STATE OF THE ENERGY MARKET 2008

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ISBN 978 1 921393 92 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 Agricultural and Resource Economics; Australian Financial Markets Association; d-cyphaTrade; Economic Regulation Authority of Western Australia; EnergyQuest; Essential Services Commission of Victoria; Essential Services Commission of South Australia; Independent Competition and Regulatory Commission; Independent Market Operator of Western Australia; Independent Pricing and Regulatory Tribunal of New South Wales; Office of the Tasmanian Energy Regulator; Queensland Competition Authority; National Electricity Market Management Company; Utilities Commission of the Northern Territory; VaasaETT; and VENCorp.

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Editing: Biotext Pty Ltd, Melbourne
Design: True Characters Pty Ltd, Melbourne
Printing: Print Graphics, Melbourne
Cover printed on Spicers Paper Tudor Recycled RP, 300gsm
Internal pages printed on Spicers Paper Tudor Recycled RP, 115gsm

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PREFACE

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

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

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

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

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

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

Steve Edwell
Chairman

EXECUTIVE OVERVIEW


Mark Wilson

EXECUTIVE OVERVIEW

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

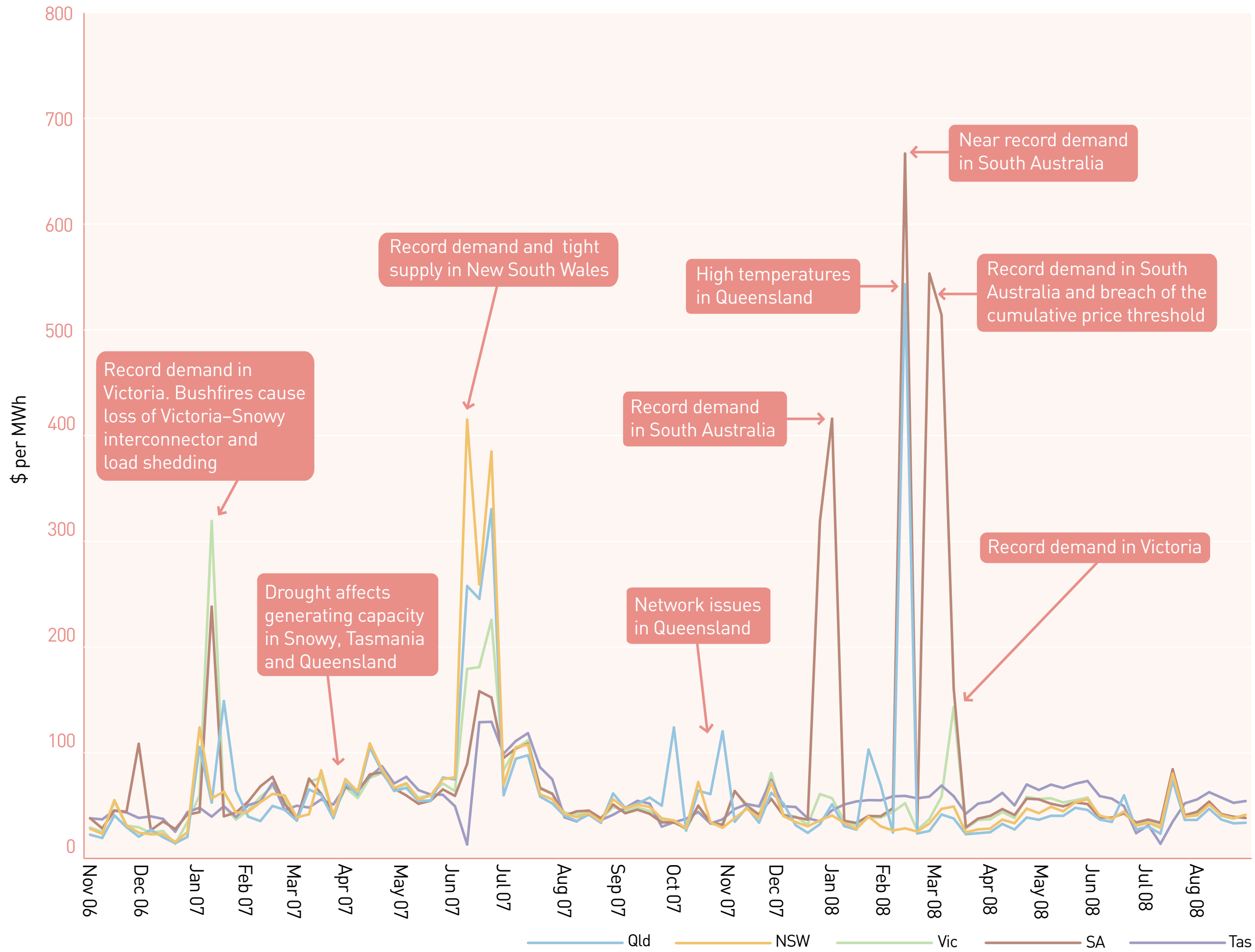
Market conditions in the natural gas sector differ between the east and west coasts. The industry is expanding rapidly on the east coast, underpinned by the burgeoning coal seam gas (CSG) sector and rising demand to supply gas-fired power stations. In the longer term, proposed liquefied natural gas (LNG)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

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

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

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

Figure 1
National Electricity Market prices



MWh, megawatt hours.

Note: Weekly volume-weighted averages.

Source: NEMMCO; AER.

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

National Electricity Market

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

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

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

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

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

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

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

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

Generation investment and reliability

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

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

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

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

Sources: NEMMCO; AER and company websites.

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

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

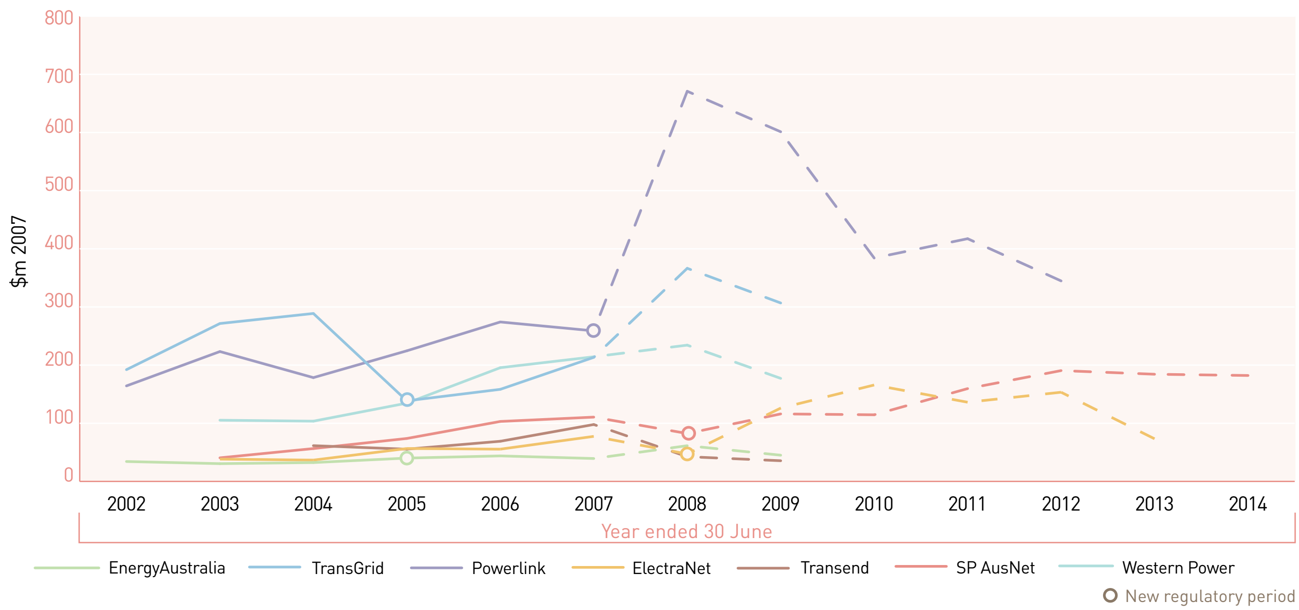
Generation investment has been slow to respond to rising demand, high prices and the need to replace some ageing plant. However, some investment response has started to emerge. The bulk of commissioned, committed and proposed new investment is in gas-fired and wind generation technologies, which are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

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

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

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

Figure 2
Electricity transmission investment



Notes:

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

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

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

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

Electricity transmission

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

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

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

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

The AER has undertaken a number of measures to encourage lower congestion costs. Aside from the investment allowances noted above, the AER revised its service target performance incentive scheme in 2008 to better reward network owners for cost-effective initiatives to improve operating practices (such as the scheduling and notification of network outages, live line work and equipment monitoring). The scheme permits a network business to earn an annual bonus of up to 2 per cent of its revenue if it can eliminate all outage events with a market impact of over $10 per MWh.[2]

Climate change policies

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Natural gas

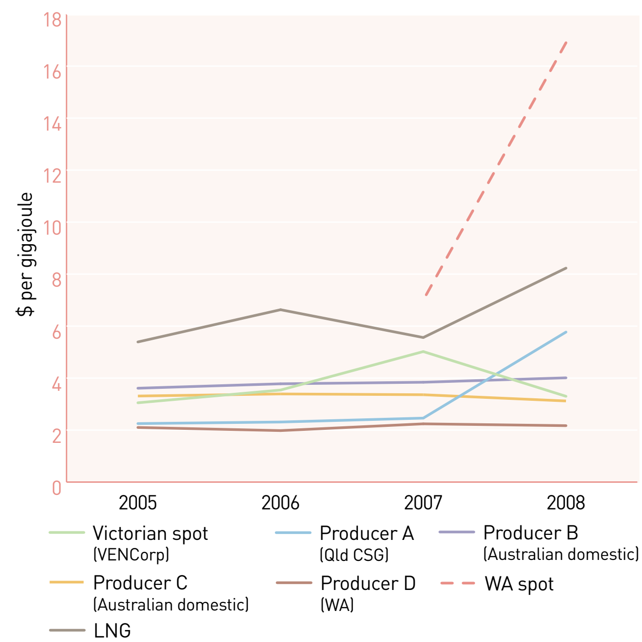
In a commissioned essay for this report, ACIL Tasman estimated that natural gas demand in Australia will more than double to around 4300 petajoules (including exports) over the next 20 years. It forecasts that demand growth will be principally driven by rising LNG production—in western, northern and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

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

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

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

Figure 3
Indicative wholesale natural gas prices



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

Notes:

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

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

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

10 EnergyQuest, *Energy Quarterly*, August 2008.

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

12 EnergyQuest, *Energy Quarterly*, August 2008.

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

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

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

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

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

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

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

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

14 ACIL Tasman, *Australia's natural gas markets: the emergence of competition?* (lead essay of this report), 2008, p. 3.

15 ACIL Tasman, *Australia's natural gas markets: the emergence of competition?* (lead essay of this report), 2008, p. 3.

16 EnergyQuest, *Energy Quarterly*, May 2008.

17 The Gas Market Leaders Group comprises 12 gas industry representatives and an independent chairperson.

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

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

n/a, not available.

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

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

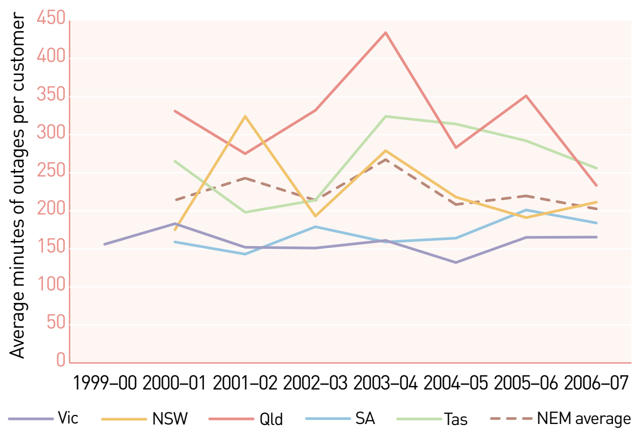
The proposed short-term trading market in gas, which is scheduled to begin by winter 2010, will be a mandatory price-based balancing mechanism at defined gas hubs in New South Wales and South Australia. Victoria has had a transparent balancing market in place since 1999. Structural and operational details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

Energy distribution

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

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

Figure 4
Electricity distribution network reliability



NEM, National Electricity Market.

Notes:

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

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

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

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

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

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

Retail

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

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

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

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

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

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

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

Figure 5

Cumulative retail switching to 30 June 2008—small customers

Notes:

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

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

Table 3 Electricity retail prices—recent regulatory and government decisions

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

CPI, consumer price index.

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

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

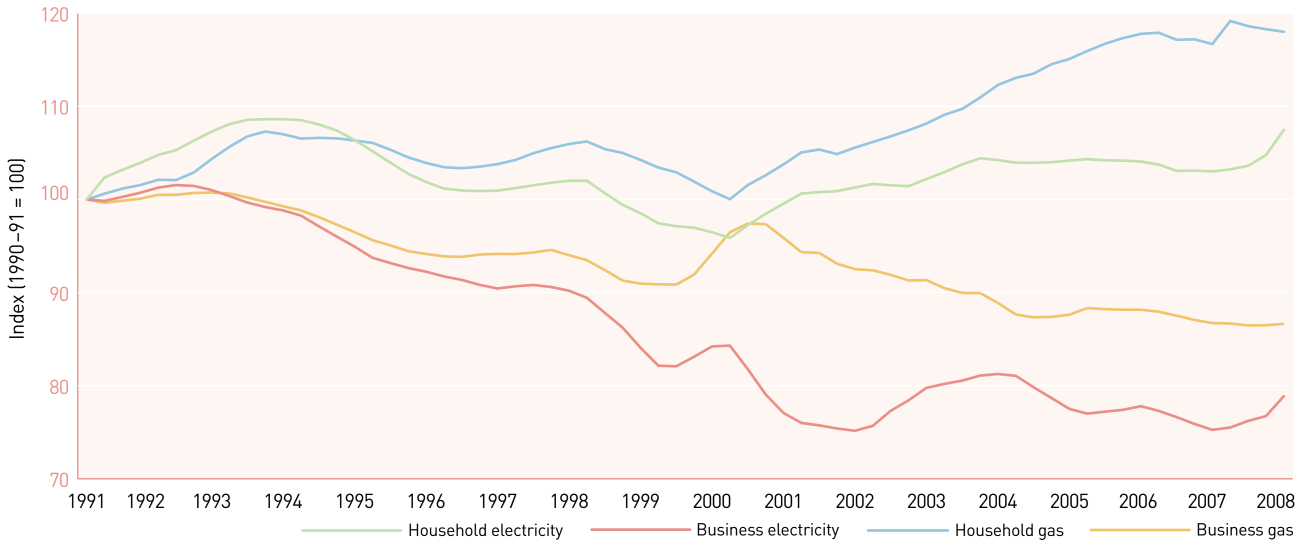
The AEMC is currently reviewing the South Australian market. The *First final report*, released in September 2008, found that competition is effective for small electricity and gas customers in South Australia, with competition being more intense in electricity than in gas. Although the AEMC considered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

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

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

Figure 6

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



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

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

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

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

Asset ownership

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

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

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

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

Table 5 **Ownership of private network infrastructure at 1 August 2008**

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

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

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

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

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

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

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

The AER's role

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

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

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

ABBREVIATIONS

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

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

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