatt hour—National Electricity Market



Note: Each trading interval is a half hour.

Source: AER.

> While *Tasmania's* wholesale market was relatively stable in 2009–10, concerns about high prices in the frequency control ancillary services market during 2009 led the Office of the Tasmanian Economic Regulator to 'declare' a number of Hydro Tasmania services in December 2009, with a view to setting price caps.

The AER monitors spot market activity to screen for noncompliance with the National Electricity Rules. While bidding capacity at high prices and rebidding prices and ramp rates do not breach the Rules, opportunistic bidding by some generators is a continuing cause of extreme price events. The AER will continue to monitor and report on generator bidding behaviour.

Following an investigation of sustained high electricity prices in Queensland in early 2008, the AER instituted proceedings in 2009 in the Federal Court, Brisbane, against Stanwell Corporation (a Queensland generator) for alleged contraventions of the National Electricity Rules. The AER alleged Stanwell did not make several of its offers to generate electricity on 22 and 23 February 2008 in 'good faith', contrary to clause 3.8.22A of the Rules. The AER sought orders that included declarations, civil penalties, a compliance program and costs. The trial in this matter commenced in Brisbane on 15 June 2010 before Justice Dowsett and concluded on 5 July 2010. In late 2010 the parties were waiting for the judgment.

Generation investment and reliability

Around 1800 megawatts (MW) of new generation capacity was commissioned in the NEM in 2009–10, following 2500 MW in 2008–09. New gas fired plant in Queensland accounted for over 50 per cent of new investment in 2009–10, including Origin Energy's 605 MW power station on the Darling Downs. In New South Wales, Delta Electricity completed a major expansion of its Colongra plant. Investment in wind generation has also been significant, especially in South Australia.

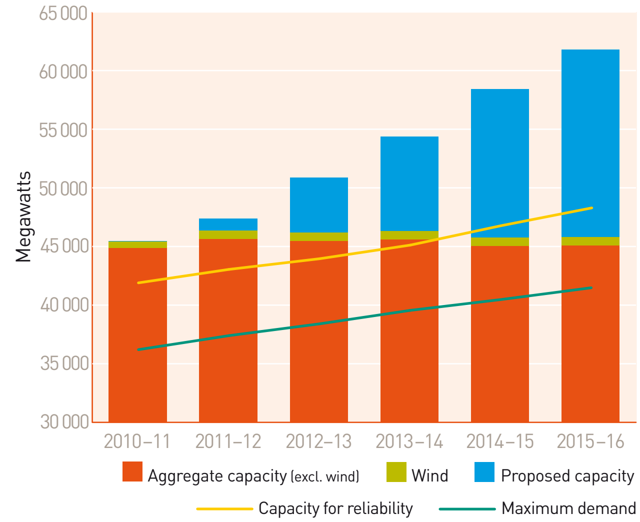
Developers had committed to around 1200 MW of new capacity that was not operational in late 2010. The most significant project is Origin Energy's 518 MW Mortlake power station in Victoria, scheduled for commissioning by the summer of 2010–11.

Generation investment over the past decade generally kept pace with rising demand and provided a safety margin of capacity to maintain the reliability of the power system. While instances of insufficient generation capacity to meet consumer demand are rare, a heatwave in Victoria and South Australia in January 2009 caused unserved energy levels to exceed the reliability standard (when measured on an annual basis) and led the AEMC Reliability Panel to review the reliability settings. The review (completed in April 2010) recommended refinements, including annual increases in the market price cap based on movements in the producer price index. The panel considered this change would improve incentives for efficient investment and was justified given rising capital costs for new entrant gas fired generators and 'peakier' electricity demand.

Recent AEMO assessments found installed and committed capacity (excluding wind) across the NEM as a whole will be sufficient until 2013–14 to meet peak demand projections and reliability requirements (figure 5). Beyond that time, some proposed generation projects may need to come online for the market as a whole to meet reliability requirements.

Figure 5

Electricity demand and supply outlook to 2015–16



Note: Figure 1.17 notes, chapter 1, set out underlying assumptions.

Data source: AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010.

AEMO found, assuming medium economic growth, that Queensland would be the first region in the NEM to require new generation investment (by 2013–14) beyond that already committed. While Queensland has had substantial new investment over the past decade, the region's economic growth is projected to increase electricity demand. Also, installed capacity is expected to fall as the Swanbank B coal fired plant is progressively retired (to be completed by 2012–13).

Victoria and South Australia were projected to require new investment (beyond committed capacity) by 2015–16, and New South Wales by 2016–17. AEMO expected Tasmania to have adequate capacity until at least 2019–20.

AEMO noted climate change policies and the emergence of new technologies would be significant investment drivers over the next few years. In particular, it noted the national renewable energy target would likely shift the generation mix towards less carbon intensive generation sources. It also noted the potential for new technology such as smart meters, smart grids and electric vehicles, combined with an increased focus on energy efficiency, to alter consumption patterns and mitigate the growth in capacity requirements.

The report also considered delays in, and associated uncertainty with, the implementation of an emissions trading scheme may pose risks for investment.[3]

3 Energy retail markets

The legislative package to transfer a range of retail regulatory functions to a national framework was introduced to the South Australian parliament in spring 2010. State and territory governments are expected to implement the framework between 2011 and 2013. The transfer of functions is not expected to occur in Western Australia or the Northern Territory at this time.

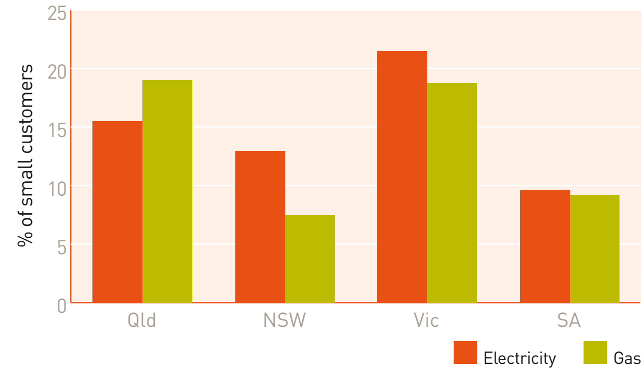
The new framework will transfer several functions to the AER, including:

- monitoring compliance and enforcing breaches of the National Energy Retail Law, Rules and Regulations
- approving the authorisation and exemption of energy retailers
- approving retailers' customer hardship policies
- reporting on performance matters such as customer service and hardship programs, and reporting on energy affordability and retail market activity
- administering a 'retailer of last resort' scheme
- publishing retailers' standing offer prices and an online price comparison service for small customers where required by a jurisdiction.[4]

The states and territories will remain responsible for control of regulated prices.

In preparation for the transition, the AER has been consulting with energy customers, consumer advocacy groups, energy retailers, jurisdictional regulators and ombudsmen, and government departments. In 2010 it ran 11 stakeholder forums on the national arrangements and its proposed approach to retail regulation. It also published issues papers on retail pricing information, retailer authorisations and exemptions, the development of hardship program indicators, performance reporting and a proposed compliance framework. For some processes, it is publishing draft guidelines. The issues papers and draft guidelines are available on the AER website (www.aer.gov.au).

Figure 6
Retail switching by small customers in 2009–10



Note: The customer base is estimated at 30 June 2010.

Sources: Electricity customer switches: AEMO. Gas customer switches: AEMO (Queensland, New South Wales, the ACT, Victoria), REMCo (South Australia). Customer numbers: IPART (New South Wales), ICRC (the ACT), ESCOSA (South Australia), ESC (Victoria), QCA (Queensland).

Retail competition

All NEM jurisdictions except Tasmania have introduced full retail contestability (FRC) in electricity, allowing all customers to enter a contract with their retailer of choice. At 1 July 2009 Tasmania extended contestability to customers using at least 150 MWh per year. Small business customers that consume more than 50 MWh per year are expected to become contestable on 1 July 2011. All jurisdictions have introduced FRC in gas retail markets.

Victoria continues to record high levels of customer switching between retailers (figure 6). While Queensland introduced FRC several years later than other jurisdictions did, customer activity has built momentum. In 2009–10 the state's switching rate in electricity was higher than the rates for New South Wales and South Australia, and was the highest of any jurisdiction for gas. While customer switching in

3 AEMO, *2010 power system adequacy: two year outlook*, 2010; AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010.

4 In New South Wales, Victoria and South Australia, small electricity customers are those consuming less than 160 megawatt hours (MWh) per year. In Queensland and the ACT, the threshold is 100 MWh per year; in Tasmania, it is 150 MWh per year. In gas, small customers are those consuming less than 1 terajoule per year.

South Australia was strong following the introduction of FRC, rates levelled out more recently. New South Wales has the lowest rate of customer switching in gas among the jurisdictions listed.

While most jurisdictions allow customers to choose their energy retailer, jurisdictions other than Victoria apply some form of electricity retail price regulation; New South Wales and South Australia apply similar arrangements in gas. Australian governments agreed to review the continued use of retail price caps and to remove them when effective competition can be demonstrated. The AEMC is assessing the effectiveness of energy retail competition in each jurisdiction, to advise ways to remove retail price caps. State and territory governments make the final decisions on this matter.

In June 2010 the AEMC released a draft report on the ACT retail electricity market, which found competition in the small customer market was not effective. It considered regulated retail prices were set at levels that did not allow adequate margins to attract new entrants, thus creating barriers to entry. Accordingly, retailer rivalry was limited, as were product choices available to small customers.

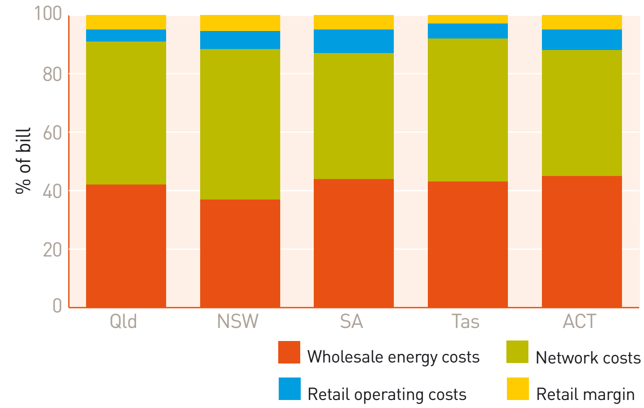
The Ministerial Council on Energy and the Council of Australian Governments have agreed to further energy retail market reviews for New South Wales, Queensland and Tasmania (if FRC is introduced).

The New South Wales Government announced plans in 2009 to privatise its state owned energy retailers—EnergyAustralia, Integral Energy and Country Energy—in combination with the electricity trading rights of its nine state owned power stations and seven power station development sites. The 'gentrader' rights will be sold in four bundles.

The government has reserved the option of bundling a number of assets and divesting them through an initial public offering if the sale process does not result in a new entrant. It expected to complete the sale process towards the end of 2010.

Figure 7

Indicative composition of residential electricity bills, 2010



Note: Table 4.2, chapter 4, sets out underlying data.

Sources: Determinations, draft determinations, fact sheets and newsletters by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (the ACT).

Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services. Figure 7 estimates the composition of a typical *electricity retail* bill for a residential customer in each NEM jurisdiction that regulates prices.

- *Wholesale energy costs* account for around 37–45 per cent of small customer retail electricity bills. This range includes costs associated with government climate change policies which, for example, contribute to around 1 per cent of retail bills in Tasmania and 3 per cent of bills in the ACT. In New South Wales, the renewable energy target scheme accounts for around 0.9 per cent of retail bills; the Energy Savings Scheme accounts for a further 0.4 per cent.
- *Network tariffs* account for 43–51 per cent of retail energy bills. The estimate for New South Wales reflects a significant pass through of distribution network costs that took effect in 2009; the contribution of network costs to retail prices is projected to rise in that jurisdiction from around 47 per cent in 2007 to 57 per cent in 2012.

- *Retailer operating costs* contribute in a range of around 4–8 per cent, and *retail margins* in a range of 3–5 per cent.

The data reflect jurisdictional averages and may vary across distribution networks. The contribution of network charges in New South Wales, for example, ranges from around 47 per cent for Integral Energy distribution customers to 57 per cent for Country Energy distribution customers.

Pipeline charges are the most significant component of *gas retail bills;* they account for around 47 per cent of gas retail bills in New South Wales and 60 per cent in South Australia. Distribution charges account for the bulk of pipeline costs. Wholesale energy costs typically account for a lower share of retail bills in gas than electricity, while retailer operating costs (including margins) account for a higher share. Given the uneven geographic spread of gas producing basins from major markets, the composition of retail prices can vary significantly across jurisdictions and regions.

Figure 8 illustrates indicative movements in *retail electricity prices* in NEM jurisdictions during 2009–10. The data measure regulated prices for those jurisdictions that apply price caps, and unregulated standing offer prices for the deregulated Victorian retail market. A spread is shown for New South Wales and Victoria, in which price movements vary across distribution networks. The percentage change in the electricity component of the consumer price index is also shown, for comparative purposes.

The data indicate that retail electricity prices rose significantly in 2009–10 in most states and territories. At 1 November 2010 further substantial increases had been announced in some jurisdictions:

- In New South Wales, regulated electricity prices rose by up to 21.7 per cent in 2009–10, with further increases of 7–13 per cent expected in 2010–11. The Independent Pricing and Regulatory Tribunal (IPART) found higher network charges accounted for 50 per cent of the 2009–10 price increases and 80 per cent of the 2010–11 increases. Rising wholesale energy costs contributed to around 30 per cent of the 2009–10 retail price rises, but will have a negligible impact in 2010–11.
- The Queensland Competition Authority (QCA) increased regulated electricity prices for 2009–10 by 11.8 per cent, which rose to 15.5 per cent following an appeal by energy retailers. It attributed the rise in roughly equal proportions to rising wholesale energy and network costs. The QCA attributed around 61 per cent of the projected 13.3 per cent rise in 2010–11 retail prices to rising network charges, mainly associated with new investment in distribution networks. The remaining sources of cost pressure were rising wholesale energy costs (contributing 29 per cent) and an increase in retail costs related to customer acquisition and retention.
- Victorian standing offer electricity prices rose by around 12–19 per cent in 2009–10. Given these are unregulated prices, only limited information is available on underlying cost factors. Unlike most jurisdictions, Victoria had relatively flat (or slightly declining) distribution charges, and was the only mainland jurisdiction to record a decrease in spot

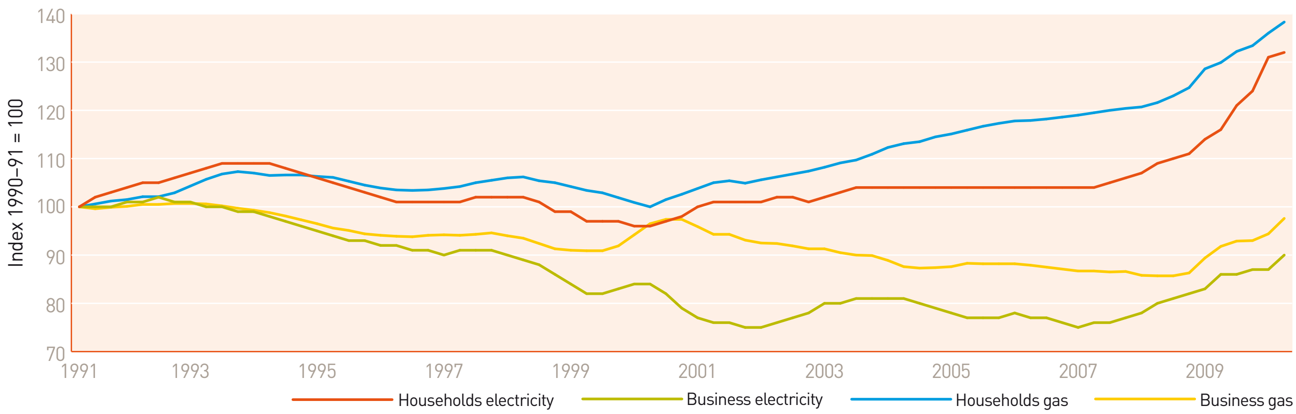
Figure 8
Retail electricity price rises—regulated and standing offers, 2009–10

Note: Victorian prices are based on unregulated standing offer prices published in the Victorian Government Gazette. Price movements in other jurisdictions reflect determinations by jurisdictional regulators.

Sources: Determinations, draft determinations, fact sheets and media releases by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (the ACT); Victorian Government Gazette; ABS, *Consumer price index*, cat. no. 6401.0.

Figure 9

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



Sources: ABS, *Consumer price index* and *Producer price index*, cat. nos 6401.0 and 6427.0, various years.

electricity prices in 2009–10. Costs associated with the introduction of smart meters would have accounted for retail price increases of around 2.5–7 per cent in 2010. The pass through impact was lowest for United Energy distribution customers and highest for Jemena customers. A pass through of transmission charges would account for retail price increases of up to 2.6 per cent. Higher costs (including compliance costs) associated with government climate change policies also likely contributed.

> South Australian electricity price rises were relatively moderate in 2009–10, but in July 2010 rose by 5.6 per cent in response to rising network charges and pass throughs related to climate change policies. The South Australian regulator's inquiry into regulated prices for 2011–14 foreshadowed in a draft determination that prices may increase by a further 6.9 per cent on 1 January 2011.

> Tasmanian electricity prices rose by around 6 per cent during 2009–10, with a further 6 per cent increase occurring on 1 July 2010 in response to rising network charges. The Office of the Tasmanian Economic Regulator determined that prices would again increase by 8.8 per cent on 1 December 2010. It attributed around half of this increase to rising energy purchase costs.

> The ACT recorded a 6.4 per cent increase in prices in 2009–10 and expects a moderate 2.3 per cent increase in 2010–11.

Customers in most jurisdictions can negotiate discounts against regulated and standing offer prices by entering a market contract. The scope for discounting appears to be greatest in Victoria. A St Vincent de Paul Society analysis (with funding from the Consumer Advocacy Panel) found a price spread of 26–37 per cent across retail offers within Victorian electricity distribution zones.[5]

Recent retail price increases have generally been lower in gas than electricity. South Australia expected a moderate 3.1 per cent increase in regulated gas prices in 2010–11. In New South Wales, IPART attributed price increases of around 3–8 per cent over the same period mainly to higher distribution pipeline charges. In the deregulated Victorian market, gas retail prices rose in 2009–10 by between 6 and 12 per cent.

Retail prices—long term trends

Figure 9 estimates movements in real energy retail prices in major capital cities over time. It illustrates the recent upswing in real electricity and gas retail prices, especially for households. In part, the tendency for household customers to experience larger price rises

5 St Vincent de Paul Society, *Victorian energy prices July 2008 – July 2010: a report from the Victorian tariff-tracking project*, 2010.

than business customers reflects the rebalancing of charges in some jurisdictions to better reflect underlying costs. More generally, it illustrates that household customers are increasingly exposed to prices in wholesale energy markets.

4 Upstream gas

Australia's natural gas industry continues to expand rapidly, driven by buoyant interest in liquefied natural gas (LNG) exports, investment in gas fired electricity generation, and a rapidly expanding resource base of coal seam gas (CSG) in Queensland and New South Wales.

LNG export volumes from Western Australia and the Northern Territory rose in 2009–10 by 7.4 per cent,[6] and major players are continuing to expand capacity:

> Woodside Petroleum's 4.3 million tonne per year Pluto project is nearing completion and will become Australia's third operational LNG project. The first exports are expected in early 2011.

> The $50 billion Gorgon project in Western Australia is scheduled to begin operation in 2015 and produce around 15 million tonnes of LNG per year—almost equal to Australia's current total LNG production. The project partners have signed long term sales agreements with international buyers.

There are emerging issues in Western Australia's domestic gas market. Anecdotal evidence suggests that some long term contracts were written at prices of $8–9 per gigajoule in the 18 months to June 2010. Conversely, weaker demand from mining projects led to reports that short term prices eased in 2010 to around $4.50 per gigajoule.[7]

The Western Australian Department of Mines and Petroleum gave evidence to a parliamentary inquiry into domestic gas prices in September 2010 that Western Australia could face a gas supply shortfall of 300 terajoules per day between 2013 and 2022.[8] To address this shortfall, a number of smaller gas projects focused on the domestic market are expected to come online within the next three years.

On the east coast, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have improved the economics of developing LNG export facilities in Queensland. Several export projects that rely on CSG are at an advanced stage of planning. The proposals mostly involve joint ventures between major international and domestic energy businesses.

Existing CSG developments in eastern Australia have reshaped the domestic gas market by providing a new source of gas supply for New South Wales, Victoria and South Australia. CSG production in Queensland and New South Wales rose by 29 per cent in the 12 months to June 2010.[9] New infrastructure, such as the QSN transmission link (commissioned in 2009), is providing the physical capacity to enable gas to flow from Queensland into southern markets.

Rising investment in gas fired power stations is a key driver of natural gas demand in eastern Australia. Output from gas fired electricity generation rose across the NEM jurisdictions by 21 per cent in 2009–10.

While upstream gas is a lightly regulated sector, recent developments significantly enhance transparency. The National Gas Market Bulletin Board, which began in July 2008, provides real time information on the state of the gas market, system constraints and market opportunities. In addition, new spot markets for short term gas trading are being introduced at major hubs to complement a separate market that already operates in Victoria. The first markets, for Sydney and Adelaide, began operation in September 2010. While the new

6 EnergyQuest, *Energy Quarterly*, August 2010, p. 24.
7 EnergyQuest, *Energy Quarterly*, August 2010, p. 89.
8 The findings of the parliamentary inquiry are expected to be released in February 2011.
9 EnergyQuest, *Energy Quarterly*, August 2010, p. 63.

day-ahead market relates to gas for balancing purposes, it is expected to provide transparent price guidance for the market as a whole. The AER, which monitors the short term trading market and enforces the applicable Rules, publishes weekly reports on market activity.

The spot markets in Victoria, Sydney and Adelaide provide the most transparent gas price signals. The Victorian spot market in 2010 was relatively flat, with prices in the first quarter (and the early part of the fourth quarter) typically below $2 per gigajoule. Sydney and Adelaide gas prices moved in a wide range in the first eight weeks of the short term trading market's operation in 2010, which is not uncommon with the establishment of a new market.[10]

Further dynamic change is likely in east coast gas markets with the development of CSG–LNG projects in Queensland in the next few years. While this may increase wholesale gas prices in the longer term, EnergyQuest predicted that domestic prices may ease during the lengthy ramp-up of LNG export capacity.[11]

5 Australian Energy Regulator's role

As the transition to national energy regulation continues, the AER is mindful of its responsibilities in regulating energy infrastructure, monitoring wholesale energy markets for compliance with the underpinning legislation, and reporting on market outcomes, as well as its likely future responsibilities in energy retail regulation. It also has a role in informing debate on policy, including advising on the operation of the market and the regulatory framework.

The AER will continue to work closely with energy customers, industry and jurisdictional agencies in undertaking these roles. It will look to apply consistent and transparent approaches to encourage efficient investment and reliable service delivery. The AER's new retail functions will increase the focus on education and outreach to encourage energy customers to participate actively in the market, and make them aware of and confident in the protections available to them in dealing with service providers.

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

10 Design differences between the short term trading market and the Victorian spot market limit the validity of price comparisons. The Victorian market is for gas only, while prices in the short term trading market cover gas and transmission pipeline delivery to the hub.

11 EnergyQuest, 'Australia's natural gas markets: connecting with the world', published in AER, *State of the energy market 2009*, 2009.

Origin Energy's Cullerin Range wind farm, New South Wales (Origin Energy)

1 NATIONAL ELECTRICITY MARKET

The National Electricity Market (NEM) is a wholesale market through which generators sell electricity in eastern and southern Australia. The main customers are energy retailers, which bundle electricity with network services for sale to residential, commercial and industrial energy users.

The market covers six jurisdictions—Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network. It has around 200 large generators, five state based transmission networks (linked by cross-border interconnectors) and 13 major distribution networks that supply electricity to end use customers. In geographic span, the NEM is the largest interconnected power system in the world, covering a distance of 4500 kilometres.

1.1 Demand and capacity

The NEM supplies electricity to almost nine million residential and business customers. In 2009–10 the market generated around 206 terawatt hours (TWh) of electricity, with a turnover of $9.6 billion (table 1.1 and figure 1.1a). Demand levels fluctuate throughout the year, with peaks occurring in summer (for air conditioning) and winter (for heating). Figure 1.1b shows seasonal peaks have risen from around 26 gigawatts (GW) in 1999 to 34 GW in 2010. Table 1.2 sets out the regional consumption profile.

1.2 Generation in the NEM

About 200 large electricity generators operate in the NEM jurisdictions (figure 1.2).[1] The electricity produced by these generators is sold through a central dispatch process that the Australian Energy Market Operator (AEMO) manages.

Table 1.1 National Electricity Market at a glance

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
Regions	Qld, NSW, Vic, SA, Tas
Registered capacity	49 010 MW
Registered generators	299
Customers	8.9 million
Turnover 2009–10	$9.6 billion
Total energy generated 2009–10	206 TWh
Maximum winter demand 2009–10	32 274 MW[1]
Maximum summer demand 2009–10	33 758 MW[2]

MW, megawatt; TWh, terawatt hours.

1. The maximum historical winter demand of 34 422 MW occurred in 2008.
2. The maximum historical summer demand of 35 551 MW occurred in 2009.

Sources: AEMO; ESAA, *Electricity gas Australia*, 2010.

Figure 1.1a
National Electricity Market electricity consumption

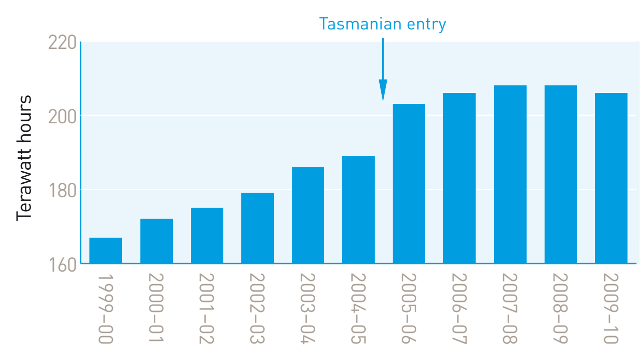
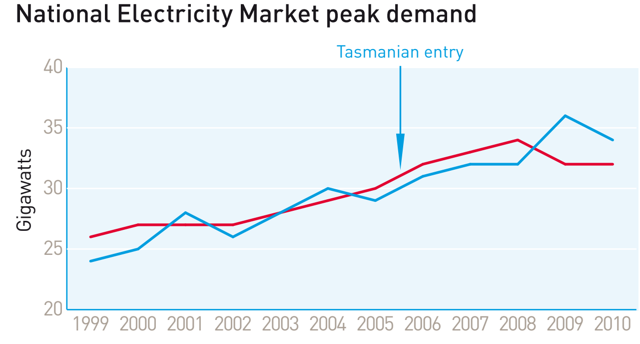


Figure 1.1b
National Electricity Market peak demand



Sources: AEMO; AER.

1 'Large' refers to generators with capacity greater than 30 megawatts.

Figure 1.2
Large electricity generators in the National Electricity Market

Sources: AEMO; AER.

Table 1.2 Electricity consumption in the National Electricity Market (terawatt hours)

	QLD	NSW	VIC	SA	TAS[1]	SNOWY[2]	NATIONAL
2009–10	53.2	78.1	51.2	13.3	10.0		206.0
2008–09	52.6	79.5	52.0	13.4	10.1		207.9
2007–08	51.5	78.8	52.3	13.3	10.3	1.6	208.0
2006–07	51.4	78.6	51.5	13.4	10.2	1.3	206.4
2005–06	51.3	77.3	50.8	12.9	10.0	0.5	202.8
2004–05	50.3	74.8	49.8	12.9		0.6	189.7
2003–04	48.9	74.0	49.4	13.0		0.7	185.3
2002–03	46.3	71.6	48.2	13.0		0.2	179.3
2001–02	45.2	70.2	46.8	12.5		0.3	175.0
2000–01	43.0	69.4	46.9	13.0		0.3	172.5
1999–2000	41.0	67.6	45.8	12.4		0.2	167.1

1. Tasmania entered the market on 29 May 2005.
2. The Snowy region was abolished on 1 July 2008. The New South Wales and Victorian data subsequently reflect electricity consumption formerly attributed to Snowy.

Sources: AEMO; AER.

1.2.1 Technology mix

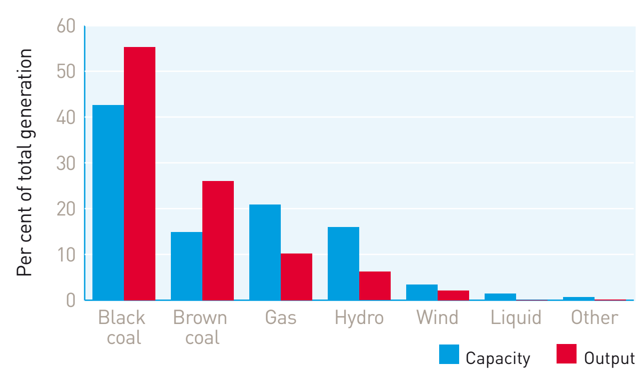
Across the NEM, black and brown coal account for around 58 per cent of registered[2] generation capacity, but this baseload plant supplies around 81 per cent of output (figure 1.3). Victoria, New South Wales and Queensland rely on coal more heavily than do other regions (figure 1.4).

Gas fired generation accounts for around 21 per cent of registered capacity across the NEM but supplies—as intermediate and peaking plant—only around 10 per cent of output. South Australia heavily relies on gas fired generation, and most new investment in other regions over the past decade was also in gas peaking plant.

Hydroelectric generation accounts for around 16 per cent of registered capacity but less than 6 per cent of output. Its contribution to output fell over the past few years as a result of drought conditions in Tasmania and eastern Australia. Wind plays a relatively minor role in the market (around 3 per cent of capacity and 2 per cent of output), but its role is expanding under climate change policies. There has been significant wind generation investment in South Australia. Wind generation now represents around 20 per cent of statewide capacity.

The extent of new and proposed investment in intermittent generation (mainly wind) has raised concerns about system security and reliability. The integration of wind generation into the market has thus changed. Since 31 March 2009 new wind generators greater than 30 megawatts (MW) must be classified as 'semi-scheduled' and participate in the central dispatch process. This allows AEMO to limit the output of these generators if necessary to maintain the integrity of the power system.

Figure 1.3
Registered generation in National Electricity Market, by fuel source, 2010

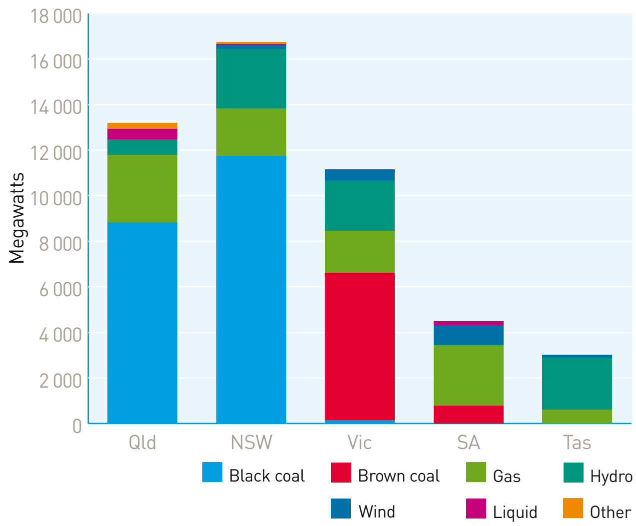


Note: Output is for 2009–10.

Sources: AEMO; AER.

2 Generators seeking to connect to the network must register with AEMO, unless granted an exemption.

Figure 1.4
Registered capacity in regions, by fuel source, 2010



Note: New South Wales and Victoria include Snowy Hydro capacity allocated to those regions.

Sources: AEMO; AER.

1.2.2 Climate change policies and technological change

The pattern of generation technologies across the NEM is evolving in response to technological change and climate change policies that governments have implemented or proposed. Given Australia's historical reliance on coal fired generation, the electricity sector contributes around 35 per cent of national greenhouse gas emissions.[3]

The Australian Government's primary emissions reduction policy is a national renewable energy target (RET) scheme, which was expanded in 2010. The scheme is designed to achieve the government's commitment to a 20 per cent share of renewable energy in Australia's electricity mix by 2020. It requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. Retailers comply with the scheme by obtaining renewable energy certificates created for each megawatt hour (MWh) of eligible renewable electricity that an accredited power station generates, or that eligible solar hot water or small generation units are deemed to generate.

From January 2011 the scheme will apply different arrangements for small scale and large scale renewable supply. A target of 41 000 gigawatt hours (GWh) of energy from large scale renewable energy projects has been set for 2020. Small scale renewable projects will no longer contribute to the national target, but still produce renewable energy certificates that retailers must acquire.

The Australian Government in 2009 introduced a Bill to implement an emissions trading scheme—the Carbon Pollution Reduction Scheme (CPRS). The Bill proposed a cap and trade mechanism to meet a carbon reduction target that would increase over time. In April 2010 the Prime Minister announced a delay in implementing the CPRS until at least 2013. The new government elected in late 2010 formed a Climate Change Committee comprising experts and parliamentary members to examine options for introducing a carbon price, including an emissions trading scheme and a carbon tax.

Government proposals and implementation of climate change policies are changing the economic drivers for new investment and shifting the mix from a reliance on coal fired generation towards less carbon intensive sources such as renewable and gas fired generation. Kogan Creek power station in Queensland is the only major new investment in coal fired generation in the past five years. The bulk of new investment has been in gas fired and wind generation.

A number of non-traditional technologies are also emerging as potential suppliers of electricity, including photovoltaic and geothermal generation. South Australia has two publicly announced geothermal projects, including a 525 MW project scheduled to provide local load in 2015 and connect to the grid in 2018.[4]

3 Garnaut Climate Change Review, *Final report*, 2008.
4 AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010, pp. 9–11.

1.2.3 Generation ownership

Across the NEM, around two thirds of generation capacity is government owned or controlled:

- Most generation capacity in *Victoria* and *South Australia* is privately owned. The major players are AGL Energy, International Power, TRUenergy, the Great Energy Alliance Corporation (in which AGL Energy holds a 32.5 per cent stake) and Alinta Energy. Origin Energy owns plant in South Australia and is developing new capacity in Victoria. Vertical integration is significant, with AGL Energy and TRUenergy being key players in both generation and retail. The government owned Snowy Hydro owns about 20 per cent of generation capacity in Victoria.[5]
- State owned corporations own around 90 per cent of generation capacity in *New South Wales*, but the government in March 2009 announced plans to contract the right to sell electricity produced by state owned generators to the private sector. The government expected to complete the privatisation process by the end of 2010 (box 1.1).
- State owned corporations control around 67 per cent of *Queensland's* generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone and Collinsville power stations). Considerable private investment has occurred over the past decade, including investment by Origin Energy, InterGen, AGL Energy, Alinta Energy and Arrow Energy. Origin Energy became a significant player in 2010 with the commissioning of its 605 MW Darling Downs plant. Also, public and private entities have formed joint ventures (such as the Tarong North and Callide C power stations).
- State owned corporations own nearly all generation capacity in *Tasmania*.

Table 1.3 provides information on the ownership of generation businesses in Australia. Figure 1.5 illustrates the ownership shares of the major players in each region of the market.

Box 1.1 Privatisation of New South Wales electricity assets

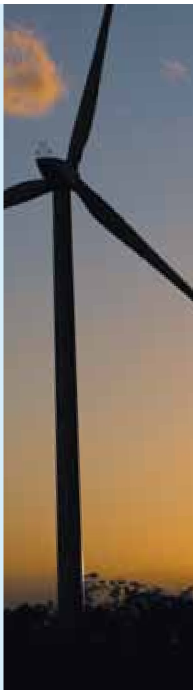
The New South Wales Government has committed to selling its energy assets that operate in contestable segments of the market. The privatisation process will include the sale of:

- the retail arms of the three state owned energy corporations—EnergyAustralia, Integral Energy and Country Energy
- the electricity trading rights of the nine state owned power stations
- seven power station development sites.

The 'gentrader' rights will be sold in four bundles. The generation portfolios of Macquarie (4640 MW) and Eraring (3120 MW) will be offered in their current configurations, while Delta's assets will be split into two bundles—Delta West (2400 MW), which includes the Mount Piper and Wallerawang power stations, and Delta Coast (2588 MW), which includes the Vales Point, Munmorah and Colongra power stations. While the nine development sites are suitable for the construction of new gas fired generation, only two have full planning approval.

The government has reserved the option of bundling a number of assets (including gentrader contracts for Eraring Energy, the retail business of Integral Energy and the Bamarang development site) and divesting them through an initial public offering if the sale process does not result in a new entrant.

The government expected to complete the sale process towards the end of 2010.



5 The New South Wales, Victorian and Australian governments jointly own Snowy Hydro.

Table 1.3 Generation ownership in the National Electricity Market, July 2010

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND			
CS Energy	Callide; Kogan Creek; Swanbank	2254	CS Energy (Qld Government)
Tarong Energy	Tarong; Tarong North; Wivenhoe	2343	Tarong Energy (Qld Government)
Stanwell Corporation	Gladstone	1680	Rio Tinto 42.1%; Transfield Services 37.5%; others 20.4% All contracted to Stanwell Corporation (Qld Government)
Stanwell Corporation	Stanwell; Barron Gorge; Kareeya; Mackay Gas Turbine; others	1571	Stanwell Corporation (Qld Government)
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	852	InterGen 50%; China Huaneng Group 50%
ERM Power and Arrow Energy	Braemar 2	462	ERM Power 25%; Arrow Energy 75%
Braemar Power Projects	Braemar 1	450	Alinta Energy
Origin Energy	Mount Stuart; Roma	441	Origin Energy
AGL Hydro	Oakey	275	Alinta Energy 25%; ERM Group 25%; Contact Energy 50% All contracted to AGL Energy
AGL Hydro	Yabulu	232	Transfield Services Infrastructure Fund All contracted to AGL Energy and Arrow Energy
CS Energy	Collinsville	187	Transfield Services Infrastructure Fund All contracted to CS Energy (Qld Government)
Pioneer Sugar Mills	Pioneer Sugar Mill	68	CSR
Ergon Energy	Barcaldine	49	Ergon Energy (Qld Government)
EDL Projects Australia	Moranbah North	46	EDL Projects Australia
CSR	Invicta Sugar Mill	39	CSR
AGL Energy	German Creek; KRC Cogeneration	32	AGL Energy
Origin Energy	Darling Downs	605	Origin Energy
QGC Sales Qld	Condamine	135	QGC Sales Qld
RTA Yarwun	Yarwun	152	Rio Tinto
Other registered capacity		273	
NEW SOUTH WALES			
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4844	Macquarie Generation (NSW Government)
Delta Electricity	Mount Piper; Vales Point B; Wallerawang; Munmorah; Colongra; others	4547	Delta Electricity (NSW Government)
Eraring Energy	Eraring; Shoalhaven; Brown Mt; Burrinjuck; others	2972	Eraring Energy (NSW Government)
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2336	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Origin Energy	Uranquinty; Cullerin Range	678	Origin Energy
TRUenergy	Tallawarra	417	TRUenergy (CLP Group)
Marubeni Australia Power Services	Smithfield Energy Facility	160	Marubeni Corporation
Redbank Project	Redbank	145	Alinta Energy
Infigen	Capital	140	Infigen Energy
Country Energy	Broken Hill Gas Turbine	50	Country Energy (NSW Government)
Other registered capacity		109	

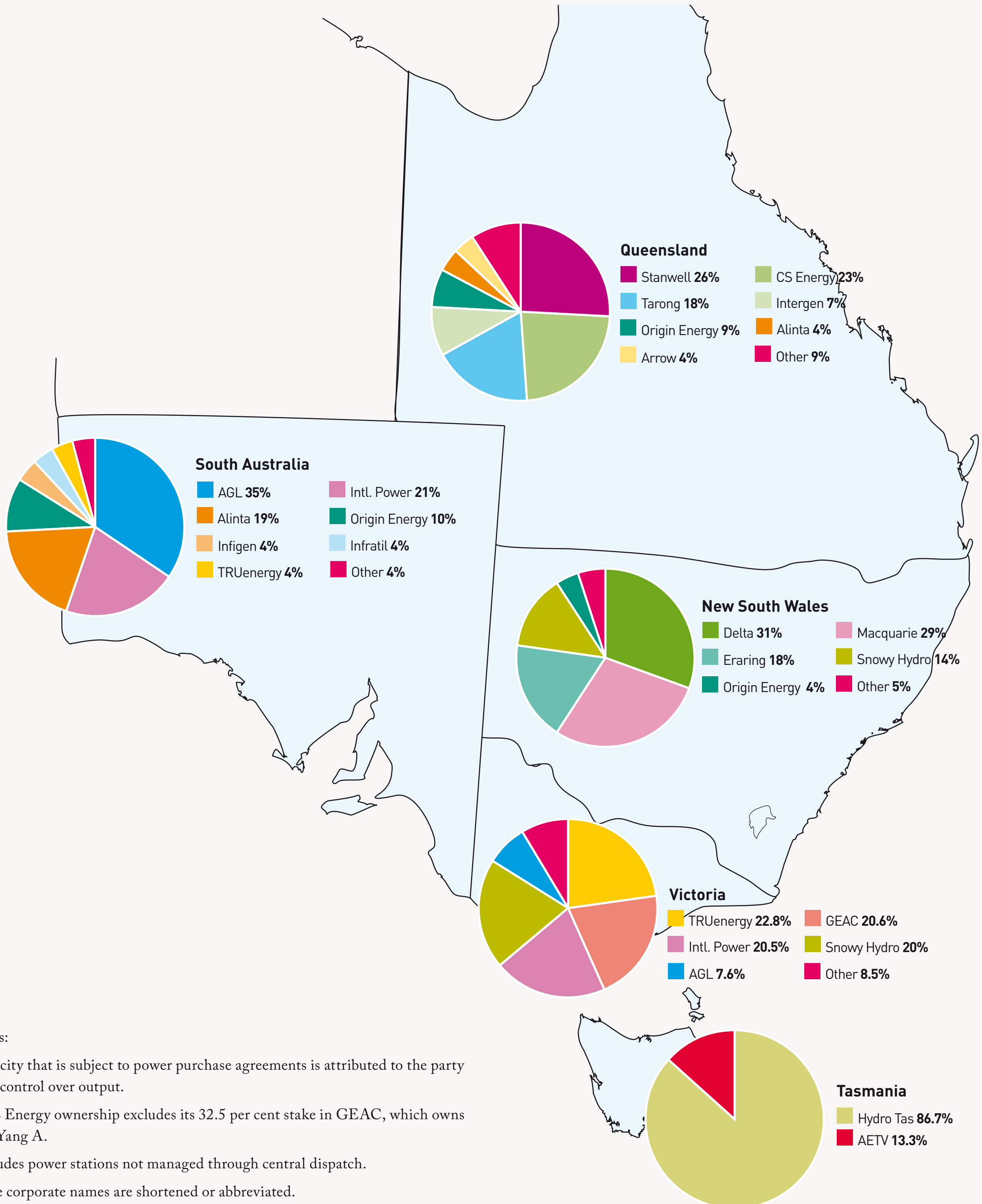
Fuel types: coal; gas; hydro; diesel/fuel oil/multi-fuel; wind; biomass, bagasse; unspecified.

Note: Capacity is as published by AEMO for summer 2010–11.

Source: AEMO.

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
VICTORIA			
LYMMCo	Loy Yang A	2080	GEAC (AGL Energy 32.5%; TEPCO 32.5%; Transfield Services 14%; others 21%)
Snowy Hydro	Laverton North; Valley Power; Murray	1933	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Hazelwood Power	Hazelwood	1580	International Power (91.8%); Commonwealth Bank (8.2%)
TRUenergy Yallourn	Yallourn; Longford Plant	1451	TRUenergy (CLP Group)
International Power	Loy Yang B	975	International Power (70%); Mitsui (30%)
Ecogen Energy	Jeeralang A and B; Newport	891	Industry Funds Management (Nominees) All contracted to TRUenergy (CLP Group)
AGL Hydro	Somerton; Eildon; Kiewa; Dartmouth; McKay; others	550	AGL Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland	247	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Energy Brix Australia	Energy Brix Complex; Hrl Tramway Road	160	HRL Group / Energy Brix Australia
Alcoa	Angelsea	152	Alcoa
Aurora Energy Tamar Valley	Bairnsdale	70	Alinta Energy
Eraring Energy	Hume	58	Eraring Energy (NSW Government)
Other registered capacity		82	
SOUTH AUSTRALIA			
AGL Hydro	Hallett 1 and 2; Wattle Point	257	AGL Energy
AGL Energy	Torrens Island	1256	AGL Energy
Cathedral Rocks Wind Farm	Cathedral Rocks	66	Roaring 40s (Hydro Tasmania (Tas Government) 50%; CLP Group 50%) 50%; Acciona Energy 50%
Infigen	Lake Bonney 1	81	Infigen Energy All contracted to Country Energy (NSW Government)
Infigen	Lake Bonney 2	159	Infigen Energy
Alinta Energy	Northern; Playford	782	Alinta Energy
Origin Energy	Osborne	175	ATCO 50%; Origin Energy 50%
Infratil Energy Australia	Angaston	49	Infratil. All contracted to AGL Energy
International Power	Pelican Point; Canunda	494	International Power
Transfield Services Infrastructure Fund	Mount Millar	70	Transfield Services Infrastructure Fund
Origin Energy	Quarantine; Ladbroke Grove	267	Origin Energy
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Snowtown	99	Infratil
Transfield Services Infrastructure Fund	Starfish Hill	35	Transfield Services Infrastructure Fund All contracted to Hydro Tasmania (Tas Government)
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	275	International Power
TRUenergy	Hallet	150	TRUenergy (CLP Group)
Other registered capacity		25	
TASMANIA			
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	374	AETV (Tas Government)
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; others	2347	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth	140	Roaring 40s (Hydro Tasmania (Tas Government) 50%; CLP Group 50%)
Other registered capacity		100	

Figure 1.5
Market shares in electricity generation capacity, by region, 2010



Notes:

Capacity that is subject to power purchase agreements is attributed to the party with control over output.

AGL Energy ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A.

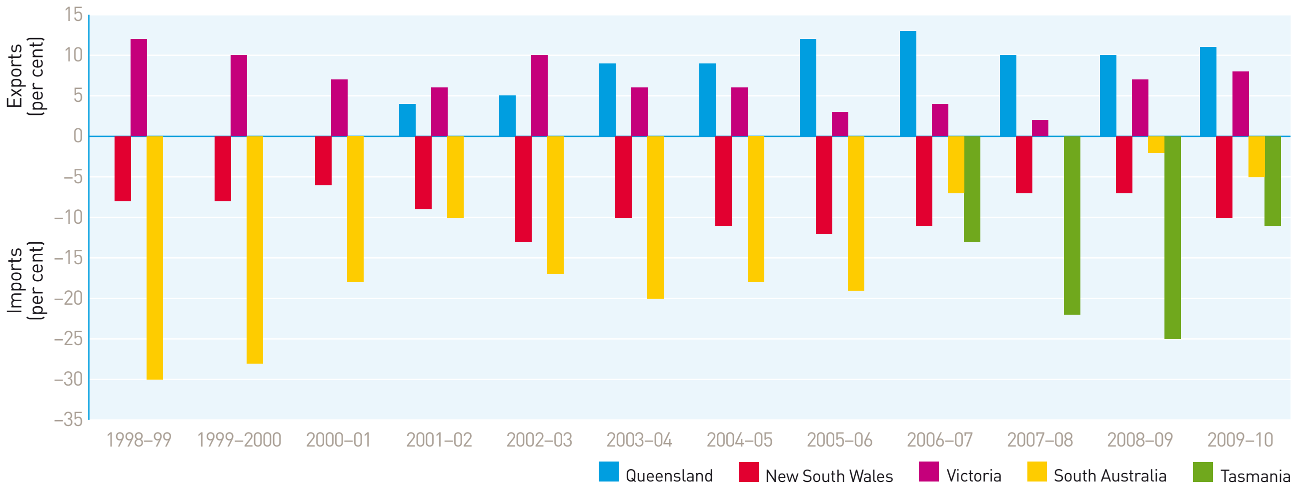
Excludes power stations not managed through central dispatch.

Some corporate names are shortened or abbreviated.

Source: AER.

Figure 1.6

Interregional trade as percentage of regional energy consumption



Sources: AEMO; AER.

1.3 Trading arrangements

Generators in the NEM sell electricity through a wholesale spot market in which changes in supply and demand determine prices. The main customers are retailers, which buy electricity for resale to business and household customers. The market has no physical location, but is a virtual pool in which AEMO aggregates and dispatches supply bids to meet demand in real time.[6]

The NEM is a gross pool, meaning all sales of electricity must occur through the spot market. In contrast, Western Australia's electricity market uses a net pool arrangement. Unlike some overseas markets, the NEM does not provide additional payments to generators for capacity or availability. Some generators bypass the central dispatch process, including some wind generators,[7] those not connected to a transmission network (for example, embedded generators) and those producing exclusively for their own use (such as in remote mining operations).

The NEM promotes efficient generator use by allowing electricity trade among the five regions. Figure 1.6 shows the net trading position of the regions:

> 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.

> Victoria has substantial low cost baseload capacity, making it a net exporter of electricity.

> Queensland's installed capacity exceeds the region's peak demand for electricity, making Queensland a significant net exporter.

> South Australia imported over 25 per cent of its energy requirements in the early years of the NEM. New investment in generation—mostly in wind capacity—has reduced this dependence since 2005–06.

> Tasmania has been a net importer since its interconnection with the NEM in 2006, partly because drought has constrained its ability to generate hydroelectricity.

6 The *State of the energy market 2009* report explained the dispatch process in detail (section 2.2).

7 From 31 March 2009 new wind and other intermittent generators must register under the new classification of 'semi-scheduled generator'. These generators must participate in the central dispatch process, which includes submitting offers and limiting their output as requested by AEMO.

1.4 Spot electricity prices

Generators provide AEMO with generation price and quantity offers (bids) for each five minute dispatch period. AEMO dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to satisfy demand. In practice, various factors may modify the dispatch order, 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 MW of generation that must be dispatched to meet demand. A wholesale spot price is then determined for each half hour (trading interval) from the average of the five minute dispatch prices. This is the price that all generators receive for their supply during the half hour, and the price that market customers pay for the electricity they use in that period. Spot prices may range between a floor of –$1000 per MWh and a cap of $12 500 per MWh. The cap was increased from $10 000 per MWh on 1 July 2010.

While the market determines a separate price for each region, the mainland regions typically operate as an 'integrated' market with price alignment for 60–80 per cent of the time. Price alignment occurred for about 67 per cent of the time in 2009–10, compared with 70 per cent in 2009–10. These estimates allow for minor price disparities caused by transmission losses that occur when transporting electricity over long distances. More significant market separation occurs when a cross-border transmission interconnector becomes congested and restricts interregional trade. This scenario may occur at times of peak demand or when an interconnector undergoes maintenance or experiences an unplanned outage.

The Australian Energy Regulator (AER) monitors the market and reports weekly on wholesale and forward market activity. It also publishes more detailed analyses of extreme price events. Figure 1.7 charts quarterly volume weighted average prices in each region, while table 1.4 sets out annual prices. Figure 1.8 provides a snapshot of weekly prices since December 2007.

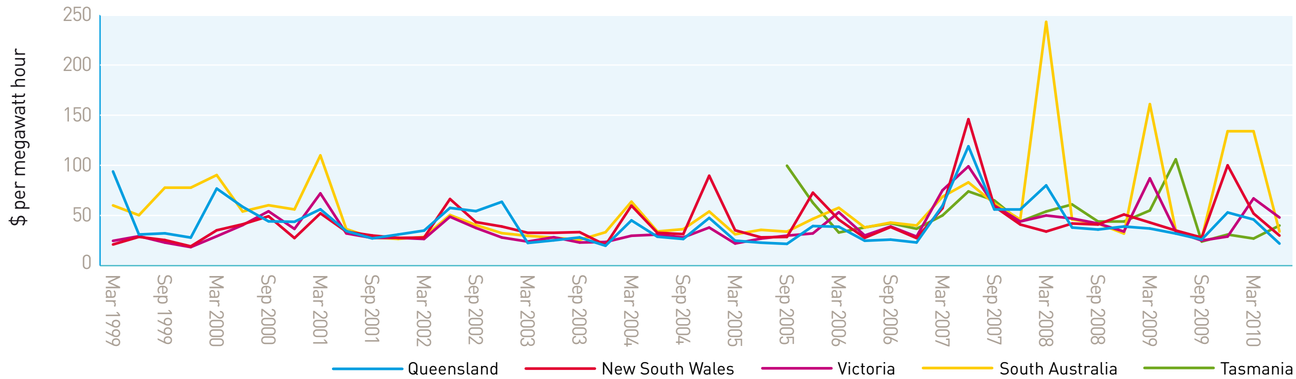
Table 1.4 Volume weighted average spot electricity prices ($ per megawatt hour)

	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
2009–10	37	52	42	82	30	
2008–09	36	43	49	69	62	
2007–08	58	44	51	101	57	31
2006–07	57	67	61	59	51	38
2005–06	31	43	36	44	59	29
2004–05	31	46	29	39		26
2003–04	31	37	27	39		22
2002–03	41	37	30	33		27
2001–02	38	38	33	34		27
2000–01	45	41	49	67		35
1999–2000	49	30	28	69		24
1999[1]	60	25	27	54		19

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

Sources: AEMO; AER.

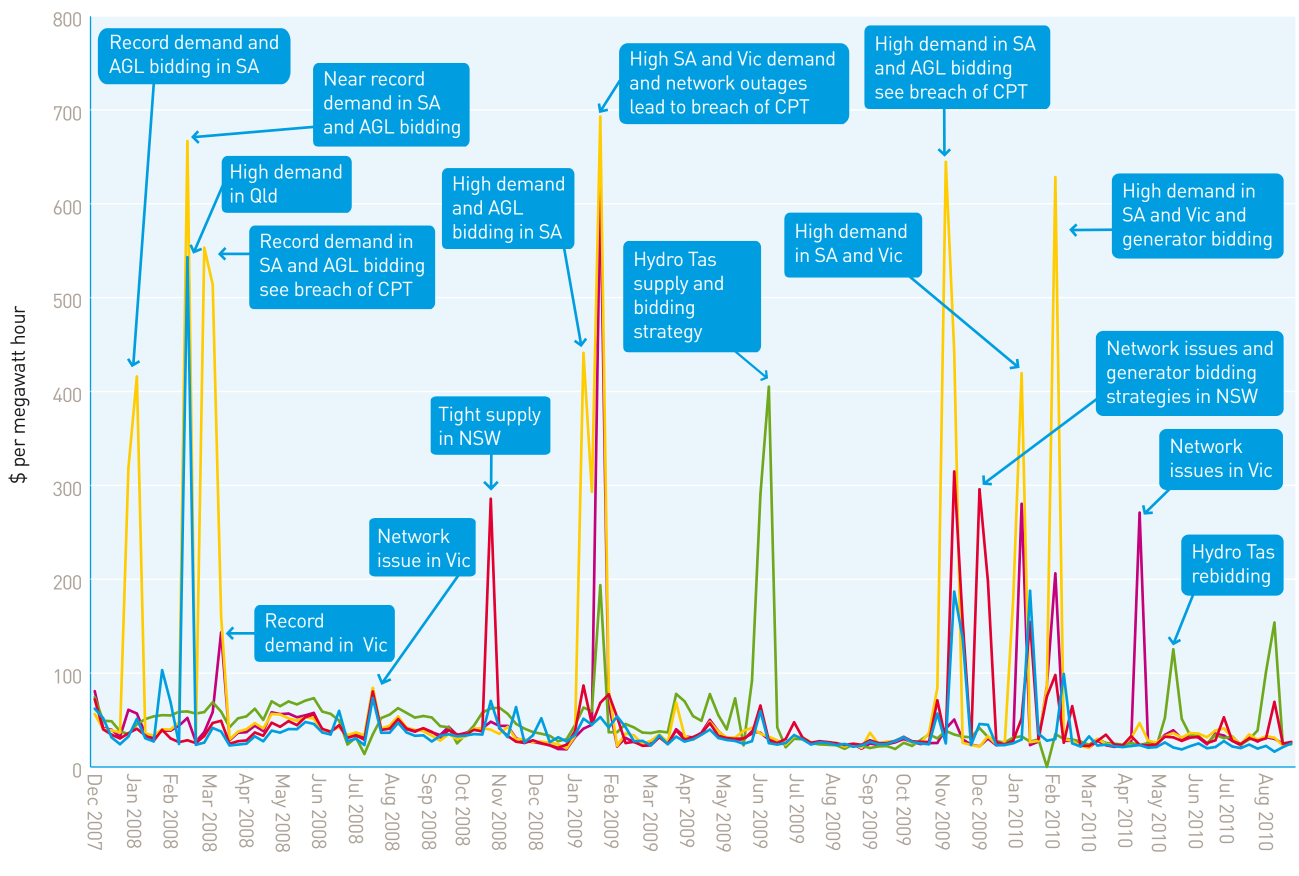
Figure 1.7
Quarterly spot electricity prices



Note: Volume weighted average prices.

Sources: AEMO; AER.

Figure 1.8
Weekly spot electricity prices



CPT, cumulative price threshold; Hydro Tas, Hydro Tasmania.

Note: Volume weighted average prices.

Source: AER.

1.4.1 Spot prices in 2009–10

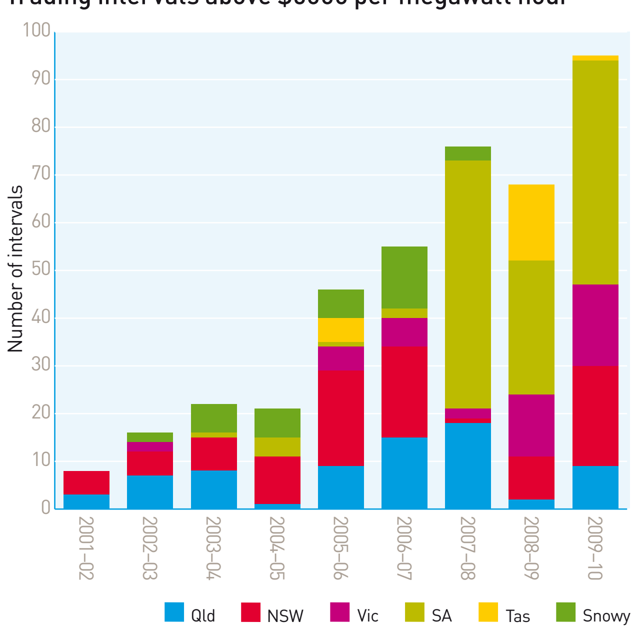
Average spot prices in 2009–10 rose significantly from the previous year in South Australia and New South Wales, and marginally in Queensland. Spot prices fell in Tasmania and Victoria.

Average spot prices in South Australia ($82 per MWh) and New South Wales ($52 per MWh) were higher than in other regions. Tasmania ($30 per MWh) and Queensland ($37 per MWh) recorded the lowest average spot prices in 2009–10, closely followed by Victoria ($42 per MWh). Tasmania recorded its lowest average spot price since joining the NEM.

While conditions were generally benign across much of the market in 2009–10, the spot price exceeded $5000 per MWh in 95 trading intervals—a record number of extreme price events in the NEM (figure 1.9). Price spikes can have a material impact on market outcomes. If prices approach the market cap of $12 500 per MWh for just three hours in a year, then the average annual spot price may rise by almost 10 per cent.

Figure 1.9

Trading intervals above $5000 per megawatt hour



Note: Each trading interval is a half hour.

Sources: AEMO; AER.

Table 1.5 summarises all extreme price events in 2009–10, noting the regions in which they occurred and underlying causes. The bulk of extreme price events occurred in South Australia and New South Wales, and were associated typically with opportunistic generator bidding. There were also instances of extreme pricing in ancillary services markets in South Australia and Tasmania.

A period of sustained extreme prices may trigger administered pricing at a cap of $300 per MWh.[8] One instance of administered pricing occurred in 2009–10, when several days of extreme prices in South Australia triggered activation of the cap in November 2009.

Market focus—South Australia

Spot prices in South Australia rose by 20 per cent to $82 per MWh in 2009–10, which was the second highest price for any region since the NEM commenced. This outcome reflects that around 50 per cent of NEM prices above $5000 per MWh in 2009–10 occurred in South Australia (table 1.5). Most of these events were associated with opportunistic bidding by AGL Energy, the region's largest electricity generator.

AGL Energy owns the Torrens Island power station, which accounts for around 40 per cent of South Australia's generation capacity. Transmission limits on importing electricity from Victoria mean AGL Energy can, on days of high electricity demand, bid a significant proportion of its capacity at prices around the market cap and drive up the spot price. It adopted this type of bidding strategy during many of South Australia's 47 extreme price events in 2009–10 (table 1.5). The events typically occurred on days of extreme weather, which led to high electricity demand and a tight regional supply–demand balance. There was also evidence AGL Energy engaged in opportunistic bidding in the market for frequency control ancillary services on two days in April 2010, such that the cost of those services to South Australian consumers averaged around $4 million per day, compared with the typical daily rate of less than $3000.

8 AEMO must apply the administered price cap if the sum of half hourly spot prices over a rolling seven days exceeds a cumulative threshold (currently $187 500 per MWh).

Table 1.5 Price events above $5000 per megawatt hour, 2009–10

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
2 November 2009	SA	1	$10 000	Above-forecast demand and import restrictions from Victoria led to a tight market. In addition, around 1000 MW of low priced SA capacity was unavailable, including 730 MW of AGL capacity. These conditions meant high priced capacity offered by AGL for its Torrens Island plant was dispatched and set the spot price.
3 November 2009	NSW and Qld	1 (NSW) 1 (Qld)	$6337 (NSW) $5706 (Qld)	Unseasonably high NSW temperatures combined with planned and unplanned generator outages and reduced import capability from Victoria to create a tight NSW market. This required the dispatch of high priced capacity, which set the NSW spot price. In Queensland, Stanwell responded to high export demand into NSW by rebidding 200 MW of capacity into higher price bands. The high interstate demand led to the dispatch of this high priced generation, which set the Queensland price.
10–13 November 2009	SA	14	$10 000	Extreme November temperatures led to demand exceeding 2800 MW each day. When combined with below-forecast import capability from Victoria, this led to a tight market. AGL anticipated market conditions by bidding 70 per cent of its capacity at Torrens Island power station at over $5000 per MWh. The tight market required the dispatch of this AGL capacity, which set the price at above $9999 per MWh for 80 of 84 dispatch intervals over this four day period. The extreme prices led to administered pricing (with a $300 per MWh cap) being imposed for several days.
19 November 2009	SA	8	$10 000	Record November temperatures led to unseasonally high demand, and imports from Victoria were lower than forecast. AGL anticipated market conditions by offering around 66 per cent of its available Torrens Island capacity (about 30 per cent of South Australia's total available capacity) at above $5000 per MWh. In the tight market, it was necessary to dispatch this capacity, which set the spot price at above $9997 per MWh for 43 of 48 dispatch intervals.
20 November 2009	NSW and Qld	7 (NSW) 3 (Qld)	$9284 (NSW) $8388 (Qld)	Extreme NSW temperatures led to above-forecast demand on a day when around 3000 MW of NSW generation was not offered to the market. In addition, planned network outages in NSW reduced import capability from Victoria. AEMO did not forecast the impact of the outages and allowed them to proceed. As market conditions became apparent during the day, AEMO directed a NSW generator be made available for dispatch and instructed TransGrid to return network equipment to service to increase reserves. The interconnectors between NSW and Queensland were unconstrained during much of this period, which enabled generators to rebid capacity into higher price bands in both regions. This contributed to prices exceeding $5000 per MWh for prolonged periods. There was some demand-side response in NSW to the high prices.
27 November 2009	NSW and Qld	2 (NSW) 1 (Qld)	$8933 (NSW) $8933 (Qld)	Above-forecast demand in NSW and Queensland coincided with a planned network outage in NSW that significantly reduced import capability from Victoria. Generators responded to the tight market by rebidding capacity into higher price bands. These factors combined to raise prices above $1000 per MWh for several trading intervals, including three intervals above $5000 per MWh.
7 December 2009	NSW	6	$9176	Extreme temperatures led to very high demand. Low cost electricity imports from Queensland and Victoria were constrained to manage congestion on the NSW transmission network. These factors, combined with plant outages, led to a very tight NSW market. A number of generators, including Delta Electricity, shifted capacity offers to higher price bands to take advantage of the tight market. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for 5.5 hours.

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
17 December 2009	NSW	3	$8703	Extreme temperatures led to very high demand. Low cost electricity imports from Queensland and Victoria were constrained to manage congestion on the NSW transmission network. These factors, combined with plant outages, led to a very tight NSW market. A number of generators, including Delta Electricity, shifted capacity offers to higher prices to take advantage of market conditions. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for eight hours.
8 January 2010	SA	3	$10 000	Extreme temperatures led to very high demand. Constraints used to manage congestion in the SA transmission network restricted imports from Victoria and constrained off 340 MW of low priced SA generation. AGL anticipated market conditions by bidding two thirds of its available capacity at Torrens Island power station at close to the price cap. The tight market required the dispatch of this AGL capacity, which set the spot price.
11 January 2010	SA and Vic	8 (SA) 6 (Vic)	$9116 (SA) $9201 (Vic)	Extreme temperatures in both regions led to high demand. Import capability into both regions was about 400 MW lower than forecast. In Victoria, day ahead bidding by LYMMCO combined with rebidding on the day by International Power to set high prices. In South Australia, AGL anticipated market conditions by bidding two thirds of its available capacity at Torrens Island power station at over $5000 per MWh. The tight market required the dispatch of this AGL capacity, which set the spot price at above $9100 per MWh for 43 of 54 dispatch intervals.
18 January 2010	Qld	4	$9208	High temperatures led to record Queensland demand. A constraint to manage transmission congestion restricted imports from NSW. Queensland generators anticipated market conditions in their day-ahead bids by offering around 2000 MW of capacity at above $5000 per MWh. They also rebid around 750 MW of capacity on the day from low prices to above $5000 per MWh. In the tight market, these bids set the dispatch prices in four intervals.
4 February 2010	NSW	1	$5541	Planned maintenance on the NSW distribution network led to a potential overload on cables into the Sydney CBD. In response, TransGrid took a 330 kilovolt transmission line out of service. To manage congestion on the NSW transmission network, AEMO constrained low cost electricity imports from Victoria and Queensland. These factors, combined with plant outages, led to a very tight NSW market. A number of generators, including Delta Electricity, rebid their dispatch offers to take advantage of market conditions. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for two hours.
8–10 February 2010	SA and Vic	13 (SA) 4 (Vic)	$10 000 (SA) $7847 (Vic)	High temperatures in South Australia and Victoria led to high demand on all three days. There were also supply issues, including reduced import capability into both regions. On 8 February high temperatures caused a reduction in available generation capacity in Victoria. On 9 February a network reclassification issue forced electricity flows out of South Australia into Victoria, triggering a reserve alert (insufficient reserves to cater for the loss of the largest generator or interconnector) in South Australia. Generators in both regions anticipated market conditions through their day-ahead bids and rebids into high price bands, resulting in a series of extreme prices. On 8–9 February South Australian generators made day-ahead offers to supply over 25 per cent of total SA capacity at above $8900 per MWh. The majority was offered by AGL. Less capacity was offered in this way on 10 February, but AGL rebid 240 MW of capacity from below $50 per MWh to over $9000 per MWh on the day. The threshold for administered pricing was almost reached in South Australia on 10 February.

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
22 February 2010	NSW	1	$8346	Hot weather drove high electricity demand. In addition, an unplanned outage of a Delta Electricity generator altered flows on the NSW transmission network. This led to restrictions on low priced generators and imports to manage network congestion. These factors led to a tight market. A number of generators, including Delta Electricity, rebid their dispatch offers to take advantage of market conditions. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for 30 minutes.
22 April 2010	Vic	7	$9999	Networks issues restricted Victoria's ability to import electricity. Planned network outages restricted imports from NSW and South Australia, and an unplanned outage of Basslink prevented imports from Tasmania. International Power anticipated a tight Victorian market by pricing significant capacity at close to the price cap in day-ahead bids. A number of subsequent rebids by other generators left Victoria with no capacity priced between $500 and $9000 per MWh. Network issues led to Victoria exporting electricity to the lower priced NSW and South Australian regions. Demand-side response in Victoria cushioned the price impact for about 40 minutes.
22 May 2010	Tas	1	$6750	Cold temperatures led to the highest demand on a Saturday for two years, although demand was close to forecast levels. Day-ahead offers saw 90 per cent of Tasmanian capacity (around 2000 MW) priced below $500 per MWh between 5.30 and 8.30 pm. Hydro Tasmania subsequently rebid almost half of Tasmania's capacity to above $9400 per MWh for this period, which set the dispatch price for about half an hour. The price movements coincided with Hydro Tasmania making significant changes to the output of its non-scheduled generators, which effectively altered the demand that scheduled generators had to meet.
MARKET ANCILLARY SERVICES				
31 December 2009	Tas	90 minutes	$10 000 per MW	Lightning storms in Tasmania led to the reclassification of a number of transmission circuits, which restricted the ability of some generators to provide 'raise six second' frequency control ancillary services (FCAS). The services are used to manage frequency issues arising in the first six seconds of a credible shock to the power system. While AEMO directed Hydro Tasmania to provide additional services, the price remained at the $10 000 cap. Once the storms passed, one reclassification was revoked and the price fell to less than $1 per MW. As a result of this and similar events, the total cost of FCAS in Tasmania for the week to 2 January 2010 was about 20 per cent of total energy turnover in the state (compared with about 1 per cent on the mainland in the same period).
21–22 April 2010	SA	470 minutes over two days		A planned transmission outage in Victoria reduced the capability of the Heywood interconnector. High energy prices in Victoria on both days drove exports from South Australia to Victoria. In combination, these events led to a requirement for local FCAS in South Australia. AGL, the most significant South Australian provider, offered through day-ahead bids and rebidding the majority of its capacity for these services at the price cap. The cost of FCAS totalled more than $8 million, compared with a typical daily rate of less than $3000.

Source: AER.

Market focus—New South Wales

Spot prices in New South Wales rose by 23 per cent to $52 per MWh in 2009–10, which was the largest regional price increase in that year in the NEM. New South Wales recorded 21 price events above $5000 per MWh, which was the second highest number for any region.

At least 11 of these events featured an interplay of factors aggravated by opportunistic generator rebidding (table 1.5). In particular, AEMO was obliged on several summer days in 2009–10 to constrain low cost electricity imports from Queensland and Victoria to manage congestion in the New South Wales transmission network. The congestion resulted from a delayed network upgrade. The constraints typically affected the market on days of high demand and/or infrastructure outages, which led to a tight demand–supply balance. A number of generators, including Delta Electricity, rebid capacity to higher prices to take advantage of the tight market. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for up to eight hours at a time.

These events contributed to New South Wales experiencing 14 days in 2009–10 when prices exceeded $300 per MWh for one or more trading intervals, including four days on which prices exceeded $5000 per MWh.

Market focus—Tasmania

In 2008–09 opportunistic bidding and output decisions by Hydro Tasmania led to a series of price spikes in the spot electricity market. Tasmania's spot prices were much lower in 2009–10, with only one instance of opportunistic bidding by Hydro Tasmania contributing to prices above $5000 per MWh (table 1.5).

The region also recorded a series of high prices for frequency control ancillary services over three weeks in April 2009. The local market for these services is dominated by Hydro Tasmania, which is always the marginal cost producer.[9] Concerns about high prices led the Office of the Tasmanian Economic Regulator to 'declare' a number of Hydro Tasmania services in December 2009, with a view to setting price caps. The regulator made the declaration to prevent the misuse of substantial market power and to promote competition in the markets for those services. It found Hydro Tasmania had been misusing its market power, extracting monopoly rents and bidding anti-competitively on frequency control ancillary services at high prices.[10]

Tasmania had one instance in 2009–10 of 'raise six second' frequency control ancillary services reaching $10 000 per MW for 90 minutes. These services are used to manage frequency issues arising in the first six seconds of a credible shock to the power system. The total cost of these services in Tasmania for the week to 2 January 2010 was about 20 per cent of total energy turnover in the state (compared with about 1 per cent on the mainland in the same period).

The event occurred when lightning storms in Tasmania led AEMO to identify a heightened risk of unplanned outages in the transmission network. AEMO invoked constraints that restricted some generators from supplying frequency control ancillary services, leading to a shortage during the storm. In 2010 AEMO revised its approach to managing this type of event, to enable more generators to provide the services in similar circumstances.

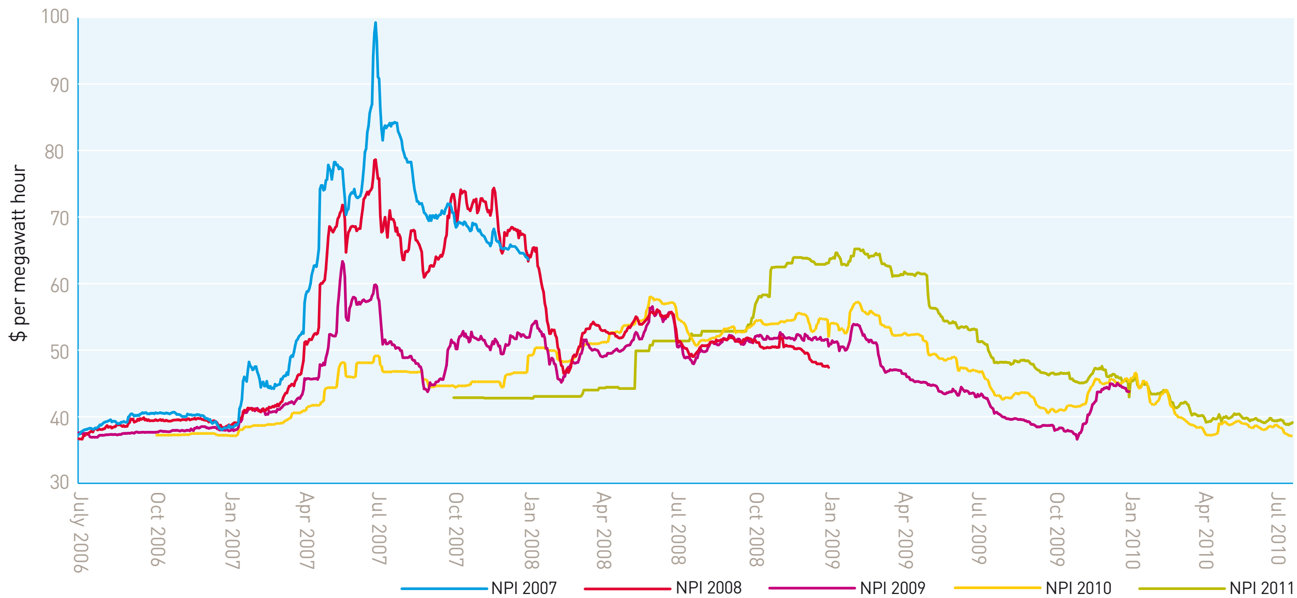
1.5 Electricity futures

Spot price volatility in the NEM can cause significant risk to wholesale market participants. While generators face a risk of low prices affecting earnings, retailers face a complementary risk that prices may rise to levels they cannot pass on to their customers. Market participants commonly manage their exposure to forward price risk by entering financial contracts (derivatives) that lock in firm prices for the electricity they intend to produce

9 Office of the Tasmanian Economic Regulator, *Declaration of frequency control ancillary services, Statement of reasons*, 2009, p. 4.

10 Office of the Tasmanian Economic Regulator, *Declaration of frequency control ancillary services, Statement of reasons*, 2009, pp. 3, 6.

Figure 1.10
National Power Index



Source: d-cyphaTrade.

or buy. 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 financial markets support the wholesale electricity market:

> over-the-counter (OTC) markets, comprising direct transactions between counterparties, often assisted by a broker
> the exchange traded market, in which electricity futures products developed by d-cyphaTrade are traded on the Sydney Futures Exchange (SFE).[11] 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.

The AER *State of the energy market 2009* described the operation of these markets and the financial instruments traded within them.

Futures trading in d-cyphaTrade products on the SFE is the fastest growing segment of the electricity derivatives market. The market covers futures instruments for the Victoria, New South Wales, Queensland and South Australia regions. Trading volumes in this market in 2009–10 were equivalent to about 204 per cent of underlying energy consumption. Victoria accounted for 36 per cent of traded volumes, followed by New South Wales (33 per cent) and Queensland (30 per cent). Liquidity in South Australia has remained low since 2002, accounting for only 1 per cent of volume.[12]

1.5.1 Electricity futures prices

Figure 1.10 shows average price outcomes for electricity base futures, as reflected in the National Power Index.[13] The index (which d-cyphaTrade publishes for each calendar year) represents a basket of electricity base futures for New South Wales, Victoria, Queensland

11 In 2006 the SFE merged with the Australian Stock Exchange. The merged business operates as the Australian Securities Exchange.

12 d-cyphaTrade, *Energy focus FY 2009–10 review*, 2010, p. 2.

13 Base futures account for most SFE trading volumes and open interest positions. Prices for peak futures tend to be higher than for base futures, but follow broadly similar trends. Base futures cover 0.00 to 24.00 hours, seven days per week. Peak futures cover 7.00 am to 10.00 pm, Monday to Friday, excluding public holidays.

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.

Base futures prices eased significantly from the first half of 2009 through to June 2010, falling to below $40 per MWh. Lower prices reflected relatively benign spot market conditions in Victoria and Queensland, and expectations that new generation plant coming on line in Queensland would ease the risks of price pressure.[14] Government announcements in 2009 and 2010 to delay the implementation of the CPRS also led to carbon being priced out of 2010 and 2011 futures.

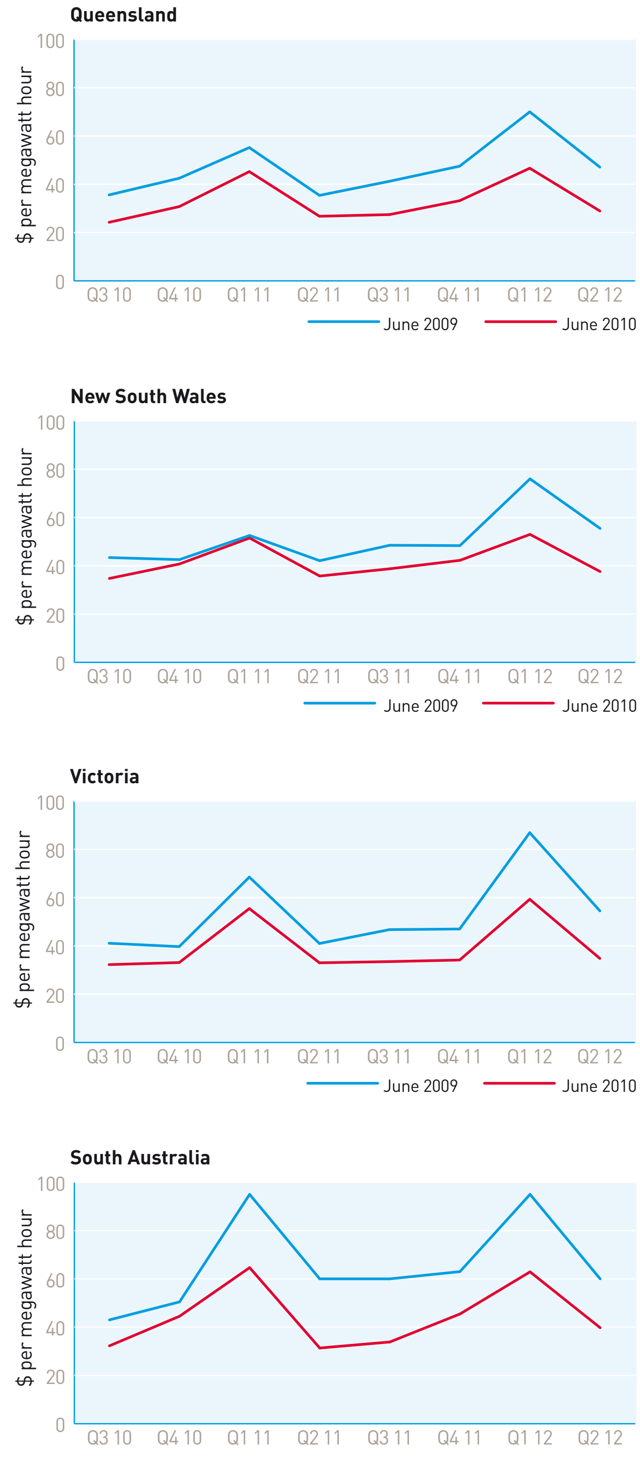
Forward curves

Figure 1.11 provides a snapshot at 30 June 2010 of forward prices for quarterly base futures on the SFE, up to two years from the trading date. These snapshots are often described as forward curves. For comparative purposes, forward prices at 30 June 2009 are also provided.

Forward prices in June 2010 were generally down on the levels of June 2009. This fall was consistent with an easing in spot prices for electricity, and may reflect the commissioning in 2009–10 of around 1600 MW of new generation capacity (mostly in Queensland) and a further 1200 MW of committed capacity beyond 2009–10 (tables 1.6 and 1.7).

Forward prices remained higher in South Australia than elsewhere, especially for the summer peak periods. This may reflect continuing market concerns that high prices in South Australia's physical electricity market over the past three summers—as a result of high temperatures, interconnector constraints and opportunistic bidding by AGL Energy—may recur. But while South Australian forward prices remained higher than elsewhere, they eased off their extreme 2009 levels.

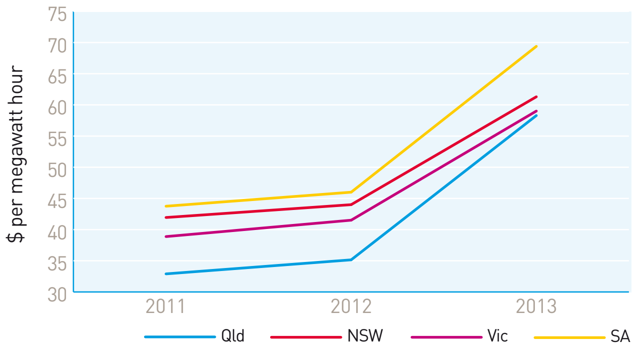
Figure 1.11
Base futures prices, June 2009 and June 2010



Sources: AER; d-cyphaTrade.

14 d-cyphaTrade, *Energy focus FY 2009–10 review*, 2010, p. 3.

Figure 1.12
Base calendar strip, June 2010



Sources: AER; d-cyphaTrade.

Victoria's 'peaky' demand profile can also lead to high summer prices. The market appears to be factoring in concerns that Victoria's supply–demand balance may become tight in summer 2012 unless committed new capacity (such as Origin Energy's 518 MW plant at Mortlake) is operational.

Forward prices for Queensland remain lower than elsewhere. The commissioning of new generation plant in 2010, including Origin Energy's 605 MW Darling Downs power station, has increased regional supply and is expected to mitigate price pressure in the short to medium term. The new plant also increases Queensland's export capacity to New South Wales, which may help ease price pressure in that region.

While futures contracts typically relate to a specific quarter of a year, contracts are increasingly being traded as calendar year strips, comprising a 'bundle' of the four quarters of the year. This tendency is more pronounced for contracts starting at least one year from the trade date. Figure 1.12 charts prices in June 2010 for calendar year futures strips to 2013. While prices are generally consistent with those evident in the forward curves, they smooth out the impact of seasonal peaks.

In June 2010 all regions had forward curves in contango—that is, prices were higher for contracts in the later years. This trend may reflect uncertainty about climate change policies (especially for calendar year 2013), including the effects of policy uncertainty on investment. More generally, the market may be factoring in assessments of supply adequacy in some regions.

1.6 Generation investment

New investment in the NEM is largely driven by price signals in the wholesale and forward markets for electricity. From the inception of the NEM in 1999 to June 2010, new investment added around 12 100 MW of registered generation capacity.[15] Figures 1.13 and 1.14 illustrate investment since market start.

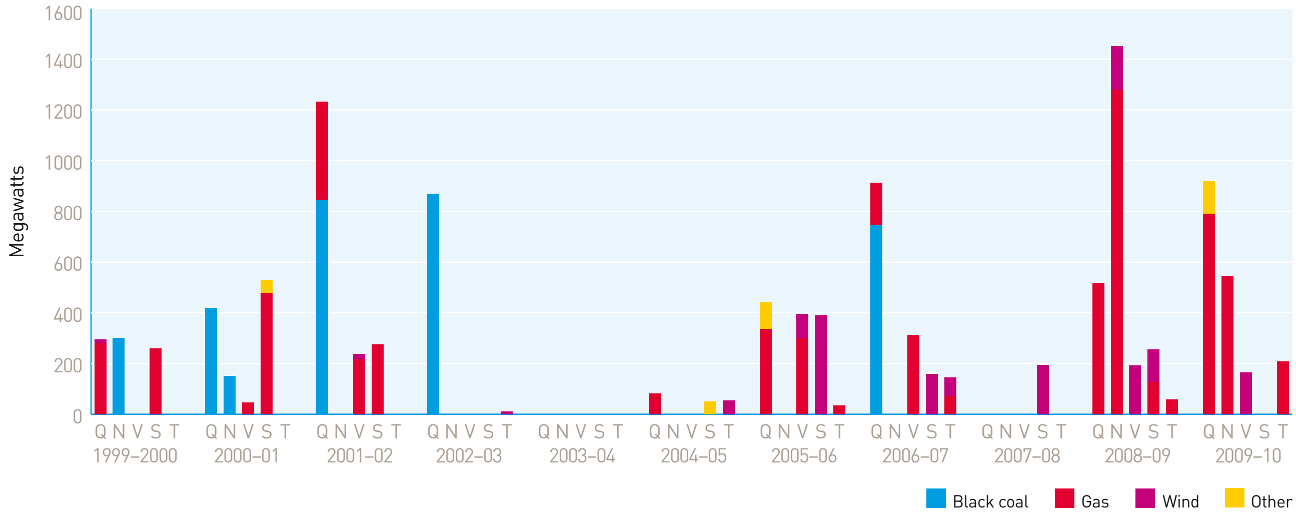
Tightening supply conditions led to an upswing in generation investment from around 2005. The bulk of new investment over the two years to 30 June 2010 was in Queensland (44 per cent of NEM-wide investment) and New South Wales (31 per cent). Developers have committed to further capacity, including major new plant in Victoria. Investment in wind generation has also been significant, especially in South Australia.

Table 1.6 sets out major new generation investment that came on line in the NEM in 2009–10. Around 1800 MW of new capacity was added, following 2500 MW of investment in 2008–09. New gas fired plant in Queensland accounted for over 50 per cent of new investment in 2009–10, including Origin Energy's 605 MW power station on the Darling Downs. In New South Wales, Delta Electricity completed a major expansion of its Colongra plant. Also, in Victoria, investment was made in hydro and wind capacity.

Table 1.7 sets out investment projects in the NEM at June 2010 that were committed but not yet operational. It includes those projects under construction and those for which developers and financiers had formally committed to construction. AEMO accounts for committed projects in projecting electricity supply and demand. At June 2010 the NEM had over 1200 MW of committed capacity, mostly in gas fired and wind generation. The most significant project was Origin Energy's 518 MW Mortlake power station in Victoria, scheduled for commissioning by the summer of 2010–11.

15 There has also been investment in small generators, remote generators not connected to a transmission network, and generators that produce exclusively for self-use (such as for remote mining operations).

Figure 1.13
Annual investment in registered generation capacity



Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.

Note: Data are gross investment estimates that do not account for decommissioned plant.

Sources: AEMO; AER.

In addition to committed projects, AEMO lists 'proposed' generation projects that are 'advanced' or publicly announced. While some of these projects come to fruition, AEMO considers them to be speculative and thus excludes them from its supply and demand outlooks. At June 2010 it listed over 40 000 MW of proposed capacity in the NEM (figure 1.15). The bulk of proposed investment is in New South Wales and Victoria.

The proposals mostly rely on gas fired and wind technologies. While most of the gas plants adopt open or combined cycle technologies, proposals also include:

> one of the world's first integrated gasification combined cycle (IGCC) plants with carbon capture and storage, which Stanwell proposes for Queensland by 2015–16. The 400 MW plant would be capable of capturing 90 per cent of carbon emissions in the fuel stream for future storage.[16]

> a 600 MW integrated drying and gasification combined cycle (IDGCC) plant proposed for Victoria by 2013–14. The plant would rely on a technology to dry and gasify moist reactive coals (including brown coal), and would reduce carbon emissions by around 30 per cent compared with conventional plant.[17]

South Australia has two publicly announced geothermal projects, including a 525 MW project scheduled to connect to the grid in 2018.

1.7 Reliability of supply

Reliability refers to the continuity of electricity supply to customers. The Australian Energy Market Commission (AEMC) Reliability Panel sets the reliability standard for the NEM. The standard is the expected amount of energy at risk of not being delivered to customers due to a lack of available capacity. To meet this standard, AEMO determines the necessary spare capacity that must be available for each region (including via transmission interconnectors) to provide a buffer against unexpected demand spikes and generation failure.

16 Wandoan Power, 'Cleaner coal technology moves forward in Australia', Media release, 8 December 2009.

17 Victorian Department of Primary Industries, 'HRL's new coal technology to lower carbon dioxide emissions intensity', Media release, 31 August 2010.

Figure 1.14
Net change in generation capacity since market start, cumulative

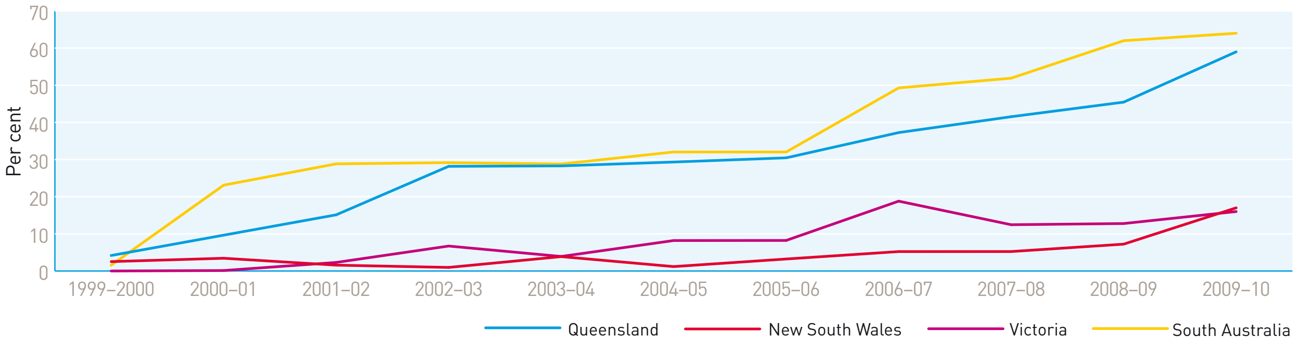


Table 1.6 Generation investment in the National Electricity Market, 2009–10

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED	ESTIMATED COST ($ MILLION)
QUEENSLAND					
Origin Energy	Darling Downs	CCGT	605	December 2009	780
QGC Sales	Condamine	CCGT	135	July 2009	200
Origin Energy	Mount Stuart (expansion)	OCGT	127	October 2009	110
NEW SOUTH WALES					
Delta Electricity	Colongra (units 2–4)	OCGT	471	October 2009	500
VICTORIA					
AGL Hydro	Bogong (part of McKay)	Hydro	140	November 2009	230
Pacific Hydro	Portland	Wind	164	October 2009	330
TASMANIA					
Aurora Energy	Tamar Valley	CCGT	196	July 2009	240

Table 1.7 Committed investment in the National Electricity Market, June 2010

DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND				
Rio Tinto	Yarwun	Gas cogeneration	146	2010
NEW SOUTH WALES				
Eraring Energy	Eraring (upgrade)	Coal fired	240	2012–13
VICTORIA				
Origin Energy	Mortlake	OCGT	518	2010
AGL Energy	Oaklands Hill Wind Farm	Wind	42	2011–12
SOUTH AUSTRALIA				
AGL Energy	North Brown Hill Wind Farm	Wind	82	2010
AGL Energy	The Bluff Wind Farm	Wind	33	2011–12
Infigen Energy	Lake Bonney 3	Wind	39	2010–11
Roaring 40s	Waterloo Wind Farm	Wind	111	2010–11
International Power	Port Lincoln	OCGT	25	2010

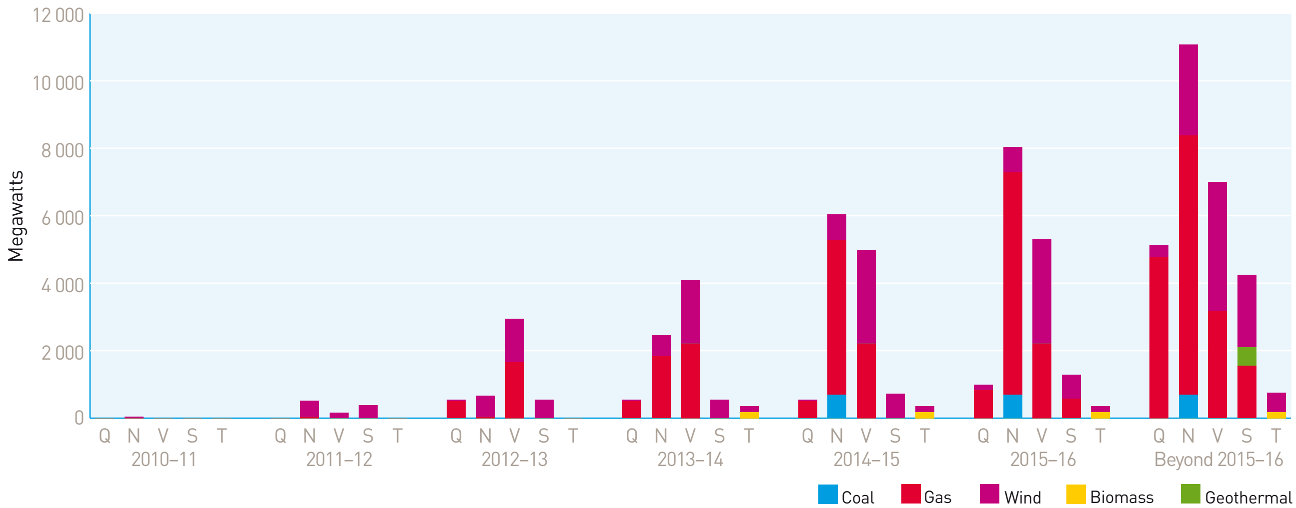
CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

Sources (figure 1.14 and tables 1.6 and 1.7): AEMO; AER.

Photo courtesy of TRUenergy

Figure 1.15

Major proposed generation investment in the National Electricity Market, cumulative, June 2010



Source: AEMO.

The current reliability standard for the NEM is that no more than 0.002 per cent of customer demand in each NEM region should be unserved by generation capacity in the region, allowing for demand-side capacity and import capacity from interconnectors. It does not account for supply interruptions in transmission and distribution networks, which are subject to different standards and regulatory arrangements (chapter 2).

1.7.1 Reliability settings

Procedures are in place to ensure the reliability standard is met—for example, AEMO publishes forecasts of electricity demand and generator availability to allow generators to respond to market conditions and schedule maintenance outages. The reliability panel also recommends settings to ensure the standard is met, including:

- a spot market price cap, which is set at a sufficiently high level to stimulate the required investment in generation capacity to meet the standard. The cap increased from $10 000 per MWh to $12 500 per MWh on 1 July 2010
- a cumulative price threshold to limit the exposure of participants to extreme prices. If cumulative spot prices exceed this threshold over a rolling seven days, then AEMO must impose an administered price cap. The threshold is $187 500 per MWh, and the administered cap is $300 per MWh
- a market floor price, set at –$1000 per MWh
- safety net mechanisms through which AEMO can manage a short term risk of unserved energy:
  - —AEMO can enter reserve contracts with generators under a reliability and emergency reserve trader (RERT) mechanism to ensure reserves are available to meet the reliability standard. When entering these contracts, AEMO must give priority to facilities that would least distort wholesale market prices.
  - —AEMO can use its directions power to require generators to provide additional supply at the time of dispatch to ensure sufficient reserves are available.

1.7.2 Reliability performance

The reliability panel annually reports on the performance of the generation sector against the reliability standard and minimum reserve levels set by AEMO. All regions of the NEM have consistently met the 0.002 per cent reliability standard, which is measured over the long term (based on a 10 year moving average). 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.

Insufficient generation capacity to meet consumer demand occurred only three times from the NEM start to 30 June 2010. The most recent instance resulted from a heatwave in Victoria and South Australia in January 2009. The unserved energy from these events on an annual basis was 0.0032 per cent for South Australia and 0.004 per cent for Victoria.[18]

AEMO issued seven directions in 2009–10 to manage local power system issues (compared with 18 directions in 2008–09): four directions for Queensland, and one each for New South Wales, South Australia and Tasmania.

1.7.3 Review of reliability settings

Following the unserved energy events in south east Australia in January 2009, the AEMC asked the reliability panel to review whether the current reliability standard and settings remained appropriate. The review (completed in April 2010) recommended:

- retaining the current reliability standard of 0.002 per cent unserved energy per year for each region and across the NEM as a whole. It also proposed performance be assessed against the standard each year, rather than against a 10 year moving average
- annually increasing (from 1 July 2012) the market price cap from $12 500 per MWh, based on movements in the Producer Price Index. The panel considered this change would improve incentives for efficient generation investment. It noted a range of justifications, including rising capital costs for new entrant gas fired generators and 'peakier' electricity demand
- annually increasing (from 1 July 2012) the cumulative price threshold from $187 500 per MWh, based on movements in the Producer Price Index, to mirror increases in the market price cap.[19]

The reliability panel is conducting a separate review of the RERT scheme, which expires in June 2012. Following the unserved energy events in south east Australia during the heatwave in 2009, the panel proposed to make the RERT arrangements more flexible to better address the risk of short term generation capacity shortfalls. The Electricity Rules were amended in October 2009 to implement these changes, which allow more flexibility in contracting under the RERT mechanism. The changes include the establishment of a panel of participants and a short notice contracting process.

In addition, the panel published a review in December 2009 of the operational arrangements to meet the reliability standard. The review recommended refinements to the process for determining minimum reserve levels and obligations on market participants, to provide AEMO with more accurate information on generation availability.

The AEMC in May 2010 completed a review of the effectiveness of the security and reliability arrangements in the light of extreme weather events. The review stemmed from the Ministerial Council on Energy's (MCE) concerns about supply interruptions during the heatwave in south east Australia in January 2009. The report recommended a comprehensive review of arrangements for managing the NEM's technical performance, to be completed by June 2011. It also recommended the AEMC take over (from the Reliability Panel) reviewing the reliability standard and settings, with a review every five years.

The AEMC also supported changing the Electricity Rules to require more accurate reporting of demand-side capability. This proposal aims to minimise AEMO's intervention in the market by improving the quality of reserve assessments.

1.7.4 Security issues

The power system is operated to cope with only credible contingencies. Some power supply interruptions are caused by non-credible (multiple contingency) events. This may involve several credible events occurring 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

18 AEMC Reliability Panel, *Reliability standard and reliability settings review, Final report*, 2010, p. 11.
19 AEMC Reliability Panel, *Reliability standard and reliability settings review, Final report*, 2010, p. viii.

time as a generator trips. When such events occur, the market operator may need to interrupt customer supply to prevent a power system collapse.

It would be economically inefficient to operate the power system to cope with non-credible events, which are classified as security issues. Likewise, additional investment in generation or networks may not avoid such interruptions. For this reason, reliability calculations exclude security issues.

While security issues are not reflected in reliability calculations, they may affect the continuity of supply. Five security incidents each disrupted at least 50 MW of customer supply in the NEM in 2009–10, and a number of incidents had more localised impacts.

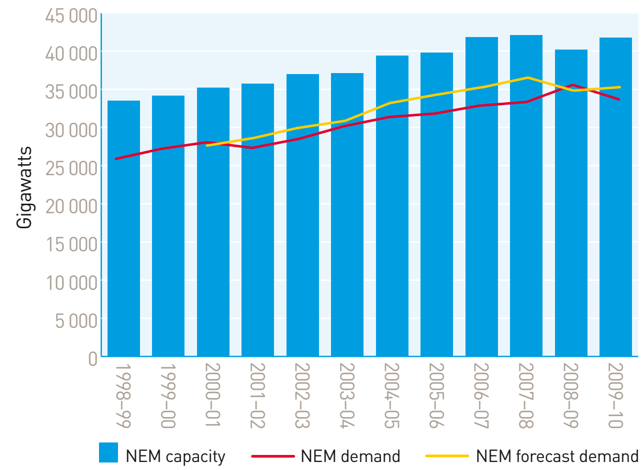
1.7.5 Historical adequacy of generation

A reliable power supply in the longer term needs sufficient investment in generation to meet customers' needs. A central element of the NEM's design is that spot prices respond to a tightening in the supply–demand balance. Regions with potential generation shortages, therefore, exhibit rising prices in spot and contract markets, which may help attract investment to those regions.

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 $12 500 per MWh is necessarily high to encourage investment in peaking plant, which is expensive to run and operates sporadically. Over the longer term, peaking plant plays a critical role in ensuring adequate generation capacity (and thus reliability). Investment in peaking capacity has been significant in most NEM regions over the past few years.

Figure 1.16 compares total generation capacity with national peak demand since the NEM began. It shows actual demand and AEMO's demand forecasts two years in advance. The data indicate that investment in the NEM over the past decade kept pace with rising demand (both actual and forecast levels), and provided a safety margin of capacity to maintain the reliability of the power system.

Figure 1.16
National Electricity Market peak demand and generation capacity



Notes:
Demand forecasts are two years in advance, based on a 50 per cent probability that the forecast will be exceeded and a coincidence factor of 95 per cent.

NEM capacity excludes wind generation and power stations not managed through central dispatch.

Source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, various years.

1.7.6 Reliability outlook

The relationship between future demand and available capacity will determine electricity prices and the reliability of the power system. Figure 1.17 charts forecast peak demand in the NEM against installed, committed and proposed generation capacity. It indicates the amount of capacity that AEMO considers would be needed to maintain reliability, given projected demand.

Figure 1.17 indicates installed and committed capacity (excluding wind) across the NEM as a whole will be sufficient until 2013–14 to meet peak demand projections and reliability requirements. Beyond that time, the ability of the market as a whole to meet reliability requirements may require some proposed generation projects to come online. While the uncertain nature of proposed projects means they cannot be factored into reliability equations, the amount of proposed capacity indicates the market's awareness of future capacity needs.

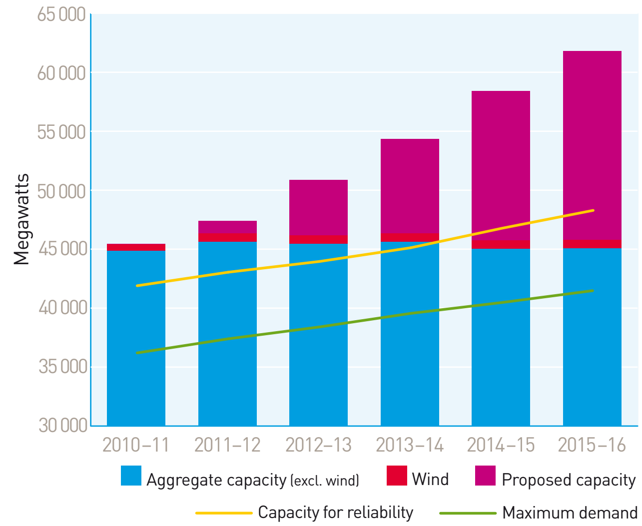
While figure 1.17 indicates longer term capacity requirements in the NEM as a whole, it does not indicate the required timing of new capacity in particular regions. AEMO's 2010 *Power system adequacy* report found the power system should have sufficient supply capacity to meet forecast peak demand plus a minimum reserve level for reliability in every NEM region over the two year period to June 2012. This assessment assumed Origin Energy's committed Mortlake generator in Victoria would be commissioned by summer 2010–11. Accordingly, AEMO did not expect to invoke its reliability and emergency reserve trader tender process in any region over the period to June 2012.[20]

AEMO's longer term market review found that assuming medium economic growth, Queensland would be the first region in the NEM to require new generation investment (by 2013–14) beyond that already committed.[21] While Queensland has had substantial new investment over the past decade, the region's economic growth is projected to rise given buoyant demand in the Surat Basin gas producing area as a result of coal seam gas developments, coal mining developments, and growth in supporting infrastructure and services. Also, installed capacity is expected to fall as the Swanbank B coal fired plant is progressively retired (to be completed by 2012–13).

AEMO projected Victoria and South Australia would require new investment (beyond committed capacity) by 2015–16, as would New South Wales by 2016–17. It expected Tasmania to have adequate capacity until at least 2019–20.

The AEMO report noted climate change policies and the emergence of new technologies would be significant investment drivers over the next few years. In particular, it noted the national RET scheme would likely shift the generation mix towards less carbon intensive generation sources. It also noted the potential for new technology such as smart meters, smart grids and electric vehicles, combined with an increased focus on energy efficiency, to alter consumption patterns and mitigate the growth in capacity requirements. The report considered the delay in, and associated uncertainty with, the implementation of an emissions trading scheme may pose risks for investment.[22]

Figure 1.17
Electricity demand and supply outlook to 2015–16



Notes:
Capacity (excluding wind) is scheduled capacity and encompasses installed and committed capacity. Wind capacity includes scheduled and semi-scheduled wind generation. Proposed capacity includes wind projects.

Wind generation is treated differently from conventional generation for the supply–demand balance. At times of peak demand, the availability of wind capacity as a percentage of total generation supply is assumed to be 3 per cent in South Australia, 8 per cent in Victoria and 5 per cent in New South Wales.

The maximum demand forecasts for each NEM region are aggregated based on a 50 per cent probability of exceedance and a 95 per cent coincidence factor. Unscheduled generation is treated as a reduction in demand.

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: AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010.

20 AEMO, *2010 power system adequacy: two year outlook*, 2010, p. 2.
21 AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010, pp. 3–4.
22 AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010, p. 9.

1.8 AER market investigations and compliance monitoring

The AER monitors activity in the spot market to screen for noncompliance with the Electricity Rules. In addition to reporting on all extreme price events in the NEM, it conducts more intensive investigations if warranted.

1.8.1 Stanwell compliance with clause 3.8.22A

The AER launched an investigation in 2008 into a period of sustained high electricity prices in Queensland in early 2008. It subsequently instituted proceedings in the Federal Court, Brisbane, against Stanwell Corporation Limited (a Queensland generator) for alleged contraventions of the Electricity Rules.

The AER alleged Stanwell did not make several of its offers to generate electricity on 22 and 23 February 2008 in 'good faith', contrary to clause 3.8.22A of the Electricity Rules. The AER sought orders that included declarations, civil penalties, a compliance program and costs. The trial in this matter commenced in Brisbane on 15 June 2010 before Justice Dowsett and concluded on 5 July 2010. In late 2010 the parties were waiting for the judgment.

1.8.2 Babcock & Brown compliance with dispatch instructions

The AER published an investigation report in December 2009 into the compliance of Babcock & Brown Power (BBP, now Alinta Energy) with Electricity Rules provisions relating to the operation of two BBP power stations: Playford in South Australia and Braemar in Queensland.

The AER alleged:

- Playford power station failed on 11 February 2009 to follow dispatch targets issued by AEMO. The AER also alleged BBP failed to notify AEMO of an event likely to change the operational availability of Playford.
- Braemar power station began producing electricity on 17 March 2009 without first receiving a dispatch target from AEMO.

The AER issued infringement notices (totalling $40 000) in September 2009, relating to the alleged failure of Playford and Braemar power stations to follow AEMO's dispatch instructions. While the AER did not issue an infringement notice to BBP for failing to notify AEMO of a change in Playford's operational availability, BBP committed to improve its compliance in this area.

EnergyAustralia's City West Cable Tunnel, Sydney (EnergyAustralia)

2 ELECTRICITY NETWORKS

Electricity networks transport power from generators to customers. Transmission networks transport power over long distances, linking generators with load centres. Distribution networks transport electricity from points along the transmission network, and criss-cross urban and regional areas to provide electricity to customers.

2.1 Electricity networks in the NEM

In Australia, each state and territory has electricity transmission networks, with cross-border interconnectors that link some networks (table 2.1). The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected network from Queensland through to New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania. The NEM transmission network has a long, thin, low density structure reflecting the location of, and distance between, major demand centres.

The NEM has 13 major electricity distribution networks (table 2.2). Queensland, New South Wales and Victoria have multiple networks, of which each is a monopoly provider in a designated area. Each of the other jurisdictions has one major network. Some jurisdictions also have small regional networks with separate ownership. The total length of distribution infrastructure in the NEM is around 750 000 kilometres—17 times longer than transmission infrastructure.

Figure 2.1 illustrates the transmission and distribution networks in the NEM.

2.1.1 Ownership

Tables 2.1 and 2.2 list ownership arrangements for electricity networks in the NEM. The transmission networks in Victoria and South Australia, and the three direct current network interconnectors (Directlink, Murraylink and Basslink) are privately owned.

Victoria's five distribution networks are also privately owned, while the South Australian network (ETSA Utilities) is leased to private interests. The ACT network has joint government and private ownership. All networks (transmission and distribution) in Queensland, New South Wales and Tasmania are owned by governments.

Aside from governments, there were two principal network owners at June 2010:

> *Cheung Kong Infrastructure* and Hongkong Electric Holdings have a 51 per cent stake in two Victorian distribution 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 the Jemena distribution network and has part ownership of the United Energy distribution network, both in Victoria. It has a 50 per cent share in the ACT distribution network (ActewAGL) and a 51 per cent stake in SP AusNet, which owns the Victorian transmission network and SP AusNet distribution network.

These businesses also own a number of gas networks in Australia (see chapter 3).

Victoria has a unique transmission network structure, which separates asset ownership from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Australian Energy Market Operator (AEMO, formerly VENCorp) plans and directs network augmentation. AEMO also buys bulk network services from SP AusNet for sale to customers.

In some jurisdictions, there are ownership links between electricity networks and other segments of the electricity sector. In New South Wales,[1] Tasmania and the ACT,[2] common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation. Queensland privatised much of its energy retail sector in 2006–07, but Ergon Energy continues to provide both distribution and retail services.

1 In New South Wales, privatisation plans for the contestable sectors of the energy market (generation and retail) will result in structural separation of the distribution and retail sectors (box 1.1, chapter 1).

2 In the ACT, ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. AGL Energy and Singapore Power International respectively own the remaining shares.

Figure 2.1

Electricity networks in the National Electricity Market

QNI, Queensland – New South Wales Interconnector.

Table 2.1 Electricity transmission networks

NETWORK	LOCATION	LINE LENGTH (KM)	ELECTRICITY TRANSMITTED (GWh), 2008–09	MAXIMUM DEMAND (MW), 2008–09	ASSET BASE (2009 $ MILLION)[1]	INVESTMENT—CURRENT PERIOD (2009 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS								
Powerlink	Qld	13 106	49 104	8 677	3 979	2 564	1 July 2007 – 30 June 2012	Queensland Government
TransGrid	NSW	12 445	75 744	14 274	4 213	2 440	1 July 2009 – 30 June 2014	New South Wales Government
SP AusNet	Vic	6 553	51 777	10 446	2 265	1 004[3]	1 Apr 2008 – 30 Mar 2014	Publicly listed company (Singapore Power International 51%)
ElectraNet	SA	5 589	13 327	3 408	1 303	659	1 July 2008 – 30 June 2013	Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust
Transend	Tas	3 650	11 031	2 236	950	615	1 July 2009 – 30 June 2014	Tasmanian Government
NEM TOTALS		**41 343**	**200 983**		**12 710**	**7 282**		
INTERCONNECTORS[4]								
Directlink (Terranora)	Qld–NSW	63		180	132		1 July 2005 – 30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220	121		1 Oct 2003 – 30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375			858[5]		Unregulated	CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)

GWh, gigawatt hours; MW, megawatts.

1. The regulated asset bases are as set at the beginning of the current regulatory period for each network, converted to June 2009 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2009 dollars.
3. SP AusNet's investment data include forecast augmentation investment by the Australian Energy Market Operator (formerly VENCorp).
4. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state based networks, are Heywood (Victoria – South Australia), QNI (Queensland – New South Wales) and Snowy-Victoria.
5. Basslink is not regulated, so has no regulated asset base. The listed asset value is the estimated construction cost.

Sources: AER, *Transmission network service providers: electricity performance report for 2008–09*, 2010 and previous years; AER/ACCC revenue cap decisions.

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW) (2008–09)	ASSET BASE (2009 $ MILLION)[1]	INVESTMENT — CURRENT PERIOD (2009 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
ENERGEX	1 256 574	52 361	4 593	7 867	5 602	1 Jul 2010– 30 Jun 2015	Queensland Government
Ergon Energy	636 480	145 904	2 498	7 149	4 866	1 Jul 2010– 30 Jun 2015	Queensland Government
NEW SOUTH WALES AND ACT							
EnergyAustralia[3]	1 591 372	49 546	5 918	8 431	7 837	1 Jul 2009– 30 Jun 2014	New South Wales Government
Integral Energy	859 718	33 579	3 798	3 744	2 721	1 Jul 2009– 30 Jun 2014	New South Wales Government
Country Energy	786 241	189 823	2 332	4 382	3 826	1 Jul 2009– 30 Jun 2014	New South Wales Government
ActewAGL	161 061	4 795	…	607	275	1 Jul 2009– 30 Jun 2014	ACTEW Corporation (ACT Government) 50%, Jemena (Singapore Power International (Australia)) 50%
VICTORIA							
Powercor	698 509	83 468	2 380	2 132	1 276	1 Jan 2011– 31 Dec 2015	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%, Spark Infrastructure 49%
SP AusNet	609 855	47 999	1 682	2 043	1 365	1 Jan 2011– 31 Dec 2015	SP AusNet (listed company, Singapore Power International 51%)
United Energy	620 300	12 707	2 070	1 330	725	1 Jan 2011– 31 Dec 2015	Jemena (Singapore Power International (Australia)) 34%, DUET Group 66%
CitiPower	304 957	6 478	1 463	1 240	740	1 Jan 2011– 31 Dec 2015	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%, Spark Infrastructure 49%
Jemena	303 245	5 928	1 011	729	418	1 Jan 2011– 31 Dec 2015	Jemena (Singapore Power International (Australia))
SOUTH AUSTRALIA							
ETSA Utilities	807 500	86 634	3 086	2 772	1 549	1 Jan 2011– 31 Dec 2015	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%, Spark Infrastructure 49%
TASMANIA							
Aurora Energy	269 554	25 050	1 073	1 072	631	1 Jan 2008– 20 Jun 2013	Tasmanian Government
NEM TOTALS	**8 905 366**	**744 272**		**43 498**	**31 832**		

MW, megawatts.

1. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2009 dollars. Regulated asset base data do not include capital contributions except for Queensland. Capital contributions can form a significant proportion of new network investment—for example, they typically account for around 10–20 per cent of distribution network investment in Victoria and over 20 per cent of investment in South Australia.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2009 dollars.
3. EnergyAustralia's distribution network includes 885 kilometres of transmission assets. From 1 July 2009, these assets are treated as distribution assets for the purpose of economic regulation. Future performance of the network will be assessed under the framework applicable to distribution network service providers.

Sources: Regulatory determinations by the AER and OTTER (Tasmania); performance reports by the AER (Victoria), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy.

2.1.2 Scale of the networks

Tables 2.1 and 2.2 show the asset values of NEM electricity networks, as measured by the regulated asset base (RAB). In general, the RAB reflects the replacement cost of an asset at the time it was first regulated, plus subsequent new investment, less depreciation. More generally, it indicates relative scale.

Networks in Queensland and New South Wales have significantly higher RABs than those of other jurisdictions. Many factors can affect the size of the RAB, including the basis of original valuation, network investment, the age of a network, geographic scale, the distances required to transport electricity, population dispersion and forecast demand profiles.

The combined opening RABs of distribution networks in the NEM are around $43.5 billion—more than three times the valuation for transmission infrastructure (around $12.7 billion).

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining marginal costs as output increases, leading to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing. The Australian Energy Regulator (AER) regulates all electricity networks in the NEM. The Economic Regulation Authority regulates networks in Western Australia, and the Utilities Commission regulates networks in the Northern Territory.

2.2.1 Regulatory process and approach

Regulated electricity network businesses must periodically apply to the AER to assess their revenue requirements (typically, every five years). The regulatory process is set out in the National Electricity Law and the National Electricity Rules, as summarised in the following discussion. The AER *State of the energy market 2009* report (sections 5.3 and 6.3) provides more detail.

For a transmission network, the AER must determine a revenue cap that sets the maximum revenue the network can earn during a regulatory period. The range of available control mechanisms is wider in distribution, but generally involves setting a ceiling on the revenues or prices that a network can earn or charge during a period. Control mechanisms in use include:

- *weighted average price caps,* which allow flexibility in individual tariffs within an overall ceiling—used for the New South Wales, Victorian and South Australian networks
- *average revenue caps,* which set a ceiling on revenue yields that may be recovered during a regulatory period—used for the Queensland and ACT networks.

Regardless of the regulatory approach, the AER must forecast the revenue requirement of a business to cover its efficient costs and provide a commercial return. It uses a building block model that accounts for a network's efficient operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and a commercial return on capital. The Australian Energy Market Commission (AEMC) is reviewing a total factor productivity approach as an alternative to the building block model (box 2.1).

The largest component of network revenue is the return on capital, which accounts for up to two thirds of network revenues. The return on capital is influenced by the size of a network's regulated asset base (and projected investment) and its weighted average cost of capital (the rate of return necessary to cover efficient equity raising and debt costs). An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

2.2.2 Regulatory timelines and recent AER determinations

Figure 2.2 shows the regulatory timelines for electricity networks in each jurisdiction. In 2010 the AER completed distribution reviews for networks in Queensland and South Australia (released May 2010) and Victoria (released October 2010).

Box 2.1 Total factor productivity approach

In November 2010 the Australian Energy Market Commission (AEMC) published a draft report on using a total factor productivity approach to regulating network revenues and prices.[3] The approach measures how businesses use resources to produce output. It exposes regulated businesses to competitive pressures by linking revenues to industry performance rather than the cost structure of a particular business.

The AEMC identified potential benefits of using this method over the current building block approach:

> a less information intensive approach, with reduced regulatory costs
> reduced information asymmetry between regulated businesses and regulators
> stronger performance incentives for regulated businesses.

It found that applying a total factor productivity approach is likely to have benefits, especially in the distribution sector. It considered, however, that existing regulatory data may not be sufficiently robust or consistent to implement the approach in the short term.

The draft report recommended that the initial focus should be on establishing a better, more consistent data-set to allow for the undertaking of initial trials. The proposed reporting requirements would apply in both the transmission and distribution sectors.

3 AEMC, *Review into the use of total factor productivity for the determination of prices and revenues, draft report*, 2010.

The South Australian and Queensland distribution businesses lodged appeals with the Australian Competition Tribunal over aspects of the AER decisions. The *Market overview* in this report provides information on these appeals.

2.3 Revenues

Figure 2.3 illustrates AER revenue allowances for electricity networks in the current five year regulatory periods compared with previous periods. Combined network revenues were forecast to exceed $55 billion over the current cycle, comprising over $11 billion for transmission and $44 billion for distribution. Average revenues are forecast to rise by around 41 per cent (in real terms) over those of the previous regulatory periods.

Under AER determinations in 2010 for the distribution sector, average revenues are forecast to rise by around 37 per cent in Queensland, 24 per cent in South Australia and 11 per cent in Victoria. The largest increases in current determinations (over 70 per cent) are forecast for the EnergyAustralia and Country Energy networks in New South Wales (figure 2.3). As outlined in section 2.4.1, these outcomes reflect differences in the operating environments and cost drivers of each network.

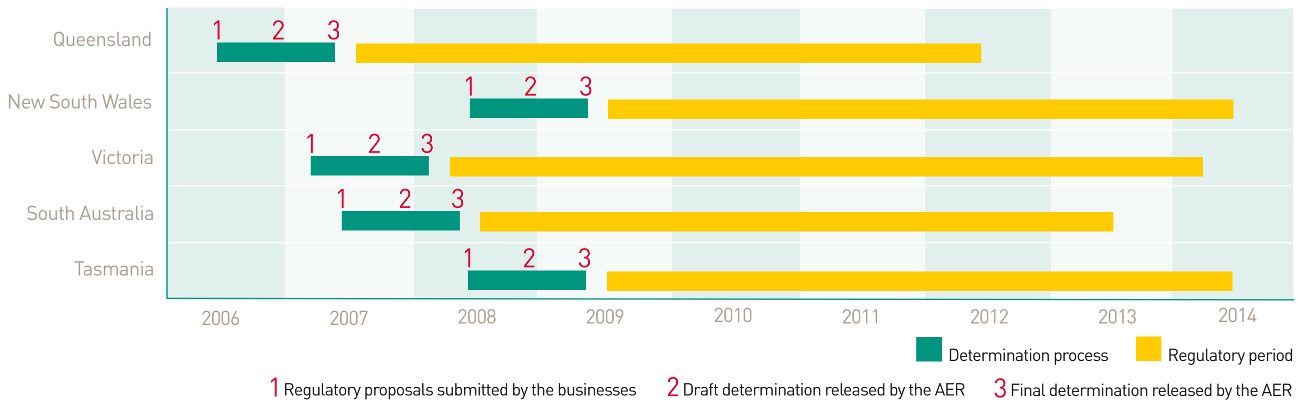
2.4 Electricity network investment

New investment in 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 regulatory requirements on matters such as network reliability, or by technological innovations that can improve network performance.

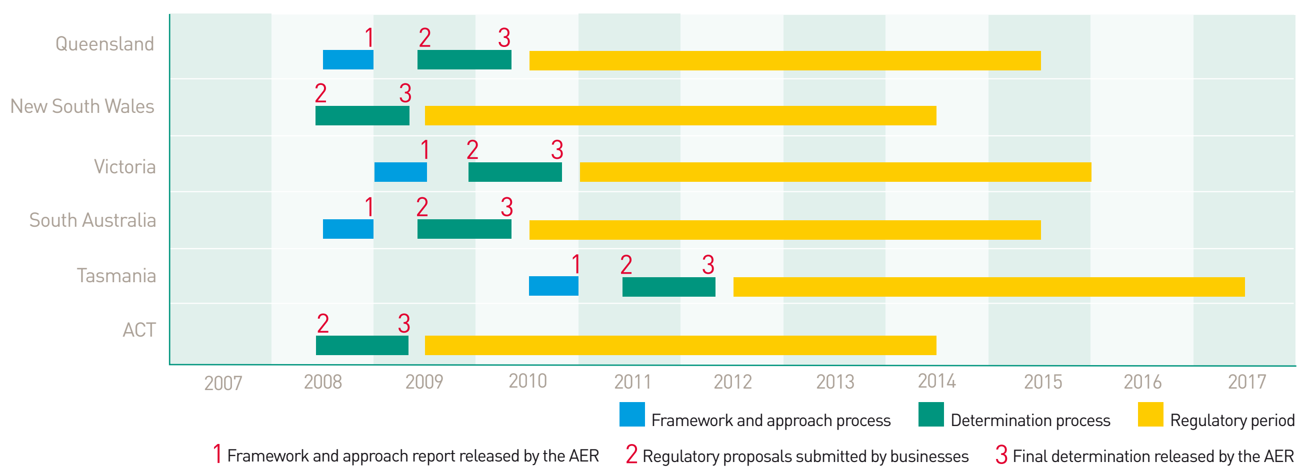
The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can also approve contingent projects—large investment projects that are foreseen at the time of the revenue determination, but that involve significant uncertainty.

Figure 2.2
Indicative timelines for AER determinations on electricity networks

Electricity transmission



Electricity distribution



Note: The New South Wales and ACT distribution determinations were developed under transitional Electricity Rules, which did not provide for a framework and approach process.

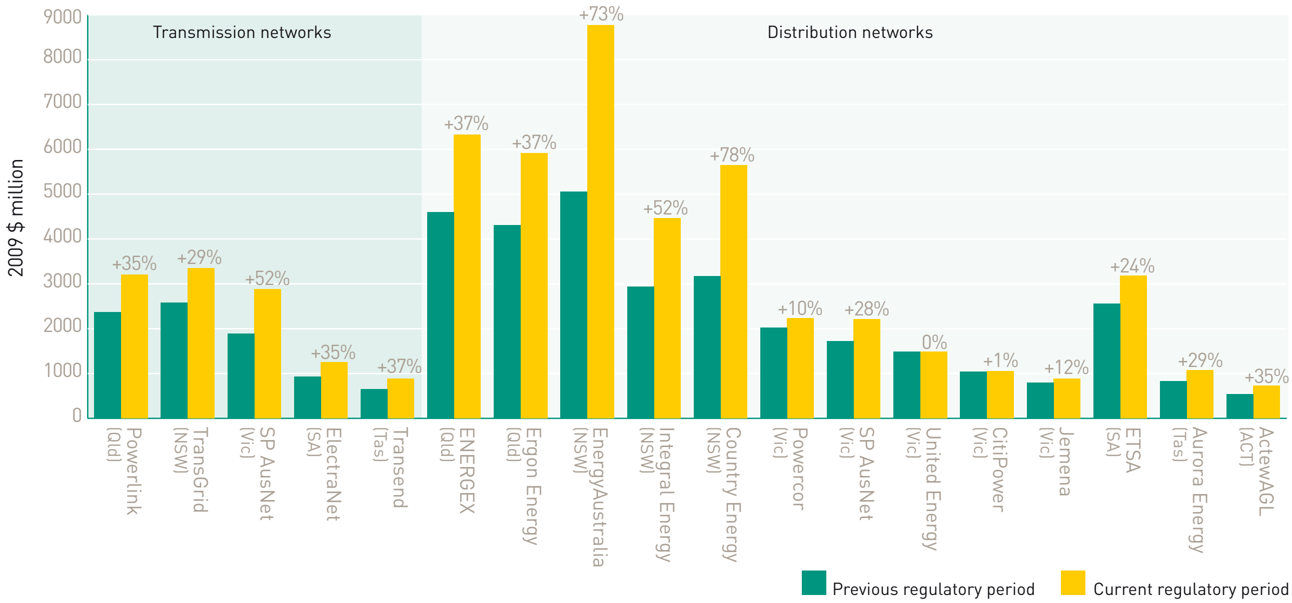
While the regulatory process approves a pool of funds for capital expenditure, individual projects must undergo an economic efficiency assessment that aims to identify the most efficient method—accounting for network augmentation and non-network options—to meet an identified need.

There are separate versions of the test for distribution and transmission. For distribution networks, the regulatory test requires a business to determine that a proposed augmentation passes a cost–benefit analysis or provides a least cost solution to meet network reliability standards.[4]

A new regulatory investment test for transmission (RIT-T) took effect on 1 August 2010.[5] Transmission projects are now assessed through a single consultation and assessment framework that is more comprehensive and applies to a wider range of investment projects than previously. It also gives more prescription of the

4 AER, *Regulatory test for network augmentation, version 3*, 2007.
5 AER, *Regulatory investment test for transmission*, 2010

Figure 2.3
Electricity network revenues



Notes:

Current regulatory period revenues are forecasts in regulatory determinations.

All data are converted to June 2009 dollars.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

market benefits and costs that the analysis can consider. In September 2009 the AEMC recommended that a test similar to the RIT-T apply in distribution.[6]

The AER in 2010 reviewed the compliance of TransGrid (New South Wales) with the regulatory test, in regard to a proposed 330 kilovolt (kV) transmission line from Dumaresq to Lismore.[7] It found shortcomings in TransGrid's analysis and process in deciding to build the line. TransGrid subsequently committed to the AER to improve future processes.

2.4.1 Investment trends

Figure 2.4 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. It shows the RAB for each network as a scale reference.

Network investment over the current five year cycle is forecast at over $7 billion for transmission networks and $32 billion for distribution networks. Investment is set to rise by around 84 per cent in transmission and 54 per cent in distribution (in real terms). The key drivers of rising investment include:

- more rigorous licensing conditions and other obligations for network security, safety and reliability
- load growth and rising peak demand
- new connections
- the need to replace ageing assets, given much of the networks were developed between the 1950s and 1970s.

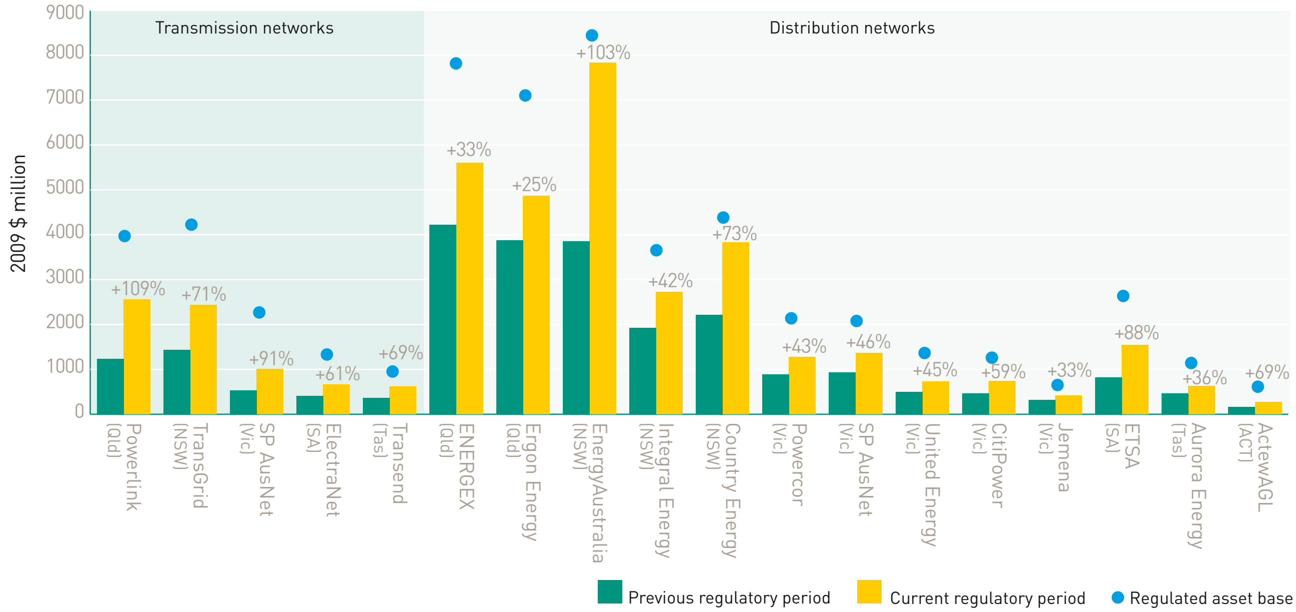
Other drivers include changes to system operation due to climate change policies and the introduction of smart meters and grids.

While these factors are driving higher levels of investment, each network faces a different blend of challenges—for example, each network has unique issues relating to its age and technology, its load characteristics, the costs of meeting the demand for

6 AEMC, *Review of national framework for electricity distribution network planning and expansion, final report*, 2009.

7 AER, *Investigation report, Compliance with the planning and network development provisions of the National Electricity Rules—TransGrid*, 2010.

Figure 2.4
Electricity network investment



Notes:

Regulated asset bases are as at the beginning of the current regulatory periods.

Investment data reflect forecast capital expenditure for the current regulatory period (typically, five years). See tables 2.1 and 2.2 for the timing of current regulatory periods.

EnergyAustralia's distribution network includes 885 kilometres of transmission assets.

SP AusNet includes augmentation investment by AEMO (formerly VENCorp).

All data are converted to June 2009 dollars.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

new connections, and its licensing, reliability and safety requirements. Other issues are common to all network businesses—for example, rising input and finance costs.

As required by the regulatory regime, the AER accounts for these factors when assessing the needs of each network. Electricity distribution determinations in 2010 reflected that:

> the Queensland networks have pressing capital requirements associated with population growth, new connections and industrial demand, as well as rising energy use per customer. The networks are also obliged to improve performance in response to stricter reliability standards
> the South Australian network requires significant investment to meet rising load growth and peak demand driven by the use of air conditioners during summer heatwaves. The network also needs to address reliability risks from ageing assets and new reliability standards for the Adelaide central business district (involving complementary upgrades to transmission and distribution systems). Investment costs in both Queensland and South Australia have also been rising as a result of real increases in the cost of labour and materials
> the Victorian distributors operate mostly mature and comparatively reliable networks. While the AER considers past expenditure (in what has been a relatively stable operating environment) provides a good starting point for assessing future needs, it also accounted for the need to replace ageing infrastructure, address Victoria's new bushfire safety standards, and maintain reliability in the face of growing costs and demand. While these considerations led it to approve higher levels of investment, the AER did not accept the full extent of the increases proposed by distribution businesses

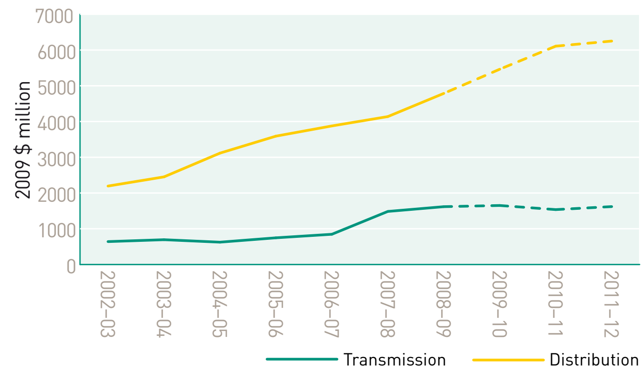
> the global financial crisis has significantly increased debt financing costs for all networks. The rate of return on capital in the next regulatory periods has thus increased by more than 100 basis points compared with the rate in previous periods. Recent AER determinations reflected that higher debt costs increased the revenue requirements of distribution businesses by between 5 and 9 per cent from requirements in previous regulatory periods.

Differences in operating environments can result in significant variations in capital investment requirements (figure 2.4). Electricity distribution investment over the current five year regulatory periods is expected to exceed investment in the previous regulatory periods by around 25–33 per cent in Queensland, 42–103 per cent in New South Wales, 33–59 per cent in Victoria, 88 per cent in South Australia and 69 per cent in the ACT (in real terms).

Differing capital requirements across the networks contribute to different retail impacts on consumers. The *Market overview* in this report comments on the retail impacts of recent AER determinations.

On an annual basis, transmission investment in the NEM totalled around $1.6 billion in 2008–09 and was forecast to remain at this level to 2011–12 (figure 2.5). Distribution investment was almost $4.5 billion in 2008–09 and is expected to rise to over $6 billion in 2011–12.

Figure 2.5
Total electricity network investment



Notes:

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

Transmission investment excludes private interconnectors.

All data are converted to June 2009 dollars.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

2.5 Operating and maintenance expenditure

The AER determines allowances for each network to cover efficient operating and maintenance expenditure. The needs of a network depend on load densities, the scale and condition of the network, geographic factors and reliability requirements.

Figure 2.6 illustrates operating expenditure allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. In the current five year cycle, transmission businesses will each spend, on average, around $100 million per year on operating and maintenance costs. In distribution, operating costs per business are forecast at around $200 million per year.

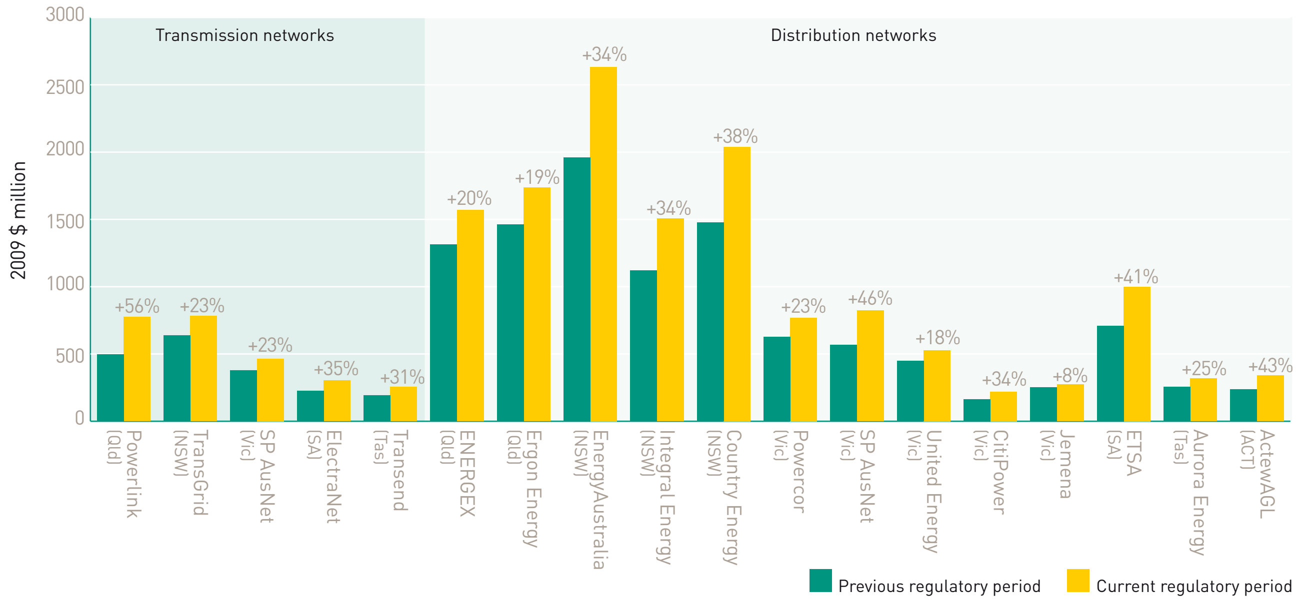
Overall, real expenditure allowances are rising over time, in line with rising demand and costs. On average, real operating and maintenance costs are forecast to rise by around 34 per cent in transmission and 30 per cent in distribution over the current five year regulatory periods.

Differences in the networks' operating environments (outlined in section 2.4.1) resulted in significant variations in expenditure allowances. Under determinations made in 2010 for the distribution sector, operating and maintenance expenditure is projected to rise in the current regulatory cycle by around 19 per cent in Queensland, 27 per cent in Victoria and 41 per cent in South Australia (in real terms) (figure 2.6). The *Market overview* in this report comments on the retail impacts of the determinations.

In assessing operating expenditure forecasts, the AER considers relevant cost drivers, including load growth, expected productivity improvements, and changes in real input costs for labour and materials. The recent Victorian determinations, for example, accounted for an expected increase in regulatory compliance costs

Figure 2.6

Operating expenditure of electricity networks



Note: Current regulatory period expenditure are forecasts in regulatory determinations.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

for electrical safety, network planning and customer communications, largely stemming from changes associated with the 2009 Victorian bushfires.

2.5.1 Efficiency benefit sharing schemes

The AER operates incentive schemes for businesses to make efficient operating and maintenance expenditure in running their networks. The schemes allow a business to retain efficiency gains (and to bear the cost of any efficiency losses) for five years after the gain (loss) is made. In the longer term, the businesses share efficiency gains or losses with customers through price adjustments.

A benchmark level of expenditure determines the level of efficiency gains or losses. Under the incentive schemes, the businesses retain around 30 per cent of efficiency gains or losses against the benchmark, and pass on the remaining 70 per cent to customers through price adjustments.

The incentive schemes apply to all transmission networks and the Queensland and South Australian distribution networks. They will apply to the Victorian distribution networks from 1 January 2011, and to other networks from the start of their next regulatory periods.

2.6 Network quality of service

Reliability (the continuity of energy supply to customers) is the main barometer of service for an electricity network. 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 electricity supply to be unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or routine external causes such as damage caused by extreme weather, trees, birds, possums, vehicle impacts or vandalism. Reliability issues may be ongoing if part of a network has inadequate maintenance or is used near its capacity limits at times of peak demand. These factors sometimes occur in combination.

While a serious transmission network failure may require the power system operator to disconnect some customers (known as load shedding), most power outages result from reliability issues with the distribution network. Distribution outages account for over 90 per cent of the duration of all electricity outages in the NEM.[8]

A reliable network keeps electricity outages to efficient levels rather than trying to eliminate every possible interruption. An efficient outcome requires assessing the value of reliability to the community (measuring the impact on services) and the willingness of customers to pay.

2.6.1 Transmission network reliability

The quality of transmission network services relates principally to network reliability and network congestion. The following section considers network reliability, while section 2.7 considers network congestion issues.

Transmission networks are designed to deliver high rates of reliability. They are generally engineered and operated with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system.

Energy Supply Association of Australia data indicate the NEM jurisdictions have generally achieved high rates of transmission reliability. In 2008–09 total unsupplied energy in Victoria totalled 7.5 minutes—up from less than one minute in the previous year. Tasmania has continued to record improved transmission reliability, with 1.83 minutes of unsupplied energy in 2008–09. Unsupplied energy in New South Wales and South Australia has remained low.

The AER's national service target performance scheme provides incentives for transmission businesses to maintain or improve network performance. It acts as a counterbalance to the efficiency benefit sharing scheme (section 2.5.1) so businesses do not reduce costs at the expense of service quality. The scheme sets performance targets on:

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

The transmission network scheme also includes a component based on the market impact of transmission congestion (section 2.7.2).

Rather than impose a common benchmark target on all transmission networks, the AER sets separate standards that reflect the circumstances of each network based on its past performance. Under the scheme, the over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of its regulated revenue.

The results are standardised for each network to derive an 's-factor' that can range between –1 (the maximum penalty) and +1 (the maximum bonus). Table 2.3 sets out the s-factors for each network for the past six years.

The major networks in eastern and southern Australia have generally outperformed their targets. The only businesses to receive a financial penalty in 2009 were TransGrid (New South Wales), for the second half of the year, and Directlink.

2.6.2 Distribution network reliability

The trade-offs between improved reliability and cost mean the standards for distribution networks are less stringent than those for generation and transmission. These less stringent standards also reflect that the impact of a distribution outage tends to be localised to part of the network, compared with the potentially widespread geographic impact of a generation or transmission outage. The capital intensive nature of distribution networks makes it 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.

The most frequently used indicators of distribution network reliability in Australia are the system average interruption duration index (SAIDI) and the system

8 See AER, *State of the energy market 2007*, 'Essay B', 2007, pp. 38–53.

Table 2.3 S-factor values

	2004	2005	2006	2007	2008		2009	
Powerlink (Qld)				0.82		0.53		0.20
TransGrid (NSW)	0.93	0.70	0.63	–0.12		0.31	0.20	–0.30
EnergyAustralia (NSW)	1.00	0.67	0.39	–0.14		0.72		0.37
SP AusNet (Vic)	0.22	0.09	–0.17	0.06	0.15	0.82		0.50
ElectraNet (SA)	0.63	0.71	0.59	0.28	0.29	–0.40		0.60
Transend (Tas)	0.55	0.19	0.06	0.56		0.85	0.90	0.10
Directlink (Qld–NSW)			–0.54	–0.62		–1.00		–1.00
Murraylink (Vic–SA)			0.21	–0.32		0.69		0.90

Notes:

SP AusNet reported separately for the first quarter of 2008 and the remainder of the year.

ElectraNet reported separately for the first and second halves of 2008.

TransGrid and Transend reported separately for the first and second halves of 2009. EnergyAustralia data for 2009 is for the six months to June.

In 2008 SP AusNet transitioned to a new regulatory control period, with the financial incentive capped at +1 per cent of its maximum allowable revenue. Its financial incentive in previous regulatory control periods was capped at +0.5 per cent.

Source: AER, *Transmission network service providers: electricity performance report for 2008–09*, 2010.

average interruption frequency index (SAIFI). The indicators relate to the average duration and frequency of network interruptions and outages. They do not distinguish between the nature and size of loads affected by supply interruptions.

Table 2.4 estimates historical data on the average duration (SAIDI) and frequency (SAIFI) of outages experienced by distribution customers. The 'Market overview' in this report presents SAIDI data in graphical form.

The SAIDI and SAIFI data include outages that originate in the generation and transmission sectors. From a customer perspective, the unadjusted data presented here are relevant, but an assessment of network performance should normalise data to exclude interruption sources beyond the network's reasonable control.

A number of issues limit the validity of comparing reliability data across jurisdictions. In particular, the data rely on the accuracy of the businesses' information systems, which may vary considerably. Design, geographic conditions and historical investment also differ across the networks.

Noting these caveats, the SAIDI data indicate electricity networks in the NEM have delivered reasonably stable reliability outcomes over the past few years. Across the NEM, a typical customer experiences around 200–250 minutes of outages per year, but with significant regional variations.

The average duration of outages per customer rose in most jurisdictions in 2008–09. Queensland customers experienced the largest increase, with the average outage duration rising by more than 100 minutes. The rise was largely the result of storm activity, but Ergon Energy also noted that changed maintenance practices contributed to the outcome. Queensland experiences significant variations in performance, partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other NEM jurisdictions.

Extreme weather events contributed to load shedding and network failures in Victoria during the summer 2009 heatwave and bushfires. Even after adjusting for excluded events, Victoria in 2008–09 experienced its highest rate of outages in a decade. Extreme weather was also a factor in New South Wales, although equipment faults and human error were responsible for failures in EnergyAustralia's subtransmission network.

Table 2.4 System average interruption duration index (SAIDI) and frequency index (SAIFI)

	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09
SAIDI (MINUTES)									
Queensland	314	275	265	434	283	351	233	264	365
New South Wales	175	324	193	279	218	191	211	180	211
Victoria	152	151	161	132	165	165	197	228	255
South Australia	164	147	184	164	169	199	184	150	161
Tasmania	265	198	214	324	314	292	256	304	252
NEM weighted average	**198**	**245**	**199**	**258**	**211**	**221**	**211**	**213**	**254**
SAIFI (NUMBER OF INTERRUPTIONS)									
Queensland	3.0	2.8	2.7	3.4	2.7	3.1	2.1	2.4	2.9
New South Wales	2.5	2.6	1.4	1.6	1.6	1.8	1.9	1.7	1.8
Victoria	2.0	2.0	2.2	1.9	1.8	1.9	2.1	1.7	2.5
South Australia	1.7	1.6	1.8	1.7	1.7	1.9	1.8	1.5	1.5
Tasmania	2.8	2.3	2.4	3.1	3.1	2.9	2.6	2.6	1.9
NEM weighted average	**2.4**	**2.4**	**2.0**	**2.2**	**1.9**	**2.1**	**2.0**	**1.9**	**2.2**

Notes:

The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator's reasonable control. Some data have been adjusted to remove the impact of natural disasters (for example, Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year beginning in that period.

Sources: Performance reports by the AER (Victoria), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates when developing historical data.

The SAIFI data show the average frequency of outages has been relatively stable since 2002–03, with distribution customers across the NEM experiencing outages around twice a year. The average frequency of outages rose in 2008–09, driven mainly by poorer outcomes in Queensland and Victoria.

2.6.3 Customer service—distribution networks

The monitoring of service quality for electricity distribution networks typically includes assessing customer service. Network businesses report on their responsiveness to issues, including the timely connection of services, call centre performance and customer complaints.

Table 2.5 provides a selection of customer service data for the networks. Performance in 2008–09 broadly aligned with that of previous years.

2.6.4 Distribution service performance incentive schemes

Jurisdictions operate guaranteed service level (GSL) schemes that provide for payments to customers that experience poor service. The schemes are intended not to provide legal compensation to customers, but to enhance the service performance of distribution businesses.

Jurisdictional GSL schemes provide payments for poor service quality in areas such as streetlight repair, the frequency and duration of supply interruptions, new connections and notice of planned interruptions. Under most of the jurisdictional schemes, the majority of GSL payments in 2008–09 related to the duration and frequency of supply interruptions exceeding specified limits. Payments in Queensland resulted mainly from late connections, while New South Wales networks also made significant payments for not providing sufficient notice of planned network interruptions.

Table 2.5 Timely provision of service by electricity distribution networks

NETWORK	PERCENTAGE OF CONNECTIONS COMPLETED AFTER AGREED DATE					PERCENTAGE OF CALLS ANSWERED BY HUMAN OPERATOR WITHIN 30 SECONDS				
	2004–05	2005–06	2006–07	2007–08	2008–09	2004–05	2005–06	2006–07	2007–08	2008–09
QUEENSLAND[1]										
ENERGEX	3.98	0.62	0.55	10.79	2.54	89.4	89.4	79.1	96.3	89.7
Ergon Energy	6.62	0.84	0.49	0.72	0.30	85.0	85.1	87.0	86.2	87.2
NEW SOUTH WALES[2]										
EnergyAustralia	0.01	0.02	0.02	0.01	0.01	44.6	81.3	74.3	81.1	79.7
Integral Energy	0.01	0.02	0.02	0.01	0.01	81.0	89.0	70.9	96.2	92.0
Country Energy	0.02	0.02	0.02	0.01	0.01	48.4	47.2	…	61.4	51.4
ActewAGL	…	…	…	…	…	65.6	39.7	62.4	70.5	…
VICTORIA[3]										
Powercor	0.12	0.06	0.04	0.02	0.01	88.7	86.7	89.4	90.0	86.6
SP AusNet	0.21	2.40	2.66	1.74	2.58	82.7	92.3	91.2	92.3	91.6
United Energy	0.05	0.29	0.05	0.08	0.12	73.8	72.9	74.0	73.0	73.1
CitiPower	0.02	0.03	0.05	0.01	0.00	89.2	85.7	87.2	87.8	82.0
Jemena	0.12	0.09	0.19	0.8	0.89	75.2	77.4	79.9	73.1	77.4
SOUTH AUSTRALIA[1]										
ETSA Utilities	0.91	1.33	0.51	1.30	0.58	86.9	85.2	89.3	88.7	88.5
TASMANIA										
Aurora Energy	…	0.15	0.14	2.00	1.77	…	…	…	…	…

1. Completed connections data for Queensland and South Australia include new connections only.
2. New South Wales completed connections data from 2005–06 are state averages.
3. Victorian data are for the calendar year beginning in that period.

Sources: Distribution network performance reports by the AER (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

As for transmission, the AER has developed a national incentive scheme to encourage distribution businesses to maintain or improve service performance. The scheme focuses on supply reliability (the frequency and duration of network outages) and customer service. The distribution scheme includes a GSL component, under which customers are paid directly if performance falls below threshold levels. The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations. Victoria will be the first jurisdiction to apply the GSL component of the national scheme (from 1 January 2011).

The national scheme generally provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets.[9] The results are standardised for each network to derive an 's-factor' that reflects deviations from target performance levels. While the scheme should be consistent nationally where practical, it has some flexibility to allow for transitional issues and the differing circumstances and operating environments of each network.

The national scheme currently applies to the Queensland and South Australian networks and as a paper trial in New South Wales and the ACT (that is, targets are set but no financial penalties or rewards apply). It will apply to all other networks from the start of their next regulatory periods.

9 Queensland network businesses face financial bonuses and penalties of up to 2 per cent of revenue.


Mark Wilson

2.7 Electricity transmission congestion

Transmission networks do not have unlimited capacity to carry electricity from one location to another. Physical limits are imposed on the amount of power that can flow over any part or region of a network, to avoid damage and ensure stability during small disturbances.

Some transmission congestion results from factors within the control of a service provider—for example, the provider's scheduling of outages, its maintenance and operating procedures and its standards for network capability (such as thermal, voltage and stability limits). 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. Typically, most congestion costs accumulate on just a few days, and are largely attributable to network outages.

If a major transmission outage occurs in combination with other generation or demand events, it can cause the load shedding of some customers. This scenario is rare in the NEM, however. Rather, the main impact of congestion is on the cost of producing electricity. In particular, transmission congestion increases the total cost of electricity by displacing low cost generation with more expensive generation.

Congestion can also create opportunities for the exercise of market power. If a network constraint prevents generators from moving electricity to customers, then there is less competition in the market.

In addition to the direct economic cost of using more expensive generation to meet demand, congestion can create risks for participants and promote behaviour that may inhibit economic efficiency. This behaviour can include 'disorderly bidding', whereby a generator tries to ensure dispatch by bidding its capacity at prices that do not reflect underlying costs.

2.7.1 Measuring transmission congestion

AEMO is developing a Congestion Information Resource (CIR) to provide information on patterns of congestion and expected market outcomes. It released an interim resource in March 2010, and aimed to release the first full CIR by September 2011.

As part of this process, AEMO compiles data on the extent and pattern of 'mispricing'. Mispricing occurs when network congestion causes a generator to be constrained on or off.[10] The data measure the additional cost of dispatching energy as a result of congestion.

Figure 2.7 indicates the extent of mispricing in the NEM over the past two years. The data illustrate the number of mispriced connection points (between generators and the transmission network) in each region, and the average duration of mispricing per connection point. While the number of mispriced connection points remained relatively stable in each region, the duration of mispricing fluctuated significantly. In 2009–10 Queensland experienced both a greater number of mispriced connection points and a longer average duration of mispricing, compared with other jurisdictions.

2.7.2 Reducing congestion costs

Recognising the significance of congestion costs, the AER has provided for rising transmission investment in regulatory decisions to increase network capacity (section 2.4.1), and in 2008 introduced an incentive scheme to reduce congestion.

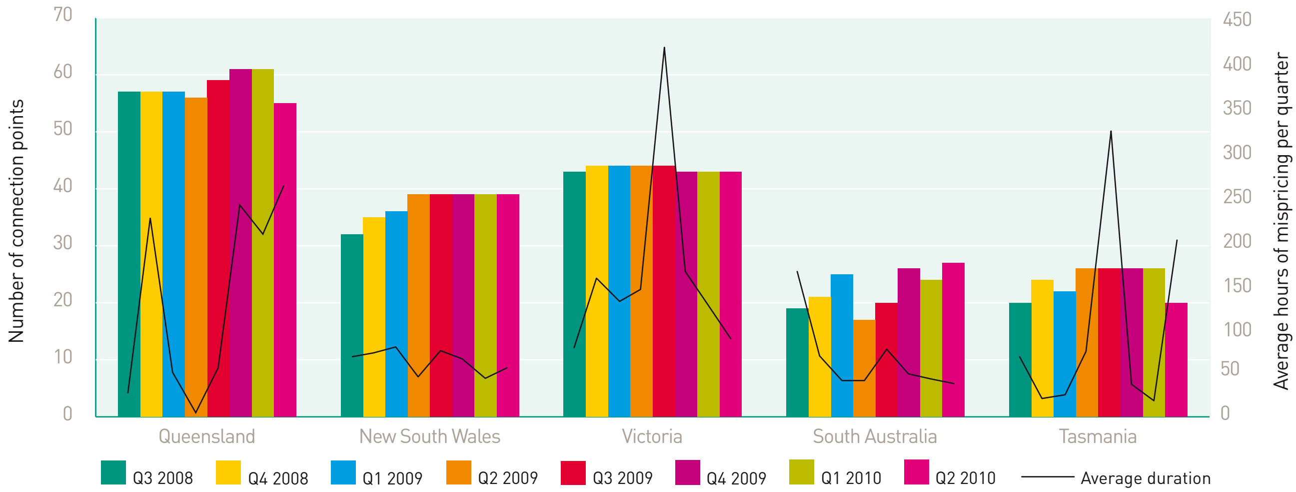
The incentive mechanism forms part of the service performance incentive scheme and aims to encourage network owners to account for the impact of their behaviour on the market.[11] It operates as a bonus-only scheme and rewards network owners for improving operating practices such as outage timing and notification, the minimising of outage impact on network flows—for example, by conducting live line work, maximising line ratings and reconfiguring

10 A generator is 'constrained on' if it is required to be dispatched despite offering to supply energy at above the market price. A generator is 'constrained off' if it has offered to supply energy below the market price, but cannot be dispatched because the network is congested.

11 AER, *Electricity transmission network service providers: service target performance incentive scheme,* 2008.

Figures 2.7

Number of mispriced connection points and the average duration of mispricing per connection point



Source: AEMO.

the network—and equipment monitoring. In some cases, these improvements may be more cost-efficient solutions to reduce congestion than those requiring investment in infrastructure.

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 megawatt hour.[12]

Only TransGrid and Powerlink participate in the scheme; ElectraNet will participate in 2011. In its first compliance period (1 July 2009 – 31 December 2009), TransGrid reduced material outage events by 20 per cent from its benchmark, and earned incentive payments of $1.3 million.

2.7.3 Interregional congestion

Congestion in transmission interconnectors can cause wholesale electricity prices to differ across the regions of the NEM. In particular, prices may spike in a region that is constrained in its ability to import electricity.

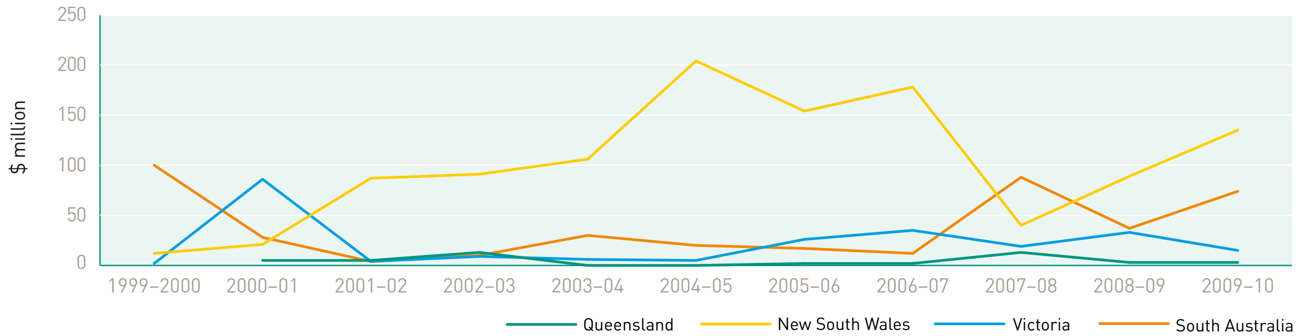
To the extent that trade is possible, electricity generally flows from lower to higher price regions. When trade occurs, the exporting generators are paid at their local regional spot price, while importing retailers must pay the (typically higher) spot price in their region. The difference between the 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. The volume of settlement residues indicates the extent of interregional congestion.

Figure 2.8 charts the annual accumulation of interregional settlement residues in each region. There is some volatility in the data, given 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 typically records the highest level of settlement residues. The level 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. Residues accruing to South Australia rose over the past three years, reflecting higher spot prices in the region (particularly over summer). As net exporters, Queensland and Victoria tend to accumulate modest settlement residues.

12 The performance improvement required for the full 2 per cent bonus may be unrealistic. A realistic level of performance may be difficult to determine until the scheme has been in place for some time.

Figure 2.8
Settlement residues in the National Electricity Market



Source: AEMO.

2.8 Policy developments for electricity networks

In July 2009 AEMO began operating as a single, industry funded national energy market operator for both electricity and gas. It has a National Transmission Planner (NTP) role, overlaying the traditional jurisdiction based approach to network planning with a national, long term focus on efficiently developing the transmission grid.

AEMO expected to publish its first annual national transmission network development plan in December 2010, outlining its view of the efficient development of the power system over the next 20 years. The plan details network and non-network investment needs based on a range of demand growth and generation investment scenarios.

The plan will inform AER network revenue determinations. Transmission businesses and jurisdictional planning bodies will use the plan to develop annual planning reports, conduct RIT-T analyses and assess scale efficient network extensions (section 2.8.2).

In addition to this annual planning role, AEMO reviews major network development opportunities—for example, in 2010 AEMO (with ElectraNet) undertook a feasibility study of options to increase the interconnector transfer capability between South Australia and other NEM load centres.[13] The study aimed to identify options to expand the development of South Australia's renewable and other energy resources.

2.8.1 Climate change (review of energy market frameworks)

The AEMC in 2009 completed a review of the likely impacts of climate change policies on energy market frameworks. Following that review, a number of changes to the market framework are being progressed.

Interregional transmission charging

In February 2010 the Ministerial Council on Energy (MCE) submitted a rule change to implement new interregional charging arrangements for transmission businesses. This change is designed to promote more efficient operation of, and investment in, transmission networks.

Under current arrangements, a transmission network business recovers its costs from customers within its region. Customers in an importing region, therefore, do not pay the transmission costs incurred in the exporting region to serve their load. The rule change introduces a load export charge that effectively treats the transmission business in the importing region as a

13 Interconnectors between South Australia and Victoria have a history of congestion, especially during peak demand. South Australia's increasing reliance on wind generation has aggravated this issue.

customer of the transmission business in the exporting region. All network charges will be ultimately recovered from the network's customers.

Scale efficient network extensions

While electricity networks historically developed around the location of coal fired generators, new investment in renewable generation is likely to cluster in locations that are remote from customers and networks. In February 2010 the MCE submitted a rule change to promote the efficient connection of clusters of new generation. The framework aims to take advantage of economies of scale in network assets and avoid the inefficient duplication of connection assets.

Under the proposed approach, AEMO would identify geographic zones in which generation expansion is likely. Network businesses would then develop extension options to accommodate anticipated future generation capacity. Construction would occur once a connecting generator accepts an option.

Generators would pay their share of the connection asset that they use, with customers underwriting the risk of asset stranding or delays in connection. The AER would have a role in protecting consumers' interests, with powers to disallow any project that it considers does not meet the requirements of the scheme.

The AEMC published an options paper in September 2010 testing the proposal against alternative solutions. It expects to make a draft determination in February 2011.

Transmission frameworks review

The AEMC in 2010 was reviewing arrangements for the provision and use of electricity transmission services, and implications for the market frameworks governing network services in the NEM. It was examining:

> the extent to which appropriate financial incentives ensure efficient and timely provision of transmission services
> the extent to which the transmission planning framework effectively aligns with the regulatory process for transmission investment
> whether network businesses have sufficient financial incentives to operate their networks in a manner that optimises overall network availability and market efficiency
> mechanisms that may promote more efficient bidding and pricing behaviour by generators in congested parts of the network
> the effectiveness of network charging and access arrangements, including the impacts on generator investment
> options to improve locational signals for generators.

A consultative committee made up of energy market stakeholders was established to assist the review. The final report is expected by November 2011.

2.9 Demand management and metering

Demand management (or demand-side participation) relates to strategies to manage the growth in overall or peak demand for energy services. The objective is to reduce or shift demand, or implement efficient alternatives to network augmentation. Such strategies are implemented typically at the distribution or retail level, and require cooperation between energy suppliers and customers.

In distribution regulation, the AER applies demand management schemes with incentives for businesses to implement efficient non-network approaches to manage demand. The schemes fund projects or initiatives that reduce network demand. In some jurisdictions, the schemes also allow businesses to recover revenue forgone as a result of successful demand reduction initiatives. No business is compelled to take up the scheme, with the allowance provided on a 'use it or lose it' basis. The AER has developed demand management schemes for New South Wales and the ACT, South Australia and Queensland, and Victoria.

The AEMC, in its review of the impact of climate change policies on energy market frameworks, recommended expanding the allowance to cover innovations in connecting generators to distribution networks.

2.9.1 Metering and smart grids

Meters record the energy consumption of customers at their point of connection to the distribution network. Effective metering, when coupled with appropriate price signals, can encourage customers to more actively manage their electricity use. Both the Australian and state governments are implementing plans to introduce smart meters with communication capabilities that allow for remote meter reading and the connection and disconnection of customers.

The Council of Australian Governments (COAG) has committed to the progressive rollout of smart meters in jurisdictions where the benefits outweigh costs. Development of a framework to support rolling out smart electricity meters in the NEM was continuing in 2010.

The Victorian Government has initiated a program, outside the COAG process, to provide smart meters to all customers over four years from 2009. Despite the rollout, the Victorian Government has imposed a moratorium on the introduction of time-of-use tariffs for customers.[14]

In October 2009 the AER released a final determination on metering services budgets for 2009–11 and charges for 2010 and 2011.[15] It amended this determination in January 2010 following an appeal to the Australian Competition Tribunal. Smart meter costs began to be passed on to Victorian customers from 1 January 2010, with network charges increasing on average by almost $70. A further increase of around $8 is expected in 2011.

In addition to the smart meter developments, the Australian Government has implemented a $100 million Smart Grid, Smart City initiative to support the installation of Australia's first commercial scale smart grid. The initiative will be based in Newcastle, New South Wales. It will explore options to connect additional renewable and distributed energy and hybrid vehicles to the grid; provide customers with improved energy use information, automation and savings; and improve network reliability.

14 If the customer consumes less than 20 megawatt hours of electricity per year.
15 AER, *Victorian advanced metering infrastructure review—2009–11 AMI budget and charges applications, final determination*, 2009.

3 NATURAL GAS

The two main types of natural gas in Australia are conventional natural gas and coal seam gas (CSG). Conventional natural gas is found in underground reservoirs trapped in rock, often along with oil. In contrast, CSG is produced when coal is created from peat. There are also renewable gas sources, such as biogas (landfill and sewage gas) and biomass (wood, wood waste and sugarcane residue).

Natural gas is produced both for domestic markets and for export as liquefied natural gas (LNG). High pressure transmission pipelines transport natural gas over long distances to domestic markets. 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 reduce the pressure of the gas before it enters the distribution network.

This chapter covers natural gas production, wholesale market arrangements, and the transmission and distribution pipeline sectors. While the chapter focuses on domestic markets in eastern Australia in which the Australian Energy Regulator (AER) has regulatory responsibilities,[1] it also covers gas markets in Western Australia, the Northern Territory and LNG export markets. Chapter 4 considers the retailing of natural gas to end customers.

3.1 Reserves and production

In August 2010 Australia's proved and probable (2P) natural gas reserves—those with reasonable prospects for commercialisation—stood at around 106 000 petajoules (PJ), comprising 78 000 PJ of conventional natural gas and 28 000 PJ of CSG.[2] Total proved and probable reserves increased by around 76 per cent in 2009–10. This increase was mainly due to 40 000 PJ of reserves added in the Gorgon fields in Western Australia's Carnarvon Basin. CSG reserves in Queensland and New South Wales also rose by 34 per cent.

Australia produced 1911 PJ of natural gas in 2009–10, of which around 54 per cent was for the domestic market. The CSG share of total production rose from 8 per cent in 2008–09 to 10 per cent in 2009–10. Around 46 per cent of Australia's gas production—all sourced from offshore basins in Western Australia and the Northern Territory—is exported as LNG.

3.1.1 Geographic distribution

Table 3.1 sets out the geographic distribution of Australia's natural gas reserves in June 2010 and production for the year to 30 June 2010. Figure 3.1 illustrates the locations of major gas basins and the transmission pipelines used to ship gas from the basins to domestic markets.

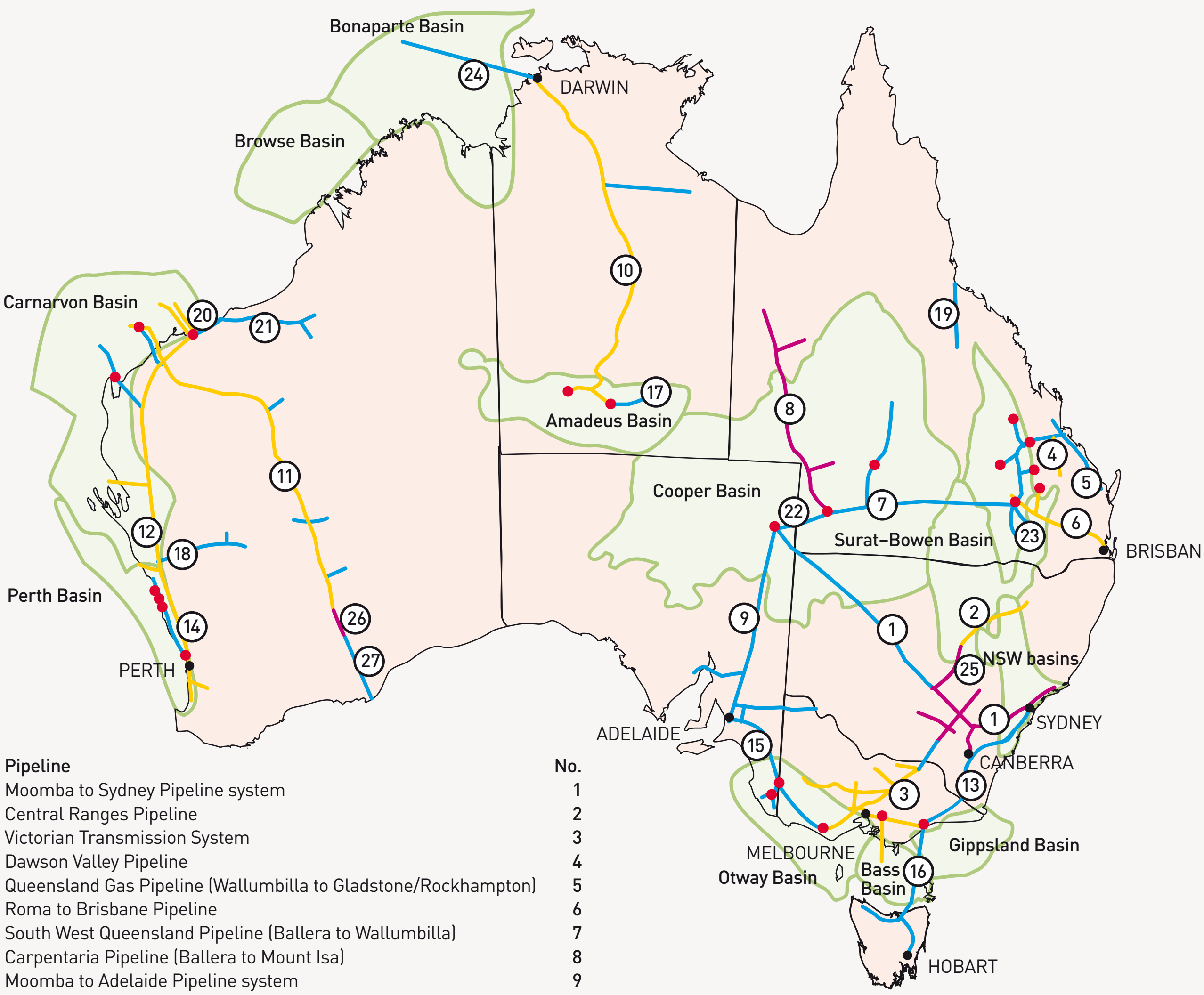
Western Australia's offshore Carnarvon Basin holds the majority of Australia's proved and probable natural gas reserves. It supplies around one third of Australia's domestic market and 99 per cent of Australian gas for LNG export. Newly added reserves in the Gorgon fields increased the share of Australian reserves in this basin from around 48 per cent to 64 per cent in 2009–10.

The Bonaparte Basin along the north west coast contains around 1 per cent of Australia's gas reserves. While its development has focused on producing LNG for export (which began in 2006), the Bonaparte Gas Pipeline was commissioned in 2008 to ship gas to Darwin for domestic consumption. This capacity will supplement gas from the Amadeus Basin, which is in decline.

1 The AER has compliance and enforcement responsibilities—under ss. 18–20 of the National Gas Rules—in relation to the Natural Gas Bulletin Board, the Victorian wholesale gas market and the short term trading market that commenced operating in Sydney and Adelaide in 2010.

2 EnergyQuest, *Energy Quarterly*, August 2010.

Figure 3.1
Australian gas basins and transmission pipelines



Pipeline	No.
Moomba to Sydney Pipeline system	1
Central Ranges Pipeline	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 Mount 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
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24
Central West Pipeline	25
Kalgoorlie to Kambalda Pipeline	26
Kambalda to Esperence Pipeline	27

Source: AER.

Table 3.1 **Natural gas reserves and production, 2010**

GAS BASIN	PRODUCTION (YEAR TO JUNE 2010) PETAJOULES	PRODUCTION (YEAR TO JUNE 2010) PERCENTAGE OF DOMESTIC SALES	PROVED AND PROBABLE RESERVES[2] (30 JUNE 2010) PETAJOULES	PROVED AND PROBABLE RESERVES[2] (30 JUNE 2010) PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
WESTERN AUSTRALIA				
Carnarvon	354	34.2	68 353	64.3
Perth	4	0.4	23	0.0
NORTHERN TERRITORY				
Amadeus	10	1.0	156	0.1
Bonaparte	9	0.8	1 198	1.1
EASTERN AUSTRALIA				
Cooper (South Australia – Queensland)	103	10.0	1 157	1.1
Gippsland (Victoria)	228	22.0	5 233	4.9
Otway (Victoria)	105	10.1	1 245	1.2
Bass (Victoria)	12	1.2	275	0.3
Surat–Bowen (Queensland)	16	1.6	196	0.2
Total conventional natural gas	842	81.2	77 836	73.2
COAL SEAM GAS				
Surat–Bowen (Queensland)	189	18.2	26 008	24.5
New South Wales basins	6	0.6	2 466	2.3
Total coal seam gas	195	18.8	28 474	26.8
AUSTRALIAN TOTALS	**1 036**	**100.0**	**106 310**	**100.0**
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	862			
Bonaparte (Northern Territory)	12			
Total liquefied natural gas	874			
TOTAL PRODUCTION	**1 911**			

1. Conventional natural gas reserves include LNG and ethane.
2. Proved reserves are those for which geological and engineering analysis suggests at least 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 2010.

Eastern Australia contains around 35 per cent of Australia's natural gas reserves, of which the majority are CSG. The principal sources of reserves are the Gippsland Basin off coastal Victoria (which meets around 22 per cent of national demand) and the Surat–Bowen Basin in Queensland (20 per cent). The Cooper Basin in central Australia meets about 10 per cent of demand but its reserves are declining. Production in Victoria's offshore Otway Basin (10 per cent) has risen significantly since 2004.

Production of CSG has risen exponentially since 2004, 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. In New South Wales, commercial production of CSG began in 1996 in the Sydney Basin.

While CSG is produced only in Queensland and New South Wales, it is the fastest growing gas production sector. CSG production rose by around 32 per cent to 195 PJ in 2009–10, and accounted for almost 30 per cent of gas production in eastern Australia over the same period.[3]

3.2 Domestic and international demand

Australia consumed around 1036 PJ of natural gas in 2009–10.[4] Natural gas has a range of industrial, commercial and domestic applications in Australia. It is increasingly used for electricity generation, mainly to fuel intermediate and peaking generators. The residential sector uses natural gas mainly for heating and cooking.

The consumption profile varies across the jurisdictions. Natural gas is widely used in most jurisdictions for industrial manufacturing. Western Australia, South Australia, Queensland and the Northern Territory especially rely 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.

3.2.1 Liquefied natural gas exports

The production of LNG converts natural gas into liquid. The development of an LNG export facility requires large upfront capital investment in processing plant and port and shipping facilities. The magnitude of investment means a commercially viable LNG project requires access to substantial reserves of natural gas. The reserves may be sourced through the LNG owner's interests in a gas field, a joint venture arrangement with a natural gas producer, or long term gas supply contracts.

Australia has LNG export projects in Western Australia's North West Shelf and Darwin. Export volumes rose in 2009–10 by 7.4 per cent to 874 PJ, mostly from the Carnarvon Basin,[5] and the major players are continuing to expand capacity:

> Woodside's 4.3 million tonne per year Pluto project is nearing completion and will become Australia's third operational LNG project. The first exports are expected in early 2011.
> The $50 billion Gorgon project in Western Australia is scheduled to begin operation in 2015 and produce around 15 million tonnes of LNG per year—almost equal to Australia's current total LNG production. The project partners have signed a number of long term sales agreements with international buyers.

Long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have improved the economics of developing LNG export facilities in eastern Australia. Several export projects that rely on CSG are at an advanced stage of planning in Queensland. Major domestic and international players are developing the proposed projects, which range in size from 1.5 to 14 million tonnes of LNG per year.

3.3 Industry structure

Gas production in Australia is relatively concentrated. EnergyQuest estimated six major producers supplied around 79 per cent of the domestic market in 2009–10: BHP Billiton (19 per cent), Santos (18 per cent), Esso (14 per cent), Woodside (12 per cent), Apache Energy (10 per cent) and Origin Energy (6 per cent).[6]

3.3.1 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.

3 All data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2010.
4 EnergyQuest, *Energy Quarterly*, August 2010.
5 LNG production and export data are sourced from EnergyQuest, *Energy Quarterly*, August 2010, p. 24.
6 EnergyQuest, *Energy Quarterly*, August 2010.

The energy retailers Origin Energy and AGL Energy each have substantial interests in gas production and electricity generation:

- Origin Energy is a leading energy retailer in Queensland, Victoria and South Australia, and is expanding its electricity generation portfolio in eastern Australia. It has significant equity in CSG production in Queensland and in conventional gas production in Victoria's Otway and Bass basins, and a minority interest in gas production in the Cooper Basin.
- AGL Energy is a leading energy retailer in Queensland, Victoria, New South Wales and South Australia, and is a major electricity generator in eastern Australia. A relative newcomer to gas production, AGL Energy began acquiring CSG interests in Queensland and New South Wales in 2005. It has continued to expand its portfolio through mergers and acquisitions.

3.3.2 Market concentration

Market concentration in particular gas basins depends on multiple factors, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Figure 3.2 illustrates EnergyQuest estimates of market shares in gas production for the domestic market in the major basins. Table 3.2 sets out market shares in proved and probable gas reserves (including reserves available for export) at August 2010.

Several major companies have equity in Western Australia's Carnarvon Basin, which is Australia's largest producing basin. The businesses participate in joint ventures, typically with overlapping ownership interests. Chevron (33 per cent), Shell (18 per cent) and Esso (15 per cent) have the largest stake in gas reserves in the Carnarvon Basin, given their equity in the Gorgon project.

Woodside (24 per cent) and Apache Energy (23 per cent) are the largest producers for the domestic market, but Santos (14 per cent), BP and Chevron (10 per cent each), and BHP Billiton and Shell (3 per cent each) have significant market shares.

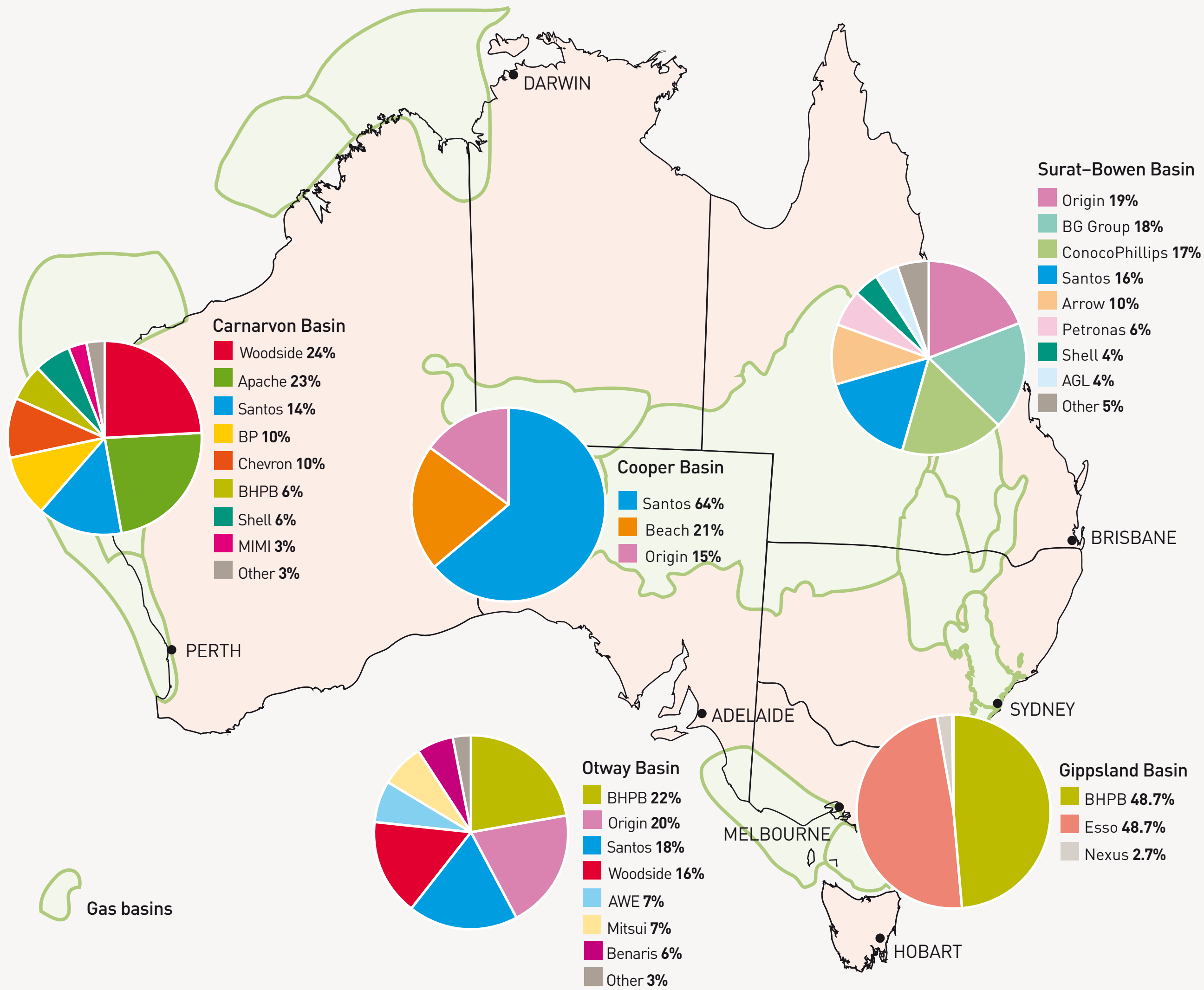
Gas for the Northern Territory was historically sourced from the Amadeus Basin and produced by Santos and Magellan. The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. Eni owns over 80 per cent of Australian reserves in the basin.

In eastern Australia, control of the Gippsland and Cooper basins is concentrated among a handful of established producers. 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.

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and export gas to New South Wales, South Australia and Tasmania. A joint venture between Esso and BHP Billiton accounts for around 98 per cent of production in the Gippsland Basin, which is the largest producing basin in eastern Australia. The Otway Basin off south west Victoria has a more diverse ownership base, with BHP Billiton (22 per cent), Origin Energy (20 per cent), Santos (18 per cent) and Woodside (16 per cent) accounting for the bulk of production. 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. The largest producers are Origin Energy (19 per cent), BG Group (18 per cent), ConocoPhillips (17 per cent), Santos (16 per cent), Arrow Energy (now owned by Shell and PetroChina, 10 per cent), Petronas (6 per cent), and Shell and AGL Energy (4 per cent each). These businesses also own the majority of gas reserves in the Surat–Bowen Basin.

Figure 3.2
Market shares in domestic gas production, by basin, 2009–10



Notes:

Excludes liquefied natural gas.

Some corporate names are shortened or abbreviated.

Source: EnergyQuest 2010 (unpublished data).

Table 3.2 Market shares in proved and probable gas reserves, by basin, 2010 (per cent)

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
Chevron	32.6													21.0
Shell	18.2					10.1								14.2
Esso	15.0										44.5			11.8
Woodside	11.5													7.4
Origin			51.7		13.5	19.4						36.5	42.5	5.4
Santos	1.1	2.3		60.7	65.8	11.8	35.0				4.4	17.7		5.3
BHP Billiton	4.1										44.5	11.5		4.9
ConocoPhillips		11.6				19.4								4.9
QGC/BG						17.1								4.2
BP	5.1													3.3
MIMI	3.9													2.5
PetroChina						10.1								2.5
Apache	3.7													2.4
Petronas						6.1								1.5
AGL						2.9			100.0	100.0				1.5
Eastern Star Gas							65.0							0.9
ENI		81.9												0.9
CNOOC	1.3													0.9
Kufpec	1.2													0.8
Tokyo Gas	1.0													0.6
Osaka Gas	0.7													0.5
Metgasco								100.0						0.4
Nexus											6.7			0.3
Mitsui						0.7						8.3		0.3
AWE			48.3									8.1	57.5	0.3
Other	0.6	4.2		39.3	20.7	2.6						17.9		1.6
TOTAL (PETAJOULES)	**68 353**	**1 198**	**33**	**156**	**1 157**	**26 202**	**1 520**	**397**	**669**	**154**	**5 233**	**1 163**	**275**	**106 511**

Notes:

Based on proved and probable reserves at August 2010.

Some corporate names are shortened or abbreviated. Not all minority owners are listed.

Source: EnergyQuest 2010 (unpublished data).

3.3.3 Mergers and acquisitions

Merger and acquisition activity in upstream gas since 2006 has focused mainly on CSG (and associated LNG proposals) in Queensland and New South Wales. The AER *State of the energy market 2009* report listed proposed and successful acquisitions from June 2006 to September 2009 (section 8.4.3, including table 8.5). Activity from that time until October 2010 included the following:

> Origin Energy acquired Woodside's interest in the Otway Basin in March 2010. The acquisition increased Origin's market share in Otway Basin reserves from 15 per cent to 36 per cent.

> Shell and PetroChina acquired Arrow Energy in August 2010. The acquisition increased Shell's market share in the Surat–Bowen Basin from 3 per cent to 10 per cent.

> Santos proposed in September 2009 to sell a 15 per cent interest in its Gladstone LNG project to Total for $650 million. Petronas proposed to sell a further 5 per cent interest in the same project to Total for around $210 million.

> AGL Energy acquired Mosaic Oil (which owned around 0.3 per cent of reserves in the Surat–Bowen Basin) in October 2010.

3.4 Gas wholesale markets

Gas producers sell natural gas in wholesale markets to major industrial, mining and power generation customers, and to energy retailers which on-sell it to business and residential customers. In Australia, wholesale gas is sold mostly under confidential, long term contracts. The trend in recent years has been towards shorter term supply, but most contracts still run for at least five years. Foundation contracts underpinning new production projects are often struck for up to 20 years. Such long term contracts are commonly argued as being 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.

Reforms have increased transparency and competition in Australian gas markets. Victoria established a wholesale spot market in 1999 to facilitate gas sales for managing system imbalances and pipeline network constraints. More recently, governments established the National Gas Market Bulletin Board and short term gas trading markets in Sydney and Adelaide.

3.4.1 Victoria's gas wholesale market

Victoria established a spot market for gas in 1999 to manage gas flows on the Victorian Transmission System. The market allows participants to trade gas supply imbalances (the difference between contracted gas supply quantities and actual requirements) on a daily basis. The Australian Energy Market Operator (AEMO) operates both the wholesale market and the Victorian Transmission System.

The *State of the energy market 2009* report provides background on the operation of the Victorian market (pp. 246–7). In summary, participants submit daily bids ranging from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap). Following initial bidding at the beginning of the gas day (6 am), the bids may be revised four times a day at the scheduling intervals of 10 am, 2 pm, 6 pm and 10 pm.

At the beginning of each day, AEMO stacks supply offers and selects the least cost bids to match demand across the market. This establishes a spot market clearing price. Given Victoria has a net market, this price applies only to differences between contracted and actual amounts. Sometimes AEMO needs to schedule additional injections of gas (typically LNG) at above market price to alleviate short term constraints.

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. Section 3.5.2 of this chapter notes recent price activity.

3.4.2 National Gas Market Bulletin Board

The National Gas Market Bulletin Board, which commenced in July 2008, is a website covering major gas production plants, storage facilities, demand centres and transmission pipelines in southern and eastern Australia. Provision has been made for facilities in Western Australia, the Northern Territory and north Queensland to participate in the future.

The bulletin board aims to provide transparent, real-time information to gas customers, small market participants, potential new entrants and market observers on the state of the gas market, system constraints and market opportunities. It covers:

> gas pipeline capacity and daily aggregated data on expected gas volumes
> production capabilities (maximum daily quantities) and three day outlooks for production facilities
> pipeline storage (linepack) and three day outlooks for gas storage facilities
> daily demand forecasts, changes in supply capacity and the management of gas emergencies and system constraints.

Market participants must provide the information, and the AER monitors and enforces participants' compliance with the relevant rules. The bulletin board is operated by AEMO, which also publishes an annual Gas Statement of Opportunities (GSOO) to help industry participants plan and make commercial decisions on infrastructure investment. AEMO published the first GSOO in December 2009.

3.4.3 Short term trading market

Gas pipeline flows must be scheduled to ensure gas produced and injected into a pipeline system remains balanced with gas withdrawn for delivery to customers. A variety of systems assist with physical imbalances between nominated injections and actual withdrawals. AEMO operates a spot market in Victoria to manage gas balancing (section 3.4.1). Market arrangements for balancing are also being introduced in other major gas hubs in eastern Australia.

A short term trading market in gas was launched in September 2010 in the metropolitan hubs of Sydney and Adelaide, following a trial from March 2010. The reform creates a day-ahead wholesale spot market in gas for balancing purposes. It aims to enhance market transparency and competition, to address concerns that the traditional gas balancing arrangements in Sydney and Adelaide hindered retail market entry and gas supply efficiency.[7] AEMO operates the short term trading market, which may be extended to other gas hubs. Victoria will retain its own gas wholesale market.

The short term trading market sets a daily clearing price at each hub, based on bids by gas shippers to deliver additional gas. The market operator then settles, at the clearing price, the difference between each user's daily deliveries and withdrawals of gas. The mechanism aims to provide transparent price signals to market participants, to stimulate trading (including secondary trading) and demand-side response by users.

The short term trading market was designed to work with existing gas market arrangements and operates in conjunction with longer term gas supply and transportation contracts. It provides an option for users to buy or sell gas on a spot basis without entering delivery contracts in advance. It also allows contracted parties to manage short term supply and demand variations to their contracted quantities.

There are differences in design and operation between the short term trading market and the Victorian spot market:

> In the short term trading market, AEMO operates the financial market but does not operate the actual flow of gas (which remains the responsibility of pipeline operators). In the Victorian market, AEMO undertakes both roles.

7 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, 2007, p. 19; McLennan Magasanik Associates, *Report to the Joint Working Group on Natural Gas Supply*, 2007.

> The Victorian market is for gas only, while prices in the short term trading market cover gas and transmission pipeline delivery to the hub.

The AER monitors the short term trading market, enforces the applicable National Gas Rules (Gas Rules), and publishes weekly reports on market activity.

3.5 Gas market activity

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 perceived as a substitute for coal and coal fired electricity. Australia's abundant low cost coal sources have effectively capped gas prices.

3.5.1 Western Australia

As Western Australia is a major LNG exporter, the domestic market is exposed to price volatility in international energy markets. Domestic gas prices in Western Australia remained relatively low until 2006, when rising production costs and strong gas demand—driven partly by the mining boom—put upward pressure on prices. Rising LNG and oil prices added to this pressure.

While international energy prices eased with the onset of the global financial crisis, they again rose strongly from 2009. Anecdotal evidence suggests that some long term contracts in Western Australia were written at prices of $8–9 per gigajoule in the 18 months to June 2010. Conversely, weaker demand from mining projects led to reports that short term prices eased in 2010 to around $4.50 per gigajoule.[8]

The Western Australian Department of Mines and Petroleum gave evidence to a parliamentary inquiry into domestic gas prices in September 2010 that Western Australia could face a gas supply shortfall of 300 terajoules per day between 2013 and 2022.[9] To address this shortfall, a number of smaller gas projects focused on the domestic market are expected to come online within the next three years. These include the Halyard–Spar (50–100 terajoules per day) and Reindeer (110–215 terajoules per day) projects. Additionally, the Macedon gas development, sanctioned by BHP Billiton and its partners in 2010, should supply up to 210 terajoules per day to the domestic market from 2013.

3.5.2 Eastern Australia

An interconnected transmission pipeline network in southern and eastern Australia enables gas producers in the Surat–Bowen, Cooper, Gippsland, Otway, Bass and Sydney basins to sell gas to customers across Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT.

An interaction of several factors affects the gas supply–demand balance and price outcomes in eastern Australia. On the supply side, rising CSG production in Queensland and improved pipeline interconnection among the eastern gas basins have enhanced the flexibility of the market to respond to customer demand. CSG production in Queensland and New South Wales rose by 29 per cent in 2009–10.[10] New infrastructure (such as the QSN transmission link, commissioned in 2009) is providing the physical capacity to enable gas to flow from Queensland into southern markets.

While new pipeline investment and rising CSG reserves are strengthening the supply base, a number of factors may put upward pressure on demand. Rising investment in gas fired power stations is a key driver of natural gas demand in eastern Australia. Output from gas fired electricity generation rose across the NEM by 21 per cent in 2009–10. The introduction of climate change policies may further increase reliance on natural gas as a fuel for electricity generation.

The spot markets in Victoria, Sydney and Adelaide provide transparent data on short term gas prices.

8 EnergyQuest, *Energy Quarterly*, August 2010, p. 89.
9 The findings of the parliamentary inquiry are expected to be released in February 2011.
10 EnergyQuest, *Energy Quarterly*, August 2010, p. 63.

Market volumes in the Victorian spot market can range from around 300 to 1200 terajoules per day. While the market accounts for only about 10–20 per cent of wholesale volumes in Victoria, its price outcomes are widely used as a guide to underlying contract prices. Gas prices have generally eased since early 2008 when an expansion to the Victorian Transmission System eased capacity constraints on the network. The market remained relatively stable in 2010, with prices in the first quarter (and the early part of the fourth quarter) typically below $2 per gigajoule (figure 3.3).

Sydney and Adelaide gas prices moved in a wide range in the first six weeks of the short term trading market's operation in 2010, which is not uncommon with the establishment of a new market (figure 3.4).[11]

Further dynamic change is likely in east coast gas markets with the development of CSG–LNG projects in Queensland in the next few years. EnergyQuest predicted domestic prices may ease during the lengthy ramp-up of LNG export capacity.[12] In the longer term, prices for new domestic gas contracts may rise closer to international levels, as has occurred in Western Australia.

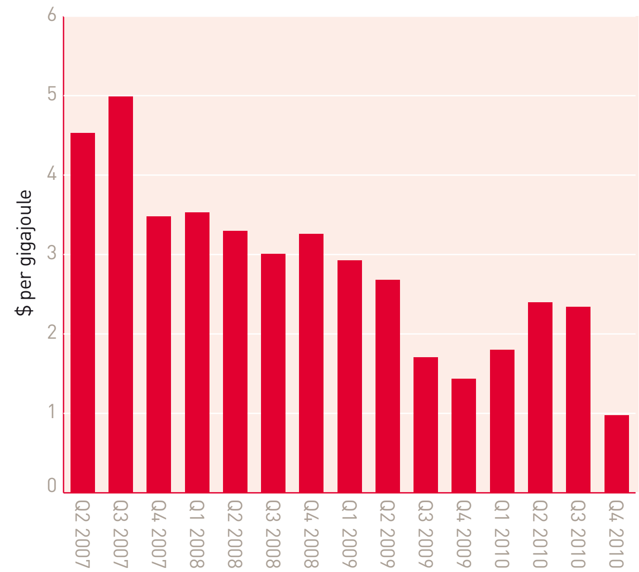
The structure of east coast gas markets may cushion price impacts. Unlike Western Australia, the east coast has a number of gas basins, with greater diversity of supply. It has substantial exploration acreage with relatively low barriers to entry, and an extensive gas transmission network links the producing basins.

3.6 Gas transmission

Transmission pipelines transport natural gas from production fields to demand centres. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. Table 3.3 sets out summary details of Australia's major transmission pipelines; figure 3.1 illustrates pipeline routes.

Figure 3.3

Victorian spot gas prices—quarterly averages

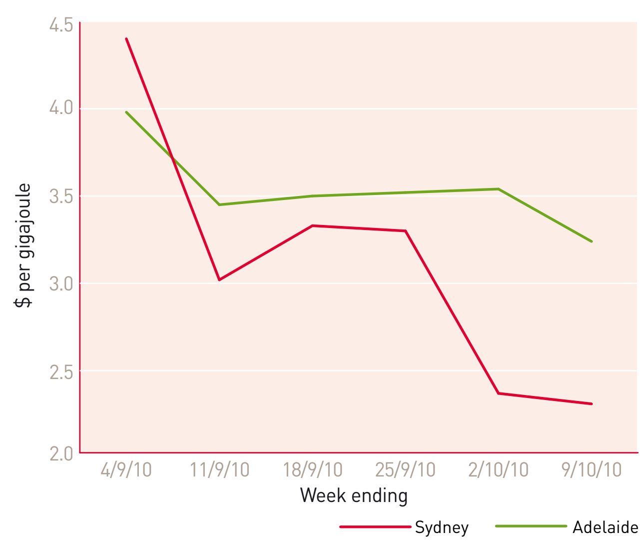


Note: Q4 2010 prices cover the period to 9 October 2010.

Sources: AEMO; AER.

Figure 3.4

Sydney and Adelaide spot gas prices—weekly averages



Note: Data are weekly averages of the ex ante daily price in each hub.

Sources: AEMO; AER.

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11 Design differences between the short term trading market and the Victorian spot market limit the validity of price comparisons. In particular, the Victorian market is for gas only, while prices in the short term trading market cover gas and transmission pipeline delivery to the hub.

12 EnergyQuest, 'Australia's natural gas markets: connecting with the world', in AER, *State of the energy market 2009*, 2009.

Table 3.3 Major gas transmission pipelines

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/D)	CONSTRUCTED	COVERED?
NORTH EAST AUSTRALIA					
North Queensland Gas Pipeline	Qld	391	108	2004	No
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	629	142	1989–91	No
Carpentaria Pipeline (Ballera to Mount Isa)	Qld	840	119	1998	Yes (light)
Berwyndale to Wallumbilla Pipeline	Qld	113		2009	No
Dawson Valley Pipeline	Qld	47	30	1996	Yes
Roma (Wallumbilla) to Brisbane Pipeline	Qld	440	219	1969	Yes
Wallumbilla to Darling Downs Pipeline	Qld	205	400	2009	No
South West Queensland Pipeline (Ballera to Wallumbilla)	Qld	756	181	1996	No
QSN Link (Ballera to Moomba)	Qld–SA and NSW	180	212	2009	No
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	SA–NSW	2029	420	1974–93	Partial (light)
Central West Pipeline (Marsden to Dubbo)	NSW	255	10	1998	Yes (light)
Central Ranges Pipeline (Dubbo to Tamworth)	NSW	300	7	2006	Yes
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	795	268	2000	No
Victorian Transmission System (GasNet)	Vic	2035	1030	1969–2008	Yes
South Gippsland Natural Gas Pipeline	Vic	250		2006–10	No
VicHub	Vic		150 (into Vic)	2003	No
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	734	129	2002	No
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	680	303	2003	No
Moomba to Adelaide Pipeline	SA	1185	253	1969	No
WESTERN AUSTRALIA					
Dampier to Bunbury Pipeline	WA	1854	892	1984	Yes
Goldfields Gas Pipeline	WA	1427	150	1996	Yes
Parmelia Pipeline	WA	445	70	1971	No
Pilbara Energy Pipeline	WA	219	188	1995	No
Midwest Pipeline	WA	353	20	1999	No
Telfer Pipeline (Port Hedland to Telfer)	WA	443	25	2004	No
Kambalda to Esperance Pipeline	WA	350	6	2004	No
Kalgoorlie to Kambalda Pipeline	WA	44	20		Yes (light)
NORTHERN TERRITORY					
Bonaparte Pipeline	NT	287	80	2008	No
Amadeus Basin to Darwin Pipeline	NT	1512	44	1987	Yes
Wickham Point Pipeline	NT	13		2009	No
Daly Waters to McArthur River Pipeline	NT	330	16	1994	No
Palm Valley to Alice Springs Pipeline	NT	140	27	1983	No

TJ/d, terajoules per day; CKI, Cheung Kong Infrastructure; REST, Retail Employees Superannuation Trust.

Notes:

Covered pipelines are subject to regulatory arrangements under the National Gas Law. The AER regulates covered pipelines outside Western Australia (where the Economic Regulation Authority is the regulator).

For covered pipelines subject to full regulation, valuation refers to the opening capital base for the current regulatory period. For the Moomba to Sydney Pipeline, the Australian Competition Tribunal determined the valuation. For non-covered pipelines, listed valuations are estimated construction costs, subject to availability of data.

VALUATION ($ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
160 (2005)	Not required	Victorian Funds Management Corporation	AGL Energy, Arrow Energy
	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
	Not required	APA Group	APA Group
70 (2009)	Not required	APA Group	APA Group
8 (2007)	2007–16	Anglo Coal 51%, Mitsui 49%	Anglo Coal
296 (2006)	2007–11	APA Group	APA Group
90 (2009)	Not required	Origin Energy	Origin Energy
	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 16.8%)	Epic Energy
165 (2009)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 16.8%)	Epic Energy
835 (2003)	Not required	APA Group	APA Group
28 (1999)	Not required	APA Group	APA Group
53 (2003)	2005–19	APA Group	Country Energy (NSW Govt)
450 (2000)	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
524 (2007)	2008–12	APA Group	APA Group, AEMO
50 (2007)	Not required	Multinet Gas	Jemena Asset Management
	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
440 (2005)	Not required	Prime Infrastructure	Prime Infrastructure
500 (2003)	Not required	International Power, APA Group and REST (equal shares)	APA Group
370 (2001)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 16.8%)	Epic Energy
1618 (2004)	2005–10	DBP Transmission (DUET Group 60%, Alcoa 20%, Prime Infrastructure 20%)	DBP Transmission
439 (2009)	2010–15	APA Group 88.2%, Alinta Energy 11.8%	APA Group
	Not required	APA Group	APA Group
	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 16.8%)	Epic Energy
	Not required	APA Group 50%, Horizon Power (WA Govt) 50%	APA Group
114 (2004)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
45 (2004)	Not required	ANZ Infrastructure Services	WorleyParsons Asset Management
	Not required	APA Group	APA Group
170 (2008)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
229 (2001)	2001–11	Amadeus Gas Trust (APA Group 96%)	NT Gas (APA Group)
36 (2009)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
	Not required	APA Group, Power and Water	NT Gas (APA Group)
	Not required	Envestra (APA Group 31%, CKI 19%)	APA Group

Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden (figure 3.1). The covered portion became a light regulation pipeline in 2008.

'Current access arrangement' refers to access terms and conditions approved by the regulator.

Some corporate names are abbreviated or shortened.

Sources: Capacity: Office of Energy (Western Australia); National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites. Other data: access arrangements for covered pipelines; EnergyQuest, *Energy Quarterly* (various issues); corporate websites, annual reports and media releases.

Australia's gas transmission network covers over 20 000 kilometres. Around $4 billion has been invested or committed to new transmission pipelines and expansions since 2000. In combination, these projects have created an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. This investment has enhanced the competitive environment for gas producers, pipeline operators and gas retailers, and improved security of supply. While pipeline investment in Western Australia and the Northern Territory has also been significant, there is no transmission interconnection with other jurisdictions.

3.6.1 Ownership of transmission pipelines

The AER *State of the energy market 2009* report traces the ownership history of Australia's gas transmission pipelines (section 9.2). The principal owners in the sector are:

> *Jemena*, owned by *Singapore Power International*, which acquired a portfolio of gas transmission assets from Alinta in 2007. It owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline, and operates the Tasmanian Gas Pipeline.

> *APA Group*, which owns three pipelines in New South Wales, including the Moomba to Sydney Pipeline, the Victorian Transmission System, two major Queensland pipelines, three major Western Australian pipelines and a major Northern Territory pipeline. It also part owns the SEA Gas Pipeline. In December 2008 APA Group sold three pipelines to an unlisted investment vehicle, Energy Infrastructure Investments, but continues to operate the assets. In 2010 APA Group increased its interest in Hastings Diversified Utilities Fund (see below) from about 4.5 per cent to 16.8 per cent.

> *Prime Infrastructure*, formerly Babcock and Brown Infrastructure, which acquired a 20 per cent interest in the Dampier to Bunbury Pipeline from Alinta in 2007.[13] It also owns the Tasmanian Gas Pipeline and has a minority interest in Western Australia's Goldfields Gas Pipeline.

> *Hastings Diversified Utilities Fund*, managed by a fund acquired by Westpac in 2005, which acquired Epic Energy's gas transmission assets in 2000. It owns the Moomba to Adelaide Pipeline, the Pilbara Energy Pipeline, the South West Queensland Pipeline and the QSN Link. APA Group has a 16.8 per cent interest in Hastings.

3.6.2 Regulation of transmission pipelines

The National Gas Law (Gas Law) and Gas Rules set out the regulatory framework for the gas transmission sector. On 1 July 2008 the AER replaced the Australian Competition and Consumer Commission as the regulator of pipelines outside Western Australia (where the Economic Regulation Authority is the regulator).

The Gas Law and Gas Rules apply to covered pipelines. The AER *State of the energy market 2009* report explains the coverage process and the different forms of economic regulation that may apply (section 9.3).

Table 3.3 indicates the coverage status of each major transmission pipeline. In summary, seven transmission pipelines are subject to *full regulation*, which requires the service provider to submit an access arrangement to the regulator for approval. An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. The AER has published an *Access arrangement guideline* (available on its website) that details the regulatory process. A separate guideline explains dispute resolution under the Gas Law.[14]

A pipeline may, in some circumstances, convert to *light regulation* without upfront price regulation. Where light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. Four transmission pipelines are subject to light regulation: the Carpentaria Gas Pipeline in

13 DUET Group is the majority owner (60 per cent) of the Dampier to Bunbury Pipeline.

14 AER, *Access arrangement guideline*, 2009; AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules*, 2008.

Queensland, the covered portions of the Moomba to Sydney Pipeline, the Central West Pipeline in New South Wales, and the Kalgoorlie to Kambalda Pipeline in Western Australia.

The Gas Law anticipates the potential for market conditions to evolve, and includes a mechanism for reviewing whether a particular pipeline needs regulation. The coverage of several major transmission pipelines has been revoked over the past decade. In addition, only one pipeline constructed in the past decade is covered. In June 2010, the Minister for Resources and Energy granted a 15 year 'no coverage' determination for a proposed Queensland pipeline from the Surat Basin to Curtis Island. The pipeline's construction was scheduled to begin in 2010.

3.6.3 Recent investment in transmission pipelines

Table 3.4 summarises major transmission investment (including expansions of existing pipelines) since 2009. It also lists major projects that, in 2010, were under construction or had been announced for future development.

The development of Queensland's CSG industry continues to spur transmission pipeline investment. Epic Energy commissioned the QSN Link and expanded capacity on the South West Queensland Pipeline in 2009, to enable gas delivery between Queensland and the southern states. It was constructing a $760 million expansion of the QSN Link and South West Queensland Pipeline in 2010, and plans a further expansion by 2013. Also in Queensland, the planned development of LNG projects spurred plans for new transmission infrastructure to transport CSG to Gladstone for processing.

In Western Australia, new investment has centred on capacity expansions of the Dampier to Bunbury Pipeline, which is the major link between the state's North West Shelf and gas markets around Perth. A $690 million stage 5B expansion to add 120 terajoules per day of capacity was completed in 2010. The expansion involved 440 kilometres of looping. On completion, around 94 per cent of the pipeline had been duplicated. A stage 5C expansion has been announced for 2011–12.

3.7 Upstream competition

Investment over the past decade has developed an interconnected gas pipeline system linking gas basins in southern and eastern Australia. While gas tends to be purchased from the closest possible source to minimise transport costs, interconnection of the major pipelines provides energy customers with greater choice and enhances the competitive environment for gas supply.

Gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are now served by multiple transmission pipelines from multiple gas basins. In particular, the construction of new pipelines and the expansion of existing ones have opened the Surat–Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition.

The National Gas Market Bulletin Board provides real-time information on the gas market to enhance competition. The AER draws on the bulletin board to report weekly on gas market activity in southern and eastern Australia. The reporting covers gas flows on particular pipelines and gas flows from competing basins to end markets.

Figures 3.5–3.7 illustrate recent trends in gas delivery from competing basins into New South Wales, Victoria and South Australia since the bulletin board opened in July 2008:

- While New South Wales historically relied on Cooper Basin gas shipped on the Moomba to Sydney Pipeline, gas shipped on the Eastern Gas Pipeline from Victoria's Gippsland Basin now supplies an equivalent proportion of the state's gas requirements.
- While the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway Basin via the South West Pipeline (an artery of the Victorian Transmission System). Victoria also sources some gas from the northern basins via the New South Wales – Victoria Interconnect Pipeline.

- While the Moomba to Adelaide Pipeline historically transported most of South Australia's gas, the SEA Gas Pipeline now transports greater volumes of gas for that market. The Moomba to Adelaide Pipeline transports gas from Queensland's Surat–Bowen Basin via the QSN Link, and from South Australia's Cooper Basin. The SEA Gas Pipeline delivers gas from Victoria's Otway Basin.

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 limit access on some pipelines. Access seekers must decide whether to try to negotiate a capacity expansion. For a covered pipeline, the regulator (or, in Western Australia, a separate arbitrator) may be asked to arbitrate a dispute over capacity expansions.

Table 3.4 Major gas transmission pipeline investment since 2009

PIPELINE	LOCATION	OWNER/PROPONENT	SCALE	COST ($ MILLION)	COMPLETION DATE
COMPLETED					
NORTH EAST AUSTRALIA					
Wallumbilla to Darling Downs Pipeline	Qld	Origin Energy	205 km	90	2009
Berwyndale to Wallumbilla Pipeline	Qld	AGL Energy	113 km	70	2009
South West Queensland Pipeline—stage 1	Qld	Epic Energy	Expansion to 170 TJ/d	165	2009
QSN Link—stage 1	Qld–SA and NSW	Epic Energy	180 km, 250 TJ/d		
Carpentaria Pipeline	Qld	APA Group	15% expansion to 117 TJ/d		2009
Queensland Gas Pipeline expansion	Qld	Jemena	Expansion from 79 TJ/d to 140 TJ/d	112	2010
SOUTH EAST AUSTRALIA					
South Gippsland Natural Gas Pipeline	Vic	Multinet Gas	250 km	50	2009
Eastern Gas Pipeline	Vic–NSW	Jemena	Expansion from 250 TJ/d to 268 TJ/d	41	2010
WESTERN AUSTRALIA					
Goldfields Gas Pipeline	WA	APA Group 88.2%, Alinta Energy 11.8%	20% expansion to 150 TJ/d		2009
Dampier to Bunbury stage 5B expansion	WA	DUET Group 60%, Prime Infrastructure 20%, Alcoa 20%	Expansion—additional 120 TJ/day	690	2010
NORTHERN TERRITORY					
Wickham Point Pipeline	NT	Energy Infrastructure Investments	13 km	36	2009

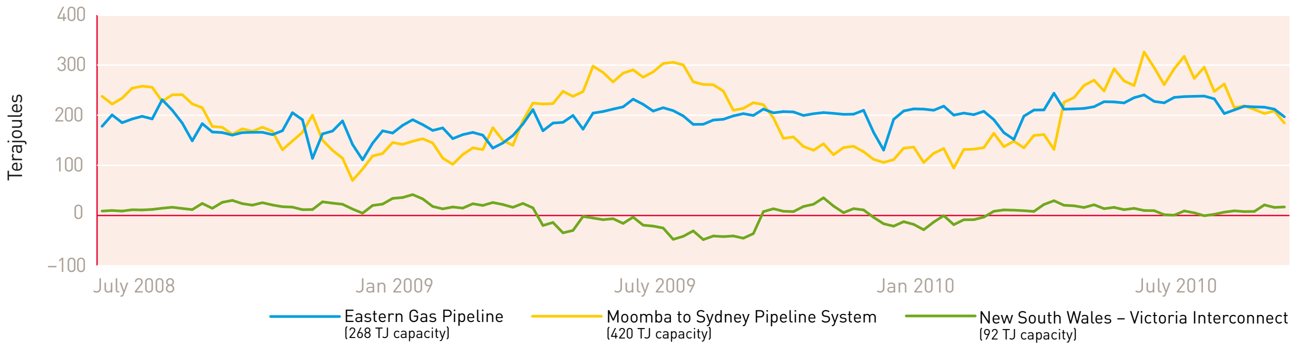
PIPELINE	LOCATION	OWNER/PROPONENT	SCALE	COST ($ MILLION)	COMPLETION DATE
UNDER CONSTRUCTION					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 3	Qld	Epic Energy	Expansion by additional 212 TJ/d	760	2012
QSN link—stage 3	Qld–SA and NSW	Epic Energy			
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	NSW	APA Group	Five year 20% capacity expansion	100	From 2008
ANNOUNCED					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 2	Qld	Epic Energy	Expansion by additional 52 TJ/d	64	2013
QSN link—stage 2	Qld–SA and NSW	Epic Energy			
Queensland Hunter Pipeline (Wallumbilla to Newcastle)	Qld–NSW	Hunter Gas Pipeline	831 km	750–850	Construction commencing in 2012
Lions Way Pipeline (Casino to Ipswich)	NSW–Qld	Metgasco	145 km	120	Construction commencing in 2012
Gladstone LNG Pipeline (Fairview to Gladstone)	Qld	Santos	432 km		2014
Surat Basin to Gladstone	Qld	Arrow	450 km	500	
QCLNG Pipeline (Wandoan to Gladstone)	Qld	BG Group	340 km		Construction commencing in 2010
WESTERN AUSTRALIA					
Dampier to Bunbury stage 5C expansion	WA	DUET Group 60%, Prime Infrastructure 20%, Alcoa 20%	Expansion—additional 100 TJ/day		2011–12

TJ/d, terajoules per day.

Note: Projections of future scale, costs and completion dates are indicative.

Sources: ABARE, *Major development projects*, 2010; EnergyQuest, *Energy Quarterly* (various issues); National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites, reports and media releases.

Figure 3.5
Gas flows into New South Wales



Note: Negative flows on the New South Wales – Victoria Interconnect represent flows out of New South Wales into Victoria.

Figure 3.6
Gas flows into Victoria

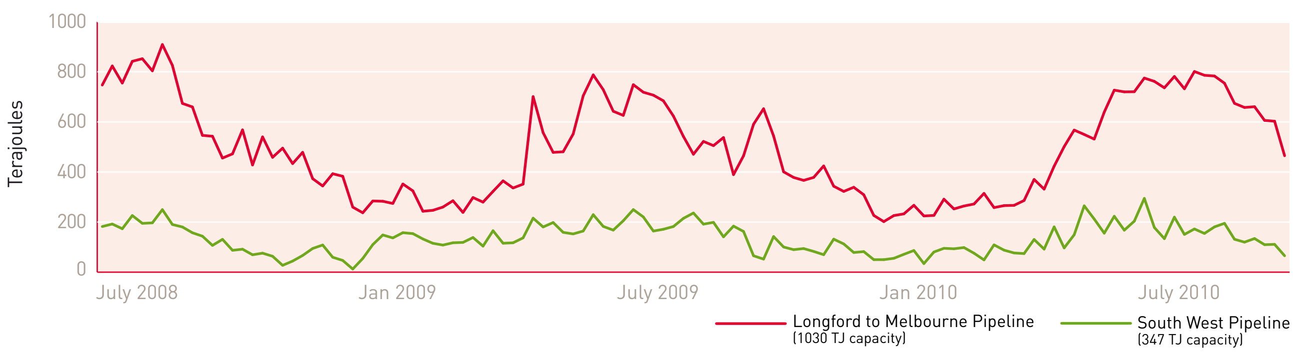
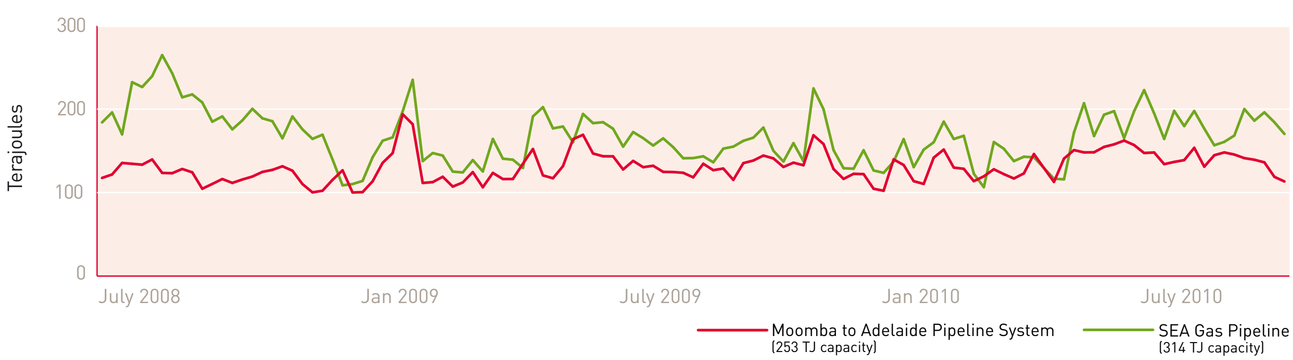


Figure 3.7
Gas flows into South Australia



Sources (figures 3.5–3.7): AER; Natural Gas Market Bulletin Board (www.gasbb.com.au).

3.8 Gas storage

Natural gas can be stored in its natural state in depleted underground reservoirs and pipelines or post liquefaction in purpose built facilities as LNG. Given Australia's increasing reliance on gas fired electricity generation, gas storage enhances security of supply by allowing for injections into the system at short notice to better manage peak demand and emergencies. It also allows producers to meet contract requirements if production is unexpectedly curtailed, and provides retailers with a hedging mechanism if gas demand is significantly above forecast.

The Dandenong LNG storage facility in Victoria (0.7 petajoules) is Australia's only LNG storage facility. It provides the Victorian Transmission System with peak shaving and security of supply services and truck loading services for LNG tankers. In 2010, AGL Energy announced it would develop a $300 million LNG storage facility in New South Wales by 2014 to ensure security of supply during peak periods and supply disruptions. There are also conventional gas storage facilities in Victoria, Western Australia and the Cooper Basin. Following its purchase of Mosaic Oil in 2010, AGL Energy is developing a CSG storage facility in Queensland, to be operational in 2011.

3.9 Gas distribution

A gas 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.

Natural gas is now reticulated to most Australian capital cities, major regional areas and towns. This chapter focuses on distribution networks in southern and eastern Australia, over which the AER has regulatory responsibilities. Table 3.5 summarises the major networks; figure 3.8 illustrates their locations.

The total length of gas distribution networks in the southern and eastern jurisdictions was nearly 73 000 kilometres in 2010. The networks have a combined value of almost $7 billion. Investment to augment and expand the networks is forecast at around $2.5 billion in the current access arrangement periods (typically five years).

3.9.1 Ownership of distribution networks

The major gas distribution networks in southern and eastern Australia are privately owned, with four principal players:

> *Jemena*, owned by *Singapore Power International*, owns the principal New South Wales gas distribution network (Jemena Gas Networks). It has a 51 per cent share in the Victorian network (SP AusNet) and a 50 per cent share of the ACT network (ActewAGL).

> *Envestra*, a public company in which APA Group (32 per cent) and Cheung Kong Infrastructure (19 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.

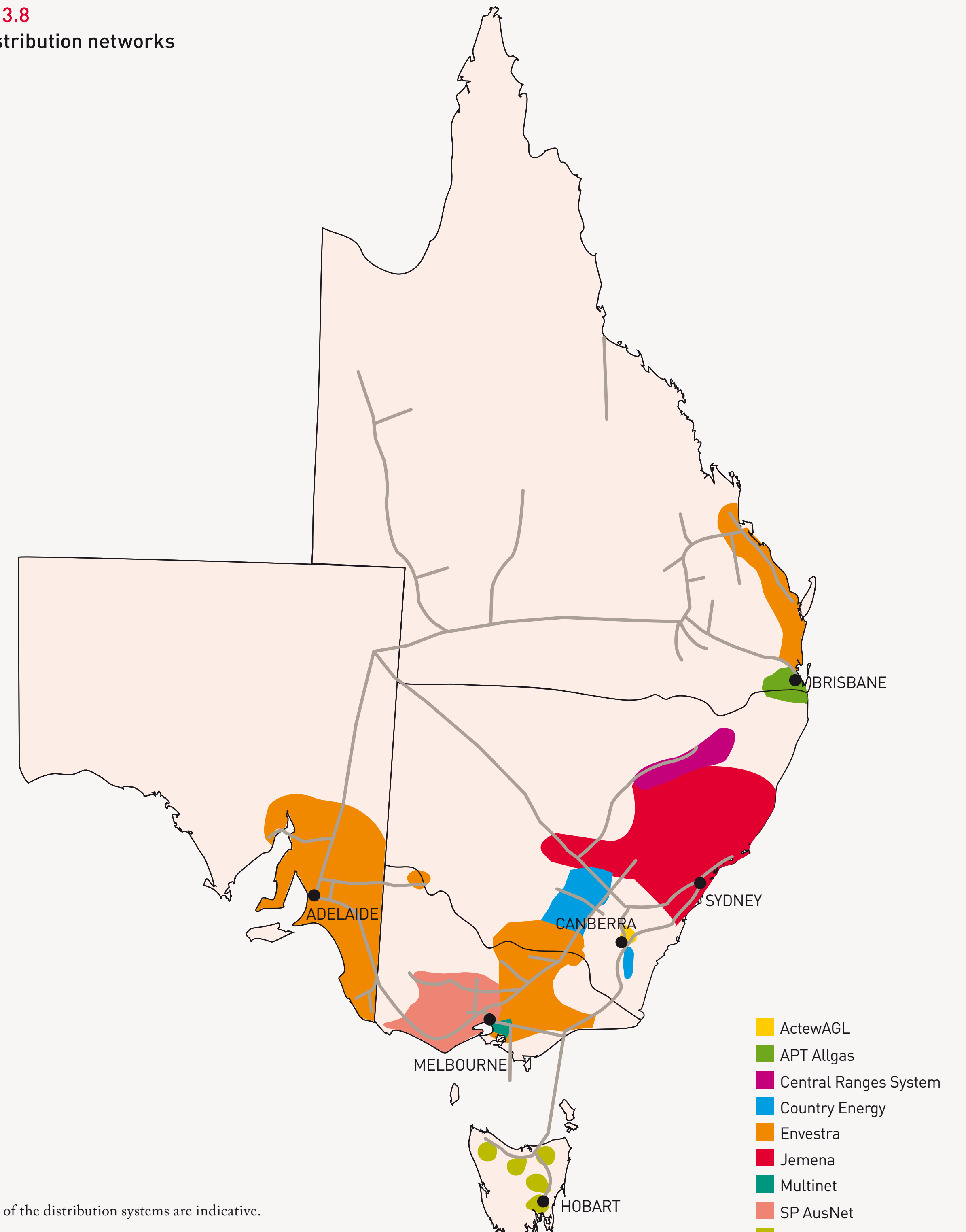
> *Prime Infrastructure* (formerly Babcock & Brown Infrastructure) owns the Tasmanian distribution network and has an interest in the Multinet network (Victoria).

> *APA Group* owns the APT Allgas networks in Queensland and has a 31 per cent stake in Envestra.

There are significant ownership links between gas distribution and other energy networks. In particular, Jemena and APA Group own and/or operate gas transmission pipelines (section 3.6.1). In addition, Jemena, APA Group, Cheung Kong Infrastructure and DUET Group all have ownership interests—in some cases, substantial interests—in the electricity network sector (chapter 2).

15 The unregulated 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.

Figure 3.8
Gas distribution networks



Notes:

Locations of the distribution systems are indicative.

Some corporate names are abbreviated.

Source: AER.

Table 3.5 Natural gas distribution networks in southern and eastern Australia

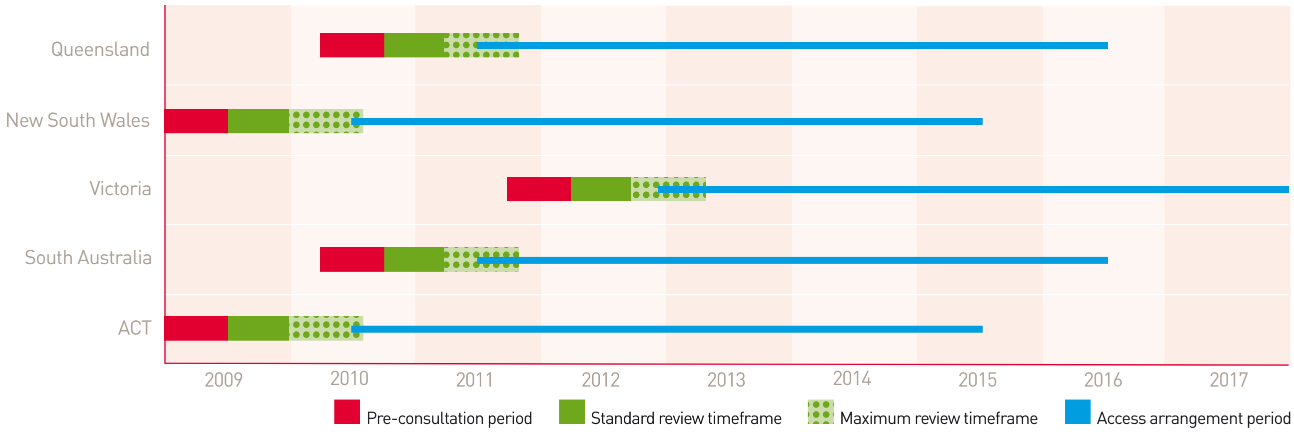
NETWORK	CUSTOMER NUMBERS	LENGTH OF MAINS (KM)	OPENING CAPITAL BASE (2009 $ MILLION)[1]	INVESTMENT—CURRENT ACCESS ARRANGEMENT (2009 $ MILLION)[2]	CURRENT ACCESS ARRANGEMENT PERIOD	OWNER
QUEENSLAND						
APT Allgas	75 000	2 800	367	143	1 Jul 2006 – 30 Jun 2011	APA Group
Envestra	82 500	2 510	265	106	1 Jul 2006 – 30 Jun 2011	Envestra (APA Group 31.7%, Cheung Kong Infrastructure 19%)
NEW SOUTH WALES AND ACT						
Jemena Gas Networks (NSW)	1 050 000	24 430	2 239	749	1 Jul 2010 – 30 Jun 2015	Jemena (Singapore Power International)
ActewAGL	112 000	4 200	272	85	1 Jul 2010 – 30 Jun 2015	ACTEW Corporation (ACT Government) 50%, Jemena (Singapore Power International) 50%
Wagga Wagga	18 700	680	20	59	1 Jul 2010 – 30 Jun 2015	Country Energy (NSW Govt)[3]
Central Ranges System	7 000	180	n/a	n/a	2006 – 19	APA Group
VICTORIA						
SP AusNet	570 000	9 400	969	347	1 Jan 2008 – 31 Dec 2012	SP AusNet (listed company; Singapore Power International 51%)
Multinet	646 600	10 010	901	235	1 Jan 2008 – 31 Dec 2012	DUET Group 79.9%, Prime Infrastructure 20.1%
Envestra	559 600	10 080	872	417	1 Jan 2008 – 31 Dec 2012	Envestra (APA Group 31.7%, Cheung Kong Infrastructure 19%)
SOUTH AUSTRALIA						
Envestra	393 800	7 800	956	216	1 Jul 2006 – 30 Jun 2011	Envestra (APA Group 31.7%, Cheung Kong Infrastructure 19%)
TASMANIA						
Tas Gas Networks	6 500	730	114[1]	Not regulated	Not regulated	Tas Gas (Prime Infrastructure)
NEM TOTALS	**3 521 700**	**72 820**	**6 975**	**2 357**		

n/a, not available.

1. For Tasmania, the opening capital base value is an estimated construction cost. For other networks, the opening capital base is the initial capital base, adjusted for additions and deletions, as reset at the beginning of the current access arrangement period. All data are converted to June 2009 dollars.
2. Investment data are forecasts for the current access arrangement period, adjusted to June 2009 dollars.
3. In October 2010 Envestra entered an agreement to acquire Country Energy's Wagga Wagga network.

Sources: Access arrangements for covered pipelines; company websites.

Figure 3.9
Indicative timelines for AER determinations on gas networks



Note: The timeframes are indicative. The standard review period begins when a network business submits an access arrangement proposal to the AER by a date specified in the previous access arrangement. The timeframes may vary if the AER grants a time extension for the proposal submission. An access arrangement period is typically five years, but a provider may apply for a different duration.

3.9.2 Regulation of distribution networks

The AER regulates all major distribution networks in New South Wales, Victoria, Queensland, Western Australia, South Australia and the ACT, following a transfer of this role from state and territory agencies in July 2008. The Economic Regulation Authority undertakes this role in Western Australia. The recently constructed Tasmanian network is the only major unregulated network. In addition, a number of small regional networks are unregulated.[15]

The Gas Law and Gas Rules set out the regulatory framework. Different forms of economic regulation apply to covered pipelines, based on criteria in the Gas Law. Most Australian distribution networks are subject to full regulation, which requires the service provider to submit an initial access arrangement to the regulator for approval, and revise it periodically (typically every five years).[16]

An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. The AER has published an *Access arrangement guideline* (available on its website) that details the regulatory process. A separate guideline explains dispute resolution under the Gas Law.[17] The AER *State of the energy market 2009* report (section 10.4) also outlines the regulatory process.

In summary, the regulatory process employs a building block approach to determine total network revenues and derive reference tariffs. The Gas Rules also allow for income adjustments from incentive mechanisms that reward efficient operating practices. In a dispute, an access seeker may request the regulator to arbitrate and enforce the terms and conditions of the access arrangement.

Figure 3.9 shows indicative regulatory timeframes for the networks. The AER approved access arrangements for the ACT and New South Wales gas distribution networks in 2010 (in April and June respectively). It also commenced in 2010 reviews of access arrangements for the South Australian and Queensland gas distribution networks.

16 A distribution pipeline may be subject to light regulation, in some circumstances, which means the service provider must publish the terms and conditions of access on its website. No distribution networks in Australia are covered by light regulation.

17 AER, *Access arrangement guideline*, 2009; AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules*, 2008.

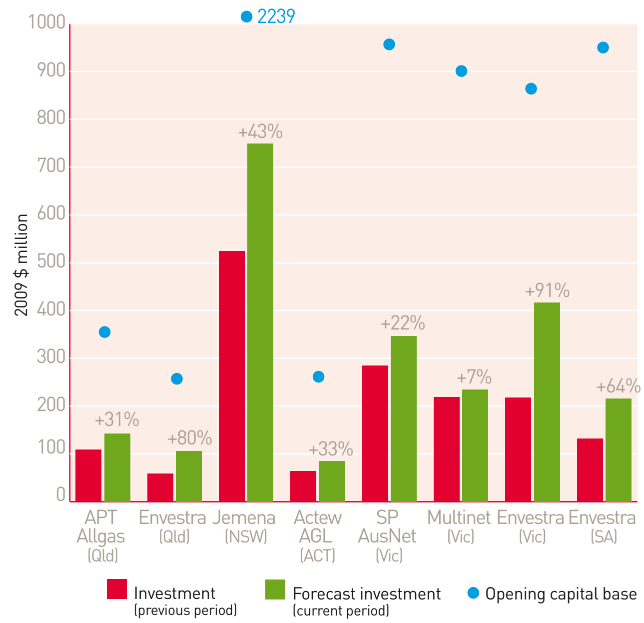
3.9.3 Investment in distribution networks

The capital drivers for gas distribution networks are broadly similar to those for electricity distribution—for example, the AER's 2010 determination for the New South Wales gas networks approved higher capital expenditure to meet demand growth and maintain network capacity. The underlying investment drivers included rising connection numbers, the development of renewal and replacement infrastructure to maintain the capacity of ageing networks, and infrastructure to support changes in market operations.

Figure 3.10 compares forecast investment over the current access arrangement periods (typically five years) for major distribution networks with outcomes in previous access arrangements. It also shows the opening capital bases for each network as a scale reference:

- Investment in the major networks is forecast at around $2.4 billion (in real terms) during the current access arrangement periods—a real increase of 43 per cent over investment in the previous periods.
- Investment in current access arrangements is running at around 25 per cent of the underlying capital base for most networks, but around 35 per cent for SP AusNet (Victoria) and 40–50 per cent for Envestra (Victoria) and the Queensland networks.
- Investment in the New South Wales and ACT distribution networks is forecast to rise by around 43 per cent and 33 per cent respectively over the current access arrangement period, compared with investment in previous periods. The AER approved these forecasts in its first decisions on the gas distribution sector, which it released in 2010.

Figure 3.10
Gas distribution network investment



Notes:

Opening capital bases are at the beginning of the current access arrangement period.

Investment data are forecast capital expenditure over the current access arrangement period (typically five years). See table 3.5 for the timing of current regulatory periods.

All values are converted to June 2009 dollars.

Sources: Access arrangements approved by the AER (New South Wales and the ACT), the ESC (Victoria), the QCA (Queensland) and ESCOSA (South Australia).


Jim Rice (Fairfax)

4 RETAIL ENERGY MARKETS

Energy retailers buy electricity and gas in wholesale markets and package it with transportation services for sale to customers. State and territory governments are responsible for regulating retail energy markets. Governments agreed in 2004, however, to transfer several non-price regulatory functions to a national framework that the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER) will administer (box 4.1).

This chapter covers the retailing of energy to small customers in those jurisdictions expected to implement the national reforms—Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT).[1]

4.1 Retail market structure

The energy retail sector is increasingly run by privately owned businesses. Three privately owned retailers—AGL Energy, Origin Energy and TRUenergy—collectively supply the bulk of small customers in Victoria and South Australia, and are 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 state owned retailers. More recently, Simply Energy and Lumo Energy have emerged as significant private retailers in some jurisdictions.

While ownership is increasingly in private hands, some governments own energy retailers:

> The New South Wales Government owns EnergyAustralia, Integral Energy and Country Energy, but in 2010 was progressing plans to privatise these entities (box 1.1, chapter 1).
> Snowy Hydro (jointly owned by the New South Wales, Victorian and Australian governments) owns Red Energy.
> The Tasmanian Government owns Aurora Energy and Momentum Energy.
> The Queensland Government owns Ergon Energy, which has significant market share in rural and regional Queensland but is not permitted to compete for new customers.
> The ACT Government operates ActewAGL—a joint venture with the private sector—to provide both electricity and gas retail services.

Table 4.1 lists licensed retailers that were active in the electricity and gas markets for residential and small business customers in July 2010. An active retailer is an authorised retailer that is supplying energy services to customers (whether or not the retailer is seeking new customers). Two retailers—Dodo Power & Gas and Qenergy—began operating in 2009–10. Also, a number of retailers (including Australian Power & Gas, Click Energy, Lumo Energy and Sanctuary Energy) widened the geographic range of their activity. Jackgreen was suspended from wholesale market trading in the National Electricity Market (NEM) in December 2009, and subsequently entered voluntary administration.

While governments introduced reforms to structurally separate the energy supply industry in the 1990s, the sectors have significant ownership links. In particular, significant vertical integration exists between energy retail markets and upstream energy production:

> AGL Energy, Origin Energy, TRUenergy and International Power are significant players in both electricity generation and energy retail.
> The public electricity sector also exhibits vertical integration. Snowy Hydro owns Red Energy, which has market share in Victoria and South Australia. In 2009 Hydro Tasmania (Tasmanian Government) acquired full ownership of Momentum Energy.
> AGL Energy, Origin Energy and TRUenergy have interests in gas production and/or gas storage. Origin Energy is a gas producer in Queensland, South Australia and Victoria. AGL Energy is a producer of coal seam gas in Queensland and New South Wales. TRUenergy has gas storage facilities in Victoria.

1 In New South Wales, Victoria and South Australia, small electricity customers are those consuming less than 160 megawatt hours (MWh) per year. In Queensland and the ACT, the threshold is 100 MWh per year; in Tasmania, it is 150 MWh per year. In gas, small customers are those consuming less than 1 terajoule per year.

Box 4.1 National retail regulation

Governments agreed in the Australian Energy Market Agreement 2004 to introduce a national scheme for energy retail regulation. The reform's architecture, the National Energy Customer Framework, includes the National Energy Retail Law, Rules and Regulations. The framework aims to deliver streamlined national regulation that supports an efficient retail market with appropriate consumer protection.

The legislative package to implement the national framework was introduced to the South Australian parliament in the 2010 spring sitting. State and territory governments are expected to implement the framework between 2011 and 2013. The transfer of functions is not expected to occur in Western Australia or the Northern Territory at this time.

The national framework will transfer several functions to the AER, including:

- monitoring compliance and enforcing breaches of the laws, rules and regulations
- approving the authorisation and exemption of energy retailers
- approving retailers' customer hardship policies
- reporting on performance matters such as customer service, and on energy affordability and retail market activity
- administering a 'retailer of last resort' scheme
- publishing retailers' standing offer prices and an online price comparison service for small customers, where required by a jurisdiction.

The states and territories will retain responsibility for control of regulated prices.

To prepare for the transition, the AER has been consulting with energy customers, consumer advocacy groups, energy retailers, jurisdictional regulators and ombudsmen, and state and territory government departments. In 2010 it ran 11 stakeholder forums on the national arrangements and its proposed approach to retail regulation. It also published issues papers covering retail pricing information, retailer authorisations and exemptions, the development of hardship program indicators, performance reporting and a proposed compliance framework. For some of these processes, it has published draft guidelines. The issues papers and draft guidelines are available on the AER's web site (www.aer.gov.au).

In addition, the New South Wales,[2] Queensland and Tasmanian governments own joint distribution–retail businesses. The ACT Government has ownership interests in both the host energy retailer and distributor. If links exist between retail and network sectors, regulators apply ring fencing arrangements to ensure operational separation of the businesses.

4.1.1 Queensland

At June 2010 Queensland had 28 licensed electricity retailers and five licensed gas retailers, of which 11 were active in the electricity market and three were active in the gas market. Origin Energy and AGL Energy are the leading retailers, with Integral Energy emerging as the third major player in electricity.

The Queensland Government owns Ergon Energy's retail business, which supplies electricity at regulated prices to customers in rural and regional areas. Ergon Energy is not permitted to compete for new customers.

4.1.2 New South Wales

At June 2010 New South Wales had 27 licensed electricity retailers, of which 11 supplied to residential and/or small business customers. The latter group included three host retailers—the government owned EnergyAustralia, Integral Energy and Country Energy, which jointly supply over 80 per cent of small customers—and eight new entrants (comprising a mix of established interstate players and niche market entrants).

2 In New South Wales, privatisation plans for the contestable sectors of the energy market (generation and retail) will result in structural separation of the distribution and retail sectors.

Table 4.1 Active energy retailers—small customer market, June 2010

RETAILER	OWNERSHIP	QLD	NSW	VIC	SA	TAS	ACT
ActewAGL Retail	ACT Government and AGL Energy		E; G •				E •; G •
AGL Energy	AGL Energy	E; G •	E; G •	E •; G •	E •; G		
Aurora Energy	Tasmanian Government				E	E •; G	
Australian Power & Gas	Australian Power & Gas	E; G	E	E; G			
Click Energy	Click Energy	E		E			
Country Energy	New South Wales Government[1]	E	E •; G •	E	E		
Dodo Power & Gas	Dodo Power & Gas			E			
Energy Australia	New South Wales Government[1]	E	E •; G	E; G			E; G
Ergon Energy	Queensland Government	E					
Integral Energy	New South Wales Government[1]	E	E •				
Lumo Energy	Infratil	E	E	E; G	E		
Momentum Energy	Hydro Tasmania (Tasmanian Government)			E	E		
Neighbourhood Energy	Neighbourhood Energy[2]			E			
Origin Energy	Origin Energy	E •; G •	E; G •	E •; G •	E; G •		
Powerdirect[3]	AGL Energy	E •	E	E	E		
Qenergy	Qenergy	E					
Red Energy	Snowy Hydro[3]		E	E; G	E		
Sanctuary Energy	Sanctuary Energy[4]	E	E				
Simply Energy	International Power			E; G	E; G		
Tas Gas Retail (formerly Option One)	Prime Infrastructure[5]					G	
TRUenergy	CLP Group	E	E; G	E •; G •	E; G		E; G

Electricity retailer
Gas retailer
Local area retailer •

1. The New South Wales Government was in 2010 progressing plans to privatise this entity.
2. Alinta Energy (formerly Babcock & Brown Power) became a major shareholder of Neighbourhood Energy in March 2010.
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. Sanctuary Energy is owned by Living Choice Australia (50 per cent) and Sanctuary Life (50 per cent).
5. Prime Infrastructure was formerly named Babcock & Brown Infrastructure.

Note: A 'local area retailer' is required to offer a contract to supply energy services to customers that establish a new connection to the electricity or gas network within a designated geographic region.

Sources: Jurisdictional regulator websites, retailer websites and other public sources.

CHAPTER 4 RETAIL ENERGY MARKETS

Six of the 11 active electricity retailers were also active in gas. AGL Energy (the host gas retailer) and EnergyAustralia supply the majority of customers.

4.1.3 Victoria

At June 2010 Victoria had 30 licensed electricity retailers, of which 14 were active in the residential and small business market. The active retailers include three host retailers—AGL Energy, Origin Energy and TRUenergy—and 11 new entrants, of which two are established interstate players.

Figure 4.1 illustrates energy retail market shares. The three host retailers supply about 74 per cent of small electricity customers, and each has acquired market share beyond its local area. New entrant penetration increased from around 7 per cent of small customers in June 2005 to almost 27 per cent in June 2009.

In gas at June 2010, Victoria had 15 licensed retailers, of which eight actively supplied small customers. The three host retailers, which are also the host retailers in electricity, collectively supplied over 81 per cent of small customers at June 2009.

4.1.4 South Australia

At June 2010 South Australia had 21 licensed electricity retailers, of which 10 were active in the small customer market. The host retailer, AGL Energy, supplied around 53 per cent of small customers in 2009, down from 79 per cent in 2005 (figure 4.2). Penetration by niche retailers has been only marginal, with the four largest retailers accounting for around 90 per cent of the market. Origin Energy (18 per cent) has been the most successful of the new entrants in building market share over the past five years.

South Australia had 11 licensed gas retailers at June 2010, of which four actively supplied to small customers. At June 2009 Origin Energy supplied around 56 per cent of small customers, but the three competing retailers have each built market share over the past five years.

4.1.5 Tasmania

Aurora Energy, the government owned host retailer, supplies small electricity customers in Tasmania. Legislative restrictions prevent new entrants from supplying small customers. At June 2010 Tasmania had two gas retailers active in the small customer market: the state owned Aurora Energy and Tas Gas Retail (owned by Prime Infrastructure).

4.1.6 Australian Capital Territory

At June 2010 the ACT had 18 licensed electricity retailers and eight licensed gas retailers. Three retailers—ActewAGL, EnergyAustralia and TRUenergy—actively sell to small customers. ActewAGL remains the dominant retailer, and in 2009 supplied around 93 per cent of small customers.[3]

4.2 Retail competition

All NEM jurisdictions except Tasmania have introduced full retail contestability (FRC) in electricity, allowing all customers to enter a contract with their retailer of choice. At 1 July 2009, Tasmania extended contestability to customers using at least 150 megawatt hours (MWh) per year. Small business customers that consume more than 50 MWh per year are expected to become contestable on 1 July 2011. All jurisdictions have introduced FRC in gas retail markets.

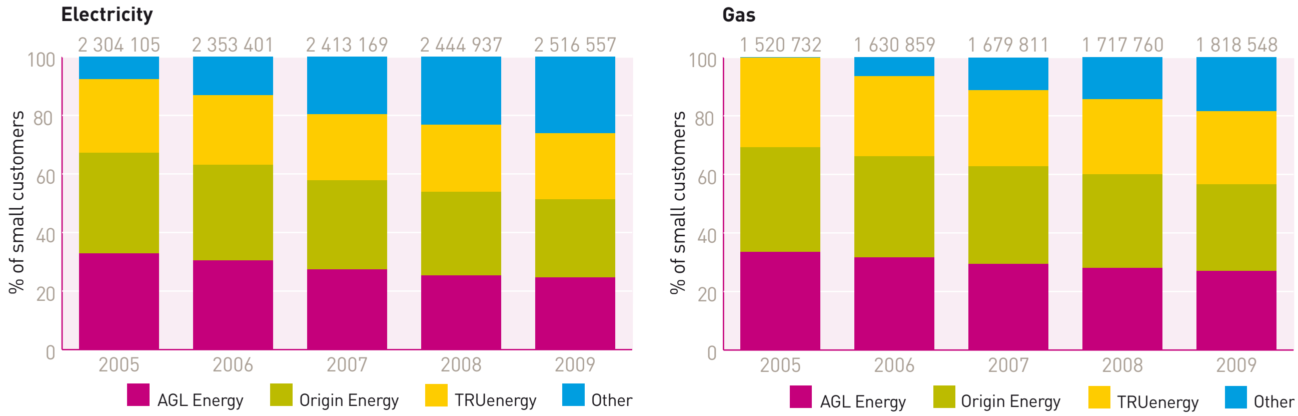
In the transition to effective competition, price cap regulation continues to apply in several jurisdictions. At July 2010 all jurisdictions except Victoria applied some form of price cap regulation for electricity services. In gas retail markets, New South Wales and South Australia regulate prices for small customers.

Australian governments have agreed to review the continued use of retail price caps and to remove them if effective competition can be demonstrated.[4] The AEMC is assessing the effectiveness of retail competition in each jurisdiction, to advise on ways to

3 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT*, 2010, p. 23.
4 Australian Energy Market Agreement 2004 (as amended).

Figure 4.1

Retail market share (small customers)—Victoria

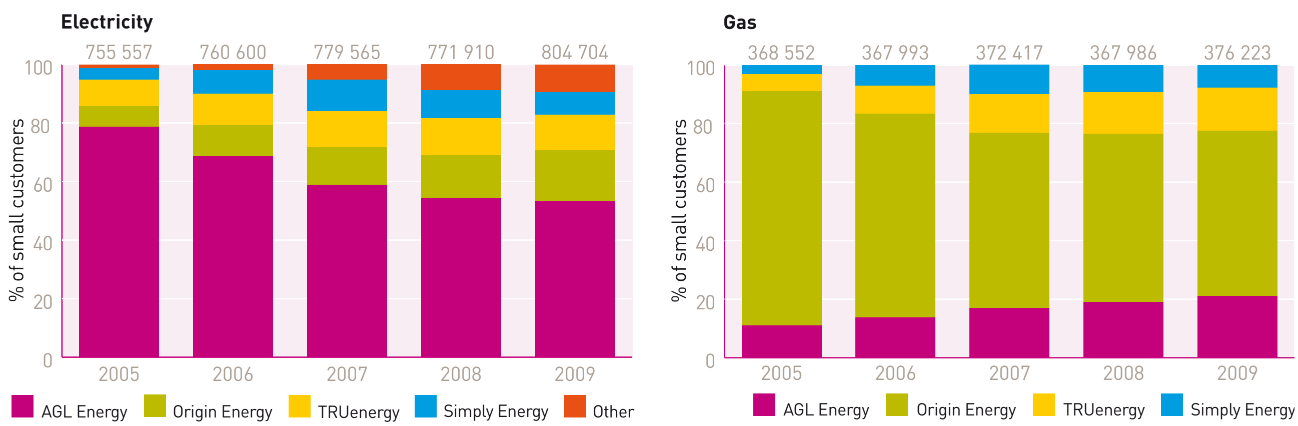


Note: Figures at top of columns are total small customer numbers.

Source: ESC (Victoria), *Energy retailers: comparative performance report — customer service*, various years.

Figure 4.2

Retail market share (small customers)—South Australia



Note: Figures at top of columns are total small customer numbers.

Source: ESCOSA (South Australia), *Annual performance report: performance of South Australian energy retail market*, various years.

remove retail price caps. The relevant state or territory government makes the final decision on this matter.

The AEMC in 2008 separately reviewed the effectiveness of competition in the Victorian and South Australian energy retail markets. It found competition was effective in both markets, but competition in South Australia was more intense in electricity than in gas.[5] In response to the review, the Victorian Government removed retail price caps on 1 January 2009. The South Australian Government did not accept the AEMC's recommendations to remove retail price regulation; it was concerned that more than 30 per cent of small customers remained on standing contracts, and that stakeholders had differing views on the effectiveness of competition.

5 AEMC, *Review of the effectiveness of competition in the electricity and gas retail markets in Victoria—first final report*, 2007; AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia—first final report*, 2008.

In June 2010 the AEMC released a draft report on the ACT retail electricity market, which found competition in the small customer market was not effective. It considered regulated retail prices were set at levels that did not allow adequate margins to attract new entrants, thus creating barriers to entry. Accordingly, retailer rivalry was limited, as were product choices available to small customers. The AEMC also noted customer switching among retailers was lower in the ACT than in other jurisdictions.[6]

The Ministerial Council on Energy and the Council of Australian Governments have agreed to further energy retail market reviews for New South Wales, Queensland and Tasmania (if FRC is introduced).[7]

4.2.1 Customer switching

The rate at which customers switch their supply arrangements indicates customer participation in the market. While switching (or churn) rates can also indicate competitive activity, they must be interpreted with care. Switching is sometimes high during the early stages of market development, when customers can first exercise choice. Switching rates may then stabilise as a market acquires more depth. Similarly, switching may be low in a very competitive market if retailers deliver good quality service that gives customers no reason to change.

The Australian Energy Market Operator (AEMO) publishes churn data measuring the number of customer switches from one retailer to another. The data for electricity are available for New South Wales and Victoria from the introduction of FRC in 2002, for South Australia from October 2006 and for Queensland from July 2007. Since 1 July 2009 AEMO has also published gas churn data.

Figure 6 in the *Market overview* of this report illustrates retail switching activity in 2009–10. Figure 4.3 sets out cumulative switching data. All data includes 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. If a customer switches to a number of retailers in succession, then each move counts as a separate switch. Cumulative switching rates may thus exceed 100 per cent.

Victoria and South Australia continue to have higher cumulative switching rates than those of other jurisdictions. By June 2010 Victoria's cumulative switching rate was around double the New South Wales rate for electricity and triple the rate for gas. While Queensland introduced FRC several years later than other jurisdictions did, customer activity has gathered momentum; in 2010 Queensland's cumulative switching in gas overtook that recorded in New South Wales. More generally, switching rates have been lower in gas than electricity in all jurisdictions.

4.3 Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services. Table 4.2 estimates the composition of a typical electricity retail bill for a residential customer in each NEM jurisdiction that regulates prices. While recent data for gas are limited, the table includes gas retail estimates for New South Wales and South Australia.

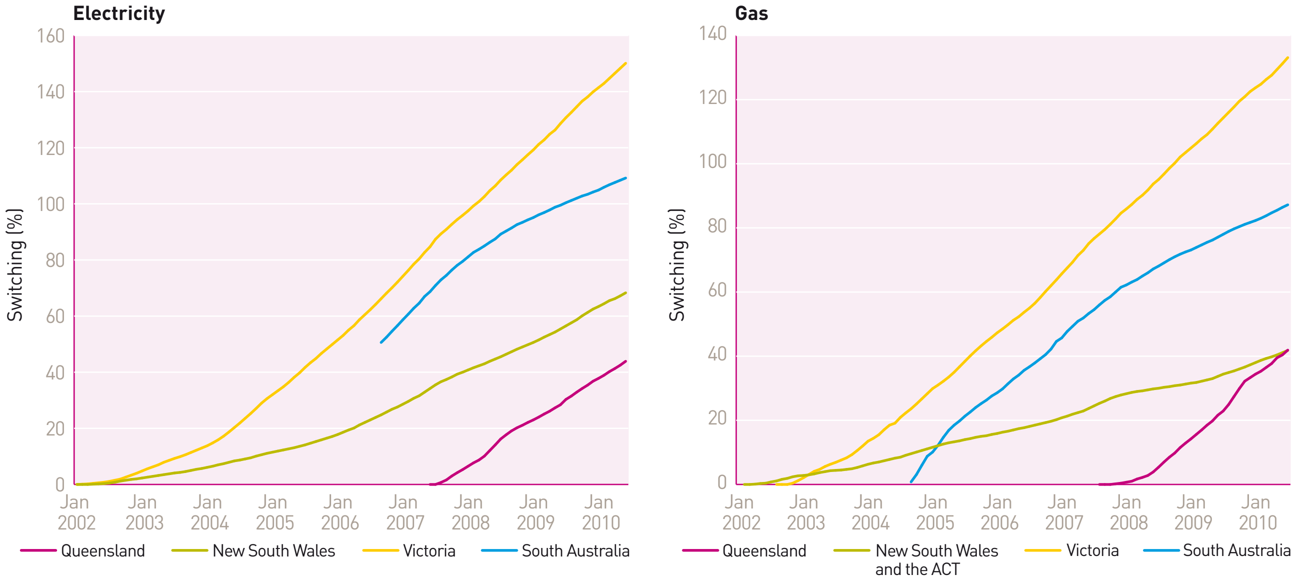
In electricity, wholesale energy costs account for around 37–45 per cent of retail bills, while network tariffs account for 43–51 per cent. Retailer operating costs have a range of around 4–8 per cent, and retail margins have a range of 3–5 per cent.

The cost estimates for New South Wales reflect a significant pass through of distribution network costs that took effect in 2009; the contribution of network costs to retail prices is projected to rise from around 47 per cent in 2007 to 57 per cent in 2012–13.

6 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT*, 2010, p. 4.
7 COAG, *Implementation plan for competition reforms*, 2010.

Figure 4.3

Cumulative monthly customer switching of retailers as a percentage of small customers



Notes:

The customer base is estimated at 30 June 2010.

No comparable public data are available for South Australia electricity switching before June 2006.

The New South Wales and ACT, Queensland and Victorian gas data are based on transfers at delivery points.

Sources: Customer switches: AEMO, MSATS transfer data to June 2010 and gas market reports, transfer history to June 2010; customer numbers: IPART (New South Wales), *NSW electricity information paper—electricity retail businesses' performance against customer service indicators,* various years; ESCOSA (South Australia), *08/09 Annual performance report: South Australian energy supply industry,* 2009; ESC (Victoria), *Energy retailers: comparative performance report—customer service 2008–09,* 2009; QCA (Queensland), *Market and non-market customers, December quarter 2009,* 2010.

Table 4.2 Indicative composition of residential electricity and gas bills

JURISDICTION	WHOLESALE ENERGY COSTS	NETWORK COSTS	RETAIL OPERATING COSTS	RETAIL MARGIN
	PER CENT OF TYPICAL SMALL CUSTOMER BILL			
ELECTRICITY				
New South Wales	37	51	6	5
Queensland	42	49	4	5
South Australia	44	43	8	5
Tasmania	43	49	5	3
ACT	45	43	7	5
GAS				
New South Wales	33	47	13	7
South Australia	18	60	17	5

Note: South Australian gas estimates are based on 2008 data. All other estimates are based on 2010 data.

Sources: Determinations, draft determinations, fact sheets and newsletters by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT).

Pipeline charges are the most significant component of gas retail prices. Transmission and distribution charges combined account for around 47 per cent of gas retail prices in New South Wales and 60 per cent in South Australia. Distribution charges account for the bulk of pipeline costs. Estimates published in 2008 for South Australia and Queensland found distribution costs contributed around 52 per cent to retail prices in those jurisdictions.[8] Wholesale energy costs typically account for a lower share of retail prices in gas than electricity, while retailer operating costs (including margins) account for a higher share. Given the uneven geographic spread of gas producing basins from major markets, the composition of retail prices can vary significantly across jurisdictions and regions.

4.3.1 Price diversity

Retailers offer contracts for a range of products with different price structures. The offers may include standard products, green products, 'dual fuel' contracts (for gas and electricity) and packages that bundle energy with services such as telecommunications. Some contracts bundle energy services with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. Additional discounts may be offered for prompt payment of bills or direct debit bill payments. These offers may vary depending on the length of a contract. Many contracts carry a severance fee, however, for early withdrawal.

The variety of discounts and non-price inducements makes direct price comparisons difficult. Further, the transparency of price offerings varies. The Queensland, South Australian, New South Wales and Victorian regulators and a number of private entities operate websites that allow customers to compare their current electricity and gas retail contracts with available market offers.

Under the National Energy Retail Law, the AER will have a role in assisting customers to compare different retail product offerings. The Law also requires the AER to develop an online price comparison service for jurisdictions that choose to participate.

4.3.2 Regulated prices—recent trends

Most jurisdictions that apply price cap regulation set prices that small customers are entitled to access if they choose not to enter a market contract with an energy retailer. The AER *State of the energy market 2009* report described approaches across the jurisdictions in setting these prices (section 7.4.1). Typically, the jurisdictional economic regulator conducts an independent review. All NEM jurisdictions except Victoria regulate prices for electricity retail services; only New South Wales and South Australia regulate gas prices.

While Victoria does not apply price caps, its retailers are required to publish unregulated standing offer prices on their websites that small customers can access. The prices are also published in the Victorian government gazette.

Table 4.3 summarises announced movements in regulated and standing offer electricity prices for 2009–10 and 2010–11, and estimates the annual electricity bill for customers under these arrangements. Figure 8 in the *Market overview* of this report sets out the 2009–10 data in chart form.

In some jurisdictions, customers may be able to negotiate significant discounts against these prices by entering a market contract. A St Vincent de Paul Society analysis of the Victorian market found a price spread of 26–37 per cent across retail offers within electricity distribution zones.[9]

The data indicate that retail *electricity* prices rose significantly in 2009–10 in most states and territories. At 1 November 2010, further increases had been announced or proposed in some jurisdictions.

- New South Wales regulated prices rose by up to 21.7 per cent in 2009–10, with further significant increases occurring in 2010–11. IPART found higher network charges accounted for 50 per cent of

8 McLennan Magasanik & Associates, *Final report to the Queensland Competition Authority—costs of gas supply for a second tier retailer supplying small customers in Queensland*, 2008; ESCOSA (South Australia), *2008 Gas standing contract price path inquiry: draft inquiry report and draft price determination*, 2008.

9 St Vincent de Paul Society, *Victorian energy prices July 2008 – July 2010: a report from the Victorian tariff-tracking project*, 2010.

Table 4.3 Movements in regulated and standing offer prices—electricity

JURISDICTION	REGULATOR	RETAILER	AVERAGE PRICE INCREASE (PER CENT) 2009–10	2010–11	ESTIMATED ANNUAL COST ($)
New South Wales	IPART	EnergyAustralia	21.7	10.0	1127
		Integral Energy	21.1	7.0	1250
		Country Energy	17.9	13.0	1549
Queensland	QCA	All licensed retailers	15.5	13.3	1166
Victoria	Unregulated	Origin Energy (Citipower)	14.5	..	1203
		Origin Energy (Powercor)	14.5	..	1341
		TRUenergy (SP AusNet)	11.2	..	1213
		AGL Energy (Jemena)	19.3	..	1317
		AGL Energy (United Energy)	11.8	..	1214
South Australia	ESCOSA	AGL Energy	3.1	5.6 (1 July 2010) 6.9 (1 January 2011)	1276
Tasmania	OTTER	Aurora Energy	6.2	6.0 (1 July 2010) 8.8 (1 December 2010)	1311
ACT	ICRC	ActewAGL	6.4	2.3	977

Notes:

The South Australian electricity price increase scheduled for January 2011 is a draft determination by the jurisdictional regulator. All other price increases are final outcomes.

Estimated annual cost is based on a customer using 5000 kilowatt hours of electricity per year with no controlled load as at 1 August 2010.

The Victorian price movements (and estimated annual costs) are for the local area retailer in each of Victoria's five distribution areas. The estimates are based on unregulated standing offer prices published in the Victorian government gazette.

Sources: Determinations, draft determinations, fact sheets and media releases from 2007 to 2010 by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government Gazette.

the 2009–10 price increases and 80 per cent of the 2010–11 increases. Rising wholesale energy costs contributed to around 30 per cent of the 2009–10 retail price rises, but will have a negligible impact in 2010–11.[10]

> The Queensland Competition Authority (QCA) increased regulated electricity prices for 2009–10 by 11.8 per cent, which rose to 15.5 per cent following an appeal by energy retailers. It attributed the rise in roughly equal proportions to rising wholesale energy costs and network costs. The QCA attributed around 61 per cent of the projected 13.3 per cent rise in 2010–11 retail prices to rising network charges, mainly associated with new investment in distribution networks. The remaining sources of cost pressure were rising wholesale energy costs (contributing 29 per cent) and an increase in retail costs related to customer acquisition and retention.[11]

> Victorian standing offer prices for electricity rose by around 12–19 per cent in 2009–10. Given these are unregulated prices, only limited information is available on underlying cost factors. Unlike most jurisdictions, Victoria had relatively flat (or slightly declining) distribution charges, and was the only mainland jurisdiction to record a decrease in wholesale electricity prices in 2009–10. Charges for the introduction of smart meters would have accounted for retail price increases of around 2.5–7 per cent in 2010. The pass through impact was lowest for United Energy distribution customers and highest for Jemena customers. A pass through of transmission charges would account for retail price increases of up to 2.6 per cent. Higher costs (including compliance costs) associated with government climate change policies were other likely contributing factors.

10 IPART, *Market-based electricity purchase cost allowance—2009 electricity review, final report and determination*, 2009; IPART, 'Regulated electricity retail tariffs for 1 July 2010 to 30 June 2013—final report', Fact sheet, 2010.

11 QCA, *Benchmark retail cost index for electricity, final decisions, 2009–10* and *2010–11*, 2009 and 2010.

Origin Energy call centre (Origin Energy)

- South Australian price rises were relatively moderate in 2009–10, but in July 2010 rose by 5.6 per cent in response to rising network charges and pass throughs related to climate change policies. The South Australian regulator's inquiry into regulated prices from 2011 to 2014 foreshadowed in a draft determination that prices may increase by a further 6.9 per cent on 1 January 2011.[12]
- Tasmanian electricity prices rose by around 6 per cent during 2009–10, with a further 6 per cent increase on 1 July 2010 in response to rising network charges. The Tasmanian regulator determined that prices would again increase by 8.8 per cent on 1 December 2010. It attributed around half of the price increase to rising energy purchase costs.[13]
- The ACT recorded a 6.4 per cent in prices in 2009–10 and expects a moderate 2.3 per cent increase in 2010–11.

Recent retail price increases have generally been lower in *gas* than electricity. South Australia expected a moderate 3.1 per cent increase in retail gas prices in 2010–11. In New South Wales, IPART attributed price increases of around 3–8 per cent over the same period mainly to higher distribution pipeline charges.[14] Victorian gas retail prices in 2009–10 rose by around 6–12 per cent. Information on the cost pressures underlying these unregulated price movements is limited. More generally, a St Vincent de Paul Society analysis of the Victorian market found geographic price spreads were higher in gas than electricity.[15]

4.3.3 Retail prices—long term trends

Figure 4.4 tracks movements in real energy retail prices for metropolitan households since 1991. It illustrates movements in the electricity and gas components of the consumer price index over this period, and reflects a mix of regulated and market price outcomes. Figure 9 in the *Market overview* of this report compares price outcomes for household and business customers.

Real energy prices have trended upwards since jurisdictions began phasing in retail contestability for small customers in 2001. In part, this trend reflects the unwinding of historical cross-subsidies from business to household customers that was necessary for competitive markets to develop. Price rebalancing caused significant electricity retail price rises in Melbourne and Adelaide early in the decade, for example. In Brisbane (where small customer prices remained fully regulated until 2007) and Hobart (where small customer prices are still fully regulated), electricity retail prices remained relatively stable until the past three or four years. In many jurisdictions, retail prices for gas tended to rise earlier and more steadily than for electricity.

Retail energy prices have risen sharply in most jurisdictions since 2007. A key factor in 2007 and 2008 was that drought conditions drove up wholesale energy prices. More recently, rising network costs (especially for distribution networks and pipelines) have flowed through to retail prices. The discussion of regulated price movements in section 4.3.2 outlines the issues in each jurisdiction.

4.4 Quality of retail service

Reporting on the quality of service by retailers tends to focus on access, affordability and customer service indicators. This section provides summary data on recent outcomes.

4.4.1 Affordability and access

A key performance indicator of affordability and access is the rate of residential customer disconnections for failure to meet bill payments (figure 4.5). In 2008–09 the rate of electricity disconnections declined in Queensland and the ACT, and was unchanged in New South Wales. Tasmania recorded a slight increase in disconnection rates.

12 ESCOSA, '2010 Regulated electricity price adjustment impact on residential and small business customers', Media release, June 2010; ESCOSA, *2010 Review of retail electricity standing contract price path, draft inquiry report and draft price determination,* 2010.

13 OTTER, 'Electricity price investigation, final report', Media release, 29 October 2010.

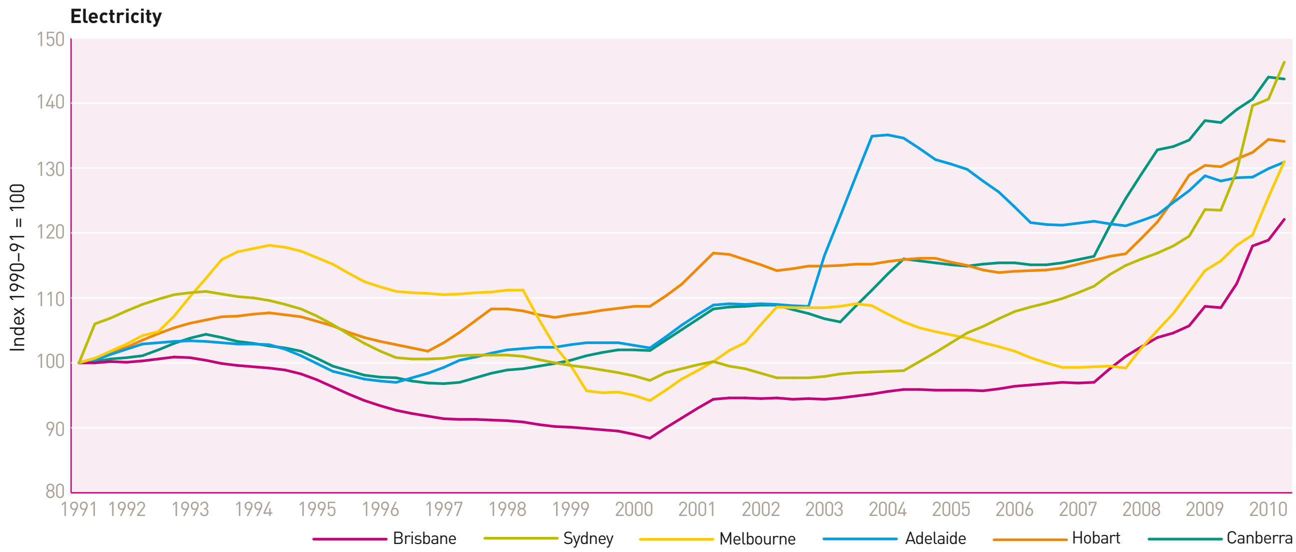
14 IPART, 'Review of regulated retail tariffs and charges for gas from 1 July 2010 to 30 June 2013—final report', Fact sheet, 2010.

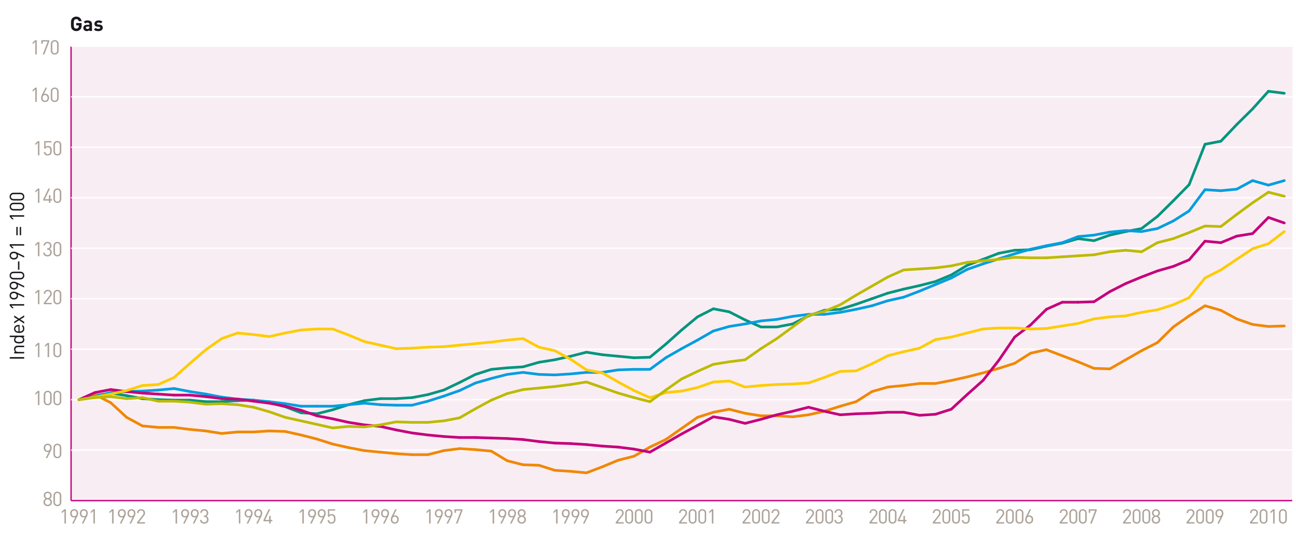
15 St Vincent de Paul Society, *Victorian energy prices July 2008 – July 2010: a report from the Victorian tariff-tracking project,* 2010.

Victoria and South Australia recorded an increase in disconnection rates for both electricity and gas. In Victoria, disconnection rates for AGL Energy and TRUenergy increased significantly.[16]

The South Australian regulator noted that a slight increase in disconnection rates may indicate increased financial hardship among small customers, but equally could reflect tighter credit management practices by energy retailers.[17]

Figure 4.4
Retail price index (inflation adjusted), Australian capital cities





Note: Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

Source: ABS, *Consumer price index*, cat. no. 6401.0, various years.

16 ESC, *Energy retailers—comparative performance report 2008–09*, 2009, p. 13.
17 ESCOSA, *08/09 Annual performance report: South Australian energy supply industry*, 2009.

4.4.2 Customer complaints

Figure 4.6 illustrates rates of retail customer complaints for electricity and gas. In 2008–09 the rate of electricity customer complaints increased significantly in Victoria, Queensland and South Australia. The increases were partly attributed to billing system issues that AGL Energy experienced.[18]

Figure 4.5

Residential disconnections for failure to pay amount due, as a percentage of the small customer base

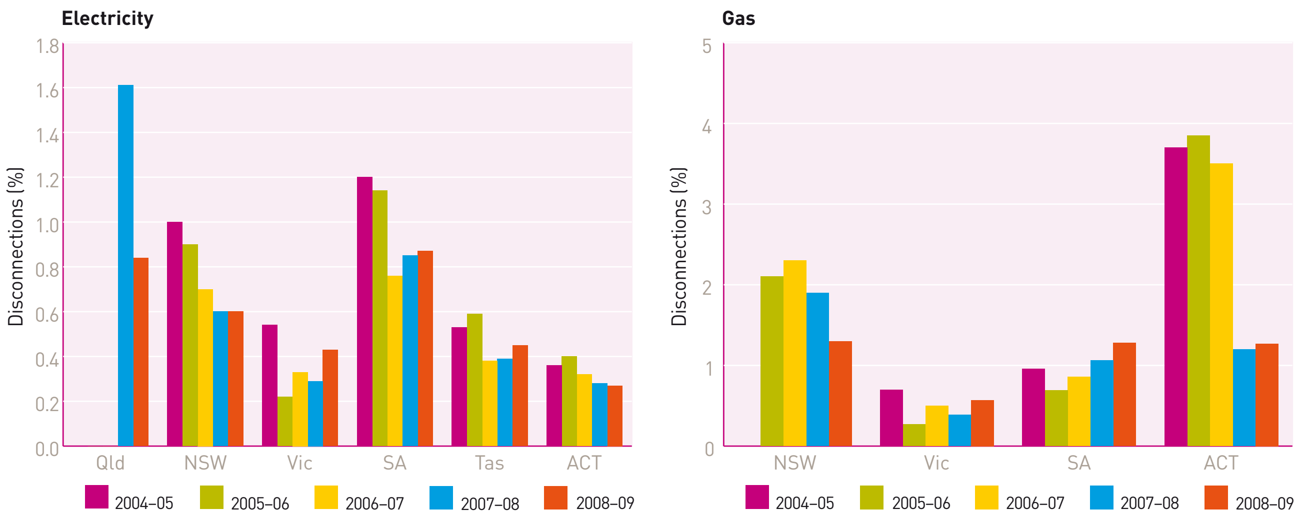
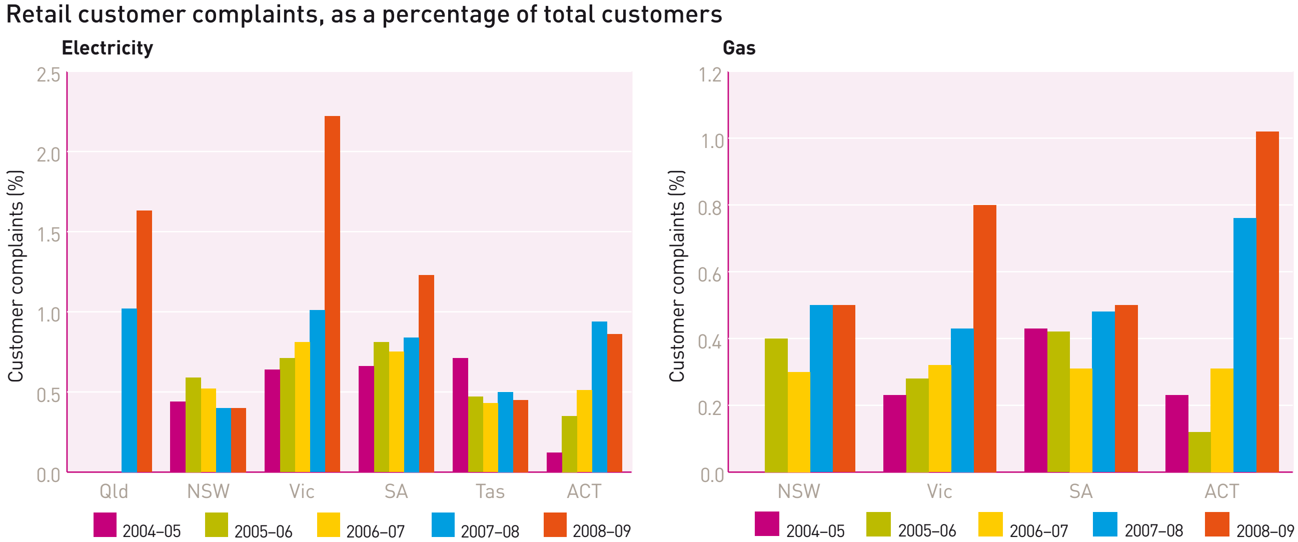


Figure 4.6

Retail customer complaints, as a percentage of total customers



Sources for figures 4.5 and 4.6: Reporting against Utility Regulators Forum templates and retail performance reports by IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA and the Department of Employment, Economic Development and Innovation (Queensland), and the ICRC (ACT).

18 ESC, *Energy retailers—comparative performance report 2008–09*, 2009, p. 15; ESCOSA, *08/09 Annual performance report: South Australian energy supply industry*, 2009, p. 50; QCA, *Small electricity customer disconnection and complaints data—year ended 30 June 2009*, 2009, p. 3.

ABBREVIATIONS

2P	proved plus probable natural gas reserves
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CCGT	combined cycle gas turbine
CIR	Congestion Information Resource
COAG	Council of Australian Governments
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CPT	cumulative price threshold
CSG	coal seam gas
DRP	debt risk premium
Electricity Law	National Electricity Law
Electricity Rules	National Electricity Rules
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
FRC	full retail contestability
Gas Law	National Gas Law
Gas Rules	National Gas Rules
GJ	gigajoule
GSL	guaranteed service level
GSOO	Gas Statement of Opportunities
GW	gigawatt

GWh	gigawatt hour
ICRC	Independent Competition and Regulatory Commission
IDGCC	integrated drying gasification combined cycle
IGCC	integrated gasification combined cycle
IPART	Independent Pricing and Regulatory Tribunal
kV	kilovolt
KW	kilowatt
KWh	kilowatt hour
LNG	liquefied natural gas
MCE	Ministerial Council on Energy
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NTP	National Transmission Planner
OCGT	open cycle gas turbine
opex	operating expenditure
OTTER	Office of the Tasmanian Economic Regulator
PJ	petajoule
Q	quarter
QCA	Queensland Competition Authority
QNI	Queensland to New South Wales interconnector
RAB	regulated asset base
RERT	reliability and emergency reserve trader
RET	renewable energy target
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SFE	Sydney Futures Exchange
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
WACC	weighted average cost of capital

Australian
Competition &
Consumer
Commission