STATE OF THE ENERGY MARKET 2009

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CONTENTS

PREFACE

The Australian Energy Regulator (AER) aims to keep stakeholders informed of policy, regulation and market developments in the energy sector. This is the AER's third *State of the energy market* report, which 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. 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 one user friendly publication. The aim is to better inform market participants and assist policy debate on energy market issues. The AER is not a policy body, however. In that context, the report focuses on presenting facts, rather than advocating policy agendas.

This 2009 edition consists of a market overview, supported by 11 chapters on the electricity and natural gas sectors. The essay this year is an assessment by EnergyQuest of the state of the natural gas industry, focusing on the growing integration of Australian and global energy markets. There is also an appendix providing background on energy market reform in Australia, including the roles of key policy and regulatory bodies.

The 11 chapters of the report provide more detail on 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, it also contains some coverage of Western Australia and the Northern Territory.

The *State of the energy market* is an evolving project. This year's edition provides increased coverage of energy policy and regulatory developments, including the AER's recent activity. The chapters also provide a stronger focus on key market developments in each sector over the past 12–18 months. The market overview includes some discussion of the implications of climate change policies and the global financial crisis for the energy industry, with the chapters containing more detailed coverage.

Looking forward, the AER will review its approach to *State of the energy market* reporting and consider ways to better inform our audience. As always, we hope to hear the views of readers in this regard. In the meantime, I hope this 2009 edition will provide a valuable resource for market participants, policymakers and the wider community.

Steve Edwell
Chairman

MARKET OVERVIEW

Mark Wilson

MARKET OVERVIEW

Despite difficult economic conditions, there has been considerable momentum in the energy sector over the past 12–18 months. We have seen renewed growth in generation investment, especially in Queensland, New South Wales and South Australia. Network investment is also increasing to meet the challenges of rising peak demand, ageing assets and more rigorous licensing requirements to improve network security.

There has been continued growth and diversification in the natural gas industry, with major projects underway in Western Australia, the continued expansion of Queensland's coal seam gas (CSG) industry and the likelihood of east coast liquefied natural gas (LNG) exports in the next few years. Australia's gas pipeline network continues to expand, with Queensland now interconnected with the south east gas markets, and Bonaparte Basin gas coming onstream in Darwin.

A number of recent policy initiatives will enhance transparency and efficiency in upstream gas markets. The National Gas Market Bulletin Board, which began in July 2008, provides real-time and independent information on the state of the gas market, system constraints and market opportunities. To complement this reform, new spot markets for short term gas trading will begin in the winter of 2010.

On the regulatory front, the transition to national energy regulation has continued. The Australian Energy Regulator (AER) is now the economic regulator of all electricity networks and covered gas pipelines in southern and eastern Australia. It has completed its first determinations for the electricity distribution sector, and is undertaking its first access arrangement reviews in gas distribution.

A new body—the Australian Energy Market Operator (AEMO)—began operation on 1 July 2009 as the single electricity and gas market operator in southern and eastern Australia. It is also coordinating high level national transmission planning and will report on investment opportunities in electricity and natural gas.

Alongside these developments are challenges and concerns. Rising investment and operating costs are significantly increasing network charges and placing upward pressure on retail energy prices. There are also concerns that market power is affecting wholesale electricity prices in some regions.

While generation investment has picked up, there is continued uncertainty over climate change policies. The Australian Energy Market Commission (AEMC) cited concerns that this uncertainty may be delaying generation investment needed for reliability purposes.[1] At the same time, climate change policies are providing momentum for network improvements such as the installation of smart meters to help consumers actively manage their energy consumption.

1 National Electricity Market

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

Wetter conditions in parts of eastern Australia and a mild winter in 2009 led to an easing of wholesale price pressure in most regions of the NEM in the past 18 months or so. Tasmania was the only region in which spot electricity prices rose during 2008–09. Queensland's average spot price in that period was its lowest for several years. While prices fell sharply in South Australia, they remained high relative to those in other mainland regions.

Despite generally benign conditions, concerns remain that some generators have been exercising market power in some regions. The NEM was designed to minimise the risk of market power, through an interconnected transmission grid that allows competition between generators. But there are circumstances in which baseload generators can price capacity at around the market cap and be certain of at least partial dispatch. This behaviour is often more evident at times of peak demand, typically on days of extreme temperatures.

The opportunities for market power are enhanced if transmission interconnector limits are reduced. Given the relatively inelastic demand for electricity and the high market price cap, such circumstances can lead to significant opportunities for price manipulation.

The AER referred in previous *State of the energy market* reports to generators exercising market power in New South Wales in 2007 and South Australia in 2008. These occurrences were reflected in significant price spikes (figure 1). While some price events relate to exogenous factors such as extreme weather, bushfires and unplanned infrastructure outages, a number of spikes in the past two years coincided with strategic generator bidding.

There have been continuing concerns in South Australia, where spot prices in the past two years were significantly higher than in other mainland NEM regions. In the early months of 2009 South Australian spot prices exceeded $5000 per megawatt hour (MWh) on 27 occasions. The bidding strategies of AGL Energy for its Torrens Island power station were a key contributing factor on most occasions. The events typically occurred on days of extreme temperatures and demand, which created a tight supply–demand balance. Under these conditions, Torrens Island can bid a significant proportion of its capacity at around the market cap and be guaranteed at least partial dispatch.

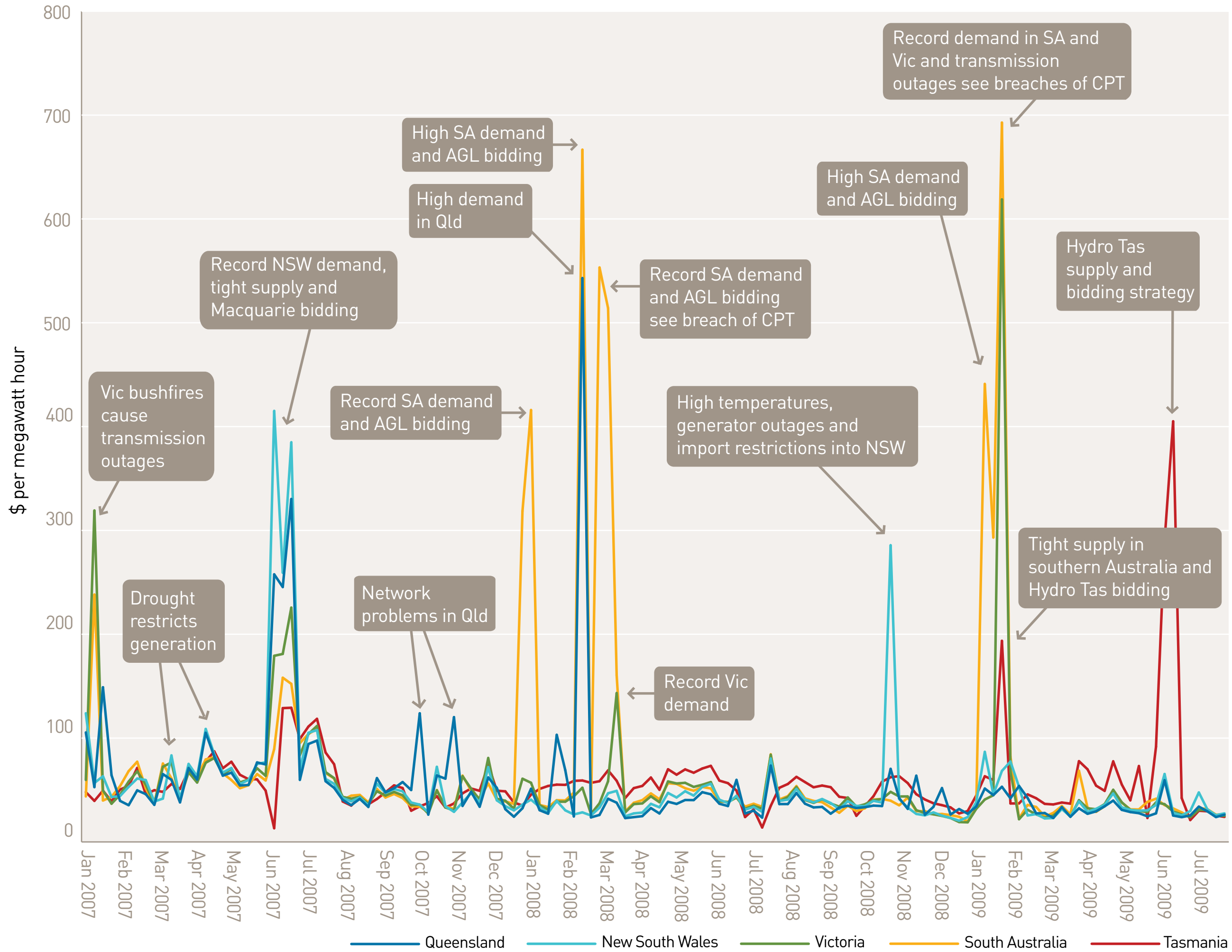
More recently, market bidding strategies emerged as a concern in Tasmania. In June 2009 the spot price in Tasmania exceeded $5000 per MWh on 13 occasions. The spikes were often driven by Hydro Tasmania making sudden and repeated cuts in the output of its non-scheduled (mini hydro) generators, in conjunction with strategic bidding for the rest of its portfolio. The strategy led to administered pricing being applied for four days in June—the first time for Tasmania.

Tasmania also experienced extreme prices for raise contingency frequency control services in early April. The Office of the Tasmanian Economic Regulator has given notice of its intention to declare the supply

1 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, Sydney, October 2009, pp. 81–2.

Figure 1

National Electricity Market—average weekly prices



AGL, AGL Energy; CPT, cumulative price threshold; Macquarie, Macquarie Generation; Hydro Tas, Hydro Tasmania.

Note: Volume weighted prices.

Sources: AEMO; AER.

of these services, which would enable it to regulate prices. While the AER recognises the need for this proposal, such an outcome cannot be seen as a positive development for the market.

The AER monitors activity in the spot market to screen for issues of noncompliance with the Electricity Rules. While bidding capacity at high prices is not a breach of the Rules, it may raise issues under the anti-competitive conduct provisions of the *Trade Practices Act 1974* (Cwth). The AER assists the Australian Competition and Consumer Commission (ACCC) in relation to enforcing these provisions.

The exercise of market power by some generators is a continuing concern. There is evidence that it is leading to increased market volatility and higher spot prices in some regions. The AER will continue to monitor and report on generator bidding behaviour.

The AER reports on all extreme price events in the NEM and conducts more intensive investigations where warranted. It has conducted two recent investigations into the rebidding behaviour of generators. While the Electricity Rules allow generators to amend their original price bids to supply electricity, they require that generators make all bids and rebids in 'good faith.'

The rebidding provisions play an important role in promoting accurate dissemination of information for efficient market dispatch.

In 2008 the AER launched separate investigations into whether Stanwell (a Queensland generator) and AGL Energy (in relation to its South Australian generators) acted 'in good faith' (as contemplated under the Rules) when they rebid capacity during periods of high prices in early 2008. In its investigation findings, published on 12 May 2009, the AER found AGL Energy's bidding was not in breach of the Rules.

The AER investigation into the rebidding behaviour of Stanwell led to it instituting proceedings in the Federal Court, Brisbane. It has alleged that several of Stanwell's rebids of offers to generate electricity on 22 and 23 February 2008 were not in 'good faith'. The AER is seeking orders that include declarations, civil penalties, a compliance program and costs. The matter has been set down for trial in June 2010.

The AER also investigated the operation of the market on 29 and 30 January 2009, when extreme temperatures in Victoria and South Australia led to record electricity demand. There were also significant interruptions to transmission lines and interconnectors on those two days. In combination, these events led to extreme spot prices, administered pricing and supply interruptions. The investigation identified issues relating to the performance of, and reporting on, network capabilities by network businesses, but no breaches of the Rules.

Generation investment and reliability

The *State of the energy market 2008* report referred to concerns that generation investment had been slow to respond to rising electricity demand. There was little generation investment across the NEM in the middle of the current decade, but then tightening supply conditions led to significant new investment in the past few years (figure 2). New investment has occurred in coal and gas fired capacity in Queensland since 2005–06 and in wind capacity in South Australia over the same period. In part, the shift towards investment in gas fired plant and wind generation reflects market expectations that climate change policies will improve the competitiveness of these technologies in the generation mix.

Table 1a sets out major new generation investment that came on line in the NEM in 2008–09, excluding wind. The bulk of new investment—1100 megawatts (MW)—was in privately developed gas fired plant in New South Wales. Origin Energy commissioned the 648 MW Uranquinty plant near Wagga Wagga, and TRUenergy commissioned the 435 MW Tallawarra plant.

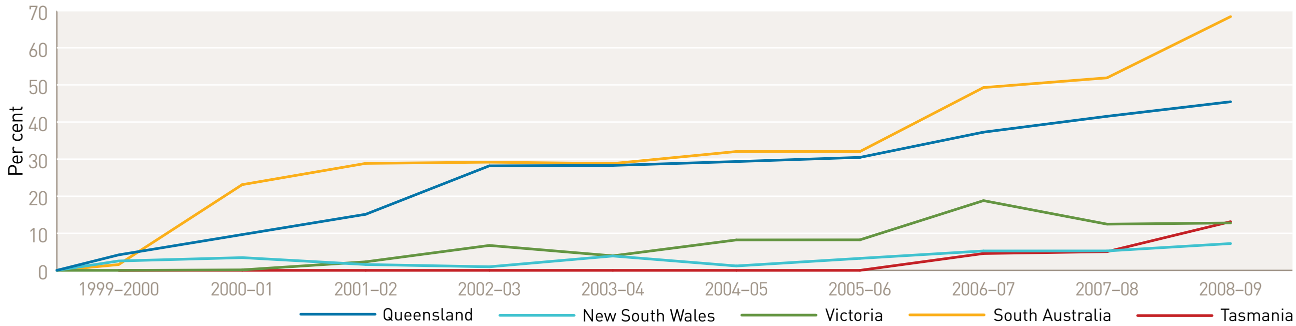
Queensland added around 460 MW of private investment with the commissioning in 2009 of the Braemar 2 plant, developed by ERM Power and Arrow Energy. In South Australia, Origin Energy completed a 128 MW expansion of its Quarantine plant. Government businesses in New South Wales and Tasmania also commissioned new plant in 2009. In addition, Victoria, New South Wales and South Australia recorded around 500 MW of new wind generation capacity.

Table 1b sets out *committed* investment projects in the NEM at June 2009. It includes those under construction and those where developers and financiers have formally committed to construction. There is around 2650 MW of committed capacity in the NEM, of which more than 2000 MW is in gas fired generation. Origin Energy has committed to major developments in Queensland (including a 605 MW plant on the Darling Downs) and Victoria (a 518 MW plant at Mortlake). In addition, government owned generators in New South Wales have committed to significant investment. At June 2009 AEMO reported another 15 490 MW of *proposed* investment, including:

- 8760 MW of non-wind capacity, mostly in gas fired generation for New South Wales, Queensland and Victoria
- 6730 MW of wind capacity, mainly in Victoria, New South Wales and South Australia.

Figure 2

Change in net generation capacity (including wind) since market start



Note: Net change in registered capacity from 1998–99. A decrease may reflect a reduction of capacity due to decommissioning or a change in the ratings of generation units.

Sources: AEMO; AER.

Table 1a **Generation investment, 2008–09 (excluding wind)**

REGION	POWER STATION	DATE COMMISSIONED	TECHNOLOGY	CAPACITY (MW)	ESTIMATED COST ($ MILLION)	OWNER
Qld	Braemar 2	April–June 2009	OCGT	462	546	ERM Power and Arrow Energy
NSW	Colongra (unit 1)	June 2009	OCGT	157		Delta Electricity
NSW	Tallawarra	February 2009	CCGT	435	350	TRUenergy
NSW	Uranquinty	October 2008 – January 2009	OCGT	648	700	Origin Energy
SA	Quarantine	March 2009	OCGT	128	90	Origin Energy
Tas	Tamar Valley Peaking	April 2009	OCGT	58		Aurora Energy

Table 1b **Committed investment in the National Electricity Market, June 2009**

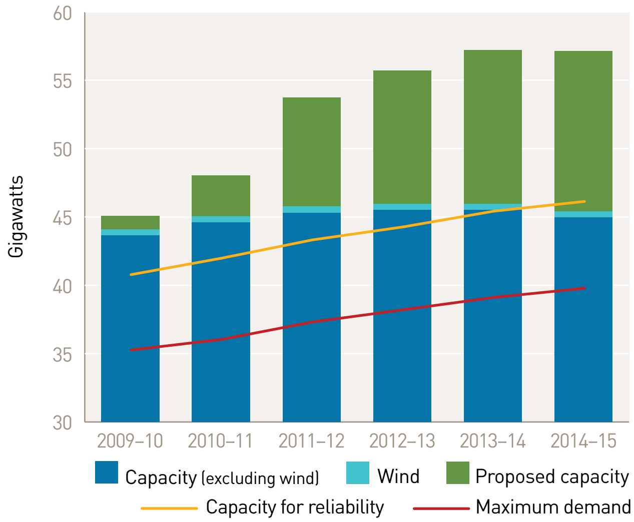
DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
QUEENSLAND				
Queensland Gas Company	Condamine	CCGT	135	2009–10
Origin Energy	Darling Downs	CCGT	605	2010
Origin Energy	Mount Stuart (extension)	OCGT	127	2009
Rio Tinto	Yarwun Cogen	Gas cogeneration	152	2010
NEW SOUTH WALES				
Eraring Energy	Eraring (extension)	Coal fired	120	2010–11
Delta Electricity	Colongra (units 2–4)	OCGT	471	
VICTORIA				
AGL Energy	Bogong	Hydro	140	2009–10
Origin Energy	Mortlake	OCGT	518	2010
Pacific Hydro	Portland	Wind	164	2009–10
SOUTH AUSTRALIA				
International Power	Port Lincoln	OCGT	25	2010
TASMANIA				
Aurora Energy	Tamar Valley	CCGT	196	2009

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

Note: Capacity is summer capacity for all generators.

Source: AEMO.

Figure 3
Demand and generation capacity outlook to 2014–15



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

Data source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, Melbourne, 2009.

Investment in wind generation continues to rise, especially in South Australia, where it now accounts for around 20 per cent of installed generation capacity. The extent of new and proposed investment in wind generation has raised concerns about system security and reliability. These concerns led to a change of the Electricity Rules, requiring from 31 March 2009 that new wind generators greater than 30 MW must be classified as 'semi-scheduled' and participate in the central dispatch process. This allows AEMO to reduce the output of these generators if necessary. The Australian Government's expanded renewable energy target (RET), passed in August 2009, will likely further stimulate investment in wind generation.

Figure 3 charts forecast peak demand in the NEM against installed, committed and proposed capacity over the next six years. It also shows the amount of capacity that AEMO considers necessary to maintain a reliable power system, given projected demand. It indicates current installed and committed capacity will be sufficient to meet peak demand projections and reliability requirements until at least 2012–13 on a national basis. Individual regions may require generation investment at an earlier date.

While only a small percentage of proposed projects would need to be developed to meet reliability requirements beyond 2012–13, the AEMC has cited uncertainty over the details of climate change policies as one factor that may delay some investment. As the details of climate change policies become more certain, the investment response will likely strengthen.

2 Energy networks

The transition to national regulation of energy networks is continuing. The AER completed its first revenue determinations in electricity distribution in April 2009, for the New South Wales and ACT networks. It also published determinations for the New South Wales and Tasmanian transmission networks at that time.

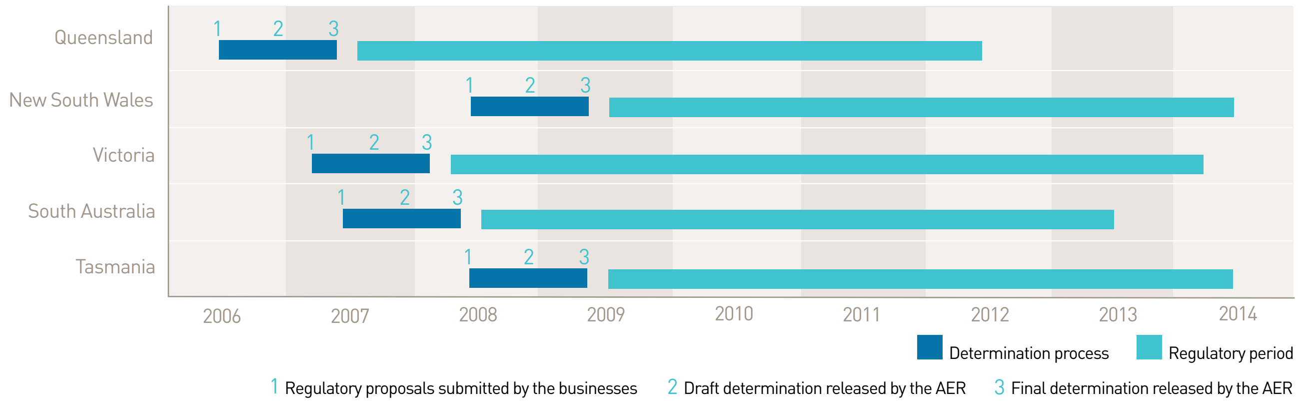
The AER received its first proposals on access arrangement revisions in gas distribution in June 2009. It is also considering new regulatory proposals for electricity distribution networks in Queensland and South Australia.

Figure 4 sets out indicative timelines for the AER's consideration of regulatory proposals for energy networks. The AER has published guidelines and frameworks to explain its regulatory approach.

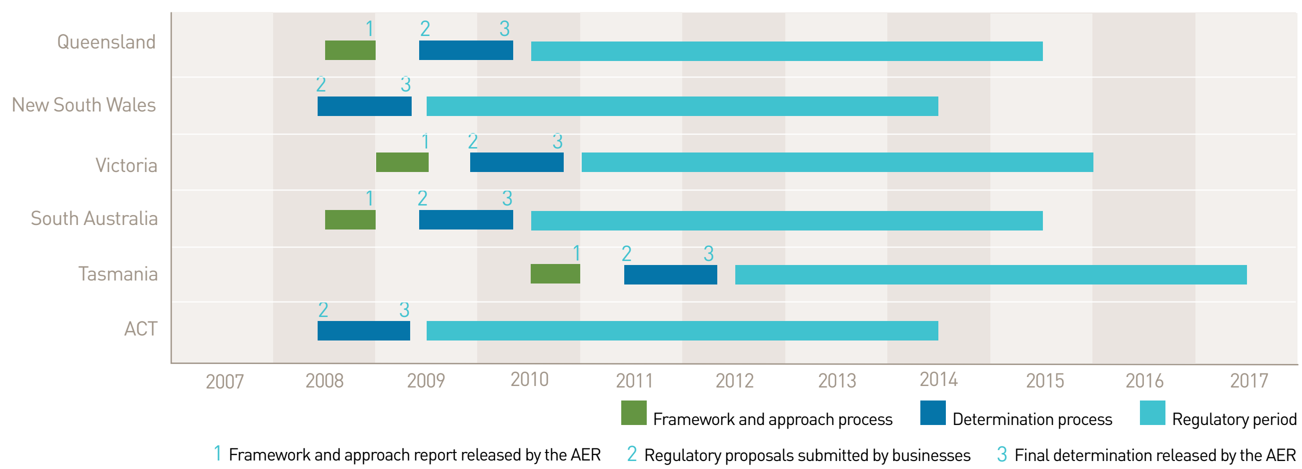
A common feature of recent proposals has been substantial increases in capital and operating expenditure requirements. Figure 5 illustrates new investment under current regulatory proposals and AER determinations compared with investment in previous regulatory periods.

Figure 4
Indicative timelines for AER determinations on energy networks

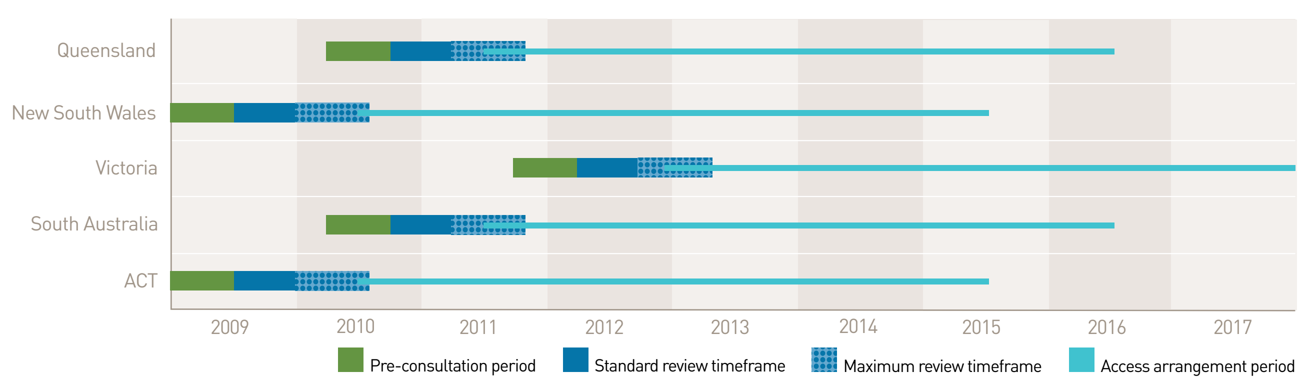
Electricity transmission



Electricity distribution

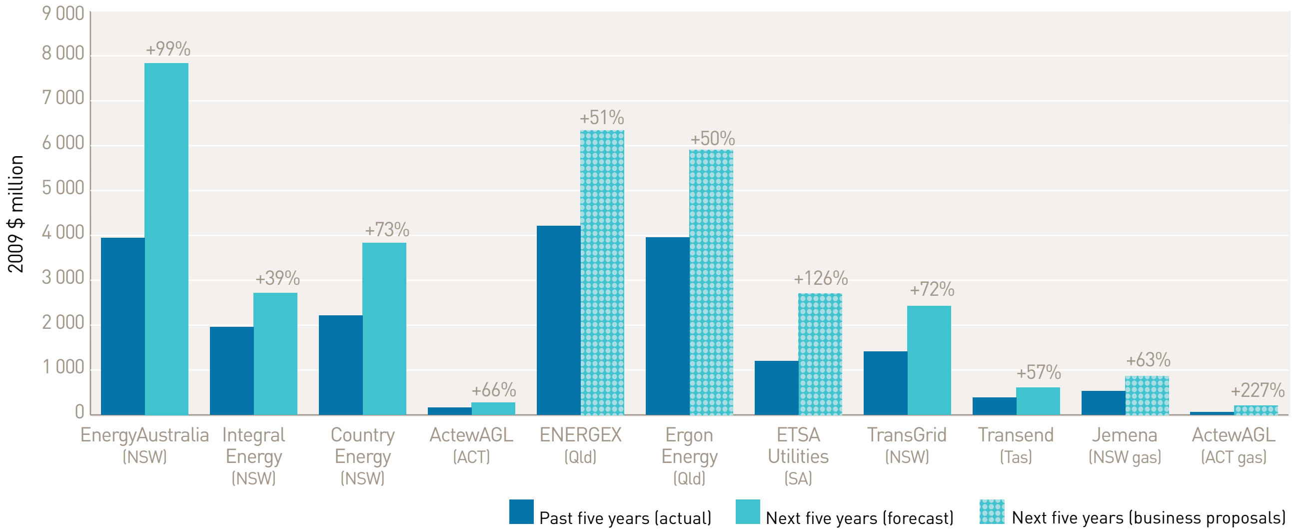


Gas distribution



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

Figure 5
Network investment—AER determinations and regulatory proposals, 2009



Note: Proposed investment refers to business proposals not yet assessed by the AER.

Investment in electricity distribution will rise by around 80 per cent in New South Wales and 66 per cent in the ACT in the new five year regulatory cycle. In total, the AER signed off in April 2009 on over $14 billion of distribution investment for New South Wales and the ACT over the next five years. Across the NEM, distribution investment is running at over 40 per cent of the underlying asset base in most networks, over 65 per cent in Queensland and up to 90 per cent in parts of New South Wales.

The story is similar for transmission, for which investment will rise by 72 per cent in New South Wales and 57 per cent in Tasmania over the current regulatory cycle. In total, transmission investment across the NEM was forecast to rise to over $1.6 billion in 2008–09.

A number of factors are driving rising investment requirements. In particular, the networks need to:
> meet load growth and rising peak demand
> replace ageing and obsolete assets
> satisfy more rigorous licensing conditions for network security and reliability.

More generally, all networks face the issue of needing to build capacity to keep air conditioners running on a few very hot days each year.

Several businesses challenged aspects of the recent AER revenue determinations in the Australian Competition Tribunal. In part, the appeals related to inputs in calculating the weighted average cost of capital. The tribunal was considering the appeals in late 2009.

As in New South Wales, the Queensland and South Australian electricity distributors have proposed substantial increases in investment. In South Australia, ETSA Utilities proposed a 126 per cent increase in capital investment over the next five years. In Queensland, ENERGEX and Ergon Energy proposed increases of around 50 per cent. In total, the Queensland and South Australian proposals would involve around $15 billion of investment in the next regulatory cycle.

There are similar trends in gas. Access arrangement revisions for gas distribution networks in New South Wales and the ACT encompass significant increases in investment. Jemena has proposed a 63 per cent increase in investment for its New South Wales gas networks and ActewAGL proposed a 227 per cent increase for the ACT network.

In addition to step-increases in capital spending, operating and maintenance costs are also rising across the networks (figure 6). While these costs are rising less sharply than capital spending, the increases are nonetheless substantial. The Electricity Rules allow network businesses discretion in how they use their capital and operating expenditure allowances. There are also mechanisms to reward businesses for efficient investment and operating programs, balanced with incentives for reliable service delivery.

With network costs accounting for around 50 per cent of a typical electricity bill, rising capital and operating expenditure are flowing through to energy customers. In May 2009 the New South Wales regulator (the Independent Pricing and Regulatory Tribunal) announced that higher distribution charges will increase the average residential electricity bill in the state by around 10 per cent. The impact on large energy users is even greater. The Energy Users Association of Australia has referred to network tariff increases of up to 55 per cent for some large customers.

ETSA Utilities' regulatory proposal would increase distribution charges in South Australia by around 6–7 per cent per year for a small residential customer and 10 per cent for a small business customer. The Queensland proposals would increase distribution charges by around 10 per cent in the first year, followed by annual increases of around 4 per cent.

Energy customers will expect a return for these price increases. In particular, they will look to reliability outcomes and the types of services offered, and in the longer term, to more efficient networks with more competitive pricing structures.

Rising capital and operating expenditure over the past few years has enabled the networks to deliver reasonably stable reliability. The average duration of outages per customer in the NEM has generally been 200–250 minutes per year, allowing for regional variations (figure 7). Electricity customers will look to network businesses to continue to translate rising investment and operating costs into stable or improving reliability outcomes.

While reliability is one aspect of service delivery, network businesses should also look to improve the range of services offered—for example, demand management has many benefits for consumers, from deferring capital expenditure to offsetting the needle peaks in energy demand. The AER has introduced a demand management innovation allowance to encourage network businesses to consider non-network augmentations. The scheme allows businesses to recover implementation costs and forgone revenues from introducing demand management measures. While the scheme is in its early stages, it will mature and likely become more important over time.

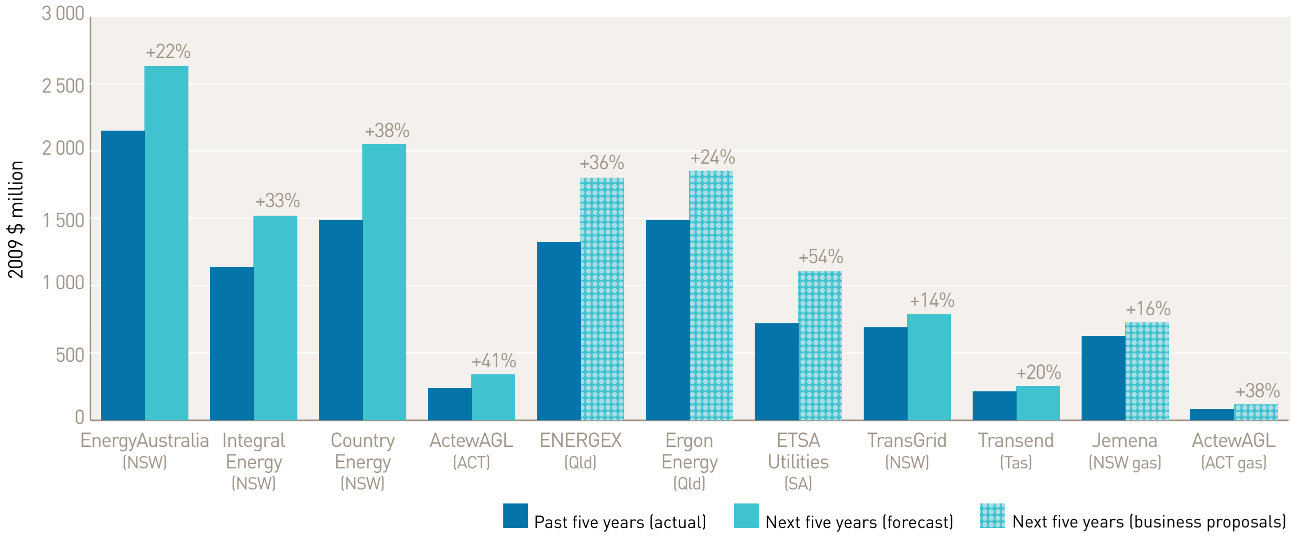
Policy and regulatory responses are underway to enhance network performance. One response is the rollout of smart meters and, potentially, smart grids. Smart meters allow customers to track their energy consumption. When combined with appropriate tariff structures, they can reduce peak and overall demand and delay network augmentations. The Council of Australian Governments has committed to a national rollout of smart meters where the benefits outweigh the costs, with initial deployment in Victoria and New South Wales. The rollout in Victoria began in 2009.

Smart grids take the concept of smart meters further towards direct control of load, the use of communications technology to rapidly detect and switch around faults to minimise supply disruptions, and the integration of embedded generation that can be switched on and off to support the network. The Australian Government recently committed $100 million for a trial of smart grid technologies.

While innovations such as smart meters and smart grids will pose operational challenges for the distribution sector, their introduction can be accommodated within the regulatory framework. The Electricity Rules allow for stable returns on efficient investment in network innovations to improve grid operation and control. If these innovations are accepted into the regulated asset base, the costs will be ultimately borne by consumers, who will expect to benefit through enhanced network performance. In particular, consumers would expect better information on their energy use, which would enable (in the longer term) wider product choice and greater control over their energy consumption and costs.

Figure 6

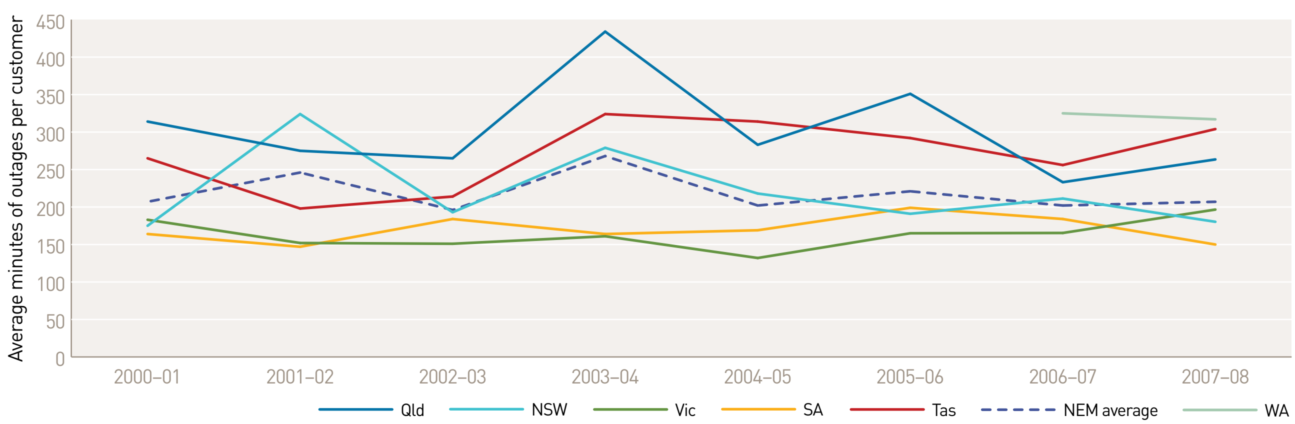
Operating and maintenance expenditure—AER determinations and regulatory proposals, 2009



Note: Proposed investment refers to business proposals not yet assessed by the AER.

Figure 7

Electricity distribution—reliability of supply



Notes:

The data reflect total outages experienced by distribution customers. In some instances, the data may include outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude distribution network issues beyond the reasonable control of the network operator. The data for Queensland in 2005–06 and New South Wales in 2006–07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

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

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

An overarching reform towards more efficient network investment is the establishment of a national transmission planning function within AEMO. The goal is to overlay the traditional jurisdiction based approach to network planning with a more strategic, long term focus on the efficient development of the transmission grid from a national perspective. To this end, AEMO will publish an annual network development plan to complement shorter term regional planning. The first plan is scheduled for release by the end of 2010.

In addition, a new regulatory investment test will help transmission businesses identify effective ways of responding to rising demand for electricity services—for example, in assessing whether the most efficient response is a network augmentation or an alternative such as generation investment. The new test, which takes effect in August 2010, will account for the effects of planned investment on reliability and a range of market impacts. The AER will publish the test and associated guidelines by July 2010.

Similar reforms are underway—but at an earlier stage of development—in distribution. In September 2009 the AEMC recommended a new regulatory test similar to that for transmission.[2] It also recommended more transparent planning requirements, including annual reports that detail projections of load and network capacity and potential projects for the next five years; and arrangements to jointly plan investment affecting both transmission and distribution networks.

Recent reviews have identified impediments to efficient network investment—for example, the AEMC recently recommended changes in interregional transmission charging mechanisms to enhance network planning across regions. The new charging regime is expected to commence on 1 July 2011. The AEMC also recommended reforms in response to climate change policies (see below).

Review of capital costs

A key element of the energy regulatory framework is the return on capital to network owners, which may account for up to 60 per cent of allowed revenues. In May 2009 the AER released a decision on the parameters of the weighted average cost of capital model, which determines the return on capital for regulated electricity networks.[3] The weighted average cost of capital represents the cost of debt and equity required by an efficient benchmark electricity network business to supply regulated electricity services.

The review covered the rate of return values and methods to be adopted in electricity network pricing determinations over the next five years. It was the first review of its type under the Electricity Rules, and its release coincided with the onset of the global financial crisis. Based on the parameters established through the review, the weighted average cost of capital in October 2009 was around 10 per cent—reflecting a cost of debt of 9.7 per cent and an equity return of 10.6 per cent.

The decision accounted for the global financial crisis and recognised the potential for a shift in the market's assessment of risk. More generally, however, the AER takes a long term perspective on the cost of capital. In particular, the regulatory regime should allow returns that provide incentives for efficient investment over the long term—in what are long term assets—rather than reacting to shorter term influences. More recent events in financial markets tend to reinforce this view, with equity yields and credit spreads moving back towards levels more in keeping with those before the global financial crisis.

Businesses will continue to be compensated for any rises in debt margins at each reset. This compensation, being based on a benchmark corporate bond of BBB+ rating, is well above that which higher rated network businesses incur. More generally, evidence from a number of sources suggests the regulatory regime helps insulate network businesses from market volatility. Significantly,

2 AEMC, *Review of national framework for electricity distribution network planning and expansion, final report*, Sydney, September 2009.
3 AER, *Electricity transmission and distribution network service providers: review of the weighted average cost of capital (WACC) parameters, final decision*, Melbourne, May 2009.

the ability of a regulated network business to align its debt issuance to the time of a regulatory determination mitigates a large proportion of the risks associated with rising debt costs.

3 Climate change policies

Australian governments are implementing measures to encourage the use of low greenhouse gas emission technologies. These policies have significant implications for energy markets. The Australian Government's primary emissions reduction policies are an expanded RET and a proposed emissions trading scheme—the Carbon Pollution Reduction Scheme (CPRS).

On 20 August 2009 the Commonwealth Parliament passed legislation to implement the expanded RET scheme. The scheme requires 20 per cent of Australia's electricity generation to come from renewable energy sources by 2020. It increases the pre-existing national target by more than four times to 45 850 gigawatt hours in 2020, before falling to 45 000 gigawatt hours in the following decade. The scheme is set to expire in 2030, when the proposed CPRS is intended to provide sufficient stimulus for renewable energy projects.

The expanded scheme aims to encourage investment in renewable energy technologies by providing for the creation of renewable energy certificates. One certificate is created for each megawatt hour of eligible renewable electricity generated by an accredited power station, or deemed to have been generated by eligible solar hot water or small generation units. Retailers must obtain and surrender certificates to cover a proportion of their wholesale electricity purchases. If a retailer fails to surrender enough certificates to cover its liability, then it must pay a penalty for the shortfall.

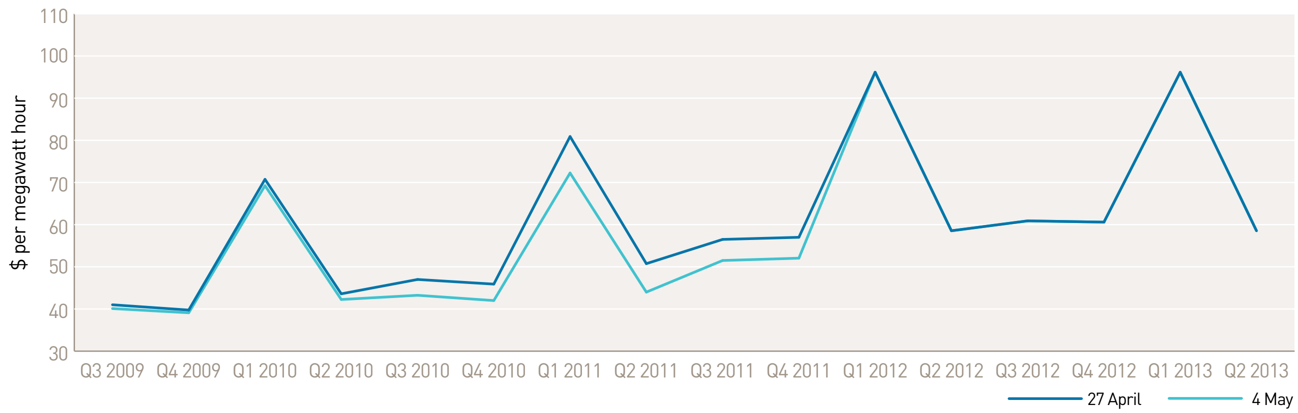
The design of the proposed CPRS was set out on 15 December 2008 in the *Carbon Pollution Reduction Scheme: Australia's low pollution future* (white paper). It aims to create a market for the right to emit carbon by placing a cap on Australia's total emissions. It is designed as a broad based trading scheme, covering sectors responsible for around 75 per cent of Australia's carbon emissions. The target for emissions reduction will depend on international mitigation efforts. The Australian Government has committed to a minimum 5 per cent reduction in emissions (from 2000 levels) by 2020, with the potential for a 25 per cent reduction by 2020 in the event of coordinated international action.

On 4 May 2009 the Australian Government announced a one year delay in the introduction of the CPRS, to 1 July 2011. Figure 8 illustrates how this announcement affected prices for electricity base futures on the Sydney Futures Exchange. Taking Victorian contracts as an example, the chart compares base futures prices on 27 April 2009 (one week before the announcement) with prices on 4 May 2009 (after the announcement). The difference between the lines approximates market expectations of the net impact of the CPRS on future spot electricity prices. The impact is predictably stronger during the summer peak period, but is mostly around $5 per MWh. As expected, the impact was minimal outside the period of the delay.

Climate change policies pose challenges and opportunities for the energy sector. In particular, coal fired electricity generation, which accounts for around 85 per cent of Australia's generation output, is emissions intensive. The introduction of the CPRS may result in some asset write-downs. Mitigating factors such as forward market trading, vertical integration and new investment in gas fired generation are likely to ease the risk of possible supply issues.

There has been debate over the issue of assistance to coal fired generators. The white paper proposed a one-off assistance package for the energy sector, consisting of free carbon permits directed at mainly brown coal generators, valued at around $3.6 billion. The Australian Government has engaged Morgan Stanley to further review the forecast impacts of climate change policies on high emission plant.

Figure 8
Victorian electricity base futures prices



Q, quarter

Source: d-cyphaTrade.

The CPRS is likely to improve the competitiveness of gas fired generation in relation to coal fired technology. This is reflected in the extent of gas fired generation in recent and committed investment decisions, including 2400 MW of new capacity in 2008–09 (tables 1a and 1b). There will be substantial opportunities for the natural gas industry, although rising demand for gas—both for electricity generation and for likely LNG exports from eastern Australia—may increase gas prices in the longer term and partly neutralise its cost advantages (section 6).

As the cheapest and most mature renewable energy technology, wind generation is likely to grow significantly under the expanded RET. But wind generation depends on prevailing weather conditions, and its intermittent nature poses challenges for power system reliability and security. In addition, momentary fluctuations in wind output create issues for maintaining power flows within the capacity limits of transmission infrastructure. To maintain reliability and security, standby capacity—in transmission and generation that can respond quickly to changing market conditions—is required. Peaking plant (such as open cycle gas turbines) typically provides standby generation capacity. This may necessitate refinements in the market's design, in terms of inertia services and the procurement of transmission network control services.

In the longer term, there is potential to develop other renewable energy technologies, such as geothermal, solar, wave and tidal generation. Additionally, carbon capture and storage technologies that extract carbon dioxide from fossil fuel power plants and store it in deep geological formations may become viable. None of these technologies is currently capable of large scale entry into the market, given either technical issues or cost.

Review of energy market frameworks

In October 2009 the AEMC completed a review of Australia's energy market frameworks in light of climate change policies. It found the frameworks are efficient and robust enough to deal with most issues, but need refinements.

In relation to generation, the report considered concerns that the potential early closure of some coal fired plant could lead to short term capacity shortfalls. The current reliability mechanisms to address this risk include:

- AEMO's power to direct generators to provide additional supply
- the reliability and emergency reserve trader mechanism, which allows AEMO to enter reserve contracts with generators to ensure sufficient supply.

The proposals to address potential capacity risks include allowing AEMO more flexibility to procure emergency supplies, such as through short notice contracting.

The AEMC also proposed more accurate reporting of demand-side capability and the removal of regulatory barriers to using embedded generation to meet supply shortfalls. These changes would better place AEMO to minimise intervention in the market and avoid involuntary load shedding.

The increasing use of gas fired and renewable generation will present challenges for the network sector. Electricity networks have developed around the location of coal fired generation plant. New investment in renewable generation, however, is likely to occur in areas not presently serviced by networks. Specifically, the transmission network may need augmentation to deliver electricity from remote generators to load centres.

The AEMC has proposed an approach whereby transmission businesses can size network extensions to remote generators to accommodate anticipated future needs, with customers underwriting the risk of asset stranding. The AER will have a role in ensuring consumers' interests are protected. Additionally, in August 2009 the AEMC amended the confidentiality provisions for network connection applications, to allow for a more coordinated approach under the existing framework.

The sourcing of large volumes of electricity from new locations on the network may also affect flows and create new points of transmission congestion. Congestion can sometimes impede the dispatch of cost-efficient generation and create opportunities for the exercise of market power.

The AEMC has proposed a form of generator transmission use-of-system charge to provide better locational signals for new generation investment (and exit) that would avoid significant increases in network congestion. The new charging system would provide price signals to investors on areas of the network that may require new capacity.[4] Given the proposal represents a significant departure from current arrangements, the AEMC will establish a working group to develop an implementation plan by late 2010.

Climate change policies have implications for the natural gas sector. Greater reliance on gas fired generation would increase both the level and volatility of gas demand. Generators are likely to need access to large quantities of gas at relatively short notice at times of peak demand and to back up intermittent generation. This will likely require substantial new investment in gas pipeline and storage capacity, as well as greater flexibility in gas contracting arrangements. The convergence of the electricity and gas markets also raises issues of security of supply. Any response to emergency shortfall events in one part of the energy market will need to consider consequences across the energy sector as a whole. Section 6 further discusses gas market activity.

4 Global economic and financial conditions

From late 2007 the emergence of the global financial crisis has affected the availability and cost of funding for new investment and refinancing. This impact has been particularly evident in significant increases in risk premiums on all forms of debt.

While Australian financial and economic conditions have remained relatively robust, the crisis has had ramifications for the energy sector. Coal fired generators have raised concerns that tighter liquidity and more risk averse financial markets have made it more difficult to refinance debt. More generally, they argue that financial conditions have aggravated the risks they already face from the introduction of climate change policies. Financial conditions have also raised issues for new entrant generators, and might have delayed some new investment that would have increased competitive pressures on incumbents. Further, less finance has been available to develop renewable technologies such as for solar and geothermal generation.

Tighter credit markets have also posed issues for energy retailers—for example, those seeking access to prudential cover to support wholesale and contract

4 The AEMC is also exploring the need for congestion pricing at points on the network with prolonged and material levels of congestion.

Construction of Origin Energy's Darling Downs gas fired power station (Origin Energy) market exposures—as well as for network businesses and gas industry participants.

As noted, the AER accounted for the impact of the global financial crisis in its 2009 review of capital costs for regulated networks (section 2). It increased the market risk premium to 6.5 per cent (from the previous value of 6 per cent), for example, recognising the uncertainty in financial markets. Similarly, it took a cautious approach to interpreting empirical evidence on the equity beta of a benchmark electricity network business, by adopting a value above the range indicated by empirical estimates.

The AER is also accounting for financial conditions in revenue determinations for regulated networks. The recent New South Wales and ACT electricity distribution determinations, for example, took account of the effects of financial conditions on demand forecasts, the cost of capital, materials and labour input cost escalators, and defined benefit superannuation costs in operating expenditure forecasts.

EnergyQuest's essay in this report discusses the effects of the financial crisis on gas markets. It notes that while the recession has weakened global demand for gas, Australian LNG exports have increased against this trend. Domestically, the downturn does not appear to have significantly affected gas consumption. The essay also notes, while financing has become more difficult and expensive since 2007, that Australian gas development projects have not been seriously affected. Companies have managed to raise finance, rationalise exploration and sell non-core assets to fund key projects.

The relatively high gearing of pipeline companies has created difficulties for them in obtaining finance at an acceptable cost for new projects. A proposed expansion of the South West Queensland Pipeline to provide capacity for Origin Energy, for example, was made subject to obtaining the necessary funding on acceptable commercial terms.

Financial market conditions have contributed to some changes in asset ownership across the energy sector. Babcock & Brown Power, for example, sold a number of generation assets and trading contracts. In December 2008 APA Group spun off some of its network assets into a new unlisted investment vehicle, and applied the proceeds to reduce $647 million of corporate debt. More generally, EnergyQuest notes in its essay that companies are reviewing their portfolios and disposing of non-core assets to fund core projects. It notes that competition has generally been keen for those assets offered for sale.

5 Retail markets

The first exposure draft of legislation to establish a national energy customer framework was released on 30 April 2009. The legislation will transfer several non-price retail functions from state and territory jurisdictions to the AER. Consultation on a second exposure draft was scheduled for late 2009, and the legislation is scheduled for introduction to the South Australian Parliament in spring 2010.

Under the proposed framework, the AER will be responsible for authorising (licensing) energy retailers, approving authorisation exemptions, monitoring retailers' compliance with the legislation and undertaking any enforcement action, and providing guidance on matters such as hardship issues and how retailers represent their products to customers. The states and territories will retain responsibility for any continuing price regulation, unless they choose to transfer those arrangements.

Market structure

AGL Energy, Origin Energy and TRUenergy collectively account for most retail market share in Victoria, South Australia and Queensland, but Simply Energy (owned by International Power) has acquired a significant customer base in Victoria and South Australia. There has also been ongoing new entry by niche businesses. Retailers with full or part government ownership supply the bulk of customers in other jurisdictions.

The New South Wales Government in September 2009 released the *Energy Reform Transaction Strategy*, outlining the proposed structure for the sale of its three state owned energy retailers: EnergyAustralia, Integral Energy and Country Energy. Bidders for EnergyAustralia will have the flexibility to bid for its gas and electricity customers separately, or for both. The government also proposes to contract out the right to sell electricity produced by state owned generators to the private sector, and to sell seven power station development sites. Subject to market conditions, it expects to complete the sale process in the first half of 2010.

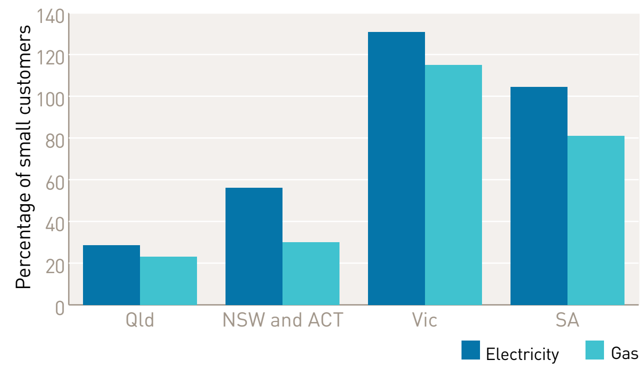
The New South Wales Government will simultaneously prepare for a share market listing of an entity that includes the retail business of Integral Energy, the generation trading contract for Eraring Energy and the Bamarang power station development site. The float will proceed if the initial sales process fails to meet the government's strategic, competition and valuation requirements.

Retail competition

Energy retail competition has continued to develop over the past year. Customer switching continued strongly in Victoria (and, to a lesser extent, in South Australia and Queensland) in 2008–09. Cumulative switching rates for small customers in Victoria and South Australia are about double those for New South Wales (figure 9). The low rates for Queensland partly reflect that small customer switching has been possible only since July 2007. Across all jurisdictions, switching rates are higher in electricity than in gas, although the rates are comparable in Victoria, where gas is used more widely for household purposes than in other states. South Australia and Victoria have also reported high rates of customer movement from standing offer contracts to market contracts with their host retailer.

While most jurisdictions allow customers to choose their energy retailer, jurisdictions other than Victoria apply some form of electricity retail price regulation, and several apply similar arrangements in gas. 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 final decisions.

Figure 9
Cumulative retail switching to 30 June 2009—small customers



Notes:

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.

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.

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

Victoria responded to an AEMC review by removing retail price caps on 1 January 2009. To balance this change, the Essential Services Commission of Victoria is monitoring and reporting on retail prices. In addition, retailers must publish a range of offers, to help consumers compare energy prices. Other obligations on retailers, including the obligation to supply and the consumer protection framework, remain in place. The Victorian Government retains a reserve power to reinstate price regulation if competition is found to be no longer effective.

The AEMC review of South Australian retail energy markets, completed in December 2008, found competition was effective for small customers, but more intense in electricity than in gas. It noted, while overall competition was effective, that the state's relatively high wholesale prices, price volatility and increasing vertical integration may limit further new entry. The AEMC proposed that South Australia introduce price monitoring to support the competitive market, and that it retain reserve powers to re-introduce price regulation if competition deteriorates. In April 2009 the South Australia Government stated it did not accept the AEMC's recommendations at that time. It was concerned that more than 30 per cent of small customers remain on standing contracts and that stakeholders have differing views on the effectiveness of competition.

The Ministerial Council on Energy has agreed to proceed with reviews of retail competition for the ACT in 2010, New South Wales in 2011, Queensland in 2012 and Tasmania in 2013 (if it introduces full customer choice by that time). The AEMC recommended in October 2009 that jurisdictions bring forward their consideration of the removal of retail price regulation.[5] For those jurisdictions that retain regulated energy prices beyond the introduction of the proposed CPRS, the AEMC recommended that price setting frameworks allow for regular wholesale energy and carbon cost reviews (as frequently as six monthly). Prices could then be adjusted if costs have changed materially.

The Queensland Competition Authority is reviewing its electricity retail price setting framework. The review aims to ensure the framework captures all relevant costs (including costs from environmental obligations) and provides flexibility to set tariff structures that will encourage customers to use electricity efficiently. Queensland expects to apply the review's recommendations in setting retail prices for 2010–11.

Retail prices

As noted, retail price pressure is an emerging concern in energy markets. In 2009 several jurisdictions announced significant increases in regulated electricity prices, in response to rising network and wholesale energy costs:

- In New South Wales, a typical retail electricity bill will rise by around 18–22 per cent in 2009–10. About 50 per cent of the increase is due to higher network costs.
- The Queensland Competition Authority announced in June 2009 that regulated electricity retail prices for 2009–10 would rise by 11.82 per cent. Following a successful appeal by Origin Energy and AGL Energy, the authority announced a further increase that would raise prices in total by 15.5 per cent.
- The Independent Competition and Regulatory Commission announced that retail electricity prices in the ACT would increase by up to 6.4 per cent in 2009–10, mainly reflecting higher network costs.
- In Western Australia, the Office of Energy recommended in 2008 that retail electricity prices increase by 52 per cent, following several years of declining real prices. The Western Australian Government rejected this recommendation and announced that residential prices would increase by 10 per cent on 1 April 2009, and by a further 15 per cent on 1 July 2009.
- In the Northern Territory, electricity tariffs for non-contestable customers rose by 18 per cent from 1 July 2009.

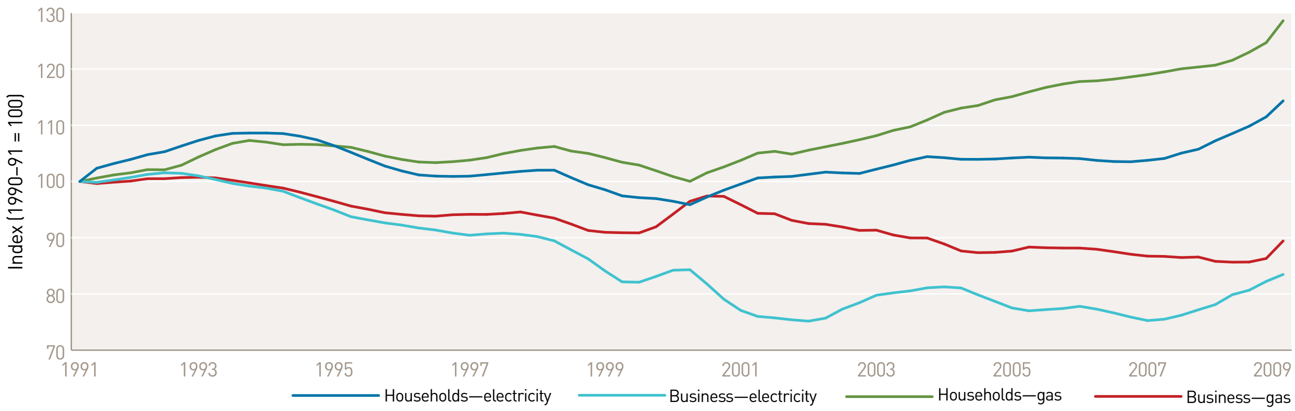
Figure 10 estimates movements in real energy retail prices (under regulated and market arrangements) in major capital cities over time. It illustrates the recent upswing in electricity and gas retail prices, especially for households. The tendency for household customers to experience larger price rises than business customers partly reflects the continued unwinding of historical cross-subsidies in some jurisdictions. More generally, it illustrates that household customers are increasingly exposed to prices in wholesale energy markets.

Climate change policies will likely add further upward pressure on retail prices. McLennan Magasanik Associates' modelling for the Australian Treasury estimated that a carbon emissions price of $35 per tonne (A$2005 prices) in 2020 could result in household electricity prices rising by up to 23 per cent.[6] Retail gas prices are also likely to rise as demand for gas fired generation increases.

5 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, Sydney, October 2009, p. v.
6 MMA, *Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets*, Report to Federal Treasury, Melbourne, December 2008, p. 7.

Figure 10

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



Sources: ABS, *Consumer Price Index* and *Producer Price Index*, cat. no. 6401.0 and 6427.0, Canberra, various years.

6 Upstream gas

In a commissioned essay for this report, EnergyQuest examines the strengthening links between Australia's natural gas industry and global energy markets. The industry continues to expand rapidly, driven by buoyant interest in Australian LNG exports, investment in gas fired electricity generation, and a rapidly expanding resource base of CSG in Queensland and New South Wales.

Australia is now the world's sixth largest LNG exporter. Notwithstanding a recent easing in LNG demand, oil and gas companies are committing to spend billions of dollars on new Australian projects. The $50 billion Gorgon project in Western Australia is scheduled to begin operation in 2014 and produce around 15 million tonnes of LNG per year—equal to Australia's current total LNG production.

Also on the west coast, the 4.3 million tonne per year Pluto project is under construction and set to become Australia's third operational LNG project. Pluto is due for completion in 2010 and will supply major Japanese buyers.

Long term projections of rising international energy prices, together with rapidly expanding reserves of CSG in Queensland, have improved the economics of developing LNG export facilities in eastern Australia. Four export projects that rely on CSG are at an advanced stage of planning. Most are at the front end engineering and design stage, aiming for final investment decisions by the end of 2010. The proposals range in size from 1.5 to 14 million tonnes of LNG per year. Over 20 million tonnes per year from these projects is already committed to buyers.

On the domestic front, weaker economic growth in 2009 led to a softening in gas demand on both sides of the country. In Western Australia, weaker global energy prices also took some pressure off domestic gas prices. On the east coast, Victoria's spot market provides the most transparent price signals. Spot prices averaged $2.68 per gigajoule for June quarter 2009, down 19 per cent on June quarter 2008.

Activity is strong in the increasingly deregulated gas transmission sector, which is taking a longer term view. Climate change policies, new investment in gas fired peaking generators and Queensland's burgeoning CSG industry are driving significant investment in gas transmission infrastructure.

The commissioning of the QSN Link and expansion of the South West Queensland Pipeline in 2009 brought Queensland into an interconnected pipeline network spanning Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. This is moving us closer to a national gas market.

For the first time, CSG from Queensland can compete in southern markets with gas produced in the Cooper and Victorian gas basins.

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

While upstream gas is a lightly regulated sector, there have been significant developments to enhance transparency. The National Gas Market Bulletin Board, which began in July 2008, provides real-time and independent information on the state of the gas market, system constraints and market opportunities. And with plans to launch a new annual statement of opportunities for gas (similar to that published for electricity), AEMO aims to improve information for planning and commercial decisions on investment in gas infrastructure. The first gas statement is scheduled for publication in December 2009.

To complement these reforms, new spot markets (in addition to that operating in Victoria) for short term gas trading will begin next winter. The first markets will be based around the Sydney and Adelaide hubs. While the markets relate to gas for balancing purposes, they will provide transparent price guidance for the market as a whole. Any move to greater depth in short term gas markets will better enable Australian energy markets to maximise the benefits of any 'surplus' gas associated with gas export projects.

7 The Australian Energy Regulator's role

As the transition to national energy regulation continues, the AER is mindful of its responsibilities as the regulator of energy infrastructure in eastern and southern Australia. In addition to regulating network assets, it monitors the wholesale energy markets for compliance with the underpinning legislation, and reports on market activity.

The AER will continue to work closely with industry and energy customers in undertaking these roles. It will look to apply consistent and transparent approaches to encourage efficient investment and reliable service delivery. Across its work program, the AER will continue to work towards best practice regulatory and enforcement outcomes, including the provision of independent and comprehensive information on market developments.


Frank Bodenmueller (Corbis)

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
AMSP	alternative maximum STEM price
BBI	Babcock & Brown Infrastructure
BBP	Babcock & Brown Power
CAIDI	customer average interruption duration index
CBD	central business district
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CNOOC	China National Offshore Oil Company
CO_2	carbon dioxide
COAG	Council of Australian Governments
CPI	consumer price index
CPRS	Carbon Pollution Reduction Scheme
CPT	cumulative price threshold
CSG	coal seam gas
DC	direct current
EBIT	earnings before interest and tax
EBITDA	earnings before interest, tax, depreciation and amortisation
Electricity Law	National Electricity Law
Electricity Rules	National Electricity Rules
ERA	Economic Regulation Authority (Western Australia)
ERIG	Energy Reform Implementation Group
ESAA	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities (published by AEMO)
ETEF	Electricity Tariff Equalisation Fund
FEED	front end engineering design
FID	final investment decision
FRC	full retail contestability
Gas Law	National Gas Law
Gas Rules	National Gas Rules
GEAC	Great Energy Alliance Corporation
GJ	gigajoules
GSL	guaranteed service level
GSOO	Gas Statement of Opportunities
GWh	gigawatt hour
ICRC	Independent Competition and Regulatory Commission
IEA	International Energy Agency
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal
JV	joint venture
kV	kilovolt
kVa	kilovolt amperes
kW	kilowatt
kWh	kilowatt hour
LNG	liquefied natural gas
MAIFI	momentary average interruption frequency index
MCC	marginal cost of constraints
MCE	Ministerial Council on Energy

MW	megawatt
MWh	megawatt hour
MVa	megavolt amperes
NCC	National Competition Council
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NPI	National Power Index
NTP	National Transmission Planner
NWIS	North West Interconnected System
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 Economic Regulator
PASA	projected assessment of system adequacy
PJ	petajoule
PV	photovoltaic
Q	quarter
QCA	Queensland Competition Authority
QNI	Queensland to New South Wales interconnector
RAB	regulated asset base
RERT	reliable and emergency reserve trader
RET	renewable energy target
RIT-T	Regulatory Investment Test for Transmission
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
SEA Gas	South East Australia Gas
SFE	Sydney Futures Exchange
STEM	short term energy market
STPIS	service target performance incentive scheme
STTM	short term trading market
SWIS	South West Interconnected System
TCC	total cost of constraints
TFP	total factor productivity
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
URF	Utility Regulators Forum
VENCorp	Victorian Energy Networks Corporation
VTS	Victorian Transmission System
WACC	weighted average cost of capital