STATE OF THE ENERGY MARKET 2011

AUSTRALIAN
ENERGY
REGULATOR

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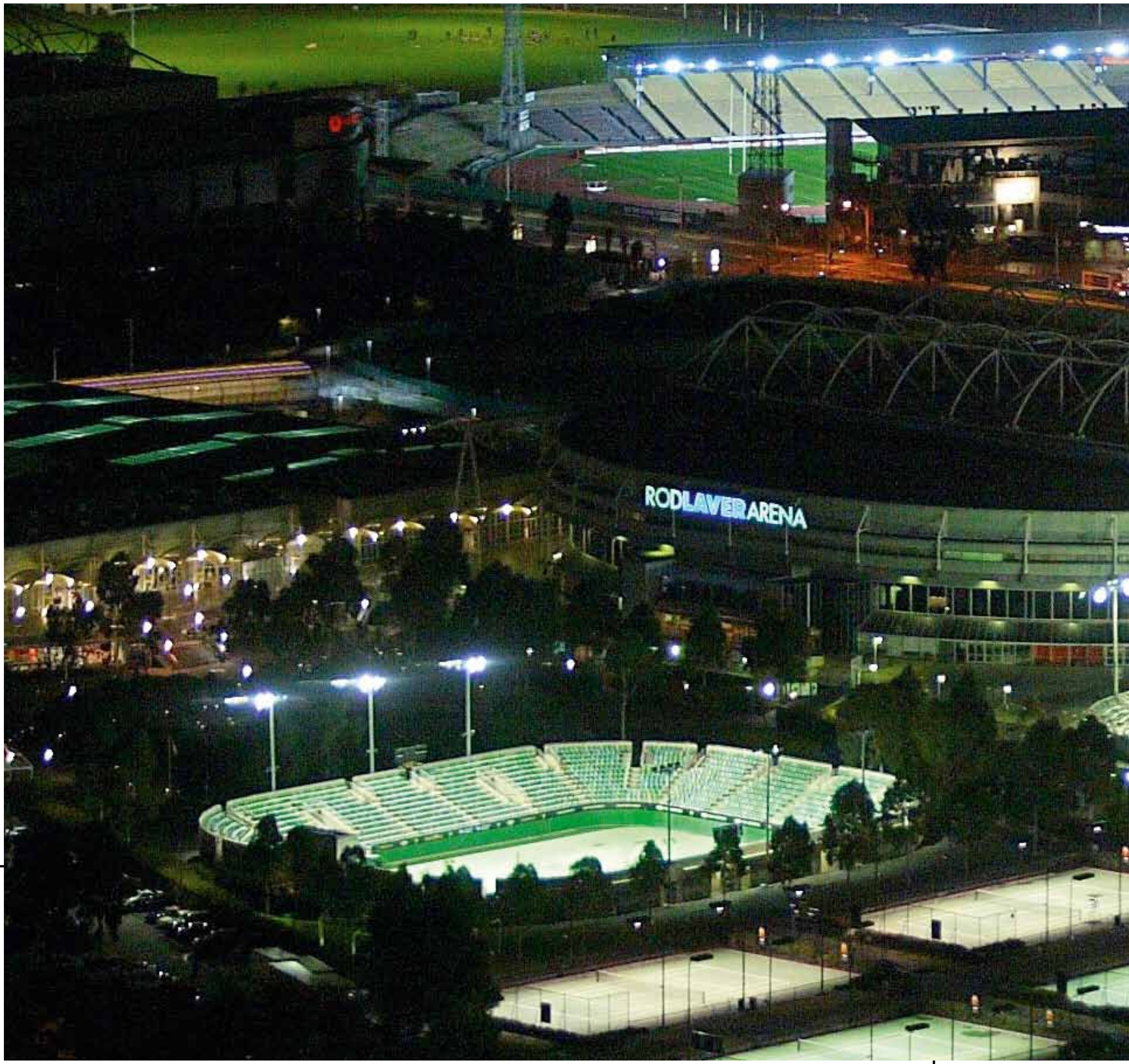
PREFACE

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.

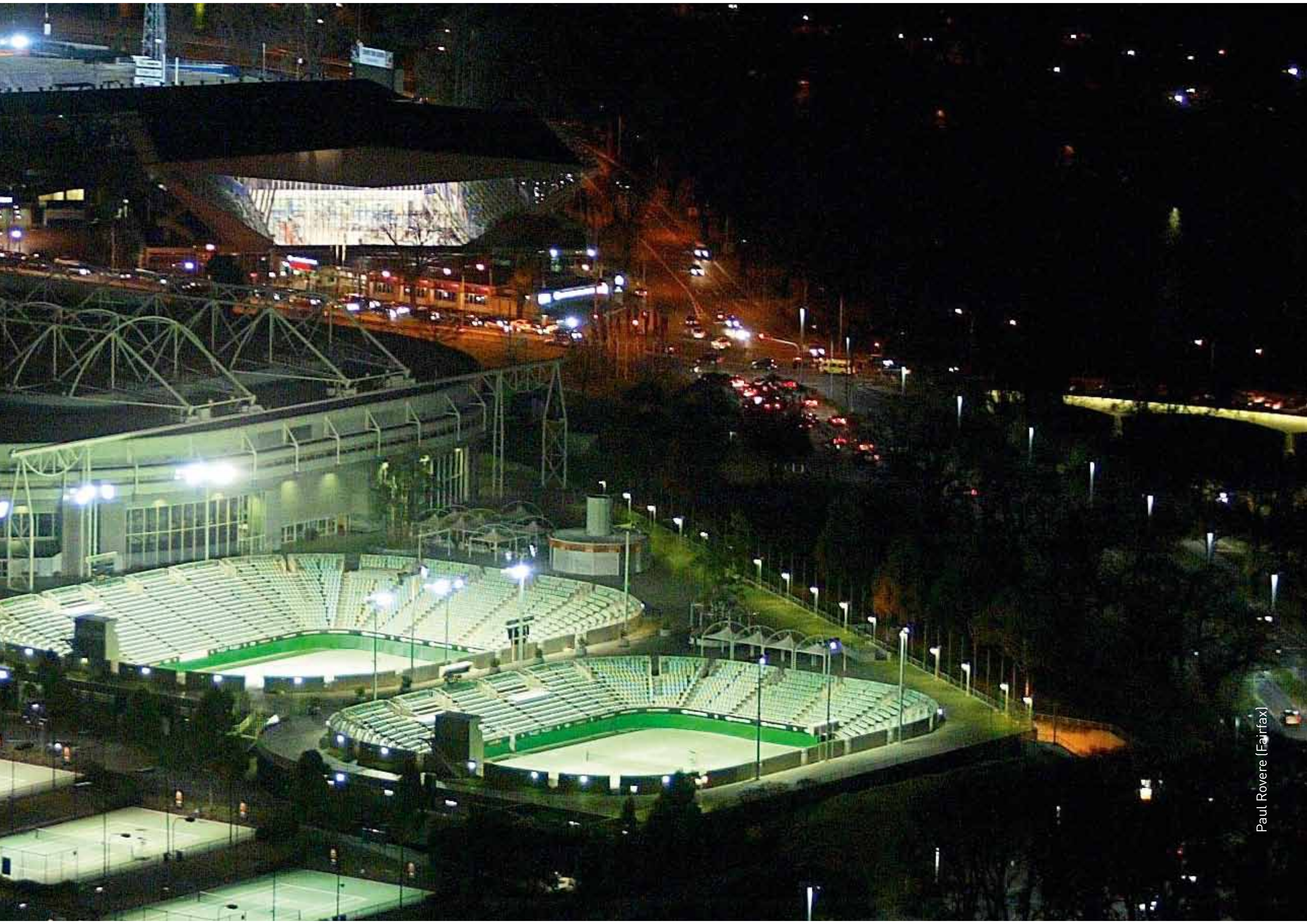
The 2011 report consists of a market overview, supported by chapters on the electricity, gas and energy retail sectors. The report focuses on activity over the past 12–18 months in those jurisdictions and areas in which the AER has regulatory responsibilities.

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

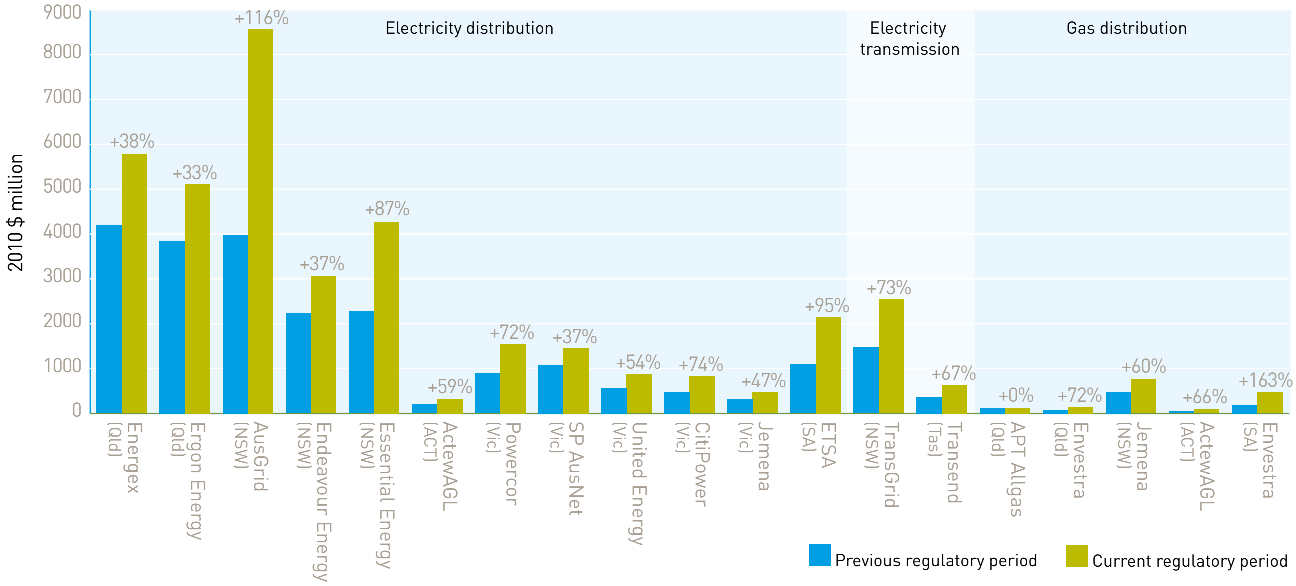
The AER regulates over 30 electricity networks and gas pipelines in southern and eastern Australia (and pipelines in the Northern Territory). In electricity, this involves setting the revenues and prices that a network business can earn from transporting electricity to customers. In gas, the AER approves 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.

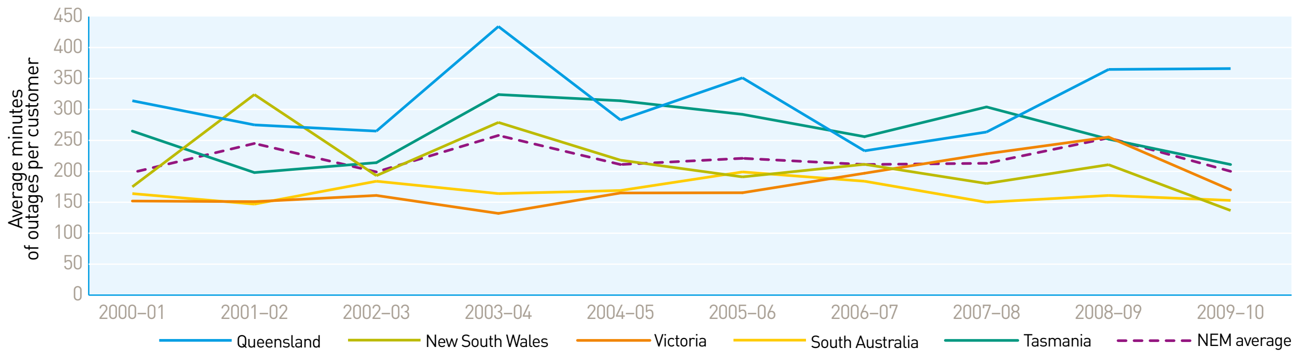
A4 Network reliability

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

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

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

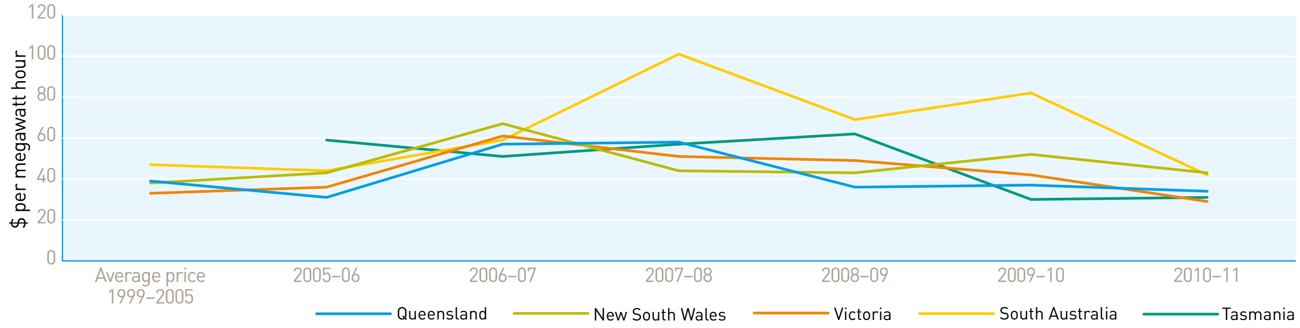
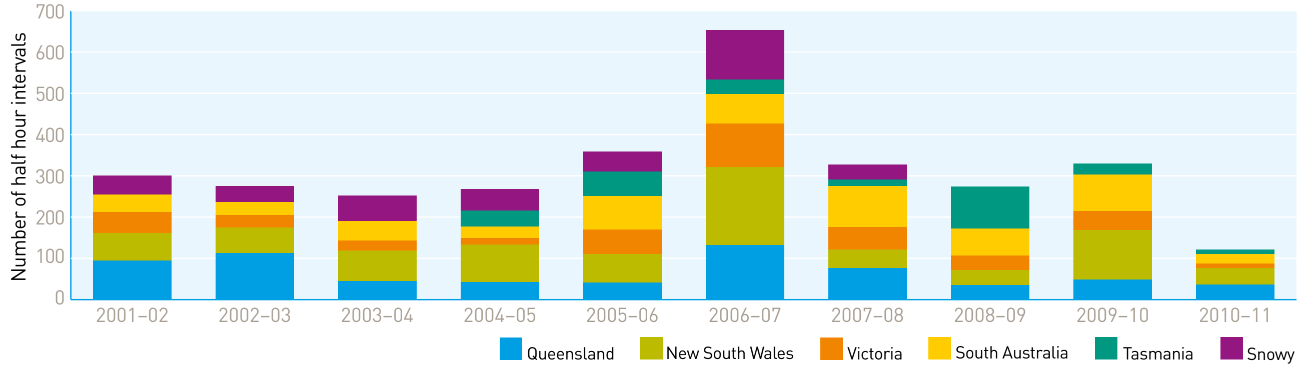


Figure 4
Trading intervals above $300 per megawatt hour—National Electricity Market



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

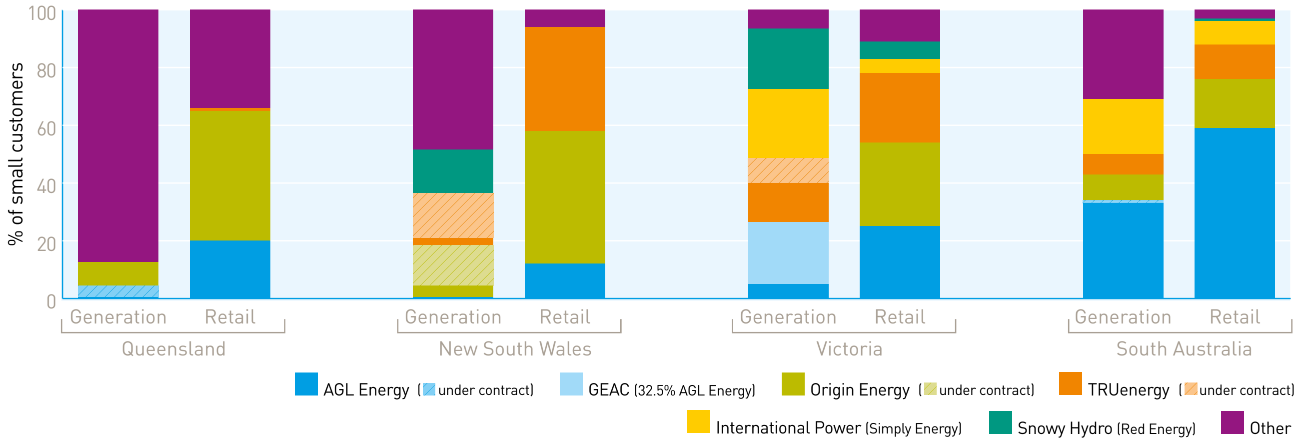
DATE	EVENT
2011	TRUenergy announced two 500 MW power plants in Queensland
	Alinta Energy entered retail market in South Australia
	Origin Energy constructing 518 MW Mortlake power station in Victoria
	AGL Energy commissioned 82 MW North Brown Hill wind farm in South Australia
	TRUenergy acquired 111 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.

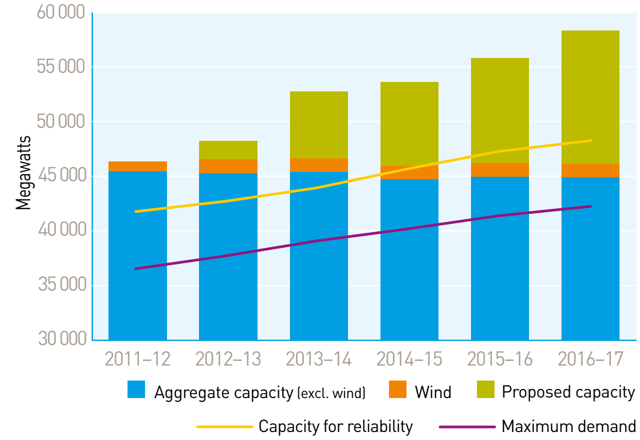
A sensitivity analysis found an unexpected NEM-wide withdrawal of 1000 MW of generation could lead to Queensland experiencing unserved energy in exceedance of the 0.002 per cent reliability standard in 2012–13. AEMO also found Queensland, assuming medium economic growth, would be the first region in 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 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.

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.

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).

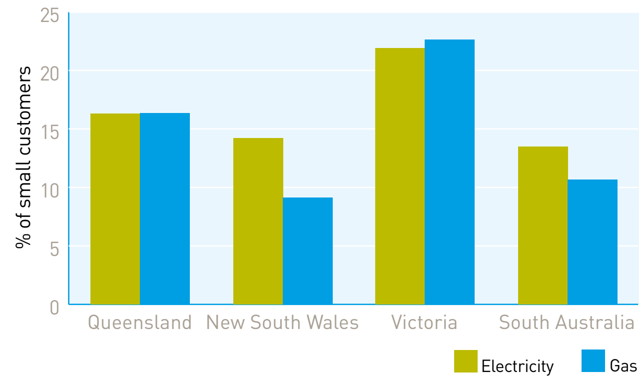
C2 Retail competition indicators

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

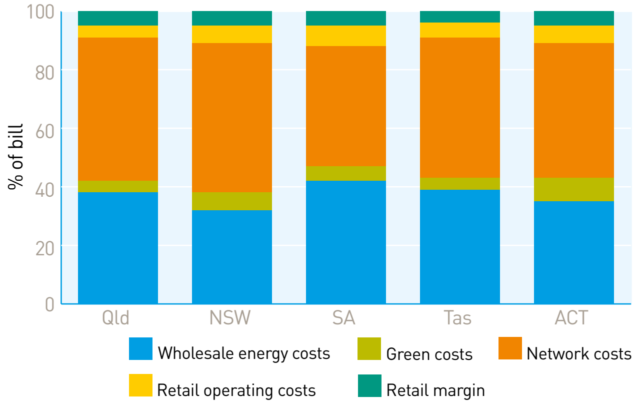
The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services. Figure 8

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.

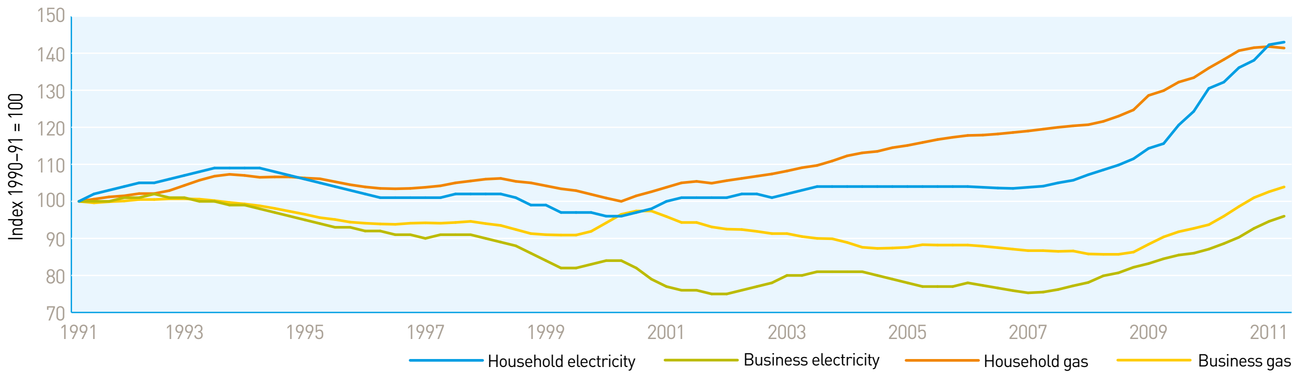
Figure 9 illustrates long term trends in energy retail prices in major capital cities. Following gradual increases over the past decade, there was a significant upswing in real electricity prices from 2007 and gas retail prices from 2008. Figure 10 illustrates indicative movements in retail electricity 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]

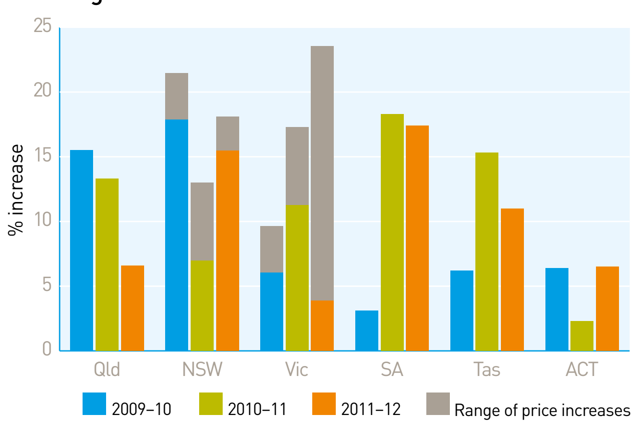
11 QCA, *Benchmark retail cost index for electricity, final decisions*, 2011–2012, 2011.

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).

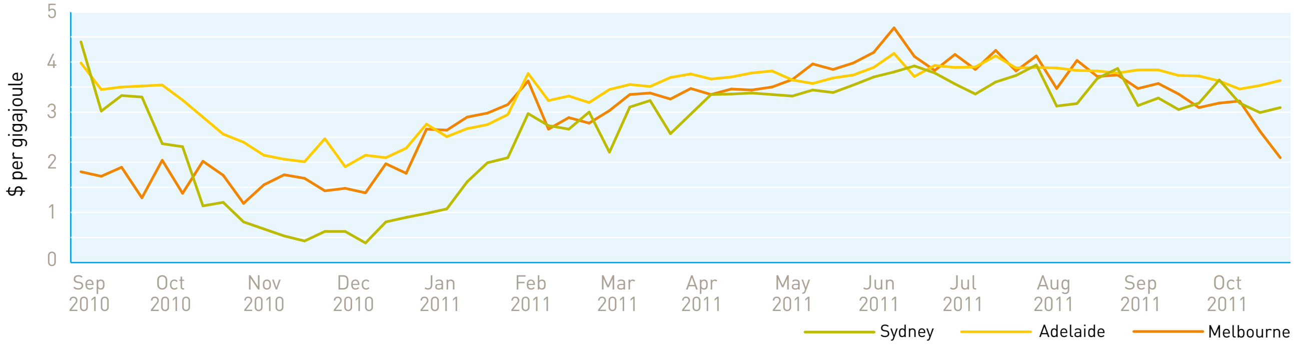
In the Victorian market, colder temperatures and an earlier onset of winter in 2011 led prices to rise above 2010 levels. The daily volume weighted average price for 2010–11 was $2.45 per gigajoule, compared with $1.83 per gigajoule in 2009–10. Both outcomes are significantly lower than long term average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