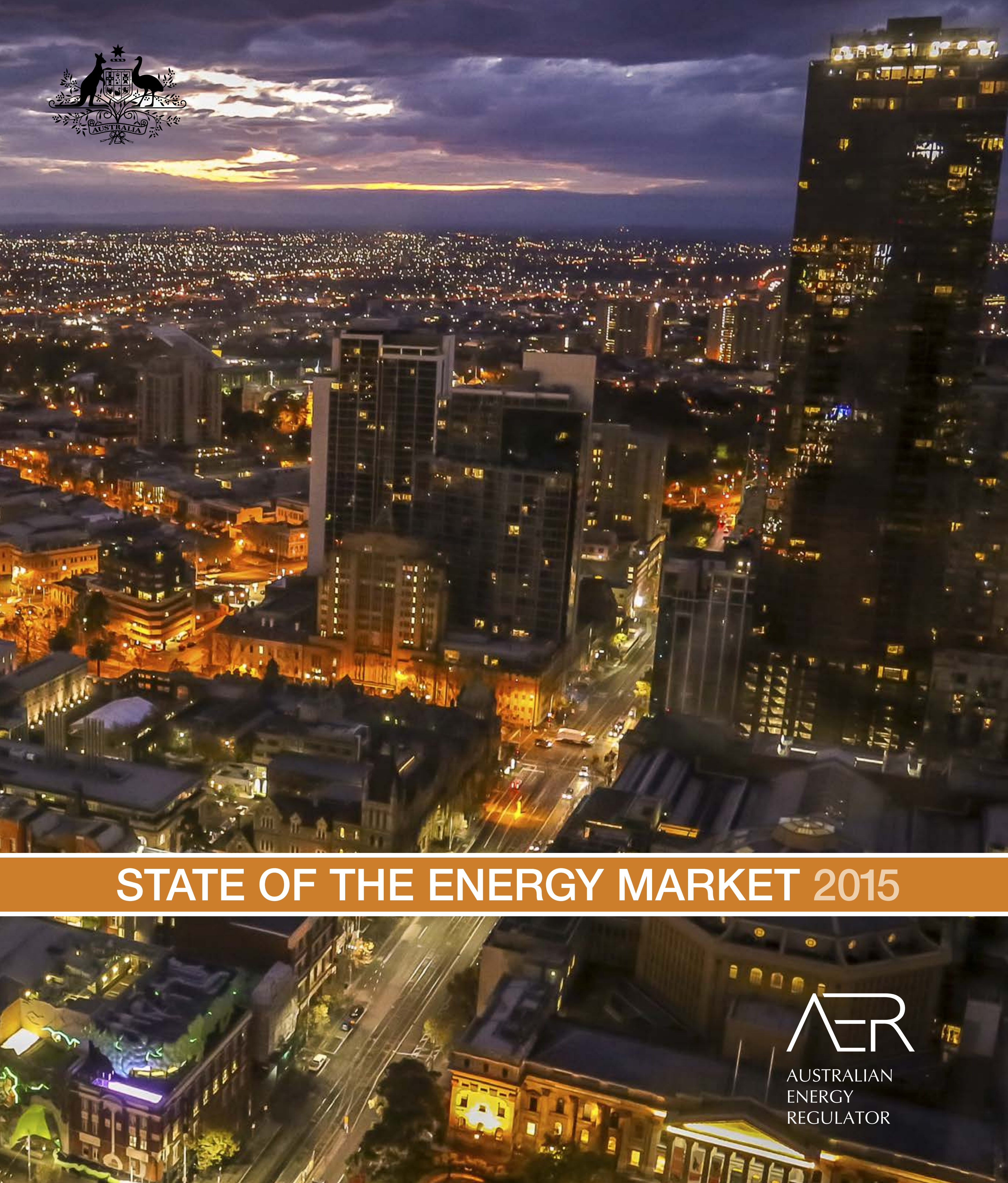

STATE OF THE ENERGY MARKET 2015

AUSTRALIAN
ENERGY
REGULATOR

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Australian Energy Regulator

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Editor: Editor’s Mark, Melbourne

Cover image courtesy of Allison Crowe

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PREFACE

I am pleased to introduce the Australian Energy Regulator's *State of the energy market 2015* report. This ninth edition explores structural shifts across the energy supply chain, both in electricity and gas, and how these shifts impact on consumers and industry.

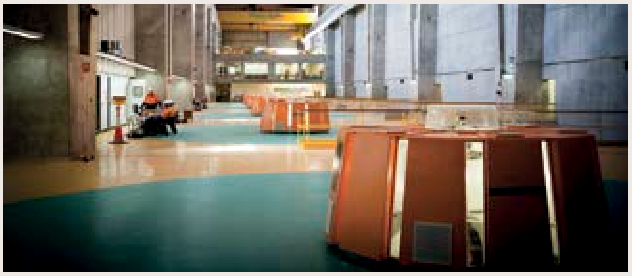
In electricity, six years of flat or negative demand growth and the continued rise of renewable generation are translating into plant redundancies and, in some regions, market volatility. These trends impact on the network sector, which is also being transformed by new regulatory rules and metering and pricing reforms that will better inform consumer choice. The retail market is responding to these changes with new approaches to selling energy. Alongside these developments, Queensland's new LNG industry is transforming eastern Australia's gas industry.

The *State of the energy market* report focuses on energy market activity over the past 12–18 months in those jurisdictions in which the AER has regulatory responsibilities. In future, the report's coverage will expand. In 2015, the AER became the electricity network regulator in the Northern Territory. It will also acquire this role in Western Australia in 2017, pending legislative approval and other regulatory processes.

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 2015 edition is a valuable resource for policy makers, consumers, industry and the media.

Paula Conboy
Chair
December 2015

SNAPSHOT

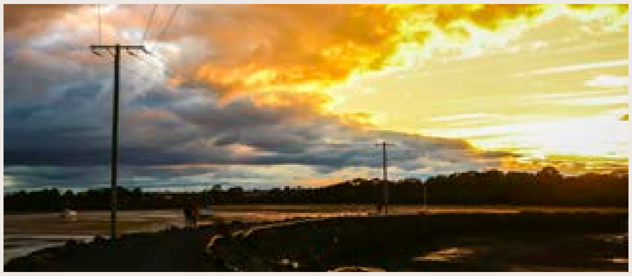


National Electricity Market

- Demand for electricity declined or stayed flat for six consecutive years to 30 June 2015.
- Demand for electricity at peak times was 20 per cent below historical highs in NSW, Victoria and South Australia in 2014–15, but set a new record in Queensland.
- Rising electricity bills over the past five years drove consumers to adopt energy efficiencies and 1.5 million households to install rooftop solar photovoltaic panels. By 2024–25 solar PV is forecast to generate 7.5 per cent of total energy requirements.
- The first commercial solar farms opened in 2015, with capacity of 175 megawatts.
- Investment in wind generation has been ongoing, but coal and gas plant have closed in South Australia, Queensland, NSW, Victoria and Tasmania.
- Wholesale electricity prices fell in 2014–15, except in Queensland, where generator bidding contributed to high summer prices. The South Australia market also had volatile pricing.

Eastern Australia gas market

- Domestic gas demand was flat in 2014–15 (especially for gas powered generation), but export demand is rising as Queensland LNG projects compete for locally produced gas.
- Two LNG projects commenced exports in 2015, and a third will commence by early 2016.
- Gas markets were volatile in 2015, with weekly spot prices ranging from near zero to $12 per gigajoule.
- Transmission pipelines in eastern Australia were re-engineered for bidirectional flows, allowing more flexible gas trading.
- New transmission pipeline linking Queensland with the Northern Territory will open the eastern gas market to new supply sources by 2018.
- Major ACCC and AEMC reviews of eastern gas markets were underway in 2015.



Regulated energy networks

- Lower electricity demand has meant less network investment to augment capacity but higher replacement expenditure for ageing assets.
- The cost of capital in AER distribution network determinations made in 2015 ranged from 5.41 per cent (NSW gas) to 6.68 per cent (NSW electricity). In previous determinations, the cost of capital was 10.4 per cent for NSW gas (2010) and 10.02 per cent for NSW electricity (2009), following merits review by the Australian Competition Tribunal.
- AER benchmarking identified material operating inefficiencies in some electricity networks.
- Distribution network costs are estimated to be around $250 lower for a typical NSW electricity customer in 2015–16 than immediately before the current regulatory period. The estimated reduction for Queensland, South Australia and ACT electricity customers, and NSW gas customers is around $100–200.
- Network owners and consumer groups applied to the Australian Competition Tribunal for merits review of determinations on the NSW electricity and gas networks, and the South Australian and ACT electricity networks.
- Preparatory work is underway to launch competition in metering services and more cost-reflective distribution tariffs by 2017.

Retail energy markets

- Retail electricity prices mostly fell in in 2015, reflecting declining network costs pressures.
- Retail gas prices rose in most jurisdictions, driven by higher pipeline charges and rising gas contract prices.
- The majority of electricity customers in Victoria, South Australia, NSW and south east Queensland now have a market contract rather than a standing offer.
- The AEMC found electricity markets in Tasmania, regional Queensland and the ACT are not effectively competitive.
- New retail products are emerging.
- On 1 July 2015 Queensland became the fifth jurisdiction to adopt the National Energy Retail Law.
- The Federal Court imposed penalties on retailers in 2015 for failing to obtain the explicit informed consent of customers; misleading conduct or representations; and false or misleading statements on available discounts under energy plans.

Image courtesy of AGL Energy

MARKET OVERVIEW

A.1 Introduction

Demand for electricity in the National Electricity Market (NEM) declined or remained flat for six consecutive years to 30 June 2015. While weakening industrial demand was significant, rising electricity prices drove consumers to cut their energy use by adopting measures such as solar water heating and energy efficient airconditioning. Consumers also self-generated more electricity, by installing rooftop solar photovoltaic (PV) panels. Consumer interest in battery storage and electric vehicles is also gaining momentum.

In the wholesale market, subdued demand continued to exert downward pressure on wholesale electricity prices in 2014–15, except in Queensland and South Australia, where local structural issues have caused volatility. Some generators are responding by withdrawing plant from the market, through either temporary mothballing or retirements.

Maximum demand, which is a key driver of network investment, has also been flat. In 2014–15 maximum demand in New South Wales (NSW), Victoria and South Australia was almost 20 per cent below the historical peaks recorded around 2008–09. Lower levels of maximum demand require less network augmentation expenditure than in the past to provide a reliable energy supply. Australian Energy Regulator (AER) determinations made since 2012 allowed for network investment levels that are an average 25 per cent lower than levels in previous periods.

The story for gas is more complex. While domestic gas demand is flat (especially for gas powered generation), major liquid natural gas (LNG) projects are now competing with domestic customers for locally produced gas. While a number of gas developments were at an advanced stage in 2015, all were subject to uncertainty. In this uncertain environment, domestic gas supply contracts are being struck with reference to global prices, and spot gas prices in eastern Australia are volatile.

These events translated into contrasting trends in the retail space. While subdued demand flowed through to lower retail electricity prices in most jurisdictions in 2015, retail gas prices in many jurisdictions rose.

The energy market is facing other challenges too. Technological innovations are allowing consumers to be active participants in the market, as both producers (through self-generation) and customers (by seeking products tailored to their needs). As the market responds, demarcations between the wholesale, network and retail spaces are blurring. The regulatory framework must keep pace with these changes, by creating the necessary space for competitive markets to drive choice and innovation, while maintaining consumer protections.

A.2 National Electricity Market

Wholesale electricity in eastern and southern Australia is traded through the NEM, spanning Queensland, NSW, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). A transmission grid covering five state based networks and several cross-border interconnectors physically links the market.

After five years of decline, electricity demand from the grid steadied in 2014–15. But, in NSW, Victoria and South Australia, *maximum* demand—driven by airconditioning or heating loads on days of extreme temperatures—was almost 20 per cent below the historical peaks recorded around 2009. Queensland recorded a contrasting trend, setting a new record peak on 5 March 2015 when Brisbane experienced its seventh consecutive day of temperatures above 30 degrees.[1] Maximum demand also rose in Tasmania in 2014–15, but remained well below its historical peak.

While industrial energy demand has weakened since 2008, residential and commercial consumers have also reduced their grid consumption by adopting energy efficient measures—such as solar water heating and energy efficient air conditioning, refrigeration and electronics—and installing rooftop solar PV panels to self-generate electricity. Government subsidies and incentives, combined with rising electricity prices, encouraged almost 1.5 million Australian households to install small scale solar PV systems from 2009 to 2015. Installed solar PV capacity reached 3700 megawatts (MW) in 2014–15, equivalent to 8 per cent of total installed generation capacity in the NEM. Solar PV installations supplied 2.7 per cent of electricity requirements in the NEM in that year.[2] In South Australia, the solar PV contribution was 7 per cent,[3] peaking on 26 December 2014 at 36 per cent of the state's energy requirements.

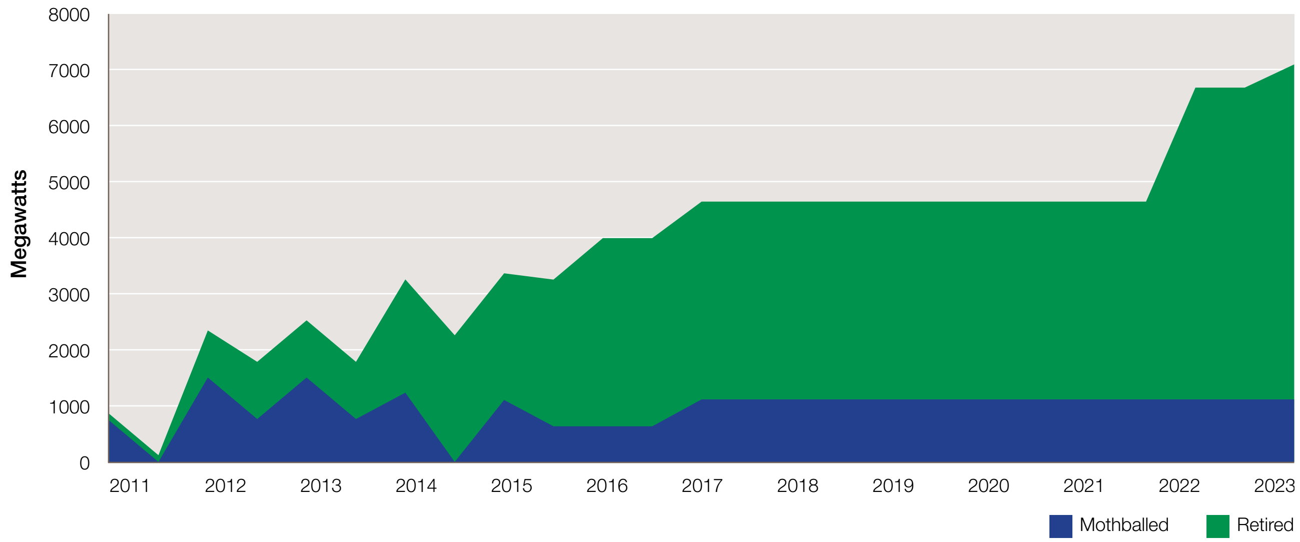
While the rate of new installations has eased since 2011, the average capacity of new installations is rising. In part, these shifts reflect the progressive rollback of subsidised feed-in tariffs towards market levels, and falling solar panel costs.

The Australian Energy Market Operator (AEMO) forecast solar installations will more than triple over the next decade, with capacity equalling 21 per cent of total installed generation in the NEM by 2024–25. This capacity will contribute around 7.5 per cent of the NEM's energy requirements at that time.[4] Queensland has the highest forecast growth in solar PV installations over the next

1 AEMO, *National electricity forecasting report* 2015, p. 16.
2 AEMO, *Emerging technologies information paper*, June 2015.
3 AEMO, *South Australian electricity report*, August 2015.
4 AEMO, *National electricity forecasting report 2015, dynamic forecasting interface*.

Figure 1

Generation capacity removed from the market since 2011



Note: Data for winter and summer each year.

Sources: AER estimates drawing on AEMO*, Electricity statement of opportunities* (various years); AEMC, *Advice to the COAG Energy Council: barriers to effective exit decisions by generators*, 16 June 2015; Company announcements.

decade, with installed solar capacity in 2024–25 forecast to be one third of all generation capacity.[5]

As consumers self-generate more electricity, interest in battery storage and electric vehicles gains momentum. While both are still too expensive for mainstream adoption, retailers have begun offering energy storage packages. Battery storage will allow for better matching of output from intermittent generation such as solar PV against demand peaks.

The uptake of electric vehicles has been relatively modest, with only 2000 electric-only vehicles sold in NEM jurisdictions to April 2015. But declining battery costs will likely accelerate uptake of these technologies. AEMO projected an uptake of around 165 000 electric-only vehicles in the NEM by 2024–25.[6] While electric vehicles will be a source of demand, they may also offer battery storage that could be used to offset peak demand.

Investment trends

Reduced electricity demand since 2008 has led to significant coal and gas powered generation plant being permanently or temporarily removed from the market (figure 1). Overall, capacity withdrawals from 2011–12 to 2014–15 exceeded new generation entry. Plant announced for withdrawal over the next seven years includes gas fired power stations at Torrens Island (South Australia), Tamar Valley (Tasmania), Daandine and Mount Stuart (Queensland) and Smithfield (NSW), and coal capacity at Northern and Playford (South Australia) and Liddell (NSW).[7]

In this environment, investment in new generation plant has largely evaporated, other than in wind and solar plant. The NEM's first three commercial solar plants—at Nyngan, Royalla and Broken Hill—were commissioned in NSW in 2015, with a combined capacity of 175 MW. Large scale solar generation has been slow to develop in Australia, partly as a result of its high cost per megawatt hour (MWh) relative to the costs of other technologies. The Australian Renewable Energy Agency (ARENA) announced in September 2015 that it would partner with the Clean Energy Finance Corporation to fund $350 million for up to 10 additional large scale solar plants by 2017.

Aside from solar, the bulk of recent investment in commercial generation has been in wind. Around 270 MW of wind capacity was added in 2014–15, and wind generation into the national grid rose during the year by 8 per cent.

5 AEMO, *National electricity forecasting report 2015*.

6 AEMO, *Emerging technologies information paper*, June 2015.

7 AEMC, *Advice to the COAG Energy Council: barriers to effective exit decisions by generators*, 16 June 2015; AEMO, *Electricity statement of opportunities* (various years), Company announcements.

The penetration of wind generation is especially strong in South Australia, where it supplied 33 per cent of electricity consumption from the grid in 2014–15. At times, wind is the dominant form of regional generation. In 1164 trading intervals in 2014–15, wind farms supplied 75 per cent of South Australian consumption from the grid.

However, wind generation tends to be lower at times of maximum demand. In South Australia, wind typically contributes 10 per cent of its registered capacity during peaks in summer demand. The proportion is lower in other regions (as low as 1 per cent in NSW).[8]

The rise in wind and solar PV generation over the past few years reflects wider shifts in the generation technology mix, driven by technological change and government policies to mitigate climate change. The Renewable Energy Target (RET) and carbon pricing impacted on the electricity sector, which contributes over one third of national greenhouse gas emissions.[9] An expert panel appointed to review the RET in 2014 reported the scheme had led to the abatement of 20 million tonnes of carbon emissions since its launch in 2001.[10]

On 23 June 2015 Australia's Parliament revised the RET's 2020 target for energy from large scale renewable projects from 41 000 gigawatt hours (GWh) to 33 000 GWh. On current estimates, this target would result in 23.5 per cent of Australia's electricity generation in 2020 being sourced from renewables.[11]

A carbon pricing scheme operated in Australia between 1 July 2012 and 1 July 2014, at $23 per tonne of carbon dioxide equivalent emitted. Over the two years of the scheme's operation, output from brown coal fired generators declined by 16 per cent (with plant use dropping from 85 per cent to 75 per cent), and output from black coal generators declined by 9 per cent. Coal generation's market share fell to an historical low of 73.6 per cent of NEM output in 2013–14.

Overall, these changes contributed to the emissions intensity of NEM generation falling by 4.7 per cent. This fall, combined with lower NEM demand, led to a 10.3 per cent fall in emissions from electricity generation over the two years that carbon pricing was in place.

8 AEMO, *South Australian wind study report*, 2015.
9 Australian Government, *Quarterly update of Australia's national greenhouse gas inventory, March quarter 2015*.
10 Expert Panel, *Renewable energy target scheme: report of the Expert Panel*, August 2014.
11 The Hon. Greg Hunt MP, Minister for the Environment, Paris and beyond: An integrated approach to climate and the environment. Speech delivered to National Press Club, Canberra, 25 November 2015.

The repeal of carbon pricing from 1 July 2014 led to some coal plant being returned to service, and to a significant fall in hydro generation output. This shift contributed to a 4.3 per cent rise in electricity emissions in the NEM in the year to 30 June 2015.

The Australian Government in 2014 replaced carbon pricing with a Direct Action plan to achieve Australia's 2020 emissions reduction target. Central to the plan is an Emissions Reduction Fund that provides funding for the Clean Energy Regulator to purchase emissions reductions at the lowest available cost through competitive auctions.

The majority of abatement from the two auctions held in 2015 is via sequestration projects that trap carbon through measures such as planting trees and storing carbon in soil; landfill and waste related projects; and bushfire prevention through savannah burning. No electricity generation projects participated in the 2015 auctions.

In September 2015 the Australian Government announced draft rules for a safeguard mechanism that penalises large businesses for increasing their emissions above a baseline, to commence from July 2016. The mechanism's role is to ensure emissions reductions purchased under the fund are not displaced by a significant rise in emissions above business as usual. Electricity generators will have a sectoral baseline referenced to the sector's highest historical annual emissions (198 million tonnes in 2009–10). If this baseline is exceeded, then individual facility baselines will apply.

The NEM in 2014–15

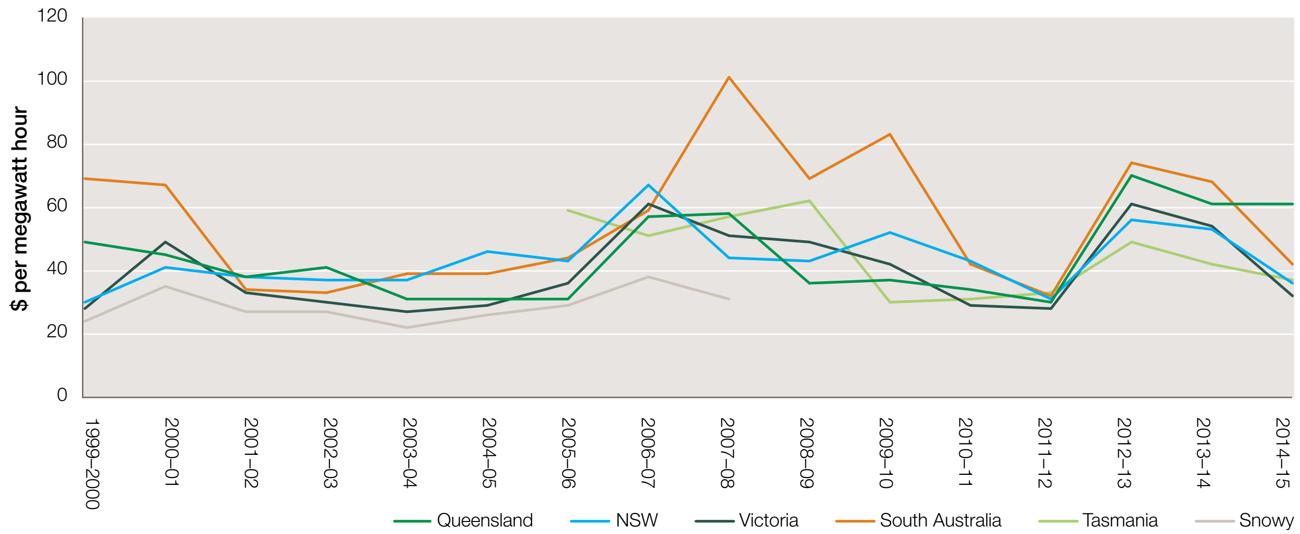
Spot prices in the NEM were significantly lower in 2014–15 than 2013–14 averages in most regions. Average wholesale prices fell by 42 per cent in Victoria, 38 per cent in South Australia and 32 per cent in NSW. Tasmania recorded a 12 per cent price reduction (figure 2). These price reductions were reflected in total NEM turnover being 24 per cent lower in 2014–15 than 2013–14. Electricity production in 2014–15 was unchanged, at 194 terawatt hours (TWh).

Queensland was the only region in 2014–15 to record an increase in prices. It also had the NEM's highest wholesale electricity prices (averaging $61 per MWh) for the first time in over a decade.

The significant price reductions in NSW, Victoria, South Australia reflected:

- the removal of carbon costs following the repeal of carbon pricing on 1 July 2014, which encouraged baseload (mainly coal) power stations to bid more capacity into the market at lower prices. Tasmanian prices had been less impacted by carbon pricing, given

Figure 2
Annual spot electricity prices



Sources: AEMO; AER.

the region's predominance of hydro generation. Similarly, the removal of carbon pricing had a lesser effect in Tasmania than on the mainland.

- continuing weak electricity demand—partly because more households were self-generating through rooftop solar PV generation—which resulted in overcapacity.

The Queensland market experienced unique conditions that offset these downward price influences. In the December quarter 2014, Queensland prices ($68 per MWh) more than doubled prices in other mainland regions, despite record low gas fuel prices. By the March quarter 2015, Queensland prices ($107 per MWh) almost tripled prices elsewhere. Overall, almost two thirds of spot prices above $200 per MWh in the NEM in 2014–15 occurred in Queensland.

Queensland

Queensland's generation sector is more highly concentrated than other mainland NEM regions, with Stanwell and CS Energy controlling 64 per cent of capacity. From November 2014 generators (including Stanwell, CS Energy and Callide) used rebidding strategies to shift large volumes of capacity from low to very high prices late in a trading interval. In tight market conditions, an unexpected shift in supply can cause prices to spike. By rebidding late, other participants lack sufficient time to respond, preserving a high 30 minute average spot price.

Volatility peaked on 5 March 2015, when Queensland's spot price exceeded $5000 per MWh for all but one trading interval from 4.30 pm to 7 pm. Forecast spot prices (both four and 12 hours ahead) for all intervals ranged from $39 to $60 per MWh. Prices were volatile for the entire day, with 39 (five minute) dispatch intervals at or above $12 900 per MWh. While a heatwave in Brisbane caused maximum demand to set a record on the day, and long term network constraints limited electricity imports from NSW, Queensland had 800 MW of surplus available capacity when the price spikes occurred.

Queensland's spot market volatility also raised contract prices in forward markets.[12] Ernst & Young estimated the late rebidding added around $8 per MWh to Queensland price caps in the December quarter 2014, and around $7 per MWh in the March quarter 2015. Across the market, this increase represented a cost of around $170 million.[13]

The AER 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 the 'rebidding in good faith' provisions in the Electricity Rules. The AER submitted that a rising incidence of late rebidding was impairing market efficiency by making forecast information less reliable.[14]

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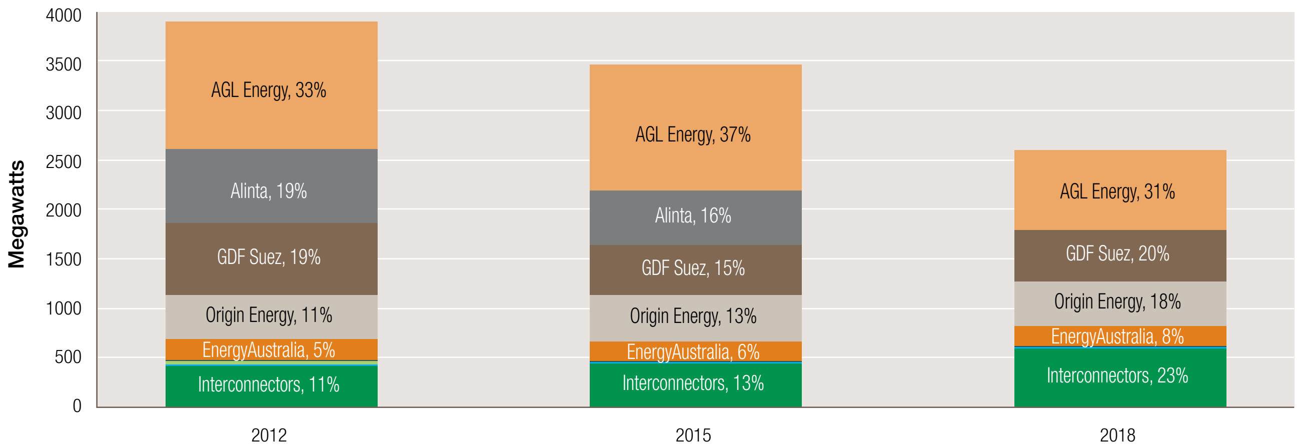
12 AEMC, *National Electricity Amendment (Bidding in Good Faith) Rule 2015*, Draft rule determination, 17 September 2015.
13 Ernst & Young, *Impact of late rebidding on the contract market,* Final report to the AEMC, 11 September 2015.
14 AER, *Submission: National Electricity Rules amendment—bidding in good faith*, May 2014.

Figure 3
South Australian generation capacity



Notes:

Capacity based on summer availability, except wind, which is adjusted for an average contribution factor.

Interconnector capacity is based on observed flows when the price differential between regions exceeds $10 per MWh in favour of the importing region. The data exclude trading intervals in which counter flows were observed (that is, when electricity was imported from a high priced region into a lower priced region).

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

Sources: AEMO; AER.

The Australian Energy Market Commission (AEMC) in December 2015 reformed the good faith provisions. The reforms:

- prohibit offers, bids and rebids that are false, misleading or likely to mislead
- require rebids to be made as soon as practicable after a generator or market participant becomes aware of the change in material conditions or circumstances that prompted the rebid
- require participants to maintain a record of the circumstances surrounding late rebids.[15]

South Australia

The South Australian market has been increasingly volatile since 2007. Relatively concentrated generator ownership, generator rebidding behaviour, thermal plant withdrawals, and limited import capability are contributing factors. South Australia's high levels of wind capacity also contribute to wholesale price swings, due to wind's intermittent nature.

While average 2014–15 wholesale prices for South Australia were significantly lower than in the previous two years, they were more than $10 higher than prices in neighbouring Victoria. Overall, South Australia recorded 82 price events above $200 per MWh, second only to Queensland.

A tightening in the supply–demand balance set the stage for a series of price spikes (above $2000 per MWh) in June 2015. The partial mothballing of Pelican Point withdrew 249 MW of capacity from the South Australian region from April 2015 and a fire at the Northern Power Station in June caused extended outages. These events followed the staged mothballing of Alinta's Playford B plant. In these tight conditions, generator rebidding and strategic changes to the output of non-scheduled plant triggered a series of high price events.

South Australia's non-scheduled generators control capacity equal to around 11 per cent of the region's scheduled capacity. When the demand–supply balance is tight, these generators can rapidly reduce output, causing the dispatch price to spike. The generators then boost output for the remainder of the trading interval to capture those higher prices. Because non-scheduled generation falls outside the market dispatch process, this behaviour is not transparent, making it difficult for other participants to react to their commercial advantage.

On early indications, South Australia may again experience high prices in 2015–16. In the September quarter 2015, prices for South Australian 2016 base futures rose by 42 per cent, compared with rises of 19 per cent for Queensland, 12 per cent for Victoria and 9 per cent for

15 AEMC, *Final rule determination, National Electricity Amendment (Bidding in Good Faith) Rule 2015*, 10 December 2015.

NSW. The rise in base futures mirrored volatility in South Australian spot prices, which in the September quarter, averaged $69 per MWh—at least 50 per cent higher than in any other region.

Contributing to these prices were low wind generation, network outages around the Heywood interconnector with Victoria, reduced generator capacity at Northern and Pelican Point, and rebidding of capacity by some generators from low to high prices. The late rebids were typically made by AGL Energy or Alinta Energy. Rapid shifts in non-scheduled generation were also evident on some days. The spikes typically happened at times of peak demand associated with cold weather, or coincided with a sudden rise in hot water loads around 11.30 pm.

Volatility spread to South Australia's frequency control ancillary services market in October 2015, when prices rose above $5000 per MW in a number of trading intervals, triggering administered pricing at a $300 per MW cap on three occasions.

The volatility stemmed from planned transmission outages associated with the upgrade to the Heywood interconnector. In October 2015 AEMO changed its approach to managing system security issues in South Australia during the upgrade, giving little warning to the market. The change required some frequency control services (particularly regulation services) to be sourced locally whenever a credible risk arises that network congestion will 'island' South Australia from the rest of the NEM.[16] The change aimed to make services immediately available if South Australia is islanded. But limited sources of frequency control services in the region created opportunities for some generators to rebid capacity into high price bands.

When the Heywood interconnector tripped on 1 November 2015, South Australia was islanded from the rest of the NEM. Because local generation could not ramp up quickly enough to replace Victorian imports, under-frequency load shedding automatically cut 160 MW of customer load, interrupting supply to 110 000 customers. With South Australia islanded, all frequency control services again had to be sourced locally, causing prices to spike above $9000 per MW for 35 minutes.

Upcoming capacity withdrawals may further change dynamics in the South Australian electricity market. Alinta Energy will close its Northern Power Station (546 MW) on 31 March 2016, and AGL Energy will mothball its Torrens Island A plant (480 MW) in 2017. The Heywood interconnector upgrade, scheduled for completion by July 2016, may help mitigate this tightening in supply. The upgrade will increase import capability on the interconnector in stages, from 460 MW to 650 MW. But despite the upgrade, current forecasts indicate total capacity (including imports) available to the South Australian region will be significantly lower in 2018 than in 2015 (figure 3).

16 Previously, the services were locally sourced only after South Australia was separated from the market.

A.3 Gas markets

Queensland's LNG industry is exerting significant influence on the domestic gas market. Two major projects commenced exports in 2015, and a third is set to commence by early 2016. Domestic gas supply contracts are now being struck with reference to global prices, and spot gas prices in eastern Australia have become increasingly volatile.

Gas production rose in the run-up to commissioning the first LNG train, creating large volumes of 'ramp' gas that was sold into the Brisbane spot market. Daily prices collapsed to near zero in late November 2014 (figure 4). But when LNG exports commenced in January 2015, prices quickly rose, with some daily averages above $8 per gigajoule.

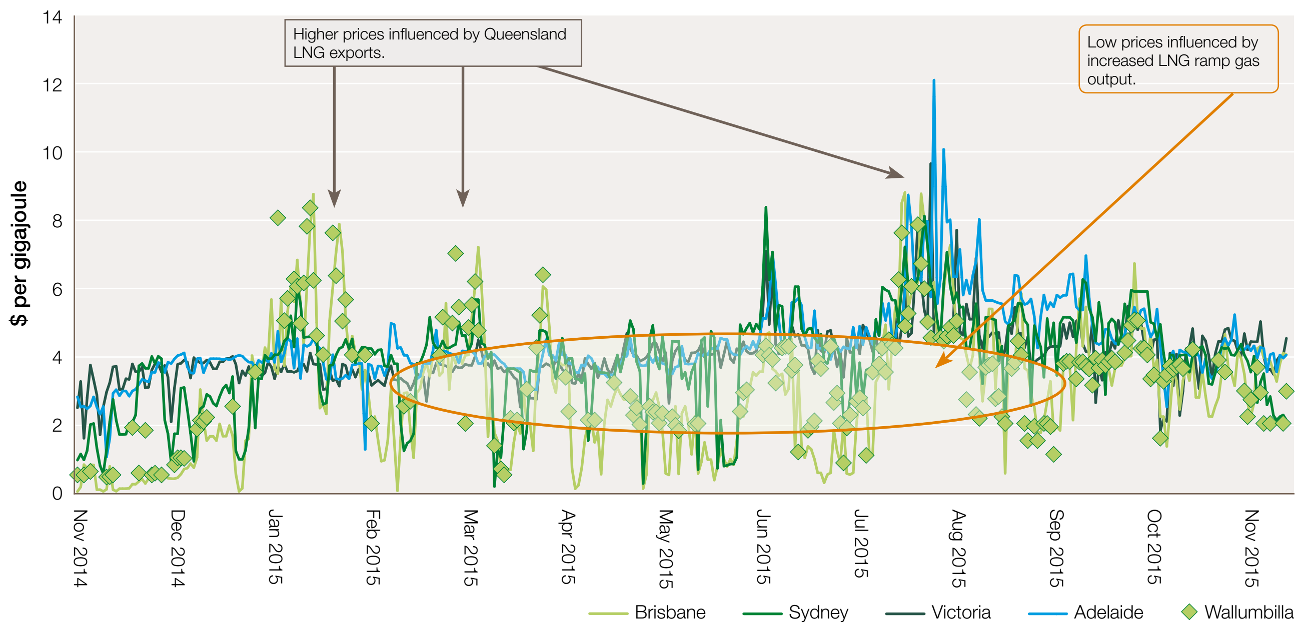
Brisbane prices remained volatile during 2015, periodically falling below $1 per gigajoule, but then rising as high as $12. This volatility largely revolved around the timing of LNG shipments and the commissioning of new LNG trains, and it flowed through to southern gas markets. Sydney was most affected, with Moomba gas often redirected to Queensland during high price events.

Given the LNG projects source some of their requirements from gas reserves that would otherwise be available domestically, the eastern gas market will further tighten once all three projects are operating at full capacity. While gas development proposals in Bass Strait (Victoria), the Cooper Basin (central Australia) and the Gloucester Basin (NSW) were at an advanced stage in 2015, all were subject to uncertainty.

Another source of uncertainty is domestic gas demand. AEMO forecast that higher wholesale gas prices, the expiration of gas supply contracts, and the ongoing rise of renewable generation would cause gas powered generation to decline by 60 per cent in 2020 from 2015 levels.[17] Some gas powered plant is being retired in consequence. Plant announced for withdrawal in the next few years include Tamar Valley (Tasmania), Daandine and Mount Stuart (Queensland), and Smithfield (NSW).

17 AEMO, *National gas forecasting report for eastern and south-eastern Australia*, December 2015.

Figure 4
Daily gas spot prices since November 2014



Sources: AER; AEMO.

In this uncertain environment, industry took measures in 2015 to manage the risks of possible supply shortfalls:

- Major transmission pipelines in eastern Australia were re-engineered for bidirectional flows, to allow gas flows to rapidly respond to changes in the supply–demand balance.
- Two major transmission pipelines (SEA Gas and Moomba to Adelaide) were physically interconnected.
- Capacity expansions of several major transmission pipelines were underway.
- Jemena won a tender to build a new transmission pipeline connecting Queensland with the Northern Territory by 2018, opening the eastern market to new supply sources.
- AGL Energy opened an LNG gas storage facility in Newcastle, with capacity to supply the greater Newcastle area for two weeks.

The efficiency and competitiveness of east coast gas markets is also under review. In 2015 the AEMC reviewed the design, function and roles of spot gas markets and gas pipeline arrangements. In March 2015 the Victorian Government tasked the AEMC with a separate review of the Victorian market. The AEMC's stage 1 report on east coast markets in 2015 referred to 'fragmented and disjointed arrangements', including three different spot market designs.[18]

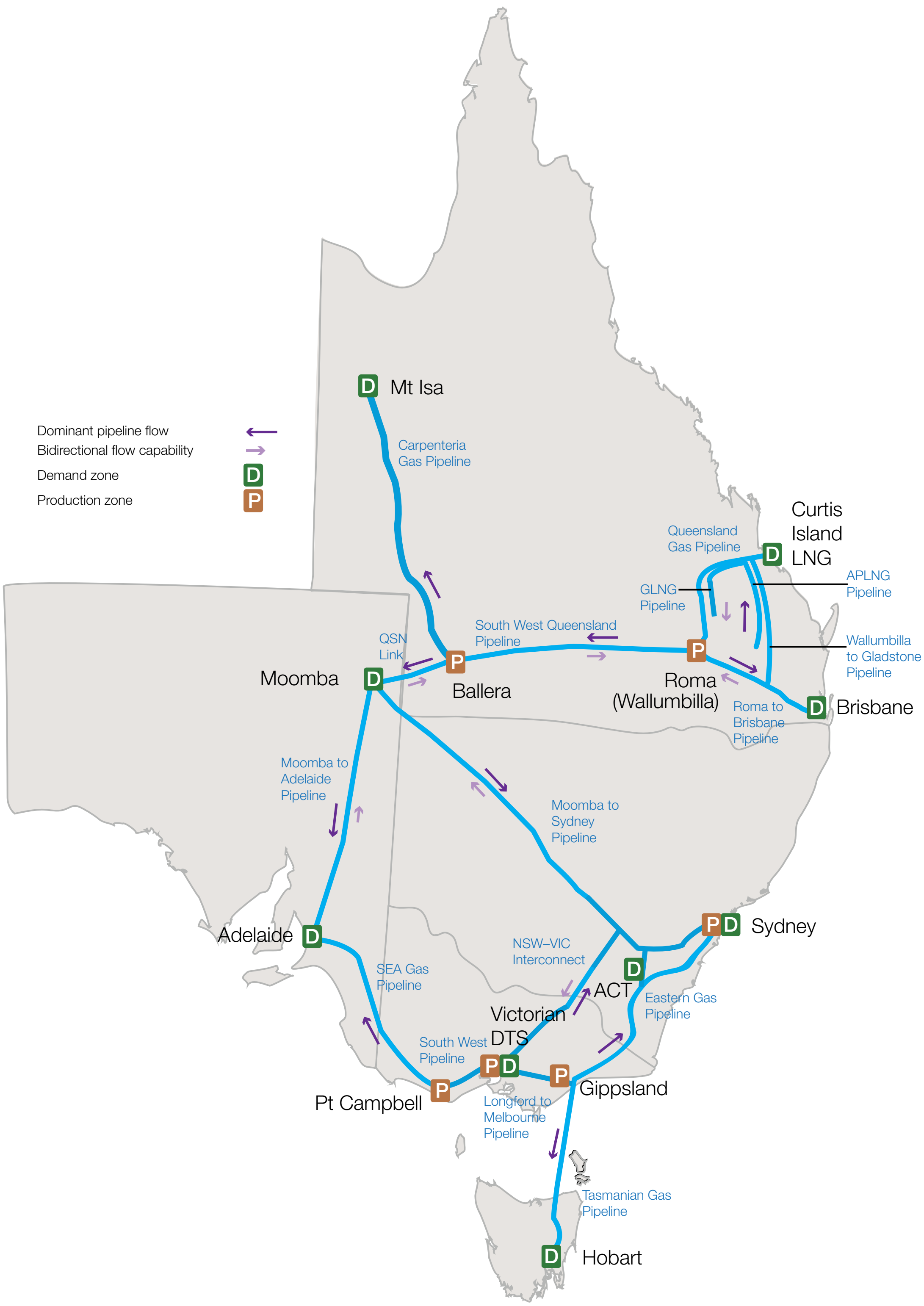
Work was underway in late 2015 to implement several of the AEMC's reform recommendations, including:

- developing an Australian Bureau of Statistics wholesale gas price index by early 2016
- harmonising the gas day start time for spot markets across the east coast. The Council of Australian Governments (COAG) Energy Council proposed a rule change to this effect in November 2015
- enhancing pipeline capacity trading information on the Gas Bulletin Board, to promote trade in contracted but idle capacity. The AEMC expected to make a determination in December 2015 to implement this reform.

The AEMC's stage 2 draft report in December 2015 proposed a longer term roadmap for gas market development, based around the creation of two virtual trading hubs, a streamlined bulletin board and efficient pipeline capacity trading. The hubs would consist of a northern hub located initially at Wallumbilla, Queensland, and a southern hub in Victoria (to eventually replace the

18 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 1 final report*, 23 July 2015.

Figure 5
Eastern Australia gas market



Source: AER, based on Gas Bulletin Board (www.gasbb.com.au).

Newcastle LNG storage facility (image courtesy AGL Energy) declared gas market currently operating in Victoria). Each hub would adopt exchange-based trading similar to that already in place at the Wallumbilla gas supply hub. Participants could also buy and sell gas via bilateral over-the-counter trading or long-term contracts.[19]

In other initiatives, AEMO is progressing reforms to the Wallumbilla gas supply hub to replace the hub's three trading locations with a single voluntary trading market, and to introduce new optional services. AEMO is also designing a gas trading hub for launch in July 2016 at Moomba, South Australia. Moomba is a gateway for the eastern Australia gas market, linking gas production in south east Australia with markets in Queensland. The AEMC noted the hub may represent an appropriate transitional measure until the new northern and southern hubs mature.[20]

Concurrently with the AEMC process, the Australian Government in April 2015 tasked the Australian Competition and Consumer Commission (ACCC) with inquiring into the competitiveness and structure of eastern Australia's gas industry.[21] Some stakeholders' submissions voiced concerns that industry players are taking advantage of a volatile market through non-competitive pricing, oil linked pricing, joint marketing, high pipeline charges, a lack of innovative transportation deals, and capacity hoarding on pipelines. The ACCC will publish its report in April 2016.

A.4 Regulated energy networks

Reforms to the energy laws and rules, along with other developments in the energy sector, have moderated network costs. In AER determinations made in 2012–15, revenue that networks can recover from customers is forecast to be an average 9 per cent lower than recoverable revenue in the previous regulatory periods. By comparison, recoverable revenue rose by an average 30 per cent in determinations made between 2009 and 2011.

The AER issued revenue decisions for 16 energy networks in 2015 (one in gas and 15 in electricity) that will result in a continued moderation of network charges. The decisions account for flat electricity demand forecasts that will ease pressure on the networks and require less investment than in the past to provide a reliable energy supply. In determinations made since 2012, forecast network investment is an average 25 per cent lower than investment in previous periods. This trend is particularly evident in declining augmentation expenditure relative to replacement expenditure. Current determinations provide for \$2.20 in replacement expenditure for every dollar of augmentation expenditure. But, for 2008–13, only \$0.80 was spent on replacement assets for every dollar of augmentation expenditure.

The investment environment for network businesses has also improved since the global financial crisis. In the current healthier environment, financing costs are lower. The overall cost of capital in network determinations declined from a peak of over 10 per cent in 2010, to average 6.11 per cent in determinations made in 2015 (figure 6). Under a revised framework that applied for the first time in these decisions, the cost of capital will be updated annually to reflect changes in debt costs.

Figure 7 estimates how AER decisions made in 2015 may affect distribution network costs for a typical residential customer over the life of the determinations. The estimates are based on information available at the time of the decisions, and may change due to factors such as annual updates to capital costs. The impact will also vary from customer to customer, depending on a customer's energy use and network tariff.

Noting these qualifications, distribution network costs are forecast to be around \$250 lower for a typical NSW electricity customer in 2015–16 than immediately before the current regulatory period. The reduction for Queensland, South Australia and ACT electricity customers, and NSW gas customers is around \$100–200. But the forecast reduction for South Australian customers will be partly offset by rises in network charges in subsequent years. Based on the AER's preliminary decisions, the reduction in network charges for a typical Victorian customer will likely be around \$50 in 2016. The smaller reduction for Victoria reflects that its networks were found to already operate relatively efficiently. The AER's final determination for Victoria in April 2016 may alter these estimates.

Merits review

The owners of electricity networks in NSW, South Australia and the ACT, and the gas network in NSW applied in 2015 to the Australian Competition Tribunal for merits review of the AER's final decisions on their networks. The electricity businesses sought review of the AER's approach to determining operating costs (including the use of benchmarking), the regulated rate of return, and tax costs. The NSW gas network sought review of the AER's decision on the regulated rate of return and tax costs, as well as on capital expenditure for connections and market expansion.

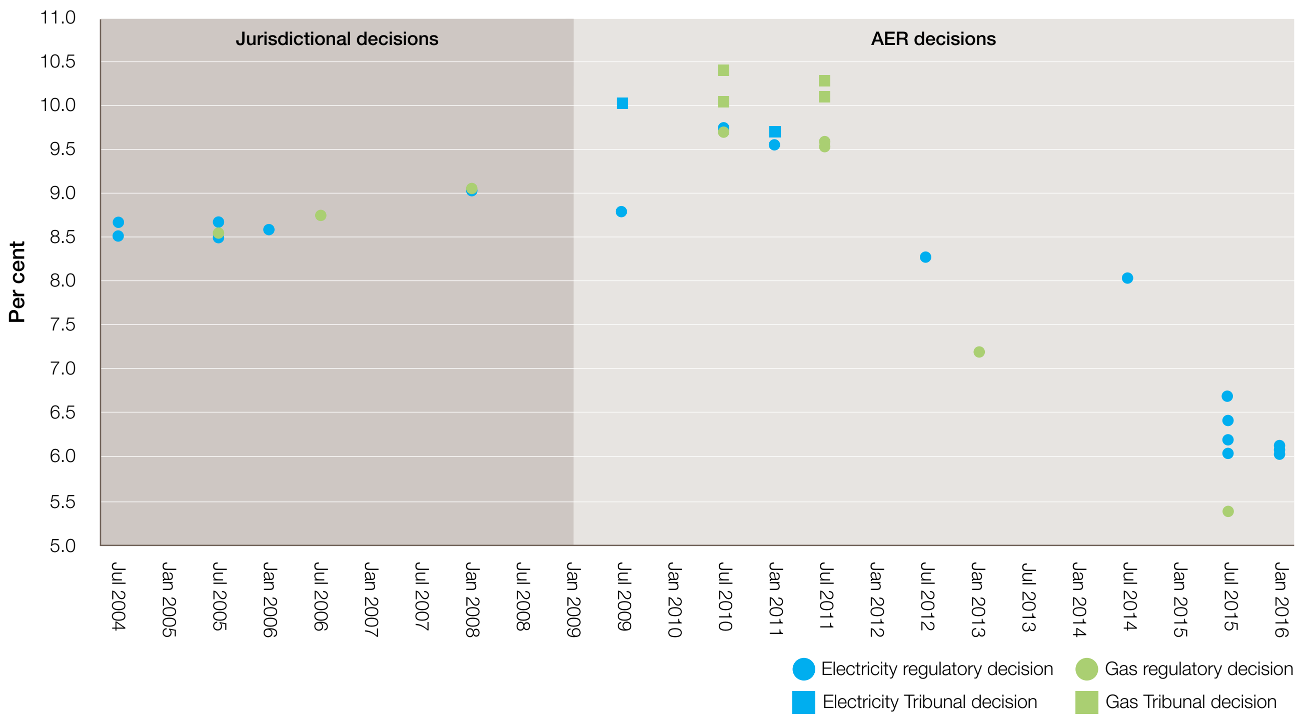
19 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 2 draft report*, 4 December 2015.

20 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 2 draft report*, 4 December 2015.

21 ACCC, 'Inquiry into Eastern and Southern Australian Wholesale Gas Prices', Media release, 13 April 2015.

Figure 6

Weighted average cost of capital—electricity and gas distribution

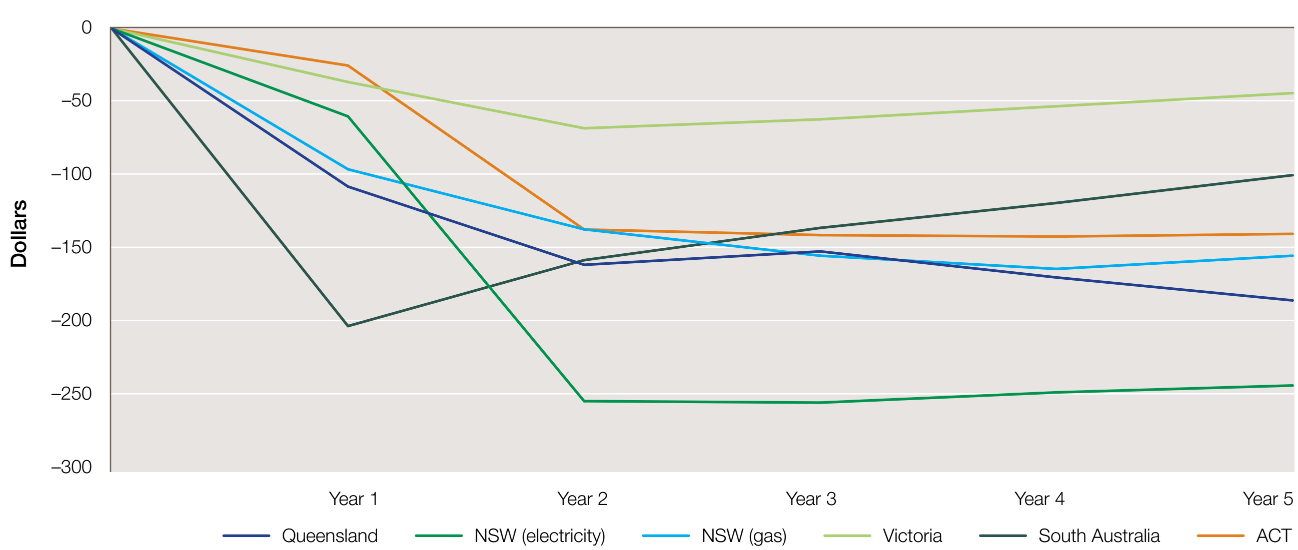


Note: Nominal vanilla weighted average cost of capital.

Source: AER.

Figure 7

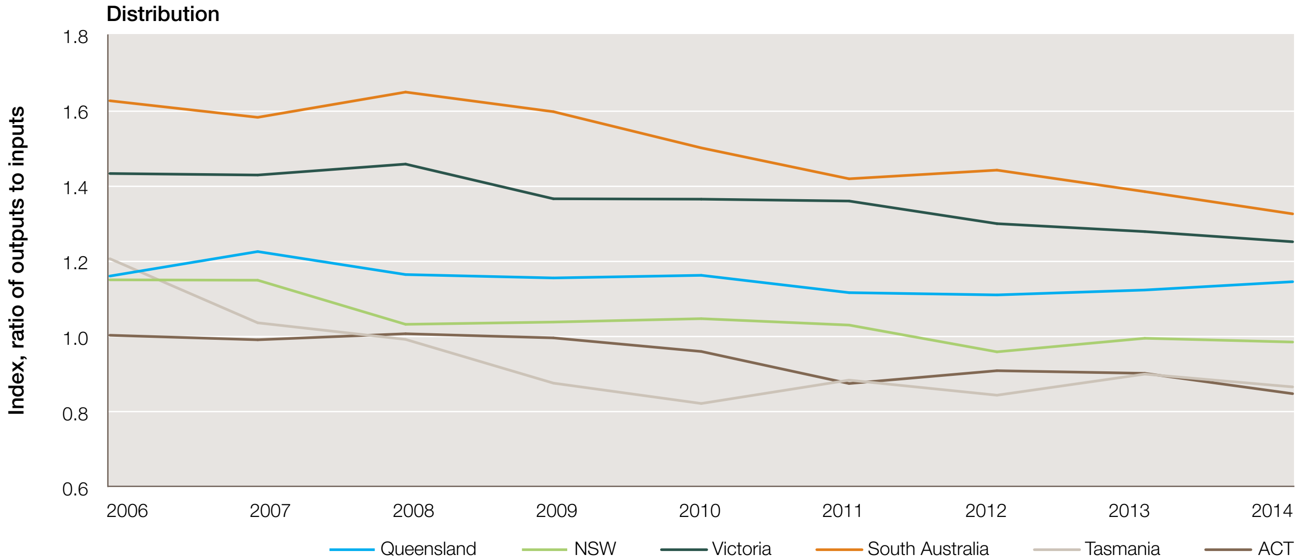
Estimated impact of latest AER distribution decisions on network charges per customer



Note: Change in energy network charges compared with charges immediately before the current regulatory period, for a typical residential customer with average energy use in that jurisdiction. Decisions are for electricity distribution networks, unless otherwise specified. The data are averages for jurisdictions with multiple networks. Year 1 is 2014–15 for NSW electricity and ACT; 2015–16 for Queensland, South Australia and NSW gas; and calendar year 2016 for Victoria.

Source: AER estimates.

Figure 8
Productivity of electricity distribution networks



Note: Index of multilateral total factor productivity relative to 2006 data for ElectraNet, South Australia (transmission) and ACT (distribution). Distribution data are jurisdictional averages.

Source: AER, *Annual benchmarking report: electricity distribution network service providers*, November 2015.

Consumer groups also applied for merits reviews. The Public Interest Advocacy Centre and the South Australian Council of Social Service sought review of the NSW and South Australian electricity determinations respectively, arguing the AER decisions provided for networks to recover excessive revenue from consumers.

The Tribunal concluded its hearings on the NSW and ACT applications in October 2015, with decisions expected in late 2015. The outcomes have potential for significant changes in network revenue.

Separately, the NSW (electricity and gas), ACT and South Australian businesses filed applications with the Federal Court in 2015 for judicial review of the AER's decisions.

Network productivity

The AER's 2015 benchmarking study found productivity in electricity networks has been declining for several years. The resources used to maintain, replace and augment the networks are increasing at a faster rate than the key factors that drive the supply of electricity network services (figure 8). For the majority of networks, productivity continued to decline in 2014, although Energex, Ergon Energy and Essential Energy (distribution), and TasNetworks (transmission) recorded improvements.

The study found electricity distribution businesses in New South Wales and the ACT generally operate less efficiently than networks in other jurisdictions. These findings are reflected in operating expenditure forecasts for those networks being an average 30 per cent lower than actual spending in the previous period.

Power of choice reforms

In 2015 the AEMC continued progressing rule changes to implement its *Power of choice* reforms on efficient use of energy networks. Central to the reforms is the provision of smart meters that provide consumers with better information about their energy use and greater control over how they manage it. The AEMC finalised a rule change in 2015, allowing competition in the provision of metering and related services from December 2017, to facilitate a market led rollout of smart meters. This change complements reforms in 2014 to allow customers more ready access to their electricity consumption data, and in 2015 for default meter communications standards to promote competitive service provision.

While smart meters allow consumers to monitor their energy use, price signals are needed to provide incentives for efficient demand response. Under traditional pricing structures, energy users pay the same network tariffs regardless of how or when they use power. But network costs closely correlate with demand requirements at peak use times. A household consuming energy at peak times may impose significant network costs, even if its average consumption over a period is low (because, for example, it self-generates much of its energy needs during the day with solar panels).

The AEMC in November 2014 determined distribution businesses must move towards tariff structures that better reflect the efficient costs of providing network services to each consumer. The approved tariff structures will take effect in 2017, allowing distributors to consider a suitable transitioning period so customers have time to adjust.

Distributors submitted tariff proposals to the AER in late 2015. The Victorian businesses proposed tariffs with a demand component that charges customers for their maximum electricity use during peak network periods, so each household contributes fairly and efficiently to meeting total network costs.[22]

A.5 Retail energy markets

Annual electricity charges for a typical residential customer fell in Queensland, NSW, South Australia and the ACT in 2015 (figure 9). Declining electricity demand and lower financial costs moderated network cost pressures in those jurisdictions, offsetting higher competitive market costs and costs associated with green schemes. The largest reduction in retail bills occurred for customers in rural NSW (averaging 17 per cent) and in South Australia (9 per cent).

Retail charges for Victorian customers rose by 4–11 per cent in early 2015. In some networks, the rise exceeded the savings from the carbon price repeal just a few months earlier. Network charges were the main driver, because the Victorian networks still operated under AER determinations made in 2010, when business costs were relatively high. New preliminary determinations for Victoria that will take effect in 2016 should lead to falling network costs, reflecting the improved investment environment since the AER's previous decisions.

Tasmanian retail bills rose marginally in 2015. This rise followed a large reduction in 2014 related to the repeal of carbon pricing and the opening of the residential sector to retail competition.

Retail gas bills have risen significantly since 2008, mainly driven by rising pipeline charges. More recently, rising wholesale costs associated with the diversion of gas supplies to LNG projects have put upward pressure on bills. Despite the removal of carbon pricing in 2014, gas bills continued to rise in all jurisdictions except Victoria. Retail charges again rose in 2015, except in NSW, where a new access arrangement lowered pipeline charges.

Retail competition

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

Despite retail contestability operating for over a decade in most regions, retail markets remain concentrated. Three 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 in southern and eastern Australia at 30 June 2015.[23] But competition from smaller retailers is gradually eroding some of their market share. In electricity, small retailers acquired 7 per cent of customers from the three market leaders between 2012 and 2015. The market share of smaller retailers grew more strongly in Victoria and NSW than elsewhere.

The share of customers on market contracts varies significantly across jurisdictions. In electricity, 89 per cent of Victorian consumers had a market contract, compared to 84 per cent in South Australia, 69 per cent in NSW, 46 per cent in Queensland (but around 70 per cent in south east Queensland), 24 per cent in the ACT and 12 per cent in Tasmania. The proportions are similar for gas customers.[24]

Overall, the AEMC in 2015 found the level of competition in energy markets varied across the NEM. It found electricity markets in Tasmania, regional Queensland and the ACT were not yet effectively competitive, citing local factors in each instance:

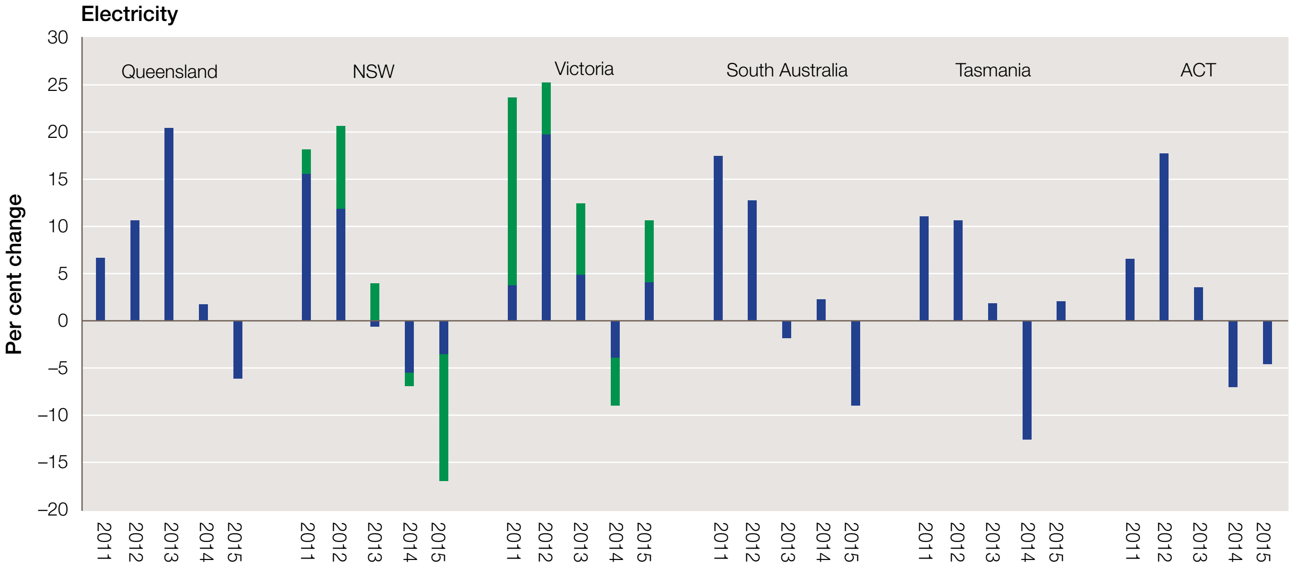
- In Queensland, some retailers stated they had deferred plans to expand marketing, following the Queensland Government's 12 month delay in removing retail price regulation until 1 July 2016. Retailers also reported wholesale market volatility in Queensland was impeding expansion.
- In the ACT, retailers reported retail price regulation and the dominance of the incumbent ActewAGL made entry and expansion difficult.

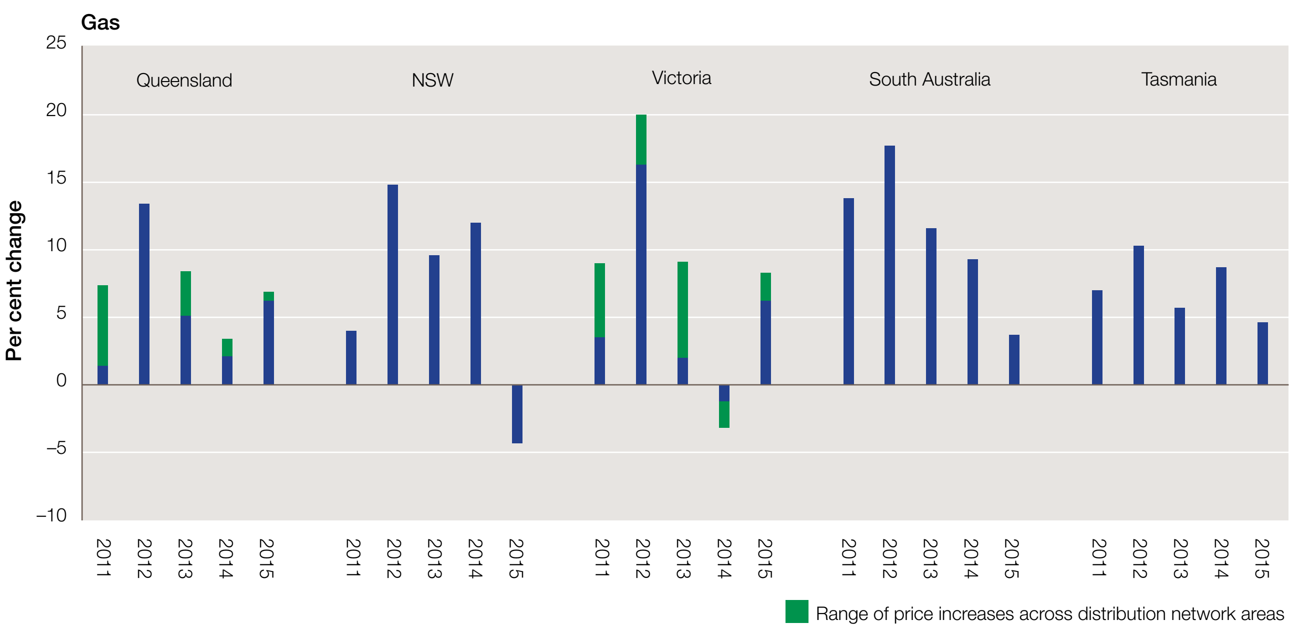
22 AER, *Tariff structure statement proposals, Victorian electricity distribution network service providers*, Issues paper, December 2015.

23 Includes brands owned by these businesses, such as Powerdirect (AGL Energy).

24 AER, *Annual report on the performance of the retail energy market 2014–15*, November 2015; ESC (Victoria) *Energy retailers comparative performance report–customer service*, December 2014.

Figure 9
Energy retail bill movements, 2011–15





Notes: Estimated annual cost based on a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year on a single rate tariff at August 2015. Prices are based on regulated prices of the local area retailer for each distribution network, or on standing offer prices where prices are not regulated.

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.

Image courtesy of Allison Crowe

- In Tasmania, retailers considered entry and expansion in the electricity market was difficult, given retail price regulation and the dominance of the incumbent retailer (Aurora Energy) and generator (Hydro Tasmania). At September 2015 no energy retailer had entered the residential electricity customer market to compete with Aurora Energy.[25]

The AEMC found gas retail competition was effective in most of NSW, Victoria and South Australia, but limited in south east Queensland. It found gas is a secondary consideration for most customers, and a less attractive value proposition for some retailers.

In electricity, jurisdictions that have removed retail price regulation exhibit the strongest price diversity within particular distribution networks. In those jurisdictions—NSW, Victoria and South Australia—annual charges under the cheapest contract in 2015 were typically at least 30 per cent lower than under the most expensive contract, with annual bill spreads of $600–1100. Bill spreads were around $300 in Queensland and the ACT (where the AEMC found competition to be less effective). Spreads were lower in gas, ranging from $100 in the ACT to $280 in South Australia.

Aside from price, another driver of retail competition is the emergence of flexible product structures, some of which are made possible by the use of interval (smart) meters. Alongside these changes, alternative energy sales models are emerging—for example:

- *onselling*, whereby an energy provider buys bulk energy from a retailer and onsells it to a cluster of customers (for example, in new multi-dwelling developments such as apartment buildings and shopping centres)
- *power purchase agreements*, whereby an energy provider installs generation capacity on a customer's premises, and sells the energy generated to that customer. Solar PV panels are the most common form of generation under this model.

While new entrant businesses are driving the emergence of these models, established energy retail businesses are becoming active in this area. Some retailers now offer power purchase agreements, for example, alongside their traditional energy products.

Increasing rates of rooftop solar PV generation—both through power purchase agreements and energy users' installation of their own solar panels—create challenges for the traditional retail model. These self-generating customers typically do not produce enough energy to meet all their requirements, and they source the balance from a retailer. But the lower volumes required by these users make them less profitable for the retailer to supply. Advances in battery storage may further reduce energy purchases by these users.

Consumer protection

On 1 July 2015 Queensland became the fifth jurisdiction to adopt the National Energy Retail Law, which provides consumer protections. The Retail Law also allows consumers full access to the Energy Made Easy website (including its price comparator tool).

Increased competition among retailers for customers intensifies retailer marketing, which sometimes results in inappropriate conduct by energy salespersons. While most major retailers stopped door-to-door marketing in 2013, following enforcement activity by the ACCC, a small number still use this channel. Most still engage in telemarketing (outward sales calls) but this activity too has been problematic. Both the ACCC and the AER have taken action against retailers for misrepresentations and a failure to obtain a customers' explicit informed consent before transferring them as a result of a telemarketing call.

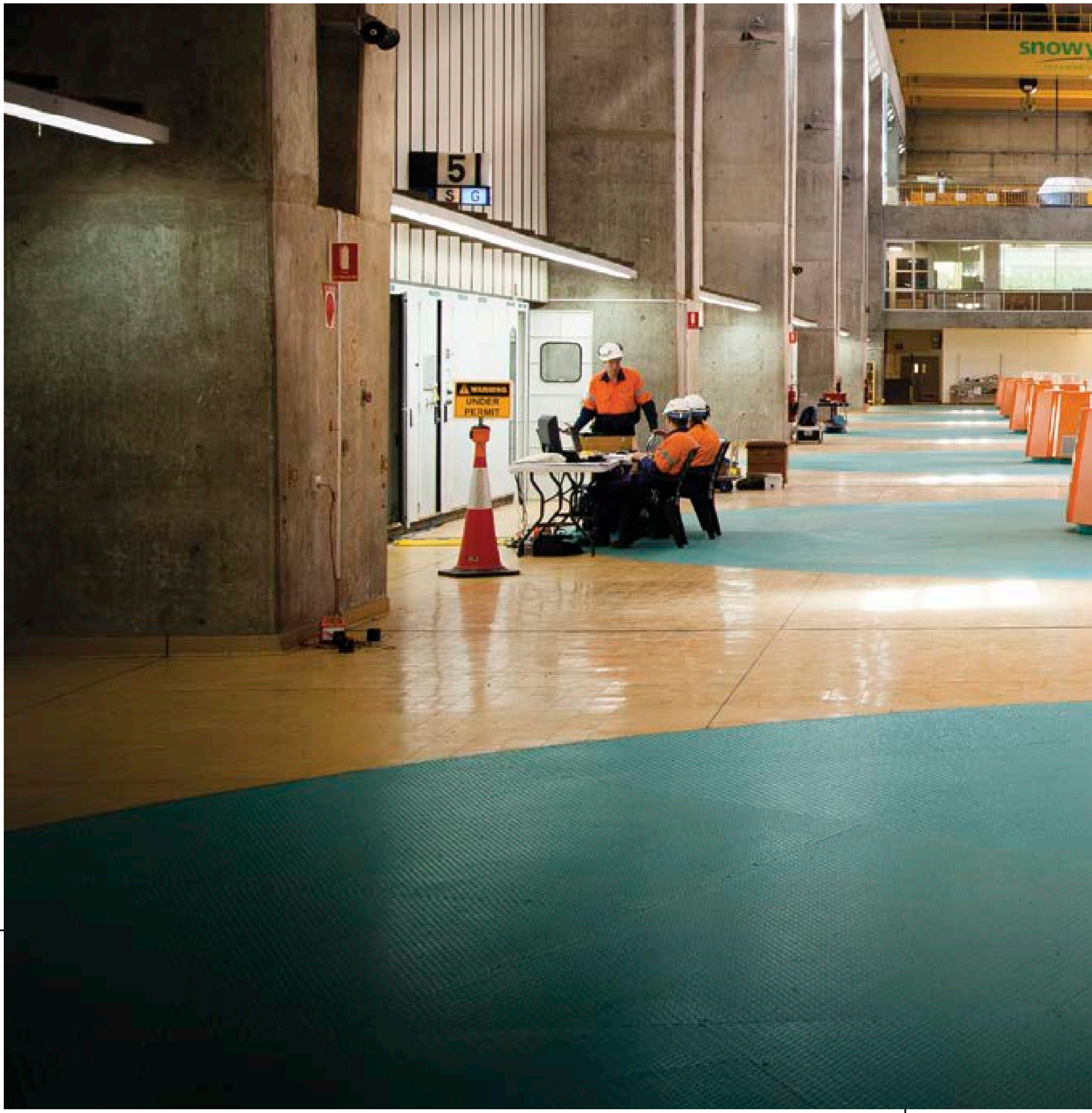
The AER in 2014 instituted proceedings in the Federal Court against EnergyAustralia (and a telemarking company acting on its behalf) for failing to obtain the explicit informed consent of customers in South Australia and the ACT before transferring them to new energy plans. The ACCC instituted proceedings against the businesses for similar behaviour in Queensland, NSW and Victoria, under provisions in the Australian Consumer Law on misleading conduct or representations. In 2015 the Federal Court imposed penalties of $1.6 million on EnergyAustralia and the telemarketing company.

In other consumer protection activity:

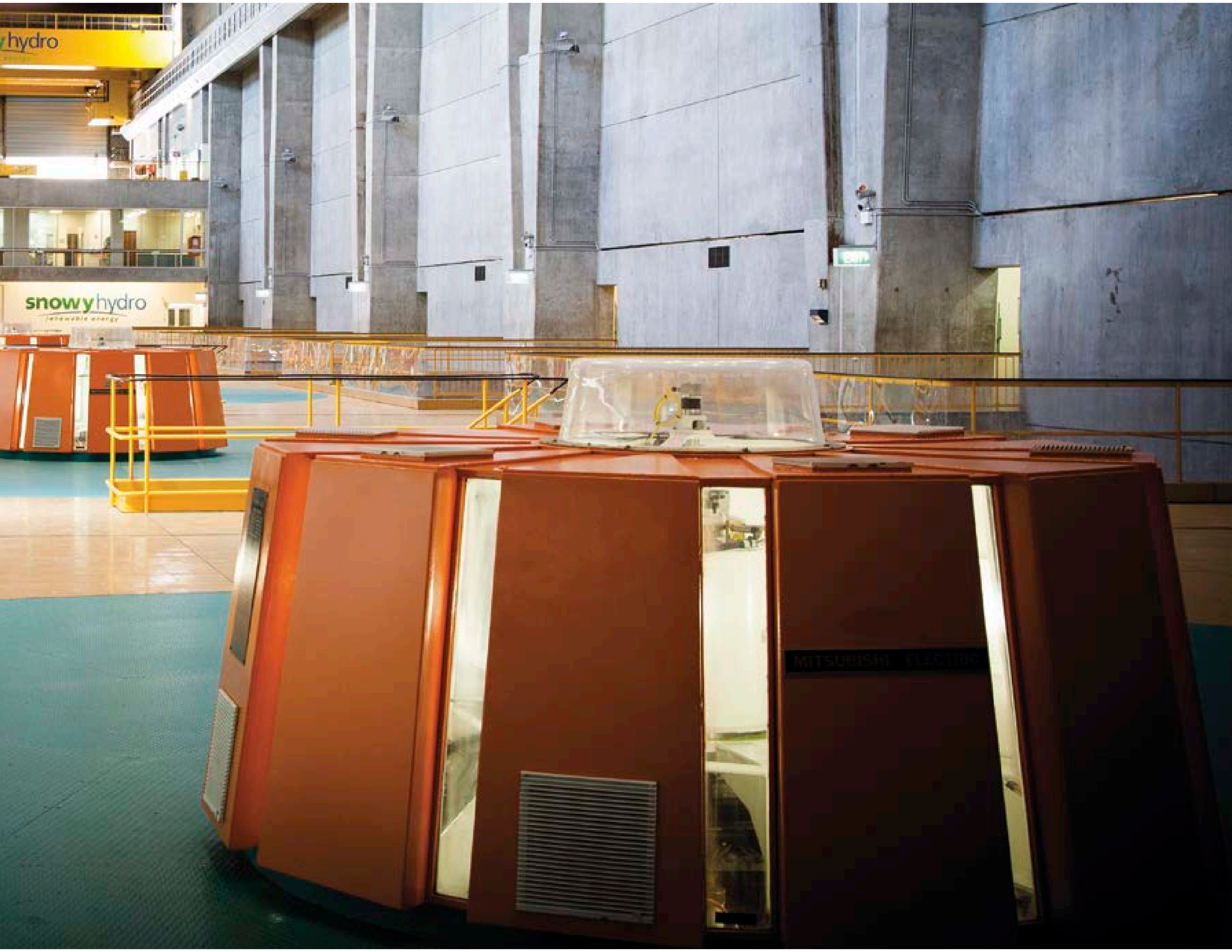
- In October 2015 the AER issued Simply Energy with infringement notices for failing to obtain customers' explicit informed consent before entering them into energy contracts. The AER subsequently released a Compliance Check, providing guidance to businesses on the explicit informed consent requirement under the Retail Law.
- In 2015 the Federal Court imposed penalties totalling over $3 million on AGL Energy and Origin Energy, with orders to compensate affected consumers for false or misleading statements on the level of discount under their energy plans. The decision resulted from proceedings launched by the ACCC in 2013.

25 AEMC, *2015 retail competition review, final report*, June 2015.

Image courtesy of Snowy Hydro



1 NATIONAL ELECTRICITY MARKET


snowy hydro
renewable energy

Wholesale electricity in eastern and southern Australia is traded through the National Electricity Market (NEM), covering Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). Over 300 generators produce electricity for sale into the market, which is physically linked by a transmission grid covering five state-based networks and six cross-border interconnectors (table 1.1). In geographic span, the NEM is one of the longest alternating current systems in the world, covering 4500 kilometres.

Energy retailers are the main customers in the market. They bundle electricity with network services for sale to residential, commercial and industrial energy users. The Australian Energy Regulator (AER) is the market regulator (box 1.1).

Table 1.1 National Electricity Market at a glance

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
Installed capacity	47 641 MW
Number of registered generators	336
Number of customers	9.8 million
NEM turnover 2014–15	$8.2 billion
Total energy generated 2014–15	194 TWh
National maximum winter demand 2014–15	30 201 MW[1]
National maximum summer demand 2014–15	29 472 MW[2]

MW, megawatts; TWh, terawatt hours.

1. The maximum historical winter demand of 34 422 MW occurred in 2008.
2. The maximum historical summer demand of 35 551 MW occurred in 2009.

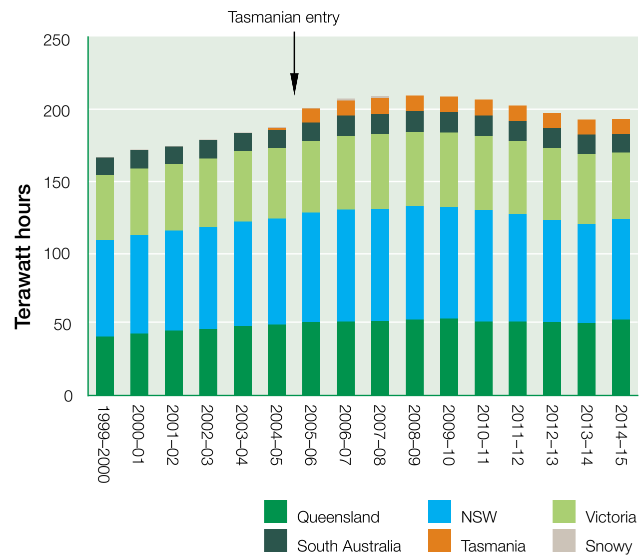
Sources: AEMO; AER.

1.1 Electricity demand

The NEM supplies electricity to almost 10 million residential and business customers. After five years of decline, electricity demand from the grid steadied in 2014–15 at 194 terawatt hours (TWh)—similar to the level in 2013–14 (figure 1.1).

In the five years to 30 June 2014, grid consumption declined at an annual average rate of 1.7 per cent. Industrial energy demand fell, with the closure of two aluminium smelters and declining energy requirements for steel making and vehicle manufacturing. Residential and commercial consumers reduced their offtake from the grid in response to rising electricity prices. Consumers adopted energy efficient measures (such as solar water heating and energy efficient air conditioning, refrigeration and electronics) and installed rooftop solar photovoltaic (PV) panels to generate their own electricity. Government subsidies and incentives encouraged these shifts in consumer behaviour (section 1.2.1).

Figure 1.1
NEM production, by region



Note: The Snowy region was abolished on 1 July 2008. Its energy demand was redistributed between the Victoria and NSW regions from that date.

Sources: AEMO; AER.

The Australian Energy Market Operator (AEMO) in June 2015 forecast an annual 2.1 per cent rise in electricity consumption from the NEM grid over the three years to 30 June 2018. The forecast accounts for the rising energy requirements of liquefied natural gas (LNG) projects in Queensland. That rise is associated with gathering and transporting coal seam gas from coal fields in southern Queensland to the LNG plants in Gladstone.[1]

Residential and commercial demand is forecast to rise marginally, due to population growth and an easing in retail electricity charges.[2] The strongest growth in residential and commercial consumption is forecast for Victoria (1.7 per cent annually over the next three years). There is also evidence that consumers are becoming less responsive to 'bill shock' following an easing of retail electricity prices in most jurisdictions from 2014, making consumers less active in managing their energy consumption.[3]

1 Pitt and Sherry, *Electricity emissions update to 30 June 2015*.
2 AEMO, *National electricity forecasting report 2015*.
3 Colmar Brunton, *Queensland household energy survey 2014*, March 2015.

Box 1.1: The AER's role in the National Electricity Market

The AER monitors the NEM to ensure market participants comply with the underpinning legislation and rules, and to detect irregularities and wider harm issues. We report on these issues to strengthen market transparency and confidence. In 2014–15 we published weekly reports on NEM performance and four reports on high price events (section 1.8).

Additionally, we draw on our monitoring activity to support compliance and enforcement work, and to assist bodies such as the Council of Australian Governments (COAG) Energy Council, the Australian Energy Market Commission and the Australian Competition and Consumer Commission.

The AER's recent compliance and enforcement work included:

- conducting technical audits of electricity generators' compliance programs
- successfully instituting proceedings in the Federal Court against Snowy Hydro for failing to follow dispatch instructions from the Australian Energy Market Operator (section 1.10.3)
- helping the ACCC monitor energy markets following the repeal of carbon pricing
- assisting the ACCC on energy market mergers.

Our wider policy work included:

- engaging with the AEMC on a proposed change to the National Electricity Rules to improve the 'bidding in good faith' provisions (section 1.10.1)
- proposing amendments to the Electricity Rules governing the rate at which generators can be required to alter their output. The amendments would make the market more responsive to changes in supply and demand (section 1.10.2).

South Australia is the only region with a forecast easing in grid consumption over the next 10 years (down 4 per cent). This fall will largely stem from the residential and commercial sectors, partly due to rising self-generation from solar PV panels.

1.1.1 Maximum demand

The demand for electricity varies by time of day, season and ambient temperature. Daily demand typically peaks in early evening, while seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning). Around three quarters of Australian households have air conditioning or evaporative cooling. Demand reaches its maximum on days of extreme temperatures, when air conditioning or heating loads are highest.

Maximum demand levels in the NEM have been declining for several years. In 2014–15, the maximum level of electricity demand in NSW, Victoria and South Australia was almost 20 per cent below the historical peaks recorded around 2009 (figure 1.2 and table 1.2). But Queensland had a contrasting trend, setting a new record peak on 5 March 2015 when Brisbane experienced its seventh consecutive day of temperatures above 30 degrees.[4] Maximum demand also rose in Tasmania in 2014–15, but remained well below its historical peak.

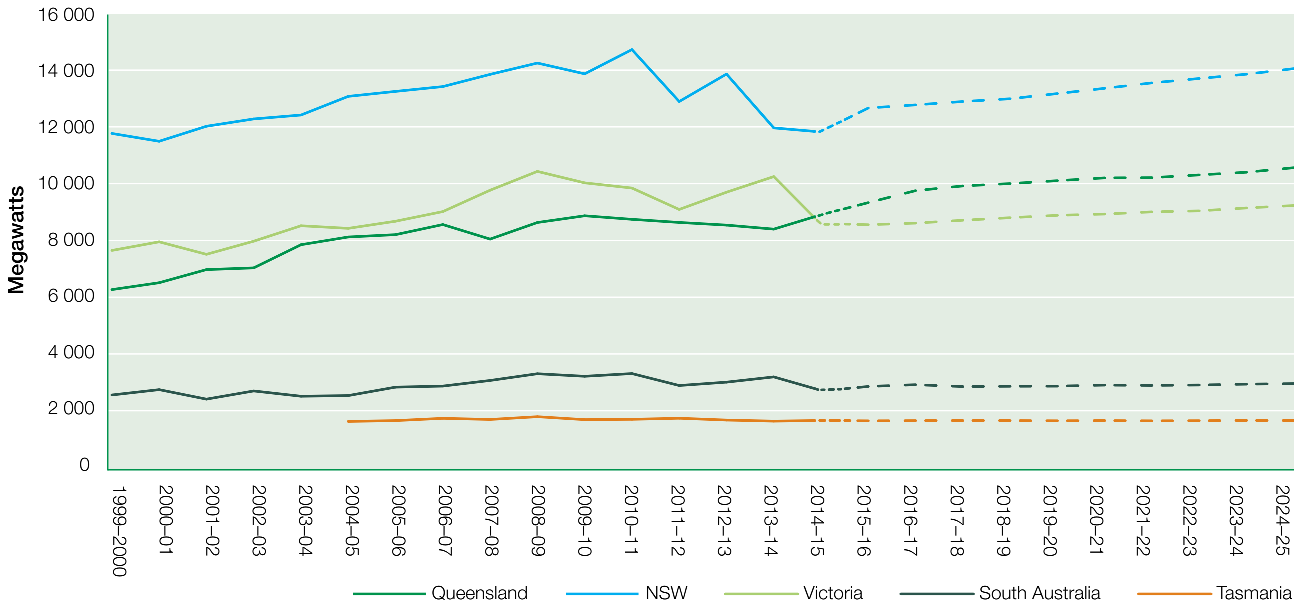
AEMO forecast a gradual recovery in residential and commercial energy use would cause maximum demand to rise over the three years to 30 June 2018, but to levels below historical highs in most regions. Queensland is the exception, with rising loads associated with LNG projects expected to drive new records in maximum demand.

While maximum demand will remain flatter than in the past, it is forecast to grow faster than overall grid consumption (figure 1.3). South Australia has the 'peakiest' demand profile. Maximum demand is forecast to grow to a record 2.2 times average demand by 2024–25 in that region, as a result of declining average grid consumption. This peakier demand profile affects the commercial viability of some large generation plant, because average plant use is falling even though capacity is needed to meet demand peaks. These conditions raise incentives for alternative ways of meeting demand peaks, such as small scale local generation, energy storage and demand-side measures.

4 AEMO, *National electricity forecasting report* 2015, p. 16.

Figure 1.2

Maximum demand, and forecast maximum demand, by region

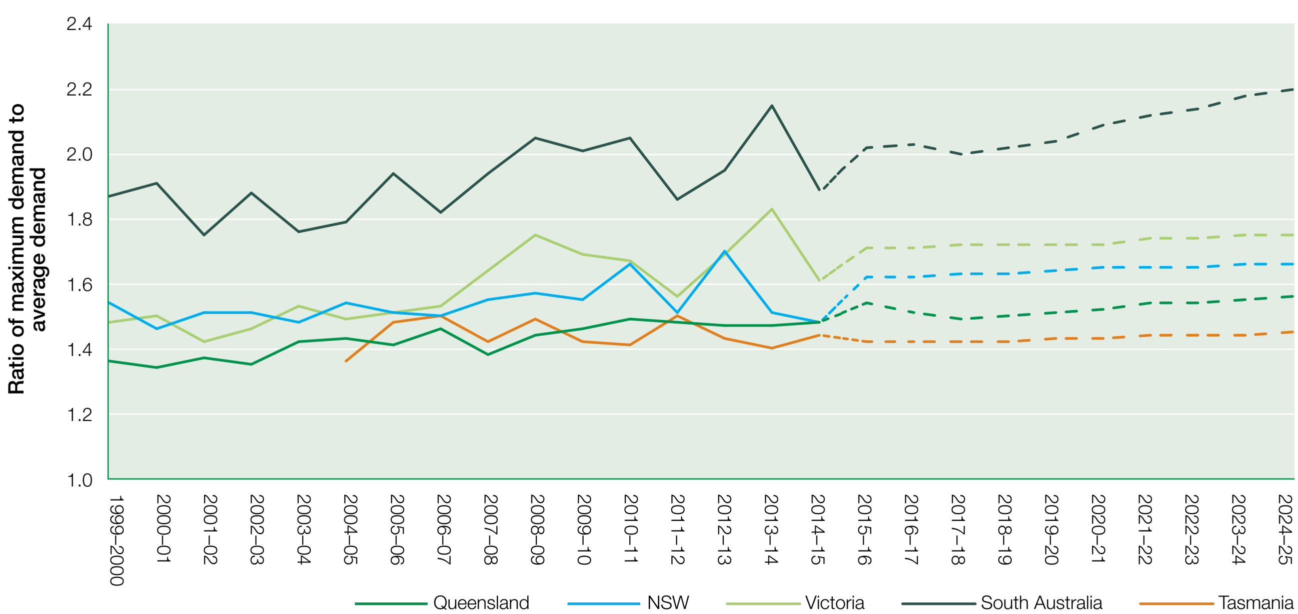


Note: Actual data to 2014–15, then AEMO forecasts published in 2015.

Sources: AEMO; AER.

Figure 1.3

Ratio of maximum demand to average demand



Sources: AEMO; AER.

Table 1.2 Maximum demand, by region, 2014–15

	QUEENSLAND	NSW	VICTORIA	SOUTH AUSTRALIA	TASMANIA
Change from 2013–14 (%)	6.0	–1.2	-16.2	-14.5	1.1
Change from historical maximum (%)	0.4	–19.6	–17.7	–17.4	-7.2
Year of historical maximum	2014–15	2010–11	2008–09	2010–11	2008–09

Sources: AEMO; AER.

1.2 Generation technologies in the NEM

Electricity in the NEM is produced mainly by burning fossil fuels (such as coal and gas) to create pressurised steam. The steam is forced through a turbine at high pressure to spin large magnets inside coils of conducting wire. Hydro and wind technologies use water and wind respectively (rather than steam) to drive the generator. Figure 1.4 illustrates the location of major generators in the NEM, and the technologies in use.

Solar PV generation is rising significantly in NEM regions, although the electricity generated from rooftop systems is not traded through the spot market. More recently, the first large scale solar PV generators in the NEM were commissioned. These generators do not rely on a turbine; rather, they directly convert sunlight to electricity.

Until recently, it was not commercially viable to store electricity, but emerging technologies are changing this dynamic. The uptake of battery storage and electric vehicles continues to gather momentum internationally. In Australia, both products are in their infancy. In the NEM, retailers have begun offering energy storage packages.[5] Declining battery costs and advances in lithium ion batteries for home power storage will likely accelerate uptake of these technologies.

Battery storage will allow for better matching of output from intermittent generation such as solar PV against evening demand peaks. And making rooftop PV more attractive to consumers will reduce consumer demand from the grid. The Grattan Institute forecast costs of $7000 to $10 000 for a 7 kilowatt hour (kWh) battery in 2017, but noted costs have halved since 1991.[6]

Only 2000 electric-only vehicles had been sold in NEM jurisdictions to 30 April 2015. AEMO projected an uptake of around 165 000 electric-only vehicles in the NEM by 2024–25.[7] While electric vehicles will be a source of demand, they may also offer battery storage that could be drawn on at times of peak demand.

A mix of generation technologies is needed to respond to fluctuating electricity demand. Plant with high start-up and shut-down costs but low operating costs tend to operate relatively continuously; for example, a coal generator may require two to three days to start up. Generators with higher operating costs, but with the ability to quickly change output levels (for example, open cycle gas powered generation), typically operate when prices are high. Hydro generation has low operating costs, but finite water supplies mean it cannot operate continuously like coal plant. Typically, it operates in peak demand periods to take advantage of high prices. Intermittent generation, such as wind and solar, operates only when weather conditions are favourable.

Black and brown coal generators accounted for 54 per cent of registered capacity in the NEM in 2014–15, but supplied 76 per cent of output (figure 1.5). Victoria, NSW and Queensland rely on coal more heavily than do other regions (figure 1.6).

Coal fired generation output declined by 12 per cent over the two years that carbon pricing was in place (1 July 2012 to 30 June 2014). Its market share fell to an historical low of 73.6 per cent in 2013–14. The abolition of carbon pricing on 1 July 2014 reversed this trend, most notably for brown coal generation, whose output rose by 10 per cent in 2014–15.

Gas powered generators accounted for 20 per cent of registered capacity across the NEM in 2014–15, but supplied only 12 per cent of output. Among the NEM jurisdictions, South Australia is the most reliant on gas powered generation.

Hydroelectric generators accounted for 16 per cent of registered capacity in 2014–15 but contributed 7 per cent of output. The bulk of Tasmanian generation is hydroelectric; Queensland, Victoria and NSW also have hydro generation. The introduction of carbon pricing and high dam levels

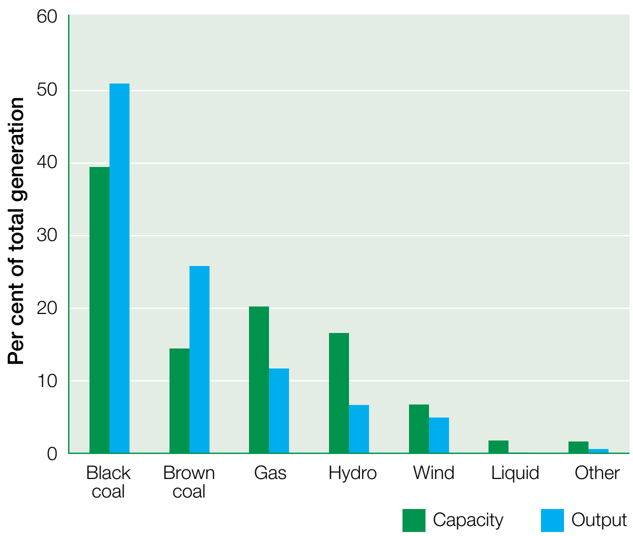
5 AEMO, *Emerging technologies information paper*, June 2015.
6 Grattan Institute, *Sundown, sunrise: how Australia can finally get solar power right*, May 2015; Macdonald-Smith, A, 'Rooftop battery storage battle is on', *Australian Financial Review*, 29 May 2015.
7 AEMO, *Emerging technologies information paper*, June 2015.

Figure 1.4
Electricity generation in the National Electricity Market

Sources: AEMO; AER.

Figure 1.5

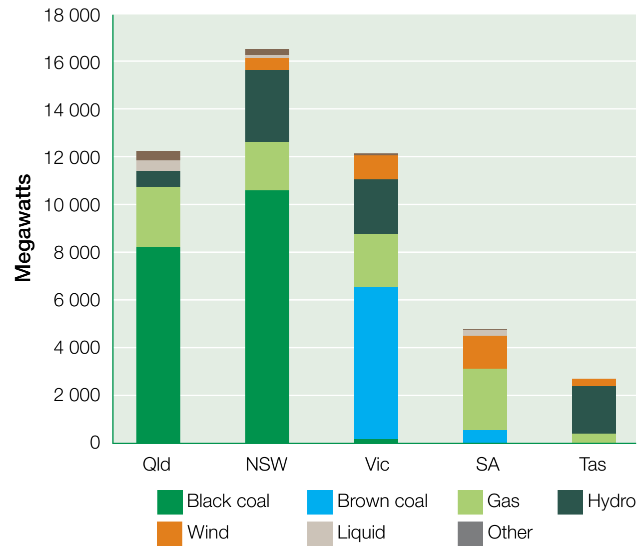
Registered generation, by fuel source, 2014–15



Note (figures 1.5–1.6): Excludes around 4000 MW of rooftop solar PV generation not traded through NEM dispatch.

Figure 1.6

Generation capacity, by region and fuel source, 30 June 2015



Sources (figures 1.5–1.6): AEMO; AER.

contributed to a 36 per cent increase in hydro output in 2012–13, with this level maintained in 2013–14. But the abolition of carbon pricing on 1 July 2014 reduced the profitability of hydro generation. Further, high output levels in the final months of carbon pricing, and below average rainfall in 2012–13 and 2013–14, caused water storages to fall below long term averages. These factors contributed to a 29 per cent decline in hydro output in 2014–15, resulting in its lowest level since the 2008–09 drought.

In September 2015, Snowy Hydro announced it would reduce hydro generation to conserve water reserves in preparation for El Nino drought conditions, which it predicted may extend into 2016. The storing of reserves in the current subdued market will allow Snowy Hydro to increase generation in future periods of market volatility.[8] Tasmania was also reducing hydro output in late 2015, due to record low rainfall. It imported 36 per cent of its electricity requirements from the mainland in October 2015—the highest proportion since Basslink was commissioned in 2006.

Wind generation has risen rapidly under climate change policies such as the renewable energy target (RET). Despite falling electricity demand and uncertainty about the RET scheme until new legislation was passed in June 2015, around 270 megawatts (MW) of wind capacity was added in 2014–15. Across the NEM, wind generators accounted for 6.6 per cent of capacity and generated 4.9 per cent of output in 2014–15. Overall, wind generation rose by 8 per cent in 2014–15. AEMO projected the bulk of generation investment over the next 20 years will be in wind plant.[9]

Favourable weather conditions across the NEM on 10 May 2015 resulted in record levels of wind output, peaking at 3190 MW, when wind turbines generated at 89 per cent of total capacity. Over that day, wind generation accounted for more than 14 per cent of all electricity generated in the NEM.

The penetration of wind generation is especially strong in South Australia, where it represented 29 per cent of capacity and met 37 per cent of electricity requirements in 2014–15 (figure 1.7). At times, wind is the dominant form of regional generation. In 1164 trading intervals in 2014–15, wind farms supplied 75 per cent of South Australian consumption from the grid. Wind generation actually exceeded regional demand for 30 hours in 2014–15, with the surplus generation exported to Victoria.[10]

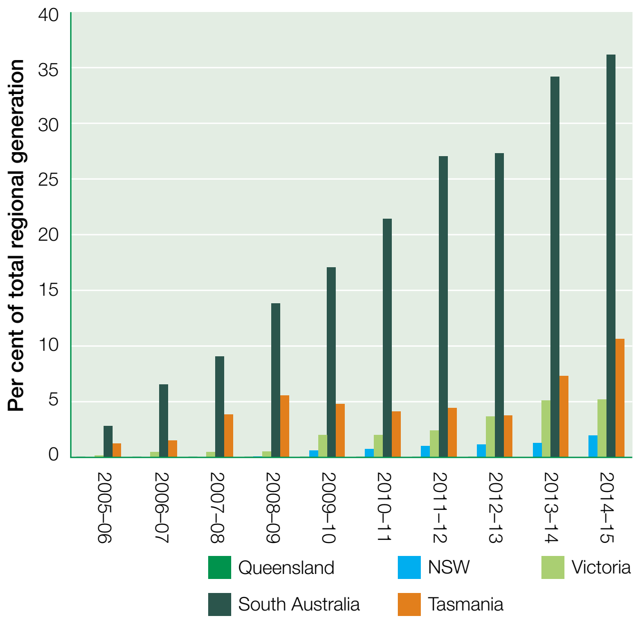
AEMO estimates that wind generation tends to be lower at times of maximum demand. In South Australia, wind can be expected to contribute around 10 per cent of its registered

8 *Snowy Hydro News*, September 2015; 'Forecast El Nino dry forces Snowy Hydro to harbour water', *Sydney Morning Herald*, 4 October 2015.

9 AEMO, *Electricity statement of opportunities*, August 2015.

10 AEMO, *South Australian wind study report*, 2015.

Figure 1.7
Wind generation share of total generation, by region



Note: Excludes rooftop solar PV generation, which is not traded through the NEM wholesale market.

Sources: AEMO; AER.

capacity during peaks in summer demand. The proportion is lower in other regions (as low as 1 per cent in NSW).[11]

The newest addition to the NEM's generation profile is commercial solar PV generation. Three solar plants were commissioned in NSW in 2015, with a combined capacity of 175 MW. Large scale solar plant has been slow to develop in Australia, partly as a result of its high cost relative to costs for other technologies, and uncertainty on the future of the RET. But the Australian Renewable Energy Agency (ARENA) aims to reduce plant costs to parity with wind by 2020. It announced in September 2015 it would partner with the Clean Energy Finance Corporation to fund $350 million for up to 10 new large scale solar plants by 2017.[12]

1.2.1 Rooftop solar PV generation

While large scale solar generation remains in its infancy in the NEM, climate change policies (including the RET and subsidies for solar PV installations) have spurred a rapid increase in solar PV generation. The subsidies include feed-in tariff schemes, under which distributors and/or retailers pay households for electricity generated from rooftop installations. The energy businesses recover costs from energy users through higher electricity charges.

Rooftop solar PV generation is not traded through the NEM. Instead, the installation owner receives a reduction in their energy bills. AEMO treats the contribution of rooftop PV generation as a reduction in energy demand, because it reduces energy demand from the grid.

Solar PV installations are predominantly in the residential sector, but commercial installations have recently grown. Commercial systems accounted for 12 per cent of installed solar PV capacity in 2014–15, and this share is forecast to grow to 23 per cent by 2024–25.[13]

Almost 1.5 million Australian households (15 per cent) have installed small scale solar PV systems. Total installed capacity in the NEM reached 3700 MW in 2014–15, equivalent to 8 per cent of total installed capacity in the NEM (figure 1.8). The output of solar PV installations was virtually zero until 2010, but by 2014–15 supplied 2.7 per cent of electricity requirements in the NEM.[14]

Solar penetration is highest in South Australia, where 25 per cent of households have installed capacity, just ahead of Queensland's 24 per cent penetration rate. The penetration rate in some suburbs is as high as 65 per cent.[15] The Energy Supply Association of Australia (ESAA) found solar PV penetration was more widespread in postcodes with low to medium incomes, but negligible among the lowest 20 per cent of income earners.[16]

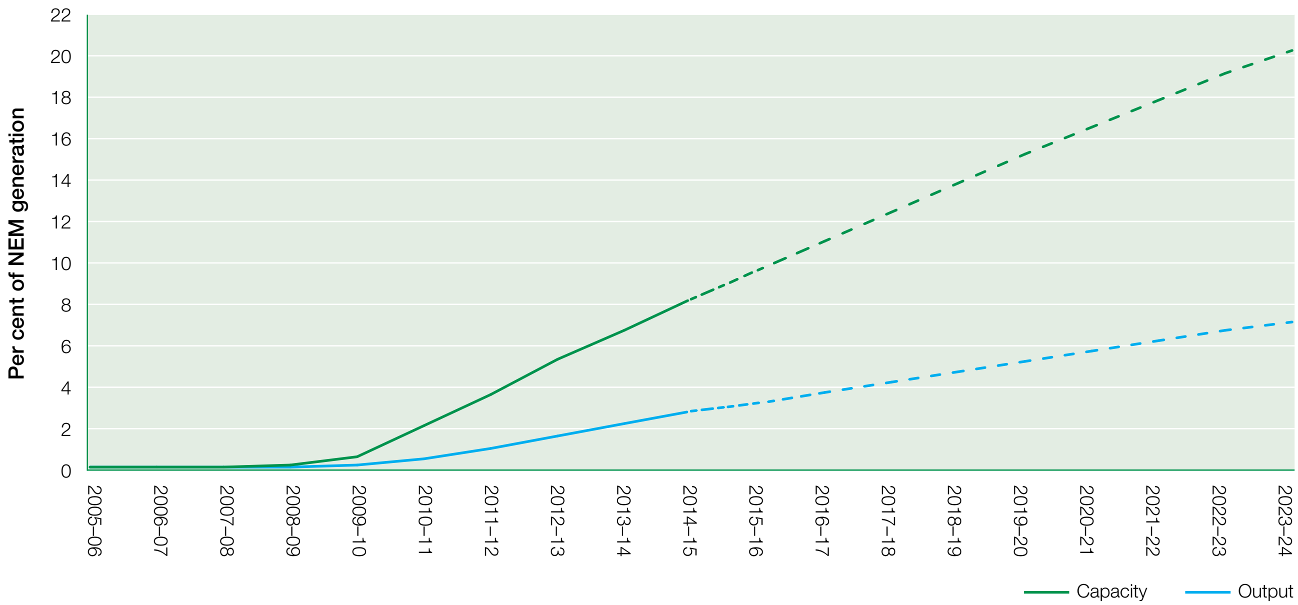
In South Australia, solar PV installations in 2014–15 generated 7 per cent of the state's annual energy requirements (up from 3.8 per cent in 2012–13).[17] Reflecting the extent of solar penetration in South Australia, the region recorded its lowest ever grid demand at 13:30 on 26 December 2014, when rooftop solar PV output supplied 36 per cent of the state's energy requirements. AEMO predicted rooftop PV by 2023–24 will be sufficient on some days in South Australia to meet all of the region's energy requirements in the middle of the day.[18]

Across the NEM, the contribution of solar PV installations to peak demand is generally lower than the rated system capacity. In mainland regions, summer energy consumption typically peaks in late afternoon, when solar PV generation is declining. The AER estimated solar PV capacity in South

11 AEMO, *South Australian wind study report*, 2015.
12 ARENA, '$350m to kick start new large scale solar projects', Media release, 9 September 2015.

13 AEMO, *National electricity forecasting report 2015*.
14 AEMO, *Emerging technologies information paper*, June 2015.
15 ESAA, *Solar PV report*, September 2015.
16 ESAA, *Solar PV report*, September 2015.
17 AEMO, *South Australian electricity report*, August 2015.
18 AEMO, *National electricity forecasting report 2015*, pp. 18–19.

Figure 1.8
Solar PV generation capacity and output



Note: Dotted lines are AEMO forecasts published in 2015.
Sources: AEMO, AER.

Australia during a heatwave in January 2014 contributed around 75 per cent of the region's installed capacity in the early afternoon. But that contribution averaged around 55 per cent at 4 pm, declining to 30 per cent at 6 pm.

More generally, the increasing use of solar PV generation is shifting demand peaks to later in the day (when solar generation is falling). AEMO estimated rooftop solar generation in South Australia can contribute 31 per cent of the region's installed capacity at times of maximum summer demand, compared with 24 per cent in NSW and 19 per cent in Queensland.[19]

Solar PV capacity continues to rise. While monthly new installed capacity halved between 2011 and 2014 (from 30 000 MW to 15 000 MW), their average capacity rose from 2.5 kilowatts (kW) to 4.4 kW over that period (figure 1.9). The trend continued in 2015, when the number of installations in January–June was 20 per cent less than for the same period in 2014, but the average capacity of those installations was 10 per cent larger (4.8 kW). In part, these shifts reflect the progressive rollback of subsidised feed-in tariffs towards market levels, and falling solar panel costs.

AEMO forecast solar installations will more than triple over the next decade, with capacity equalling 21 per cent of total installed generation in the NEM by 2024–25. This capacity will contribute around 7.5 per cent of the NEM's energy requirements at that time.[20] Queensland has the highest forecast growth in solar PV installations over the next decade, with installed capacity in 2024–25 forecast to equal one third of all generation capacity.[21]

1.3 Carbon emissions and the NEM

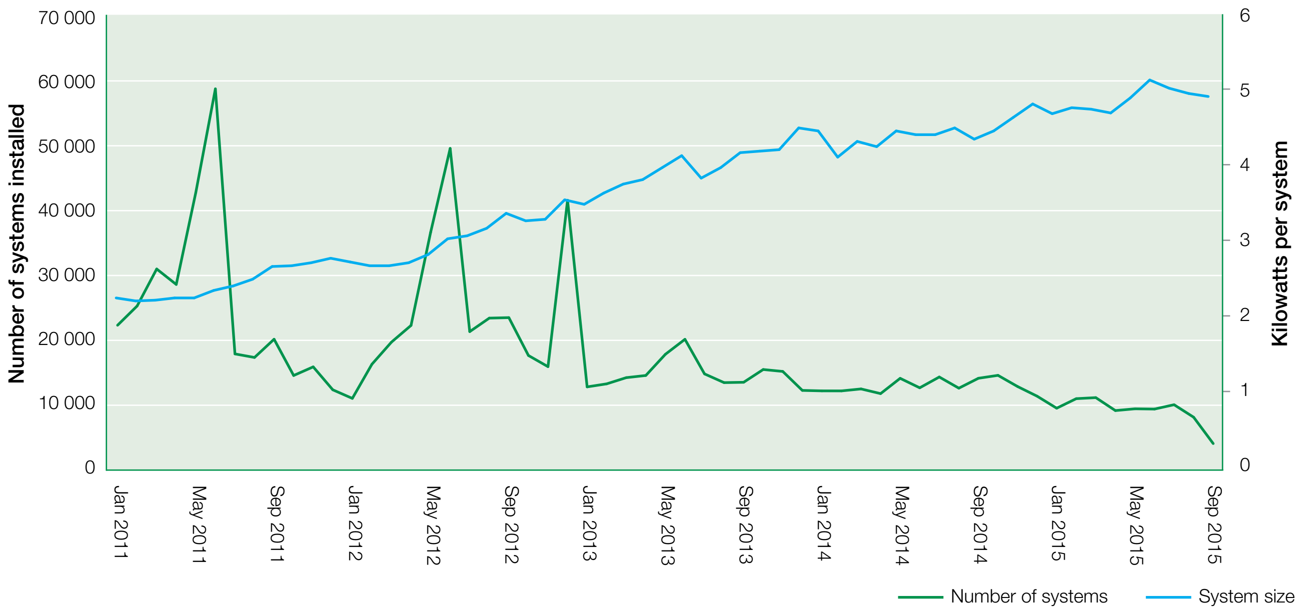
The mix of generation technologies in the NEM is evolving in response to technological change and government policies to mitigate climate change. The electricity sector contributes over one third of national greenhouse gas emissions, mainly due to its high reliance on coal fired generation.[22] Climate change policies change the economic drivers for new investment and impact on the operation of existing plant.

The Australian Government's target is to reduce carbon emissions to 5 per cent below 2000 levels by 2020.[23] In August 2015, it proposed a post-2020 target to reduce

19 AEMO, *South Australian electricity report 2015*.

20 AEMO, *National electricity forecasting report 2015, dynamic forecasting interface*.
21 AEMO, *National electricity forecasting report 2015*.
22 Australian Government, *Quarterly update of Australia's national greenhouse gas inventory, March quarter 2015*.
23 Department of the Environment (Australian Government), *Australia's abatement task*, 2015.

Figure 1.9
Monthly solar PV installations



Source: Clean Energy Regulator.

emissions by 26–28 per cent by 2030 compared with 2005 levels.

Climate change policies currently or recently implemented by Australian governments to achieve carbon abatement targets include:

- the RET scheme (launched in 2001, expanded in 2007, amended in 2015)
- carbon pricing (operating from 1 July 2012 to 30 June 2014)
- Direct Action (introduced in 2014).

1.3.1 Renewable energy target scheme

The Australian Government in 2001 introduced a RET scheme, which it expanded in 2007. The scheme requires electricity retailers to source a proportion of their energy from renewable sources developed after 1997.

The scheme applies different arrangements for small and large scale renewable supply. The large scale scheme creates incentives to establish or expand renewable energy power stations, such as wind and solar farms and hydroelectric power stations. The small scale scheme creates incentives for households, small businesses and community groups to install small scale renewable energy systems such as solar water heaters, heat pumps, solar PV systems, small scale wind systems and small scale hydro systems. For each scheme, retailers obtain renewable energy certificates created for each MWh of eligible renewable electricity that an accredited power station generates, or from the installation of eligible solar hot water or small generation units (box 1.2).

The Australian Government in 2014 appointed an expert panel to review the RET. The panel's report (the Warburton Report)[24] found the RET had led to the abatement of 20 million tonnes of carbon emissions and, if left in place, would abate a further 20 million tonnes of emissions per year from 2015 to 2030—almost 10 per cent of 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 coal fired electricity generation.

On 23 June 2015 the Australian Parliament amended the RET. The amendments reduced the 2020 target for energy from large scale renewable projects from 41 000 gigawatt hours (GWh) to 33 000 GWh. On current estimates, this

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

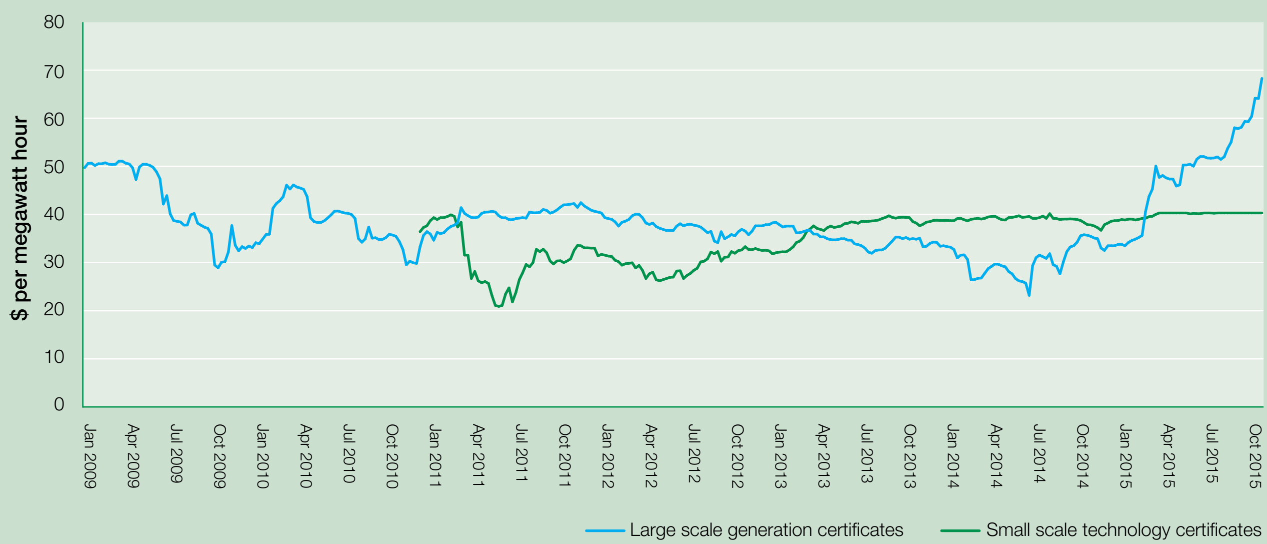
Box 1.2 Renewable energy target—certificate prices

Figure 1.10 illustrates the prices of certificates issued under each component of the RET scheme. A certificate represents 1 MWh of output from qualifying renewable generators (or deemed output from small scale generation). Qualifying generators in the NEM receive both the certificate price and the wholesale spot price for electricity.

Certificates from large scale projects traded at around $40 over 2011, following revisions to the RET scheme. Prices gradually fell over the following years, reaching a low of $22 in June 2014. This fall coincided with uncertainty over government climate change policy, particularly following the 2013 federal election and a review of the RET scheme's future. Certificate prices recovered sharply from late 2014. They rose again following the passage of legislation on the RET's future in June 2015, nearing $70 in October 2015.

The price of certificates from small scale projects were more volatile from 2011–13, trading between $20–40. Price have since steadied around $35–40. The design of the scheme for small scale technology certificates means prices are largely tied to the accuracy of forecasts on qualifying system installations.

Figure 1.10
RET Certificate prices



Source: Clean Energy Regulator.

target would result in 23.5 per cent of Australia's electricity generation in 2020 being sourced from renewables.[25]

The amendments also reinstate biomass from native forest wood waste as an eligible source of renewable energy, effectively reducing requirements to meet the target from new renewables.

25 The Hon. Greg Hunt MP, Minister for the Environment, Paris and beyond: An integrated approach to climate and the environment, speech delivered to National Press Club, Canberra, 25 November 2015.

1.3.2 Carbon pricing

A carbon pricing scheme operated in Australia between 1 July 2012 and 1 July 2014. The Coalition Government on 17 July 2014 abolished carbon pricing, effective from 1 July 2014.

The Labor Government had introduced a price on carbon in 2012 as part of its Clean Energy Future Plan. The central mechanism placed a fixed price on carbon for three years, starting at $23 per tonne of carbon dioxide equivalent emitted. An emissions trading scheme was to replace the fixed price in July 2015 (later brought forward to July 2014), whereby the market would determine a carbon price.

1.3.3 Direct Action

The Australian Government in 2014 passed legislation for a Direct Action plan to achieve Australia's 2020 emissions reduction target. The scheme requires the government to pay for emissions abatement activity. Central to the plan is an Emissions Reduction Fund that provides funding for approved emissions reduction projects. The Clean Energy Regulator purchases emissions reductions at the lowest available cost through competitive auctions.

Two auctions were held in 2015, with 120 successful bidders entering contracts covering 275 projects that will abate 92.8 million tonnes of emissions over an average contract term of nine years. The auction set an average price of $13.12 per tonne of carbon abatement (avoided greenhouse gas emissions). The total cost of the projects is $1.2 billion.

The majority of abatement from the auctions is via sequestration projects that trap carbon through measures such as planting trees and storing carbon in soil (54 million tonnes of abatement). Landfill and waste related abatement projects accounted for 22 million tonnes, and bushfire prevention through savannah burning accounted for a further 7 million tonnes. No electricity generation projects participated in the 2015 auctions. Many successful bids were for projects established before the Emissions Reduction Fund was launched.

The Department of the Environment in late 2015 forecast that the fund will provide 92 million tonnes of abatement towards meeting Australia's 2020 emissions reduction target, accounting for the first two auctions and the $1.3 billion available for future auctions.[26]

The Australian Government in August 2015 announced additional funding to support its post-2020 emissions reduction target of 26–28 per cent by 2030, compared with 2005 levels. The additional funding of $200 million per year from 2018 to 2030 will raise the scheme's funding to around $5 billion.

As part of Direct Action, the government in September 2015 announced draft rules for a safeguard mechanism that penalises large businesses for increasing their emissions above a baseline, to commence from July 2016. Electricity generators will have a sectoral baseline set by reference to the sector's highest historical annual emissions (198 million tonnes in 2009–10). If this baseline is exceeded, then baselines will apply to individual facilities by reference to their highest emissions level from 2009–10 to 2013–14. Applying this baseline will not contribute to meeting Australia's emissions abatement target. Rather, its role is to ensure emissions reductions purchased under the fund are not displaced by a significant rise in emissions above business as usual.

26 Department of the Environment (Australian Government), *Australia's abatement task: tracking to 2020,* factsheet, 2015.

1.3.4 Effects of climate change policies on electricity sector

Climate change policies have altered the composition of electricity generation in the NEM. An expansion of the RET in 2007 contributed to the addition of 2760 MW of wind capacity in the following eight years. The RET, in conjunction with attractive feed-in tariffs, also supported the uptake of almost 4000 MW of solar PV installations.

The introduction of carbon pricing in July 2012 contributed to further shifts in the generation mix. Over the two years of the scheme's operation, output from brown coal fired generators declined by 16 per cent (with plant use dropping from 85 per cent to 75 per cent), and output from black coal generators declined by 9 per cent (figures 1.11 and 1.12). Coal generation's market share fell to an historical low of 73.6 per cent of NEM output in 2013–14.

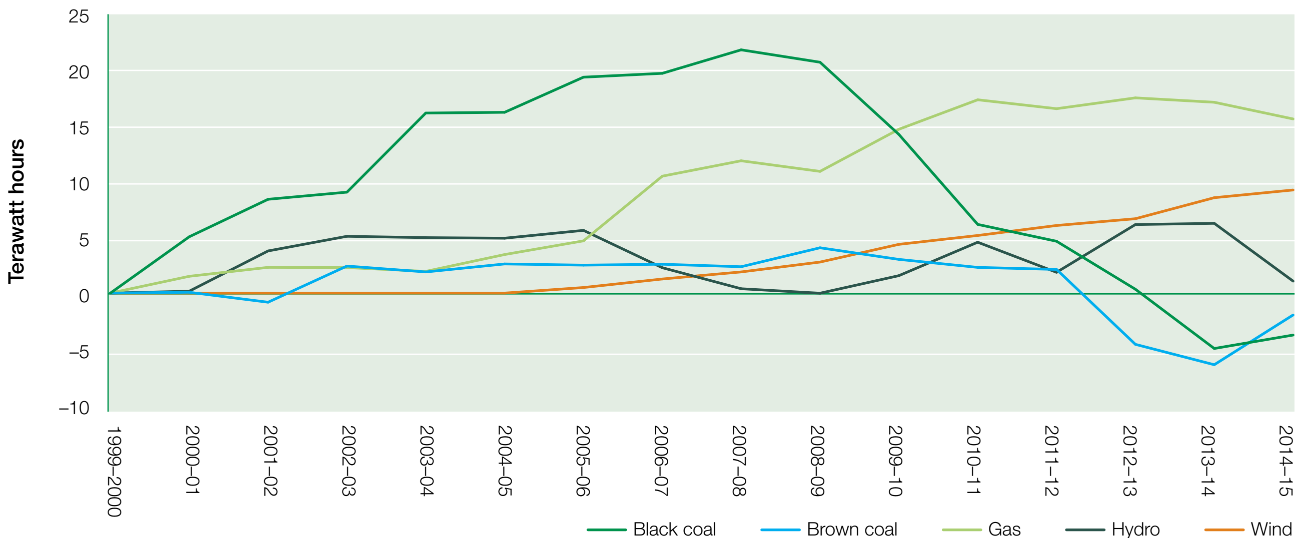
Meanwhile, carbon pricing increased returns for hydro generation, contributing to record output during the two years of the scheme's operation—36 per cent higher than in the year immediately before carbon pricing. Output from gas powered generators also rose.

Overall, these changes contributed to the emissions intensity of NEM generation falling by 4.7 per cent over the two years that carbon pricing was in place (from 0.903 tonnes of carbon dioxide equivalent emissions per MWh of electricity produced in 2011–12, to 0.861 tonnes in 2013–14). 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 those two years.

The repeal of carbon pricing from 1 July 2014 led to some coal plant being returned to service, and to a significant fall in hydro generation output. This shift contributed to a 4.3 per cent rise in electricity emissions in the NEM in the year to 30 June 2015. In the absence of carbon pricing, Pitt and Sherry argued rising electricity demand associated with Queensland LNG projects will likely be sourced from coal generation; by 2018–19 this would raise national carbon emissions from electricity by around 4.7 per cent above current levels.[27]

27 Pitt & Sherry, *Cedex electricity update*, July 2015.

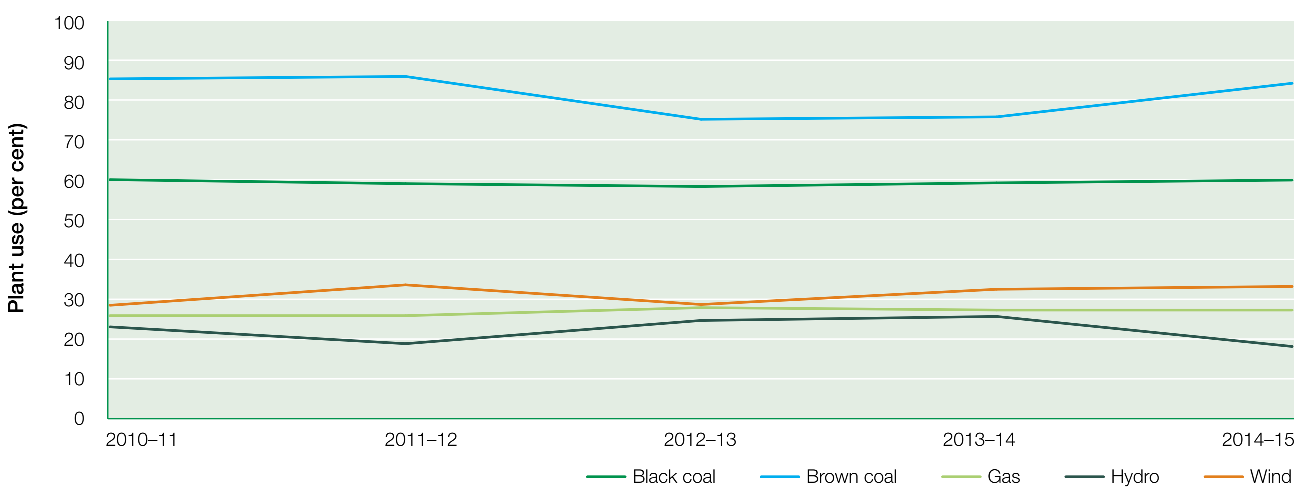
Figure 1.11
Annual change in electricity generation, by energy source



Note: Hydro generation includes Tasmanian generation prior to its entry to the NEM in 2005.

Sources: AEMO; AER.

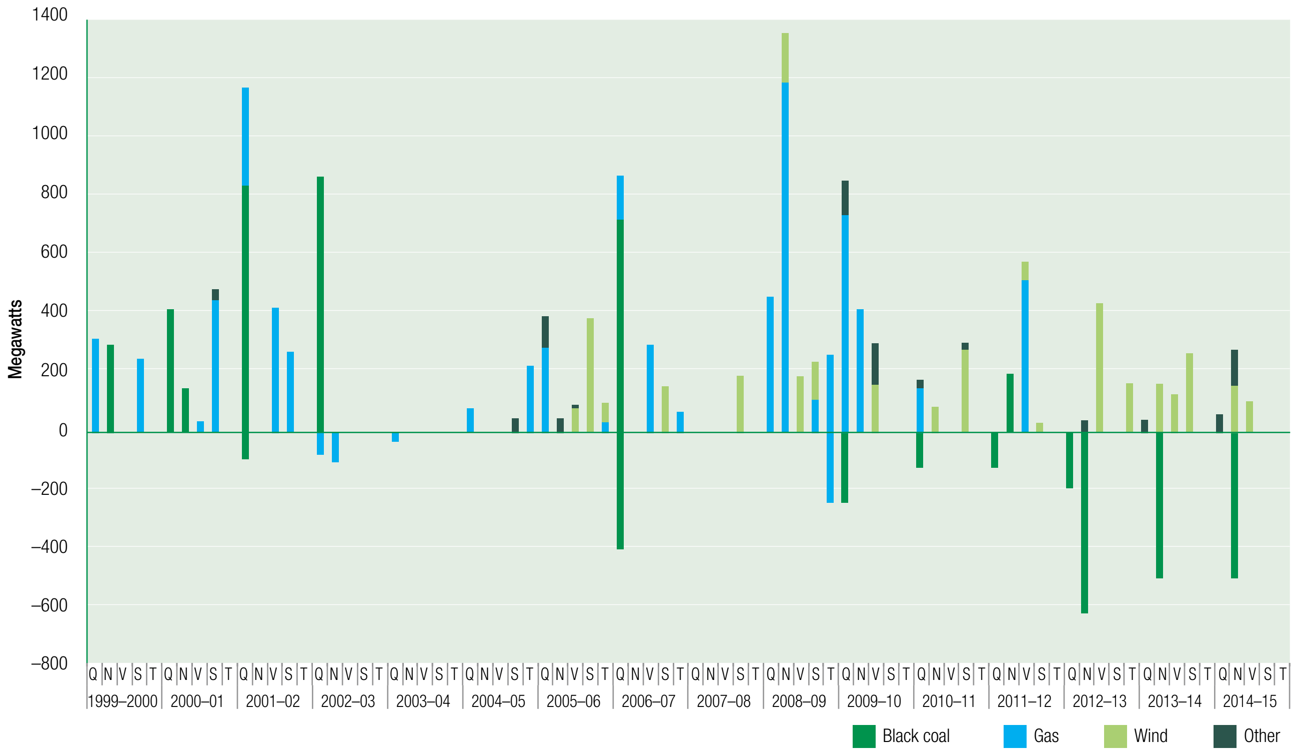
Figure 1.12
Generation plant capacity use



Sources: AEMO; AER.

Figure 1.13

Registered generation capacity—annual investment and retirements



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

Source: AEMO; AER.

1.4 Generation investment

Between the NEM's start in December 1998 and June 2015, new investment added over 14 900 MW of registered generation capacity. Over the same period, 3200 MW of generation capacity was retired, providing an average net increase in capacity of around 700 MW per year (figure 1.13). Investment surged from 2008–10, with over 4000 MW of capacity added (mainly gas fired generation in NSW and Queensland).

More recently, subdued electricity demand and surplus capacity pushed out the need for new investment. Little investment has been made since 2011–12, other than in wind generation. Additionally, significant capacity has been retired, mostly in coal fired plant (section 1.5).

The AEMC's *Power of choice* review noted the potential for demand response as an alternative to generation investment in meeting energy demand. AEMO estimated 220 MW of capacity would be available through demand-side participation in the NEM during summer 2015–16 when the spot price is above $1000 per MWh; over 1000 MW would be available if the spot price hits the cap. Of the identified capacity, 40 per cent is in NSW.

The COAG Energy Council directed AEMO to develop a mechanism enabling energy service companies to compete with retailers in offering incentives for customers to reduce demand when spot prices are high. In December 2013, however, the Council noted the ongoing weakness in electricity demand may mitigate the benefits of demand response.

1.4.1 Investment horizon

Flat energy demand has been reflected in limited recent and committed investment. Of the 2500 MW of capacity added over the four years to 30 June 2015, 61 per cent was in wind generation (which the RET scheme subsidises). The balance of investment was in gas fired plant in Victoria, large scale solar plants in NSW, and upgrades to existing plant.

Table 1.3 Generation investment in the National Electricity Market, 2014–15

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED
NSW				
CBD Energy and Banco Santanda	Taralga	Wind	107	2015
Electricity Generating Public Company	Boco Rock	Wind	113	2015
Royalla Asset	Royalla	Solar	20	2015
AGL PV Solar Development	Nyngan	Solar	102	2015
VICTORIA				
Pacific Hydro Portland Wind Farm	Portland Stage 4	Wind	47	2015
Mitsui and Co. Australia	Bald Hills p1	Wind	107	2015

Table 1.4 Committed investment in the National Electricity Market, October 2015

DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND				
CS Energy	Kogan Creek Solar Boost	Solar	44	2016
NSW				
AGL PV Solar Development	Broken Hill	Solar	53	2015
Moree Solar Farm	Moree	Solar	56	2016
VICTORIA				
Coonooer Bridge	Windlab Systems	Wind	20	2016
Partners Group, OPTrust, GE and RES	Ararat	Wind	240	2017
SOUTH AUSTRALIA				
Hornsdale Wind Farm	Hornsdale (stage 1)	Wind	102	2016

Sources (tables 1.3 and 1.4): AEMO; AER.

Table 1.3 details generation investment in the NEM in 2014–15. At October 2015 the NEM had around 500 MW of committed projects,[28] comprising wind and solar farms (table 1.4).

The NEM's first commercial solar farms—Royalla (20 MW) and AGL Energy's Nyngan (102 MW) and Broken Hill (53 MW) plants—were commissioned in 2015. Also in NSW, Fotowatio Renewable Ventures is developing a 56 MW solar farm at Moree. The farm, scheduled for commissioning in 2016, will use mechanical trackers to continually orient its solar panels to the sun to optimise power output. ARENA and the NSW Government provided funding in support of the projects.[29] ARENA is partnering with the Clean Energy Finance Corporation to support up to 10 new large scale solar plants by 2017.

In addition to committed generation projects, AEMO lists projects that are 'advanced' or publicly announced, but not formally committed for development. It excludes these projects from supply and demand outlooks, given their speculative status. At October 2015 AEMO listed 21 700 MW of proposed capacity across the NEM, mostly in wind (56 per cent) and gas fired capacity (27 per cent). Around 2 per cent of proposed capacity is in solar farms.

28 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.

29 Department of the Environment (Australian Government), *Big solar: time to shine*, 2 September 2015.

Table 1.5 **Generation withdrawals from 2011–12**

YEAR	POWER STATION		CAPACITY (MW)	GENERATION TECHNOLOGY	STAGE OF EXIT
WITHDRAWN					
2011–12	Northern	SA	540	Coal	Seasonal (winter) shutdown. One unit returned to full service in 2014. Retirement announced for 2016
2011–12	Playford B	SA	200	Coal	Seasonal (winter) shutdown and 90 day recall. Retirement announced for 2016
2011–12	Swanbank B	Qld	480	CCGT	Decommissioned progressively between April 2010 and May 2012
2012–13	Morwell, Brix	Vic	95	Coal	One unit operating 2012–14. Shutdown mid 2014
2012–13	Munmorah	NSW	600	Coal	Retired
2012–13	Tarong	Qld	700	Coal	Closed 2012 to 2014
2012–13	Collinsville	Qld	180	Coal	Retired
2014–15	Wallerawang C	NSW	1000	Coal	Retired
2014–15	Redbank	NSW	144	Coal	Retired
2014–15	Pelican Point	SA	249	CCGT	Unit 2 mothballed on 48 hour recall
2014–15	Swanbank E	Qld	385	CCGT	Mothballed
2015–16	Anglesea	Vic	150	Coal	Retired
ANNOUNCED WITHDRAWAL					
2015	Tamar Valley	Tas	208	CCGT	Retirement
2017	Torrens Island A	SA	480	CCGT	Mothballing
2017	Smithfield	NSW	171	Gas	Retirement
2022	Daandine	Qld	33	CCGT	Retirement
2022	Liddell	NSW	2000	Coal	Retirement
2023	Mt Stuart	Qld	414	OCGT	Retirement

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

Sources: AEMC, *Advice to the COAG Energy Council: barriers to effective exit decisions by generators*, 16 June 2015; AEMO, *Electricity statement of opportunities* (various years), Company announcements.

1.5 Supply–demand balance

A flattening out of electricity demand since 2008 has led to an oversupply of generation capacity. In response, significant capacity has been permanently or temporarily removed from the market (table 1.5). Overall, capacity withdrawals from 2011–12 to 2014–15 exceeded new generation investment.

The abolition of carbon pricing shifted the composition of capacity withdrawals. Some coal capacity that had been mothballed under carbon pricing was returned to service after July 2014. Queensland generation business Stanwell, for example, returned 700 MW of coal fired capacity to service at Tarong Power Station, but mothballed its 385 MW Swanbank E gas fired power station.

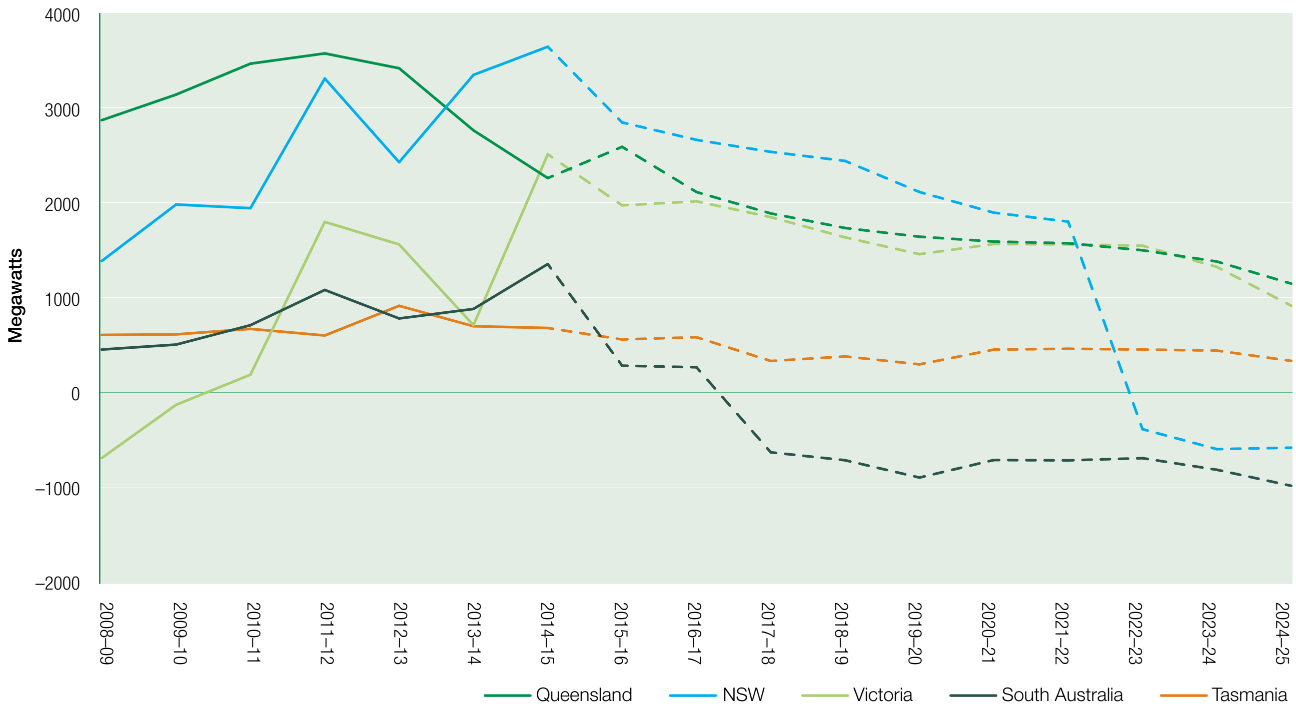
AEMO found the NEM's capacity surplus may have peaked in 2014–15. Looking ahead, plant withdrawals will reduce the surplus in most regions (figure 1.14). Plant announced for withdrawal over the next seven years includes gas fired power stations at Torrens Island (South Australia), Tamar Valley (Tasmania), Daandine and Mount Stuart (Queensland) and Smithfield (NSW), and coal capacity at Northern and Playford (South Australia) and Liddell (NSW).[30]

AEMO projected that in the absence of new investment, plant withdrawals may result in supply shortfalls that breach the reliability standard by 2019–20 in South Australia and by 2022–23 in NSW.[31]

30 AEMC, *Advice to the COAG Energy Council: barriers to effective exit decisions by generators*, 16 June 2015; AEMO, *Electricity statement of opportunities* (various years), Company announcements.

31 AEMO, *Electricity statement of opportunities,* October 2015.

Figure 1.14
Surplus generation capacity



Notes:

Historical data to 2014–15 reflect surplus of generation capacity (based on summer ratings) over maximum demand. Beyond 2014–15, the data reflect existing and committed generation capacity over maximum demand forecasts in AEMO's medium growth scenario and a 50 per cent probability of exceedance.

Wind contribution to capacity to 2014–15 is based on summer ratings for semi-scheduled plant and registered capacity for non-scheduled plant. AEMO forecasts of wind capacity are based on modelled contribution at times of peak demand.

Sources: AEMO, AER.

1.6 Market structure

The pattern of generation ownership varies across regions and includes pockets of high concentration. Additionally, significant vertical integration exists among electricity generators, energy retailers and gas producers.

1.6.1 Generation ownership

Table 1.6 lists generators in the NEM, including the entities that control dispatch. Figure 1.4 identifies plant locations. Ownership arrangements vary markedly across regions. Private businesses own most generation capacity in Victoria, NSW and South Australia, while government owned corporations own or control the majority of capacity in Queensland and Tasmania.

Figure 1.15 illustrates generation market shares based on summer capacity under each firm's trading control in January 2015. It includes import capacity from interconnectors, which provide some competitive constraint on regional generators in NSW, South Australia and Tasmania (equivalent to 10–15 per cent of regional capacity). The constraint is less effective in Victoria (6 per cent). In Queensland, imports average less than 2 per cent of regional capacity when local prices are high.

In *Queensland*, state owned corporations Stanwell and CS Energy control 64 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). The most significant private operators are InterGen (11 per cent of capacity) and Origin Energy (9 per cent).

The degree of market concentration increased in 2011, when the Queensland Government dissolved one of three state owned generation businesses (Tarong Energy) and reallocated its capacity to the remaining two state owned entities.

Table 1.6 Generation capacity and ownership, 2015

TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND (11 750 MW)			
Stanwell Corporation	Stanwell; Tarong; Tarong North; Barron Gorge; Kareeya; Mackay	3139	Stanwell Corporation (Qld Government)
CS Energy	Callide; Kogan Creek; Wivenhoe	2000	CS Energy (Qld Government)
CS Energy	Gladstone	1680	Rio Tinto 42.1%; NRG Energy 37.5%; others 20.4%
Origin Energy	Darling Downs; Mount Stuart; Roma	1013	Origin Energy
CS Energy / InterGen	Callide C	900	CS Energy (Qld Government) 50%; InterGen (China Huaneng Group / Guangdong Yudean Group 50%; others 50%) 50%
InterGen	Millmerran	760	InterGen (China Huaneng Group / Guangdong Yudean Group 50%; others 50%) 59%; Marubeni 30%; others 11%
Arrow Energy	Braemar 2	495	Arrow Energy (Shell 50%; PetroChina 50%)
Alinta Energy	Braemar 1	465	Alinta Energy
ERM Power	Oakey	282	ERM Group
AGL Energy / Arrow Energy	Yabulu	235	RATCH Australia (Ratchaburi Electricity Generation 80%; Transfield Services 20%)
RTA Yarwun	Yarwun	155	Rio Tinto Alcan
BG Group	Condamine	144	BG Group
CSR	Pioneer Sugar Mill; Invicta Sugar Mill	119	CSR
AGL Energy	Moranbah North; German Creek	102	Energy Developments (DUET Group)
Mackay Sugar Coop	Racecourse Mill	48	Racecourse Mill
Ergon Energy	Barcaldine	34	Ergon Energy (Qld Government)
Origin Energy	Daandine	30	Energy Infrastructure Investments (Marubeni 50%; Osaka Gas 30%; APA Group 20%)
National Power	Rocky Point	30	National Power
	Unscheduled plant < 30 MW	119	
NEW SOUTH WALES (16 377 MW)			
AGL Energy	Bayswater; Liddell; Hunter Valley; Broken Hill; Nyngan	4919	AGL Energy
Origin Energy	Eraring; Shoalhaven; Uranquinty; Cullerin Range; Eraring	3846	Origin Energy
Snowy Hydro	Tumut; Colongra; Upper Tumut; Blowering; Guthega	3288	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
EnergyAustralia	Mt Piper; Tallawarra	1775	EnergyAustralia (CLP Group)
Sunset Power International	Vales Point	1320	Sunset Power International
Infigen Energy	Capital; Woodlawn	188	Infigen Energy
EnergyAustralia	Gullen Range	166	Beijing Jingneng Clean Energy 75%; Goldwind Capital 25%
Marubeni Corporation	Smithfield Energy Facility	162	Marubeni Corporation
Banco Santander / BlueNRGY	Taralga	106	Banco Santander 90%; BlueNRGY 10%
Energy Developments	Appin; Tower	96	Energy Developments (DUET Group)
Capital Dynamics	Broadwater; Condong	68	Capital Dynamics
EnergyAustralia	Boco Rock	53	Electricity Generating Public Company
Essential Energy	Broken Hill	50	Essential Energy (NSW Government)
Acciona Energy	Gunning	46	Acciona Energy
Eraring Energy	Hume	29	Trustpower (51% Infratil)
	Unscheduled plant < 30 MW	265	

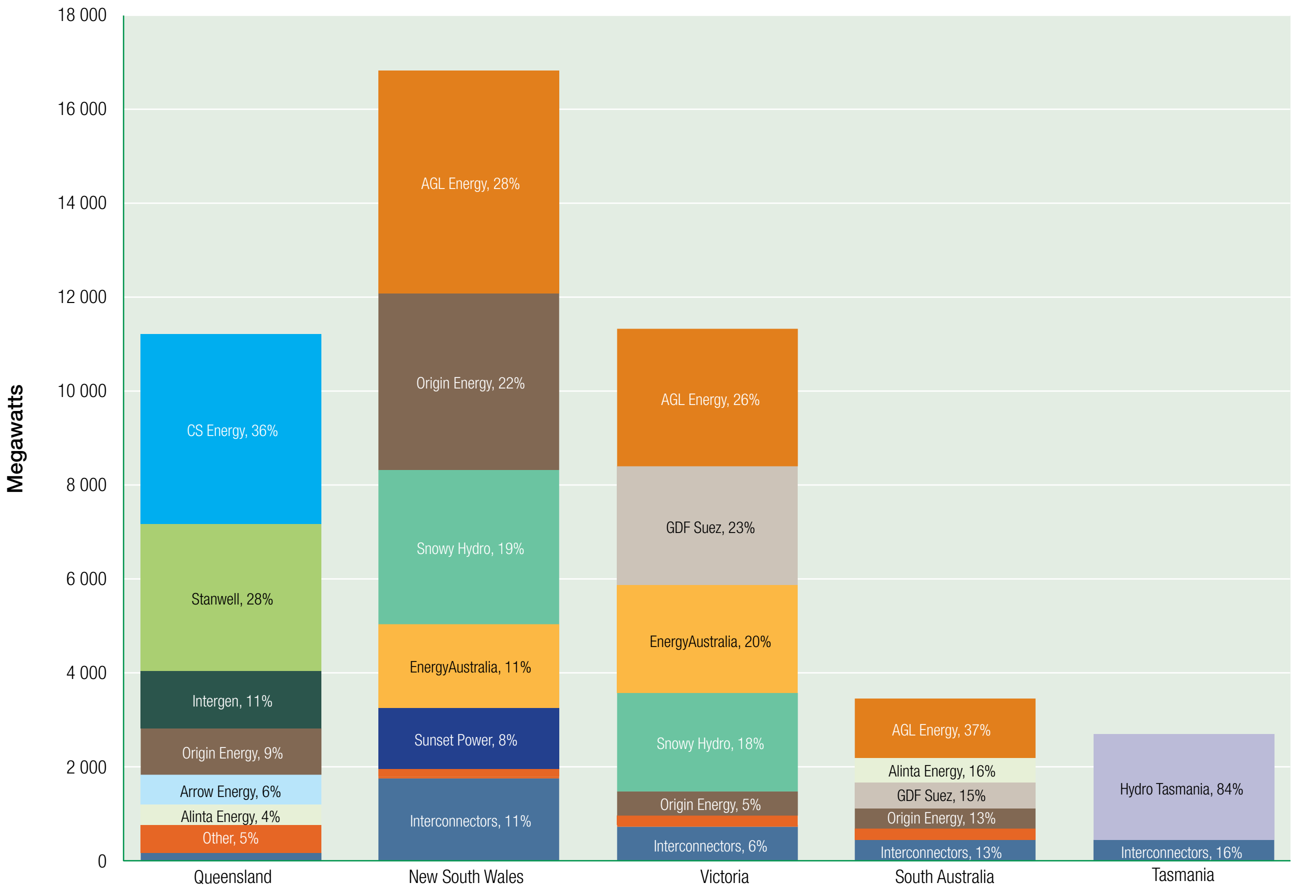
TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
VICTORIA (11 660 MW)			
AGL Energy	Loy Yang A; Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay	2907	AGL Energy
Snowy Hydro	Murray; Laverton North; Valley Power	2082	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
GDF Suez	Hazelwood	1600	GDF Suez 72%; Mitsui 28%
EnergyAustralia	Yallourn; Longford	1431	EnergyAustralia (CLP Group)
GDF Suez	Loy Yang B	965	GDF Suez 70%; Mitsui 30%
EnergyAustralia	Jeeralang A and B; Newport	883	Industry Funds Management
Origin Energy	Mortlake	518	Origin Energy
AGL Energy	Macarthur	315	Morrison & Co. 50%; Malakoff Corporation Berhad 50%
Pacific Hydro	Yambuk; Challicum Hills; Portland	231	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Meridian Energy	Mount Mercer	131	Meridian Energy
Alinta Energy	Bald Hills	106	Mitsui
Hydro Tasmania	Bairnsdale	70	Alinta Energy
AGL Energy	Oaklands Hill	47	Challenger Life
Eraring Energy	Hume	29	Trustpower (51% Infratil)
	Unscheduled plant < 30 MW	153	
SOUTH AUSTRALIA (4675 MW)			
AGL Energy	Torrens Island	1260	AGL Energy
GDF Suez	Pelican Point; Canunda; Dry Creek; Mintaro; Port Lincoln; Snuggery	790	GDF Suez 72%; Mitsui 28%
Alinta Energy	Northern	546	Alinta Energy
Origin Energy	Snowtown; Snowtown North; Snowtown South	369	Trustpower (51% Infratil)
Origin Energy	Quarantine; Ladbroke Grove	254	Origin Energy
EnergyAustralia	Hallet	198	EnergyAustralia (CLP Group)
Infigen Energy	Lake Bonney 2 and 3	182	Infigen Energy
Origin Energy	Osborne	175	ATCO 50%; Origin Energy 50%
AGL Energy	Hallett 2; Wattle Point	145	Energy Infrastructure Trust
EnergyAustralia	Waterloo	111	Palisade Investment Partners / Northleaf Capital Partners 75%; EnergyAustralia (CLP Group) 25%
Snowy Hydro	Pt Stanvac; Angaston	114	Snowy Hydro
AGL Energy	North Brown Hill	92	Energy Infrastructure Investments (Marubeni 50%; Osaka Gas 30%; APA Group 20%)
Essential Energy	Lake Bonney 1	81	Infigen Energy
AGL Energy	Hallett 1	71	Palisade Investment Partners
Meridian Energy	Mount Millar	70	Meridian Energy
EnergyAustralia	Cathedral Rocks	66	EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
Pacific Hydro	Clements Gap	57	Pacific Hydro
AGL Energy	The Bluff	39	Eurus Energy
Hydro Tasmania	Starfish Hill	35	RATCH Australia (Ratchaburi Electricity Generation 80%; Transfield Services 20%)
	Unscheduled plant < 30 MW	20	
TASMANIA (2665 MW)			
Hydro Tasmania	Gordon; Poatina; Tamar Valley; Bell Bay; others	2283	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth; Musselroe	308	Shenhua Clean Energy 75%; Hydro Tasmania 25%
	Unscheduled plant < 30 MW	74	

Note: Capacity as published by AEMO for summer 2014–15, except for non-scheduled plant (registered capacity).

Fuel types: Coal; gas; hydro; wind; diesel/fuel oil/Multi-fuel; biomass/bagasse; solar; unspecified.

Figure 1.15

Market shares in generation capacity, 2015



Notes:

Capacity based on summer availability for January 2015, except wind, which is adjusted for an average contribution factor.

Interconnector capacity is based on observed flows when the price differential between regions exceeds $10 per MWh in favour of the importing region; the data exclude trading intervals in which counter-flows were observed (that is, when electricity was imported from a high priced region into a lower priced region).

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

Sources: AEMO; AER.

The government in October 2014 announced plans to lease state owned electricity assets for 50 years, with options to extend for a further 49 years. The assets included Stanwell and CS Energy, as well as transmission and distribution networks. The plan was scrapped following a change of government at the 2015 election. The new government's election platform was to merge the remaining state owned entities, CS Energy and Stanwell.

In *NSW*, the privatisation of state owned generation businesses was finalised in 2015. The NSW Government in 2011 sold the electricity trading ('gentrader') rights to one third of state owned capacity to EnergyAustralia (Delta West) and Origin Energy (Eraring Energy). The businesses acquired the plant underlying those contracts in August 2013.

A second round of privatisations began in late 2013, with Macquarie Generation and Delta Coastal portfolios offered for sale. AGL Energy acquired Macquarie Generation in September 2014. The ACCC opposed the sale, but the Australian Competition Tribunal found the public benefits of the acquisition outweighed any detriment to competition.

Snowy Hydro, which is jointly owned by the Australian, NSW and Victorian governments, acquired Delta Electricity's Colongra plant in December 2014. Delta's Vales Point plant, with 8 per cent market share, was sold to Sunset Power International in November 2015.

Following the asset sales, AGL Energy (28 per cent), Origin Energy (22 per cent) and Snowy Hydro (19 per cent) emerged as the state's leading generators.

In *Victoria*, AGL Energy (26 per cent of capacity), GDF Suez (23 per cent) and EnergyAustralia (20 per cent) and Snowy Hydro (18 per cent) are the major players. Origin Energy has a 5 per cent share.

In *South Australia*, AGL Energy is the dominant generator, with 37 per cent of capacity. Other significant entities are Alinta (16 per cent), GDF Suez (15 per cent) and Origin Energy (13 per cent). This composition will change following several planned withdrawals from the market.

In *Tasmania*, the state owned Hydro Tasmania owns nearly all generation capacity. To encourage competition in the retail market, the Office of the Tasmanian Economic Regulator regulates the price at which Hydro Tasmania can offer four safety net contract products, and it ensures adequate volumes of these products are available.

1.6.2 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, the trend has been for vertical re-integration of retailers and generators to form 'gentailer' structures. Vertical integration provides a means for generators and retailers to internally manage risk in the spot market, reducing their need to participate in hedge (contract) markets. Less participation in contract markets can reduce liquidity in those markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

Section 5.2.3 of the retail chapter details vertical integration in the NEM. In summary, three private businesses, AGL Energy, Origin Energy and EnergyAustralia:

- increased their market share in generation capacity from 15 per cent in 2009 to 45 per cent in 2015, largely through the acquisition of previously state owned generation in NSW. Over this period, Origin Energy also commissioned new power stations in Queensland and Victoria, and AGL Energy acquired full ownership of Loy Yang A in Victoria
- supply 71 per cent of energy retail customers. Origin Energy and EnergyAustralia acquired significant retail market share in NSW in 2010 following the privatisation of government owned retailers. AGL Energy acquired Australian Power & Gas (one of the largest independent retailers) in August 2013.

Vertical integration has also occurred among state owned entities. Snowy Hydro (owned by the Australian, NSW and Victorian governments) owns the energy retailers Red Energy and Lumo Energy. The Tasmanian Government owned Hydro Tasmania also has a retail arm (Momentum Energy).

1.6.3 Potential for market power

High levels of market concentration and vertical integration between generators and retailers give rise to a market structure that may, in certain conditions, provide opportunities for the exercise of market power. Section 1.12 sets out metrics for analysing competitive conditions in electricity markets, and tracks recent data for the NEM.

In April 2013 the AEMC found potential for substantial market power to exist or be exercised in future in the NEM. In July 2015 the COAG Energy Council announced the AER would be tasked with a wholesale market monitoring role to ensure the market is flexible and responsive to changing circumstances, and to identify and quantify the costs of market inefficiencies.[32]

1.7 National Electricity Market

Generators in the NEM sell electricity through a wholesale spot market in which changes in supply and demand affect prices (box 1.3). The main customers are energy retailers, which buy electricity for sale to their customers.

1.7.1 Interregional trade

The NEM allows electricity trade across the five regions, which transmission interconnectors link. Trade enhances the reliability of the power system by allowing each region to draw on a wider pool of reserves. It also allows high cost generating regions to import electricity from lower cost regions.

Queensland and Victoria typically export electricity, while NSW and South Australia are typically importers (figure 1.17). Tasmania's trade position fluctuates.

- Victoria's brown coal fired generation makes it a net exporter of electricity (particularly to NSW and South Australia). Victoria's trading position weakened during the two years of carbon pricing, when brown coal became less competitive and hydro generation imports from Tasmania rose. But the abolition of carbon pricing reversed this trend, contributing to increased brown coal fired generation in 2014–15.

32 COAG Energy Council, *Reform agenda implementation plan—progress report*, 23 July 2015.

Box 1.3: How the NEM operates

The NEM is a virtual market into which generators sell electricity. Generators make bids (offers) to supply quantities of electricity across 10 price bands for each five minute dispatch interval in a day. They must lodge offers ahead of a trading day but can rebid at any time, provided a rebid is made in 'good faith'.

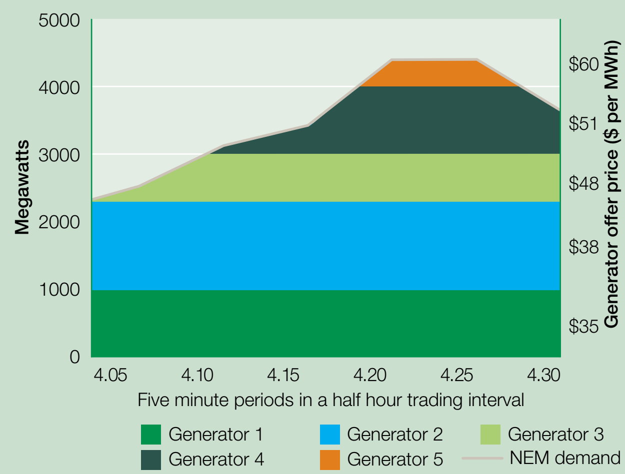
Various factors, including plant technology, affect generator offers. Coal fired generators, for example, have high start-up costs and may offer to generate at low prices to guarantee dispatch and keep plant running. Other plant, such as gas powered generators, face higher fuel costs and can only profitably supply electricity at higher prices. Bidding may also be affected by plant outages and transmission network constraints that limit transport capabilities.

AEMO operates the NEM market by matching generator supply offers against real time demand. To determine which plant is dispatched, AEMO stacks the bids of all generators from the lowest to highest price for each dispatch interval. It selects the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to meet demand. The highest priced offer needed to meet demand sets the dispatch price. The spot price paid to generators is the average dispatch price over 30 minutes; all successful bidders are paid at this price, regardless of how they bid.

Figure 1.16 illustrates a simplified bid stack in the NEM between 4.00 pm and 4.30 pm, with five generators offering capacity in different price bands. At 4.15 pm the demand for electricity is 3500 MW. To meet this, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is $51 per MWh. By 4.20 pm demand has risen to the point at which a fifth generator must be dispatched. This higher cost generator has an offer price of $60 per MWh, which drives up the price to that level. The wholesale spot price for the half hour period (trading interval) is about $54 per MWh, being the average of the five minute dispatch prices during that interval.

The market has a price floor of –$1000 per MWh and a cap of $13 800 per MWh.

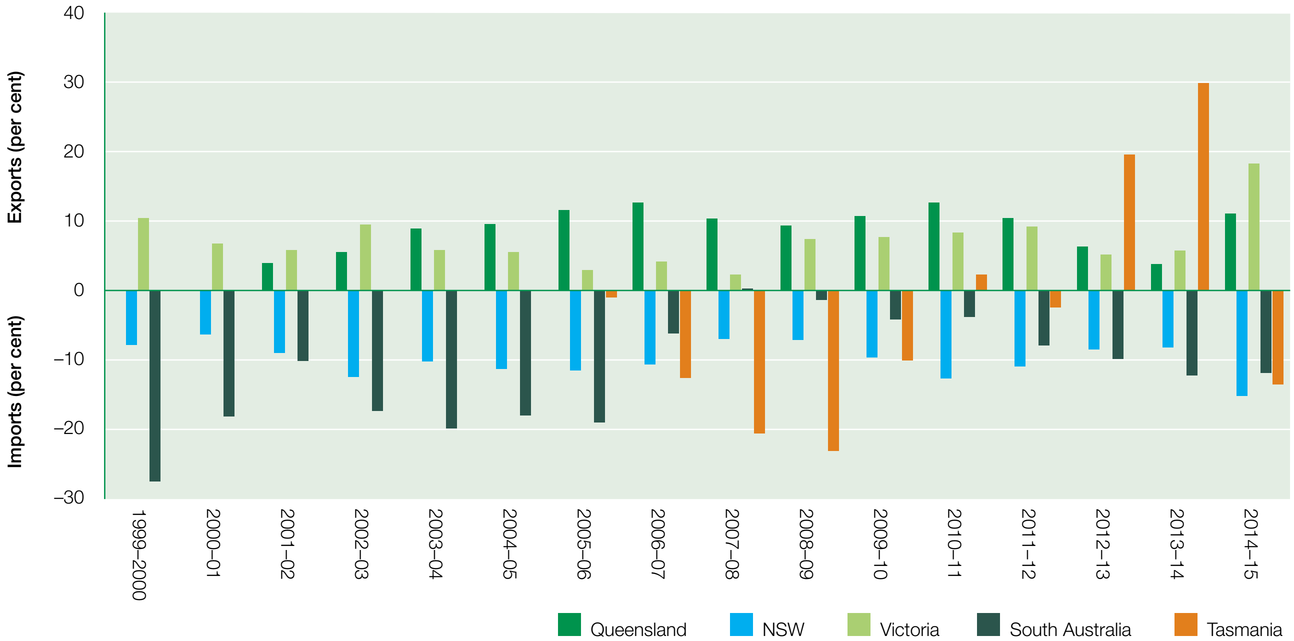
Figure 1.16
Generator bid stack



- Queensland's surplus capacity and low fuel prices make it a net electricity exporter. Price volatility contributed to lower export volumes from 2012–14. But low spot gas prices in 2014–15 encouraged local gas fired generation, displacing imports from NSW.
- NSW has relatively high fuel costs, making it a net importer of electricity. During the two years of carbon pricing, Snowy Hydro significantly increased output, reducing the region's reliance on imports. But the abolition of carbon pricing made NSW the NEM's biggest net importer in 2014–15.
- South Australia imported an average of 20 per cent of its energy requirements in the early years of the NEM. Since then, investment in wind generation allowed the region to export electricity during low demand periods. But capacity withdrawals over the past three years caused imports to rise. An expansion of the Heywood transmission interconnector between South Australia and Victoria (scheduled for completion in 2016) may allow South Australia to import greater volumes of energy at times of high demand, and also allow higher volumes of wind generation exports.
- Tasmania has a volatile trade position, depending on market and weather conditions. The introduction of carbon pricing in July 2012 enhanced the profitability of hydro generation, resulting in Tasmania becoming a major net exporter. In 2013–14 it recorded the highest ratio of exports of any region since the NEM commenced. But the abolition of carbon pricing reduced Hydro Tasmania's incentives to generate at those levels, making Tasmania a net importer of mainly brown coal fired generation from Victoria.

Figure 1.17

Interregional trade as a percentage of regional electricity demand



Sources: AEMO; AER.

The market sets a separate spot price for each NEM region. When the market is operating efficiently, prices align across regions, differing only to account for physical losses in the transport of electricity. Allowing for those losses, prices across mainland NEM regions aligned for a record low 50 per cent of the time in 2014–15. Prices aligned 83 per cent of the time in 2013–14, and have typically aligned 60–80 per cent of the time since the NEM commenced.

The poor rate of market alignment in 2014–15 reflects a high incidence of network congestion affecting the interconnectors linking the five NEM regions. In particular, the total duration of congestion on QNI (Queensland–NSW), Snowy (NSW–Victoria) and Murraylink (Victoria and South Australia) was around 20 percentage points higher than in 2013–14, for each interconnector.

1.7.2 Impediments to trade

The technical capabilities of cross-border interconnectors set upper limits on interregional trade. Further, network congestion periodically constrains trading to below nominal interconnector capabilities. These network limitations sometimes island a region from the rest of the market when local demand is high, forcing it to rely on local generation to meet demand; this may cause price separation from the rest of the market.

At times, network congestion forces electricity to flow from a high to low price region. These counter-price flows create market distortions that impose costs on consumers. All NEM regions have experienced counter-price flows at one time or another, most recently Queensland and NSW.[33]

1.8 Recent NEM activity

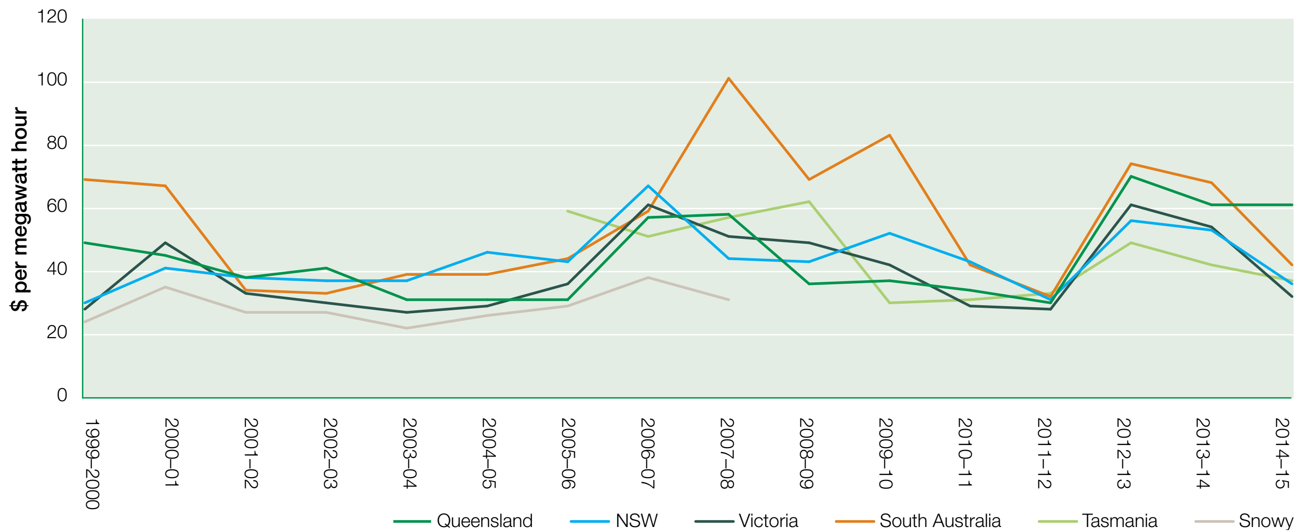
The AER monitors the NEM spot market and reports weekly on activity. Figures 1.18–20 and table 1.7 chart annual, quarterly and weekly prices. Figure 1.21 sets out data on market volatility.

Spot prices in the NEM were significantly lower in 2014–15 than in the previous year. Average wholesale prices fell by 42 per cent in Victoria, 38 per cent in South Australia and 32 per cent in NSW. Tasmania recorded a 12 per cent price reduction. Annual average prices in Victoria, NSW and Tasmania ranged from $32–37 per MWh. South Australia's annual prices averaged $42 per MWh.

Queensland was the only region to record an increase in prices. It also had the NEM's most expensive wholesale electricity prices (averaging $61 per MWh), for the first time in over a decade.

33 AER, *State of the energy market 2014*, p. 42.

Figure 1.18
Annual spot electricity prices



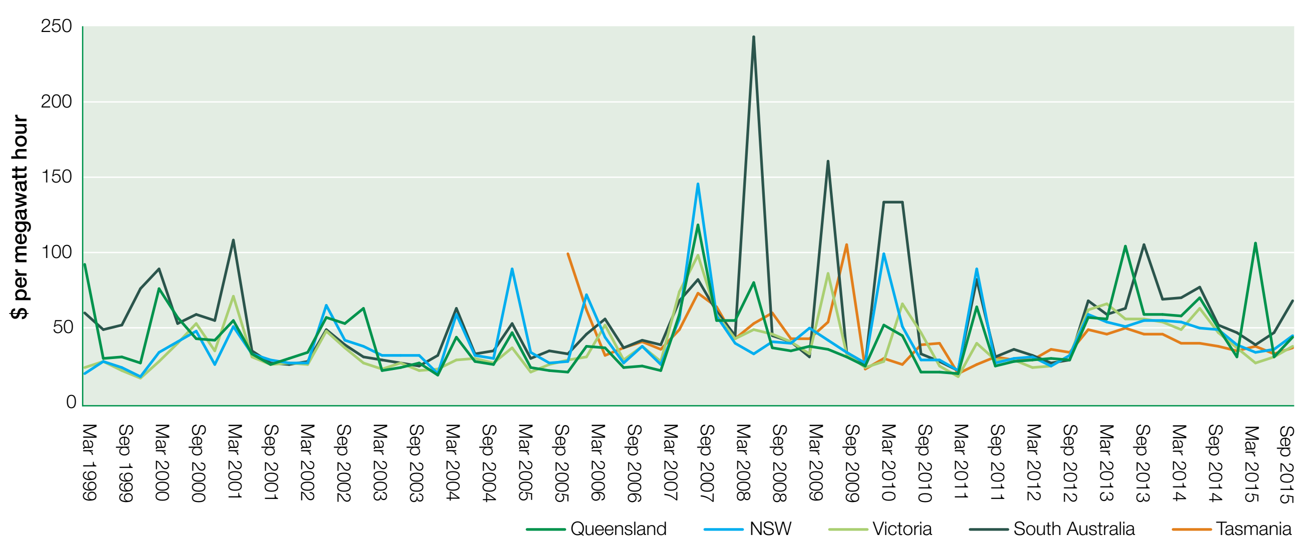
Notes:

Volume weighted average prices.

Tasmania entered the market on 29 May 2005. The Snowy region was abolished on 1 July 2008.

Sources: AEMO; AER.

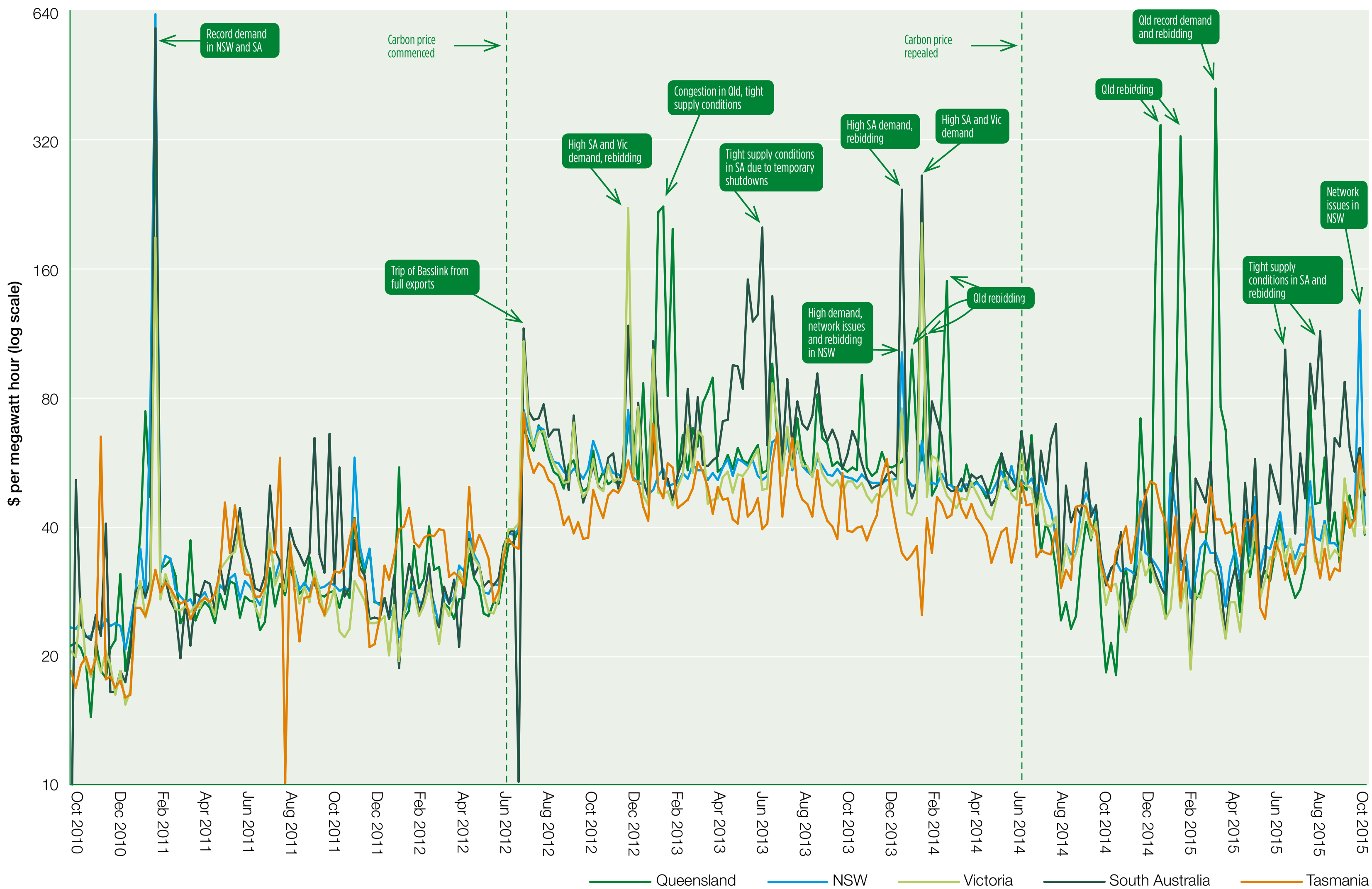
Figure 1.19
Quarterly spot electricity prices



Note: Volume weighted average prices.

Sources: AEMO; AER.

Figure 1.20
Weekly spot electricity prices

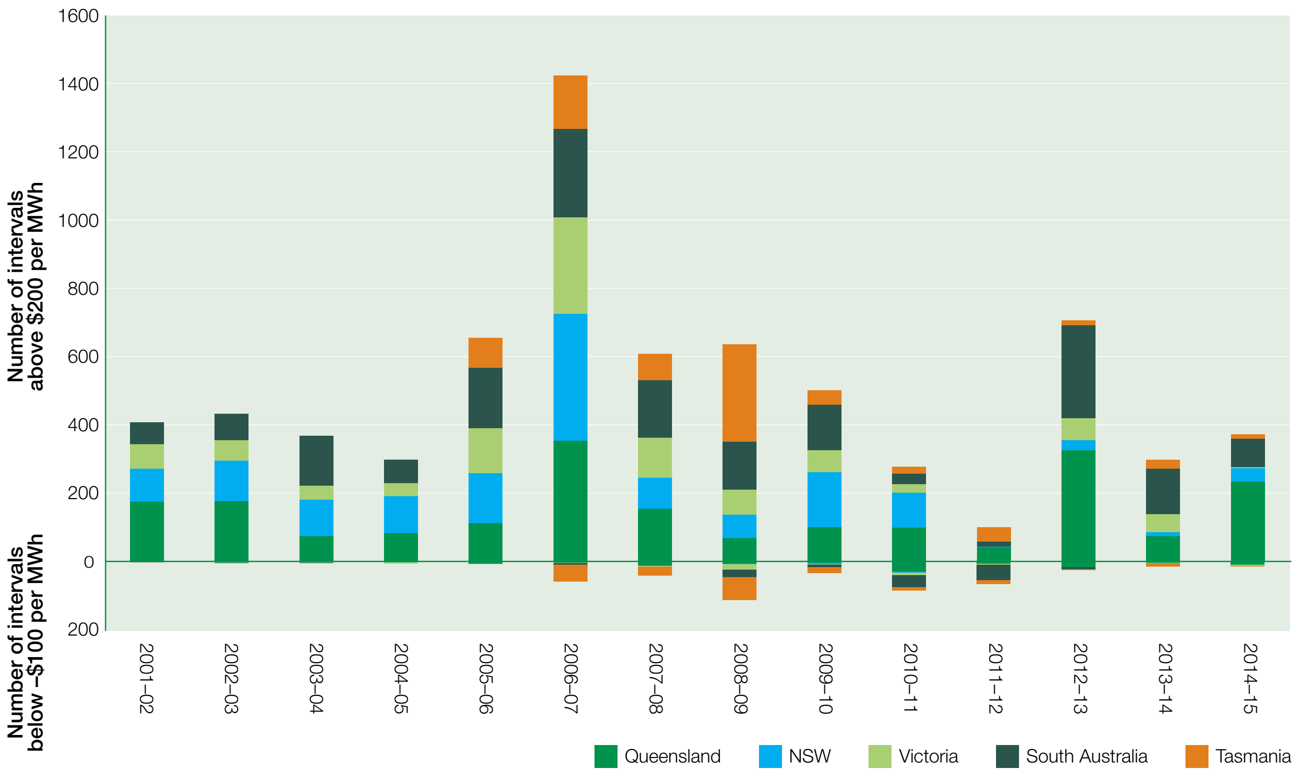


CPT, cumulative price threshold.

Note: Volume weighted average prices.

Sources: AEMO; AER.

Figure 1.21
Market volatility—prices above $200 per MWh and below –$100 per MWh



Sources: AEMO; AER.

The significant price reductions in NSW, Victoria, South Australia and Tasmania reflected:

- the repeal of carbon pricing from 1 July 2014 encouraged baseload (mainly coal) power stations to bid more capacity into the market at lower prices. Tasmanian prices had been less impacted by carbon pricing due to the region's predominance of hydro generation; similarly, the removal of carbon pricing also had a lesser effect.
- continuing weak electricity demand, including from households self-generating through rooftop solar PV generation.

The Queensland market experienced unique conditions that neutralised these downward price influences. Wholesale prices in Queensland adjusted to the carbon removal more quickly than they did elsewhere, falling by 37 per cent in the September 2014 quarter. In the other mainland regions, the pass-through was slower, taking around six months. But Queensland prices diverged markedly from the national trend from November. In the December quarter 2014, Queensland prices ($68 per MWh) more than doubled prices in other mainland regions, despite record low gas fuel prices in spot markets. By the March quarter 2015, Queensland prices ($107 per MWh) almost tripled prices elsewhere. In the June quarter 2015, Queensland prices returned to being comparable with prices in other regions.

1.8.1 Queensland market

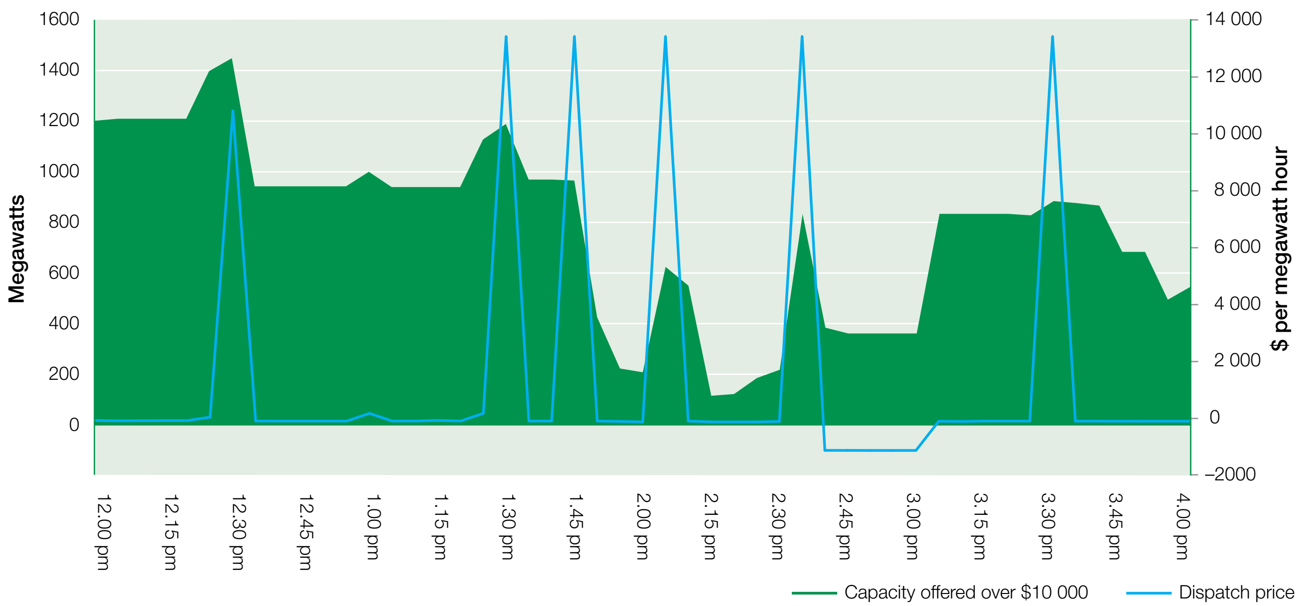
The market structure of Queensland's generation sector is more highly concentrated than other mainland NEM regions, with the state government owning or controlling the dispatch of 64 per cent of generation capacity through Stanwell and CS Energy. The level of concentration increased following the 2011 restructure of the three state owned generators into two.

An interplay of transmission network congestion and opportunistic generator bidding led to spot market volatility in Queensland in August–October 2012 and again in January 2013.[34] The construction of a transmission line

34 AER, *State of the energy market 2013*, pp. 39–42.

Figure 1.22

Queensland spot prices and capacity offers above $10 000 per MWh, 9 December 2014



Source: AER.

between Gladstone and Stanwell (completed late 2013) built out the congestion that made this bidding activity possible. But some generators began using other bidding strategies. In summer 2013–14, CS Energy (and some other generators) periodically rebid capacity from low to high price bands late in a 30 minute trading interval. The bids applied for very short periods of time (usually five to 10 minutes). The behaviour coincided with Queensland summer prices escalating by 23 per cent.[35]

This bidding behaviour was again apparent in 2014–15. From November 2014, generators including Stanwell, CS Energy and Callide periodically rebid large volumes of capacity from low to very high prices late in a trading interval. The strategy was typically used on days of high temperatures and high energy demand, and often when import capability on transmission interconnectors was limited. By rebidding late in a trading interval, other generators lacked time to respond by ramping up their output. Given the settlement price is the average of the six dispatch prices forming a trading interval, a price spike in one dispatch interval will flow through to a high 30 minute settlement price.

To illustrate, figure 1.22 shows Queensland capacity offers above $10 000 per MWh and dispatch prices on 9 December 2014. Generator rebidding is first apparent in the 12–12.30 pm trading interval, with a surge in capacity offers above $10 000 per MWh, leaving little or no available capacity in middle price bands. This last minute rebidding coincided with a spike in the dispatch price to $10 900 per MWh. In total, prices spiked above $10 000 per MWh in six trading intervals.

Volatility peaked on Thursday 5 March 2015, when Queensland's spot price exceeded $5000 per MWh for all but one trading interval from 4.30–7 pm; in the remaining interval, the price reached $4353 per MWh. Prices were volatile for the entire day, with 39 (five minute) dispatch prices at or above $12 900 per MWh. Forecast spot prices (both four and 12 hours ahead) for all intervals ranged from $39 to $60 per MWh.

While a heatwave in Brisbane caused maximum demand to set a new Queensland record on 5 March, and long term network constraints limited electricity imports from NSW, Queensland had 800 MW surplus capacity on the day. Four hours ahead of the price spikes, around 300 MW of capacity was priced between $70 and $12 500 per MWh. Through rebidding, almost all capacity was shifted to higher prices.

35 AER, *State of the energy market 2014*, pp. 48–9.

Table 1.7 Queensland spot prices above $5000 per MWh, 2014–15

	17 DECEMBER 2014	15 JANUARY 2015	18 JANUARY 2015	5 MARCH 2015
Number of events	7	3	1	6
When?	2–5.30 pm (continuous)	5, 6 and 7 pm	5 pm	4.30–7 pm (continuous)
Peak price (per MWh)	$13 499	$12 950	$6 626	$13 166
4 hour forecast prices > $5000	2 of 7	None	None	None
Maximum demand (MW)	8445 (5pm)	8561 (5 pm)	8168 (5 pm)	8969 (record)
Brisbane maximum temperature	38.5	37	36.7	36.1
Late rebidding?	Yes	Yes	Yes	Yes
Principal rebidder	CS Energy	CS Energy	CS Energy	CS Energy

Note: Half hour spot prices.

Source: AER.

Prices above $5000 per MWh

The extent to which Queensland was out of sync with the rest of the market in 2014–15 is apparent in the skewed distribution of high spot prices during the year. Across the NEM:

- 63 per cent of spot prices above $200 per MWh occurred in Queensland (figure 1.21)
- 100 per cent of spot prices above $5000 per MWh occurred in Queensland.

Queensland's $5000 per MWh events were spread over four days: 17 December 2014 (seven events), 15 January 2015 (three events), 18 January (one event) and 5 March (six events). All events occurred on days of high temperatures and high demand, and network constraints affected supply in some instances. But late generator rebidding influenced supply in each instance, often leaving no available capacity in middle price bands. The AER published detailed analysis of the events of each day.[36] Table 1.7 summarises key elements.

Impact on contract markets

Some participants claimed to the AER that price volatility and late rebidding in Queensland caused some energy market traders (including international participants) to incur substantial financial losses. One entity suggested that the links between market fundamentals and prices had broken down, and that sudden changes in bidding behaviour have damaged confidence and significantly reduced Queensland market liquidity.

36 AER, *Electricity spot prices above $5000/MWh*, Queensland, 17 December 2014; Queensland, 15 January 2015; Queensland, 18 January 2015; Queensland, 5 March 2015.

The AEMC in 2015 reported Ernst & Young research that found volatility in the spot market was raising contract prices in forward markets.[37] In effect, participants pay a premium on contract market products to manage the price volatility arising from late rebidding. Ernst & Young estimated late rebidding added around $8 per MWh to Queensland price caps in the December 2014 quarter, and around $7 per MWh in the March quarter 2015. Across the market, this increase represented a cost of around $170 million.[38]

The AEMC also cited research by ROAM[39] and Oakley Greenwood[40] that the occurrence of late rebidding—along with the timing of rebids towards the end of trading intervals—is a phenomenon of the past two years, mainly occurring in Queensland and to a lesser extent South Australia. ROAM confirmed a trend in Queensland during 2013 and 2014 of generators shifting capacity to high price bands towards the end of trading intervals.

The AER drew on its analysis of rebidding activity to support a proposal by the South Australian Minister for Mineral Resources and Energy to strengthen the rebidding in good faith provisions in the Electricity Rules (section 1.10.1.).

37 AEMC, *National Electricity Amendment (Bidding in Good Faith) Rule 2015*, Draft rule determination, 17 September 2015.

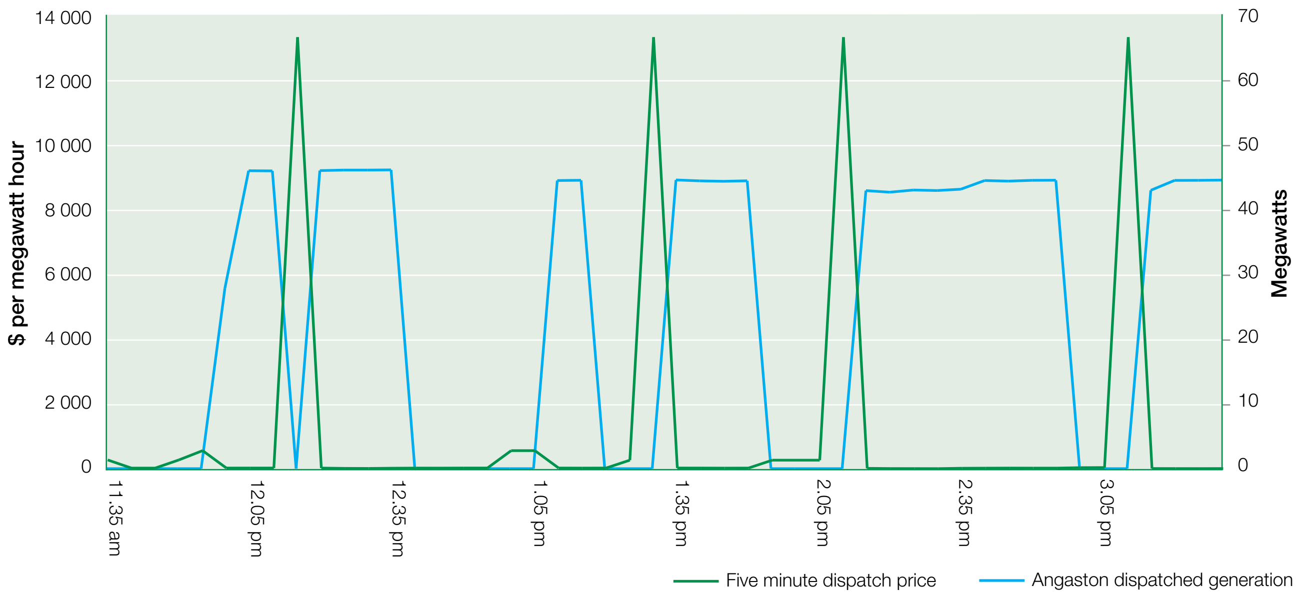
38 Ernst & Young, *Impact of late rebidding on the contract market,* Final report to the AEMC, 11 September 2015.

39 ROAM Consulting, cited in AEMC, *National Electricity Amendment (Bidding in Good Faith) Rule 2015*, Draft rule determination, 17 September 2015, pp. 69–89.

40 Oakley Greenwood, *Generator cost assessment*, Report prepared for AEMC, September 2015.

Figure 1.23

Angaston output and South Australian dispatch price, 10 June 2015



Source: AER.

1.8.2 South Australia market

Spot prices tend to be higher in South Australia than elsewhere, partly reflecting the region's historical reliance on gas powered generation, and its ratio of peak to average demand being higher than in other NEM regions.

The South Australian market has been increasingly volatile since 2007. Relatively concentrated generator ownership, generator rebidding behaviour, thermal plant withdrawals, and limited import capability are contributing factors. South Australia's high levels of wind capacity also contribute to price swings, due to wind's intermittent nature.

Average 2014–15 prices for South Australia were significantly lower than in the previous two years, but remained more than $10 higher than in neighbouring Victoria. South Australia had the highest prices among the regions in the September quarter 2014 and the June quarter 2015. Overall, it recorded 82 price events above $200 per MWh, second only to Queensland (figure 1.21).

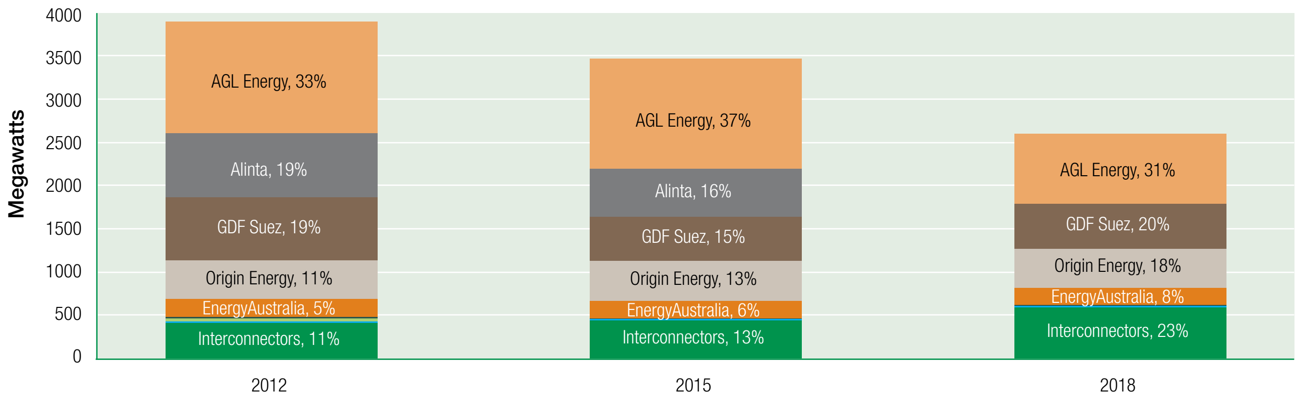
A tightening in the supply–demand balance set the conditions for a series of price spikes (above $2000 per MWh) in June 2015. The part mothballing of Pelican Point withdrew 249 MW of capacity from the South Australian region from April 2015, and a fire at Alinta's Northern Power Station in June 2015 caused extended outages. These events followed Alinta's staged mothballing of its Playford B plant from 2012. In these tight conditions, generator rebidding and strategic changes to the output of non-scheduled plant triggered a series of high prices.

South Australia's non-scheduled generators control capacity equal to around 11 per cent of the region's scheduled capacity. When the demand–supply balance is tight, these generators can rapidly reduce output, causing the 5-minute dispatch price to spike. The generators then boost output for the remainder of the half hour trading interval to capture those high prices. Because non-scheduled generation falls outside the market dispatch process, this behaviour is not transparent, making it difficult for other participants to react to their commercial advantage.

Figure 1.23 illustrates the relationship between Snowy Hydro's non-scheduled output at Angaston and the South Australia dispatch price on 10 June 2015. On that day, Snowy Hydro reacted to an already tight market (with dispatch prices of around $500 per MWh at 11.45 am), by reducing output at its Angaston plant at 12.10 pm. The sudden reduction in output increased South Australia's five minute dispatch price to the cap. Angaston kept generating for enough time to capture significant revenue in the half hour trading interval (which settled above $2000 per MWh). Snowy Hydro repeated this behaviour throughout the afternoon.[41]

41 The AER has previously reported the manipulation of non-scheduled generation to spike prices in other NEM regions, notably in Tasmania in 2009–10.

Figure 1.24
South Australian capacity and ownership



Notes:

Capacity based on summer availability, except wind, which is adjusted for an average contribution factor. Interconnector capacity is based on observed flows when the price differential between regions exceeds $10 per MWh in favour of the importing region; the data exclude trading intervals in which counter flows were observed (that is, when electricity was imported from a high priced region into a lower priced region).

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

Sources: AEMO; AER.

On early indications, South Australia may again experience high prices in 2015–16. In the September quarter 2015, prices for South Australian 2016 base futures rose by 42 per cent, compared with rises of 19 per cent for Queensland, 12 per cent for Victoria and 9 per cent for NSW. The rise in base futures mirrored volatility in South Australian spot prices which, in the September quarter, averaged $69 per MWh—at least 50 per cent higher than in any other region.

Contributing to these prices were low wind generation, network outages around the Heywood interconnector with Victoria, reduced generator capacity at Northern and Pelican Point, and rebidding of capacity by some generators from low to high prices. The late rebids were typically made by AGL Energy or Alinta Energy. Rapid shifts in non-scheduled generation were also evident on some days. The spikes typically happened at times of peak demand associated with cold weather, or coincided with a sudden rise in hot water loads around 11.30 pm.

Volatility spread to South Australia's frequency control ancillary services market in October 2015, when prices rose above $5000 per MW in a number of trading intervals, triggering administered pricing at a $300 per MW cap on three occasions.

The volatility stemmed from planned transmission outages associated with the upgrade to the Heywood interconnector. In October 2015 AEMO changed its approach to managing system security issues in South Australia during the upgrade, giving little warning to the market. The change required some frequency control services (particularly regulation services) to be sourced locally whenever a credible risk arises that network congestion will 'island' South Australia from the rest of the NEM.[42] The change aimed to make services immediately available if South Australia is islanded. But limited sources of frequency control services in the region created opportunities for some generators to rebid capacity into high price bands.

When the Heywood interconnector tripped on 1 November 2015, South Australia was islanded from the rest of the NEM. Because local generation could not ramp up quickly enough to replace Victorian imports, under-frequency load shedding automatically cut 160 MW of customer load, interrupting supply to 110 000 customers. With South Australia islanded, all frequency control services again had to be sourced locally, causing prices to spike above $9000 per MW for 35 minutes.

South Australia market outlook

Upcoming capacity withdrawals may further change dynamics in the South Australian electricity market. Alinta Energy will close its Northern Power Station (546 MW) on 31 March 2016, and AGL Energy will mothball its Torrens Island A plant (480 MW) in 2017. The Heywood interconnector upgrade, scheduled for completion by

42 Previously, the services were locally sourced only after South Australia was separated from the market.

July 2016, may help mitigate this tightening in supply. The upgrade will increase import capability on the interconnector in stages, from 460 MW to 650 MW. But despite the upgrade, current forecasts indicate total capacity (including imports) available to the South Australian region will be significantly lower in 2018 than in 2015 (figure 1.24).

1.9 Electricity contract markets

Volatility in electricity spot prices can pose significant risks to market participants. While generators face a risk of low spot prices reducing their earnings, retailers face a risk of spot prices rising to levels that they cannot pass on to customers. Market participants need to manage their exposure to price risk to ensure financial solvency.

One solution is vertical integration between electricity generators and retailers, which balances the risks in each market. Vertically integrated 'gentailers' in the NEM include AGL Energy, Origin Energy, EnergyAustralia, Snowy Hydro (with retail brands Red Energy and Lumo Energy) and GDF Suez (Simply Energy).

Stand-alone generators (such as Intergen) and retailers (such as Click Energy and M2 Energy) manage their market exposure by entering hedge contracts (derivatives) that lock in firm prices for the electricity that they intend to produce or buy.

Typically, gentailers are imperfectly hedged; their position in generation may be 'short' or 'long' relative to their position in retail. For this reason, the businesses also participate in derivatives markets to manage outstanding exposures. Other participants in electricity derivatives markets include financial intermediaries and speculators such as hedge funds. Brokers facilitate many transactions between contracting participants.

In Australia, two distinct financial markets support the wholesale electricity market:

- over-the-counter (OTC) markets, comprising direct contracting between counterparties, often assisted by a broker
- the exchange traded market, in which electricity futures products are traded on the Australian Securities Exchange (ASX). Participants—including generators, retailers, speculators, banks and other financial intermediaries—buy and sell futures contracts.

The terms and conditions of OTC contracts are confidential between the parties. But exchange trades are publicly reported, so have greater market transparency than do OTC contracts. Exchange traded derivatives are settled through a centralised clearing house, which is the counterparty to all transactions and requires daily market-to-market cash margining to manage credit default risk. In OTC trading, parties rely on the creditworthiness of their counterparties. Increasingly, OTC negotiated contracts are cleared and registered via block trading on the ASX.

Electricity derivatives markets support a range of products. The ASX products are standardised to promote trading, while OTC products can be sculpted to suit the requirements of the counterparties:

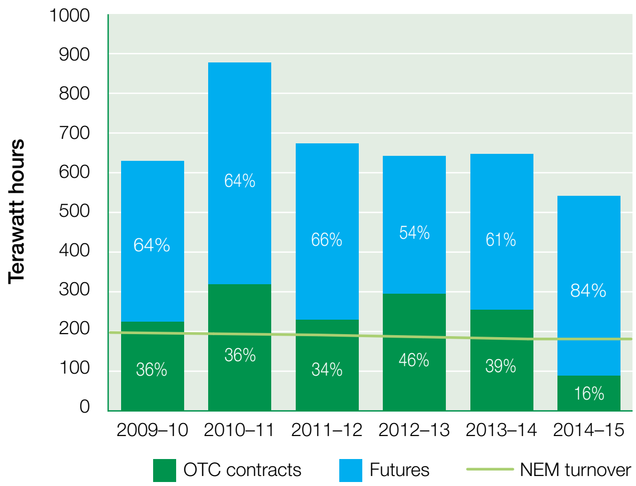
- *Futures* (swaps or contracts for difference in OTC markets) allow a party to lock in a fixed price to buy or sell a given quantity of electricity over a specified time. Each contract relates to a nominated time of day in a particular region. The products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand) for settlement in the future. Futures are also traded as calendar or financial year strips covering four quarters.
- *Options* give the holder the right—without obligation—to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility.

Caps (which set an upper limit on the price that the holder will pay for electricity in the future) and floors (which set a lower price limit) are traded as both futures and options.

Electricity derivatives markets are subject to a regulatory framework that includes the *Corporations Act 2001* (Cth) and the *Financial Services Reform Act 2001* (Cth). The Australian Securities and Investments Commission is the principal regulatory agency.

The complex financial relationships among generators, retailers and other businesses create financial interdependency, meaning financial difficulties for one participant can affect others. In its review of NEM financial market resilience, the AEMC investigated ways to mitigate risk from the financial distress or failure of a large electricity business. One consideration was the possible application of Australia's G20 commitments on OTC derivatives to the electricity sector. The reforms aim to reduce the risk of financial system instability arising from counterparty default, and to increase transparency about OTC market activity. They include the reporting of OTC derivatives to trade repositories, and obligations on the clearing and execution of standardised derivatives.

Figure 1.25
Traded volumes in electricity futures contracts



Sources: AFMA; ASX Energy.

The AEMC advised in March 2015 that the costs of applying the G20 reforms to the electricity sector would outweigh any benefits. It found the reforms would place significant costs and regulatory burdens on participants, and mandatory central clearing could discourage the use of OTCs as a hedging instrument. It argued the development of electronic trading platforms should be driven by participants' demand for such services, rather than being mandated. Further, it was not clear that the measures would effectively manage threats to financial stability in the NEM.[43]

1.9.1 Contract market activity

In 2014–15 contracts covering 534 TWh of electricity were traded in the NEM, comprising 446 TWh traded on the ASX and 88 TWh in OTC markets (figure 1.25). Trading volumes were 38 per cent below their 2010–11 peak, and 16 per cent down on 2013–14 volumes. Overall trading volumes were down from a peak of 450 per cent of underlying NEM demand in 2010–11 to 300 per cent in 2013–14.

Shifts between ASX and OTC trading have been significant in recent years. The Australian Financial Markets Association's (AFMA) addendum to manage the risks of carbon price movements drew significant turnover from the ASX to OTC markets in 2012–13.[44] But this shift has since reversed, with OTC volumes in 2014–15 being 70 per cent lower than in 2012–13. AFMA attributed this decline to the repeal of carbon pricing on 1 July 2014.[45] The decline in OTC trade was partly offset by ASX volumes rising by 30 per cent over the same period.

Electricity futures trading covers instruments for Victoria, NSW, Queensland and South Australia. Queensland accounted for 37 per cent of ASX traded volumes in 2014–15, followed by NSW (35 per cent) and Victoria (26 per cent). Liquidity in South Australia was low, accounting for only 2 per cent. In the OTC market, NSW accounted for 45 per cent of traded volumes, followed by Queensland (38 per cent), Victoria (13 per cent) and South Australia (4 per cent).

The most heavily traded ASX products in 2014–15 were options (71 per cent of volumes). In the OTC market, swaps accounted for almost 74 per cent of trade, followed by caps (20 per cent).

Liquidity is mostly in products traded 18–24 months out—for example, open interest in forward contracts at September 2015 was mostly for quarters to the end of 2016–17, with little liquidity beyond that time. The exception is Queensland, where significant volumes are being traded as far out as the June quarter 2018 (figure 1.26). This behaviour may reflect perceived risks in the Queensland market associated with recent spot market volatility.

1.9.2 Contract prices

Figure 1.27 shows prices of electricity base futures contracts for calendar years 2015 and 2016.

Base futures prices steadily declined in 2013 and through the first half of 2014, in line with expectations that the Australian Government would repeal carbon pricing from 1 July 2014. Prices then stabilised around July 2014, once the contract market had fully factored in the repeal.

Prices for 2015 base futures continued to ease or remain subdued into early 2015 for most regions. The exception was Queensland, where contract prices trended higher and mirrored high spot electricity prices.

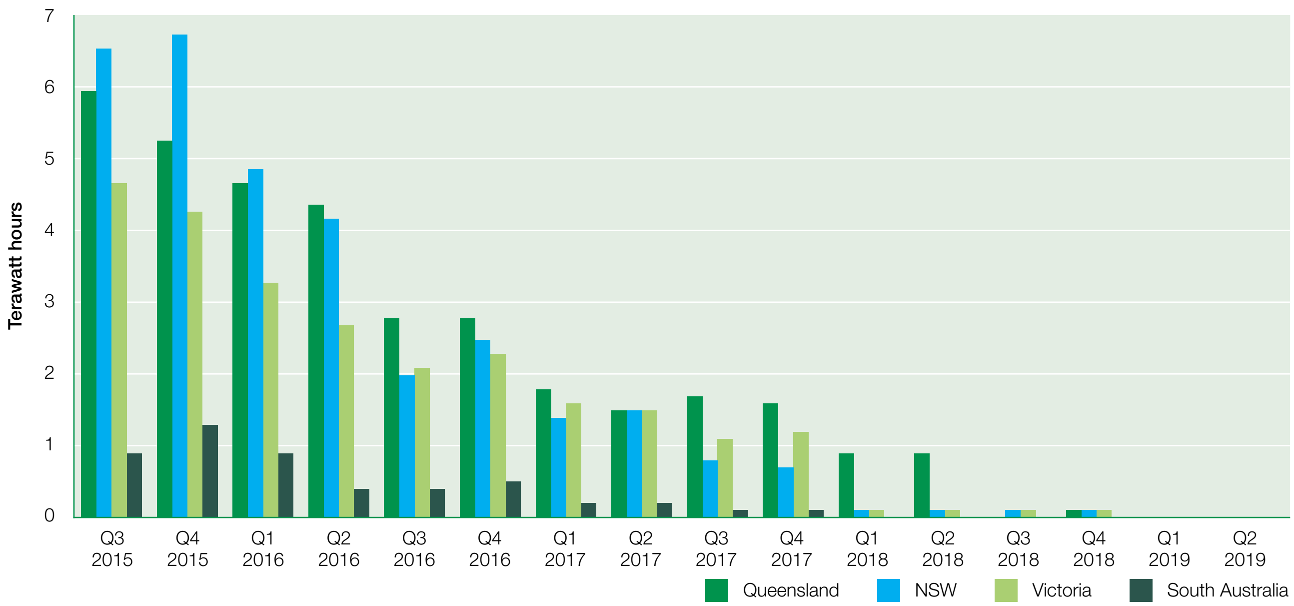
In contrast, prices for 2016 base futures rose across all regions in 2015, but most sharply in South Australia and Queensland. Between 1 July and September 2015, prices for South Australian 2016 base futures rose by 42 per cent, compared with rises of 19 per cent for Queensland, 12 per cent for Victoria and 9 per cent for NSW. Prices reached $75 per MWh in September 2015 (on very low volumes). The rise for South Australia mirrored volatility

43 AEMC, *NEM financial market resilience final report,* March 2015.
44 The AFMA addendum's carbon uplift multiplied the carbon reference price by the NEM's average carbon intensity (published by AEMO).

45 AFMA, *2015 Australian financial markets report*.

Figure 1.26

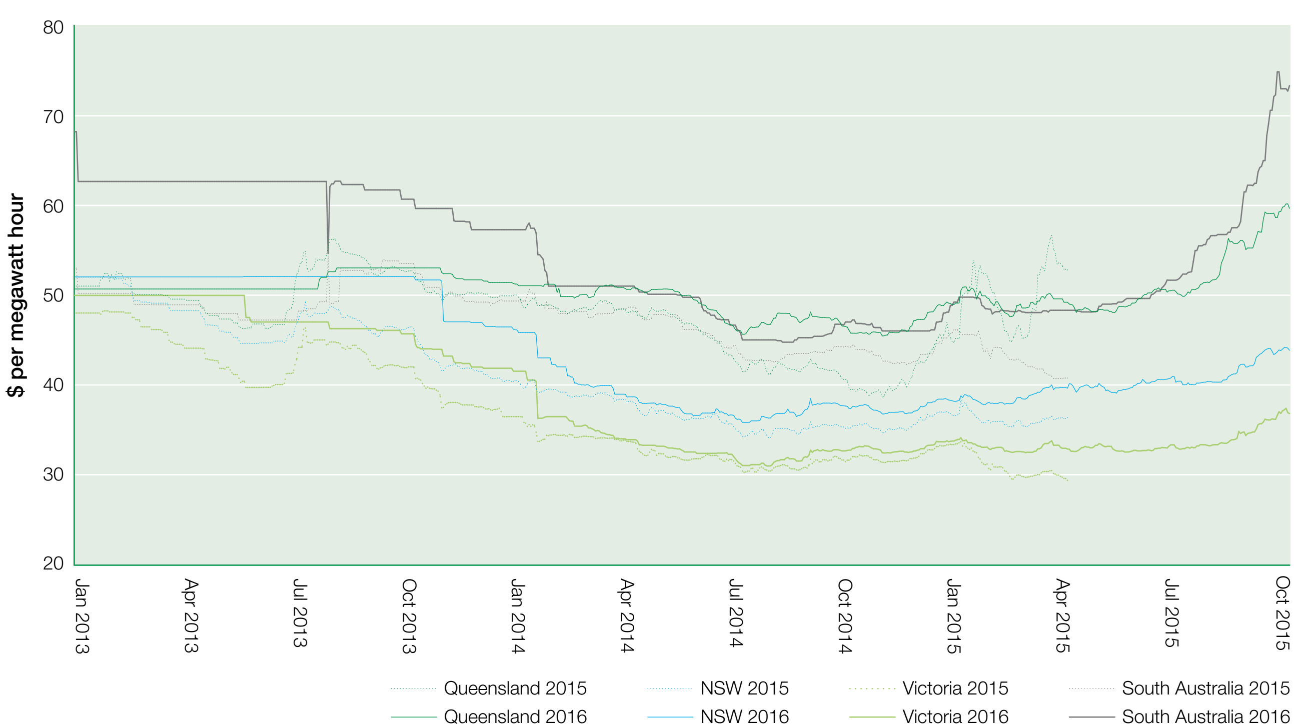
Open interest in electricity derivatives on the ASX, September 2015



Source: ASX Energy.

Figure 1.27

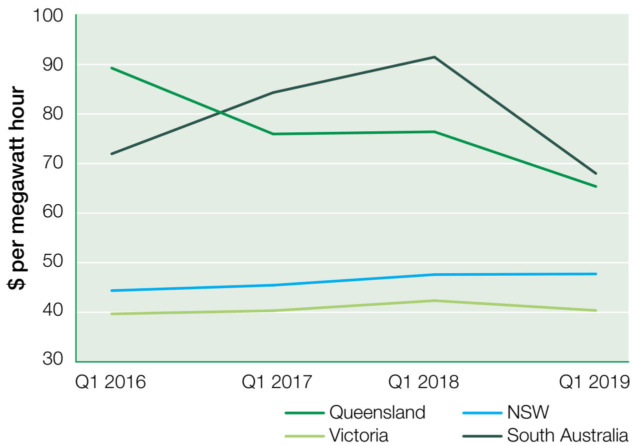
Electricity base futures contracts, calendar year prices



Note: Average daily settlement prices of base futures contracts for the four quarters of the relevant calendar year.

Source: ASX Energy.

Figure 1.28
First quarter base futures prices, by region, September 2015



Source: ASX Energy.

in the region's spot electricity prices. It might also have reflected further plant withdrawals from the region, including the decommissioning of the Northern Power Station in March 2016.

Prices for first quarter base futures prices at September 2015 tell a similar story (figure 1.28), with Queensland and South Australian prices substantially higher than prices in Victoria and NSW. March quarter prices in South Australia rise from $73 per MWh for 2016, to over $90 per MWh for 2018. Queensland's March quarter 2016 price of $90 per MWh possibly reflect market concerns that the region's price volatility in summer 2014–15 will recur in summer 2015–16.

1.10 Improving market efficiency

The COAG Energy Council and stakeholders (including the AER and AEMO) can propose reforms to the Electricity Rules. The AEMC, as rule maker, assesses rule change proposals. In 2014–15, the AER engaged closely with rule change processes governing *bidding in good faith* and *generator ramp rates*.

The AER monitors compliance and, when appropriate, takes enforcement action against participants in alleged breach of the Electricity Rules. Failure to comply with the rules can impair market efficiency. In 2014 the AER instituted proceedings in the Federal Court against a generator for allegedly failing to follow dispatch instructions issued by AEMO.

1.10.1 Rebidding in good faith

In November 2013 the South Australian Government proposed a rule change to address concerns that the NEM's bidding in good faith provisions do not adequately regulate participant behaviour. The provisions require generators to have genuine intent to honour their bids, so long as the material conditions and circumstances on which they were based remain unchanged. The AER supported the South Australian Government's proposal. It submitted that a rising incidence of late rebidding (especially in Queensland and South Australia) was impairing market efficiency by making forecast information less reliable.[46]

The AEMC in December 2015 reformed the good faith provisions. The reforms:

- prohibit offers, bids and rebids that are false, misleading or likely to mislead
- require rebids to be made as soon as practicable after a generator or market participant becomes aware of the change in material conditions or circumstances that prompted the rebid
- require participants to maintain a record of the circumstances surrounding late rebids.[47]

1.10.2 Generator ramp rates

Market efficiency would be enhanced if AEMO could dispatch the lowest cost generation plant at all times. Technical parameters constrain a plant's ability to adjust output (that is, its ramp rate). But the NEM rules allow generators some discretion to set lower ramp rates that would constrain a rapid response to a change in market conditions. This discretion may allow a generator to produce at an inefficient level of output. The NEM rules set a minimum ramp rate of 3 MW per minute for each unit, or 3 per cent of capacity for generators of under 100 MW.

In 2013 the AER proposed a rule change that generators' ramp rates reflect each plant's technical capabilities at the time. It also proposed fast start inflexibility profiles should reflect a plant's technical capabilities. It argued these changes would promote efficient dispatch by allowing the market to respond efficiently to a change in merit order.

In August 2014 the AEMC found the existing provisions governing ramp rates may distort competitive outcomes and investment signals. It thus consulted on alternative ramp rate limits. The AEMC's final rule change (released

46 AER, *Submission: National Electricity Rules amendment—bidding in good faith*, May 2014.

47 AEMC, *Final rule determination, National Electricity Amendment (Bidding in Good Faith) Rule 2015*, 10 December 2015.

March 2015) retained the existing ramp rate limit, but extended it to individual physical units that make up aggregated generation facilities. The change effectively increased minimum aggregate ramp rate capability across the NEM by around 30 per cent.[48] The new rule will apply from July 2016.

1.10.3 Following dispatch instructions

The electricity market operator, AEMO, issues dispatch instructions to generators that ensure supply and demand safely balance at all times. The rules require generators to follow these instructions. A failure to do so may enable a generator to increase its revenue at the expense of efficient prices and power system security.

In July 2014 the AER instituted proceedings in the Federal Court against Snowy Hydro, alleging the business failed to follow dispatch instructions issued by AEMO on nine occasions in 2012 and 2013. The alleged contraventions involved Snowy Hydro's operation of its Murray hydroelectric generating units and Valley Power gas generating units, located in Victoria. In each instance, Snowy Hydro exceeded the target output specified in AEMO's dispatch instructions. The AER alleged Snowy Hydro earned a greater trading amount from each transaction than it would have earned if it had complied with the instructions.

The Federal Court declared seven of the contraventions resulted from Snowy Hydro's failure to afford sufficient importance to compliance with AEMO's dispatch instructions. One contravention resulted from insufficient attention and importance being given to the instructions. The other resulted from a unit being adversely affected by an undiagnosed control system fault at another generating unit.

The Federal Court ordered by consent that Snowy Hydro pay penalties totalling $400 000—the first court ordered penalties for a breach of the National Electricity Rules. In addition, the court ordered by consent that Snowy Hydro appoint an independent expert to review the accuracy of its internal documents for compliance with dispatch instructions. Snowy Hydro provided a copy of the report to the AER in May 2015.

In conjunction with the court orders, Snowy Hydro provided an enforceable undertaking to the AER on the operation of its generators under certain conditions. This enforceable undertaking is the first accepted by the AER under the National Electricity Law.

48 AEMC, *Generator ramp rates and dispatch inflexibility in bidding*, March 2015.

In September 2015 the AEMC began consulting on a rule change request from Snowy Hydro to change the standard for compliance with dispatch instructions. Snowy Hydro contended the current arrangements are unnecessary for the NEM's safe and efficient operation, and impose an unnecessary compliance burden. It argued for a 'reasonable endeavours' approach to compliance with dispatch instructions.

1.11 Reliability of supply

Reliability refers to the continuity of electricity supply to customers. While power outages can originate from the generation or transmission sectors, about 95 per cent of reliability issues in the NEM originate in the distribution network sector.

The AEMC Reliability Panel sets the reliability standard for generation in the NEM. The standard is the expected amount of energy at risk of not being delivered to customers because not enough generation capacity is available. To meet this standard, AEMO determines the necessary spare generation capacity needed for each region (including import capacity) to manage unexpected demand spikes and generation failure.

The NEM's reliability standard is for no more than 0.002 per cent of customer demand in a region to be unserved due to a shortfall in generation capacity, allowing for demand-side response and imports. AEMO sets reserve margins so the reliability standard can be met for each region and NEM-wide. The standard is equivalent to an annual system-wide outage of seven minutes at peak demand.

1.11.1 Reliability settings

The AEMC Reliability Panel recommends price settings that help ensure the reliability standard is met, including:

- a spot market price cap, set at a level to stimulate sufficient investment in generation capacity to meet the reliability standard. The cap was raised to $13 800 per MWh on 1 July 2015.
- a cumulative price threshold that limits the exposure of participants to extreme prices. If cumulative prices exceed this threshold (currently $207 000 per MWh) over a rolling seven days, then AEMO imposes an administered price cap of $300 per MWh.
- a market floor price, set at –$1000 per MWh.

The market price cap and cumulative price threshold are adjusted in line with the consumer price index.

AGL Energy's Broken Hill Solar Plant (image courtesy of AGL Energy)

Other reliability measures

AEMO publishes forecasts of electricity demand and generator availability so generators can respond to market conditions and schedule maintenance outages. Safety net mechanisms allow AEMO to manage short term risks of unserved energy identified in forecasts:

- AEMO can enter reserve contracts with generators under a reliability and emergency reserve trader (RERT) mechanism to ensure reserves are available to meet the reliability standard. When entering these contracts, AEMO prioritises facilities that would least distort wholesale market prices.
- AEMO can use its directions power to require generators to provide additional supply at the time of dispatch to ensure sufficient reserves are available.

1.11.2 Reliability performance

The reliability standard has been breached only twice, in Victoria and South Australia during a heatwave in January 2009. The unserved energy from these events on an annual basis was 0.0032 per cent for South Australia and 0.004 per cent for Victoria.

AEMO has not been required to implement its safety net mechanisms. It engaged the RERT provision in January 2014, when a heat wave caused tight supply conditions in Victoria and South Australia. But the mechanism was not required once capability on the Basslink interconnector increased sufficiently for Tasmanian generation to meet capacity shortfalls on the mainland.

1.12 Barometers of competition in the NEM

The AER monitors a range of structural and behavioural indicators of competitiveness in the NEM. The underlying data:

- are based on offer control over plant
- cover scheduled and semi-scheduled generation units. Wind capacity is scaled by contribution factors that AEMO determines.
- account for import capacity via interconnectors, based on flows when the price differential between an importing and exporting region is at least $10 per MWh.

1.12.1 Structural indicators

The market structure of the generation sector affects the likelihood of, and incentives for, generators to exercise market power. A market structure dominated by a handful of generators—particularly in a region with limited in-flow interconnector capacity—is likely to be less competitive than a market with diluted ownership.

Structural indicators of competitiveness include:

- market shares in capacity (or output)
- the Herfindahl–Hirschman index
- the residual supply index.

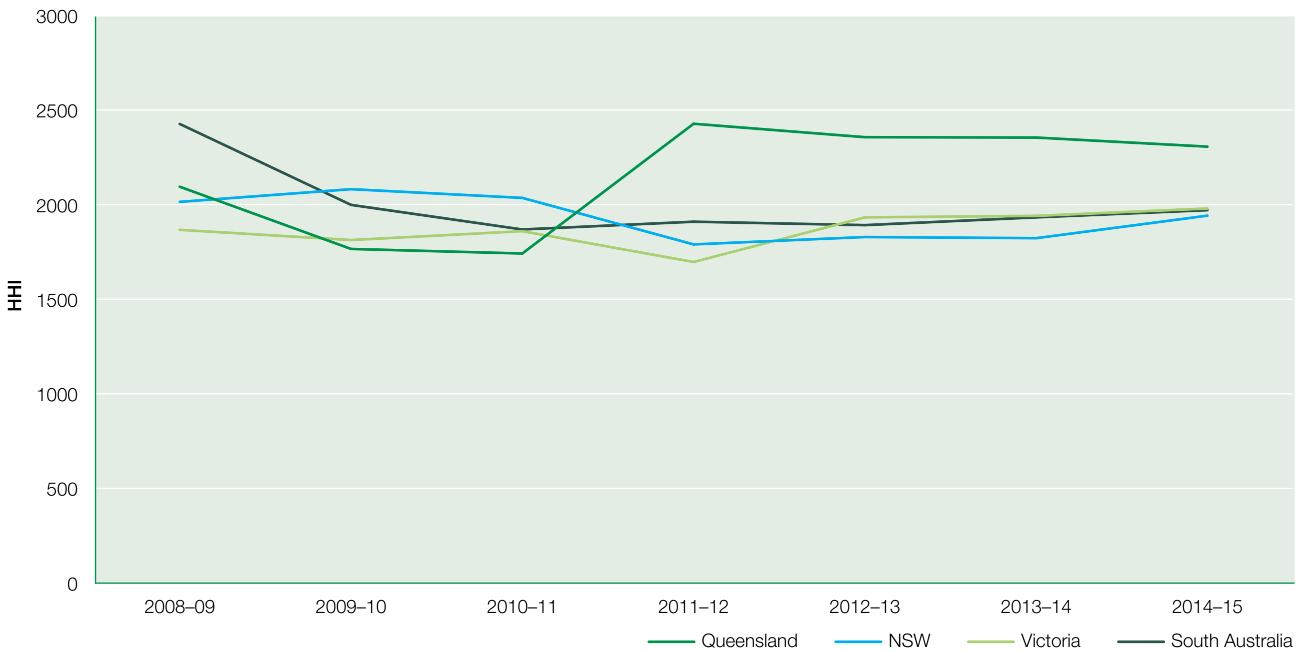
Market share illustrates the degree of concentration in a market, as well as the relative size of each generator. Markets with a high proportion of capacity controlled by one or two generators may be susceptible to the exercise of market power. Figure 1.15 illustrates generation market shares in 2015, based on capacity under each firm's trading control. It indicates the relatively strong market positions held by AGL Energy in South Australia, NSW and Victoria, and by state owned generators in Queensland (CS Energy and Stanwell) and Tasmania (Hydro Tasmania).

The *Herfindahl–Hirschman index* (HHI) accounts for the relative size of firms when analysing market structure. The HHI tallies the sum of squared market shares (in percentages) for all firms in a market. It can range from zero (in a market with many small firms) to 10 000 (that is, 100 squared) for a monopoly. By squaring market shares, the HHI emphasises the contribution of large firms. The higher the HHI, the more concentrated and less competitive is a market.

Figure 1.29 illustrates the HHI across NEM regions from 2008–09 to 2014–15. In Queensland, the index rose in 2011–12 from being the lowest in the NEM to the highest, following a consolidation of state owned generators. The index levels for other regions have recently converged to comparable levels.

But market share and HHI analysis do not account for demand. This deficiency is significant because high demand is generally necessary for market power to be profitably exercised. The *residual supply index* (RSI) measures the extent to which one or more generators is 'pivotal' to the clearing of a market. A generator is pivotal if market demand exceeds the capacity of all other generators; that is, the generator must be dispatched (at least partly dispatched) to meet demand. Multiple generators may be pivotal simultaneously.

Figure 1.29
Herfindahl–Hirschman index



Source: AER.

The RSI–1 measures the ratio of demand that can be met by all but the largest generator in a region. If the RSI–1 is greater than 1, then demand can be fully met without requiring the dispatch of the largest generator. But, if the RSI–1 is below 1, then the largest generator is pivotal.

Figure 1.30 illustrates the RSI–1 in each NEM region since 2008–09 at times of peak demand (the highest 2 per cent of demand trading intervals, equivalent to seven days per year). It also illustrates average demand at peak times. If demand increases, then the RSI–1 likely deteriorates (that is, the largest firm becomes more pivotal). The converse is also true, because weakening demand reduces how pivotal the largest generator is in meeting peak demand.

The data illustrates that the largest generator must usually be dispatched at peak times in all NEM regions. Only in Queensland, in 2010–11, was the largest generator not usually required. Following a consolidation of state owned generators in 2011, Queensland's largest generator (CS Energy) became pivotal at times of peak demand. The most pivotal generator in any NEM region is AGL Energy in South Australia.

The HHI and RSI–1 metrics indicate a gradual improvement in competitive conditions in Victoria until AGL Energy's full acquisition of Loy Yang A (2210 MW) in 2012, which increased market concentration. This shift was partly offset by Origin Energy's commissioning of the gas powered Mortlake plant (566 MW) in late 2012. A significant fall in peak electricity demand in Victoria led to AGL Energy becoming less pivotal in 2014–15. Falling peak demand also contributed to improved RSI–1 data for NSW over the past six years.

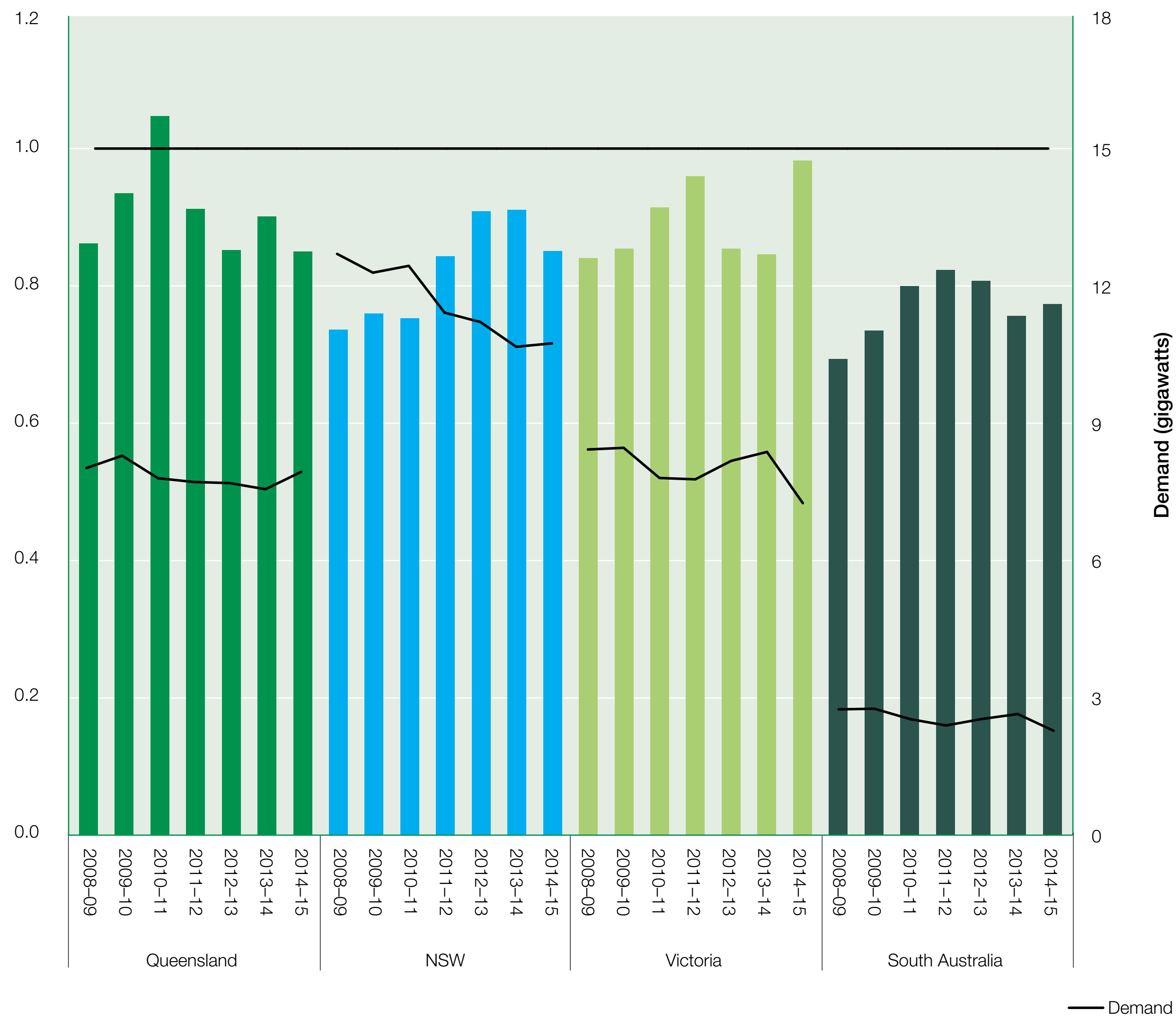
1.12.2 Behavioural indicators

The structural indicators illustrate high levels of market concentration in some NEM regions. But a generator's *ability* to exercise market power is distinct from its *incentive*s to exercise that power, which may link to the generator's exposure to spot or contract prices, or a strategy to deter competitive market entry. Behavioural indicators explore the relationship between a generator's bidding and spot price outcomes.

Figures 1.31–1.34 illustrate the relationship between capacity use and spot prices for a sample of large generators: CS Energy in Queensland, Macquarie Generation (now AGL Energy) in NSW, GDF Suez in Victoria and AGL Energy in South Australia. The data record the average percentage of available capacity that a generator dispatches when prices settle in a range of price bands. In a

Figure 1.30

Residual supply index, excluding largest generator (RSI–1) at times of peak demand



Source: AER.

competitive market, generators typically make greater use of their asset portfolios when prices rise.

As expected, figures 1.33–1.36 show generators tend to increase output as prices rise to around $100 per MWh. But in some years, output by large generators declined when prices entered higher bands. Each region has experienced periods in which its largest generator offered less capacity when prices are above $300 per MWh, than at $50–300 per MWh.

One possible explanation for this behaviour is deliberate capacity withholding to influence spot prices. Other possible explanations include the inability of some generation plant to respond quickly to sudden price movements, and transmission congestion at times of high prices that constrains the dispatch of some plant. Given the data relate to maximum plant availability on the relevant day, technical plant issues might have reduced output during some high price periods to below daily maximum availability.

Figure 1.31

Average annual capacity use, CS Energy (Queensland)

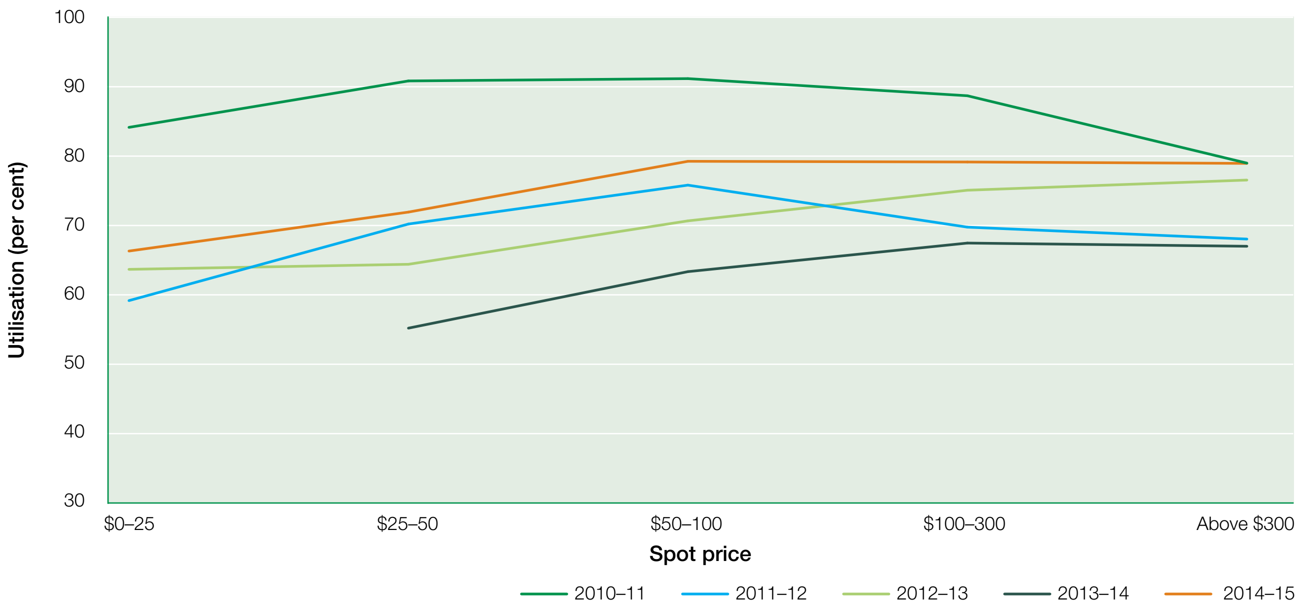


Figure 1.32

Average annual capacity use, Macquarie Generation (NSW)

Figure 1.33

Average annual capacity use, GDF Suez (Victoria)

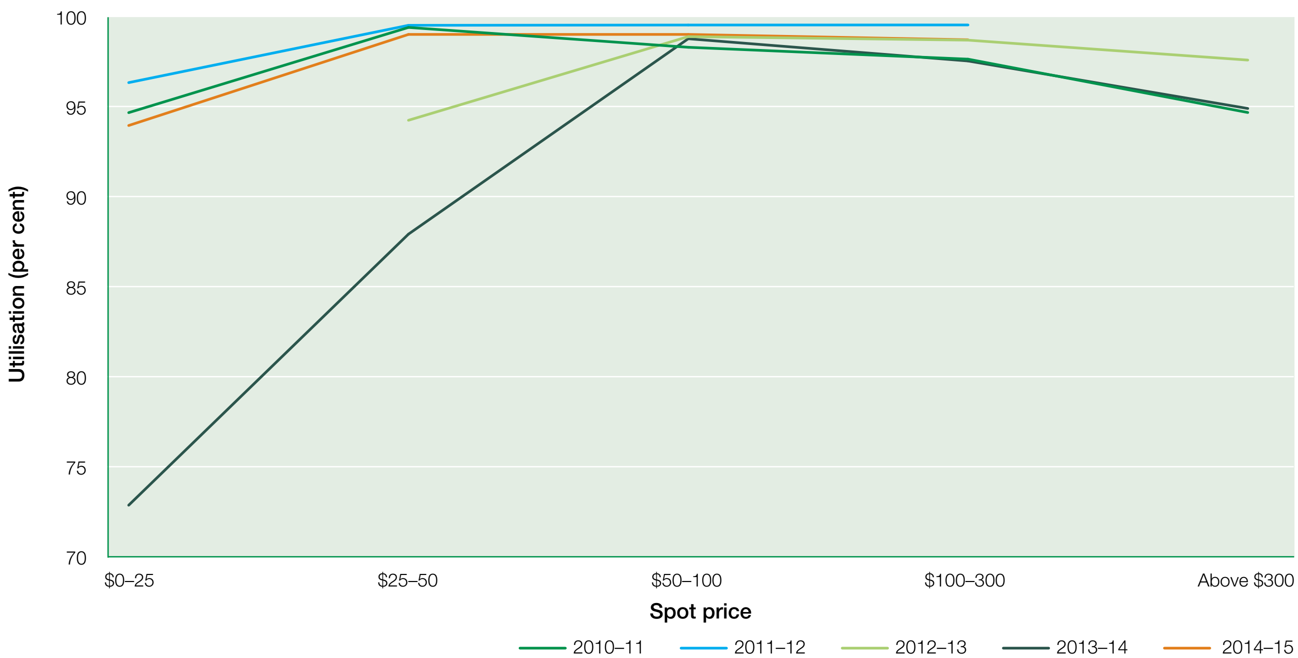


Figure 1.34

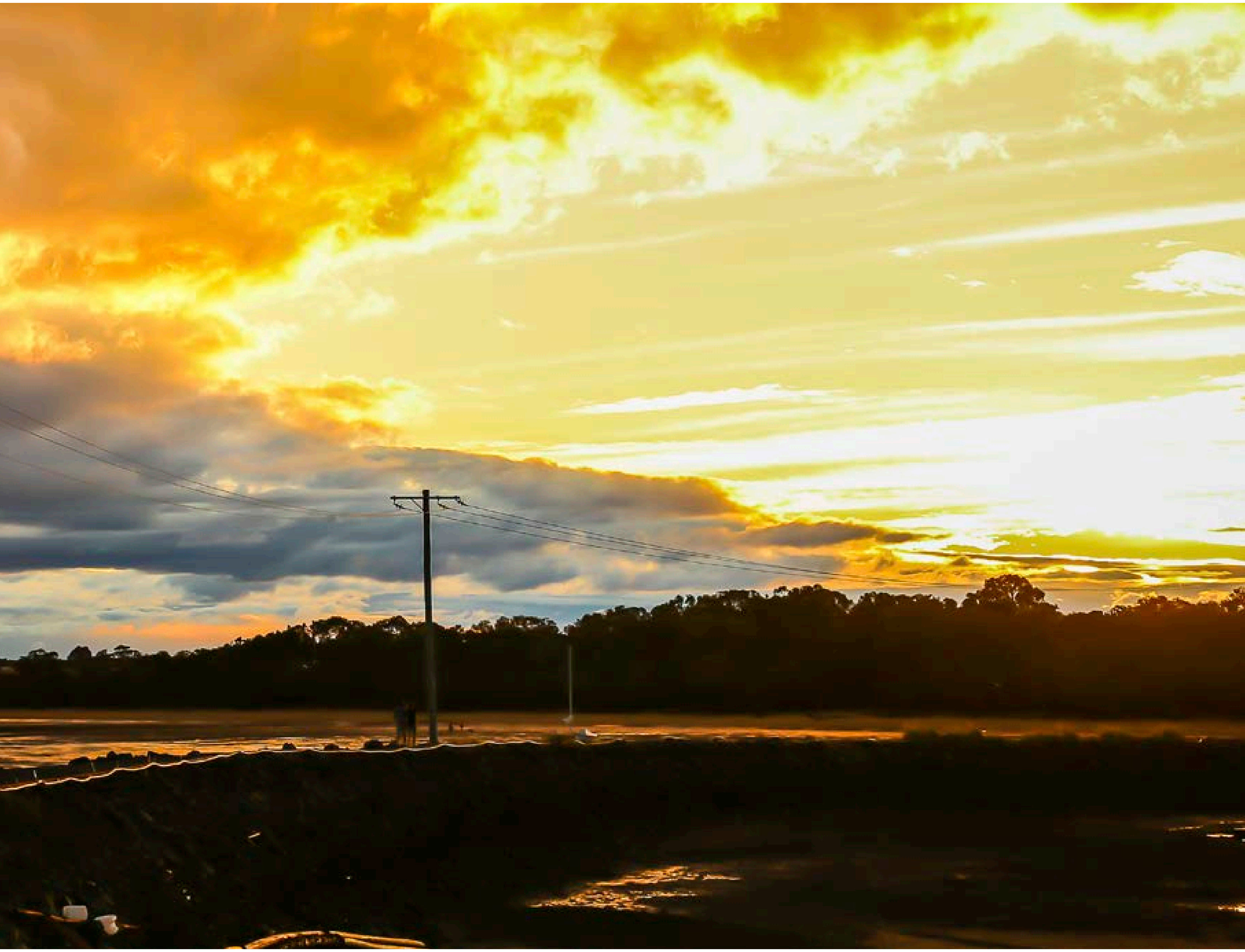
Average annual capacity use, AGL Energy (South Australia)

Note (figures 1.31–1.34): Data excluded if based on fewer than five observations.

Source (figures 1.31–1.34): AER.

Image courtesy of Allison Crowe

2 ELECTRICITY NETWORKS



Electricity networks transport power from generators to customers. *Transmission* networks transport power over long distances, linking generators with load centres. *Distribution* networks transport electricity from points along the transmission network, and criss-cross urban and regional areas to supply electricity to customers.

While energy networks traditionally provided a one-way delivery service to customers, recent technological innovations mean networks can provide a platform for trading a variety of electricity services.

2.1 Electricity networks in the NEM

The National Electricity Market (NEM) in eastern and southern Australia has a fully interconnected transmission network covering Queensland, New South Wales (NSW), the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania. The network has a long, thin, low density structure, reflecting the location of, and distance between, major demand centres. It comprises five state based transmission networks, with six cross-border interconnectors linking the grid (table 2.1).

The NEM has 13 major electricity distribution networks (table 2.2). Queensland, NSW and Victoria each have multiple networks that are monopoly providers in designated areas. The ACT, South Australia and Tasmania each have one major network. Some jurisdictions also have small regional networks with separate ownership. The total length of distribution infrastructure in the NEM is around 730 000 kilometres—17 times longer than the total for transmission. Figure 2.1 illustrates networks in the NEM.

2.1.1 Ownership

Tables 2.1 and 2.2 list ownership arrangements for electricity networks in the NEM. The Queensland and Tasmanian networks are fully government owned. The ACT distribution network has joint government and private ownership.

Until 2015, all NSW networks were fully government owned. The NSW Government in 2015 launched a partial privatisation of its networks, separately offering 99 year leases for TransGrid (transmission) and for 50.4 per cent of the AusGrid and Endeavour Energy distribution networks. The rural Essential Energy distribution network will remain in government hands. A consortium led by Hastings Funds Management (20 per cent) and Spark Infrastructure (15 per cent) won the TransGrid tender in November 2015.

All transmission networks in Victoria and South Australia, and the three NEM interconnectors (Directlink, Murraylink and Basslink) are privately owned. Victoria's five distribution networks are privately owned, and the South Australian distribution network is leased to private interests:

- *Cheung Kong Infrastructure* and *Power Assets* jointly have a 51 per cent stake in two Victorian distribution networks (Powercor and CitiPower) and a 200 year lease of the South Australian distribution network (SA Power Networks). The remaining 49 per cent of the two Victorian networks is held by *Spark Infrastructure*, which is a publicly listed infrastructure fund in which Cheung Kong has a direct interest.
- *Singapore Power International* has a minority ownership in Jemena, which owns the Jemena distribution network in Victoria and part owns the United Energy (Victoria) and ActewAGL (ACT) distribution networks. Singapore Power International also has a 51 per cent stake in AusNet Services, which owns Victoria's transmission network and the AusNet Services distribution network.
- *State Grid Corporation of China* entered the Australian market in 2012. It has a 41 per cent stake in the South Australian transmission network (ElectraNet), a 60 per cent stake in Jemena, and a 20 per cent share in AusNet Services. Jemena and AusNet Services also own or have equity in the gas pipeline sector (chapter 4).

Victoria has a unique transmission network structure that separates asset ownership from planning and investment decision making. AusNet Services owns the state's transmission assets, but the Australian Energy Market Operator (AEMO) plans and directs network augmentation. AEMO also buys bulk network services from AusNet Services for sale to customers.

In some jurisdictions, ownership of electricity networks overlaps with other industry segments, with ring fencing arrangements for operational separation:

- In the ACT, common ownership occurs in electricity distribution and retailing.[1]
- In Queensland, the state owned Ergon Energy provides distribution and retail services.
- Tasmania had common ownership in electricity distribution and retailing until 1 July 2014, when the Tasmanian Government merged the Transend transmission and Aurora Energy distribution networks to form TasNetworks. Aurora Energy became a stand-alone retailer.

1 In the ACT, ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. AGL Energy and Singapore Power International respectively own the remaining shares.

Figure 2.1
Transmission grid and distribution networks in the National Electricity Market

QNI, Queensland–NSW Interconnector.

Table 2.1 Electricity transmission networks

NETWORK	LOCATION	LINE LENGTH (CIRCUIT KM)	ELECTRICITY TRANSMITTED (GWH), 2013–14	MAXIMUM DEMAND (MW), 2013–14[1]	ASSET BASE ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS							
Powerlink	Qld	14 773	47 614	10 914	6 569	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	12 930	62 000	16 700	5 834	1 July 2014–30 June 2018	Hastings 20%, Spark Infrastructure 15%, other private equity 65%
AusNet Services	Vic	6 573	na	na	2 539	1 Apr 2014–30 Mar 2017	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
ElectraNet	SA	5 529	13 957	4 191	1 994	1 July 2013–30 June 2018	State Grid Corporation 46.5%, YTL Power Investments 33.5%, Hastings 20%
TasNetworks	Tas	3 504	13 360	2 449	1 236	1 July 2014–30 June 2018	Tasmanian Government
NEM TOTALS		43 309	136 931		18 321		
INTERCONNECTORS[3]							
Directlink	Qld–NSW	63				1 July 2015–30 June 2020	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180				1 July 2013–30 June 2018	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375				Unregulated	Publicly listed CitySpring Infrastructure Trust

GWh, gigawatt hours; MW, megawatts.

1. Transmission system non-coincident, summated maximum demand.
2. Asset bases are at June 2014 (December 2014 for Victorian businesses).
3. Only stand-alone interconnectors are listed. The unlisted interconnectors, which form part of state based networks, are Heywood (Victoria–South Australia), QNI (Queensland–NSW) and NSW–Victoria.

Sources: AER regulatory determinations and benchmarking regulatory information notices (RINs).

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (CIRCUIT KM)	ELECTRICITY DELIVERED (GWH), 2013–14	MAXIMUM DEMAND (MW), 2013–14[1]	ASSET BASE ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 376 483	52 097	20 838	5 038	10 880	1 Jul 2015–30 Jun 2020	Qld Government
Ergon Energy	721 930	160 083	13 716	3 196	9 007	1 Jul 2015–30 Jun 2020	Qld Government
NEW SOUTH WALES AND ACT							
AusGrid	1 651 160	41 271	25 523	4 977	14 555	1 Jul 2015[4]–30 Jun 2019	NSW Government
Endeavour Energy	940 029	35 492	15 637	3 815	5 698	1 Jul 2015[4]–30 Jun 2019	NSW Government
Essential Energy	854 231	183 481	12 030	2 327	6 881	1 Jul 2015[4]–30 Jun 2019	NSW Government
ActewAGL	178 710	5 151	2 830	615	848	1 Jul 2015[4]–30 Jun 2019	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%
VICTORIA							
Powercor	765 241	74 181	10 333	2 484	3 121	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
AusNet Services	685 194	44 842	7 448	1 880	3 190	1 Jan 2011–31 Dec 2015	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
United Energy	658 453	12 823	7 696	2 198	1 930	1 Jan 2011–31 Dec 2015	DUET Group 66%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 34%
CitiPower	325 917	4 481	5 919	1 507	1 707	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
Jemena	318 429	6 161	4 136	1 029	1 106	1 Jan 2011–31 Dec 2015	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SOUTH AUSTRALIA							
SA Power Networks	851 767	88 083	10 603	3 066	3 638	1 Jul 2015–30 Jun 2020	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
TASMANIA							
TasNetworks	280 750	22 496	4 112	242	1 520	1 Jul 2012–30 Jun 2017	Tasmanian Government
NEM TOTALS	9 608 292	730 642	140 821		64 081		

1. Non-coincident, summated, raw system, annual maximum demand at the zone substation level.
2. Asset bases are at June 2014 (December 2014 for Victorian businesses).

Sources: AER regulatory determinations and benchmarking RINs.

2.1.2 Scale of the networks

Tables 2.1 and 2.2 show the asset values of NEM electricity networks, as measured by the regulated asset base (RAB). In general, the RAB reflects the replacement cost of a network when it was first regulated, plus subsequent new investment, less depreciation. The combined RABs of distribution networks in the NEM is $64 billion—over three times the valuation for transmission infrastructure ($18 billion).

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining average costs as output rises. So, network services in a particular geographic area can be most efficiently provided by a single supplier, leading to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing. The Australian Energy Regulator (AER) sets the amount of revenue that network businesses can recover from customers for using electricity networks in the NEM and, from 1 July 2015, in the Northern Territory.

Western Australia announced a transfer of network regulation functions from the Economic Regulation Authority to the AER from 2017, pending legislative approval and other regulatory processes. The AER consulted with Western Australian officials in 2015 on these changes.

2.2.1 Regulatory process and approach

The National Electricity Law sets the regulatory framework for electricity networks. Its objective is to promote efficient investment in, and operation of, electricity services for the long term interest of consumers. The law also sets out revenue and pricing principles, including the principle that network businesses should have a reasonable opportunity to recover at least efficient costs.

Regulated electricity network businesses periodically apply to the AER to assess their forecast expenditure and revenue requirements (typically, every five years). Chapters 6 and 6A of the National Electricity Rules set the framework that the AER applies in undertaking this role for distribution and transmission networks respectively.

The AER assesses a network business's forecasts of the revenue that the business requires to cover its efficient costs and an appropriate return. It uses a building block model that accounts for a network's operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and for a return on capital. Figure 2.2 illustrates revenue components for the Tasmanian transmission network (for the regulatory period 2015–19) and the NSW distribution network (for 2015–19).

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

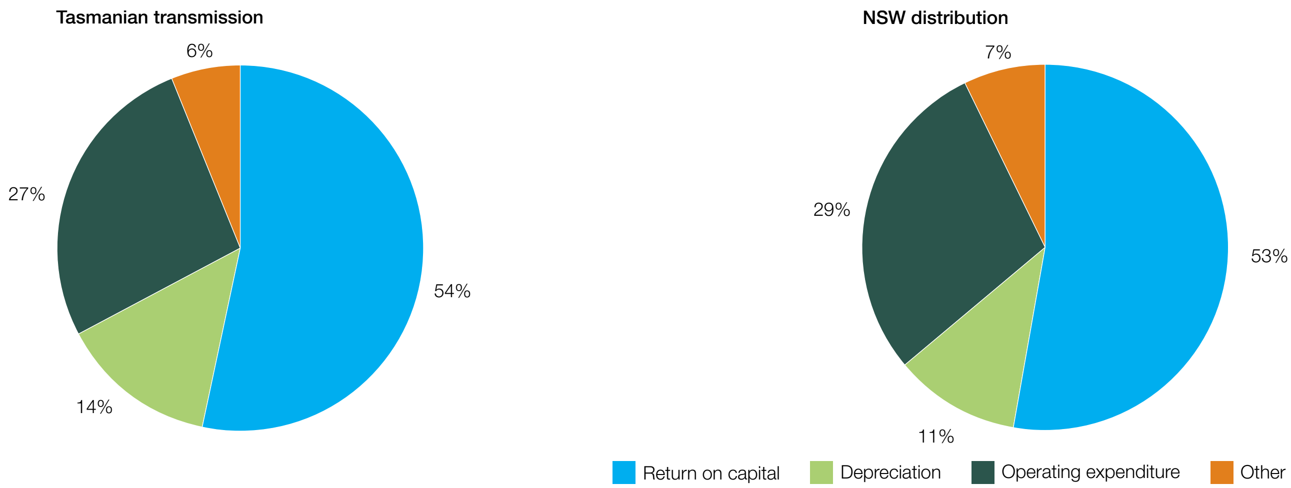
While the regulatory frameworks for transmission and distribution are similar, they do differ. In transmission, the AER determines a cap on the maximum revenue that a network can earn during a regulatory period. In distribution, the range of control mechanisms is wider, and the AER may set a ceiling on the revenue or prices that a distribution business can earn or charge during a period:

- In Queensland, NSW, South Australia and Tasmania, revenue caps set a ceiling on total revenue that a network may recover during a regulatory period.
- In the ACT, an average revenue cap (revenue yield) links revenue to volumes of electricity sold.
- In Victoria, weighted average price caps allow flexibility in individual tariffs within an overall ceiling. The networks will switch to revenue caps from 1 January 2016.

The regulatory process for an energy network begins with preliminary consultation on the framework and approach for the determination, around two years before the current regulatory period expires. The network business, in consultation with its customers, then develops a revenue proposal. The AER assesses the proposal in consultation with stakeholders, and takes advice from its Consumer Challenge Panel. The AER must publish a final decision on the proposal at least two months before the regulatory period starts.

Recent reforms encourage network businesses to seek more efficient ways of operating, to ensure consumers pay no more than necessary for a safe and reliable electricity supply. The measures support investment in essential services without requiring consumers to fund excessive returns to network businesses. The reforms include schemes that incentivise network businesses to invest and spend efficiently, and to share efficiency benefits with

Figure 2.2
Indicative composition of electricity network revenues



Source: AER.

consumers.[2] Additionally, the reforms introduced a greater emphasis on benchmarking to assess network proposals.

The reforms first applied to regulatory determinations taking effect in 2015 for transmission networks in NSW and Tasmania, and for distribution networks in NSW, Queensland, South Australia and the ACT.

2.2.2 Regulatory timelines and recent AER activity

Figure 2.3 shows the regulatory timelines for electricity networks in each jurisdiction. In 2015 the AER issued:

- final determinations for transmission networks in NSW and Tasmania, and for the Directlink interconnector between Queensland and NSW
- final determinations for distribution networks in Queensland, NSW, South Australia and the ACT
- preliminary decisions for the Victorian distribution businesses for regulatory periods commencing 1 January 2016.

The determinations approved total recoverable revenue of $44 billion, compared with the network businesses' proposed $57 billion—a reduction of 23 per cent.

Figure 7 in the Market overview estimates how AER decisions made in 2015 may affect distribution network costs for a typical residential customer, based on information available at the time of the decisions. Distribution costs are forecast to be around $250 lower for a NSW customer in 2015–16 than immediately before the current regulatory period. The reduction for Queensland, South Australia and ACT customers is around $100–200. The reduction in network charges for a Victorian customer (based on the AER's preliminary decisions) will likely be around $50 in 2016. The smaller reduction for Victoria reflects that its networks already operate relatively efficiently.

In addition to revenue determinations, the AER undertakes other regulatory functions. It undertakes annual tariff compliance reviews of distribution businesses; assesses network proposals on cost pass-throughs and contingent projects; develops and applies service incentive regimes, ring fencing policies and other guidelines; and assists in access and connection disputes. The AER also monitors the compliance of network businesses with the National Electricity Rules, and reports on outcomes, including in quarterly compliance reports.

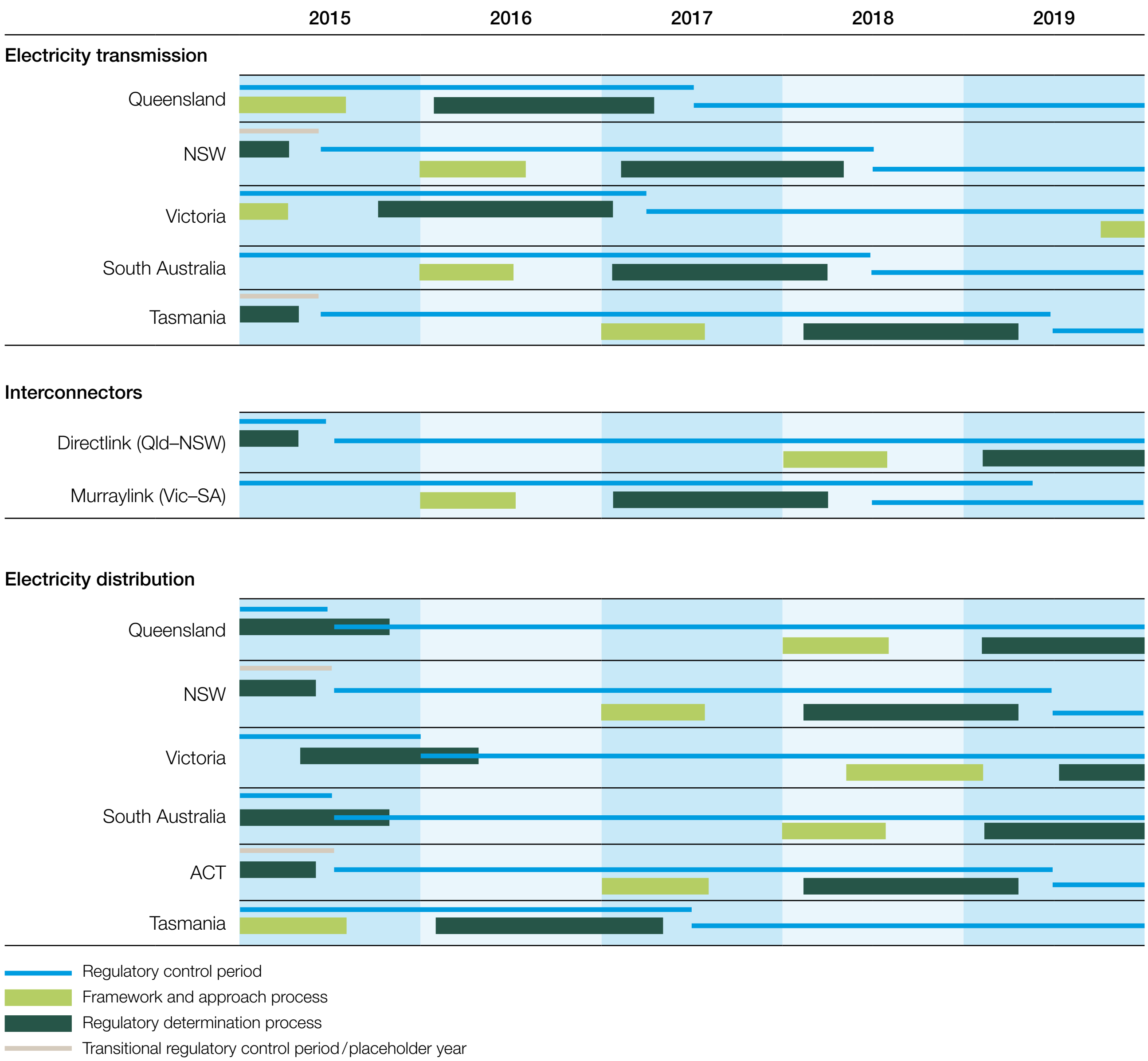
The scope of the AER's annual tariff compliance reviews will widen in future years, when the AER will assess whether distribution businesses' tariff structures are cost reflective.

2.2.3 Merits review by the Australian Competition Tribunal

The National Electricity Law allows network businesses to apply to the Australian Competition Tribunal for a limited review of an AER determination. To have a decision amended on review, the network business must

2 For a summary of the reforms, see AER, *State of the energy market 2013*, table 2.3, pp. 66–7.

Figure 2.3
Indicative timelines for AER determinations on electricity networks



Source: AER.

demonstrate the AER erred, and that addressing the grounds of appeal would lead to a materially preferable outcome in the long term interests of consumers. The Tribunal may intervene in an AER decision only if it forms the view that the AER:

- made an error of fact that was material to its decision, or
- incorrectly exercised its discretion, having regard to all the circumstances, or
- made an unreasonable decision, having regard to all the circumstances.

In making its decision, the Tribunal must consider the determination as a whole, how the parts of the determination interrelate, and any linked matters. It must also consult with relevant users and consumers. If the Tribunal finds the AER erred and addressing the error would likely lead to a materially preferable decision, then it can substitute its own decision or remit the matter back to the AER for consideration. Otherwise, it must affirm the AER's decision.

In March 2015 the owners of the NSW and ACT distribution networks applied to the Tribunal for merits reviews of the AER's determinations. In particular, the businesses sought review of the AER's approach to determining efficient operating costs (including the use of benchmarking), the regulated rate of return and tax costs. The Public Interest Advocacy Centre also applied for a review of the AER's determinations on the NSW networks. It too focused on rate of return issues and the use of operating expenditure benchmarks, but argued the AER decisions provided for networks to recover excessive revenue from consumers.

The Tribunal concluded its hearings on the NSW and ACT applications in October 2015, with decisions expected in late 2015. The outcomes have potential for significant changes in network revenue.

The NSW and ACT businesses also filed applications with the Federal Court for judicial review of the AER's decisions.

In November 2015 SA Power Networks and the South Australian Council of Social Service separately applied for merits review of the AER's determination for the South Australian electricity distribution network. SA Power Networks also applied for judicial review of the decision.

2.3 Electricity network revenue

Figure 2.4 sets out recoverable revenues for electricity networks as determined by the AER for the current regulatory periods, compared with previous periods. Combined network revenue was forecast at $12 billion per year in the current regulatory cycle, comprising $2.6 billion for transmission and $9.4 billion for distribution. The main revenue drivers are capital financing (section 2.3.1), capital expenditure (section 2.4) and operating costs (section 2.5).

Rising network costs drove escalating revenues and charges for several years. Costs rose to replace ageing assets, meet stricter reliability and bushfire (safety) 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.

These pressures have eased more recently, lowering revenue and investment requirements for energy networks. In particular, energy demand has declined, and is expected to remain below historical peaks in most regions for at least the next decade.[3] This decline coincided with reductions in capital financing costs (see below) and governments moving to provide electricity network businesses with greater flexibility in meeting reliability requirements.

These developments account for a recent flattening out of network revenues. In AER determinations made from 2012 to 2015, revenues that networks can recover from customers are forecast to be 9 per cent lower, on average, than in previous regulatory periods. By comparison, recoverable revenues rose by an average 30 per cent in determinations made between 2009 and 2011.

2.3.1 Capital financing

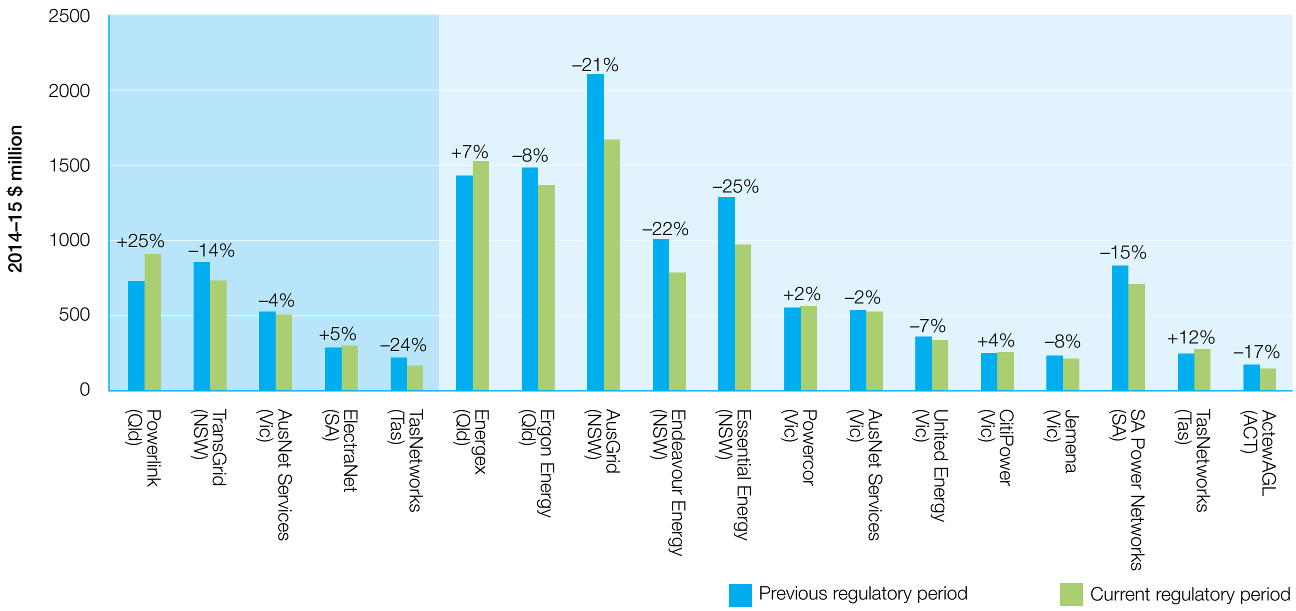
Electricity network businesses are capital intensive, so even a small change to the return earned on assets will significantly affect revenue. As an example, a 1 per cent increase in the cost of capital for Endeavour Energy in the AER determination for 1 July 2014 to 30 June 2019 would have increased the network's revenue by over 8 per cent.

In AER determinations made from 2009 to 2011, rising debt risk premiums (reflecting the cost of borrowing based on default risk) resulted in forecast capital costs being higher than in previous regulatory periods (figure 2.5). Issues in global financial markets reduced liquidity in debt markets and increased perceptions of risk from late 2008, pushing up the cost of borrowing and equity financing.

AER determinations made since 2012 reflect that reductions in the risk-free rate and market and debt risk premiums have lowered the cost of capital. The overall cost of capital in electricity determinations declined from a peak of over 10 per cent in 2010, to average 6.21 per cent in

3 AEMO, *National electricity forecasting report*, 2015.

Figure 2.4
Annual electricity network revenue



Notes:

Current regulatory period revenues are forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.

Data for the Victorian distribution networks are from the AER's preliminary decisions for the regulatory period commencing 1 January 2016.

Sources: AER regulatory determinations.

determinations made in 2015 (figure 2.5). Under a revised framework that the AER applied for the first time in these decisions, the cost of capital will be updated annually to reflect changes in debt costs.

2.4 Electricity network investment

New investment in electricity networks includes augmentations (expansions) to meet demand and replace ageing assets. The regulatory process offers incentives for efficient investment. At the start of a regulatory period, the AER forecasts an efficient level of investment (capital expenditure). If the network exceeds this level, then it will face lower returns. But if it operates with less investment, then its returns may increase. The AER can also approve contingent projects that are foreseen at the time of a determination, but that involve significant timing or cost uncertainty.

While individual network businesses make investment decisions, AEMO (in its role as national transmission planner) provides high level planning and coordination of the transmission network. It publishes a national transmission network development plan that provides a long term strategic outlook.

2.4.1 Regulatory investment tests

The regulatory process forecasts a network's total efficient investment requirements. A separate regulatory investment test must be applied to each large individual project to determine whether it efficiently meets an identified need, or whether an alternative would be more efficient. The regulatory tests for transmission (RIT-T) and distribution (RIT-D) require network businesses to assess an investment proposal against a market based cost–benefit analysis. The business must identify the purpose of a proposed investment and assess the proposal against other credible options for achieving that purpose, including non-network options. The business must publicly consult as part of the test.

The tests only apply to augmentation expenditure, which in recent years accounted for the bulk of network investment. But forecasts of flat maximum demand growth over the next decade have scaled back new investment proposals. In distribution, some augmentations may be driven by

Figure 2.5

Weighted average cost of capital—electricity and gas distribution

Note: Nominal vanilla weighted average cost of capital.

Source: AER.

the release of new areas for residential, commercial and industrial development. One RIT–T assessment (to accommodate additional forecast load throughout the Lower Eyre Peninsula) and five RIT-D assessments (three in Victoria, one in Queensland and one in NSW) commenced in 2014–15.

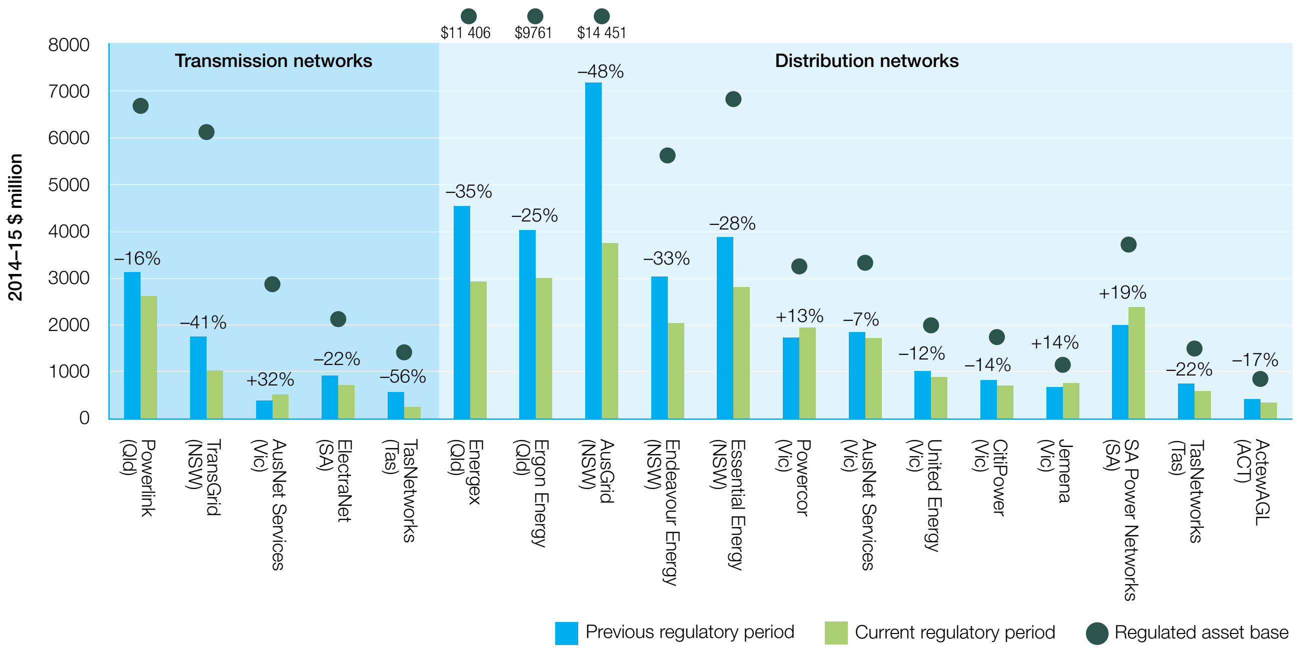
In the current market environment, replacement expenditure exceeds augmentation expenditure for distribution networks (section 2.4.2). The growth in replacement expenditure prompted the AER in 2015 to consult on a proposal to widen the scope of regulatory investment tests to include this form of investment. The change would impose new reporting requirements on network businesses to justify asset retirement decisions and allow interested parties to propose alternatives to asset replacement. The AER will submit a rule change proposal to the Australian Energy Market Commission (AEMC) to implement this extension of the regulatory tests in 2016.

2.4.2 Investment trends

Figure 2.6 illustrates the AER's assessment of efficient investment requirements for electricity networks in the current regulatory periods compared with previous periods. The asset base for each network is shown as a scale reference. Investment drivers vary across networks and depend on a network's age and technology, load characteristics, the demand for new connections, and licensing, reliability and safety requirements.

Network investment over the current regulatory cycle is forecast at $5.2 billion for transmission networks and $24 billion for distribution networks. Current determinations (made since 2012) assessed efficient investment requirements that are 25 per cent lower, on average, than levels in previous periods. Weakening industrial and residential energy use, along with less stringent reliability obligations on the network businesses, have led networks to reduce planned network investment and defer other projects. In contrast, AER determinations made from 2009 to 2011 provided for investment to rise by 46 per cent to replace ageing assets, meet higher reliability standards,

Figure 2.6
Electricity network investment



Notes:

Regulated asset bases are at the beginning of the current regulatory periods.

Investment data reflect forecast capital expenditure for the current regulatory period (typically, five years), amended for merits review decisions by the Australian Competition Tribunal. See tables 2.1 and 2.2 for the timing of current regulatory periods. The data include capital contributions and exclude adjustments for disposals.

Sources: AER regulatory determinations.

and respond to forecasts made at the time of rising peak demand.

Current investment forecasts reflect a declining need for network augmentations in particular. The current determinations for distribution networks forecast $7.9 billion of replacement expenditure, compared with $3.6 billion of augmentation expenditure (that is, $2.20 of replacement expenditure for every dollar of augmentation). But, from 2008–13, only $0.80 was spent on replacement assets for every dollar of augmentation.

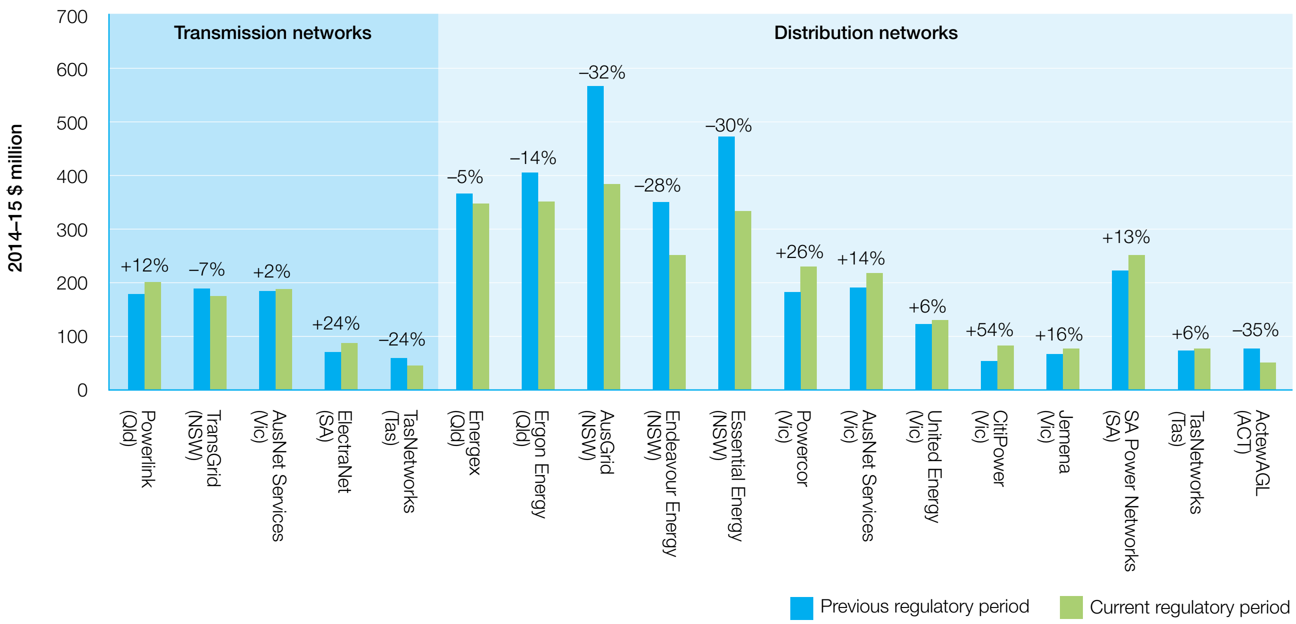
The AER's capital efficiency benefit sharing scheme creates incentives for businesses to undertake efficient expenditure, by allowing them to retain a share of any capital underspends. The AER reviews capital overspends, and excludes inefficient expenditure from the business's asset base (meaning consumers will not pay for it).

2.5 Operating and maintenance expenditure

The AER assesses operating and maintenance expenditure requirements for efficient network operation, accounting for load densities, the network's scale and condition, geographic factors and reliability requirements. In the current regulatory cycle, transmission businesses are forecast to spend $700 million on operating and maintenance costs each year. Distribution businesses are forecast to spend $2.8 billion on these costs each year (figure 2.7).

On average, operating expenditure forecasts in the current regulatory periods rose by 2 per cent for transmission networks and fell by 12 per cent for distribution networks compared with previous periods. Operating and maintenance costs are largely independent of energy use, so falling electricity demand does not significantly reduce this expenditure. The forecast reductions for distribution networks reflect the use of AER benchmarking that identified operating inefficiencies in some networks. The largest

Figure 2.7
Annual operating expenditure of electricity networks



Note: Current regulatory period expenditure reflects forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.

Sources: Regulatory determinations by the AER.

reductions were for the NSW and ACT networks, for which forecasts were an average 30 per cent lower than operating expenditure in previous regulatory periods.

In assessing operating expenditure, the AER considers cost drivers that include customer growth, expected productivity improvements, and changes in labour and materials costs. Operating costs may also reflect external drivers such as changes to regulation.

2.6 Efficiency incentive schemes

The AER operates an incentive scheme for businesses to improve the efficiency of operating and maintenance expenditure in running their networks (the efficiency benefit sharing scheme). Incentives are aligned with those provided through the AER's service target performance incentive scheme, to encourage businesses to efficiently balance cost and service quality considerations.

The efficiency benefit sharing scheme, which applies to all transmission and distribution networks, allows a business to retain efficiency gains (and to bear the cost of any efficiency losses) for five years after a gain (loss) is made.[4] In the longer term, the businesses share efficiency gains or losses with customers through tariff adjustments, passing on 70 per cent of gains or losses.

AER determinations for transmission networks since 2012 have provided benefits under the scheme of around $230 million, and penalties of $7 million.

A similar incentive scheme for capital expenditure first applied to transmission and distribution networks in 2015. Incentives under the capital expenditure sharing scheme are similar to those for operating expenditure, with the businesses retaining (paying) 30 per cent of capital underspends (overspends).

The AER's benchmarking work identifies the relative efficiency of electricity networks and tracks changes over time. It uses a multilateral total factor productivity approach that assesses the volume of inputs (assets and operating expenditure) needed to produce outputs (measured as line length, maximum energy demand, energy delivered,

4 The AER's approved expenditure forecasts set the base for calculating efficiency gains or losses, after certain adjustments. To encourage wider use of demand management, the incentive scheme does not cover this type of expenditure.

reliability of supply, customer numbers for distribution networks, and the voltage of connection points for transmission networks).

Productivity in transmission and distribution networks has been declining for several years (figure 2.8). That is, the resources used to maintain, replace and augment the networks are rising at a faster rate than the drivers of demand for network services. Declining productivity may reflect (1) reduced efficiency in using resources, (2) rising input costs when outputs are flat or declining, or (3) jurisdictional requirements requiring networks to spend more without a corresponding rise in output (for example, if reliability or bushfire mitigation obligations are made more stringent).

The AER found electricity distribution businesses in NSW and the ACT generally operate less efficiently than do those in other jurisdictions. While productivity continued to decline for most networks in 2014, Energex, Ergon Energy and Essential Energy (distribution), and TasNetworks (transmission) were among a minority that raised their productivity.

2.7 Power of choice reforms

The nature and function of energy networks are evolving. Escalating cost pressures have given impetus to 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, more recently, 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 better control how they manage that use.

These developments are transforming the nature of a network from being a one-way conduit for energy transportation, to being a platform for multilateral trade in energy products. Alongside this transformation, some electricity consumers are becoming producers and can switch from net consumption to net production in response to market signals. As an example, 1.5 million households installed rooftop solar PV systems in the past few years. 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 have stemmed the historical growth in peak demand, delaying the need for costly network augmentations.

In 2015 the AEMC progressed rule changes as part of reforms to promote efficient use of energy networks and to empower customers to make efficient energy decisions. The reform areas include metering, network pricing and embedded generation. The AER is working to implement reforms, initially in cost-reflective network pricing

2.7.1 Metering

The *Power of choice* reforms recommended all new meters installed for residential and small businesses consumers be smart meters. These meters can record energy consumption on a near real-time basis, and have capabilities for remote reading and customer connection to the network. Smart meters thus provide consumers with information about their energy use, and greater control over how they manage it. Consumers can also access a wider range of retail offers, or take up offers of demand management products.

Victoria was the first jurisdiction to progress metering reforms, with its distribution businesses undertaking a compulsory rollout of smart meters with remote communications from 2009 to 2014. The rollout costs were progressively passed on to retail customers, with network charges rising by around $80 for a typical small customer from 2010–12, and further annual increases of $9–21 from 2012 to 2015.[5]

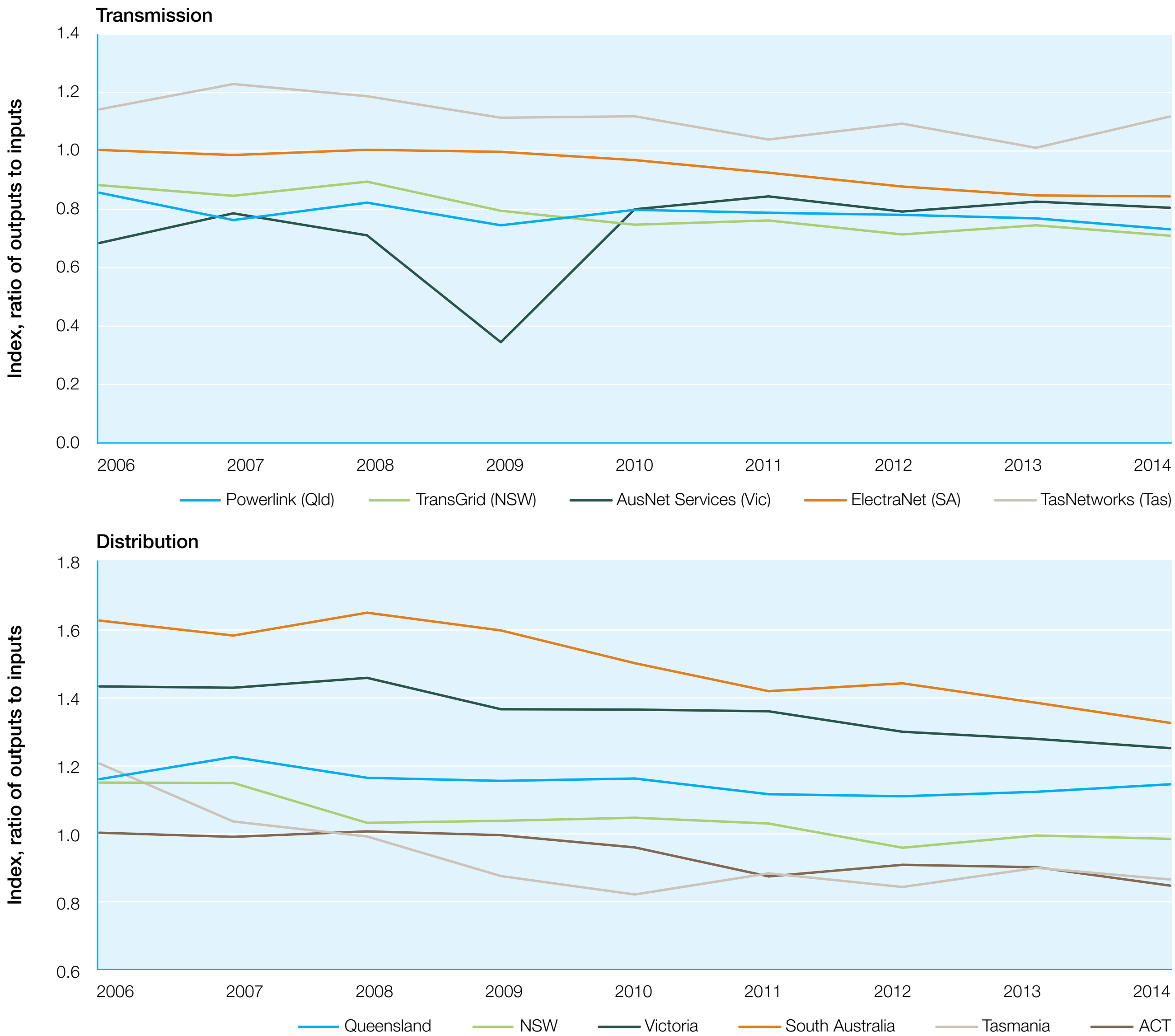
Network businesses were the traditional providers of electricity meters on residential premises. But this arrangement can inhibit competition and consumer choice. It also discourages investment in metering technology that could support the uptake of new and innovative energy products.

The AEMC in November 2015 finalised a rule change allowing competition in the provision of metering and related services from 1 December 2017, to facilitate a market led rollout of smart meters. This change complements reforms in 2014 that allow customers more ready access to their electricity consumption data, and reforms in 2015 that introduce default meter communications standards to promote competition in service provision.

The AEMC in November 2015 found related reforms that would allow for multiple trading relationships at a customer's connection point were unnecessary. The reforms would allow, for example, separate supply to separate parts of a premises, or different retailers to supply electricity to specific appliances (such as electric vehicles). The AEMC found that

5 AER, *Victorian Advanced Metering Infrastructure Review: 2012–15 AMI budget and charges applications, final determination*, 2011.

Figure 2.8
Network productivity



Note: Index of multilateral total factor productivity relative to 2006 data for ElectraNet in South Australia (for transmission) and the ACT (for distribution). Distribution data are jurisdictional averages.

Source: AER, *Annual benchmarking report: electricity distribution network service providers*, November 2015.

reforms to distribution pricing and competition in metering would achieve a similar outcome. In particular, those reforms will reduce the cost for a customer to engage with multiple retailers by establishing a second connection point. And they will facilitate alternative products and tariffs that deliver similar value to customers without the customer needing to engage with multiple retailers.

The NSW Government in 2014 announced its support for a competitive voluntary rollout of smart meters, with providers (such as electricity retailers) offering the meters to customers as part of energy deals. In its recent review of the NSW networks, the AER reclassified certain metering services, making them open to competition. It also provided that individual customers will not incur exit fees to move from legacy (regulated) meters to third party provided meters. Rather, the distribution networks will recover the cost of that move from all customers.

If network businesses offer services in a contestable market, then the costs should be clearly separated from the RAB. The AER sets ring fencing guidelines to ensure network businesses do not shift costs between regulated and unregulated activities. Ring fencing may also set out rules for non-discrimination or prohibit a network business from engaging in a potentially contestable activity.

In September 2015 the AEMC released a draft rule lowering barriers to competition for customers in embedded networks. Many customers in those networks currently cannot arrange for energy supply by a provider other than the network operator, or can do so only at significant cost. The draft rule will require an embedded network manager to link customers to AEMO's electricity market systems—a necessary first step for customers to access retail market offers.

2.7.2 Cost-reflective network tariffs

While smart meters allow consumers to monitor their energy use, price signals are needed to encourage efficient demand responses. Under traditional pricing structures, energy users pay the same network tariffs regardless of how or when they use power. But network costs closely correlate with demand at times of peak use. A household consuming energy at peak times may impose significant network costs, even if its average consumption is low.

A household using a 5 kilowatt airconditioner at peak times, for example, imposes around $1000 a year in additional network costs, but might pay only $300 under current tariff structures. Other customers subsidise the remaining $700, paying more than what it costs to supply their own network services.[6]

Similarly, customers with solar PV systems do not bear the full cost of their network use under current pricing, which rewards reduced energy consumption regardless of when the reduction occurs. For example, a customer can save around $200 in network costs per year by installing a solar PV system and reducing their offtake of electricity from the grid. But, because most solar energy is generated at non-peak times, the customer will reduce network costs by around $80 only. Other consumers without a solar PV system cross-subsidise the remaining $120 by paying higher network charges.[7]

The AEMC in November 2014 determined distribution businesses must move towards tariff structures that better reflect the efficient costs of providing network services to each consumer. Such tariffs would vary by time of use, encouraging consumers to choose efficient times to use appliances (perhaps by shifting some use from peak times when charges are high, to off-peak times such as late evening).

Under cost-reflective pricing, the AEMC estimated 81 per cent of residential customers would face lower network charges in the medium term, and up to 69 per cent would have lower charges at peak times.[8] Business users with relatively flat load profiles could also expect lower network charges.

Distributors submitted tariff proposals to the AER in late 2015. The Victorian businesses proposed tariffs include a demand component that charges customers for their maximum electricity use during peak network periods, so each household contributes fairly and efficiently to meeting total network costs.[9]

The approved tariff structures will take effect in 2017, allowing distributors to consider a suitable transitioning period so customers have time to adjust.

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

7 Paul Smith (AMEC Chief Executive Officer), 'Responding to consumer demands, promoting competition and preparing for change', Speech at 2014 Australian Institute of Energy symposium, 22 September 2014.

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

9 AER, *Tariff structure statement proposals, Victorian electricity distribution network service providers*, Issues paper, December 2015.

2.7.3 Demand management and embedded generation

The *Power of choice* reforms include a focus on demand management. The AER runs a scheme for distribution businesses to fund innovative projects for non-network approaches to manage demand. The approaches include measures to reduce demand or provide alternative ways to meet supply (such as connecting small scale local generation). In August 2015 the AEMC released a rule change that strengthens incentives for distribution businesses to undertake demand management projects that deliver a net benefit.

Power of choice also focused on removing impediments to investment in embedded generation that connects directly to the distribution network. A range of stakeholders and market reviews suggested a lack of consistent technical standards for mid-scale embedded generator connections creates a barrier to deployment of those generators.

In April 2014 the AEMC finalised a rule change for a clearer enquiry and application process, and set out new information requirements. In November 2014 it finalised a further rule change to give smaller embedded generator proponents greater flexibility and scope to negotiate a connection. Under the new rule, smaller generators can use the newly created connection process for larger embedded generators, or a more flexible negotiated process.

2.8 Transmission reliability and congestion

Transmission networks are engineered and operated with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. While a serious failure may require the power system operator to disconnect some customers (known as load shedding), transmission networks in the NEM deliver high rates of reliability.

According to Energy Supply Association of Australia data, transmission outages in 2013–14 caused less than two minutes of unsupplied energy across NSW and Victoria. South Australia and Tasmania experienced higher levels (6.6 minutes and 2.9 minutes respectively), but both regions improved on their performance in 2013–13 (20.5 minutes and 10.7 minutes respectively). No data were published for Queensland.[10]

10 ESAA, *Electricity gas Australia 2015*.

2.8.1 Transmission reliability standards

State and territory agencies determine transmission reliability standards. The Council of Australian Governments (COAG) Energy Council in December 2014 endorsed principles requiring the standards to reflect the value that customers place on reliability. It required the standards be set independently of the transmission business.

2.8.2 Transmission network congestion

Limits (constraints) are imposed on electricity flows along transmission networks to avoid damage and maintain power system stability. The constraints periodically result in network congestion. Some congestion arises from factors within the control of a network business—for example, the scheduling of outages, maintenance and operating procedures, and network capability limits (such as thermal, voltage and stability limits). Factors such as hot weather can cause congestion by sharply raising airconditioning loads. Typically, congestion with high market impacts occurs on just a few days each year, and is often associated with network outages.

A major transmission outage combined with other generation or demand events can interrupt the supply of energy. But this scenario is rare in the NEM. More commonly, congestion raises electricity prices by displacing low cost generation with more expensive generation. Congestion can also force inefficient electricity trade flows between the regions.

Not all congestion is inefficient. Reducing congestion through investment to augment the transmission network is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs. The AER operates an incentive scheme encouraging network businesses to reduce the impact of outages on the wholesale market.

2.8.3 Service target performance incentive scheme—transmission

The AER's service target performance incentive scheme provides incentives for transmission businesses to improve or maintain network performance. It acts as a counterbalance to the efficiency benefit sharing scheme (section 2.5.1) so businesses do not reduce expenditure at the expense of service quality.

The scheme in place has three components:

- A *service component* sets performance targets for the frequency of supply interruptions, the duration of

Table 2.3 S factor values

		2010	2011	2012		2013		2014	
Powerlink (Qld)	Service component	0.65	0.42	0.44	0.45		0.54		0.46
	Market impact component	1.97	1.95	1.98	2.00		1.86		0.00
TransGrid (NSW)	Service component	–0.24	–0.13		–0.49		–0.61		–0.43
	Market impact component	1.45	1.39		1.48		1.58	1.87	0.20
	Network capability component								1.50
AusNet Services (Vic)	Service component	0.58	0.72		0.82		0.67	0.95	0.24
	Market impact component		0.00		0.80		1.31	1.70	1.06
	Network capability component								1.50
ElectraNet (SA)	Service component	0.00	0.32		–0.30	–0.17	0.31		0.63
	Market impact component		0.52		0.00	1.90	0.00		1.88
TasNetworks (Tas)	Service component	0.35	–0.41		0.33		0.57		0.77
	Market impact component								0.00
	Network capability component								1.50
Directlink (Qld–NSW)	Service component	–1.00	–0.87		–1.00		–0.47		–1.00
Murraylink (Vic–SA)	Service component	1.00	0.70		0.92	–0.41	0.59		–0.33
	Market impact component						1.19		1.54

Notes: Powerlink reported separately for the first and second halves of 2012. ElectraNet and Murraylink reported separately for the first and second halves of 2013. TransGrid and TasNetworks reported separately for the first and second halves of 2014. AusNet Services reported first quarter results separately from the rest of 2014.

Source: AER, *Service standards compliance report* for various businesses.

outages, and the number of unplanned faults on the network. It also covers protection and control equipment failures. The over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of the network's regulated revenue.

- A *market impact component* encourages a network to improve its operating practices to reduce congestion. These practices may include efficiently planning outage timing and duration, and minimising the outage impact on network flows (for example, by conducting live line work, maximising line ratings and reconfiguring the network). A business can earn up to 2 per cent of its regulated revenue if it eliminates all relevant outage events with a market impact of over $10 per megawatt hour.
- A *network capability component* offers incentives of up to 1.5 per cent of regulated revenue. Payments are available to fund one-off projects that improve a network's capability, availability or reliability at times when users most value reliability, or when wholesale electricity prices are likely to be affected. An eligible project may not exceed $5 million, and the total cost of funding through the component may not exceed 1 per cent of network revenue. AEMO helps prioritise projects that deliver best value for money to consumers, and the AER approves a project list. Network businesses face a penalty of up to 2 per cent of revenue in the final year of their regulatory period if they fail to achieve improvement targets.

The service component applies to all transmission businesses. The market impact component applies to all businesses except Directlink. The network capability component was first applied to transmission networks in NSW, Victoria and Tasmania in 2014.

Rather than impose a common benchmark target, the AER sets separate targets reflecting the circumstances of each network based on its past performance. The results under each component are standardised for each network, to derive an 's factor' that can range between –1 (the maximum penalty) and +4.5 (the maximum bonus).

Table 2.3 sets out s factors for each network for the past five years. While performance against individual component targets varied, the networks generally received financial bonuses for overall performance. Underperformance was most common in relation to network availability targets.

Under the service component of the scheme, TransGrid, Directlink and Murraylink received financial penalties in 2014 totalling $4 million. The three networks failed to meet their network availability targets; TransGrid also failed to meet its average outage duration target.

Network performance in managing the market impact of congestion fell for all networks except AusNet Services and ElectraNet. Under the congestion component, networks received a total of $22 million in 2014, compared with $33 million in 2013.

Those networks applying the network capability requirement—TransGrid, AusNet Services and TasNetworks—received the maximum payment of 1.5 per cent of regulated revenue (totalling $14 million).

2.9 Distribution network performance

Most electricity outages in the NEM originate in distribution networks. The capital intensive nature of distribution networks makes it expensive to build sufficient capacity to avoid all outages. In addition, the impact of a distribution outage tends to be localised to part of the network, compared with the potentially widespread impact of a generation or transmission outage. For these reasons, distributors try to keep outages to efficient levels—based on the value of reliability to the community, and the willingness of customers to pay for reliability—rather than trying to eliminate every possible interruption.

Capital investment to ensure the networks delivered on reliability requirements was a significant driver of rising network charges in past years. Concerns about the impact of network investment on retail electricity bills led the COAG Energy Council in 2014 to endorse a new approach to setting distribution reliability targets. The approach accounts for (1) the value that customers place on reliability and (2) the likelihood of interruptions. The Energy Council conferred responsibility on the AER to establish customer values of reliability to coincide with the round of regulatory determinations commencing in mid-2019.

Queensland and NSW reformed their distribution reliability standards in 2014. The Queensland Government removed strict input based reliability standards. Similarly, the NSW Government removed deterministic planning obligations from network licence conditions. The remaining conditions focus solely on 'output' standards for reliability. This approach means network businesses have more discretion in how they plan to meet the standards.

2.9.1 Distribution reliability indicators

Distribution reliability is measured by the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI) and total energy unsupplied.

The SAIDI and SAIFI indicators measure the average duration and frequency respectively of unplanned outages experienced by distribution network customers. Figure 2.9 sets out historical data for both indicators. Comparisons across jurisdictions should be made with care. In particular, the data rely on the accuracy of businesses' information systems, which may vary considerably. Geographic conditions and historical investment also differ across the networks.

The SAIDI data indicate electricity networks delivered reasonably stable reliability outcomes over the past few years. Across the NEM, a typical customer experienced around 200 minutes of outages per year, but with significant regional variations.

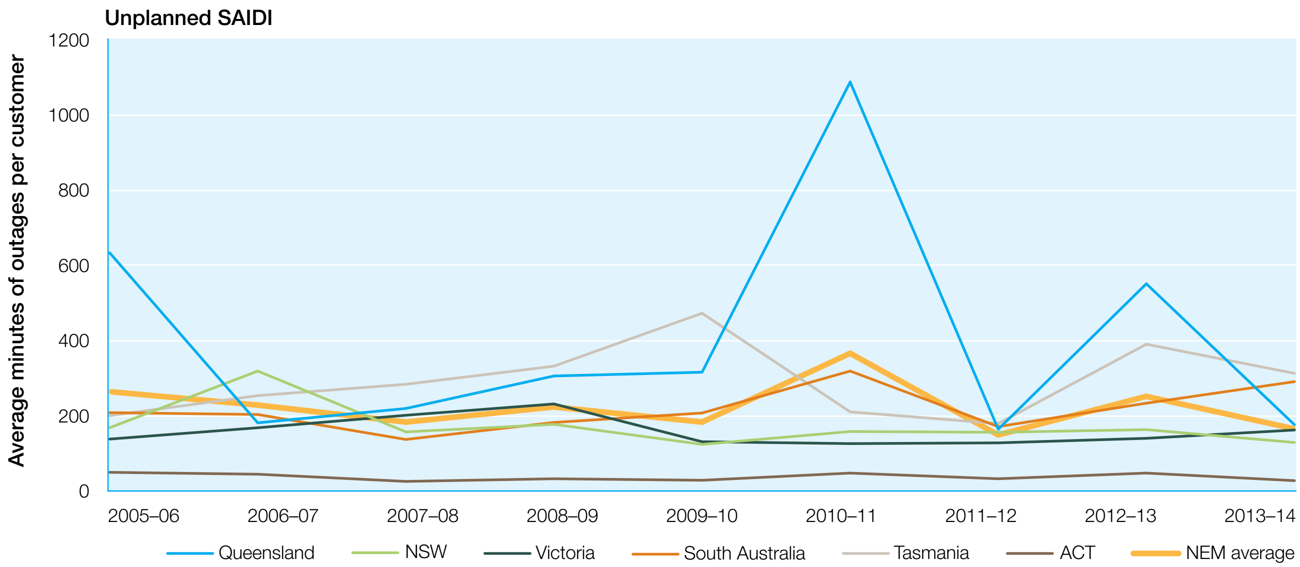
The average outage duration in 2013–14 fell in Queensland, NSW and the ACT to near their lowest levels of the past decade, reflecting relatively benign weather conditions. Queensland recorded the largest fall, with reliability outcomes in 2012–13 affected by severe weather activity (including ex-tropical cyclone Oswald). Unplanned outage levels also fell in Tasmania, but remained above typical levels. The average outage duration rose in Victoria and South Australia in 2013–14 (up 15 per cent and 24 per cent respectively).

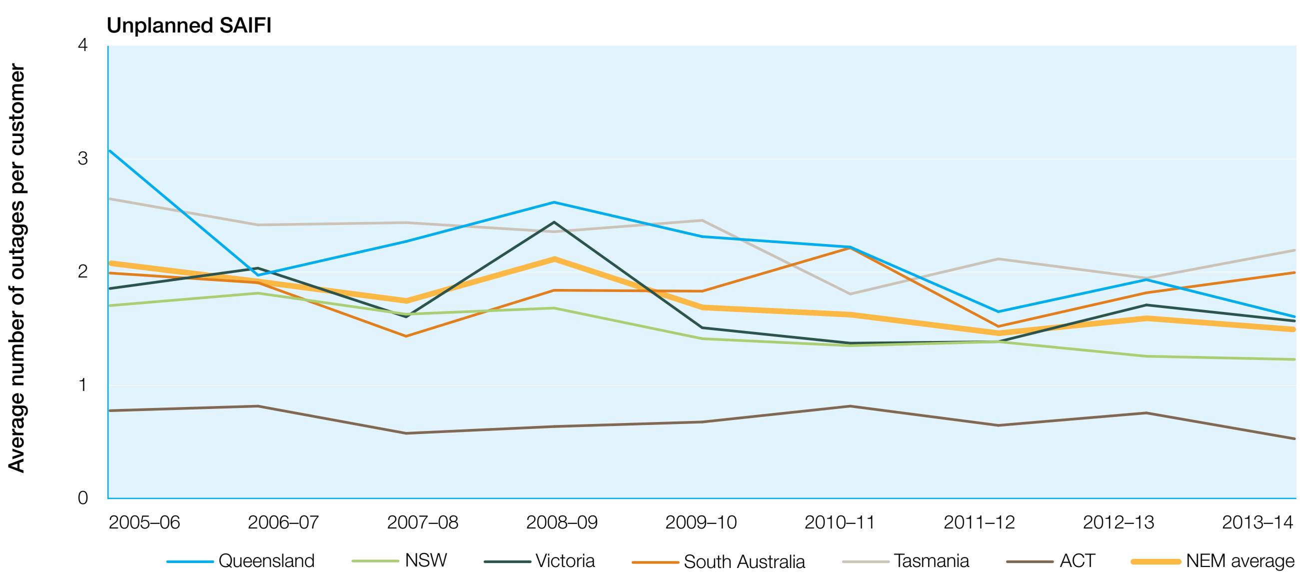
The SAIFI data show the average frequency of unplanned outages gradually declined between 2004–05 and 2013–14. Energy customers across the NEM experienced an average of 1.5 outages in 2013–14. The average frequency of outages was lower than the previous year's average in all jurisdictions except South Australia and Tasmania.

Another reliability measure—total energy unsupplied—estimates the volume of energy not supplied as a result of interruptions. Total energy unsupplied was relatively stable over the past decade in all jurisdictions except Queensland (figure 2.10). The ACT experienced an average of less than 1 gigawatt hour of unsupplied energy per year; Victoria and Tasmania experienced 2–3 gigawatt hours; and NSW and South Australia experienced 5–6 gigawatt hours. Queensland experienced an average of 24 gigawatts of unsupplied energy per year. One reason for this higher average is that large and widely dispersed rural networks make Queensland especially vulnerable to outages.

Figure 2.9

System reliability





Notes:

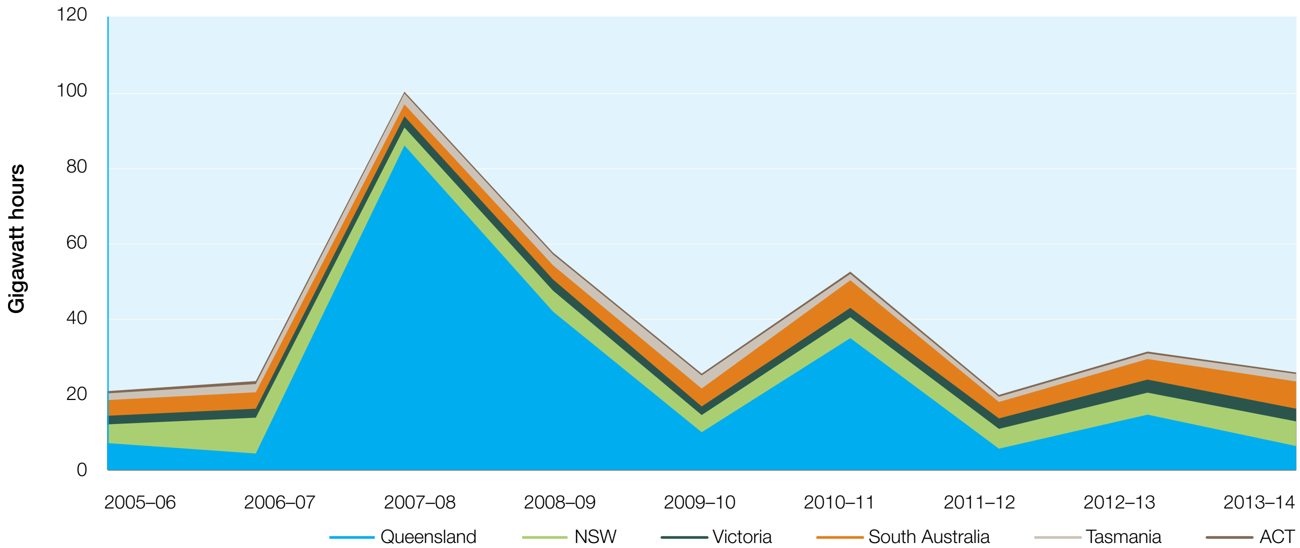
The data reflect total outages experienced by distribution customers, including outages originating in generation and transmission. The data are not normalised to exclude outages beyond the network operator's reasonable control.

The NEM averages are weighted by customer numbers.

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

Sources: Performance reports by the AER, the QCA (Queensland), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), AusGrid, Endeavour Energy and Essential Energy. Some data are AER estimates derived from official jurisdictional sources.

Figure 2.10
Total energy unsupplied



2.9.2 Service target performance incentive scheme—distribution

The AER's service target performance incentive scheme encourages distribution businesses to maintain or improve network performance. It focuses on supply reliability and customer service, including the timely connection of services and call centre performance. A guaranteed service level (GSL) component provides for a business to pay customers if its performance falls below threshold levels.[11]

The incentive scheme provides financial bonuses and penalties of up to 5 per cent of revenue for network businesses that meet (or fail to meet) performance targets.[12] The results are standardised for each network, to derive an 's factor' that reflects deviations from performance targets. While the scheme aims to be nationally consistent, it has flexibility to deal with the circumstances and operating environment of each network.

The reliability component of the scheme sets targets for the average duration and frequency of outages for each distribution business. The targets are based on the business's outcomes over the previous five years, normalised to exclude interruptions beyond the network's reasonable control.

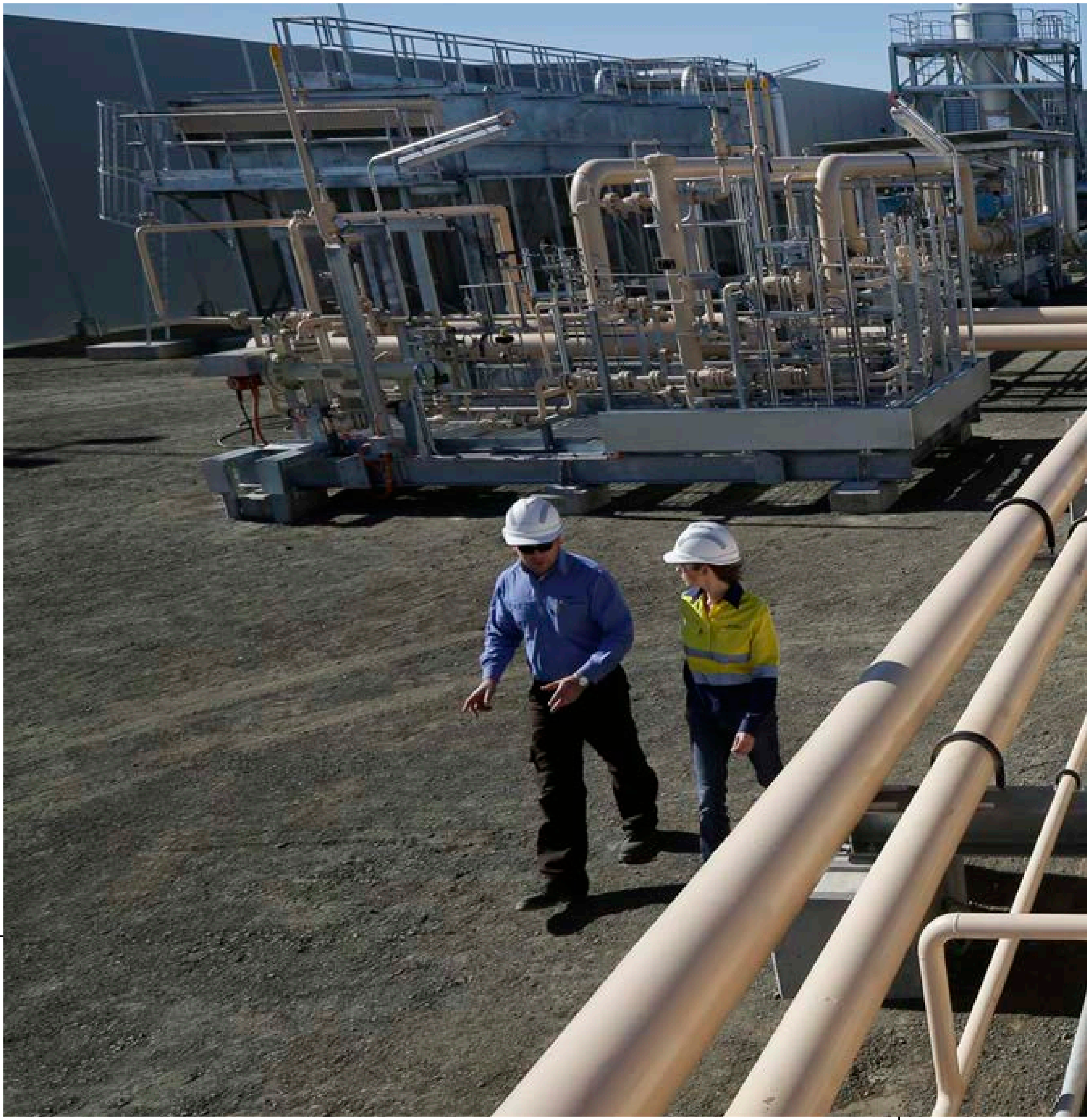
In 2013–14 Energex, Ergon and Jemena met all reliability targets. AusNet Services missed some targets, but exceeded its overall benchmark. All businesses exceeded their customer service benchmark. The scheme did not apply to NSW and ACT network businesses in that year.

Since 1 January 2012 the Victorian distribution businesses have been subject to an additional incentive scheme. The scheme aims to reduce the risk of fire starts originating from a network, or caused by something coming into contact with the network. This 'f factor' scheme rewards or penalises the businesses $25 000 per fire under or over their targets. AusNet Services was the only business to outperform its target in 2013 and 2014, receiving a $1.9 million payment in 2014. Penalties in 2014 ranged from $15 000 for CitiPower to $2.3 million for United Energy. While missing their targets in 2014, CitiPower, Jemena and Powercor improved on their 2013 performance.

11 The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations.

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

Image courtesy of APA Group



3 GAS MARKETS

The main forms of gas produced in Australia are conventional gas and coal seam gas (CSG). Conventional gas is found trapped in underground reservoirs, often along with oil, while CSG is extracted from coal beds. Advancements in extraction techniques have improved the commercial prospects for other types of unconventional gas, including shale and tight gas.[1]

Australian gas sales are evenly split between domestic markets and liquefied natural gas (LNG) for export. The LNG share is rising as more LNG export projects come online in Queensland and Western Australia, with export volumes likely to double between 2015 and 2019.

The gas supply chain begins with exploration and development activity, which may involve geological surveys and the drilling of wells (figure 3.1). Following a commercial discovery, gas is extracted and processed to separate methane from liquids and other gases, and impurities are removed.

In the domestic market, high pressure transmission pipelines transport gas from gas fields to demand hubs. A network of distribution pipelines then delivers gas from points along transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. Gate stations measure the gas leaving a transmission system for billing and gas balancing purposes, and reduce the pressure of the gas before it enters a distribution network. Energy retailers complete the supply chain; they buy gas and package it with pipeline transportation services for sale to customers.

This chapter covers gas production and wholesale market arrangements, focusing on the eastern Australian markets in which the Australian Energy Regulator (AER) has regulatory responsibilities.[2] It also refers to Western Australia and the Northern Territory, and to LNG export markets. Other segments of the gas chain are covered in chapters 4 (gas pipelines) and 5 (retail markets).

1 Shale gas is contained within organic-rich rocks such as shale and fine grained carbonates, rather than in underground reservoirs. The application of horizontal drilling techniques in the past five years is enhancing the economic viability of shale gas development. Tight gas is found in low porosity sandstone and carbonate reservoirs.

2 The AER has compliance and enforcement responsibilities under the National Gas Rules in relation to the Gas Bulletin Board, the Victorian wholesale gas market and the short term trading market in Sydney, Adelaide and Brisbane.

3.1 Gas reserves and production

In August 2015 Australia's proved and probable (2P) gas reserves stood at 126 000 petajoules (PJ), comprising 83 000 PJ of conventional gas and 43 000 PJ of CSG (table 3.1). Australia produced 2460 PJ of gas in 2014–15, of which 50 per cent was for the domestic market. The balance—sourced from CSG in Queensland, and offshore basins in Western Australia and the Timor Sea—was exported as LNG (section 3.1.2).

While gas is widely used for industrial manufacturing, around 31 per cent of domestic consumption is for electricity generation.[3] Household demand accounts for 14 per cent of consumption, except in Victoria (37 per cent), where gas is widely used for cooking and heating.[4]

In eastern Australia, domestic gas consumption rose by 2.7 per cent in 2014–15 compared with 2013–14. But, following the abolition of carbon pricing, a shift back to coal fired generation contributed to a 2 per cent decline in gas use for power generation over the same period.[5]

3.1.1 Geographic distribution and major players

Australia has three distinct regional gas markets (figure 3.2):

- an eastern Australian gas market, encompassing Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT), interconnected by a network of transmission pipelines, and principally supplied by the Surat–Bowen, Cooper, Gippsland and Otway basins
- a Western Australian market, supplied by the Carnarvon and Perth basins
- a Northern Territory market, supplied by the Bonaparte and Amadeus basins.

While the three markets are not interconnected, Jemena expects to complete the North East Gas Interconnector from Tennant Creek to Mount Isa by 2018. The pipeline will effectively link the Bonaparte Basin off northern Australia with gas markets in southern and eastern Australia.[6]

3 ESAA, *Electricity gas Australia 2015*.

4 http://onshoregas.vic.gov.au/victorias-energy-supply/gas-in-victoria/demand-for-gas-in-victoria

5 EnergyQuest, *Energy Quarterly*, August 2015, p. 108.

6 Jemena, 'Jemena to build North East Gas Interconnector,' Media release, 17 November 2015.

Figure 3.1

Domestic gas supply chain

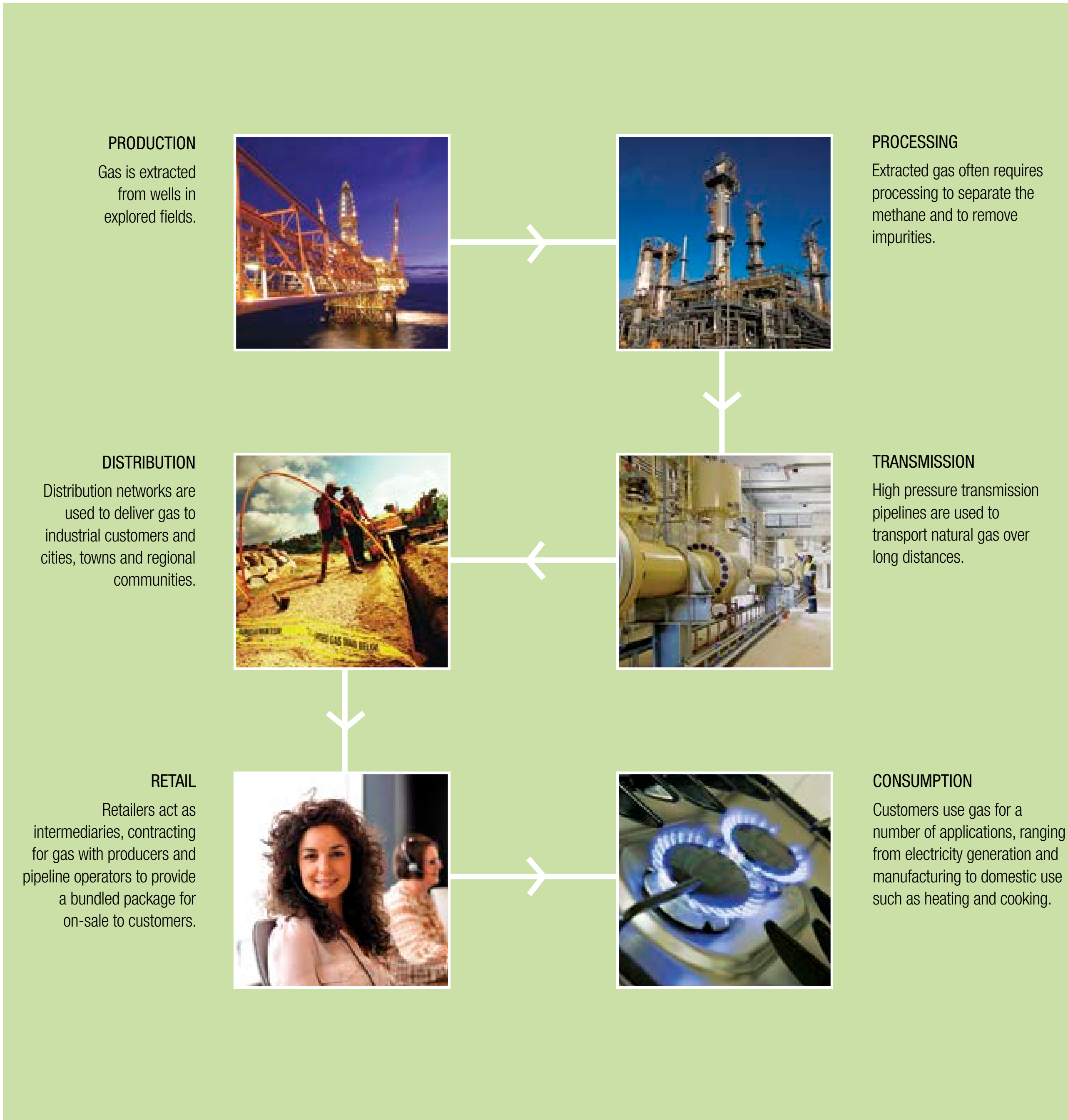


Image sources: Origin Energy, Woodside, Jemena.

Table 3.1 Gas reserves and production, 2015

GAS BASIN	GAS PRODUCTION[1] (YEAR TO JUNE 2015) PETAJOULES	SHARE OF AUSTRALIAN PRODUCTION (%)	CHANGE FROM PREVIOUS YEAR (%)	PROVED AND PROBABLE RESERVES[2] (AUGUST 2015) PETAJOULES	SHARE OF AUSTRALIAN RESERVES (%)
DOMESTIC GAS					
EASTERN AUSTRALIA					
Cooper (South Australia–Queensland)	91	7.4	5.2	1 544	1.2
Gippsland (Victoria)	223	18.2	–7.5	3 106	2.5
Otway (Victoria)	93	7.5	–18.4	648	0.5
Bass (Victoria)	12	0.9	–34.5	158	0.1
Surat–Bowen (Queensland)					
Conventional gas	3	0.2	–11.1	118	0.1
Coal seam gas	409	33.3	47.4	41 880	33.2
NSW basins	5	0.4	0.4	1 280	1.0
WESTERN AUSTRALIA					
Browse	355	28.9	–0.5	58 723	46.5
Carnarvon	9	0.8	24.5	243	0.2
Perth	0	0.0	0.0	17 384	13.8
NORTHERN TERRITORY					
Amadeus	1.6	0.1	343.0	180	0.1
Bonaparte (Blacktip)	27	2.2	11.7	944	0.7
TOTAL DOMESTIC GAS	1 228		8.3	126 207	
LNG (EXPORTS)					
Carnarvon (Western Australia)	1 132	91.8	1.9		
Bonaparte (Northern Territory)	14	1.2	–9.9		
Surat–Bowen (Queensland)	87	7.1	na		
TOTAL LNG	1 234		9.5		
TOTAL PRODUCTION	2 462				

1. Production is conventional gas, other than in the Surat–Bowen and NSW basins.
2. Proved reserves are those for which geological and engineering analysis suggests at least a 90 per cent probability of commercial recovery. Probable reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.

Note: Due to accounting differences, the EnergyQuest data are typically lower than the BREE production data published in the 2014 edition of this report.

Sources: EnergyQuest, *Energy Quarterly*, August 2015.

Eastern gas market

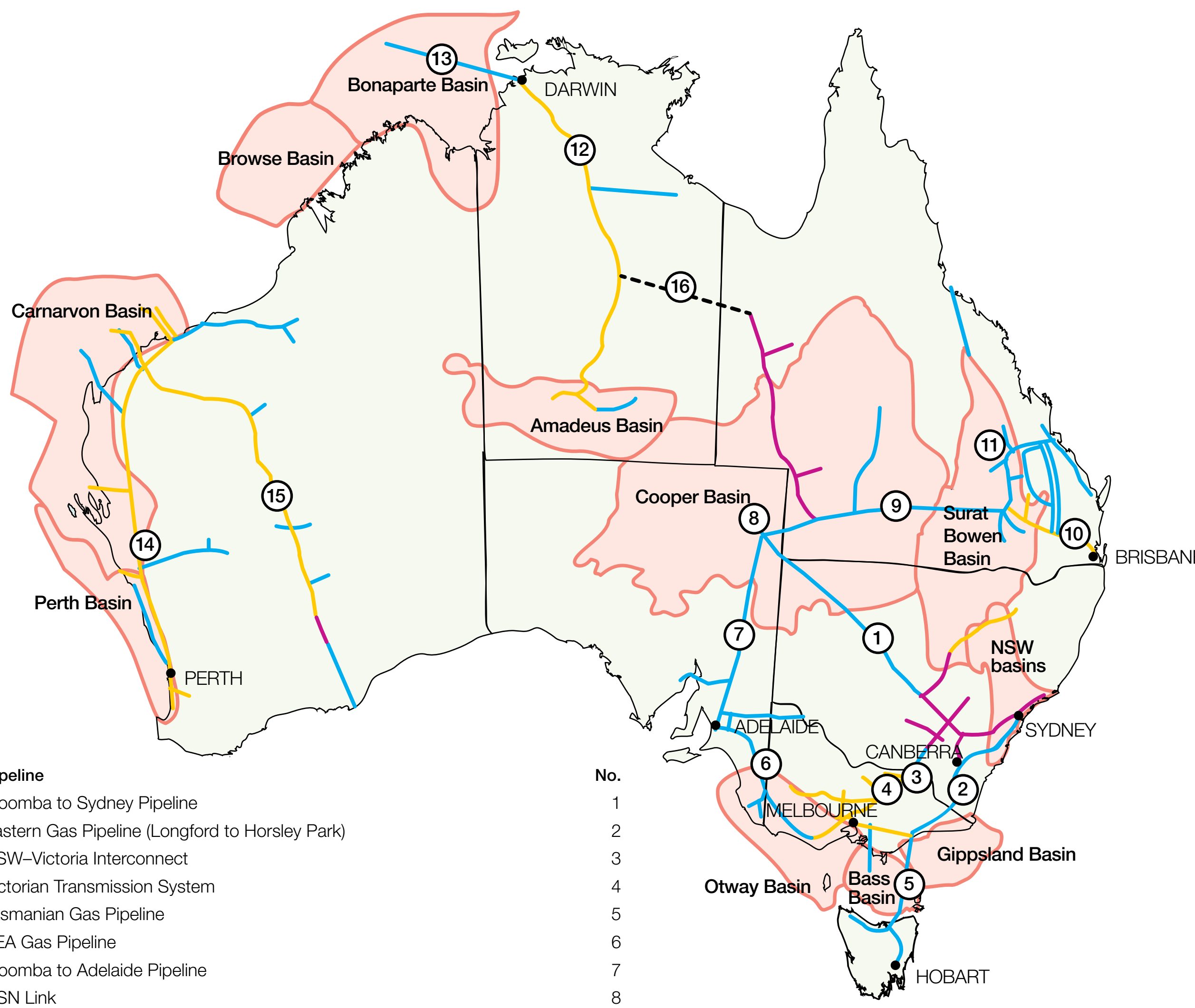
The eastern gas market contains 39 per cent of Australia's gas reserves, mainly located in Queensland and Victorian basins. Table 3.2 and figure 3.3 provide data on gas producers operating in the eastern market, including market shares in production and gas reserves.

Queensland's Surat–Bowen Basin supplies 49 per cent of the eastern gas market and holds 85 per cent of its reserves. Almost all gas produced in the basin is CSG. BG Group, Origin Energy, ConocoPhillips and Sinopec were the largest producers in 2014–15 (figure 3.3). Other players included CNOOC, Santos, PetroChina, Shell, Petronas, Total and AGL Energy. The same businesses own the majority of reserves in the basin (table 3.2). Many of these entities entered the Queensland market to develop LNG projects (section 3.1.2).

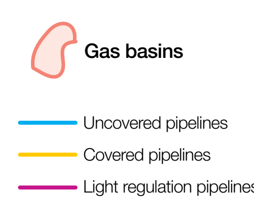
The Gippsland Basin is the most significant of the three gas basins off coastal Victoria. It supplied 27 per cent of the eastern market in 2014–15. A joint venture between ExxonMobil and BHP Billiton accounts for 96 per cent of the basin's production. Production in the Otway Basin (11 per cent) has risen significantly since 2004. Origin Energy, BHP Billiton and Santos are the main players. The principal producers in the smaller Bass Basin are Australian Worldwide Exploration and Origin Energy.

Figure 3.2

Australian gas basins and transmission pipelines



Pipeline	No.
Moomba to Sydney Pipeline	1
Eastern Gas Pipeline (Longford to Horsley Park)	2
NSW–Victoria Interconnect	3
Victorian Transmission System	4
Tasmanian Gas Pipeline	5
SEA Gas Pipeline	6
Moomba to Adelaide Pipeline	7
QSN Link	8
South West Queensland Pipeline (Ballera to Wallumbilla)	9
Roma to Brisbane Pipeline	10
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	11
Amadeus Basin to Darwin Pipeline	12
Bonaparte Pipeline	13
Dampier to Bunbury Natural Gas Pipeline	14
Goldfields Gas Pipeline	15
North East Gas Interconnector (proposed)	16



Source: AER.

Table 3.2 **Market shares in gas reserves in eastern Australia**

COMPANY	SURAT–BOWEN (QLD)	GIPPSLAND (VIC)	COOPER (SA/QLD)	NSW CSG BASINS	OTWAY (VIC)	BASS (VIC)	RESERVES—ALL BASINS	PRODUCTION—ALL BASINS
BG Group	17.4						14.8	9.8
Origin	13.4		12.0		40.5	41.1	12.5	14.1
ConocoPhillips	12.7						10.9	7.9
PetroChina	10.6						9.0	2.2
Santos	5.3	6.5	61.3	56.3	15.6		8.7	12.0
Shell	9.8						8.3	2.2
Sinopec	8.5						7.2	5.2
CNOOC	4.8						4.1	3.3
AGL	3.2			41.3			3.9	1.5
Petronas	3.7						3.2	0.9
Total	3.7						3.2	0.9
BHP Billiton		45.1			9.4		3.2	16.5
Exxon		45.1					3.1	13.7
Kogas	2.0						1.7	0.5
Mitsui	1.2				8.6		1.2	0.9
Senex	1.2						1.0	
Landbridge	0.8						0.7	
Beach			19.8				0.6	2.4
Toyota Tsusho	0.6				2.7	11.5	0.6	0.5
AWE					8.6	35.8	0.3	1.5
NEXUS		3.3					0.2	1.1
Benaris					14.7		0.2	1.6
Other	1.2		6.9	2.5		11.5	1.4	1.3
TOTAL (PETAJOULES)	41 550	3 327	1 586	1 381	681	229	48 754	779

Notes:

Reserves including proved and probable (2P) reserves at May 2015.

NSW CSG basins include the Sydney, Gloucester, Clarence–Morton and Gunnedah basins.

Not all minority owners are listed.

Source: EnergyQuest 2015 (unpublished data).

In South Australia, a joint venture led by Santos dominates production in the Cooper Basin, which supplies 11 per cent of the eastern market. Beach Petroleum and Origin Energy are other participants. After several years of declining conventional gas production, renewed activity in the Cooper Basin is focusing on the development of shale gas. Santos commenced limited shale gas production in 2012.

NSW has a small amount of CSG production in the Sydney and Gunnedah basins.

Western Australia

Western Australia's offshore Carnarvon Basin holds 46 per cent of Australia's 2P gas reserves. It is Australia's largest producing basin, supplying both the local domestic market and LNG exports. Chevron, Shell, ExxonMobil and Woodside are among the major companies with equity in the basin. The businesses participate in joint ventures, typically with overlapping ownership interests.

Northern Territory

The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. Eni Australia owns over 90 per cent of Australian reserves in the basin, which produces LNG for export and gas for consumption in the Northern Territory (via the Bonaparte Pipeline). The basin has displaced the Amadeus Basin as the main source of gas for the Northern Territory.

In November 2015 Jemena was announced as the preferred bidder for the North East Gas Interconnector—a transmission pipeline connecting the Territory (from Tennant Creek) to Mount Isa, Queensland. The pipeline would complete an interconnected network from the Bonaparte Basin to eastern Australia.

3.1.2 Liquefied natural gas exports

The production of LNG converts gas into liquid for efficient storage or transport. LNG export facilities require large upfront capital investment in processing plant, port and shipping facilities. The magnitude of investment requires access to substantial reserves of gas, which may be sourced through the owner's interests in gas fields, joint venture arrangements with gas producers, or long term gas supply contracts. Australia operates LNG export projects on Curtis Island in Queensland, on Western Australia's North West Shelf and in Darwin.

Australia's LNG sector has been transformed by three major projects in Queensland, two of which began operating in 2015. Projections of rising international energy prices, together with large CSG reserves in the Surat–Bowen Basin, spurred the projects' development. Each involved the construction of processing facilities at Gladstone and new transmission pipelines to ship gas from the Surat–Bowen Basin. The projects (which are the world's first to convert CSG to LNG) will each have two trains (liquefaction and purification facilities). A fourth proposed LNG project for Queensland was formally abandoned in January 2015.

- The $20 billion *Queensland Curtis LNG* (QCLNG) project, owned by BG Group, began exporting LNG in January 2015, and launched a second train in July 2015. The project has capacity to produce 8.5 million tonnes of LNG per year (mtpa), which could be raised to 12 mtpa.
- The $18.5 billion *Gladstone LNG* (GLNG) project, owned by Santos, Petronas, Total and Kogas, began exporting from its first train in October 2015. The project has capacity to produce 7.8 mtpa, which could be raised to 10 mtpa.
- The $24.7 billion *Australia Pacific LNG* project (APLNG), owned by Origin Energy, ConocoPhillips and Sinopec, is scheduled to begin LNG exports in late 2015 or early 2016.

LNG players are also expanding capacity in western and northern Australia. Chevron's Gorgon project (Carnarvon Basin) was 90 per cent complete in August 2015, with first shipments likely in late 2015 or early 2016. It is expected to produce 15.6 mtpa of LNG. Chevron's Wheatstone project (8.9 mtpa) was 65 per cent complete in August 2015.

In the Browse Basin, Shell's Prelude floating LNG project (3.6 mtpa) is scheduled to commence production in 2017. Construction of the Ichthys LNG project (8.4 mtpa) was 74 per cent complete in August 2015. Woodside was exploring a floating LNG project capable of producing up to 3.9 mtpa. The project entered front end engineering and design work in 2015.[7]

The LNG sector faces challenges. Weaker Chinese growth and rising shale gas production in North America caused oil and gas prices to fall from July 2014. Share prices for LNG participants such as Santos and Origin Energy fell sharply from September 2014, with the trend continuing into 2015. Takeover bids followed. Shell launched a takeover bid for BG Group in 2015, while Santos rejected a takeover bid from private equity fund Sceptre Partners in October 2015.

The Australian Competition and Consumer Commission (ACCC) decided in November 2015 not to oppose Shell's proposed acquisition of BG Group, finding it unlikely the acquisition would substantially lessen competition in the wholesale gas market.[8]

While global oversupply and falling prices may restrict the development of new oil and gas projects, EnergyQuest noted incumbent Australian producers were raising volumes in 2015 to capture the benefits of a weaker Australian dollar.[9] ANZ Bank forecast LNG prices would recover over the next five years, mainly due to rising demand for clean energy from Asia.[10]

3.1.3 Gas storage

Gas can be stored in its natural state in depleted underground reservoirs and pipelines, or post liquefaction as LNG in purpose built facilities. Gas storage enhances the security of energy supply by allowing for system injections at short notice to manage peak demand and emergencies. It also allows producers to meet contract requirements if production is unexpectedly curtailed. Additionally, it provides retailers with a hedging mechanism if gas demand varies significantly from forecast.

The importance of gas storage in managing supply and demand fluctuations is rising as east coast market dynamics evolve to integrate LNG exports.[11] EnergyQuest found

7 Progress on LNG projects sourced from Energy Quest, *Energy Quarterly*, August 2015.

8 ACCC, 'ACCC will not oppose Shell's acquisition of BG,' Media release, 19 November 2015.

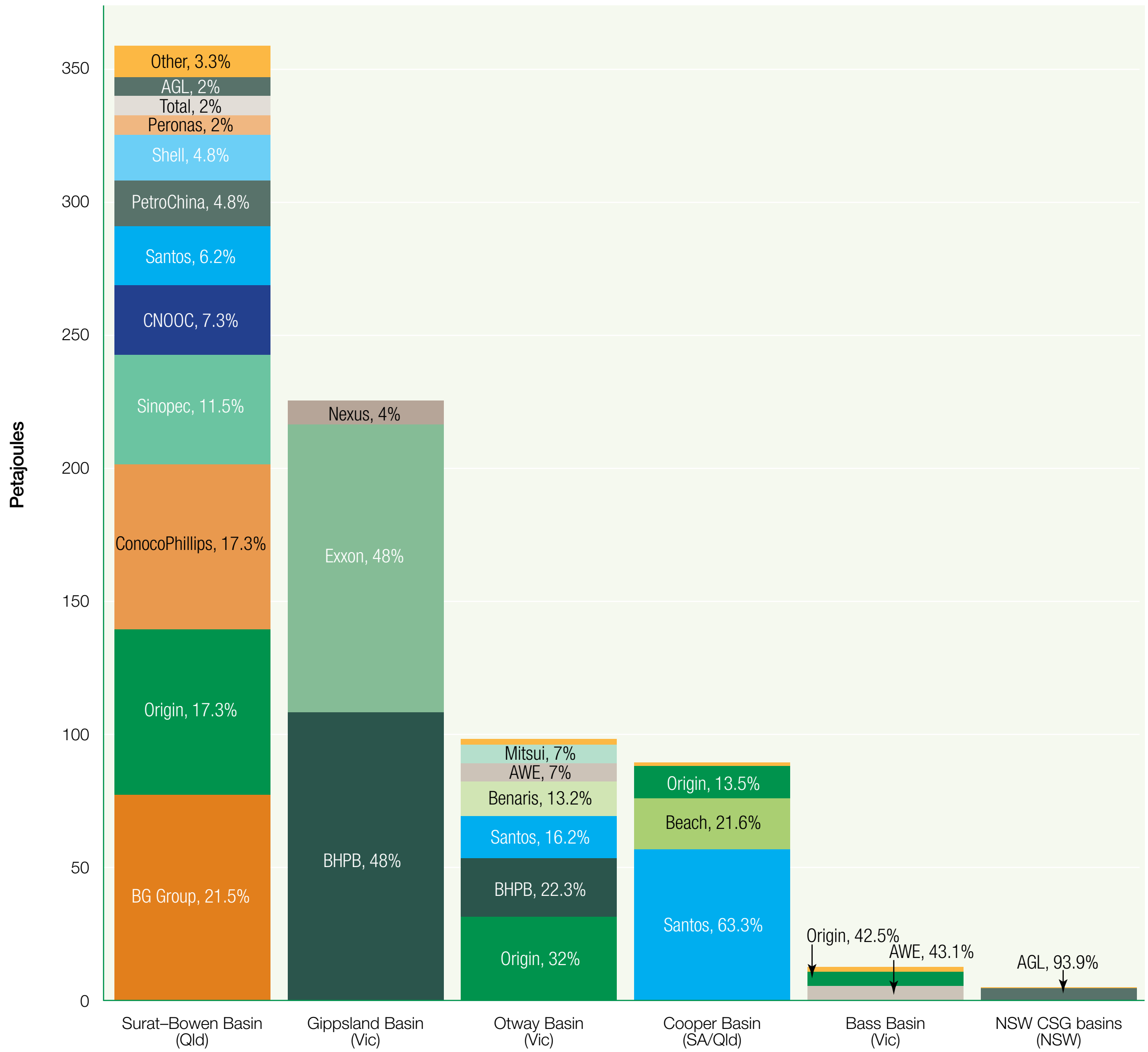
9 Energy Quest, *Energy Quarterly*, August 2015, pp. 10, 14, 16, 25–6.

10 ANZ, *Australia's gas industry, Research in-depth*, July 2015.

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

Figure 3.3

Market shares in gas production in eastern Australia, 2014–15



Notes:

Data are for the 12 months to 31 March 2015.

NSW CSG basins include the Sydney and Gunnedah basins.

Not all minority owners are listed.

Source: EnergyQuest 2015 (unpublished data).

stored gas reserves may be pivotal in meeting peak demand in southern Australia from 2016 if Cooper Basin gas is sold to Queensland LNG projects (which it considers likely).[12]

The key storage facilities serving southern Australia are:

- Victoria's Iona gas plant, which can store 23 PJ of gas and deliver 500 terajoules (TJ) of gas per day. In October 2015 QIC (a Queensland Government owned fund manager) acquired the facility from EnergyAustralia. The ACCC had previously raised concerns that a proposed sale of the facility to APA Group would consolidate gas storage ownership in Victoria and increase vertical integration in the gas market.[13]
- AGL Energy's LNG storage facility at Newcastle, which was developed to secure gas supply during peak periods and supply disruptions. Opened in July 2015, the facility has 1.5 PJ of storage capacity, with a peak supply capability of 120 TJ per day—enough to supply the greater Newcastle area for about two weeks.
- an LNG storage facility at Dandenong, Victoria (0.7 PJ), which provides the Victorian Transmission System with additional capacity for security of supply at times of peak demand.

In Queensland, AGL Energy stores gas at the depleted Silver Springs reservoir in central Queensland (35 PJ). The facility supported the development of the Queensland Curtis LNG project and allows AGL to manage its gas supply during seasonal variations in summer and winter. The Gladstone LNG project has 50 PJ of storage capacity at Roma.

The Cooper Basin Joint Venture owns 85 PJ of underground storage at Moomba and another 10 PJ at Ballera.[14]

3.2 Eastern Australia gas markets

In the domestic market, producers sell gas to major industrial, mining and power generation customers, and to energy retailers that onsell it to business and residential customers. With gas historically perceived as a substitute for coal and coal fired electricity generation, Australia's low cost coal sources effectively capped gas prices. But domestic gas prices have aligned more closely with international prices since the development of Queensland's LNG projects.

The method of contracting for gas supplies is also changing. While gas prices were historically struck under confidential, long term contracts, the industry has shifted towards shorter term contracts, the inclusion of review provisions, and the use of spot markets:

- A short term trading market for gas was launched in Sydney and Adelaide in 2010, with Brisbane following in 2011 (section 3.2.1). The market allows participants to manage contractual imbalances, and is supported by a Gas Bulletin Board (section 3.2.3).
- Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline constraints (section 3.2.2).
- A gas supply hub was launched at Wallumbilla, Queensland in March 2014. The hub, which links gas markets across eastern Australia, aims to relieve bottlenecks by facilitating short term gas trades (section 3.2.4).

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to spot markets and the bulletin board. Timely and accurate data and efficient pricing bring about confidence in gas markets and encourage efficient investment in energy infrastructure. The AER monitors the markets and bulletin board to identify and investigate compliance issues and to improve data quality. Its monitoring role at the Wallumbilla gas supply hub includes a focus on price manipulation.

The AER draws on its gas monitoring to publish weekly market reports.

3.2.1 Short term trading market

A short term trading market—a wholesale spot market for gas—operates at major hubs (junctions) linking transmission pipelines and distribution systems in eastern Australia. The Australian Energy Market Operator (AEMO) operates the market, which enhances transparency and competition by setting prices that reflect supply and demand conditions. The market has a floor price of $0 per gigajoule and a cap of $400 per gigajoule. Section 3.4.1 notes recent activity.

The market was launched in September 2010 in Sydney and Adelaide, and was extended to Brisbane in December 2011. Each hub is scheduled and settled separately, but all hubs operate under the same rules. Victoria operates a separate spot market (section 3.2.2).

The short term trading market provides a spot mechanism for parties to manage contractual imbalances between their gas injections (deliveries) into and withdrawals from the market. Participants include energy retailers, power generators and other large gas users. Shippers deliver gas for sale in the market, and users buy the gas for delivery

12 EnergyQuest, *Energy Quarterly*, August 2015, p.16.

13 ACCC, 'ACCC releases Statement of Issues on the proposed acquisition of EnergyAustralia's Iona Gas Plant by APA Group', Media release, 2 October 2015.

14 Core Energy Group, *Gas storage facilities, eastern and south eastern Australia*, Report produced for AEMO, February 2015.

to customers; many participants act both as shippers and users, but only their net position is traded.

Gas is traded a day ahead of the actual gas day, and AEMO sets a day-ahead (ex ante) clearing price at each hub, based on scheduled withdrawals and offers by shippers to deliver gas. All gas supplied according to the schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the rules oblige participants to bid in 'good faith'.

Based on the market schedule, shippers nominate the quantity of gas that they require from a pipeline operator, which develops a schedule for that pipeline to ensure it remains in physical balance. On the gas day, quantities delivered to and withdrawn from a hub may not match the day-ahead nominations, due to demand variations and other factors. As gas requirements become better known during the day, shippers may renominate quantities with pipeline operators (depending on the terms of their contracts).

Typically, gas traded at the spot price accounts for 15 per cent of wholesale volumes in Sydney and Adelaide, and 5 per cent in Brisbane, after accounting for net positions.[15] The balance of gas is sourced via bilateral contracts or vertical ownership arrangements between producers and retailers.

Pipeline operators use balancing gas to prevent imbalances in gas supply to distribution networks if demand forecasts prove inaccurate. AEMO procures this balancing gas—market operator services (MOS)—from shippers with capacity to absorb daily fluctuations, and the short term trading market sets a price for it. Gas procured under this balancing mechanism is settled primarily through payments by the parties responsible for the imbalances.

3.2.2 Victoria's declared gas market

Victoria launched a spot (declared) gas market in 1999 to manage flows on the Victorian Transmission System and allow market participants to buy and sell gas at spot prices. Market participants submit daily bids ranging from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap). Following initial bidding at the beginning of the gas day (6 am), the bids may be revised at 10 am, 2 pm, 6 pm and 10 pm.

At the beginning of each day, AEMO selects the least cost bids (gas supply offers) to match demand. This process establishes a spot market clearing price. In common with the short term trading market, only net positions are traded—that is, the difference between a participant's scheduled gas deliveries into and out of the market. AEMO can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term transmission constraints.[16]

Typically, gas traded at the spot price accounts for around 20 per cent of wholesale volumes in Victoria, after accounting for net positions.[17] The balance of gas is sourced via bilateral contracts or vertical ownership arrangements between producers and retailers.

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

- In the short term trading market, AEMO operates the financial market but does not manage physical balancing (which remains the responsibility of pipeline operators). In the Victorian market, AEMO undertakes both roles.
- The Victorian market is for gas only, while prices in the short term trading market cover gas as well as transmission pipeline delivery to the hub.

The Australian Energy Market Commission (AEMC) in 2015 reviewed spot gas markets in eastern Australia, including a stand-alone review of the Victorian declared market. Its December 2015 draft report on the Victorian market recommended transitioning to a new Southern Hub model offering enhanced flexibility and options for gas trading, with voluntary exchange trading and the creation of firm pipeline capacity trading rights at different locations in the network (see also section 3.4.4).[18]

3.2.3 Gas Bulletin Board

The Gas Bulletin Board (www.gasbb.com.au) is an electronic platform covering major gas production fields, storage facilities, major demand centres and transmission pipeline systems in eastern and south eastern Australia. It gives gas market participants and the general public immediate access to transparent, current system and market data. It covers:

- gas pipeline capabilities (maximum daily flow quantities, including bi-directional flow information), three day linepack capacity adequacy outlooks, seven day outlooks for pipeline capacity, three day outlooks for nominated gas flow quantities, and actual gas quantities

15 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 1 final report*, 23 July 2015, p. 90.

16 AEMO publishes an explanatory guide on its website: AEMO, *Guide to Victoria's declared wholesale market*, 2012.

17 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, *stage 1 final report*, 23 July 2015, p. 124.

18 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft report, 4 December 2015.

- production capabilities (maximum daily quantities) and seven day capacity outlooks for production facilities
- gas storage (maximum daily withdrawal and holding capacities) and seven day supply capacity outlooks for gas storage facilities, and actual injections/withdrawals.

In December 2014 AEMO launched a major redevelopment of the Gas Bulletin Board. The new website provides better data quality and improves transaction processes. An interactive map gives fast access to participant-supplied data on plant capacity and production, and pipeline capacity and flow, at any chosen point in the network. It also improved the registration process. AEMO has worked with participants and the AER in 2015 to drive improvements in data quality, compliance and reporting.

The Curtis Island LNG demand zone became effective on the bulletin board in October 2015. Transmission pipelines for the LNG projects, and facilities connected to those pipelines, must now provide information such as flow data, delivery nominations and capacity outlook. Production facilities in the Roma production zone also report, capturing new facilities operating in the area to serve the LNG projects. These changes are reflected in reported production rising from 900 TJ of gas per day in December 2014 to over 2000 TJ per day in October 2015.

The AEMC in 2015 reviewed the coverage of the Gas Bulletin Board to identify gaps. Currently, the bulletin board does not cover all east coast production facilities, pipelines or gas storage; rather, it covers facilities linked to declared zones. The AEMC also established a technical working group to review the wider role of the bulletin board, including any impediments to information provision, the accuracy and timeliness of information reported, and governance and cost recovery arrangements. The AEMC expected to make a determination in December 2015 on a rule change to enhance pipeline capacity trading information on the bulletin board (section 3.4.4).

3.2.4 Gas supply hub at Wallumbilla, Queensland

AEMO launched a new gas supply hub at Wallumbilla, Queensland, in March 2014. Wallumbilla hub is a pipeline interconnection point for the Surat–Bowen Basin, linking gas markets in Queensland, South Australia, NSW and Victoria (figures 3.2 and 3.10).

The hub promotes transparent gas trading, allowing participants to manage risk and imbalances. 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.

The hub's brokerage model allows buyers and sellers to trade spot (balance-of-day or day ahead) or forward (daily or weekly) gas products through a voluntary trading exchange. The mechanism sits alongside bilateral contracts for balancing gas requirements. The hub allows separate trading for gas at Wallumbilla's three delivery points: the South West Queensland, Roma to Brisbane and Queensland Gas pipelines.

The market design avoids the need to change infrastructure, operations or contracts. But participants require access to the transmission pipelines serving the hub, not all of which interconnect. To manage this issue, the hub is supported by a web based platform for participants to advertise their interest in buying or selling pipeline capacity.

Trading in the hub has been intermittent, but LNG exporters used the hub in late 2014 and during 2015 to manage their portfolios; typically, they sold surplus gas in the ramp-up to commissioning new LNG trains. Lumpy trading volumes and volatile hub prices reflected this behaviour.

Overall volumes are small in relation to the scale of the Queensland gas market. Around 10 participants made 573 trades totalling 3.2 PJ in 2014–15. Average trades total around 10 TJ per day, compared with daily production in the Wallumbilla area of around 1600 TJ per day. But activity rose during 2015 as more participants entered the market. Hub volumes recorded a new high in September 2015.

Various refinements for the hub were introduced in 2015:

- AEMO launched a benchmark price to help participants negotiate prices in gas contracts and to support a futures market.
- The Australian Securities Exchange launched Wallumbilla gas futures on 7 April 2015, using the Wallumbilla benchmark price as the reference price.
- AEMO launched a new monthly product in June 2015, to help with gas forward contracting.

In late 2015 AEMO was progressing further reforms to replace the hub's three trading locations with a single voluntary trading market. In December 2015, the AEMC recommended the hub's exchange trading model as a template for a new southern gas hub, to be located in Victoria.[19]

19 AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft report, 4 December 2015.

3.3 Upstream competition

An interconnected transmission pipeline system links gas basins in southern and eastern Australia. Gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are served by multiple transmission pipelines linking multiple gas basins; Brisbane is served by only one transmission pipeline (Roma to Brisbane).

The extent to which interconnection benefits customers depends on the availability of gas contracts and pipeline capacity from alternative providers. Capacity constraints limit access to some pipelines, although a customer may negotiate a capacity expansion. For covered pipelines, the regulator may be asked to arbitrate a dispute over a capacity expansion.

Figure 3.4 illustrates trends in gas delivery from competing basins into NSW, Victoria and South Australia since the bulletin board opened in July 2008. Trade flows in all regions became increasingly volatile in late 2014 and 2015, reflecting changing gas market dynamics associated with Queensland's LNG projects.

- NSW sources gas from basins in Queensland and central Australia (via the Moomba to Sydney Pipeline), and from Victoria (via the Eastern Gas Pipeline and the NSW–Victoria Interconnect). Gas flows on the Moomba to Sydney Pipeline fluctuate seasonally, while flows on the Eastern Gas Pipeline are usually steadier. In 2014 weaker gas demand in NSW caused a downturn in gas imports from Victoria; imports from Queensland via the Moomba to Sydney Pipeline were less affected, given Queensland's very low spot gas prices. Import volumes from Victoria recovered somewhat over 2015, but flows on the NSW–Victoria Interconnect grew increasingly volatile.
- While the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway Basin via the South West Pipeline (an artery of the Victorian Transmission System). Figure 3.4 illustrates the seasonal nature of Victorian gas demand, with significant winter peaks. The South West Pipeline had record flows in July 2015. Victoria's self-sufficiency in gas, and remoteness from the Queensland market, means the region has less volatile gas flows than have other regions.
- South Australia sources gas from central Australia and Queensland via the Moomba to Adelaide Pipeline, and from Victoria via the SEA Gas Pipeline. Trade flows on both pipelines were lower in 2015 than in the previous two years. The Moomba to Adelaide and SEA Gas pipelines were physically interconnected in 2015, enabling Victorian gas to bypass Adelaide to be shipped north. The capacity to bypass Adelaide is making it increasingly difficult for large South Australian gas users to reliably source gas; for example, the gas fired Pelican Point generator was partly mothballed in early 2015.

Major transmission pipelines were re-engineered in 2015 for bidirectional flows, allowing gas to flow north when required to meet LNG shipments, and south when surplus gas is available in Queensland (section 3.4.3 and figure 3.10).

3.4 State of the eastern gas market

Queensland's LNG industry is exerting a significant influence on the domestic gas market. Two major projects commenced exports in 2015, and a third will begin by early 2016. Demand for LNG production at Gladstone will almost triple east coast gas production by 2018 (figure 3.5), when Australia will rival Qatar as the world's largest LNG exporter.[20]

While Queensland's LNG projects each have dedicated gas reserves, they also source reserves that would otherwise be available to the domestic market. This scenario is causing difficulties for domestic customers seeking to negotiate gas purchases under medium to long term contracts. With a large number of domestic gas supply contracts soon to expire, gas buyers claim they are being offered fewer contracts, with shorter terms and less flexibility to vary volumes.[21]

In these tight market conditions, prices in new gas contracts are increasingly linked to international oil prices or LNG netback.[22] The Australian Government's energy green paper in 2014 noted sellers have access to more market information than have buyers, raising policy concerns.[23] Additionally, the spot markets have been volatile since the LNG projects moved into development.

In this rapidly evolving and complex environment, the efficiency and competitiveness of east coast gas markets is under scrutiny. The COAG Energy Council in December 2014 directed the AEMC to review the design, function and roles of spot gas markets and gas pipeline arrangements. In March 2015, the Victorian Government tasked the AEMC with a separate review of the Victorian market. The AEMC's stage 1 report on east coast markets referred to

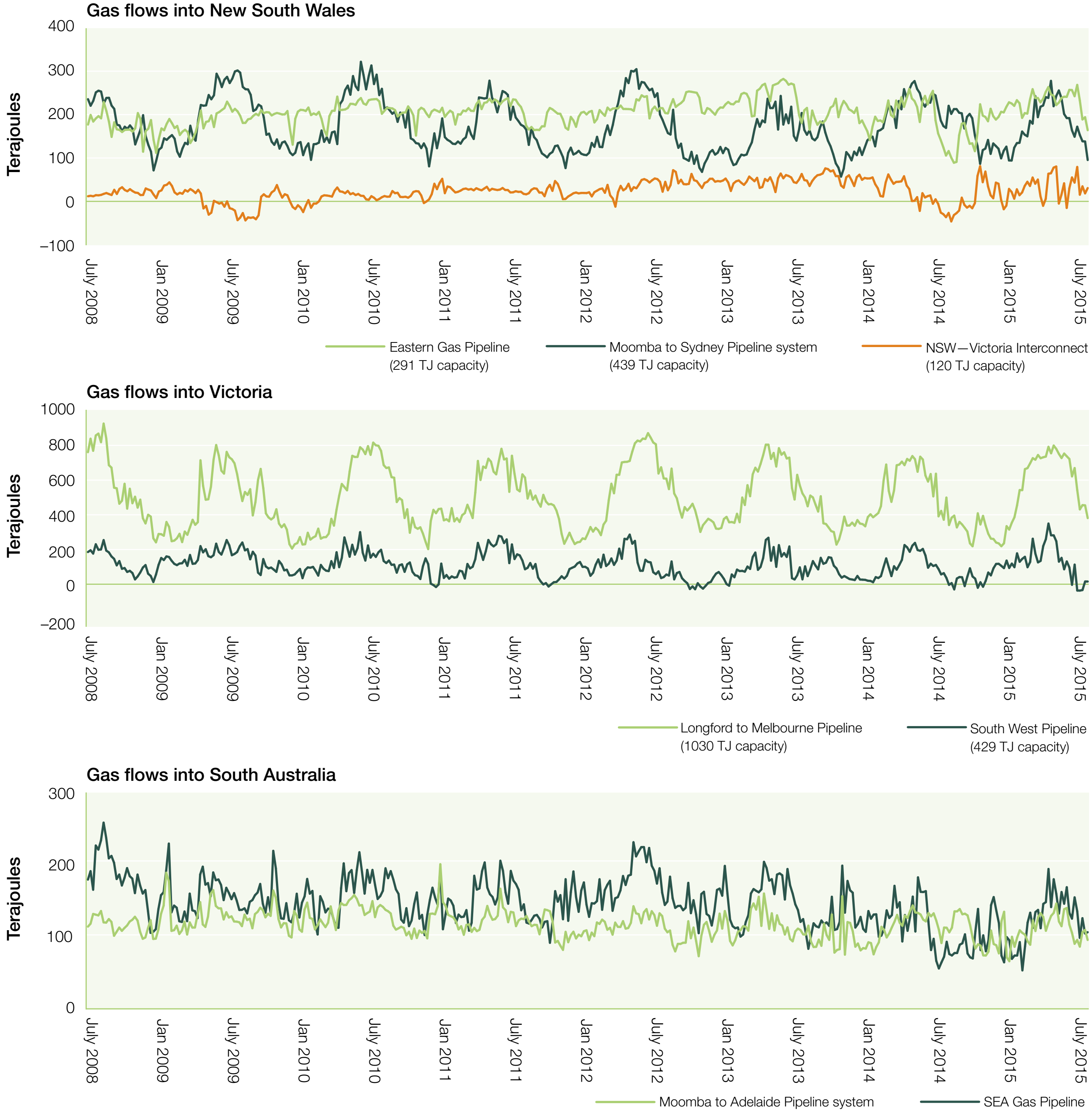
20 International Gas Union, *World LNG report*, 2014.

21 ACCC, *East coast gas inquiry, Issues paper*, 2015, pp. 9, 14.

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

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

Figure 3.4
Gas flows in eastern Australia

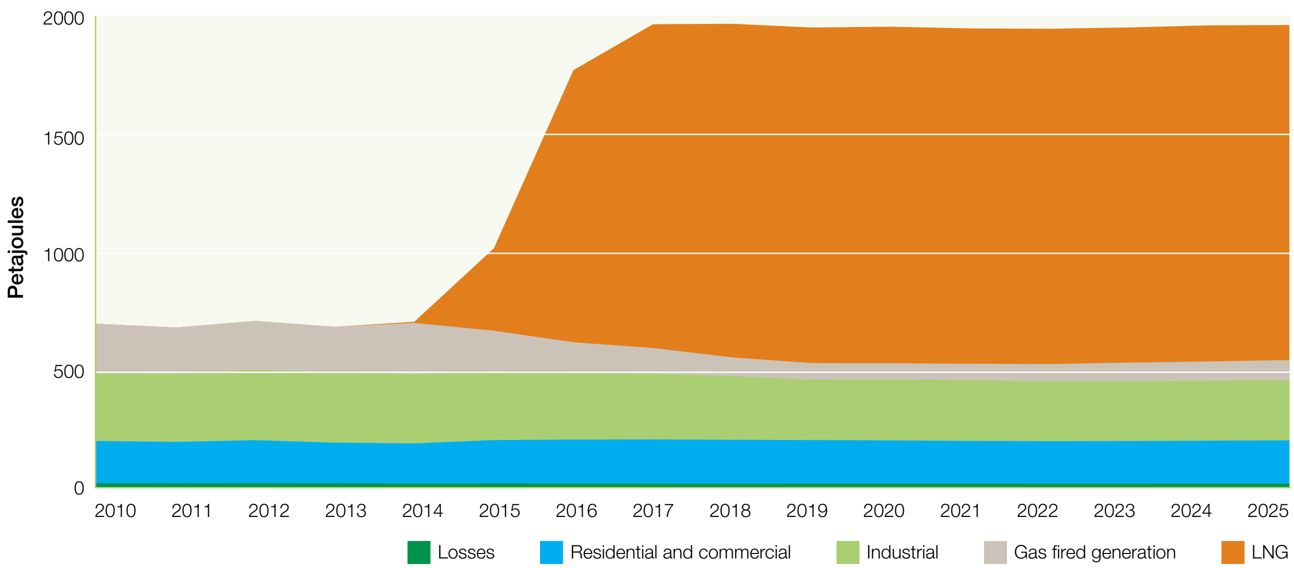


Note: Negative flows on the NSW–Victoria Interconnect represent flows out of NSW into Victoria.

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

Figure 3.5

East coast gas production



Source: AEMO, *National gas forecasting report December 2015*.

'fragmented and disjointed arrangements'.[24] The AEMC recommended immediate reforms, on which progress occurred in 2015. It also recommended a longer term roadmap for gas market development, based around the creation of two virtual trading hubs, a streamlined bulletin board and efficient pipeline capacity trading (section 3.4.4).

Concurrently, the Australian Government in April 2015 tasked the ACCC with inquiring into the competitiveness and structure of the east Australian gas industry.[25] Some stakeholders voiced concerns in submissions to the inquiry that industry players are taking advantage of a volatile market through non-competitive pricing, oil linked pricing, joint marketing, high pipeline charges, a lack of innovative transportation deals, and capacity hoarding on pipelines.[26]

3.4.1 Market activity

While domestic gas supply contracts are being struck with reference to global prices, spot gas prices in eastern Australia are volatile, reflecting volatile shifts in short term supply volumes (figure 3.6).

Queensland spot prices steadily fell during 2014. Gas production rose in the run-up to commissioning the first LNG train, creating large volumes of 'ramp' gas that was sold into the Brisbane spot market. Daily prices collapsed to near zero in late November 2014 (figure 3.7).[27] But when LNG exports commenced in January 2015, prices quickly rose, with some daily averages above $8 per gigajoule.

Brisbane prices remained volatile during 2015, periodically falling below $1 per gigajoule, but then rising as high as $12. This volatility largely revolved around the timing of LNG shipments and the commissioning of new LNG trains. Surplus gas available between LNG shipments was also sold into spot markets. But when gas was being loaded for export, prices tended to rise due to tighter supply conditions. This volatility will likely persist at least until all three LNG projects are fully operational.

Trade at the Wallumbilla hub rose over 2015, as greater quantities of surplus gas linked to the LNG projects was made available to the market (figure 3.8). Lower spot gas prices also increased short term demand for gas by electricity generators.[28] Trading volumes for the hub thus reached new records in September 2015, with a greater diversity of sellers entering the market.

24 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 1 final report*, 23 July 2015, p.26.

25 ACCC, 'Inquiry into Eastern and Southern Australian Wholesale Gas Prices', Media release, 13 April 2015.

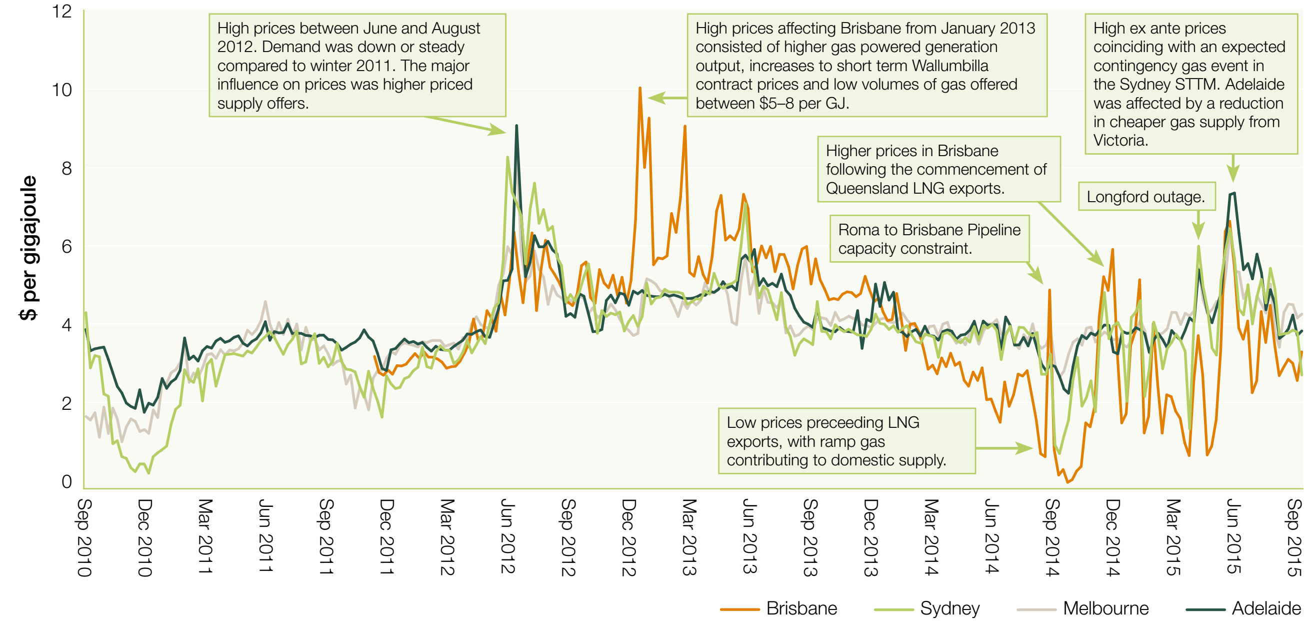
26 Annabel Hepworth and Matt Chambers, 'Gas giants 'ignore' domestic market', *The Australian Business Review*, July 15 2015; 'Gas producers profiteering,' *Australian Financial Review*, 6 July 2015.

27 The Brisbane hub of the short term trading market and the Wallumbilla gas supply hub.

28 Argus, *LNG daily*, 30 January 2015.

Figure 3.6

Spot gas prices—weekly averages

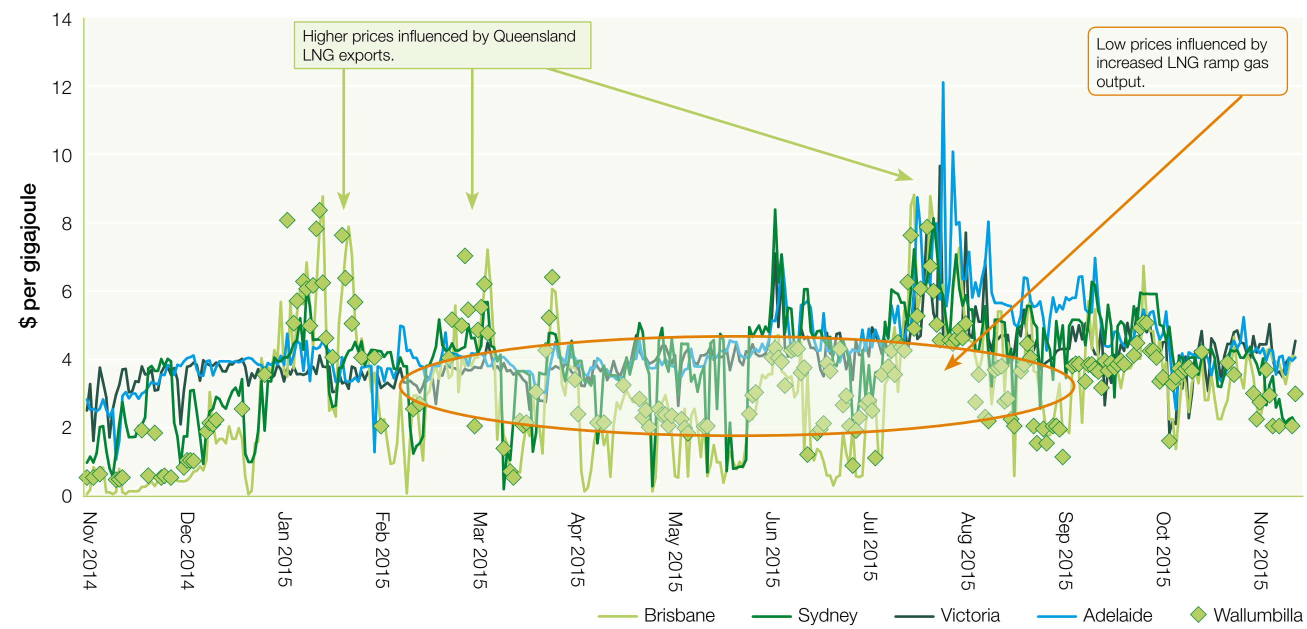


Notes: Volume weighted ex ante prices derived from demand forecasts. Sydney, Adelaide and Brisbane data are short term trading market prices. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's transmission withdrawal tariff for the two Melbourne metropolitan zones. The Brisbane price for 2011–12 covers 1 December 2011 (market start) to 30 June 2012.

Source: AER; AEMO.

Figure 3.7

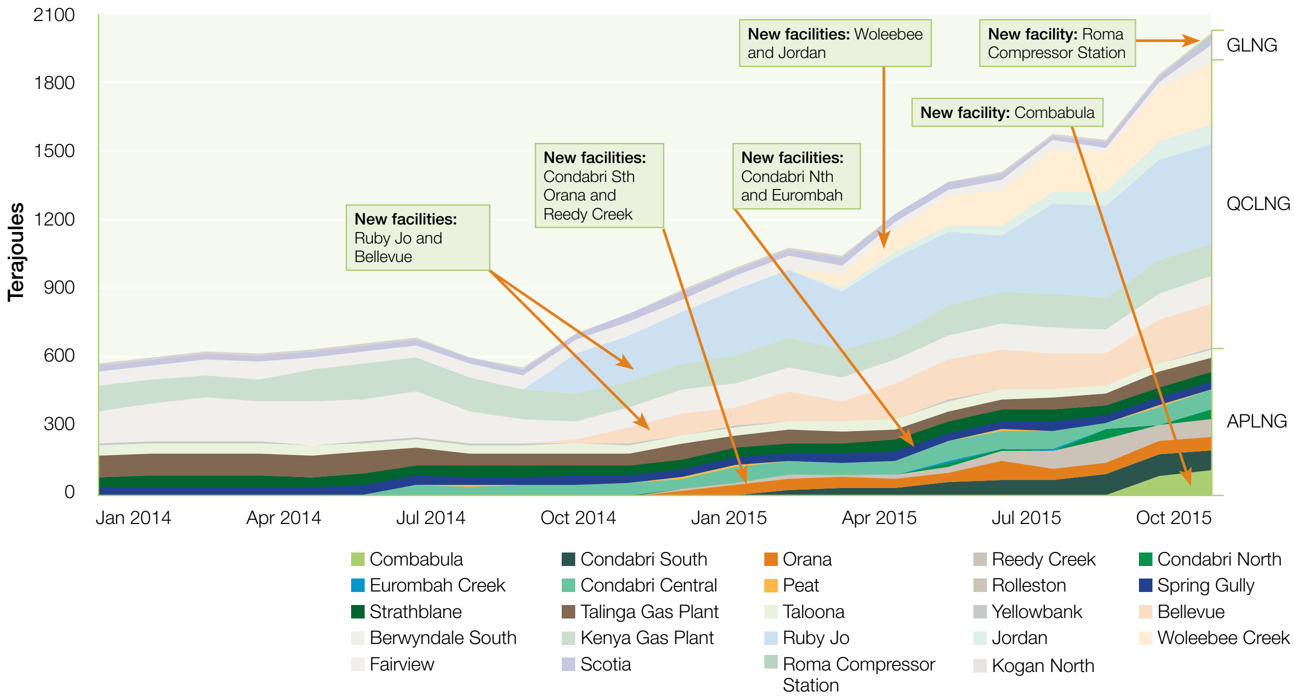
Daily spot prices from November 2014



Sources: AER; AEMO.

Figure 3.8

Gas production around Roma, Queensland



GLNG, Gladstone LNG; QCLNG, Queensland Curtis LNG; APLNG, Australia Pacific LNG.

Note: The Roma region covers the Surat–Bowen Basin from which gas is sourced, processed and supplied to the Queensland Gas Pipeline, Roma to Brisbane Pipeline and South West Queensland Pipeline.

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

Queensland market volatility also affected the southern states. Some ramp gas flowed south along the QSN link connecting Queensland with NSW and South Australia (figure 3.11). During high price periods in Queensland, the QSN Link changed flow direction to increase gas supplies into Queensland, causing Sydney prices to track higher as well. Prices in all hubs trended higher during the build-up to GLNG commissioning its LNG project in October 2015.

Local factors periodically affected the market. Sydney prices spiked on 22 July 2015, when a line valve closure on the Moomba to Sydney Pipeline caused a drop in pressure in the distribution network. Similarly, a production outage at Otway in late July caused Adelaide prices to spike. Brisbane prices briefly spiked in early October 2014 when planned outages and capacity constraints on the Roma to Brisbane Pipeline temporarily restricted capacity to transport gas.[29]

3.4.2 Eastern Australia market outlook

Eastern Australia's supply–demand balance has tightened since the commencement of LNG exports from Gladstone in 2015, and prices are trending higher. Given the LNG projects source some of their requirements from gas reserves that would otherwise be available domestically, the eastern gas market will further tighten once all three projects are operating at full capacity.

While new gas development proposals in Bass Strait (Victoria), the Cooper Basin (central Australia) and the Gloucester Basin (NSW) were at advanced stage in 2015, all were subject to uncertainty. Another source of uncertainty is future domestic gas demand. Rising gas contract prices, weak electricity demand and the abolition of carbon pricing have stifled growth in gas powered generation, which accounts for 31 per cent of domestic gas demand.[30] Gas generators announced for withdrawal in the next few years include Tamar Valley (Tasmania), Daandine and Mount Stuart

29 AER, *Significant price variation report*, 8 December 2014.

30 ESAA, *Electricity gas Australia 2015*.

(Queensland), and Smithfield (NSW). AEMO forecast gas consumption by gas fired generators will fall from an average of 200 PJ over 2010–14, to 70 PJ in 2019. The largest fall is expected for Queensland, from 89 PJ to 26 PJ (figure 3.9).

There is conjecture about the likely net impact of these conflicting forces on the future supply–demand balance for gas in eastern Australia. AEMO's 2015 *Gas statement of opportunities* forecast falling domestic gas consumption will result in no region having gas supply gaps in the period to 2019, and only Queensland may face a supply gap beyond that time.

AEMO in 2015 reversed earlier forecasts of a gas supply shortfall for NSW, given weaker demand forecasts for industrial, residential and commercial gas consumption. It also found upgrades to gas market infrastructure, the commissioning of the Newcastle storage facility, and increased capacity on the NSW–Victoria Interconnect will alleviate gas supply gaps.[31]

EnergyQuest argued AEMO's 2015 forecasts understate gas demand, overstate future east coast gas production, and do not sufficiently address the risks of undeveloped gas reserves.[32] Under EnergyQuest's revised assumptions, with stronger demand growth, and assuming Cooper Basin will not supply gas to the southern states after 2016 (which EnergyQuest considers to be realistic), it predicts domestic supply and demand will be finely balanced to 2020.[33]

ANZ Bank predicted LNG prices will recover from 2015, putting upward pressure on domestic supply. It predicted east coast wholesale gas prices will double by 2018, reaching $10 per gigajoule in Brisbane.[34]

3.4.3 Market responses

In the current uncertain market environment, industry is taking measures to manage the risks of possible supply shortfalls. The initiatives include:

- capacity expansions on existing transmission pipelines
- re-engineering of transmission pipelines for bi-directional flows
- interconnecting existing transmission pipelines
- interconnecting the eastern gas market with the Northern Territory
- building new gas storage facilities
- developing gas fields and basins.

Pipeline expansions

Pipeline owners are expanding capacity on transmission pipelines to accommodate rising demand.

- APA is progressively expanding capacity on the NSW–Victoria Interconnect to accommodate increased northbound gas exports from Victoria. Four expansions announced from 2013–15 collectively treble the pipeline's capacity. APA Group is also looping (duplicating) parts of the Victorian Transmission System and Moomba to Sydney Pipeline to accommodate northbound exports. The latest round of expansions is due for completion in 2016.[35]
- Jemena in 2015 announced a capacity expansion of the Eastern Gas Pipeline to boost northbound capacity.

Bidirectional pipeline flows

Major transmission pipelines have been re-engineered for bidirectional flows to allow a flexible market response to changes in Queensland's supply–demand balance (figure 3.10). The upgraded facilities include the South West Queensland Pipeline, the QSN Link (connecting South Australia and Queensland), the Roma to Brisbane Pipeline (from July 2015), the Moomba to Sydney Pipeline (from September 2015), and the Moomba to Adelaide Pipeline (from mid–September 2015). The NSW–Victoria Interconnect is also bi-directional.

The first northbound gas flows on the QSN Link were shipped in December 2014. The pipeline's flow direction reversed several times in 2015, in response to spot price movements in Queensland (figure 3.11). High spot prices in Queensland were typically mirrored in a switch to northbound flows on the QSN.

Interconnection of existing pipelines

The SEA Gas and Moomba to Adelaide pipelines were interconnected on 1 July 2015, allowing Victorian gas to be shipped north via South Australia. This development was accompanied by works to make the Moomba to Adelaide Pipeline bi-directional.

Interconnection with the Northern Territory

The NSW and Northern Territory governments in November 2014 signed a Memorandum of Understanding to develop a transmission pipeline connecting the Northern Territory with eastern gas markets. In November 2015, Jemena was announced as the preferred bidder for the North East Gas

31 AEMO, *Gas statement of opportunities update*, April 2015.

32 EnergyQuest, *Energy Quarterly*, May 2015,

33 EnergyQuest, *Energy Quarterly*, August 2015.

34 ANZ, *Australia's gas industry, Research in-depth*, July 2015.

35 'APA signs new pipeline deal', *Gas Today*, 24 July 2015.

Figure 3.9
Annual domestic gas consumption, by jurisdiction

Source: *AEMO, National gas forecasting report 2014*.

Interconnector, to run from Tennant Creek to Mount Isa. The pipeline will effectively link the Bonaparte Basin off northern Australia with gas markets in southern and eastern Australia. Jemena expects to complete the pipeline by 2018.

New gas storage facilities

Gas storage capacity is being expanded, including at Newcastle (completed 2015) (section 3.1.3) and on the Tasmanian Gas Pipeline.

Development of gas fields and basins.

Various gas development proposals were at an advanced stage in 2015, including in Bass Strait (Victoria), the Cooper Basin (central Australia) and the Gloucester Basin (NSW). All projects are subject to some form of uncertainty.[36] The introduction of government regulations in response to community concerns about health and environmental impacts, for example, delayed the development of CSG projects in NSW.

The NSW Government in July 2015 commenced a new strategic framework to determine appropriate areas to develop and extract gas, accounting for economic benefits and evidence of the effects on the environment and communities. It extinguished pending licence applications under previous arrangements. The NSW Environment Protection Authority is the lead regulator for gas exploration and production, and is responsible for compliance and enforcement of conditions under gas licences. A Bill to ban CSG production in northern NSW, and to place a moratorium on all exploration across the state, was narrowly defeated in the NSW Parliament in August 2015.

Concerns about environmental impacts also led the Victorian Government to place a moratorium on CSG extraction and fracking, which it later extended to cover all onshore gas exploration.[37] The moratorium will continue until at least 2016.

The potential to develop unconventional gas in the Cooper Basin is significant. While two shale wells were online and producing in 2014,[38] Santos indicated production could take up to a decade to be commercially viable.[39]

36 EnergyQuest, *Energy Quarterly*, August 2015, p. 15.

37 Grattan Institute, *Gas at the crossroads*, October 2014, p. 9.

38 Santos, 2014 *CLSA investors' forum presentation*, 15 September 2014.

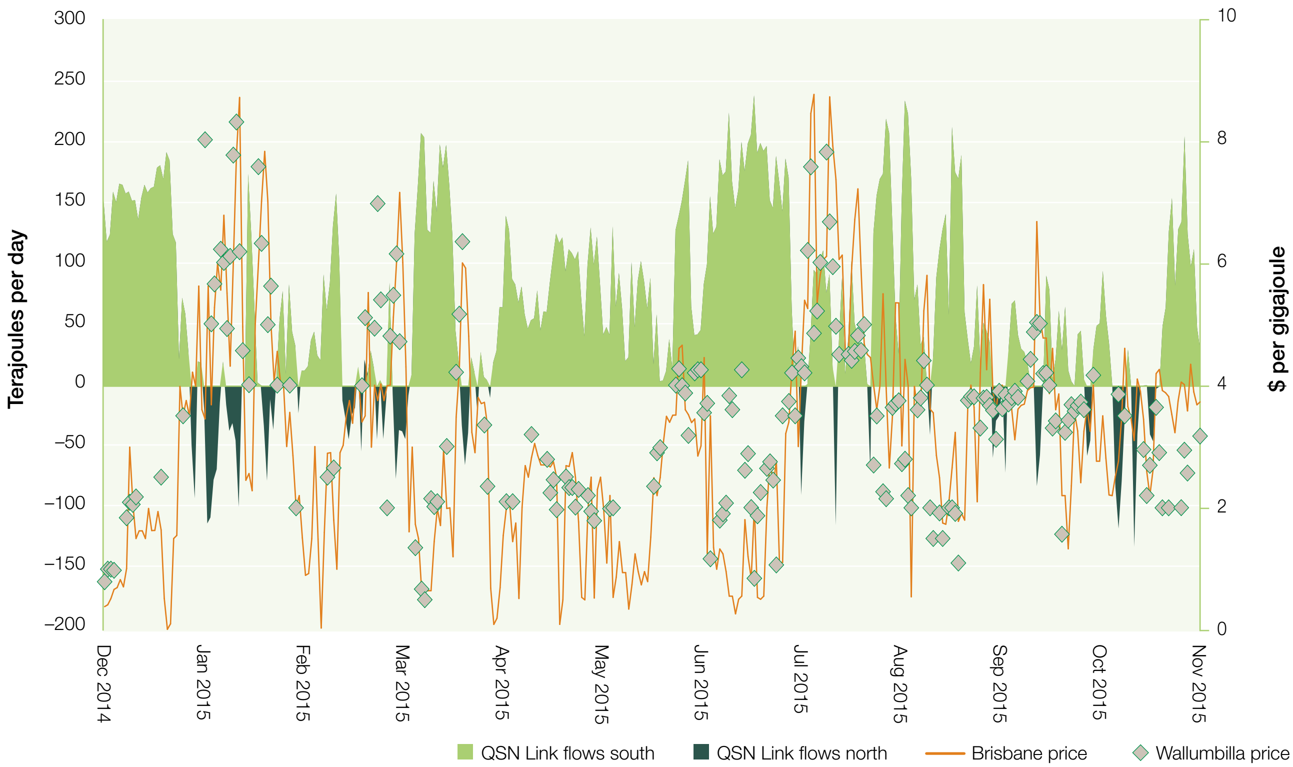
39 'Shale gas success still a decade away for Australia, says Santos,' *The Australian*, 26 September 2014.

Figure 3.10

East coast market dynamics

Source: AER.

Figure 3.11
Gas flows on the QSN Link, and Queensland spot prices



Source: AER; AEMO.

3.4.4 Government policy responses

Policy makers are progressing reforms to help alleviate pressures in the eastern gas market. The reform programs, some of which overlap, include:

- reforming gas spot market design
- pipeline capacity trading reforms
- Wallumbilla gas supply hub reforms
- a Moomba gas supply hub
- the ACCC inquiry into the competitiveness of east coast gas markets.

Reforming gas spot market design

The COAG Energy Council in December 2014 directed the AEMC to review the design, function and roles of spot gas markets and gas pipeline arrangements. In March 2015, the Victorian Government tasked the AEMC with a separate review of the Victorian market.

The AEMC in July 2015 reported the east coast gas market and underpinning regulatory frameworks are fragmented and disjointed, despite ongoing reform. It noted a diversity of arrangements, including:

- three different spot market designs (the short term trading market, the Victorian gas market and the Wallumbilla hub) with five pricing points
- two different pipeline carriage arrangements (market carriage in Victoria and contract carriage elsewhere)
- four sets of pipeline regulatory arrangements (full regulation, light regulation, no regulation and 15 year coverage exemptions).[40]

The AEMC raised specific issues for the Victorian market, including difficulties in identifying a clear price to form the basis of derivatives trading. It also found Victoria's market carriage model may not provide effective incentives for market led investment.[41]

40 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 1 final report*, 23 July 2015.

41 AEMC, *Review of the Victorian Declared Wholesale Gas Market, Discussion paper*, 10 September 2015.

The AEMC proposed immediate actions to improve market and price transparency in gas markets. Work was underway in late 2015 to implement several of the AEMC's reform recommendations, including:

- developing an ABS wholesale gas price index by early 2016
- harmonising the gas day start time for spot markets across the east coast—the COAG Energy Council proposed a rule change to this effect in November 2015
- enhancing pipeline capacity trading information on the Gas Bulletin Board, to promote trade in contracted but idle capacity—the AEMC expected to make a determination on a rule change to implement this reform in December 2015.

The AEMC also established a technical working group to review the role of the bulletin board, including any impediments to information provision, the accuracy and timeliness of information reported, and governance and cost recovery arrangements.

The AEMC's stage 2 draft report in December 2015 proposed a longer term roadmap for gas market development, based around the creation of two virtual trading hubs, a streamlined bulletin board and efficient pipeline capacity trading. The hubs would consist of a northern hub located initially at Wallumbilla, Queensland, and a southern hub in Victoria (to eventually replace the declared gas market currently operating in Victoria). Each hub would adopt exchange-based trading similar to that already in place at the Wallumbilla gas supply hub. Participants could also buy and sell gas via bilateral over-the-counter trading or long-term contracts.[42]

Pipeline capacity trading reforms

The COAG Energy Council in 2015 proposed a rule change to the AEMC to reform pipeline capacity trading arrangements. Throughout the year, some pipelines have significant contracted capacity that is idle and not available to the market.

The AEMC in July 2015 made a draft rule to improve information on the Gas Bulletin Board, including detailed information on gas pipeline and gas storage capacity. The reforms aim to reduce search and transaction costs, thereby promoting pipeline and storage capacity trading.

42 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 2 draft report*, 4 December 2015.

Separately, the AEMC began consulting in September 2015 on an optimal model to facilitate trading in contracted but unused pipeline capacity in the future.[43]

Wallumbilla gas supply hub reform

The AEMC in 2015 noted participants find the Wallumbilla gas supply hub to be a useful and low cost platform for gas trade. But physical limitations on flows impede liquidity, with trade split across Wallumbilla's three major pipelines. In 2015 AEMO progressed reforms to replace the hub's three trading locations with a single voluntary trading market, and introduce new optional services.

Moomba gas supply hub

AEMO is designing a gas trading hub for launch in July 2016 at Moomba, South Australia. Moomba is a gateway for the eastern Australia gas market, linking gas production in south east Australia with markets in Queensland.

The AEMC noted the hub may represent an appropriate transitional measure until the new northern and southern hubs mature.[44]

ACCC review of market competitiveness

In April 2015 the Minister for Small Business directed the ACCC to hold an inquiry into the competitiveness of east coast gas markets. The ACCC is considering competition at the gas producer, processor, pipeline and wholesale market levels, and matters such as access to infrastructure, barriers to entry, and anti-competitive behaviour. It will report to the Minister by April 2016.[45]

43 AEMC, *Pipeline regulation and capacity trading discussion paper, East Coast Wholesale Gas Market and Pipeline Frameworks Review*, 18 September 2015.

44 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 2 draft report*, 4 December 2015.

45 ACCC, 'Inquiry into Eastern and Southern Australian Wholesale Gas Prices', Media release, 13 April 2015.

Construction of the Wallumbilla–Gladstone Pipeline (image courtesy of BG Group)

4 GAS PIPELINES

Gas pipelines transport gas from upstream producers to downstream energy customers (figure 3.1). This chapter focuses on pipelines in jurisdictions for which the Australian Energy Regulator (AER) has regulatory responsibilities—that is, jurisdictions other than Western Australia.

High pressure *transmission* pipelines transport gas from production fields to major demand centres (hubs). The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. Australia's gas transmission network covers over 20 000 kilometres.

An interconnected transmission pipeline network runs from Queensland to Tasmania, allowing competition between gas basins and strengthening security of supply. While Western Australia and the Northern Territory are not interconnected with eastern Australia, Jemena won a tender in 2015 to construct the North East Gas Interconnector (NEGI) from Tennant Creek in the Northern Territory to Mount Isa, Queensland, by 2018.

A network of *distribution* pipelines delivers gas from demand hubs to commercial and residential customers. A gas distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers. The total length of gas distribution networks in eastern Australia is around 74 000 kilometres, with a combined asset value of $9 billion.

Gas is reticulated to most Australian capital cities, major regional areas and towns, but the proportion of households and businesses connected to the networks varies across regions. Gas penetration in the residential market in 2015 was around 90 per cent in Victoria, 80 per cent in the Australian Capital Territory (ACT), 60 per cent in South Australia, 45 per cent in New South Wales (NSW), 10 per cent in Queensland and 5 per cent in Tasmania.[1]

Figure 4.1 illustrates the routes of major transmission pipelines and the locations of major distribution networks in jurisdictions for which the AER has regulatory responsibilities. Figure 3.2 includes a more extensive mapping of gas transmission pipelines, including those in Western Australia. Tables 4.1 and 4.2 summarise the major gas pipelines and networks.

1 Residential gas customer numbers: AER, *Retail statistics*, 2015, www.aer.gov.au/retail-markets/retail-statistics; Total household numbers; Australian Bureau of Statistics 2015.

4.1 Ownership

Australia's gas pipelines are privately owned. APA Group is the principal owner in gas transmission. State Grid Corporation of China and Singapore Power International own a number of transmission and distribution pipelines through Jemena and AusNet Services (tables 4.1 and 4.2). Cheung Kong Infrastructure in 2014 acquired full ownership of Australian Gas Networks, with interests principally in gas distribution.

- *APA Group* owns three NSW pipelines (including the Moomba to Sydney Pipeline), the Victorian Transmission System, five major Queensland pipelines (including three pipelines that jointly connect the Cooper Basin in central Australia with Brisbane) and a Northern Territory pipeline. It has a 50 per cent interest in the SEA Gas Pipeline running from Victoria to South Australia, and a 20 per cent interest in Energy Infrastructure Investments (EII), which owns pipelines in the Northern Territory.

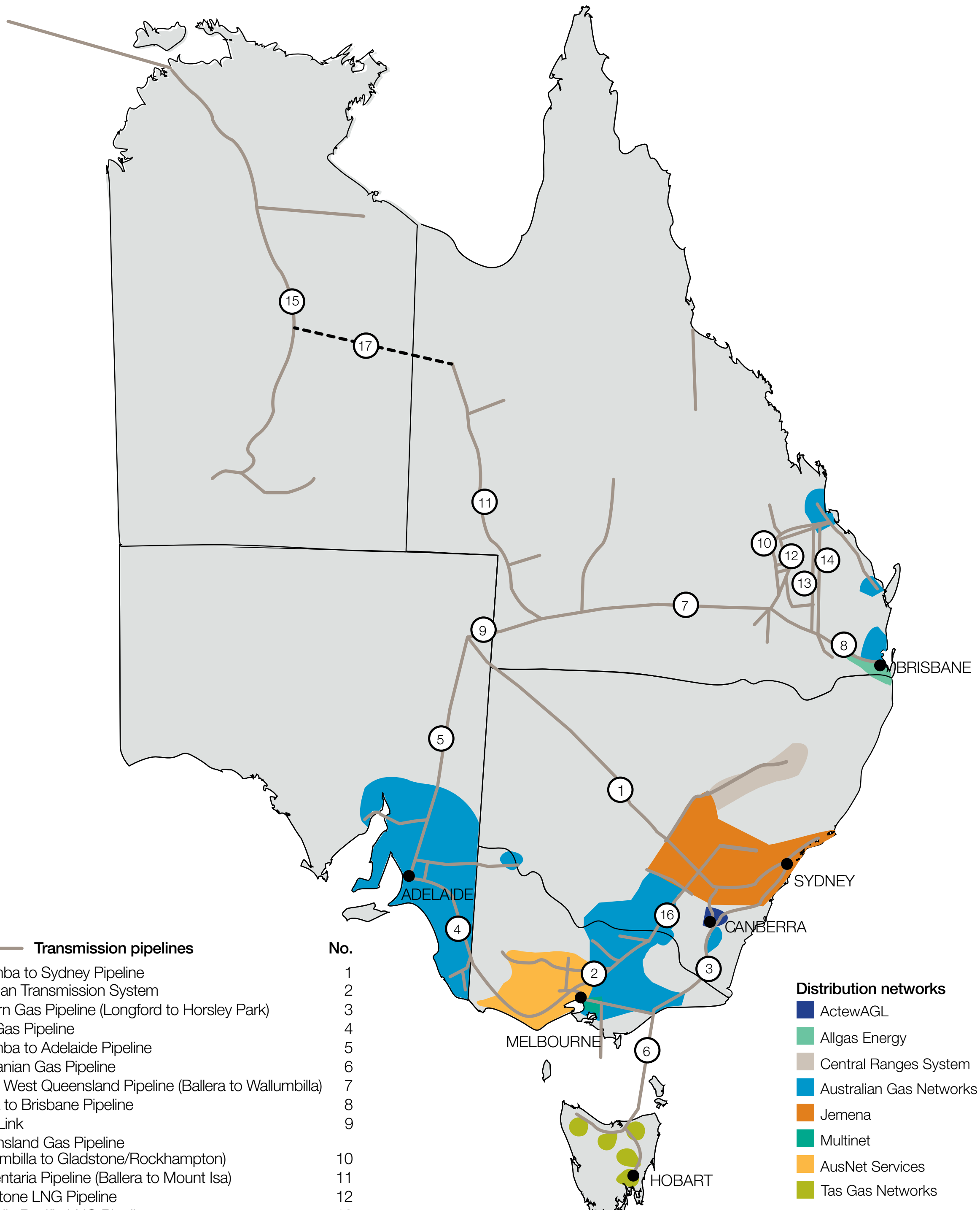
  APA Group also has a minority interest in the Allgas Energy distribution network in Queensland, and owns the Central Ranges system in NSW. It manages and operates these assets.
- *Australian Gas Networks* (Cheung Kong Infrastructure) owns distribution networks in Victoria, South Australia, Queensland and the Northern Territory, along with a transmission pipeline in the Northern Territory.
- *Jemena* owns the Eastern Gas, VicHub and Queensland Gas pipelines, along with the principal distribution network in NSW and 50 per cent of the ACT network. Jemena's owners (*State Grid Corporation of China)*, and *Singapore Power International,* also have equity interest in Victoria's AusNet Services gas distribution network. In 2015 Jemena won a tender to construct a transmission pipeline linking Queensland with the Northern Territory.

The ownership links between gas and electricity networks are significant. Jemena, AusNet Services, APA Group and Cheung Kong Infrastructure have ownership interests (some substantial) in both sectors (section 2.1.1).

4.2 Regulation of gas pipelines

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

Figure 4.1
Major gas pipelines—eastern Australia



Transmission pipelines	No.
Moomba to Sydney Pipeline	1
Victorian Transmission System	2
Eastern Gas Pipeline (Longford to Horsley Park)	3
SEA Gas Pipeline	4
Moomba to Adelaide Pipeline	5
Tasmanian Gas Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Roma to Brisbane Pipeline	8
QSN Link	9
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	10
Carpentaria Pipeline (Ballera to Mount Isa)	11
Gladstone LNG Pipeline	12
Australia Pacific LNG Pipeline	13
Queensland Curtis LNG Pipeline	14
Amadeus Basin to Darwin Pipeline	15
NSW–Victoria Interconnect	16
North East Gas Interconnector (proposed)	17

Source: AER.

Table 4.1 **Major gas transmission pipelines**

PIPELINE	LENGTH (KM)	CAPACITY (TJ/D)	COVERED?	OWNER
EASTERN AUSTRALIA				
QUEENSLAND				
North Queensland Gas Pipeline	391	108	No	Victorian Funds Management Corporation
Queensland Gas Pipeline (Wallumbilla to Gladstone)	629	149	No	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
Carpentaria Pipeline (Ballera to Mount Isa)	840	119	Yes (light)	APA Group
Berwyndale to Wallumbilla Pipeline	113		No	APA Group
Dawson Valley Pipeline	47	30	No (revoked 2014)	Westside 51%, Mitsui 49%
Roma (Wallumbilla) to Brisbane	440	233/125	Yes (2012–17)	APA Group
Wallumbilla to Darling Downs Pipeline	205	400	No	Origin Energy
South West Queensland Pipeline (Ballera to Wallumbilla)	756	404/340	No	APA Group
QSN Link (Ballera to Moomba)	180	404/340	No	APA Group
Gladstone LNG Pipeline	435	1430	No	Santos, Petronas, Total, Kogas
Wallumbilla Gladstone Pipeline	334	1530	No	APA Group
Australia Pacific LNG Pipeline	362	1530	No	Origin Energy, ConocoPhillips, Sinopec
NEW SOUTH WALES				
Moomba to Sydney Pipeline	2029	439/381	Partial (light)	APA Group
Central West Pipeline (Marsden to Dubbo)	255	10	Yes (light)	APA Group
Central Ranges Pipeline (Dubbo to Tamworth)	300	7	Yes (2005–19)	APA Group
Eastern Gas Pipeline (Longford to Sydney)	795	291	No	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
VICTORIA				
Victorian Transmission System (GasNet)	2035	1030	Yes (2013–17)	APA Group
South Gippsland Natural Gas Pipeline	250		No	DUET Group
VicHub		126/120	No	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SOUTH AUSTRALIA				
Moomba to Adelaide Pipeline	1185	241/55	No	QIC Global Infrastructure
SEA Gas Pipeline (Port Campbell to Adelaide)	680	314	No	APA Group 50%, Retail Employees Superannuation Trust 50%
TASMANIA				
Tasmanian Gas Pipeline (Longford to Hobart)	734	129	No	Palisade Investment Partners
NORTHERN TERRITORY				
Bonaparte Pipeline	287	80	No	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)
Amadeus Gas Pipeline	1512	104	Yes (2011–16)	APA Group
Daly Waters to McArthur River Pipeline	330	16	No	Power and Water
Palm Valley to Alice Springs Pipeline	140	27	No	Australian Gas Networks (Cheung Kong Infrastructure)

TJ/d, terajoules per day.

Note: The Moomba to Sydney Pipeline is uncovered from Moomba to the offtake point of the Central West Pipeline at Marsden.

Sources: National Gas Bulletin Board (www.gasbb.com.au); Bureau of Resources and Energy Economics; EnergyQuest; corporate websites.

Table 4.2 **Gas distribution networks in eastern Australia**

NETWORK	CUSTOMER NUMBERS	LENGTH OF MAINS (KM)	ASSET BASE ($ MILLION)[1]	INVESTMENT—CURRENT PERIOD ($ MILLION)[2]	REVENUE—CURRENT PERIOD ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Allgas Energy	90 200	3 060	na	na	na	Light regulation from July 2015	APA Group 20%, Marubeni 40%, RREEF 40%
Australian Gas Networks	91 800	2 700	na	na	na	Light regulation from February 2015	Cheung Kong Infrastructure
NEW SOUTH WALES AND ACT							
Jemena Gas Networks (NSW)	1 264 800	25 380	2 936	964	2 058	1 Jul 2015–30 Jun 2020	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
ActewAGL	134 300	4 620	308	97	311	1 Jul 2010–30 Jun 2016	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%
Wagga Wagga	20 000	690	na	na	na	Not regulated (coverage revoked 2014)	Australian Gas Networks (Cheung Kong Infrastructure)
Central Ranges System	7 000	220	na	na	na	2006–19	APA Group
VICTORIA							
AusNet Services	637 500	10 440	1 324	484	918	1 Jan 2013–31 Dec 2017	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
Multinet	687 400	10 090	1 095	251	873	1 Jan 2013–31 Dec 2017	DUET Group
Australian Gas Networks	633 900	10 560	1 160	417	879	1 Jan 2013–31 Dec 2017	Cheung Kong Infrastructure
SOUTH AUSTRALIA							
Australian Gas Networks	423 300	7 950	1 093	527	1 103	1 Jul 2011–30 Jun 2016	Cheung Kong Infrastructure
TASMANIA							
Tas Gas Networks	12 000	710	na	na	na	Not regulated	Brookfield Infrastructure
TOTALS	3 656 200	74 110	8 275	2 807	7 062		

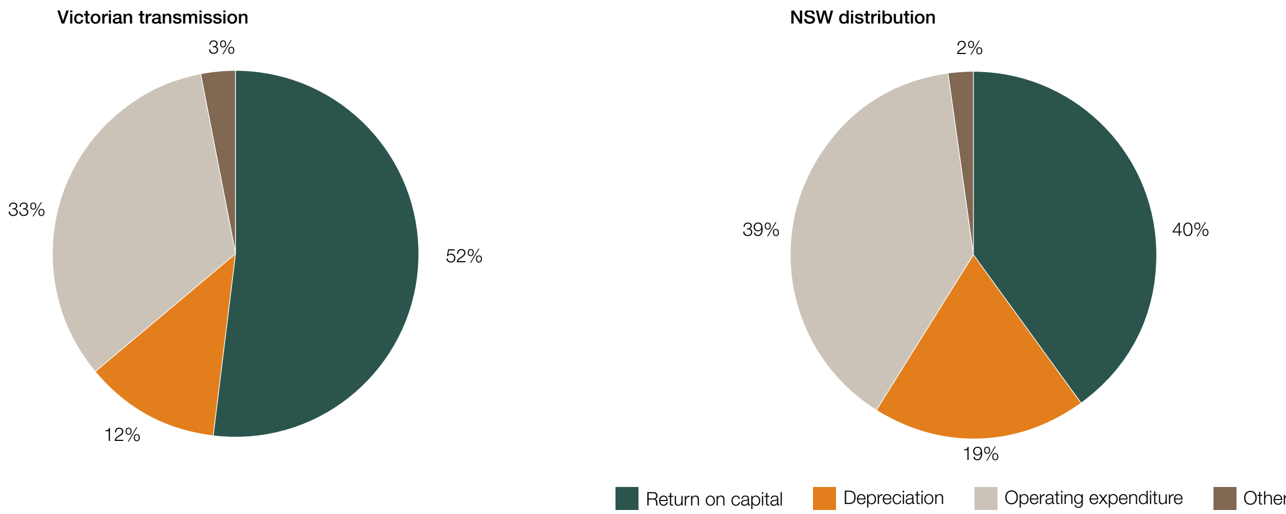
na, Not available.

1. The asset base is the initial capital base, adjusted for additions and deletions, as reset at the beginning of the current access arrangement period.
2. Investment and revenue data are forecasts for the current access arrangement period (typically, five years).

Note: Asset base, investment and revenue data are converted to June 2014 dollars.

Sources: Access arrangements for covered pipelines; company websites.

Figure 4.2
Indicative composition of gas pipeline revenues



Source: AER.

4.2.1 Full regulation

The National Gas Law and Rules apply economic regulation to covered pipelines. Different forms of regulation apply, based on competition and significance criteria. Under *full regulation*, a pipeline provider must periodically submit an access arrangement to the regulator for approval. An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service that a significant part of the market is likely to seek, and a reference tariff for that service.

The AER assesses the revenue that a pipeline business needs to recover its efficient costs (including a benchmark return on capital), then derives reference tariffs for the pipeline. It uses a building block model that accounts for operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and a return on capital. Figure 4.2 illustrates the revenue components for the Victorian transmission system (2013–17) and Jemena's NSW gas distribution network (2015–20).

The largest component is the return on capital, which accounts for up to two thirds of revenue. The scale of a pipeline's asset base (and projected investment) and its weighted average cost of capital (the rate of return covering a commercial return on equity and efficient debt costs) determine the return on capital. An allowance for operating expenditure typically accounts for a further 30–40 per cent of revenue requirements. The rules include incentive mechanisms that reward efficient operating practices.

In a dispute, an access seeker may request the regulator arbitrate on and enforce the access arrangement. Regulatory decisions on full regulation pipelines are subject to merits review by the Australian Competition Tribunal.

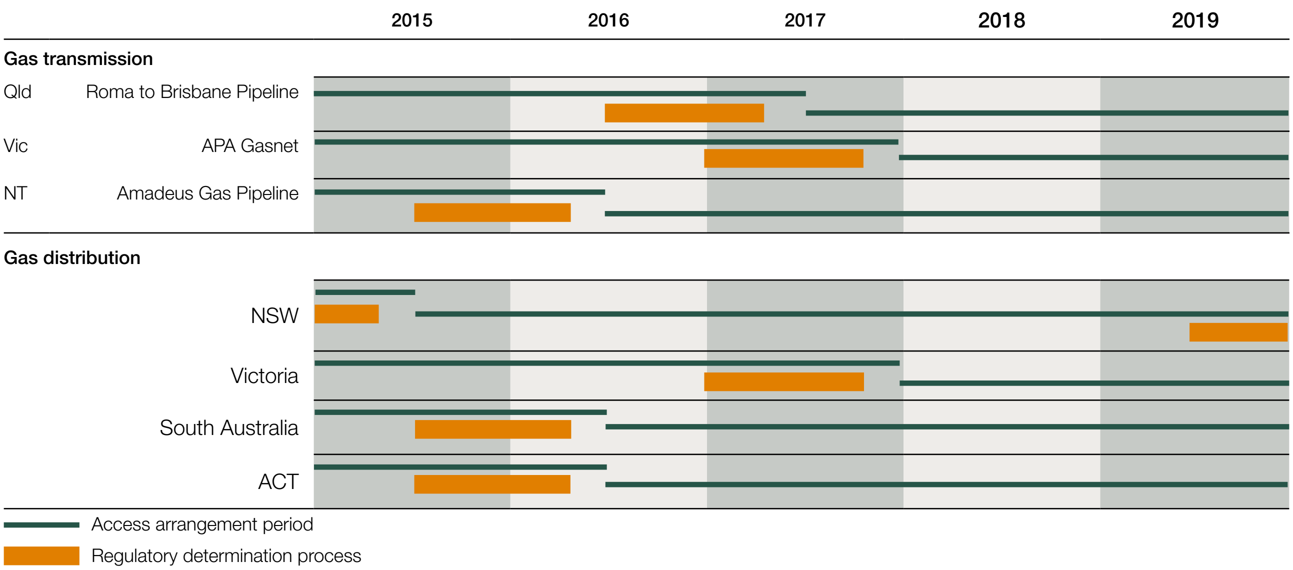
Regulatory timelines and recent AER activity

In 2015 four transmission pipelines and seven distribution networks were under full regulation, including:

- transmission pipelines supplying Brisbane, Melbourne and Darwin, and the Central Ranges pipeline in NSW (table 4.1)
- all major distribution networks in NSW, Victoria, South Australia and the ACT (but not in Queensland, Tasmania or the Northern Territory).

Figure 4.3 sets out the timelines for regulatory reviews of gas pipelines. In 2015 the AER issued its final decision on Jemena's access arrangement for the NSW gas networks. The determination approved recoverable revenues of $2.2 billion, compared with the Jemena's proposed $2.6 billion—a reduction of 14 per cent. Following the decision, gas distribution charges for a typical NSW customer are projected to be around $100 lower in 2015–16, compared with under the previous access arrangement. Larger reductions are projected in the later years of the access arrangement (which runs until 2019–20), although outcomes may change due to such factors as annual updates to capital costs (see figure 7 in the Market overview).

Figure 4.3
Indicative timelines for regulatory reviews of gas pipelines



Note: The timeframes are indicative. The standard review period begins when a network business submits an access arrangement proposal to the AER. Timeframes may vary if the AER grants a time extension for the proposal submission. An access arrangement period is typically five years, but a provider may apply for a different duration.

On 24 June 2015 Jemena filed an application to the Australian Competition Tribunal for merits review of the AER decision. In particular, it sought review of the decision not to approve its proposed allowed rate of return, its proposed value of imputation credits (gamma) and its proposed capital expenditure on connections and market expansion. Jemena also filed an application with the Federal Court for judicial review of the decision.

4.2.2 Light regulation

In some circumstances, a pipeline may convert to *light regulation* without upfront price regulation. When light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. In eastern Australia, the Carpentaria Gas Pipeline in Queensland, the covered portions of the Moomba to Sydney Pipeline, and the Central West Pipeline in NSW are subject to light regulation. Queensland's two distribution networks—Australian Gas Networks and Allgas Energy—in 2015 become the first major distribution networks to convert to light regulation.

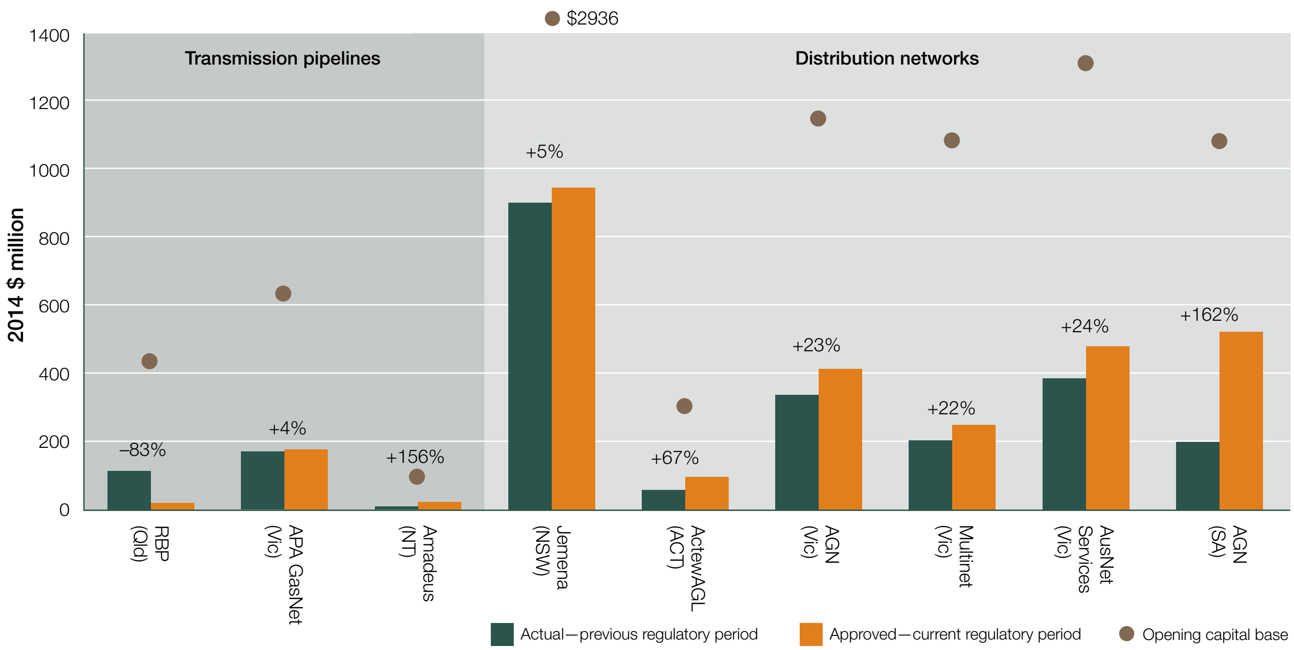
4.2.3 Changes in coverage status

The National Gas Law includes a mechanism to review whether a pipeline needs economic regulation. The coverage of several major transmission pipelines has been revoked over the past decade. Additionally, only one transmission pipeline constructed in the past decade is covered.

In November 2014 the National Competition Council determined Australian Gas Networks' Queensland distribution network would convert from full to light regulation in February 2015. It found light regulation of the network would be similarly effective to full regulation, but provide significant cost savings that may benefit customers. In April 2015 the National Competition Council made a similar determination for Queensland's Allgas Energy distribution network, which took effect from July 2015.

The Gas Law enables the federal Minister for Resources and Energy to grant a 15 year 'no coverage' determination for new pipelines in certain circumstances. Following a recommendation from the National Competition Council, the minister in June 2015 granted a 'no coverage' determination for a transmission pipeline supplying gas from the Surat–Bowen Basin to the Gladstone liquid natural gas (LNG) project in Queensland.

Figure 4.4
Pipeline investment—five year period



RBP, Roma to Brisbane Pipeline; AGN, Australian Gas Networks.

Notes: Forecast capital expenditure in the current access arrangement period (typically, five years), compared with actual levels in previous periods. The data account for the impact of decisions by the Australian Competition Tribunal. Opening capital bases are at the beginning of the current access arrangement period.

Source: AER final decisions on access arrangements.

4.3 Pipeline investment

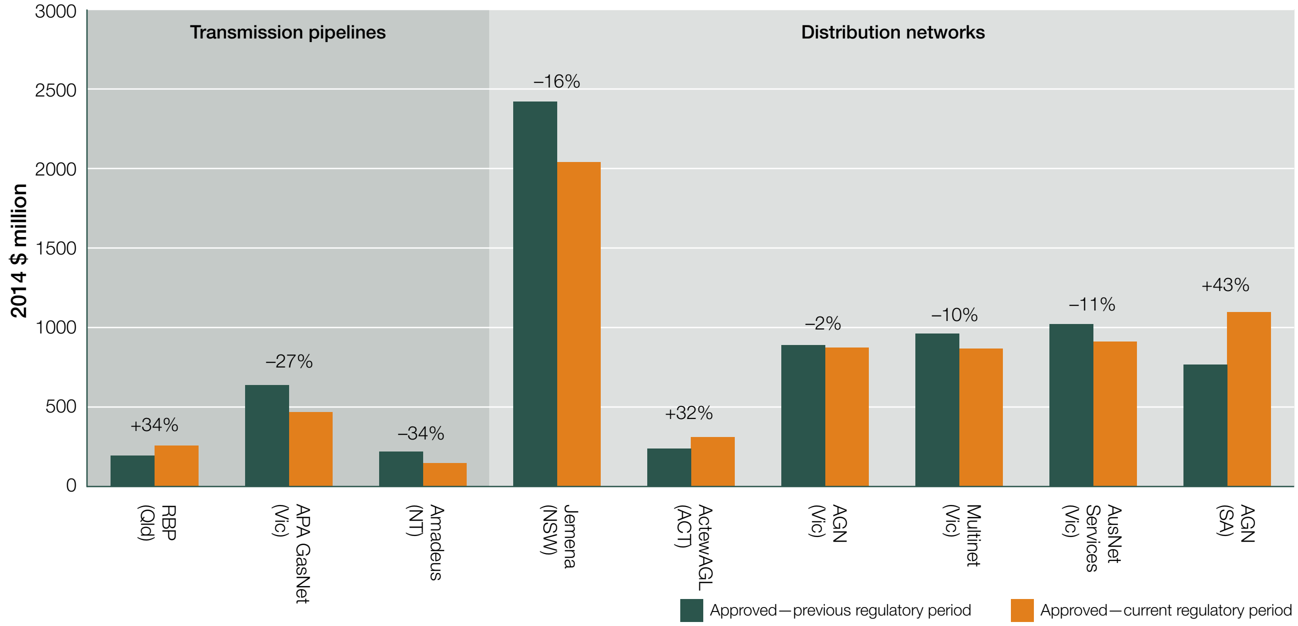
Gas *transmission* investment typically involves large and lumpy capital projects to expand existing pipelines (through compression, looping or extension) or construct new infrastructure. Significant investment in eastern Australia's transmission sector has occurred since 2010 to expand pipeline capacity, and to link gas supplies with LNG processing facilities in Queensland. Additionally, some transmission pipelines are being re-engineered for bidirectional flows. Section 3.4.3 reviews recent investment in this area, much of which is in pipelines that are not regulated or are subject to only light regulation. Public data on this investment are therefore limited.

Investment in *distribution* networks in eastern Australia that are subject to full regulation is forecast at around $2.7 billion in the current access arrangement periods (typically, five years). The underlying drivers include rising connection numbers, the replacement of ageing networks, and the maintenance of capacity to meet customer demand. Figure 4.4 illustrates approved investment forecasts in current access arrangements. For comparison, it also shows actual investment in previous periods. The data cover both transmission pipelines and distribution networks subject to full regulation.

For *distribution* networks, investment is forecast to rise by an average 30 per cent in current access arrangement periods, compared with previous periods. Investment is equal, on average, to 35 per cent of the networks' opening capital bases. Forecast growth is highest in the South Australian and ACT distribution networks (up 162 per cent and 67 per cent respectively).

Recent regulatory reviews reflect a moderation in investment growth. Investment in Victoria's distribution networks will rise by an average 23 per cent in 2013–17, compared with previous periods. Investment in Jemena's NSW gas network in 2015–20 is forecast to rise by 5 per cent over the previous period. Replacement investment is the fastest rising component, comprising 31 per cent of the total (up from 19 per cent in the previous period).

Figure 4.5
Pipeline revenues—five year period



RBP, Roma to Brisbane Pipeline; AGN, Australian Gas Networks.

Notes: Forecast revenues in the current access arrangement period (typically, five years), compared with forecasts in previous periods. The data account for the impact of decisions by the Australian Competition Tribunal.

Source: AER final decisions on access arrangements.

For *transmission* pipelines, investment forecasts vary widely. An expansion of the Roma to Brisbane Pipeline in the previous regulatory period contributed to a large capital expenditure allowance. But, with no major augmentations planned, forecast expenditure fell by over 80 per cent. Investment growth is steady across the two periods in Victoria's GasNet system, while the Northern Territory's Amadeus Pipeline had a large increase in approved investment for an enhanced integrity program.

4.4 Pipeline revenues and retail impacts

Figure 4.5 illustrates approved revenue forecasts for gas transmission pipelines and distribution networks that are subject to full regulation. It compares approved forecasts in current access arrangements with those approved in previous periods.

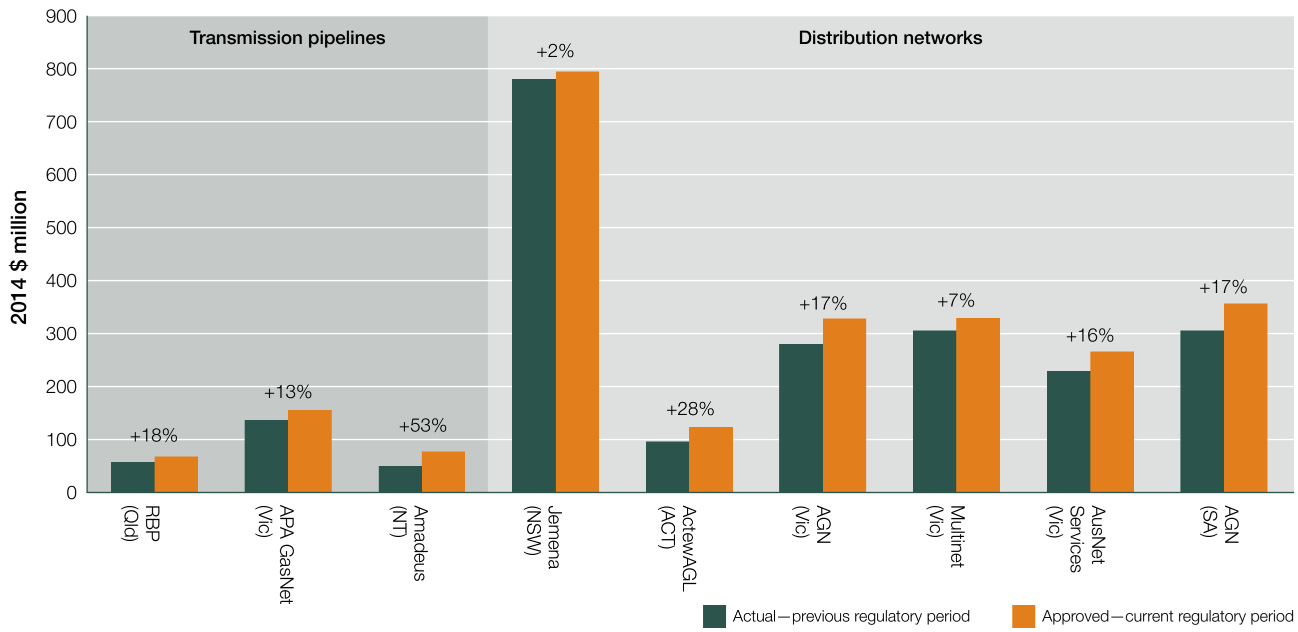
For *distribution* networks, revenue is forecast to fall by an average 3 per cent in the current access arrangement periods, compared with forecast revenue in the previous periods. Weakening gas demand and lower capital costs (due to reductions in the risk free rate) are lowering revenue and investment requirements. In access arrangement determinations for the Victorian and NSW networks (made since 2013), forecast revenues are an average 11 per cent lower than forecast revenues in the previous periods.

For *transmission* pipelines, revenue is forecast to fall on the Roma to Brisbane Pipeline, but rise for the GasNet system and the Amadeus Pipeline.

4.4.1 Operating expenditure

Operating and maintenance costs are a key driver of pipeline revenue requirements. In assessing operating expenditure forecasts, the AER considers cost drivers that include customer growth, expected productivity improvements, and changes in real input costs for labour and materials. Operating cost increases may also reflect step change factors arising from external drivers, such as changes to government regulation.

Figure 4.6
Pipeline operating expenditure—five year period



RBP, Roma to Brisbane Pipeline; AGN, Australian Gas Networks.

Notes: Forecast operating expenditure in the current access arrangement period (typically, five years), compared with actual levels in previous periods. The data account for the impact of decisions by the Australian Competition Tribunal.

Source: AER final decisions on access arrangements.

Figure 4.6 illustrates recent operating expenditure data for gas transmission pipelines and distribution networks that are subject to full regulation. It compares approved forecasts in current access arrangements with actual expenditure in previous regulatory periods.

For *distribution* networks, real operating expenditure is forecast to rise by an average 10 per cent in the current access arrangement periods, compared with actual expenditure in previous periods. The largest rise is for the ACT network (28 per cent). For *transmission* pipelines, operating expenditure is forecast to rise by an average 22 per cent.

The AER's 2015 decision on Jemena's NSW distribution network forecast operating expenditure will rise by 2 per cent across 2015–20 from levels in the previous period.

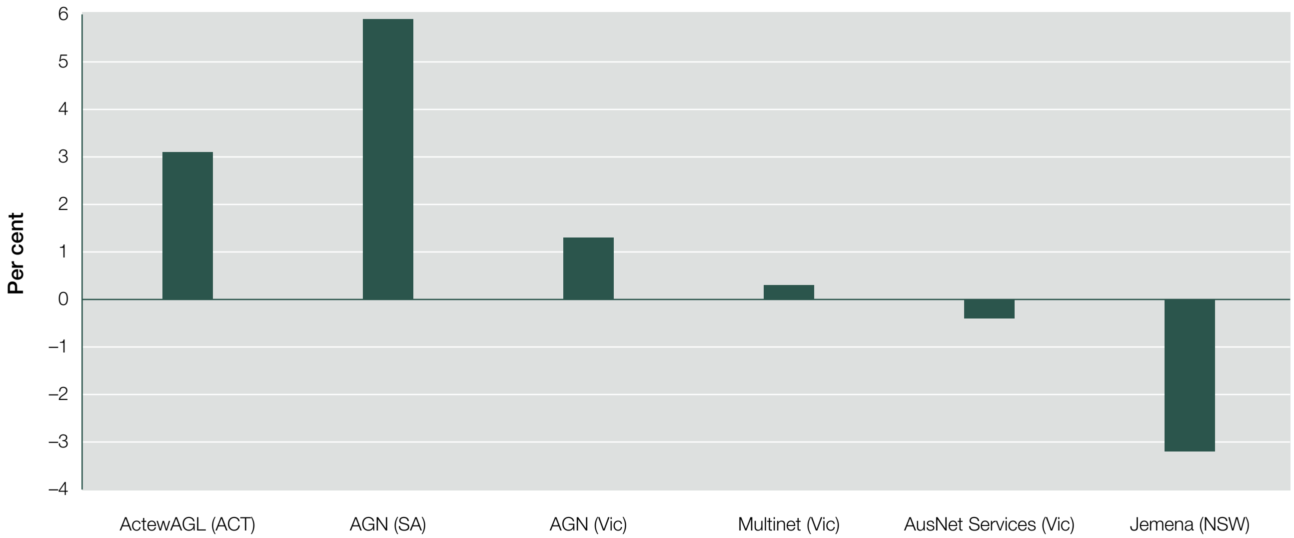
4.4.2 Retail impacts of regulatory decisions

Gas *transmission* charges make up 5–10 per cent of a typical residential gas bill. The percentage is significantly higher for industrial users. In Victoria, the AER's 2013 decision on the Victorian Transmission System resulted in a typical residential bill falling by around 0.4 per cent per year.

The contribution of gas *distribution* charges to a residential gas bill varies from around 30 per cent in Victoria and the ACT, to 70 per cent in South Australia. AER determinations made in 2010 and 2011 for the ACT and South Australian networks respectively reflected rising capital and operating expenditure and other cost drivers (including higher financing costs and the rising cost of unaccounted for gas) that caused retail charges for residential customers to rise by up to 6 per cent per year (figure 4.7).

But, more recent AER decisions for Victoria (2013) and NSW (2015) show a different trend, with customer charges likely to rise marginally in two Victorian networks, and fall in a third Victorian network and Jemena's NSW gas network. The shift reflects reductions in the risk free rate that lowered the overall cost of capital for gas networks.

Figure 4.7
Annual impact of AER decisions on residential gas charges



AGN, Australian Gas Networks.

Notes: Impact on annual gas charges for a typical residential customer in that jurisdiction in the current access arrangement period. The data account for the impact of decisions by the Australian Competition Tribunal.

Source: AER final decisions on access arrangements.

Image courtesy of Allison Crowe

5 ENERGY RETAIL MARKETS

Energy retailers typically buy electricity and gas in wholesale markets and package it with network (transportation) services for sale to customers. Most retail contracts are for just the supply of energy. Charges may be flat, or vary according to the time of day or season, but they usually insulate the customer from movements in wholesale energy prices. Retailers use hedging arrangements to manage their risk of price volatility in the wholesale market.

However, the range of products offered to customers is expanding. Some retailers offer:

- *pool pass through arrangements*, whereby the customer takes on the risk of wholesale market volatility
- *customised or packaged energy sales*, whereby a retailer tailors its product to customers with specific energy requirements (such as households with swimming pools) or sells energy as part of a package offering customers greater control over their energy use.

The increasing use of interval (smart) meters—that measure a customer's energy use in near real time—will drive further innovation. Retailers may offer, for example, products that reward customers for reducing energy use at times of high demand (including via direct load control, whereby a retailer can remotely adjust a customer's energy use).

Alongside these changes, a growing number of alternative energy sales models have become available in recent years, driven by rising energy prices, consumers seeking more control over their energy use, and wider access to renewable energy options. These models, depicted in figure 5.1, include:

- *onselling*, whereby an energy provider buys bulk energy from a retailer and onsells it to a cluster of customers.[1] Onselling is increasingly used in new multi-dwelling developments such as apartment buildings and shopping centres.
- *power purchase agreements*, whereby an energy provider installs generation capacity on a customer's premises, and sells the energy generated to that customer. The provider retains ownership of the generation assets. Solar photovoltaic (PV) panels are the most common form of generation under this model.

While new entrant businesses are driving the emergence of these models, established energy retail businesses are also moving in this area. Some retailers now offer, for example, power purchase agreements alongside their traditional products.

1 This model only applies in embedded networks that supply groups of customers located behind a single connection point to the main distribution network.

Increasing rates of rooftop solar PV generation—both through power purchase agreements and energy users' installation of their own solar panels—create challenges for the traditional retail model. These users typically do not produce enough energy to meet all their requirements, and they buy the balance from a retailer. But the lower volumes required by these users make them less profitable for the retailer. Advances in battery storage may further reduce energy purchases by these users.

5.1 Energy market regulation

The National Energy Retail Law (Retail Law) establishes consumer protections for small energy customers—that is, residential energy users and small businesses that consume less than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas per year.[2] Small customers make up 98 per cent of electricity connections and over 99 per cent of gas connections, but account for less than 50 per cent of energy sales by volume.

The Retail Law operates with the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements. It commenced in Tasmania (for electricity only) and the Australian Capital Territory (ACT) on 1 July 2012, in South Australia on 1 February 2013, in New South Wales (NSW) on 1 July 2013, and in Queensland on 1 July 2015. Victoria is yet to implement the Retail Law.

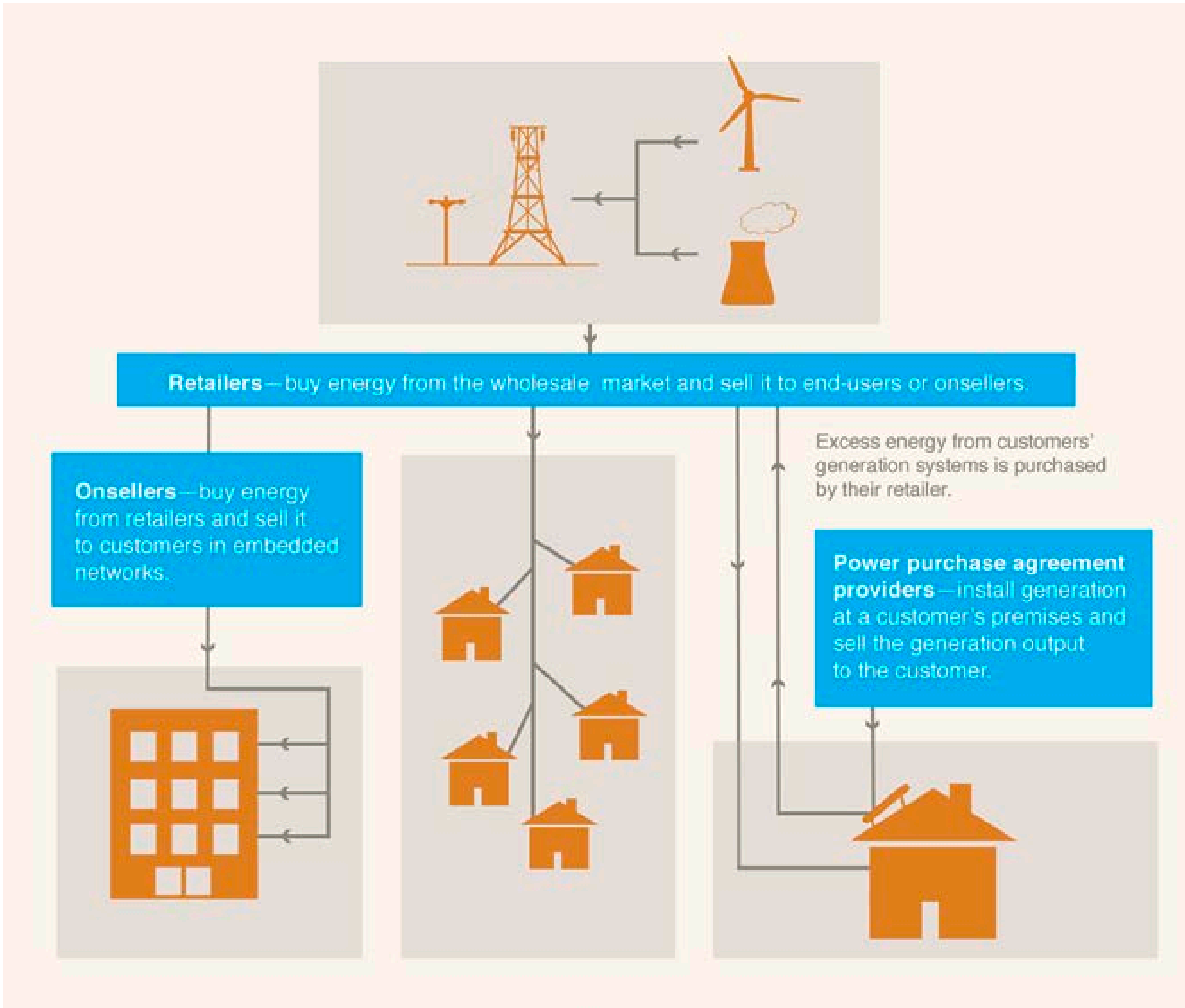
The Retail Law established the Australian Energy Regulator (AER) as the national regulator of retail energy markets. The AER's role is to:

- provide an energy price comparator website (www.energymadeeasy.gov.au) for small customers
- authorise energy retailers to sell energy, and grant exemptions from the authorisation requirement
- approve retailers' policies for dealing with customers facing hardship
- administer a 'retailer of last resort' scheme, to protect customers and the market if a retail business fails
- report on retailer performance and market activity, including energy affordability, disconnections and competition indicators
- enforce compliance with the Retail Law and its supporting rules and regulations.

Consumers in Queensland, NSW, South Australia, the ACT and Tasmania have access to consumer protections under

2 For electricity, some jurisdictions have a consumption threshold different from that specified in the Retail Law. In South Australia, for example, small electricity customers are those consuming less than 160 MWh per year; in Tasmania, the threshold is 150 MWh per year.

Figure 5.1
Energy retail models



the Retail Law, as well as all functions on the Energy Made Easy website. The functions include a price comparator tool with information on generally available market offers, a benchmarking tool for households to compare their electricity use with that of similar households in the same location, and information on the energy market, energy efficiency and consumer protections.

The AER does not regulate retail energy prices. Some state and territory governments retain a role in this area (section 5.4.1).

5.2 Retail market structure

The Retail Law requires an entity to be authorised to operate as an energy retailer. An authorisation covers energy sales in all participating jurisdictions. Authorised retailers must comply with consumer protection and other obligations set out in the Retail Law.

An entity may apply to the AER for an exemption from the need to be authorised if that entity intends to supply energy services to a limited customer group (for example, at a specific site or where energy is being supplied incidentally through an existing relationship, such as by a body corporate). The exemptions framework tailors an energy seller's obligations to the products that the seller offers. The AER determines the conditions of an exemption. Applicants are typically those seeking to supply energy through onselling or power purchase agreements.

At November 2015:

- 57 businesses held authorisations to retail electricity and 25 held authorisations to retail gas.[3]
- 90 businesses held individual exemptions to sell electricity, mainly covering the sale of energy through solar power purchase agreements. An individual exemption is one that is tailored to an applicant's requirements.
- over 1500 businesses held registered exemptions, typically to onsell energy within an embedded network. Registered exemptions have a fixed set of conditions for each category of energy selling.

The Retail Law also establishes deemed exemption classes for small onselling arrangements. A person operating under a deemed exemption does not need to register with the AER.

5.2.1 Energy retailers serving small customers

While many retailers offer energy services to all customers, some target particular market segments. In making this choice, a retailer considers factors such as price regulation (if it applies), market scale, competition, the ability to source hedging contracts to manage risk and, for gas retailing, whether wholesale gas contracts and pipeline access are available.

Table 5.1 lists authorised or licensed energy retailers with residential or small business customers at June 2015. In total, energy contracts were offered under 30 retail brands.

Around 50 per cent of retailers offer both electricity and gas in at least one jurisdiction in which they are active. Some offer only electricity, while one specialises in just gas (Tas Gas Retail, in Tasmania). Less active competition in gas may be explained by its smaller retail market (not all households have a gas connection) and by the difficulties for new entrants contracting for wholesale gas supplies.

The number of active retailers has risen over the past decade. Victoria has the largest number of active retailers selling to small customers, in both electricity (24) and gas (10). NSW and South Australia also have a significant number of participants in electricity (22 and 17 retailers respectively) and gas (seven and five retailers respectively). Queensland has 16 active electricity retailers, but only two active gas retailers.

New entrant retailers in the NSW and Victorian markets in 2014–15 included Next Business Energy, Online Power & Gas, Pooled Energy and SparQ.

Some established electricity retailers widened their activities in 2014–15. Momentum Energy, Click Energy and CovaU—which previously targeted only electricity—acquired some gas customers. Other retailers, including GoEnergy and Powershop, expanded into new geographic markets.

5.2.2 Market concentration

Australia's retail energy markets tend to be concentrated, with significant vertical integration between retailers and energy producers.

Three private businesses—AGL Energy, Origin Energy and EnergyAustralia—are the leading energy retailers in southern and eastern Australia (figure 5.2). The three jointly supplied over 70 per cent of small electricity customers and over 80 per cent of small gas customers at 30 June 2015.[4] But competition from smaller retailers has eroded their market share. In electricity, small retailers acquired 7 per cent of customers from the three market leaders between 2012 and 2015. The market share of smaller retailers grew more strongly in Victoria and NSW than elsewhere. This growth was capped by AGL's acquisition of the small retailer Australian Power & Gas in 2013.

Snowy Hydro—owned by the NSW, Victorian and Australian governments—has emerged as a fourth significant energy retailer, with 7–8 per cent market share in electricity and gas. In September 2014 it acquired Lumo Energy from Infratil Energy, adding to its existing Red Energy retail business.

Victoria has the highest penetration of small private retailers, which supplied 36 per cent of electricity customers and 28 per cent of gas customers at 30 June 2015. In South Australia, small retailers supplied 21 per cent of electricity customers and 12 per cent of gas customers.

Other than Snowy Hydro, government retailers retain a strong presence in some jurisdictions:

- The Queensland Government owns Ergon Energy, which supplies electricity at regulated prices to customers

3 Some company groups hold multiple authorisations. In Victoria, in which the Retail Law does not apply, over 30 retailers at November 2015 held an electricity and/or gas licence allowing them to sell energy.

4 Includes brands owned by these businesses, such as Powerdirect (AGL Energy).

Table 5.1 Active energy retailers—small customer market, June 2015

RETAILER	OWNERSHIP	QLD	NSW	VIC	SA	TAS	ACT
ActewAGL Retail	ACT Government/AGL Energy		E, G*				E*, G*
AGL Energy	AGL Energy	E, G*	E, G*	E*, G*	E*, G		
Alinta Energy	TPG Capital			E, G	E, G		
Aurora Energy	Tasmanian Government					E*, G	
BlueNRG	BlueNRG		E	E			
Click Energy	Click Energy	E	E	E, G			
Commander	M2 Energy		E	E	E		
CovaU	Tel.Pacific		E, G	E			
Diamond Energy	Diamond Energy	E	E	E	E		
Dodo Power & Gas	M2 Energy	E	E, G	E, G	E		
EnergyAustralia	CLP Group	E	E*, G	E*, G*	E, G		E, G
Ergon Energy	Queensland Government	E*					
ERM Power	ERM Power	E	E	E	E	E	E
GoEnergy	GoEnergy	E	E	E	E		
Lumo Energy	Snowy Hydro[1]	E	E, G	E, G	E		
Momentum Energy	Hydro Tasmania (Tasmanian Government)	E	E	E, G	E		E
Next Business Energy	Next Business Energy		E	E			
Online Power and Gas	Online Power and Gas			E			
Origin Energy	Origin Energy	E*, G*	E*, G*	E*, G*	E, G*		E, G
Pacific Hydro	IFM Investors			E	E		
People Energy	People Energy			E			
Pooled Energy	Pooled Energy		E				
Powerdirect	AGL Energy	E	E	E	E		E
Powershop	Meridian Energy		E	E			
Qenergy	Qenergy	E	E	E	E		
Red Energy	Snowy Hydro[1]	E	E	E, G	E		E
Sanctuary Energy	Living Choice Australia/Sanctuary Life	E	E		E		
Simply Energy	GDF Suez/Mitsui	E	E	E, G	E, G		
SparQ	SparQ			E			
Tas Gas Retail	Brookfield Infrastructure					G	

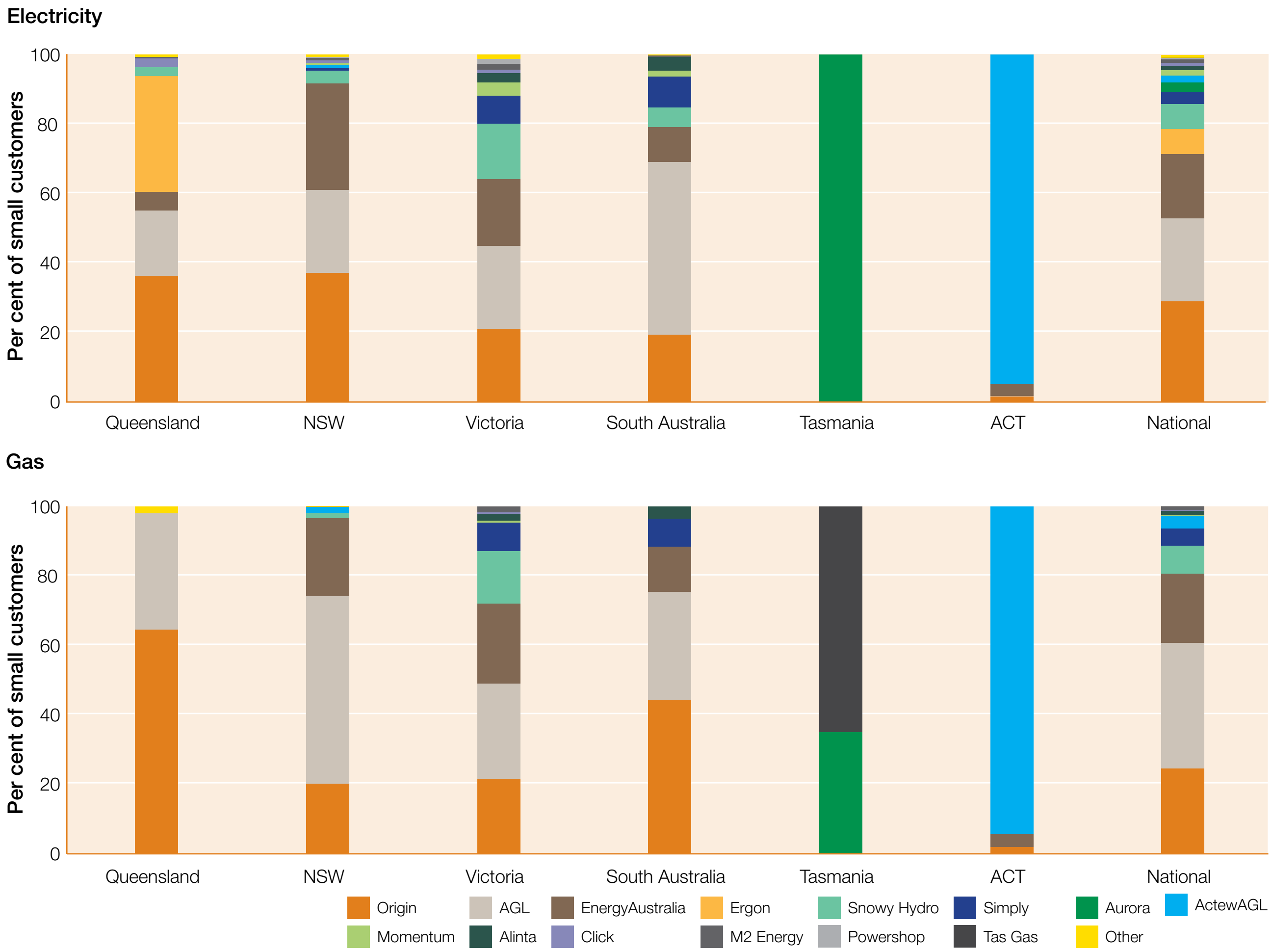
1 Snowy Hydro is owned by the NSW Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).

Note: Host retailers in Tasmania and the ACT must offer 'regulated offer' contracts to customers. Host retailers in NSW, Victoria, South Australia and Queensland must offer 'standing offer' contracts to customers that establish a new connection in a defined region.

Sources: AER; jurisdictional regulator websites; retailer websites; other public sources.

Electricity retailer (E)
Gas retailer (G)
Host retailer *

Figure 5.2
Retail market share (small customers), by jurisdiction, June 2015



Source: AER retail performance reporting statistics, and AER estimates.

in rural and regional Queensland. Ergon Energy is not permitted to compete for new customers.

- In Tasmania, the government owned Aurora Energy supplies all residential and most small business electricity customers. Until 1 July 2014 legislation prevented new entrants from supplying customers using less than 50 MWh per year.
- In the ACT, ActewAGL (a joint venture between the ACT Government and AGL Energy) is the dominant retailer, with 95 per cent of small customers.
- Momentum Energy (Tasmanian Government) operates in a number of jurisdictions.

5.2.3 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, subsequent vertical integration between retailers and generators to form 'gentailers' has been significant. Vertical integration provides a means for retailers and energy producers to internally manage the risk of price volatility in wholesale markets, reducing their need to enter forward contracts in derivatives markets. This reduced need for hedge contracts can drain liquidity from derivatives markets, posing a barrier to entry and expansion by stand-alone generators, gas producers and energy retailers that are not vertically integrated.

In the National Electricity Market (NEM), AGL Energy, Origin Energy and EnergyAustralia each have significant market share in both generation and retail markets. The three businesses:

- increased their market share in electricity generation from 15 per cent in 2009 to 45 per cent in 2015, largely by acquiring state owned generation assets in NSW. Additionally, Origin Energy commissioned new power stations in Queensland and Victoria, and AGL Energy acquired full ownership of Loy Yang A in Victoria.
- supplied 71 per cent of energy retail customers in 2015. Origin Energy and EnergyAustralia acquired significant retail market share in NSW following the privatisation of government owned retailers in 2010. AGL Energy acquired Australian Power & Gas (one of the largest independent retailers) in 2013.
- have interests in upstream gas production and/or gas storage that complement their interests in gas fired electricity generation and energy retailing. Origin Energy is a gas producer in Queensland, South Australia and Victoria. AGL Energy is a producer of coal seam gas in Queensland and NSW, and in 2015 opened a liquefied natural gas storage facility in Newcastle.

Vertical integration occurs among other market participants too, with a number of former stand-alone generators having established retail arms. These businesses include GDF Suez (which established Simply Energy), Alinta, ERM Power, Pacific Hydro and Meridian Energy (Powershop). Government owned generators—Snowy Hydro (which owns the retailers Red Energy and Lumo Energy) and Hydro Tasmania (which owns Momentum Energy)—have similar structures.

The nature of vertical integration between electricity generation and energy retailing varies across jurisdictions (figure 5.3).

The **NSW** electricity sector was dominated by government entities until 2011, when Origin Energy and EnergyAustralia acquired assets through a privatisation process. Those two businesses now supply 68 per cent of retail electricity customers and control 37 per cent of generation capacity. They also supply 43 per cent of gas retail customers.

AGL Energy acquired Macquarie Generation from the NSW Government in September 2014, giving it 32 per cent of statewide capacity. It was already the incumbent gas retailer, and supplies 54 per cent of gas customers. Its position in gas helped it develop market share in electricity (around 24 per cent of customers). AGL Energy owns the state's only operating gas producer.

Following its acquisition of Colongra from Delta Electricity in December 2014, Snowy Hydro's market share in NSW generation rose from 15 per cent to 22 per cent. Snowy Hydro also expanded its retail portfolio by acquiring Lumo Energy in September 2014, and now supplies 4 per cent of retail electricity customers (and 1 per cent of gas customers).

Victoria's generation sector is disaggregated across private entities. It has no single dominant retailer, with AGL Energy, Origin Energy and EnergyAustralia each supplying 20–25 per cent of retail electricity and gas customers. But, while having reasonable market depth, Victoria has significant vertical integration. The three major retailers control 54 per cent of generation capacity.

In addition, Victoria's other major generators—GDF Suez (24 per cent of capacity) and Snowy Hydro (20 per cent)—have strong positions in the electricity retail market (supplying 8 per cent and 16 per cent of customers respectively). The businesses supply a similar proportion of gas customers.

South Australia's electricity sector is highly concentrated, with AGL Energy supplying 50 per cent of retail customers and controlling 42 per cent of generation capacity. Origin Energy, EnergyAustralia, GDF Suez (Simply Energy) and Alinta are significant but minority players in both generation and retail.

Vertical integration is less evident in **Queensland** and **Tasmania**, with a majority of generation capacity in each state controlled by state owned corporations. Origin Energy and (to a lesser extent) AGL Energy are the leading retailers in Queensland, following privatisation in 2007. Those entities also account for 10 per cent of statewide generation capacity. In Tasmania, the state owned Aurora Energy supplies most small retail customers, while the state owned Hydro Tasmania controls nearly all generation capacity.

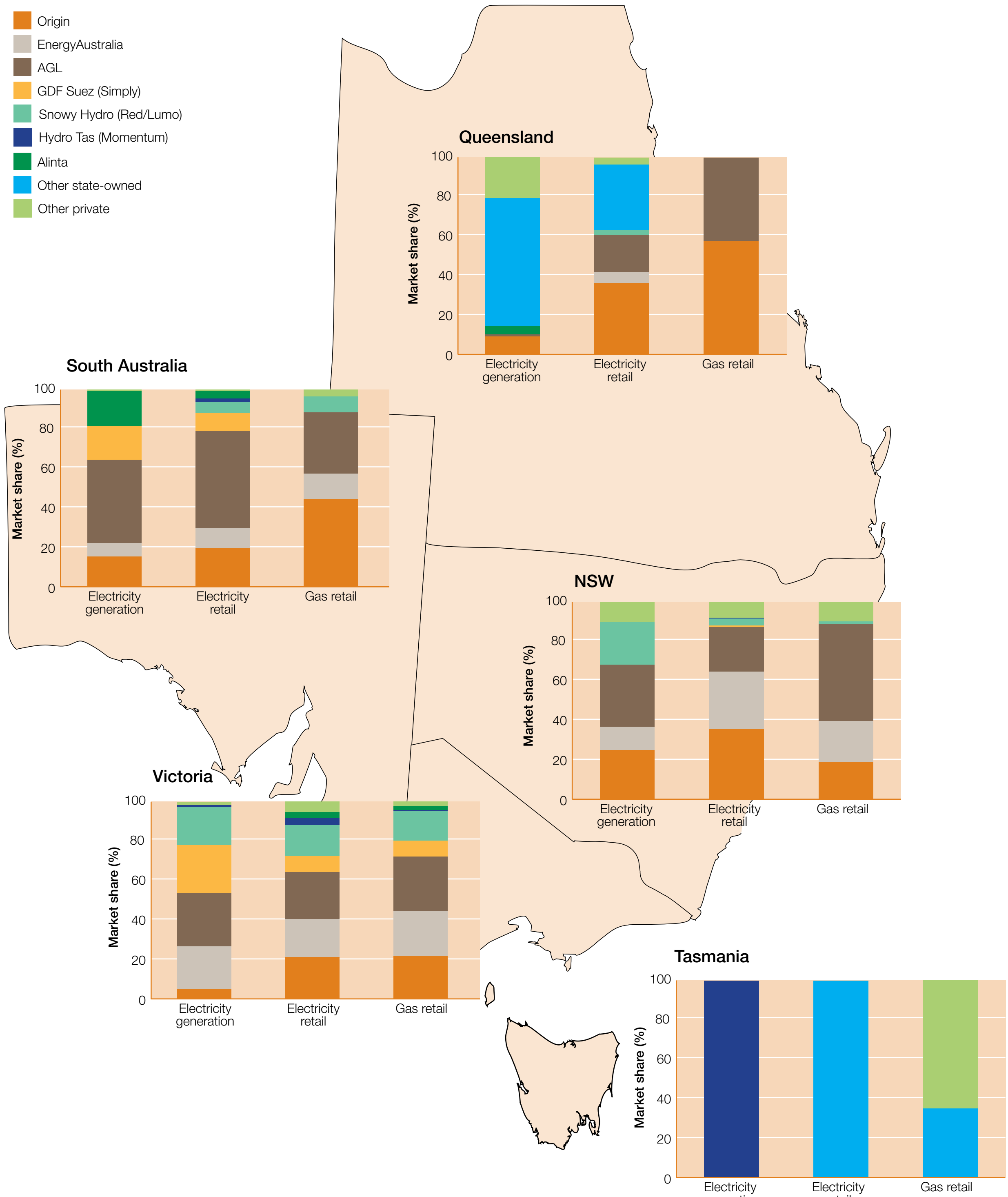
5.3 Retail competition

Full retail contestability (FRC) in electricity and gas applies in all NEM jurisdictions, allowing all energy customers to enter a contract with their retailer of choice. Tasmania was the most recent jurisdiction to introduce FRC, extending choice from 1 July 2014 to electricity customers using less than 50 MWh per year.

While retail contracts vary, the Retail Law requires them to incorporate minimum terms and conditions. A contract may be widely available or offered to only specific customers. It may offer discounts on a retailer's standard rates, along with other inducements. It may have a fixed term duration, with exit fees for early withdrawal. Retailers must obtain

Figure 5.3

Vertical integration in NEM jurisdictions, 2015



Note: Electricity generation market shares are based on summer availability for January 2015, except wind, which is adjusted by an average contribution factor. Electricity and gas retail market shares are based on small customer numbers at June 2015.

Source: AER estimates.

explicit informed consent from a customer before entering a market contract.

Customers without a *market* contract are placed on a *standard* contract with the retailer that most recently supplied energy at those premises (or, for new connections, with a retailer designated for that geographic region). A standard retail contract includes model terms and conditions that a retailer may not amend.

The share of customers on market contracts varies significantly across jurisdictions. In electricity, 88 per cent of Victorian consumers have a market contract, compared to 84 per cent in South Australia, 69 per cent in NSW, 46 per cent in Queensland (but around 70 per cent in south east Queensland), 24 per cent in the ACT and 12 per cent in Tasmania. The proportions are similar for gas customers. The Australian Energy Market Commission (AEMC) in 2015 found the level of competition in energy markets varies across the NEM, reflecting the different pace of reform across jurisdictions. It found electricity markets in Tasmania, regional Queensland and the ACT were not yet effectively competitive, citing local factors in each instance:

- In Queensland, some retailers stated they had deferred plans to expand marketing, following the Queensland Government's 12 month delay in removing retail price regulation until 1 July 2016. Retailers also reported wholesale market volatility in Queensland is an impediment to expansion.
- In the ACT, retailers reported retail price regulation and the dominance of the incumbent ActewAGL make entry and expansion difficult.
- In Tasmania, retailers considered entry and expansion in the electricity market is difficult due to retail price regulation and the dominance of an incumbent retailer (Aurora Energy) and generator (Hydro Tasmania). At September 2015 no energy retailer had entered the residential electricity customer market to compete with Aurora Energy.[5]

Competition is generally more effective in electricity than gas, due to differences in market scale and difficulties in sourcing gas and pipeline services in some regions. The AEMC found competition was effective in most of NSW, Victoria and South Australia, but limited in south east Queensland. It found gas is a secondary consideration for most customers and a less attractive value proposition for some retailers.

Despite finding competition is effective in most regions, the AEMC identified different customer groups vary in their level of market engagement. In Victoria, south east Queensland and NSW, customers on standing offers are typically older or living in regional areas. In Melbourne and Sydney, customers in higher income localities are more likely to be on standing offers; but, in many regional areas, customers in lower income localities are more likely to be on standing offers.

The AEMC found customer awareness of government price comparator websites is very low, with less than 1 per cent of customers able to name the website operating in their jurisdiction without prompting. It recommended governments increase efforts to raise awareness of available information and tools, highlighting potential savings to customers and how the tools can simplify comparisons of energy offers. The AER is considering ways to build the profile of Energy Made Easy and encourage greater uptake by consumers.

Lack of understanding among consumers increases the risk of their exploitation. Given this risk, the behaviour of energy retailers is a compliance and enforcement priority for the AER and the Australian Competition and Consumer Commission (ACCC) (section 5.3.2)

5.3.1 Customer switching and awareness

The rate at which customers switch their supply arrangements is an indicator of market participation. While switching (or churn) rates may indicate competitive activity, they must be interpreted with care. Switching is sometimes high during the early stages of market development, when customers can first exercise choice, but may then stabilise as a market acquires depth. Similarly, switching may be low in a competitive market if retailers deliver good quality and low priced service that gives customers no reason to change.

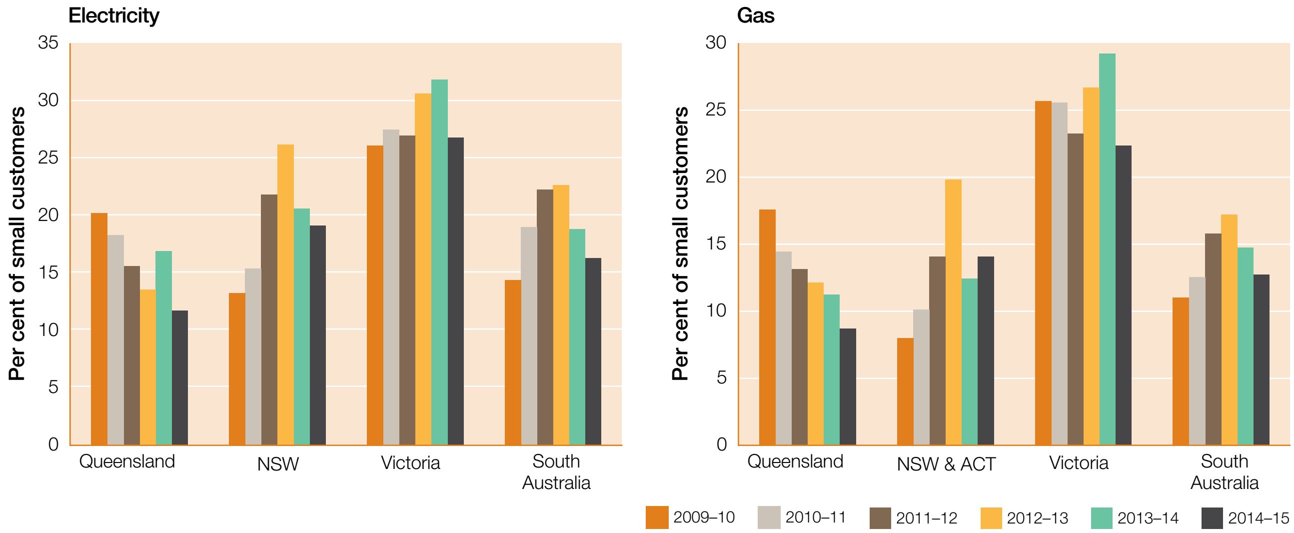
The Australian Energy Market Operator (AEMO) publishes churn data measuring the number of customer switches from one retailer to another (but not customer switches between contracts with the same retailer). Figure 5.4 sets out the data, which show switching rates remain lower in gas than electricity in all jurisdictions, reflecting the lower number of active participants in the gas market.

Switching rates fell in all jurisdictions in 2014–15, except for gas in NSW and the ACT. Changes in retailer marketing levels likely explain some of the decline: the AEMC in 2015 reported survey findings that fewer customers had been approached by a retailer than in the previous year (39 per cent of customers were approached in 2015,

5 AEMC, *2015 retail competition review, final report*, June 2015.

Figure 5.4

Customer switching of energy retailers, as a percentage of small customers



Sources: Customer switches: AEMO, MSATS transfer data to July 2015 and gas market reports, transfer history to July 2015; customer numbers: estimated from retail performance reports by the AER, the ESC (Victoria) and the QCA (Queensland).

compared with 53 per cent in 2014). This trend may reflect a move away from door knocking, and a shift in retailer focus away from customer acquisition towards customer retention.[6]

Victoria continues to have higher switching rates than elsewhere. This situation is likely due to a wider choice of products (following the installation of smart meters) and a greater awareness of choice. The state also has more retailers than have other jurisdictions. Further, the price spread in energy bills is typically higher in Victoria than elsewhere, meaning the potential savings from switching are also greater (section 5.4.3).

Queensland's switching rates remain lower than for other jurisdictions. In electricity, this situation likely reflects hesitancy among retailers to expand their marketing activity while price regulation remains in place, as well as recent wholesale market volatility. In gas, competition is limited due to the market's small scale and difficulties in sourcing wholesale gas.

The AEMC found residential consumers in 2015 generally have good awareness of their ability to choose a retailer. In those markets demonstrating effective competition, awareness ranged from 89 per cent of electricity customers (85 per cent for gas) in NSW and south east Queensland to 96 per cent of electricity and gas customers in Victoria. Awareness was lower in the ACT, at 72 per cent for electricity customers and 54 per cent for gas customers. The ACT result is a substantial improvement on the previous year, when awareness of electricity and gas competition was 57 per cent and 36 per cent respectively. In Tasmania in 2015, only 16 per cent of residential electricity customers knew they could choose a retailer, with Aurora Energy still the only active retailer in that segment of the market.

5.3.2 Consumer protection in retail markets

Increased competition among retailers for new customers has generally intensified retailer marketing. This activity has been matched by rising customer complaints about inappropriate conduct by energy salespersons. The Australian Consumer Law, enforced by the ACCC, contains provisions that protect customers from improper sales or marketing conduct. The provisions relate to unsolicited sales, misleading and deceptive conduct, and unconscionable conduct. The Retail Law's marketing provisions also protect customers.

Direct marketing (door-to-door and telemarketing)

While most major retailers stopped door-to-door marketing in 2013, following a range of enforcement activity by the ACCC, a small number still use this channel. Most still engage in telemarketing (outward sales calls) but this activity too has been problematic. Both the ACCC and the AER

6 AEMC, *2015 retail competition review, final report*, June 2015.

have taken action against retailers for misrepresentations and a failure to obtain a customer's explicit informed consent before transferring the customer as a result of a telemarketing call.

The AER in 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 Australian Consumer Law provisions on misleading conduct or representations. In 2015 the Federal Court imposed penalties of $1.6 million on EnergyAustralia and the telemarketing company.

In October 2015 the AER issued Simply Energy with infringement notices for failing to obtain customers' explicit informed consent before entering those customers into energy contracts. The AER subsequently released a Compliance Check, to guide businesses on the explicit informed consent requirement under the Retail Law.

Discounts off what?

From 2013 the ACCC has focused on how businesses promote discounts and savings under their energy offers, following concerns that consumers were being misled about the extent of savings available.

The ACCC in 2013 instituted proceedings in the Federal Court against AGL Energy and Origin Energy, for false or misleading statements to consumers on the level of discount under their energy plans. In 2015 the Federal Court imposed penalties totalling over $3 million on the retailers, with orders to compensate affected consumers.

5.4 Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through energy networks, and retail services. Figure 5.5 estimates the composition of a typical electricity and gas retail bill for a residential customer in each jurisdiction.

A typical electricity retail bill consists of:

- network charges for transporting electricity (38–60 per cent), which are regulated by the AER. The charges cover the efficient costs of building and operating electricity networks, and a return on capital
- competitive market costs (36–56 per cent), that cover purchases of wholesale electricity in the spot market and financial hedge contracts, retailing and marketing costs, and a retailer margin (return on investment)
- costs associated with schemes for renewable or low emission generation, or energy efficiency (4–14 per cent). The most significant 'green' cost relates to the renewable energy target (section 1.3.1) and feed-in tariffs for solar photovoltaic installations.[7]

In gas, distribution charges account for 31–69 per cent of retail prices and transmission charges account for 3–15 per cent. Variations in the contribution of these costs to energy bills largely relates to customer density and gas volumes. Unit costs for distribution services are lower when more customers are connected to a network and when average customer volumes are high.

Wholesale costs typically account for less than 20 per cent of retail gas prices, except in Victoria and the ACT. Wholesale gas prices are not higher in these regions, but they account for a larger share of energy bills because network costs are lower.[8]

Retailer operating costs (including margins) are similar for gas and electricity customers, but lower overall gas charges mean these costs account for a higher share of gas bills.

5.4.1 Retail price regulation

Governments are phasing out energy retail price regulation as effective competition develops. Victoria (2009), South Australia (2013) and NSW (2014) removed retail price regulation for electricity, following AEMC findings of effective competition. While removing price regulation, governments require retailers to publish unregulated standing offer prices that small customers can access. Retailers can adjust these prices no more than once every six months.

In electricity, retail price regulation applied in 2015 in Queensland, Tasmania and the ACT. In gas, only NSW applied price regulation. The regulated prices are set by state or territory government agencies; the AER does not regulate retail prices in any jurisdiction. Retailers are free in *all* NEM jurisdictions to offer market contracts with price terms different from the regulated rates.

Of the jurisdictions yet to remove retail price regulation, the AEMC in 2015 found only south east Queensland has effective energy retail competition.[9] The previous Queensland LNP Government committed to removing electricity retail price regulation in south east Queensland

7 AEMC, *2015 residential electricity price trends, final report*, 2015.

8 Oakley Greenwood, *Gas price trends review report*, 2015.

9 AEMC, *2015 retail competition review, final report*, June 2015.

Figure 5.5
Indicative composition of residential energy bills, 2015

Sources: AEMC, *2015 residential electricity price trends, final report*, 2015 (electricity); Oakley Greenwood, *Gas price trends review report*, 2015 (gas).

from 1 July 2015. However, the Queensland Labor Government delayed deregulation by 12 months to allow for a Queensland Productivity Commission inquiry into electricity prices. Regulated price setting will continue for the Ergon Energy distribution area, pending the development of a strategy to introduce retail competition in regional Queensland.

In gas, only NSW regulates retail prices for small customers. In October 2015 the NSW Government announced it would look to deregulate retail gas prices from 1 July 2017, if certain market benchmarks are met. The benchmarks include a 'considerable increase' in the level of competitive gas supply offers available for regional customers. The government planned to establish a working group of pipeline operators, retailers, consumer groups and the NSW Energy and Water Ombudsman, to help increase competition in gas supply.

5.4.2 Retail price trends

Table 5.2 (and figure 9 in the Market overview) summarises recent movements in regulated and standing offer energy prices, and estimates annual customer bills under those arrangements, for distribution network areas in the NEM. The data assume fixed electricity and gas use nationally and so, may not accurately represent typical household consumption in a particular jurisdiction. In practice, energy use varies between (and within) jurisdictions for reasons related to climate, the penetration of gas supply, and other factors. Standing offer prices are typically higher in networks servicing regional and remote areas, where the costs of providing and servicing infrastructure are higher and recovered from fewer customers.

Retail electricity prices rose significantly between 2008 and 2013, mainly due to escalating network costs. During this

Table 5.2 Movements in regulated and standing offer prices—electricity and gas

JURISDICTION	REGULATOR	DISTRIBUTION NETWORK	AVERAGE PRICE INCREASE (PER CENT) 2011	2012	2013	2014	2015	ESTIMATED ANNUAL COST ($)
ELECTRICITY								
Queensland	QCA	Energex and Ergon Energy	6.6	10.6	20.4	1.7	-6.1	2019
NSW	Unregulated	AusGrid	17.9	20.6	3.9	-5.5	-6.6	1859
		Endeavour Energy	15.5	11.8	1.6	-6.7	-3.5	1842
		Essential Energy	18.1	19.7	-0.6	-6.9	-17.0	2104
Victoria	Unregulated	Citipower	3.7	19.9	6.4	-9.0	7.5	1962
		Powercor	7.7	23.1	5.8	-6.8	7.1	2385
		AusNet Services	23.6	19.7	12.4	-3.9	10.6	2536
		Jemena	10.5	23.2	6.1	-5.8	4.0	2289
		United Energy	9.7	25.2	4.8	-6.2	4.2	2117
South Australia	Unregulated	ETSA Utilities	17.4	12.7	-1.8	2.2	-9.0	2333
Tasmania	OTTER	Aurora Energy	11.0	10.6	1.8	-12.6	2.0	1964
ACT	ICRC	ActewAGL	6.5	17.7	3.5	-7.0	-4.6	1399
GAS								
Queensland	Unregulated	AGN	1.4	13.4	8.4	2.1	6.2	1148
		Allgas Energy	7.4	13.4	5.1	3.4	6.9	1199
NSW	IPART	Jemena	4.0	14.8	9.6	12.0	-4.3	988
Victoria	Unregulated	AusNet Services	9.0	16.3	3.0	-1.2	8.3	716
		Multinet	3.5	20.0	2.0	-1.6	6.4	750
		AGN	7.3	18.4	9.1	-3.2	6.2	725
South Australia	Unregulated	AGN	13.8	17.7	11.6	9.3	3.7	1215
ACT	Unregulated	ActewAGL	7.0	10.3	5.7	8.7	4.6	1001

Notes:

Estimated annual cost is based on a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year on a single rate tariff at August 2015.

Prices are based on regulated prices of the local area retailer for each distribution network, or on standing offer prices where prices are not regulated.

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.

period, network businesses invested heavily in assets to accommodate expected demand growth, and financial market instability raised debt costs. The carbon price also contributed, raising retail prices by 5–13 per cent in 2012–13, although the Australian Government's Household Assistance Package offset the impact on low and middle income residential customers.

The repeal of carbon pricing reduced retail electricity prices in 2014 in most regions. In Queensland, carbon price reductions were offset by higher wholesale energy costs and feed-in tariff payments for solar PV systems. In South Australia, they were offset by rising network costs.

Retail electricity prices fell in Queensland, NSW, South Australia and the ACT in 2015. Declining electricity demand led network businesses to scale back expansions and financial costs stabilised, offsetting higher competitive market costs and costs associated with green schemes. The largest reduction in retail bills in 2015 occurred for customers in rural NSW (averaging 17 per cent) and in South Australia (9 per cent). A large reduction in network costs in Queensland was partly offset by rising costs under the solar bonus scheme. Queensland residential tariffs were also rebalanced (with higher fixed charges but lower usage charges), which raised the annual cost for a typical consumer.

Retail prices rose only in Victoria and Tasmania, which were subject to network determinations made at a time of higher business costs. Victorian prices rose 4–11 per cent in early 2015; in some networks, the rise exceeded the savings from the carbon repeal just a few months earlier. The new preliminary Victorian determinations taking effect in 2016 should lead network costs to fall, as in other jurisdictions.

Tasmanian retail bills rose marginally in 2015. This rise followed a large reduction in 2014 related to carbon savings and the opening of the residential sector to retail competition.

Gas prices have risen significantly since 2008, mainly driven by rising pipeline charges. More recently, rising wholesale costs associated with the diversion of gas supplies to LNG projects have put upward pressure on retail bills. Despite the removal of carbon pricing in 2014, gas prices continued to rise in all jurisdictions except Victoria. Prices again rose in 2015, except in NSW, where a new access arrangement lowered pipeline charges.

ABS data on energy prices

Figure 5.6 tracks movements in real energy prices for metropolitan households since 1991, based on the electricity and gas components of the consumer price index. Adjusting for inflation, national electricity prices rose by around 10 per cent annually (13 per cent in nominal terms) over the five years to 2012–13. Real prices moderated in 2013–14, with falls recorded in Hobart and Adelaide—the first reductions in those regions since 2005–06. Brisbane was the only city to experience substantial price rises, with real prices up by 15 per cent, following a delayed pass through of network cost increases. All cities except Brisbane recorded price falls in 2014–15, with an average reduction of 6 per cent (4 per cent in nominal terms).

Gas prices rose by an average of 7 per cent per year in real terms over the five years to 2012–13 (10 per cent in nominal terms). Prices continued to rise in all regions in 2013–14, but outcomes were more divergent than in previous years. The largest rises were in Adelaide (9 per cent in real terms) and Sydney (7 per cent), while the other capital cities recorded increases below 4 per cent. In 2014–15 prices again rose faster in Sydney and Adelaide than in the other capital cities. Melbourne was the only city to record a fall in real gas prices over the year.

Projected trends in retail electricity prices

In December 2015, the AEMC estimated that residential electricity prices in most jurisdictions would remain flat or slightly increase over the three years to 2017–18.[10] It expected prices to rise by less than 1 per cent in NSW, South Australia and the ACT, and by around 2 per cent in Queensland and Tasmania. Victorian prices are expected to remain stable.

These projections are driven by opposing expectations of declining network costs and rising wholesale electricity costs. While AER determinations are expected to lower network costs, merits review proceedings by the Australian Competition Tribunal may offset some of these reductions (section 2.2.3). A gradual recovery in electricity demand and generator retirements are likely to raise wholesale electricity costs from their current historically low levels.

5.4.3 Price diversity

Retailers offer a range of contracts with different price and product structures. Their offers include standard products, green products, 'dual fuel' contracts (for gas and electricity) and energy bundled with services such as telecommunications. Some contracts bundle energy with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. The increasing use of smart meters has spurred offerings of low price or free energy at certain times of the day or week. Discounts may be offered for prompt or prepayment of bills, or for direct debit payments. Offers may vary depending on the length of a contract. Many contracts carry a termination fee for early withdrawal.

The variety of discounts and non-price inducements makes direct price comparisons difficult. Further, the transparency of price offerings varies. The AER operates an online price comparison website—Energy Made Easy—to help small customers compare retail product offerings. The website's full functionality is available to customers in jurisdictions that have implemented the Retail Law (at December 2015: Queensland, NSW, South Australia, Tasmania and the ACT). The Victorian regulator and a number of private entities also operate websites allowing customers to compare market offers.

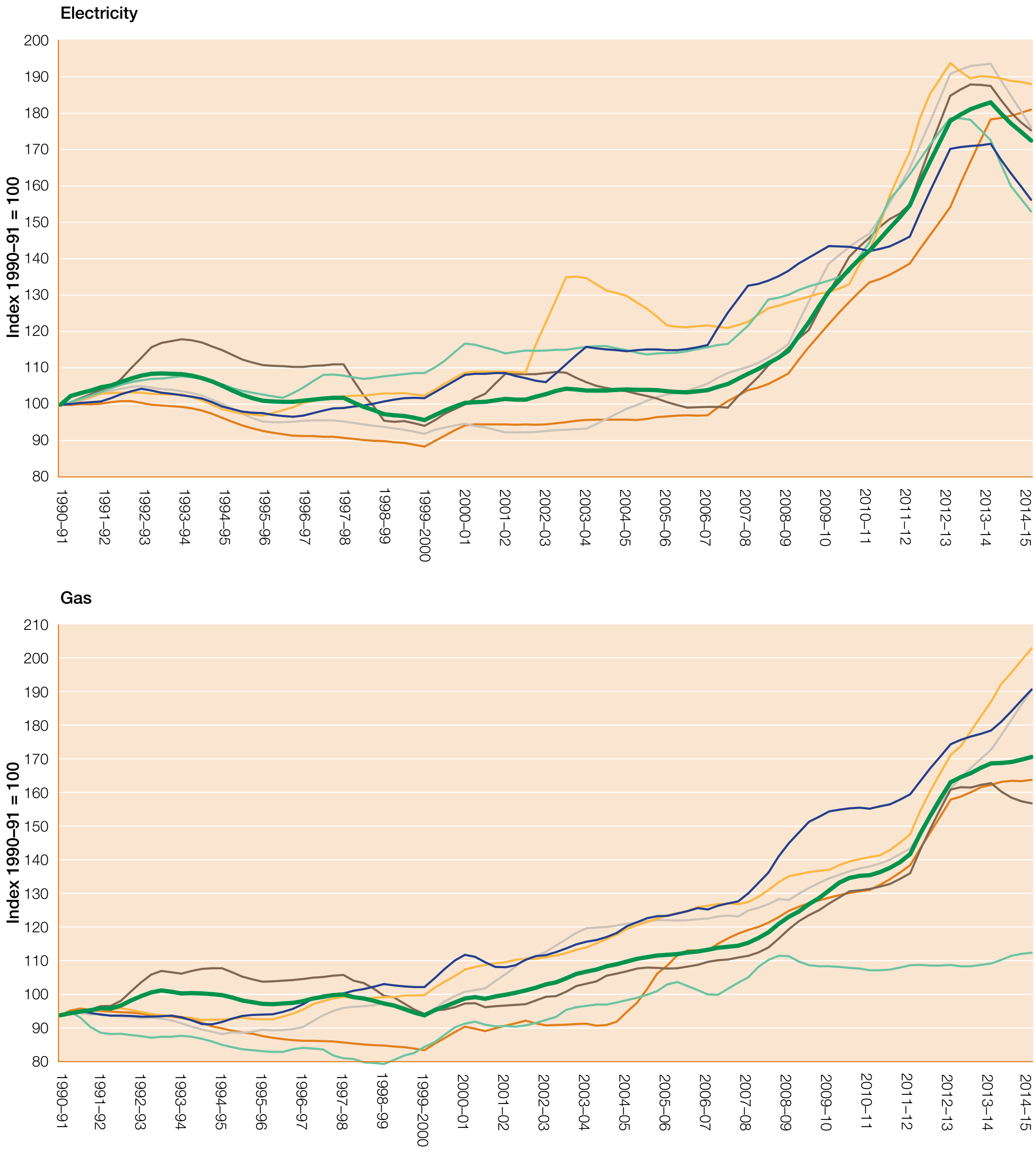
Figure 5.7 and table 5.3 draw on Energy Made Easy and state regulators' price comparison websites to list price offerings for residential customers in September 2014 and September 2015.

In electricity, jurisdictions that have removed retail price regulation exhibited the strongest price diversity in 2015. In those jurisdictions—NSW, Victoria and South Australia—

10 AEMC, *2015 Residential electricity price trends, final report*, December 2015.

Figure 5.6

Retail price index (inflation adjusted)—Australian capital cities



Note: Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

Source: ABS, *Consumer price index*, cat. no. 6401.0, various years.

annual charges under the cheapest contract were typically at least 30 per cent lower than under the most expensive contract, with annual bill spreads of $600–1100. In Queensland and the ACT, the lowest priced contracts were 16–18 per cent lower, with a spread of around $300.

In market contracts, the average discount in annual electricity bills from standing offers ranged from 2 per cent in Queensland to 17–18 per cent in Victoria in 2015. Compared with 2014, discounting in 2015 was greater in NSW and South Australia, steady in Victoria, and lower in Queensland and the ACT.

In 2015 market offer discounts over standing offers were greater in electricity than gas for all jurisdictions except Queensland. The discount for gas ranged from 3 per cent in Queensland to 10 per cent in Victoria. Annual bill spreads (based on the highest and lowest offer in each jurisdiction) ranged from $100 in the ACT to $280 in South Australia.

Large annual bill spreads indicate scope for customers to save significantly on their energy bills by switching retailers. But customers can also gain savings by switching contracts with the same retailer. In 2015 the difference between a retailer's standing offer and its lowest market offer averaged over $500 in Victoria and around $400 in South Australia. While the difference was lower in NSW ($270), Queensland ($150) and the ACT ($120), customers still had considerable scope to benefit by comparing available offers from their current retailer.

5.4.4 Retail prices and energy affordability

Energy affordability relates to customers' ability to pay their energy bills. While rising energy prices typically increase the number of customers with payment difficulties, affordability also depends on energy consumption levels, household income, the availability of financial assistance or concessions, and other competing costs of living.

AER research found average electricity costs as a proportion of household disposable income were lower in 2014–15 than in the previous two years in all jurisdictions except Queensland. Gas costs as a proportion of household disposable income in 2014–15 were generally lower than in 2013–14, but higher than 2012–13 levels, except in Victoria (figure 5.8).

For a benchmark low income household receiving energy bill concessions:

- electricity costs accounted for about 5 per cent of disposable income in 2012–13, falling to 4.6 per cent in 2014–15
- gas costs accounted for 3.6 per cent of disposable income in 2012–13, rising to 3.8 per cent in 2013–14, but easing to 3.7 per cent in 2014–15.[11]

Those jurisdictions with the highest electricity use (Tasmania) and gas use (Victoria) recorded the highest proportion of income spent on those fuels. The analysis does not account for the impact on bills of a change in energy use. A reduction in average electricity use over the past few years might have caused bills to fall further than identified by the analysis.

Electricity bills in 2014–15 were highest in Tasmania. While that region's unit charges were lower than for some other regions, low income households used an average 6500 kilowatt hours (kWh) per year (compared with 3700–5600 kWh elsewhere). Despite high electricity consumption in the ACT, that region's electricity bills are among the lowest in Australia because its usage charges are substantially lower than elsewhere.

Gas bills in 2014–15 were highest in the ACT and Victoria, where average use was 48 gigajoules and 63 gigajoules respectively (compared with 10–24 gigajoules elsewhere). Queensland had the lowest gas bills, with an average gas use of 10 gigajoules per year.

A key indicator of affordability and access is the rate of residential customer disconnections for failure to meet bill payments (figure 5.9). In 2014–15 electricity disconnections for non-payment reached their highest rate in six years in Queensland, at over 1.5 per cent of customers. The disconnection rate in the ACT also rose, but remained well below that of other regions. Electricity customer disconnection rates fell in all other regions. Gas disconnections in 2014–15 were up on the previous year in all regions, but well below historical highs.

Over 45 per cent of disconnected electricity customers and 25 per cent of disconnected gas customers were reconnected within a week.

11 AER, *Annual report on the performance of the retail energy market 2014–15*, 2015.

Table 5.3 **Comparison of standing and market offers—September 2015**

JURISDICTION (DISTRIBUTION NETWORK)	NUMBER OF OFFERS	LOWEST OFFER ($)	HIGHEST OFFER ($)	PRICE SPREAD ($)	% RANGE HIGHEST TO LOWEST OFFER	AVERAGE STANDING OFFER ($)	AVERAGE MARKET OFFER ($)	% DISCOUNT STANDING TO MARKET OFFER	DISCOUNT STANDING OFFER TO LOWEST MARKET OFFER ($)
ELECTRICITY									
Queensland									
Energex	30	1866	2212	346	15.6	2041	2002	1.9	153
NSW									
Ausgrid	51	1427	2106	679	32.2	1867	1670	10.6	253
Endeavour Energy	58	1434	2044	610	29.8	1870	1643	12.1	276
Essential Energy	52	1746	2725	979	35.9	2206	1974	10.5	278
Victoria									
Citipower	52	1320	2160	840	38.9	1946	1597	17.9	462
Powercor	55	1630	2550	920	36.1	2301	1901	17.4	544
United Energy	55	1470	2310	840	36.4	2109	1728	18.1	493
AusNet Services	53	1740	2850	1110	38.9	2505	2073	17.2	574
Jemena	56	1560	2440	880	36.1	2222	1838	17.3	517
South Australia									
SA Power Networks	42	1831	2788	957	34.3	2477	2205	11.0	395
ACT									
ActewAGL	17	1251	1523	272	17.9	1417	1327	6.4	116
GAS									
Queensland									
AGN (north Brisbane)	8	1096	1292	196	15.2	1217	1175	3.5	76
APT Allgas (south Brisbane)	8	1097	1237	140	11.3	1170	1142	2.4	61
NSW									
Jemena	25	803	1046	243	23.2	978	887	9.3	148
Victoria									
AusNet Services (central 2)	22	586	790	204	25.8	715	641	10.3	87
Multinet (main 1)	21	585	780	195	25.0	733	656	10.5	89
AGN (central 2)	22	568	738	170	23.0	710	645	9.2	83
South Australia									
AGN (metropolitan)	13	1062	1341	279	20.8	1232	1162	5.7	159
ACT									
ActewAGL	8	909	1011	102	10.1	1004	951	5.3	95

Notes:

Estimated annual cost is based on a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year on a single rate tariff at August 2015.

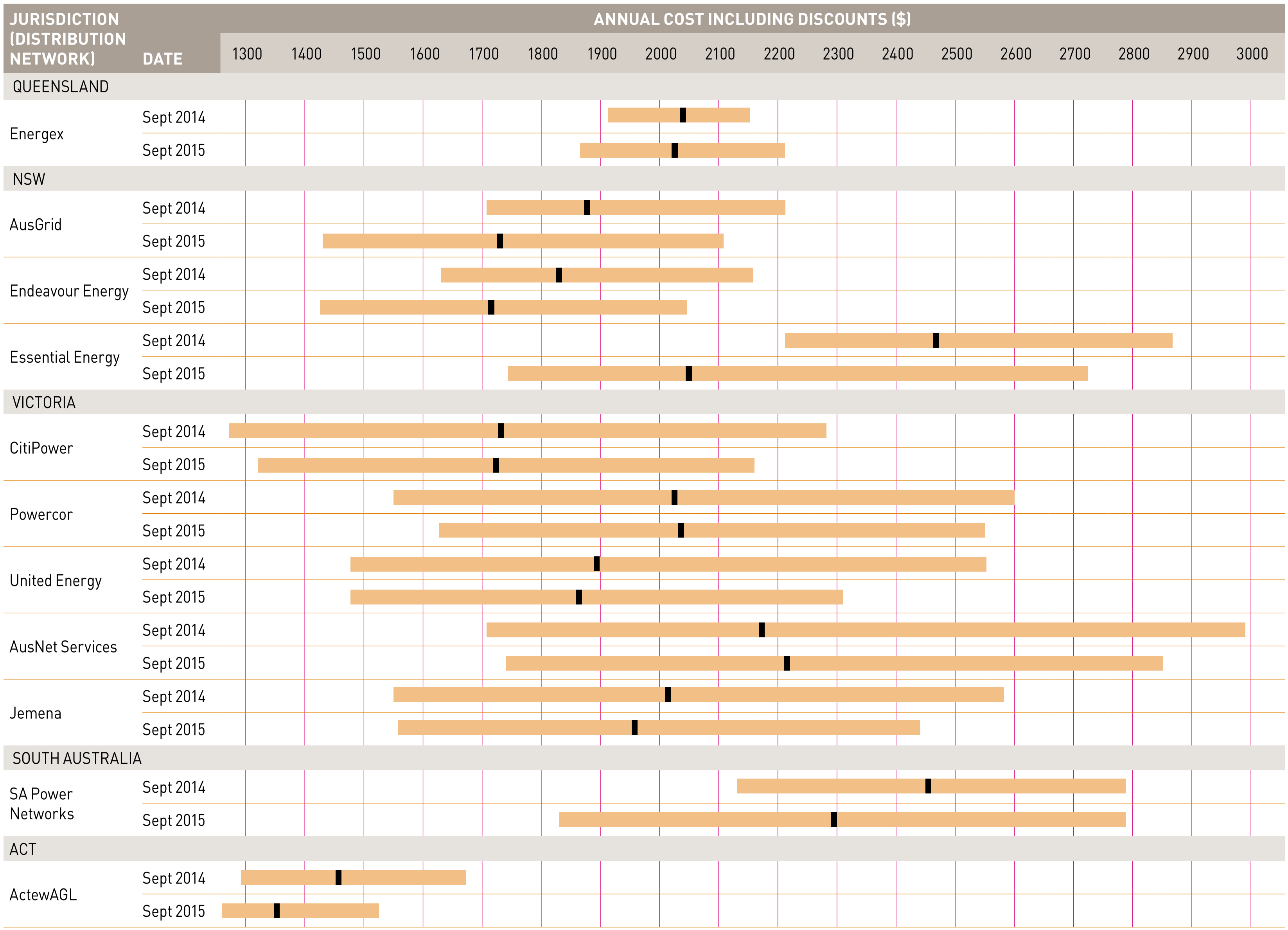
Prices are based on regulated or standing offer prices of the local area retailer for each distribution network.

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.

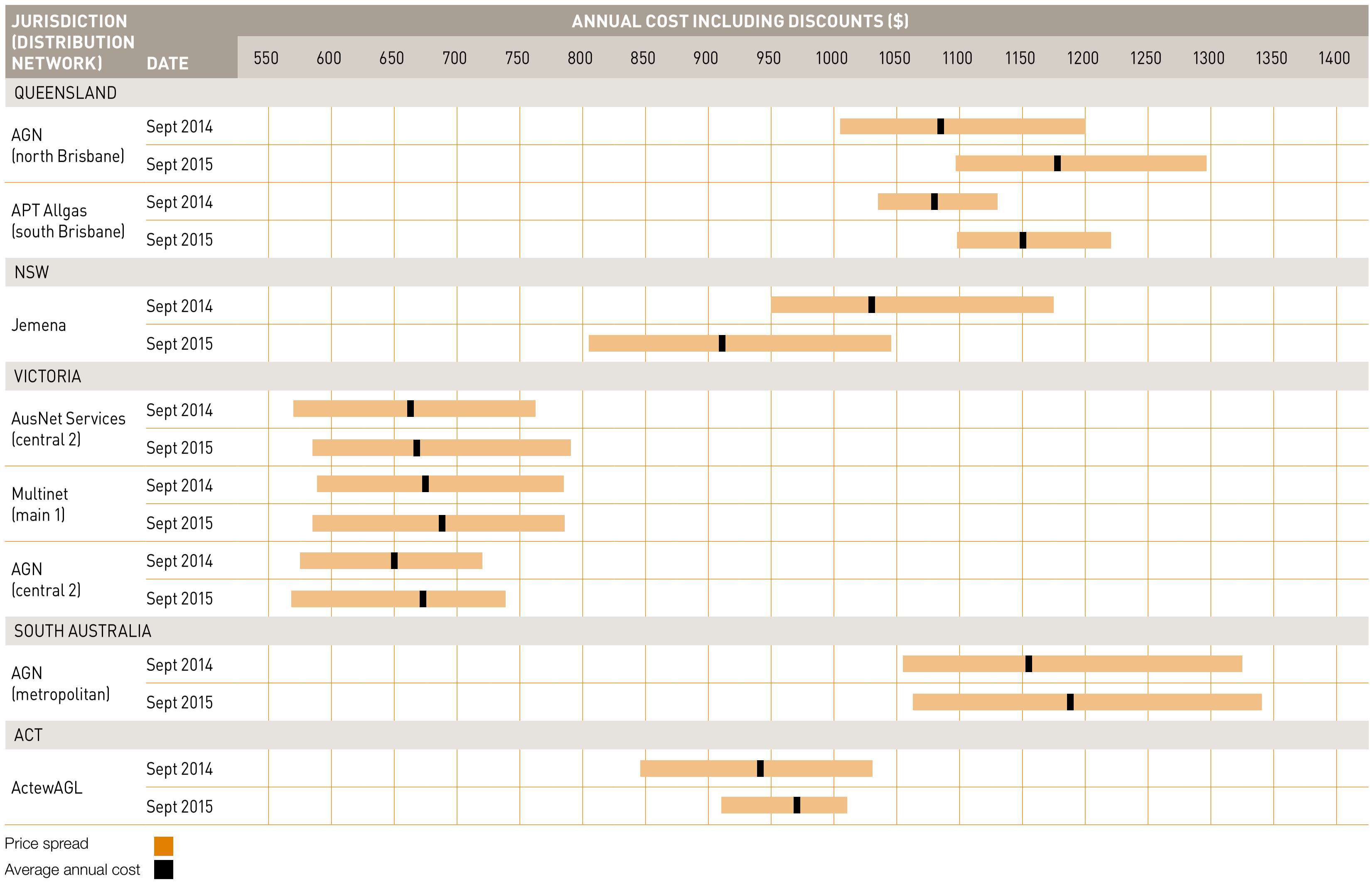
Figure 5.7

Price diversity in retail product offers—September 2015 and September 2014

Electricity



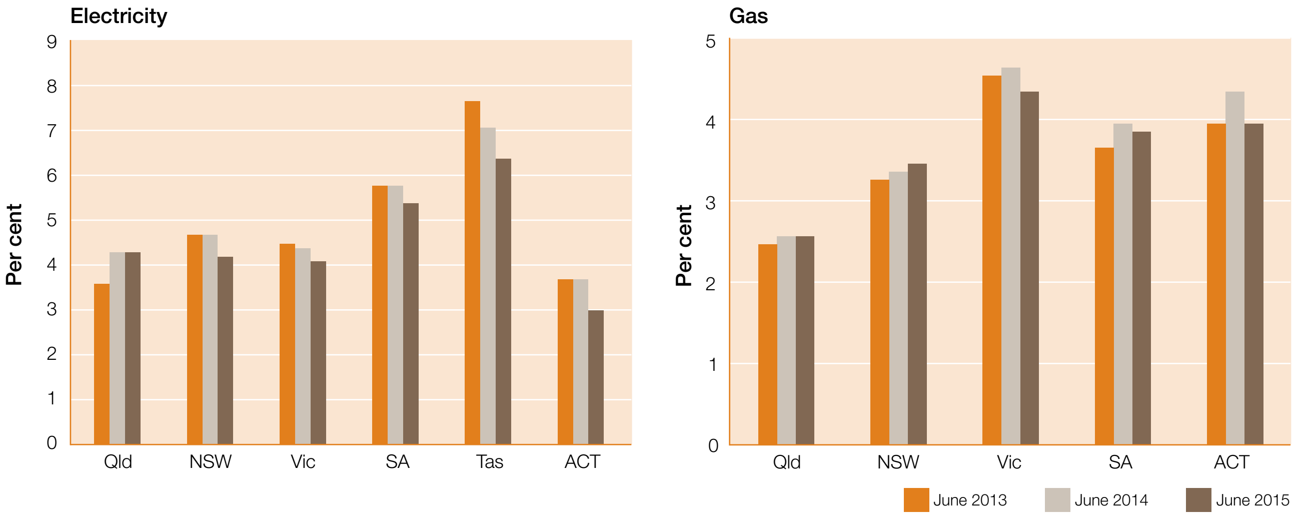
Gas



Sources: Price comparison websites operated by the AER (NSW, South Australia and the ACT), the QCA (Queensland) and the ESC (Victoria).

Figure 5.8

Annual energy costs as a percentage of disposable income for a low income household



Notes:

Energy consumption levels vary for each jurisdiction. Electricity consumption is the average for low income households. Gas consumption is the average for all households.

Energy charges are based on the median market offer. Charges are adjusted for concessions available to low income households.

Disposable income for a low income household is that of the lowest two deciles, excluding the first and second percentiles.

Sources: ABS; AER; price comparator websites operated by jurisdictional regulators.

Hardship issues

The Retail Law requires retailers to assist customers experiencing payment difficulties or financial hardship. Retailers must:

- protect customers from disconnection in certain circumstances, including when a customer's premises are registered as requiring life support equipment
- assist customers (through hardship programs, for example) before considering disconnection for non-payment of a bill.

Hardship programs aim to provide early assistance to customers. They may include:

- extensions of time to pay, as well as flexible payment options
- advice on government concession and rebate programs
- referrals to financial counselling services
- a review of a customer's energy contract to make sure it suits their needs
- energy efficiency advice to help reduce a customer's bills, which may include conducting an energy audit and helping replace appliances
- a waiver of late payment fees that might have applied.

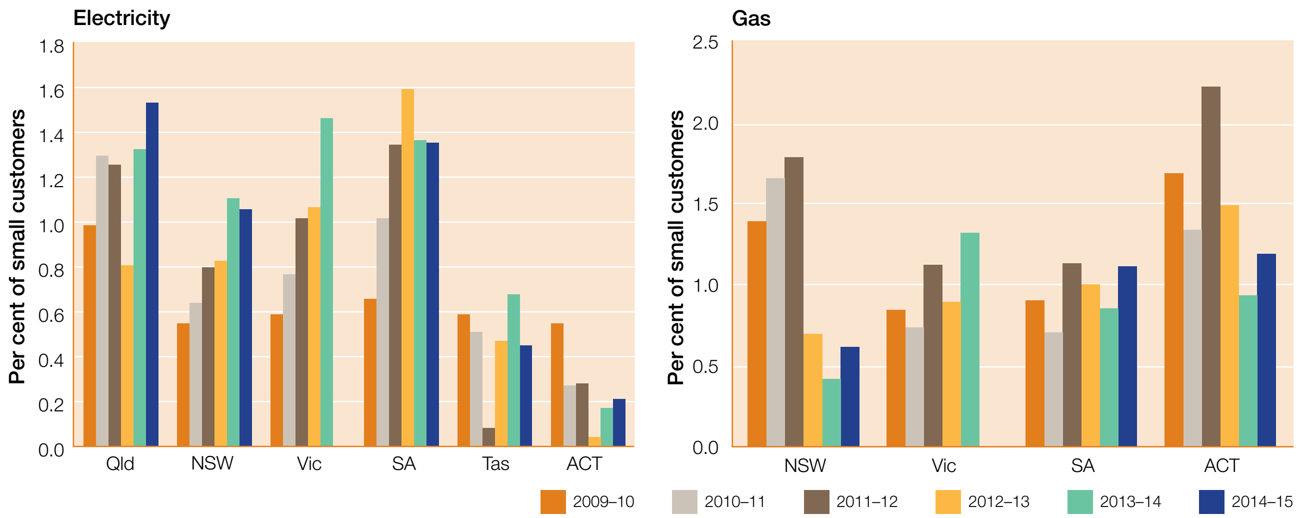
At 30 June 2015 the number of customers on hardship programs ranged from 0.4 per cent in NSW (electricity) and the ACT (electricity), to 1.5 per cent in South Australia (electricity). The total number of customers on hardship programs increased over the previous year in all jurisdictions, rising by an average of 26 per cent.

Customers typically enter a hardship program with less than $500 of debt owing to the energy retailer (44 per cent of electricity customers and 55 per cent of gas customers entering a program in 2014–15). Most energy customers had an average debt of less than $1500. But over 15 per cent had debts greater than $2500 before joining a hardship program.

Of those customers exiting a hardship program in 2014–15, 24 per cent of electricity customers and 22 per cent of gas customers successfully completed the program (up from 19 per cent for both electricity and gas in 2013–14). A further 19 per cent of electricity customers and 21 per cent of gas customers changed retailers. The remaining customers were removed from hardship programs for failing to meet energy repayments. For individual retailers, low debt levels on entry to hardship programs correlate somewhat with higher success rates.

Figure 5.9

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



Note: 2014–15 disconnection data were not available for Victoria.

Sources: Retail performance reports by the AER, IPART (NSW), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA (Queensland) and the ICRC (ACT).

5.5 Customer complaints

Energy retailers are required to have complaints handling and dispute resolution processes. Additionally, each jurisdiction has an energy ombudsman scheme offering a free and independent dispute resolution service for energy customers who have been unable to resolve a complaint with their retailer.

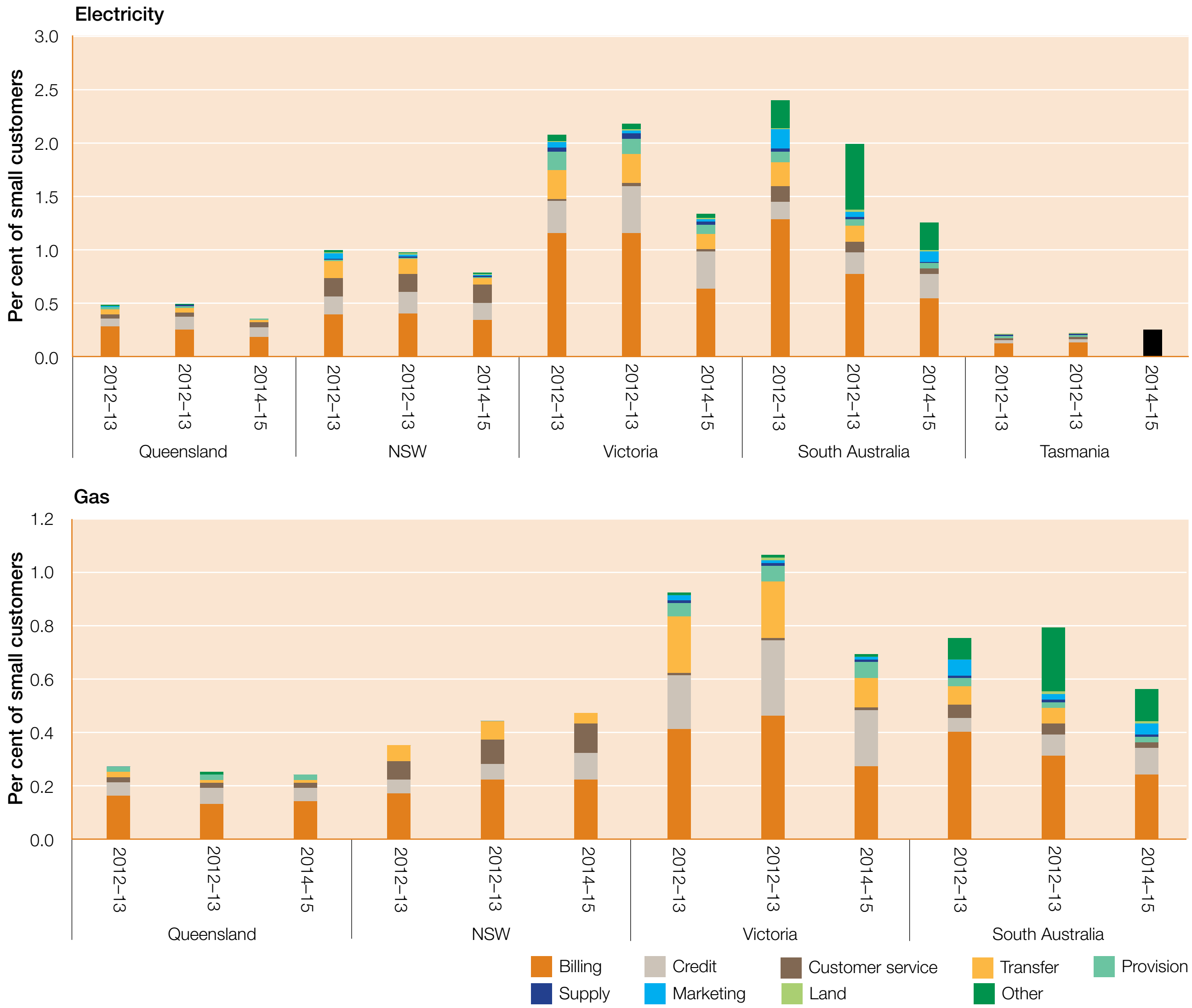
Figure 5.10 illustrates rates of customer complaints in electricity and gas to ombudsman schemes. The complaint rate varies across jurisdictions, from less than 0.5 per cent of customers in Queensland and Tasmania, to around 1 per cent of customers in Victoria and South Australia. While the results may reflect retailers' performance and the effectiveness of their internal dispute resolution procedures, they should be interpreted with caution; the maturity of competition, market depth and customers' awareness of the schemes may also affect outcomes. The proportion of customers with unsatisfactory experiences is higher than the proportion of those making complaints. The AEMC's 2015 retail competition review found 9 per cent of electricity customers and 7 per cent of gas customers were dissatisfied with their retailer.

The total number of complaints across electricity and gas fell by 32 per cent in 2014–15. Complaints were lower in all jurisdictions, except for gas customers in NSW and electricity customers in Tasmania.

Billing issues accounted for 45 per cent of all complaints in 2014–15. Credit issues—including processes for disconnection in the case of non-payment, and for the collection of outstanding charges—accounted for a further 25 per cent of complaints. Unauthorised transfers of customers to a new retailer accounted for 9 per cent of complaints. But complaints in this area fell by over 50 per cent from the previous year, reflecting reduced retailer marketing (section 5.3.1). Other prominent issues included network connection disputes and retailers' customer service.

Figure 5.10

Complaints to ombudsman schemes, as a percentage of total customers



Note: Categorised data were not available for Tasmania electricity complaints for 2014–15.

Sources: Annual reports by the Energy and Water Ombudsman schemes in Queensland, NSW, Victoria and South Australia, and by the Energy Ombudsman of Tasmania.

ABBREVIATIONS

2P	proved plus probable (natural gas reserves)
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
BREE	Bureau of Resources and Energy Economics
CCGT	Combined cycle gas turbine
CoAG	Council of Australian Governments
CPT	Cumulative price threshold
CSG	coal seam gas
EII	Energy Infrastructure Investments
Electricity Rules	National Electricity Rules
ESC	Essential Services Commission
ESCOSA	Essential Services Commission of South Australia
FRC	full retail contestability
GJ	gigajoule
GSL	Guaranteed Service Level
GW	gigawatt
GWh	gigawatt hour
HHI	Herfindahl–Hirschman index
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
km	kilometre
kW	kilowatt
kWh	kilowatt hour
LNG	liquid natural gas
MOS	market operator services
MSATS	market settlement and transfer solutions
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
NCC	National Competition Council
NEM	National Electricity Market
NSW	New South Wales
OCGT	open cycle gas turbine
OTC	over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PJ	petajoule
PV	photovoltaic
QCA	Queensland Competition Authority
QCLNG	Queensland Curtis liquid natural gas project
QNI	Queensland—NSW Interconnector
RAB	regulated asset base
RERT	reliability and emergency reserve trader
RET	renewable energy target
Retail Law	National Energy Retail Law
RIN	regulatory information notice
RIT-D	regulatory investment test—distribution
RIT-T	regulatory investment test—transmission
RSI	residual supply index
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
WACC	weighted average cost of capital