STATE OF THE ENERGY MARKET 2014

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Editor: Editor’s Mark, Melbourne

CONTENTS

PREFACE

The Australian Energy Regulator's *State of the energy market* report explores conditions in energy markets over the past 12–18 months in those jurisdictions in which the AER has regulatory responsibilities. The report consists of a market overview, supported by five chapters on the electricity and gas sectors. As usual, it employs accessible language to reach a wide audience. I hope this year's report is a valuable resource for policy makers, consumers, industry and the media.

This eighth edition of *State of the energy market* comes at a time when declining energy demand is bringing structural shifts across the entire supply chain. In the wholesale electricity market, declining demand is reflected in a widening surplus of generation capacity and subdued prices. The abolition of carbon pricing further lowered wholesale prices in 2014, although carbon emissions from electricity generation rose as coal fired generation increased its market share.

Weakening demand is also removing the impetus for network expansions and flattening revenue requirements. At the same time, there is a greater focus on demand response and small scale local generation as viable alternatives to network investment to help meet energy demand. Pricing and metering reforms are also underway to help consumers make efficient use of their electrical appliances, especially at times of high demand.

In gas, liquid natural gas (LNG) export projects in Queensland are nearing completion. But the ramp up of gas production for LNG, at a time of subdued domestic demand, caused market volatility in 2014, with Brisbane spot prices falling close to zero late in the year.

Developments in the wholesale and network sectors impact on the retail energy sector. The repeal of carbon pricing led retail electricity prices to fall over 2014 in many jurisdictions, although gas prices fell only in Victoria. There was also evidence of more widespread retail price discounting in all regions. But many customers find energy contracts complex and struggle to compare available offers. The AER continues to explore ways of improving the quality of information available to consumers choosing an energy retail contract, and will roll out improvements to the Energy Made Easy price comparison website throughout 2015.

Paula Conboy
Chair
December 2014

MARKET OVERVIEW

A.1 Introduction

Electricity demand continued to decline in 2013–14, resulting in a widening surplus of generation capacity and subdued wholesale prices. The abolition of carbon pricing further lowered wholesale prices, but reversed a trend of declining carbon emissions from electricity generation. Other climate change policies (such as the renewable energy target scheme) were under review in 2014, creating uncertainty in the renewable energy sector.

Weakening demand, lower capital financing costs and more flexible arrangements for electricity network businesses to meet reliability requirements are removing the impetus for network expansions and flattening revenues. Alongside changes in the operating environment, significant regulatory reforms are encouraging network businesses to seek more efficient ways of providing services.

The nature and function of energy networks are also evolving. Escalating cost pressures in recent years gave impetus to alternatives such as demand response (whereby users adjust their energy use in response to price signals), small scale local generation (such as rooftop solar photovoltaic (PV) generation) and, potentially, energy storage technologies. Metering and pricing reforms are underway to create a regulatory framework that can respond to this dynamic landscape and allow consumers greater control over how they manage their energy use. Alongside the regulatory changes, alternative retail models are emerging that provide consumers with energy service packages that reflect when and how they use energy.

In gas, the development of liquid natural gas (LNG) export projects in Queensland will fuel exponential growth in international demand for Australian gas. But domestic demand is subdued, with the abolition of carbon pricing reducing the cost competitiveness of gas powered generation. The ramp up of gas production for LNG export caused volatility in domestic spot markets, with prices falling close to zero in late 2014. Policy reforms are being implemented to manage the impacts of LNG developments on domestic markets, including the new Wallumbilla gas supply hub and enhanced pipeline capacity trading arrangements.

Developments in wholesale energy markets and energy network regulation impact on retail energy prices. The repeal of carbon pricing led retail electricity prices to fall over 2014 in jurisdictions other than Queensland and South Australia (where higher solar feed-in tariff costs and higher network charges respectively offset the carbon savings). Retail gas prices fell only in Victoria. In other jurisdictions, rising costs associated with the reduced availability of wholesale gas contracts offset savings from the repeal of carbon pricing. Pipeline charges also rose in most regions, putting additional pressure on retail gas prices.

The average extent of retail price discounting was greater in 2014 than in the previous year in all regions. Following the findings of the Australian Energy Market Commission (AEMC) that competition was effective in its energy markets, New South Wales (NSW) in July 2014 joined Victoria and South Australia in removing retail price regulation for electricity. The Queensland Government committed to removing electricity retail price regulation in south east Queensland from 1 July 2015.

For competition to be effective, consumers must be able to make informed choices on the energy product that best meets their needs. But many customers find energy contracts complex and struggle to compare available offers, creating a risk of exploitation. Given this risk, the behaviour of energy retailers is a compliance and enforcement priority. For example, the Australian Energy Regulator (AER) and Australian Competition and Consumer Commission (ACCC) in 2014 instituted proceedings in the Federal Court against EnergyAustralia for failing to obtain customers' consent before transferring them to new energy plans.

The AER continues to explore ways of improving the quality of information available to consumers choosing an energy retail contract. It intends to roll out improvements to the Energy Made Easy price comparison website in 2015, making it easier for customers to see which offer would best suit their needs.

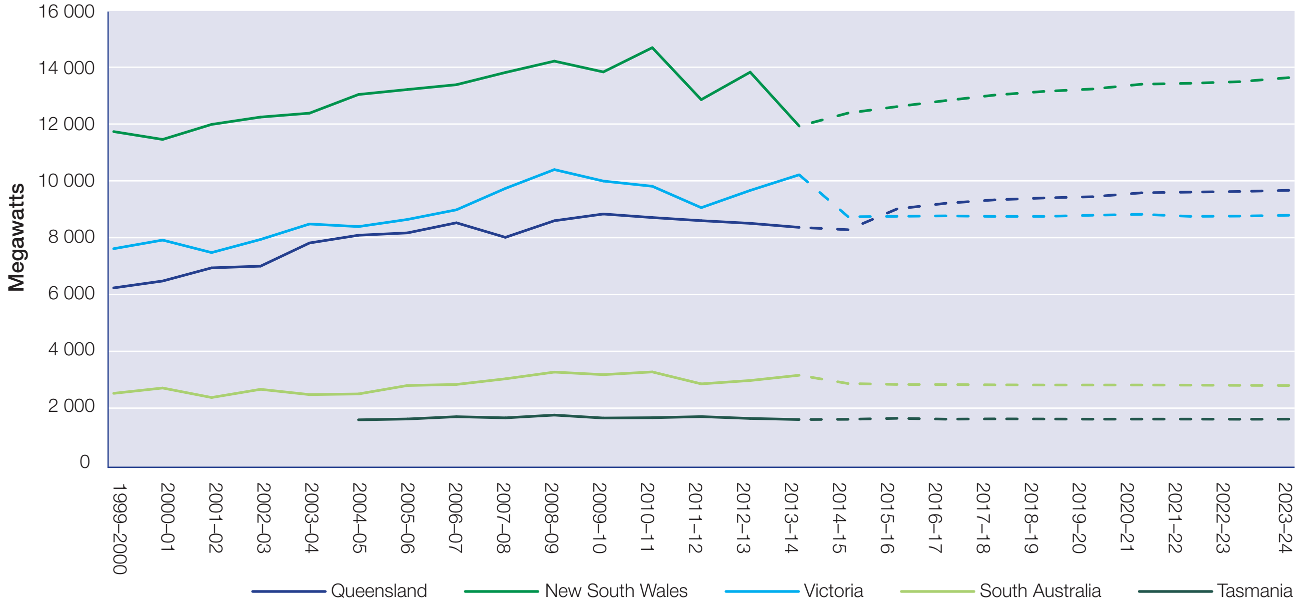
A.2 National Electricity Market

Wholesale electricity in eastern and southern Australia is traded through the National Electricity Market (NEM), covering Queensland, NSW, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). A significant structural development in the market in 2014 was the ongoing privatisation of state owned generation businesses in NSW. In particular, AGL Energy acquired the region's largest generation business—Macquarie Generation—in September 2014. The ACCC opposed the sale, but its decision was overturned by the Australian Competition Tribunal, which found the public benefits of the acquisition outweighed any detriment to competition.

The NEM in 2013–14 generated 194 terawatt hours (TWh) of electricity—a 2.5 per cent reduction from the previous year, and 3 per cent below forecast.[1] This outcome

1 AEMO, *National electricity forecasting report 2014*.

Figure 1
Annual maximum demand, and forecast maximum demand, by region



Note: Actual data to 2013–14, then AEMO forecasts published in 2014.
Sources: AEMO; AER.

continued a trend of declining electricity consumption from the NEM grid. Over the past five years, annual grid consumption declined by an average 1.7 per cent, for the following reasons:

- Commercial and residential customers are more actively managing their energy use in response to price signals. The Australian Energy Market Operator (AEMO) estimated total energy savings of around 10 per cent annually over the next three years, with key contributions from more energy efficient air conditioning, refrigeration and electronics.
- Economic growth has been subdued, and energy demand from the manufacturing sector has weakened, reflecting an ongoing decline in energy intensive industries.
- Rooftop solar PV generation continues to increase, which reduces demand for electricity supplied through the grid. In 2013–14 solar PV generation rose to 2 per cent of all electricity produced. This growth has been driven by incentives under the renewable energy target (RET) scheme and lower cost systems. Solar penetration is highest in South Australia, where 22 per cent of households have installed capacity, just ahead of Queensland's 20 per cent penetration rate.[2] AEMO projected around 24 per cent annual growth in installations over the next three years.

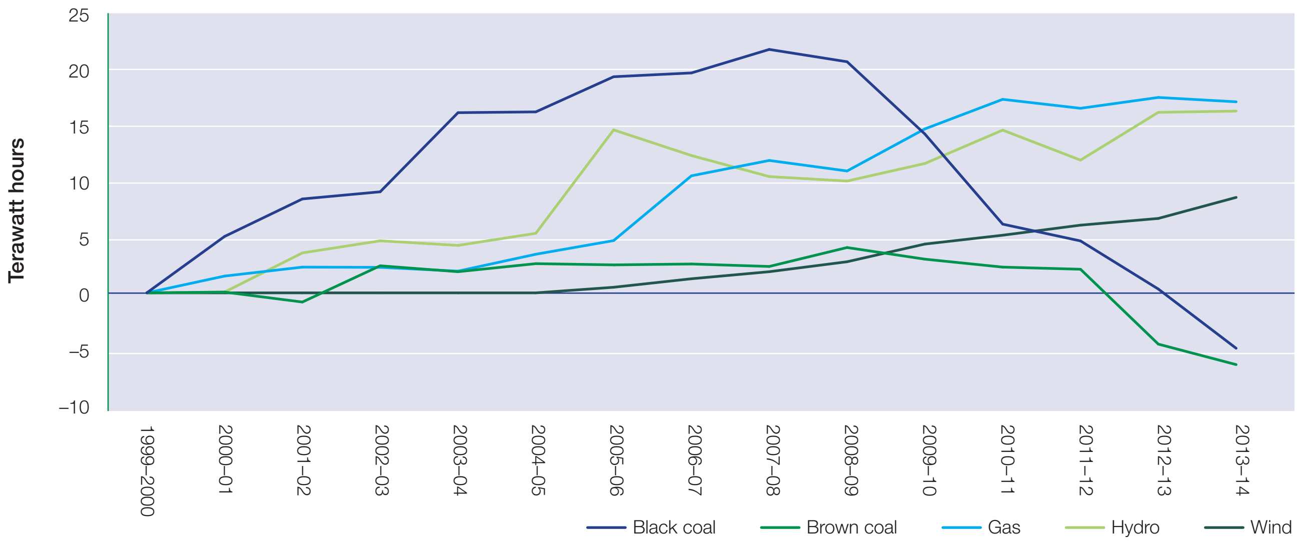
Maximum demand, which typically occurs during heatwaves when air conditioning use is high, has also flattened. It moved significantly below trend in the three years to 30 June 2014 (figure 1). AEMO forecast maximum demand will remain below historical peaks in most regions for at least the next 20 years. Queensland is the exception, due to its LNG projects.

Declining grid consumption and flat growth in maximum demand are reflected in a widening oversupply of generation capacity. AEMO projected in 2014 that no NEM region would require additional capacity to maintain supply–demand adequacy for the next 10 years. Despite this trend, around 650 megawatts (MW) of committed projects remained committed[3] at July 2014, comprising wind and commercial solar farms supported by the RET. The NEM's first commercial solar farm—Royalla—was commissioned in September 2014.

2 ESAA, *Solar PV report*, January 2014.

3 Committed projects include those under construction or for which developers and financiers have formally committed to construction. AEMO accounts for committed projects in projecting electricity supply and demand.

Figure 2
Annual change in electricity generation, by energy source



Sources: AEMO; AER.

Note: The rise in hydro generation in 2005–06 reflects Tasmania's entry into the NEM in 2005.

Climate change policies and electricity generation

Climate change policies have altered the composition of electricity generation in the NEM (figure 2). An expansion of the RET scheme in 2007 contributed to 2300 MW of wind capacity being added in the following six years, more than tripling existing capacity. Wind capacity in 2013–14 supplied 4.4 per cent of electricity generated across the NEM (35 per cent in South Australia). On 8 September 2014, wind output accounted for 76 per cent of South Australian generation. Spot prices are typically lower when wind generation is high.

The Coalition Government in 2014 appointed an expert panel to review the RET. The panel's report (the Warburton Report)[4] found the RET had led to the abatement of 20 million tonnes of carbon emissions. If left in place, the scheme was expected to abate a further 20 million tonnes of emissions per year from 2015 to 2030—almost 10 per cent of annual electricity sector emissions. The report also found the RET's cumulative effect on household energy bills over 2015–30 was likely to be small. But it considered the RET to be an expensive emissions abatement tool that subsidises renewable generation at the expense of fossil fuel fired electricity generation. In November 2014 the Australian Government was negotiating a policy response to the report.

The introduction of carbon pricing by the Labor Government in July 2012 increased operating costs for coal fired plant. Over the two years of the scheme's operation, coal fired generation declined by 11 per cent; its share of the market reached an historical low of 73.6 per cent in 2013–14. The reduction in coal generation (18 TWh) almost doubled the overall fall (associated with weak demand) in NEM electricity generation during this period (10 TWh). Over 2000 MW of coal plant was shut down or periodically taken offline during the period that carbon pricing was in place.

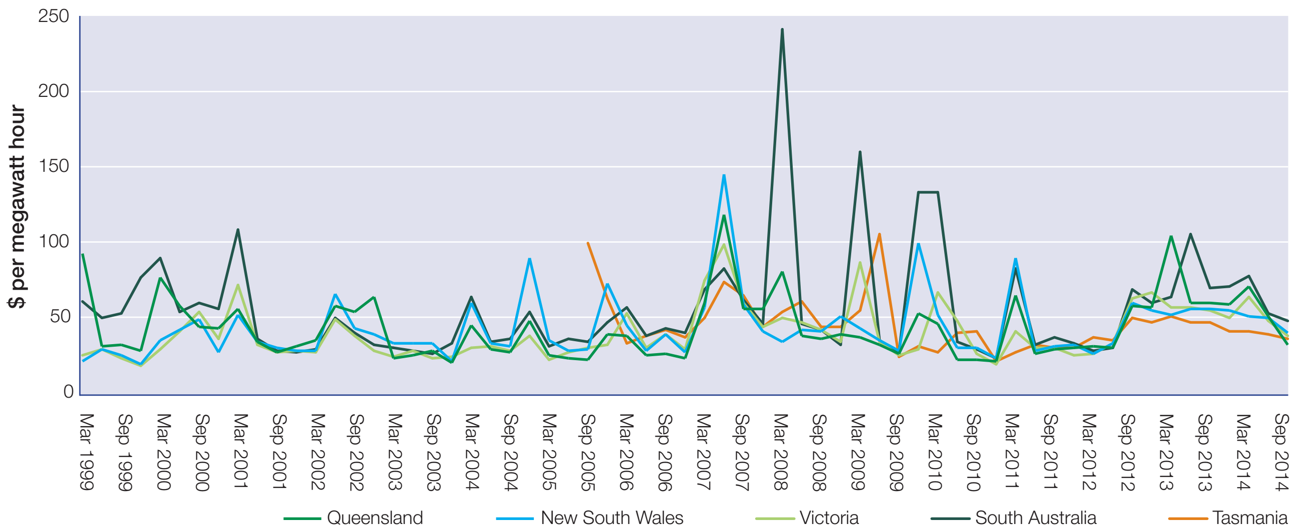
Some generators planned to return coal plant to service following the repeal of carbon pricing on 1 July 2014. Queensland generator Stanwell, for example, announced plans to return 700 MW of coal fired capacity to service at Tarong Power Station in 2014–15; the units had been withdrawn from service in 2012. It planned to operate the plant in place of the Swanbank E gas fired power station.[5]

Meanwhile, carbon pricing increased returns for hydro generation, contributing to record output levels during the two years of the scheme's operation—output in each year

4 Expert Panel, *Renewable energy target scheme: report of the Expert Panel*, August 2014.

5 Stanwell, 'Tarong power station to return generating units to service', Media release, 5 February 2014.

Figure 3
Quarterly spot electricity prices



Note: Volume weighted average prices.

Sources: AEMO; AER.

was 36 per cent higher than in the year before carbon pricing. The share of gas powered generation in the energy mix also rose in the two years.

Reflecting these changes in the generation mix, the overall emissions intensity of NEM generation fell by 4.7 per cent in the past two years. It fell from 0.903 tonnes of carbon dioxide equivalent emissions per megawatt hour (MWh) of electricity produced in 2011–12, to 0.861 tonnes in 2013–14.[6] This fall in emissions intensity, combined with lower NEM demand, led to a 10.3 per cent fall in total emissions from electricity generation over the two years that carbon pricing was in place.

Following the repeal of carbon pricing from 1 July 2014, carbon emissions from electricity generation in the NEM were 3.2 million tonnes higher in the following five months than in the comparable period in 2013. The rise reflected both an increase in electricity demand (up 2.4 per cent) and a rise in emissions intensity (2.4 per cent higher in the year to November 2014 than in the year to June 2014) as coal fired generation increased its market share.[7]

The Coalition Government in 2014 passed legislation for a Direct Action plan to achieve Australia's commitment to a 5 per cent reduction in greenhouse emissions by 2020. The scheme requires the government to pay for emissions abatement activity. Central to the plan is a $2.55 billion Emissions Reduction Fund to provide incentives for abatement activities. The fund allows businesses, local governments, community organisations and individuals to undertake approved emissions reduction projects and to seek funding for those projects. The Clean Energy Regulator will purchase emissions reductions at the lowest available cost, generally through competitive auctions.

A safeguard mechanism that penalises businesses for increasing their emissions above a baseline will commence on 1 July 2015, applying to around 130 large businesses with direct emissions over 100 000 tonnes a year. The government planned to release draft legislation to implement the safeguard mechanism in early 2015.[8]

Spot electricity market dynamics

Spot prices eased across all regions of the NEM in 2013–14, with falls ranging from 5 per cent (NSW) to over 13 per cent (Queensland and Tasmania). On average, volume weighted prices fell across the NEM by 10 per cent compared with the previous year (figure 3). Declining electricity demand and the continued uptake of renewable generation, including large scale wind and domestic solar PV generation, contributed to these price outcomes.

6 AEMO, Carbon dioxide equivalent intensity index, accessed 15 September 2014.

7 Pitt & Sherry, *Cedex*, December 2014.

8 Australian Government (Department of Industry), *The Emissions Reduction Fund: the safeguard mechanism*, 2014.

Following the repeal of carbon pricing on 1 July 2014, spot prices fell during the third quarter (1 July to 30 September 2014) in all NEM regions, most notably in Queensland. Monthly prices for July 2014 were the lowest since May 2012 for Queensland, and the lowest since June 2012 for NSW and Victoria. Monthly averages for August were lower again in all regions except Tasmania. After rebounding towards their July levels in early September, spot prices fell sharply later in the month and into October 2014, when a collapse in spot gas prices flowed through to electricity markets (section A.4).

Price volatility in Queensland

While average spot prices in Queensland eased in 2013–14, they were 14 per cent higher than NSW prices, after previously being lower for several years. Queensland spot prices were volatile during summer, repeating a pattern of the previous year. Over the summer, the five minute dispatch price exceeded $1000 per MWh on 50 occasions.

The rebidding strategies of some Queensland generators caused this volatility. Generators rebid capacity from lower to higher price bands during each affected trading interval. Demand and generation plant availability were within forecasts on each occasion, and pre-dispatch forecasts did not predict the price spikes.[9]

Most rebids occurred late in the 30 minute trading interval and applied for very short periods of time (usually five to 10 minutes), allowing other participants little, if any, time to make a competitive response. CS Energy was by far the most active player rebidding capacity into high price bands (above $10 000 per MWh) close to dispatch. Towards the end of the summer, other participants similarly rebid capacity from low to high prices, causing prices to spike more frequently.

The behaviour compromised the efficiency of dispatch, causing prices to spike independently of underlying supply–demand conditions. The average Queensland price for summer 2013–14 was $68.77 per MWh. Had the short term price spikes not occurred, the average price would have been 18 per cent lower at $56.10 per MWh. The increase represents a wealth transfer of almost $200 million based on energy traded. More generally, spot price volatility puts upward pressure on forward contract prices, which ultimately flows through to consumers' energy bills.

9 AER, *Electricity report 23 February to 1 March 2014*.

Promoting market efficiency

The AER in 2014 drew on its analysis of rebidding activity in Queensland to support a proposal by the South Australian Minister for Mineral Resources and Energy to strengthen and clarify the 'rebidding in good faith' provisions of the National Electricity Rules. The AER argued a recent rise in the incidence of late rebidding was making forecast information in the NEM less dependable, which affects market efficiency. The AEMC expected to publish a draft determination on the proposal in April 2015.

The effects of late rebidding on price and market efficiency would be mitigated if the output of competing generators could adjust more quickly. In 2013 the AER proposed a rule change that generators' ramp rates—the minimum rates at which generators may adjust output—must reflect the technical capabilities that the plant can safely achieve at the time. Currently, the minimum rate is 3 MW per minute, or 3 per cent for generators under 100 MW.

In August 2014 the AEMC found the existing provisions governing ramp rates may distort competitive outcomes and investment signals. It proposed ramp rates be at least 1 per cent of maximum generation capacity per minute (or the plant's technical capability if the generator cannot meet that threshold), regardless of plant size, configuration or technology. The AEMC expected to make a final determination on the ramp rate proposal in March 2015.

More generally, the AER takes enforcement action against market participants in alleged breach of the National Electricity Rules. Failure to comply with the rules can impair market efficiency. In 2014 the AER instituted proceedings in the Federal Court against Snowy Hydro for allegedly failing to follow dispatch instructions issued by AEMO. The AER alleged Snowy Hydro, on each occasion, generated substantially more power than the dispatch instruction required it to generate, and earned a greater trading amount from each transaction than it would have earned if it had complied with the instructions.

A.3 Energy networks

Rising costs of using energy networks (electricity poles and wires, and gas pipelines) were the main driver of rising energy retail prices for several years. Costs rose to replace ageing assets, meet stricter reliability standards, and respond to forecasts made at the time of rising peak demand. Additionally, instability in global financial markets exerted upward pressure on the costs of funding investment.

Figure 4
Weighted average cost of capital—electricity and gas distribution

Note: Nominal vanilla weighted average cost of capital.

Source: AER.

These pressures have eased more recently, lowering revenue and investment requirements for energy networks. Energy demand has declined, and is expected to remain below historical peaks in most regions for at least the next 20 years.[10] This trend has coincided with reductions in capital financing costs and government efforts to provide electricity network businesses with greater flexibility in meeting reliability requirements.

Alongside changes in the operating environment, significant reforms to energy network regulation in 2012 encourage network businesses to operate more efficiently in providing services. New measures support ongoing investment in essential services without requiring consumers to pay for excessive returns to network businesses. In AER determinations made since 2012:

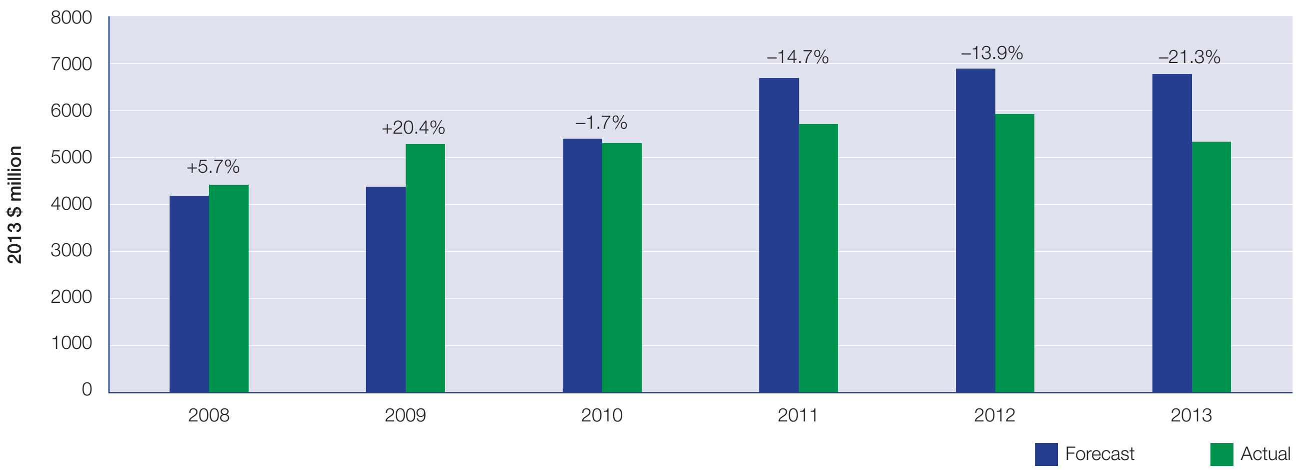
- electricity network revenues are on average 2 per cent *lower* than in previous regulatory periods. A similar trend is apparent in gas, with Victorian pipeline revenues being 11 per cent lower on average than in previous regulatory periods.
- reductions in the risk-free rate and market and debt risk premiums lowered the cost of capital from around 10 per cent in 2010 to 7.2–8.3 per cent in recent electricity and gas determinations (figure 4). The cost of capital set out in draft AER decisions in November 2014 was lower again, at 6.9–7.2 per cent. Under a revised framework applying for the first time in these decisions, the cost of capital will be revised annually to reflect changes in debt costs.
- approved investment forecasts for electricity networks are 24 per cent lower, on average, than levels in previous regulatory periods. The lower forecasts are mainly due to falling energy demand.

Delivering efficient network investment

Weakening energy demand is reducing the number of planned network investments, deferring projects that had already passed a regulatory investment test (a cost–benefit analysis to assess a project's viability). This trend is particularly reflected in declining network augmentations. Draft decisions for the NSW and ACT distribution networks in November 2014 provided for $1.2 billion of augmentation expenditure (16 per cent of total capital expenditure) across the four businesses—one-quarter of the amount approved in the previous regulatory period ($5 billion, or 35 per cent of total capital expenditure).

10 AEMO, *Electricity statement of opportunities*, 2014.

Figure 5
Capital expenditure by distribution networks against forecasts



Source: Annual financial RIN responses by distribution businesses.

Investment trends for the AusGrid distribution network (NSW) illustrate the effects of falling energy demand can be complex. The network's regulatory determination for 2009–14 provided for investment to meet an expected rise in maximum demand from 5500 to 6700 MW over the period. But these forecasts proved optimistic; maximum demand peaked at around 6000 MW, allowing the business to defer significant capital investment. This trend of underspending in capital programs occurred across all networks in recent years; from 2011 to 2013, distribution businesses underspent their approved forecasts by an average 17 per cent (figure 5).

One of the drivers of rising network charges in recent years was capital investment to ensure the networks delivered on reliability requirements. The AEMC in September 2013 proposed a new approach to setting distribution reliability targets—one that weighs the cost of new investment against the value that customers place on reliability and the likelihood of interruptions. In 2014 AEMO consulted with industry stakeholders to measure the value that customers place on a reliable supply of electricity. The valuations will feed into future regulatory determinations to ensure network investment delivers a secure and reliable electricity supply, while maintaining reasonable costs for consumers.

Some jurisdictions are already moving to reform distribution reliability standards. The removal of strict input based reliability standards for Queensland networks from 1 July 2014 is expected to save $2 billion in capital expenditure over the next 15 years. Supply interruptions will likely increase by 13 minutes for urban customers in 2020 (to 83 minutes, compared with 69 minutes under the previous standard).[11]

Similarly, the NSW Government in July 2014 removed deterministic planning obligations on distributors set out in network licence conditions. The remaining conditions focus solely on 'output' standards for reliability, providing more discretion for the businesses to determine the most appropriate ways to plan their network to meet the standard.[12]

The regulatory process includes incentives to improve service quality, particularly at times most valued by customers. As part of the service target performance incentive scheme, for example, transmission businesses can earn additional revenue for projects that improve a network's capability, availability or reliability when users most value reliability, or when wholesale electricity prices are likely to be affected. They face penalties if they fail to achieve improvement targets.

An element of network performance that has attracted recent policy focus is that pockets of network congestion periodically interfere with the efficient dispatch of generation plant. The AEMC in April 2013 began work on an *optional firm access* model to better manage this issue. In 2014 it developed core elements of the model's design and consulted widely with stakeholders.

11 Queensland Department of Energy and Water Supply, *Changes to electricity network reliability standards factsheet*.

12 AER, *Ausgrid distribution determination 2015–16 to 2018–19* (draft decision), Attachment 6: Capital expenditure, November 2014.

Optional firm access is intended to create locational signals that account for congestion costs against network expansion costs, providing efficient locational signals for new and existing generation plant. As a result, generation and transmission investment would likely become more efficient. The model also provides incentives for transmission businesses to maximise network availability when it is most valuable to the market.

Power of choice reforms

The nature and function of energy networks is evolving. Escalating cost pressures in recent years gave impetus to alternatives such as demand response (whereby users adjust their energy use in response to price signals), small scale local generation (such as rooftop solar PV generation) and, potentially, energy storage technologies. Innovations in network and communications technology, including smart meters and interactive household devices, are allowing consumers to access real-time information on their energy use and to have greater control over how they manage it.

These developments are transforming the nature of a network from being a one-way conduit for energy transportation, to a platform for multilateral trade in energy products. Some electricity consumers are becoming producers, able to switch from net consumption to net production in response to market signals. Over one million households have installed rooftop solar PV, for example. Further, customer investment in smart appliances and battery storage could shift the amount of power that customers withdraw from or inject into a network throughout the day. These developments are slowing the growth in peak demand, reducing the need for costly network augmentations.

In 2012 the AEMC launched *Power of choice*, an umbrella of reforms relating to efficient use of energy networks and non-network alternatives. The Council of Australian Governments (CoAG) Energy Council endorsed the reforms and proposed rule changes to apply them. The use of smart meters is central to the reforms, allowing consumers to access a wider range of retail price offers and demand management products.

Most electricity meters on residential premises are exclusively provided by regulated network businesses. But this arrangement can inhibit competition and consumer choice, and discourage investment in metering technology that could support the uptake of innovative energy products and services.

The AEMC consulted in 2014 on a CoAG Energy Council proposal to allow competition in the provision of metering and related services. It also progressed related reforms to allow customers more ready access to their electricity consumption data, and for multiple trading relationships at the customer's connection point. The reforms aim to create a regulatory framework that matches the realities of a dynamic and evolving energy market.

Victoria was the first jurisdiction to progress metering reforms, launching a rollout of smart meters with remote communications to all customers from 2009. The rollout was close to completion in late 2014. NSW in October 2014 announced a competitive framework for its own voluntary rollout of smart meters. The framework aims to encourage competition by allowing metering providers, such as electricity retailers or other energy service providers, to offer smart meters to customers as part of energy deals.[13]

In its current review of the NSW networks, the AER reclassified certain metering services, making them open to competition. It is also looking at other ways to facilitate the competitive framework. One way is to ensure exit fees are not unreasonably high, so customers incur only the efficient costs of moving from legacy (regulated) meters to third party provided meters.

While smart meters allow consumers to monitor their energy use, price signals are needed to create incentives for efficient demand response. Under traditional pricing structures, energy users pay the same network price regardless of how or when they use power. Charges to customers using large amounts of electricity at peak times do not reflect the costs that they impose on the network. For example, a residential consumer using a five kilowatt (kW) air conditioner at peak times causes around $1000 a year in additional network costs, but might pay only $300 under current price structures. The remaining $700 is covered by other customers, who pay more than what it costs to supply their own network services.[14]

Similarly, customers with solar PV installations may not bear the full cost of their network use under current price structures, which reward reductions in total energy consumption regardless of whether they occur at peak times. A customer can save around $200 in network costs per year by installing solar PV and reducing their use of electricity from the grid. But most solar energy is

13 The Hon. Anthony Roberts MP (NSW Minister for Resources and Energy), 'NSW gets smart about meters', Media release, Tuesday 28 October 2014.

14 Commissioner Neville Henderson (AEMC), 'Power of choice and other energy market reforms', Speech delivered to 2014 Energy Users Association of Australia (EUAA) conference, 13 October 2014.

generated at non-peak times, so the customer will reduce network costs by only $80 because they will still use the network at peak times. Other consumers without solar PV cross-subsidise the remaining $120 by paying higher network charges.[15]

To address these inefficiencies, *Power of choice* proposed network prices should vary depending on time of use, thus encouraging retailers to reflect those charges in customer contracts. Time varying prices encourage consumers to make efficient choices on the best times to use their electrical appliances—for example, customers could shift some use from peak times when charges are high, to off-peak times (such as late evening). More generally, cost-reflective pricing structures create incentives for customers to invest in local generation and smart devices.

To progress the matter, energy ministers in 2013 proposed reforms to distribution network pricing. The AEMC in November 2014 set out principles for distribution prices to reflect the efficient costs of providing network services to each consumer. Network businesses will need to consult with stakeholders when developing their charging structures, to account for consumer impacts.

The reforms aim to minimise network costs over time. The AEMC estimated 81 per cent of residential customers will face lower network charges in the medium term under cost-reflective pricing, and up to 69 per cent will see lower charges at peak times.[16] Business users with relatively flat load profiles can also expect lower network charges. The AEMC recommended the new rules be progressively implemented in 2016–17, to give energy customers time to adjust to the changes.

Victoria was the first jurisdiction to implement time varying prices. From September 2013 Victorian small customers could choose to remain on a traditional tariff structure or move to a more flexible structure.

15 Paul Smith (CEO, AMEC), 'Responding to consumer demands, promoting competition and preparing for change', Speech delivered to 2014 Australian Institute of Energy symposium, 22 September 2014.

16 Commissioner Neville Henderson (AEMC), 'Power of choice and other energy market reforms', Speech delivered to 2014 EUAA conference, 13 October 2014.

A.4 Gas markets

Despite a weakness in global demand, Australia's LNG exports rose in 2013–14 by 15 per cent to $16.5 billion, becoming Australia's third largest export after iron ore and coal.[17] Australia's gas industry is about to be transformed, with three major LNG projects in Queensland nearing completion. The three projects—the world's first to convert coal seam gas (CSG) to LNG—include processing facilities at the port of Gladstone and transmission pipelines to ship gas from CSG fields in the Surat–Bowen Basin.

In 2014 the Queensland LNG project developers continued to build and test wells, and began operating new production facilities. Developers also neared the completion of gas processing facilities, liquefaction plants and transmission pipelines, including the interconnection of pipelines to enable gas flows between projects.

The development of Queensland's LNG industry is exerting significant pressure on the domestic gas market. Gas production in eastern Australia is forecast to treble over the next two decades to meet international LNG demand,[18] with the first exports scheduled for 2014–15. With LNG proponents sourcing reserves that might otherwise have been available to the domestic market, domestic customers are having difficulty buying gas under medium to long term contracts.[19] The effect of these market conditions was apparent in 2013 and 2014, with prices in new gas contracts reportedly linked to international oil prices or LNG netback.[20] Further, the Australian Government's energy green paper noted in September 2014 that sellers appear to have access to more market information than buyers, raising policy concerns.[21]

While prices in spot markets reflected similar behaviour to contract prices in 2012–13, the markets diverged from late 2013. Winter prices were lower in all hubs in 2014 than in 2013, averaging just below $4 per gigajoule (GJ) in Sydney, Melbourne and Adelaide, and $2.50 per GJ in Brisbane. The abolition of carbon pricing, which took effect on 1 July 2014, reduced the cost competitiveness of gas powered generation, contributing to weaker gas demand.

17 EnergyQuest, *EnergyQuarterly* August 2014, Media release, 29 August 2014.

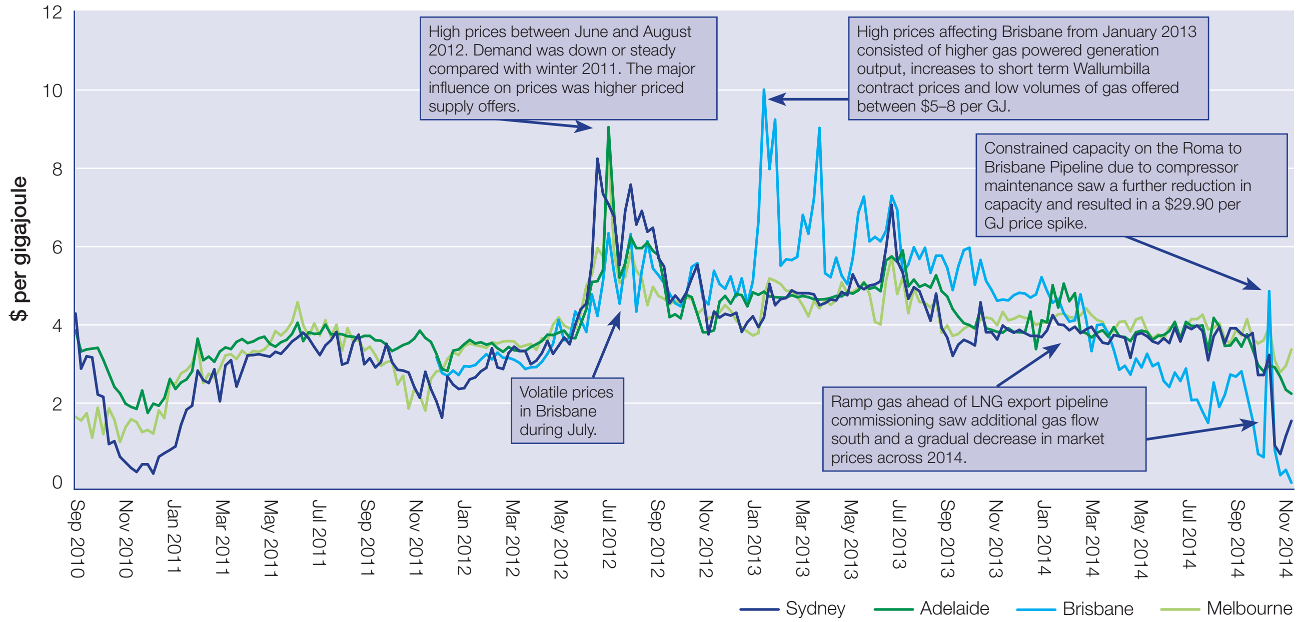
18 AEMO, *Gas statement of opportunities*, May 2014.

19 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

20 LNG netback prices simulate an export parity price by stripping out shipping, transportation and liquefaction costs.

21 Australian Government (Department of Industry), *Energy green paper*, September 2014.

Figure 6
Spot gas prices—weekly averages



Notes: Volume weighted ex ante prices derived from demand forecasts. Sydney, Adelaide and Brisbane data are short term trading market prices. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's transmission withdrawal tariff for the two Melbourne metropolitan zones. The Sydney data exclude the 1 November 2010 price of $150 per GJ, which data errors caused.

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

Queensland prices diverged markedly from prices in southern markets in 2014, coinciding with rising gas production around Roma as production facilities ramped up for LNG export (figure 6). Significant quantities of the ramp-up gas were sold into the Brisbane hub of the short term trading market and the gas supply hub at Wallumbilla.

These increased gas flows caused Brisbane spot prices to collapse during 2014. October and November prices were typically below $1 per GJ and fell close to zero on some days. Prices also trended lower in the gas supply hub at Wallumbilla. Ramp-up gas also flowed into the southern states. In September and October 2014 gas flows from Queensland to South Australia and NSW via the QSN Link more than doubled the flows in the corresponding period in 2013. The rise in gas volumes caused lower than average prices, with Sydney prices falling below $1 per GJ on a number of days from late October into November. Additionally, these flows reduced NSW's usual reliance on Victorian gas, causing a reversal in flows between the two states along the NSW–Victoria Interconnect; that is, gas flowed south along the pipeline, from NSW into Victoria.

The collapse in gas prices flowed through to electricity markets in 2014. Falling gas prices in Brisbane coincided with higher levels of gas powered generation in Queensland and low spot electricity prices, which fell as low as $11 per MWh in October 2014 (figure 7).

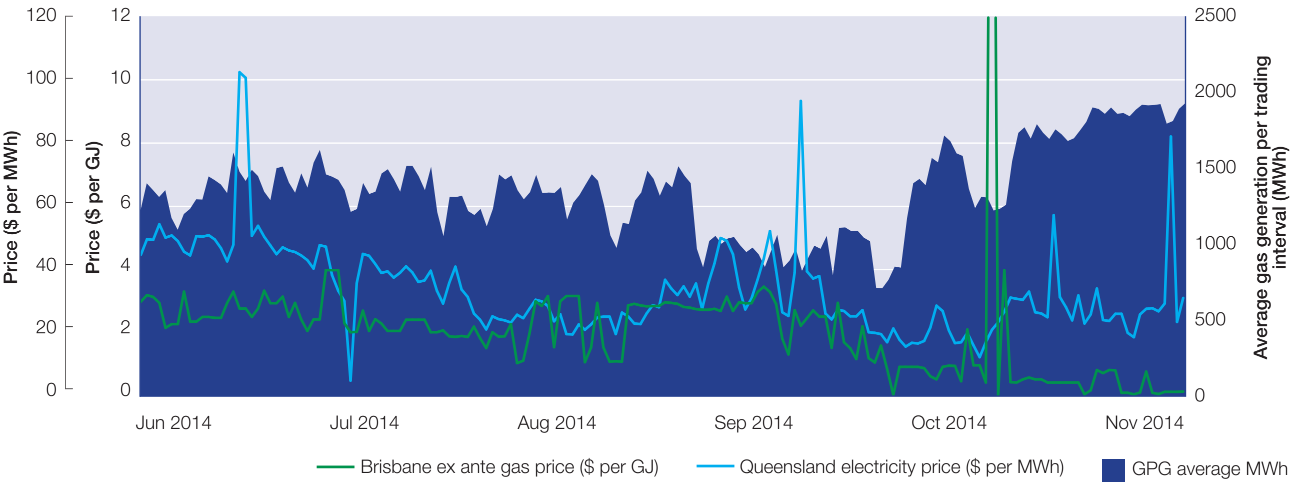
East coast supply–demand balance

Ramp-up gas will continue to be sold into domestic spot markets in the lead-up to commissioning each of Queensland's six committed LNG trains, exerting downward pressure on spot prices. The timing of each train's commissioning is uncertain, although each of the three LNG projects expects to commission at least one train by mid-2015.

While the domestic gas market will tighten once all LNG facilities are exporting at full capacity, a countervailing influence is weaker projections of gas powered electricity generation (which accounts for 31 per cent of domestic

Newcastle Gas Storage Project (AGL Energy)

Figure 7:
Spot gas prices (Brisbane) and spot electricity prices and gas powered generation (Queensland)



Note: Brisbane average ex ante daily gas price per GJ. Volume weighted average daily spot electricity price per MWh. Gas powered generation (MWh) per trading interval.

Sources: AER; AEMO.

gas demand in Australia).[22] Stanwell took its Swanbank E generator offline in December 2014 for up to three years, reducing domestic gas demand over that period.

Accounting for these factors, AEMO in 2014 scaled back earlier projections of gas supply shortfalls in eastern Australia.[23] But various contingencies affect the forecasts, including the timing of each LNG train's commissioning, changing forecasts of electricity demand growth (and the proportion of forecast demand expected to be sourced from gas powered generation), the effects of government climate change policies on gas demand, and the availability of gas storage facilities.

In this volatile environment, industry participants are considering supply alternatives to avoid possible shortfalls. Pipeline owners, for example, have expanded or are expanding capacity on several transmission pipelines. The NSW and Northern Territory governments in November 2014 signed a Memorandum of Understanding to work closely on the development of a pipeline connecting the Northern Territory with eastern gas markets. Additionally, AGL Energy in 2015 will complete a 1.5 petajoule (PJ) LNG storage facility near Newcastle to help manage fluctuations in gas supply, particularly during peak periods.

Proponents are seeking to develop new CSG resources in eastern Australia, although community concerns about health and environmental impacts have delayed their development. The NSW Government in November 2014 launched a new strategic framework to determine appropriate areas to develop and extract gas, accounting for economic benefits and any effects on the environment and communities. The potential to develop unconventional gas in the Cooper Basin is also significant. While two shale wells were producing in 2014,[24] Santos indicated production could take up to a decade to be commercially viable, given the costs of drilling and extraction technologies, and varying geological conditions.[25]

Policy responses

Policy makers are progressing reforms to help alleviate pressures in the eastern gas market. A gas supply hub launched at Wallumbilla, Queensland in March 2014 aims to alleviate bottlenecks by facilitating short term gas trades. As a pipeline interconnection point, Wallumbilla links gas markets in Queensland, South Australia, NSW and Victoria. The market model could be adapted to other hubs in the future.

22 Bureau of Resources and Energy Economics (BREE), *Gas market report*, October 2013, p. 26.
23 AEMO, *Gas statement of opportunities update*, May 2014.
24 Santos, Presentation to 2014 CLSA investors' forum, 15 September 2014.
25 'Shale gas success still a decade away for Australia, says Santos', *The Australian*, 26 September 2014.

The hub promotes transparent and efficient gas trading, allowing participants to manage the risks associated with variable gas prices. It also deepens market liquidity by attracting participants such as LNG plants, industrial customers and gas powered generators. The diversity of contract positions and the number of participants at Wallumbilla create a natural point of trade.

Trading activity in the gas supply hub was intermittent in 2014, which is not unusual in a new market. The existence of long term contracts and physical pipeline constraints also limited the volume of trades. While few traders were active, the number of buyers and sellers rose during the year, with more sellers than buyers in October 2014. On average, around 12 trades per week occurred between four participants. While a majority of trades were for gas delivered along the Roma to Brisbane Pipeline, trading on the South West Queensland Pipeline rose from August 2014.

Industry participants expect liquidity in the hub to improve in 2015, with pipeline augmentations and market conditions around Wallumbilla expected to free up more gas for trade. The ongoing development of hub products should further promote trade. A number of participants indicated the availability of a single trading price would also enhance liquidity, but may require improved interconnection between the three transmission pipelines serving the hub.

In other developments, the CoAG Energy Council is reforming pipeline capacity trading arrangements, to promote trade in idle contracted capacity. Throughout the year, some pipelines have significant idle capacity that is contracted to gas retailers and industrial consumers. In 2014 the Energy Council and AEMO consulted with stakeholders on enhancing pipeline capacity trading information on the National Gas Market Bulletin Board. As a preliminary step, AEMO in 2014 changed the bulletin board's interface to improve accessibility and data discoverability. It also launched an eastern market capacity listing service, with voluntary standard contractual terms and conditions for secondary capacity trade.

Pipeline entities also made progress towards secondary trading in capacity. APA Group launched an operational transfer capacity trading platform in 2014, and Jemena expects to launch a trading platform in December 2014. Customers have not widely used existing platforms, with some suggesting prices of around $1 per GJ are too high.

The AEMC in September 2013 proposed further market reforms, including refining spot market design and streamlining the rule change process for spot markets.[26] AEMO progressed reforms to interregional trade in 2013–14 by improving the interface between the Victorian spot market and interconnecting pipelines and facilities. It similarly progressed reforms of market operator (gas balancing) services in the short term trading market.[27]

The Australian Government's 2014 energy green paper cited a need for greater transparency of gas production potential and trading information (including prices), to improve gas market operation.[28] Additionally, stakeholders in 2014 called for closer harmonisation of the gas spot market models. Three spot market models operate in eastern Australia—the short term trading market in Brisbane, Sydney and Adelaide; the Victorian spot market; and the gas supply hub at Wallumbilla. The existence of multiple market structures imposes a significant regulatory burden on participants.

The Business Council of Australia noted an absence of standardisation across markets hinders the development of a viable forward market in gas.[29] The Victorian Government recently advocated more integrated market arrangements, including a possible move to a single market design to reduce barriers to interregional trading. It also advocated a single set of principles for access to east coast pipelines.[30]

A.5 Retail energy markets

The repeal of carbon pricing led retail electricity prices in 2014 to fall in jurisdictions other than Queensland and South Australia (figure 8). Retailers estimated annual electricity cost savings for residential customers from the carbon repeal were 5.2–12.4 per cent.[31] However, in Queensland, higher wholesale energy costs and feed-in tariff payments for solar PV systems offset the savings; in South Australia, rising network costs drove up prices.

26 AEMC, *Taking stock of Australia's east coast gas market*, Information paper, September 2013; K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

27 AEMO, *2014 Annual report*, 2014.

28 Australian Government (Department of Industry), *Energy green paper*, September 2014.

29 Business Council of Australia, *Australia's energy advantages*, November 2014.

30 Victorian Government (Department of State Development, Business and Innovation), *Victoria's energy statement*, 2014.

31 ACCC, *Monitoring of prices, costs and profits to assess the general effect of the carbon tax scheme in Australia*, October 2014.

Figure 8
Movements in regulated and standing offer prices

Notes:

Estimated annual cost is based on a customer using 6500 kilowatt hours (kWh) of electricity per year and 24 GJ of gas per year on a single-rate tariff at September 2014.

Prices are based on regulated or standing offer prices of the local area retailer for each distribution network.

Sources: energymadeeasy.gov.au; switchon.vic.gov.au; yourchoice.vic.gov.au; comparator.qca.org.au; determinations, factsheets and media releases by IPART (NSW), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

Retail gas prices fell only in Victoria. In other jurisdictions, rising costs associated with a reduced availability of wholesale gas contracts (section A.4) offset savings from the repeal of carbon pricing. Pipeline charges also rose in most regions, putting additional pressure on retail prices.

Retail energy prices remain high by historical standards, reflected in the number of customers experiencing payment difficulties. At 30 June 2014 the rate of energy customers on hardship programs ranged from 0.4 per cent in Tasmania (electricity) and the ACT (electricity and gas), to 1.2 per cent in South Australia (electricity). Almost 12 per cent of electricity customers (and 4 per cent of gas customers) had debts greater than $2500 before joining a hardship program. Of those customers exiting a program in 2013–14, only 20 per cent had successfully completed it. Other customers were removed from hardship programs for failing to meet energy repayments.

Some consumer stakeholders raised concerns that barriers restrict access to hardship assistance and that some retailers set unaffordable payment plans. In response to these and related concerns, the AER in 2014 reviewed hardship policies and practices, focusing on how retailers identify and assist customers experiencing payment difficulties.

Retail competition

All energy customers in eastern and southern Australia are free to choose their retailer, following Tasmania's extension of full retail contestability to electricity customers using less than 50 MWh per year from 1 July 2014.

Despite retail contestability operating for over a decade in most regions, retail markets remain concentrated. Three private retailers—AGL Energy, Origin Energy and EnergyAustralia—jointly supplied over 70 per cent of small electricity customers and over 80 per cent of small gas customers at 30 June 2014. Competition from smaller retailers eroded around 5 per cent of their market share over the past two years.

Vertical integration with the generation sector increased following AGL Energy's acquisition of Macquarie Generation in 2014. Overall, the three major retailers now control 46 per cent of generation capacity, up from 15 per cent in 2009. Another major player, Snowy Hydro, increased its market share to 10 per cent in December 2014, following its acquisition of Colongra power station from Delta Electricity. Snowy Hydro also emerged as the fourth large energy retailer in September 2014, when it acquired Lumo Energy (adding to its existing Red Energy business). The acquisition raised Snowy Hydro's retail market share in electricity and gas to 7 per cent.

But retail competition has deepened with the emergence of alternative retail models, driven by rising energy prices, consumers wishing to manage their energy use, and wider access to renewable energy options. The models include solar power purchase agreements (whereby businesses sell energy generated from solar panels installed at a customer's residence), tailored products for customers with specific energy requirements (such as households with swimming pools), and energy sales as part of a package that provides a customer with greater control over their energy use.

The regulatory approach will need to keep pace with these changes. The AER published a statement of approach in July 2014, focusing on solar power purchase agreements. In November 2014 it published an issues paper on regulating innovative energy selling business models more generally (including energy storage), to help develop an appropriate and flexible approach.

The AEMC in 2014 found that energy retail competition was effective in NSW, Victoria, South Australia and south east Queensland. Competition is generally more effective in electricity than gas, due to differences in market scale and the difficulties in sourcing gas and transport services in some regions.[32]

Following advice from the AEMC, NSW in July 2014 joined Victoria and South Australia in removing retail price regulation for electricity. The Queensland Government committed to removing electricity retail price regulation in south east Queensland from 1 July 2015.

The average extent of retail price discounting was greater in 2014 than in the previous year in all regions. The average discount for electricity bills under market contracts, over standing contracts, ranged from 5 per cent in Queensland to 16–19 per cent in Victoria. Discounts were typically lower for gas, at around 5 per cent in most jurisdictions and 10 per cent in Victoria.

The annual bill spread in September 2014 also varied across jurisdictions. Victoria exhibited the strongest price diversity. The spread for electricity contracts ranged from $200 in Queensland to over $1000 in Victoria. Gas contract spreads were consistent with the previous year, at around $200 for most networks.

32 AEMC, *2014 Retail competition review, final report*, August 2014.

For competition to be effective, consumers must be able to make informed choices on the energy product that best meets their needs. The AEMC found consumers generally have good awareness of their ability to choose a retailer. In markets with effective competition, awareness ranged from 90 per cent of electricity customers (85 per cent for gas) in NSW to 95 per cent of electricity and gas customers in Victoria. However, consumers were less aware of tools available to compare retail offers effectively. Over 60 per cent of respondents in the AEMC review were not aware of, or unable to name, a price comparator website. The review noted many customers find energy contracts complex and struggle to compare available offers.

Consumer protection

Lack of understanding among consumers increases the risk of exploitation. For this reason, the behaviour of energy retailers has become a compliance and enforcement priority:

- The AER in November 2014 instituted proceedings in the Federal Court against EnergyAustralia, and a telemarking company acting on its behalf, for failing to obtain the explicit informed consent of customers in South Australia and the ACT before transferring them to new energy plans. The ACCC instituted proceedings against the businesses for similar behaviour in Queensland, NSW and Victoria under provisions in the Australian Consumer Law on misleading conduct or representations.
- The ACCC instituted proceedings in the Federal Court against AGL Energy in December 2013 and Origin Energy in March 2014 relating to how the businesses promote discounts and savings under their energy plans. The action followed concerns that the retailers were misleading consumers about the extent of savings available, and the period over which discounts would be provided.

The Consumer Action Law Centre and the Consumer Utilities Advocacy Centre raised concerns in 2013 about the ability of retailers to raise prices under fixed term energy contracts with termination fees. They considered this arrangement unfairly shifts price risk onto consumers, which may erode confidence in the market and weaken competition.

The AEMC in October 2014 rejected a rule change proposal on this matter. It considered the key issue is that some consumers may enter contracts unaware that prices may change. To address this issue, it introduced a rule requiring a retailer to clearly inform a consumer entering a contract whether prices can change and, if so, when the retailer would notify the customer of the change.

The AER participated in the rule change process and is exploring ways to improve the quality of information available to consumers choosing an energy retail contract. It is also reviewing the *Retail pricing information guideline* that sets out how retailers must present offers, including all information that must be provided. Additionally, the AER intends to roll out improvements to the Energy Made Easy price comparison website in 2015, making it easier for customers to see which offer would best suit their needs.