STATE OF THE ENERGY MARKET 2011

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ISBN 978 1 921964 05 3

First published by the Australian Competition and Consumer Commission 2011

10 9 8 7 6 5 4 3 2 1

ACKNOWLEDGEMENTS
This report was prepared by the Australian Energy Regulator. The AER gratefully acknowledges the following corporations and government agencies that have contributed to this report: Australian Bureau of Statistics; Australian Energy Market Operator; d-cyphaTrade; Department of Resources, Energy and Tourism (Cwlth); EnergyQuest; Essential Services Commission (Victoria); Essential Services Commission of South Australia; Independent Competition and Regulatory Commission (ACT); Independent Pricing and Regulatory Tribunal of New South Wales; Office of the Tasmanian Economic Regulator; and Queensland Competition Authority.

The AER also acknowledges Mark Wilson for supplying photographic images.

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Cover image: Tim Marsden (Newspix)

CONTENTS

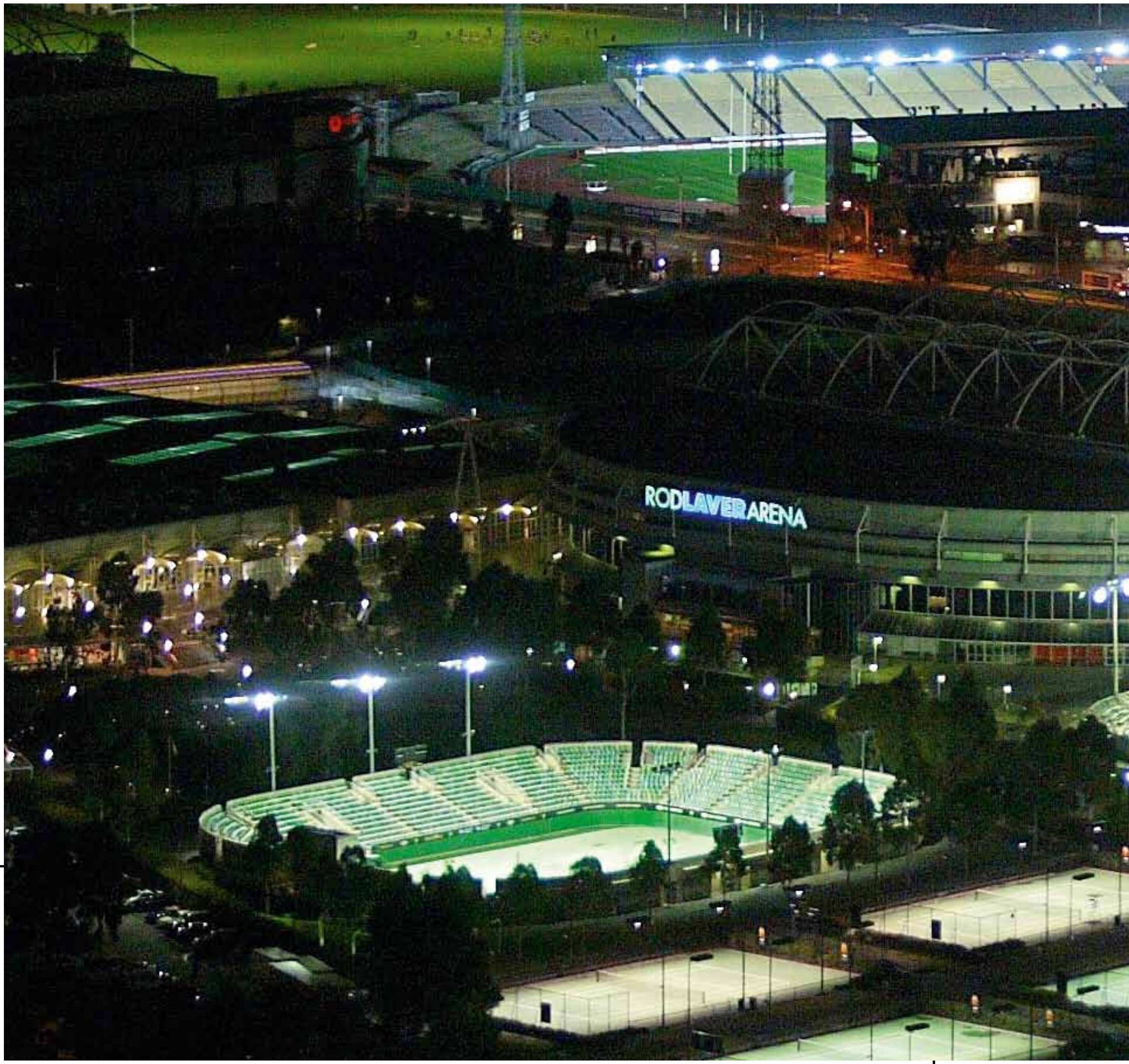
PREFACE

The Australian Energy Regulator's fifth *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.

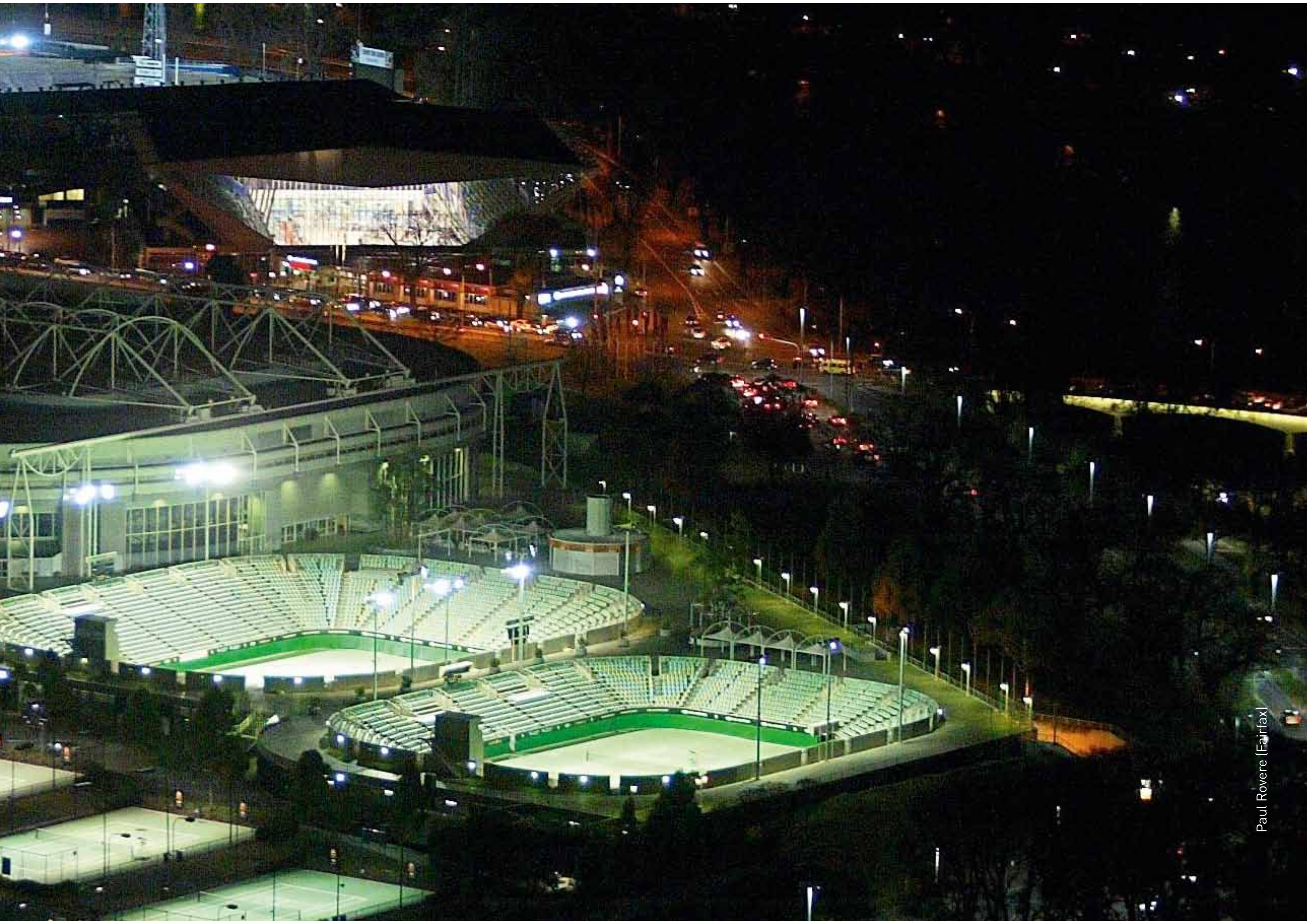
The 2011 report consists of a market overview, supported by chapters on the electricity, gas and energy retail sectors. The report focuses on activity over the past 12–18 months in those jurisdictions and areas in which the AER has regulatory responsibilities.

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

Andrew Reeves
Chairman



MARKET OVERVIEW


Paul Rovere (Fairfax)

For many years Australia enjoyed relatively stable electricity prices. But this situation has changed markedly, with substantial price increases since 2007. The increases are mostly attributable to rising charges for energy networks—the poles and wires, and gas pipelines that transport energy. In some jurisdictions, cost pressures have also resulted from wholesale energy costs, retailer costs and margins, and climate change policies (including renewable energy targets, incentives for small scale solar generation and energy efficiency schemes).

Rising network charges are being driven by a mix of factors that have increased the costs of building and running electricity networks and gas pipelines. These factors include continued growth in peak energy demand, stricter reliability and safety standards imposed by jurisdictional agencies, growth in customer numbers, the need to replace ageing equipment, and higher debt costs.

But the regulatory framework—the national energy Rules that set out how the Australian Energy Regulator (AER) must regulate electricity and gas networks—has led to some price increases that are difficult to justify. The framework was introduced in 2006, when capacity issues were emerging after many years in which Australia had lived off the legacy of historical overinvestment in energy infrastructure. New Rules were drafted to stimulate network investment by locking down the regulatory decision making process. While this approach has successfully increased network investment, it restricts the regulator from making holistic assessments of how much of that investment is efficient or necessary. This restriction has led to consumers paying more than necessary for a safe and reliable energy supply.

The AER in 2011 proposed Rule changes to both promote efficient network investment and advance the long term interests of consumers. The proposals focus on allowing the regulator to make holistic and independent assessments of the costs of delivering safe and reliable energy services. This would allow the regulator to weigh up all relevant evidence and reach balanced decisions. The AER also proposed a new approach to setting the rate of return on network investment, to provide certainty for investors and allow the regulatory approach to keep pace with changing financing practices. The Australian Energy Market Commission (AEMC) is consulting on the Rule change proposals, and will make a determination in 2012.

While rising network costs have driven up household energy bills, wholesale energy costs exerted less pressure in 2010–11. In the spot market for electricity, benign weather conditions led to average prices falling significantly in most parts of the market. While this was a positive development, average spot prices are only a partial indicator of the energy costs that retailers pay. Retailers and generators manage the risk of spot price volatility by entering hedge contracts with each other and through futures markets such as the Sydney Futures Exchange.

But, increasingly, vertical integration between generators and retailers is being used as an alternative to manage this risk. While it makes commercial sense for the entities concerned, vertical integration reduces liquidity and contracting options in futures markets. It thus drives up energy costs for independent retailers and may pose a barrier to entry and expansion for both independent generators and retailers.

A related development in some regions is that short term fluctuations in spot prices do not always reflect the underlying cost of generation. Strategic bidding—rather than changes in the underlying costs of meeting demand—is sometimes driving very high or very negative prices. When spot prices do not reflect underlying costs, market participants rely on futures markets more heavily to manage risk and secure future earnings. However, significant vertical integration creates a more challenging risk management environment that may deter efficient investment by new entrants.

Reform in wholesale gas markets continued with the launch in September 2010 of a short term trading market in Sydney and Adelaide. The market was extended to Brisbane in December 2011. While data errors have led to some price instability, the short term

Table 1 Recent AER decisions—energy networks

SECTOR	LOCATION	PERIOD COVERED (5 YRS TO)	% CHANGE FROM PREVIOUS 5 YEAR PERIOD		ESTIMATED IMPACT ON RETAIL BILL FOR TYPICAL HOUSEHOLD
			CAPEX	OPEX	
Electricity (T)	Tas	30 Jun 2014	67	29	2.3% rise (year 1), then 1% per year
	NSW	30 Jun 2014	73	28	9.3% to 10.4% rise (year 1), then cumulative 16–35% rise (years 2–4)
Electricity (D)	NSW	30 Jun 2014	37–116	24–39	
	ACT	30 Jun 2014	59	43	4.1% rise (year 1), then 1.3% per year
	SA	30 Jun 2015	95	41	6.0% rise (year 1), then 4.4% per year
	Qld	30 Jun 2015	33–38	21	9.2% rise (year 1), then 2.6% per year
	Vic	31 Dec 2015	37–74	10–47	1.8% rise (year 1), then 2.6% per year
Gas (T)	NT	30 Jun 2016	76	54	na
Gas (D)	NSW	30 Jun 2015	60	12	8.0% rise (year 1), then 5.1% per year
	ACT	30 Jun 2015	66	28	7.7% rise (year 1), then 4.1% per year
	SA	30 Jun 2016	163	4	8.0% rise (year 1), then 5.1% per year
	Qld	30 Jun 2016	0–72	11–27	7.7% rise (year 1), then 4.1% per year

Capex, capital expenditure; D, distribution; Opex, operating expenditure; T, transmission; na, Not applicable.

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

The retail impacts from the Queensland electricity distribution decisions reflect a merits review decision. The actual price rises will be lower, due to the Queensland Government preventing the networks from recovering additional revenue determined by the tribunal.

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

Sources: Regulatory determinations by AER and IPART.

trading market enhances transparency and competition for a commodity that was, until recently, traded mainly under opaque long term contracts.

National energy retail reforms will transfer significant new functions to the AER from 1 July 2012. The reforms aim to deliver streamlined national regulation that supports an efficient retail market with appropriate consumer protection. In 2011 the AER continued to consult with energy customers, consumer advocacy groups, energy retailers and distributors, state and territory agencies, ombudsman schemes and other stakeholders to ensure a smooth transition and protection for energy customers.

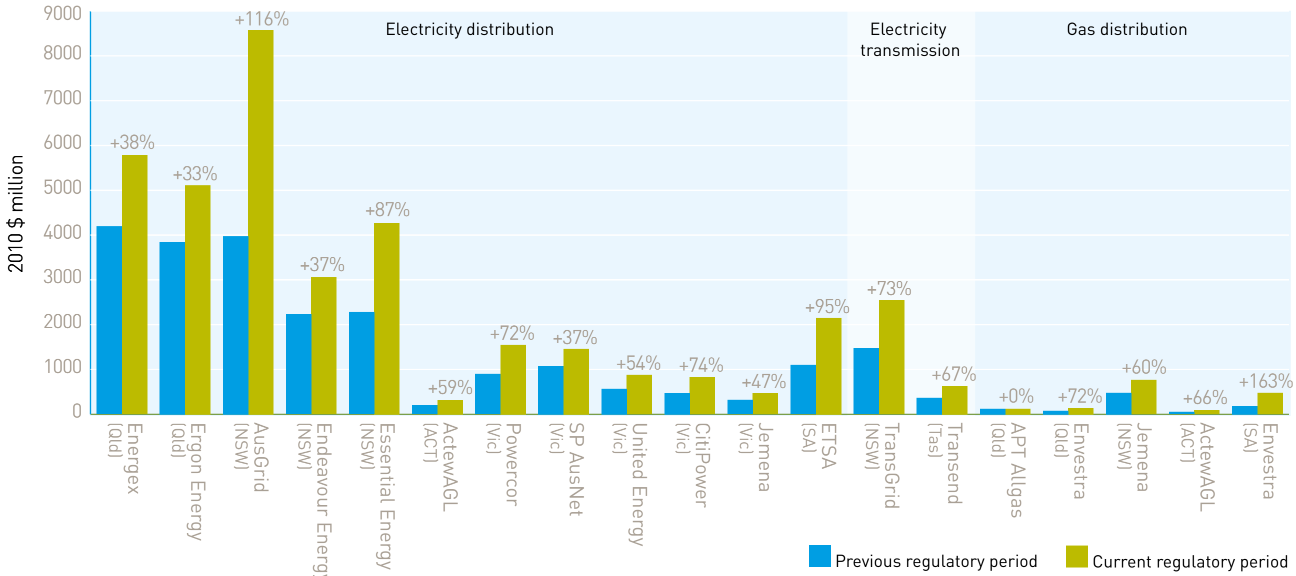
A Energy networks

The AER regulates over 30 electricity networks and gas pipelines in southern and eastern Australia (and pipelines in the Northern Territory). In electricity, this involves setting the revenues and prices that a network business can earn from transporting electricity to customers. In gas, the AER approves reference tariffs (prices) that pipeline owners propose in access arrangements. Since 2009 the AER has made determinations on two electricity transmission networks, 12 electricity distribution networks, one gas transmission pipeline and five gas distribution networks (table 1).

A1 Network investment, costs and charges

Energy network investment in the current five year regulatory cycle is running at historically high levels—over $7 billion in electricity transmission, $35 billion in electricity distribution and $3 billion in gas distribution (figure 1). These forecasts represent an increase on investment in the previous regulatory periods of around 82 per cent in electricity transmission, 62 per cent in electricity distribution and 74 per cent in gas distribution (in real terms).

Figure 1
Network investment—AER determinations since 2009



Source: AER.

A blend of factors is driving higher investment, including:

- more rigorous licensing conditions and other obligations for network security, safety and reliability (including new bushfire safety standards in Victoria)
- load growth and rising peak demand (driven by the use of air conditioners during summer heatwaves)
- new connections
- ageing assets, requiring significant replacement and reinforcement capital expenditure.

In contrast to the mainland jurisdictions, Tasmania's electricity distribution network (Aurora Energy) has proposed investment requirements for the period beginning 1 July 2012 that are below current levels. While at October 2011 the AER had not completed a review of the proposal, Aurora Energy committed to avoiding unnecessary customer price increases, while ensuring a safe and reliable supply of electricity. The proposal recognised significant expenditure in the current period has contributed to a strong and resilient network. This, coupled with subdued economic growth forecasts in Tasmania, would allow for a period of consolidation.[1]

Across the National Electricity Market (NEM), higher operating and maintenance expenditure and rising capital financing costs are other factors driving up network revenues and charges. Average revenues for electricity networks in current regulatory periods are forecast to rise by around 43 per cent (in real terms) above levels in the previous periods.

Current regulatory determinations allowed for cost of capital increases in all networks, ranging from less than 0.1 percentage points to over 2.6 percentage points. The primary driver has been rising borrowing costs arising from changes and fluctuations in global financial markets that have reduced liquidity in debt markets and increased perceptions of risk.

With network costs accounting for 40–50 per cent of a typical electricity bill and over 50 per cent of a typical gas bill, rising network costs and revenue allowances are flowing through to higher retail prices for energy customers (table 1 and section C3).

1 Aurora Energy, *Energy to the people: Aurora Energy regulatory proposal 2012–2017*, 2011.

A2 Rule change proposal on regulatory framework

The substantial price impact of recent determinations led the AER in 2011 to conduct an internal review of the framework in the national energy Rules that governs the regulatory process. While the review found many aspects of the framework operate well, several features were leading to consumers paying more than necessary for energy services. In particular:

> the framework restricts the AER from making holistic and independent assessments of a network's efficient expenditure needs
> the mandatory addition of all capital expenditure to a network's asset base creates incentives for overinvestment
> inconsistent approaches to setting the cost of capital for electricity and gas network businesses, along with constraints on the AER from setting costs that reflect current commercial practices, lead to inflated cost estimates
> the current consultation arrangements hinder effective stakeholder engagement.

Following its review, the AER in September 2011 submitted Rule change proposals to the AEMC to address these issues.[2] The AEMC in October 2011 began consulting on the Rule change proposals. It expects to release a draft determination by July 2012, and a final determination by October 2012.

Capital and operating expenditure forecasts

The AER is restricted from making holistic and independent assessments of a network's efficient capital and operating expenditure requirements. Instead, it must accept a network business's forecasts of its spending requirements if those forecasts reasonably reflect the efficient costs of a prudent operator. The evidentiary burden is on the AER to prove a forecast is not efficient or prudent, which encourages businesses to submit forecasts at the high end of a 'reasonable' range.

The issue is compounded in electricity distribution determinations by a provision that the AER may amend a business forecast only to the minimum extent necessary to conform to the Rules. Additionally, the AER must base any amendments on the original forecast.

The AER proposed a more balanced approach, in which it would draw on all available information when determining the efficient expenditure needed to deliver a reliable electricity supply. It would be bound by the requirements of the National Electricity Law and guided by clear, consistent and transparent criteria in the Rules. The AER could thus weigh up all available information, evidence and data—including benchmarking analysis—when assessing forecasts.

Incentives to overinvest

All capital expenditure incurred in a regulatory period is automatically added to a network's asset base at the next regulatory reset, regardless of whether that expenditure is efficient, prudent or within forecast. Because the networks earn a return on this asset base, this arrangement may create incentives to overinvest. In the past few years, large capital overspends in some jurisdictions—particularly New South Wales and Queensland—have flowed through to significant retail price rises for consumers.

The AER proposed that when a business spends above its approved capital expenditure forecast, only 60 per cent of the overspend be rolled into the asset base. To strengthen the discipline on networks to manage their expenditure efficiently, network owners would bear the remaining costs.

Cost of capital provisions

The current Rules apply different frameworks to determine the weighted average cost of capital (WACC) for electricity transmission networks, electricity distribution networks and gas pipelines. These differences can distort investment decisions across the sectors. In addition, the approach for gas pipelines and

2 AER, *Rule change proposal, Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules*, September 2011 (available on the AER and AEMC websites).

electricity distribution reopens debate on the WACC parameters in each determination process, creating a high administrative burden on stakeholders and causing investment uncertainty.

Further, in setting the WACC, the AER must determine a debt allowance using benchmarks that do not reflect current debt management practices, often resulting in significantly higher prices for consumers.

The AER proposed to enhance certainty by introducing a common approach to calculating the cost of capital for all gas and electricity network businesses. Under this approach, the AER would review the fundamental parameters of the cost of capital at least once every five years, and apply the outcome to all network determinations that follow.

It also proposed removing much of the prescription around determining WACC parameters, to allow the regulatory process to keep pace with changing debt financing practices. Currently, the AER must estimate a debt allowance using benchmarks that do not reflect how the energy sector actually manages its debt, resulting in significantly higher prices for consumers.

Consultation arrangements

Many network businesses submit regulatory proposals and then make detailed submissions (with significant additional information) on their own proposals. Some appear to strategically withhold key information until the final stages of a regulatory review. The late submission of key information impairs stakeholder engagement and limits the time available for stakeholders and the AER to analyse the late information.

To address this issue, the AER proposed restricting network businesses from making submissions on their regulatory proposals, but retaining their right to submit revised proposals. This change would streamline the regulatory process, encourage businesses to submit fully formed proposals at the outset, and allow for more meaningful stakeholder engagement.

A3 Merits and judicial review

While the AER's network decisions have contributed to retail price increases, the impacts have been magnified by the review provisions in the national energy legislation. In particular, the AER's decisions are subject to merits review by the Australian Competition Tribunal and judicial review by the Federal Court.

Since January 2008 network businesses have sought merits review of the determinations on three electricity transmission networks, 11 electricity distribution networks and five gas distribution networks (table 2). There were also two reviews of AER determinations on advanced metering infrastructure (smart meter) charges for Victorian networks. Eight tribunal reviews were continuing in late 2011.

The decisions on these reviews have increased allowable network revenues by around $2.9 billion, with substantial flow-on impacts on retail energy charges. The most significant contributors to this increase were tribunal decisions on:

- the averaging period for the risk free rate (an input into the WACC)—reviewed for four New South Wales and one Tasmanian network, with a combined revenue impact of $2 billion
- the value adopted for tax imputation credits (gamma), which affects the estimated cost of corporate income tax—reviewed for two Queensland and one South Australian distribution network, with a combined revenue impact of $780 million.

The tribunal handed down decisions in 2011 on reviews for Energex and Ergon Energy (Queensland) and ETSA Utilities (South Australia). The decisions increased the networks' allowable revenues by around $850 million (including the $780 million gamma component), which amounted to a 5 per cent increase in total revenue over the regulatory period. Following the decisions, the Queensland Government intervened to prevent Energex and Ergon Energy from recovering the additional revenue allowances determined by the tribunal. This intervention amounted to a $93 million

Table 2 **Australian Competition Tribunal decisions on AER determinations, June 2008 – October 2011**

DECISION DATE	SECTOR	OUTCOME	NETWORKS	REVENUE IMPACT ($M)
30 September 2008	ET	Increased the opening RAB by $36.1 million	ElectraNet (SA)	+21
25 November 2009	ET, ED	WACC increased from 8.8% to 10%; AusGrid's controllable operating expenditure allowance increased by $4.5 million; amended definition of general nominated pass through event; remitted AER decision on AusGrid public lighting for redetermination; TransGrid's controllable operating expenditure allowance increased by $14 million	AusGrid (NSW) Endeavour Energy (NSW) Essential Energy (NSW) TransGrid (NSW) Transend (Tas)	+818 +321 +411 +381 +80
23 December 2009	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 +13
17 September 2010	GD	Debt risk premium - method	ActewAGL (ACT)	+5
19 May 2011	ED	Gamma value decreased from 0.65 to 0.25; opening RAB increased by $128 million (ETSA); capital expenditure allowance increased by $124 million (Ergon); amended values of labour cost escalators (Ergon); amended method to determine price of quoted alternative control services (Ergon)	Energex (Qld) Ergon Energy (Qld) ETSA (SA)	+298 +243 +310
30 June 2011	GD	Gamma decreased from 0.65 to 0.25; WACC increased from 9.7% to 10.4%; reclassification of mine subsidence expenditure as capital expenditure; varied some terms and conditions	Jemena Gas Networks(NSW)	+182
Continuing	ED	Gamma value; debt risk premium value; escalation of RAB; close-out of jurisdictional s factor scheme (United Energy and SP AusNet); pass throughs (SP AusNet, CitiPower and Powercor); operating expenditure (not SP AusNet); carryover amounts (Powercor); capital expenditure (Jemena); RBA margin; RAB depreciation; public lighting	United Energy (Vic) SP AusNet (Vic) CitiPower (Vic) Powercor (Vic) Jemena (Vic)	
Continuing	GD	Debt risk premium value; market risk premium value (not APT Allgas); allowance for unaccounted-for gas (Envestra SA); network management fee (Envestra SA)	APT Allgas (Qld) Envestra (Qld) Envestra (SA)	

D, distribution; E, electricity; G, gas; T, transmission; RAB, regulated asset base; WACC, weighted average cost of capital.

Notes:

Following the privatisation of electricity and gas retail assets in New South Wales in 2011, the distribution businesses of EnergyAustralia, Integral Energy and Country Energy were rebranded as AusGrid, Endeavour Energy and Essential Energy respectively.

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

The AusGrid 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.

The Jemena Gas Networks decision (30 June 2011) does not account for increased revenue arising from mine subsidence expenditure.

All data are nominal.

reduction in the combined revenue forecasts of the businesses in 2011–12 alone.[3]

The current Rules framework has increasingly made reviews of AER decisions an extension of the determination process. The energy legislation requires a review of the merits review mechanism by 2015. The Minister for Resources, Energy and Tourism in September 2011 announced he would seek to bring forward the review to ensure the provisions deliver fair outcomes for consumers and network businesses. When appropriate, the AER will participate in this review.

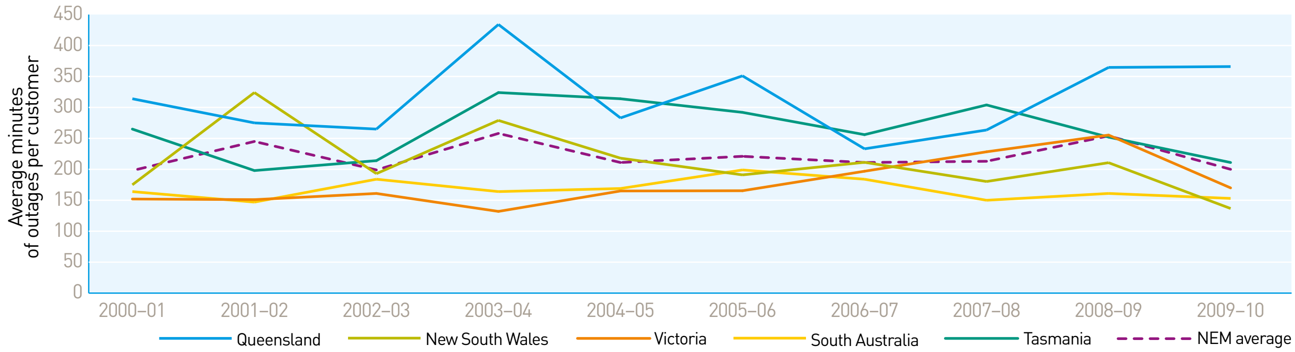
3 QCA, *Benchmark retail cost index for electricity: 2011–12, final decision*, 2011.

A4 Network reliability

A key driver of network investment and operating expenditure is meeting the reliability and safety requirements set by state and territory agencies. Trade-offs between reliability and cost mean government decisions to increase reliability standards can require substantial new investment, with significant impacts on customer bills.

The AEMC recommended in 2008 (and again in 2010) that a national framework be introduced for

Figure 2
Electricity distribution—reliability of supply



Note: The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors.

Data sources: Performance reports by the AER, the QCA, ESCOSA, OTTER, the ICRC, AusGrid, Endeavour Energy and Essential Energy.

a more consistent approach to setting transmission reliability standards. The proposed framework would economically derive standards using a customer value of reliability, or a similar measure. The Standing Council on Energy and Resources (SCER, formerly the Ministerial Council on Energy) was in 2011 finalising its policy position on the review. It also noted the large contribution of distribution network investment to retail electricity prices, and directed the AEMC to review the frameworks for setting distribution reliability standards. In November 2011 the AEMC released an issues paper on reliability outcomes in New South Wales. A broader review of approaches used to determine reliability outcomes across the NEM will commence in 2012.

A key performance measure of network reliability is the average duration of outages per customer, which for the NEM is typically 200–250 minutes per year (figure 2). In 2009–10 outcomes improved in all jurisdictions other than Queensland (which recorded little change). Annual fluctuations in the data typically reflect climatic variability—for example, heavy rains, floods and Cyclone Ului in Queensland in 2010–11 contributed to increased outages on Ergon Energy's network.

A5 Other policy developments for energy networks

Australia's energy markets operate in an increasingly challenging environment that affects network operation and performance. Government policy to mitigate climate change, for example, may lead to an influx of new low carbon generation plant. The connection framework was amended in 2011 to promote the efficient connection of clusters of new remotely located generation. The AEMC was also reviewing the transmission framework to ensure future network investment is efficient and coordinated with generation investment; congestion is managed effectively; and pricing reflects the actual use of the network.

The regulatory investment test for transmission (introduced in 2010) requires businesses to evaluate the most efficient methods—for example, network augmentation or alternatives such as generation investment—to address rising demand. In 2011 the AEMC began consulting on a Rule change to introduce a similar test for distribution investment. The proposal included a new dispute resolution process, and requirements on distribution businesses to release annual planning reports and maintain a demand side engagement strategy.

B National Electricity Market

The AER monitors activity in the NEM—the wholesale spot market covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT)—to detect irregularities and enforce the underpinning Law and Rules.

Figure 3
Volume weighted average spot prices—electricity

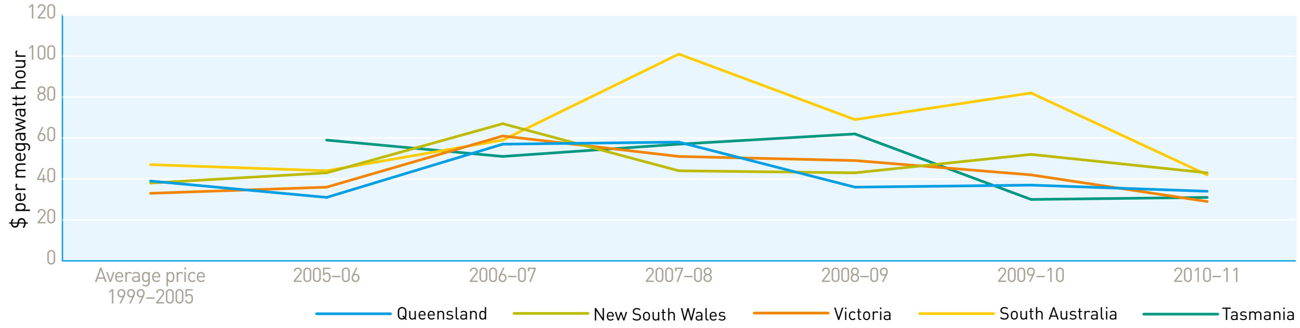
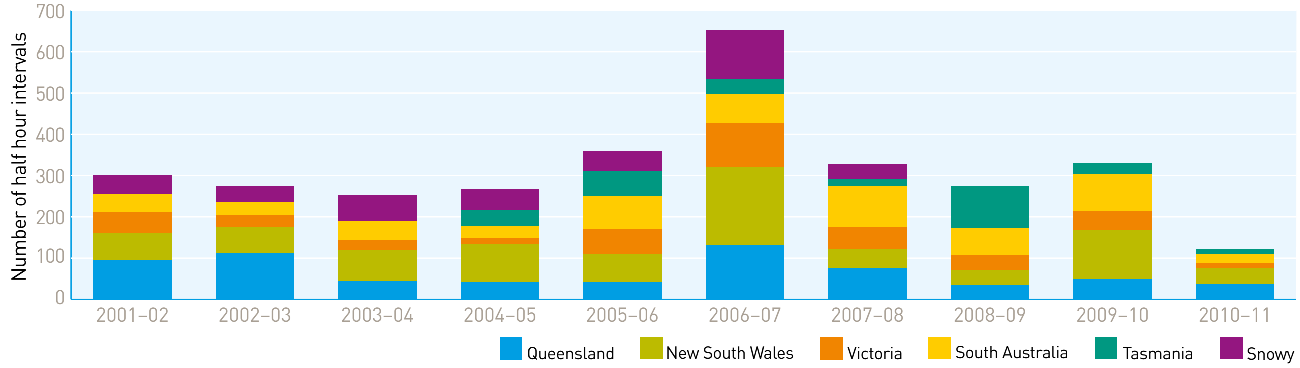


Figure 4
Trading intervals above $300 per megawatt hour—National Electricity Market



Source (figures 3 and 4): AER.

B1 Market outcomes in 2010–11

The 2010–11 summer was comparatively mild (with the lowest average maximum temperature across Australia since 2001), resulting in lower than expected electricity demand. On the supply side, higher rainfall increased hydro generation—for example, generation by Southern Hydro (owned by AGL Energy) in 2010–11 more than doubled the level of 2009–10.

Figure 3 tracks volume weighted annual average spot electricity prices. Prices in 2010–11 fell significantly from 2009–10 levels in South Australia, Victoria and New South Wales, and marginally in Queensland, but rose slightly in Tasmania. Average prices in New South Wales and South Australia—$43 per megawatt hour (MWh) and $42 per MWh respectively—were higher than in other regions. Victoria ($29 per MWh) and Tasmania ($31 per MWh) recorded the lowest NEM prices in 2010–11, closely followed by Queensland ($34 per MWh). All regions other than Tasmania recorded their lowest average spot prices in at least five years.

In addition to lower average prices, fewer extreme price events occurred in 2010–11. The spot price exceeded $300 per MWh in 121 trading intervals (figure 4)—the lowest number in a decade.[4] Similarly, 40 prices were above $5000 per MWh—the lowest number since 2004–05 (figure 1.9, chapter 1). The bulk of extreme price events occurred during a heat wave from 31 January to 2 February 2011 that affected all mainland regions of the NEM.

4 A trading interval is 30 minutes.

But while 2010–11 had fewer events, those that occurred set record prices in New South Wales, South Australia and Tasmania, following an increase in the market price cap on 1 July 2010 to $12 500 per MWh. The maximum price in 2010–11 was $12 400 per MWh, reached on three occasions in Tasmania.

B2 Market structure issues

While average spot prices in the wholesale electricity market were relatively subdued in 2010–11, spot prices are only a partial indicator of the energy costs that retailers pay. Independent retailers and generators manage the risk of spot price volatility by entering hedge contracts with each other, or through futures markets such as the Sydney Futures Exchange. But, increasingly, retailers and generators are bypassing these markets, and instead managing spot price risk through vertical integration.

The New South Wales energy privatisation process in 2011 (and the Queensland privatisation in 2007) continues a trend of vertical integration between electricity generators and energy retailers into 'gentailers' (table 3 and figure 5). Origin Energy, AGL Energy and TRUenergy now jointly supply over 80 per cent of small electricity retail customers, and they control almost 30 per cent of generation capacity in the mainland regions of the NEM. The same entities are also expanding their interests in upstream gas production.

Vertical integration provides a means for retailers and generators to internally manage the risk of price volatility in the electricity spot market, reducing their need to participate in electricity futures markets. While it makes commercial sense for the entities concerned, vertical integration reduces liquidity and contracting options in futures markets. It thus drives up energy costs for independent retailers and may pose a barrier to entry and expansion for both independent generators and retailers.

Table 3 Vertical integration—energy retail and electricity generation, 2006–11

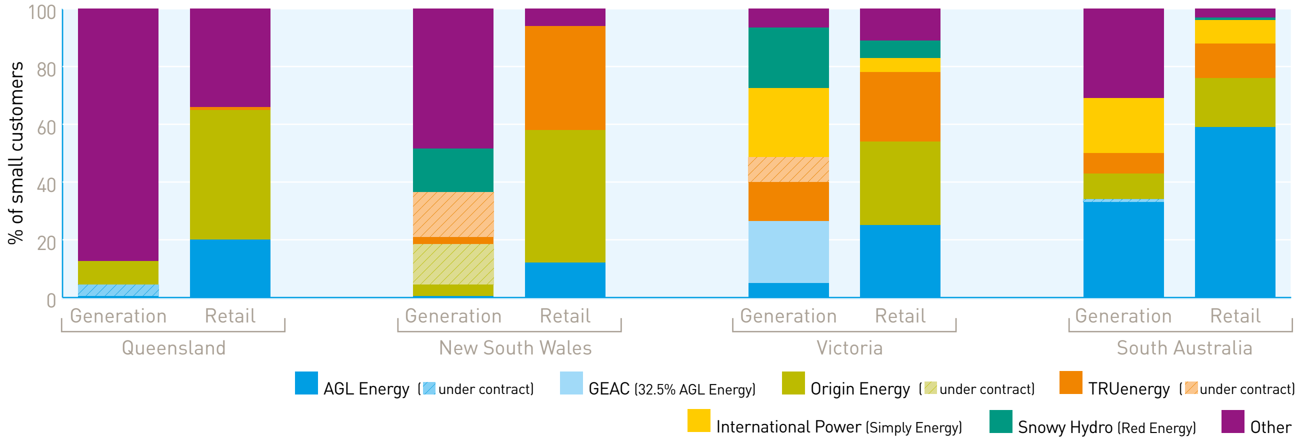
DATE	EVENT
2011	TRUenergy announced two 500 MW power plants in Queensland
	Alinta Energy entered retail market in South Australia
	Origin Energy constructing 518 MW Mortlake power station in Victoria
	AGL Energy commissioned 82 MW North Brown Hill wind farm in South Australia
	TRUenergy acquired 111 MW Waterloo wind farm in South Australia
	AGL Energy (with Meridian Energy) committed to 420 MW Macarthur wind farm in Victoria
2010	AGL Energy committed to 63 MW Oaklands Hill wind farm in Victoria and 33 MW The Bluff wind farm in South Australia
	Origin Energy acquired Integral Energy and Country Energy (retail) and trading rights for Eraring and Shoalhaven power stations from the New South Wales Government
	TRUenergy acquired EnergyAustralia (retail) and trading rights for Mount Piper and Wallerawang power stations from the New South Wales Government
2009	Origin Energy commissioned 605 MW Darling Downs power station in Queensland
	Origin Energy commissioned 648 MW Uranquinty power station in New South Wales
	Origin Energy completed a 131 MW expansion of the Mount Stuart power station in Queensland
	Origin Energy completed a 128 MW expansion of the Quarantine power station in South Australia
	AGL Energy commissioned 71 MW Hallett 2 wind farm in South Australia
	AGL Energy commissioned 140 MW Bogong hydro power station in South Australia
2008	TRUenergy commissioned 435 MW Tallawarra power station in New South Wales
	Hydro Tasmania acquired controlling interest in Momentum Energy (full acquisition occurred in 2010)
2007	AGL Energy acquired Torrrens Island power station (40 per cent of South Australian capacity) from TRUenergy in exchange for the 150 MW Hallett power station and a cash sum
	Origin Energy commissioned 30 MW Cullerin Range wind farm in New South Wales
	AGL Energy commissioned 95 MW Hallett 1 wind farm in South Australia
	Origin Energy acquired Sun Retail from the Queensland Government
	AGL Energy acquired Powerdirect from the Queensland Government
2006	Infratil entered retail market (now trading as Lumo Energy)
	International Power entered retail market (now trading as Simply Energy)

MW, megawatt.

Source: AER.

Figure 5

Vertical integration—electricity retail and electricity generation, 2011



Note: Generation market share relates to installed capacity; retail market share is for small electricity customers.

Source: AER estimates.

Around 58 per cent of new generation capacity commissioned or committed since 2007 is controlled by Origin Energy, AGL Energy and TRUenergy. Generation investment since 2007 by entities that do not also retail energy has been negligible. In addition, many new entrant retailers in this time are vertically integrated with entities that were previously stand-alone generators—for example, International Power (trading as Simply Energy in retail markets), Infratil (Lumo Energy) and Alinta Energy.

d-cyphaTrade (which develops products for trading on the Sydney Futures Exchange) reported in 2011 that futures market liquidity remains poor in South Australia—the mainland region with the highest degree of vertical integration. It also noted vertical integration appeared to reduce liquidity in the market for New South Wales electricity futures following the 2011 privatisation process.[5]

A related development is an increasing separation between spot prices and the underlying cost of generation in some regions. The NEM design was predicated on a competitive structure that encouraged generators to bid into the market at prices reflecting their marginal costs, and with dispatch prices reflecting supply and demand conditions. But bidding strategies periodically reflect a generator's ability to influence prices. A generator may seek to drive either high or low prices, depending on its incentives (including contract positions). These events are usually concealed in long term average prices, which smooth out inefficient short term outcomes.

Where spot prices do not reflect underlying costs, market participants rely on futures markets more heavily to manage risk and secure future earnings. However, significant vertical integration and poor liquidity in futures markets create a challenging operating environment that may deter efficient investment by new entrants.

South Australia

Significant vertical integration, poor liquidity in the market for electricity futures, and strategic bidding by the leading regional generator make South Australia a challenging market for potential new entrant generators and retailers.

Periods of sustained high demand and strategic withholding of generation capacity by AGL Energy contributed to three years of very high average spot prices in South Australia, from 2007–08 to 2009–10. This trend was reversed in 2010–11, when a mild

5 d-cyphaTrade, *Strategic priorities for energy market development*, Submission to AEMC, 2011.

summer (with only a few days above 40 degrees) contributed to the average spot price falling by almost 50 per cent. Another contributing factor was the region's 177 trading intervals with negative prices—up from 86 in the previous year, and the highest annual number ever recorded for a region.

Wind generators sometimes bid negative prices to ensure dispatch, relying on the value of the renewable energy certificates they earn to cover their costs. But several instances of negative prices near the –$1000 market floor were driven by AGL Energy rebidding large amounts of capacity at times of high wind generation and low demand. The negative prices caused other generators, including wind farms, to shut down.

A generator may rebid prices to the floor at short notice for a number of reasons. Such bidding may reflect the costs of shutting down and restarting plant; alternatively, it may reflect a generator's net exposure to the spot price, taking account of the generator's retail load and contract market position. But repeated instances of negative prices increase volatility, which may discourage entry by competing independent generators and retailers.

In response to the recent surge of negative price events, the AER in October 2010 began analytical reporting on spot prices below –$100 per MWh as part of its weekly market updates.

Tasmania

Good rainfall allowed for increased hydro generation in Tasmania in 2010–11 and contributed to a second year of relatively low spot prices ($31 per MWh). But this low average smoothes the effects of individual prices. Tasmania's spot price was significantly higher than the Victorian price for many sustained periods. On some occasions, Hydro Tasmania strategically withdrew its non-scheduled generation to raise prices (as it has periodically done since 2009). There were also instances when the Tasmanian spot price reached the floor (–$1000) when the spot price in Victoria was high.

The Tasmanian Government established the Electricity Supply Industry Expert Panel in 2010 to assess the state of the industry. The panel released an issues paper in June 2011 addressing matters core to its terms of reference, and also questioned Hydro Tasmania's market power and use of its non-scheduled generation to raise prices. It expected to publish its final report in December 2011.

The AER's submission to the issues paper provided evidence of Hydro Tasmania's strategic manipulation of prices (particularly at off peak times) causing inefficient dispatch of open cycle gas turbines and demand side response (particularly from large industrial customers). The AER concluded Hydro Tasmania's strategic behaviour would, in addition to having negative impacts on market efficiency, pose a major spot market risk for any new retailer in Tasmania.[6]

Rule change proposal on market power

The AEMC began consulting in 2011 on an Electricity Rule change proposal by Major Energy Users in relation to generators' potential exercise of market power in the NEM. The proponent argued some large generators have the ability and incentive to use market power to increase wholesale electricity prices during periods of high demand. The proposed Rule change would require 'dominant' generators, as determined by the AER, to offer their entire capacity at times of high demand at a price of no more than $300 per MWh.

The AER noted in a submission to the AEMC that short periods of high prices are necessary in an energy only market to signal underlying supply and demand conditions and the need for investment. Market power concerns arise when high average prices reflect generators' systemic economic withholding of capacity, rather than scarcity pricing. In addition to the behaviour of AGL Energy and Hydro Tasmania noted above, the AER referred to similar activity by Macquarie Generation in New South Wales in 2007.

6 AER, *Submission to Independent Review of the Tasmanian Electricity Sector—response to Electricity Supply Industry Expert Panel's issues paper*, August 2011.

The AEMC expected to make a draft Rule determination in April 2012, following further stakeholder consultation.

B3 Compliance and enforcement issues

While the AER monitors the market to detect issues such as market manipulation, it also monitors the compliance of market participants with the Rules governing the NEM. A key monitoring project in 2011 focused on generators' provision of accurate rebidding information.

Scheduled generators in the NEM submit offers for each of the 48 intervals in a trading day. The initial offers, submitted before the trading day, can be varied through rebidding at any time up to the relevant trading interval. The AER launched a new rebidding enforcement strategy in March 2011 to encourage the provision of more accurate and timely bidding information to the market. Under the strategy, the AER issues two warnings to generators that submit offer and/or rebid information that does not satisfy the Rules. A third occurrence within six months may lead to the issue of an infringement notice. Since the strategy was launched, the number of rebids flagged by the AER's internal compliance system and requiring further review has fallen significantly (figure 1.18, chapter 1).

On another rebidding matter, the Federal Court on 30 August 2011 dismissed the AER's case against Stanwell Corporation (a Queensland generator) for alleged contraventions of the 'good faith' rebidding provisions in the 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.

In February 2008 Stanwell controlled more than a quarter of Queensland's registered generation capacity. On 22 and 23 February the spot price for electricity in Queensland exceeded $5000 per MWh on 14 occasions. Stanwell made 92 rebids over those trading days. More than 50 rebids were made within 15 minutes of dispatch, with around 40 rebids affecting the next 5 minute dispatch interval. The AER alleged Stanwell's reasons for eight rebids failed to identify a change in material conditions and circumstances. It sought orders that included declarations, civil penalties, a compliance program and costs. Justice Dowsett found the rebids did not contravene the Rules.

Generators must offer to supply energy into the market in good faith so the Australian Energy Market Operator (AEMO) can coordinate efficient dispatch to meet demand. The Rules allow generators to rebid (alter) their offers only in response to a change in the material conditions and circumstances on which the offer was based.

The litigation marked the first judicial test of the 'good faith' provision, and the first occasion on which any provision of the Rules has been brought before the courts. Previous AER investigations into compliance with the good faith provision produced insufficient evidence to pursue the matters. Those investigations typically centred on rebids made shortly before dispatch for reasons of financial optimisation rather than technical necessity.

The policy objective of the good faith provision, when introduced in 2002, was to promote firm offers and rebids, and improve the quality of forecast information necessary for an efficient spot market. In particular, the firmness of market offers and rebids affects the quality of forecasts that market participants rely on when making decisions. Rebids submitted shortly before market dispatch affect the credibility of these forecasts and limit opportunities for competitive supply and/or demand side response.

The Federal Court's decision calls into question the effectiveness of the good faith provision in achieving these objectives. Together with the AER's previous investigations when insufficient evidence was found, it suggests the provision's effectiveness may need review.

B4 Generation investment and reliability

Tightening supply conditions have led to an increase in generation investment, with over 4700 megawatts (MW) of capacity added in the three years to 30 June 2011—predominantly gas fired generation in New South Wales and Queensland. But only 500 MW of this investment occurred in 2010–11, of which 64 per cent was in wind generation (table 1.6, chapter 1).

At July 2011 developers had committed to another 1300 MW of capacity, mostly in gas fired and wind generation. The most significant projects were in Victoria, including the 518 MW Mortlake gas fired power station and the 420 MW Macarthur wind farm (which will be the largest wind farm in the southern hemisphere).

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 6). Beyond that time, some proposed generation projects may need to come online for the market to meet reliability requirements.

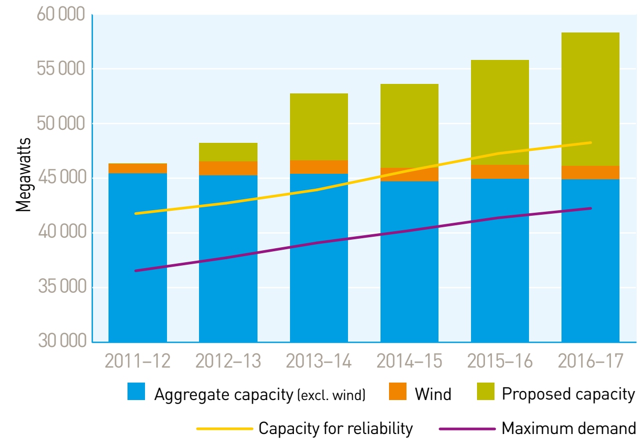
A sensitivity analysis found an unexpected NEM-wide withdrawal of 1000 MW of generation could lead to Queensland experiencing unserved energy in exceedance of the 0.002 per cent reliability standard in 2012–13. AEMO also found Queensland, assuming medium economic growth, would be the first region in the NEM to require new generation investment (by 2013–14). Subsequently, TRUenergy in October 2011 announced it would invest in two 500 MW gas fired generators in Queensland (at Ipswich and Gladstone), each with the potential to expand to 1500 MW. Construction is expected to commence in 2013.

AEMO projected Victoria and South Australia would require new investment beyond committed capacity by 2014–15, and New South Wales by 2018–19. Tasmania was expected to have adequate capacity over the 10 year outlook period.

The modeling incorporated scenarios based on implementation of the Australian Government's Clean Energy Future Plan, announced on 10 July 2011. The plan targets a reduction in carbon and other

Figure 6

Electricity demand and supply outlook to 2016–17



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 5 per cent in South Australia, 7.7 per cent in Victoria and 9.2 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 92 per cent diversity 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, *2011 electricity statement of opportunities for the National Electricity Market*, 2011.

greenhouse emissions to at least 5 per cent below 2000 levels by 2020 (and up to 25 per cent with equivalent international action). The central mechanism, to begin on 1 July 2012, will place a fixed price on carbon for three years, starting at $23 per tonne. It will then move to an emissions trading scheme in 2015, with the price determined by the market. The plan includes assistance of $5.5 billion for emission intensive generators, and contracts for the closure of up to 2000 MW of coal fired generation. The plan also establishes the Clean Energy Finance Corporation, with access to $10 billion over five years for investment in renewable and low emissions energy. The Australian Parliament passed the legislation in November 2011.

The initiatives in the Clean Energy Future Plan, combined with policies such as the national renewable energy target scheme, are likely to shift the mix of generation output and investment away from fossil fuel fired generation technologies (particularly brown coal), in favour of lower emission and renewable energy technologies.

AEMO's reliability assessment found the Clean Energy Future Plan (including carbon pricing and financial assistance to emission intensive generators) is unlikely to affect power supply reliability or security over the period to 30 June 2013, given the timing of the policy measures, as well as initiatives to offset potential reliability impacts.

A lack of bipartisan political agreement on carbon pricing is creating uncertainty that may deter generation investment. The AEMC noted perceptions of the longer term stability of the new carbon policy will be an important factor affecting investment decisions.[7] The electricity industry has also raised these concerns. The Energy Supply Association of Australia stated in October 2011 that uncertainty on carbon pricing would reduce the availability of futures contracts and increase retail prices. It published modeling by ACIL Tasman in August 2011 showing even a 5 per cent reduction in contracting would cause a 10 per cent rise in retail electricity prices in a single year for small customers.[8]

C Energy retail markets

The AER will take on significant functions when national energy retail reforms take effect from 1 July 2012. The reforms aim to deliver streamlined national regulation that supports an efficient retail market with appropriate consumer protection.

The South Australian parliament passed the National Energy Retail Law in the 2011 autumn sitting. The legislation will apply in Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. Western Australia and the Northern Territory do not propose to implement the reforms.

The Retail Law will transfer several functions to the AER, including:

> monitoring compliance and enforcing breaches of the Law and its supporting Rules and Regulations
> authorising energy retailers to sell energy, and granting exemptions from authorisation requirements
> approving retailers' policies for dealing with customers facing hardship
> providing an online energy price comparison service for small customers, expected to be launched on 1 July 2012
> administering a national retailer of last resort scheme, which protects customers and the market if a retail business fails
> reporting on the performance of the market and participants, including energy affordability, disconnection and competition indicators.

The states and territories will remain responsible for regulating retail energy prices.

In 2011 the AER released final procedures and guidelines outlining how it will undertake its roles under the Retail Law, including information on retail performance reporting, retail pricing information, retailer of last resort arrangements, customer hardship policies, compliance and enforcement, authorisations and exemptions, and connection charging arrangements. It developed these documents in consultation with energy customers, consumer advocacy groups, energy retailers and distributors, state and territory agencies, ombudsman schemes and other stakeholders. The documents are available on the AER's website (www.aer.gov.au).

C1 Retail market developments

The New South Wales Government in 2011 privatised its state owned retailers and the electricity trading rights of state owned power stations and power station development sites. TRUenergy acquired the retailer EnergyAustralia and trading rights for the Mount Piper and Wallerawang power stations, while Origin Energy acquired the retailers

7 AEMC, *Strategic priorities for energy market development*, 2011, p. 17.
8 ACIL Tasman, *National electricity market modelling*, Report prepared for the Energy Supply Association of Australia, 2011.

Country Energy and Integral Energy, and trading rights for the Eraring and Shoalhaven power stations. These acquisitions solidified the positions of Origin Energy, TRUenergy and AGL Energy as the dominant energy retailers in the eastern mainland states. The New South Wales energy privatisation process continues a trend of vertical integration between electricity generators and energy retailers (section B2).

C2 Retail competition indicators

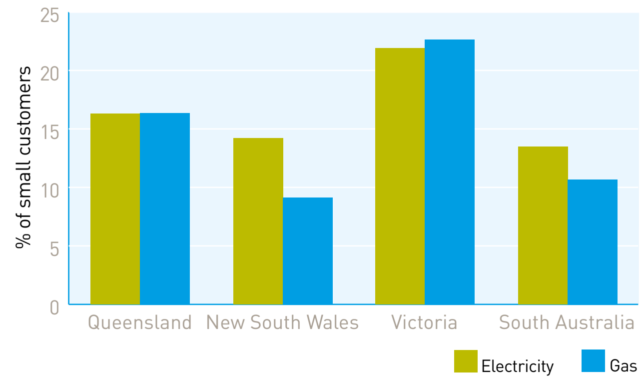
All NEM jurisdictions except Tasmania have introduced full retail contestability (FRC) in electricity, allowing all customers to enter a contract with their retailer of choice. On 1 July 2011 Tasmania extended contestability to customers using at least 50 MWh per year. All jurisdictions have introduced FRC in gas retail markets.

Victoria continues to record high levels of customer switching between retailers (figure 7). While Queensland introduced FRC several years later than other jurisdictions did, customer activity has built momentum. In 2010–11 the state's switching rates in electricity and gas remained higher than the rates for New South Wales and South Australia. Despite a move to cost reflective retail price controls and the sale of state owned energy retailers in 2011, customer switching rates in New South Wales did not change significantly from those of the previous two years.

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.

Figure 7

Retail switching by small customers, 2010–11



Note: The customer base is estimated at 30 June 2011.

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

In March 2011 the AEMC released its final report on the ACT retail electricity market. It found competition in the small customer market was not effective, partly because customers were unaware of their ability to switch retailers. The AEMC recommended removing retail price caps from 1 July 2012, in conjunction with running a consumer education campaign to increase awareness of the benefits of competition.[9] However, the ACT Government decided in 2011 to retain electricity price controls for another two years. It noted the AEMC found removing price controls would increase the average cost of electricity so would not benefit customers.[10]

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

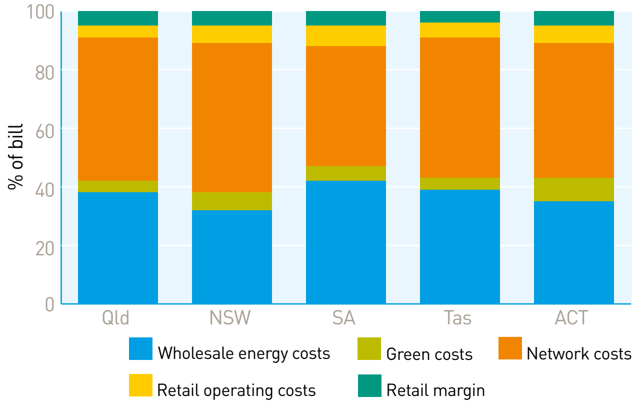
C3 Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services. Figure 8

9 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT, stage 2 final report*, 2011, p. 11.

10 ACT Government, 'ACT to keep price regulation for Canberra households', Media release, www.chiefminister.act.gov.au/media.php?v=10936&m=53 2011, September 2011.

Figure 8
Indicative composition of residential electricity bills, 2011



Notes:

The data reflect jurisdictional averages and may vary across distribution networks.

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).

estimates the composition of a typical electricity retail bill for a residential customer in each NEM jurisdiction that regulates prices:

> Wholesale electricity costs account for 32–42 per cent of small customer retail bills. They include the costs of participating in, and acquiring electricity through, the wholesale and futures markets.

> Network tariffs account for 41–51 per cent of retail energy bills.

> Green costs—that is, costs associated with carbon emission reduction or energy efficiency schemes—have risen significantly over the past two years but still make up only 4–8 per cent of retail bills.

> Retailer operating costs (including margins) contribute around 10 per cent to retail bills.

Pipeline charges are the most significant component of gas retail bills, accounting for around 47 per cent of bills in New South Wales and 63 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.

Figure 9 illustrates long term trends in energy retail prices in major capital cities. Following gradual increases over the past decade, there was a significant upswing in real electricity prices from 2007 and gas retail prices from 2008. Figure 10 illustrates indicative movements in retail electricity prices over the past three years. The data reflect unregulated standing offer prices for Victoria and regulated prices elsewhere. A spread is shown for New South Wales and Victoria, in which price movements vary across distribution networks.

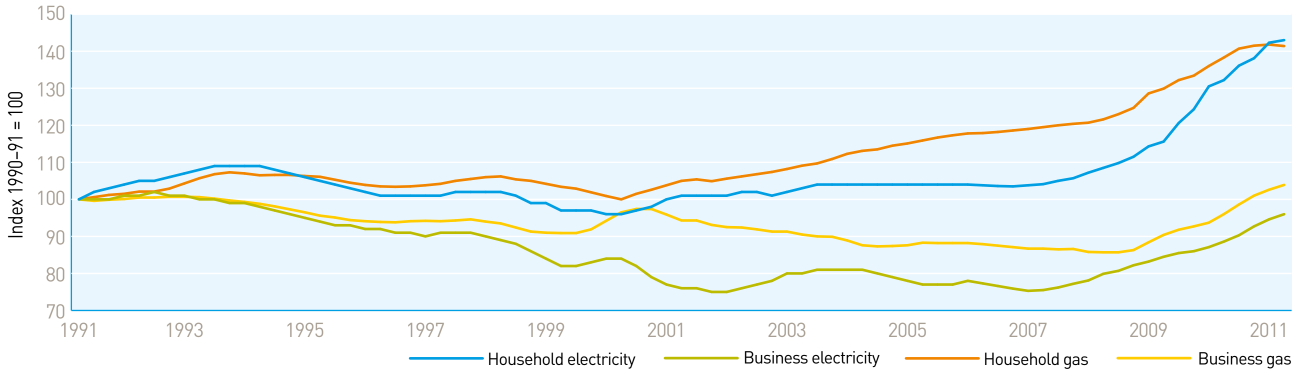
The data indicate retail electricity prices continued to rise significantly in 2011–12. In most jurisdictions, network costs continue to be the largest contributor to price rises, although the Victorian and ACT networks experienced only modest cost pressures. The cost of complying with green schemes has increased significantly since 2010 with the introduction and expansion of schemes to reduce carbon emissions and improve energy efficiency. The 2011–12 green cost increases are largely the result of changes from 1 January 2011 to the renewable energy target scheme.

> *Queensland* regulated electricity prices rose by 6.6 per cent in 2011–12, driven by network increases (5.2 per cent), changes to the renewable energy target scheme (3 per cent) and increased retailer costs (0.7 per cent). These rises were partly offset by a 2.3 per cent decrease due to changes in other green schemes (mainly the Queensland gas scheme, which requires a proportion of electricity to be sourced from gas fired generators) and falling wholesale energy costs. The price rise would have been 8.3 per cent had the Queensland Government not prevented the distribution businesses, Energex and Ergon Energy, from recovering increased revenue allowances determined by the Australian Competition Tribunal.[11]

11 QCA, *Benchmark retail cost index for electricity, final decisions*, 2011–2012, 2011.

Figure 9

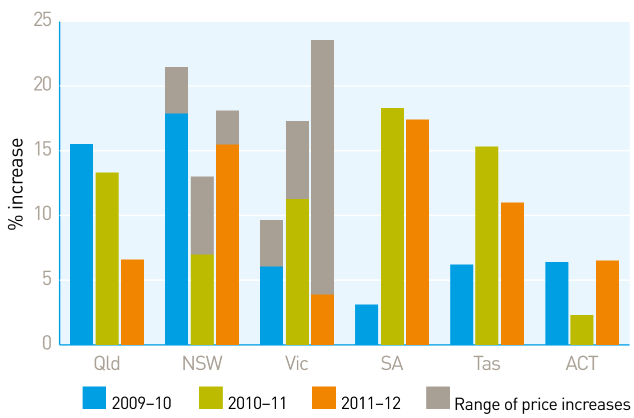
Electricity and gas retail price index (real)—Australian capital cities



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

Figure 10

Retail electricity price rises—regulated and standing offers



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.

> *New South Wales* regulated electricity prices rose by an average of 17.3 per cent in 2011–12, following rises of 7–13 per cent in 2010–11. Network charges accounted for 80 per cent of the price increase in 2010–11 and over 50 per cent in 2011–12.[12] Green scheme costs resulted in a 6 per cent increase in average retail bills in 2011–12.[13]

> *Victorian* standing electricity price rises in 2011 varied significantly across distribution networks, ranging from 4 per cent to almost 24 per cent. Because prices are unregulated, limited information is available on underlying cost drivers, including reasons for these diverse outcomes. But distribution costs were clearly not a major driver, accounting for retail price changes of between –1.9 per cent and 2.5 per cent in 2011. Charges for the introduction of smart meters accounted for retail price increases of 2.5–7 per cent in 2010, but price impacts in this area were negligible in 2011. Compliance cost associated with government climate change policies would also have affected retail prices. Limited information is available on the impact of wholesale energy costs (including hedging costs), retailer costs and retail margins on Victorian retail prices.

> *South Australian* prices rose by 12 per cent on 1 January 2011, and by a further 17.4 per cent on 1 August 2011. Higher wholesale energy costs accounted for 60 per cent of the January increase, with the remainder evenly split between green scheme costs and increased retail operating costs (including margins). Network price increases and a consumer price index adjustment accounted for the bulk of the August 2011 price increase.[14]

12 IPART, *Changes in regulated electricity retail prices from 1 July 2011*, 2011; IPART, 'Regulated electricity retail tariffs for 1 July 2010 to 30 June 2013—final report', Fact sheet, 2010.

13 IPART, *Changes in regulated electricity retail prices from 1 July 2011*, 2011.

14 ESCOSA, *2011–2014 Electricity standing contract price determination—variation price determination*, 2011.

- *Tasmanian* electricity prices rose by 11 per cent on 1 July 2011 in response to rising network charges and green scheme costs. A reduction in forecast consumption also had an impact.[15] The July increase followed a price rise in December 2010 of 8.8 per cent, of which around half related to wholesale energy costs. Network costs were also a significant factor in the December price rise.
- The *ACT* recorded a 6.5 per cent retail electricity price increase in 2011–12. The rise was largely attributed to green scheme costs (increasing prices by 5 per cent) and network costs (3.6 per cent), partly offset by a fall in wholesale energy costs.

Retail price increases have generally been lower in gas than electricity. In 2011–12 retail gas prices rose in South Australia by 13.8 per cent and in New South Wales by 4 per cent. Higher distribution pipeline charges contributed to 80 per cent and 70 per cent of the increases in those states respectively.[16]

Customers in most jurisdictions can negotiate discounts against regulated and standing offer prices by entering a market contract. For a typical residential customer, the spread in the annual cost between the lowest and highest offers is around $300–600 in electricity and $150–400 in gas.

The Queensland, South Australian, New South Wales and Victorian regulators and a number of private entities operate websites that allow customers to compare their energy 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. It is developing an online price comparison service for small customers, which it expects to launch on 1 July 2012.

D Upstream gas

Australia's 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.[17]

D1 Gas market conditions

LNG export volumes from Western Australia and the Northern Territory rose in 2010–11 by 11 per cent,[18] and major players such as Chevron and Woodside are further expanding capacity. Western Australia's status as a major LNG exporter exposes the domestic gas market to international demand and price pressures.

In 2011 a Western Australian parliamentary inquiry reported prices in new domestic contracts ranged from $5.55 to $9.25 per gigajoule. The inquiry recommended initiatives to enhance gas market transparency, competition and liquidity. Several initiatives mirror recent reforms in eastern Australia, including the introduction of a short term trading market, a gas market bulletin board and a gas statement of opportunities. The inquiry also recommended eliminating joint marketing arrangements when authorisations granted by the Australian Competition and Consumer Commission come up for review in 2015.[19]

On the east coast, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have spurred the development of several LNG projects near the Queensland port of Gladstone. Construction of three projects is underway, and a fourth is at the planning stage. The first CSG–LNG exports are expected by 2014.

15 OTTER, 'Approval of 2011–12 electricity retail tariffs', Media release, 10 June 2011.
16 IPART, 'Review of regulated retail tariffs and charges for gas from 1 July 2010 to 30 June 2013—final report', Fact sheet, 2010.
17 EnergyQuest's lead essay in the *State of the energy market 2009* report provides background on the Australian gas industry.
18 EnergyQuest, *Energy Quarterly*, August 2011, p. 24.
19 Economics and Industry Standing Committee (Parliament of Western Australia), *Inquiry into Domestic Gas Prices*, Report no. 6 in the 38th Parliament, 24 March 2011.

CSG production has already reshaped the domestic market by providing a new source of gas supply for eastern and southern Australia. CSG production in Queensland and New South Wales rose by 17 per cent in the 12 months to June 2011.[20] New transmission pipelines, such as the QSN Link (commissioned in 2009), provide the physical capacity to transport the gas to southern markets.

Aside from LNG exports, domestic factors are putting upward pressure on demand. While output from gas powered generation fell across the NEM by 10 per cent in 2010–11 (mainly offset by an increase in wind generation),[21] the introduction of carbon pricing will drive greater reliance on gas powered generation in the medium to long term. AEMO's 2011 *Gas statement of opportunities* forecast gas powered generation would account for the largest component of domestic demand growth in the next 20 years.[22]

Expanding CSG production and the ramp-up of LNG capacity are constraining short term gas prices in Queensland, which EnergyQuest reported in August 2011 were typically below $2 per gigajoule.[23] Queensland's 2011 *Gas market review* found supplies of ramp-up gas would likely constrain short term prices until LNG exports commence.[24]

However, the likely diversion of gas resources for LNG export may put upward pressure on domestic prices from 2014.[25] AEMO noted, for example, many large producers are securing sufficient reserves to enter LNG supply contracts with overseas customers, which may, over time, put pressure on domestic gas availability.[26] Queensland's 2011 *Gas market review* predicted Queensland domestic gas prices would rise to $5–8 per gigajoule by 2016, with prices being more likely to reach the high end of this range. It predicted prices would likely rise slightly later in the southern states than in Queensland.[27]

D2 Spot market activity

While gas prices were historically struck under long term contracts, there has been a shift in recent years towards shorter term contracts and the emergence of spot markets. Victoria established a wholesale spot market in 1999 for gas sales to manage system imbalances and pipeline network constraints. More recently, governments established the National Gas Market Bulletin Board and a short term trading market in major hubs.

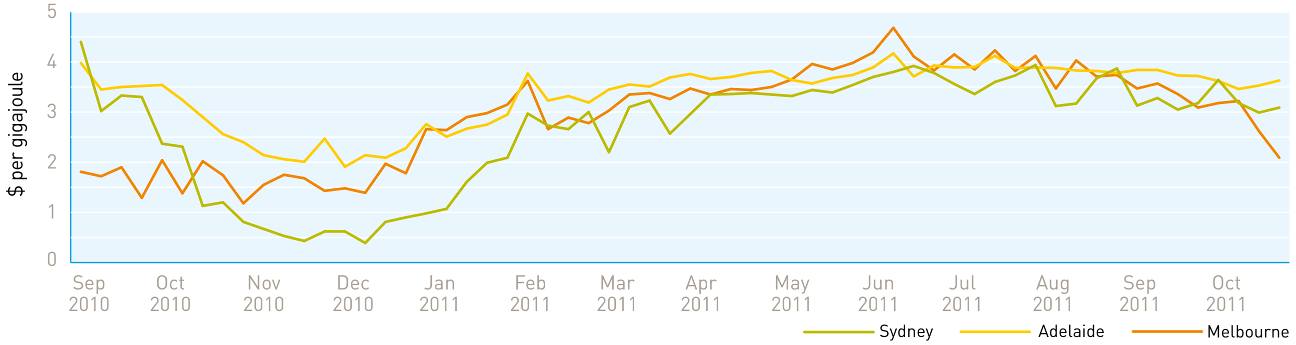
The bulletin board, which began in July 2008, provides real time information on the state of the gas market, system constraints and market opportunities. It provides information that supports Victoria's spot market and the short term trading market (which has operated since September 2010 in Sydney and Adelaide, and since December 2011 in Brisbane).

In the Victorian market, colder temperatures and an earlier onset of winter in 2011 led prices to rise above 2010 levels. The daily volume weighted average price for 2010–11 was $2.45 per gigajoule, compared with $1.83 per gigajoule in 2009–10. Both outcomes are significantly lower than long term average prices.

The short term trading market recorded some price instability in its early months, mainly due to data errors. Average ex ante prices in the nine months from market start to 30 June 2011 were $2.87 per gigajoule in Sydney and $3.17 per gigajoule in Adelaide. While design differences between the short term trading market and Victorian market limit the validity of price comparisons, Melbourne, Sydney and Adelaide prices are reasonably aligned, after accounting for these differences (figure 11).

20 EnergyQuest, *Energy Quarterly*, August 2011.
21 EnergyQuest, *Energy Quarterly*, August 2011, p. 97.
22 AEMO, *2011 Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
23 EnergyQuest, *Energy Quarterly*, August 2011, p. 94.
24 Queensland Department of Employment, Economic Development and Innovation, *2011 Gas Market Review Queensland*, 2011, p. 42.
25 AEMO, *2011 Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
26 AEMO, *2011 Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
27 Queensland Department of Employment, Economic Development and Innovation, *2011 Gas Market Review Queensland*, 2011, pp. 42–3.

Figure 11
Sydney, Adelaide and Melbourne spot gas prices—weekly averages



Notes:

Sydney and Adelaide data are weekly averages of the ex ante daily price in each hub. Ex ante prices are derived from demand forecasts in the short term trading market and form the main basis for settlement. The Sydney data exclude the 1 November 2010 price of $150 per gigajoule, which data errors caused.

Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff ($0.37 per gigajoule) for the two Melbourne metropolitan zones.

Sources: AEMO; AER.

D3 Compliance and enforcement issues

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to the bulletin board, the short term trading market and the Victorian gas market. It takes a transparent approach to monitoring, compliance and enforcement, publishing quarterly reports on activity. The AER also draws on bulletin board and spot market data to publish weekly reports on gas market activity in southern and eastern Australia.

The AER's monitoring activity has helped improve data provision to the bulletin board and the Victorian gas market. In the short term trading market, however, failures to submit demand forecasts and data errors involving pipeline operators caused significant price impacts in the early months of operation. The AER in 2011 undertook measures to reduce the amount of missing, late or erroneous data submitted by participants, and reporting performance has since improved. More generally, the AER committed to the SCER to monitor the market for the exercise of market power.


Edgar Hotan (Newspix)

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 over nine million residential and business customers. In 2010–11 the market generated around 204 terawatt hours (TWh) of electricity, with a turnover of $7.4 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 rose from around 26 gigawatts (GW) in 1999 to 35 GW in 2011. Table 1.2 sets out the regional consumption profile.

1.2 Generation in the NEM

Electricity produced by large electricity generators in the NEM jurisdictions is sold through a central dispatch process that the Australian Energy Market Operator (AEMO) manages. Figure 1.2 illustrates the location of large generators in the NEM.

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	49 110 MW
Registered generators	305
Customers	9.0 million
Turnover 2010–11	$7.4 billion
Total energy generated 2010–11	204 TWh
Maximum winter demand 2010–11	31 240 MW[1]
Maximum summer demand 2010–11	34 933 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*, 2011.

Figure 1.1a
National Electricity Market electricity consumption

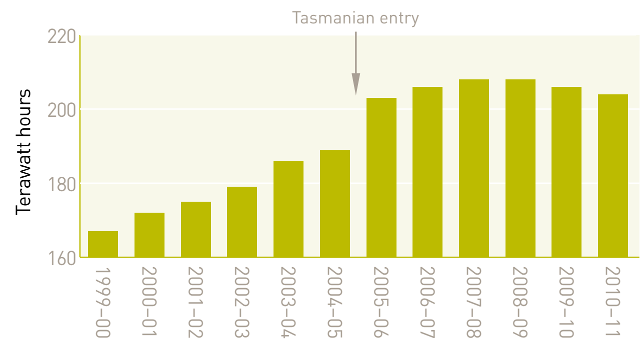
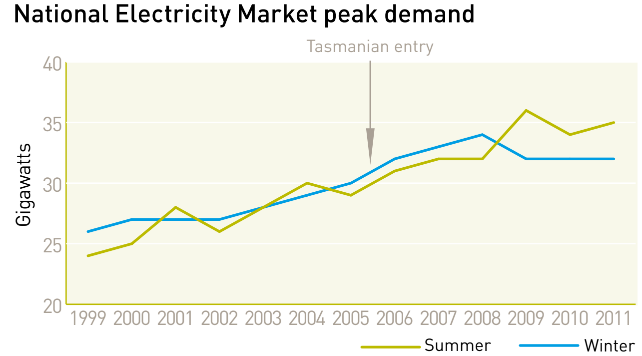


Figure 1.1b
National Electricity Market peak demand



Sources: AEMO; AER.

Figure 1.2

Large electricity generators in the National Electricity Market

Sources: AEMO; AER.

Table 1.2 **Electricity supply to regions of the National Electricity Market (terawatt hours)**

	QLD	NSW	VIC	SA	TAS[1]	SNOWY[2]	NATIONAL
2010–11	51.5	77.6	50.9	13.5	10.2		203.7
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.

Note: Estimates based on generation required to meet energy requirements within a region—calculated as regional generation plus net flows into the region across interconnectors.

Sources: AEMO; AER.

1.2.1 Technology mix

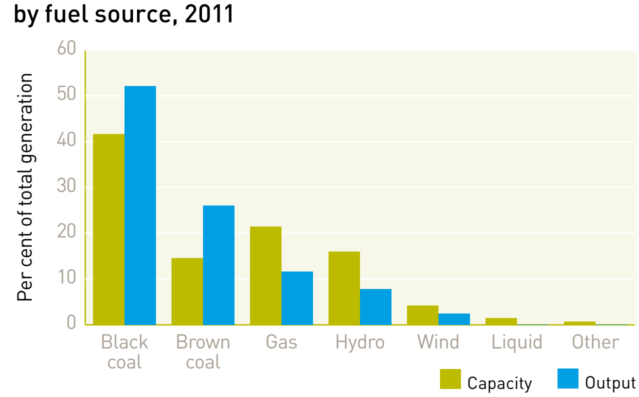
Across the NEM, black and brown coal account for around 56 per cent of registered[1] generation capacity, but this baseload plant supplies around 78 per cent of output (figure 1.3). Victoria, New South Wales and Queensland rely on coal more heavily than do other regions (figure 1.4).

Gas fired generation accounts for around 21 per cent of registered capacity across the NEM but supplies—as intermediate and peaking plant—only around 12 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 8 per cent of output. Its contribution to output has increased recently with improved rainfall in Tasmania and eastern Australia. Wind plays a relatively minor role in the market (around 4 per cent of capacity and 3 per cent of output), but its role is expanding under climate change policies. Following significant wind generation investment in South Australia, wind now represents 24 per cent of statewide capacity but has accounted for up to 86 per cent of output.

Non-traditional technologies are also emerging as potential suppliers of electricity, including solar and geothermal generation (section 1.6).

Figure 1.3
Registered generation in National Electricity Market, by fuel source, 2011

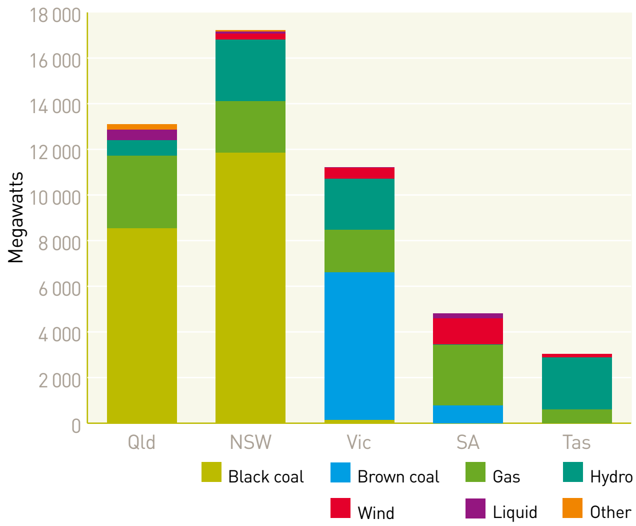


Note: Output is for 2010–11.

Sources: AEMO; AER.

1 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, 2011



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

The extent of new and proposed investment in weather dependant generation such as wind and solar power raises concerns about system security and reliability. This led to changes in how wind generation is integrated into the market. 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 requirement allows AEMO to manage the output of these generators to maintain the integrity of the power system.

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.[2]

Climate change policies aim to change the economic drivers for new investment and shift the mix from a reliance on coal fired generation towards less carbon intensive sources. Kogan Creek power station in Queensland is the only major new investment in coal fired generation in the past five years. Gas fired and wind generation have attracted the bulk of new investment.

The Australian Government will introduce a carbon price on 1 July 2012 as part of its Clean Energy Future Plan. The plan targets a reduction in carbon and other greenhouse emissions to at least 5 per cent below 2000 levels by 2020 (and up to 25 per cent with equivalent international action). The central mechanism will place a fixed price on carbon for three years, starting at $23 per tonne. It will then move to an emissions trading scheme in 2015, with the price determined by the market.

The plan includes assistance of $5.5 billion for emission intensive generators, and contracts for the closure of up to 2000 MW of coal fired generation. The plan also establishes the Clean Energy Finance Corporation, with access to $10 billion over five years for investment in renewable and low emissions energy. The Australian Parliament passed the legislation to implement the plan in November 2011.

The Australian Government also operates a national renewable energy target (RET) scheme, which it revised in 2011. 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 energy 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.

The scheme applies different arrangements for small scale and large scale renewable supply. It has a target of 41 000 gigawatt hours (GWh) of energy from large scale renewable energy projects by 2020. Small scale renewable projects no longer contribute to the national target, but still produce renewable energy certificates that

2 Garnaut Climate Change Review, *Final report*, 2008.

retailers must acquire. Since the 2011 revisions to the scheme, certificates from large scale projects have traded at around $35–40. The price of certificates from small scale projects has been more volatile, trading at $20–40.

1.2.3 Generation ownership

Private entities own the bulk of generation capacity in Victoria and South Australia. While public corporations control a majority of capacity in New South Wales and Queensland, there is increasing private sector activity. The Tasmanian generation sector remains mostly in government hands.

- In *Victoria* and *South Australia*, the major generation 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, mostly comprising historical investment associated with the Snowy Mountains scheme.[3]
- The *New South Wales* Government in 2011 sold the electricity trading rights of some state owned power stations. TRUenergy acquired the trading rights for the Mount Piper and Wallerawang power stations, while Origin Energy acquired the trading rights for the Eraring and Shoalhaven power stations. While state owned corporations still own around 90 per cent of generation capacity, TRUenergy and Origin Energy now control around one-third of this.
- State owned corporations control around 70 per cent of *Queensland's* generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone and Collinsville power stations). In 2011 the Queensland Government restructured its generation portfolio, with Tarong Energy exiting the market and all state owned capacity being reallocated between CS Energy and Stanwell. Considerable private investment has occurred over the past decade, including investment by Origin Energy, InterGen, AGL Energy, Alinta Energy and Arrow Energy.
- 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.

The New South Wales energy privatisation process in 2011 (and privatisation in Queensland in 2007) continues a trend of vertical integration between electricity generators and energy retailers into 'gentailers'. Origin Energy, AGL Energy and TRUenergy now control almost 30 per cent of generation capacity in the mainland regions of the NEM and jointly supply over 80 per cent of small electricity retail customers. Section B2 of the *Market overview* in this report outlines developments in vertical integration and implications for energy markets.

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.[4]

The NEM is a gross pool, meaning all electricity sales must occur through the spot market. In contrast, Western Australia's electricity market uses a net pool arrangement. Unlike some 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, those not connected to a transmission network (for example, embedded generators) and those producing exclusively for their own use (such as remote mining operations).

3 The New South Wales, Victorian and Australian governments jointly own Snowy Hydro.
4 The *State of the energy market 2009* report explained the dispatch process (section 2.2).

Table 1.3 **Generation ownership in the National Electricity Market, July 2011**

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND	TOTAL CAPACITY	12 692	
Stanwell Corporation	Stanwell; Tarong; Tarong North; Swanbank; Barron Gorge; Kareeya; Mackay Gas Turbine; others	4 015	Stanwell Corporation (Qld Government)
CS Energy	Callide; Kogan Creek; Wivenhoe	1 969	CS Energy (Qld Government)
CS Energy	Gladstone	1 680	Rio Tinto 42.1%; NRG Energy 37.5%; others 20.4% Contracted to CS Energy
Origin Energy	Darling Downs; Mount Stuart; Roma	1 046	Origin Energy
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	760	InterGen (China Huaneng Group 50%; others 50%) 50%; China Huaneng Group 50%
Arrow Energy	Braemar 2	495	Arrow Energy (Shell 50%; PetroChina 50%)
Braemar Power Projects	Braemar 1	435	Alinta Energy
AGL Hydro	Oakey	275	ERM Group 62.5%; others 37.5% Contracted to AGL Energy
AGL Hydro	Yabulu	235	RATCH Australia Contracted to AGL Energy / Arrow Energy
Stanwell Corporation	Collinsville	187	RATCH Australia Contracted to Stanwell Corporation
RTA Yarwun	Yarwun	146	Rio Tinto Alcan
QGC Sales Qld	Condamine	135	BG Group
AGL Energy	German Creek; KRC Cogeneration; others	78	AGL Energy
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
NEW SOUTH WALES	TOTAL CAPACITY	16 742	
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4 839	Macquarie Generation (NSW Government)
Delta Electricity	Vales Point B; Munmorah; Colongra; others	2 648	Delta Electricity (NSW Government)
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2 466	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
TRUenergy	Mount Piper; Wallerawang	2 400	Delta Electricity (NSW Government) Contracted to TRUenergy
Origin Energy	Eraring; Shoalhaven	2 322	Eraring Energy (NSW Government) Contracted to Origin Energy
Origin Energy	Uranquinty; Cullerin Range	670	Origin Energy
TRUenergy	Tallawarra	422	TRUenergy (CLP Group)
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	386	AETV (Tas Government)
Infigen Energy	Capital; Woodlawn	182	Infigen Energy
Marubeni Australia Power Services	Smithfield Energy Facility	160	Marubeni Corporation
Redbank Energy	Redbank	145	Redbank Energy
EDL Group	Appin; Tower; Lucas Heights	108	EDL Group
Eraring Energy	Brown Mountain; Burrinjuck; others	98	Eraring Energy (NSW Government)
AGL Hydro	Copeton; Burrendong; Wyangala; others	74	AGL Energy
Essential Energy	Broken Hill Gas Turbine	50	Essential Energy (NSW Government)
Acciona Energy	Gunning	47	Acciona Energy
Infratil Energy Australia	Hunter; Awaba	30	Infratil

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
VICTORIA	TOTAL CAPACITY	10 791	
LYMMCo	Loy Yang A	2 170	GEAC (AGL Energy 32.5%; TEPCO 32.5%; RATCH Australia 14%; others 21%)
Snowy Hydro	Murray; Laverton North; Valley Power	2 098	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
International Power	Hazelwood	1 600	International Power / GDF Suez 91.8%; Commonwealth Bank 8.2%
TRUenergy Yallourn	Yallourn; Longford Plant	1 451	TRUenergy (CLP Group)
International Power	Loy Yang B	965	International Power / GDF Suez 70%; Mitsui 30%
Ecogen Energy	Jeeralang A and B; Newport	891	Industry Funds Management (Nominees) Contracted to TRUenergy (CLP Group)
AGL Hydro	Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay; others	596	AGL Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland; Codrington	265	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Energy Brix Australia	Energy Brix Complex; others	160	HRL Group / Energy Brix Australia
Alcoa	Angelsea	156	Alcoa
Aurora Energy Tamar Valley	Bairnsdale	68	AETV (Tas Government)
SOUTH AUSTRALIA	TOTAL CAPACITY	4 430	
AGL Energy	Torrens Island	1 280	AGL Energy
Alinta Energy	Northern; Playford	742	Alinta Energy
International Power	Pelican Point; Canunda	494	International Power / GDF Suez
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	315	International Power / GDF Suez
TRUenergy	Hallet; Waterloo	287	TRUenergy (CLP Group)
Origin Energy	Quarantine; Ladbroke Grove	261	Origin Energy
Infigen Energy	Lake Bonney 2 and 3	198	Infigen Energy
AGL Hydro	Hallett 1 and 2; Wattle Point; North Brown Hill	194	AGL Energy
Origin Energy	Osborne	175	ATCO 50%; Origin Energy 50%
Infratil Energy Australia	Snowtown	99	Infratil
Infigen Energy	Lake Bonney 1	81	Infigen Energy Contracted to Essential Energy (NSW Government)
Meridian Energy	Mount Millar	70	Meridian Energy
TRUenergy	Cathedral Rocks	66	TRUenergy (CLP Group) 50%; Acciona Energy 50%
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Angaston	49	Infratil Contracted to AGL Energy
RATCH Australia	Starfish Hill	35	RATCH Australia Contracted to Hydro Tasmania (Tas Government)
TASMANIA	TOTAL CAPACITY	2 693	
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; Woolnorth; others	2 305	Hydro Tasmania (Tas Government)
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	386	AETV (Tas Government)

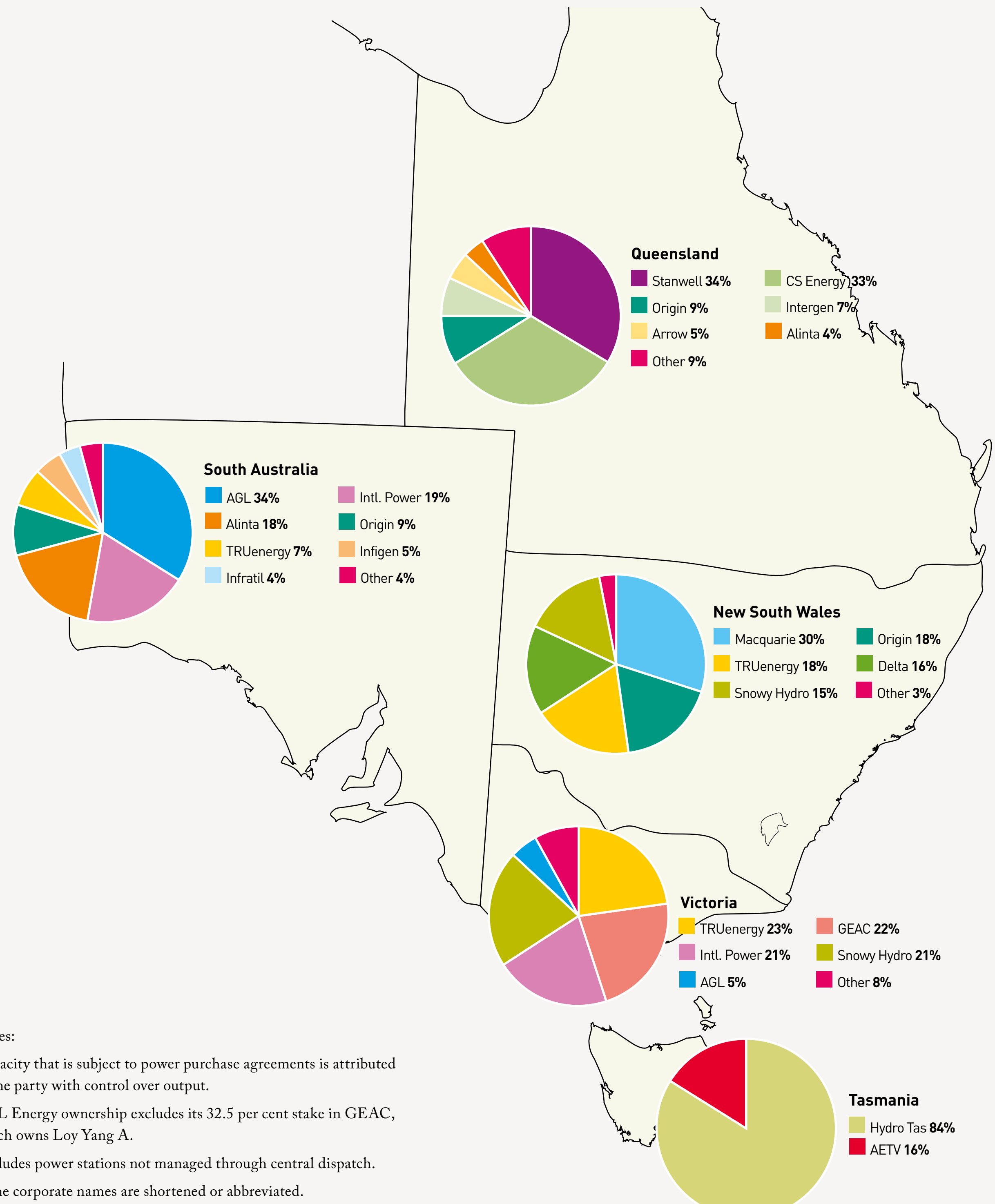
Fuel types: coal; gas; hydro; wind; diesel/fuel oil/multi-fuel; biomass/bagasse; unspecified.

Note: Capacity is as published by AEMO for summer 2011–12.

Source: AEMO.

Figure 1.5

Market shares in electricity generation capacity, by region, 2011



Notes:

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

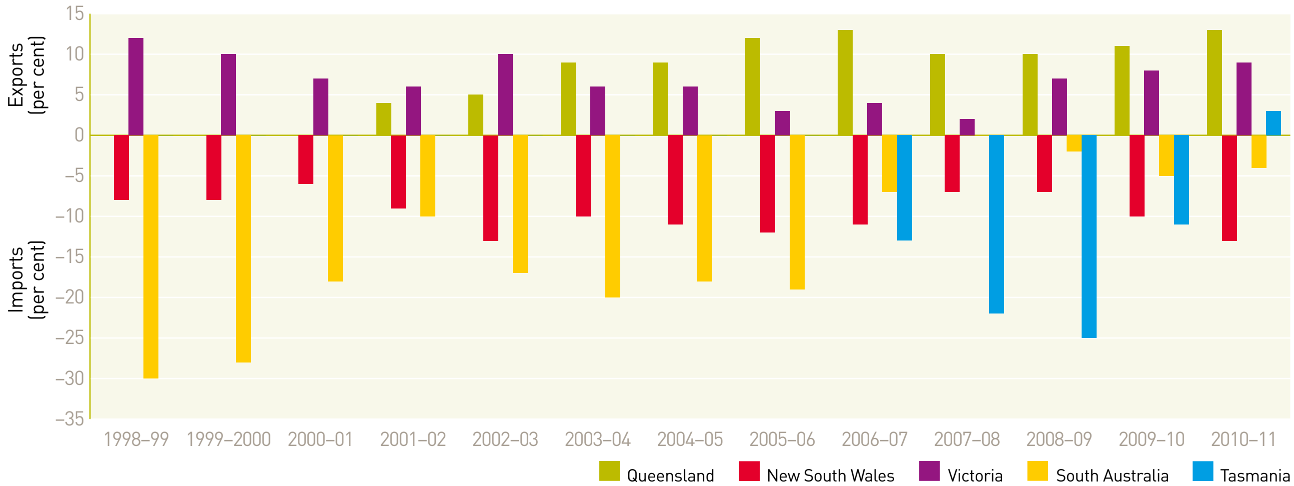
AGL Energy ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A.

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.

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.
- In 2010–11 *Tasmania* was a net exporter of energy for the first time since its interconnection with the NEM in 2006. The region's ability to generate hydroelectricity rose due to greater water availability (more than double the levels in 2007). In addition, new gas fired generation was installed in 2009.

1.4 Spot electricity prices

Generators provide AEMO with generation price and quantity offers (bids) for each 5 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 5 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 5 minute dispatch prices. This is the price that all generators receive for their supply during the half hour, and the price that wholesale 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 will be increased annually from 1 July 2012 to reflect changes in the consumer price index. The Australian Energy Market Commission (AEMC) can further change the cap through its reviews of reliability standards and other market settings (section 1.8).

While the market determines a separate price for each region, prices across the mainland regions are aligned for a majority of the time.[5] Alignment occurred for about 61 per cent of the time in 2010–11, compared with 67 per cent in 2009–10. The rate of alignment has steadily decreased from over 80 per cent in 2001–02. 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 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.

1.4.1 Spot prices in 2010-11

The 2010–11 summer was comparatively mild (with the lowest average maximum temperature across Australia since 2001), resulting in lower than expected electricity demand. Average spot prices fell significantly from the previous year in South Australia, Victoria and New South Wales, and marginally in Queensland, but rose slightly in Tasmania.

As with the previous year, average spot prices in New South Wales ($43 per MWh) and South Australia ($42 per MWh) were higher than in other regions. Victoria ($29 per MWh) and Tasmania ($31 per MWh) recorded the lowest average spot prices in 2010–11, closely followed by Queensland ($34 per MWh). All regions other than Tasmania recorded their lowest average spot prices in at least five years.

In addition to lower average prices, fewer extremely high price events occurred in 2010–11. The NEM recorded 40 trading intervals above $5000 per MWh —the lowest number since 2004–05 (figure 1.9). But while there were fewer events, those that occurred set record prices in New South Wales, South Australia and Tasmania, following an increase in the market price cap on 1 July 2010 to $12 500 per MWh. The maximum price in 2010–11 was $12 400 per MWh, reached on three occasions in Tasmania.

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

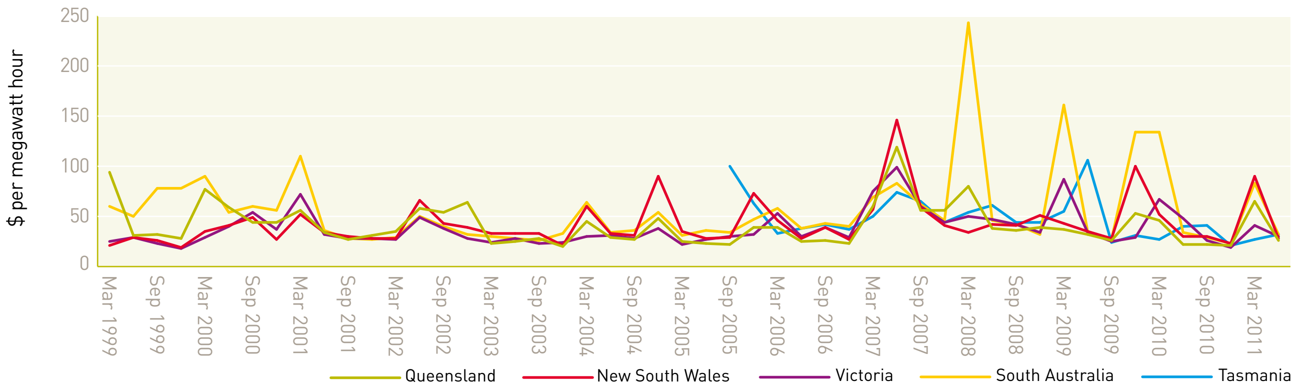
	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
2010–11	34	43	29	42	31	
2009–10	37	52	42	82	30	
2008–09	36	43	49	69	62	31
2007–08	58	44	51	101	57	31
2006–07	57	67	61	59	51	38
2005–06	31	43	36	44	59	29
2004–05	31	46	29	39		26
2003–04	31	37	27	39		22
2002–03	41	37	30	33		27
2001–02	38	38	33	34		27
2000–01	45	41	49	67		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.

5 Even when aligned, prices will exhibit minor disparities across regions, caused by transmission losses that occur when electricity is transported over long distances.

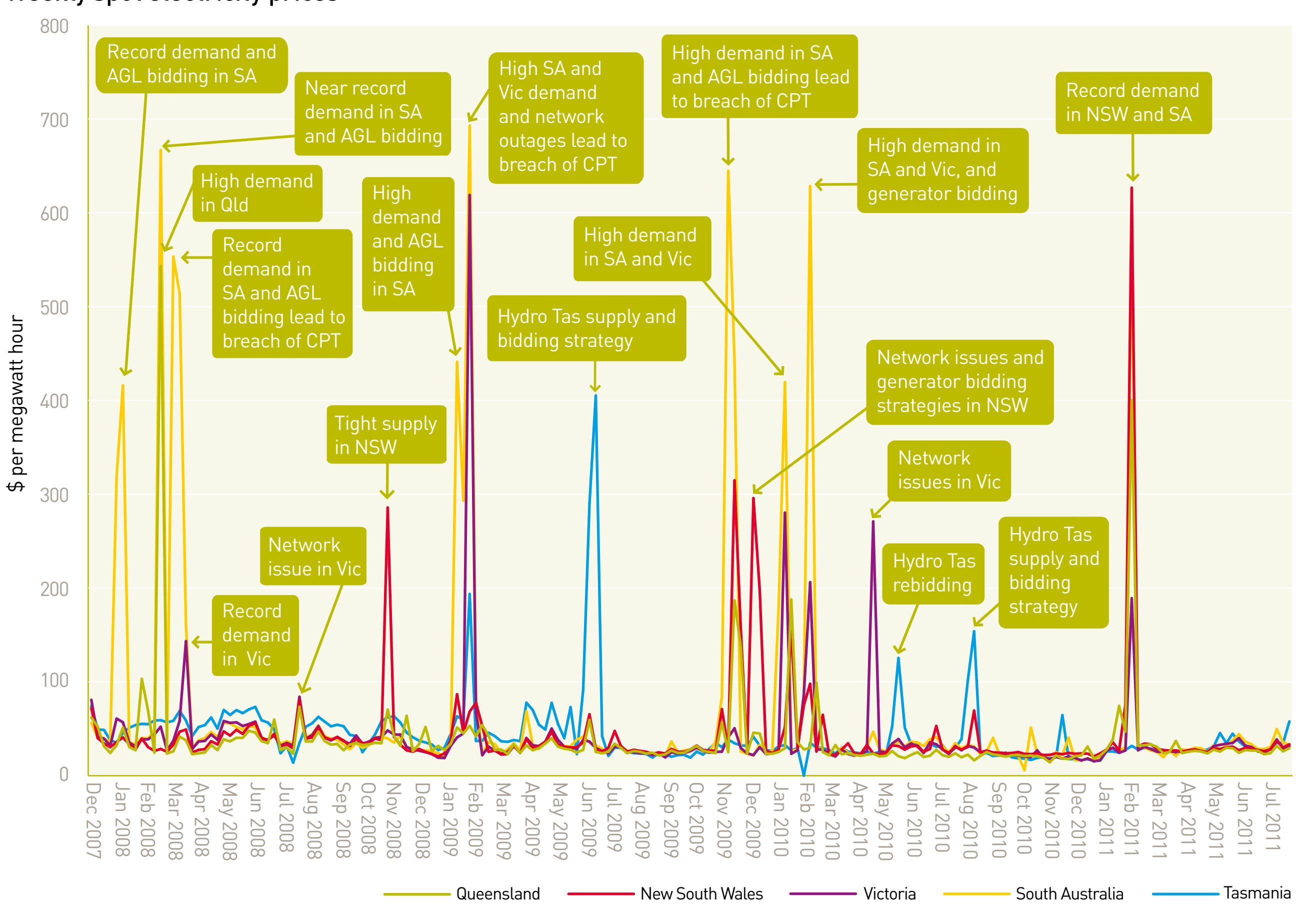
Figure 1.7
Quarterly spot electricity prices



Note: Volume weighted average prices.

Sources: AEMO; AER.

Figure 1.8
Weekly spot electricity prices

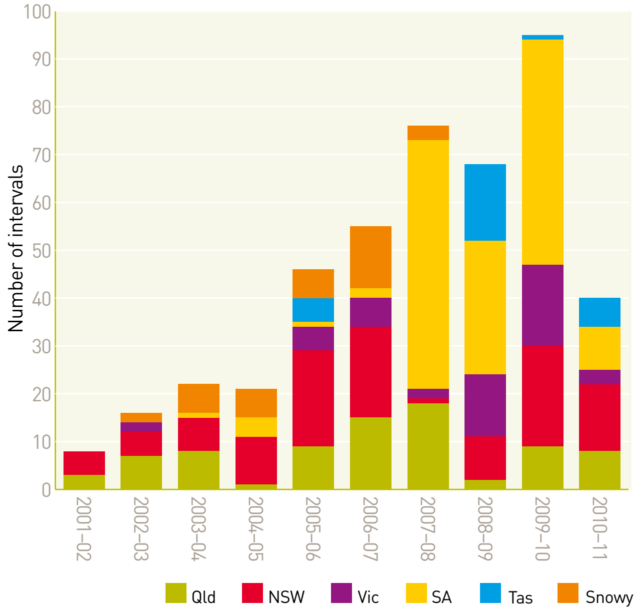


CPT, cumulative price threshold; Hydro Tas, Hydro Tasmania.

Note: Volume weighted average prices.

Source: AER.

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 price events above $5000 per MWh in 2010–11, noting the regions in which they occurred and the underlying causes. Eighty per cent of the events occurred during a heat wave from 31 January to 2 February 2011 affecting New South Wales (12 events), South Australia (nine), Queensland (eight) and Victoria (three). The high temperatures led to record demand of 14 598 MW in New South Wales (where the temperature reached 41 degrees on 1 February), and 3378 MW in South Australia (43 degrees on 31 January). Demand was also high in Victoria on 1 February (at 9585 MW), but short of the record 10 445 MW set in January 2009.

The events across the four regions were related, with demand and supply conditions in South Australia on 31 January contributing to high prices in Victoria on that day. Similarly, high demand in New South Wales affected prices in Queensland and Victoria. Floods in Queensland also led to transmission outages and volatile pricing during this period.

NEM turnover for the week covering these days exceeded $2 billion—a 50 per cent increase on the previous record. New South Wales also recorded its highest weekly volume weighted average price of $627 per MWh. The increase in the market price cap contributed to these new records.

Market focus—South Australia

At $42 per MWh, the average spot price in South Australia for 2010–11 was almost 50 per cent lower than in 2009–10. The price exceeded $5000 per MWh in nine trading intervals, down significantly on the previous year (figure 1.9). A mild summer, with only a few days above 40 degrees, affected this outcome.

Another contributing factor was South Australia's 177 trading intervals with negative prices in 2010–11, up from 86 in the previous year and the highest annual number ever recorded for any region. Wind generators sometimes bid negative prices to ensure dispatch, relying on the value of the renewable energy certificates they earn to cover their costs. But several instances of prices near the –$1000 market floor were driven by AGL Energy rebidding large amounts of capacity at times of high wind generation and low demand. The negative prices caused other generators, including wind farms, to shut down (See Section B2, *Market overview*).

The South Australian data contributed to a record number of negative price events (282) for the NEM in 2010–11. As a result, the AER in October 2010 began analytical reporting on spot prices below –$100 per MWh as part of its weekly market updates.

Market focus—Tasmania

Good rainfall allowed for increased hydro generation in Tasmania in 2010–11 and contributed to a second year of relatively low spot prices ($31 per MWh). Tasmania had six extreme price events, compared with one in 2009–10, typically caused by Hydro Tasmania strategically withdrawing its non-scheduled generation to raise prices (as it has periodically done since 2009). There were also instances where the spot price reached the floor (–$1000) when the Victorian spot price was high.

Table 1.5 Price events above $5000 per megawatt hour, 2010–11

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
7 and 8 August 2010	Tas	5	$12 400	In day-ahead bidding, Hydro Tasmania offered significant capacity to the market at high prices. It then reduced output from its small hydro (non-scheduled) generators during peak demand periods on both days. A spot price of $12 400 per MWh in one period set a new record for the NEM, following an increase in the market price cap from $10 000 per MWh to $12 500 per MWh on 1 July 2010. Some demand side response to the high prices appeared to mitigate the price impact in some trading intervals.
10 August 2010	NSW	2	$6 267	Capacity at Delta Electricity's Wallerawang plant was significantly reduced—unit 8 was not operational and Delta delayed unit 7's return to service by several hours. The ratings of the Mount Piper to Wallerawang lines were reduced to allow unit 7 to return to service, contributing to more severe network congestion than expected. This congestion reduced the dispatch of low priced generation and forced electricity flows out of New South Wales, causing prices to significantly exceed the forecast and almost reach the market cap in five dispatch intervals. There appeared to be a demand response to the high prices, with a 300 MW reduction in New South Wales electricity demand.
19 November 2010	Tas	1	$12 400	In day-ahead bidding, Hydro Tasmania offered significant capacity at prices near the market cap for two hours in the morning. On the day, it reduced output from its small hydro (non-scheduled) generators. Due to constraints on Basslink (which limited imports from the mainland) and a lack of alternative local capacity, Hydro Tasmania's high priced scheduled generation was dispatched to meet demand.
31 January 2011	SA	9	$12 200	Record South Australian demand (3378 MW), combined with Alinta Energy pricing around 70 per cent of its capacity at Northern Power Station near the cap, caused spot prices to rise to $12 200 per MWh—a record for the region. Wind generation on the day fell from around 540 MW to an average of 100 MW during the high price period. Had wind generation not fallen, the price impact might have been significantly reduced. The events in South Australia contributed to spot prices exceeding $5000 per MWh in Victoria on the same day.
31 January and 1 February 2011	Vic	3	$9 597	High temperatures led to demand reaching its highest level in Victoria for the summer, peaking at 8924 MW on 31 January and 9585 MW on 1 February. On both days, LYMMCO priced around one-third of its capacity at Loy Yang A at close to the market cap in its day-ahead offers. The tight supply–balance was further aggravated when Newport Power Station tripped on 31 January, causing a 510 MW reduction in available capacity. The combined impact of these factors caused prices to spike above $10 000 per MWh in eight (5 minute) dispatch intervals. The impact was prolonged when Snowy Hydro shifted capacity into negative prices for its Murray generator (located in Victoria) to ensure dispatch and accrue the high Victorian prices. Network constraints did not allow this electricity to flow into Victoria, but instead forced flows into the lower priced New South Wales region. AEMO intervened to reduce exports from Victoria to New South Wales. Record demand and high prices in New South Wales and South Australia also contributed to the high Victorian prices. Rebidding by International Power at Hazelwood and Loy Yang B had an impact on Victorian prices on 1 February.
31 January to 2 February 2011	NSW	12	$12 136	High temperatures led to record New South Wales electricity demand on all three days, peaking at 14 598 MW on 1 February. Sustained high prices over the three days led the weekly cumulative price in New South Wales to increase to $151 025 on 2 February. The events affected neighbouring regions, with prices above $5000 per MWh in Victoria and Queensland on 1 February, and in Queensland on 2 February. Rebidding by Macquarie Generation and Eraring contributed to the high prices.

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
1 and 2 February 2011	Qld	8	$9 044	CS Energy, Millmerran, Stanwell and Callide Power Trading rebid significant amounts of capacity at prices above $9000 per MWh. This rebidding, combined with record demand and high prices in New South Wales, drove a series of extreme price outcomes in Queensland, none of which was forecast.
MARKET ANCILLARY SERVICES				
1 February 2011	SA	35 minutes	$7 591	High Victorian electricity prices drove exports from South Australia into Victoria on a day when a planned transmission outage reduced the capability of the Heywood interconnector between the regions. These conditions led to the need for frequency control ancillary services, and the transmission outage meant these services could be sourced only from South Australia. AGL Energy is the most significant provider of frequency control ancillary services in South Australia, and it offered the majority of its capacity for these services at the price cap. The offers were made through day-ahead offers and rebidding. The combination of high energy prices in the eastern states and AGL Energy's high offers caused prices for lower frequency control services to exceed $5000 per MW for seven (5 minute) dispatch intervals. These services for the seven dispatch intervals, which South Australian customers paid for, cost a total of $441 000 (compared with less than $3000 for the same services on a typical day).

MW, megawatt; MWh, megawatt hour.

Source: AER.

The Tasmanian Government established the Electricity Supply Industry Expert Panel in 2010 to assess the state of the industry. The panel released an issues paper in June 2011 that, in addition to addressing matters core to its terms of reference, questioned Hydro Tasmania's market power and its use of its non-scheduled generation to raise prices. It expected to release its final report in December 2011.

The AER's submission to the issues paper provided evidence of Hydro Tasmania's strategic manipulation of prices (particularly at off peak times) causing inefficient dispatch of open cycle gas turbines and demand side response from large industrial customers. Hydro Tasmania's strategy was not associated with any supply scarcity. The AER concluded Hydro Tasmania's strategic behaviour would, in addition to having negative impacts on market efficiency, pose a major spot market risk for any new retailer in Tasmania.

1.4.2 Rule change proposal on market power

The AEMC began consulting in 2011 on an Electricity Rule change proposal by Major Energy Users in relation to generators' potential exercise of market power in the NEM. The proponent argued some large generators have the ability and incentive to use market power to increase wholesale electricity prices during periods of high demand. The proposed Rule change would require 'dominant' generators, as determined by the AER, to offer their entire capacity at times of high demand at a price of no more than $300 per MWh.

The AER noted in a submission to the AEMC that short periods of high prices are necessary in an energy only market to signal underlying supply and demand conditions and the need for investment. Market power concerns arise when high average prices reflect systemic economic withholding of capacity by generators, rather than scarcity pricing. The AER has noted evidence of such behaviour in its reports on extreme prices in the NEM, and in *State of the energy market* reports.

It reported, for example, systemic economic withholding by Macquarie Generation in New South Wales in 2007, by AGL Energy in South Australia between 2008 and 2010, and by Hydro Tasmania between 2009 and 2011.

The AEMC expects to make a draft determination in April 2012, following further stakeholder consultation.[6]

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 hedge contracts (derivatives) that lock in firm prices for the electricity they intend to produce 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 markets, comprising direct contracting 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). 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 on the SFE covers instruments for the Victoria, New South Wales, Queensland and South Australia regions. Trading volumes in this market were equivalent to about 284 per cent of underlying energy consumption in 2010–11, up from 204 per cent in 2009–10. New South Wales accounted for 42 per cent of traded volumes, followed by Queensland (29 per cent) and Victoria (28 per cent). Liquidity in South Australia has remained low since 2002, accounting for only 1 per cent of volumes.

1.5.1 Electricity futures prices

Figure 1.10 shows average price outcomes for electricity base futures, as reflected in the national power index.[7] The index (which d-cyphaTrade publishes for each calendar year) represents a basket of electricity base futures for New South Wales, Victoria, Queensland and South Australia. It is calculated as the average daily settlement price of base futures contracts across the four regions for the four quarters of the relevant calendar year.

The expected effects of carbon pricing on electricity generation costs led to higher base futures prices in 2008, which then eased following government announcements in 2009 and 2010 to delay new policies in this area. Prices continued to fall throughout 2010, reflecting subdued prices in the electricity spot market. Futures prices were below $40 per MWh in all NEM regions by the end of 2010. They rebounded during the summer of 2010–11 when high temperatures, record electricity demand and record spot prices raised price expectations (especially for 2011 calendar futures).

Prices for 2012 futures continued to rise during 2011 as momentum grew towards the introduction of carbon pricing in 2012. By July 2011 prices for 2012 futures were above $47 per MWh in South Australia and New South Wales, and around $42 per MWh in Victoria and Queensland. Conversely, prices for 2011 futures (which would not be affected by carbon pricing) fell back to around $36 per MWh.

6 AEMC, *National Electricity amendment (potential generator market power in the NEM) Rule 2011, directions paper*, 2011.
7 Base futures contracts cover all trading intervals over the term of the contract.


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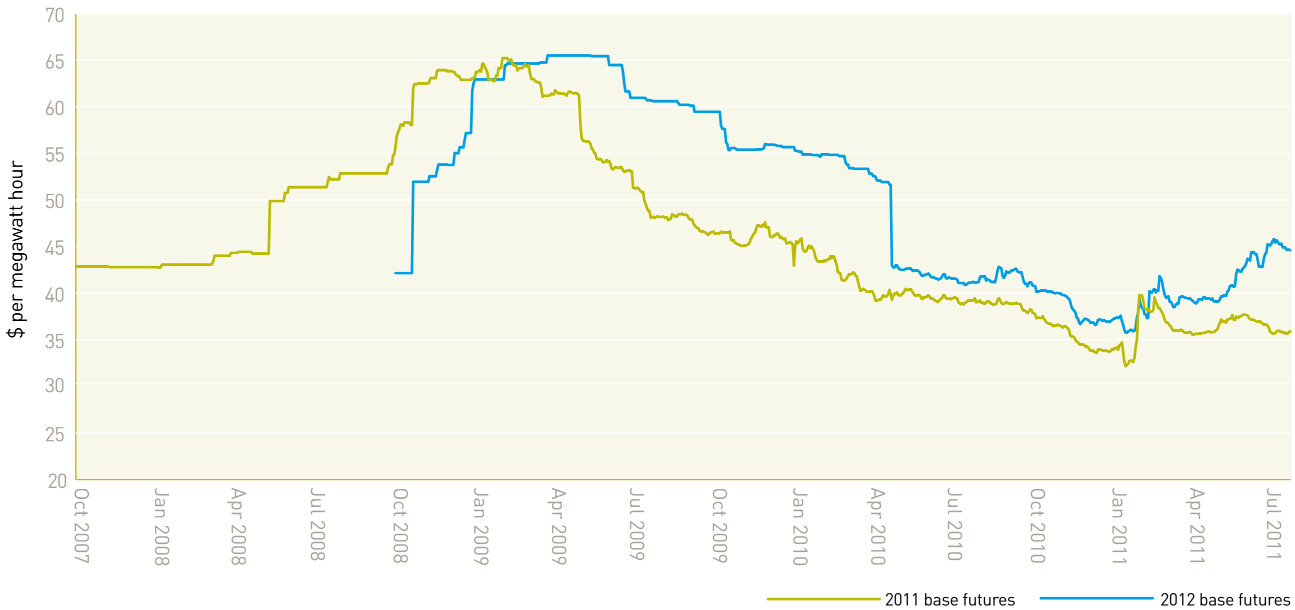
Figure 1.10
National power index



Source: d-cyphaTrade.

Forward prices

Figure 1.11 illustrates base futures prices at June 2011 for quarters up to two years ahead. For comparative purposes, forward prices at June 2010 are also provided.

Prices in June 2011 for the quarters in 2011–12 eased in most jurisdictions from the levels set in June 2010, reflecting relatively benign spot prices. The largest shift occurred for the Victorian summer, with prices for futures in the first quarter of 2012 falling from almost $60 to $47 per MWh. This fall might have reflected revised perceptions about the state's supply–demand balance, following announcements that new capacity from Origin Energy's 518 MW plant at Mortlake will be operational at that time.

Prices in June 2011 for the late 2012 quarters were generally higher than those set in 2010, reflecting the revised timing for carbon pricing, now expected to take effect from 1 July 2012. Increased certainty around the details of government policy in this area may also explain the significant fall in prices for 2013 futures from the levels set in the previous year.

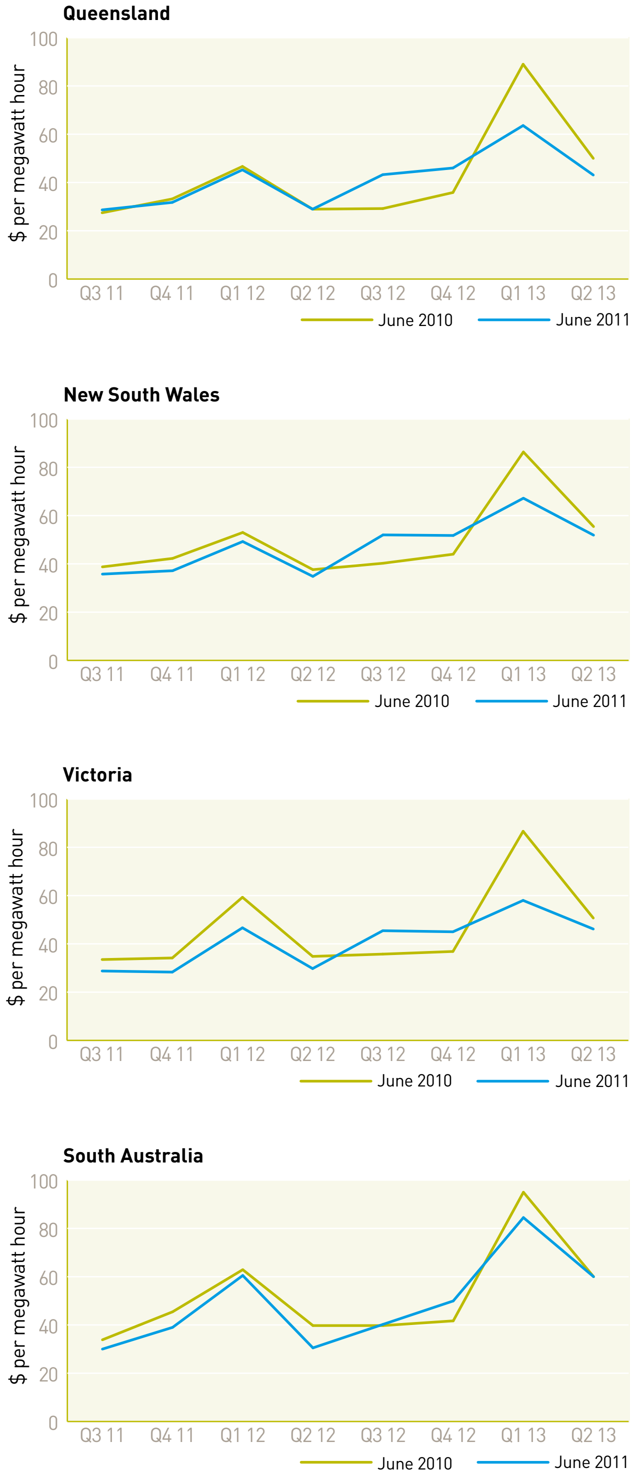
Forward prices remained higher in South Australia than elsewhere, especially for the summer peak periods. This might have reflected market concerns that periodically high summer prices in South Australia's spot electricity market—as a result of high temperatures, interconnector constraints and market power—remain a potential risk.

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 2011 for calendar year futures strips to 2014. While prices are generally consistent with those evident in the forward curves, they smooth out the impact of seasonal peaks.

The data indicate a spread of prices across the regions, with New South prices being around $5–8 per MWh higher than those in Victoria and Queensland over the next two years, but with Victorian prices rising above those in New South Wales in 2014.

Figure 1.11

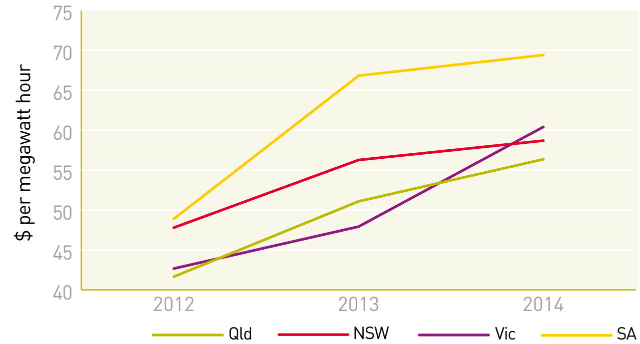
Base futures prices, June 2010 and June 2011



Sources: AER; d-cyphaTrade.

Figure 1.12

Base calendar strip, June 2011



Sources: AER; d-cyphaTrade.

In June 2011 all regions had forward curves in contango —that is, prices were higher for contracts in the later years. This trend might have reflected the expectation of higher generation costs associated with climate change policies, and uncertainty about the effects of those policies on investment. More generally, the market might have factored in assessments of supply adequacy in some regions.

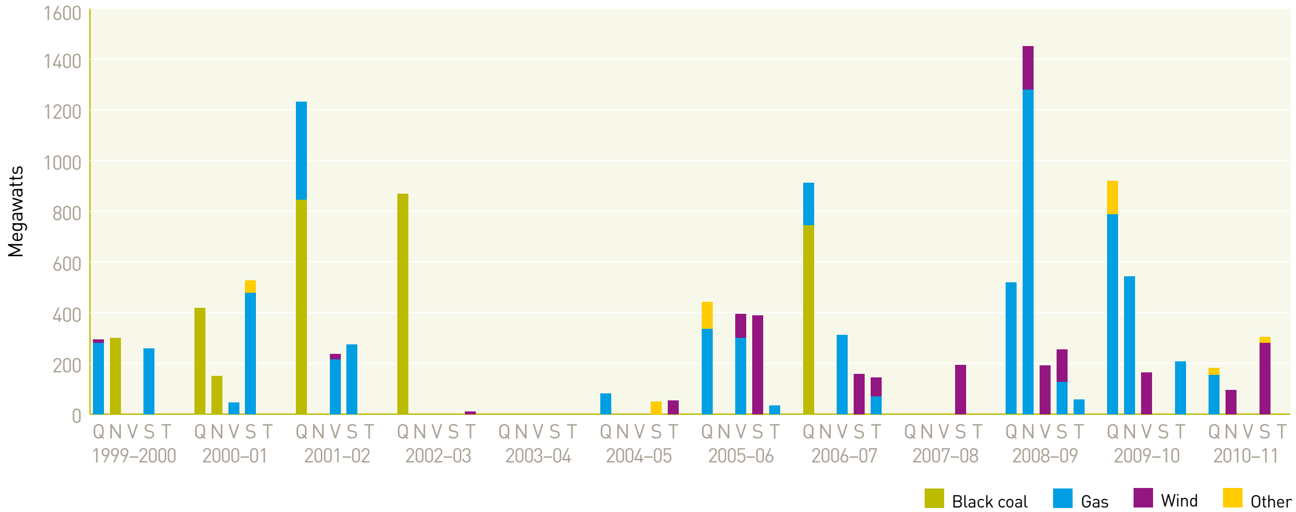
1.6 Generation investment

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 2011, new investment added around 12 600 MW of registered generation capacity.[8] Figures 1.13 and 1.14 illustrate investment since market start.

Tightening supply conditions have led to an upswing in generation investment, with over 4700 MW of new capacity added in the three years to 30 June 2011—predominantly gas fired generation in New South Wales and Queensland. But only 500 MW of this investment occurred in 2010–11, of which over 64 per cent was in wind generation (table 1.6).

8 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.

Table 1.7 sets out investment projects in the NEM at June 2011 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 2011 the NEM had almost 1300 MW of committed capacity, mostly in gas fired and wind generation. The most significant projects were in Victoria, including the 518 MW Mortlake gas fired power station and the 420 MW Macarthur wind farm (which will be the largest wind farm in the southern hemisphere).

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 31 000 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 plants, with carbon capture and storage, which Stanwell proposes for Queensland by 2017–18. The plant would be capable of capturing 90 per cent of carbon emissions.[9]
- an integrated drying and gasification combined cycle 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.[10]

9 Wandoan Power, 'Cleaner coal technology moves forward in Australia', Media release, 8 December 2009.
10 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

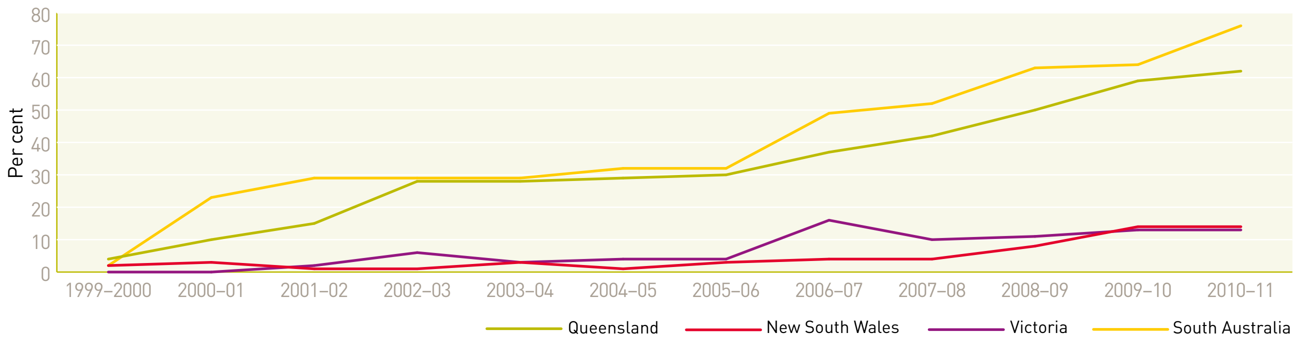


Table 1.6 Generation investment in the National Electricity Market, 2010–11

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED	ESTIMATED COST ($ MILLION)
QUEENSLAND					
Rio Tinto	Yarwun	Gas cogeneration	155	July 2010	200
NEW SOUTH WALES					
Acciona Energy	Gunning	Wind	47	April 2011	147
Infigen Energy	Woodlawn	Wind	48	June 2011	100
SOUTH AUSTRALIA					
Infigen Energy	Lake Bonney 3	Wind	39	July 2010	120
AGL Energy	North Brown Hill	Wind	82	August 2010	334
TRUenergy (CLP Group)	Waterloo	Wind	111	August 2010	300
International Power	Port Lincoln	OCGT	25	November 2010	30

Table 1.7 Committed investment in the National Electricity Market, June 2011

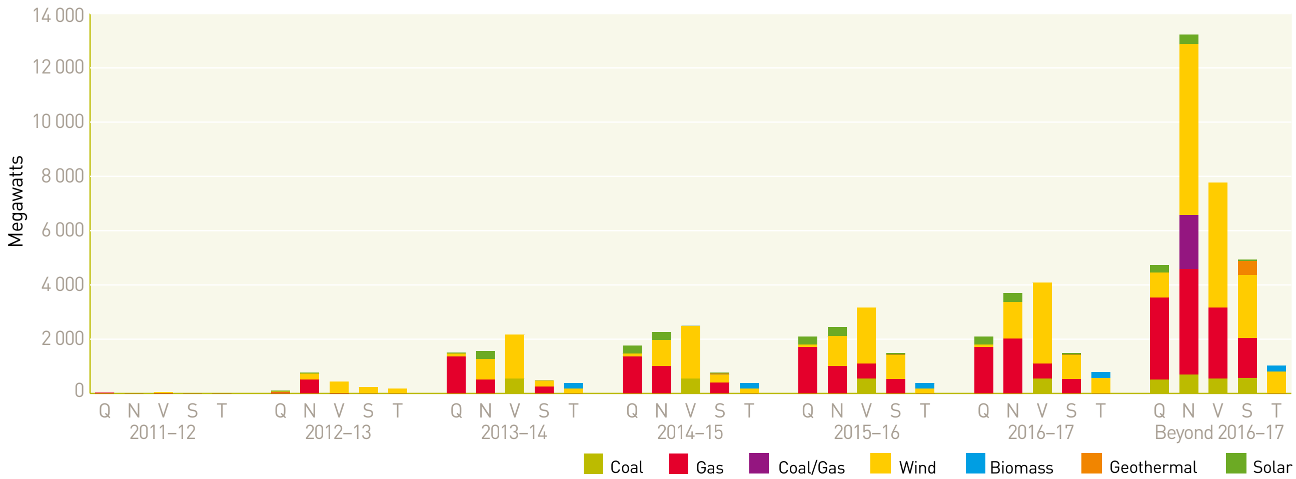
DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
NEW SOUTH WALES				
Eraring Energy	Eraring (upgrade)	Coal fired	240	2012–13
VICTORIA				
Origin Energy	Mortlake	OCGT	518	2011
AGL Energy/Meridian Energy	Macarthur	Wind	420	2011–12
AGL Energy	Oaklands Hill	Wind	63	2011–12
SOUTH AUSTRALIA				
AGL Energy	The Bluff	Wind	34	2011

OCGT, open cycle gas turbine.

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

Figure 1.15

Major proposed generation investment in the National Electricity Market, cumulative, June 2011



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

Source: AEMO.

The introduction of the Australian Government's Solar Flagships program has led to several proposals for large scale solar projects, including:

- the world's largest solar thermal gas hybrid plant in Queensland, combining solar generation with a low emission gas boiler back-up system. The 250 MW plant near Chinchilla is proposed for 2014–15.[11]
- Australia's first utility scale solar photovoltaic generation plant. The 150 MW plant at Moree (New South Wales) is proposed for 2013–14.[12] A further four solar plants, with a combined capacity of up to 200 MW, are proposed for New South Wales by 2015–16.
- a 44 MW solar thermal addition to the existing coal fired Kogan Creek power station in Queensland, proposed for 2012–13. The solar project will augment the power station's steam generation system to increase electricity output and fuel efficiency, and will be the world's largest solar integration with a coal fired power station.[13]

There are also plans for geothermal generation. A 525 MW geothermal plant announced for Innamincka (South Australia) is scheduled to connect to the grid in 2018.

1.7 Demand side participation

An alternative or supplement to generation investment is to increase demand side participation—in which energy users contract to reduce consumption at times of peak demand. In 2011 the AEMC was undertaking the third stage of a review into whether the NEM's design allows for effective demand side participation.

In the review's first two stages, the AEMC found the NEM framework does not materially bias against demand side participation. However, it considered some technological barriers, particularly in relation to the flow of information over energy networks, may limit the extent of demand side participation.

Stage three of the review focuses on identifying options for consumers to reduce or manage their energy use, along with the market conditions (including technology, information systems and pricing structures) needed to facilitate uptake of those options. The review will then consider whether those market conditions can be achieved under the current market and regulatory arrangements. The AEMC published an issues paper on stage three in July 2011.[14]

11 Solar Dawn, 'Dawn for proposed Solar Flagships project', Media release, 18 June 2011.
12 Moree Solar Farm, 'Australia's first utility scale solar power station to be built in Moree', Media release, 18 June 2011.
13 CS Energy, 'World's largest solar integration with a coal fired power station gets go ahead', Media release, 13 April 2011.
14 AEMC, 'Information sheet: AEMC review—power of consumer choice', 15 July 2011.

In its 2011 *Electricity statement of opportunities* report, AEMO identified 142 MW of capacity that was 'very likely' to be available across the NEM through demand side participation over the 2011–12 summer. It forecast annual growth in demand side participation of 3.2 per cent (for New South Wales) to 5.4 per cent (for Victoria and South Australia).[15]

1.8 Reliability of supply

Reliability refers to the continuity of electricity supply to customers. The 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. It aims for the reliability standard to be met in each financial year, for each region and for the NEM as a whole.

The current reliability standard is that no more than 0.002 per cent of customer demand in each NEM region should be unserved by generation capacity, 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). The standard is equivalent to an annual system-wide outage of 7 minutes at times of peak demand.

1.8.1 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 is $12 500 per MWh.
- 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.

In June 2011 the AEMC finalised a Rule change that provides for the market price cap and cumulative price threshold to be adjusted each year, from 1 July 2012, in line with movements in the consumer price index. The Rule change also provided for a comprehensive review of the reliability standard and settings to occur every four years.

Safety net mechanisms allow AEMO to 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.

The reliability panel finalised a review of the RERT mechanism in April 2011, finding the mechanism was of limited effectiveness and not required to ensure reliability of supply. It recommended the mechanism be closed on 30 June 2013. It also recommended the AEMC review other mechanisms for delivering

15 AEMO, *2011 electricity statement of opportunities for the National Electricity Market*, 2011, pp. 3–50.

capacity and how the NEM's risk allocation framework may affect the reliability of supply. In September 2011 the AEMC commenced a Rule change consultation to implement these recommendations.

1.8.2 Reliability performance

The reliability panel annually reports on the generation sector's performance against the reliability standard and minimum reserve levels set by AEMO. 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 2011. The most recent instance, and the only exceedance of the 0.002 per cent reliability standard, 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.[16]

AEMO was not required to issue any directions in 2010–11 to manage local power system issues (compared with seven directions in 2009–10 and 18 in 2008–09).

1.8.3 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. Such interruptions may involve several credible events occurring simultaneously or in a chain reaction—for example, several generating units may fail or 'trip' at the same time, or a transmission fault may occur at the same time as a generator trips. When such events occur, the market operator may need to interrupt customer supply to prevent a power system collapse.

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

1.8.4 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.

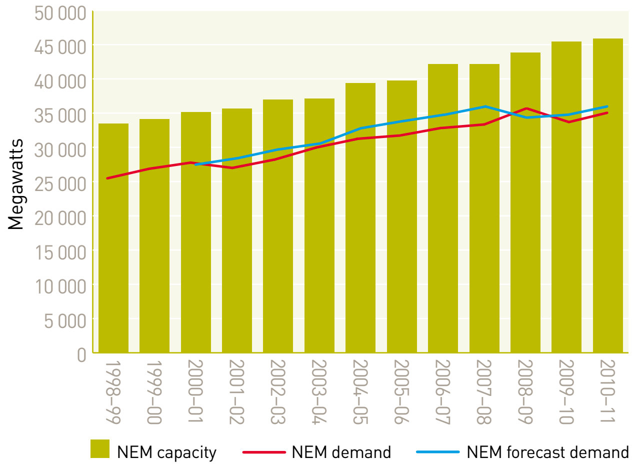
Seasonal factors (for example, summer peaks in air conditioning loads) create a need for peaking generation to cope with periods of extreme demand. The NEM price cap of $12 500 per MWh is necessarily high to encourage investment in peaking plant, which is expensive to run and operates sporadically. Over 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 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.

16 AEMC Reliability Panel, *Reliability standard and reliability settings review, final report,* 2010, p. 11.

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 an average diversity factor.

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.

1.8.5 Reliability outlook

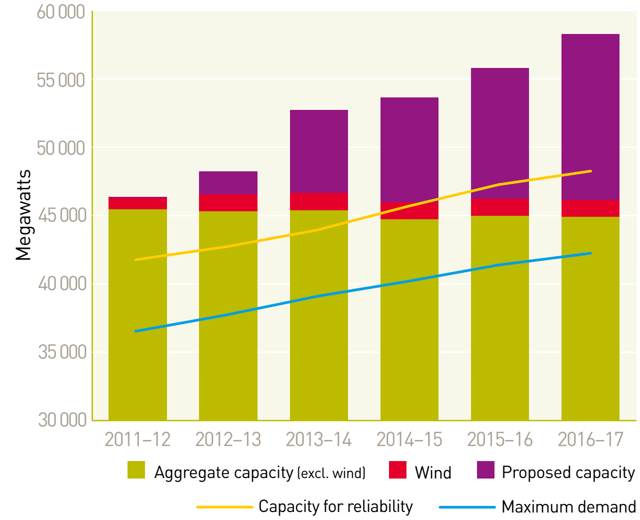
The relationship between future demand and generation capacity will determine electricity prices and the reliability of the power system. Figure 1.17 charts forecast peak demand in the NEM against installed, committed and proposed generation capacity. It indicates the amount of capacity that AEMO predicts will 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.

The required timing of new capacity in particular regions may vary. AEMO's 2011 *Power system adequacy* report found the power system, under expected demand and capacity scenarios, should have sufficient capacity to meet forecast peak demand plus minimum reserve

Figure 1.17

Electricity demand and supply outlook to 2016–17



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 5 per cent in South Australia, 7.7 per cent in Victoria and 9.2 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 92 per cent diversity 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, *Electricity statement of opportunities for the National Electricity Market*, 2011.

levels for reliability in every NEM region over the two year period to June 2013. Accordingly, AEMO did not expect to invoke its reliability and emergency reserve trader tender process in any region. It identified concerns about the adequacy of frequency control during periods of high wind generation, and is working on this issue.

A sensitivity analysis found an unexpected NEM-wide withdrawal of 1000 MW of generation could lead to Queensland experiencing unserved energy in exceedance of the 0.002 per cent reliability standard in 2012–13; but that other regions would continue to meet the standard.

According to the report, the Australian Government's Clean Energy Future Plan (including carbon pricing and financial assistance to emission intensive generators) is unlikely to impact on power supply reliability or security over the period to 30 June 2013. The reasons are the timing of the policy measures, and initiatives to offset potential reliability impacts.[17]

AEMO's longer term market review found that Queensland, assuming medium economic growth, would be the first region in the NEM to require new generation investment (by 2013–14) beyond that already committed.[18] While Queensland has had substantial new investment over the past decade, the region's economic growth is projected to rise, given an expansion of mining activity in central Queensland and flood related reconstruction. Coal seam gas developments, and growth in supporting infrastructure and services, are also expected to contribute to demand growth.

AEMO projected Victoria and South Australia would require new investment beyond committed capacity by 2014–15 (a year earlier than forecast in 2010). New South Wales would require new investment by 2018–19 (two years later than forecast in 2010). These adjustments largely reflect revised economic growth projections. The New South Wales forecast was also affected by the impact of energy efficiency policies.

AEMO expected Tasmania to have adequate capacity over the 10 year outlook period. The assessment did not account for potential reserve shortfalls due to energy limitations (when there is insufficient fuel to use available capacity). Tasmania's dependence on hydroelectric generation can periodically lead to energy limitations, as in the drought from 2007 to 2009. Basslink, as well as local gas fired and wind generation, safeguarded against supply shortfalls in that period.

AEMO noted climate change policies and the emergence of new technologies would be significant investment drivers over the next few years. In particular, the national RET scheme and carbon pricing would likely shift the generation mix towards less carbon intensive generation sources. AEMO considered wind generation was likely to be the main technology for new developments in the short term. 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.[19]

1.9 Compliance monitoring and enforcement

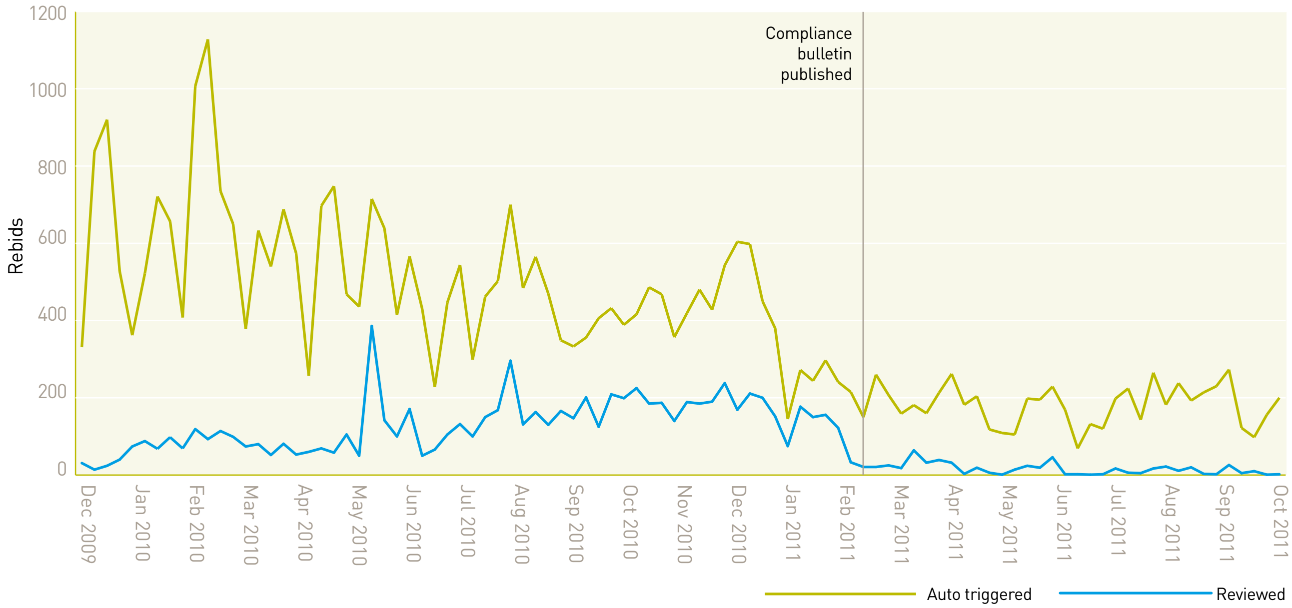
The AER monitors the wholesale electricity market to ensure compliance with the Law and Rules governing the NEM and, where appropriate, takes enforcement action for breaches. It also monitors the market to detect issues such as market manipulation. The AER draws on its monitoring activity to report on the NEM and make submissions and other contributions to the Standing Council on Energy and Resources (formerly the Ministerial Council on Energy), AEMC, and other bodies.

The AER's compliance and enforcement activity includes:

> market monitoring to identify compliance issues.
> targeted compliance reviews and audits of provisions —both randomly and in response to market events or inquiries that raise concerns—to identify how participants comply with their obligations.
> audits of compliance programs for technical performance standards.
> forums and other meetings with industry participants to discuss compliance.
> publishing quarterly wholesale market compliance reports (outlining the AER's compliance activity) and compliance bulletins (when additional guidance on the Rules is warranted).

17 AEMO, *Power system adequacy*, 2011.
18 AEMO, *Electricity statement of opportunities for the National Electricity Market*, 2011.
19 AEMO, *Electricity statement of opportunities for the National Electricity Market*, 2011, pp. ix and 2–15.

Figure 1.18
Rebids auto-triggered and reviewed by the AER, weekly



Source: AER

The AER considers a number of factors when deciding whether to take enforcement action and which action to adopt. It aims for a proportionate enforcement response taking into account the impact of the breach, its circumstances, and the participant's compliance programs and compliance culture.

1.9.1 Rebidding

A key monitoring project in 2011 focused on generators' provision of accurate rebidding information. Scheduled generators in the NEM submit offers for each of the 48 trading intervals in a day. The initial offers, submitted before the trading day, can be varied through rebidding at any time up to dispatch.

The AER launched a new rebidding enforcement strategy in March 2011 to encourage the provision of more accurate and timely bidding information to the market. Under the strategy, the AER issues two warnings to generators that submit offer and/or rebid information that does not satisfy the Electricity Rules. A third occurrence within six months may lead to the issue of an infringement notice.

Since the strategy was launched, the number of rebids flagged by the AER's internal compliance system and requiring further review has fallen significantly (figure 1.18). Additionally, during the first six months of the strategy's operation, generators contacted the AER on 35 occasions to declare erroneous (or questionable) rebids. This appears to reflect a stronger focus on the quality of rebids and a clearer commitment to compliance within corporate trading teams.

Stanwell compliance with clause 3.8.22A

On another rebidding matter, the Federal Court on 30 August 2011 dismissed the AER's case against Stanwell Corporation (a Queensland generator) for alleged contraventions of the 'good faith' provision in the 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.

In February 2008 Stanwell controlled more than a quarter of Queensland's registered generation capacity. On 22 and 23 February the spot price for electricity in Queensland exceeded $5000 per MWh on 14 occasions.

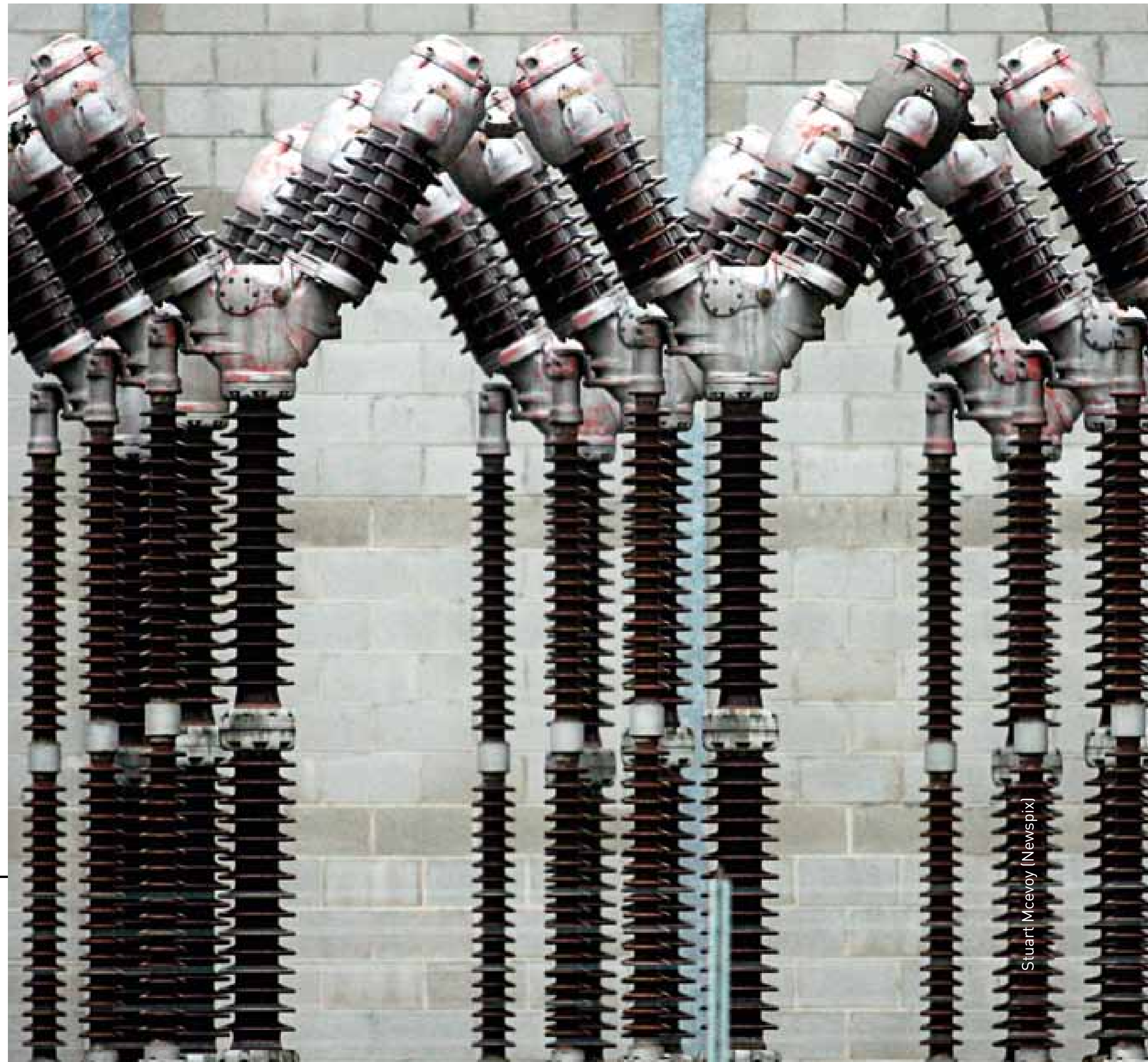
Stanwell made 92 rebids over those trading days. More than 50 rebids were made within 15 minutes of dispatch, with around 40 rebids affecting the next 5 minute dispatch interval. The AER alleged Stanwell's reasons for eight rebids failed to identify a change in material conditions and circumstances. It sought orders that included declarations, civil penalties, a compliance program and costs. Justice Dowsett found the rebids did not contravene the Rules.

Generators must offer to supply energy into the market in good faith so AEMO can coordinate efficient dispatch to meet demand. The Rules allow generators to rebid their offers only in response to a change in the material conditions and circumstances on which the offer was based.

The litigation marked the first judicial test of the good faith provision, and the first occasion on which any provision of the Rules has been brought before the courts. Previous AER investigations into compliance with the good faith provision produced insufficient evidence to pursue the matters. Those investigations typically centred on rebids made shortly before dispatch for reasons of financial optimisation rather than technical necessity.

The policy objective of the good faith provision, when introduced in 2002, was to promote firm offers and rebids, and improve the quality of forecast information necessary for an efficient spot market. In particular, the firmness of market offers and rebids affects the quality of forecasts that market participants rely on when making decisions. Rebids submitted shortly before dispatch affect the credibility of these forecasts and limit opportunities for competitive supply and/or demand side response.

The Federal Court's decision calls into question the effectiveness of the good faith provision in achieving these objectives. Together with the AER's previous investigations when insufficient evidence was found, it suggests the provision's effectiveness may need review.



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

The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected transmission 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. There are five state based transmission networks, with cross-border interconnectors linking the grid (table 2.1).

The NEM has 13 major electricity distribution networks (table 2.2). Queensland, New South Wales and Victoria each have multiple networks that are monopoly providers within designated areas. The ACT, South Australia and Tasmania each have 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—18 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 distribution network (ActewAGL) has joint government and private ownership. All networks (transmission and distribution) in Queensland, New South Wales and Tasmania are government owned.

Aside from state and territory governments, the principal network owners at June 2011 were:

- *Cheung Kong Infrastructure* and *Power Assets Holdings*, which jointly 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*, which 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 or have equity in a number of gas networks (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) plans and directs network augmentation. AEMO also buys bulk network services from SP AusNet for sale to customers.

In some jurisdictions, ownership links exist between electricity networks and other segments of the electricity sector. In Tasmania and the ACT,[1] 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 the state owned Ergon Energy continues to provide both distribution and retail services.

1 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), 2009–10	MAXIMUM DEMAND (MW), 2009–10	ASSET BASE (2010 $ MILLION)[1]	INVESTMENT—CURRENT PERIOD (2010 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS								
Powerlink	Qld	13 569	49 593	8 891	4 100	2 642	1 July 2007 – 30 June 2012	Queensland Government
TransGrid	NSW	12 656	72 814	14 051	4 346	2 541	1 July 2009 – 30 June 2014	New South Wales Government
SP AusNet	Vic	6 553	50 925	9 858	2 291	806	1 Apr 2008 – 30 Mar 2014	Publicly listed company (Singapore Power International 51%)
ElectraNet	SA	5 591	13 266	3 408	1 372	816	1 July 2008 – 30 June 2013	Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust
Transend	Tas	3 469	11 658	2 366	981	625	1 July 2009 – 30 June 2014	Tasmanian Government
NEM TOTALS		**41 838**	**198 256**		**13 090**	**7 430**		
INTERCONNECTORS[3]								
Directlink (Terranora)	Qld–NSW	63		180	136		1 July 2005 – 30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220	124		1 Oct 2003 – 30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375			884[4]		Unregulated	Publicly listed 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 2010 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2010 dollars.
3. 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.
4. 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 2009–10*; regulatory determinations by the AER.

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 the network when it was first regulated, plus subsequent new investment, less depreciation. 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 $44 billion—more than three times the valuation for transmission infrastructure (around $13 billion).

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW), (2009–10)	ASSET BASE (2010 $ MILLION)[1]	INVESTMENT —CURRENT PERIOD (2010 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 298 790	53 256	4 817	7 867	5 783	1 Jul 2010 – 30 Jun 2015	Qld Government
Ergon Energy	680 095	146 000	2 608	7 149	5 113	1 Jul 2010 – 30 Jun 2015	Qld Government
NEW SOUTH WALES AND ACT							
AusGrid[3,4]	1 605 635	49 442	5 609	8 688	8 579	1 Jul 2009 – 30 Jun 2014	NSW Government
Endeavour Energy[3]	866 724	33 817	3 697	3 803	3 052	1 Jul 2009 – 30 Jun 2014	NSW Government
Essential Energy[3]	801 913	190 844	2 239	4 451	4 277	1 Jul 2009 – 30 Jun 2014	NSW Government
ActewAGL	157 635	4 858	604	617	314	1 Jul 2009 – 30 Jun 2014	ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International) 50%
VICTORIA							
Powercor	706 577	84 027	2 362	2 189	1 550	1 Jan 2011 – 31 Dec 2015	Cheung Kong Infrastructure/ Power Assets Holdings 51%; Spark Infrastructure 49%
SP AusNet	623 307	48 259	1 774	2 052	1 465	1 Jan 2011 – 31 Dec 2015	SP AusNet (listed company; Singapore Power International 51%)
United Energy	634 508	12 628	2 016	1 365	877	1 Jan 2011 – 31 Dec 2015	Jemena (Singapore Power International) 34%; DUET Group 66%
CitiPower	308 203	6 506	1 354	1 273	821	1 Jan 2011 – 31 Dec 2015	Cheung Kong Infrastructure/ Power Assets Holdings 51%; Spark Infrastructure 49
Jemena	309 505	5 971	958	748	468	1 Jan 2011 – 31 Dec 2015	Jemena (Singapore Power International)
SOUTH AUSTRALIA							
ETSA Utilities	817 300	87 220	2 981	2 772	2 154	1 Jan 2011 – 31 Dec 2015	Cheung Kong Infrastructure/ Power Assets Holdings 51%; Spark Infrastructure 49%
TASMANIA							
Aurora Energy	271 750	24 385	1 042	1 105	650	1 Jan 2008 – 30 Jun 2012	Tas Government
NEM TOTALS	**9 081 942**	**747 213**		**44 079**	**35 103**		

MW, megawatts.

1. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2010 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2010 dollars. The data include capital contributions, which can be significant—for example, 10–20 per cent of investment in Victoria and over 20 per cent in South Australia—but do not form part of the regulated asset base for the network.
3. Following the privatisation of energy retail assets in New South Wales, the network divisions of EnergyAustralia, Integral Energy and Country Energy were rebranded as AusGrid, Endeavour Energy and Essential Energy respectively.
4. AusGrid's distribution network includes 962 kilometres of transmission assets that are treated as distribution assets for the purpose of economic regulation and performance assessment.

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), AusGrid, Essential Energy and Endeavour Energy.

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining average costs as output increases. This means network services in a particular geographic area can be most efficiently served by a single supplier, 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

The National Electricity Law lays the foundation for the regulatory framework governing electricity networks. In particular, it sets out the National Electricity Objective: to promote efficient investment in, and operation of, electricity services in the long term interest of consumers. It also sets out revenue and pricing principles, including that network businesses should have a reasonable opportunity to recover at least efficient costs.

Regulated electricity network businesses must periodically apply to the AER to assess their revenue requirements (typically, every five years). Chapters 6 and 6A of the National Electricity Rules lay out the framework that the AER must apply in undertaking this role for distribution and transmission networks respectively. The AER's *State of the energy market 2009* report (sections 5.3 and 6.3) provides an overview of the regulatory process.

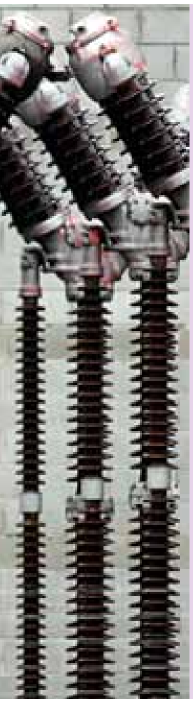
While the regulatory frameworks for transmission and distribution are similar, there are differences. In transmission, the AER must determine a cap on the maximum revenue that a network can earn during a regulatory period. The range of available control mechanisms is wider in distribution, but generally involves setting a ceiling on the revenues or prices that a network can earn or charge during a period. The available mechanisms 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 or maximum revenue caps*, which set a ceiling on revenue that may be recovered during a regulatory period—used for the Queensland and ACT networks, and to be used for the Tasmanian network from 1 July 2012.

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 largest component is the return on capital, which may account for up to two-thirds of revenues. The size of a network's RAB (and projected investment) and its weighted average cost of capital (the rate of return necessary to cover a commercial return on equity and efficient debt costs) both influence the return on capital. An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

In 2011 the AER reviewed the regulatory framework under chapters 6 and 6A of the Rules to identify whether improvements could be made to better promote efficient investment in, and use of, energy services for the long term interests of consumers. It highlighted deficiencies in the framework, and in September 2011 the AER proposed Rule changes to address these issues (box 2.1 and section A2 of the *Market overview*).



Box 2.1 AER Rule change proposals on regulatory framework

The substantial price impact of some recent determinations led the AER in 2011 to conduct an internal review of the framework in the national energy Rules for setting energy network charges. While the review found many aspects of the framework operate well, several features were leading to consumers paying more than necessary for energy services.

Following its review, the AER in September 2011 submitted Rule change proposals to the Australian Energy Market Commission (AEMC) to address these issues.[2] Section A2 of the *Market overview* discusses the proposals which, in summary, would:

> allow the AER to make holistic and independent assessments of a network's efficient expenditure needs, based on all available information, evidence and data—including benchmarking analysis
> remove incentives for network overinvestment by allowing only 60 per cent of any spending above approved forecasts to be added to a network's asset base
> introduce a common approach to setting the cost of capital for all electricity and gas network businesses; and allow the AER to set cost of capital parameters that reflect current commercial practices
> improve consultation arrangements with stakeholders.

The AEMC began consulting on the proposals in October 2011. It expects to release a draft determination by July 2012, and a final determination by October 2012.

2.2.2 Regulatory timelines and recent AER determinations

Figure 2.2 shows the regulatory timelines for electricity networks in each jurisdiction. In 2011 the AER commenced reviews for Powerlink (Queensland transmission) and Aurora Energy (Tasmania distribution) for the regulatory periods commencing 1 July 2012. It published draft determinations in November 2011.

Table 1 in the *Market overview* provides summary details of AER determinations made since April 2009.

2.2.3 Merits review by the Australian Competition Tribunal

Under the National Electricity Law, network businesses can apply to the Australian Competition Tribunal for review of an AER determination, or a part of it. Network businesses have typically sought review of specific matters in a determination rather than the whole determination.

To have an AER decision overruled, the network business must demonstrate the AER either:

> made an error of fact that was material to the AER's decision
> incorrectly exercised its discretion, having regard to all the circumstances
> made an unreasonable decision having regard to all the circumstances.

If the tribunal finds the AER erred, it will substitute its own decision or remit the matter back to the AER for consideration.

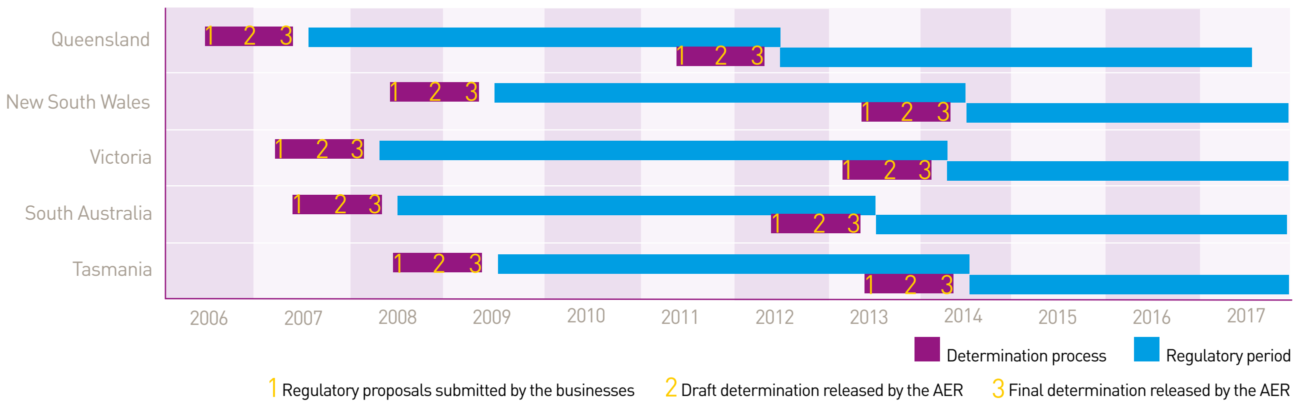
Between June 2008 and October 2011 network businesses sought review of 16 AER determinations on electricity networks—three reviews in transmission and 13 in distribution.[3] Five reviews were continuing in October 2011. The decisions on these reviews have

2 AER, *Rule change proposal, Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules*, September 2011 (available on the AER and AEMC websites).

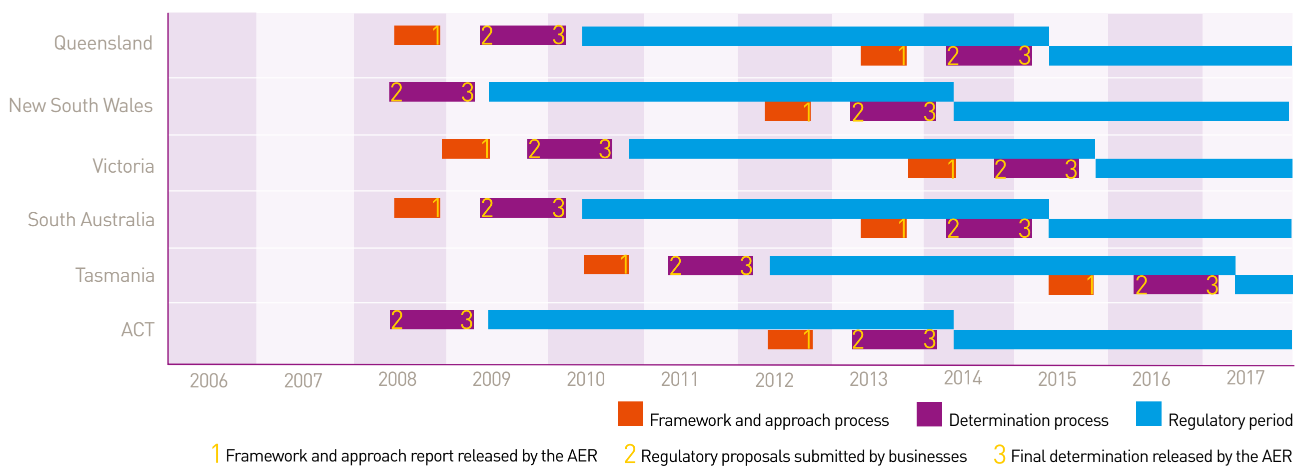
3 Two of the distribution reviews related to charges for advancing metering infrastructure (smart meters) in Victoria. In addition, two determinations have been subject to judicial review under the *Administrative Decisions (Judicial Review) Act 1977* (Cth). At October 2011 the judgment on one matter was reserved.

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.

increased allowable electricity network revenues by around $2.9 billion, with substantial flow-on impacts on retail energy charges. The two most significant contributors to this increase were tribunal decisions on:

> the averaging period for the risk free rate (an input into the weighted average cost of capital)—reviewed for five networks, with a combined revenue impact of $2 billion
> the value adopted for tax imputation credits (gamma), which affects the estimated cost of corporate income tax—reviewed for three networks, with a combined revenue impact of $780 million.

In 2011 the tribunal reviewed AER determinations (made in October 2010) on Victoria's five electricity distribution networks. The matters on which the businesses sought review varied. All sought review of gamma and the debt risk premium that is applied to calculate the cost of capital. Other matters included aspects of approved capital and operating expenditure; the method of escalating the asset base over the regulatory period; and the application of pass through provisions. The tribunal is expected to hand down its decisions in January 2012.

The tribunal also handed down decisions in 2011 on reviews for Energex and Ergon Energy (Queensland) and ETSA Utilities (South Australia). The decisions increased the networks' allowable revenues by around $850 million (a 5 per cent increase in total revenue over the regulatory period). The most significant part of the decision was to lower the value for gamma from 0.65 to 0.25. This change raised the networks' estimated cost of corporate income tax and, consequently, their allowable revenues.

Following the decisions, the Queensland Government intervened to prevent Energex and Ergon Energy from recovering the additional revenue allowance determined by the tribunal. This intervention amounted to a $93 million reduction in the combined revenue forecasts of the businesses in 2011–12 alone.[4]

Table 2 in the *Market overview* summarises outcomes of the tribunal's reviews of AER determinations since 2008.

2.3 Electricity network 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 at almost $58 billion over the current cycle, comprising over $12 billion for transmission and $46 billion for distribution. Average revenues are forecast to rise by around 43 per cent (in real terms) above levels in the previous regulatory periods. The main drivers are higher capital expenditure (investment) and operating costs (discussed in sections 2.4 and 2.5), and higher capital financing costs.

The cost of capital estimates used to determine revenue allowances in the current regulatory periods were higher for all network business than in previous periods. The increase ranged from less than 0.1 percentage points for Powerlink (Queensland transmission) to over 2.6 percentage points for ETSA Utilities (South Australia distribution).

The cost of capital comprises several parameters. The primary parameter underpinning the increases is the debt risk premium, which reflects the cost of borrowing for a business based on its risk of default. Changes and fluctuations in global financial markets have reduced liquidity in debt markets and increased perceptions of risk, pushing up the cost of borrowing. Changes in the risk free rate also affected the determinations.

The tribunal's decision to reduce the value adopted for tax imputation credits (gamma) for the Queensland and South Australian distribution networks also increased revenue allowances (section 2.2.3).

2.4 Electricity network investment

New investment in infrastructure is needed to maintain or improve network performance over time. Investment includes network augmentations (expansions) to meet rising demand and the replacement of ageing assets.

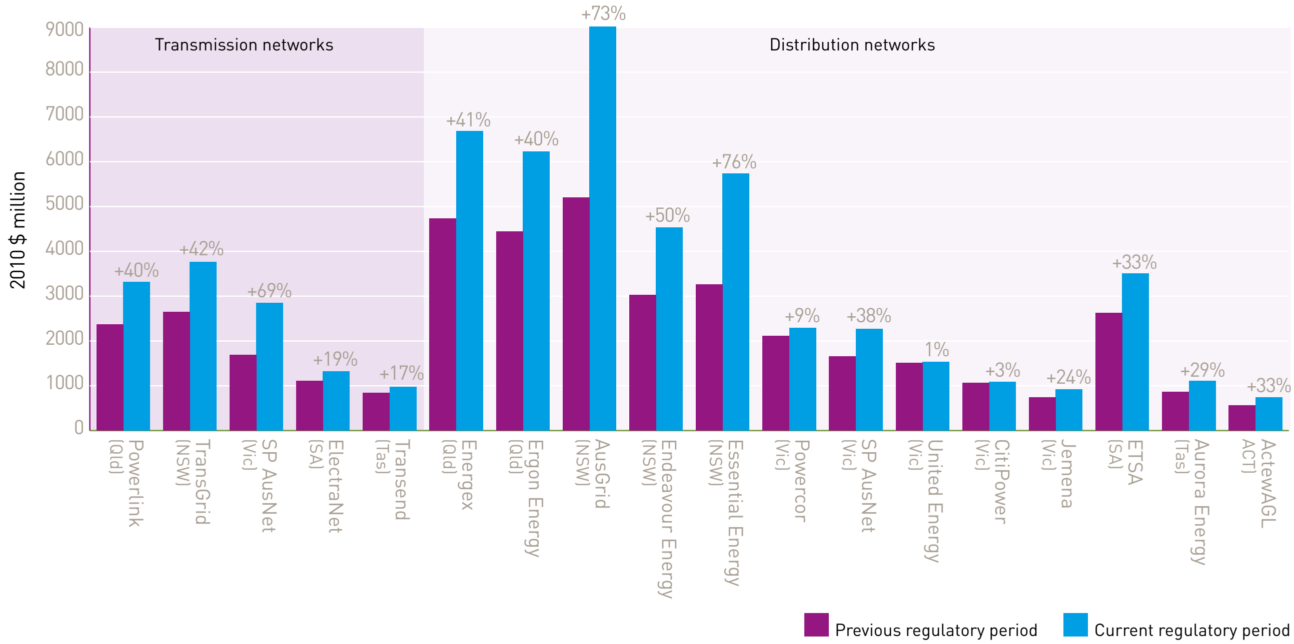
The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can also approve contingent projects—large investment projects that are foreseen at the time of a determination,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

While the regulatory process approves a pool of funds for capital expenditure, each individual project must be assessed for whether it is the most efficient way of meeting an identified need, or whether an alternative (such as investment in generation capacity) would be more efficient.

There are separate assessment requirements 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.[5]

4 QCA, *Benchmark retail cost index for electricity: 2011–12, final decision*, 2011.
5 AER, *Regulatory test for network augmentation, version 3*, 2007.

Figure 2.3
Electricity network revenues



Notes:

Current regulatory period revenues are forecasts in regulatory determinations.

All data are converted to June 2010 dollars.

The current period revenue allowances for Energex and Ergon Energy are as determined by the Australian Competition Tribunal in May 2011. The Queensland Government prevented Energex and Ergon Energy from recovering $270 million and $220 million respectively of these allowances.

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

A new regulatory investment test for *transmission* (RIT-T) took effect on 1 August 2010.[6] Transmission projects are now assessed under a framework that is more comprehensive and applies to a wider range of investment projects than previously. It also gives more prescription of the market benefits and costs that the analysis can consider.

Two RIT-T processes began in the first year that the test was in place:

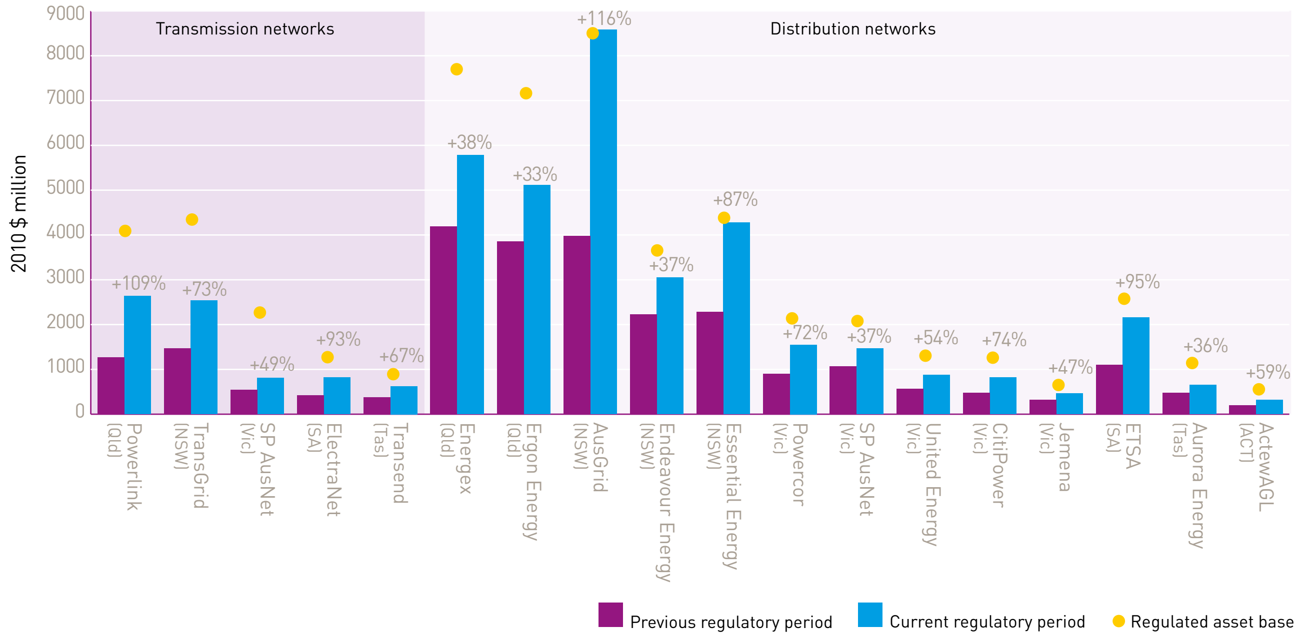
> TransGrid began consulting on a network upgrade around the Gunnedah, Narrabri and Moree areas of New South Wales.
> SP AusNet (transmission) and CitiPower (distribution) initiated joint consultation on an upgrade to the Brunswick Terminal Station in Victoria.

In September 2011 the Australian Energy Market Commission (AEMC) began consulting on a Rule change to introduce a test similar to the RIT-T for distribution.[7] This RIT-D test will apply to projects over $5 million (but with scope for the AER to conduct audits on projects under $5 million to confirm non-network options were considered). The proposal includes a new dispute resolution process, and requirements on distribution businesses to release annual planning reports and maintain a demand side engagement strategy.

6 AER, *Regulatory investment test for transmission*, 2010.

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

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.

Investment data include capital contributions and do not include adjustments for disposals.

AusGrid's distribution network includes 962 kilometres of transmission assets.

All data are converted to June 2010 dollars.

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

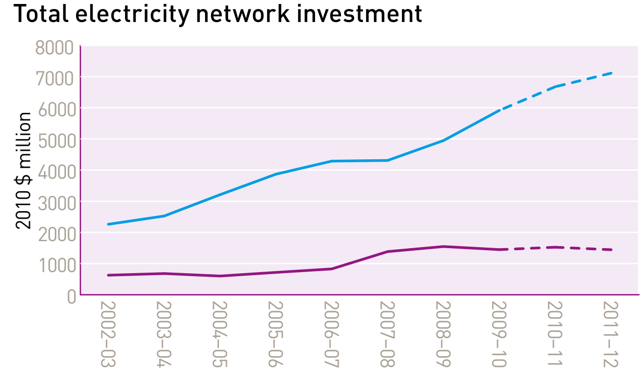
2.4.1 Investment trends

Figure 2.4 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous 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 $35 billion for distribution networks. These forecasts represent an increase on investment in the previous regulatory periods of around 82 per cent in transmission and 62 per cent in distribution (in real terms).

On an annual basis, transmission investment in the NEM totalled around $1.4 billion in 2009–10 and was forecast to plateau around this level to 2011–12 (figure 2.5). Distribution investment was expected to rise from around $5 billion in 2009–10 to $6 billion in 2011–12.

Figure 2.5
Total electricity network investment



Notes:

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

Transmission investment excludes private interconnectors.

All data are converted to June 2010 dollars.

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

The factors driving higher levels of investment vary across networks and depend on a network's age and technology, load characteristics, the demand for new connections, and licensing, reliability and safety requirements. Differences in operating environments can result in significant variations in capital investment requirements (figure 2.4).

Recent AER determinations reflected that:

> the *Queensland* networks have capital requirements associated with population growth, new connections and industrial demand, as well as rising demand per customer. The distribution networks are also obliged to improve performance in response to stricter reliability standards.

> the *New South Wales* networks have ageing assets, requiring significant replacement and reinforcement capital expenditure. The networks have also experienced growth in peak demand.

> the *Victorian* distributors operate mostly mature and comparatively reliable networks. Capital expenditure is required to replace ageing infrastructure, address Victoria's new bushfire safety standards, and maintain reliability in the face of rising costs and demand.

> the *South Australian* networks require investment to meet rising load growth and peak demand driven by the use of air conditioners during summer heatwaves. The networks also need to address reliability risks from ageing assets and new reliability standards for the Adelaide central business district (involving upgrades to transmission and distribution systems).

> the *ACT* networks require increased capital investment, but not to the extent of other jurisdictions. As in New South Wales, the ACT distribution network requires the replacement of ageing network assets. The local network business, ActewAGL, faces a changing regulatory environment, with new legal obligations on safety, security, reliability and environmental issues.

Other factors affecting network investment include changes to system operation due to climate change policies and the introduction of smart meters and grids.

In contrast to the mainland jurisdictions, Tasmania's distribution network (Aurora Energy) proposed capital investment requirements for the regulatory period beginning 1 July 2012 that are below levels in the current period. While at October 2011 the AER had not completed its review of the proposal, Aurora Energy committed to avoiding unnecessary customer price increases, while ensuring a safe and reliable supply of electricity. To do so, it aims to drive cost reductions from current service delivery methods, together with the selective deployment of innovative technologies.

Aurora's proposal recognises that significant capital and operating expenditure in the current period has contributed to a strong and resilient network. This, coupled with subdued economic growth forecasts in Tasmania, would limit network expenditure requirements.[8]

2.5 Operating and maintenance expenditure

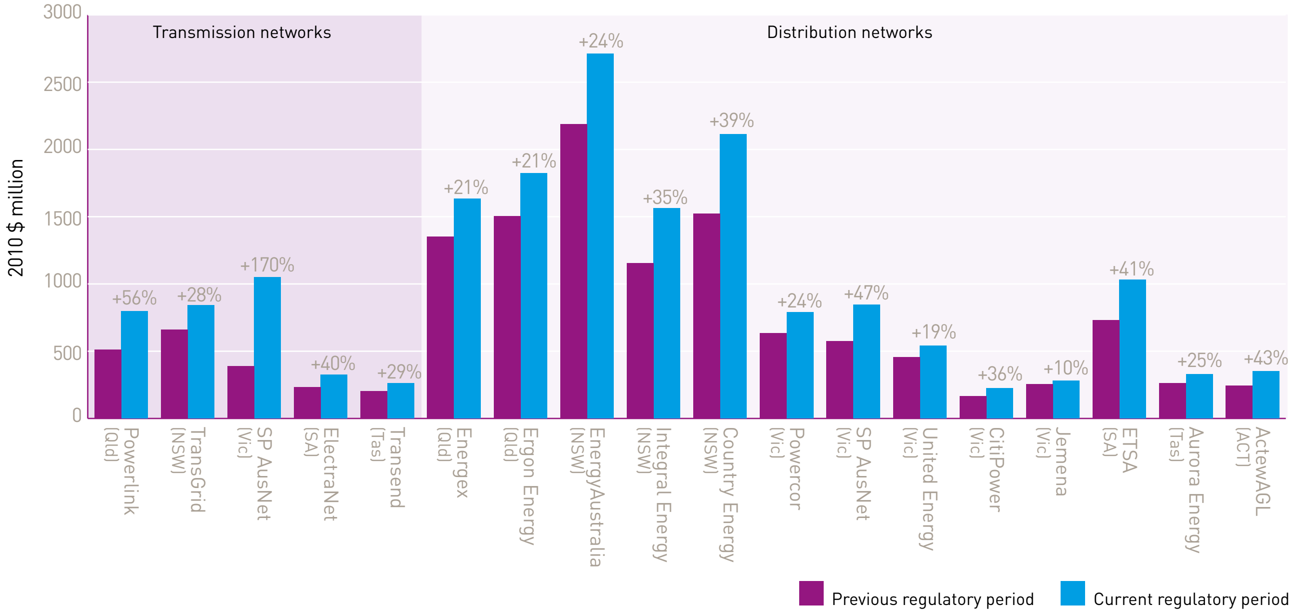
The AER determines allowances for each network to cover efficient operating and maintenance expenditure. The needs of a network depend on load densities, the scale and condition of the network, geographic factors and reliability requirements.

Figure 2.6 illustrates operating expenditure allowances for electricity networks in the current five year regulatory periods compared with previous periods. In the current cycle, transmission businesses will each spend, on average, around $130 million per year on operating and maintenance costs. In distribution, operating costs per business are forecast at around $220 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 64 per cent in transmission and 29 per cent in distribution over the current regulatory periods. Differences in the networks' operating environments (section 2.4.1) resulted in significant variations in expenditure allowances (figure 2.6).

8 Aurora Energy, *Energy to the people: Aurora Energy regulatory proposal 2012–2017*, 2011.

Figure 2.6
Operating expenditure of electricity networks



Notes:

Current regulatory period expenditure reflects forecasts in regulatory determinations.

The increase in SP AusNet's transmission operating expenditure in the current period was partly due to the introduction of an easement land tax mid way through the previous period (around $80 million per year).

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

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 2010 Victorian 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.

2.5.1 Efficiency benefit sharing schemes

The AER operates a national incentive scheme for businesses to make efficient operating and maintenance expenditure in running their networks. The scheme allows 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.

The forecast level of expenditure determines the base level for calculation of efficiency gains or losses, after certain adjustments. Under the incentive scheme, a business retains around 30 per cent of efficiency gains or losses against the forecast, and passes on the remaining 70 per cent to customers through price adjustments.

The incentive scheme applies to all transmission and distribution networks, except the Tasmanian distribution network (Aurora)—to which it will apply from 1 July 2012. In June 2011 the AEMC began consulting on a proposal to amend the transmission scheme by excluding expenditure on non-network alternatives from the performance assessment, thus removing a disincentive to undertake this type of expenditure. The distribution scheme already excludes this expenditure.

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, animals, vehicle impacts or vandalism.

While a serious transmission network failure may require the power system operator to disconnect some customers (known as load shedding), over 90 per cent of power outages are caused by reliability issues in distribution networks.[9] 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

Transmission service issues relate principally to reliability and network congestion. This section considers reliability, while section 2.7 considers 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.

State and territory agencies determine transmission reliability standards. The AEMC in 2008 recommended to the Standing Council on Energy and Resources (SCER, formerly the Ministerial Council on Energy) that a national framework for transmission reliability standards be introduced to achieve a more consistent national approach. The framework would economically derive standards using a customer value of reliability or a similar measure. Standards would be determined on a jurisdictional basis by a body independent of transmission network owners. A national reference template would provide a basis for comparing the standards in each jurisdiction, and jurisdictions would need to justify any divergence from the template. The AEMC updated its recommendations in December 2010. At October 2011 the SCER was finalising its policy position on the review.

Energy Supply Association of Australia data indicate the NEM jurisdictions have generally achieved high rates of transmission reliability. In 2009–10 total unsupplied energy was higher than in the previous year in all jurisdictions except Victoria (which had unusually high levels of unsupplied energy in 2008–09). Unsupplied energy in Tasmania totalled 11 minutes. This followed a period of improved reliability, with less than 2 minutes of unsupplied energy in the previous year. Total unsupplied energy was around 3 minutes in South Australia, and 1 minute in New South Wales and Victoria.

The AER's national service target performance incentive scheme provides incentives for transmission businesses to maintain or improve 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).

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

Stuart Mcevoy (Newspix)

Table 2.3 S factor values

	2005	2006	2007	2008		2009		2010
Powerlink			0.82		0.53		0.20	0.65
TransGrid	0.70	0.63	−0.12		0.31	0.20	−0.30	−0.24
AusGrid	0.67	0.39	−0.14		0.72		0.37	
SP AusNet	0.09	−0.17	0.06	0.15	0.82		0.50	0.58
ElectraNet	0.71	0.59	0.28	0.29	−0.40		0.60	0.00
Transend	0.19	0.06	0.56		0.85	0.90	0.10	0.11
Directlink		−0.54	−0.62		−1.00		−1.00	−1.00
Murraylink		0.21	−0.32		0.69		0.90	1.00

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. AusGrid data for 2009 are for the six months to June; AusGrid moved to the distribution performance framework on 1 July 2009.

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

Source: AER, *Transmission network service providers: electricity performance report for 2009–2010*, 2011.

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 financial penalties in 2009 and 2010 were TransGrid and Directlink.

The AER commenced a review of the incentive scheme in October 2011. Any amendments will be applied to networks in their next regulatory period.

2.6.2 Distribution network reliability

The capital intensive nature of distribution networks makes it expensive to build in high levels of redundancy (spare capacity) to improve reliability. In addition, the impact of a distribution outage tends to be localised to part of the network, compared with the potentially widespread impact of a generation or transmission outage. These factors help explain why reliability standards for distribution networks are less stringent than those for generation and transmission, and why distribution outages account for such a high proportion of electricity outages in the NEM.

State and territory agencies determine distribution reliability standards. The trade-off between reliability and cost means government decisions to increase reliability standards may require substantial new investment, with significant impacts on customer bills. The SCER in July 2011 noted the large contribution of distribution network investment to retail electricity prices, and directed the AEMC to review the frameworks for setting distribution reliability standards. This review follows an AEMC review of transmission reliability standards, completed in 2010 (section 2.6.1).

In November 2011 the AEMC released an issues paper on reliability outcomes in New South Wales. A broader review of the approaches used to determine reliability outcomes across the NEM will commence in 2012.

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

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	2009–10
SAIDI (MINUTES)										
Queensland	314	275	265	434	283	351	233	264	365	366
New South Wales	175	324	193	279	218	191	211	180	211	137
Victoria	152	151	161	132	165	165	197	228	255	170
South Australia	164	147	184	164	169	199	184	150	161	153
Tasmania	265	198	214	324	314	292	256	304	252	211
NEM weighted average	**198**	**245**	**199**	**258**	**211**	**221**	**211**	**213**	254	**200**
SAIFI (NUMBER OF INTERRUPTIONS)										
Queensland	3.0	2.8	2.7	3.4	2.7	3.1	2.1	2.4	2.9	2.7
New South Wales	2.5	2.6	1.4	1.6	1.6	1.8	1.9	1.7	1.8	1.5
Victoria	2.0	2.0	2.2	1.9	1.8	1.9	2.1	1.7	2.5	1.7
South Australia	1.7	1.6	1.8	1.7	1.7	1.9	1.8	1.5	1.5	1.9
Tasmania	2.8	2.3	2.4	3.1	3.1	2.9	2.6	2.6	1.9	1.8
NEM weighted average	**2.4**	**2.4**	**2.0**	**2.2**	**1.9**	**2.1**	**2.0**	**1.9**	2.2	**1.8**

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. Queensland data for 2009–10 are for the year ended 31 March 2010.

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

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* presents SAIDI data in graphical form (figure 2).

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. Geographic conditions and historical investment also differ across the networks.

Noting these caveats, the SAIDI data indicate electricity networks in the NEM 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.

In 2009–10 the average duration of outages per customer fell in all jurisdictions other than Queensland. Victoria and New South Wales experienced the greatest improvement, largely driven by benign weather. Reliability works programs and network capital expenditure may have contributed to the improved outcomes in New South Wales.

Queensland recorded a similar volume of outages in 2008–09 and 2009–10. Energex recorded a large fall in the average duration of outages on its network. But heavy rains, floods and Cyclone Ului contributed to increased outages on Ergon's network. 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.

The SAIFI data show the average frequency of outages has been relatively stable since 2002–03, with distribution customers across the NEM experiencing an outage around twice a year. The average frequency of outages fell in all jurisdictions in 2009–10, except South Australia. Victoria had the largest reduction in outage frequency, following decade high outage levels in 2008–09 associated with extreme weather (a heat wave and bushfires).

2.6.3 Customer service—distribution networks

The monitoring of service quality for distribution networks typically includes assessing customer service. Network businesses report on their responsiveness to customer concerns, 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. Service performance in 2009–10 broadly aligned with that of previous years. Timeliness of connections improved or was stable in all jurisdictions. Call centre performance also improved, with the percentage of phone calls answered within 30 seconds rising in all jurisdictions. New South Wales (particularly Essential Energy) delivered the most marked improvement.

2.6.4 Distribution service performance incentive schemes

Jurisdictions operate guaranteed service level (GSL) schemes that provide for payments to customers experiencing 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 require payments for poor service quality in matters such as streetlight repair, the frequency and duration of supply interruptions, new connections and notice of planned interruptions. Under the jurisdictional schemes, the majority of GSL payments in 2009–10 related to the duration and frequency of supply interruptions exceeding specified limits. In New South Wales, GSL payments fell in 2009–10 from the previous year due to improved performance in repairing streetlights; providing customers with better notice of planned interruptions (although the number of planned interruptions increased); and the timeliness of connections.

Aurora Energy (Tasmania) increased GSL payments in 2009–10 (to around \$4.7 million, up from \$0.9 million in 2008–09), largely due to outages caused by a major storm in September 2009. ETSA Utilities (South Australia) also increased GSL payments in 2009–10, to almost \$1.6 million—more than double the amount paid in any of the previous three years. The bulk of these payments (\$1.2 million) was for prolonged interruptions generally associated with severe weather events.

The AER 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. It 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.

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.[10] The results are standardised for each network to derive an s factor that reflects deviations from target performance levels. While the scheme aims to be nationally consistent, it has flexibility to deal with the differing circumstances and operating environments of each network.

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

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				
	2005–06	2006–07	2007–08	2008–09	2009–10	2005–06	2006–07	2007–08	2008–09	2009–10
QUEENSLAND[1]										
ENERGEX	0.62	0.55	10.79	2.54	0.44	89.4	79.1	96.3	89.7	90.0
Ergon Energy	0.84	0.49	0.72	0.30	0.38	85.1	87.0	86.2	87.2	87.0
NEW SOUTH WALES[2]										
EnergyAustralia	0.02	0.02	0.01	0.02	0.01	81.3	74.3	81.1	79.7	89.1
Integral Energy	0.02	0.02	0.01	0.02	0.01	89.0	70.9	96.2	92.0	96.6
Country Energy	0.02	0.02	0.01	0.02	0.01	47.2	…	61.4	51.4	73.2
ActewAGL	…	…	…	…	…	39.7	62.4	70.5	…	…
VICTORIA[3]										
Powercor	0.06	0.04	0.02	0.01	0.02	86.7	89.4	90.0	86.6	85.3
SP AusNet	2.40	2.66	1.74	2.58	1.74	92.3	91.2	92.3	91.6	92.6
United Energy	0.29	0.05	0.08	0.12	0	72.9	74.0	73.0	73.1	76.2
CitiPower	0.03	0.05	0.01	0	0.02	85.7	87.2	87.8	82.0	82.3
Jemena	0.09	0.19	0.80	0.89	0.11	77.4	79.9	73.1	77.4	77.2
SOUTH AUSTRALIA[1]										
ETSA Utilities	1.33	0.51	1.30	0.58	0.60	85.2	89.3	88.7	88.5	88.6
TASMANIA										
Aurora Energy	0.15	0.14	2.00	1.77	1.08	…	…	…	…	…

1. Completed connections data for Queensland and South Australia include new connections only. Queensland data for 2009–10 are for the period 1 July 2009 to 31 March 2010.
2. New South Wales completed connections data 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.

The national scheme applies to the Queensland, Victorian 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 in Tasmania from the start of Aurora Energy's next regulatory period (1 July 2012).

Victorian distribution businesses will be subject to an additional scheme from 1 January 2012 that provides incentives for the businesses to reduce the risk of fire starts in their networks. A fire start includes any fire that originates from a network, or is caused by something coming into contact with the network. This 'f factor' scheme will reward or penalise the businesses $25 000 per fire under or over their fire start targets.

2.7 Electricity transmission congestion

Physical limits (constraints) are imposed on electricity flows along transmission networks to avoid damage and maintain power system stability. These constraints can lead to network congestion, especially at times of high demand. Some congestion results from factors within the control of a service provider—for example, the scheduling of outages, maintenance and operating procedures, and 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.

Figure 2.7
Number of mispriced connection points

Source: AEMO.

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. 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

To provide information on patterns of congestion and expected market outcomes, AEMO developed a Congestion Information Resource. The resource includes data on 'mispricing', which occurs when network congestion causes a generator to be constrained on or off.[11] 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 three years. It illustrates 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.

2.7.2 Reducing congestion costs

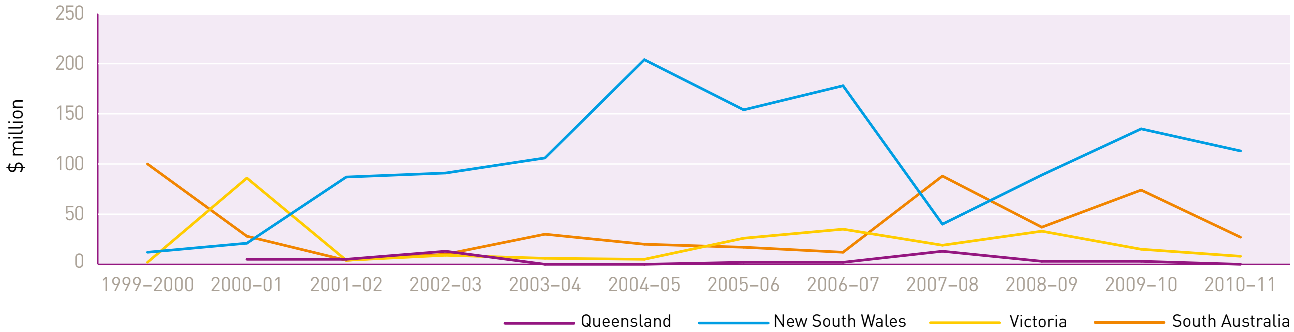
The AER in 2008 introduced an incentive scheme to reduce congestion. The mechanism forms part of the service performance incentive scheme.[12] It operates as a

11 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.

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

Figure 2.8

Settlement residues in the National Electricity Market



Source: AEMO.

bonus only scheme and rewards transmission network owners for improving their operating practices to reduce congestion. These practices may include more efficient outage timing and notification, the minimising of outage impact on network flows (for example, by conducting live line work, maximising line ratings and reconfiguring the network) and equipment monitoring. 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.[13]

TransGrid, Powerlink, ElectraNet and SP AusNet participate in the scheme. From early indications, the scheme is driving improved behaviour by the transmission businesses. TransGrid received $11.62 million in incentive payments between July 2009 and December 2010, and Powerlink received $6.83 million in incentive payments between July 2010 and December 2010. ElectraNet's performance target was set in December 2010, and SP AusNet's in August 2011. The first performance assessments for these businesses will occur in 2012.

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. The data show some volatility, because a complex range of factors can lead to price separation—for example, the availability of transmission interconnectors and generation plant, weather conditions and the bidding behaviour of generators.

As the NEM's largest electricity importer, New South Wales is vulnerable to price separation events and typically records the highest level of settlement residues. South Australian residues fluctuated over the past four years, reflecting movements in regional spot prices. As net exporters, Queensland and Victoria tend to accumulate modest settlement residues.

13 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.

2.8 Policy developments for electricity networks

The AEMC undertakes reviews on its own initiative or as directed by the SCER, and provides policy advice on electricity market issues. It is also responsible for Rule making under the Electricity Law, including determinations on proposed Rule changes. It progressed or finalised a number of reviews and Rule change proposals in 2011.

2.8.1 Total factor productivity

In July 2011 the AEMC published its final report on a total factor productivity approach to regulating network revenues and prices.[14] The approach would expose 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, including:

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

It found a total factor productivity approach—especially in distribution—could lead to more efficient outcomes for consumers. It considered, however, that existing regulatory data may not be sufficiently robust or consistent to implement the approach in the short term.

In its final report, the AEMC proposed the SCER submit a Rule change proposal to facilitate the collection of more consistent and robust data from network businesses. Using the data, the AER could test whether the conditions necessary to introduce a total factor productivity approach have been met, which would allow paper trials to commence.

Interregional transmission charging

In February 2010 the SCER proposed a Rule change to implement new interregional charging arrangements for transmission networks. This change is designed to promote more efficient operation of, and investment in, the networks.

Under current arrangements, a transmission business recovers its costs from customers within the region in which its network is located. Customers in an importing region, therefore, do not pay the costs incurred in an exporting region to serve their load. The proposed Rule change would introduce a load export charge that effectively treats the business in the importing region as a customer of the business in the exporting region.

Consultation on the Rule change identified issues with existing transmission charging methods, including a lack of consistency in how charges are calculated across NEM regions. These issues could reduce the efficiency of the proposed scheme and make interregional charges more volatile. The AEMC is developing a uniform national interregional transmission charging regime to address these issues. It released a discussion paper in August 2011, setting out options.[15] A final Rule determination is expected by February 2012.

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 SCER proposed a Rule change to promote the efficient connection of clusters of new generation.

The AEMC finalised a Rule in June 2011 that aims to take advantage of economies of scale in network assets and avoid the inefficient duplication of connection assets.[16] The Rule requires a network business, at the request of a third party, to publish a study of

14 AEMC, *Review into the use of total factor productivity for the determination of prices and revenues, final report*, 2011.
15 AEMC, *National Electricity Amendment (Inter-regional Transmission Charging) Rule 2011*, Discussion paper, 2011.
16 AEMC, *National Electricity Amendment (Scale Efficient Network Extensions) Rule 2011, Rule determination*, 2011.

opportunities for efficiency gains from the coordinated connection of new generation in an area. This study would help investors make informed decisions about funding a network extension. Funding arrangements would be subject to commercial negotiation between the relevant entities. Once a network extension is constructed, other generators could seek access to it under a framework set out in the Rules.

Unlike the Rule as initially proposed, the adopted Rule does not compel anyone to bear the risk and cost of assets being underused. Rather, the risk is borne by investors with the appropriate information, ability and incentive to manage the risk.

Transmission frameworks review

The AEMC in 2011 continued its review of arrangements for the provision and use of electricity transmission services, and implications for the NEM's market frameworks. A consultative committee made up of energy market stakeholders was assisting the AEMC.

The review aims to ensure market frameworks—including incentives for generation and network investment—effectively align with frameworks for network operation to deliver efficient overall outcomes. It stems from earlier AEMC findings that climate change policies would affect the use of transmission networks and place stress on market frameworks.[17]

Based on issues raised in the review to date, the AEMC in April 2011 published a directions paper outlining matters for further holistic investigation, including:

> how generators access transmission services
> apportioning network charges between generators and users
> managing network congestion
> transmission planning, including the role of the RIT-T
> managing third party connections to the transmission network.

The final report is expected by June 2012.

2.9 Demand management and metering

Demand management relates to strategies to manage the growth in overall or peak demand for energy services. It aims to reduce or shift demand, or implement efficient alternatives to network augmentation. Such strategies are typically applied at the distribution or retail level, and require cooperation between energy suppliers and customers.

In distribution, the AER applies demand management schemes with incentives for businesses to investigate and implement efficient non-network approaches to manage demand. The schemes fund projects or initiatives that reduce network demand. In some jurisdictions, the schemes 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 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. A Rule change consultation on this issue commenced in June 2011.

2.9.1 Metering and smart grids

Meters record the energy consumption of customers at their point of connection to a 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) 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 2011.

17 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, 2009.

The Victorian Government initiated a program outside the COAG process to provide smart meters to all customers over four years from 2009. Although the rollout is continuing, the government initiated a review of the program's future in 2011. The review includes a cost–benefit analysis to determine whether, and under what circumstances, the program can deliver consumers value for money. A moratorium exists on the introduction of time-of-use tariffs for customers with smart meters.[18]

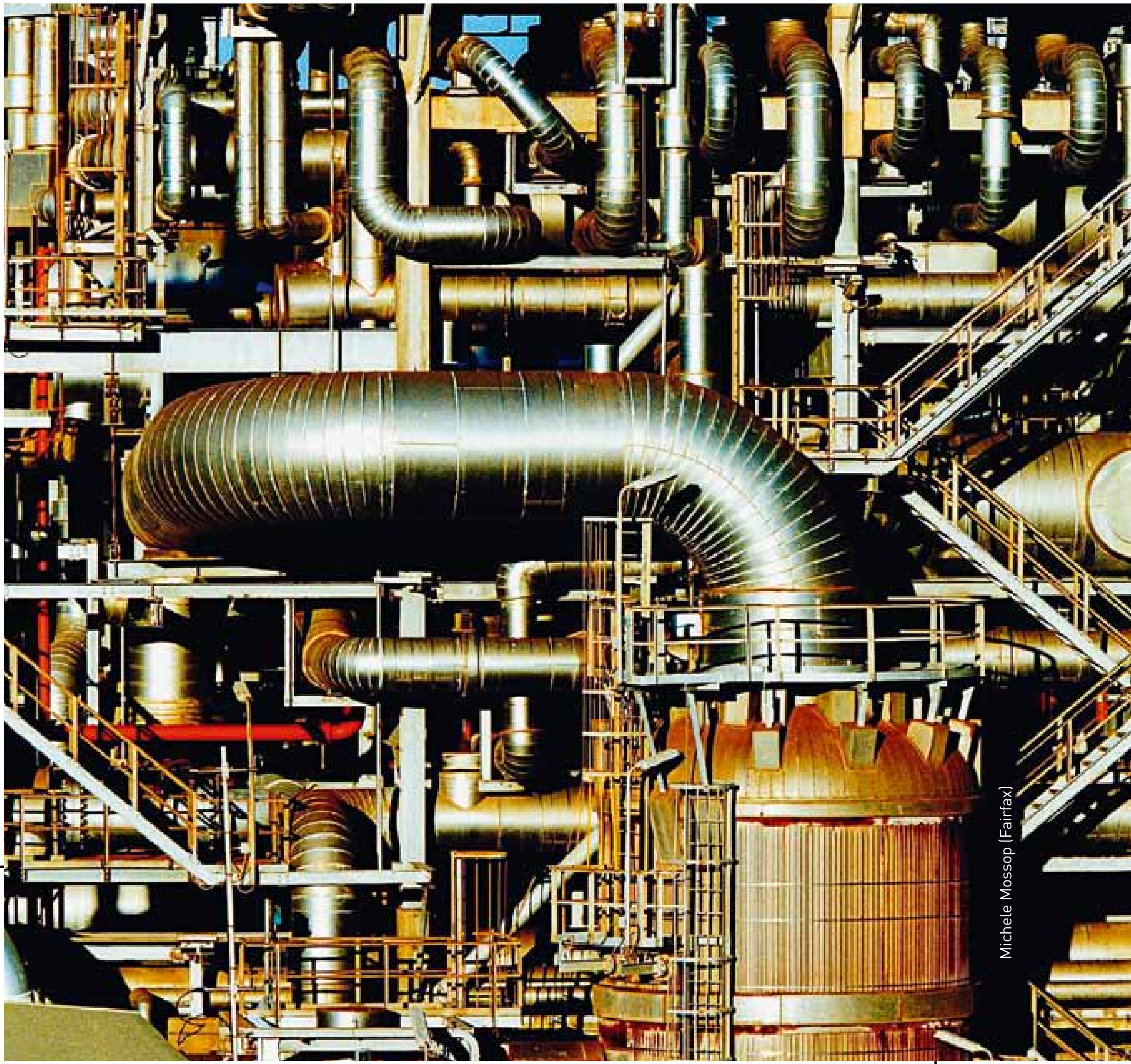
Smart meter costs have been progressively passed on to Victorian retail customers since 1 January 2010. Network charges increased by almost $70 for a typical small retail customer in 2010, with a further increase of around $8 in 2011. In October 2011 the AER released a final determination on metering services budgets and charges for 2012–15.[19] Over this period, smart meter costs will increase network charges for a typical small retail customer by $9–21 per year.[20]

In addition to smart meter developments, the Australian Government in 2010 implemented a $100 million Smart Grid, Smart City initiative to support the installation of Australia's first commercial scale smart grid. Based in Newcastle, New South Wales, the initiative explores the use of advanced communication, sensing and metering equipment to provide customers with improved energy use information, automation and savings, and to improve network reliability. The initiative is also looking at options to connect additional renewable and distributed energy and hybrid vehicles to the grid.

18 If the customer consumes less than 20 megawatt hours of electricity per year.

19 AER, *Victorian advanced metering infrastructure review—2009–11 AMI budget and charges applications, final determination*, 2009.

20 AER, *Victorian advanced metering infrastructure review—2012–15 AMI budget and charges applications, final determination*, 2011.


Michele Mossop (Fairfax)

3 GAS

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

Gas is produced both for domestic markets and for export as liquefied natural gas (LNG). High pressure transmission pipelines transport gas over long distances to domestic markets. A network of distribution pipelines then delivers gas from points along transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. Gate stations measure the gas leaving a transmission system for billing and gas balancing purposes, and reduce the pressure of the gas before it enters a distribution network.

This chapter covers 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 and the Northern Territory, and LNG export markets. Chapter 4 considers the retailing of gas to small customers.

3.1 Reserves and production

In August 2011 Australia's proved and probable (2P) gas reserves stood at around 115 000 petajoules (PJ), comprising 77 000 PJ of conventional natural gas and 38 000 PJ of CSG.[2] Total proved and probable reserves increased by around 9 per cent in 2010–11. CSG reserves in Queensland and New South Wales rose by 33 per cent.

Australia produced 2030 PJ of gas in 2010–11, of which around 53 per cent was for the domestic market. The CSG share of production for the domestic market rose from 19 per cent in 2009–10 to 21 per cent in 2010–11. Around 47 per cent of Australia's gas production—all currently sourced from offshore basins in Western Australia and the Northern Territory—is exported as LNG. This ratio is likely to increase in the future, with the development of major LNG projects in Queensland and Western Australia (section 3.2.1).

The Australian Energy Market Operator's (AEMO) 2011 *Gas statement of opportunities* projected gas reserves in eastern and south eastern Australia would be sufficient to meet domestic and LNG export demand over the next 20 years under a range of modeled scenarios.[3]

3.1.1 Geographic distribution

Table 3.1 sets out the geographic distribution of Australia's gas reserves in August 2011 and production in 2010–11. 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 (about 60 per cent) of Australia's proved and probable gas reserves. It supplies almost one-third of Australia's domestic market and 98 per cent of Australian gas for LNG export.

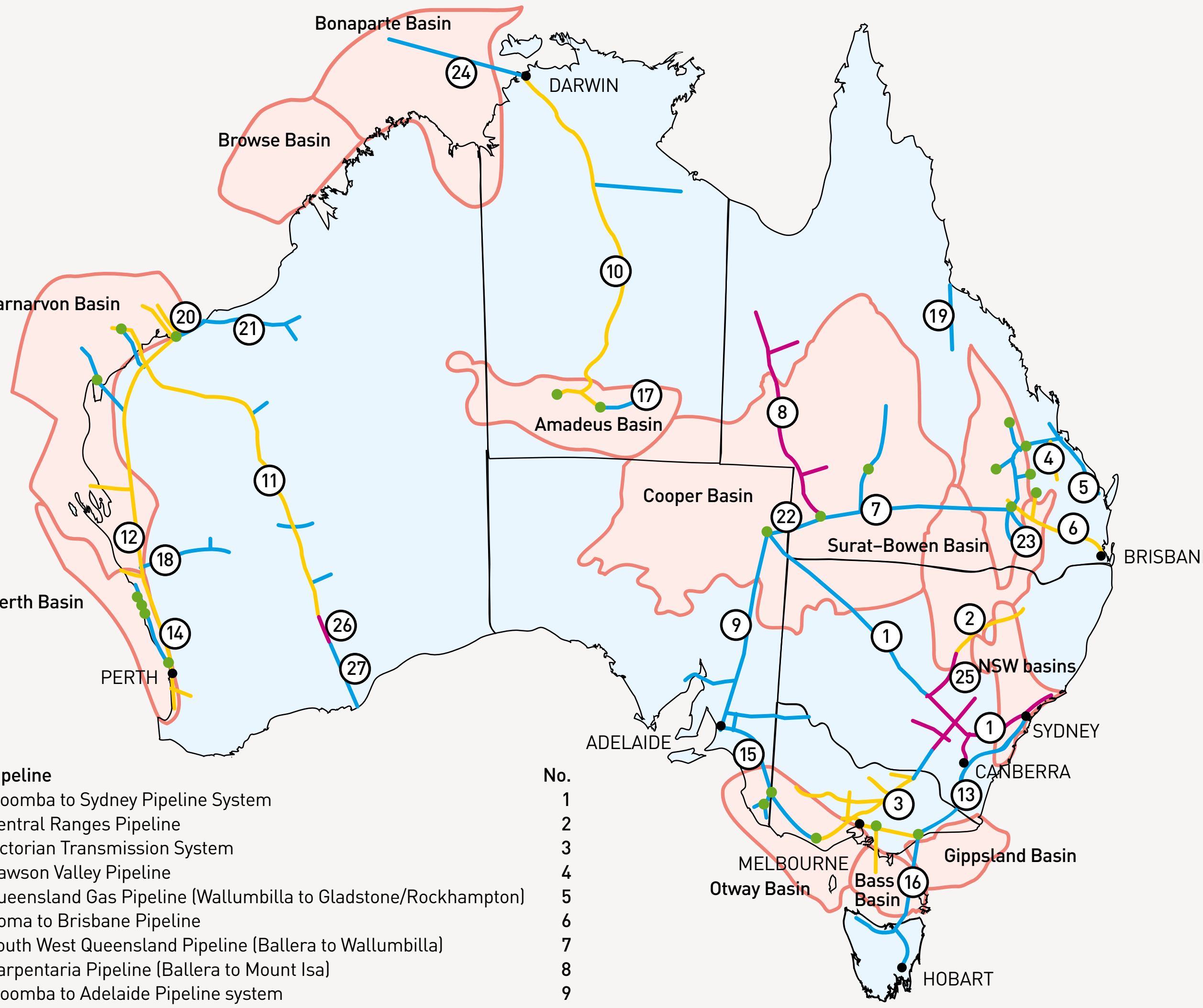
The Bonaparte Basin along the north west coast contains around 1 per cent of Australia's gas reserves. While its development has focused on producing LNG for export (which began in 2006), the Bonaparte Pipeline was commissioned in 2008 to ship gas to the Northern Territory for domestic consumption. The basin has displaced the Amadeus Basin as the main source of domestic gas for the Territory. Production from the Amadeus Basin decreased from 10.2 PJ in

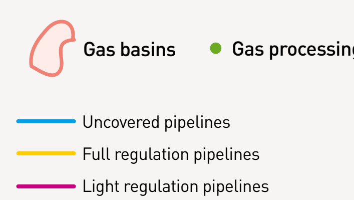
1 The AER has compliance and enforcement responsibilities—under parts 18–20 of the National Gas Rules—in relation to the Natural Gas Market Bulletin Board, the Victorian wholesale gas market and the short term trading market that commenced operating in Sydney and Adelaide in 2010.

2 EnergyQuest, *Energy Quarterly*, August 2011.

3 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.

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 Gas reserves and production, 2011

GAS BASIN	PRODUCTION (YEAR TO JUNE 2011)		PROVED AND PROBABLE RESERVES[2] (AUGUST 2011)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
WESTERN AUSTRALIA				
Carnarvon	344	31.8	68 856	59.6
Perth	4	0.3	42	0.0
NORTHERN TERRITORY				
Amadeus	2	0.1	141	0.1
Bonaparte	20	1.8	1 184	1.0
EASTERN AUSTRALIA				
Cooper (South Australia – Queensland)	96	8.9	1 373	1.2
Gippsland (Victoria)	252	23.3	4 571	4.0
Otway (Victoria)	106	9.8	939	0.8
Bass (Victoria)	18	1.6	268	0.2
Surat–Bowen (Queensland)	10	1.0	183	0.2
Total conventional natural gas	851	78.6	77 557	67.2
COAL SEAM GAS				
Surat–Bowen (Queensland)	225	20.8	34 986	30.3
New South Wales basins	6	0.6	2 910	2.5
Total coal seam gas	231	21.4	37 896	32.8
AUSTRALIAN TOTALS	**1082**	**100.0**	**115 453**	**100.0**
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	933			
Bonaparte (Northern Territory)	14			
Total liquefied natural gas	948			
TOTAL PRODUCTION	**2030**			

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 2011.

2009–10 to 1.6 PJ in 2010–11, while production from the Blacktip field in the Bonaparte Basin increased from 8.5 PJ to 19.6 PJ over the same period.

Eastern Australia contains around 39 per cent of Australia's gas reserves, of which the majority are CSG reserves in the Surat–Bowen Basin in Queensland. The basin accounts for over 30 per cent of national gas reserves and supplies over 20 per cent of the domestic market. The Gippsland Basin off coastal Victoria supplies 23 per cent of the domestic market. While reserves in the Cooper Basin in central Australia are in long term decline, they increased by 19 per cent in the year to June 2011. Production in Victoria's offshore Otway Basin (10 per cent) has risen significantly since 2004, but was steady in 2010–11.

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 and more recently in the Gunnedah 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 17 per cent to 231 PJ in 2010–11, accounting for over 32 per cent of gas production in eastern Australia. CSG's share of Australia's proved and probable reserves increased from 27 per cent at August 2010 to 33 per cent at August 2011.[4]

3.2 Domestic and international demand

Australia consumed around 1082 PJ of gas in 2010–11 for a range of industrial, commercial and domestic applications. Gas is increasingly used for electricity generation, mainly to fuel intermediate and peaking generators. The residential sector uses gas mainly for heating, hot water and cooking.

The consumption profile varies across the jurisdictions. Gas is widely used in most jurisdictions for industrial manufacturing. Western Australia, South Australia, Queensland and the Northern Territory especially rely on gas for electricity generation. In Western Australia, the mining sector is also a major user of gas. Household demand is relatively small, except in Victoria, where residential demand accounts for around one third of total consumption. This proportion reflects the widespread use of gas for cooking and heating in that state.

3.2.1 Liquefied natural gas exports

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

Australia has operating LNG export projects in Western Australia's North West Shelf and Darwin. Exports of Australian produced LNG in 2010–11 rose by 11 per cent to 17.3 million tonnes,[5] and major players are continuing to expand capacity:

> Woodside's 4.3 million tonne per year Pluto project (Carnarvon Basin) is nearing completion and will become Australia's third operational LNG project. The estimated development cost is $14.9 billion. The first exports are expected in March 2012.

> Chevron's $43 billion Gorgon project (Carnarvon Basin) is scheduled to begin operation in 2014 and will produce around 15 million tonnes of LNG per year. The project partners have signed long term sales agreements with international buyers. A final decision on Chevron's $25 billion Wheatstone project (foundation capacity of 8.9 million tonnes per year) was made in September 2011. The project's first LNG would be produced in 2016.

> Shell's $10–$13 billion floating LNG project (Browse Basin) is under construction and is expected to commence production in 2016.

> Inpex and Total are expected to make a final investment decision before the end of 2011 on the $23 billion Ichthys LNG project (Browse Basin).

In Queensland, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have spurred the development of several LNG projects near the port of Gladstone. Construction of three projects is underway, and a fourth is at the planning stage:

> The $15 billion Curtis LNG project (BG Group) is under construction. It will initially produce 8.5 million tonnes per year, with potential capacity of 12 million tonnes. The first exports are expected in 2014.

> The $16 billion Gladstone LNG project (Santos, Petronas, Total and Kogas) is under construction. It will initially produce 7.8 million tonnes per year, with potential capacity of 10 million tonnes. The first exports are expected in 2015.

4 All data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2011.

5 LNG production and export data are sourced from EnergyQuest, *Energy Quarterly*, August 2011, p. 24.

- The Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) has commenced construction. It will initially produce 4.3 million tonnes per year, with first exports expected in 2015.
- The Arrow LNG project (Shell and PetroChina) is at the planning stage. It would produce 16 million tonnes per year, with first exports expected in 2017.

AEMO forecast in its 2011 *Gas statement of opportunities* that LNG exports from Queensland would likely exceed total domestic gas demand in eastern and south eastern Australia by 2016. It also forecast they would exceed the total energy that the National Electricity Market is projected to produce in that year.[6]

3.3 Industry structure

Six major producers met 65 per cent of domestic gas demand in 2010–11: BHP Billiton, Santos, ExxonMobil, Origin Energy, Woodside and Apache Energy.[7] The mix of players varies across the basins.

3.3.1 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 estimates of market share 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 2011.

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 (32 per cent), Shell (18 per cent) and ExxonMobil (15 per cent) have the largest gas reserves in the basin, given their equity in the Gorgon project.

Woodside (25 per cent) and Apache Energy (23 per cent) are the largest producers for Western Australia's domestic market. Santos (13 per cent), BP and Chevron (10 per cent each), and BHP Billiton and Shell (6 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, which is now the dominant source of gas supply to the Territory. 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 (65 per cent) dominates production in South Australia's Cooper Basin. The other participants are Beach Petroleum (21 per cent) and Origin Energy (14 per cent).

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and provide gas to New South Wales, South Australia and Tasmania. A joint venture between ExxonMobil and BHP Billiton accounts for around 94 per cent of production in the Gippsland Basin, which is the largest producing basin in eastern Australia. Nexus, which began production from the Longtom gas project in October 2009, has acquired a 6 per cent market share.

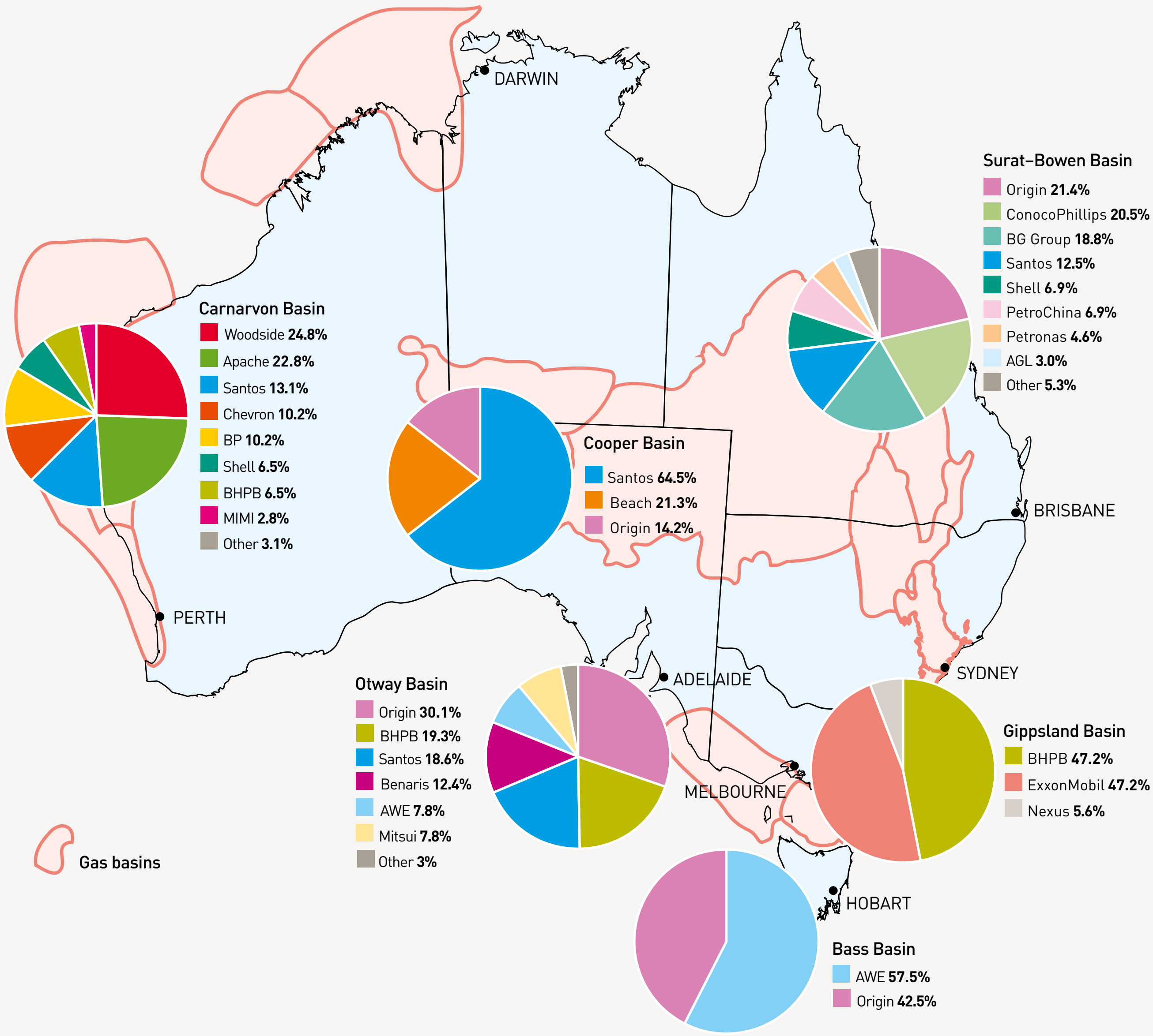
The Otway Basin off south west Victoria has a more diverse ownership base, with Origin Energy (30 per cent), BHP Billiton (19 per cent) and Santos (19 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration.

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 (21 per cent), ConocoPhillips (20 per cent), BG Group (19 per cent), Santos (12 per cent), Shell and PetroChina (7 per cent each), Petronas (5 per cent) and AGL Energy (3 per cent). These businesses also own the majority of gas reserves in the basin.

6 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
7 EnergyQuest, *Energy Quarterly*, August 2011.

Figure 3.2

Market shares in domestic gas production, by basin, 2010–11



Notes:

Excludes liquefied natural gas.

Some corporate names are shortened or abbreviated.

Data source: EnergyQuest 2011 (unpublished data).

Table 3.2 Market shares in proved and probable gas reserves, by basin, 2011 (per cent)

COMPANY	CARNARVON (WA)	PERTH (WA)	BONAPARTE (WA/NT)	AMADEUS (NT)	SURAT–BOWEN (QLD)	COOPER (SA/QLD)	CLARENCE MORTON (QLD/NSW)	GUNNEDAH (NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	HUNTER (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	32.2														19.2
Shell	17.9				9.1										13.4
ExxonMobil	14.9											43.8			10.6
Woodside	12.3														7.3
BG					22.7										6.9
Origin		62.1			14.6	13.1							36.1	41.0	5.0
Santos	1.2		2.4	64.4	6.2	63.2		80.0				4.8	16.1		4.8
BHPB	4.4											43.8	15.7		4.5
ConocoPhillips			11.9		14.2										4.5
BP	4.8														2.9
PetroChina					9.1										2.8
Apache	3.8														2.3
MIMI	3.6														2.2
AGL					3.3				100.0	100.0	100.0				1.8
Sinopec					5.0										1.5
Petronas					3.9										1.2
Total					3.9										1.2
CNOOC	1.2														1.1
Eni			81.5												0.8
Tokyo Gas	1.0				0.3										0.7
Kufpec	1.2														0.7
Kogas					2.1										0.7
Osaka Gas	0.7														0.4
Mitsui					1.1								7.2		0.4
Metgasco							100.0								0.4
Molopo					1.0										0.3
Nexus												7.6			0.3
TRUenergy								20.0							0.3
Beach						21.8									0.3
Kansai Electric	0.4														0.3
AWE		37.9											7.2	59.0	0.2
Other	0.3		4.3	35.6	3.4	1.9							17.7		1.1
TOTAL (PETAJOULES)	**68 856**	**42**	**1184**	**141**	**35 169**	**1373**	**428**	**1520**	**669**	**151**	**142**	**4571**	**939**	**268**	**115 453**

Notes:

Based on 2P (proved and probable) reserves at August 2011.

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

Source: EnergyQuest 2011 (unpublished data).

Figure 3.3 shows changes in market shares of gas reserves in the Surat–Bowen Basin between 2008 and 2011. The changes reflect both mergers and acquisitions, and the development of new projects. In 2008 three entities owned about 75 per cent of reserves (Origin Energy with 35 per cent, Santos with 22 per cent and Queensland Gas with 18 per cent). In contrast, the three largest players in 2011 own about 52 per cent of reserves (BG Group with 23 per cent, Origin Energy with 15 per cent and ConocoPhillips with 14 per cent).

3.3.2 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 2009 and 2010 editions of the AER's *State of the energy market* report listed proposed and successful acquisitions from June 2006 to October 2010. Activity from that time until October 2011 included the following:

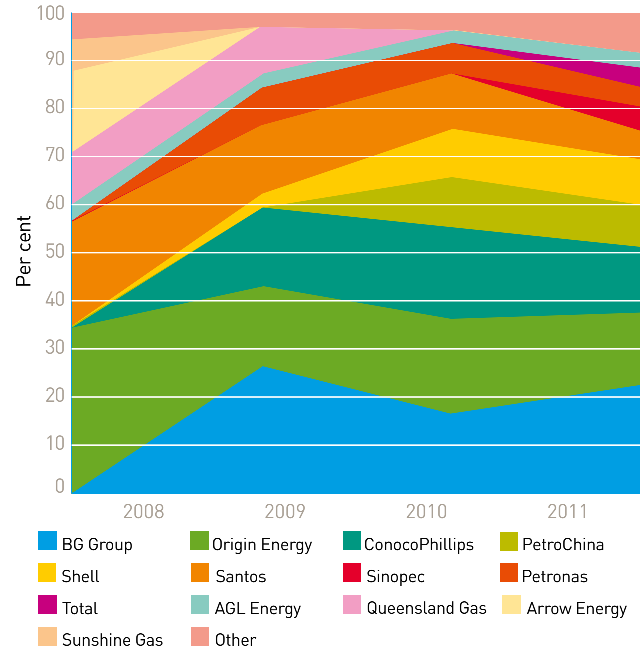
- In July 2011 Santos acquired Eastern Star Gas, which has CSG assets in the Gunnedah Basin (New South Wales). It subsequently sold a 20 per cent interest to TRUenergy. The entities will develop the project as joint venture partners.
- In August 2011 Sinopec Group acquired a 15 per cent share in the Australia Pacific LNG project (Queensland).
- In September 2011 Arrow Energy (Shell and PetroChina) announced that it had agreed to pay $535 million for gas explorer Bow Energy, to source additional CSG resources for its Queensland LNG project.

3.3.3 Vertical integration

The increasing use of gas as a fuel for electricity generation creates synergies for energy retailers to manage price and supply risk through equity in gas production and gas fired electricity generation. The energy retailers Origin Energy and AGL Energy each have substantial interests in gas production and electricity generation:

- Origin Energy is a leading energy retailer and is expanding its electricity generation portfolio in eastern Australia. It has significant equity in CSG production in Queensland and in conventional natural 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 and a major electricity generator in eastern Australia. A relative newcomer to gas production, it began acquiring CSG interests in Queensland and New South Wales in 2005.

Figure 3.3
Market shares in proved and probable reserves, Surat–Bowen Basin, 2008–11



Data source: EnergyQuest 2008–11 (unpublished data).

TRUenergy, a third major retailer and generator in eastern Australia, acquired an interest in New South Wales CSG reserves in 2011.

3.4 Gas wholesale markets

Gas producers sell gas in wholesale markets to major industrial, mining and power generation customers, and to energy retailers that onsell it to business and residential customers. While gas prices were historically struck under confidential, long term contracts, there has been a recent shift towards shorter term contracts and the emergence of spot markets. Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline network constraints. More recently, governments and industry established the National Gas Market Bulletin Board and a short term trading market in major hubs.

3.4.1 Victoria's gas wholesale market

Victoria's spot market for gas was introduced to manage gas flows on the Victorian Transmission System and allow market participants to buy and sell gas at a spot price. The *State of the energy market 2009* report provides background on the market's operation (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 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 process establishes a spot market clearing price. Given Victoria has a net market, this price applies to only net positions—the difference between a participant's scheduled gas deliveries into and out of the hub. AEMO can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term constraints.

Typically, gas traded at the spot price accounts for 10–20 per cent of wholesale volumes in Victoria, after accounting for net positions. The balance of gas is sourced via bilateral contracts or vertical ownership arrangements between producers and retailers. Section 3.5.3 notes recent price activity.

3.4.2 Short term trading market

A short term trading market—a wholesale spot market for gas—is being progressively implemented at selected hubs that link transmission pipelines and distribution systems in southern and eastern Australia. AEMO operates the market, which was designed to enhance gas market transparency and competition by setting prices based on supply and demand conditions. Market participants include energy retailers, power generators and other large scale gas users. The market was launched in September 2010 in Sydney and Adelaide, and was extended to Brisbane in December 2011. Each hub is scheduled and settled separately, but all hubs operate under the same rules. Victoria has retained its own spot market for gas (section 3.4.1).

The short term trading market allows participants to buy or sell some, or all, of their gas requirements on a spot basis without long term sales contracts. The market provides general price guidance as well as a platform for trading (including secondary trading) and demand side response by users. It operates in conjunction with longer term gas supply and transportation contracts. The AER monitors and enforces compliance with the market Rules (section 3.6).

The market sets a daily (ex ante) clearing price at each hub, based on scheduled withdrawals and day-ahead offers by gas shippers to deliver gas. All gas supplied according to the market schedules is settled at this price. When participants deviate from their scheduled gas deliveries or withdrawals, AEMO maintains physical system balance by procuring additional gas (market operator services). Gas procured under this balancing mechanism is settled primarily through deviation payments and charges on the parties responsible for the imbalances.

The short term trading market and the Victorian spot market have differences in design and operation:

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

3.4.3 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. There is provision for facilities in Western Australia and the Northern Territory to participate in the future.

The bulletin board aims to provide transparent, real- time information 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.

Bulletin board participants must provide the information, and the AER monitors and enforces compliance with the relevant Rules (section 3.6). The bulletin board is operated by AEMO, which also publishes an annual gas statement of opportunities to help industry participants plan and make commercial decisions on infrastructure investment.

3.5 Gas prices

Australian gas prices have historically been low by international standards. They have also been relatively stable, defined by provisions in long term supply contracts. In the United States and Europe, gas prices closely follow oil prices. Conversely, 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. The growth of LNG export capacity in Western Australia from the late 1980s led to the domestic market being increasingly exposed to international energy prices. A similar scenario may be unfolding on the east coast, with LNG exports expected to commence from Queensland in 2014.

3.5.1 Western Australia

Because 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 international LNG and oil prices added to this pressure.

In 2011 a Western Australian parliamentary inquiry into domestic gas prices found the average price in domestic gas contracts in 2009–10 was $3.70 per gigajoule. But prices in new contracts ranged from $5.55 to $9.25 per gigajoule. The inquiry recommended initiatives to improve the efficiency of the wholesale market by enhancing transparency, competition and liquidity. Several initiatives mirror recent reforms in eastern Australia, including the introduction of a short term trading market, a gas market bulletin board and a gas statement of opportunities. The inquiry also recommended eliminating joint marketing arrangements when authorisations granted by the Australian Competition and Consumer Commission come up for review in 2015.[8]

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 New South Wales basins to sell gas to customers across Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. EnergyQuest reported east coast prices for conventional gas under existing long term contracts in 2011 were around $3.50–4.00 per gigajoule.[9]

8 Economics and Industry Standing Committee (Parliament of Western Australia), *Inquiry into Domestic Gas Prices*, Report no. 6 in the 38th Parliament, 24 March 2011.

9 EnergyQuest, *Energy Quarterly*, August 2011, p. 94.

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 17 per cent in 2010–11.[10] New transmission pipelines, such as the QSN Link (commissioned in 2009), provide the physical capacity to transport the gas to southern markets.

The development of LNG projects in Queensland is also producing 'ramp-up' gas that is being diverted to the domestic market until the projects are commissioned. Once a CSG well is in production, it is generally difficult to shut it in without having to start the process again. This ramp-up gas is being made available at relatively low prices.[11]

Aside from LNG exports, domestic factors are putting upward pressure on demand. Rising investment in gas fired power stations is a key driver. Gas powered electricity generation represents around 24 per cent of domestic gas demand in eastern and southern Australia.[12] While output from gas powered generation fell across the National Electricity Market (NEM) by 10 per cent in 2010–11 (mainly offset by an increase in wind generation),[13] the introduction of carbon pricing will drive greater reliance on gas powered generation in the medium to long term. AEMO's 2011 *Gas statement of opportunities* forecast gas powered generation would be the largest component of domestic demand growth in the next 20 years.[14]

Expanding CSG production and the ramp-up of LNG capacity are constraining short term gas prices in Queensland, which EnergyQuest reported in August 2011 were typically below $2 per gigajoule.[15] Queensland's 2011 *Gas market review* found supplies of ramp-up gas would likely constrain short term prices until LNG exports commence.[16]

However, the likely diversion of gas resources for LNG export may put upward pressure on Queensland prices from about 2014.[17] EnergyQuest noted the focus on developing LNG projects meant, while short term prices were low, few long term domestic gas contracts were available. It considered Queensland prices could move towards $7 per gigajoule for new long term domestic contracts.[18]

AEMO similarly noted the development of an east coast LNG industry may result in domestic gas prices rising towards parity with international prices. It noted, for example, many large producers in 2011 were securing sufficient reserves to enter LNG supply contracts with overseas customers, which over time may put pressure on domestic gas availability. It reported new contract prices in 2011 may be rising towards $5 per gigajoule.[19]

Queensland's 2011 *Gas market review* predicted Queensland domestic gas prices would rise to $5–8 per gigajoule by 2016, with the high end of this range being likely. It predicted prices would likely rise slightly later in the southern states than in Queensland.[20]

3.5.3 Spot market prices

The spot markets in Victoria (from 1999), Sydney and Adelaide (from September 2010) and Brisbane (from December 2011) provide data on short term gas prices. In the Victorian market (section 3.4.1), volumes can range from around 300 to 1200 terajoules per day. While the market accounts for only about 10–20 per cent of

10 EnergyQuest, *Energy Quarterly*, August 2011, p. 60.
11 EnergyQuest, 'Australia's natural gas markets: connecting with the world,' in AER, *State of the energy market 2009*.
12 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
13 EnergyQuest, *Energy Quarterly*, August 2011, p. 97.
14 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
15 EnergyQuest, *Energy Quarterly*, August 2011, p. 94.
16 Queensland Department of Employment, Economic Development and Innovation, *2011 gas market review Queensland*, 2011, p. 42.
17 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
18 EnergyQuest, *Energy Quarterly*, August 2011.
19 AEMO, *Gas statement of opportunities for eastern and southern Australia, executive briefing*, 2011.
20 Queensland Department of Employment, Economic Development and Innovation, *2011 gas market review Queensland*, 2011, pp. 42–3.

wholesale volumes in Victoria, its price outcomes are widely used as a guide to underlying contract prices.

Victorian gas prices tended to ease after 2008. Reasons for the easing included an expansion of the Victorian Transmission System, which reduced capacity constraints. More recently, an apparent oversupply of contracted gas, along with an increase in the number of participating retailers, might have constrained bid prices in the market.

The Victorian market was relatively subdued throughout 2010, with prices in the first quarter (and the early part of the fourth quarter) typically below $2 per gigajoule (figure 3.4). However, colder temperatures in 2011 led to higher prices. The daily volume weighted average price for 2010–11 was $2.45 per gigajoule, compared with $1.83 per gigajoule in 2009–10. Both outcomes are significantly lower than long term average prices.

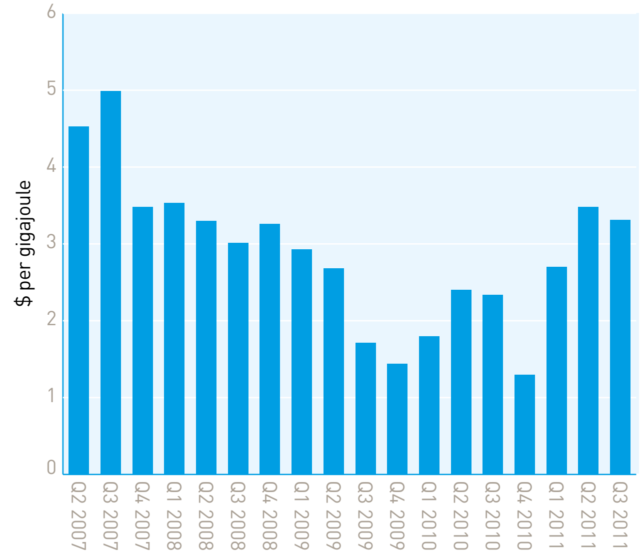
The short term trading market recorded some price instability in its early months, mainly due to data errors (figure 3.5). Average ex ante prices in the nine months from market start to 30 June 2011 were $2.87 per gigajoule in Sydney and $3.17 per gigajoule in Adelaide.

Design differences between the short term trading market and the Victorian 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. Figure 3.5 includes price estimates for Melbourne, based on spot prices plus an estimate of transmission pipeline delivery to the metropolitan hub. It shows a reasonable degree of alignment across prices in the three capital cities.

3.6 Compliance monitoring and enforcement

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to the short term trading market, the Victorian gas market and the bulletin board. It takes a transparent approach to monitoring, compliance and enforcement, publishing quarterly reports on activity. The AER also draws on spot market and bulletin board data to publish weekly reports on gas market activity in southern and eastern Australia.

Figure 3.4
Victorian spot gas prices—quarterly averages



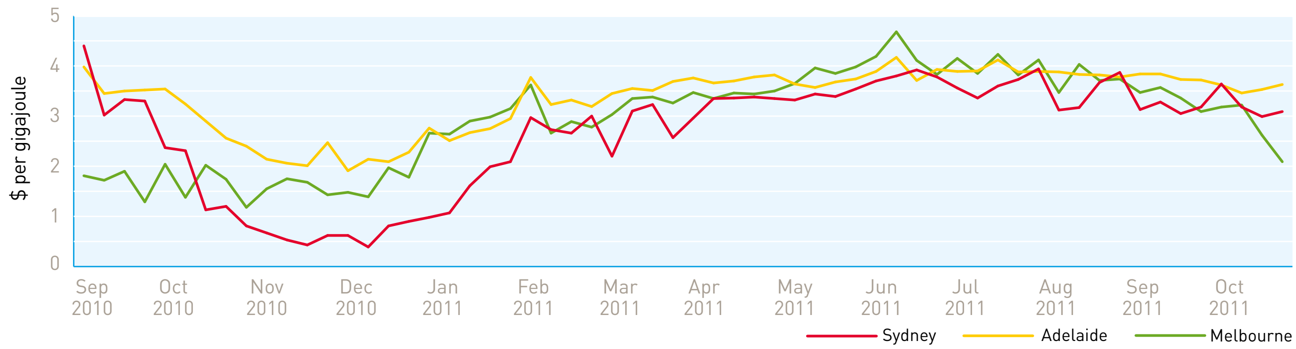
Sources: AEMO; AER.

Timely and accurate data and efficient pricing arrangements are essential to maintain confidence in gas markets and efficient investment in gas infrastructure and gas reliant infrastructure such as electricity generation. The AER monitors the spot markets and bulletin board to improve data provision and detect evidence of structural and market manipulation issues.

The AER's monitoring activity has helped improve data provision to the Victorian gas market and bulletin board. In the short term trading market, however, some failures to submit demand forecasts and data errors involving pipeline operators caused significant price impacts in the early months of operation. The AER began taking measures in 2011 to reduce participants' missing, late or erroneous data. The measures included meetings with the chief executive officers of major pipeline companies to outline the AER's views on 'good gas industry practice', and compliance audits of pipeline operators' systems for submitting data. More generally, the AER committed to the Standing Council on Energy and Resources (formerly the Ministerial Council on Energy) to monitor the market to detect any evidence of the exercise of market power.

Figure 3.5

Sydney, Adelaide and Melbourne spot gas prices—weekly averages



Notes:

Sydney and Adelaide data are weekly averages of the ex ante daily price in each hub. Ex ante prices are derived from demand forecasts in the short term trading market and form the main basis for settlement. The Sydney data exclude the 1 November 2010 price of $150 per gigajoule, which was caused by data errors.

Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff ($0.3685 per gigajoule) for the two Melbourne metropolitan zones.

Sources: AER estimates (Melbourne); AEMO (other cities).

3.7 Gas transmission

Transmission pipelines transport 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 summarises Australia's major transmission pipelines; figure 3.1 illustrates pipeline routes.

Australia's gas transmission network covers over 20 000 kilometres. The construction of new pipelines and the expansion of existing facilities in the past decade created an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. This investment enhanced the competitive environment for gas producers, pipeline operators and gas retailers, and improved security of supply. While Western Australia and the Northern Territory have also had significant pipeline investment, they have no transmission interconnection with other jurisdictions.

3.7.1 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:

- *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 (EII), in which it retained a 20 per cent share. Since 2010 APA Group has increased its interest in Hastings Diversified Utilities Fund (see below) from about 4.5 per cent to 19.7 per cent. APA Group's portfolio includes gas distribution assets, both through direct ownership and via a 33 per cent stake in Envestra (section 3.9.1).
- *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.

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	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 Gas Pipeline	NT	1512	104	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 in jurisdictions other than Western Australia; the Economic Regulation Authority is the regulator in Western Australia.

For covered pipelines subject to full regulation, valuation refers to the opening capital base for the current regulatory period. 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)	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)	2007–12	APA Group	APA Group
90 (2009)	Not required	Origin Energy	Origin Energy
	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 19.7%)	Epic Energy
165 (2009)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 19.7%)	Epic Energy
835 (2003)	Not required	APA Group	APA Group
28 (1999)	Not required	APA Group	APA Group
53 (2003)	2005–19	APA Group	Jemena Asset Management
450 (2000)	Not required	Jemena (Singapore Power International)	Jemena Asset Management
524 (2007)	2008–12	APA Group	APA Group/AEMO
50 (2007)	Not required	DUET Group	Jemena Asset Management
	Not required	Jemena (Singapore Power International)	Jemena Asset Management
440 (2005)	Not required	Palisade Investment Partners	Tas Gas Networks
500 (2003)	Not required	APA Group 50%, REST 50%	APA Group
370 (2001)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 19.7%)	Epic Energy
3375 (2011)	2010–15	DUET Group 80%, Alcoa 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 19.7%)	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
92 (2011)	2011–16	APA Group	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	APA Group
	Not required	Envestra (APA Group 33.1%, CKI 19.5%)	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. The listed valuation of the pipeline is that determined by the Australian Competition Tribunal for the regulatory period before the pipeline converted from full to light regulation.

'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.

- *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 holds a 19.7 per cent interest in Hastings.

The following ownership changes have occurred in the gas transmission sector since 2010:
- *Brookfield Infrastructure* acquired a portfolio of former Babcock & Brown gas transmission and distribution assets in December 2010, via a merger with Prime Infrastructure. In July 2011 Brookfield sold the Tasmanian Gas Pipeline to *Palisade Investment Partners*, and it sold a minority share in the Dampier to Bunbury Pipeline to *DUET Group* (raising DUET's equity in the pipeline from 60 to 80 per cent). AMP Capital Holdings and Macquarie Funds Group jointly own DUET Group.
- APA Group has significantly increased its equity in the pipeline sector.
  - In June 2011 it acquired the Northern Territory's Amadeus Gas Pipeline from a consortium of financial institutions. The pipeline had been leased to the Amadeus Gas Trust (in which APA Group held a 96 per cent interest) since 1986.
  - In November 2010 it acquired a further 16.7 per cent share in the SEA Gas Pipeline from International Power, raising its equity in the pipeline to 50 per cent.
  - Since 2010 it has progressively increased its equity in Hastings Diversified Utilities Fund (which owns Epic Energy) from around 4.5 per cent to 19.7 per cent, and in Envestra (which owns gas distribution assets) from 30.6 per cent to 33 per cent.
  - In March 2010 it acquired Queensland's Berwyndale to Wallumbilla Pipeline from AGL Energy.

3.7.2 Regulation of transmission pipelines

The National Gas Law and Rules set out the regulatory framework for the gas transmission sector. The AER regulates pipelines in jurisdictions other than Western Australia; the Economic Regulation Authority is the regulator in Western Australia.

The Law and Rules apply economic regulation provisions to covered pipelines. Various tiers of regulation apply, based on competition and significance criteria. 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 a pipeline provider to periodically 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 regulator assesses the revenues needed to cover efficient costs (including a benchmark return on capital), then derives reference tariffs for the pipeline. The Rules allow for income adjustments from incentive mechanisms to reward efficient operating practices.

The AER currently regulates five transmission pipelines under full regulation.[21] Figure 3.6 shows indicative regulatory timeframes. An *Access arrangement guideline* (available on the AER website) details the regulatory process. Separate guidelines address dispute resolution and compliance with obligations under the Gas Law.[22] The AER's decisions on full regulation pipelines are subject to merits review by the Australian Competition Tribunal.

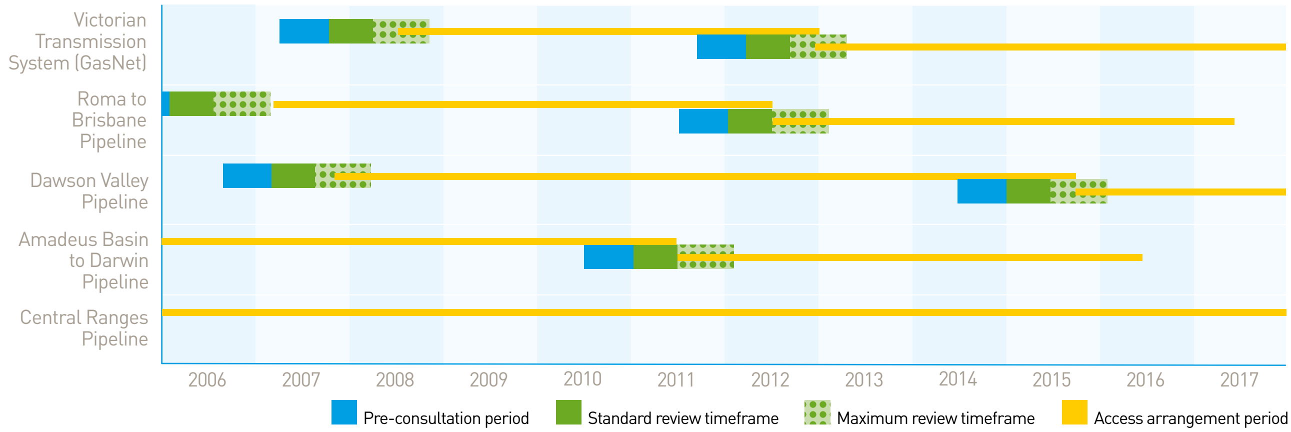
In September 2011 the AER submitted a Rule change proposal to the Australian Energy Market Commission (AEMC), recommending changes in the approach to determining the weighted average cost of capital for gas pipelines. The proposal aimed to create a more

21 The Economic Regulation Authority regulates two Western Australian transmission pipelines under full regulation.

22 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; AER, *Annual compliance guideline*, 2010.

Figure 3.6

Indicative timelines for AER determinations on gas transmission 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.

consistent framework between the electricity and gas sectors for determining the cost of capital. The proposed changes involve a periodic industry-wide review of the cost of capital parameters (box 2.1, chapter 2).

A pipeline may, in some circumstances, convert to *light regulation* without upfront price regulation. When 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 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 economic 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.

The Gas Law also enables the federal Minister for Resources and Energy to grant a 15 year 'no coverage' determination for new pipelines in certain circumstances. In June 2010 the Minister granted such a determination for BG Group's Queensland Curtis LNG Pipeline from the Surat Basin to Curtis Island; construction of the pipeline commenced in 2010 (table 3.4).

3.7.3 Recent investment in transmission pipelines

Table 3.4 summarises major transmission investment (including expansions of existing pipelines) since 2010. It also lists major projects that in 2011 were under construction or had been announced for development.

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 is constructing a $760 million expansion of the pipelines, expected for completion in 2012. Also in Queensland, the planned development of LNG projects spurred plans for new transmission infrastructure to transport CSG to Gladstone for processing and export.

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

Table 3.4 Major gas transmission pipeline investment since 2010

PIPELINE	LOCATION	OWNER/ PROPONENT	SCALE	COST ($ MILLION)	COMPLETION DATE
COMPLETED					
NORTH EAST AUSTRALIA					
Queensland Gas Pipeline expansion	Qld	Jemena	Expansion from 79 TJ/d to 140 TJ/d	112	2010
SOUTH EAST AUSTRALIA					
Eastern Gas Pipeline	Vic–NSW	Jemena	Expansion from 250 TJ/d to 268 TJ/d	41	2010
Victorian Transmission System (GasNet)	Vic	APA Group	Northern section expansion		2011
Moomba to Sydney Pipeline	NSW	APA Group	Young to Wagga lateral		2010
WESTERN AUSTRALIA					
Dampier to Bunbury Stage 5B expansion	WA	DUET Group 80%, Alcoa 20%	Expansion—additional 110 TJ/day	675	2010
UNDER CONSTRUCTION					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 3	Qld	Epic Energy	Expansion—additional 199 TJ/d	760	2012
QSN Link—stage 3	Qld–SA and NSW	Epic Energy			
Queensland Curtis LNG (QCLNG) Pipeline	Qld	BG Group	540 km		Construction commenced in 2010
Roma to Brisbane	Qld	APA Group	10 per cent capacity expansion	50	2012
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	NSW	APA Group	Five year 20 per cent capacity expansion	100	2009–13
Victorian Transmission System (GasNet)	Vic	APA Group	Sunbury looping project		2012
ANNOUNCED					
NORTH EAST AUSTRALIA					
Queensland Hunter Pipeline (Wallumbilla to Newcastle)	Qld–NSW	Hunter Gas Pipeline	831 km	900	Construction commencing in 2012
Gladstone LNG (GLNG) Pipeline	Qld	Santos, Petronas, Total, Kogas	420 km		2015
Arrow Bowen Pipeline (Bowen Basin–Gladstone)	Qld	Arrow (Shell and PetroChina	600 km	1000	Construction commencing in 2012
Australian Pacific LNG (APLNG) Pipeline	Qld	Origin, Sinopec, ConocoPhillips	450 km		2014
Arrow Surat Pipeline	Qld	Arrow	450 km	550	Construction commencing in 2015–16
SOUTH EAST AUSTRALIA					
Narrabri to Wellington Pipeline	NSW	Eastern Star Gas	272 km	275	2009
Young to Wellington Pipeline	NSW	ERM Power	219 km	200	Construction commencing in 2012
Lions Way Pipeline (Casino to Ipswich)	NSW–Qld	Metgasco	145 km	120	Construction commencing in 2012
Coolah to Newcastle Pipeline	NSW	Eastern Star Gas	280 km		2009

TJ/d, terajoules per day.

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

in 2010. The expansion involved 440 kilometres of pipeline looping (duplication). On completion, around 94 per cent of the pipeline had been looped.

3.8 Upstream competition

Investment over the past decade has developed an interconnected transmission 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 has opened the Surat–Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition.

The bulletin board (section 3.4.3) 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.

Figure 3.7 illustrates 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). Figure 3.7 also illustrates the seasonal nature of Victorian gas demand, with significant winter peaks.

> 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.

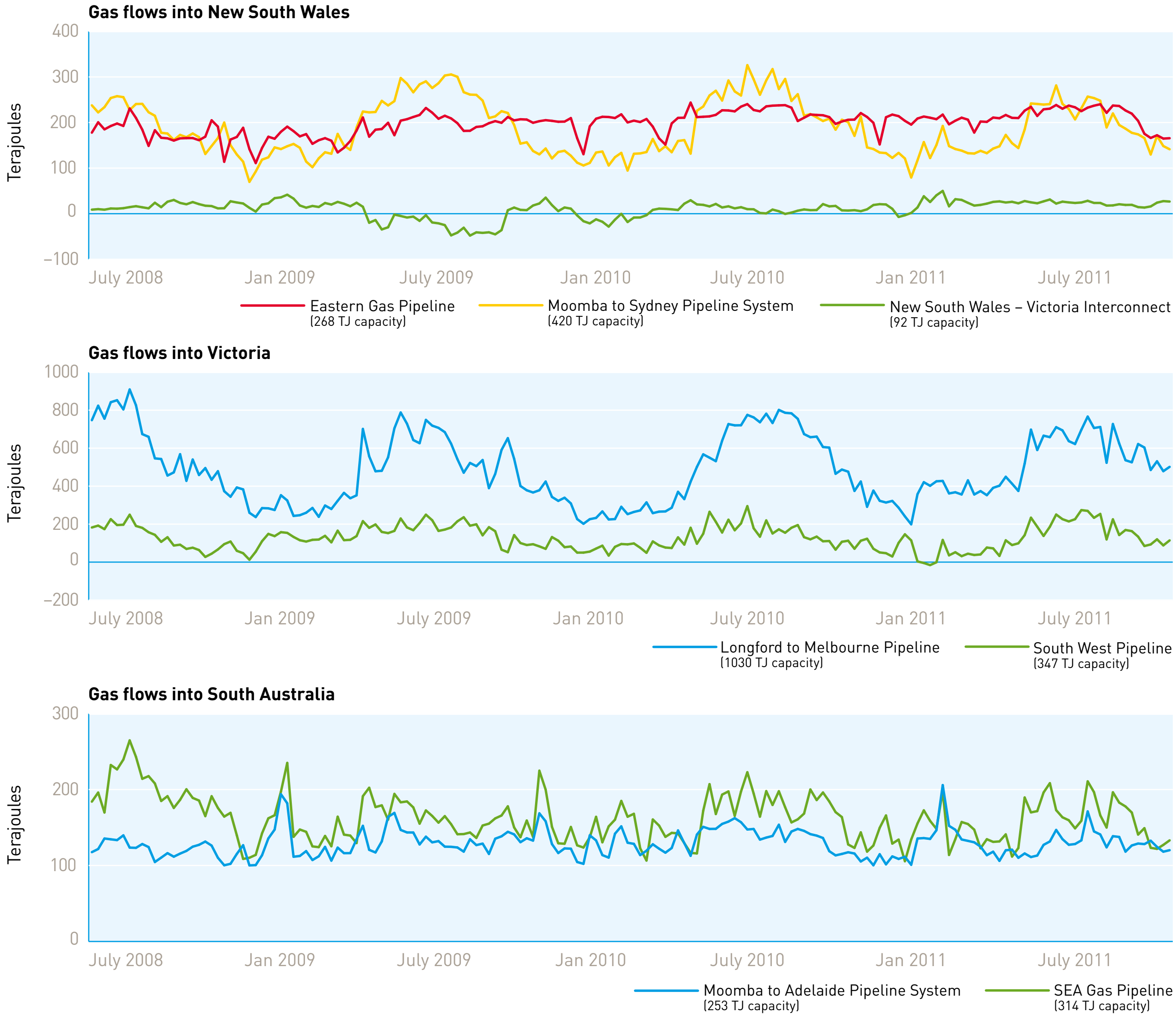
The extent to which new investment delivers competition benefits to customers depends on a range of factors, including pipeline access and the availability of gas from alternative sources. In particular, capacity constraints limit access on some pipelines. Access seekers must decide whether to try to 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.

3.9 Gas storage

Gas can be stored in its natural state in depleted underground reservoirs and pipelines, or post liquefaction as LNG in purpose built facilities. Given Australia's increasing reliance on gas fired electricity generation, gas storage enhances security of energy 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.

Conventional gas storage facilities are located in Victoria, Western Australia and the Cooper Basin. In Victoria, the largest facility is the Iona gas plant, owned by TRUenergy, which has 22 PJ of storage capacity and can deliver 570 terajoules of gas per day. In Western Australia, a scheduled expansion of the Mondarra storage facility will increase storage capacity to 15 PJ, and will allow injection and withdrawals to be made on both the Dampier to Bunbury and Parmelia pipelines. Also, following its purchase of Mosaic Oil in 2010, AGL Energy is developing a CSG storage facility in Queensland.

Figure 3.7
Gas flows in eastern Australia



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

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

The Dandenong LNG storage facility in Victoria (0.7 PJ) is Australia's only LNG storage facility. It provides the Victorian Transmission System with additional capacity to meet peak demand and provide security of supply. 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.

3.10 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.

Table 3.5 **Gas distribution networks in southern and eastern Australia**

NETWORK	CUSTOMER NUMBERS	LENGTH OF MAINS (KM)	OPENING CAPITAL BASE (2010 $ MILLION)[1]	INVESTMENT—CURRENT ACCESS ARRANGEMENT (2010 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND						
APT Allgas	84 400	2 900	413	125	1 Jul 2011–30 Jun 2016	APA Group
Envestra	84 710	2 560	309	136	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
NEW SOUTH WALES AND ACT						
Jemena Gas Networks (NSW)	1 050 000	24 430	2 313	768	1 Jul 2010–30 Jun 2015	Jemena (Singapore Power International)
ActewAGL	112 000	4 160	278	88	1 Jul 2010–30 Jun 2015	ACTEW Corporation (ACT Government) 50%, Jemena (Singapore Power International) 50%
Wagga Wagga	23 800	680	60	20	1 Jul 2010–30 Jun 2015	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
Central Ranges System	7 000	180	n/a	n/a	2006–19	APA Group
VICTORIA						
SP AusNet	570 000	9 400	1 078	372	1 Jan 2008–31 Dec 2012	SP AusNet (listed company; Singapore Power International 51%)
Multinet	646 600	10 010	1 011	265	1 Jan 2008–31 Dec 2012	DUET Group
Envestra	550 070	9 640	949	447	1 Jan 2008–31 Dec 2012	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
SOUTH AUSTRALIA						
Envestra	401 300	7 890	991	478	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33.1%, Cheung Kong Infrastructure 19.5%)
TASMANIA						
Tas Gas Networks	6 500	730	117[1]	Not regulated	Not regulated	Tas Gas (Brookfield Infrastructure)
TOTALS	**3 536 380**	**72 580**	**7 519**	**2 699**		

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 2010 dollars.
2. Investment data are forecasts for the current access arrangement period, adjusted to June 2010 dollars.

Sources: Access arrangements for covered pipelines; company websites.

Gas is now reticulated to most Australian capital cities, major regional areas and towns. This section 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.

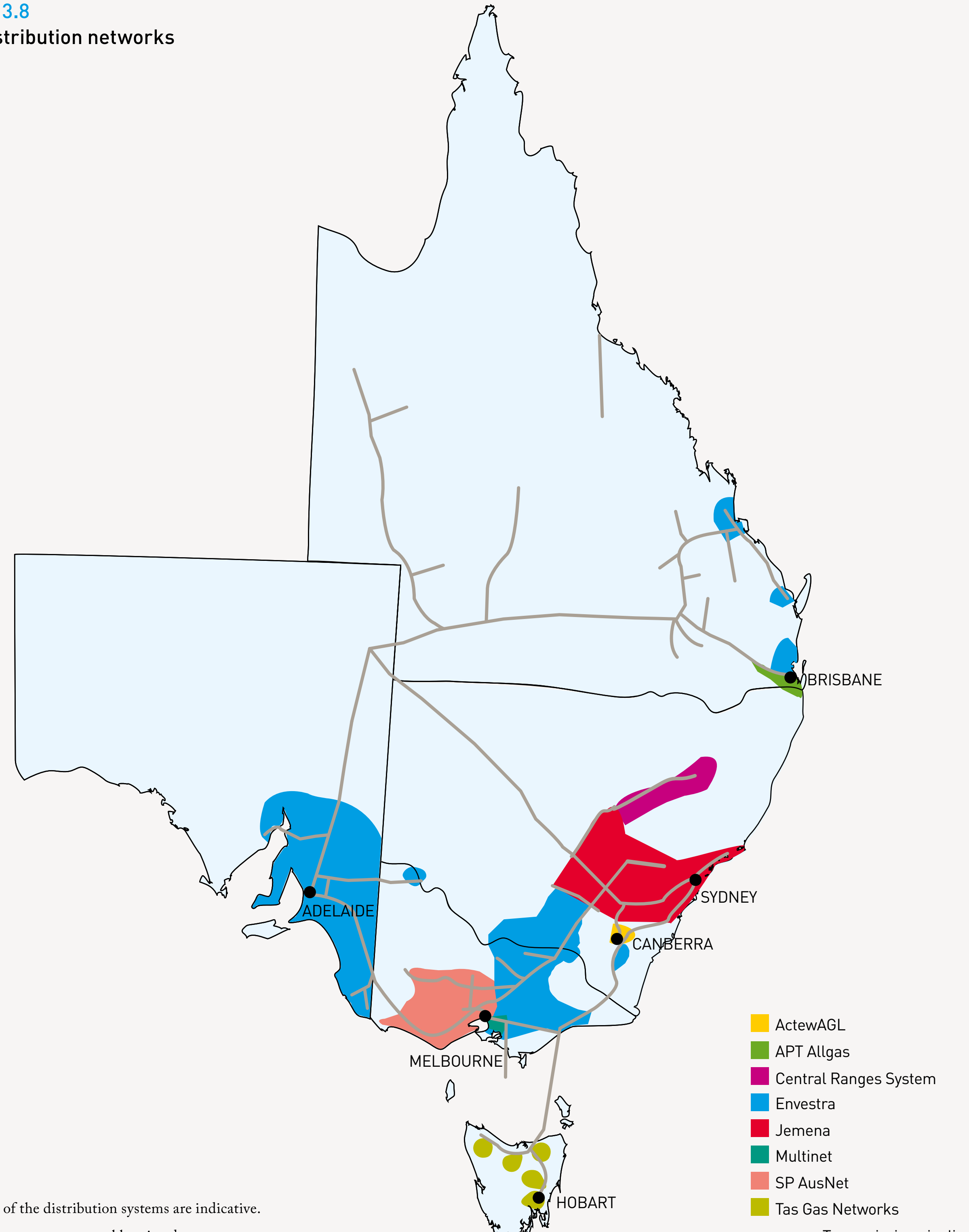
The total length of gas distribution networks in the southern and eastern jurisdictions was around 73 000 kilometres in 2011. The networks have a combined value of over $7 billion. Investment to augment and expand the networks is forecast at around $2.7 billion in the current access arrangement periods (typically five years).

3.10.1 Ownership of distribution networks

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

> *Jemena*, owned by *Singapore Power International*, owns the principal New South Wales gas distribution network (Jemena Gas Networks) and has a 50 per cent

Figure 3.8
Gas distribution networks



Notes:

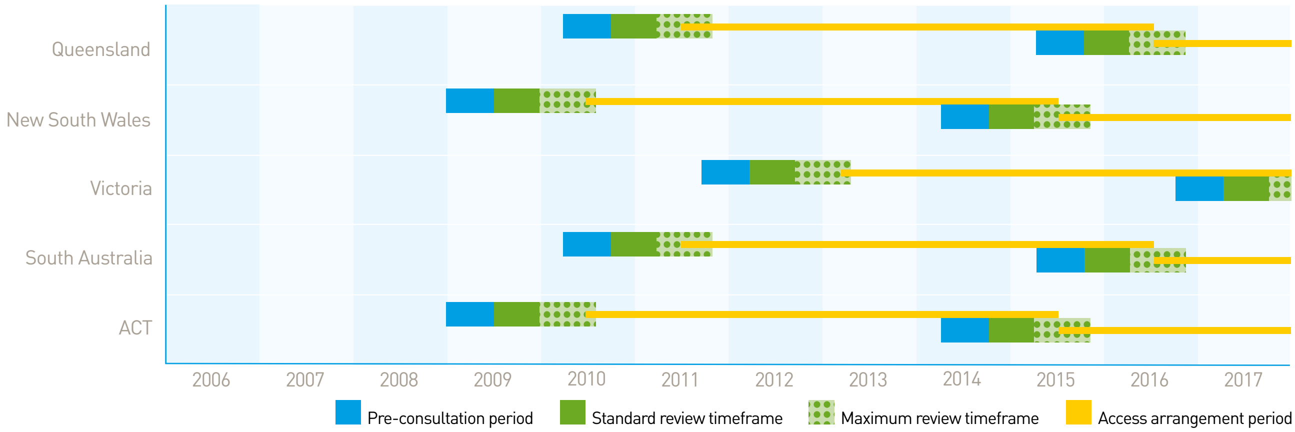
Locations of the distribution systems are indicative.

Some corporate names are abbreviated.

Source: AER.

Figure 3.9

Indicative timelines for AER determinations on gas distribution 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.

share of the ACT network (ActewAGL). Singapore Power International also has 51 per cent direct equity in a Victorian network (SP AusNet).

- *APA Group* owns the APT Allgas network in Queensland and the Central Ranges system in New South Wales, and has a 33 per cent stake in Envestra (up from 30.6 per cent in 2009).
- *Envestra*, a public company in which *APA Group* (33 per cent) and *Cheung Kong Infrastructure* (19 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.

There has been a series of recent ownership changes related to former Babcock & Brown assets. In December 2010 *Brookfield Infrastructure* acquired a portfolio of these assets via a merger with Prime Infrastructure. Brookfield retained ownership of Tas Gas Networks, but in July 2011 sold a minority share in Victoria's Multinet distribution network to *DUET Group* (raising DUET's equity in the network from 80 to 100 per cent). Also in July 2011 Brookfield and DUET Group sold WA Gas Networks to *ATCO*.

The ownership links between gas distribution and other energy networks are significant. In particular, Jemena and APA Group own and/or operate gas transmission pipelines (section 3.7.1). 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).

3.10.2 Regulation of distribution networks

The AER regulates all major distribution networks in New South Wales, Victoria, Queensland, 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.[23]

The Gas Law and 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).[24]

23 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.

24 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.

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 published an *Access arrangement guideline* (available on its website) that details the regulatory process. Separate guidelines address dispute resolution and compliance with obligations under the Gas Law.[25]

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 on and enforce the terms and conditions of the access arrangement.

Figure 3.9 shows indicative regulatory timeframes for the networks. In June 2011 the AER completed reviews of access arrangements for the South Australian and Queensland gas distribution networks.

The AER's decisions are subject to merits review by the Australian Competition Tribunal. Between September 2008 and October 2011, network businesses sought reviews of five AER determinations on gas distribution networks. Three reviews were continuing in October 2011. The two completed merits reviews increased allowable network revenues by around $190 million.

In September 2011 the AER submitted a Rule change proposal to the AEMC, which recommended changes in the approach to determining the weighted average cost of capital for gas pipelines. The proposal aimed to create a more consistent framework between the electricity and gas sectors for determining the cost of capital. The proposed changes involve a periodic industry-wide review of the cost of capital parameters (box 2.1, chapter 2).

3.10.3 Investment in distribution networks

The capital drivers for gas distribution networks are broadly similar to those for electricity distribution. The underlying drivers include rising connection numbers, the replacement of ageing networks, and the maintenance of capacity to meet customer demand. For example, a significant driver of Envestra's capital expenditure for its South Australian distribution network is the replacement of cast iron and unprotected steel mains, to address leaks from older sections of the pipeline.

Figure 3.10 illustrates investment forecasts by access arrangement periods (typically five years) for those networks over which the AER has conducted reviews—networks in Queensland, New South Wales, South Australia and the ACT; the first reviews of the Victorian networks will be completed in 2012.

- Investment in the reviewed networks is forecast to increase in real terms by 74 per cent over investment in the previous periods.
- Investment in current access arrangements is running, on average, at 36 per cent of the underlying opening capital base for the networks.
- Investment in Envestra's Queensland and South Australian distribution networks is forecast to rise by 72 per cent and 163 per cent respectively in the current access arrangement periods, compared with levels in previous periods. In contrast, forecast investment in APT Allgas's Queensland distribution network is roughly unchanged from the level in the previous period.

3.10.4 Operating expenditure

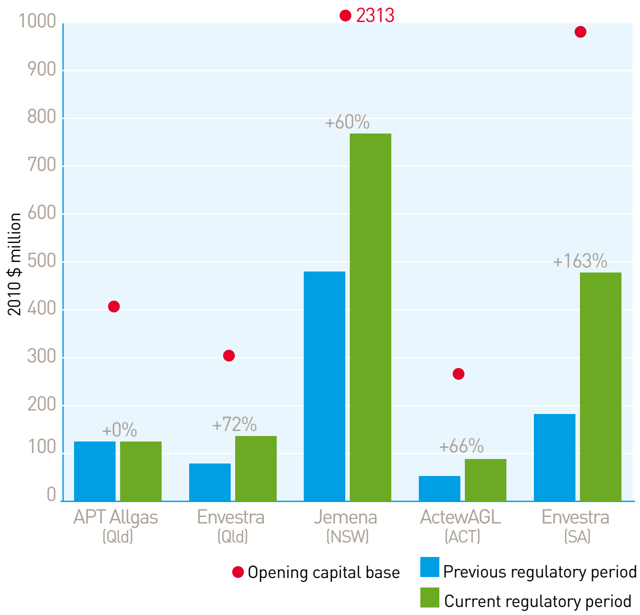
Operating expenditure refers to the operating, maintenance and other costs of a non-capital nature that service providers incur in providing distribution pipeline services. Figure 3.11 compares forecast operating expenditure in current access arrangement periods with levels in previous periods, for those networks over which the AER has reviewed access arrangements.

Real operating expenditure is forecast to increase in the current access arrangement periods, compared with previous periods, by 4 per cent (Envestra in South Australia) to 28 per cent (ActewAGL in the ACT).

25 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; AER, *Annual compliance guideline*, 2010.

Figure 3.10

Gas distribution network investment



Notes:

Forecast capital expenditure in the current regulatory period (typically five years), compared with levels in previous periods. See table 3.5 for the timing of current regulatory periods.

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

All values are converted to June 2010 dollars.

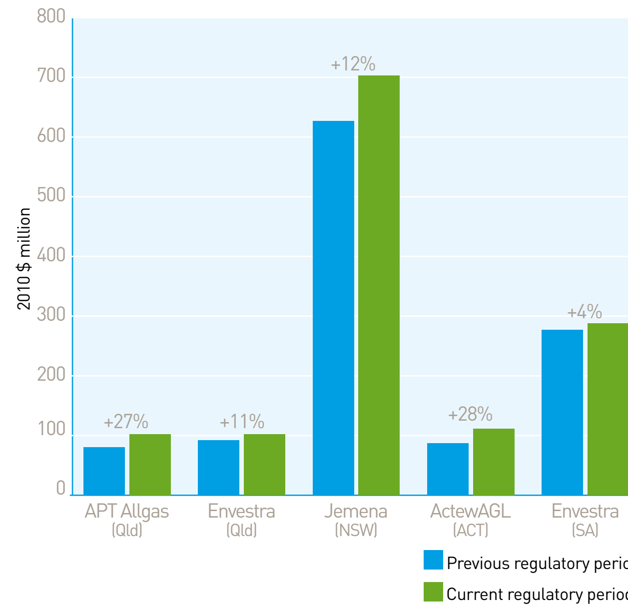
Sources: Access arrangements approved by the AER.

3.10.5 Retail impacts

Rising capital and operating expenditure, as well as other cost drivers (including higher financing costs and the rising cost of unaccounted for gas), are expected to increase distribution network charges in current access arrangement periods beyond levels in previous periods. Figure 3.12 shows the effects of higher network charges on gas retail prices (in nominal terms). The decisions resulted in initial retail price rises of 4–8 per cent and further increases of 4.1–5.5 per cent for each subsequent year of the access arrangement period. Gas distribution charges typically make up about 40–60 per cent of the retail price of gas (section 4.3).

Figure 3.11

Gas distribution operating expenditure



Notes:

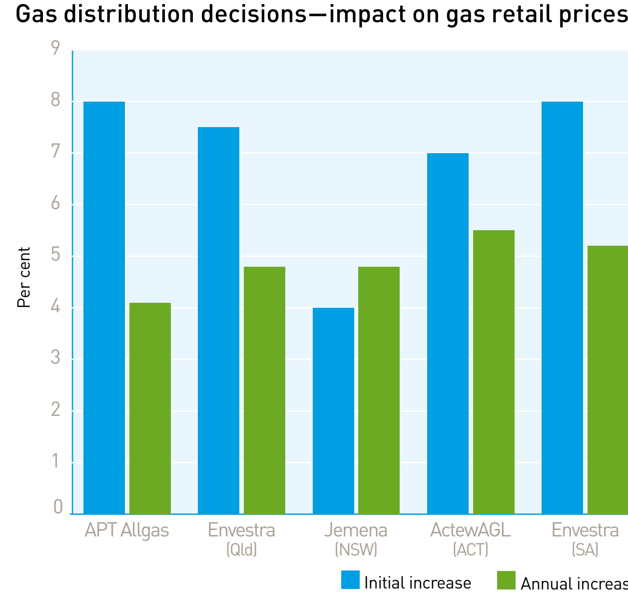
Forecast operating expenditure in the current access arrangement period (typically five years), compared with levels in previous periods. See table 3.5 for the timing of current regulatory periods.

All values are converted to June 2010 dollars.

Sources: Access arrangements approved by the AER.

Figure 3.12

Gas distribution decisions—impact on gas retail prices



Note: Price impact estimate is for a typical residential customer.

Sources: Access arrangements approved by the AER.

4 RETAIL ENERGY MARKETS

Energy retailers buy electricity and gas in wholesale markets and package it with transportation services for sale to customers. While state and territory governments are responsible for regulating retail energy markets, the Australian Energy Regulator (AER) will take on significant functions when national reforms take effect on 1 July 2012 (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

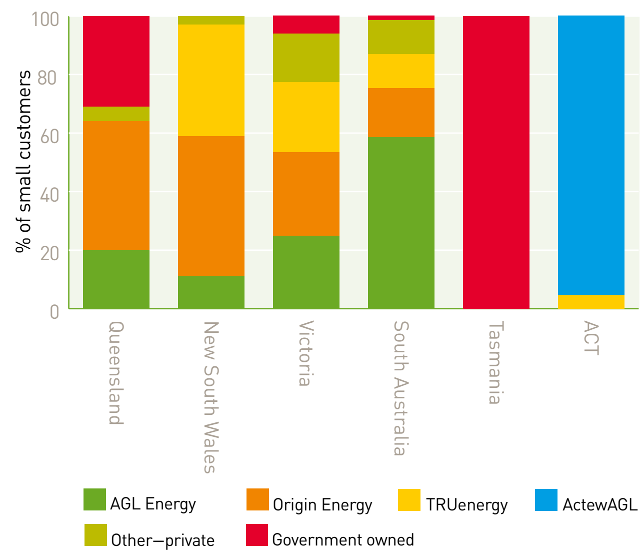
Table 4.1 lists licensed energy retailers that were active in the market for residential and small business customers in October 2011. An active retailer is an authorised retailer that is supplying energy services to customers (whether or not the retailer is seeking new customers). The retailers in most jurisdictions include one or more 'host' retailers that are required to offer energy services to customers under 'standing offer' contracts with regulated terms and conditions.

Figure 4.1 illustrates electricity retail market share by jurisdiction. Three privately owned retailers—AGL Energy, Origin Energy and TRUenergy—supply the bulk of small customers in the eastern mainland states:

- In Victoria and South Australia, the three retailers supply the bulk of small customers.
- In Queensland, AGL Energy and Origin Energy are the largest retailers following the privatisation of state owned entities in 2006–07.
- In New South Wales, TRUenergy and Origin Energy are the largest electricity retailers following the privatisation of state owned entities in 2011. TRUenergy acquired EnergyAustralia, while Origin Energy acquired Country Energy and Integral Energy. AGL Energy is the state's largest gas retailer, and is looking to increase its market share in electricity.

More recently, Simply Energy, Lumo Energy and Australian Power & Gas have emerged as significant private retailers in some jurisdictions. Alinta Energy and Diamond Energy began active retailing in 2010–11, and Dodo Power & Gas widened the geographic range of its activity.

Figure 4.1
Electricity retail market share (small customers), by jurisdiction, 2011



Source: AER estimates.

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

- The Tasmanian Government owns local retailer Aurora Energy, as well as 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 has a 50 per cent interest in ActewAGL—a joint venture with the private sector.
- Snowy Hydro (owned by the New South Wales, Victorian and Australian governments) owns Red Energy.

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

State and territory governments are expected to implement a package of reforms under the National Energy Retail Law from 1 July 2012. The reforms aim to streamline national regulation to support an efficient retail market with appropriate consumer protection.

The South Australian parliament passed the Retail Law in the 2011 autumn sitting. The legislation is expected to take effect in Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. Western Australia and the Northern Territory do not propose to implement the reforms.

The Retail Law will transfer several functions to the AER, including:

- monitoring compliance and enforcing breaches of the Law and its supporting Rules and Regulations
- authorising energy retailers to sell energy, and granting exemptions from the authorisation requirements (for example, to nursing homes and caravan parks that onsell energy)
- approving retailers' policies for dealing with customers facing hardship
- providing an online energy price comparison service for small customers, expected to be launched on 1 July 2012
- administering a national retailer of last resort scheme, which protects customers and the market if a retail business fails
- reporting on the performance of the market and participants, including on energy affordability, disconnections and competition indicators.

The states and territories will remain responsible for regulating retail energy prices.

In 2011 the AER released final procedures and guidelines on how it will undertake its roles under the Retail Law, covering retail performance reporting, retail pricing information, retailer of last resort arrangements, customer hardship policies, compliance and enforcement, authorisations and exemptions, and connection charging arrangements.

It developed these documents in consultation with energy customers, consumer advocacy groups, energy retailers, state and territory agencies, ombudsman schemes and other stakeholders. The documents are available on the AER's website (www.aer.gov.au).

4.1.1 Queensland

At June 2011 Queensland had 27 licensed electricity retailers and nine licensed gas retailers, of which 11 were actively retailing electricity to small customers, and three were actively retailing gas. Origin Energy and AGL Energy are the leading retailers of electricity and gas.

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 2011 New South Wales had 27 licensed electricity retailers, of which 12 supplied to residential and small business customers. Following privatisation in 2011, Origin Energy and TRUenergy supplied over 85 per cent of small electricity customers.

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

Table 4.1 Active energy retailers—small customer market, October 2011

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		
Alinta Energy	Alinta Energy				E		
Aurora Energy	Tasmanian Government				E	E•, G	
Australian Power & Gas	Australian Power & Gas	E, G	E, G	E, G			
Click Energy	Click Energy	E		E			
Country Energy	Origin Energy	E	E•, G•	E	E		
Diamond Energy	Diamond Energy			E	E		
Dodo Power & Gas	Dodo Power & Gas	E	E	E			
Ergon Energy	Queensland Government	E					
Integral Energy	Origin Energy	E	E•				
Lumo Energy	Infratil	E	E	E, G	E		
Momentum Energy	Hydro Tasmania (Tasmanian Government)			E	E		
Neighbourhood Energy	Alinta Energy			E			
Origin Energy	Origin Energy	E•, G•	E, G•	E•, G•	E, G•		
Powerdirect	AGL Energy	E•	E	E	E		
Qenergy	Qenergy	E					
Red Energy	Snowy Hydro[1]		E	E, G	E		
Sanctuary Energy	Living Choice Australia/ Sanctuary Life	E	E				
Simply Energy	International Power			E, G	E, G		
Tas Gas Retail (formerly Option One)	Brookfield Infrastructure					G	
TRUenergy	CLP Group	E	E, G	E•, G•	E, G		E, G

Electricity retailer (E)

Gas retailer (G)

Host retailer •

1. 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).

Notes:

The 'host' retailers listed for Victoria and Queensland are those responsible for offering 'standing offer' contracts to customers that establish a new connection.

TRUenergy surrendered EnergyAustralia's licence in July 2011.

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

4.1.3 Victoria

At June 2011 Victoria had 22 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.

Figure 4.2 illustrates energy retail market shares. The three host retailers supplied about 70 per cent of small electricity customers at June 2010, and each had acquired market share beyond its local area. New entrant penetration increased from around 7 per cent of small customers at June 2005 to almost 30 per cent at June 2010.

Victoria had 15 licensed gas retailers, of which eight actively supplied small customers. The three host retailers, which are also the host retailers in electricity, collectively supplied around 80 per cent of small customers at June 2010.

4.1.4 South Australia

At June 2011 South Australia had 21 licensed electricity retailers, of which 12 were active in the small customer market. The four largest retailers account for around 90 per cent of the market. The host retailer, AGL Energy, supplied around 54 per cent of small customers in 2010, down from 79 per cent in 2005 (figure 4.3). Origin Energy (18 per cent) has built significant market share over the past six years.

South Australia had 11 licensed gas retailers at June 2011, of which four actively supplied to small customers. At June 2010 Origin Energy supplied around 54 per cent of small customers, but the other active retailers have each built market share over the past six 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 2011 Tasmania had two gas retailers active in the small customer market: the state owned Aurora Energy and Tas Gas Retail (owned by Brookfield Infrastructure).

4.1.6 Australian Capital Territory

At June 2011 the ACT had 18 licensed electricity retailers and eight licensed gas retailers. Two retailers—ActewAGL and TRUenergy—actively sold to small customers. ActewAGL remains the dominant retailer, supplying over 90 per cent of small customers.[2]

4.2 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, there has since been a trend towards vertical reintegration between retailers and generators (gentailers). The New South Wales energy privatisation process (and the Queensland privatisations in 2007) continued this trend (table 3 and figure 5 in the *Market overview*).

Vertical integration provides a means for retailers and generators to internally manage the risk of price volatility in the electricity spot market, reducing their need to participate in hedge (contract) markets. This can reduce liquidity in contract markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

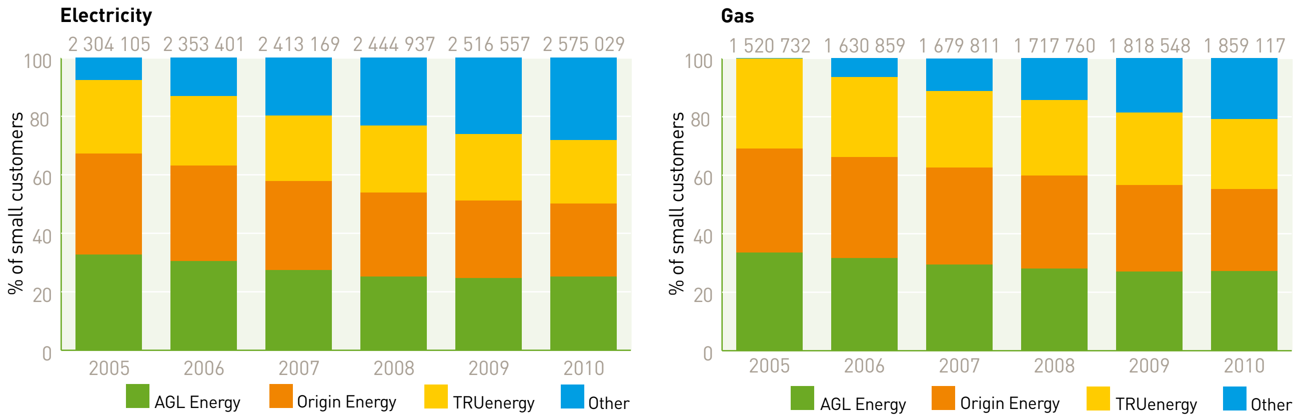
Origin Energy, AGL Energy and TRUenergy now jointly supply over 80 per cent of small electricity retail customers and control almost 30 per cent of generation capacity in the mainland regions of the National Electricity Market (NEM).

Around 58 per cent of new generation capacity commissioned or committed since 2007 is controlled by these three entities. Generation investment since 2007 by entities that do not also retail energy has been negligible. In addition, many new entrant retailers in this time are vertically integrated with entities that were previously stand-alone generators—for example, International Power (trading as Simply Energy in retail markets) and Infratil (Lumo Energy).

2 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT*, 2010, p. 23.

Figure 4.2

Retail market share (small customers)—Victoria

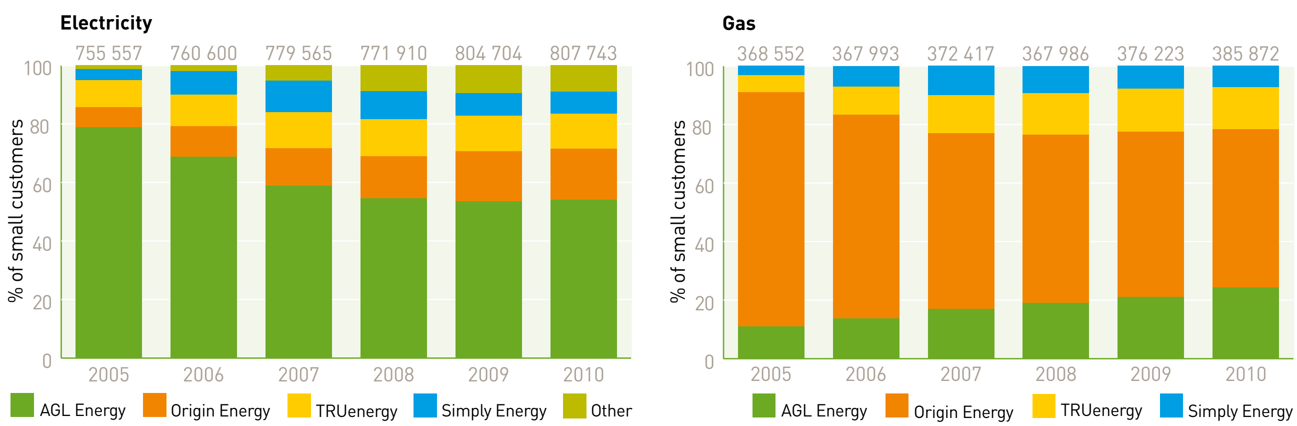


Note: Figures above the columns are total small customer numbers.

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

Figure 4.3

Retail market share (small customers)—South Australia



Note: Figures above the columns are total small customer numbers.

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

Alinta Energy has generation capacity in South Australia, Queensland and Victoria, owns the Victorian retailer Neighbourhood Energy and entered the South Australian retail market in 2011.[3]

AGL Energy, Origin Energy and TRUenergy also have interests in gas production and/or gas storage that complement their interests in gas fired electricity generation and energy retailing. 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 and acquired gas reserves in the Gunnedah Basin (New South Wales) in 2011.

The public electricity sector also exhibits vertical integration. The generator Snowy Hydro owns Red Energy, which operates in the New South Wales, Victorian and South Australian retail markets.

3 A proposed sale of Neighbourhood Energy to CBD Energy in 2011 did not proceed.

The Tasmanian Government owns generation through Hydro Tasmania and maintains a retail presence through Aurora Energy and Momentum Energy.

In addition, the Queensland and Tasmanian governments own joint distribution–retail businesses. The ACT Government has ownership interests in both the host energy retailer and distributor. Ring fencing arrangements aim to ensure operational separation of the retail and network arms of these entities.

4.3 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 2011 Tasmania extended contestability to customers using at least 50 megawatt hours (MWh) per year. All jurisdictions have introduced FRC in gas retail markets.

In the transition to effective competition, retail price regulation continues to apply in many jurisdictions. All jurisdictions except Victoria apply some form of retail price regulation for electricity services. In gas, only New South Wales and South Australia regulate prices for small customers.

Australian governments agreed to review the continued use of retail price regulation and to remove it if effective competition can be demonstrated.[4] The Australian Energy Market Commission (AEMC) is assessing the effectiveness of retail competition in each jurisdiction, to advise on ways to remove price regulation. State and territory governments make the final decisions 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 regulation 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 (with a regulated price), and that stakeholders had differing views on the effectiveness of competition.

In March 2011 the AEMC released its final report on the ACT retail electricity market. It found competition in the small customer market was not effective, partly because customers were unaware of their ability to switch retailers. The AEMC recommended removing retail price controls from 1 July 2012, in conjunction with running a consumer education campaign to increase awareness of the benefits of competition.[6] However, the ACT Government decided in 2011 to retain price controls for another two years. It noted the AEMC found removing price controls would increase the average cost of electricity so would not benefit customers.[7]

The Standing Council on Energy and Resources (SCER, formerly the Ministerial Council on Energy) and the Council of Australian Governments agreed to further energy retail market reviews for New South Wales (in 2012), Queensland (2013), South Australia (2015), the ACT (2016) and Tasmania (within 18 months of FRC being introduced in the electricity retail market).[8]

4.3.1 Customer switching

The rate at which customers switch their supply arrangements indicates customer participation in the market. While switching (or churn) rates can 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

4 Australian Energy Market Agreement 2004 (as amended).

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.

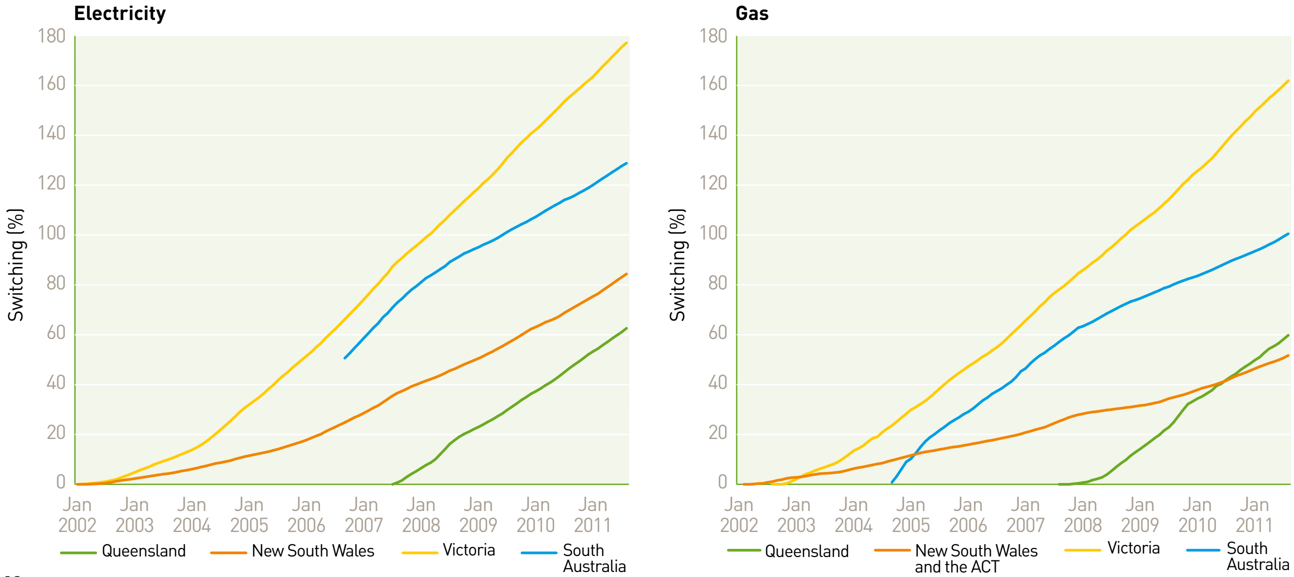
6 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT, stage 2 final report*, 2011, p. 11.

7 ACT Government, 'ACT to keep price regulation for Canberra households', Media release, www.chiefminister.act.gov.au/media.php?v=10936&m=53 2011, September 2011.

8 MCE, *Standing Council on Energy and Resources Meeting Communiqué*, 2011.

Figure 4.4

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



Notes:

Customer base as estimated at 30 June 2011.

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

Sources: Customer switches: AEMO, MSATS transfer data to July 2011 and gas market reports, transfer history to July 2011; customer numbers: IPART (New South Wales), *NSW electricity information paper—electricity retail businesses' performance against customer service indicators*, various years; ESCOSA (South Australia), *09/10 Annual performance report: South Australian energy supply industry*, 2010; ESC (Victoria), *Energy retailers comparative performance report—customer service 2009–10*, 2010; QCA (Queensland), *Market and non-market customers, June quarter 2011*, 2011.

choice, but may then stabilise as a market acquires depth. Similarly, switching may be low in a 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 7 in the *Market overview* of this report illustrates retail switching activity in 2010–11. Figure 4.4 sets out cumulative switching data. The data include customer switches from one retailer to another, but not customer switches between contracts with the same retailer. 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 continues to have a higher switching rate than other jurisdictions. At June 2011 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 later than other jurisdictions, its annual switching rates are higher than those in New South Wales and South Australia.

While churn was higher in gas than electricity in Victoria and Queensland in 2010–11, cumulative switching levels remain lower in gas than electricity in all jurisdictions.

4.4 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 data for gas are limited, the table includes estimates for New South Wales and South Australia.

Table 4.2 Indicative composition of residential electricity and gas bills

JURISDICTION	WHOLESALE ENERGY COSTS	GREEN COSTS	NETWORK COSTS	RETAIL OPERATING COSTS	RETAIL MARGIN
			PER CENT OF TYPICAL SMALL CUSTOMER BILL		
ELECTRICITY					
Queensland	38	4	49	4	5
New South Wales	32	6	51	6	5
South Australia	42	5	41	7	5
Tasmania	39	4	48	5	4
ACT	35	8	46	6	5
GAS					
New South Wales	33	–	47	13	7
South Australia	16	–	63	16	5

Note: New South Wales gas estimates are based on 2010 data; all other estimates are based on 2011 data.

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

In electricity, network tariffs are the largest component of retail bills (accounting for 41–51 per cent of retail bills), followed closely by wholesale energy costs (32–42 per cent). Green costs—that is, costs associated with carbon emission reduction or energy efficiency schemes—rose significantly over the past two years but still make up only 4–8 per cent of retail bills. Retailer operating costs (including margins) contribute around 10 per cent of retail bills.

In gas, pipeline charges are the most significant component of retail prices. Transmission and distribution charges combined account for around 47 per cent of gas retail prices in New South Wales and 63 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 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.

4.4.1 Price diversity

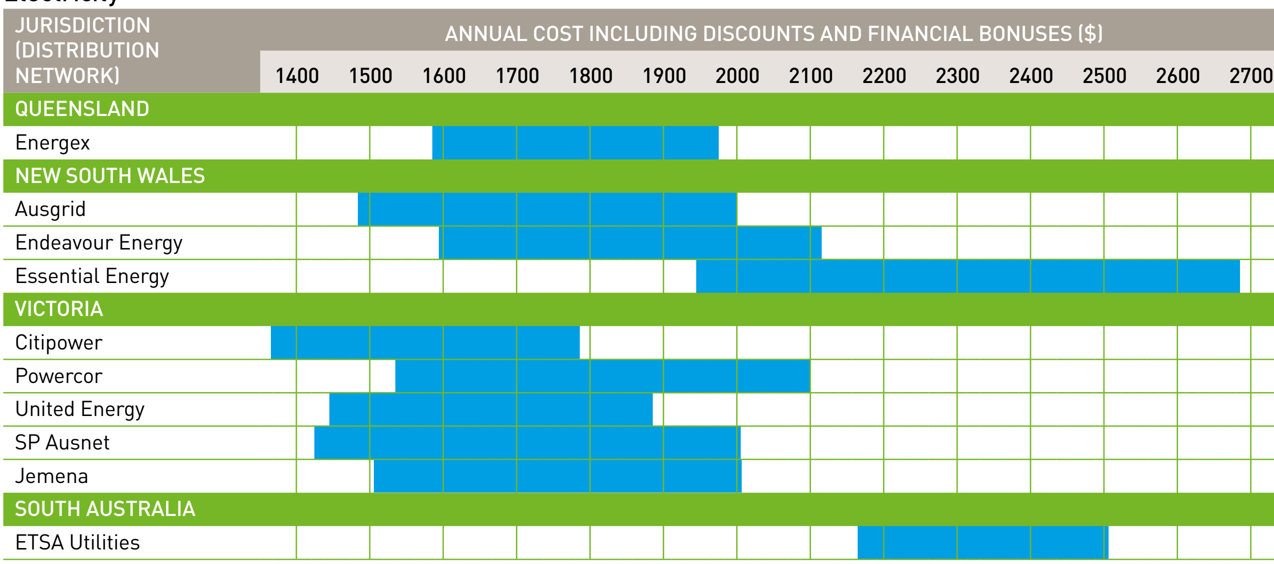
Retailers offer contracts for a range of products with different price structures. The offers may include standard products, green products, 'dual fuel' contracts (for gas and electricity) and packages that bundle energy with services such as telecommunications. Some contracts bundle energy services with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. Additional discounts may be offered for prompt payment of bills, or for direct debit bill payments. These offers may vary depending on the length of a contract. Many contracts carry a termination fee 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 energy 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. It is developing an online price comparison service for small customers, which it expects to launch on 1 July 2012.

Table 4.3 draws on state regulators' price comparison websites to estimate price offerings at September 2011 for customers in NEM jurisdictions other than Tasmania and the ACT. The data indicate some price and product diversity, with a spread in the estimated annual cost for customers of around $300–600 in electricity and $150–400 in gas.

Table 4.3 Price diversity in retail product offers

Electricity



Gas

■ Price spread

Note: Data are based on market offers (adjusting for discounts) for a customer consuming 7500 kilowatt hours of electricity and 60 gigajoules of gas per year on a 'peak only' tariff at August 2011 in the specified distribution network areas. Data do not account for Greenpower offers.

Sources: Data from jurisdictional online price comparison services in New South Wales (IPART), South Australia (ESCOSA), Victoria (ESC) and Queensland (QCA).

iStock

4.4.2 Regulated prices—recent trends

Most jurisdictions that apply retail price regulation set prices that small customers are entitled to access under a standing contract if they do not have a market contract with an energy retailer. The number of customers on standing contracts varies significantly across jurisdictions. For example, 26 per cent of customers are on standing contracts in South Australia, 57 per cent in Queensland and 80 per cent in the ACT.

All NEM jurisdictions except Victoria regulate prices for electricity retail services; only New South Wales and South Australia regulate gas prices. Jurisdictions have generally applied one of two methods to determine regulated energy retail prices:

- a building block approach, whereby the regulator determines efficient cost components (for example, wholesale costs, retail operating costs and costs associated with regulatory obligations), and passes through costs that have been determined elsewhere (for example, network costs). The regulator uses these costs to determine a maximum revenue requirement to be reflected in the prices charged by the retailer. Determinations typically cover a number of years, but some cost components are adjusted annually. There are separate pass through provisions for unexpected costs. New South Wales and Tasmania use this approach, which Queensland will also use from 2012–13.
- a benchmark retail cost index, whereby the regulator determines movements in benchmark costs to calculate annual adjustments in retail prices. Queensland (until 2012–13) and the ACT use this approach.

In 2011 the Essential Services Commission of South Australia introduced a new approach to determining regulated prices—a building block assessment at the start of the regulatory period, with annual adjustments based on movements in the price of market (unregulated) offers. The annual adjustments are limited by a tolerance band determined at the start of the regulatory period.

While Victoria does not regulate retail prices, its retailers are required to publish unregulated standing offer prices that small customers can access.[9] The prices are also published in the Victorian Government gazette.

Table 4.4 summarises announced movements in regulated and standing offer electricity and gas prices for the past three years, and estimates the annual bills for customers under these arrangements. Figure 10 in the *Market overview* of this report sets out the data in chart form.

The data indicate retail *electricity* prices rose significantly in the past three years. In some jurisdictions, customers can negotiate significant discounts against these prices by entering a market contract (table 4.3).

Consistent with the past two years, network costs were the largest contributor to price rises in 2011–12. Chapter 2 discusses the factors driving network costs. The cost of complying with green schemes also contributed, having increased significantly since 2010 as Australian governments introduced and expanded schemes to reduce carbon emissions and improve energy efficiency. The 2011–12 green cost increases are largely the result of changes to the renewable energy target scheme, which came into effect on 1 January 2011 (section 1.2.2).

- *Queensland* regulated electricity prices rose by 6.6 per cent in 2011–12, driven by network increases (5.2 per cent), changes to the renewable energy target scheme (3 per cent) and increased retailer costs (0.7 per cent). These rises were partly offset by a 2.3 per cent decrease due to changes in other green schemes (mainly the Queensland gas scheme, which requires a proportion of electricity to be sourced from gas fired generators) and falling wholesale energy costs. The price rise would have been 8.3 per cent if the Queensland Government had not prevented the distribution businesses, Energex and Ergon Energy, from recovering increased revenue allowances determined by the Australian Competition Tribunal (section 2.2.3).[10]

9 Customers can access the standing offer of only the 'financially responsible retailer' for their premises. This is the retailer that last supplied the premises or, for new connections, a designated 'local area retailer'.

10 QCA, *Benchmark retail cost index for electricity, final decisions, 2011–2012*, 2011.

Table 4.4 Movements in regulated and standing offer prices—electricity and gas

JURISDICTION	REGULATOR	DISTRIBUTION NETWORK AREA	AVERAGE PRICE INCREASE (PER CENT)			ESTIMATED ANNUAL COST ($)
			2009–10	2010–11	2011–12	
ELECTRICITY						
Queensland	QCA	Energex and Ergon Energy	15.5	13.3	6.6	1812
New South Wales	IPART	AusGrid	21.7	10.0	17.9	1939
		Endeavour Energy	21.1	7.0	15.5	2056
		Essential Energy	17.9	13.0	18.1	2557
Victoria	Unregulated	Citipower	9.4	14.5	3.9	1794
		Powercor	9.9	14.7	8.5	2090
		SP AusNet	6.1	11.3	23.5	1940
		Jemena	7.5	17.3	10.5	2010
		United Energy	6.8	11.3	9.6	1861
South Australia	ESCOSA	ETSA Utilities	3.1	18.3	17.4	2492
Tasmania	OTTER	Aurora Energy	6.2	15.3	11.0	2210
ACT	ICRC	ActewAGL	6.4	2.3	6.5	1541
GAS						
New South Wales	IPART	Jemena	4.4	5.2	4.0	1318
South Australia	ESCOSA	Envestra	5.3	3.1	13.8	1359

Notes:

Estimated annual cost is based on a customer using 7500 kilowatt hours of electricity per year and 60 gigajoules of gas per year on a 'peak only' tariff at August 2011. The South Australian gas cost is estimated for a metropolitan customer.

The Victorian price movements (and estimated annual costs) are for the calendar year ending in that period—for example, the 2011–12 Victorian data are for calendar year 2011. They are based on unregulated standing offer prices published in the Victorian Government gazette by the local area retailer in each of Victoria's five distribution networks.

Sources: Determinations, fact sheets and media releases from 2009 to 2011 by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

- *New South Wales* regulated electricity prices rose by an average of 17.3 per cent in 2011–12, following rises of 7–13 per cent in 2010–11. Network charges accounted for 80 per cent of the price increase in 2010–11 and over 50 per cent in 2011–12.[11] Green scheme costs resulted in a 6 per cent increase in average retail bills in 2011–12.[12]
- *Victorian* standing electricity price rises in 2011 varied significantly across distribution networks, ranging from 4 per cent in the CitiPower network to almost 24 per cent in the SP AusNet network. Because prices are unregulated, limited information is available on underlying cost drivers, including reasons for these diverse outcomes. But distribution network costs were not a major driver, accounting for retail price changes of between –1.9 per cent and 2.5 per cent in 2011. Charges for the introduction of smart meters accounted for retail price increases of around 2.5–7 per cent in 2010, but price impacts in this area were negligible in 2011. Compliance costs associated with government climate change policies would have had some retail impact. Limited information is available on the impact of wholesale energy costs (including hedge costs in futures markets), retailer costs and retail margins on Victorian retail prices.
- *South Australian* prices rose by 12 per cent on 1 January 2011, and a further 17.4 per cent on 1 August 2011. Higher wholesale energy costs accounted for 60 per cent of the January increase, with the remainder evenly split between green scheme costs and increased retail operating costs (including margins). Network price increases and a consumer price index adjustment accounted for the bulk of the August 2011 price increase.[13]

11 IPART, *Changes in regulated electricity retail prices from 1 July 2011*, 2011; IPART, 'Regulated electricity retail tariffs for 1 July 2010 to 30 June 2013—final report', Fact sheet, 2010.

12 IPART, *Changes in regulated electricity retail prices from 1 July 2011*, 2011.

13 ESCOSA, *2011–2014 Electricity standing contract price determination—variation price determination*, 2011.

- *Tasmanian* electricity prices rose by 11 per cent on 1 July 2011 in response to rising network charges and green scheme costs. A reduction in forecast consumption also had an impact.[14] The July increase followed a price rise in December 2010 of 8.8 per cent, of which around half was attributed to wholesale energy costs. Network costs were also a significant factor in the December price rise.
- The *ACT* recorded a moderate 6.5 per cent retail electricity price increase in 2011–12. The rise was largely attributed to green scheme costs (increasing prices by 5 per cent) and network costs (3.6 per cent), partly offset by a fall in wholesale energy costs.

Retail price increases have generally been lower in *gas* than electricity. In 2011–12 retail gas prices rose by 13.8 per cent in South Australia and 4 per cent in New South Wales. Higher distribution pipeline charges contributed to 70 per cent of the rise in New South Wales and 80 per cent in South Australia.[15]

4.4.3 Retail prices—long term trends

Figure 4.5 tracks movements in real energy prices for metropolitan households since 1991, using the electricity and gas components of the consumer price index. Figure 9 in the *Market overview* of this report compares price outcomes for household and business customers.

Real energy prices have trended upwards for small customers over the past decade. In part, this trend reflects the unwinding of historical cross-subsidies from business to household customers that was necessary as jurisdictions phased in retail contestability. In Brisbane (where small customers did not have access to a retailer of choice until 2007) and Hobart (where small customers are still unable to choose their retailer), electricity retail prices remained relatively stable until the past four years. In many jurisdictions, retail prices for gas tended to rise earlier and more steadily than for electricity.

Rising wholesale energy prices drove up retail prices in 2007–08, when the drought constrained hydro generation and low cost thermal generators that rely on water for cooling. More recently, rising network costs (especially for distribution networks and pipelines) and the costs of introducing and expanding green schemes flowed through to retail prices. The discussion of regulated price movements in section 4.3.2 outlines the issues in each jurisdiction.

4.5 Quality of retail service

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

A key performance indicator of affordability and access is the rate of residential customer disconnections for failure to meet bill payments (figure 4.6). In 2009–10 the rate of electricity disconnections increased in Tasmania, the ACT and Queensland. In Victoria, the disconnection rate increased for all retailers except Origin Energy and TRUenergy.[16] The rate in New South Wales was consistent with that of the previous year.

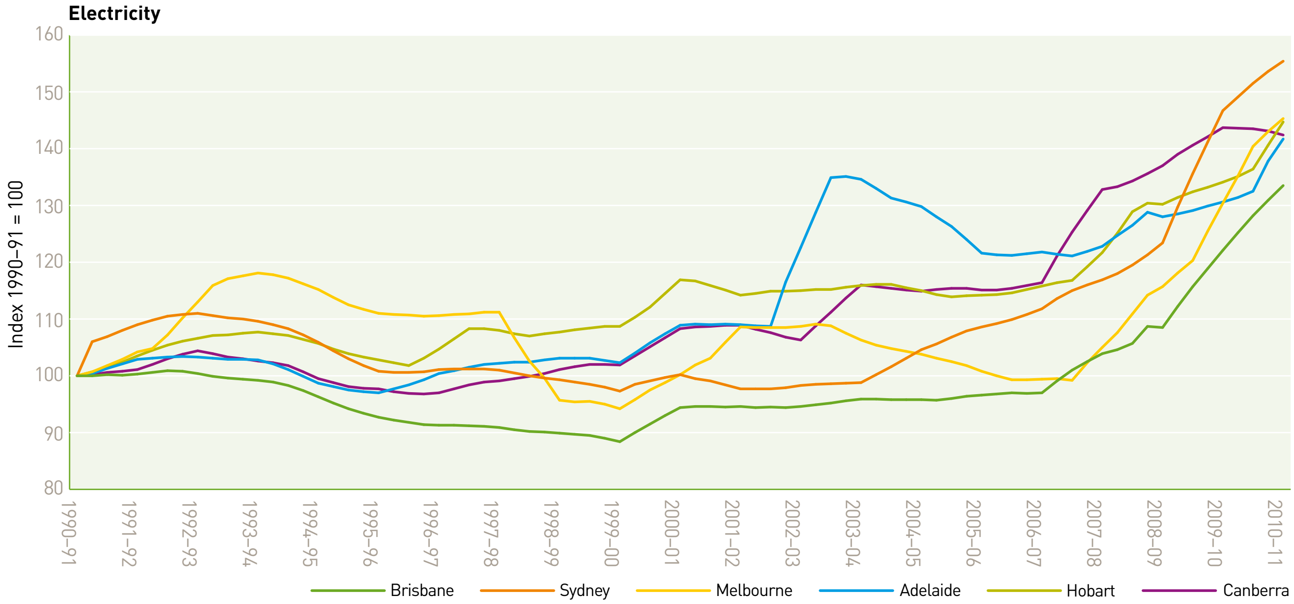
South Australia recorded a decrease in disconnection rates for both electricity and gas. The regulator noted this decrease, combined with an increase in instalment plans, may indicate improved financial hardship arrangements among retailers.[17]

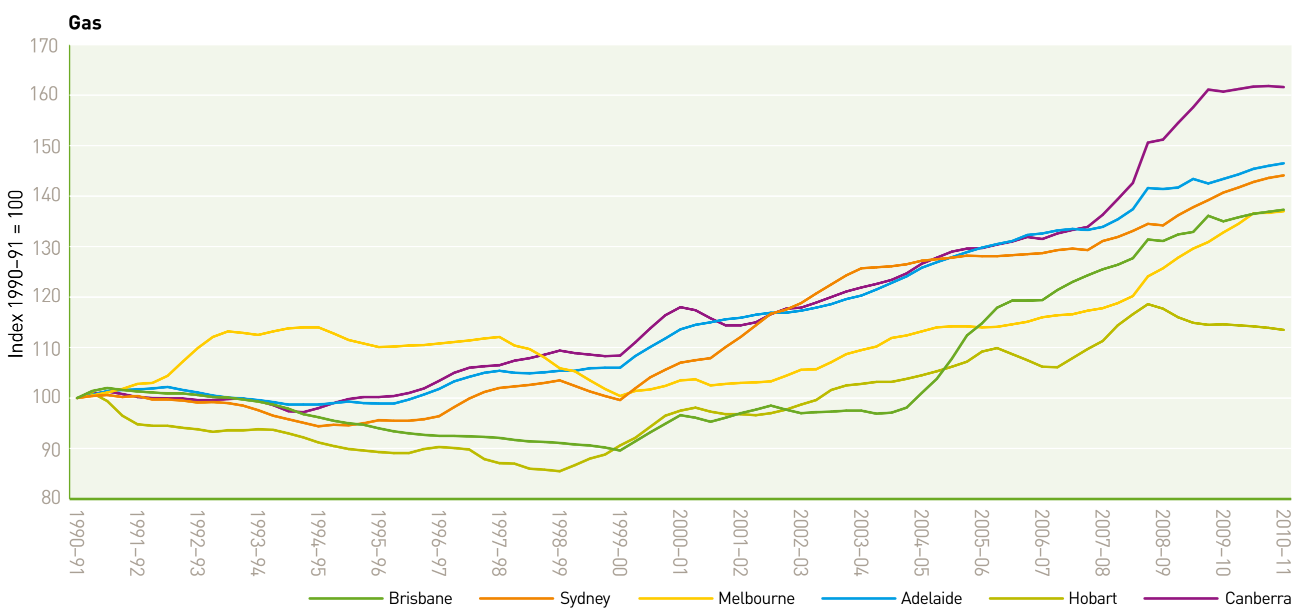
Figure 4.7 illustrates rates of retail customer complaints in electricity and gas. In 2009–10 the rate of electricity complaints rose in several jurisdictions. Billing issues were a significant source of complaint.

14 OTTER, 'Approval of 2011–12 electricity retail tariffs', Media release, 10 June 2011.
15 IPART, 'Review of regulated retail tariffs and charges for gas from 1 July 2010 to 30 June 2013—final report', Fact sheet, 2010.
16 ESC, *Energy retailers comparative performance report 2009–10*, 2010, p. 26.
17 ESCOSA, *2009–10 Annual performance report: South Australian energy supply industry*, 2010.

Figure 4.5

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.

Figure 4.6

Residential disconnections for failure to pay amount due, as a percentage of small customers

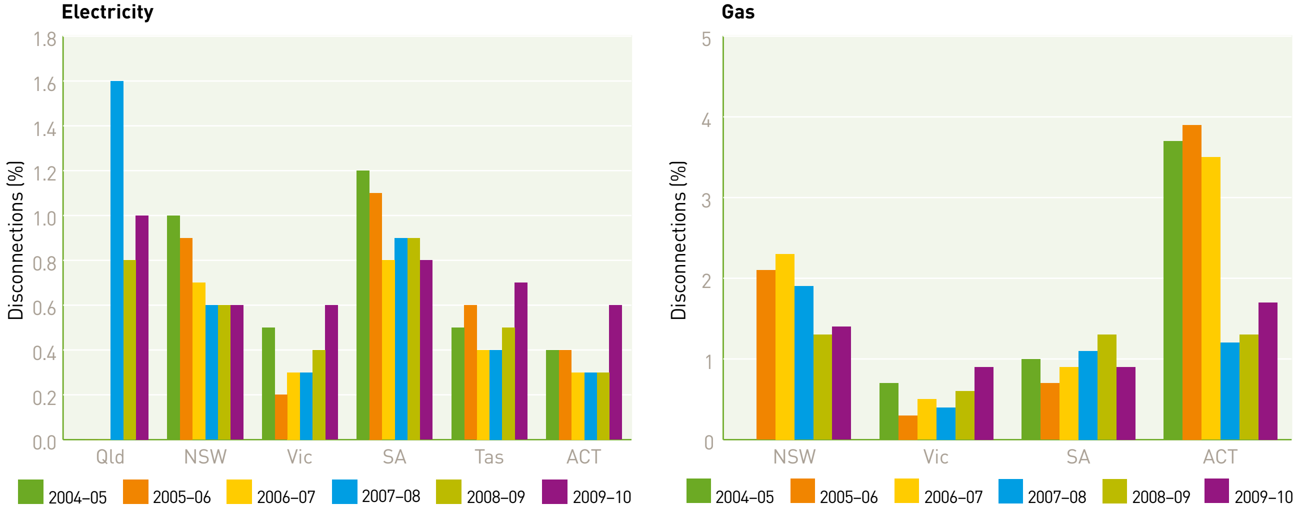
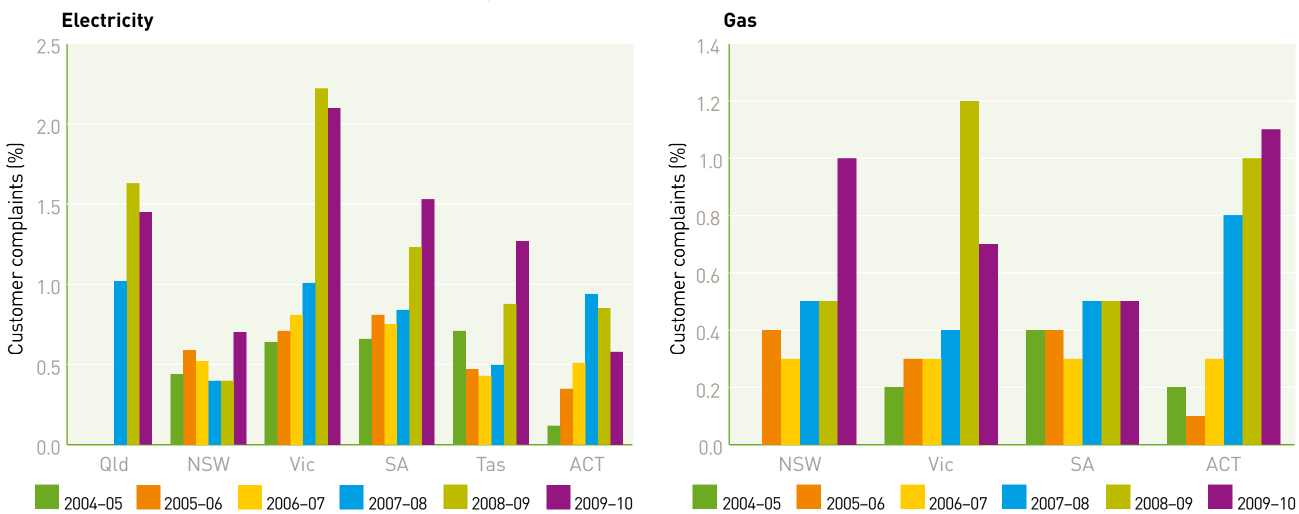


Figure 4.7

Retail customer complaints, as a percentage of total customers



Sources for figures 4.6 and 4.7: Reporting against Utility Regulators Forum templates; 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).

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
COAG	Council of Australian Governments
CPI	consumer price index
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
GSL	guaranteed service level
GW	gigawatt
GWh	gigagwatt hour
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
kWh	kilowatt hour
LNG	liquefied natural gas

MSATS	market settlement and transfer solution
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NPI	national power index
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
RIT-D	regulatory investment test for distribution
RIT-T	regulatory investment test for transmission
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCER	Standing Council on Energy and Resources
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