IN THE AUSTRALIAN COMPETITION TRIBUNAL

AGL ENERGY LIMITED

of 2014

RE: PROPOSED ACQUISITION OF MACQUARIE GENERATION (A CORPORATION ESTABLISHED UNDER THE ENERGY SERVICES CORPORATIONS ACT 1995 (NSW))

ANNEXURE CERTIFICATE

This is the annexure marked "**AF-10**" annexed to the statement of **ANTHONY GARTH FOWLER** dated 23 March 2014

Annexure AF-10

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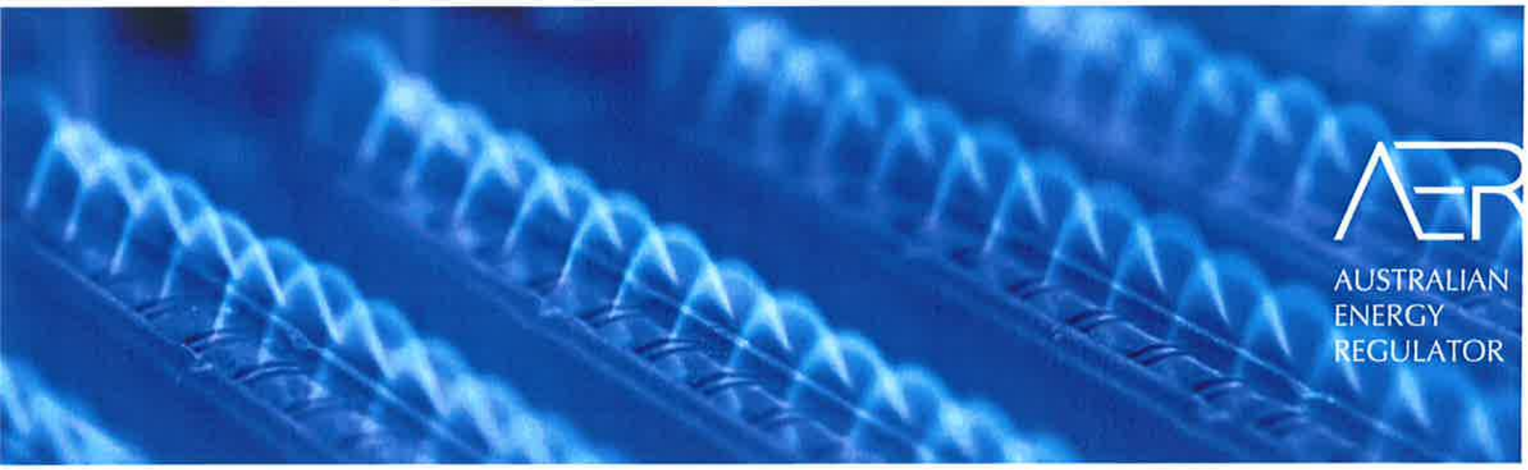
STATE OF THE ENERGY MARKET 2013



STATE OF THE ENERGY MARKET 2013

AUSTRALIAN
ENERGY
REGULATOR

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PREFACE

The Australian Energy Regulator's seventh *State of the energy market* report comes at a time of changing dynamics in the energy industry. Declining electricity demand has led to surplus generation capacity in most regions and has delayed the need to invest in electricity networks. Additionally, greater stability in global financial markets has eased finance costs for energy businesses. In 2013, these developments translated into more stable retail electricity prices in most jurisdictions.

Reforms to the energy rules (announced in November 2012) aim to deliver future decisions on network revenues and investment that are in the long term interests of consumers. In 2013 the AER published guidelines under the Better Regulation program on implementing the rules. The guidelines will apply first to regulatory determinations taking effect in 2015.

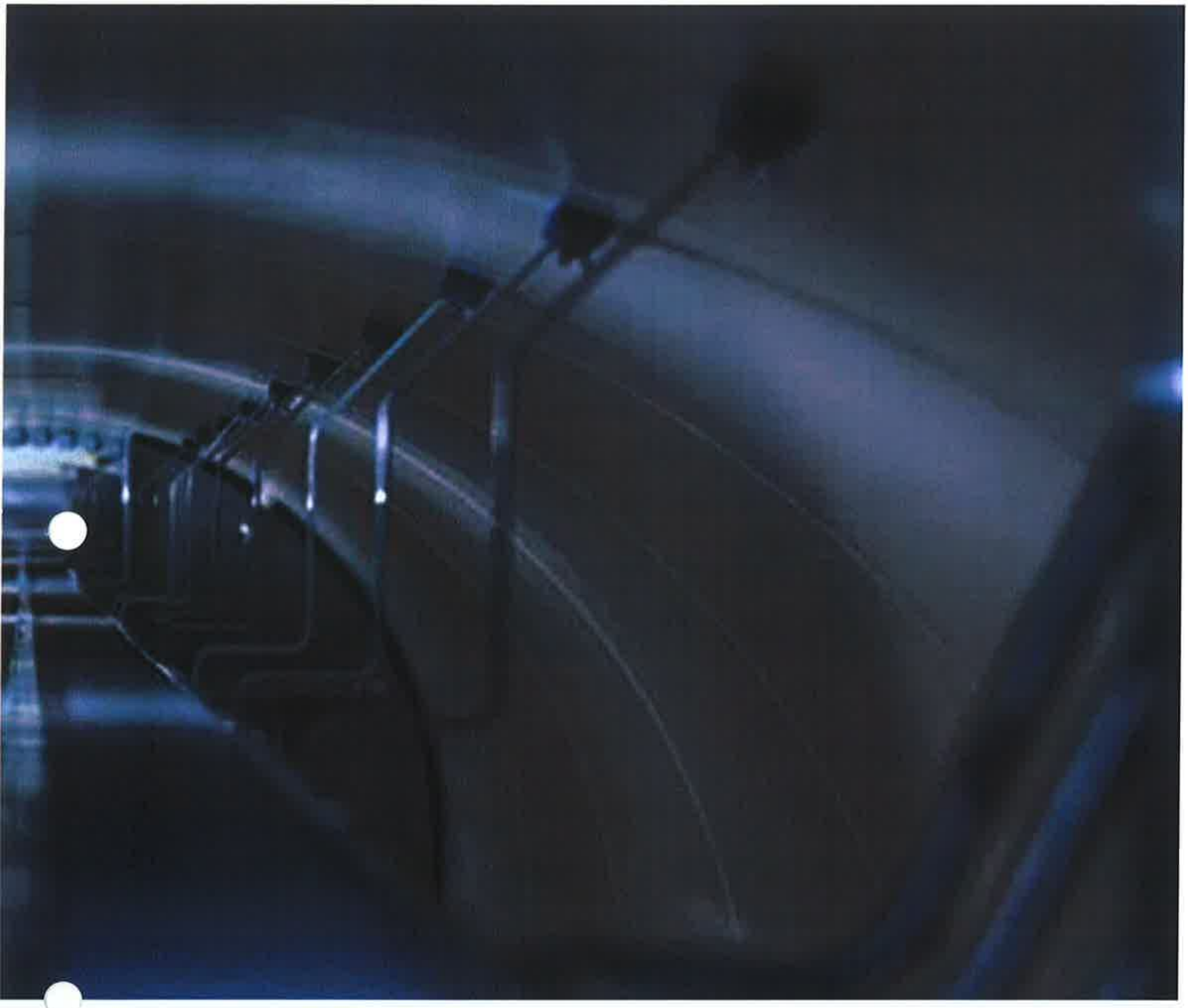
In retail, the transition to national regulation is continuing, with New South Wales on 1 July 2013 becoming the fourth jurisdiction (following South Australia, Tasmania and the ACT) to implement the National Energy Retail Law. Consumers in those jurisdictions now enjoy access to the AER's price comparator, www.energymadeeasy.gov.au.

Dynamics in the eastern gas market differ from those in electricity. While domestic demand has weakened, international demand for liquefied natural gas (LNG) exports from Queensland (scheduled to commence in 2014–15) is exerting pressure on gas prices. Policy makers are introducing reforms to help manage pressures in the eastern gas market.

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

Andrew Reeves
Chairman
December 2013

MARKET OVERVIEW



The energy market landscape has shifted considerably over the past 12–18 months. Rising energy prices were a major focus for the community and policy makers in 2012, but the dynamics of underlying cost drivers are shifting. A trend of rising electricity demand—which exerted upward pressure on wholesale and network costs for several years—has now reversed. The change is causing surplus generation capacity and removing the impetus for a number of network expansions. Further, the instability in global financial markets has eased, bringing down finance costs for energy businesses.

These developments are translating into more stable retail electricity prices in most jurisdictions. Following double digit rises in 2012–13, electricity retail price increases under regulated offers for 2013–14 were contained to below 4 per cent in New South Wales, Tasmania and the ACT (figure 1). In one New South Wales network area (Essential Energy), retail prices fell by 0.6 per cent.

Victoria and South Australia do not regulate retail electricity prices. In Victoria, standing contract prices rose by 5–12 per cent in 2013 across the state's five distribution network areas, following increases of 20–25 per cent in 2012. Because prices are unregulated, limited information is available on the reasons for these outcomes. But the Essential Services Commission reported in May 2013 that retailer margins in Victoria have increased since the removal of retail price regulation in 2009. In South Australia, electricity prices in standing contracts fell by 9.1 per cent following deregulation on 1 February 2013. Subsequent movements resulted in a net price decrease of 1.8 per cent during 2013.

An exception to this move towards more stable electricity prices was Queensland, where the regulated single-rate residential tariff rose by 20.4 per cent for 2013–14. The rise passes through two years of network cost increases following the Queensland Government's price freeze for this tariff in 2012–13.

Retail prices tended to rise more strongly for gas than electricity in 2013–14. In New South Wales, higher network costs contributed 60 per cent to the gas retail price rise. And gas retail prices are unlikely to ease in the near future. While domestic demand recently flattened, international demand for liquefied natural gas (LNG) exports from Queensland (scheduled to commence in 2014–15) is placing upward pressure on wholesale prices.

A.1 Transition to national regulation

The transition to national regulation of retail energy markets is continuing. The National Energy Retail Law commenced in Tasmania (for electricity only) and the ACT on 1 July 2012, in South Australia on 1 February 2013 and in New South Wales on 1 July 2013. Victoria and Queensland are yet to implement the Retail Law.

The Retail Law operates with the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements. It also transfers significant functions from state and territory governments to the Australian Energy Regulator (AER). While the AER does not regulate retail energy prices, it maintains the Energy Made Easy website, which provides a tool for energy customers to compare prices of generally available retail market offers. The website also provides a benchmarking tool for households to compare their electricity use with that of similar households, and information on the energy market, energy efficiency and consumer protections. At 1 December 2013 small energy customers in New South Wales, South Australia, Tasmania and the ACT had access to all functions of the website.

The AER also monitors energy affordability and retailers' policies for assisting hardship customers. AER research found average energy costs rose faster than household disposable income in 2012–13. For a benchmark low income household that receives energy bill concessions:

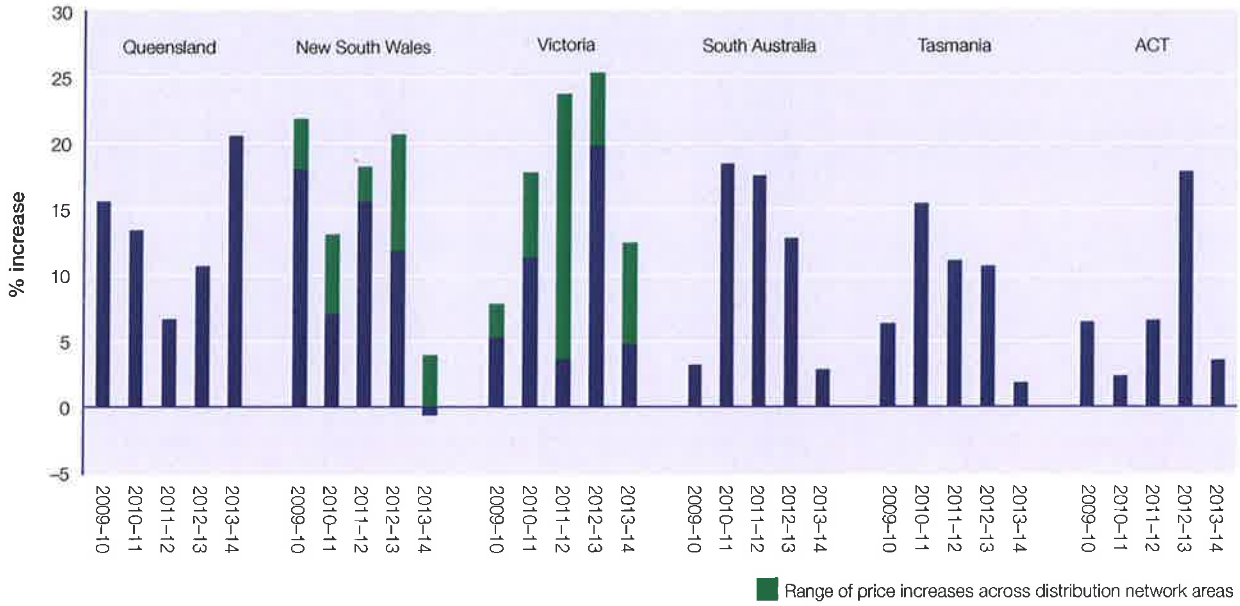
- electricity costs accounted for 2.4–7.1 per cent of their disposable income in 2011–12 (depending on region), rising to 2.9–7.9 per cent in 2012–13
- gas costs accounted for 1.2–3.2 per cent of their disposable income in 2011–12, rising to 1.4–3.4 per cent in 2012–13.

Electricity costs were highest in Tasmania, where average electricity use is significantly higher than elsewhere. Gas costs were highest in Victoria, for a similar reason.

A.2 State of retail competition

The retail sector experienced a slight increase in market depth in 2012–13. While three retailers—AGL Energy, Origin Energy and EnergyAustralia (formerly TRUenergy)—jointly supplied 77 per cent of small electricity customers and 85 per cent of small gas customers in southern and eastern Australia, their combined market share fell by 2 per cent in 2012–13. Small private retailers (mostly new entrants) in the New South Wales and Victorian electricity markets gained market share during the year. In Victoria, which is the region

Figure 1
Movements in regulated and standing offer prices—electricity



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 2013.

The Victorian price movements (and estimated annual costs) are for the calendar year ending in that period—for example, the 2013–14 Victorian data are for calendar year 2013. Victorian price movements (and those for South Australia in 2013–14) are based on unregulated standing offer prices of the local area retailer for each distribution network. The data for South Australia in 2013–14 relates to movements in the standing offer in the six months to December 2013.

The price increase for Tasmania in 2013–14 relates to the period 1 July 2013 to 31 December 2013. A further price adjustment will occur on 1 January 2014.

Sources: Determinations, factsheets and media releases by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

with the most diverse market structure, small private retailers supplied 27 cent of electricity customers. Some of the gains to smaller retailers were reversed in August 2013 when AGL Energy acquired the former independent retailer Australian Power & Gas.

Customer switching activity continued to be strong, with record highs for both electricity and gas in Victoria, New South Wales and South Australia in 2012–13 (figure 2). Particularly strong growth in New South Wales led its switching rate for electricity to reach a level previously seen only in Victoria. But switching rates fell in Queensland, where energy retailers reduced their marketing efforts in response to concerns about how regulated electricity prices are set.[1]

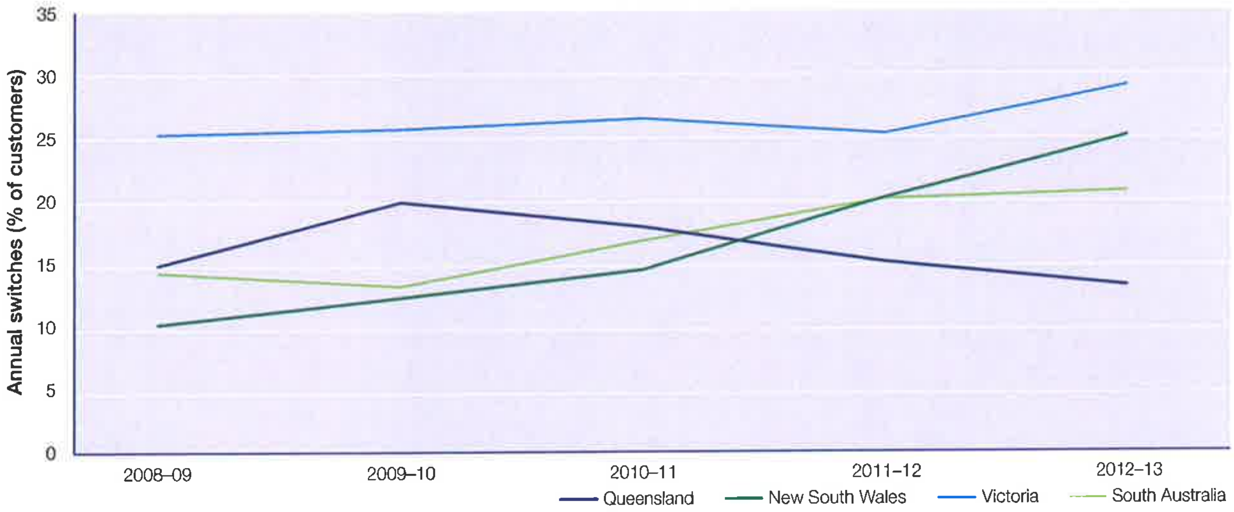
High switching rates were mirrored by evidence of reasonable price diversity, although discounting fell in some jurisdictions. In August 2012 the average discount off base offers[2] was 5–6 per cent in Queensland, New South Wales and South Australia, and 8–9 per cent in Victoria. In August 2013 the average discount was relatively unchanged in Queensland, but lower in New South Wales (below 4 per cent) and South Australia (1.5 per cent). The variation across Victorian network areas was generally higher, from 7–11 per cent.

In August 2013 the average discount off base offers was lower in gas than electricity—less than 4 per cent in jurisdictions other than Victoria. The average discount for Victoria was 6 per cent. In South Australia and in

1 See, for example, AGL, 'AGL 2013 earnings guidance', Media release, 23 October 2012.

2 Base offers are regulated offers in New South Wales (electricity and gas) and Queensland (electricity). In other jurisdictions, base offers are the standing offers of the local area retailer for each distribution network.

Figure 2
Switching of energy retailers by small customers



Sources: Customer switches: AEMO, MSATS transfer data to July 2013 and gas market reports, transfer history to July 2013; customer numbers: estimated from retail performance reports by the AER, IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia) and the QCA.

Queensland's North Brisbane network, gas contract prices on average exceeded the base offer price of the local area retailer.

Increased competition among retailers for new customers has intensified marketing activity, resulting in a greater volume of customer complaints about inappropriate conduct. The Australian Competition and Consumer Commission (ACCC) has acted on several alleged breaches of the Australian Consumer Law related to door-to-door and other marketing activity. As a result, the Federal Court imposed penalties on a number of businesses. In response, and recognising the widening use of price comparison and switching websites, the three largest energy retailers—AGL Energy, EnergyAustralia and Origin Energy—committed in 2013 to cease door-to-door marketing.

The Australian Energy Market Commission (AEMC) advises jurisdictions on the effectiveness of retail competition and whether to remove price regulation. In February 2013 South Australia became the second jurisdiction to remove retail energy price regulation. As in Victoria (which removed price regulation in 2009), retailers must publish unregulated standing offer prices that small customers can access.

The AEMC in September 2013 found competition was effective in New South Wales energy retail markets, with retailers' offering substantial discounts off the regulated price. It recommended the New South Wales Government remove price regulation and improve consumer information and ongoing market monitoring. The AEMC provided further advice in October 2013 on how to inform and empower consumers to promote effective competition.

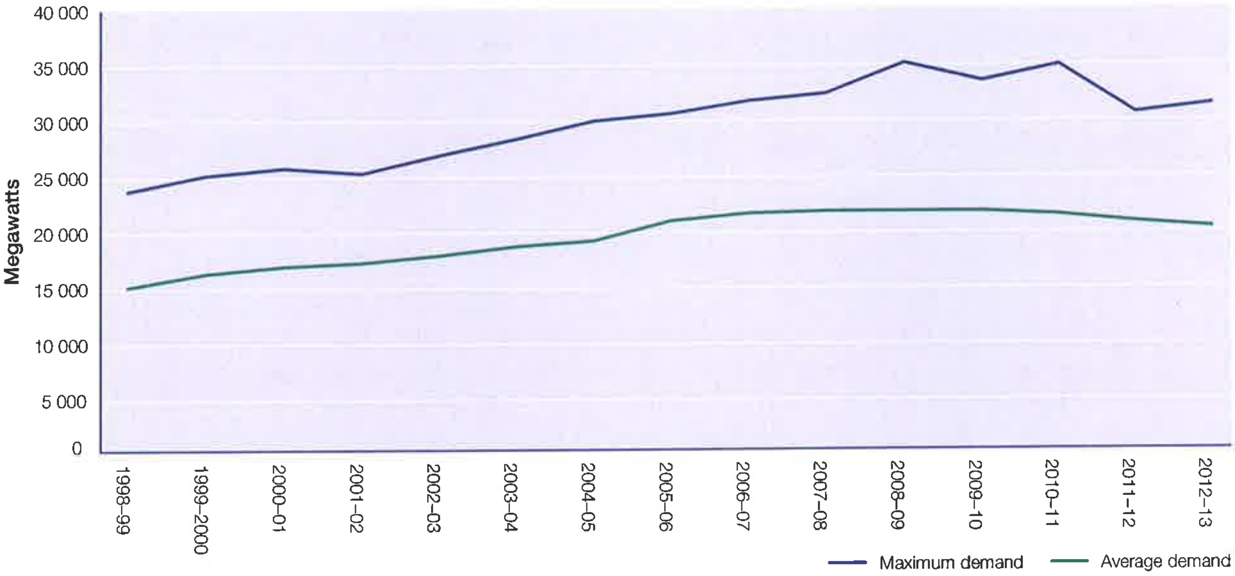
The Queensland Government committed to removing electricity retail price regulation in south east Queensland by 1 July 2015, so long as appropriate consumer protection and engagement policies are in place. Regulated price setting will continue for the Ergon Energy distribution area, pending the development of a strategy to introduce retail competition in regional Queensland.

In Tasmania, the government plans to allow all customers to choose their energy retailer from 1 July 2014. A planned sale of Aurora Energy's retail customer base to private retailers was abandoned in September 2013. But reforms to Tasmania's wholesale market arrangements began in June 2013, to encourage new retail entry.

A.3 National Electricity Market

Wholesale electricity in eastern and southern Australia is traded through the National Electricity Market (NEM), covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. Electricity demand peaked across the NEM in 2008–09 but has since declined (figure 3). The Australian Energy Market Operator (AEMO) has twice revised down the demand forecast for 2013–14. Maximum demand, which typically occurs during heatwaves

Figure 3
Maximum and average electricity demand



Sources: AER, AEMO.

when air conditioning use is high, has also flattened since 2008–09. It moved significantly below trend in the 24 months to 30 June 2013.

This trend of declining demand reflects:

- commercial and residential customers responding to higher electricity costs by reducing energy use and adopting energy efficiency measures such as solar water heating
- subdued economic growth and weaker energy demand from the manufacturing sector
- the continued rise in rooftop solar photovoltaic (PV) generation (which reduces demand for energy supplied through the grid). During 2012–13, PV generation output rose by 58 per cent to 2700 gigawatt hours, equal to around 1.3 per cent of electricity consumption. This growth has been driven by small scale renewable energy certificates and lower cost solar systems.[3]

Subdued electricity demand has led to surplus generation capacity in the NEM, causing around 2300 megawatts (MW) of plant to be retired or periodically offline since 2012. Some plant is running only over summer, when demand is typically high (for example, Alinta's Northern plant in South Australia). Other owners are rotating plant throughout the year. CS Energy, for example, operated only three of its six 280 MW Gladstone units in Queensland during January 2013.

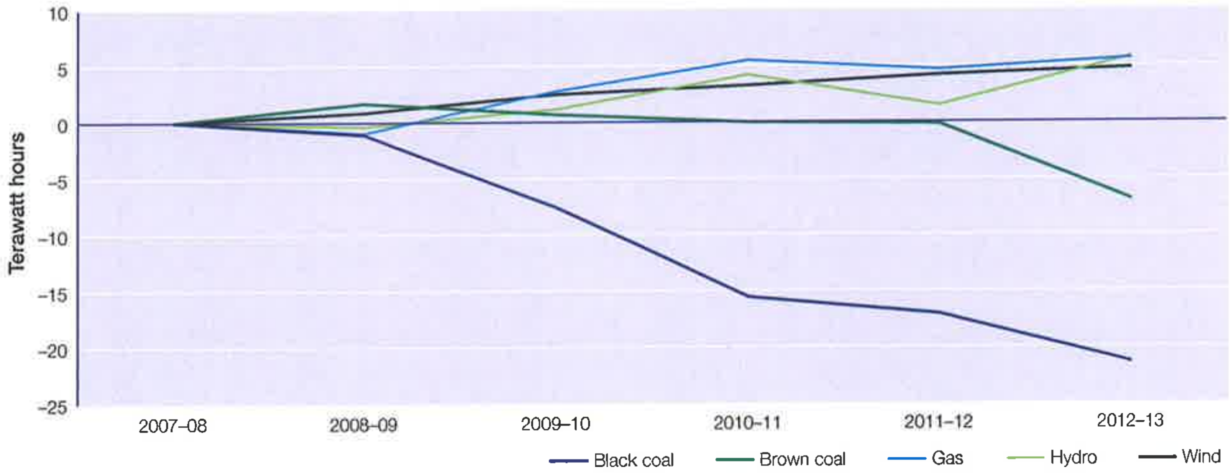
In these market conditions, AEMO forecast in 2013 that New South Wales, Victoria and South Australia were unlikely to need new generation capacity for at least 10 years. Two years ago, the outlook was quite different, with New South Wales and Victoria expected to require new plant capacity as early as 2014–15. In contrast to other regions, industrial development in Queensland (mostly associated with LNG projects) caused AEMO to bring forward the timing of new investment requirements to 2019–20.[4]

Climate change policies also contributed to change in the generation sector by altering the competitiveness of alternative technologies (figure 4). The renewable energy target scheme stimulated investment in wind generation, which supplied 3.4 per cent of electricity in the NEM in 2012–13 (including 28 per cent of output in South Australia). Additionally, the carbon pricing regime introduced in July 2012 made older coal fired plant less competitive, leading to some plant closures. But it enhanced the competitiveness of hydro generation, contributing to a 36 per cent rise in output in 2012–13 to supply 9 per cent of electricity in the NEM. The share of gas powered generation in the energy mix also rose.

3 AEMO, *National electricity forecasting report 2012* and *National electricity forecasting report 2013*.

4 AEMO, *Electricity statement of opportunities 2013*.

Figure 4
Change in generation mix since 2007–08



Sources: AEMO; AER.

Overall, these changes contributed to the emissions intensity of generation in the NEM falling by 4.5 per cent in 2012–13. This fall in emissions intensity, combined with lower NEM demand, led to a 7 per cent fall in total emissions from electricity generation in 2012–13.

A.4 Wholesale electricity prices

Declining electricity demand and the rising uptake of renewable generation, including wind and solar PV, contributed to historically low spot electricity prices in 2011–12 (figure 5). But this trend reversed in 2012–13: average prices more than doubled in Queensland (to $70 per megawatt hour (MWh)), Victoria (to $61 per MWh) and South Australia (to $74 per MWh), and almost doubled in New South Wales (to $56 per MWh). Tasmanian prices rose by around 50 per cent (to $49 per MWh).

In part, the higher prices reflected carbon pricing, introduced on 1 July 2012 at $23 per tonne of emissions. The carbon pass through to spot electricity prices was broadly consistent in mainland regions (averaging $17.70 per MWh), but significantly lower in Tasmania ($10 per MWh) due to its high concentration of hydro generation. But average prices for 2012–13 rose by around $31 per MWh, suggesting other factors contributed. The largest increases occurred in South Australia and Queensland, where carbon adjusted prices rose by over 70 per cent (figure 6). These outcomes were mainly driven by price spikes in summer 2013 (Queensland) and autumn 2013 (South Australia). While prices came off a low base in 2011–12, the rises occurred against a backdrop of weak electricity demand.

A.4.1 South Australia

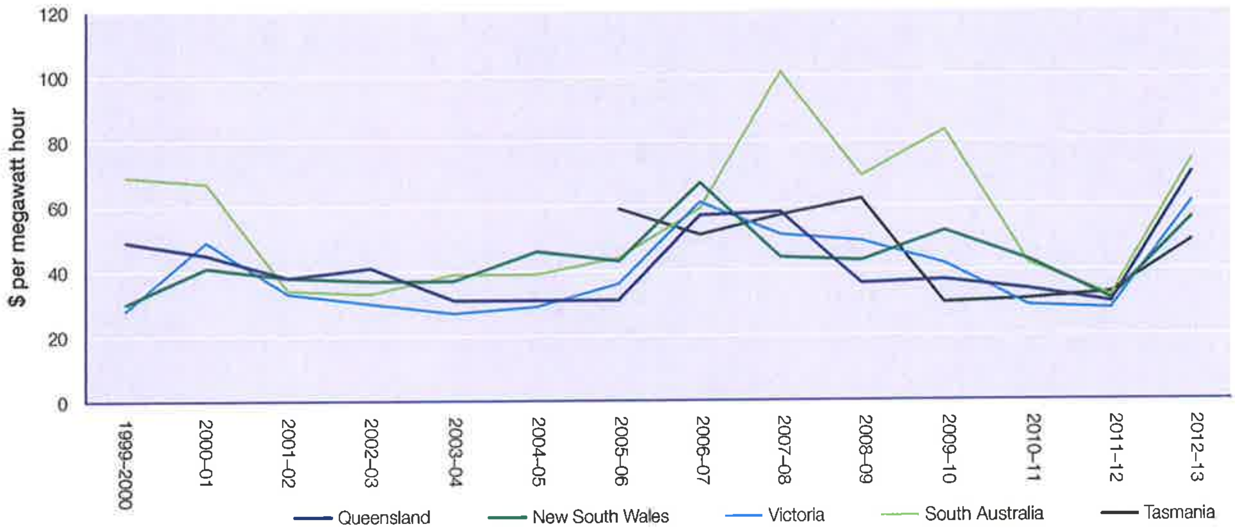
A tight supply–demand balance caused South Australian spot prices to average $106 per MWh in April–June 2013, almost double the average in other mainland regions of the NEM. This outcome occurred at a time of year when energy use is normally subdued.

The tight supply conditions were caused by Alinta, International Power and AGL Energy making commercial decisions to take some of their generation capacity offline and to increase the offer prices of remaining capacity. Overall, the maximum available capacity offered into the market by South Australian generators was around 700 MW lower in April–June (Q2) 2013 than in the corresponding period in 2012 (figure 7). This reduction in available capacity significantly raised the market clearing price.

Challenging market conditions contributed to the decisions to reduce available capacity. In addition to the weak energy demand affecting all regions, South Australia's high reliance on wind generation drove down spot prices, eroding generator returns. Meanwhile, input costs (including carbon and gas costs) had risen.

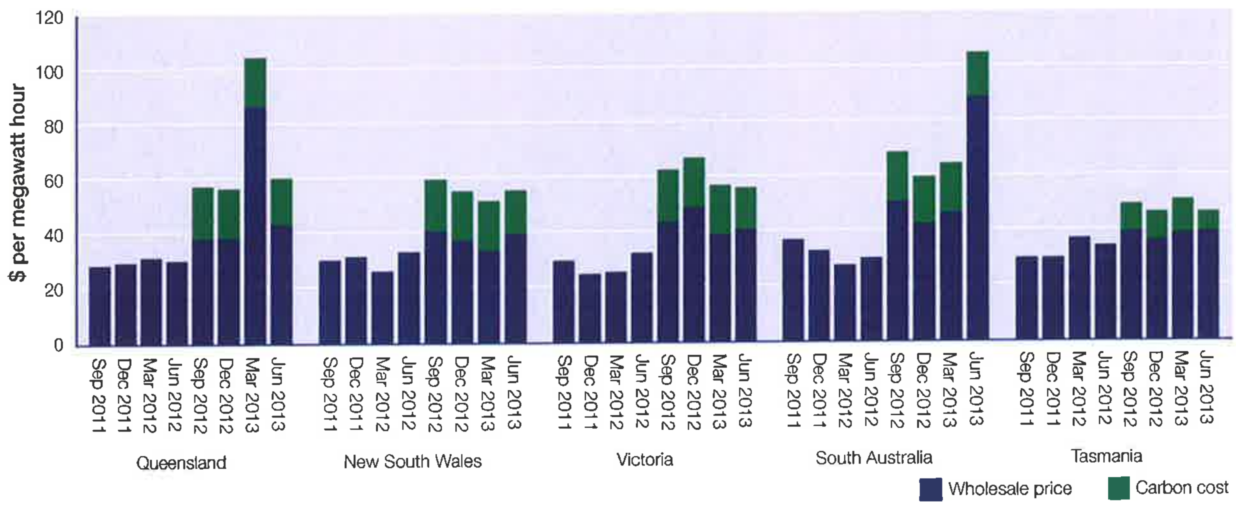
Higher spot prices led to a rise in South Australian energy imports from Victoria during April–June 2013. But technical limits on the interconnectors, and AEMO's management of

Figure 5
Annual spot electricity prices



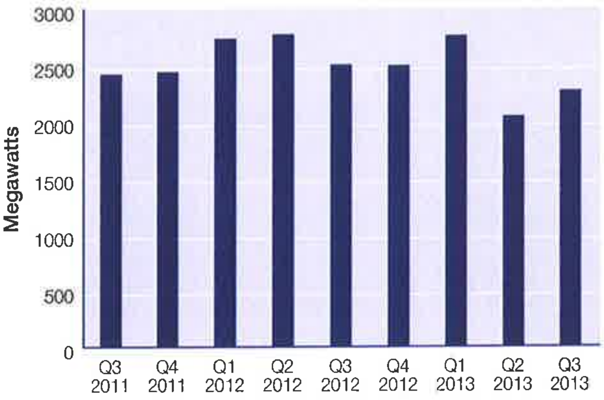
Note: Volume weighted annual average prices.
Sources: AER; AEMO.

Figure 6
Spot electricity prices, isolating carbon costs



Note: Average implied carbon cost represents the amount required to meet carbon price financial obligations, based on the emissions and carbon permit costs for the marginal generator in each dispatch interval.
Source: AER.

Figure 7
Average half hourly maximum generation availability, South Australia



Source: AER.

those limits, restricted import capacity. The AER has worked closely with AEMO to improve market systems and lessen the impact of these issues.

In such a tight market, issues that usually have a negligible impact can significantly affect prices. In April and May 2013 step changes in overnight demand associated with hot water loads contributed to a number of high prices. The AER held discussions with SA Power Networks to find better ways of managing this issue. More generally, even small forecasting errors can cause market volatility when the supply–demand balance is so finely tuned.

A.4.2 Queensland

An interplay of factors caused volatility in the Queensland market in January 2013, resulting in 116 prices above $300 per MWh, including 16 prices above $1000 per MWh (figure 8). While the events occurred in summer, a number occurred between midnight and 7 am, when demand was low.

Queensland's supply–demand balance was relatively tight in the first quarter of 2013, with generators offering 12 per cent less capacity (around 1320 MW) into the market than during the same quarter in 2012. These conditions were aggravated during much of January by transmission network congestion around central Queensland.

Following an ownership restructure in July 2011, CS Energy acquired control over generation plant at both ends of a strategic transmission line in central Queensland. Subsequently, its bidding behaviour periodically resulted in power flows that contributed to network congestion. AEMO was obliged to manage the issue by 'constraining off' low cost generation in southern Queensland and 'constraining on' higher cost generation around Gladstone. It also forced power flows out of Queensland into New South Wales, often contrary to price signals—that is, electricity flowed from the higher priced Queensland region to the lower priced New South Wales region.

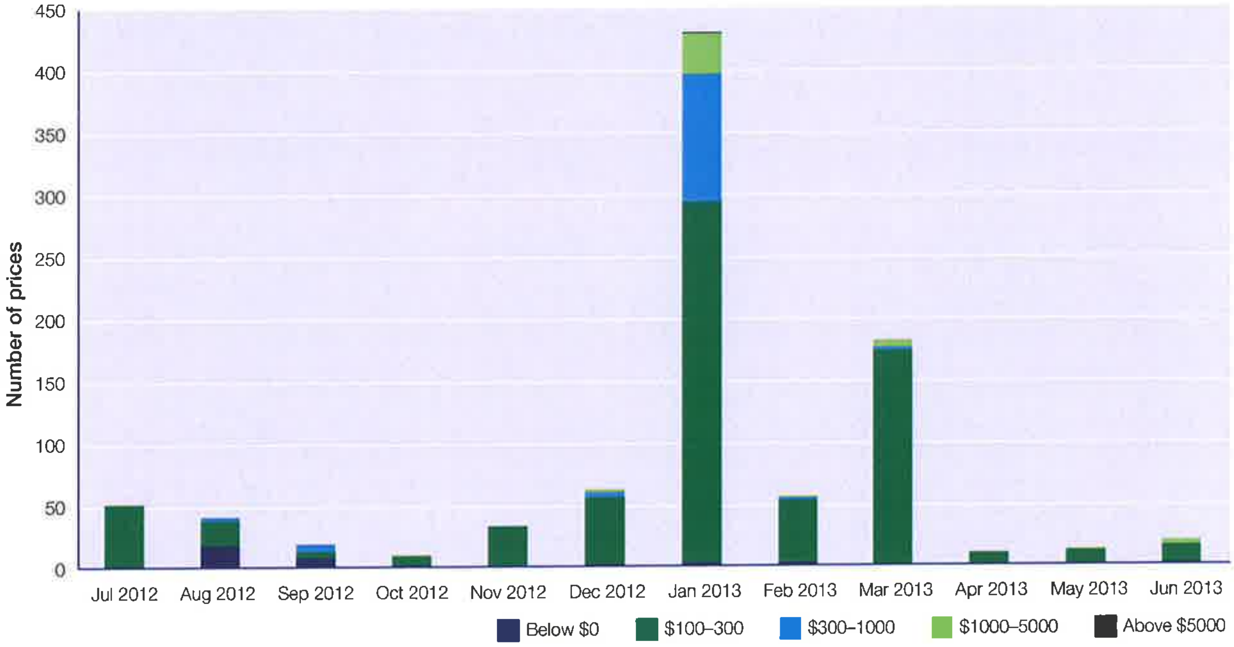
In combination, the reduction in low cost generation in southern Queensland, the dispatch of higher priced capacity around Gladstone, and the counter-price export of electricity into New South Wales caused the Queensland price to spike. The problem was exacerbated by generators engaging in disorderly bidding—that is, bidding contrary to the underlying cost structures and/or technical limitations of generation plant. In particular, generators tried to maintain output levels and receive high spot prices by rebidding capacity to low (or negative) prices. They also rebid down the ramp rates of their plant so they could be constrained off only slowly.

Disorderly bidding causes random and very short fluctuations in prices that are impossible to predict (figure 9), making it difficult for competing generation to respond. Additionally, the effects on interregional trade flows are significant. When electricity flows counter price across state borders, the market operator pays out more to generators in the exporting region than it receives from importing customers. The cost of this negative settlement residue falls on the transmission network provider in the importing region (in this instance, New South Wales). Ultimately, consumers in the importing region bear the cost through increased transmission network charges.

Network augmentation is a costly solution to network congestion and disorderly bidding, which periodically affect all regions of the NEM. The AEMC proposed an 'optional firm access' model, under which generators pay transmission businesses for firm network access, based on the costs of increasing network capacity. If congestion prevents a generator with firm access from being dispatched, then non-firm generators contributing to the problem would be required to pay compensation to the affected generator.

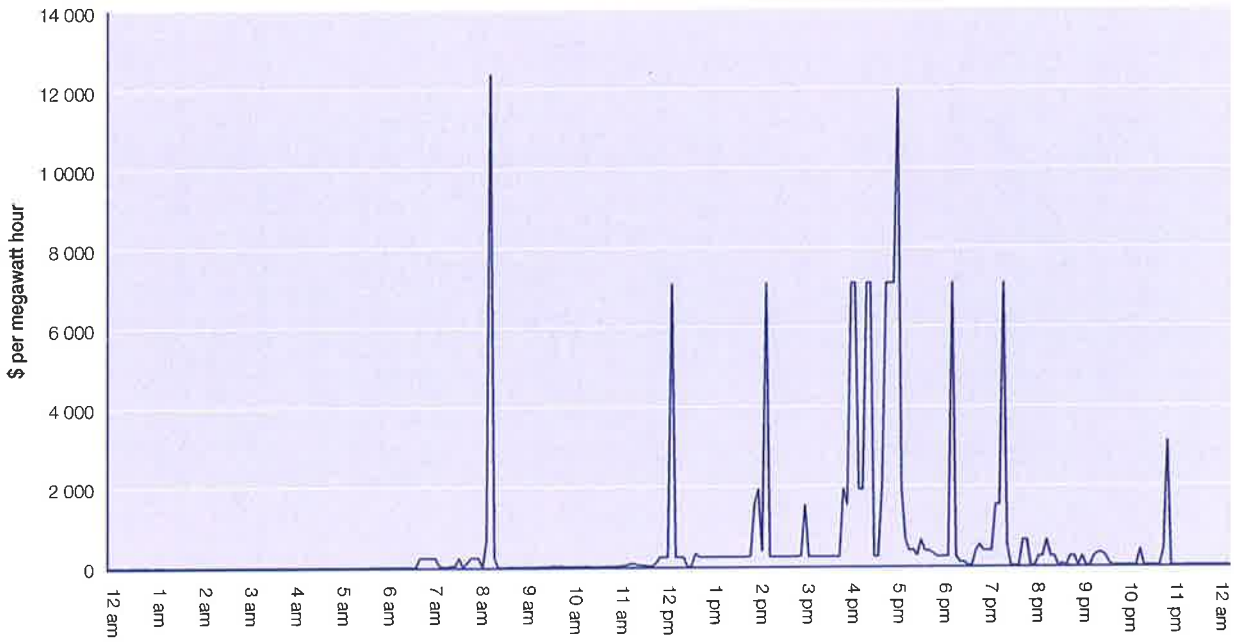
Full implementation of this approach could take several years. So, in August 2013 the AER proposed an interim measure requiring generators to submit ramp rates that reflect the maximum technical rate that their plant can safely achieve. It considers this requirement would limit the frequency and scope of disorderly bidding because AEMO could quickly alter generators' output to resolve constraints.

Figure 8
Frequency of extreme prices, Queensland



Source: AER.

Figure 9
Queensland dispatch prices, 29 January 2013



Note: Five minute dispatch prices.
Source: AER.

A.5 Energy networks

Rising costs of energy networks (electricity poles and wires, and gas pipelines) were the main driver of rising energy retail prices over the past five years in many jurisdictions. Regulatory allowances to network businesses rose to fund investment 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.

More recently, weaker energy demand forecasts have lowered investment requirements for network businesses. With demand projections driving around 25 per cent of capital investment for electricity distribution networks and 60 per cent for transmission, this weakening in demand caused the deferral of several projects. Recent regulatory reviews reflect this shift, with forecast investment for the Powerlink, ElectraNet and Aurora Energy networks *below* the levels approved in reviews made five years earlier (figure 10).

Weaker energy demand caused the deferral of a number of planned investments that had already passed a regulatory investment test (a cost–benefit analysis to assess a project's viability). The deferrals include TransGrid projects for new transmission infrastructure between Dumaresq and Lismore, and a network expansion on the mid north coast of New South Wales. Ergon Energy's planned line from Warwick to Stanthorpe was also deferred.

In other cases, assessment processes have been terminated or deferred:

- ElectraNet deferred its assessment of options to address rising demand in the Lower Eyre Peninsula until it is clear whether mining developments in the area will proceed. It also deferred its assessment of options to address voltage limitations in the mid-north of South Australia. The project was initially forecast to be required for summer 2015–16, but that timeframe was extended to 2024.
- AEMO terminated its assessment of options to address emerging voltage stability limitations in regional Victoria. Weaker demand forecasts mean these limitations are now unlikely to arise.

Recent developments in capital markets also lowered capital costs. Regulatory determinations made since 2012 reflect recent reductions in the risk free rate and market and debt risk premiums, which lowered the cost of capital (figure 11). The overall cost of capital in determinations made in 2013 was 7–7.5 per cent, compared with up to 10.4 per cent in 2010.

Reforms to the energy rules (announced in November 2012) will help prevent unjustified increases in network costs. The new rules aim to deliver future decisions on network revenues and investment that are in the long term interests of consumers. The reforms:

- create a common approach to setting the cost of capital across electricity and gas network businesses, based on the rate of return for a benchmark efficient service provider
- provide new tools to (a) incentivise electricity network businesses to invest efficiently, (b) safeguard consumers from paying for inefficient expenditure, and (c) ensure efficiency benefits are shared between consumers and service providers
- strengthen stakeholder involvement in the regulatory review of electricity networks.

In 2013 the AER published guidelines under the Better Regulation program on implementing the new rules. The guidelines will apply first to regulatory determinations taking effect in 2015—that is, for electricity transmission networks in New South Wales and Tasmania, and for electricity distribution networks in New South Wales, Queensland, South Australia and the ACT.

Recent reforms to the appeals provisions in the energy rules will also benefit consumers. Between June 2008 and June 2013 network businesses sought Australian Competition Tribunal review of 25 AER determinations on energy networks—18 reviews for electricity networks and seven for gas pipelines. The Tribunal's decisions increased allowable revenues by around $3.3 billion, with substantial impacts on retail energy charges.

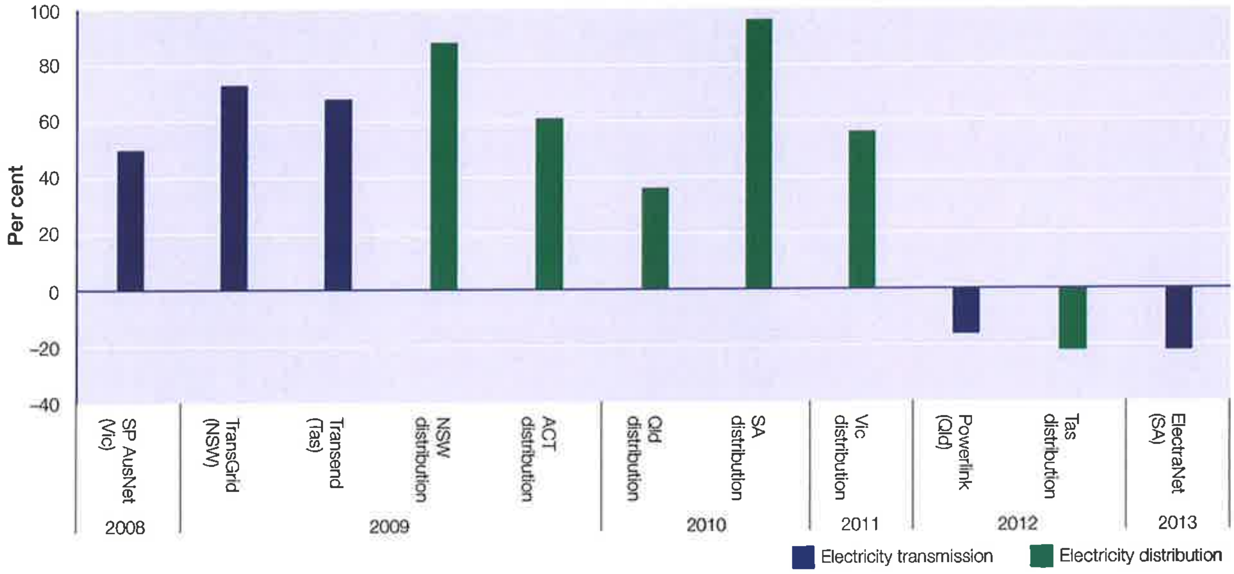
An independent review in 2012 of the limited merits review regime found the regime did not operate as intended. In response, the Standing Council on Energy and Resources (SCER) agreed to amendments requiring:

- a network business to demonstrate that 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 to consider any matters interlinked with the grounds of the appeal, and to consult with relevant users and consumers.

The South Australian Parliament in November 2013 passed legislation to implement the reforms.

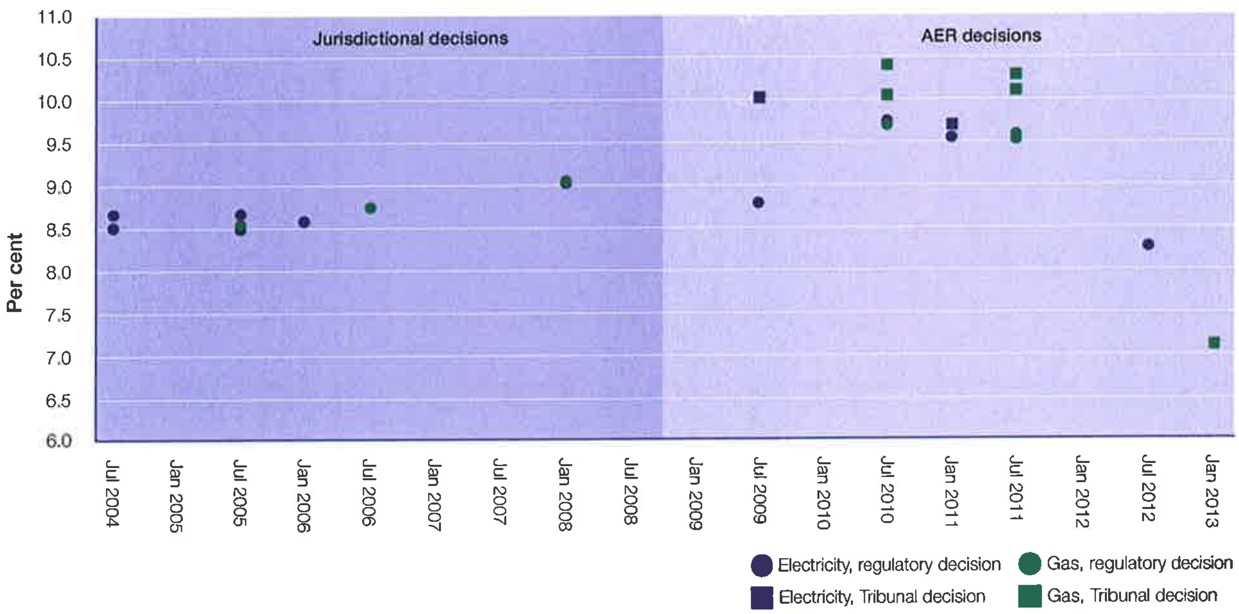
Wider reforms to the policy landscape are in train to better manage network costs in the long term interests of consumers. The AEMC's *Power of choice* review identified a range of efficient alternatives to network investment to

Figure 10
Investment growth for electricity networks

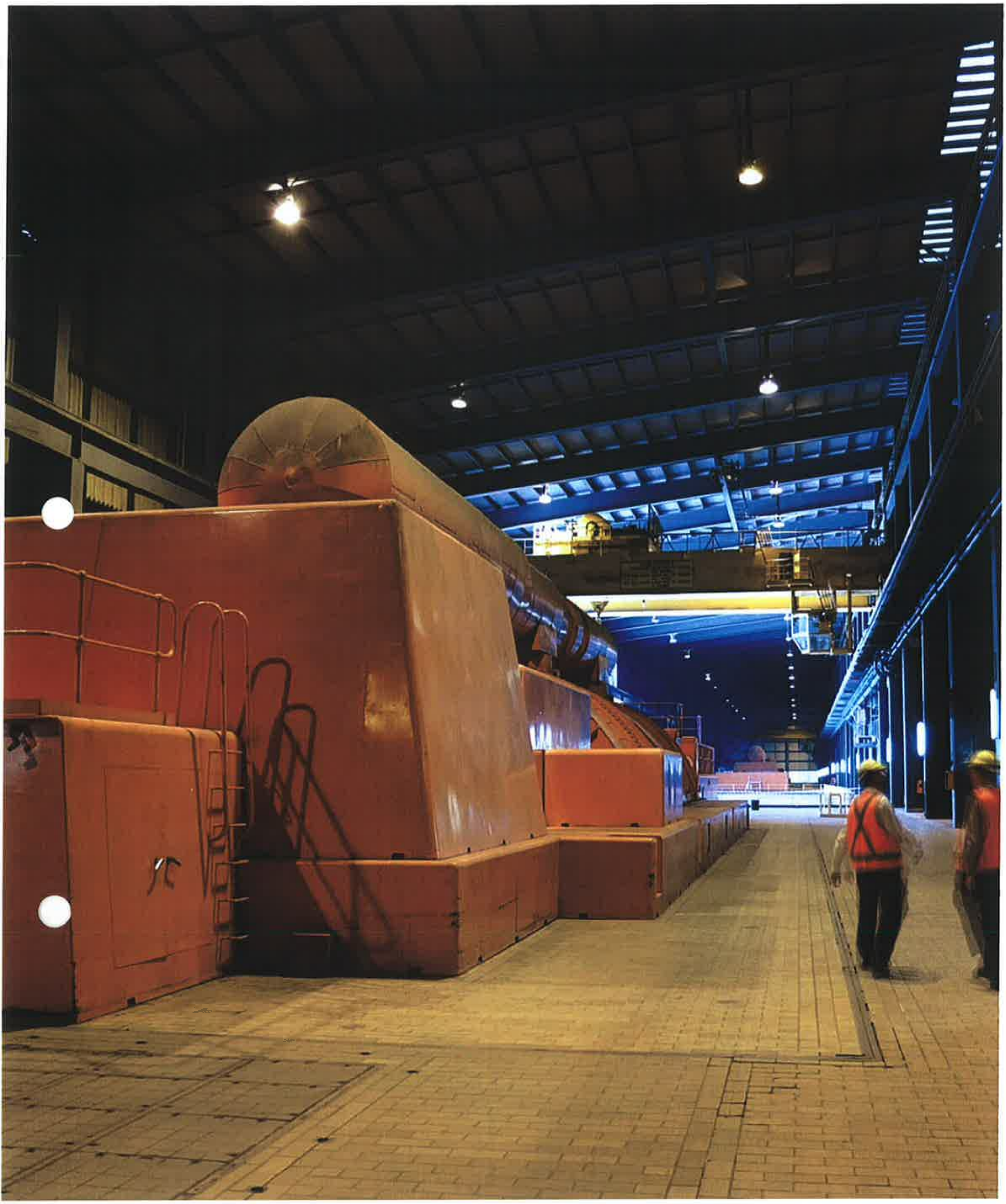


Notes:
Percentage change in forecast investment in current five year regulatory period compared with levels in previous regulatory periods.
Data appears in chronological order of AER determinations for transmission and distribution sectors.
Data are state averages for electricity distribution networks in Queensland, New South Wales and Victoria.
Source: AER.

Figure 11
Weighted average cost of capital—electricity and gas distribution



Note: Nominal vanilla weighted average cost of capital.
Source: AER.



deal with rising peak demand. Interval meters—with time based data on energy use—are central to many of the recommendations. This type of metering, when coupled with time varying prices, can encourage customers to actively manage their electricity use.

The SCER in September 2013 submitted a rule change proposal to the AEMC on changes to the distribution network pricing principles. The changes would encourage distribution businesses to set cost reflective network prices that provide efficient pricing signals to consumers. The Victorian Government expects to complete a rollout of interval meters with remote communications to all customers in 2014. From September 2013 small customers have been offered the choice of moving to more flexible tariff structures.

The AEMC also reviewed network reliability standards, which have been a significant driver of network investment. Its assessment for New South Wales found less stringent reliability standards would save an average consumer $3–15 per year. Following advice from the Council of Australian Governments, the AEMC in September 2013 proposed a new approach to setting distribution reliability targets. The proposal would weigh the cost of new investment against the value that customers place on reliability and the likelihood of interruptions. The AER's service target performance incentive scheme would provide incentives for network businesses to meet their reliability targets.

The AEMC also recommended a national approach to reporting on reliability, under which the AER would develop values of customer reliability for each jurisdiction every five years. In August 2013 AEMO finalised a method for estimating the value of customer reliability. It will develop the associated values by March 2014.

A.6 Gas markets

An interaction of several factors is shifting the dynamics of gas markets in eastern Australia. Rising coal seam gas (CSG) production, the emergence of spot markets, and improved pipeline interconnection of gas basins have made domestic markets more responsive to customer demand. But the development of at least three LNG export projects in Queensland is exerting significant supply and price pressure.

Gas production in eastern Australia is forecast to treble over the next three to five years to satisfy a rapid expansion in LNG export demand.[5] While Queensland's LNG proponents each have dedicated gas reserves and pipeline infrastructure, difficulties in developing some gas fields are requiring them to source additional supplies from elsewhere. By doing so, they have reduced reserves that would otherwise have been available to the domestic market, leaving few producers in a position to sell gas under medium to longer term contracts.[6]

The effect of these tight conditions was apparent in 2013, with prices in new contracts reportedly linked to international oil prices or LNG netback prices[7] (currently around $10 per gigajoule for export to Japan). Average daily spot prices for gas also rose in 2012–13, mainly due to high winter prices in 2012 and a short term rise in demand associated with the introduction of carbon pricing.

More generally, spot market volatility was evident, with an above average frequency of price spikes (figure 12). Notably, Brisbane prices diverged markedly from prices in other markets. Overall, average prices for 2012–13 rose by 69 per cent in Brisbane, 51 per cent in Sydney, 33 per cent in Melbourne and 34 per cent in Adelaide.[8]

Spot prices tended to ease after June 2013, although they remained at higher levels than those before 2012–13. Winter demand was mostly fairly subdued, however. In Victoria, a mostly mild winter and a reduction in gas powered generation contributed to an overall 8.8 per cent decrease in gas demand during winter 2013.

Gas market conditions will tighten further when LNG facilities come on line and ramp up to full capacity from 2015–18. While delays affected some projects in 2012, Energy Quest reported favourable weather conditions in 2013 put back on schedule the development of each project's first train.[9]

AEMO in November 2013 forecast potential gas supply shortfalls may occur in Queensland if facilities currently dedicated to domestic demand are prioritised to supply LNG export contracts. Without further investment, this shortfall could reach 250 terajoules per day once all LNG trains reach full output, which is scheduled to occur in 2019. If production in Queensland and South Australia is prioritised

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

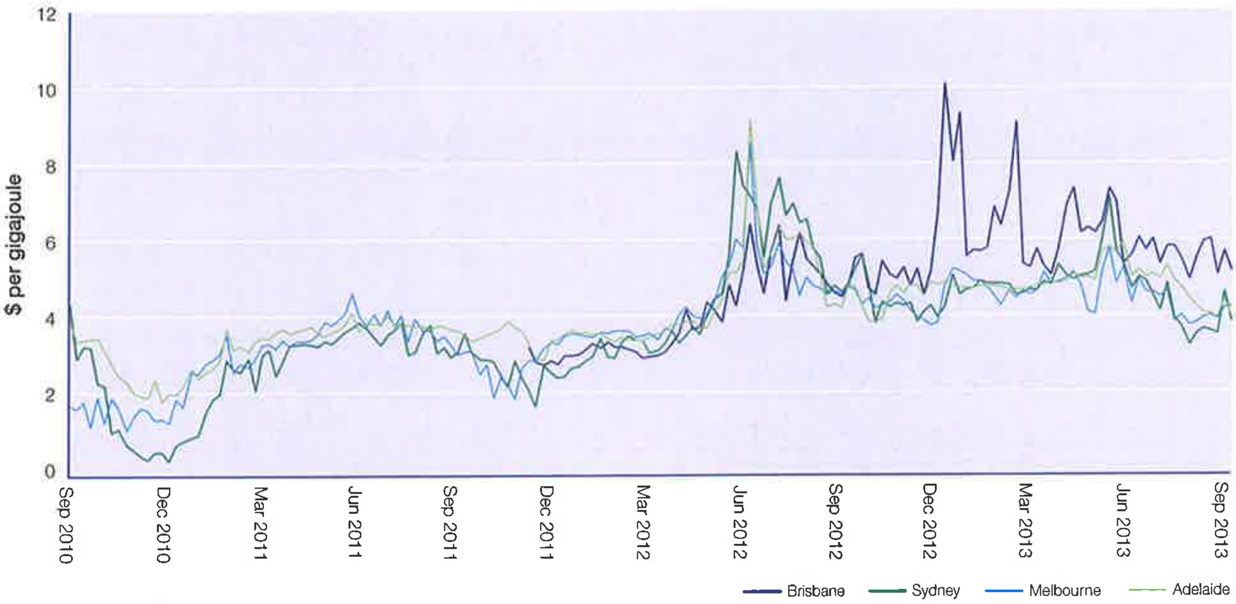
6 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

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

8 The Brisbane price for 2011–12 covers the period 1 December 2011 (market start) to 30 June 2012 in which the Brisbane market operated. Brisbane prices rose by 82 per cent when comparing average prices for December 2012 to June 2013 with those of the corresponding period in the previous year.

9 EnergyQuest, *Energy Quarterly*, August 2013, p. 64.

Figure 12
Spot gas prices—weekly averages



Notes: Volume weighted ex ante prices. 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 the period 1 December 2011 (market start) to 30 June 2012.

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

for export, New South Wales could experience flow-on effects, with potential shortfalls of 50–100 terajoules per day on winter peak demand days from 2018.[10]

The ramp up to full LNG export capacity will coincide with the expiry of a large number of domestic gas supply contracts. The review and negotiation of contracts in a market exposed to global prices will place further pressure on domestic prices. Overall, contracts covering the supply of around 260 PJ of gas are due to expire by 2018. The problem is acute for New South Wales: by 2018, existing contracts will meet less than 15 per cent of that state's demand.[11]

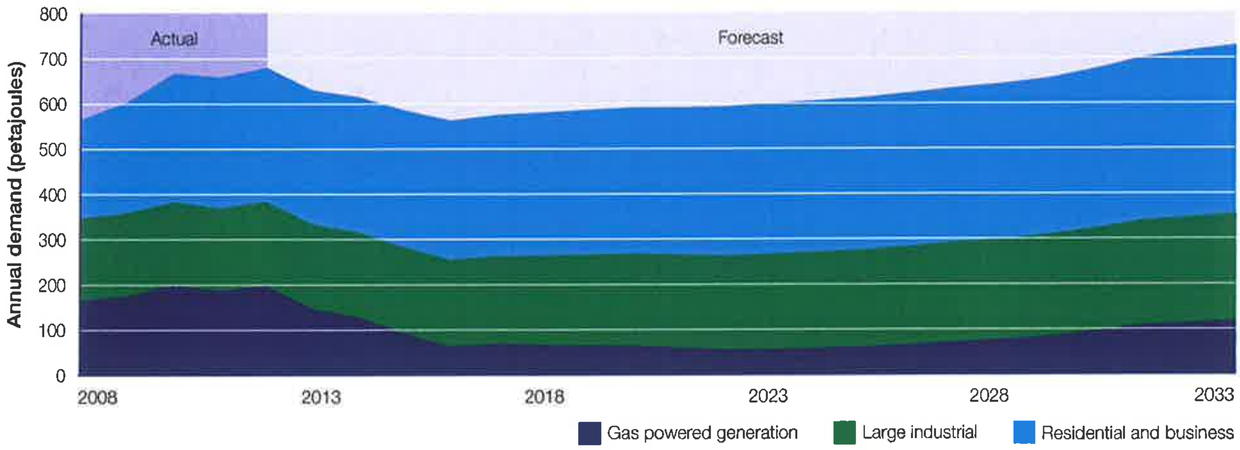
Some domestic producers are increasing supply to meet demand. AEMO reported Victorian gas exports to New South Wales were 46 per cent higher in winter 2013 than a year earlier, and significantly higher than in each of the past four years.[12] APA Group in 2013 committed to an expansion of the Victorian Transmission System (for completion by winter 2015) to support higher export volumes from Victoria to New South Wales. Jemena is also considering an expansion of the Eastern Gas Pipeline to boost capacity into New South Wales, which could be completed by the end of 2015. Elsewhere, Cooper Basin production is also likely to rise, but with the bulk of the increase going into LNG exports.[13]

Interest exists in developing new sources of supply to meet the likely gap in the domestic market. Production from the Kipper Tuna Turrum project in the Gippsland Basin began in 2013. Other proposals relate to the Gunnedah and Gloucester basins in New South Wales, the Ironbark field in the Surat Basin, unconventional sources in the Cooper Basin, and the South Nicholson and Isa Super basins in the Northern Territory and north west Queensland.[14]

The development of coal seam and shale gas resources has raised community concerns about potential impacts on agricultural land use, waterways and native vegetation.[15] These concerns have delayed the development of some

10 AEMO, *Gas statement of opportunities 2013*, p. iv.
11 BREE, *Gas market report*, October 2013, pp. 17, 41.
12 AEMO, *Energy update*, October 2013.
13 EnergyQuest, *Energy Quarterly*, August 2013, p. 19.
14 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.
15 See, for example, ACIL Allen Consulting, *NSW coal seam gas*, Report to the Australian Petroleum Production and Exploration Association (APPEA), 2013, p. 2.

Figure 13
East coast domestic gas demand



Source: AEMO, *Gas statement of opportunities 2013*, figure 5.

projects, notably in New South Wales, which restricted development around communities and water catchments critical to agriculture.

While LNG export demand is set for exponential growth, a countervailing market influence is flatter domestic demand for gas, especially for electricity generation. Subdued electricity demand, the continued rise in renewable generation, the coalition government's intention to abolish carbon pricing, rising gas prices and the cessation of the Queensland Gas Scheme (which mandated a minimum rate of gas powered generation) have significantly weakened projections of gas powered generation.

AEMO forecast gas demand will decline until 2016, followed by a gradual recovery (figure 13). The sharpest contraction will be for gas powered generation, with a forecast annual average decline of 9.8 per cent between 2014 and 2022. In contrast, LNG demand is expected to rise from zero to around 1450 petajoules, accounting for around 70 per cent of total gas demand in eastern Australia.[16]

Policy makers are implementing reforms to help alleviate pressures in the eastern gas market. The most advanced reform is a gas trading exchange at the Wallumbilla gas hub in Queensland, set for launch in March 2014. The exchange aims to alleviate unnecessary bottlenecks in the tight Queensland gas market by facilitating short term gas trades.

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

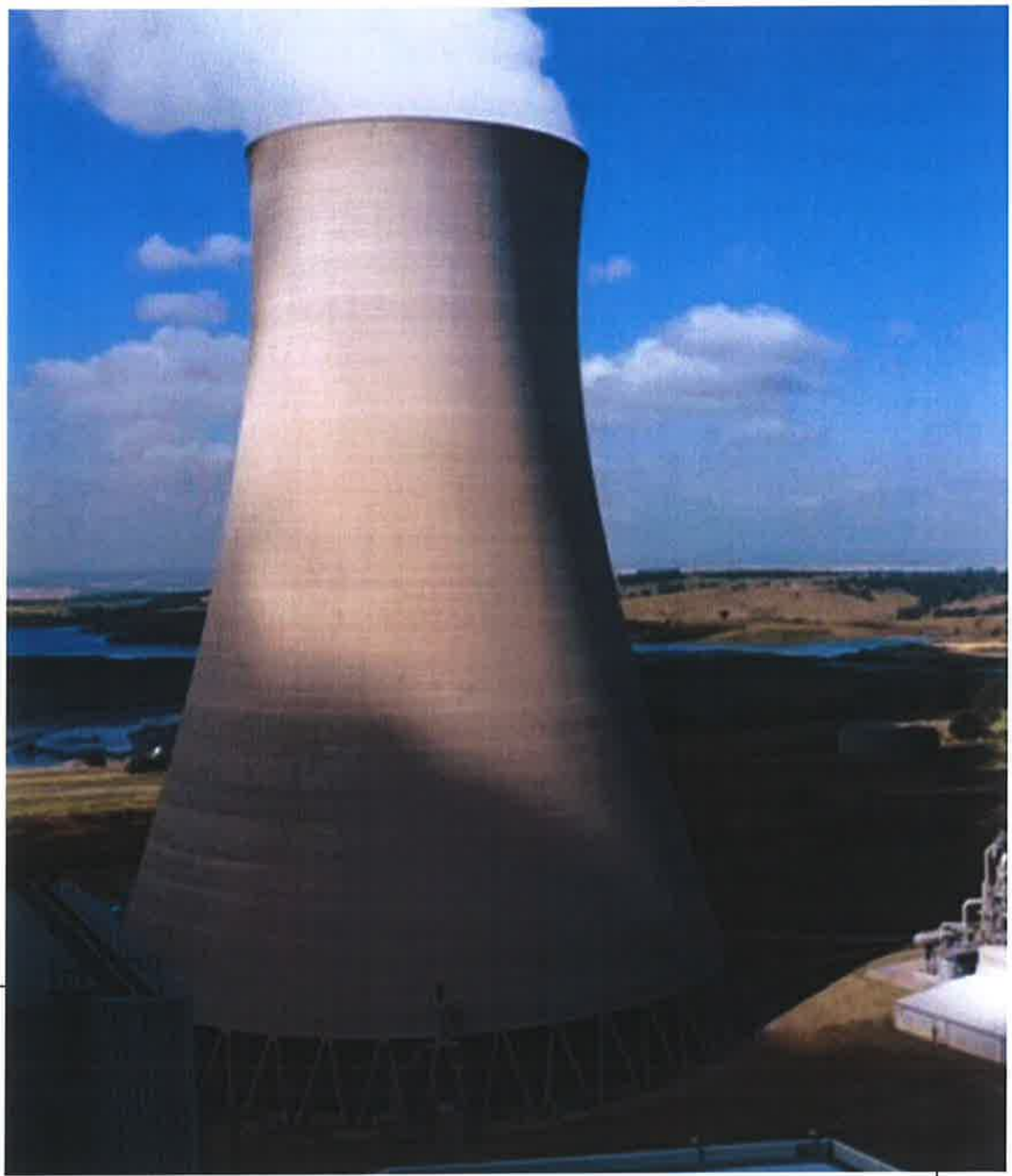
In other developments, the SCER consulted in 2013 on possible reforms to pipeline capacity trading to promote trade in idle contracted capacity. The reform could help small participants that lack the scale to invest in transmission capacity.[17] An AEMC scoping study published in September 2013 proposed consideration of further measures. These measures included strategically planning gas market development, refining spot market design, and streamlining the processes for making rule changes that affect gas spot markets.[18]

16 AEMO, *Gas statement of opportunities 2013*, p. 8.

17 Standing Council on Energy and Resources officials, *Regulation impact statement: gas transmission pipeline capacity trading*, Consultation paper, 15 May 2013.

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

Kyle Auret



1 NATIONAL ELECTRICITY MARKET

The National Electricity Market (NEM) is a wholesale market in which generators sell electricity in eastern and southern Australia (table 1.1). The main customers are energy retailers, which bundle electricity with network services for sale to residential, commercial and industrial energy users.

The market covers six jurisdictions—Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network. It has around 200 large generators, five state based transmission networks (linked by cross-border interconnectors) and 13 major distribution networks that supply electricity to end use customers. In geographic span, the NEM is one of the longest continuous alternating current systems in the world, covering a distance of 4500 kilometres.

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	48 321 MW
Number of registered generators	317
Number of customers	9.3 million
NEM turnover 2012–13	$12.2 billion
Total energy generated 2012–13	199 TWh
National maximum winter demand 2012–13	30 491 MW[1]
National maximum summer demand 2012–13	32 539 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.

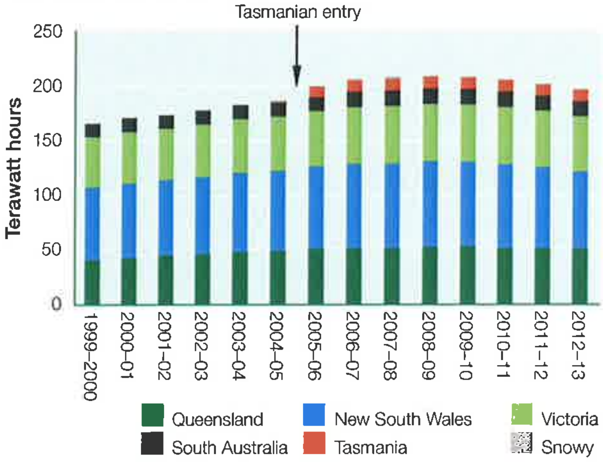
Sources: AEMO; AER.

1.1 Electricity demand

The NEM supplies electricity to over nine million residential and business customers. In 2012–13 the market generated 199 terawatt hours (TWh) of electricity—a 2.5 per cent reduction from the previous year, and around 1 per cent below forecast.[1] This outcome continues a trend of declining electricity demand since 2007–08 (figure 1.1); over the past five years, demand declined by an annual average of 1.1 per cent.[2]

1 AEMO, *National electricity forecasting report 2013*, p. x.
2 AEMO, *Energy update*, June 2013, p. 4.

Figure 1.1
Electricity demand, by region



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

Sources: AEMO; AER.

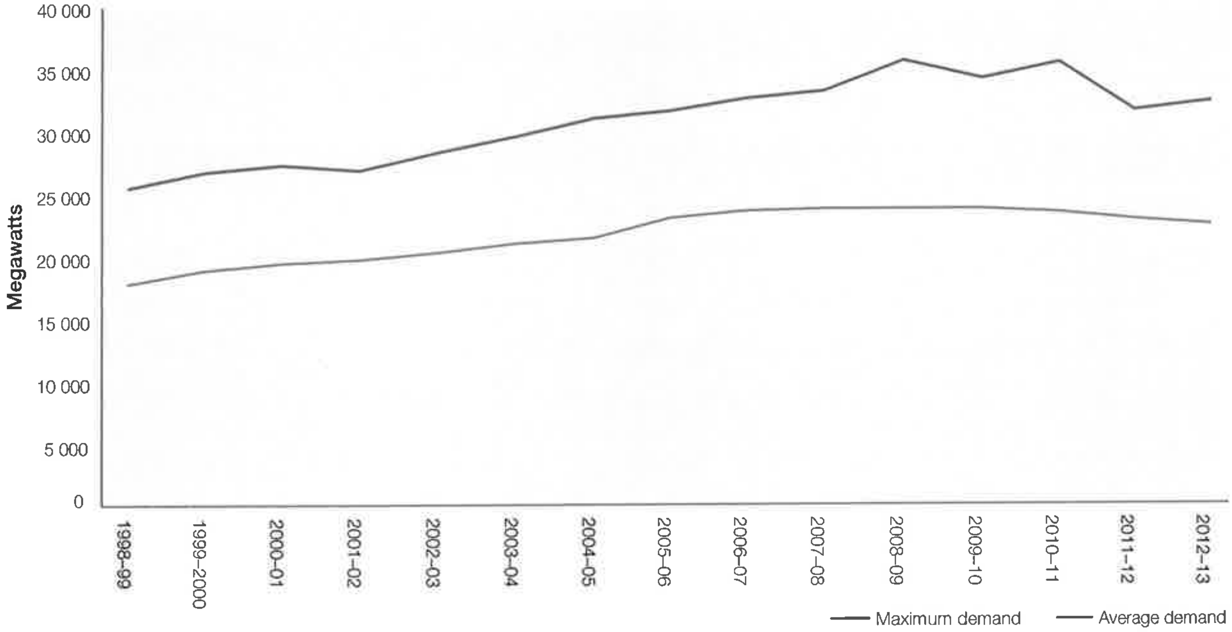
While electricity demand is projected to rise on average by 0.5 per cent across the NEM during 2013–14, this rate is weaker than forecast 12 months ago. The Australian Energy Market Operator (AEMO) revised down the level of forecast demand for 2013–14 by 2.4 per cent.[3]

Electricity demand has been declining as a result of:

- commercial and residential customers responding to higher electricity costs by reducing energy use and adopting energy efficiency measures such as solar water heating. New building regulations on energy efficiency reinforce this trend.
- subdued economic growth and weaker energy demand from the manufacturing sector. Large industrial electricity use has declined by more than 2 TWh since 2007–08.[4] Industrial energy demand is expected to weaken further in 2013–14, with the closure of the Kurri Kurri aluminium smelter in New South Wales and changes in operating levels of Victoria's Wonthaggi desalination plant.
- the continued rise in rooftop solar photovoltaic (PV) generation (which reduces demand for electricity supplied through the grid). In 2012–13 PV generation output rose by 58 per cent to 2700 gigawatt hours (GWh), equal to around 1.3 per cent of electricity consumption. This growth has been driven by small scale renewable energy certificates and lower cost systems (section 1.2.1).[5]

3 AEMO, *National electricity forecasting report 2013*.
4 AEMO, *Energy update*, June 2013, p. 4.
5 AEMO, *National electricity forecasting report 2012* and *National electricity forecasting report 2013*.

Figure 1.2
Electricity maximum and average demand



Sources: AER, AEMO.

In the longer term, electricity demand is forecast to grow annually by around 1.3 per cent[6] over the next decade—lower than the previous year's forecast of 1.7 per cent. A rising population, a moderation in electricity price growth, and the development of liquefied natural gas (LNG) projects in Queensland are expected to drive the return to positive growth.

1.1.1 Maximum demand

Electricity demand fluctuates throughout the day (usually peaking in early evening) and by season (peaking in winter for heating and summer for air conditioning). Over the course of a year, demand typically reaches its zenith on a handful of days of extreme temperatures, when air conditioning (or heating) loads are highest.

Maximum (or peak) demand rose steadily until 2008–09—typically at a faster rate than average demand (figure 1.2). A succession of hot summers and the increasing use of air conditioners drove this trend. The proportion of Australian households with air conditioning or evaporative cooling rose from 59 per cent in 2005 to 73 per cent in 2011.[7] The growth in maximum demand was a key driver of rising investment in energy networks over the past decade. At the time, maximum demand was forecast to keep rising at a rapid rate.

But maximum demand has flattened since 2008–09, moving significantly below trend in the 24 months to 30 June 2013. The underlying causes are similar to those that have weakened overall energy demand (section 1.1.1). Summer 2012–13 was Australia's warmest on record (and January 2013 was the hottest month on record). Despite these record breaking temperatures (albeit without extended heatwaves), summer maximum demand remained well below historical levels (table 1.2).

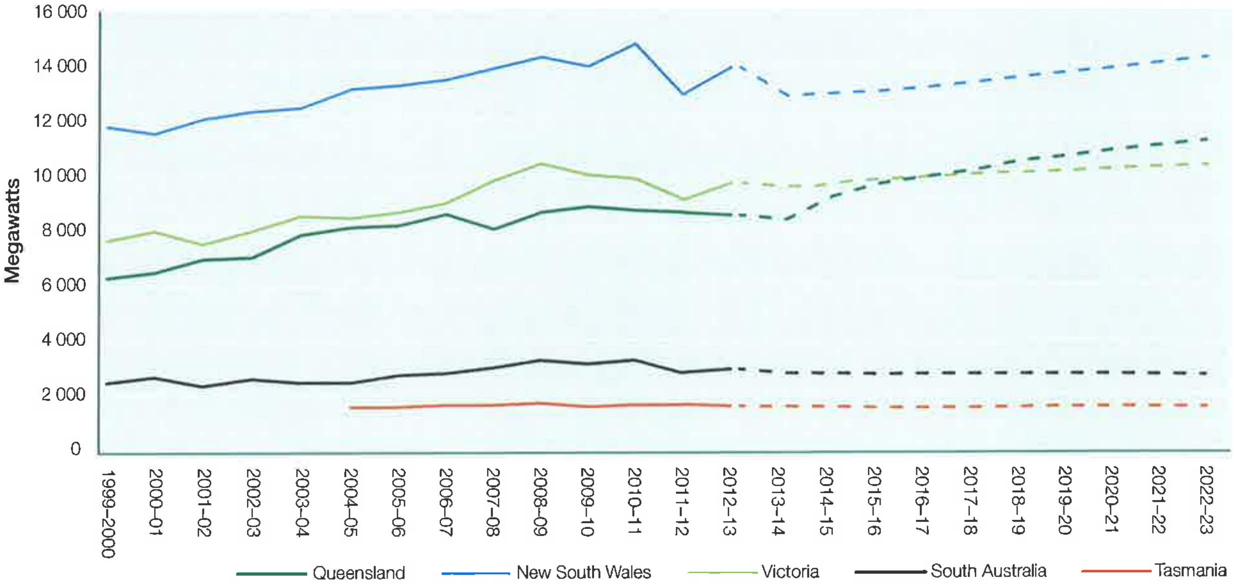
Maximum demand over the next decade is expected to remain below previous highs in most regions (figure 1.3). The exception will be Queensland, where the commencement of LNG projects will result in maximum demand rising by 10 per cent in 2014–15, then annually by around 2.4 per cent. In other regions, maximum demand is expected to rise annually by no more than 1 per cent.[8]

6 AEMO, *National electricity forecasting report 2013*, p. ix.

7 Australian Bureau of Statistics, *Household energy use and conservation 2011*.

8 AEMO, *National electricity forecasting report 2013*.

Figure 1.3
Annual maximum demand, by region



Note: Actual data to 2012–13, then AEMO forecasts published in 2013.
Sources: AEMO; AER.

Table 1.2 **Maximum demand growth, by region, 2012–13**

	QUEENSLAND	NEW SOUTH WALES	VICTORIA	SOUTH AUSTRALIA	TASMANIA
Change from 2011–12 (%)	–1.1	7.5	6.6	4.0	–3.5
Change from historical maximum (%)	–3.7	–5.8	–7.0	–8.9	–6.2
Year of historical maximum	2009–10	2010–11	2008–09	2010–11	2008–09

Sources: AEMO; AER.

Subdued electricity demand has contributed to surplus generation capacity in the NEM, causing around 2300 megawatts (MW) of plant to be shut down or periodically offline since 2012 (sections 1.3.3 and 1.7).

1.2 Generation technologies in the NEM

Most electricity dispatched in the NEM is generated using coal, gas, hydro and wind technologies. A generator creates electricity by using energy to turn a turbine, making large magnets spin inside coils of conducting wire. In Australia, electricity is mainly produced by burning fossil fuels (such as coal and gas) to create pressurised steam. The steam is forced through a turbine at high pressure to drive the generator. Other types of generator rely on renewable energy sources such as water, the sun and wind. Figure 1.4 illustrates the location of major generators in the NEM, and the technologies in use.

The demand for electricity is not constant, varying with the time of day, the season and the ambient temperature. A mix of generation technologies is needed to respond to these demand characteristics. Plant with high start up and shut down costs, but low operating costs tend to operate relatively continuously; for example, coal generators may require up to 48 hours 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 (especially in peak demand periods). Intermittent generation, such as wind

Figure 1.4
Electricity generation in the National Electricity Market

Sources: AEMO; AER.

Figure 1.5

Registered generation, by fuel source, 2012–13

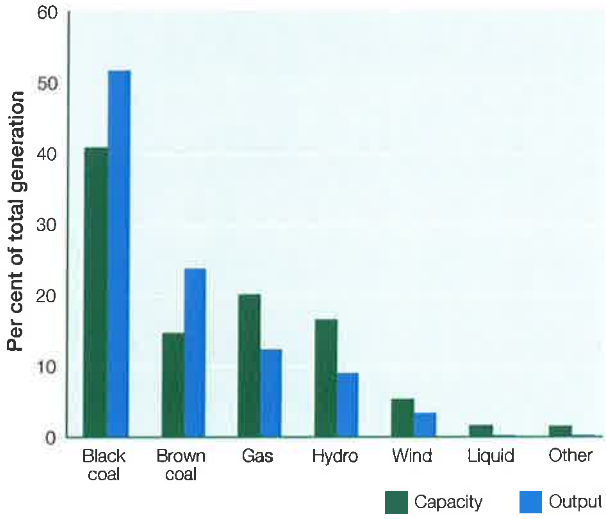


Figure 1.6

Generation capacity, by region and fuel source, 30 June 2013

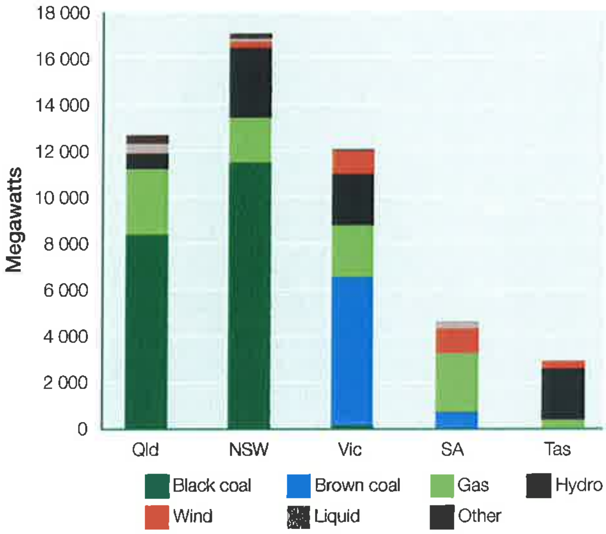
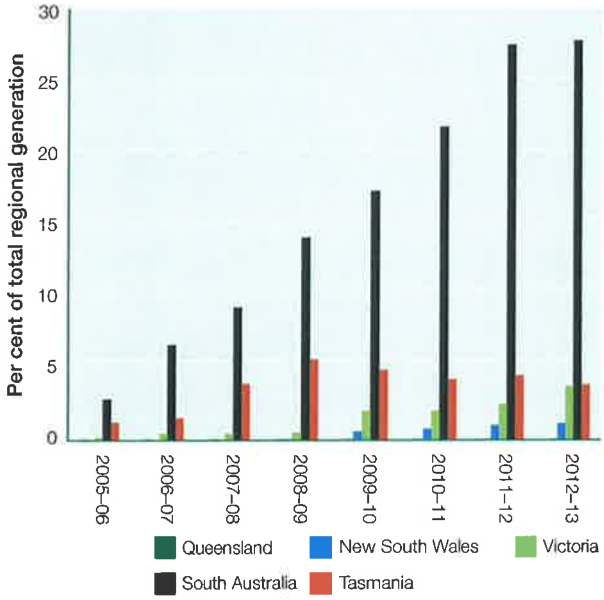


Figure 1.7

Wind generation share of total generation, by region



Sources (figures 1.5, 1.6 and 1.7): AEMO; AER.

and solar, can operate only when the weather conditions are favourable.

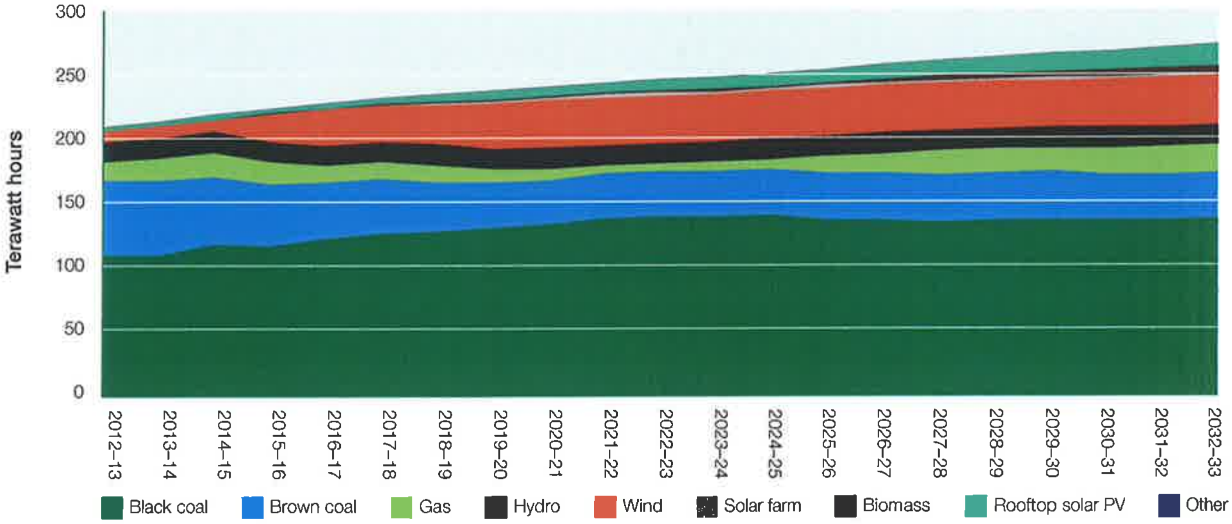
Black and brown coal account for 55 per cent of registered generation capacity, but supply 75 per cent of output (figure 1.5). Victoria, New South Wales and Queensland rely on coal more heavily than do other regions (figure 1.6). Weakening electricity demand and the introduction of carbon pricing contributed to coal fired generation declining by 7 per cent in 2012–13.

Gas powered generators account for 20 per cent of registered capacity across the NEM, but they supply only 12 per cent of output. Among the NEM jurisdictions, South Australia is the most reliant on gas powered generation. More generally, 55 per cent of new generation investment over the past decade was in gas plant.

Hydroelectric generators account for 17 per cent of registered capacity but contribute 9 per cent of output. The bulk of Tasmanian generation is hydroelectric; there is also hydro generation in Queensland, Victoria and New South Wales. The introduction of carbon pricing and good rainfall in catchment areas contributed to a 36 per cent increase in hydro generation in 2012–13.

Intermittent wind generation has expanded under climate change policies such as the renewable energy target (RET) (section 1.3.1). Nationally, wind generators account for 5.4 per cent of capacity and contribute 3.4 per cent of output. In South Australia, however, wind represents 23 per cent of capacity, and met 28 per cent of electricity requirements in 2012–13 (figure 1.7). South Australia has one of the highest penetrations of wind generation of any electricity market in the world. On some days, wind has accounted for up to 65 per cent of total generation in the state (and up to 86 per cent of generation for a trading interval).

Figure 1.8
Forecast contribution of generation technologies to meeting electricity demand



Sources: AEMO, AER.

However, wind generation is generally lower at times of peak demand—on average, it contributes to less than 9 per cent of supply during peak demand periods in summer. Yet, it appears to be having a moderating impact on electricity prices in South Australia; that is, spot prices are typically lower at times of high wind.[9]

1.2.1 Rooftop solar generation

Climate change policies, including the RET and subsidies for rooftop solar PV installations, led to a rapid increase in solar PV generation over the past five years. The subsidies include feed-in tariff schemes established by state and territory governments, under which distributors or retailers pay households for electricity generated from rooftop installations. The energy businesses recover subsidies from energy users through electricity charges.

Rooftop PV generation is not traded through the NEM. Instead, the installation owner receives a reduction in their energy bills. AEMO calculates the contribution of rooftop PV generation as a reduction in energy demand, in the sense that it reduces the community's energy requirements from the national grid.

Installed rooftop PV capacity rose from around 1500 MW in 2011–12 to 2300 MW in 2012–13. The contribution of rooftop installations to annual energy requirements was estimated to rise from 0.9 per cent in 2011–12 to 1.3 per cent in 2012–13. The uptake of these systems has been especially significant in South Australia, which has a higher average solar intensity than other NEM jurisdictions. In 2012–13 solar PV installations in South Australia generated around 497 GWh, or 3.7 per cent of the state's annual energy requirements (up from 2.4 per cent in 2011–12).[10]

The contribution of rooftop PV installations to peak demand is generally lower than the rated system capacity. In the mainland regions, summer demand typically peaks in late afternoon, when rooftop PV generation is declining from its midday levels and operating at around 33 per cent of capacity (40 per cent in South Australia).[11] Maximum demand in Tasmania typically occurs on winter evenings, when rooftop PV generation is negligible.

AEMO expects the uptake of rooftop PV installations to continue rising, but at a slower rate due mainly to a reduction of feed-in tariffs.[12] The contribution of rooftop PV generation is forecast to rise to 3.3 per cent of the NEM's energy requirements by 2022–23. In South Australia, it is forecast to reach 8.9 per cent, reflecting an average annual growth of 7.5 per cent over the next decade (figure 1.8).[13]

9 AEMO, *South Australian wind study report*, 2012, p. 2–1.

10 AEMO, *South Australian electricity report 2013*, pp. 2–7 and 2–8.
11 AEMO, *South Australian electricity report 2013*, p. 2–8.
12 AEMO, *Rooftop PV information paper*, 2012, p. iii.
13 AEMO, *South Australian electricity report 2013*, p. 2–8.

1.3 Climate change policies

The mix of generation technologies across the NEM is evolving in response to technological change and government policies to mitigate climate change. The electricity sector contributes around 35 per cent of national greenhouse gas emissions, mainly because of its reliance on coal fired generation.[14] Climate change policies aim to change the economic drivers for new investment and shift the reliance on coal fired generation towards less carbon intensive energy sources.

1.3.1 Renewable energy target scheme

The Australian Government in 2001 introduced a national RET scheme, which was expanded in 2007. The scheme aims to achieve a 20 per cent share for renewable energy in Australia's electricity mix by 2020. It requires electricity retailers to source a proportion of their energy from renewable sources developed after 1997. Retailers comply with the scheme by obtaining renewable energy certificates created for each megawatt hour of eligible renewable electricity that an accredited power station generates, or that eligible solar hot water or small generation units generate.

The scheme applies different arrangements for small scale generation (such as rooftop solar PV installations) and large scale renewable supply (such as wind farms). It has a 2020 target of 41 000 GWh of energy from large scale renewable energy projects. Small scale renewable projects no longer contribute to the national target, but still produce renewable energy certificates that retailers must acquire. Since the 2011 revisions to the RET scheme, certificates from large scale projects have traded at around $30–40 (box 1.1). The price of certificates from small scale projects has been more volatile, trading at $20–40.

The Coalition Government elected in September 2013 committed to review the RET scheme in 2014.

1.3.2 Carbon pricing

The Australian Labor Government (2007–13) introduced a price on carbon on 1 July 2012 as the central plank of its Clean Energy Future Plan. The plan targeted a reduction in carbon and other greenhouse emissions to at least 5 per cent below 2000 levels by 2020 (and a reduction of up to 25 per cent with equivalent international action). 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 on 1 July 2015, whereby the market would determine the price. The government revised the scheme in August 2012 to closely link the carbon price in Australia to the price of carbon allowances in the European Union (EU) emissions trading market. Before the 2013 election, the government committed to bring forward the shift to an emissions trading scheme to 1 July 2014.

The Coalition Government elected in September 2013 introduced legislation to repeal carbon pricing in November 2013. It reaffirmed Australia's commitment to a 5 per cent reduction in greenhouse emissions by 2020 and committed to launch a Direct Action plan, whereby the government will pay for emissions abatement activity in Australia. The lynchpin of the plan is a $1.55 billion Emissions Reduction Fund to provide incentives for abatement activities across the Australian economy, with funding provided to least cost sources of abatement (as determined through a reverse auction). The plan also includes funding for urban tree planting and rooftop solar installations.[15]

1.3.3 Effects of climate change policies on generation

The use of black and brown coal for electricity generation peaked in 2008–09 and has since declined (figure 1.10). While energy demand has also declined, gas powered generation rose over the past decade, following new investment in all regions of the NEM. Wind generation has risen strongly, particularly since a 2007 expansion of the RET increased the target and extended the scheme to 2020.

The introduction of carbon pricing in 2012 contributed to further shifts in the generation mix. Notably, around 2300 MW of coal plant has been shut down (retired) or periodically offline since 2012 (table 1.3). The closures generally affected older, higher cost plant. Some plant is running only in summer, when demand is typically high (for example, Alinta's Northern plant in South Australia). Other owners are rotating plant throughout the year. CS Energy, for example, operated only three of its six 280 MW Gladstone units in Queensland in January 2013.

AEMO cited carbon pricing and the growth of renewable energy at a time of weak electricity demand as driving the reduced availability of coal plant.[16] Most plant owners cited

14 Australian Government, *Quarterly update of Australia's national greenhouse gas inventory, December quarter 2012*, 2013.

15 Department of the Environment (Australian Government), 'Repeal of the carbon tax and introduction of the Direct Action Plan', Media release, 29 September 2013.

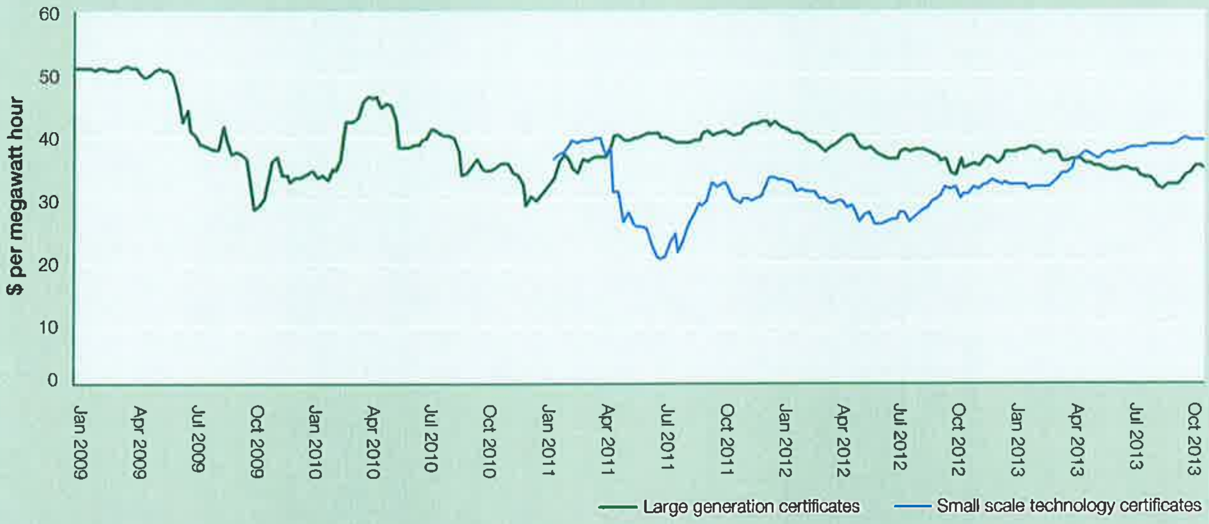
16 AEMO, *Power system adequacy 2013*, p. 1–2.

Box 1.1 Renewable energy target—certificate prices

Figure 1.9 illustrates the prices of certificates issued under each component of the RET scheme. A certificate represents one megawatt hour 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.

Some price movements reflect scheme changes and market uncertainty about possible changes. The decline in prices in 2009 reflected a significant supply of certificates from rooftop PV and other small scale installations. It led to a change in the scheme to separate small and large generators. The number of small scale certificates created in 2011 and 2012 exceeded the quota required by the Clean Energy Regulator for surrender. This oversupply contributed to prices remaining around $30. Prices rose steadily towards $40 in 2013, following the regulator's setting of a higher than expected target for the year and a slower uptake in PV and other installations that generate certificates. Around 400 000 certificates were created each week from January to August 2013, compared with over 700 000 a week in 2012.

Figure 1.9
Certificate prices



Source: Next Generation Energy Solutions.

low energy demand as a key factor in their decisions. The owners of Tarong (Queensland), Munmorah (New South Wales), Morwell and Yallourn (Victoria) also cited climate change policies as a contributing factor.

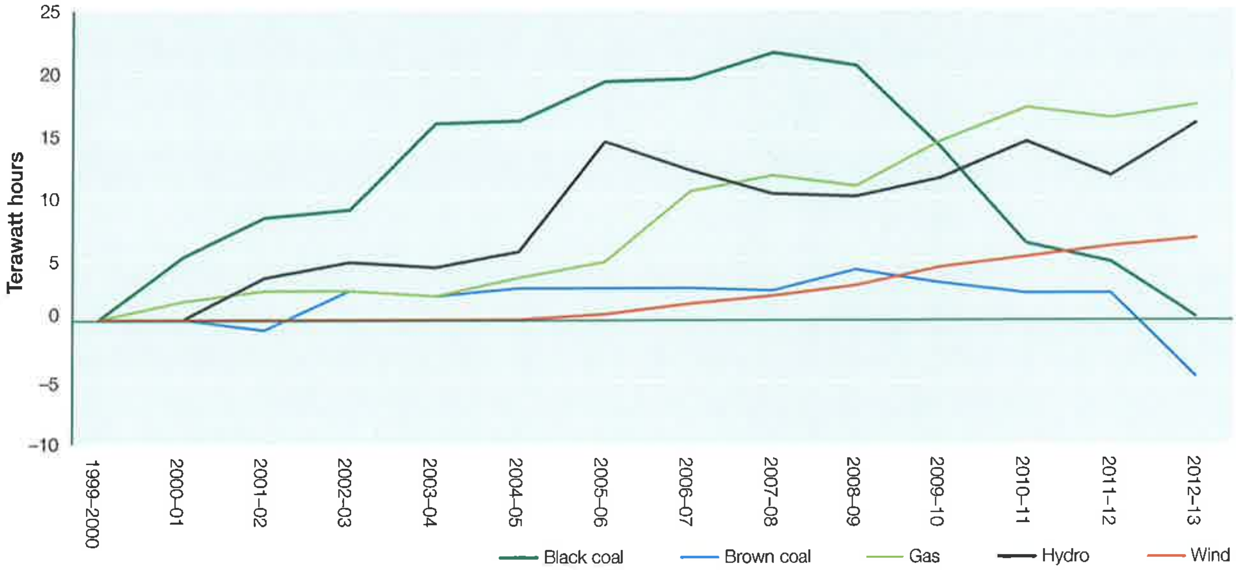
Conversely, the introduction of carbon pricing enhanced the competitiveness of hydro generation, contributing to a 36 per cent rise in output in 2012–13 to supply 9 per cent of electricity in the NEM. The increased hydro generation consumed water faster than it could be replenished, causing storage to be 40 per cent lower in July 2013 than a year earlier. But dam levels recovered in spring 2013.[17]

The share of gas powered and wind generation in the energy mix also rose in 2012–13. Overall, these changes in the generation mix contributed to the emissions intensity of generation in the NEM falling from 0.916 tonnes of carbon emissions per megawatt hour (MWh) of electricity produced in 2011–12, to 0.875 tonnes per MWh in 2012–13—a decline of 4.5 per cent.[18] This fall in emissions intensity, combined with lower NEM demand, led to a 7 per cent fall in total emissions from electricity generation in 2012–13.

17 Hydro Tasmania, Energy storage—historical data, accessed 15 October 2013.

18 AEMO, Carbon dioxide equivalent intensity index, accessed 15 October 2013.

Figure 1.10
Annual change in electricity generation, by energy source



Sources: AEMO; AER.

Table 1.3 Generation plant shut down or offline since 2012

BUSINESS	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PERIOD AFFECTED
QUEENSLAND				
Stanwell	Tarong (2 units)	Coal fired	700	October 2012 to at least October 2014
RATCH Australia	Collinsville	Coal fired	190	From December 2012 until viable
NEW SOUTH WALES				
Delta Electricity	Munmorah	Coal fired	600	Retired July 2012
VICTORIA				
Energy Brix	Morwell unit 3	Coal fired	70	From July 2012 until viable
Energy Brix	Morwell unit 2	Coal fired	25	Not run since July 2012. Only operates when unit 1 is under maintenance
SOUTH AUSTRALIA				
Alinta Energy	Northern	Coal fired	540	April to September each year from 2012
Alinta Energy	Playford	Coal fired	200	From March 2012 until viable

MW, megawatts.
Source: AER.

1.4 Market structure of the generation sector

While the NEM operates as a single market, the pattern of generation ownership varies markedly across regions. This variation includes pockets of high concentration. Additionally, the trend of vertical integration of electricity generators, energy retailers and gas producers continues.

1.4.1 Generation ownership

Table 1.4 provides details of generators in the NEM, including the entities that control dispatch. Figure 1.4 identifies the location of each plant. The ownership arrangements in electricity generation vary markedly across regions. Private businesses own most generation capacity in Victoria and South Australia, while government owned corporations own or control the majority of capacity in New

South Wales and Queensland. The Tasmanian generation sector remains mostly in government hands.

Figure 1.11 illustrates the controlling shares of the major players in each region:[19]

- In **Victoria**, three private entities are the major players: AGL Energy (29 per cent of capacity), International Power (22 per cent) and EnergyAustralia (formerly TRUenergy, 19 per cent). Before AGL Energy acquired Loy Yang A power station in June 2012, its market share in Victorian generation was 5 per cent. The government owned Snowy Hydro has market share in Victoria (20 per cent of statewide capacity) and New South Wales (15 per cent), mostly comprising historical investment associated with the Snowy Mountains scheme.[20]
- In **South Australia**, AGL Energy is the dominant generator, with 38 per cent of capacity. Other significant entities are Alinta (18 per cent), International Power (17 per cent), Origin Energy (11 per cent), EnergyAustralia (8 per cent) and Infigen (5 per cent each).
- In **New South Wales**, state owned corporations own around 90 per cent of generation capacity. In 2011 the New South Wales Government sold the electricity trading (gentrader) rights to around one-third of state owned capacity to TRUenergy (rebranded in 2012 as EnergyAustralia) and Origin Energy. Following the sale, control over the dispatch of state owned plant is now split between the government entities Macquarie Generation (28 per cent) and Delta Electricity (12 per cent), and the private entities Origin Energy (26 per cent) and EnergyAustralia (17 per cent).

  In 2013 the New South Wales Government sold those generation assets under gentrader agreements to their respective gentraders (Origin Energy and EnergyAustralia). In July 2013 the government called for expressions of interest to begin the sale of Macquarie Generation, the largest generator in the NEM. The first stage is the sale of Macquarie's coal fired power stations, Liddell and Bayswater. Parties were free to bid on one or both power stations.
- In **Queensland**, state owned corporations Stanwell and CS Energy control around 65 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). The degree of market concentration increased in 2011, when the Queensland Government dissolved the state owned Tarong Energy and reallocated its capacity to the remaining two state owned entities.

  In September 2013 the Queensland Government announced it would not invest in new generation capacity unless private investment was clearly absent in response to an emerging capacity shortfall. It was examining the potential costs, risks and benefits of selling Stanwell and CS Energy, as recommended by a Commission of Audit. The government reiterated that no sale would proceed without a mandate from the Queensland electorate.[21]

  The most significant private generators in Queensland are InterGen (13 per cent) and Origin Energy (8 per cent).
- In **Tasmania**, the state owned Hydro Tasmania owns nearly all generation capacity, following a transfer of assets from Aurora Energy in June 2013. To encourage new entry in the retail market, the Office of the Tasmanian Economic Regulator will regulate the price at which Hydro Tasmania can offer four safety net contract products and ensure there are adequate volumes of these products available.

1.4.2 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 price volatility in the electricity spot market, reducing their need to participate in hedge (contract) markets (section 1.8). Less need for hedge contracts can reduce liquidity in contract markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

Section 5.2.1 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 electricity generation from 15 per cent in 2009 to 36 per cent in 2013, following the commissioning of Origin Energy's Mortlake power station and AGL Energy's full acquisition of Loy Yang A in Victoria (previously having a one-third minority interest)
- control around 45 per cent of new generation capacity commissioned or committed in the NEM since 2009. Investment by entities that do not also retail energy has been negligible, except in wind generation.

19 Market shares do not account for import capacity via interconnectors. Wind farm capacity is adjusted for an average contribution factor.

20 The New South Wales, Victorian and Australian governments jointly own Snowy Hydro.

21 Department of Energy and Water Supply (Queensland Government), *Powering Queensland's future, the 30-year electricity strategy—discussion paper*, September 2013.

Table 1.4 Generation capacity and ownership, 2013

TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND	**TOTAL CAPACITY**	**11 703**	
Stanwell Corporation	Stanwell; Tarong; Tarong North; Swanbank; Barron Gorge; Kareeya; Mackay	3 141	Stanwell Corporation (Qld Government)
CS Energy	Callide; Kogan Creek; Wivenhoe	1 960	CS Energy (Qld Government)
CS Energy	Gladstone	1 680	Rio Tinto 42.1%; NRG Energy 37.5%; others 20.4%
Origin Energy	Darling Downs; Mt Stuart; Roma	1 013	Origin Energy
CS Energy 50%; InterGen 50%	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
InterGen	Millmerran	760	InterGen (China Huaneng 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
AGL Energy	Oakey	282	ERM Group 83%; others 17%
AGL Energy / Arrow Energy	Yabulu	235	RATCH Australia
RTA Yarwun	Yarwun	155	Rio Tinto Alcan
BG Group	Condamine	144	BG Group
CSR	Pioneer Sugar Mill; Invicta Sugar Mill	118	CSR
Mackay Sugar Coop	Racecourse Mill	48	Racecourse Mill
EDL Projects Australia	Moranbah North	46	EDL Projects Australia
AGL Energy	German Creek	45	AGL Energy
Ergon Energy	Barcaldine	34	Ergon Energy (Qld Government)
Essential Energy	Daandine	33	Arrow Energy (Shell 50%; PetroChina 50%)
National Power	Rocky Point	30	National Power
	Unscheduled plant < 30 MW	119	
NEW SOUTH WALES	**TOTAL CAPACITY**	**16 932**	
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4 784	Macquarie Generation (NSW Government)
Origin Energy	Eraring; Shoalhaven	3 120	Eraring Energy (NSW Government)
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2 492	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
EnergyAustralia	Mt Piper; Wallerawang	2 340	Delta Electricity (NSW Government)
Delta Electricity	Vales Point; Colongra; Broadwater; Condong	2 104	Delta Electricity (NSW Government)
Origin Energy	Uranquinty; Cullerin Range	712	Origin Energy
EnergyAustralia	Tallawarra	415	EnergyAustralia (CLP Group)
Infigen Energy	Capital; Woodlawn	188	Infigen Energy
Marubeni Corporation	Smithfield Energy Facility	162	Marubeni Corporation
EnergyAustralia	Redbank	145	Redbank Energy
EDL Group	Appin; Tower	96	EDL Group
Essential Energy	Broken Hill	50	Essential Energy (NSW Government)
Acciona Energy	Gunning	47	Acciona Energy
Eraring Energy	Hume	29	Green State Power (NSW Government)
	Unscheduled plant < 30 MW	248	
TASMANIA	**TOTAL CAPACITY**	**3 176**	
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tamar Valley; Bell Bay; others	2 768	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth; Musselroe	308	Shenhua Clean Energy 75%; Hydro Tasmania 25%
	Unscheduled plant < 30 MW	100	

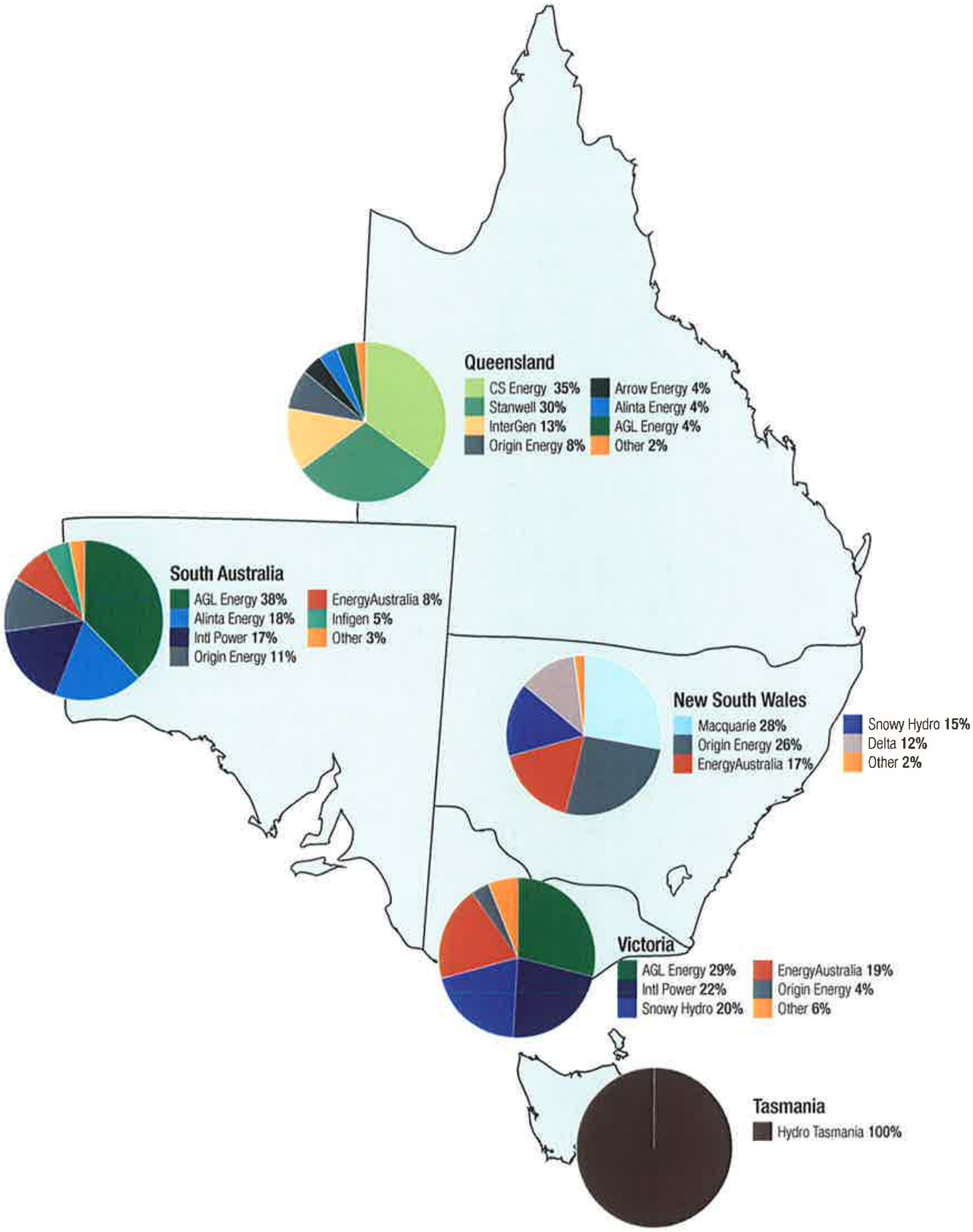
TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
VICTORIA	**TOTAL CAPACITY**	**12 242**	
AGL Energy	Loy Yang A; Macarthur; Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay	3 425	AGL Energy
Snowy Hydro	Murray; Laverton North; Valley Power	2 353	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
International Power	Hazelwood	1600	International Power (GDF Suez 72%, Mitsui 28%)
EnergyAustralia	Yallourn; Longford	1431	EnergyAustralia (CLP Group)
International Power	Loy Yang B	965	International Power (GDF Suez 72%, Mitsui 28%) 70%; Mitsui 30%
Ecogen Energy	Jeeralang A and B; Newport	883	Industry Funds Management
Origin Energy	Mortlake	518	Origin Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland	247	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Energy Brix Australia	Energy Brix	179	HRL Group / Energy Brix Australia
Alcoa	Angelsea	157	Alcoa
Hydro Tasmania	Bairnsdale	70	Alinta Energy
AGL Energy	Oaklands Hill	50	Challenger Life
Eraring Energy	Hume	29	Green State Power (NSW Government)
	Unscheduled plant < 30 MW	173	
SOUTH AUSTRALIA	**TOTAL CAPACITY**	**4 357**	
AGL Energy	Torrens Island	1 260	AGL Energy
Alinta Energy	Northern	546	Alinta Energy
International Power	Pelican Point; Canunda	494	International Power (GDF Suez 72%, Mitsui 28%)
Origin Energy	Quarantine; Ladbroke Grove	256	Origin Energy
International Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	221	International Power (GDF Suez 72%, Mitsui 28%)
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%
Infratil Energy Australia	Snowtown, Pt Stanvac	157	Infratil
AGL Energy	Hallett 2; Wattle Point	145	Energy Infrastructure Trust
EnergyAustralia	Waterloo	111	Palisade Investment Partners / Northleaf Capital Partners 75%; EnergyAustralia (CLP Group) 25%
AGL Energy	North Brown Hill	99	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
RATCH Australia	Starfish Hill	35	RATCH Australia
AGL Energy	The Bluff	39	Eurus Energy
AGL Energy	Angaston	30	Infratil

Fuel types: coal; gas; hydro; wind; diesel/fuel oil/multi-fuel; biomass/bagasse; unspecified

Note: Capacity as published by AEMO for summer 2013–14, except for wind farms (registered capacity).

Sources: AEMO; AER.

Figure 1.11
Market shares in electricity generation capacity, by region, 2013



Notes:

Capacity based on summer availability for January 2014, except wind, which is adjusted for an average contribution factor. Market shares do not account for import capacity via interconnectors. Capacity that is subject to power purchase agreements is attributed to the party with control over output. Excludes power stations not managed through central dispatch.

Source: AER.

- supply 80 per cent of energy retail customers. All three acquired significant market share in Queensland (in 2007) and New South Wales (in 2010) following the privatisation of government owned retailers in those states.
- are expanding their interests in upstream gas production and storage.

Government owned generators are also vertically integrating. The generator Snowy Hydro owns Red Energy, which operates in the New South Wales, Victorian and South Australian retail markets. The Tasmanian Government owns Hydro Tasmania, which is a generation business that also has a retail arm (Momentum Energy), and the stand-alone retailer Aurora Energy.

1.4.3 How competitive is the NEM?

High levels of market concentration and greater 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, particularly in South Australia. It recommended the Standing Council on Energy and Resources (SCER) consider conferring on the AER powers to monitor the market for that possibility. In May 2013 the SCER agreed to task officials with further work around the need for changes to the National Electricity Law before the SCER considers its policy position.[22]

1.5 How the NEM operates

Generators in the NEM sell electricity through a wholesale spot market in which changes in supply and demand determine prices. The NEM is a gross pool, meaning all electricity sales must occur through the spot market. As an energy only market, it has no payments to generators for capacity or availability. The main customers are energy retailers, which pay for the electricity used by their business and household customers.

Registered generators make bids (offers) into the market to produce particular quantities of electricity at various prices for each of the five minute dispatch periods in a day. A generation business can bid at 10 different price levels of its choosing. It must lodge offers ahead of each trading day, but can change its offers (rebid) at any time, subject to those bids being in 'good faith'. In rebidding, a generator may alter supply quantities at each price level, but cannot alter prices.

Generator offers are affected by a range of factors, including plant technology. Coal fired generators, for example, need to ensure their plants run constantly to cover their high start-up costs, and they may offer to generate some electricity at low or negative prices to guarantee dispatch.[23] Gas powered generators face higher operating costs and normally offer to supply electricity only when prices are high.

Bidding may also be affected by supply issues such as plant outages or constraints in the transmission network that limit transport capabilities. Some generators have market power in particular regions and periodically offer capacity at above competitive prices, knowing capacity must be dispatched if regional demand exceeds a certain level. This behaviour most commonly occurs at times of peak demand, often accompanied by generator outages or network constraints.

To determine which generators are dispatched, AEMO stacks the offer bids of all generators from the lowest to highest price offers for each five minute dispatch period. It dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to meet demand. The highest priced offer (the marginal offer) needed to meet demand sets the dispatch price. The wholesale spot price paid to generators is the average dispatch price over 30 minutes; all generators are paid at this price, regardless of the price that they bid (box 1.2).[24]

The market allows spot prices to respond to movements in supply and demand. Prices may range between a floor of –$1000 per MWh and a cap of $13 100 per MWh (raised from $12 900 per MWh on 1 July 2013). The cap is increased annually to reflect changes in the consumer price index. The Australian Energy Market Commission (AEMC) can further change the cap through its reviews of reliability standards and other market settings (section 1.11).

The market sets a separate spot price for each of the five NEM regions. Price separation of a region occurs when only local generation sources can meet an increase in demand—that is, network constraints prevent a neighbouring region from supplying additional electricity across a transmission interconnector. At other times, prices align across regions, except for minor price disparities due to physical losses

22 SCER, *Meeting communiqué*, Brisbane, 31 May 2013.

23 The price floor equals –$1000 per MWh.

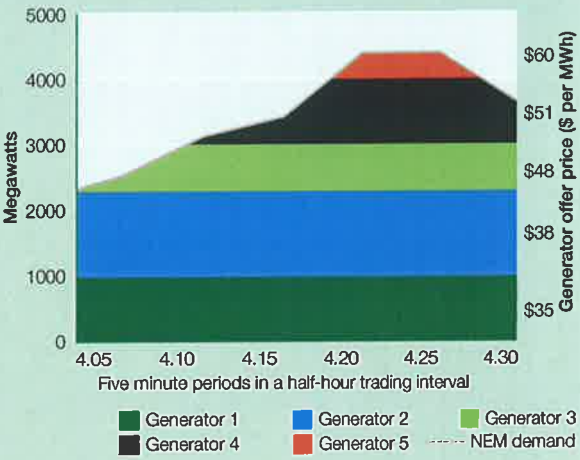
24 Some generators bypass this central dispatch process, including some older wind generators, those not connected to a transmission network (for example, solar rooftop installations) and those producing exclusively for their own use (such as remote mining operations).

Box 1.2 Setting the spot price in the NEM

Figure 1.12 illustrates a simplified bid stack in the NEM between 4.00 pm and 4.30 pm. Five generators are offering capacity into the market in different price ranges. At 4.15 pm the demand for electricity is about 3500 MW. To meet this demand, 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.

A wholesale spot price is determined for each half hour period (trading interval) and is the average of the five minute dispatch prices during that interval. In figure 1.12, the spot price in the 4.00–4.30 interval is about $54 per MWh. This is the price that all generators receive for their supply during this 30 minute period, and the price that customers pay in that period.

Figure 1.12
Generator bid stack



in the transport of electricity over long distances. Allowing for these transmission losses, prices across the mainland regions of the NEM were aligned for 77 per cent of the time in 2012–13, compared with 70 per cent in 2011–12.

1.6 Interregional trade

The NEM promotes efficient generator use by allowing electricity trade among the five regions, which transmission interconnectors link (figure 1.4). Trade enhances the reliability of the power system by allowing each region to draw on a wider pool of reserves to manage generator outages. It also allows high cost generating regions to import electricity from lower cost regions. The technical capabilities of cross-border interconnectors set an upper limit on interregional trade. At times, network congestion constrains trading levels to below nominal interconnector capabilities.

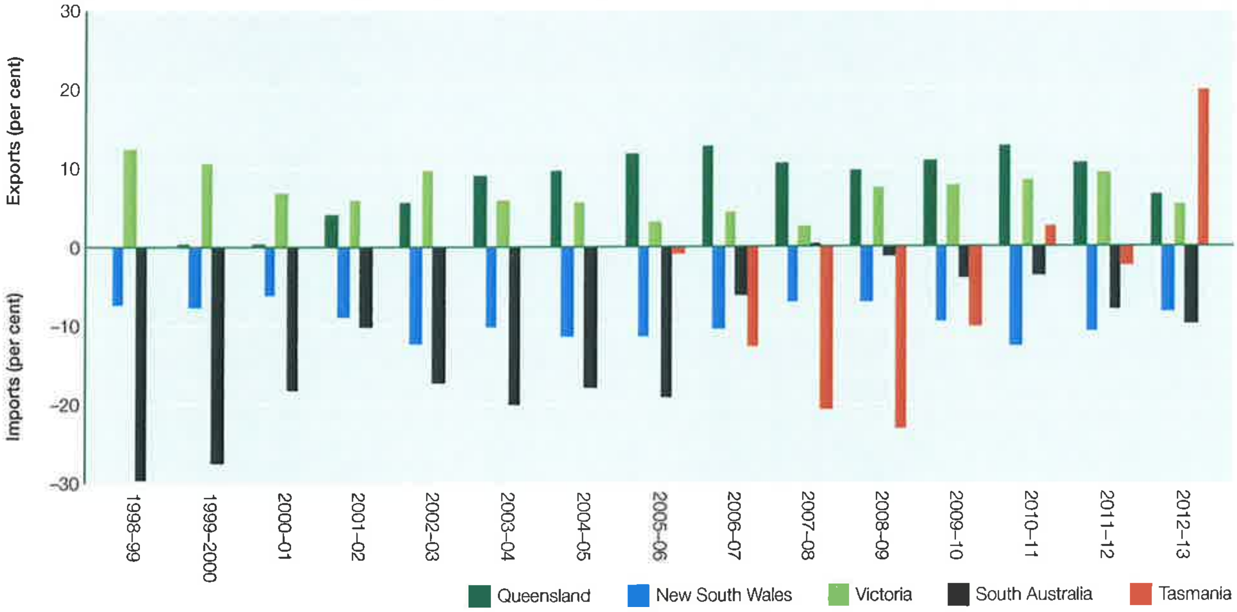
Figure 1.13 shows the net trading position of the five regions:

- Victoria has substantial low cost coal fired generation, making it a net exporter of electricity (particularly to New South Wales and South Australia). However, its exports to those regions in 2012–13 were partly offset by a significant increase in hydro generation imports from Tasmania.
- Queensland's surplus capacity and low fuel prices make it a net exporter. The region's relatively high spot prices in 2012–13 resulted in lower export volumes than in previous years.
- New South Wales has relatively high fuel costs, making it a net importer of electricity.
- South Australia imported over 25 per cent of its energy requirements in the early years of the NEM. While new investment in wind generation has significantly increased exports during low demand periods, the shutdown of some plant that traditionally operated almost continuously caused net imports to rise in 2012–13.
- Tasmania has a volatile trade position, depending on market conditions for hydro generation. It has frequently been a net importer, notably when drought affected hydro generation in 2007–09. But the introduction of carbon pricing in July 2012 enhanced the competitiveness of hydro generation, resulting in Tasmania becoming a major net exporter in 2012–13.

There is ongoing evidence that network congestion is affecting interregional trade, constraining the market from exporting electricity from lower to higher price regions. The issue has affected all regions of the NEM at one time or another. Network congestion and disorderly generator bidding in Queensland, for example, periodically led to power flowing in the reverse direction in 2012–13 to what prices would suggest—that is, electricity was flowing from high price to low price regions. Counter-price flows create market distortions that damage interregional trade and impose costs on consumers (section 1.7.3).[25]

25 See also AER, *State of the energy market 2012*, pp. 43–4.

Figure 1.13
Interregional trade as a percentage of regional electricity demand



Sources: AEMO; AER.

1.7 Electricity spot prices

The AER monitors the spot market and reports weekly on activity. It also publishes detailed analyses of extreme price events. Table 1.5 sets out annual average spot prices while figure 1.14 charts quarterly average prices. Figure 1.15 provides a snapshot of weekly prices since 2009.

Prices across most regions peaked during 2006–08, when drought constrained the availability of water for hydro generation and cooling in coal generation. This period coincided with escalating peak and average demand for electricity. Additionally, the AER noted evidence of the periodic exercise of market power affecting spot prices, particularly by AGL Energy in South Australia between 2008 and 2010.[26]

1.7.1 The market in 2012–13

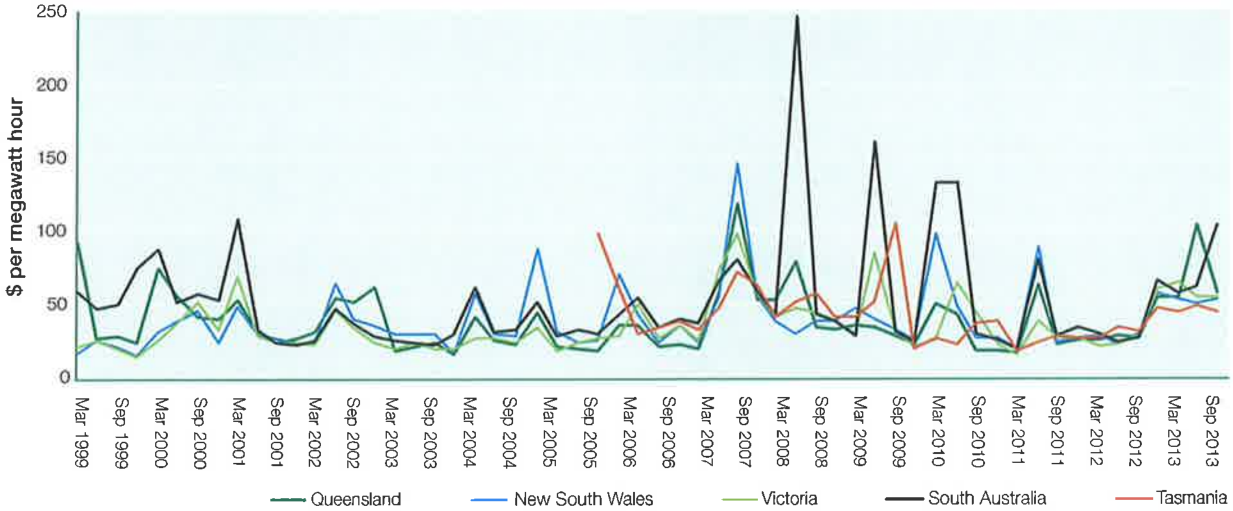
Declining electricity demand and the rising uptake of renewable generation, including wind and solar PV contributed to historically low spot electricity prices in 2011–12 (table 1.5). But this trend reversed in 2012–13: average prices more than doubled in Queensland (to $70 per MWh), Victoria (to $61 per MWh) and South Australia (to $74 per MWh), and almost doubled in New South Wales (to $56 per MWh). Tasmanian prices rose by around 50 per cent (to $49 per MWh).

In part, the higher prices reflected carbon pricing, introduced on 1 July 2012 at $23 per tonne of emissions. The initial impact on spot electricity prices was much greater, with average prices in the week 1–7 July 2012 ranging from $38 to $84 per MWh above 2011–12 averages. While factors unrelated to carbon affected outcomes, some generators raised their offer prices above the levels required to adjust for the carbon intensities of their plant. Spot prices moderated over the following weeks and continued to ease into spring 2012.

The average carbon pass through to spot electricity prices during 2012–13 was broadly consistent in mainland regions ($17.70 per MWh), but significantly lower in Tasmania ($10 per MWh), due to its high concentration of hydro

26 AER, *Submission on draft determination—potential generator market power in the NEM*, 1 August 2012. The AER also reported on this behaviour in its weekly electricity market reports.

Figure 1.14
Quarterly spot electricity prices



Note: Volume weighted average prices.
Sources: AEMO; AER.

generation. But average prices for 2012–13 rose across the NEM by around $31 per MWh, suggesting other factors contributed. The largest increases occurred in South Australia and Queensland, where carbon adjusted prices rose by over 70 per cent (table 1.6; see also figure 6 in the *Market overview*). These outcomes were mainly driven by price spikes in summer 2013 (Queensland) and autumn 2013 (South Australia). While prices came off a low base in 2011–12, the rises occurred against a backdrop of weak electricity demand. The underlying causes were complex but generator behaviour appears to have contributed:

- In Queensland, transmission network congestion precipitated disorderly generator bidding, causing high prices in August–October 2012 and more dramatically in January 2013 (section 1.7.3).
- In mainland NEM regions, plant closures contributed to lower than expected reserves at times, driving high prices and occasionally making possible opportunistic bidding by major generators. Such conditions were evident in South Australia in April–May 2013 (section 1.7.4).

1.7.2 Price volatility

A relatively tight supply–demand balance during periods of peak demand contributed to an escalating trend of extreme price outcomes in the NEM between 2004–05 and 2009–10. During that period, the number of 30 minute prices above $5000 per MWh peaked at 95 events in 2009–10.

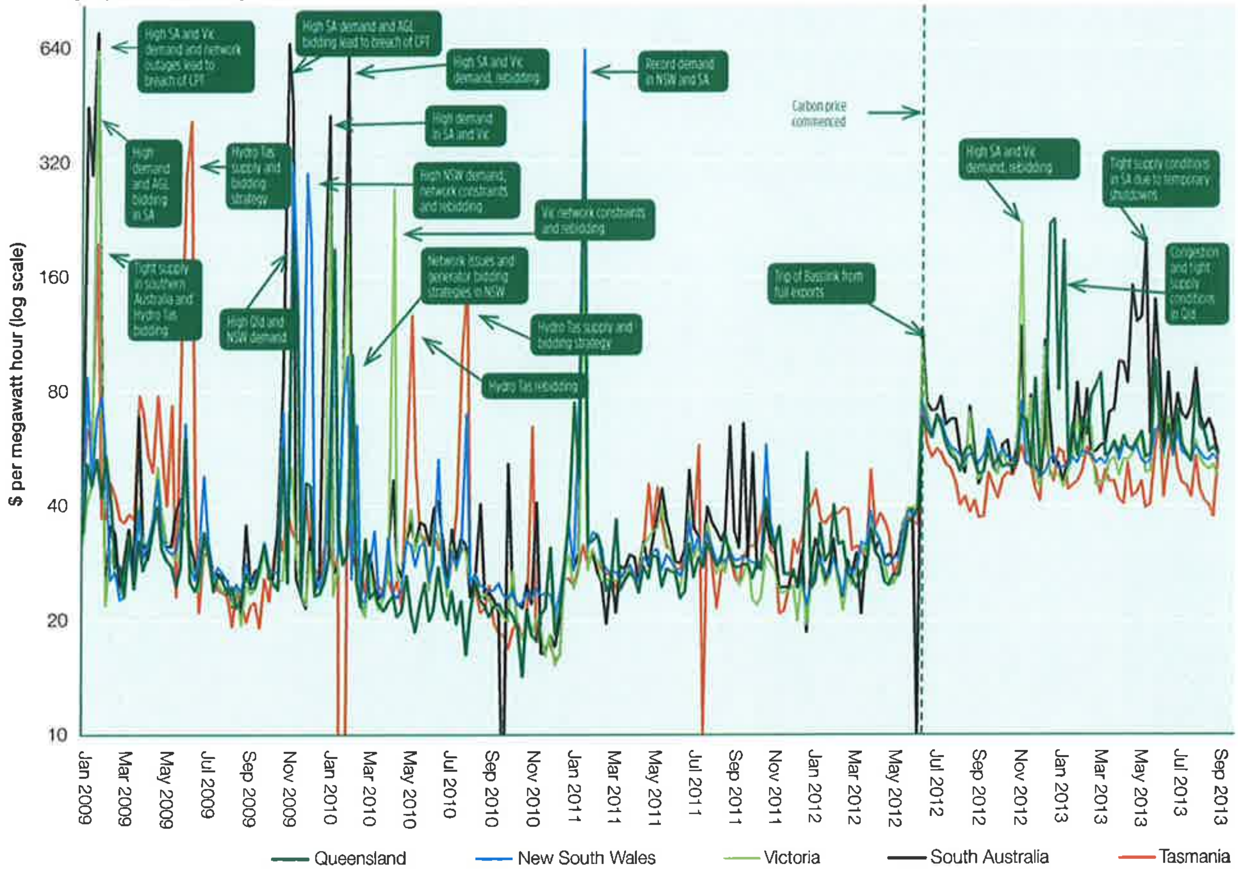
The incidence of extreme prices has since fallen sharply. Only one such event occurred in 2011–12 (the lowest number since the NEM commenced), with four events in 2012–13 (figure 1.16):

- three events in Victoria on 29 November 2012, with the peak of $9974 per MWh at 4.30 pm. The prices were driven by higher than expected temperatures causing Victorian electricity demand to significantly exceed forecasts and reach its highest level since February 2011. Several generators reacted to the tight market conditions by rebidding low priced capacity into higher price bands.[27]
- a price of $6299 per MWh in Queensland on 29 January 2013. While Brisbane temperatures were higher than expected, energy demand was well below historical peaks. A tight supply–demand position was created when generators withdrew around 1000 MW of capacity from the market via rebidding activity.[28] This behaviour was not related to the network congestion and disorderly bidding that also occurred in Queensland in January 2013 (section 1.7.3).

Additionally, South Australia experienced one price event above $5000 per MW in an ancillary services market, on 6 March 2013. The event was triggered by a transmission network outage and aggravated by generator rebidding. The

27 AER, *Electricity spot prices above $5000/MWh: 29 November 2012*.
28 AER, *Electricity spot prices above $5000/MWh: 29 January 2013*.

Figure 1.15
Weekly spot electricity prices



Notes: CPT, cumulative price threshold. Volume weighted average prices.
Source: AER.

Table 1.5 Volume weighted average spot electricity prices ($ per megawatt hour)

	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
2012–13	70	56	61	74	49	
2011–12	30	31	28	32	33	
2010–11	34	43	29	42	31	
2009–10	37	52	42	83	30	
2008–09	36	43	49	69	62	
2007–08	58	44	51	101	57	31
2006–07	57	67	61	59	51	38
2005–06	31	43	36	44	59	29
2004–05	31	46	29	39		26
2003–04	31	37	27	39		22
2002–03	41	37	30	33		27
2001–02	38	38	33	34		27
2000–01	45	41	49	67		35
1999–2000	49	30	28	69		24
1999[1]	60	25	27	54		19

Notes: 1. Six months to 30 June 1999; 2. Tasmania entered the market on 29 May 2005; 3. The Snowy region was abolished on 1 July 2008.
Sources: AEMO; AER.

Table 1.6 Carbon adjusted spot prices

		QLD	NSW	VIC	SA	TAS
	Volume weighted spot price	70	56	61	74	49
2012–13	Estimated carbon pass-through	18	18	17	17	10
	Carbon adjusted spot price	52	38	43	57	39
2011–12	Volume weighted price	30	31	28	32	33
Per cent change (actual price)		134	84	115	132	48
Per cent change (carbon adjusted price)		74	25	54	79	18

Note: Average implied carbon cost represents the amount required to meet carbon price financial obligations, based on the emissions and carbon permit costs for the marginal generator in each dispatch interval.
Source: AER.

cost to South Australian customers was around $1 million, compared with less than $100 for the same service on a typical day.[29]

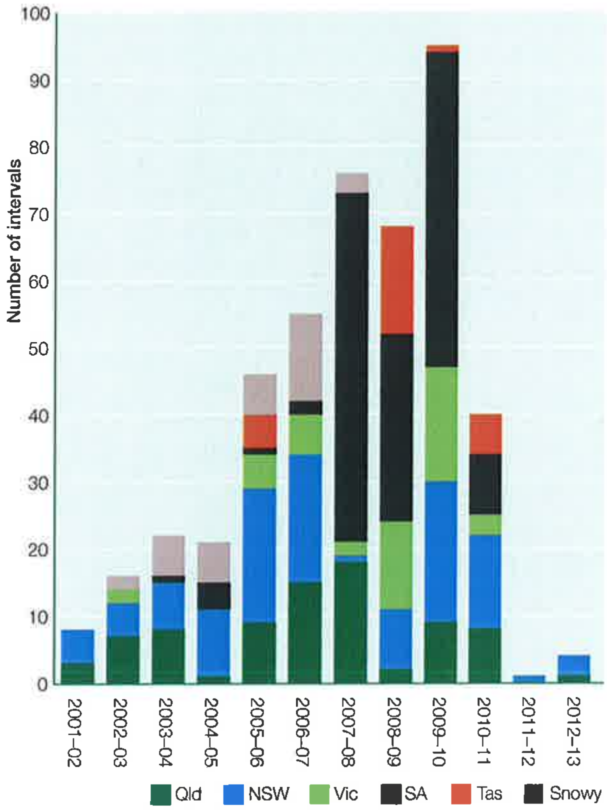
The sharp decline in the number of extreme prices reflects changing market conditions. In particular, energy use has been falling and peak demand has plateaued (section 1.1), causing surplus installed capacity in most regions. Additionally, recent summers have had few prolonged heatwaves, avoiding the spike in demand for air conditioning that typically occurs in those conditions.

Yet, volatility has continued to be a feature of the market. While prices rarely spiked above $5000 per MWh in 2012–13, the number of prices above $200 per MWh was the highest for seven years (figure 1.17). The number of such events recorded a sevenfold increase compared with 2011–12, rising from 99 to 704 events. The events mostly occurred in Queensland and South Australia, and were often unrelated to demand:

- In Queensland, network congestion triggered waves of disorderly generator bidding and market volatility (section 1.7.3).
- In South Australia, the withdrawal of significant capacity from the market led to a tight supply–demand balance, enabling relatively minor shifts in demand to spike prices (section 1.7.4).

Market volatility can also result in negative spot prices. The incidence of negative prices fell sharply in Tasmania and South Australia in 2012–13 but rose in Queensland, where disorderly bidding among generators drove outcomes (section 1.7.3). The AER analyses all spot prices below –$100 per MWh in its weekly market reports.[30]

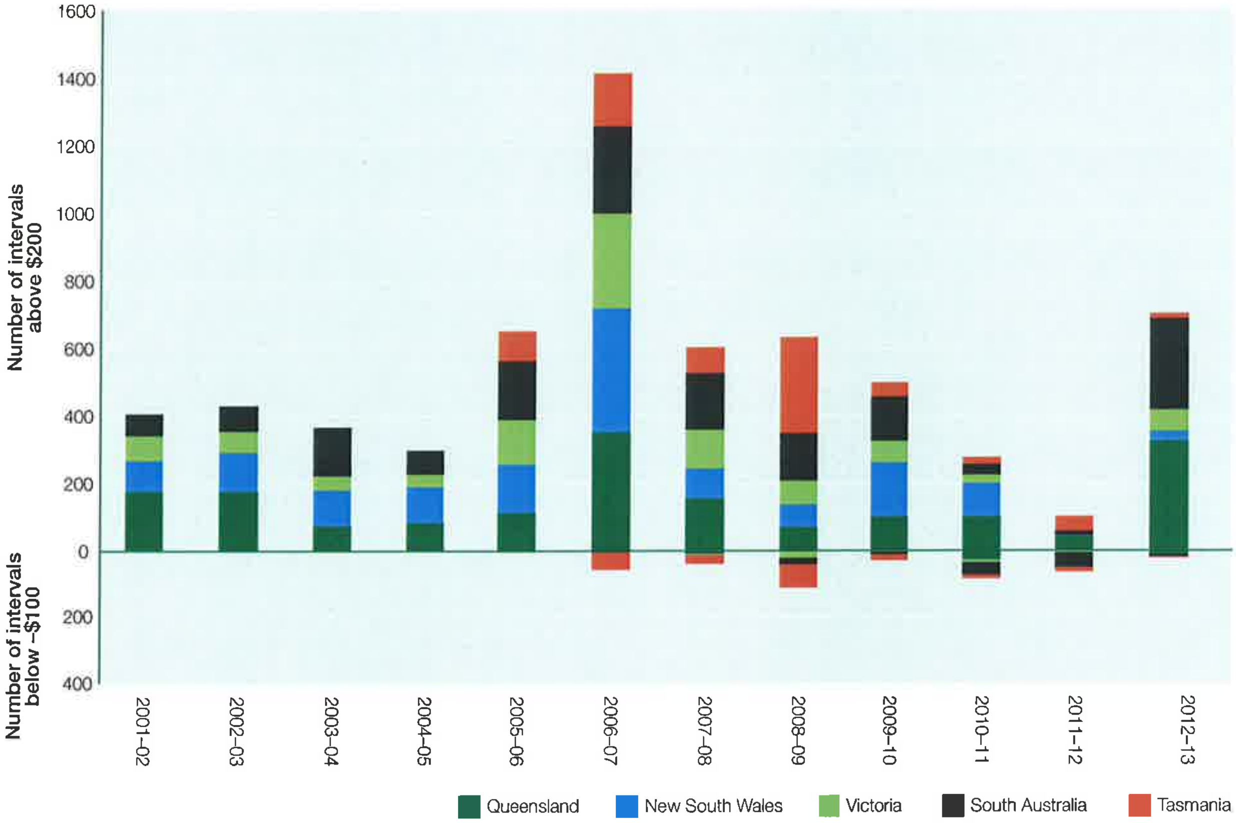
Figure 1.16
Trading intervals above $5000 per megawatt hour



Note: Each trading interval is a half hour.
Sources: AEMO; AER.

29 AER, *Market ancillary service prices above $5000/MW: 6 March 2013.*
30 See also AER, *State of the energy market 2012*, pp. 16–17 and 46–7.

Figure 1.17
Market volatility—prices above $200 per MWh and below -$100 per MWh



Sources: AEMO; AER.

1.7.3 Network congestion and disorderly bidding in Queensland

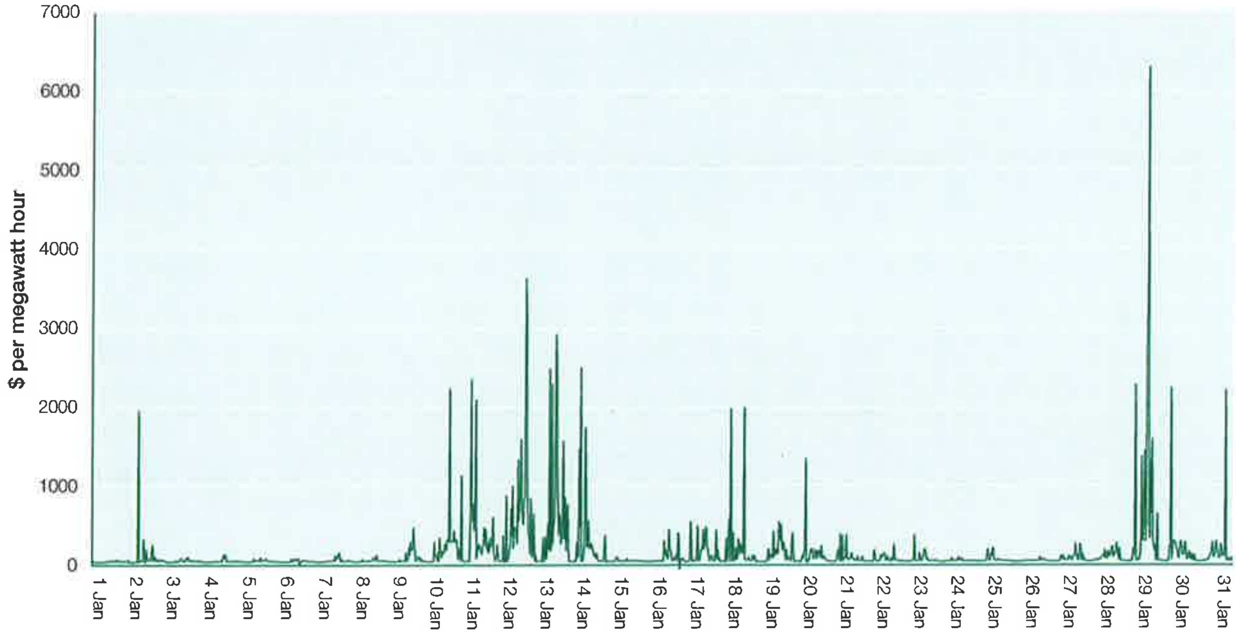
An interplay of factors caused volatility in the Queensland market during January 2013, resulting in 116 prices above $300 per MWh, including 16 prices above $1000 per MWh (figure 1.18). While the events occurred in summer, a number occurred between midnight and 7 am, when demand was low. Overall, spot electricity prices in the first quarter of 2013 averaged $105 per MWh in Queensland, compared with $51–64 per MWh elsewhere.

Queensland's supply–demand balance was relatively tight in the first quarter of 2013, with generators offering 12 per cent less capacity (around 1320 MW) into the market than during the same quarter in 2012 (figure 1.19). These conditions were aggravated during much of January by transmission network congestion around central Queensland (figure 1.20).

Following an ownership restructure in July 2011, CS Energy acquired control over generation plant at both ends of a strategic transmission line (the Calvale to Wurdong line) in central Queensland. Subsequently, its bidding behaviour periodically resulted in power flows that contributed to network congestion. AEMO was obliged to manage the issue by 'constraining off' low cost generation in southern Queensland and 'constraining on' higher cost generation north of the congested line. AEMO also forced power flows out of Queensland into New South Wales, often contrary to price signals (that is, electricity flowed from the higher priced Queensland region to the lower priced New South Wales region). Interconnectors have no ramp rates, allowing for electricity flows to be diverted very quickly in this way.

In combination, the reduction in low cost generation in southern Queensland, the dispatch of higher priced capacity around Gladstone, and the counter-price export of electricity into New South Wales caused the Queensland price to spike. The problem was exacerbated by generators

Figure 1.18
Price volatility in Queensland, January 2013



Source: AER.

engaging in disorderly bidding—that is, bidding contrary to the underlying cost structures and/or technical limitations of generation plant. In particular, generators tried to maintain output levels and receive high spot prices by rebidding capacity from high to low (or negative) prices. They also rebid down the ramp rates of their plant so they could be constrained off only slowly. This behaviour drove 80 of the 116 spot prices above $300 per MWh during January 2013. The incidents followed a similar round of disorderly bidding in August–October 2012.[31]

Disorderly bidding causes random and very short fluctuations in prices that are impossible to predict (figure 1.18) making it difficult for competing generation to respond. Some plant owners reported instances of ramping up generation only to find the spot price had already fallen back (sometimes to negative, following the disorderly bidding by constrained generators to optimise their chances of dispatch). In some cases, potentially competing generation could not respond because the price changes were not forecast, making it difficult to adjust output levels quickly enough. In other cases, capacity that might otherwise have been used was locked into frequency control ancillary service contracts.[32]

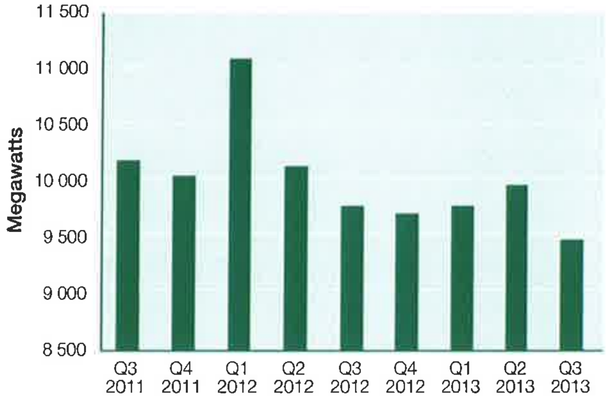
An environment of disorderly bidding causes market uncertainty and the inefficient dispatch of generation. It also increases the risk profile for generators, retailers and consumers, as reflected in a spike in Queensland's $300 cap contract prices for the first quarter of 2013. Figure 1.21 illustrates the difference in premiums paid by buyers to enter a contract in Queensland and one in New South Wales. The cost of Queensland's higher risk profile ultimately flows through to consumers through higher energy charges. More generally, disorderly bidding causes a productive efficiency loss when high cost generation is dispatched in place of low cost generation.

Additionally, the effects on interregional trade flows are significant. When electricity flows counter-price across state borders, the market operator pays out more to generators in the exporting region than it receives from importing customers. The cost of this negative settlement residue falls on the transmission network provider in the importing region

31 AER, *The impact of congestion on bidding and inter-regional trade in the NEM*, December 2012.

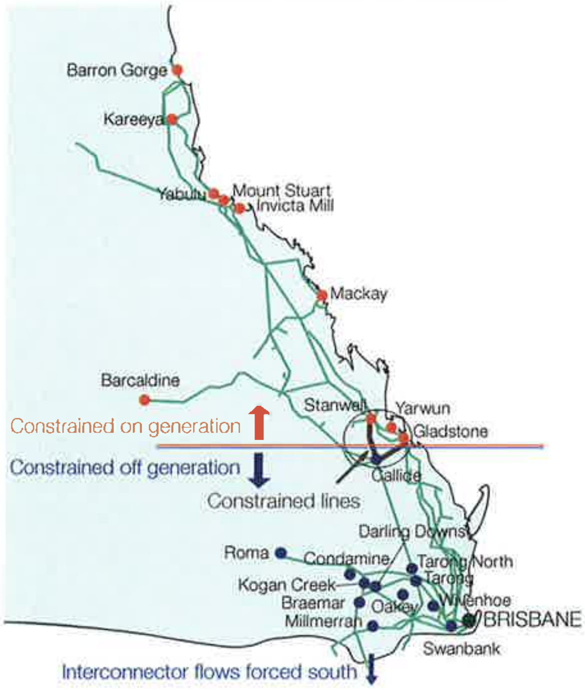
32 Some generation capacity is reserved to manage fluctuations in the frequency of electricity flows in the grid. Some of this reserved capacity cannot be drawn on at short notice for generation dispatch.

Figure 1.19
Maximum available generator capacity, Queensland



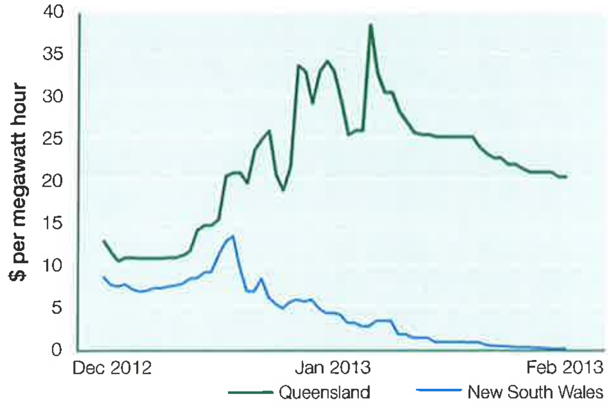
Source: AER.

Figure 1.20
Queensland transmission network configuration



Source: AER.

Figure 1.21
Prices for $300 cap contracts, first quarter 2013



Source: ASX Energy.

(in this instance, New South Wales). Ultimately, consumers in the importing region bear the cost through increased transmission network charges.

More generally, the forcing of power flows across borders contrary to price signals inhibits the effectiveness of interconnectors, making it harder for generators and retailers to hedge across boundaries, which damages interregional trade and competition. The AEMC in 2013 was reviewing AEMO's processes for limiting negative settlement residues that arise from counter-price flows.

Addressing disorderly bidding

Powerlink is augmenting transmission lines around Gladstone, which is expected to reduce congestion in this area. But disorderly bidding is not limited to central Queensland; it has occurred in all regions of the NEM at one time or another.

Network augmentation is a costly solution to network congestion and disorderly bidding, which periodically affect all regions of the NEM. The AEMC proposed an 'optional firm access' model, under which generators pay transmission businesses for firm network access, based on the costs of increasing network capacity. If congestion prevents a generator with firm access from being dispatched, then non-firm generators contributing to the problem would be required to pay compensation to the affected firm generator.

Given full implementation of this approach could take several years, the AER in August 2013 proposed an interim measure requiring generators to submit ramp rates that reflect the maximum technical rate that their plant can safely achieve. The AER considers this requirement would limit the frequency and scope of disorderly bidding because AEMO could quickly alter generators' output to resolve constraints.

Queensland price spikes in August–September 2013

Queensland experienced another round of price spikes, unrelated to network congestion, in August–September 2013. The spikes were driven by relatively small increases in five minute demand that could not be met from low price generation in Queensland or imports, thus requiring the dispatch of local generation at around the price cap. They occurred at demand levels of around 6000 MW, well below the region's 2012–13 maximum demand of 8606 MW and installed capacity of around 11 000 MW.[33]

While the spikes in August–September 2013 did not relate to network congestion in Queensland, import capacity from New South Wales was constrained. The Directlink interconnector was out of service, and import capability across the Queensland to New Source Wales interconnector (QNI) was limited to around 180 MW (compared with a nominal limit of 480 MW). The following factors also contributed:

- Around 800 MW of Queensland capacity (usually offered at low prices) was offline.
- Technical limitations (including plant being ramp rate limited, or trapped in frequency control ancillary services) meant around 5 per cent of available low price capacity in Queensland could not be dispatched, requiring the dispatch of higher price generation.
- A significant proportion of fast start plant was offline before the time of the high prices. Much of this capacity takes more than five minutes to start generating, so it could not ramp up in time to meet an increase in five minute demand.

Significantly, the price spikes in August–September 2013 were typically for five minutes only. Given the relatively low level of demand, competing generation would have been in a position to come online or ramp up to prevent spikes of a longer duration. The AER reported on these events in its weekly market report for 25–31 August 2013.

33 Excludes mothballed generation, including 700 MW at Stanwell's Tarong Power Station (unit 2 was mothballed in October 2012 and unit 4 was mothballed in December 2012).

1.7.4 Market volatility in South Australia—autumn 2013

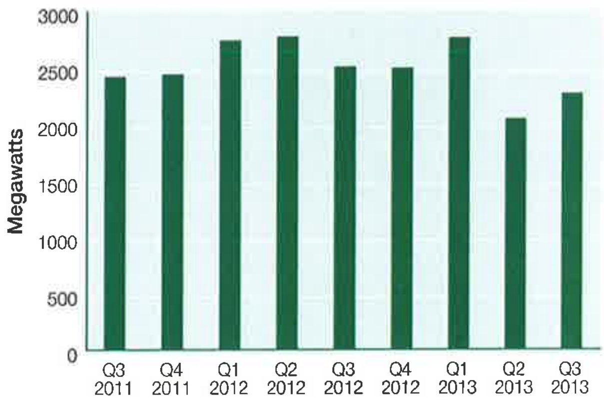
A tight supply–demand balance caused South Australian spot prices to average $106 per MWh in April–June 2013, almost double the average in other mainland regions of the NEM. Prices were the highest for those months in South Australia since market start. The outcomes included 212 prices above $200 per MWh, of which 19 were greater than $1500 per MWh. No prices were above $200 per MWh during the equivalent period in 2012. These outcomes occurred at a time of year when energy use is normally subdued, and against a longer term trend of declining electricity demand (section 1.1).

The high prices were driven by tight supply conditions, evidenced by the lowest reserves for four years. During this period, AEMO issued market notices forecasting a lack of reserve conditions for 41 days. South Australia narrowly avoided interrupting customer load. The supply conditions were the tightest in South Australia since the blackouts during the summer of 2009.

The tight supply conditions were not due to a lack of installed capacity in South Australia. Rather, three major generators—Alinta, International Power and AGL Energy—made commercial decisions to reduce their available capacity to the market and increase the offer prices of remaining capacity. Reflecting that change, generator offers markedly contracted compared with the corresponding period in 2012. The reduction in offers reflected:

- Alinta progressively taking both Northern power station units offline (546 MW) and International Power taking half of the Pelican Point power station offline (240 MW)

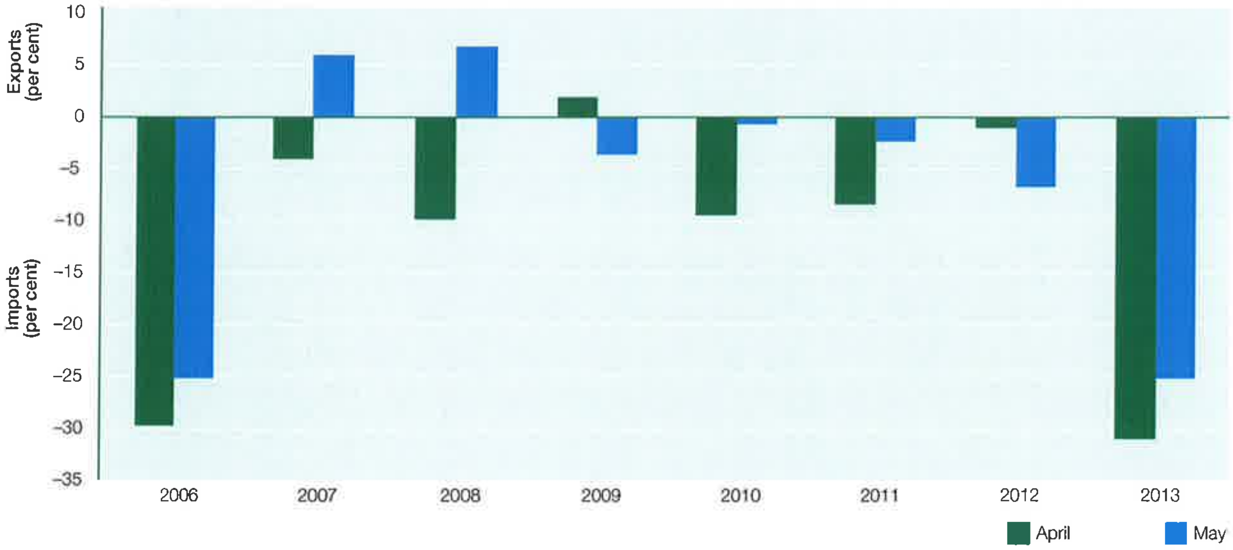
Figure 1.22
Average half hourly maximum generation availability, South Australia



Source: AER.

Figure 1.23

Net imports as percentage of South Australian energy, April and May 2013



Source: AER, AEMO.

- AGL Energy reducing the available capacity at Torrens Island by around 225 MW, and offering a greater proportion of the remaining capacity in higher price bands. In April and May 2012 it offered up to 700 MW of Torrens Island capacity at prices less than $50 per MWh, compared with only 165 MW in 2013. In line with this change in offer strategy, Torrens Island's average dispatch was nearly 200 MW lower in 2013.

Overall, the maximum available capacity offered into the market by South Australian generators was around 700 MW lower in April–June 2013 than in the corresponding quarter in 2012 (figure 1.22). This reduction in available capacity significantly raised the market clearing price.

Challenging market conditions contributed to the decisions to reduce available capacity. In addition to the weak energy demand affecting all regions, South Australia's high reliance on wind generation has driven down spot prices, eroding generator returns. Wind generation accounts for 24 per cent of installed capacity in South Australia, compared with 4 per cent across the NEM. Meanwhile, input costs (including carbon and gas costs) have risen.

Higher spot prices led to a rise in South Australian energy imports from Victoria during April–June 2013. Electricity imports during this period reached their highest levels for six years (figure 1.23). But technical limits on the interconnectors, and AEMO's management of those limits, restricted import capacity. The AER has worked closely with AEMO to improve market systems and lessen the impact of these issues in future.

In such a tight market, issues that usually have a negligible impact can significantly affect prices. In April and May 2013 step changes in overnight demand associated with hot water loads contributed to a number of high prices. The AER held discussions with SA Power Networks to find ways to better manage this issue. More generally, even small forecasting errors can cause market volatility when the supply–demand balance is so finely tuned.

The AER published a detailed report on the South Australian market during April–May 2013.[34] It did not find evidence of generators engaging in significant short term strategic bidding to capitalise on market conditions during this period. Instead, a general withdrawal of capacity created tight conditions that left AGL Energy's Torrens Island plant strongly positioned to materially influence spot prices. During this period, it was the key generator available to meet demand when the interconnectors were importing at limit and/or wind output was low.

34 AER, *Special report: market outcomes in South Australia during April and May 2013*, July 2013.

1.8 Electricity futures

Volatility in electricity spot prices can pose a significant risk to market participants. While generators risk low spot prices affecting earnings, retailers face a complementary risk of spot prices rising to levels that they cannot pass on to their customers. Market participants commonly manage their exposure to forward price risk by entering hedge contracts (derivatives) that lock in firm prices for the electricity that they intend to produce or buy. The participants in electricity derivatives markets include generators, retailers, 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. Unlike OTC transactions, 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 being 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* (called contracts for difference or swaps 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 both as futures and options.

Electricity derivatives markets are subject to a regulatory framework that includes the *Corporations Act 2001* (Cwlth) and the *Financial Services Reform Act 2001* (Cwlth). 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 2013 the AEMC was investigating ways to mitigate risk from the financial distress or failure of a large electricity retailer. One consideration was the possible application of Australia's G20 commitments on OTC derivatives to the electricity sector. The reforms include the reporting of OTC derivatives to trade repositories. They also include obligations on the clearing and execution of standardised derivatives. The AEMC in November 2013 set out options for the possible application of the G20 reforms to the electricity sector.[35]

1.8.1 Electricity futures trading on the ASX

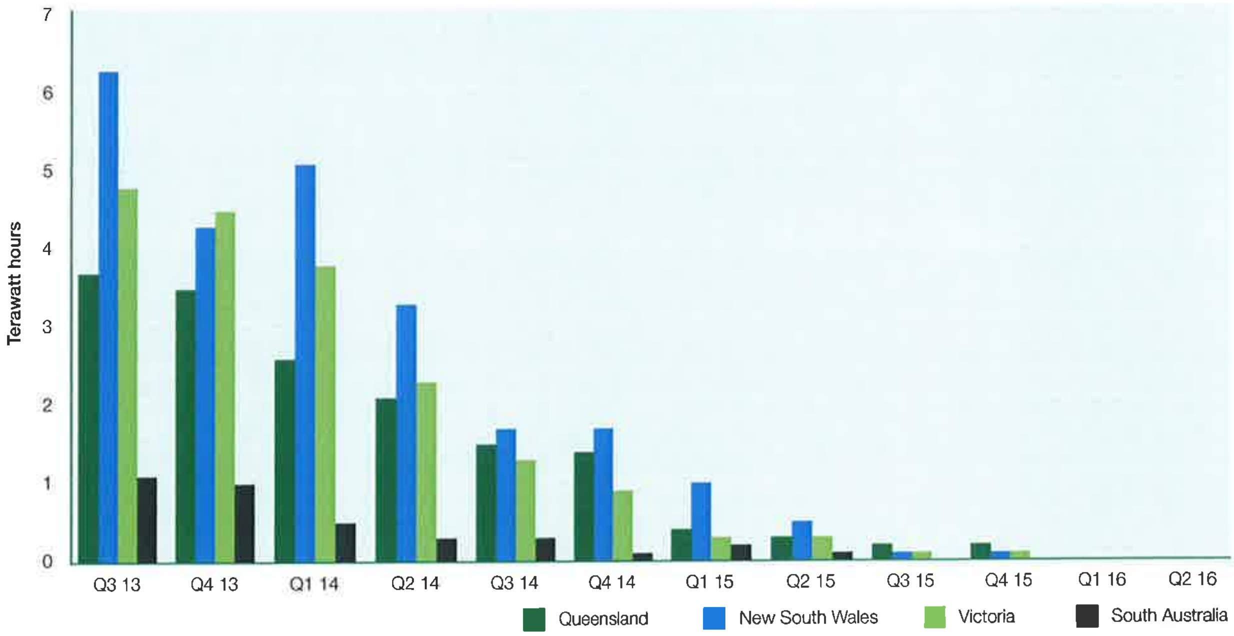
Electricity futures trading on the ASX covers instruments for Victoria, New South Wales, Queensland and South Australia. The trading volume in 2012–13 was equivalent to 186 per cent of underlying energy demand, down from 231 per cent in 2011–12 and 285 per cent in 2010–11. New South Wales accounted for 44 per cent of traded volume, followed by Queensland (29 per cent) and Victoria (24 per cent). Liquidity in South Australia is low, accounting for only 3 per cent.

The most heavily traded products in 2012–13 were base futures (54 per cent of traded volume), followed by options (27 per cent), $300 cap futures (14 per cent) and peak futures (3 per cent). Liquidity is mostly in products traded 18–24 months out—for example, open interest in forward contracts at 1 July 2013 was mostly for quarters to the end of 2014, with little liquidity into 2015 (figure 1.24).

35 AEMC, *NEM financial market resilience, Stage 2 options paper*, November 2013.

Figure 1.24

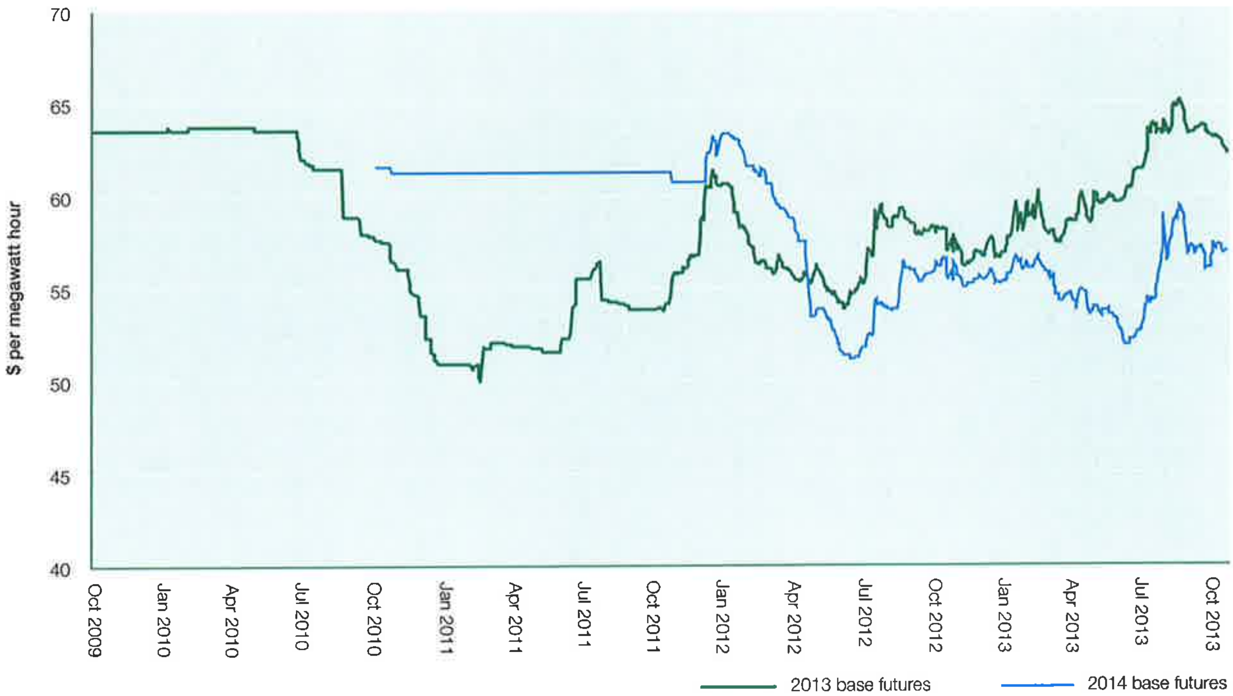
Open interest in electricity derivatives on the ASX, September 2013



Source: ASX Energy.

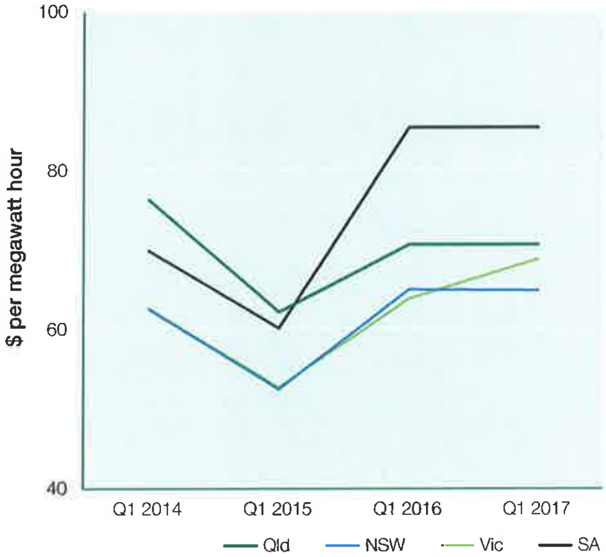
Figure 1.25

National power index



Source: ASX Energy.

Figure 1.26
First quarter base futures prices, by region, September 2013



Source: ASX Energy.

1.8.2 Forward prices

Figure 1.25 shows average price outcomes for electricity base futures for calendar years 2013 and 2014, as reflected in the national power index. The index (which ASX Energy publishes for each calendar year) represents a basket of electricity base futures for New South Wales, Victoria, Queensland and South Australia. It is calculated as the average daily settlement price of base futures contracts across the four regions for the four quarters of the relevant calendar year.

Fluctuations in futures prices reflect changing expectations of the cost of underlying wholesale electricity. In recent years, uncertainty about the introduction of a carbon price scheme led to prices fluctuating as the scheme's likelihood and nature was reassessed. Prices peaked towards the end of 2011 when the Senate passed the Clean Energy Future Plan, and rose again in the first half of 2012 when the scheme's introduction was imminent.

Prices eased later in 2012 and remained flat in summer 2012–13 when peak demand remained subdued, despite some extremely hot days in January. Queensland was the only region to record an overall increase in futures prices during 2012–13, reflecting the impacts of network congestion and disorderly bidding on spot prices (section 1.7.3).

At September 2013, first quarter base futures prices for the next three years were highest in Queensland and South Australia (figure 1.26), reflecting the market's recent experience of volatility in those regions (sections 1.7.3 and 1.7.4). Futures prices for the first quarter of 2014 were higher than actual spot prices in the first quarter of 2013 in New South Wales (by 17 per cent), Victoria (by 7 per cent) and South Australia (by 6 per cent), but 28 per cent lower for Queensland. In the latter region, futures prices reflected the market's expectations that the network congestion and disorderly bidding issues affecting 2013 outcomes would be averted in 2014.

1.9 Generation investment

Price signals in the wholesale and forward contract markets for electricity largely drive new investment in the NEM. From the start of the NEM in 1999 to June 2013, new investment added 13 850 MW of registered generation capacity—around 1000 MW per year. Figures 1.27 and 1.28 illustrate investment in registered capacity since market start. Additionally, significant investment has been made in generation not connected to the transmission grid, including investment in rooftop PV installations (section 1.1).

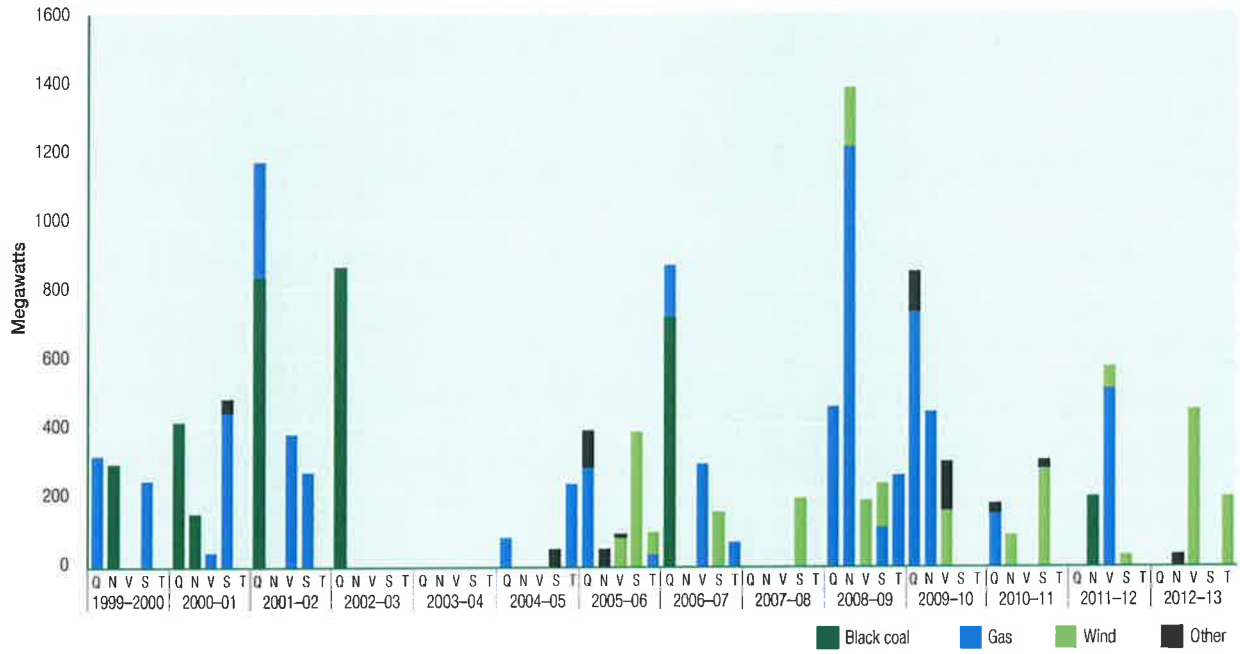
Tightening supply conditions led to an upswing in generation investment in 2008–09 and 2009–10, with over 4100 MW of new capacity added in those years—predominantly gas fired generation in New South Wales and Queensland. More recently, subdued electricity demand and surplus capacity have pushed out the required timing for new generation investment. AEMO found in 2013 that New South Wales, Victoria and South Australia were unlikely to need new capacity for at least 10 years. Two years ago, the outlook was quite different, with New South Wales and Victoria expected to require new plant capacity as early as 2014–15. In contrast, industrial development in Queensland caused AEMO to bring forward the timing of new investment requirements for the region to 2019–20, one year earlier than forecast 12 months ago.[36]

These expectations are reflected in the limited amount of recent investment. Of the 2000 MW of capacity added over the three years to 30 June 2013, over 50 per cent was in wind generation (which the RET scheme partly subsidises). The balance of investment over the past three years was in gas fired plant in Victoria, South Australia and Queensland. The only investment in coal fired generation related to upgrades of the Eraring power station in New South Wales.

36 AEMO, *Electricity statement of opportunities 2013*.

Figure 1.27

Annual investment in registered generation capacity



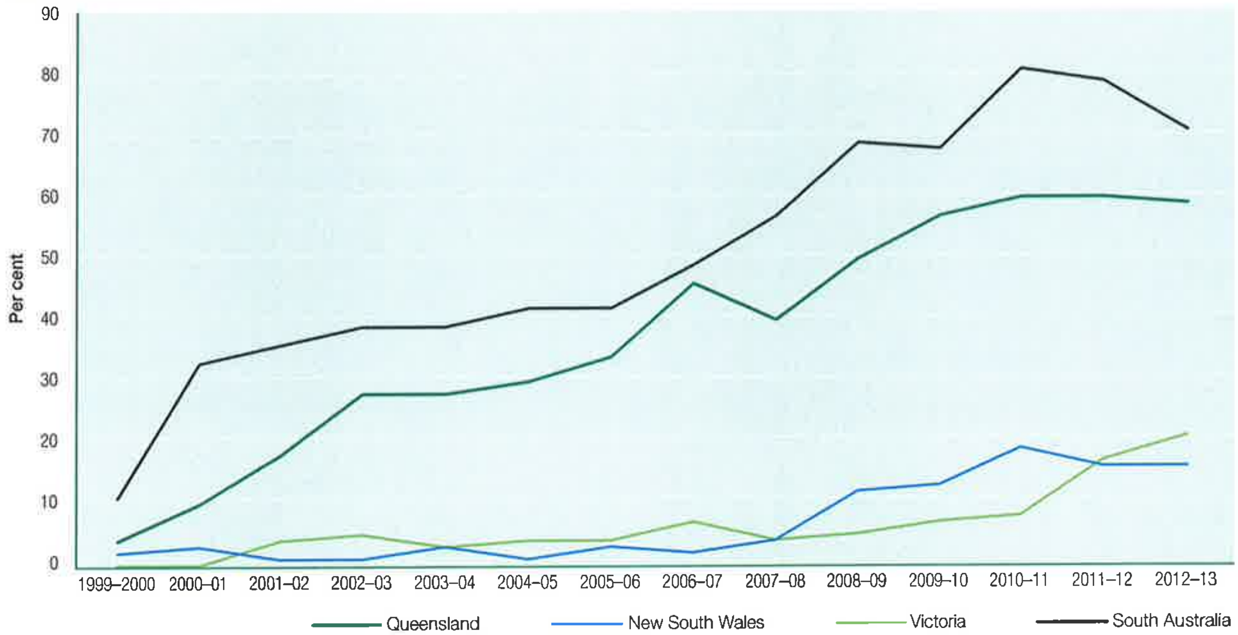
Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.

Note: Data are gross investment estimates that do not account for decommissioned plant.

Sources: AEMO; AER.

Figure 1.28

Net change in generation capacity since market start—cumulative



Source: AER.

Table 1.7 Generation investment, 2012– 13

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED	ESTIMATED COST ($ MILLION)
NEW SOUTH WALES					
Eraring Energy	Eraring (upgrade)	Coal fired	60	March 2013	70
VICTORIA					
AGL Energy/ Meridian Energy	Macarthur	Wind	420	January 2013	900
Goldwind/New En	Morton's Lane	Wind	20	December 2012	50
Qenos	Qenos Cogeneration Facility	CCGT	21	March 2013	45
TASMANIA					
Hydro Tasmania	Musselroe	Wind	168	June 2013	394

Table 1.8 Committed investment in the National Electricity Market, 1 July 2013

DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND				
CS Energy	Kogan Creek Solar Boost	Solar	44	2014
NEW SOUTH WALES				
Goldwind	Gullen Range	Wind	166	2014
Electricity Generating Public Company	Boco Rock	Wind	113	2014
CBD Energy/Banco Santanda	Taralga	Wind	107	2014
VICTORIA				
Meridian Energy Australia	Mount Mercer	Wind	131	2013
SOUTH AUSTRALIA				
Infratil	Snowtown North	Wind	144	2014
Infratil	Snowtown South	Wind	126	2014

CCGT, combined cycle gas turbine.
Sources (tables 1.7 and 1.8): AEMO; AER.

The relatively weak investment outlook has been complemented by significant amounts of plant being decommissioned or periodically taken offline. Muted demand and climate change policies have contributed to around 2300 MW of coal plant being shut down since 2012, with additional plant being periodically taken offline (section 1.3.3).

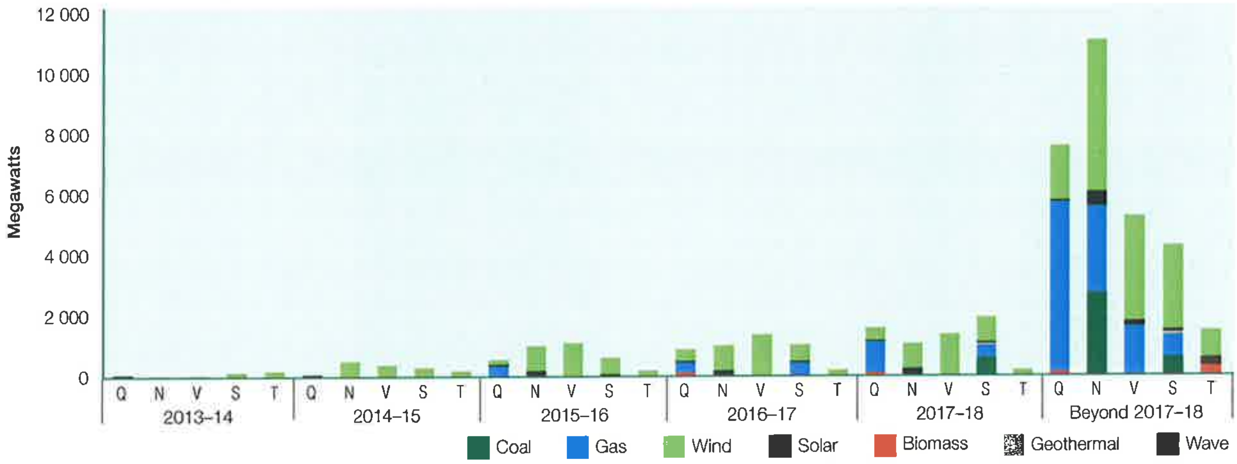
Table 1.7 details generation investment in the NEM since 1 July 2012. The most significant developments were the commissioning of two major wind farms—AGL Energy / Meridian Energy's Macarthur wind farm in Victoria, and Hydro Tasmania's Musselroe wind farm in Tasmania. Macarthur is the largest wind farm in the southern hemisphere

Generation investment (other than in wind) is likely to be limited over the next few years, with only a small number of projects in development. At June 2013 the NEM had around 800 MW of committed capacity[37]—mostly in wind generation, which the RET may make profitable despite depressed wholesale prices (table 1.8). The six committed wind farms are roughly equal in scale and will be developed in New South Wales, Victoria and South Australia.

CS Energy has committed to 45 MW of solar generation at Kogan Creek. The project will provide a solar thermal system to augment the existing coal fired station's steam

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

Figure 1.29
Major proposed generation investment—cumulative, June 2012



Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.
Sources: AEMO; AER.

generation system. It will be Australia's first commercial solar generator to dispatch electricity into the national grid. Additionally, a 1.5 MW solar demonstration plant for Mildura was scheduled to be commissioned in 2013, as the first stage of a proposed 100 MW plant.

While few generation projects are being developed, a large number are 'proposed' and some of these may be developed in the medium to long term. AEMO lists proposed generation projects that are 'advanced' or publicly announced, but excludes them from supply and demand outlooks because they are speculative. At July 2013 it listed almost 30 000 MW of proposed capacity in the NEM (figure 1.29). While 6000 MW of capacity is scheduled to be commissioned before 2018–19, only Queensland is likely to need new capacity by the end of the decade, based on current demand forecasts.[38]

While the bulk of proposed capacity is in wind (47 per cent) and gas powered generation (36 per cent), the proposals also include:

- 740 MW of solar generation capacity in New South Wales, Victoria and South Australia, including projects with committed funding under the Australian Government's Solar Flagships program. In June 2013 AGL's 159 MW solar PV project at Broken Hill and Nyngan (New South Wales) was selected to receive funding under the program.
- 350 MW of generation using wave technology for Tasmania and Victoria
- 550 MW of geothermal generation in South Australia at Innamincka and Paralana.

1.10 Demand side participation

An alternative to generation investment is demand side participation, whereby energy users are incentivised to reduce consumption at times of peak demand. Customer participation in the NEM spot market for demand management is limited, and available mainly to large customers. AEMO in 2013 estimated around 210 MW of capacity would likely be available through demand side participation across the NEM during summer 2013–14 when the spot price is above $1000 per MWh.[39] The bulk of the identified capacity was in Victoria and Queensland.

The AEMC's *Power of choice* review recommended allowing consumers to participate directly or via their agents in the spot market, and to receive payment from the market for reducing their electricity use on days of very high demand. Payments would be based on a consumer's reductions in demand against a predetermined baseline for that customer. The reforms are part of a suite of measures aimed at reducing costly investment in energy networks (section 2.6.1).

38 AEMO, *Electricity statement of opportunities 2013*, p. iii.

39 AEMO, *Forecasting methodology information paper 2013*, p. D-12.

The SCER agreed to the recommendation and directed AEMO to develop the necessary rule change proposals, including a method for determining baseline consumption. The reforms are scheduled to take effect in 2015. The new mechanism will enable energy service companies to compete with retailers in offering financial incentives for customers to reduce demand when spot prices are high.

1.11 Reliability of supply

Reliability refers to the continuity of electricity supply to customers. While power outages can originate from the generation, transmission or distribution sectors, about 95 per cent of reliability issues in the NEM originate in the distribution network sector (section 2.8.1).

The AEMC Reliability Panel sets the reliability standard for the NEM generation sector. The standard is the expected amount of energy at risk of not being delivered to customers because not enough capacity is available. To meet this standard, AEMO determines the necessary spare generation capacity needed for each region (including capacity via transmission interconnectors) to provide a buffer against unexpected demand spikes and generation failure. It aims for the reliability standard to be met in each financial year, for each region and for the NEM as a whole.

The current reliability standard is that no more than 0.002 per cent of customer demand in each NEM region should be unserved by generation capacity per financial year, allowing for demand side response and imports from interconnectors. It does not account for supply interruptions in transmission and distribution networks, which are subject to different standards and regulatory arrangements (sections 2.7.1 and 2.8.1). The standard is equivalent to an annual systemwide outage of seven minutes at peak demand.

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.

1.11.1 Reliability settings

Procedures are in place to ensure the reliability standard is met—for example, AEMO publishes forecasts of electricity demand and generator availability to allow generators to respond to market conditions and schedule maintenance outages. The AEMC Reliability Panel also recommends settings to ensure the standard is met, including:

- a spot market price cap, which is set at a sufficiently high level to stimulate the required investment in generation capacity to meet the standard. The cap was raised from $12 900 per MWh to $13 100 per MWh on 1 July 2013.
- a cumulative price threshold to limit the exposure of participants to extreme prices. If cumulative spot prices exceed this threshold over a rolling seven days, then AEMO imposes an administered price cap. The threshold was raised to $197 100 per MWh on 1 July 2013; the administered cap is $300 per MWh.
- a market floor price, set at –$1000 per MWh.

The market price cap and cumulative price threshold are adjusted each year in line with movements in the consumer price index. Additionally, the reliability panel conducts a full review of the reliability standard and settings every four years.

Further, safety net mechanisms allow AEMO to manage a short term risk of unserved energy:

- 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 must prioritise facilities that would least distort wholesale market prices. It does not expect to invoke the RERT mechanism in the two years to 30 June 2015,[40] and the mechanism is due to expire in 2016.
- AEMO can use its directions power to require generators to provide additional supply at the time of dispatch to ensure sufficient reserves are available.

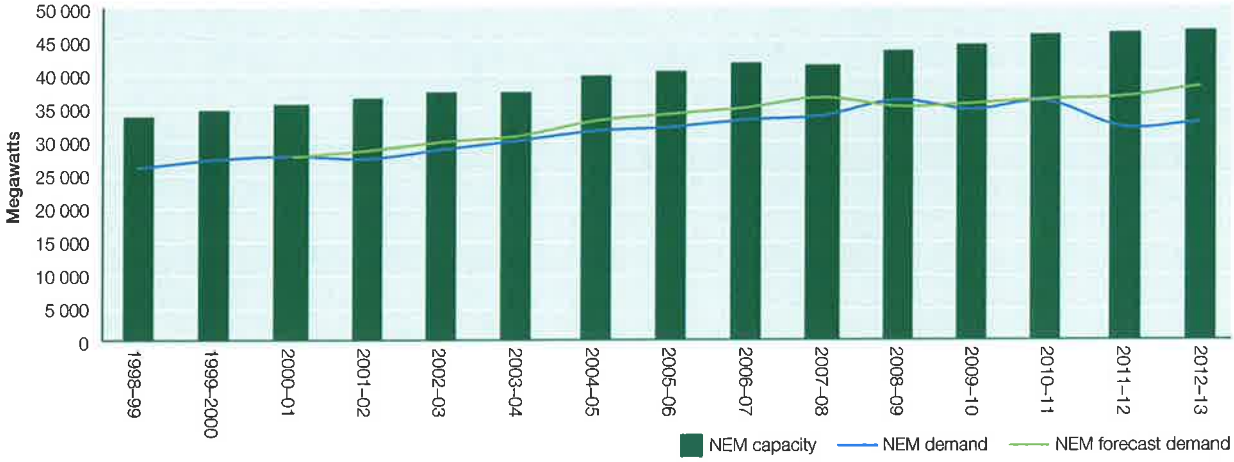
1.11.2 Historical adequacy of generation

Figure 1.30 compares total generation capacity with national peak demand since the NEM began. It shows actual demand and AEMO's demand forecasts two years in advance. The data indicate investment in the NEM consistently kept pace with demand, allowing reserve margins of capacity to maintain reliability. Peak demand flattened out after 2007–08, with recent outcomes being significantly below forecast. Accordingly, reserve margins

40 AEMO, *Power system adequacy 2013*, p. iii.

Figure 1.30

Peak demand and generation capacity



Notes:

Demand forecasts are two years in advance, based on a 50 per cent probability that the forecast will be exceeded and an average diversity factor.

NEM capacity excludes wind generation and power stations not managed through central dispatch.

Source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, various years.

have risen, indicating significant amounts of surplus generation capacity. This factor has contributed to the shutdown or mothballing of over 2300 MW of generation plant since 2012 (section 1.3.3).

1.12 Barometers of competition in the NEM

There is no universally accepted approach to measuring competitiveness in electricity markets. The AER monitors a number of structural and behavioural indicators for each NEM region, adopting the following assumptions:

- **Trading rights owner**—The entity that controls a generator's offers may be distinct from the entity that owns and/or operates the plant, due to power purchasing agreements and joint ownership. The AER's analysis focuses on the participant with offer control. Table 1.4 provides information on the entities with trading rights over generation plant in the NEM.
- **Generation units**—The analysis is limited to scheduled and semi-scheduled generation units. Wind generation capacity is scaled by contribution factors determined by AEMO.
- **Tasmania**—The analysis excludes Tasmania, given its highly concentrated ownership.
- **Interconnectors**—The analysis accounts for imports into a region via network interconnectors, by including flows when the price differential between the importing and exporting regions is at least $10 per MWh. Any negative flows are assumed to be zero, because interconnectors do not provide a competitive constraint when a region is exporting. Figure 2.1 illustrates the geography of interconnectors in the NEM.

1.12.1 Types of structural indicator

The market structure of the generation sector affects the likelihood of and incentives for generators to exercise market power. A structure with few 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 considered include:

- market shares
- the Herfindahl-Hirschman Index
- the residual supply index.

Market shares provides information on the extent of concentration as well as the relative size of each generator. Markets with a high proportion of capacity controlled by a small number of generators are usually more susceptible to the exercise of market power.

Figure 1.31 illustrates generation market shares in January 2013, based on capacity under each firm's trading control. The chart indicates the relatively strong market positions held by AGL Energy in South Australia, Macquarie Generation in New South Wales, and the state-owned generators CS Energy and Stanwell in Queensland.

Interconnectors provide a competitive constraint for generators in New South Wales, Victoria and South Australia; the constraint is less effective for Queensland, which recently experienced significant counter-price trade flows at times of high prices (section 1.7.3).

The *Herfindahl–Hirschman Index* (HHI) is a structural indicator that accounts for the relative size of firms. It is defined as the sum of squared market shares (expressed as percentages) of all firms in the market. The HHI can range from zero (for a market with a large number of negligible firms) to 10 000 (that is, 100 squared) for a monopoly. By squaring market shares, the HHI enhances the contribution of large firms. The higher the HHI is, the more concentrated and less competitive is the market.

Figure 1.32 illustrates the HHI across NEM regions from 2008–09 to 2012–13. In Queensland, the index rose in 2011–12 from being the lowest in the NEM to the highest, following a consolidation of the state owned generation sector.

A deficiency of market share and HHI analysis is a failure to account for variations in demand over time. This failure is significant because high demand is generally necessary for market power to be profitably exercised. The *residual supply index* (RSI) and pivotality analysis measure the extent to which one or more generators are 'pivotal' to the clearing of a market. A generator is said to be pivotal if market demand exceeds the capacity controlled by all other generators; that is, some capacity controlled by the generator is *required* for the market to clear. It is possible for multiple generators to be pivotal simultaneously.

Table 1.9 shows the percentage of trading intervals in 2012–13 when the largest generator was pivotal. In all regions it was necessary to dispatch the largest generator for a significant portion of the time.

Table 1.9 Percentage of time when the largest generator is pivotal, 2012–13

QLD	NSW	VIC	SA
17	18	20	29

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 one, demand can be fully met without requiring the dispatch of the largest generator. But with an RSI-1 of below one, the largest generator becomes pivotal. In general, a lower RSI-1 indicates a less competitive market; a lower value may result, for example, from an increase in demand, a decrease in available generation capacity, or an increase in the proportion of available capacity that is supplied by the largest generator.

Figure 1.33 illustrates the RSI-1 in each NEM region since 2008–09; the data are for times of peak demand (based on the highest 2 per cent of demand trading intervals, equivalent to seven days per year). The largest generator must usually be dispatched during peak periods across all NEM regions. Only in Queensland during 2010–11 was the largest generator not usually required.

The chart also illustrates average demand during peak periods. If demand increases, then RSI-1 is likely to deteriorate (the largest firm is more likely to be pivotal). The converse is also true, as illustrated by lower peak demand in New South Wales in 2011–12 being reflected in an improved RSI-1.

1.12.2 Regional analysis of structural indicators

Queensland

The two largest generators in Queensland, CS Energy and Stanwell, held a combined market share of 65 per cent in 2012–13. The indicators suggest an improvement in competitive conditions in the Queensland market between 2008–09 and 2010–11, when private investment in new capacity drove down the market share of the state owned generators. But this trend was reversed in 2011–12 with a restructure of state owned generation assets. The restructure led to Queensland's HHI moving from being the lowest to the highest for any region. The RSI-1 indicator also reflects this change.

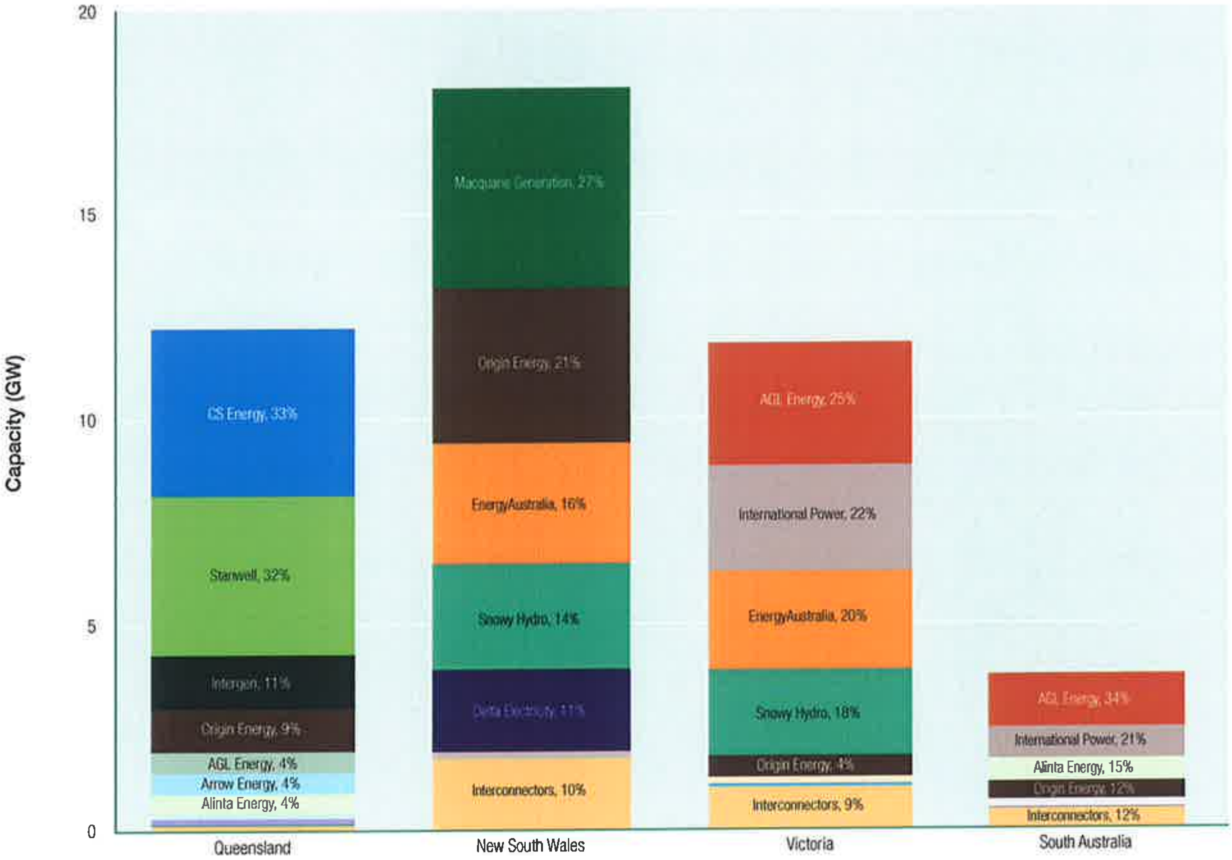
New South Wales

New South Wales has five large players in the generation market: three government-owned firms in Macquarie Generation (27 per cent of capacity), Snowy Hydro[41] (14 per cent) and Delta Electricity (11 per cent) as well as Origin Energy (21 per cent) and EnergyAustralia (16 per cent). The metrics suggest an improvement in competitive

41 Snowy Hydro is jointly owned by the Commonwealth, New South Wales and Victorian governments.

Figure 1.31

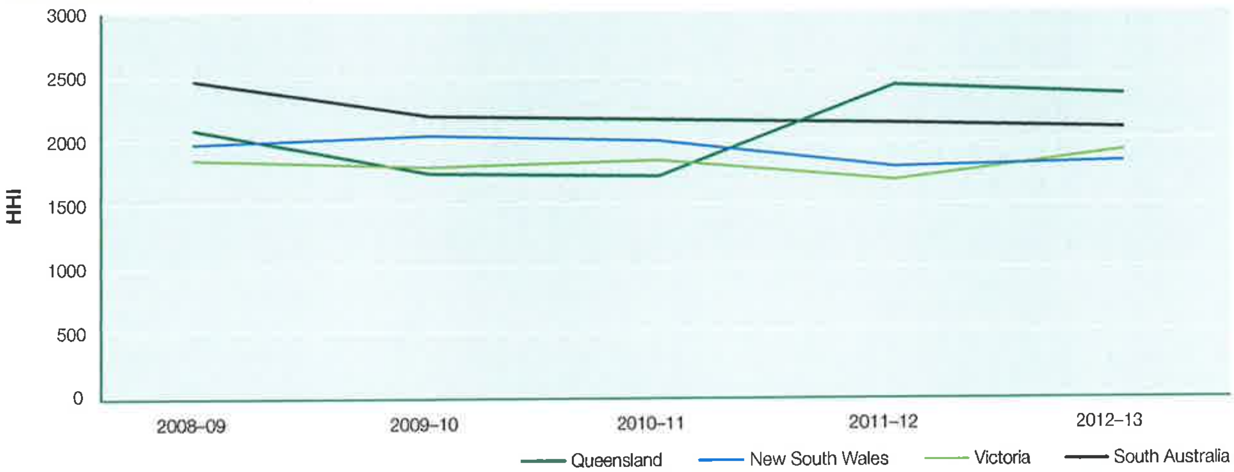
Market share in generation at January 2013



Source: AER.

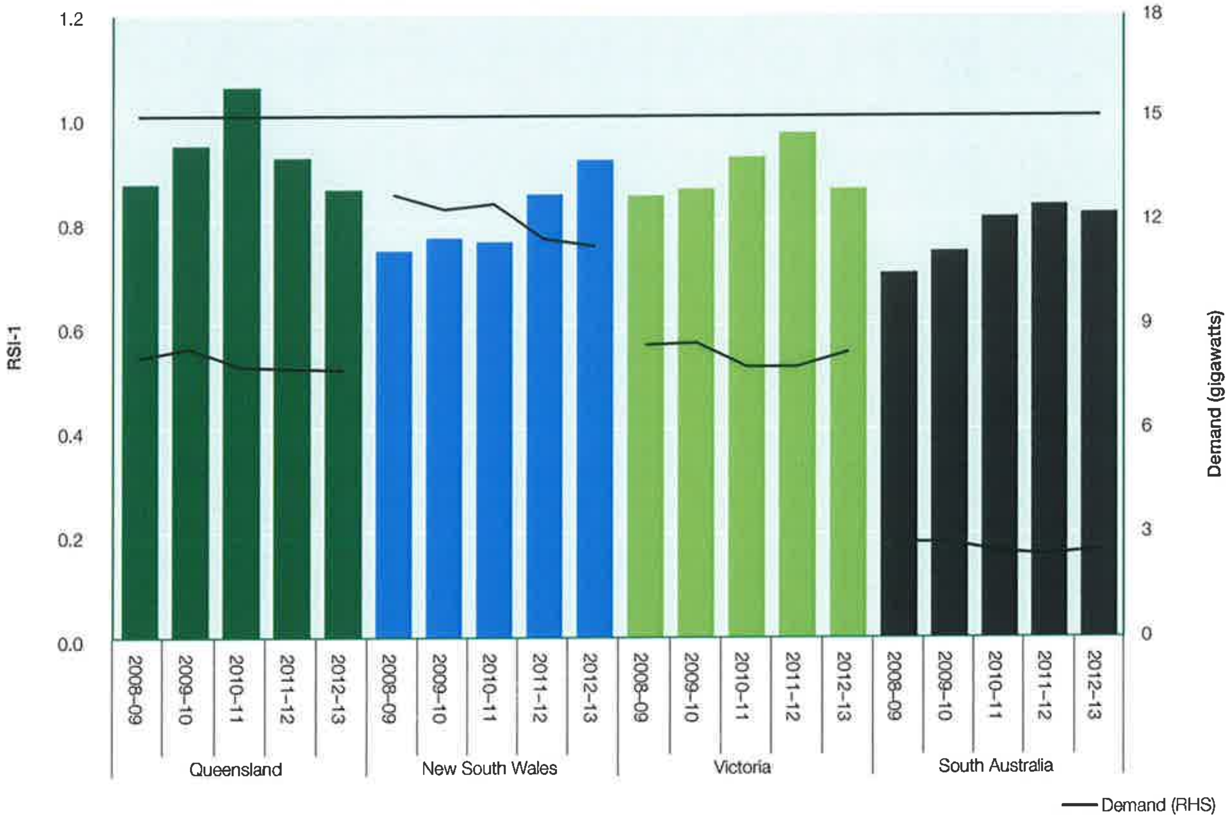
Figure 1.32

Herfindahl–Hirschman Index



Source: AER.

Figure 1.33
One-firm residual supply index (RSI-1) at times of peak demand



Source: AER.

conditions in New South Wales, following the government's sale of generation trading rights in 2010–11 to private entities.[42] Weakening demand also reduced the pivotality of the largest generator in meeting peak demand, as reflected in the RSI-1.

Victoria

Victoria has four large players in the generation market: three privately owned firms in AGL Energy (25 per cent), International Power (22 per cent) and EnergyAustralia (20 per cent), as well as the government owned Snowy Hydro (18 per cent). It benefits from a high degree of interconnection with other regions.

The metrics indicate a gradual improvement in competition for Victoria until AGL Energy's full acquisition of Loy Yang A (2210 MW) in June 2012 increased market concentration. This shift was partly offset by Origin Energy's commissioning of the gas powered Mortlake plant (566 MW) in late 2012.

South Australia

In South Australia, AGL Energy is the largest generator, with 34 per cent of capacity. Other significant firms are International Power (21 per cent), Alinta (15 per cent) and Origin Energy (12 per cent).

Recent investment in wind generation appears to have improved the competitive landscape in the region. But since 2012, the extent of intermittent generation has influenced decisions by thermal generators such as Alinta to withdraw capacity from the market. This removal of capacity likely contributed to a recent increase in the pivotality of AGL Energy in meeting demand during peak periods, as reflected in the RSI-1.

42 In September 2012, the New South Wales Government announced a scoping study was underway on the proposed privatisation of its remaining state owned generation assets. Decisions around the allocation of these assets will affect the competitive outlook for the region.

1.12.3 Behavioural indicators

The structural indicators indicate significant levels of market concentration in some NEM regions. But a generator's ability to exercise market power is distinct from its incentive to exercise that power. In part, the incentives link to a generator's exposure to the spot price. The greater its exposure, the greater is its incentive to exercise market power. Behavioural indicators explore the relationship between a generator's bidding and spot price outcomes.

Table 1.10 reports the average volume of capacity *not* dispatched by certain generators when the spot price exceeds $300 per MWh—a price that would cover the marginal cost of most plant in the NEM, including peaking plant.[43] In a competitive market, generators would typically make greater use of their assets portfolio as prices rise. The data suggest significant amounts of capacity were not dispatched by each generator during the high price periods.

Table 1.10 Average capacity not dispatched when spot price exceeds $300 per MWh

GENERATOR	CAPACITY NOT DISPATCHED (MWH)	
	July 2008–December 2010	January 2011–June 2013
CS Energy (Qld)	543	826
Macquarie Generation (NSW)	243	41
International Power (Vic)	260	177
AGL Energy (SA)	328	250

Note: CS Energy's assets changed significantly in 2011 when the Queensland Government restructured its generation portfolio.
Source: AER.

Figures 1.34–1.37 further illustrate the relationship between capacity utilisation and spot prices. The charts record the average percentage of available capacity that is dispatched when prices settle in each price band for a sample of large generators: CS Energy in Queensland, Macquarie Generation in New South Wales, International Power in Victoria and AGL Energy in South Australia.

As would be expected, the charts illustrate that generators tend to increase their output as prices rise to around $100 per MWh. However, there is a tendency in some years for output by some large generators to decline as prices enter higher price bands.

One possible explanation for this behaviour is deliberate capacity withholding to influence spot prices. Other possible explanations include that some generation plant cannot respond quickly to sudden price movements. Alternatively, transmission congestion at times of high prices can result in some plant being constrained to low levels of utilisation. Given the data relate to maximum plant availability on the relevant day, there is also a possibility of technical plant issues reducing output during some high price periods to below daily maximum availability.

43 The data compare output in each trading interval with the relevant plant's maximum availability on that day.

Figure 1.34

Average annual capacity utilisation, CS Energy (Queensland)

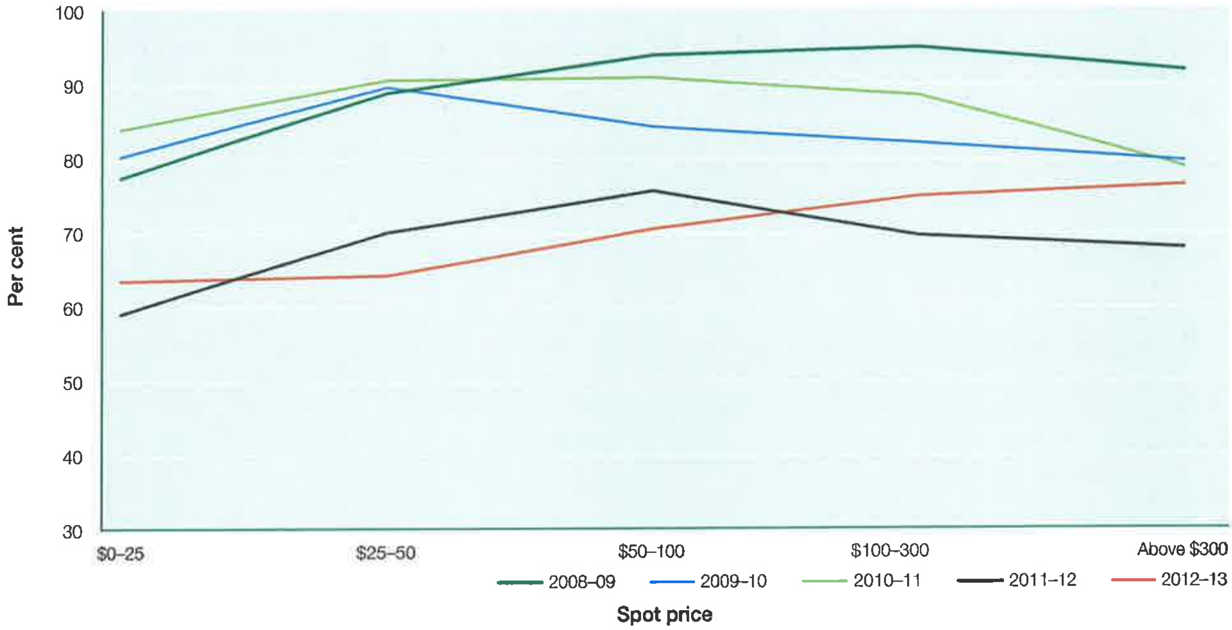


Figure 1.35

Average annual capacity utilisation, Macquarie Generation (New South Wales)

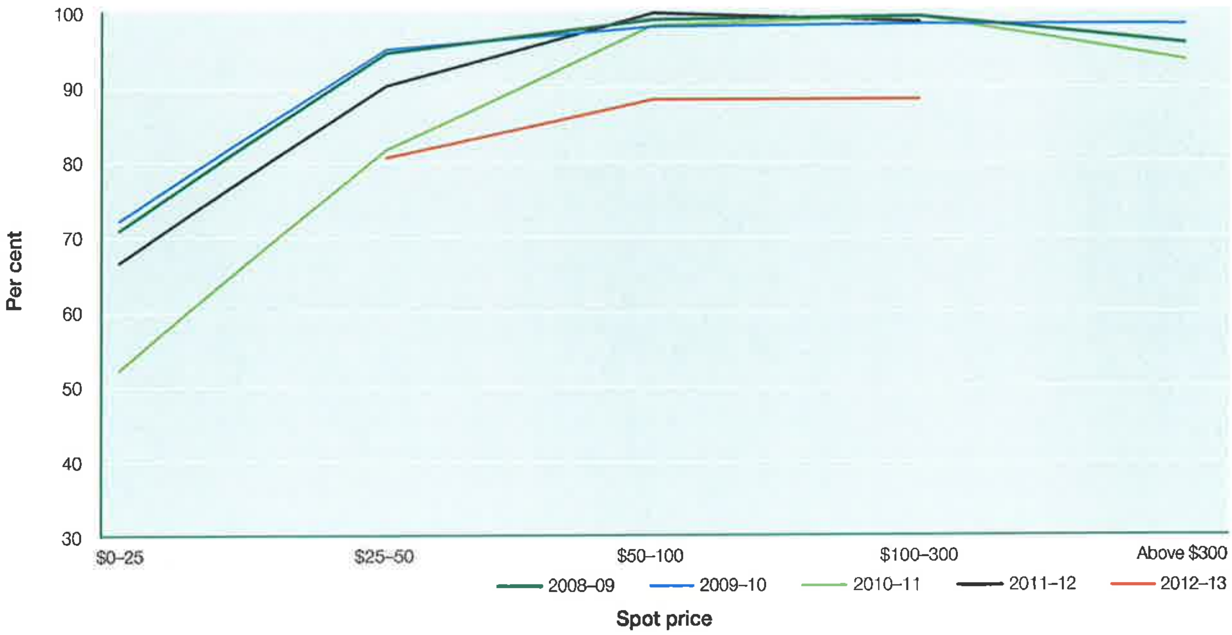


Figure 1.36

Average annual capacity utilisation, International Power (Victoria)

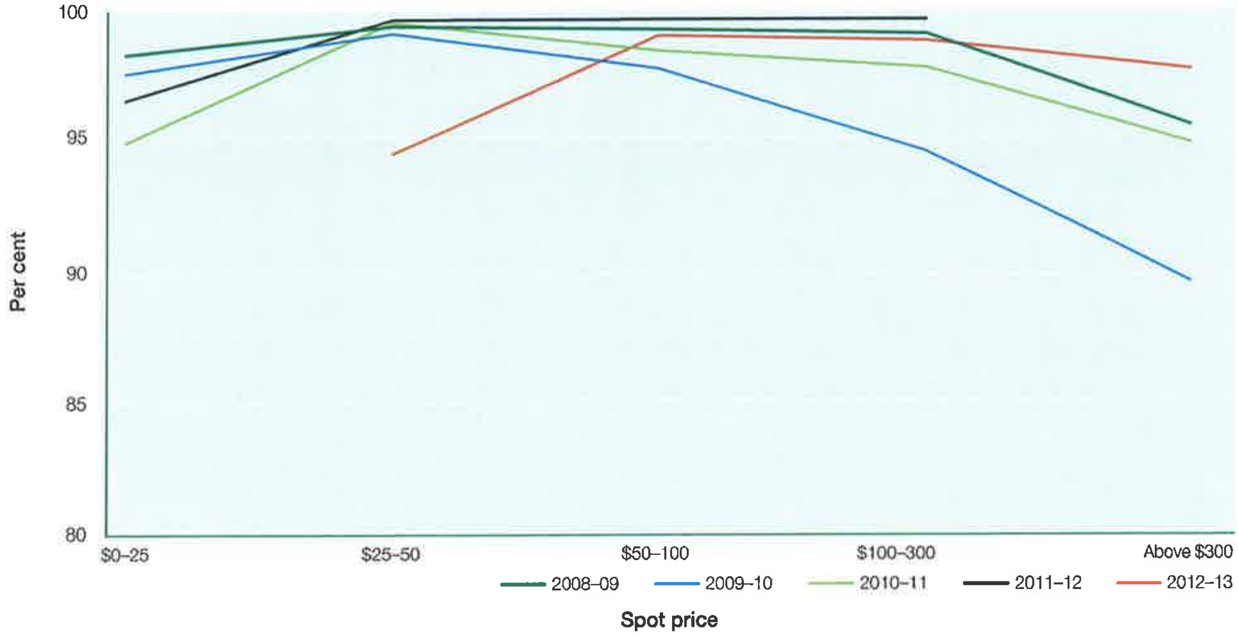
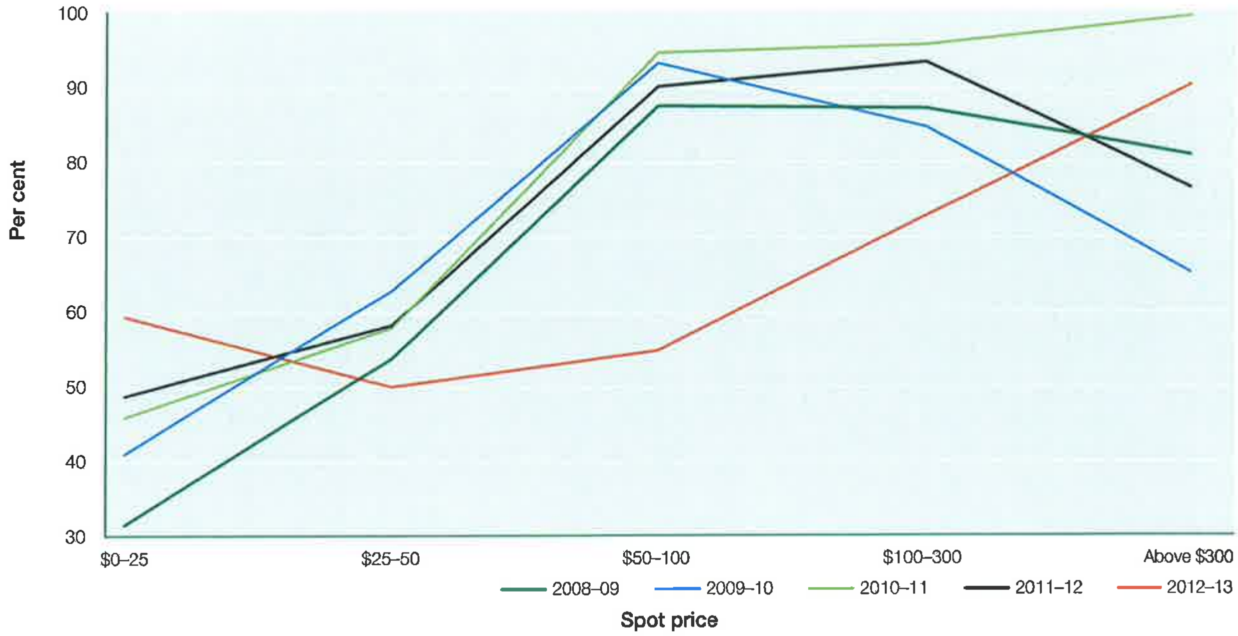
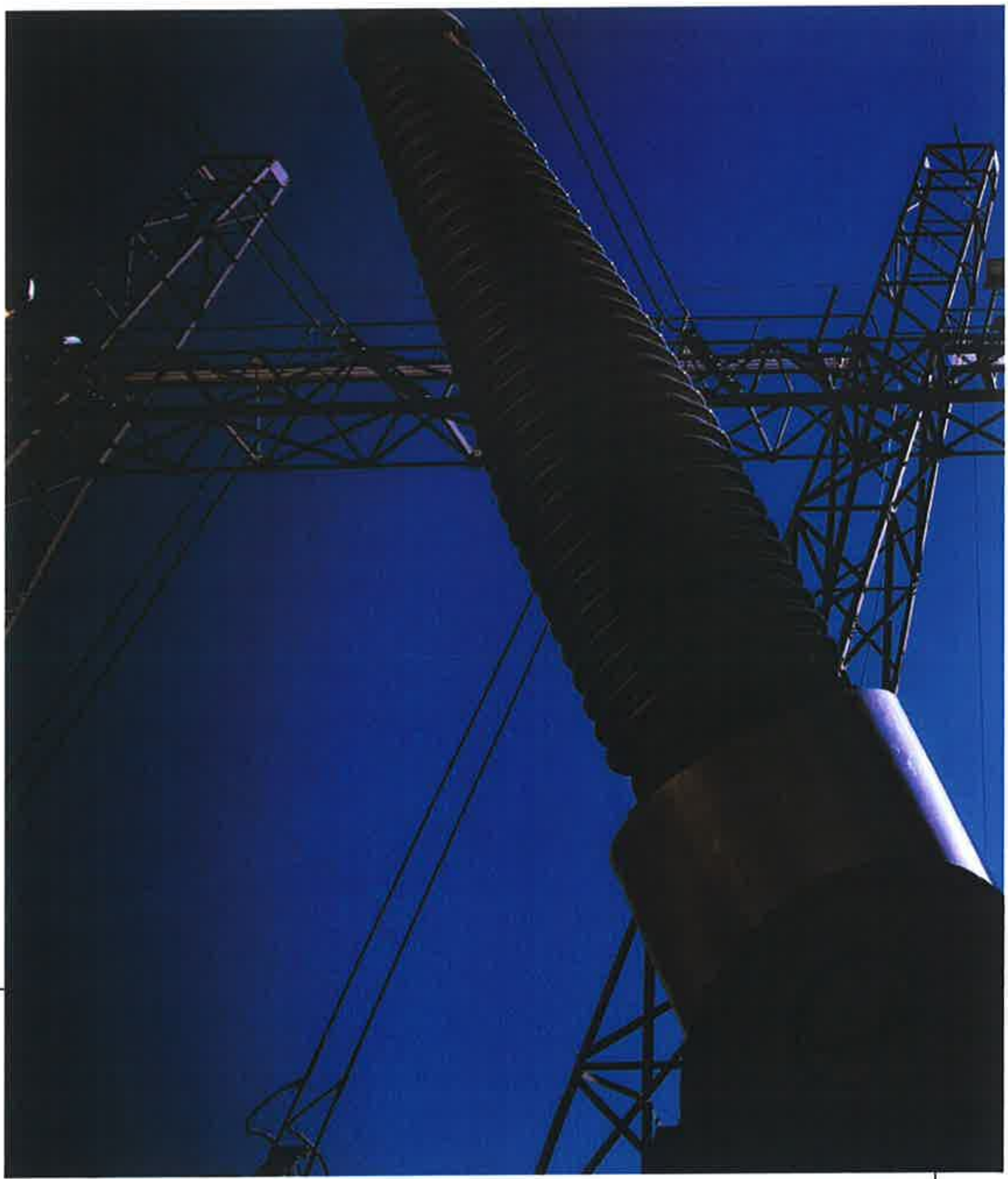


Figure 1.37

Average annual capacity utilisation, AGL Energy (South Australia)



Note (figures 1.34–1.37): Data excluded if based on fewer than five observations.
Source (figures 1.34–1.37): AER.


SP AusNet

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 provide electricity to customers.

2.1 Electricity networks in the NEM

The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected transmission network from Queensland through to New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania. The NEM transmission 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 cross-border interconnectors linking the grid (table 2.1).

The NEM has 13 major electricity distribution networks (table 2.2). Queensland, New South Wales and Victoria each have multiple networks that are monopoly providers within 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 760 000 kilometres—17 times longer than transmission infrastructure. Figure 2.1 illustrates the transmission and distribution 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, New South Wales and Tasmanian networks are all government owned. The ACT distribution network has joint government and private ownership.

All transmission networks in Victoria and South Australia, and three interconnectors (Directlink, Murraylink and Basslink) are privately owned. Victoria's five distribution networks are also privately owned, while 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, formerly ETSA Utilities). The remaining 49 per cent of the two Victorian networks is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure 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 SP AusNet, which owns Victoria's transmission network and the SP AusNet distribution network. Singapore Power International contracted to sell a 60 per cent stake in Jemena, and a 20 per cent share in SP AusNet, to State Grid Corporation of China in 2013. The transaction was before the Foreign Investment Review Board in November 2013.
- *State Grid Corporation of China* entered the Australian market in 2012, purchasing a 41 per cent stake in the South Australian transmission network. It raised its stake to 46 per cent in 2013. In 2013 it contracted to acquire stakes in electricity distribution assets from Singapore Power International.

These businesses also own or have equity in the gas pipeline sector (chapter 4).

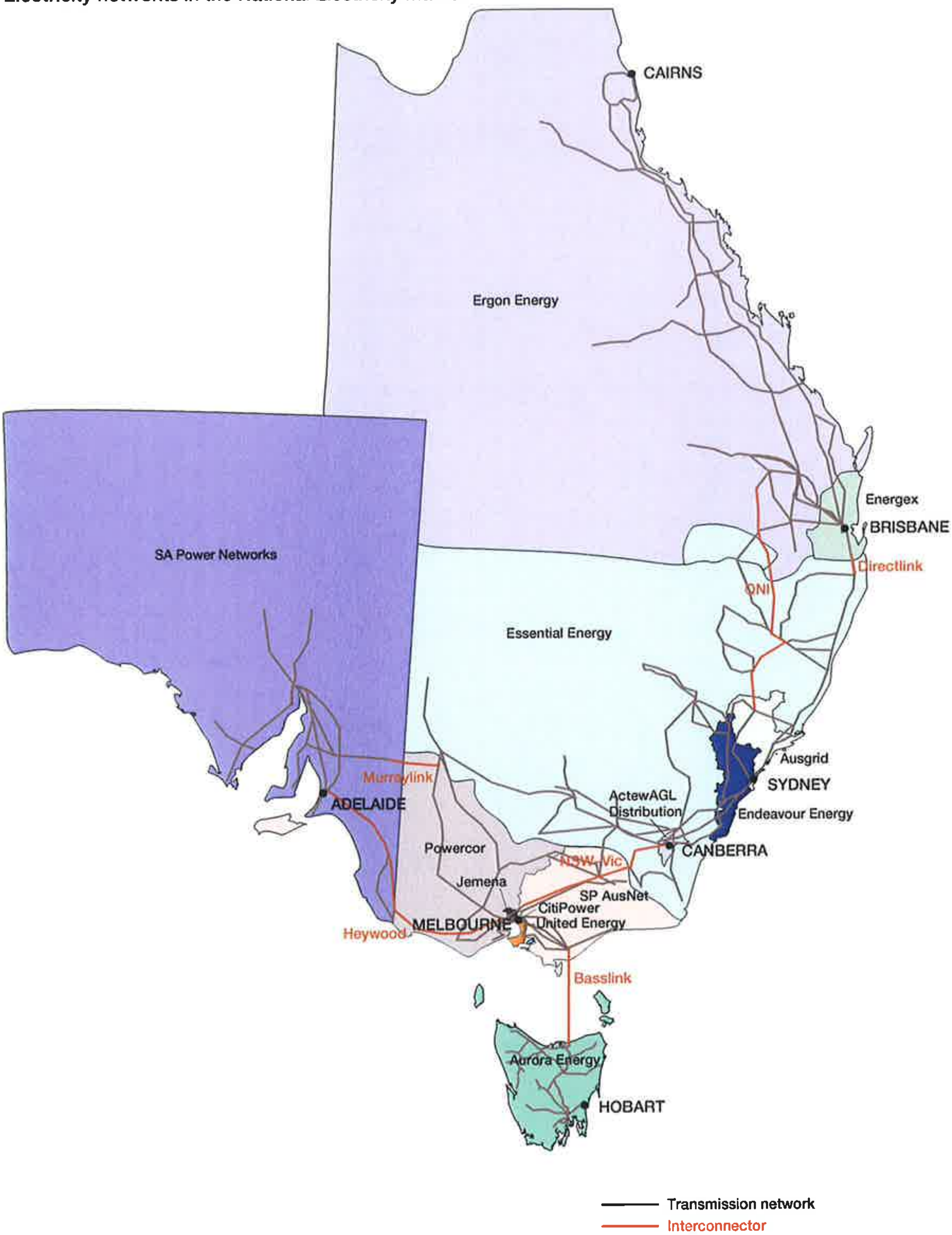
Victoria has a unique transmission network structure that separates asset ownership from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Australian Energy Market Operator (AEMO) plans and directs network augmentation. AEMO also buys bulk network services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

In some jurisdictions, ownership links exist between electricity networks and other segments of the electricity sector:

- In the ACT,[1] common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation.
- Tasmania also has common ownership in electricity distribution and retailing, with an attempt to privatise Aurora Energy's retail arm being abandoned in 2013. It aims to merge its transmission (Transend) and distribution (Aurora Energy) networks by 1 July 2014 to enhance operating efficiency.
- Queensland privatised much of its energy retail sector in 2006–07, but the state owned Ergon Energy continues to provide both distribution and retail services.

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
Electricity networks in the National Electricity Market



QNI, Queensland–New South Wales Interconnector.

Table 2.1 Electricity transmission networks

NETWORK	LOCATION	LINE LENGTH (KM)	ELECTRICITY TRANSMITTED (GWH), 2010–11	MAXIMUM DEMAND (MW), 2010–11	REVENUE—CURRENT PERIOD ($ MILLION)[1]	ASSET BASE ($ MILLION)[2]	INVESTMENT—CURRENT PERIOD ($ MILLION)[1]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS									
Powerlink	Qld	13 986	47 341	8 109	4 325	6 335	2 485	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	13 957	70 828	13 760	4 000	4 540	2 650	1 July 2009–30 June 2014	New South Wales Government
SP AusNet	Vic	6553	52 352	9 982	3 005	2 395	840	1 Apr 2008–30 Mar 2014	Listed company (Singapore Power International 31%, State Grid Corporation 20%)[5]
ElectraNet	SA	5 591	13 045	3 570	1 430	2 020	685	1 July 2013–30 June 2018	State Grid Corporation 46.5%, YTL Power Investments 33.5%, Hastings Utilities Trust 20%
Transend	Tas	3 688	11 185	1 377	1 045	1 020	655	1 July 2009–30 June 2014	Tasmanian Government
NEM TOTALS		**43 775**	**194 751**		**13 805**	**16 310**	**7 315**		
INTERCONNECTORS[3]									
Directlink (Terranora)	Qld–NSW	63		180		140		1 July 2005–30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220	65	105	5	1 July 2013–30 June 2018	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375				920[4]		Unregulated	Publicly listed CitySpring Infrastructure Trust (Temasek 37%)

GWh, gigawatt hours; MW, megawatts.

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2012 dollars. The data are adjusted for the impact of merits review decisions by the Australian Competition Tribunal.
2. The regulated asset bases are as set at the beginning of the current regulatory period for each network, converted to June 2012 dollars.
3. Not all interconnectors are listed. The unlisted interconnectors, which form part of state based networks, are Heywood (Victoria–South Australia), QNI (Queensland–New South Wales) and New South Wales–Victoria.
4. Basslink is not regulated, so has no regulated asset base. The listed asset value is the estimated construction cost in 2012 dollars.
5. Singapore Power International contracted to sell a 20 per cent stake in SP AusNet to State Grid Corporation of China in 2013. The transaction was before the Foreign Investment Review Board in November 2013.

Sources: AER regulatory determinations and performance reports.

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW), 2011–12	REVENUE—CURRENT PERIOD ($ MILLION)[1]	ASSET BASE ($ MILLION)[2]	INVESTMENT—CURRENT PERIOD ($ MILLION)[1,3]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND								
Energex	1 333 670	51 432	4 464	7 065	8 220	6 040	1 July 2010–30 June 2015	Queensland Government
Ergon Energy	694 880	163 215	2 417	6 590	7 470	5 340	1 July 2010–30 June 2015	Queensland Government
NEW SOUTH WALES AND ACT								
AusGrid[4]	1 637 000	41 578	5 149	9 590	9 075	8 960	1 July 2009–30 June 2014	New South Wales Government
Endeavour Energy	883 663	34 569	3 236	4 830	3 970	3 190	1 July 2009–30 June 2014	New South Wales Government
Essential Energy	803 496	190 777	2 185	6 110	4 651	4 470	1 July 2009–30 June 2014	New South Wales Government
ActewAGL	173 186	4 992	674	800	645	330	1 July 2009–30 June 2014	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%[5]
VICTORIA								
Powercor	734 523	85 310	2 161	2 500	2 285	1 620	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
SP AusNet	649 634	49 287	1 577	2 405	2 170	1 528	1 Jan 2011–31 Dec 2015	Listed company (Singapore Power International 31%, State Grid Corporation 20%)[5]
United Energy	644 511	12 924	1 700	1 640	1 425	915	1 Jan 2011–31 Dec 2015	DUET Group 66%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 34%[5]
CitiPower	315 689	4 274	1 323	1 175	1 330	860	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
Jemena	317 050	6 104	848	1 005	780	490	1 Jan 2011–31 Dec 2015	Jemena (State Grid Corporation 60%, Singapore Power International 40%)[5]
SOUTH AUSTRALIA								
SA Power Networks	832 072	87 648	2 715	3 715	2 895	2 250	1 July 2010–30 June 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
TASMANIA								
Aurora Energy	275 956	25 857	1 022	1 310	1 425	560	1 July 2012–30 June 2017	Tasmanian Government
NEM TOTALS	9 295 329	757 966		48 735	46 341	36 554		

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2012 dollars. The data are adjusted for the impact of merits review decisions by the Australian Competition Tribunal.
2. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2012 dollars.
3. Investment data include capital contributions, which can be significant—for example, 10–20 per cent of investment in Victoria and over 20 per cent in South Australia—but do not form part of the regulated asset base for the network.
4. AusGrid's distribution network includes 962 kilometres of transmission assets that are treated as distribution assets for economic regulation and performance assessment.
5. Singapore Power International contracted to sell a 60 per cent stake in Jemena, and a 20 per cent stake in SP AusNet, to State Grid Corporation of China in 2013. The transaction was before the Foreign Investment Review Board in November 2013.

Sources: AER and OTTER (Tasmania) regulatory determinations and performance reports.

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 opening RAB of distribution networks in the NEM is around $46 billion—almost three times the valuation for transmission infrastructure (around $16 billion).

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining average costs as output increases. 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 and encourage efficient investment in infrastructure. The Australian Energy Regulator (AER) sets the prices for using electricity networks in the NEM. The Economic Regulation Authority regulates networks in Western Australia, and the Utilities Commission regulates networks in the Northern Territory.

2.2.1 Regulatory process and approach

The National Electricity Law lays the foundation for the regulatory framework governing electricity networks. In particular, it sets out the National Electricity Objective: to promote efficient investment in, and operation of, electricity services for the long term interest of consumers. It also sets out revenue and pricing principles, including that network businesses should have a reasonable opportunity to recover at least efficient costs.

Regulated electricity network businesses must 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 out the framework that the AER must apply 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 the revenue components of the Queensland transmission network (2012–17) and Victorian distribution networks (2011–15).

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) affect the return on capital. An allowance for operating expenditure typically accounts for a further 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. The range of control mechanisms is wider in distribution; the AER may set a ceiling on the revenue or prices that a distribution business can earn or charge during a period. The available mechanisms for distribution include:

- weighted average price caps, allowing flexibility in individual tariffs within an overall ceiling—used for the New South Wales, Victorian and South Australian networks
- average or maximum revenue caps, setting a ceiling on revenue that may be recovered during a regulatory period—used for the Queensland, ACT and Tasmanian networks.

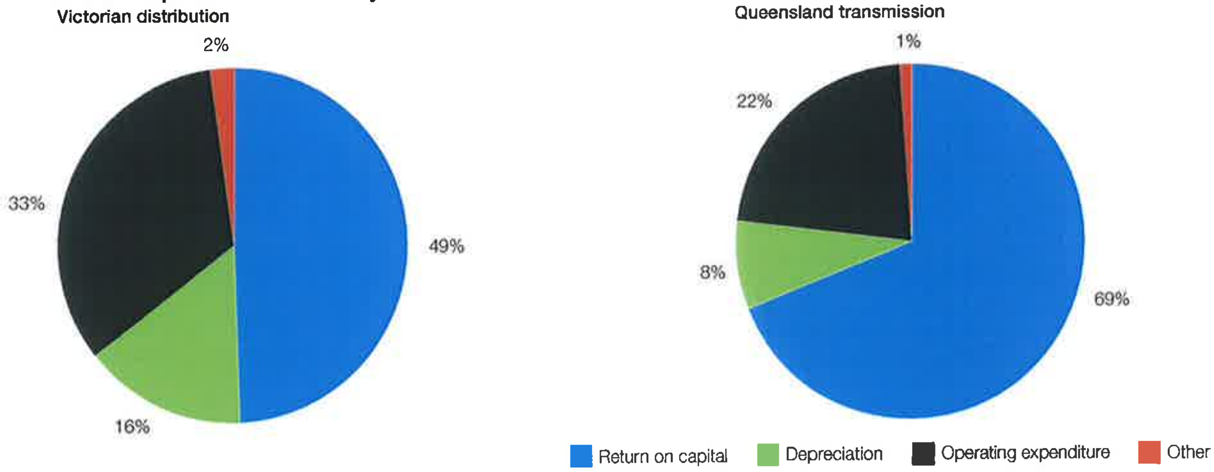
The regulatory process for network businesses was revised under a rule change in November 2012. It begins with preliminary consultation on the framework and approach for the determination, around two years before the current regulatory period expires. The network business then submits a regulatory proposal to the AER, which assesses the proposal in consultation with stakeholders (section 2.2.2). The AER must publish a final decision on a proposal at least two months before the regulatory period starts.

2.2.2 Refining the regulatory process and approach

In 2011 the AER proposed changes to the energy rules to ensure customers pay no more than necessary for an economically efficient and reliable supply of energy. Following detailed public consultation, the Australian Energy Market Commission (AEMC) in November 2012 announced significant reforms to the rules for setting energy network prices. The reforms aim to better meet the long term interests of consumers, while providing investment certainty in a dynamic market environment. They do so by:

Figure 2.2

Indicative composition of electricity network revenues



Source: AER.

- creating a common approach to setting the cost of capital across electricity and gas network businesses, based on the rate of return for a benchmark efficient service provider
- providing new tools to (a) incentivise electricity network businesses to invest efficiently, (b) safeguard consumers from paying for inefficient expenditure, and (c) ensure efficiency benefits are shared between consumers and service providers
- strengthening stakeholder involvement in the regulatory review of electricity networks.

In December 2012 the AER launched the Better Regulation program to apply the reforms, the scope of which is outlined in table 2.3. It published guidelines during 2013 on its approach to implementation. The new guidelines and related schemes will apply first to regulatory determinations taking effect in 2015 for electricity transmission networks in New South Wales and Tasmania, and for electricity distribution networks in New South Wales, Queensland, South Australia and the ACT.

The Better Regulation program also covers wider refinements to the AER's regulatory approach, including:

- the application of a new regulatory investment test for distribution networks (RIT-D, section 2.4.1)
- reforms arising from the AEMC's *Power of choice* review (section 2.6.1)
- the development of benchmarking techniques and tools in regulatory decisions
- more consistent information requirements on energy business, to improve the quality of data for regulatory reviews and annual performance reporting, and to support the use of benchmarking.

The Productivity Commission in 2013 also reviewed the use of benchmarking in network regulation. It found benchmarking is not yet capable of replacing the current framework for setting network revenues, but could be used to test network business proposals.[2]

2.2.3 Regulatory timelines and recent AER activity

Figure 2.3 shows the regulatory timelines for electricity networks in each jurisdiction. In 2013 the AER:

- published final determinations for ElectraNet (South Australian transmission) and Murraylink (the transmission interconnector between Victoria and South Australia), covering the regulatory period commencing 1 July 2013
- released a draft determination in August 2013 for SP AusNet (Victorian transmission), covering the regulatory period commencing 1 April 2014

2 Productivity Commission, *Electricity networks regulatory framework, inquiry report*, April 2013.

Table 2.3 **Changes to the regulatory process under Better Regulation**

REFORM	WHAT HAS CHANGED?	PURPOSE	AER ACTIVITY
Greater stakeholder involvement in regulatory reviews	Creation of a Consumer Challenge Panel to assess whether: • regulatory proposals are in the long term interests of consumers • network businesses are engaging effectively with customers The review process has been extended by four months and the AER and network businesses must provide more information to stakeholders at an early stage The AER may consider how a business has engaged with its consumers when setting expenditure allowances Clearer guidelines on types of information submitted by network businesses that may be treated as confidential	Strengthen accountability that regulatory reviews meet the national electricity objective to promote the long term interests of consumers Address concerns that confidentiality provisions have allowed network businesses to strategically withhold or limit scrutiny of key information	Consumer Challenge Panel established 1 July 2013 Consumer engagement guideline published October 2013 Confidentiality guideline published November 2013
Stronger powers for the AER to assess and amend network spending proposals	The AER can apply new tools and techniques to better forecast how much network businesses need to spend It is no longer limited to a narrow assessment of a network business's proposal The new tools include benchmarking and trend techniques to test expenditure proposals and compare the relative performance of each business	Under the old rules the AER was required to assess expenditure forecasts on the basis of the business's proposal, usually requiring a detailed bottom-up assessment. The AER was limited to amending forecasts only to the extent necessary for compliance with the rules; this created an upward bias in revenue allowances	Expenditure assessment guideline published November 2013
New approach to setting rates of return for network businesses	A common approach now applies for setting the cost of capital across all electricity and gas network businesses, based on the costs for a benchmark efficient service provider The AER's assessment can account for a wider range of information than previously, and allows for decisions that better reflect conditions in capital markets The AER must undertake a full public review of its approach at least every three years	The old rules provided separate rate of return frameworks for electricity distribution, electricity transmission, and gas pipelines The AER was locked into a parameter-by-parameter assessment of the rate of return, with limited scope to consider the appropriateness of the overall allowance	Rate of return guideline scheduled for publication December 2013

REFORM	WHAT HAS CHANGED?	PURPOSE	AER ACTIVITY
New incentives for efficient investment	A new incentive scheme ensures efficiency benefits are shared between consumers and network businesses The AER can assess overspends in capital expenditure allowances, and can exclude inefficient overspends from the regulated asset base	Under the old rules an efficiency benefit sharing scheme applied to operating expenditure but not capital expenditure All capital expenditure was automatically rolled into the regulated asset base, creating an incentive to overspend	Expenditure incentives guideline published November 2013
Fairer arrangements for distribution of revenue from shared assets	Revenue earned by network businesses from third party use of regulated assets will be shared with customers, for example by reducing regulated revenue allowances	Under the old rules revenues earned from third party use of network assets were not shared with consumer, despite consumers being required to wholly fund the assets	Shared assets guideline published November 2013

- began preparing for reviews of the New South Wales and ACT distribution businesses, and the New South Wales and Tasmanian transmission businesses, covering regulatory periods commencing 1 July 2014. These businesses will operate under transitional arrangements for the year commencing 1 July 2014, with a full determination under the new rules to cover the remaining four years.
- began preparing for reviews of the Queensland and South Australian distribution businesses, and Directlink (transmission interconnector between Queensland and New South Wales), covering regulatory periods commencing 1 July 2015.

In addition to revenue determinations, the AER undertakes other economic regulation functions. It assesses network proposals on matters including cost pass-throughs and contingent projects; develops and applies service incentive regimes, ring fencing policies and other regulatory guidelines; assists in access and connection disputes; and undertakes annual tariff compliance reviews of distribution businesses. The AER also monitors the compliance of network businesses with the Electricity Rules, and reports on outcomes, including in quarterly compliance reports.[3]

The AER in 2013 commenced a review (expected to be completed by September 2014) of its network pricing guideline for transmission businesses. This review followed an AEMC rule change on interregional charging arrangements for transmission networks, to provide more efficient price signals. Currently, a transmission business recovers its costs from customers within the region in which its network is located. Customers in an importing region, therefore, do not pay the costs incurred in an exporting region to serve their load. The new charging arrangements, which take effect from 1 July 2015, introduce a modified load export charge that effectively treats the business in the importing region as a customer of the business in the exporting region.

2.2.4 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 or a part of it. Network businesses have typically sought review of specific matters in a determination rather than the whole determination.

To have a decision amended, the network business must demonstrate the AER:

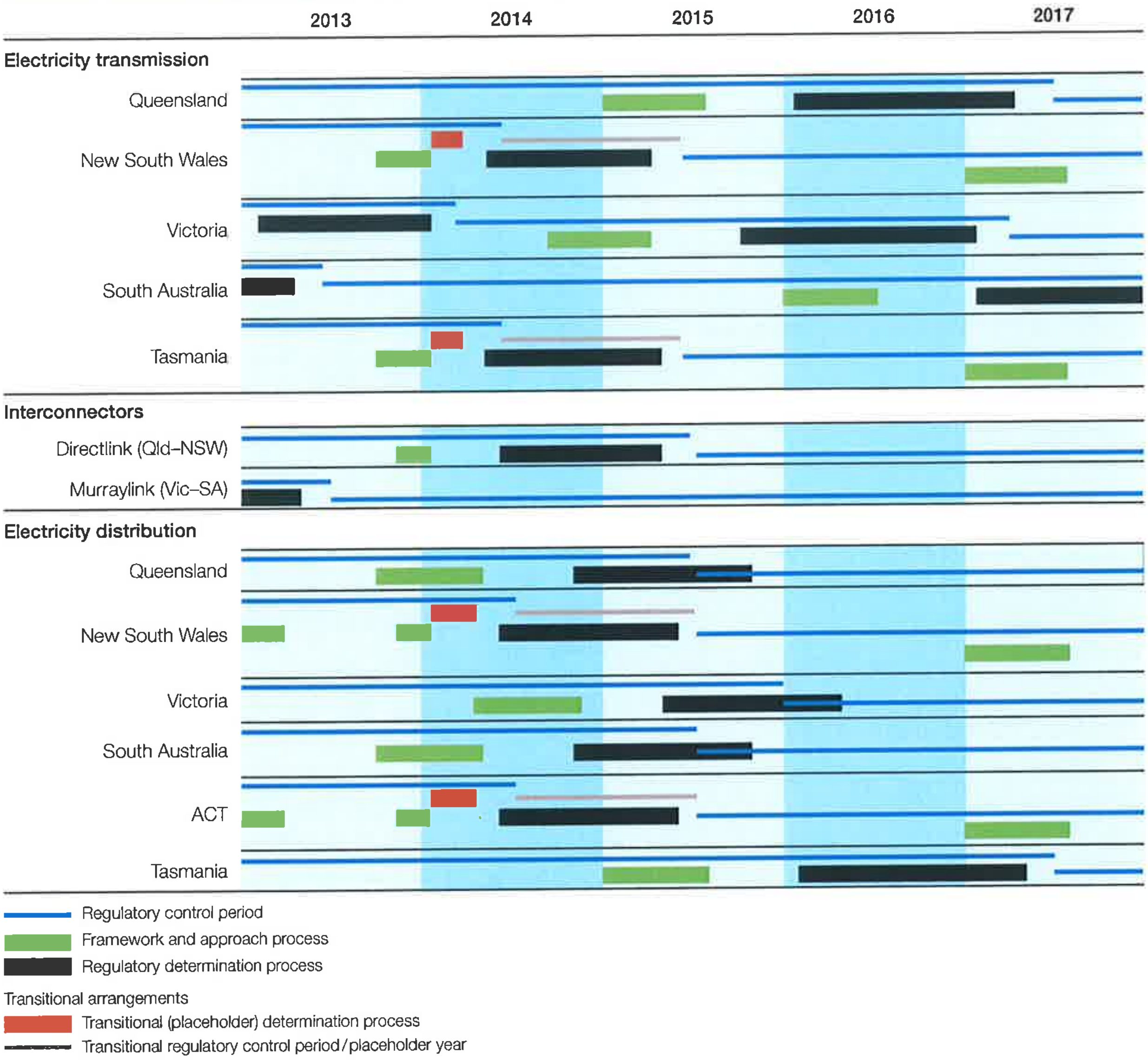
- made an error of fact that was material to its decision
- incorrectly exercised its discretion, having regard to all the circumstances, or
- made an unreasonable decision, having regard to all the circumstances.

If the Tribunal finds the AER erred, it can substitute its own decision or remit the matter back to the AER for consideration.

Between June 2008 and June 2013 network businesses sought review of 18 AER determinations on electricity networks—three reviews in transmission and 15 in

3 AER, *Strategic priorities and work program 2013–14*, 2013.

Figure 2.3
Indicative timelines for AER determinations on electricity networks



Source: AER.

distribution.[4] The Tribunal's decisions increased allowable electricity network revenues by around $3.2 billion, with substantial impacts on retail energy charges. The two most significant contributors to this increase were Tribunal decisions on:

- the averaging period for the risk free rate (an input into the weighted average cost of capital)—reviewed for five networks, with a combined revenue impact of $2 billion
- the value adopted for tax imputation credits (gamma), which affects the estimated cost of corporate income tax—reviewed for eight networks, with a combined revenue impact of over $900 million.

In April 2012 the Tribunal remitted back to the AER elements of the determination on advanced metering infrastructure costs for Victoria's SP AusNet distribution network. SP AusNet had sought significant price increases to recover unanticipated costs relating to its choice of communications technology. The AER's revised decision in February 2013 again rejected the price increases sought. Following an appeal by SP AusNet, the Tribunal in August 2013 affirmed the AER's decision. In September 2013, SP AusNet appealed the Tribunal's decision to the full Federal Court.

At October 2013 no electricity matters were before the Tribunal.

Changes to merits review arrangements

In 2012 an independent review of the limited merits review regime found the regime has not operated as intended. It found the regime:

- does not sufficiently consider the national electricity and gas objectives, which focus on the long term interests of consumers
- focuses on the matters raised for review, without sufficiently considering the overall balance of a determination.

In response, the SCER in September 2013 agreed to amendments that will require:

- a network business to demonstrate that 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 to consider any matters interlinked with the grounds of the appeal, and to consult with relevant users and consumers.

Legislation to implement these changes was passed by the South Australian Parliament in November 2013. A further review of the regime will commence in 2016.

2.3 Electricity network revenue

Figure 2.4 illustrates the AER's revenue allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. Combined network revenue was forecast at over $62 billion for the current regulatory cycle, comprising over $14 billion for transmission and $49 billion for distribution—a 43 per cent real increase from the revenue allowances in previous regulatory periods. Revenue growth is flatter, however, for more recent determinations.

The main revenue drivers are capital financing, capital expenditure (section 2.4) and operating costs (section 2.5). Electricity network businesses are capital intensive, so even small changes to the return earned on those assets can have a significant impact on overall revenue. As an example, a 1 per cent increase in the cost of capital allowed for ElectraNet in the AER determination for the period 1 July 2013–30 June 2018 would have resulted in an 8 per cent increase in revenue.

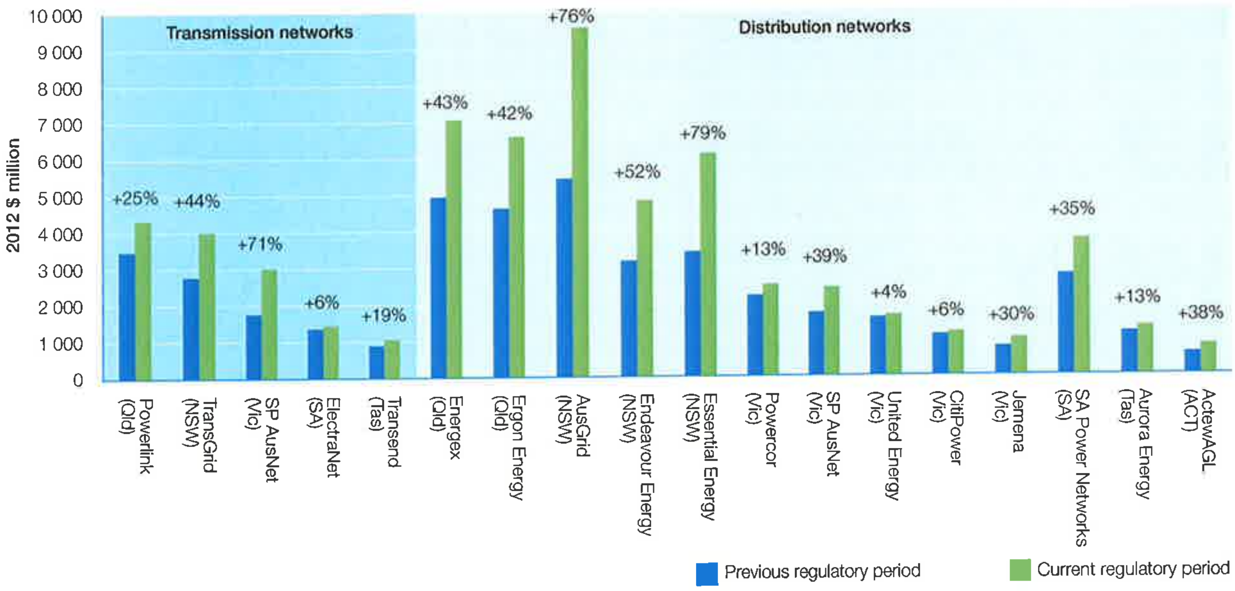
For AER determinations made from 2009 to 2011, the forecast cost of capital used to set revenue allowances was generally higher than in previous regulatory periods (figure 2.5). The primary factor underpinning the increases was a higher debt risk premium, which reflects the cost of borrowing for a business based on its risk of default. Issues in global financial markets affected liquidity in debt markets and increased perceptions of risk from late 2008, pushing up the cost of borrowing.

AER determinations made since 2012 reflect recent reductions in the risk free rate and market and debt risk premiums, which lowered the overall cost of capital. The overall cost of capital in determinations made in 2013 was 7–7.5 per cent, compared with up to 10.4 per cent in 2010.

The Tribunal's decision to amend the value adopted for tax imputation credits (gamma) for the Queensland and South Australian distribution networks increased revenue allowances. The decision also had impacts on other determinations.

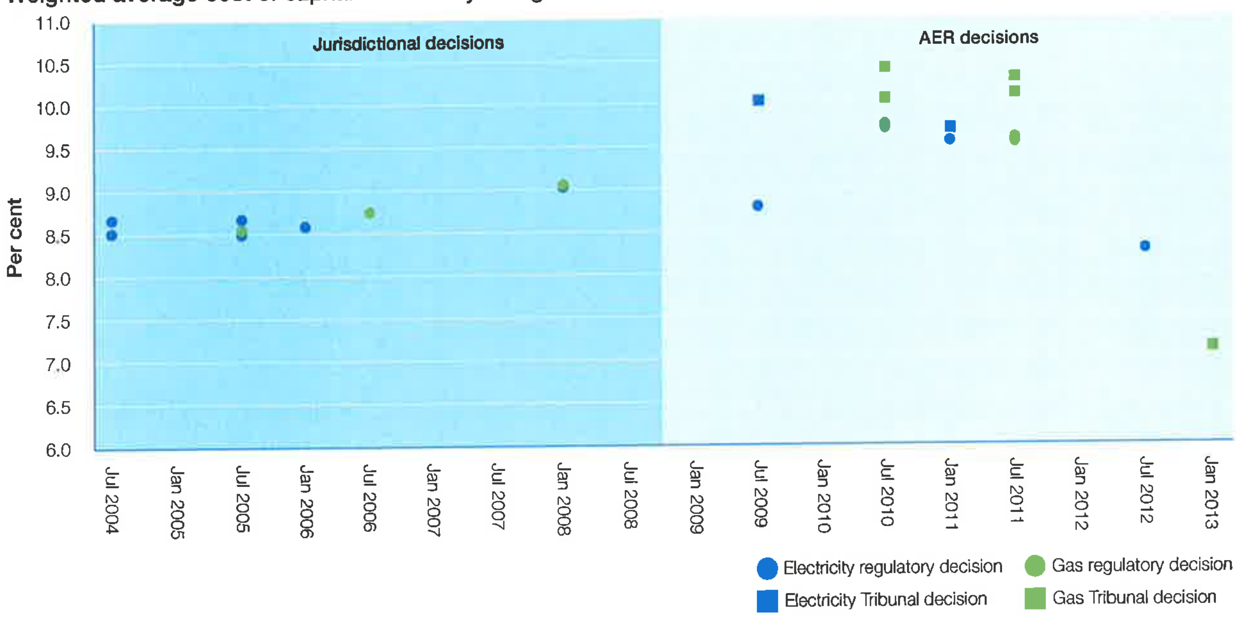
4 Four of the distribution reviews related to charges for advancing metering infrastructure (smart meters) in Victoria. In addition, two determinations were subject to judicial review under the *Administrative Decisions (Judicial Review) Act 1977* (Cwlth).

Figure 2.4
Electricity network revenue



Notes:
Current regulatory period revenues are forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.
The current period revenue allowances for Energex and Ergon Energy are as determined by the Australian Competition Tribunal in May 2011. The Queensland Government prevented Energex and Ergon Energy from recovering $270 million and $220 million respectively of these allowances.
Sources: AER regulatory determinations.

Figure 2.5
Weighted average cost of capital—electricity and gas distribution



Note: Nominal vanilla weighted average cost of capital.
Source: AER.

2.4 Electricity network investment

New investment in electricity networks includes augmentations (expansions) to meet demand and the replacement of ageing assets. The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can approve contingent projects too—large projects that are foreseen at the time of a determination, but that involve significant 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.

In 2013 the AEMC proposed to enhance transmission planning by allowing AEMO to review network planning reports and the regulatory investment test for transmission (RIT-T) processes (section 2.4.1), and to provide demand forecasts. Transmission businesses would have more input into the planning process, and would consult with each other and the national transmission planner on projects with interregional impacts. Aligning regulatory control periods for transmission business would also help planning.

2.4.1 Regulatory investment tests

The regulatory process approves the overall efficiency of a business's capital expenditure program. Additionally, separate consultation and assessment occur for large individual projects to determine whether they are the most efficient way of meeting an identified need, or whether an alternative (such as investment in generation capacity) would be more efficient. Until 2010 the assessment entailed a common regulatory test for both transmission and distribution. The test required a business to determine whether a proposed augmentation passes a cost–benefit analysis or provides a least cost solution to meet network reliability standards.[5] New tests for transmission and distribution businesses have replaced the original regulatory test.

The regulatory investment test for transmission (RIT-T), introduced in August 2010, applies to a wider range of projects than did the previous test and assesses transmission proposals against a market based cost-benefit analysis. A network business must identify the purpose of a proposed investment and assess it against all credible options for achieving that purpose. The business must publicly consult on its proposal; affected parties can lodge a dispute.

A new regulatory investment test for distribution (RIT-D) will commence on 1 January 2014. The RIT-D is similar to the RIT-T, but requires network businesses to assess investment proposals against a different set of market benefits. It applies to investment projects over $5 million and includes a dispute resolution process. The RIT-D is part of a new national framework for electricity distribution network planning and expansion. That framework also requires distribution businesses to release annual planning reports and maintain a demand side engagement strategy.

The AER's roles in relation to regulatory investment tests include:

- publishing the tests and guidelines—the AER published the RIT-D and related material in August 2013
- helping resolve disputes over how the tests are applied
- monitoring and enforcing compliance—the AER conducted a number of compliance reviews in 2013
- periodically reviewing project cost thresholds—the AER completed a review for the RIT-T in November 2012
- determining whether a preferred investment option meets the RIT-T's cost–benefit analysis, on request from the business that conducted the test. This role does not apply to reliability driven projects.

A number of RIT-T and regulatory test processes have occurred since July 2012, including for the following projects:

- ElectraNet and AEMO (the transmission network planner for Victoria) assessed the viability of upgrading the Heywood interconnector between Victoria and South Australia. The final report in January 2013 found the upgrade would provide additional energy supply to South Australia at times of maximum (summer) demand; allow more efficient generation dispatch in Victoria and South Australia; and promote new investment in low fuel cost generation. The project was estimated to have net benefits of up to $190 million. Because the project's purpose was not to meet reliability standards, ElectraNet requested the AER make a determination confirming the project passed a cost–benefit analysis. The AER confirmed in September 2013 that the project satisfied the RIT-T.
- Powerlink and TransGrid consulted on a method to assess the competition benefits of a proposed upgrade to the Queensland–New South Wales interconnector

5 AER, *Regulatory test for network augmentation, version 3*, 2007.

(QNI). The businesses consider market benefits arise from allowing generation capacity in one region to meet peak demand in another. A previous test in 2008 found an upgrade would not be required until 2015–16.

- Powerlink assessed options to meet increased demand from new coal mine developments in the Bowen Basin. It found a combined network and non-network option is the most efficient way to address emerging network limitations, with estimated net market benefits of up to $40 million.
- AEMO published draft reports assessing projects to meet rising demand in regional Victoria and eastern metropolitan Melbourne.

Since July 2012 NEM demand forecasts have eased in most regions, meaning a number of planned investments are no longer required. Projects that passed a regulatory investment test but were then deferred include TransGrid projects for new transmission infrastructure between Dumaresq and Lismore, and for a network expansion on the mid north coast of New South Wales.

Ergon Energy's planned line from Warwick to Stanthorpe was also deferred. The project had been subject to a regulatory test, but an AER review found the test's application was flawed. Ergon Energy committed to reassess the project closer to when it is required.

A number of RIT-T processes have also been terminated or deferred:

- ElectraNet deferred its assessment of options to address rising demand in the Lower Eyre Peninsula until it knows whether mining developments in the area will proceed.
- ElectraNet deferred its assessment of options to address voltage limitations in the mid-north of South Australia. The project was initially forecast to be required for summer 2015–16, but that timeframe was extended to 2024.
- AEMO terminated its assessment of options to address emerging voltage stability limitations in regional Victoria. Weaker demand forecasts mean these limitations are now unlikely to arise.

2.4.2 Investment trends

Figure 2.6 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. It shows the RAB for each network 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 five year cycle is forecast at over $7 billion for transmission networks and $36 billion for distribution networks. These forecasts represent an increase on investment in the previous regulatory periods of around 16 per cent in transmission and 60 per cent in distribution (in real terms). Determinations made since 2012 reflect a different investment trend.

Changes in operating environments, even over a relatively short period, can cause significant variations in investment requirements. A number of active AER determinations that were made several years ago reflected increased capital needs to replace ageing assets, meet higher reliability and new bushfire (safety) standards, and respond to forecasts made at the time of rising peak demand.

The determination for the AusGrid distribution network in New South Wales for 2009–14, for example, provided for capital investment to meet an expected increase in peak demand from 5500 to 6700 megawatts over the period.[6] But these forecasts proved optimistic; actual peak demand over the first four years of the period did not surpass 6000 megawatts, and the forecast for 2013–14 is below this level.[7]

With around 25 per cent of capital expenditure for distribution businesses driven by growth in electricity demand (compared with 60 per cent for transmission), this lower level of demand means businesses can defer a significant amount of allowed expenditure for the period. While customers will benefit from the deferral of investment, they still bear costs during the current period based on the higher forecast expenditure level.

More recent determinations reflect this moderation in forecast growth in industrial and residential energy use, including peak demand (section 1.1). The AER found revisions to forecast load growth for ElectraNet, for example, meant the business did not require demand driven investment over the regulatory period, reducing its original expenditure proposal by $132 million. However, the determination includes 11 contingent projects, allowing for capital expenditure to cover rises in demand associated with defined trigger events.

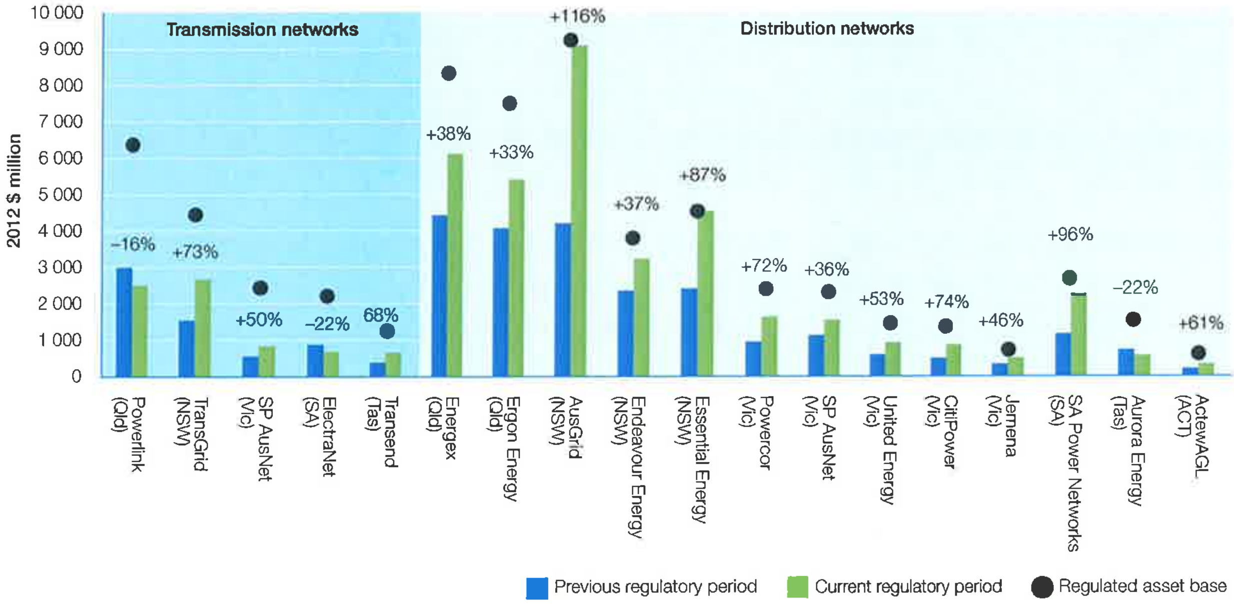
New tools available to the AER through the Better Regulation program promote efficient capital expenditure. A capital efficiency benefit sharing scheme will provide

6 AER, *New South Wales distribution determination 2009–10 to 2013–14, final decision*, 2009.

7 AusGrid, *Transmission annual planning report 2013*.

Figure 2.6

Electricity network investment



Notes:

Regulated asset bases are as 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.

businesses with an incentive to undertake efficient capital expenditure, because they can retain a share of the gains (section 2.5.1). The AER will also be able to review any capital overspend. Any inefficient expenditure will be excluded from the business's asset base (meaning consumers will not pay for it).

2.5 Operating and maintenance expenditure

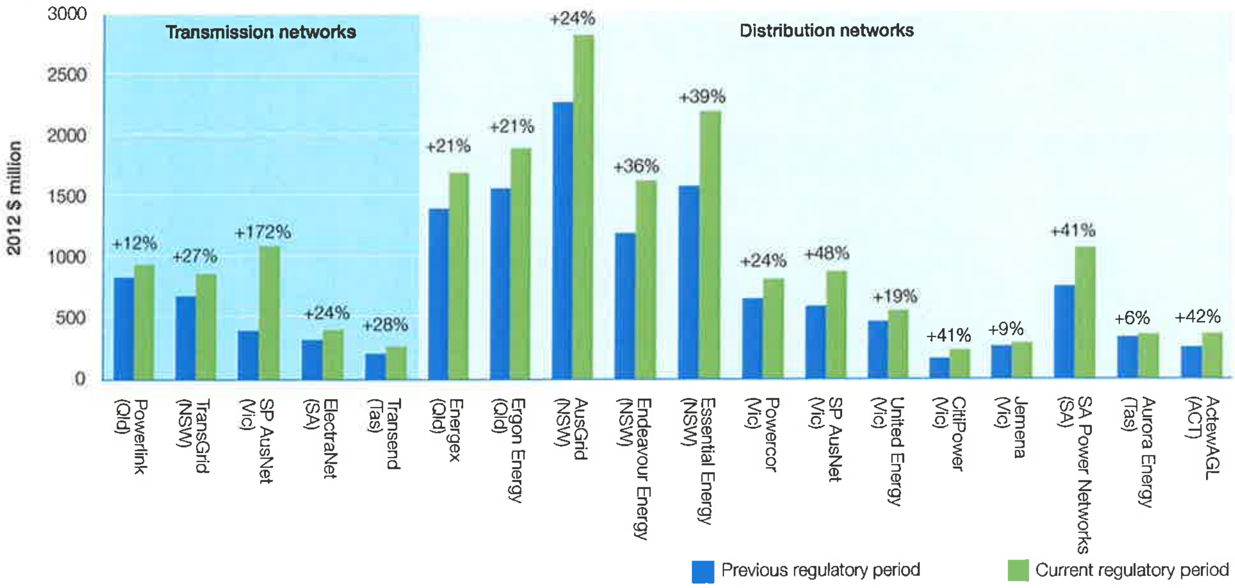
The AER determines allowances for each network to cover efficient operating and maintenance expenditure. A network's requirements depend on load densities, the scale and condition of the network, geographic factors and reliability requirements.

Figure 2.7 illustrates operating and maintenance expenditure allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. In the current cycle, transmission businesses in the NEM are forecast to spend $3.6 billion on operating and maintenance costs. Distribution businesses are forecast to spend almost $15 billion.

Differences in the networks' operating environments result in significant variations in expenditure allowances. On average, costs are forecast to rise by 45 per cent in transmission and 28 per cent in distribution for the current regulatory periods, compared with previous regulatory periods.

In assessing operating expenditure forecasts, the AER considers relevant cost drivers, including load growth, expected productivity improvements, and changes in real input costs for labour and materials. Operating cost increases may also reflect step change factors—that is, new business requirements that were not part of the previous regulatory period. The 2010 Victorian determinations, for example, had to account for an expected increase in regulatory compliance costs for electrical safety, network planning and customer communications, stemming from government decisions following the 2009 Victorian bushfires.

Figure 2.7
Operating expenditure of electricity networks



Notes:
Current regulatory period expenditure reflects forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.
The increase in SP AusNet's transmission operating expenditure in the current period was partly due to the introduction of an easement land tax (around $80 million per year) mid way through the previous regulatory period.
Sources: Regulatory determinations by the AER.

2.5.1 Efficiency benefit sharing scheme

The AER operates a national incentive scheme for businesses to improve the efficiency of operating and maintenance expenditure in running their networks. And, as part of the Better Regulation program, it is expanding the scheme to cover capital expenditure. Capital and operating expenditure incentives are aligned with those provided through the AER's service target performance incentive scheme, to encourage business decisions that balance cost and service quality.

The 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 the gain (loss) is made. In the longer term, the businesses share efficiency gains or losses with customers through price adjustments, passing on 70 per cent of the gain or loss.

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.

2.6 Demand management and metering

Demand management relates to strategies to manage the growth in overall or peak demand for energy services. It aims to reduce or shift demand, or implement efficient alternatives to network augmentation. Such strategies are typically applied at the distribution or retail level, and require cooperation between energy suppliers and customers.

2.6.1 *Power of choice* review

The AEMC in November 2012 completed its *Power of choice* review into efficient alternatives to network investment to deal with rising peak demand. It recommended:

- improving price signalling to customers, by introducing time varying network tariffs and continuing the rollout of interval metering (section 2.6.2)
- removing barriers to large consumers offering demand reduction into the wholesale electricity market

- providing more flexibility for consumers to access their own consumption data, and a framework for consumer engagement with demand side providers
- modifying the AER's demand management incentive scheme to capture wider market benefits and network deferral benefits beyond the current regulatory period
- considering, when the AER develops its national ring fencing guidelines, the benefits of allowing network businesses to own and operate generation plant connected to their networks
- enabling consumers to sell small scale generation (for example, solar or battery storage) to parties other than their electricity retailer, and to unbundle the provision of non-energy services (including ancillary services) from the supply of electricity.

The Council of Australian Governments (CoAG) in December 2012 approved the adoption in principle of the full set of *Power of choice* recommendations. Energy ministers tasked AEMO with developing and submitting rule change proposals by 2015 on recommendations relating to the wholesale market. AEMO released design proposals in August 2013 (section 1.10). Progress has also occurred with recommendations relating to the network sector, as outlined in sections 2.6.2 and 2.6.3.

2.6.2 Metering and smart grids

Interval meters—with time based data on energy use and communication capabilities for remote reading and customer connection to the network—are central to many *Power of choice* recommendations. This type of metering, when coupled with time varying prices, can encourage customers to actively manage their electricity use.

The *Power of choice* review recommended all new meters installed for residential and small businesses consumers be interval meters with remote communication capacity. It proposed accelerating the installation of new metering for large residential and small business consumers.

The AEMC proposed that network businesses be required to adopt time varying pricing in setting network charges. That requirement would encourage retailers to reflect those charges in customer contracts. In response, the SCER in September 2013 submitted a rule change proposal to change the distribution network pricing principles. The changes would encourage distribution businesses to set cost reflective network prices, which would provide more efficient pricing signals to consumers.

The Victorian Government expects to complete a rollout of interval meters with remote communications to all customers in 2014. From September 2013 small customers have been offered the choice of moving to more flexible tariff structures. Customers electing to switch to time varying prices have the option until March 2015 of reverting to a single rate tariff.

Interval meter costs have been progressively passed on to Victorian retail customers since 1 January 2010. Network charges increased by almost $80 for a typical small retail customer by 2012, with further annual increases of $9–21 for 2012–15.[8] Outside Victoria, no large scale rollout of interval meters has commenced; however, a number of distribution network businesses are installing interval meters (so far, over 1.5 million) on a new and replacement basis.[9]

2.6.3 Other demand management initiatives

The AER applies incentives that enable distribution network businesses to investigate and implement non-network approaches to manage demand. These approaches may include measures to reduce demand or provide alternative ways of meeting supply (such as connecting small scale local generation). The incentive schemes fund innovative projects that go beyond initiatives funded through capital and operating expenditure forecasts. In some jurisdictions, the schemes allow businesses to recover revenue forgone as a result of successful demand reduction initiatives. The SCER in 2013 was developing a rule change proposal on the incentive scheme.

The AEMC published a draft rule in July 2013 to streamline the process for connecting generators to the distribution network. The new rule establishes clearer enquiry and application processes, and sets out new information requirements. Distribution businesses will be required to provide connection applicants with example costs, a model connection agreement and information on technical requirements. The AEMC expects to finalise the rule change in December 2013.

8 AER, *Victorian advanced metering infrastructure review—2012–15 AMI budget and charges applications, final determination*, 2011.
9 Department of Resources, Energy and Tourism, *National smart meter infrastructure report*, February 2013.

2.7 Transmission network performance

Measures of performance for electricity transmission networks include:

- the reliability of supply (the continuity of energy supply to customers) (section 2.7.1)
- the management of network congestion (section 2.7.2).

2.7.1 Transmission network reliability

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 transmission network failure may require the power system operator to disconnect some customers (known as load shedding), most reliability issues originate in distribution networks (section 2.8.1).

Transmission networks in the NEM deliver high rates of reliability. According to Energy Supply Association of Australia data, transmission outages in 2011–12 caused less than three minutes of unsupplied energy in New South Wales, Victoria and South Australia; Tasmania had around nine minutes of unsupplied energy. No data were published for Queensland. Performance has been relatively consistent over recent years.[10]

Transmission reliability standards

State and territory agencies determine transmission reliability standards. The SCER in February 2013 directed the AEMC to develop a national framework for expressing, setting and reporting on transmission reliability. The process was aligned with work previously commenced on a national framework for distribution network reliability (section 2.8.1).

The AEMC finalised work on the distribution framework in September 2013, and on the transmission framework in November 2013.[11] The frameworks contain common features, including that jurisdictions would remain responsible for setting reliability standards (with the option of delegating to the AER), based on a transparent economic assessment and community consultation. The AEMC recommended reliability standards be set every five years, to align with the regulatory determination process, but with flexibility to adjust to reflect new information.

It also recommended a national approach to reporting on reliability performance. In August 2013 AEMO finalised a method for estimating the value of customer reliability, and it will develop the associated values by March 2014. Under the recommended approach, the AER would assume responsibility for developing the values of customer reliability for each jurisdiction every five years. To ensure the framework is consistently applied, the AER would develop a guideline on the economic assessment process and its key assumptions.

For transmission businesses, reliability standards will be defined on an input basis, but with the potential for jurisdictions to supplement these standards with output measures. Reliability measures for distribution businesses will be defined on an output basis and linked to the AER's service target performance incentive scheme (section 2.8.3).

2.7.2 Transmission network congestion

Physical limits (constraints) are imposed on electricity flows along transmission networks to avoid damage and maintain power system stability. These constraints can result in network congestion, especially at times of high demand. Some congestion results from factors within the control of a network business—for example, the scheduling of outages, maintenance and operating procedures, and standards for network capability (such as thermal, voltage and stability limits). Factors beyond the control of the business include extreme weather—for example, hot weather can result in high air conditioning loads that push a network towards its pre-determined limits. Typically, most congestion occurs on just a few days, and is largely attributable to network outages.

A major transmission outage in combination with other generation or demand events can interrupt the supply of energy. But this scenario is rare in the NEM. Rather, the main impact of congestion is on the cost of producing electricity. In particular, transmission congestion increases the total cost of electricity by displacing low cost generation with more expensive generation. Congestion can also lead to disorderly bidding in the wholesale market, and to inefficient electricity trade flows between the regions (section 1.6).

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 in 2008 introduced an incentive scheme to encourage network businesses to apply relatively low cost solutions to congestion.

10 ESAA, *Electricity gas Australia 2013*.
11 AEMC, *Review of the national framework for distribution reliability, final report*, September 2013; AEMC, *Review of the national framework for transmission reliability, final report*, November 2013.

The AEMC's transmission frameworks review (completed April 2013) looked at options to manage network congestion. Its preferred approach is an 'optional firm access' regime, whereby generators pay for priority access to the network (section 2.9.1).

2.7.3 Service target performance incentive scheme—transmission

The AER's service target performance incentive scheme provides incentives for transmission businesses to improve network performance. It acts as a counterbalance to the efficiency benefit sharing scheme (section 2.5.1) so businesses do not reduce costs at the expense of service quality. The scheme in place sets performance targets on:

- transmission circuit availability
- the average duration of transmission outages
- the frequency of 'off supply' events.

Rather than impose a common benchmark target, the AER sets separate standards that reflect the circumstances of each network based on its past performance. 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.

The scheme includes a separate component based on the market impact of transmission congestion, which encourages a network to make relatively low cost improvements to its operating practices to reduce congestion. These practices may include more efficient outage timing and notification, 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 a further 2 per cent of its regulated revenue if it eliminates all outage events with a market impact of over $10 per megawatt hour.

The results are standardised for each network to derive an 's factor' that can range between –1 (the maximum penalty) and +3 (the maximum bonus). Table 2.4 sets out s factors for each network for the past six years. While performance against individual component targets has varied, the networks generally received financial bonuses for overall performance. TransGrid, ElectraNet and Directlink received financial penalties in 2012 relating to the service component of the scheme. Underperformance was most common in relation to transmission circuit availability targets.

The performance of ElectraNet and TransGrid in 2012 was weaker than in the previous year. ElectraNet's overall transmission circuit availability fell, while TransGrid had a reduction in transformer availability and took longer on average to restore supply after an outage. Transend performed significantly better in 2012 than in the previous year, improving the availability of critical transmission circuits and reducing supply outages.

TransGrid, Powerlink, ElectraNet and SP AusNet applied the congestion component of the scheme in 2012. Transmission congestion as a result of network outages in 2010–12 was negligible in Queensland and low in New South Wales. Congestion was also significantly lower compared with levels recorded in the previous benchmark period. Transmission congestion in Victoria improved in 2012 compared with the previous year, but worsened in South Australia. Increased congestion on the ElectraNet network was driven by network outages surrounding North West Bend. Payments under the congestion component in 2012 were $33 million, up from $27 million in 2011.

The AER in December 2012 enhanced incentives for transmission businesses to improve network performance. It revised the incentive scheme to consist of:

- a *service component*, with an incentive of +/– 1 per cent of regulated revenue. This component focuses on the frequency of interruptions to supply, the duration of outages, and the number of unplanned faults on the network. It also covers protection and control equipment failures.
- a *market impact component*, with an incentive of 0–2 per cent of regulated revenue. The AER will assess this component differently under the new version of the scheme, measuring a network's performance over two years against outcomes over the previous three years.
- a *network capability component*, with an incentive of up to 1.5 per cent of regulated revenue. Payments are made to fund one-off projects that improve the capability, availability or reliability of the network at times most needed. The total cost of projects funded through this component cannot exceed 1 per cent of the network's revenue. AEMO will help prioritise the projects to deliver best value for money for consumers, and the AER will approve the project list. Network businesses will be subject to 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 new scheme is expected to apply first under regulatory determinations for SP AusNet, Transend and TransGrid that commence in 2014.

Table 2.4 S factor values

		2008		2009		2010	2011	2012	
Powerlink (Qld)	Service component		0.53		0.17	0.65	0.42	0.44	0.45
	Market impact component					1.97	1.95	1.98	2.00
TransGrid (NSW)	Service component		0.31	0.22	-0.28	-0.24	-0.13		-0.49
	Market impact component				0.39	1.45	1.39		1.48
AusGrid (NSW)	Service component		0.72		0.37				
SP AusNet (Vic)	Service component	0.15	0.82		0.51	0.58	0.72		0.82
	Market impact component						0.00		0.80
ElectraNet (SA)	Service component	0.29	-0.40		0.60	0.00	0.32		-0.30
	Market impact component						0.52		0.00
Transend (Tas)	Service component		0.85	0.88	0.11	0.35	-0.41		0.33
Directlink (Qld–NSW)	Service component		-1.00		-0.98	-1.00	-0.87		-1.00
Murraylink (Vic–SA)	Service component		0.69		0.87	1.00	0.70		0.92

Notes:

SP AusNet reported separately for the first quarter of 2008 and the remainder of the year.

ElectraNet reported separately for the first and second halves of 2008.

TransGrid and Transend reported separately for the first and second halves of 2009. AusGrid data for 2009 are for the six months to June; AusGrid moved to the distribution performance framework on 1 July 2009.

Powerlink reported separately for the first and second halves of 2012.

Source: AER, *Transmission network service providers: electricity performance report for 2010–11*, 2012.

2.7.4 Transmission frameworks review

The AEMC in April 2013 completed a review of how electricity transmission services are provided and used. Among its recommendations were proposals to streamline arrangements for connecting generators to the transmission network, and to progress the design of an 'optional firm access' model to manage risks associated with network congestion.

Connections

The review proposed changing the connections framework to strengthen competition and transparency in the market for constructing network assets required for generator connection. Construction, ownership and operation of connection assets that do not form part of the shared network would be contestable; construction of shared network assets used to connect a generator would also be contestable, but the network business would retain responsibility for their operation. Transmission network businesses would have to provide cost information to connection applicants, and publish standard contracts and design standards.

Optional firm access

Generators face the risk of network congestion constraining the dispatch of their plant. To better manage this risk, the AEMC proposed an optional firm access model under which generators would pay transmission businesses to secure firm network access. Transmission businesses would plan and operate their networks to provide the agreed capacity, with their charge to generators reflecting the cost of providing that capacity. If congestion prevents a generator with firm access from being dispatched, then non-firm generators that contributed to the congestion would compensate the firm generator for any loss.

The model would also allow generators and retailers to buy firm interregional access, entitling them to the price difference between the relevant regions. Payments for interregional access would guide and fund the expansion of interconnectors.

Optional firm access would require generators, when deciding where to locate new plant, to account for trade-offs between congestion costs and the costs of funding network expansions. As a result, generation and transmission investment would likely become more efficient. The model would also provide incentives for transmission businesses to maximise network availability when it is most valuable to the market.

The AEMC also noted the model's potential benefits for wholesale market participants, in supporting contracting between generators and retailers across regions and reducing dispatch risk for generators. It estimated optional firm access would take four years to implement.

2.8 Distribution network performance

Measures of performance for electricity distribution networks include:

- the reliability of supply
- levels of customer service.

2.8.1 Reliability of distribution networks

Reliability is a key service measure for a distribution network. Both planned and unplanned factors can impede network reliability:

- A planned interruption occurs when a distributor needs to disconnect supply to undertake maintenance or construction works. Such interruptions can be timed for minimal impact.
- Unplanned outages occur when equipment failure causes the electricity supply to be unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or routine external causes such as damage caused by extreme weather, trees, animals, vehicle impacts or vandalism.

Distribution outages account for over 95 per cent of electricity outages in the NEM. 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, distribution outages should be kept to efficient levels—based on the value of reliability to the community and the willingness of customers to pay—rather than trying to eliminate every possible interruption.

State and territory governments determine distribution reliability standards. The trade-off between reliability and cost means a government decision to increase reliability standards may require substantial new investment that affects customer bills. An AEMC assessment for New South Wales found a reduction in reliability standards that increased network outages by 2–15 minutes per year would save an average consumer $3–15 per year. It concluded the savings outweighed the impact of slightly weaker reliability.[12]

Concerns about the impact of network investment on retail electricity prices led CoAG in December 2012 to agree a new best practice approach was needed to set distribution reliability standards. Energy ministers directed the AEMC to develop a national framework by the end of 2013 (section 2.7.1). As a result, the AEMC in September 2013 proposed a new approach to setting distribution reliability targets.

The proposed process would weigh the cost of new investment against the value that customers place on reliability and the likelihood of interruptions, to help set efficient reliability targets. The assessment would be transparent and independent of the network provider. The AER's service target performance incentive scheme would provide incentives for network businesses to meet their reliability targets.

Distribution reliability indicators

The key indicators of distribution reliability in Australia are the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI). The indicators relate to the average duration and frequency of network interruptions and outages. They do not distinguish between the nature and size of loads affected by supply interruptions.

Figure 2.8 estimates historical data on the average duration (SAIDI) and frequency (SAIFI) of outages experienced by distribution customers. The data include outages that originated in the generation and transmission sectors.

Issues with reliability data limit the validity of comparisons across jurisdictions. In particular, the data rely on the accuracy of the businesses' information systems, which may vary considerably. Geographic conditions and historical investment also differ across the networks.

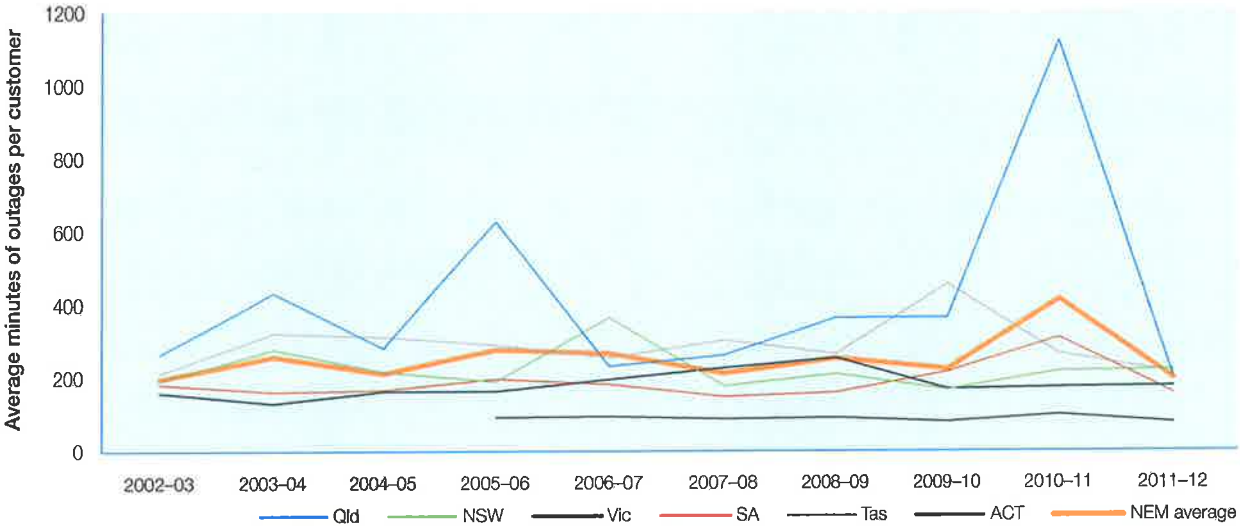
Noting these caveats, the SAIDI data indicate electricity networks in the NEM delivered reasonably stable reliability outcomes over the past few years. Across the NEM, a typical customer experiences around 200–250 minutes of outages per year, but with significant regional variations.

In 2011–12 the average duration of outages per customer was consistent with that of the previous year in New

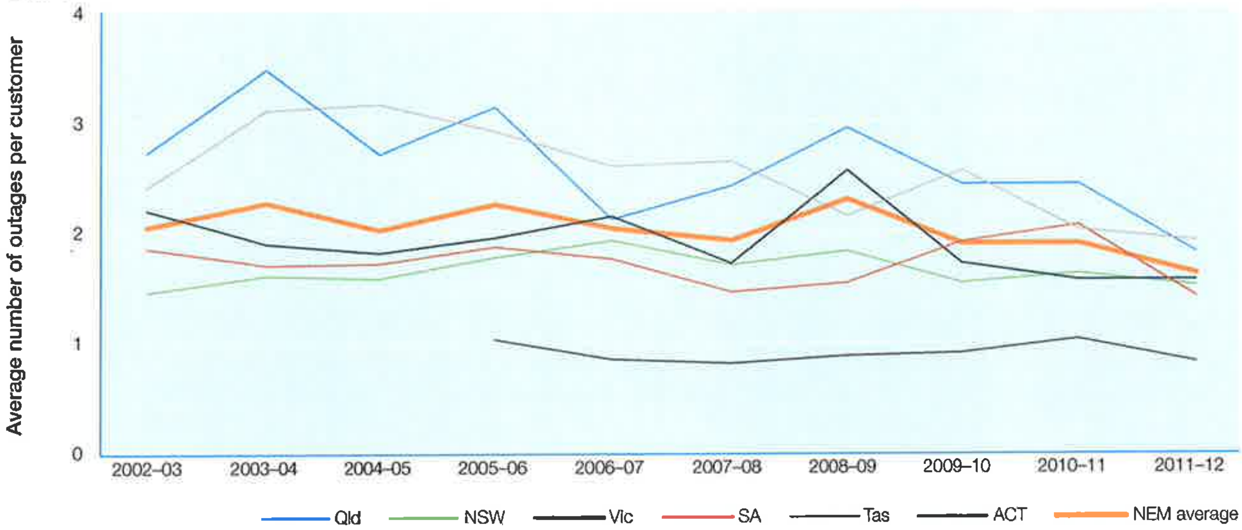
12 AEMC, *Review of distribution reliability outcomes and standards, final report—NSW workstream*, 2012.

Figure 2.8
System reliability

SAIDI



SAIFI



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

South Wales and Victoria, and fell in all other jurisdictions. Average outage duration across the NEM was the lowest in a decade, partly due to less extreme weather activity. The largest reduction in outages occurred in Queensland, where an average customer experienced around 200 minutes of outages in 2011–12—down from 1122 minutes in 2010–11 when severe flooding in the south east, and Cyclone Yasi in the north, affected performance on both the Energex and Ergon Energy networks. Queensland experiences significant variations in performance, partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other NEM jurisdictions.

The SAIFI data show the average frequency of outages was relatively stable between 2002–03 and 2011–12, with energy customers across the NEM experiencing an outage around twice a year. The average frequency of outages in 2011–12 was reduced or stable relative to that of the previous year in all jurisdictions. Queensland and South Australia recorded the largest reductions in outage frequency.

Service target performance incentive scheme—distribution

Through its service target performance incentive scheme (section 2.8.3), the AER sets targets for the average duration and frequency of outages for each distribution business. The targets are based on outcomes for the business over the previous five years. From a customer perspective, the unadjusted reliability data in figure 2.8 are relevant. But, in assessing network performance, the AER normalises data to exclude interruption sources beyond the network's reasonable control.

In 2011–12 New South Wales and ACT network businesses were not subject to the scheme. Most other businesses met outage duration and frequency targets. Three businesses—Ergon Energy, CitiPower and United Energy—underperformed against their outage duration targets. CitiPower and United Energy also missed their targets for the average frequency of outages.

2.8.2 Customer service—distribution

Network businesses report on their responsiveness to customer concerns, including the timely connection of services, call centre performance and customer complaints. Table 2.5 provides a selection of customer service related data. It shows customer service outcomes in 2011–12 broadly aligned with those of previous years. Aurora Energy (Tasmania) and SP AusNet (Victoria) recorded the highest proportion of late connections, but each network performed better than in the previous year. Call centre responsiveness fell for all New South Wales networks; AusGrid recorded the worst performance, answering less than half of all calls within 30 seconds.

2.8.3 Distribution service performance incentives

The AER's service target performance incentive scheme encourages distribution businesses to maintain or improve network performance. It focuses on supply reliability (section 2.8.1) and customer service (section 2.8.2). A guaranteed service level (GSL) component provides for a business to pay customers if its performance falls below threshold levels.[13]

The incentive scheme provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets.[14] The results are standardised for each network to derive an 's factor' that reflects deviations from target performance levels. While the scheme aims to be nationally consistent, it has flexibility to deal with the differing circumstances and operating environments of each network. The scheme applies in Queensland, Victoria, South Australia and Tasmania, and as a paper trial in New South Wales and the ACT (where targets are set but no financial penalties or rewards apply).

Since 1 January 2012, the Victorian distribution businesses have been subject to an additional scheme with incentives to reduce the risk of fire starts that originate from a network, or are 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. All businesses outperformed their targets for 2012. Incentive payments ranged from $10 000 for CitiPower to almost $2.5 million for Powercor.

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

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

Table 2.5 Timely provision of service by electricity distribution networks

NETWORK	PERCENTAGE OF CONNECTIONS COMPLETED AFTER AGREED DATE					PERCENTAGE OF CALLS ANSWERED BY HUMAN OPERATOR WITHIN 30 SECONDS				
	2007–08	2008–09	2009–10	2010–11	2011–12	2007–08	2008–09	2009–10	2010–11	2011–12
QUEENSLAND[1]										
Energex	10.8	2.5	0.4	0.9	0.3	96.3	89.7	90.0	86.6	88.6
Ergon Energy	0.7	0.3	0.4	1.3	1.4	86.2	87.2	87.0	78.1	84.6
NEW SOUTH WALES[2]										
AusGrid	<0.1	<0.1	<0.1	<0.1	<0.1	81.1	79.7	82.6	81.8	46.7
Endeavour Energy	<0.1	<0.1	<0.1	<0.1	<0.1	96.2	92.0	90.2	87.0	80.1
Essential Energy	<0.1	<0.1	<0.1	<0.1	<0.1	61.4	51.4	62.5	57.5	55.8
ActewAGL	…	…	…	…	0.0	70.5	70.2	72.9	75.7	76.9
VICTORIA[3]										
Powercor	<0.1	<0.1	<0.1	<0.1	<0.1	90.0	86.6	85.3	67.4	70.2
SP AusNet	1.7	2.6	1.7	3.9	2.5	92.3	91.6	92.6	94.1	81.4
United Energy	0.1	0.1	0.0	0.2	1.8	73.0	73.1	76.2	60.1	61.5
CitiPower	<0.1	<0.1	<0.1	<0.1	<0.1	87.8	82.0	82.3	73.4	74.4
Jemena	0.8	0.9	0.1	<0.1	0.1	73.1	77.4	77.2	60.1	64.2
SOUTH AUSTRALIA[1]										
SA Power Networks	3.3	0.6	0.6	0.6	0.9	88.7	88.5	88.6	87.6	89.0
TASMANIA										
Aurora Energy	2.0	1.8	1.1	5.6	2.7	…	…	…	…	…

1. Completed connections data for Queensland and South Australia include new connections only.
2. New South Wales' completed connections data are state averages.
3. Victorian data are for the calendar year beginning in that period.

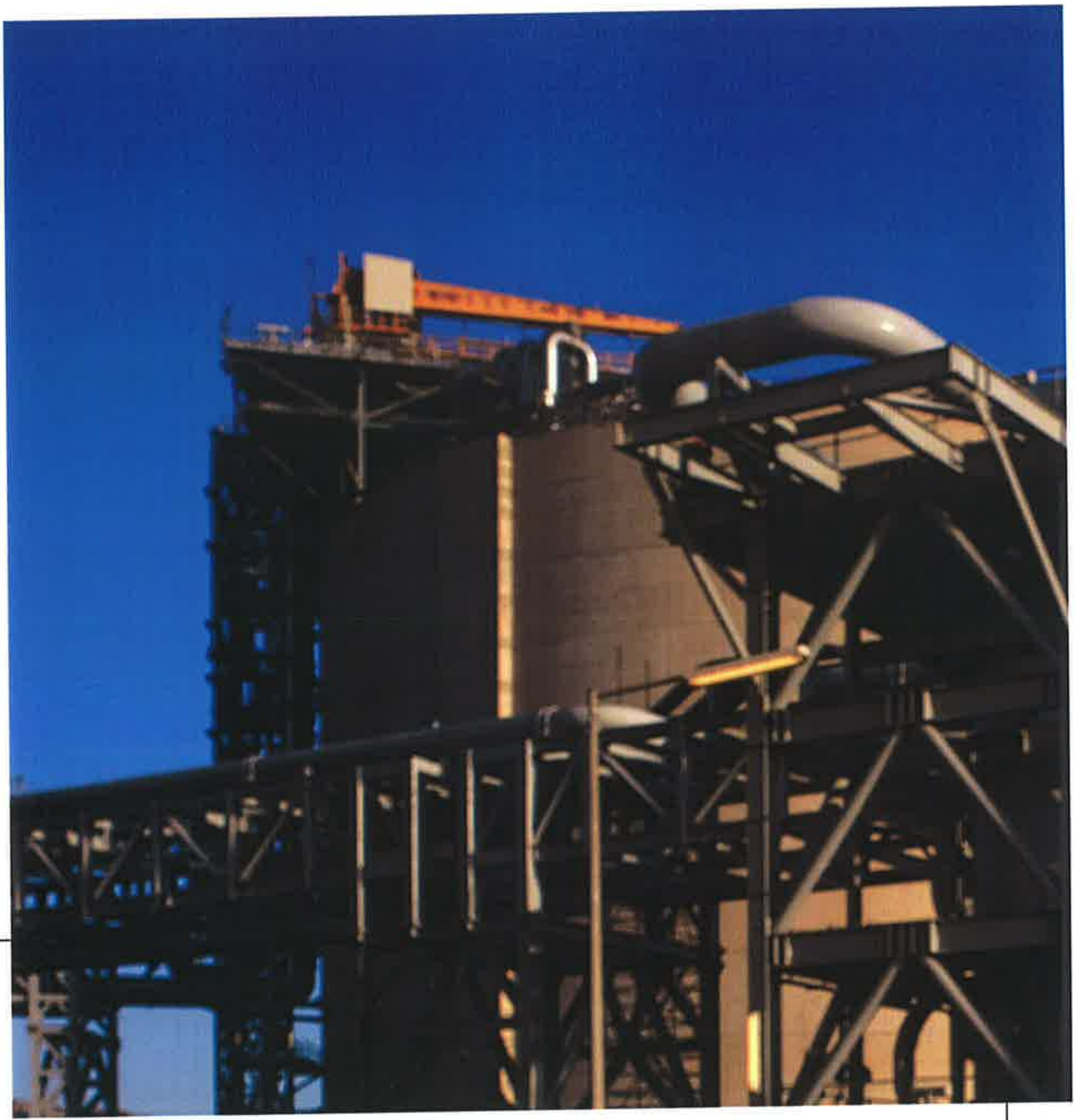
Sources: Distribution network performance reports by the AER (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia) and OTTER (Tasmania). Some data are AER estimates derived from official jurisdictional sources.

Jurisdictional GSL schemes

Jurisdictional GSL schemes provide for payments to customers experiencing poor service. They mandate payments for poor service quality in matters such as streetlight repair, the frequency and duration of supply interruptions, new connections and notice of planned interruptions. The majority of payments in 2011–12 related to the duration and frequency of supply interruptions exceeding specified limits. This outcome is consistent with previous years' results.

In Victoria in 2012, GSL payments rose slightly from the previous year, to over $8 million. A large increase in payments for low reliability in the SP AusNet network (from $3.9 million in 2011 to $6.6 million in 2012) was mostly offset by an improved reliability in the Powercor network (whose payments for low reliability fell from $3.5 million to $0.8 million). A rise in GSL payments also occurred in Queensland in 2011–12, largely due to diminished performance in the Ergon Energy network. Ergon Energy had increased instances of failing to adequately notify customers of supply interruptions and a longer average duration of unplanned supply interruptions.

SA Power Networks (South Australia) decreased GSL payments in 2011–12, to $2.6 million from $7.1 million in 2010–11. This fall was largely driven by a fall in payments for supply interruptions, with fewer severe weather events experienced over the year. Aurora Energy (Tasmania) also decreased its GSL payments in 2012–13, while payments by New South Wales networks were at a similar level to those of the previous year.



Woodside

3 UPSTREAM GAS MARKETS


woodside
Alison Barnes

Gas production in eastern Australia is forecast to treble over the next three to five years to satisfy a rapid expansion in liquefied natural gas (LNG) export demand. The development of three projects in Queensland to supply LNG exports is placing significant pressures on the domestic market. Conditions will further tighten when the projects ramp up to full capacity from 2015–18.

Australia's domestic gas supply chain begins with exploration and development activity, which may involve geological surveys and the drilling of wells (figure 3.1). In the commercialisation phase, extracted gas is processed to separate methane from liquids and other gases, and to remove impurities. The two main types 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. In contrast, CSG is a form of gas extracted from coal beds. Rising gas prices and improved extraction techniques have raised commercial interest in developing other types of unconventional gas such as shale and tight gas;[1] Santos began producing shale gas in the Cooper Basin in 2012.

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 in wholesale markets and package it with pipeline transportation services for sale to customers.

This chapter covers gas production and wholesale market arrangements. While it focuses on domestic markets in eastern Australia in which the Australian Energy Regulator (AER) has regulatory responsibilities,[2] it also refers to domestic markets in Western Australia and the Northern Territory, and to LNG export markets. Other segments of the gas supply chain are considered in chapters 4 (transmission and distribution 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 Natural Gas Market 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 2013 Australia's proved and probable (2P) gas reserves stood at around 141 000 petajoules (PJ), comprising 97 000 PJ of conventional natural gas and 44 000 PJ of CSG (table 3.1 and figure 3.2).

Australia produced 2206 PJ of gas in 2012–13, of which half was for the domestic market. Production for domestic use was up 3.3 per cent from levels in 2011–12. The CSG share of production for domestic use was steady at 23 per cent. Around half of Australia's gas production—all currently sourced from offshore basins in Western Australia and the Northern Territory—is exported as LNG. This ratio will increase, with the development of new LNG projects in Queensland and Western Australia (section 3.2.1).

3.1.1 Geographic distribution

Eastern Australia contains around 36 per cent of Australia's gas reserves, of which the majority are CSG reserves in the Surat–Bowen Basin. The basin, which extends from Queensland into northern New South Wales, accounts for 81 per cent of reserves in eastern Australia and supplies 34 per cent of that market. In New South Wales, limited commercial production of CSG occurs in the Sydney and Gunnedah basins. Overall, CSG production in eastern Australia rose by 3 per cent in 2012–13.

The Gippsland Basin off coastal Victoria supplies 37 per cent of the eastern market. Production in Victoria's offshore Otway Basin (15 per cent of eastern production) has risen significantly since 2004.

After several years of decline, Cooper Basin reserves in central Australia rose in the past three years, and were up 14 per cent in the year to June 2013. Production in the basin may continue to rise, with new activity focused on the development of shale gas. Santos commenced production from its shale gas well in the Cooper Basin in 2012.

Western Australia's offshore Carnarvon Basin holds about half of Australia's 2P gas reserves. It supplies about 31 per cent of Australia's domestic market and 99 per cent of Australia's LNG exports.[3] The Bonaparte Basin along the north west coast also produces LNG for export. The Bonaparte Pipeline ships gas from the basin to the Northern Territory for domestic consumption. The basin has now displaced the Amadeus Basin as the main source of gas for the Northern Territory.

3 Data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2013.

Figure 3.1

Domestic gas supply chain

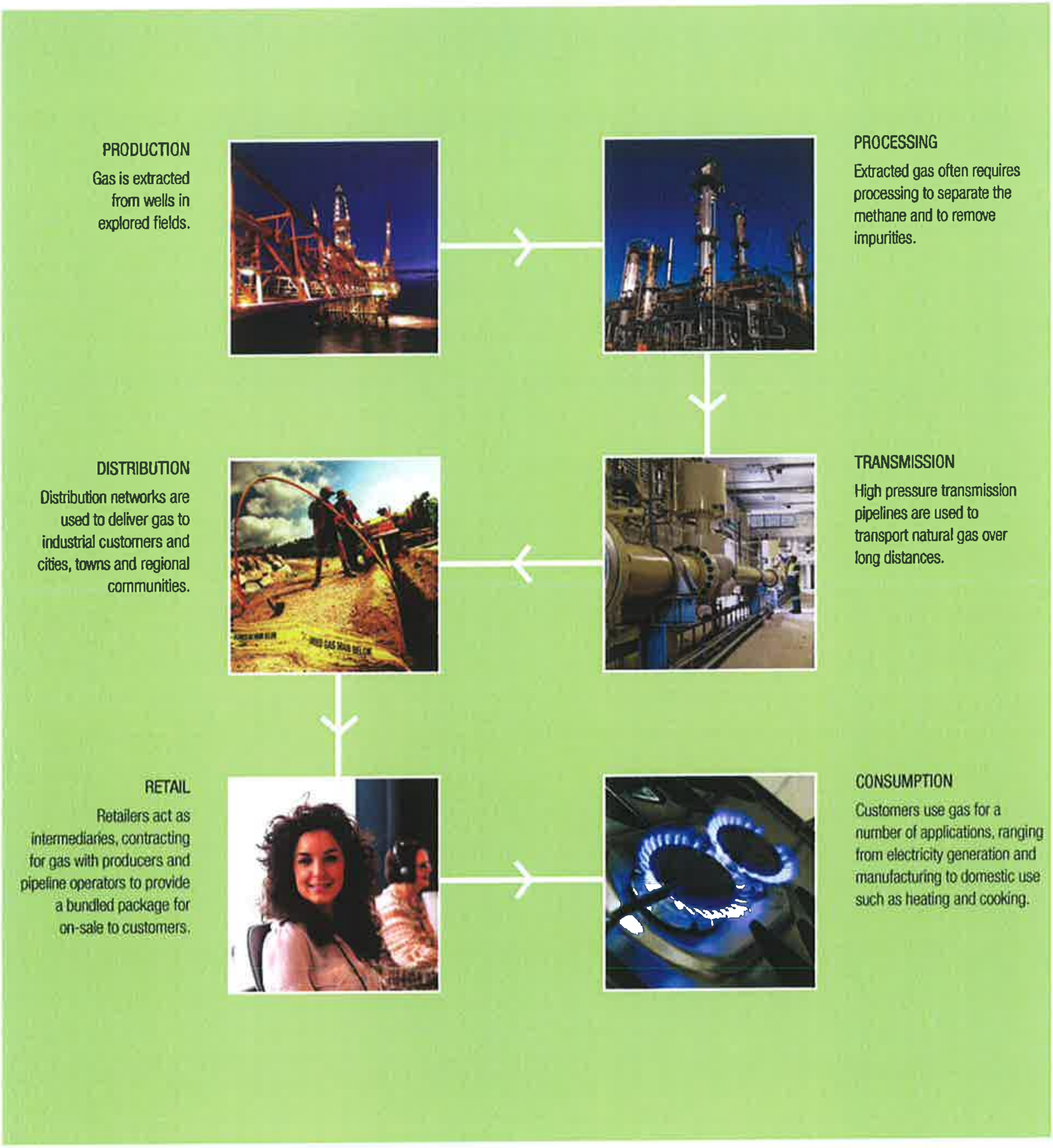


Image sources: Origin Energy, Woodside, Jemena.

Table 3.1 **Gas reserves and production, 2013**

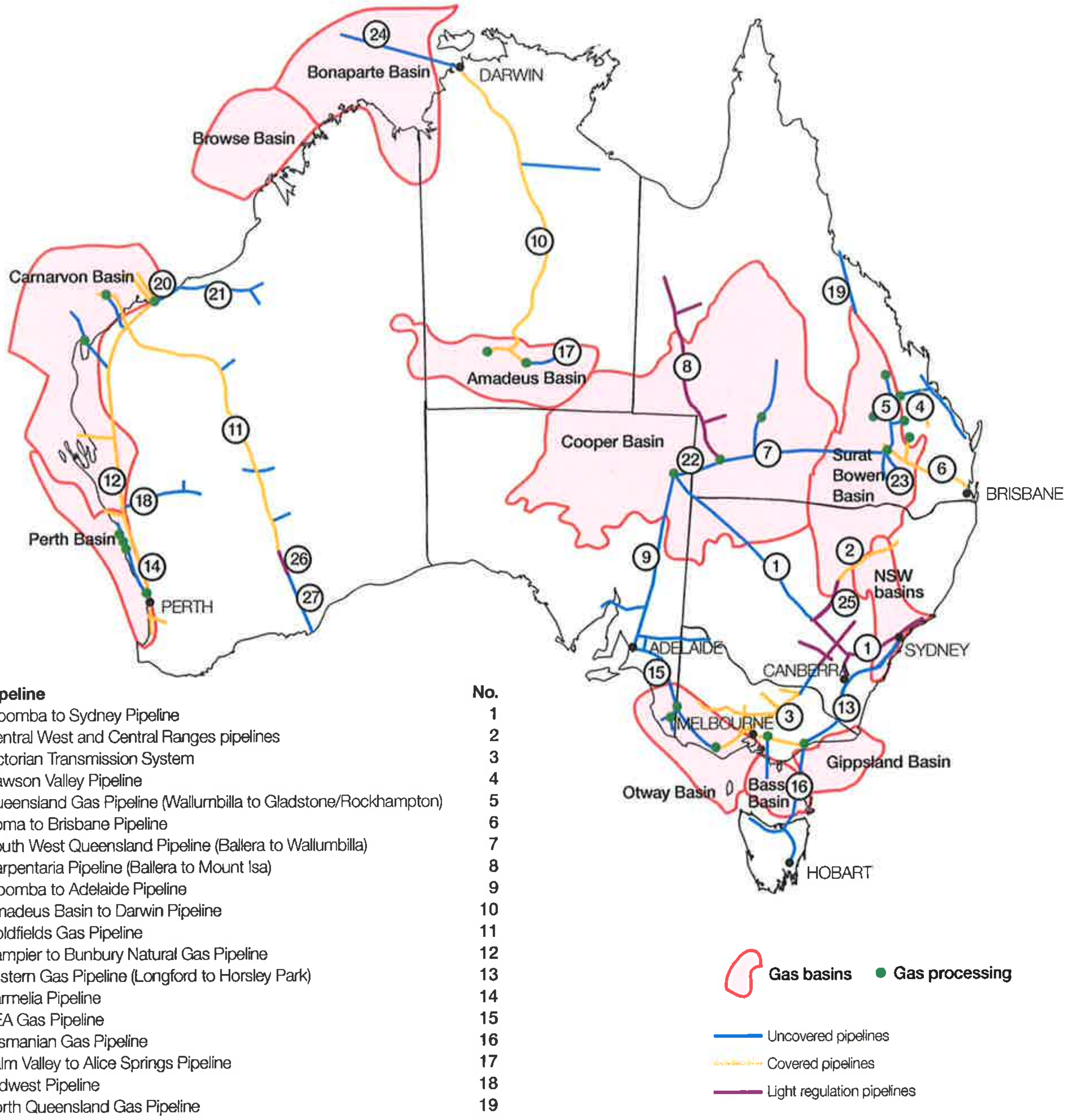
GAS BASIN	PRODUCTION (YEAR TO JUNE 2013)		PROVED AND PROBABLE RESERVES[1] (AUGUST 2013)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS				
EASTERN AUSTRALIA				
Cooper (South Australia–Queensland)	86	7.8	1 992	1.4
Gippsland (Victoria)	274	24.8	3 684	2.6
Otway (Victoria)	109	9.9	821	0.6
Bass (Victoria)	11	1.0	250	0.2
Surat–Bowen (Queensland)	1	0.1	135	0.1
New South Wales basins	0	0.0	16	0.0
WESTERN AUSTRALIA				
Browse	0	0.0	17 384	12.3
Carnarvon	337	30.6	71 855	50.8
Perth	7	0.6	41	0.0
NORTHERN TERRITORY				
Amadeus	0	0.0	138	0.1
Bonaparte	24	2.2	1 054	0.7
Total conventional natural gas	849	77.0	97 370	68.9
COAL SEAM GAS				
Surat–Bowen (Queensland)	248	22.5	41 146	29.1
New South Wales basins	5	0.5	2 805	2.0
Total coal seam gas	254	23.0	43 951	31.1
AUSTRALIAN TOTALS	1 102	100.0	141 321	100.0
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	1 089			
Bonaparte (Northern Territory)	15			
Total liquefied natural gas	1 103			
TOTAL PRODUCTION	2 206			

1. 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.

Source: EnergyQuest, *Energy Quarterly*, August 2013.

Figure 3.2

Australian gas basins and transmission pipelines



Pipeline	No.
Moomba to Sydney Pipeline	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mount Isa)	8
Moomba to Adelaide Pipeline	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24
Central West Pipeline	25
Kalgoorlie to Kambalda Pipeline	26
Kambalda to Esperence Pipeline	27

Source: AER.

3.2 Gas demand

Australia consumed 1102 PJ of gas in 2012–13 (up slightly from 1067 PJ in 2011–12) for industrial, commercial and domestic use. The consumption profile varies across the jurisdictions.

While gas is widely used for industrial manufacturing, around 31 per cent of Australian gas consumption in 2011–12 was for electricity generation.[4] Household demand is relatively small, except in Victoria, where residential demand accounts for around one-third of total consumption. This proportion reflects the widespread use of gas for cooking and heating in that state.

3.2.1 Liquefied natural gas exports

The production of LNG converts gas into liquid. The development of an LNG export facility requires 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, a joint venture arrangement with a gas producer, or long term gas supply contracts.

Australia operates LNG export projects in Western Australia's North West Shelf and Darwin, and is developing new projects in Queensland. Exports of Australian produced LNG rose in 2012–13 by 29 per cent (to 20.1 million tonnes)[5] and major players are continuing to expand capacity:

- Chevron's Gorgon project (Carnarvon Basin) is scheduled to begin operation in 2015 and will produce around 15.6 million tonnes of LNG per year. The project partners have signed long term sales agreements with international buyers. EnergyQuest reported the project was over 67 per cent complete in June 2013. In addition, Chevron committed in September 2011 to the $29 billion Wheatstone project (foundation capacity of 8.9 million tonnes per year). The project is expected to produce its first LNG in 2016.
- Shell's $10–13 billion Prelude floating LNG project (Browse Basin) is under construction and expected to commence production in 2017. The project will produce 3.6 million tonnes per year.
- Construction of Inpex and Total's $34 billion Ichthys LNG project (Browse Basin) commenced in May 2012. The project is expected to produce 8.4 million tonnes of LNG and 1.6 million tonnes of liquefied petroleum gas annually, with production expected to begin in 2016.
- Woodside announced in 2013 that development of the Browse LNG project would involve an offshore project using floating LNG technology. It expects to commence front end engineering and design work in 2014.

In Queensland, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, spurred the development of several LNG projects near the port of Gladstone. Construction of three projects, including transmission pipelines to transport gas to Gladstone, is underway:

- The $20 billion Curtis LNG project (BG Group) will initially produce 8.5 million tonnes per year, with potential capacity of 12 million tonnes. The first exports are expected in 2014.
- The $18.5 billion Gladstone LNG project (Santos, Petronas, Total and Kogas) will initially produce 7.8 million tonnes per year, with potential capacity of 10 million tonnes. The first exports are expected in 2015.
- The $24.7 billion Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) is expected to begin LNG exports in mid 2015, with exports from a second train expected to commence late 2015.

A decision on the development of a fourth project—the Arrow LNG project (Shell and PetroChina)—was delayed to the end of 2013 amid speculation that it may link to one of the other projects.

4 Bureau of Resources and Energy Economics (BREE), *Gas market report*, October 2013, p. 26.

5 LNG production and export data are sourced from EnergyQuest, *Energy Quarterly*, August 2013.

3.3 Industry structure

Six major producers met 66 per cent of domestic gas demand in 2012–13: Santos, BHP Billiton, ExxonMobil, Origin Energy, Woodside and Apache Energy.[6] The mix of players varies across the basins.

3.3.1 Market concentration

Various factors affect market concentration in a gas basin, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Figure 3.3 illustrates estimated market shares in gas production for the domestic market in the major basins. Table 3.2 sets out market shares in 2P gas reserves (including reserves available for export) at August 2013.

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and provide gas to New South Wales, South Australia and Tasmania. A joint venture between ExxonMobil and BHP Billiton accounts for 96 per cent of production in the Gippsland Basin. Nexus, which began production from the Longtom gas project in October 2009, has a 4 per cent market share.

The Otway Basin has a more diverse ownership base, with Origin Energy (31 per cent), BHP Billiton (21 per cent) and Santos (18 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration (AWE).

The growth of the CSG–LNG industry has led to considerable new entry in Queensland's Surat–Bowen Basin over the past decade. The largest producers are BG Group (21 per cent), Origin Energy (17 per cent), ConocoPhillips (17 per cent), Sinopec (11 per cent), Santos (9 per cent), Shell and PetroChina (6 per cent each). Petronas, Total and AGL Energy have smaller shares. The same businesses also own the majority of reserves in the basin.

In 2008 three entities owned 75 per cent of reserves (Origin Energy 35 per cent, Santos 22 per cent and Queensland Gas 18 per cent) in the Surat–Bowen Basin. But new entry and a series of mergers and acquisitions in 2009–11 led to a more diverse market structure (figure 3.4). By 2013 the three largest players jointly owned 44 per cent of reserves (BG Group 20 per cent, and Origin Energy and ConocoPhillips each about 12 per cent).

In central Australia, a joint venture led by Santos (65 per cent) dominates production in the Cooper Basin. The other participants are Beach Petroleum (21 per cent) and Origin Energy (13 per cent).

Several major companies have equity in Western Australia's Carnarvon Basin, which is Australia's largest producing basin. The businesses participate in joint ventures, typically with overlapping ownership interests. Chevron (36 per cent), Shell (17 per cent) and ExxonMobil (14 per cent) have the largest reserves in the basin, given their equity in the Gorgon project.

Woodside (25 per cent) and Apache Energy (24 per cent) are the largest producers for Western Australia's domestic market. Santos (19 per cent), BP and Chevron (9 per cent each), and BHP Billiton and Shell (5.5 per cent each) also have significant market shares.

The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. Eni Australia owns over 80 per cent of Australian reserves in the basin.

3.3.2 Vertical integration

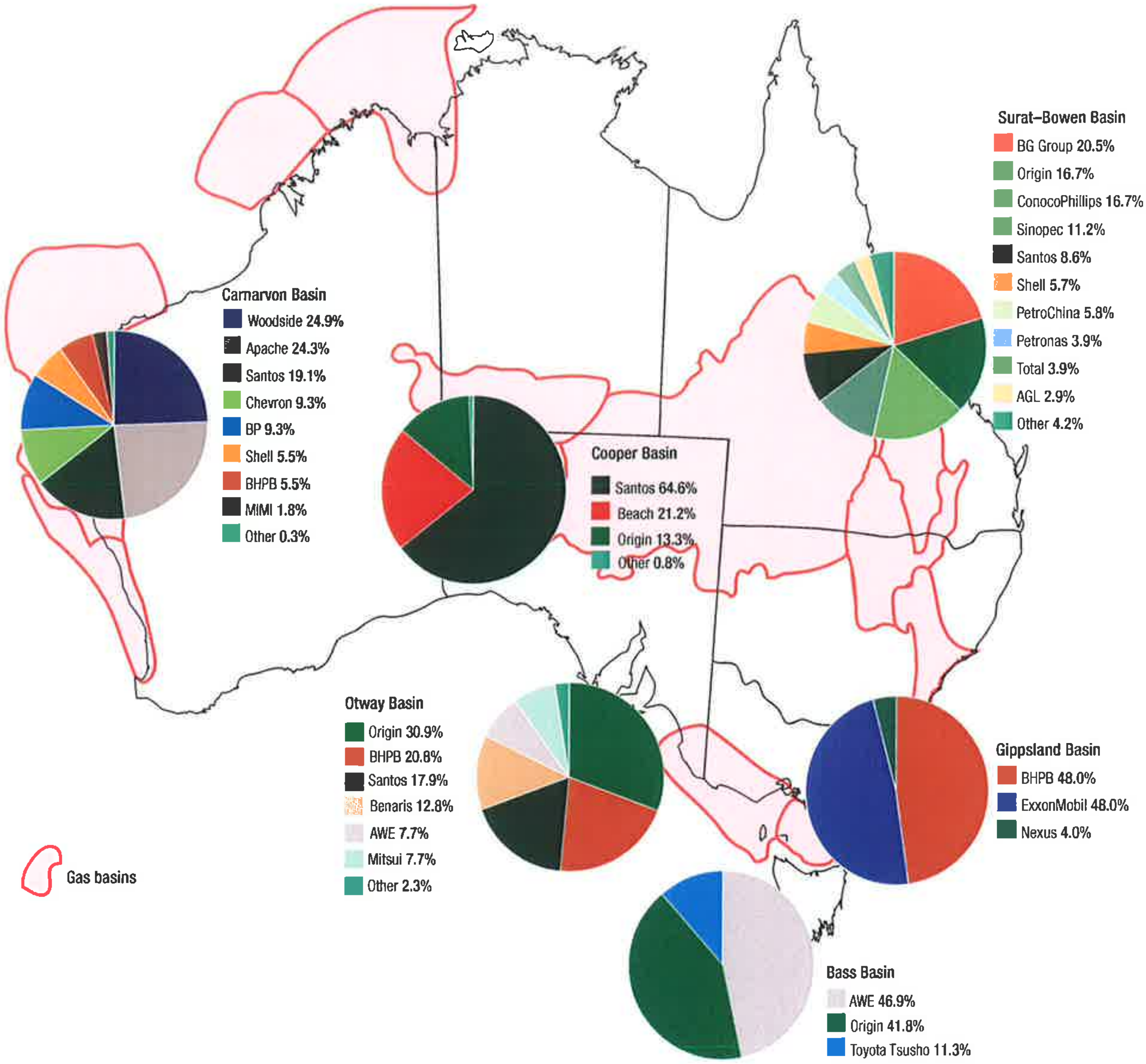
Vertical integration between gas production, gas powered generation and energy retailing is a means by which energy entities manage risk and achieve efficiencies. For example:

- Origin Energy is a leading energy retailer that owns gas powered generation plant in all mainland National Electricity Market (NEM) regions. It has significant equity in CSG production in Queensland and in conventional natural gas production in Victoria's Otway and Bass basins, and a minority interest in gas production in the Cooper Basin. It accounted for 12.5 per cent of gas production in eastern Australia in 2011–12.
- AGL Energy is a leading energy retailer and a major electricity generator in eastern Australia. It owns significant gas powered generation in South Australia and began acquiring CSG interests in Queensland and New South Wales in 2005.
- EnergyAustralia (formerly TRUenergy) is a third major retailer and generator in eastern Australia. It has gas storage facilities in Victoria and acquired gas reserves in the Gunnedah Basin (New South Wales) in 2011.

6 EnergyQuest, *Energy Quarterly*, August 2013.

Figure 3.3

Market shares in domestic gas production, by basin, 2012–13



Note: Excludes LNG.
Data source: EnergyQuest 2013 (unpublished data).

Table 3.2 **Market shares in proved and probable gas reserves, by basin, 2013 (per cent)**

COMPANY	CARNARVON (WA)	BROWSE (WA)	PERTH (WA)	BONAPARTE (WA/NT)	AMADEUS (NT)	SURAT-BOWEN (QLD)	COOPER (SA/QLD)	CLARENCE MORTON (QLD/NSW)	GUNNEDAH (NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	36.3														18.5
Shell	17.3	14.8				10.0									13.6
ExxonMobil	14.3											45.4			8.5
Inpex		53.4		1.7											6.6
BG						19.5									5.7
Woodside	11.1														5.7
Origin			50.8			12.5	12.4						35.0	42.5	4.1
Santos	1.2			1.7	68.2	4.7	63.4		80.0			5.8	18.2		4.0
Total		23.4				3.6									3.9
ConocoPhillips				8.5		12.1									3.6
BHPB	3.8											45.4	12.9		3.2
PetroChina						10.9									3.2
Sinopec						8.1									2.4
CNOOC	1.0					5.6									2.2
BP	4.1														2.1
Apache	3.7														1.9
MIMI	3.1														1.6
AGL						3.2				100.0	100.0				1.3
Petronas						3.6									1.1
Kogas		2.2				1.9									0.8
Eni				86.7											0.6
Kufpec	1.1														0.6
Osaka Gas	0.7	0.9													0.5
Mitsui						1.2							8.4		0.4
Metgasco								96.2							0.2
Beach							18.0								0.2
EnergyAustralia									20.0						0.2
Kansai Electric	0.4														0.2
Toyota Tsusho						0.5							2.6	11.3	0.2
Drillsearch							6.2								0.1
Nexus												3.3			0.1
Benaris													14.5		0.1
AWE			20.9										8.4	46.3	0.1
Magellan					31.8										0.0
Empire oil and gas			21.6												0.0
ERM Power			6.7												0.0
Other	1.9	5.3		1.4		2.6		3.8				0.1			2.4
TOTAL (PETAJOULES)	71 855	17 384	53	1054	180	41 372	1913	355	1426	454	50	3720	820	250	140 887

Notes:

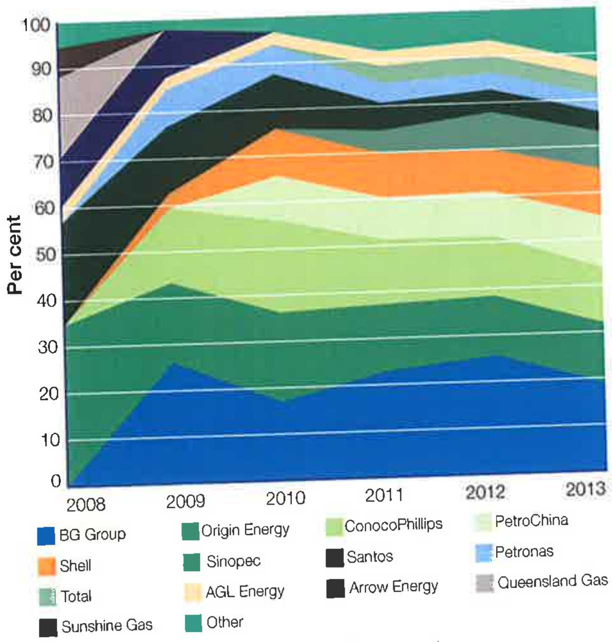
Based on 2P reserves at August 2013.

Not all minority owners are listed.

Source: EnergyQuest 2013 (unpublished data).

Figure 3.4

Market shares in proved and probable reserves, Surat–Bowen Basin, 2008–13



Data source: EnergyQuest 2008–13 (unpublished data).

3.4 Gas wholesale markets

Gas producers sell gas in wholesale markets to major industrial, mining and power generation customers, and to energy retailers that sell it to business and residential customers. Australian gas prices have generally been low by international standards, typically $3–4 per gigajoule. With gas in Australia historically perceived as a substitute for coal and coal fired electricity generation, Australia's low cost coal sources have effectively capped gas prices.

While gas prices were historically struck under confidential, long term contracts, there has been a recent shift towards shorter term contracts, the inclusion of review provisions and the emergence of spot markets:

- A short term trading market for gas was launched in Sydney and Adelaide in 2010, with Brisbane following in 2011 (section 3.4.1). The market provides a means for participants to manage contractual imbalances, and is supported by a National Gas Market Bulletin Board (section 3.4.3).
- Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline network constraints (section 3.4.2).
- In consultation with industry, the Australian Energy Market Operator (AEMO) is developing a gas trading exchange to be located at Queensland's Wallumbilla hub. The exchange is scheduled for launch by March 2014 (section 3.4.4).

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to these spot markets and the bulletin board. Timely and accurate data and efficient pricing maintain confidence in gas markets and encourage efficient investment in energy infrastructure. The AER monitors the markets and bulletin board to improve data provision and to detect any evidence of the exercise of market power. It also draws on this information to publish weekly reports on gas market activity in eastern Australia.

3.4.1 Short term trading market

A short term trading market—a wholesale spot market for gas—has been progressively implemented at selected hubs (junctions) linking transmission pipelines and distribution systems in eastern Australia. AEMO operates the market, which was designed to enhance gas market transparency and competition by setting prices based on supply and demand conditions.[7]

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 retains a separate spot market for gas (section 3.4.2).

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. Market participants include energy retailers, power generators and other large gas users. Shippers deliver gas to be sold in the market, and users buy gas for delivery 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 market schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the market rules require the participants bid in 'good faith'.

Based on the market schedule, shippers nominate the quantity of gas that they require from a pipeline operator,

7 AEMO publishes an explanatory guide on its website: AEMO, *Overview of the short term trading market for natural gas*, 2011.

Box 3.1 Reducing excessive MOS payments

There has been limited new entry in the short term trading market since it commenced in September 2010. The high costs of covering MOS services may be a deterrent. The AER has identified a tendency for excessive MOS payments on high demand days, including during winter in the Sydney and Adelaide market. In some instances, the volume of MOS gas significantly exceeds the magnitude of the underlying physical imbalance in gas volumes.

In the interests of lowering costs for participants, the AER targeted excessive MOS volumes in the Sydney and Adelaide hubs. In particular, the AER found physical design and nomination issues in the Adelaide and Sydney hubs periodically raised MOS volumes above the levels required to balance out inaccurate demand forecasts. In some circumstances, this outcome increased costs for participants.

MOS payments for the Sydney hub rose around the time the Albion Park injection point was introduced in May 2012. The injection point is one of three that supply gas from the Eastern Gas Pipeline into the Sydney hub. In meetings with industry, the AER found the high MOS payments resulted from a market participant underforecasting its demand in the Albion Park area of the distribution network. Subsequently, the participant increased its supply through the Albion Park injection point, resulting in a significant reduction in MOS requirements at the Sydney hub.

In Adelaide, the AER found large amounts of MOS were required on days when participants supplied less gas on the Moomba to Adelaide pipeline (MAP) relative to the SEA Gas Pipeline. The issue peaked on 25 June 2013, when MOS payments in Adelaide exceeded $250 000.[8] The issue partly related to design issues in Envestra's Adelaide distribution network that cause parts of the network to be better served by gas from the MAP than from the SEA Gas Pipeline. In particular, flows on SEA Gas are unable to reach all parts of the Adelaide network, resulting in excessive MOS payments on high demand days.

Following a meeting with industry participants, Envestra committed to investigate solutions to the network design issue and report on the matter by December 2013. The AER expects a resolution of this issue would likely reduce MOS payments in the Adelaide hub in 2014.

which develops a separate schedule for that pipeline to ensure it is kept in physical balance. On the gas day, quantities delivered to and withdrawn from a hub may not match the day-ahead nominations, as a result of 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).

Pipeline operators use balancing gas to prevent imbalances in gas supply to distribution networks if demand forecasts are inaccurate. AEMO procures this balancing gas—market operator services (MOS)—from shippers that have the 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 deviation payments and charges on the parties responsible for the imbalances. The AER has recently taken action to reduce a tendency for excessive MOS payments (box 3.1).

Section 3.5.1 notes recent price activity in the short term trading market. The market has a floor price of $0 per gigajoule and a cap of $400 per gigajoule.

3.4.2 Victoria's gas wholesale market

Victoria introduced a spot market for gas in 1999 to manage gas flows on the Victorian Transmission System and allow market participants to buy and sell gas at a spot price. 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 stacks supply offers and selects the least cost bids to match demand across the market. 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 constraints.[9]

8 AER, *Gas market significant price variation report: MOS service payments*, 25 June 2013, Adelaide STTM.

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

Typically, gas traded at the spot price accounts for 10–20 per cent of wholesale volumes in Victoria, after accounting for net positions. The balance of gas is sourced via bilateral contracts or vertical ownership arrangements between producers and retailers. Section 3.5.1 notes recent price activity.

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.

3.4.3 National Gas Market Bulletin Board

The National Gas Market Bulletin Board, which commenced in July 2008, is a website (www.gasbb.com.au) covering major gas production plants, storage facilities, demand centres and transmission pipelines in eastern Australia. It aims to provide transparent, real-time information on the state of the gas market, system constraints and market opportunities. It covers:

- gas pipeline capabilities (maximum daily volumes) and three day outlooks for capacity and volume, and actual gas volumes
- production capabilities (maximum daily quantities) and three day outlooks for production facilities
- pipeline storage (linepack) and three day outlooks for gas storage facilities
- daily demand forecasts, changes in supply capacity, and the management of gas emergencies and system constraints.

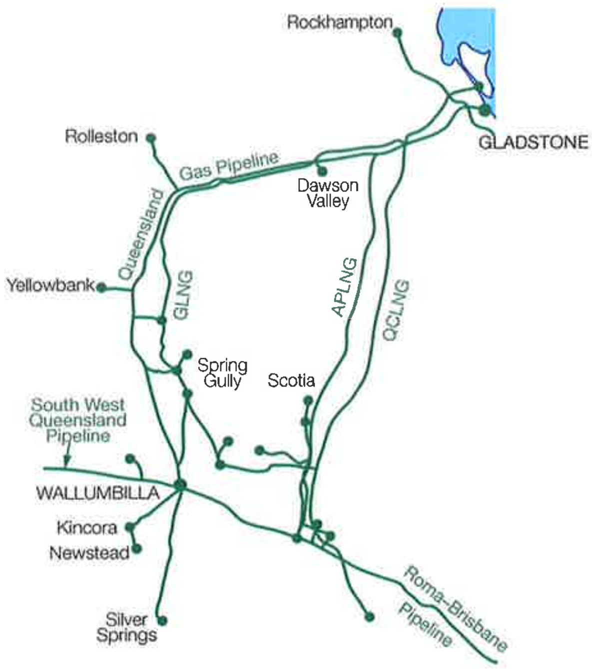
3.4.4 Gas trading exchange at Wallumbilla, Queensland

In consultation with industry, AEMO is progressing the development of a new gas trading exchange at Wallumbilla in Queensland.[10] The exchange is set to be launched by March 2014. Energy ministers commissioned work on the project to support escalating gas development in south east Queensland. In particular, the development of LNG exports

10 For further information, see Standing Council on Energy and Resources and AEMO workstreams.

Figure 3.5

Gas pipelines and production facilities in Wallumbilla area, Queensland



Source: AEMO.

will contribute to Queensland's gas demand rising from 240 PJ per year in 2012 to over 1500 PJ per year by 2016.

Wallumbilla is a major gas supply hub (figure 3.5). As a pipeline interconnection point for the Surat–Bowen Basin, it links gas markets in Queensland, South Australia, New South Wales and Victoria. The diversity of contract positions and the number of participants at Wallumbilla create a natural point of trade.

The new market arrangements aim to promote transparent and efficient gas trading so participants can manage the financial risks associated with variable gas prices. They will also deepen market liquidity by attracting participants such as LNG plants, industrial customers and gas powered generators.

The gas trading exchange will use a brokerage model to match and clear trades between gas buyers and sellers at the Wallumbilla hub's three pipeline delivery points. At market start, AEMO will offer spot and forward products for trade at each delivery point. While the exchange will initially operate only at Wallumbilla, it may later be introduced at other hubs. The flexible design aims to meet industry needs by adapting to the circumstances of any location.

The market design also avoids the need to change infrastructure, operations or contracts. But participants using the gas trading exchange will require access to the transmission pipelines serving the hub, not all of which interconnect. To manage this issue, the gas trading exchange will be supported by a web based platform for participants to advertise their interest in buying or selling gas pipeline capacity in the eastern gas market. AEMO is developing standardised trading terms.

Amendments to the National Gas Law and Rules cover the gas trading exchange. As with other spot markets, the AER will monitor and enforce compliance with the market conduct rules, and report on market activity. It is consulting on its approach with stakeholders. The AER's likely initial focus will be to ensure participants:

- trade only on the basis of gas they intend to physically deliver or receive at the hub
- have sufficient contractual rights to support trades on pipelines at all times.

3.5 Recent developments in east coast gas markets

An interaction of several factors is shifting the dynamics of gas markets in eastern Australia. Rising CSG production, the emergence of spot markets, and improved pipeline interconnection among gas basins have made domestic markets more responsive to customer demand. But the development of LNG export capacity in Queensland is exerting significant pressure on the domestic market.

Gas production in eastern Australia is forecast to treble over the next three to five years to meet international LNG demand,[11] with the first exports scheduled for 2014–15. While Queensland's three LNG proponents each have dedicated gas reserves and pipeline infrastructure, they are also sourcing reserves that might otherwise have been available to the domestic market. This development is making it difficult for domestic customers to source gas under medium to long term contracts.[12]

The effect of these tight conditions was apparent in 2013, with prices in new contracts reportedly linked to international oil prices or LNG netback prices[13] (currently around $10 per gigajoule for export to Japan). Origin Energy and Lumo entered separate gas supply arrangements in 2013 that included explicit links to oil prices.[14] EnergyQuest quoted comments by Santos that some recent gas contract prices are at the upper end of the $6–9 range.[15] A 2013 survey by the Australian Industry Group of over 60 gas using firms estimated recent contract prices for short term delivered gas averaged just over $5 per gigajoule; longer term contract prices averaged $8.72 per gigajoule.[16]

Spot prices for gas also rose in 2012–13, with an above average frequency of price spikes. Average prices rose by 69 per cent in Brisbane,[17] 51 per cent in Sydney, 33 per cent in Melbourne and 34 per cent in Adelaide (section 3.5.1).

Gas market conditions will tighten further when LNG facilities come on line and ramp up to full capacity in 2015–18. While delays affected some projects in 2012, Energy Quest reported favourable weather conditions in 2013 had put back on schedule the development of each project's first train.[18] AEMO forecast that gas supply shortfalls may occur if facilities that are currently dedicated to domestic demand are prioritised to supply LNG export contracts. Without further investment, Queensland could experience a 250 terajoules per day shortfall once all LNG trains reach full output around 2019. If production in Queensland and South Australia is prioritised for export, there would be flow-on effects to New South Wales, with potential shortfalls of 50–100 terajoules per day on winter peak demand days from 2018.[19]

The ramp up to full LNG export capacity will coincide with the expiry of a large number of domestic gas supply contracts. The review and negotiation of contracts in a market exposed to global prices will place further pressure on domestic prices. Overall, contracts covering the supply of around 260 PJ of gas are due to expire by 2018 (figure 3.6). The problem is acute for New South Wales: by 2018, existing contracts will meet less than 15 per cent of that state's gas demand.[20]

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

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

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

14 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013, p.33.

15 EnergyQuest, *Energy Quarterly*, August 2013, p. 100.

16 Australian Industry Group, *Energy shock: the gas crunch is here*, July 2013. The quoted prices include transmission pipeline charges.

17 Brisbane prices rose by 69 per cent when comparing average 2012–13 prices with average prices over the seven month period in 2011–12 (1 December 2011 to 30 June 2012) in which the Brisbane market operated. Brisbane prices rose by 82 per cent when comparing average prices for December 2012 to June 2013 with those of the corresponding period in the previous year.

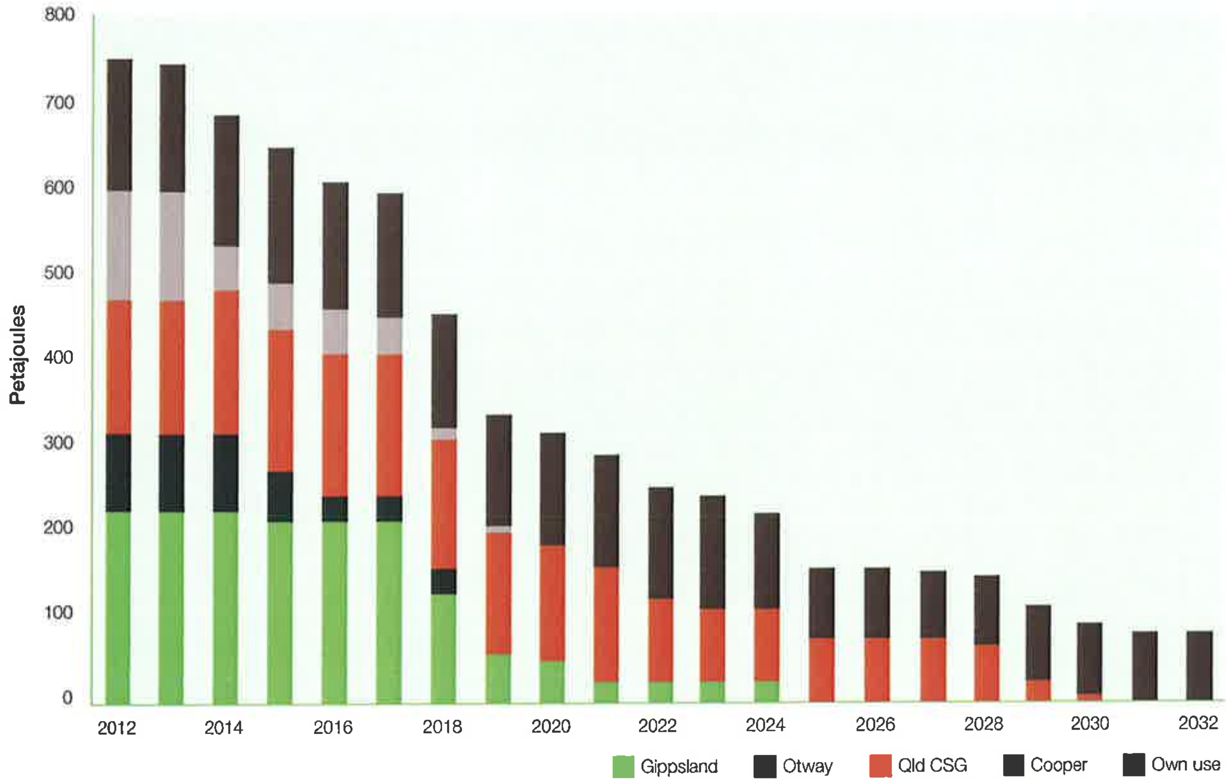
18 EnergyQuest, *Energy Quarterly*, August 2013, p. 64.

19 AEMO, *Gas Statement of Opportunities 2013*, p.iv.

20 BREE, *Gas market report*, October 2013, pp. 17, 41.

Figure 3.6

Contracted gas supply volumes, by basin



Note: Data at May 2012.

Original source: EnergyQuest; graph reproduced in BREE, *Gas market report*, October 2013.

Some domestic producers are increasing supply to meet demand. AEMO reported Victorian gas exports to New South Wales were 46 per cent higher in winter 2013 than a year earlier, and significantly higher than in each of the past four years.[21] APA Group in 2013 committed to an expansion of the Victorian Transmission System (for completion by winter 2015) to support higher export volumes from Victoria to New South Wales. Jemena was also considering an expansion of the Eastern Gas Pipeline to boost capacity into New South Wales, which could be completed by the end of 2015. Elsewhere, Cooper Basin production is also likely to rise, but with the bulk of the increase going into LNG exports.[22]

Interest exists in developing new sources of supply to meet the likely gap in the domestic market. Production from the Kipper Tuna Turrum project in the Gippsland Basin began in 2013. Other proposals relate to the Gunnedah and Gloucester basins in New South Wales, the Ironbark field in the Surat Basin, unconventional sources in the Cooper Basin, and the South Nicholson and Isa Super basins in the Northern Territory and north west Queensland.[23]

The development of coal seam and shale gas resources has raised community concerns about potential impacts on agricultural land use, waterways and native vegetation.[24] These concerns have delayed the development of some projects, notably in New South Wales, which restricted development around communities and water catchments critical to agriculture. EnergyQuest reported in August 2013 that the development of new gas projects in New South Wales had stalled since that state's government announced an exclusion zone policy in February 2013. It also noted widespread anti-CSG protest action, with many

21 AEMO, *Energy update*, October 2013.

22 EnergyQuest, *Energy Quarterly*, August 2013, p. 19.

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

24 See, for example, ACIL Allen Consulting, *NSW coal seam gas*, Report to the Australian Petroleum Production and Exploration Association (APPEA), 2013, p. 2.

farmers and environmentalists seeking tighter restrictions on CSG developments.[25]

Another uncertainty is how rapidly new supplies could be brought online to fill the likely gap in the domestic market. A number of proposed projects remain in the exploration stage and will require the development of new production facilities and transmission pipelines. Additionally, their development may need to be underwritten by long term foundation contracts, leaving it unclear how much capacity would be available for short term contracting.[26]

While LNG export demand is projected to rise exponentially, a countervailing market influence is flatter domestic demand for gas, especially for electricity generation. Gas powered generation accounts for 31 per cent of domestic gas demand in Australia.[27] Subdued electricity demand, the continued rise in renewable generation, the Coalition Government's intention to abolish carbon trading, rising gas prices and the cessation of the Queensland Gas Scheme (which mandated a minimum rate of gas powered generation) have weakened projections on gas powered generation.

AEMO forecast that domestic gas demand would decline until 2016, followed by a gradual recovery (figure 13 in market overview). The sharpest contraction is for gas powered generation, with a forecast annual average decline of 9.8 per cent between 2014 and 2022.[28] EnergyQuest agreed, expecting total domestic gas demand to fall from its peak of around 720 PJ in 2012 to 600 PJ by 2020.[29] In contrast, LNG demand is expected to rise from zero to around 1450 PJ by that time, accounting for around 70 per cent of total gas demand in eastern Australia.[30]

The net impact of these dynamic shifts in domestic demand and supply are difficult to predict, but east coast gas prices are likely to continue rising until at least 2014, and remain significantly above cost until all Queensland LNG projects are fully producing from their own reserves (around 2019–20).

Policy makers are implementing reforms to help alleviate pressures in the eastern gas market. The most advanced reform is a gas trading exchange at Wallumbilla, Queensland, set for launch in March 2014 (section 3.4.4). The exchange aims to alleviate bottlenecks in the tight Queensland gas market by facilitating short term gas trades.

In other developments, the Standing Council on Energy and Resources (SCER) consulted in 2013 on possible reforms to pipeline capacity trading to promote trade in idle contracted capacity in the eastern gas market. Throughout the year, some pipelines have significant idle capacity that is contracted to gas retailers and industrial consumers. SCER consultations with industry identified stakeholder interest in improving access to this unused capacity via a transparent, market based mechanism. Capacity trading could make more efficient use of existing infrastructure by reallocating idle capacity and allowing the delivery of additional gas to the market. The reform may be particularly useful to small participants, which lack the scale to invest in transmission capacity.[31]

An AEMC scoping study published in September 2013 proposed consideration of further measures. These measures included strategically planning gas market development, refining spot market design, and streamlining the processes for making rule changes that affect gas spot markets.[32]

3.5.1 Spot market prices

The Victorian wholesale gas market and the short term trading market for Sydney, Adelaide and Brisbane establish spot gas prices. Sections 3.4.1–3.4.3 provide background on these markets.

Table 3.3 sets out average annual spot prices, while figure 3.7 illustrates weekly averages. Figure 3.8 illustrates recent winter prices. The data are ex ante prices derived from demand forecasts. These prices form the main basis for settlement in the Victorian and short term trading markets. Design differences between the markets limit the validity of price comparisons. In particular, the Victorian market is for gas only, while prices in the short term trading market cover gas and transmission pipeline delivery to the hub. For comparison, the data include estimates for Melbourne gas prices, based on the Victorian wholesale price plus the estimated cost of transmission pipeline delivery to the metropolitan hub.[33]

25 EnergyQuest, *Energy Quarterly*, August 2013, p. 77.

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

27 BREE, *Gas market report*, October 2013, p. 26.

28 AEMO, Gas Statement of Opportunities 2013, p.8.

29 EnergyQuest, *Energy Quarterly*, August 2013, p. 19.

30 AEMO, *Gas Statement of Opportunities 2013*, p.8.

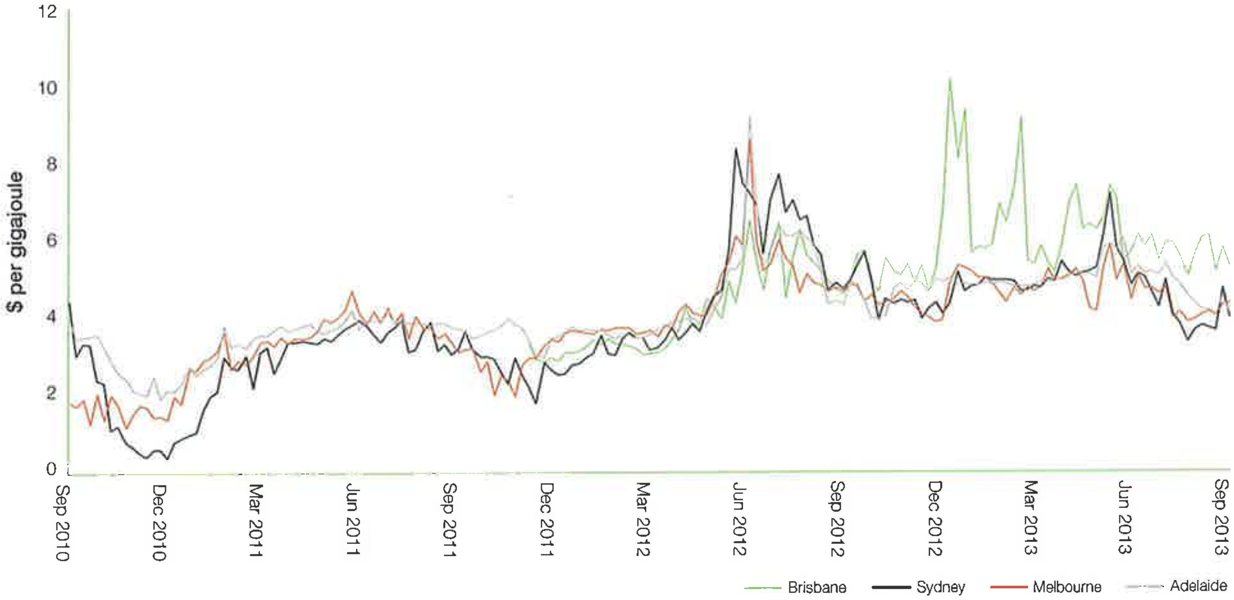
31 Standing Council on Energy and Resources officials, *Regulation impact statement: gas transmission pipeline capacity trading*, Consultation Paper, 15 May 2013.

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

33 The Sydney data in table 3.3 and figures 3.7 exclude the 1 November 2010 price of $150 per gigajoule, which data errors caused.

Figure 3.7

Spot gas prices—weekly averages



Notes (table 3.3 and figure 3.7): Volume weighted ex ante prices. 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 the period 1 December 2011 (market start) to 30 June 2012.

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

Table 3.3 **Average daily spot gas prices ($ per gigajoule)**

	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
2012–13	5.92	5.20	4.86	5.09
2011–12	3.51	3.45	3.65	3.79
2010–11		2.37	2.74	3.17

Average daily spot prices for gas in all markets were significantly higher in 2012–13 than in the previous year (table 3.3). Average prices rose by 69 per cent in Brisbane,[34] 51 per cent in Sydney, 33 per cent in Melbourne and 34 per cent in Adelaide. They ranged from $4.86 (Melbourne) to $5.92 (Brisbane).

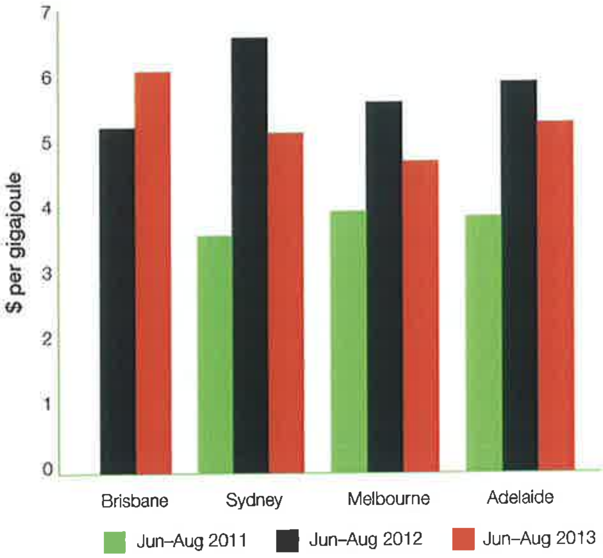
Spot gas prices have trended higher since 2010, when outcomes below $3 per gigajoule were typical. A step change occurred during winter 2012, when the introduction of carbon pricing on 1 July 2012 improved the cost competitiveness of gas powered electricity generation. The closure of significant coal fired generation capacity around this time (section 1.3.3) appears to have reinforced a rise in demand for gas.

Additionally, the AER detected market participants driving prices higher than expected in the early weeks of carbon pricing. This influence was indicated by significant variations between forecast prices, ex ante prices and ex post prices. Further, the quality of demand forecasting by participants was poor on a number of days. This period also coincided with the usual seasonal peaks in demand that occur in winter, and with a significant tightening in the contract market for gas in eastern Australia (section 3.5). In combination, these factors caused winter gas prices in 2012 to rise to above $5 per gigajoule in all spot markets, with Sydney prices averaging almost $7 per gigajoule (figure 3.8).

Gas prices eased during spring 2012, settling at around $4–5 per gigajoule. They generally remained in that range in 2013. But market volatility was considerable, with an above average frequency of price spikes. Notably, Brisbane prices diverged markedly from prices in other markets in 2013, with weekly averages as high as $10 per gigajoule in January 2013. This development mirrored higher contract prices in Queensland (section 3.5).

34 Brisbane prices rose by 69 per cent when comparing average 2012–13 prices with average prices over the seven month period in 2011–12 (1 December 2011 to 30 June 2012) in which the Brisbane market operated. Brisbane prices rose by 82 per cent when comparing average prices for December 2012 to June 2013 with the corresponding period in the previous year.

Figure 3.8
Spot gas prices—winter



Notes: Volume weighted ex ante prices. Sydney, Adelaide and Brisbane data are short term trading market prices in each hub. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff for the two Melbourne metropolitan zones.

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

Sydney prices briefly spiked in June 2013 during a week of cold temperatures and high demand. But winter demand was mostly subdued, resulting in prices for all hubs easing slightly after June 2013. In Victoria, a mostly mild winter and a reduction in gas powered generation contributed to an overall 8.8 per cent decrease in gas demand during winter 2013.[35] But prices in all hubs remained well above longer term averages. Additionally, Brisbane prices remained significantly higher than elsewhere.

Overall, winter prices were lower in 2013 than in the previous year in Melbourne (16 per cent lower), Sydney (22 per cent) and Adelaide (10 per cent). Prices peaked at $9.50 per gigajoule in Sydney (on 25 June), $6.02 per gigajoule in Adelaide (on a number of days in June and July) and $7.31 per gigajoule in Melbourne (on 24 June). Brisbane reflected a different trend: its average winter price was 16 per cent higher in 2013 than in 2012, peaking at $8.01 per gigajoule on 23 June.

35 AEMO, *Energy update*, October 2013.

3.6 Upstream competition

An interconnected transmission pipeline system links the major gas basins in southern and eastern Australia (chapter 4). While gas tends to be purchased from the closest possible source to minimise transport costs, pipeline interconnection provides energy customers with greater choice and enhances the competitive environment for gas supply. Gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are served by multiple transmission pipelines from multiple gas basins; by contrast, Brisbane is served by only one pipeline (Roma to Brisbane).

The bulletin board (section 3.4.3) provides real-time information on the gas market, to enhance transparency and competition. The AER draws on the bulletin board to report weekly on gas market activity in eastern Australia. Its reporting covers gas flows on particular pipelines and from competing basins to end markets.

Figure 3.9 illustrates recent trends in gas delivery from competing basins into New South Wales, Victoria and South Australia since the bulletin board opened in July 2008:

- While New South Wales historically relied on Cooper Basin gas shipped on the Moomba to Sydney Pipeline, gas shipped on the Eastern Gas Pipeline from Victoria's Gippsland Basin now supplies an equivalent proportion of the state's gas requirements. Gas flows on the Moomba to Sydney Pipeline show significant seasonal fluctuations, while flows on the Eastern Gas Pipeline are relatively steady. Victorian gas exports to New South Wales, via the Eastern Gas Pipeline and the New South Wales – Victoria Interconnect, were 46 per cent higher during winter 2013 than a year earlier.[36]
- 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 3.9 illustrates the seasonal nature of Victorian gas demand, with significant winter peaks.
- While the Moomba to Adelaide Pipeline historically transported most of South Australia's gas from the Cooper Basin and more recently from the Surat–Bowen Basin, the SEA Gas Pipeline now transports greater volumes of gas to South Australia from Victoria's Otway Basin.

36 AEMO, *Energy update*, October 2013.

The extent to which interconnection benefits customers depends on a range of factors, including the availability of gas and pipeline capacity from alternative sources. In particular, capacity constraints limit access to some pipelines. Access seekers must decide whether to try to negotiate a capacity expansion. For a covered pipeline, the regulator may be asked to arbitrate a dispute over capacity expansions.

3.7 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. Given Australia's increasing reliance on gas powered electricity generation, gas storage enhances the security of energy supply. It does so by allowing for system injections at short notice to better manage peak demand and emergencies. It also allows producers to meet contract requirements if production is unexpectedly curtailed. And it provides retailers with a hedging mechanism if gas demand is significantly above forecast.

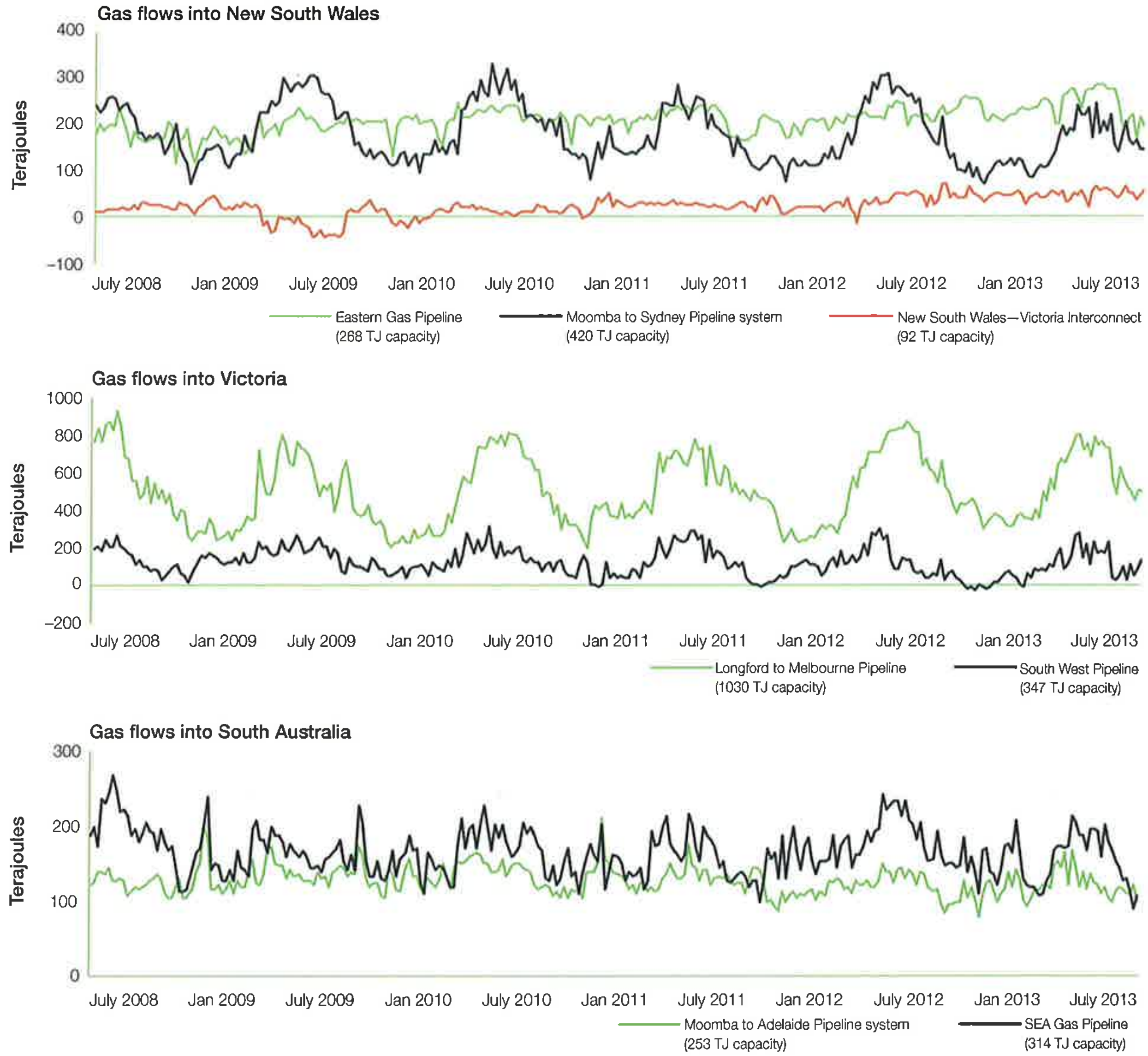
Conventional gas storage facilities are located in Victoria, Queensland and the Cooper Basin. In Victoria, the largest facility is the Iona gas plant (owned by EnergyAustralia) which has 22 PJ of storage capacity and can deliver 570 terajoules of gas per day. In Queensland, AGL Energy in August 2011 began injecting and storing gas underground at the depleted Silver Springs reservoir in central Queensland. The facility will support the development of the Curtis LNG project; it will also allow AGL Energy to manage its gas supply during seasonal variations in summer and winter. EnergyQuest estimated the facility held around 18 PJ in storage in June 2013.[37]

The Dandenong LNG storage facility in Victoria (0.7 PJ) is Australia's only LNG storage facility. It provides the Victorian Transmission System with additional capacity to meet peak demand and provide security of supply. In New South Wales, AGL Energy is constructing a $300 million LNG storage facility near Newcastle to secure supply during peak periods and supply disruptions. Due to be completed by 2015, the facility will have a peak supply rate of 120 terajoules per day.

37 Energy Quest, *Energy Quarterly*, August 2013, p. 111.

Figure 3.9

Gas flows in eastern Australia



Note: Negative flows on the New South Wales – Victoria Interconnect represent flows out of New South Wales into Victoria.

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

Jemena

4 GAS PIPELINES

Gas pipelines provide a transportation link between upstream gas producers and downstream energy customers. This chapter focuses on gas pipelines in jurisdictions for which the Australian Energy Regulator (AER) has regulatory responsibilities—namely, those in 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.

The construction of new pipelines and the expansion of existing facilities in the past decade has completed an interconnected pipeline network running from Queensland to Tasmania. This interconnection has enhanced the competitive environment for gas producers, pipeline operators and gas retailers, and improved security of supply. While Western Australia and the Northern Territory have also had significant pipeline investment, they have no transmission interconnection with other jurisdictions.

A network of *distribution* pipelines delivers gas from demand hubs to industrial 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.

Gas is reticulated to most Australian capital cities, major regional areas and towns. The total length of gas distribution networks in eastern Australia is around 74 000 kilometres. The networks have a combined asset value of $8 billion.

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 3.1 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.

4.1 Ownership

Australia's gas pipelines are privately owned. APA Group is the principal owner in both gas transmission and distribution, through both direct ownership and its interest in Envestra. State Grid Corporation of China and Singapore Power International own a number of pipelines through Jemena and SP AusNet (tables 4.1 and 4.2).

4.1.1 Transmission pipeline ownership

APA Group, a publicly listed company, has the most extensive portfolio of gas transmission assets in Australia. It owns three pipelines in New South Wales (including the Moomba to Sydney Pipeline), the Victorian Transmission System, five major Queensland pipelines (including three pipelines linking the Cooper Basin in central Australia to 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.

During 2012 APA Group acquired Epic Energy's gas transmission portfolio from Hastings Diversified Utilities Fund. The Epic portfolio included the Moomba to Adelaide Pipeline System (MAPS), the South West Queensland Pipeline and QSN Link, and the Pilbara Energy Pipeline (in Western Australia). The Australian Competition and Consumer Commission (ACCC) did not oppose the acquisition, after accepting a court enforceable undertaking from the APA Group to divest MAPS. APA Group in May 2013 completed the sale of MAPS to QIC Global Infrastructure for $400 million.

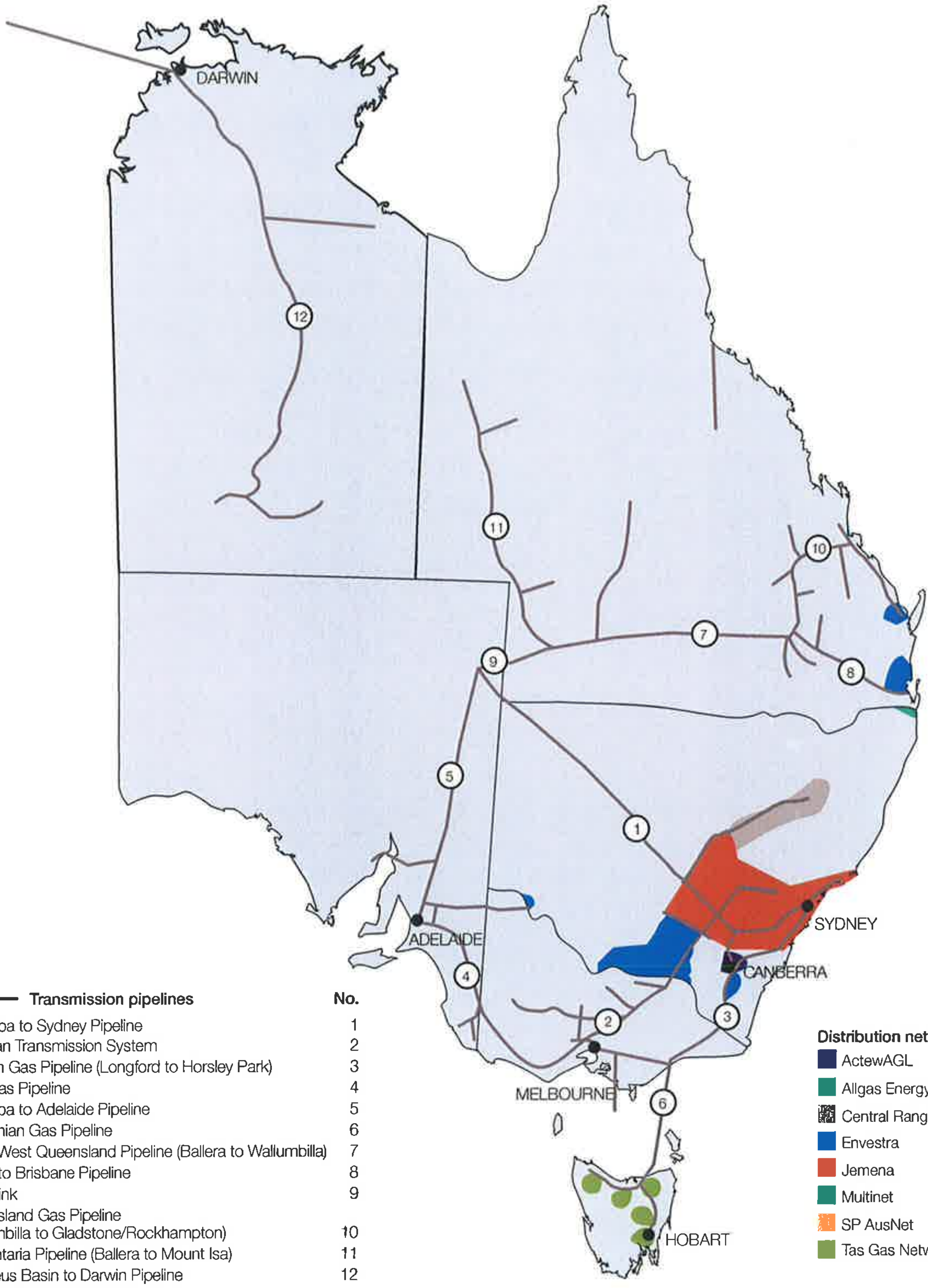
Jemena owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline. *Singapore Power International* contracted to sell a 60 per cent stake in Jemena to *State Grid Corporation of China* in 2013, but retain a 40 per cent minority share. The transaction was before the Foreign Investment Review Board in November 2013.

4.1.2 Distribution network ownership

The major gas distribution networks in southern and eastern Australia are privately owned, with four principal players:

- *Envestra*, a public company in which APA Group (33 per cent) and Cheung Kong Infrastructure (17 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.
- *Jemena* owns the principal New South Wales gas distribution network (Jemena Gas Networks) and has a 50 per cent share of the ACT network (ActewAGL). As noted, *Singapore Power International* contracted to sell a 60 per cent stake in Jemena to *State Grid Corporation of China* in 2013, but retain a 40 per cent minority share. Singapore Power International also has equity interests in Victoria's SP AusNet gas distribution network.

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
Amadeus Basin to Darwin Pipeline	12

Distribution networks
- ActewAGL
- Allgas Energy
- Central Ranges System
- Envestra
- Jemena
- Multinet
- SP AusNet
- Tas Gas Networks

Source: AER.

Table 4.1 Major gas transmission pipelines

PIPELINE	LENGTH (KM)	CAPACITY (TJ/D)	CONSTRUCTED	COVERED?
EASTERN AUSTRALIA				
QUEENSLAND				
North Queensland Gas Pipeline	391	108	2004	No
Queensland Gas Pipeline (Wallumbilla to Gladstone)	629	142	1989–91	No
Carpentaria Pipeline (Ballera to Mount Isa)	840	119	1998	Yes (light)
Berwyndale to Wallumbilla Pipeline	113		2009	No
Dawson Valley Pipeline	47	30	1996	Yes
Roma (Wallumbilla) to Brisbane Pipeline	440	219	1969	Yes
Wallumbilla to Darling Downs Pipeline	205	400	2009	No
South West Queensland Pipeline (Ballera to Wallumbilla)	756	181	1996	No
QSN Link (Ballera to Moomba)	180	212	2009	No
NEW SOUTH WALES				
Moomba to Sydney Pipeline	2029	420	1974–93	Partial (light)
Central West Pipeline (Marsden to Dubbo)	255	10	1998	Yes (light)
Central Ranges Pipeline (Dubbo to Tamworth)	300	7	2006	Yes
Eastern Gas Pipeline (Longford to Sydney)	795	268	2000	No
VICTORIA				
Victorian Transmission System (GasNet)	2035	1030	1969–2008	Yes
South Gippsland Natural Gas Pipeline	250		2006–10	No
VicHub		150 (into Vic)	2003	No
SOUTH AUSTRALIA				
Moomba to Adelaide Pipeline	1185	253	1969	No
SEA Gas Pipeline (Port Campbell to Adelaide)	680	303	2003	No
TASMANIA				
Tasmanian Gas Pipeline (Longford to Hobart)	734	129	2002	No
NORTHERN TERRITORY				
Bonaparte Pipeline	287	80	2008	No
Amadeus Gas Pipeline	1512	104	1987	Yes
Daly Waters to McArthur River Pipeline	330	16	1994	No
Palm Valley to Alice Springs Pipeline	140	27	1983	No

km, kilometres; TJ/d, terajoules per day.

1. Singapore Power International contracted to sell a 60 per cent stake in Jemena to State Grid Corporation of China in 2013, but retain a 40 per cent minority share. The transaction was before the Foreign Investment Review Board in November 2013.

Sources: Capacity: National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites. Other data: access arrangements for covered pipelines; EnergyQuest, *Energy Quarterly* (various issues); corporate websites, annual reports and media releases.

VALUATION ($ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
160 (2005)	Not required	Victorian Funds Management Corporation	AGL Energy, Arrow Energy
	Not required	Jemena (State Grid Corporation 60%, Singapore Power International 40%)[1]	Jemena Asset Management
	Not required	APA Group	APA Group
70 (2009)	Not required	APA Group	APA Group
8 (2007)	2007–16	Westside 51%, Mitsui 49%	Westside
418 (2012)	2012–17	APA Group	APA Group
90 (2009)	Not required	Origin Energy	Origin Energy
	Not required	APA Group	APA Group
165 (2009)	Not required	APA Group	APA Group
835 (2003)	Not required	APA Group	APA Group
28 (1999)	Not required	APA Group	APA Group
53 (2003)	2005–19	APA Group	Jemena Asset Management
450 (2000)	Not required	Jemena (State Grid Corporation 60%, Singapore Power International 40%)[1]	Jemena Asset Management
618 (2013)	2013–17	APA Group	APA Group, AEMO
50 (2012)	Not required	DUET Group	Jemena Asset Management
	Not required	Jemena (State Grid Corporation 60%, Singapore Power International 40%)[1]	Jemena Asset Management
370 (2001)	Not required	QIC Global Infrastructure	Epic Energy SA
500 (2003)	Not required	APA Group 50%, Retail Employees Superannuation Trust 50%	APA Group
440 (2005)	Not required	Palisade Investment Partners	Tas Gas Networks
170 (2008)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
92 (2011)	2011–16	APA Group	APA Group
	Not required	Power and Water	APA Group
	Not required	Envestra (APA Group 33.4%, Cheung Kong Infrastructure 18.9%)	APA Group

Notes:

For covered pipelines subject to full regulation, valuation refers to the opening capital base for the current regulatory period. For non-covered pipelines, listed valuations are estimated construction costs, subject to the availability of data.

Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden. The covered portion became a light regulation pipeline in 2008. The listed valuation of the pipeline is that determined by the Australian Competition Tribunal for the regulatory period before the pipeline converted from full to light regulation.

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)	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Allgas Energy	84 400	2 900	432	135	343	1 Jul 2011–30 Jun 2016	APA Group 20%, Marubeni 40%, RREEF 40%
Envestra	89 100	2 640	323	142	315	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33%, Cheung Kong Infrastructure 17%)
NEW SOUTH WALES AND ACT							
Jemena Gas Networks (NSW)	1 050 000	24 430	2 425	759	2 316	1 Jul 2010–30 Jun 2015	Jemena (State Grid Corporation 60%, Singapore Power International 40%)[3]
ActewAGL	124 000	4 720	292	92	295	1 Jul 2010–30 Jun 2015	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50% [3]
Wagga Wagga	23 800	680	62	21	51	1 Jul 2010–30 Jun 2015	Envestra (APA Group 33%, Cheung Kong Infrastructure 17%)
Central Ranges System	7 000	180	na	na	na	2006–19	APA Group
VICTORIA							
SP AusNet	602 000	9 860	1 255	459	870	1 Jan 2013–31 Dec 2017	Listed company (Singapore Power International 31%, State Grid Corporation 20%)[3]
Multinet	668 000	9 960	1 038	239	827	1 Jan 2013–31 Dec 2017	DUET Group
Envestra	587 400	10 220	1 100	396	834	1 Jan 2013–31 Dec 2017	Envestra (APA Group 33%, Cheung Kong Infrastructure 17%)
SOUTH AUSTRALIA							
Envestra	410 700	7 790	1 036	500	1 046	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33%, Cheung Kong Infrastructure 17%)
TASMANIA							
Tas Gas Networks	9 800	730	122	Not regulated	Not regulated	Not regulated	Tas Gas (Brookfield Infrastructure)
TOTALS	3 656 200	74 110	8 086	2 742	6 897		

na, Not available.

1. For Tasmania, the asset base value is an estimated construction cost. For other networks, it is the initial capital base, adjusted for additions and deletions, as reset at the beginning of the current access arrangement period.
2. Investment data are forecasts for the current access arrangement period, typically of five years duration.
3. Singapore Power International contracted to sell a 60 per cent stake in Jemena to State Grid Corporation of China in 2013, but retain a 40 per cent minority share. The transaction was before the Foreign Investment Review Board in November 2013.

Note: Asset base, investment and revenue data are converted to June 2012 dollars.

Sources: Access arrangements for covered pipelines; company websites.

- *APA Group* has minority interests in Envestra and the Allgas Energy network in Queensland, and owns the Central Ranges system in New South Wales. It manages and operates these assets. APA Group in July 2013 approached Envestra with a proposal for the two businesses to merge. In August 2013 Envestra rejected the proposal.
- *DUET Group* owns Multinet in Victoria.

The ownership links between gas and electricity networks are significant. Jemena, SP AusNet, APA Group, Cheung Kong Infrastructure and DUET Group all 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 pipelines in jurisdictions other than Western Australia, in which the Economic Regulation Authority is the regulator.

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 regulates five transmission pipelines and 10 distribution networks under full regulation, including:

- transmission pipelines supplying Brisbane, Melbourne and Darwin (table 4.1)
- all major distribution networks in New South Wales, Victoria, Queensland, South Australia and the ACT.

An *Access arrangement guideline* (available on the AER website) details the regulatory process. Separate guidelines address dispute resolution and compliance with obligations under the National Gas Law. Figure 4.2 sets out the timelines for regulatory reviews of transmission pipelines and distribution networks.

In summary, the regulator assesses the revenues needed to cover efficient costs (including a benchmark return on capital), then derives reference tariffs for the pipeline. It uses a building block model that accounts for a pipeline's operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and a return on capital. Figure 4.3 illustrates the revenue components of Queensland's Roma to Brisbane Pipeline (2012–17) and Victorian distribution networks (2013–17).

The largest component is the return on capital, accounting 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) affect the return on capital. An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

The rules allow for income adjustments via incentive mechanisms that reward efficient operating practices. In a dispute, an access seeker may request the regulator to arbitrate on and enforce the terms and conditions of the access arrangement. Regulatory decisions on full regulation pipelines are subject to merits review by the Australian Competition Tribunal (section 4.4).

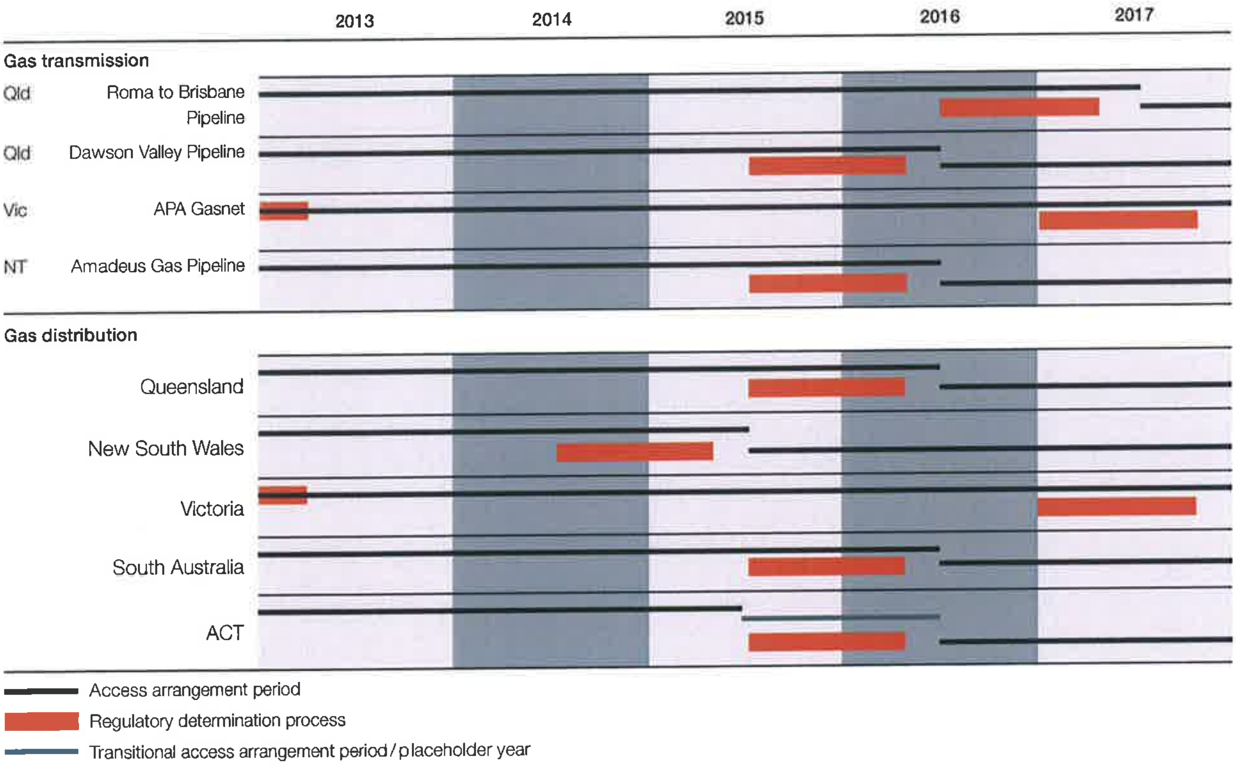
4.2.2 Reforms to setting the rate of return

Following a rule change proposal by the AER in 2011, the Australian Energy Market Commission (AEMC) in November 2012 implemented a common approach to setting the rate of return for the electricity and gas sectors. The new rule requires a holistic assessment of the overall rate of return that a benchmark entity needs to meet its efficient costs. The AER was previously locked into a parameter-by-parameter assessment of the rate of return, with limited scope to consider the appropriateness of the overall allowance. Additionally, the regulatory assessment can now account for a wider range of information, allowing for decisions that better reflect conditions in capital markets.

4.2.3 Light regulation

A pipeline may, in some circumstances, 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 New South Wales are subject to light regulation. No distribution network is currently subject to light regulation.

Figure 4.2
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.

4.2.4 Changes in coverage status

The National Gas Law includes a mechanism for reviewing whether a particular 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 recent coverage reviews:

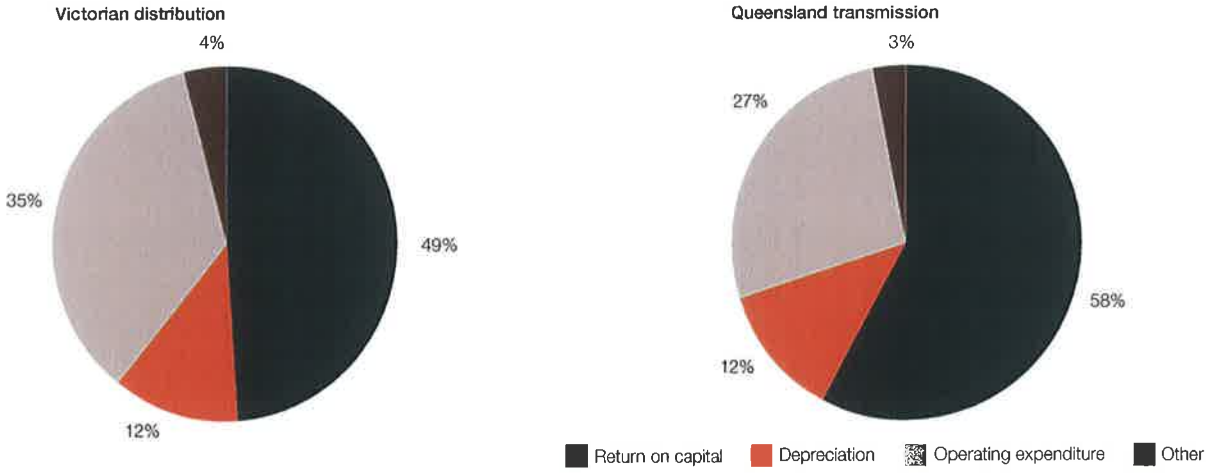
- Kimberly-Clark Australia in November 2012 applied to the National Competition Council (NCC) for coverage of the South Eastern Pipeline System (a 70 kilometre pipeline in South Australia), which QIC Global Infrastructure owns. On advice from the NCC, the South Australian Minister for Mineral Resources and Energy determined in October 2013 that the pipeline would not be covered.
- Envestra in May 2013 applied to the NCC to have coverage of its Wagga Wagga distribution network (New South Wales) revoked. In August 2013 the NCC recommended coverage should not be revoked.

  In September 2013 the New South Wales Minister for Resources and Energy informed the NCC he was unable to make a decision until the State Government considers the outcomes of the AEMC's review of retail competition in the state.

The Gas Law also enables the federal Minister for Resources and Energy to grant a 15 year 'no coverage' determination for new pipelines in certain circumstances. Following recommendations from the NCC, the Minister granted 'no coverage' determinations for three pipelines supplying gas from the Surat–Bowen Basin to LNG projects on Curtis Island in Queensland:

- BG Group's Queensland Curtis LNG Pipeline (July 2010)
- the Australia Pacific LNG Gladstone Pipeline (August 2012)
- the Gladstone LNG pipeline (June 2013).

Figure 4.3
Indicative composition of gas pipeline revenues



Source: AER.

4.3 Recent AER decisions on gas pipelines

The AER released final decisions on regulatory reviews for Victoria's gas transmission and distribution networks in March 2013.

4.3.1 Victorian gas transmission system

In March 2013 the AER released a final decision on APA GasNet's access arrangement proposal for the Victorian gas transmission system for 2013–17. The decision approved:

- revenues that are 22 per cent below the level proposed by APA GasNet
- reference tariffs that are 19 per cent below those proposed by APA GasNet.

The differences between the final decision and the network's proposal related to:

- the use of a lower rate of return than that proposed (7.22 per cent compared with APA GasNet's proposed 8.09 per cent)
- allowing for less depreciation than proposed ($56.3 million compared with APA GasNet's proposed $136.3 million).

The decision will reduce a typical residential gas bill by $5 per year (compared with an average price increase of $6 per year under APA Group's proposal). Elements of the decision were varied following a review by the Australian Competition Tribunal (section 4.4).

4.3.2 Victorian gas distribution networks

In March 2013 the AER released final decisions on revised access arrangement proposals for Victoria's three gas distribution networks—Multinet, Envestra and SP AusNet—for 2013–17. The decisions approved:

- revenues that are 6–10 per cent below those proposed by the network owners
- capital expenditure levels that are 8–23 per cent below proposed levels
- operating expenditure levels that are up to 8 per cent below proposed levels.

The differences between the final decisions and the networks' proposals related to:

- the use of a lower rate of return on capital than that proposed
- lower expectations of capital expenditure requirements than those proposed, especially in relation to distribution mains replacement
- revised operating expenditure requirements that were more in line with historical levels.

The decisions will reduce a typical residential gas bill by $5 per year for customers in the SP AusNet network (compared with a proposed average price increase of $13). Typical bills will increase by $3 per year (compared with a proposed increase of $19) for Multinet customers and $16 per year (compared with a proposed increase of $56) for Envestra customers.

Elements of the decisions were varied following a review by the Australian Competition Tribunal (section 4.4).

4.4 Tribunal reviews of regulatory decisions

Regulatory decisions on access arrangement proposals are subject to merits review by the Australian Competition Tribunal. In May 2013 Multinet applied to the Tribunal for review of the AER's decision on its Victorian gas distribution network. It sought review of the use of the Essential Services Commission of Victoria's (ESC) capital expenditure benchmark for 2012 to set the opening capital base for the network.

In July 2013 the Tribunal directed the AER to calculate the opening capital base by reference to Multinet's conforming capital expenditure in 2012, and not to the ESC benchmark. The AER remade its decision in October 2013, which increased the opening capital base by $30 million.

Also in May 2013 APA GasNet applied to the Tribunal for a review of the AER's decision on its Victorian gas transmission system. APA GasNet sought review of:

- the calculation of depreciation
- the rate of return—specifically, the cost of equity
- adjustments to reference tariffs to account for the delay between 1 January 2013 (the start of the regulatory period) and 1 July 2013 when the new tariffs take effect
- adjustments to the opening capital base.

In September 2013 the Tribunal found in the AER's favour on the first two matters above and in APA GasNet's favour on the remaining two matters. The Tribunal's decision resulted in additional revenue of $13.7 million to APA Group over the regulatory period.

4.5 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 the regulated and unregulated transmission sector has occurred since 2010. Additionally, a number of major projects are under construction or have been announced for development. In eastern Australia:

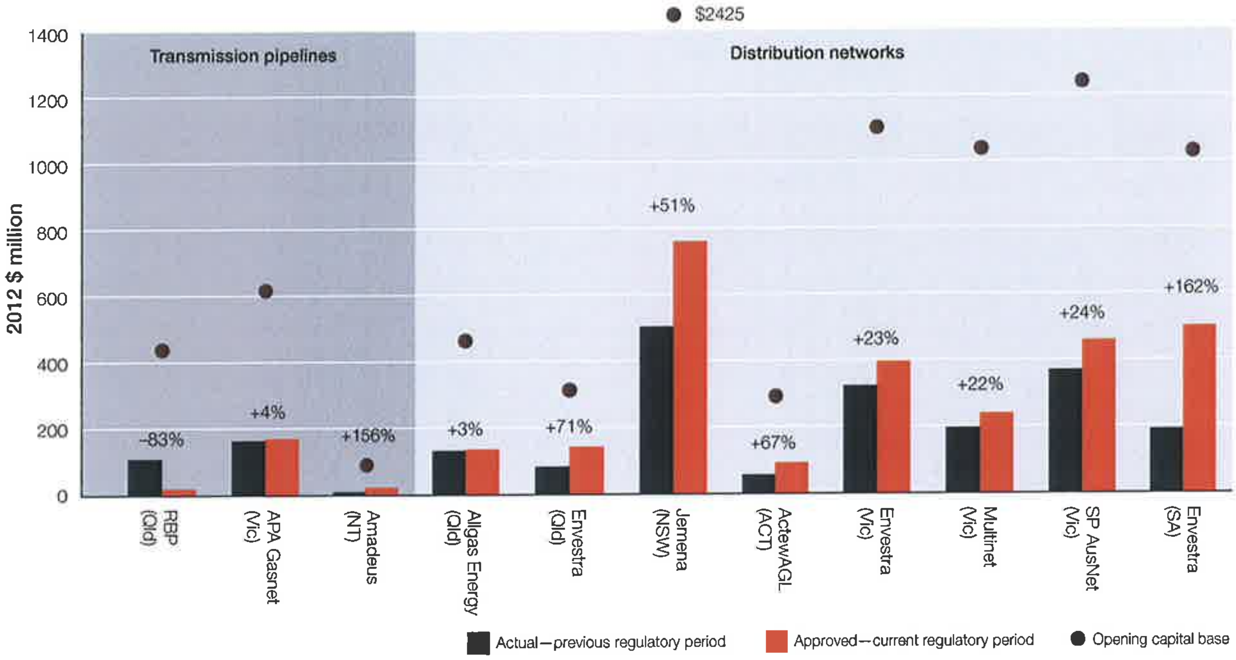
- APA Group completed a $760 million stage 3 expansion of the South West Queensland Pipeline in 2012. The expansion loops the existing 937 kilometre pipeline by building an adjacent pipeline that effectively doubles capacity. APA Group is re-configuring the pipeline for bi-directional operation by mid-2014, with an eastern haul capacity of about 340 terajoules per day. APA Group will install additional compression at Moomba and Wallumbilla by 2014–15 as part of this project.
- APA Group completed a 10 per cent capacity expansion of the Roma to Brisbane Pipeline in September 2012. It also completed a five year capacity expansion of the Moomba to Sydney Pipeline. It announced in November 2013 it will expand capacity on the northern zone of the Victorian Transmission System by 145 per cent. The expansion stems from new gas transportation and storage services agreements between APA Group and Origin Energy, EnergyAustralia and Lumo Energy to support an increase in gas sales from Victoria to New South Wales. The expansion is due for completion by winter 2015.
- construction is underway on three major transmission pipelines in Queensland (each around 400 kilometres in length) to transport gas from the Surat–Bowen Basin to Gladstone for processing and export as LNG
- Pacific Aluminium released in May 2013 a draft environmental impact statement for a 603 kilometre pipeline from Katherine to Gove. The proposed pipeline is part of a project to convert the Gove alumina refinery in the Northern Territory from fuel oil to natural gas.
- APA Group and Armour Energy announced in June 2013 they had entered into a non-binding agreement to transport gas from Armour Energy's northern Australia gas fields to various markets. The arrangement involves constructing a 350 kilometre gas pipeline (initial capacity of 130 petajoules per year) that connects the gas fields with the Ballera to Mount Isa Pipeline.
- Jemena was in late 2013 considering an expansion of the Eastern Gas Pipeline linking eastern Victoria with Sydney, for possible completion by the end of 2015.

Investment in *distribution* networks in eastern Australia—including investment to augment capacity—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 aging networks, and the maintenance of capacity to meet customer demand.

Figure 4.4 illustrates recent investment 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 periods.

For *distribution* networks, investment is forecast to increase by an average 47 per cent in the current access arrangement periods, compared with previous periods. Investment is equal, on average, to 34 per cent of the

Figure 4.4
Pipeline investment—five year period



Notes:

Forecast capital expenditure in the current access arrangement period (typically five years), compared with actual levels in previous periods. See tables 4.1 and 4.2 for the timing of regulatory 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.

networks' opening capital bases. Forecast growth is highest in Envestra's Queensland and South Australian networks (up 71 per cent and 162 per cent respectively). More recent regulatory reviews reflect a moderation in growth. The decisions for Victoria's distribution networks, for example, allow for investment to rise by an average 23 per cent in 2013–17, compared with previous periods.

4.6 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, revenues are forecast to increase in the current access arrangement periods, compared with previous periods, by an average 11 per cent. The largest increases will be for Envestra's networks in South Australia and Queensland (43 per cent and 42 per cent respectively).

The drivers include rising asset bases associated with greater investment (resulting in higher returns on capital). Some outcomes reflect a rise in underlying costs, including operating and maintenance expenditure and capital financing costs.

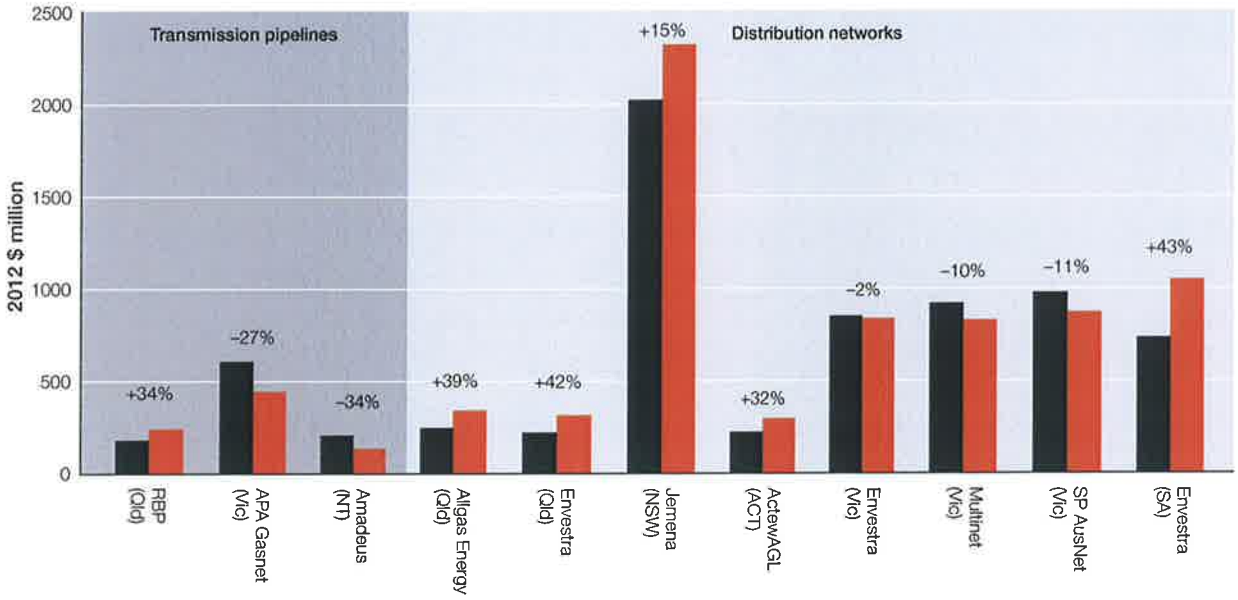
Regulatory reviews since 2012 reflect reductions in the risk free rate that have lowered the overall cost of capital. The decisions for Victoria's distribution networks in 2013 will result in revenues falling by an average 8 per cent in 2013–17, compared with revenues in 2008–12.

4.6.1 Operating expenditure

Operating and maintenance costs are a key driver of pipeline revenue requirements. Figure 4.6 illustrates recent 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 increase in the current access arrangement

Figure 4.5
Pipeline revenues—five year period



Note: 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.

periods by an average 15 per cent, compared with actual expenditure in previous periods. Outcomes vary across the networks, with the largest increases forecast for the Allgas Energy (Queensland) and ActewAGL (ACT) networks (each by 28 per cent).

Regulatory decisions in 2013 for Victoria's distribution networks allow for operating expenditure to rise on average by 13 per cent in 2013–17 from that in 2008–12.

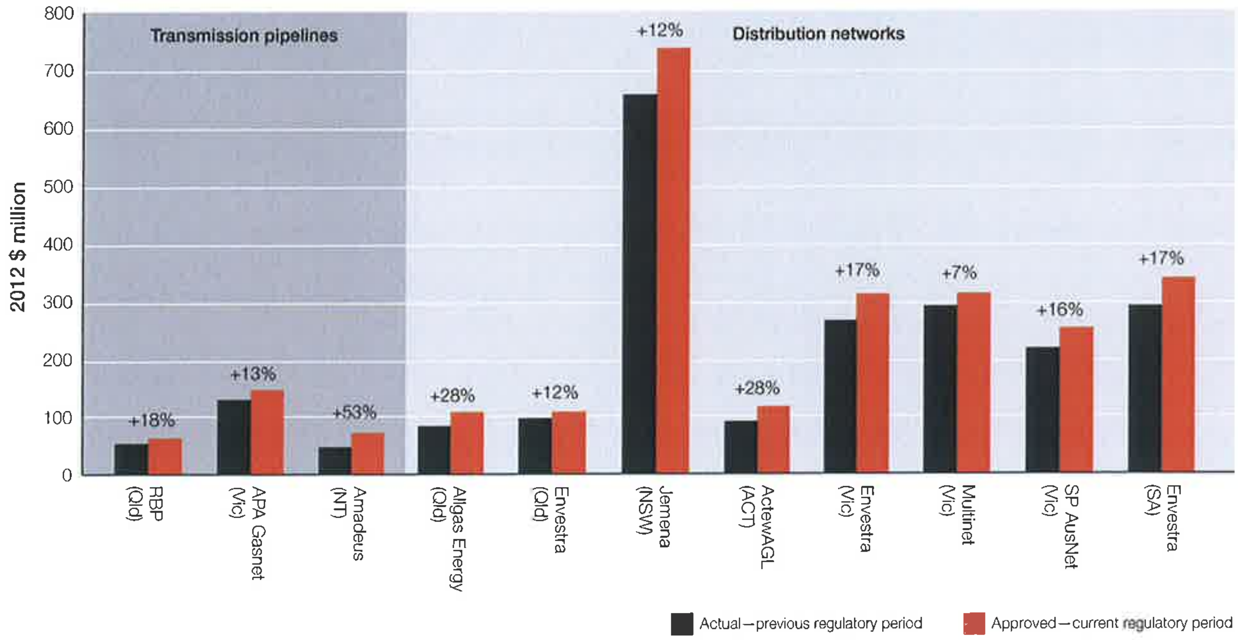
4.6.2 Retail impacts of regulatory decisions

Gas *transmission* charges typically make up 3–8 per cent of a residential gas bill. The percentage is significantly higher for industrial users. The 2012 regulatory decision on Queensland's Roma to Brisbane Pipeline is expected to cause almost no change in a typical residential customer's bill over the five years of the determination. In Victoria, the 2013 decision on APA GasNet's Victorian transmission pipeline will result in a typical residential bill falling by around 0.4 per cent per year.

Gas *distribution* charges typically make up 40–60 per cent of a residential gas bill. In recent years, rising capital and operating expenditure, as well as other cost drivers (including higher financing costs and the rising cost of unaccounted for gas) raised gas distribution costs, leading to retail charges for residential customers rising by 5–6 per cent per year (figure 4.7).

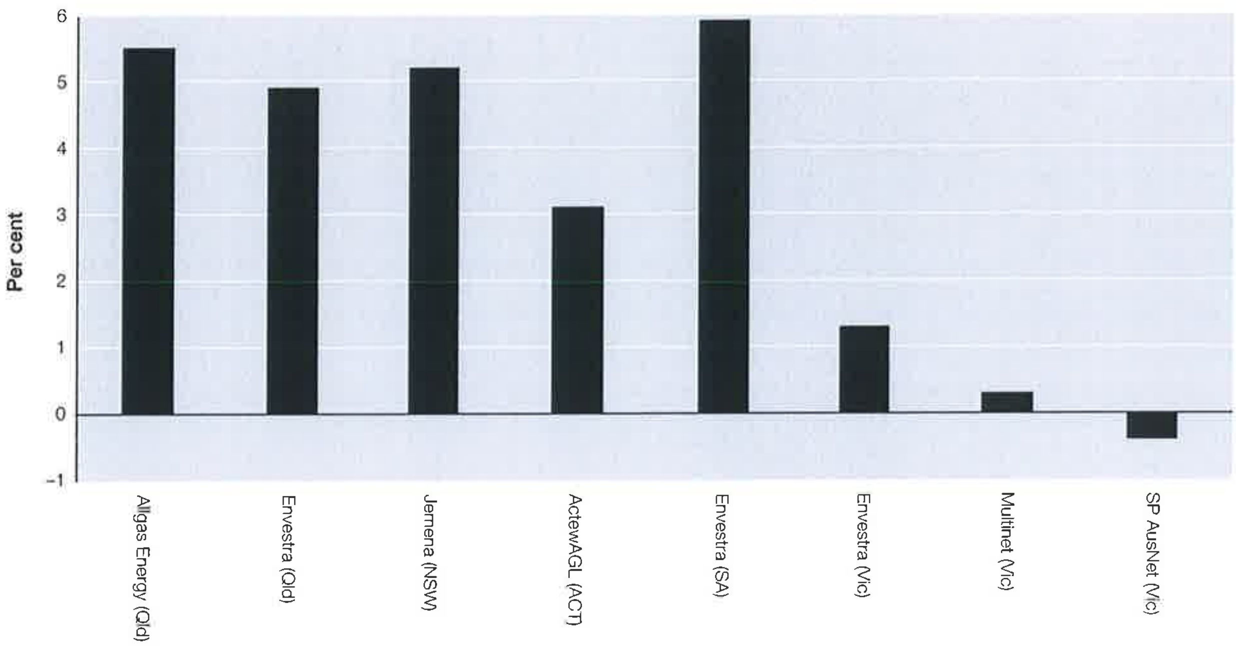
However, the 2013 regulatory decisions for the Victorian distribution networks have little impact on customer charges over 2013–17. Charges will rise annually by around 1.3 per cent for the Envestra network and 0.3 per cent for Multinet. Customer charges for SP AusNet customers are expected to fall by around 0.4 per cent annually. A key reason for this trend is that reductions in the risk free rate have lowered the overall cost of capital for gas networks.

Figure 4.6
Pipeline operating expenditure—five year period

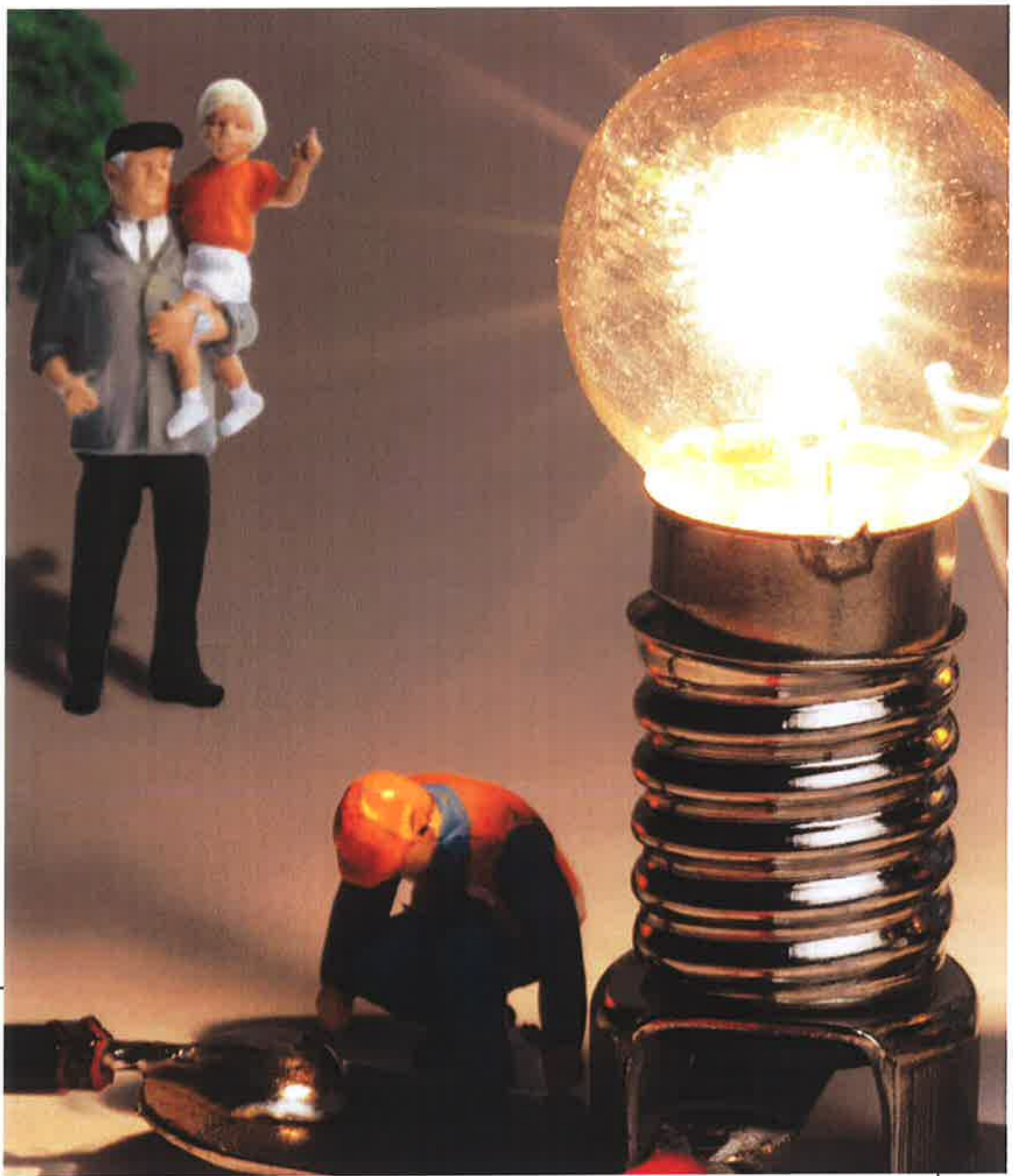


Note: Forecast operating expenditure in the current period, compared with actual levels in previous periods. The data account for the impact of decisions by the Australian Competition Tribunal.
Source: AER final decisions on access arrangements.

Figure 4.7
Annual impact of AER decisions on residential gas charges



Note: Impact on annual gas charges for a typical residential customer in that jurisdiction in the current access arrangement period. See table 4.2 for the timing of regulatory periods. The data account for the impact of decisions by the Australian Competition Tribunal.
Source: AER final decisions on access arrangements.



5 ENERGY RETAIL MARKETS

Energy retailers buy electricity and gas in wholesale markets and package it with network (transportation) services for sale to customers. While state and territory governments have been responsible for regulating retail energy markets, the Australian Energy Regulator (AER) has taken on significant functions under national energy reforms. The National Energy Retail Law (Retail Law) protects small energy customers—that is, residential energy users and small businesses annually consuming less than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas.[1]

5.1 Energy retailers

Table 5.1 lists licensed energy retailers that were active in the market for residential and small business customers in October 2013. Active retailers are those that supply energy services to customers (whether or not they are seeking new customers). The number of active retailers steadily increased over the past 10 years, following the introduction of full retail contestability in most jurisdictions.

Not all retailers are active in every jurisdiction. However, all retailers active at October 2013 were authorised to sell in each jurisdiction that adopted the Retail Law.[2] In considering whether to enter a particular market, a retailer considers a range of factors, including whether prices are regulated (and the level of those prices), the size of the market, the extent of competition, the ability to acquire hedging contracts to manage risk and, for gas retailing, whether wholesale gas contracts and pipeline access can be negotiated.

Around half of all active retailers offer to supply both electricity and gas in at least some of the jurisdictions in which they are active. Other retailers offer only electricity, and one retailer specialises in gas (Tas Gas Retail, which operates in Tasmania). Reasons for the lower competition in gas may include the smaller market (that is, not all households have a gas connection) and the difficulties that new entrant retailers face in contracting for wholesale gas supplies.

Victoria has the most active retailers selling to small customers, for both electricity (18) and gas (nine). Queensland, New South Wales and South Australia each have 12–13 electricity retailers and three to six gas retailers.

New entry occurred in retail markets in 2012–13, with People Energy commencing electricity retailing in Victoria. And some existing retailers—notably, Diamond Energy and Simply Energy (Queensland), Click Energy (New South Wales) and Qenergy (New South Wales and Victoria)—widened the geographic range of their activity. Further, two retailers that previously sold only electricity moved into the retail gas market: Alinta Energy (Victoria and South Australia) and Dodo Power & Gas (Victoria).

5.2 Retail market structure

Australia's retail energy markets tend to be highly concentrated. Three or fewer retailers account for more than 90 per cent of electricity market share in four of the six jurisdictions. Similar ratios apply in gas. In addition, substantial vertical integration exists between retailers and energy producers.

Three privately owned businesses—AGL Energy, Origin Energy and EnergyAustralia (formerly TRUenergy)—are the leading energy retailers in southern and eastern Australia (figure 5.1). The three jointly supplied 77 per cent of small electricity customers and over 85 per cent of small gas customers in southern and eastern Australia at 30 June 2013. Their combined market share fell by 2 per cent in 2012–13, mainly as a result of competition from smaller retailers in the New South Wales and Victorian electricity markets. Overall AGL Energy gained some market share (mainly in New South Wales), but largely at the expense of Origin Energy and EnergyAustralia.

Growth in the market share of smaller retailers in 2012–13 was mostly for relatively new entrants with less than 1 per cent share in any regional market. More established retailers such as Simply Energy and Lumo Energy did not have a significant change in their customer base. But in August 2013 AGL Energy acquired Australian Power & Gas, reversing most of the market share gains by the smaller retailers over the previous year.

Victoria has the highest penetration of smaller private retailers, which accounted for 27 per cent of electricity customers and 18 per cent of gas customers in 2013. In South Australia, smaller retailers accounted for 17 per cent of electricity customers and 8 per cent of gas customers.

1 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.

2 Some limitations apply, including a restriction on selling electricity to customers in Tasmania that consume less than 50 MWh of electricity per year.

Table 5.1 **Active energy retailers—small customer market, October 2013**

RETAILER	OWNERSHIP	QLD	NSW	VIC	SA	TAS	ACT
ActewAGL Retail	ACT Government and AGL Energy		E, G*				E*, G*
AGL Energy	AGL Energy	E, G*	E, G*	E*, G*	E*, G		
Alinta Energy	Alinta Energy			E, G	E, G		
Aurora Energy	Tasmanian Government					E*, G	
Australian Power & Gas	AGL Energy	E, G	E, G	E, G			
BlueNRG	BlueNRG			E			
Click Energy	Click Energy	E	E	E			
Diamond Energy	Diamond Energy	E		E	E		
Dodo Power & Gas	M2 Telecommunications Group	E	E	E, G			
EnergyAustralia	CLP Group	E	E*, G	E*, G*	E, G		E, G
Ergon Energy	Queensland Government	E*					
Lumo Energy	Infratil	E	E, G	E, G	E		
Momentum Energy	Hydro Tasmania (Tasmanian Government)		E	E	E		
Neighbourhood Energy	Alinta Energy			E			
Origin Energy	Origin Energy	E*, G*	E*, G*	E*, G*	E, G*		E
People Energy	People Energy			E			
Powerdirect	AGL Energy	E	E	E	E		
Powershop	Meridian Energy			E			
Qenergy	Qenergy	E	E	E	E		
Red Energy	Snowy Hydro[1]		E	E, G	E		E
Sanctuary Energy	Living Choice Australia/Sanctuary Life	E	E		E		
Simply Energy	International Power	E		E, G	E, G		
Tas Gas Retail	Brookfield Infrastructure					G	

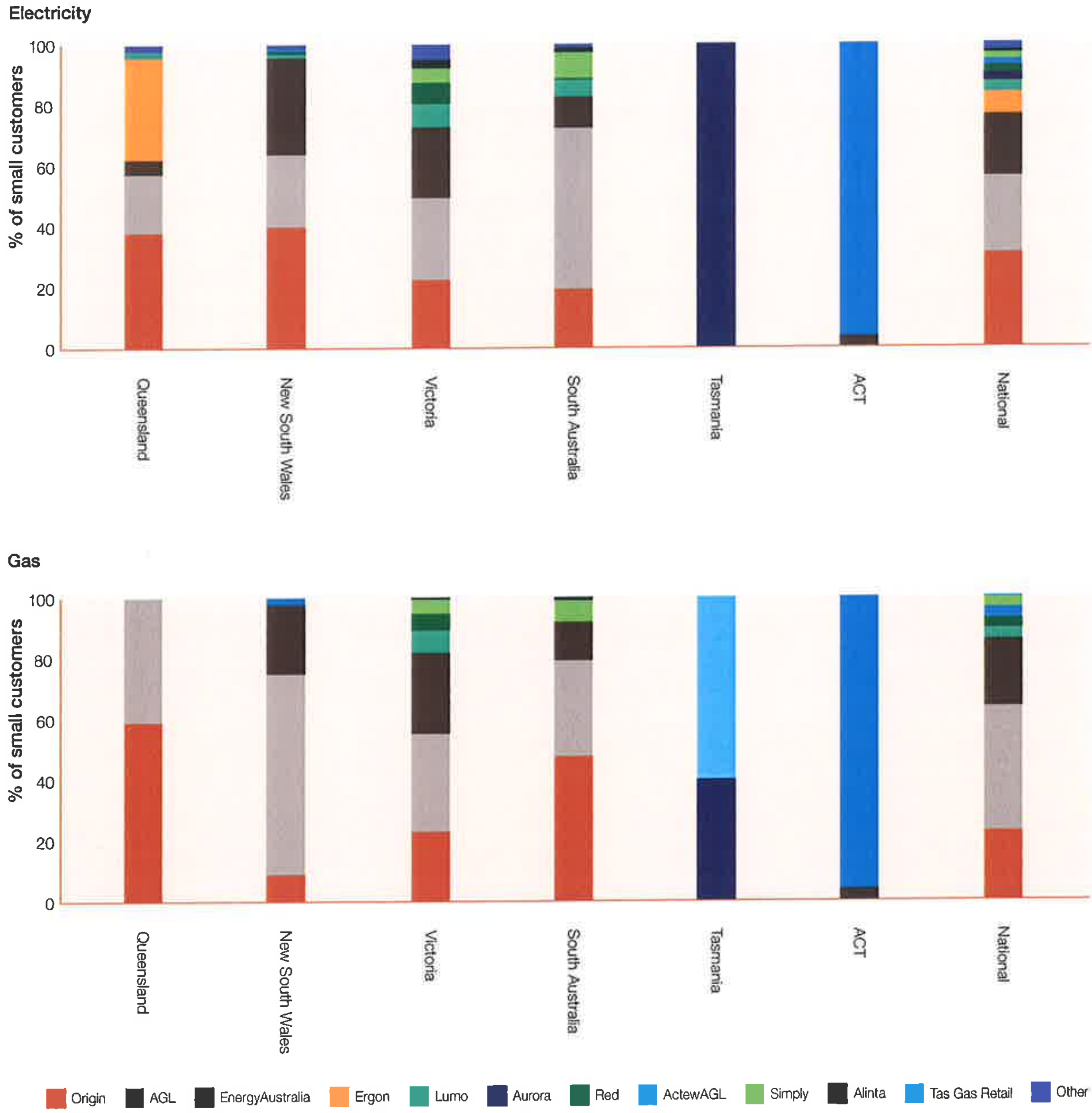
Electricity retailer (E)
Gas retailer (G)
Host retailer (*)

1. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).

Note: The host retailers listed for New South Wales, Tasmania and the ACT are those responsible for offering 'regulated offer' contracts to customers in defined regions of each state. The host retailers listed for Victoria, South Australia and Queensland are those responsible for offering 'standing offer' contracts to customers that establish a new connection in defined regions of each state.

Sources: AER, jurisdictional regulator websites, retailer websites and other public sources.

Figure 5.1
Retail market share (small customers), by jurisdiction, August 2013



Source: AER estimates.

Government retailers retain a strong presence in some jurisdictions:

- The Queensland Government owns Ergon Energy, which supplies electricity at regulated prices to customers in rural and regional Queensland. Ergon Energy is not permitted to compete for new customers.
- In Tasmania, the government owned host retailer—Aurora Energy—supplies most small electricity customers. Legislation prevents new entrants from supplying small customers that use less than 50 MWh per year. A proposal to sell Aurora Energy's retail customer base was abandoned in September 2013 (section 5.4).
- In the ACT, ActewAGL (a joint venture between the ACT Government and AGL Energy) remains the dominant retailer, with over 96 per cent of small customers.[3]
- Red Energy (owned by the New South Wales, Victorian and Australian governments) and Momentum Energy (owned by the Tasmanian Government) operate in a number of jurisdictions.

5.2.1 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, the subsequent vertical integration of retailers and generators to form 'gentailers' has been significant. Vertical integration provides a means for retailers and generators to internally manage the risk of price volatility in the electricity spot market, reducing their need to participate in hedge (contract) markets. This reduced need for hedge contracts can reduce liquidity in contract markets, posing a potential barrier to entry and expansion by generators and retailers that are not vertically integrated.

Across the National Electricity Market (NEM), three private businesses—AGL Energy, Origin Energy and EnergyAustralia—have significant market share in both generation and retail markets. The three businesses:

- control 36 per cent of generation capacity, up from 15 per cent in 2009. Over this period Origin Energy commissioned new power stations in Queensland and Victoria, and (along with EnergyAustralia) acquired the trading rights to government owned generators in New South Wales. AGL Energy acquired full ownership of Loy Yang A in Victoria.

  The three entities control 45 per cent of new generation capacity commissioned or committed since 2009. Generation investment over this period by entities that do not also retail energy was negligible, except for in wind generation.

3 AER, *Annual retail energy market performance report, 2012–13*, 2013.

- jointly supply 80 per cent of energy retail customers. Origin Energy and EnergyAustralia acquired significant retail market share in New South Wales (in 2010) following the privatisation of government owned retailers. AGL Energy acquired Australian Power & Gas (one of the largest independent retailers) in August 2013.
- supply 86 per cent of gas retail customers and are expanding their interests in upstream gas production and storage.

Vertical integration is common among other market participants too. Former stand-alone generators International Power, Infratil and Alinta established retail arms, which trade as Simply Energy, Lumo and Alinta respectively. Similar behaviour is apparent among government owned generators:

- Snowy Hydro owns Red Energy, which operates in the New South Wales, Victorian and South Australian retail markets.
- Hydro Tasmania has a retail arm (Momentum Energy) that targets medium to large customers.

Vertical integration also occurs between the retail sector and other segments of the supply chain. AGL Energy, Origin Energy and EnergyAustralia have interests in 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 New South Wales.
- EnergyAustralia has gas storage facilities in Victoria and holds gas reserves in the Gunnedah Basin (New South Wales).

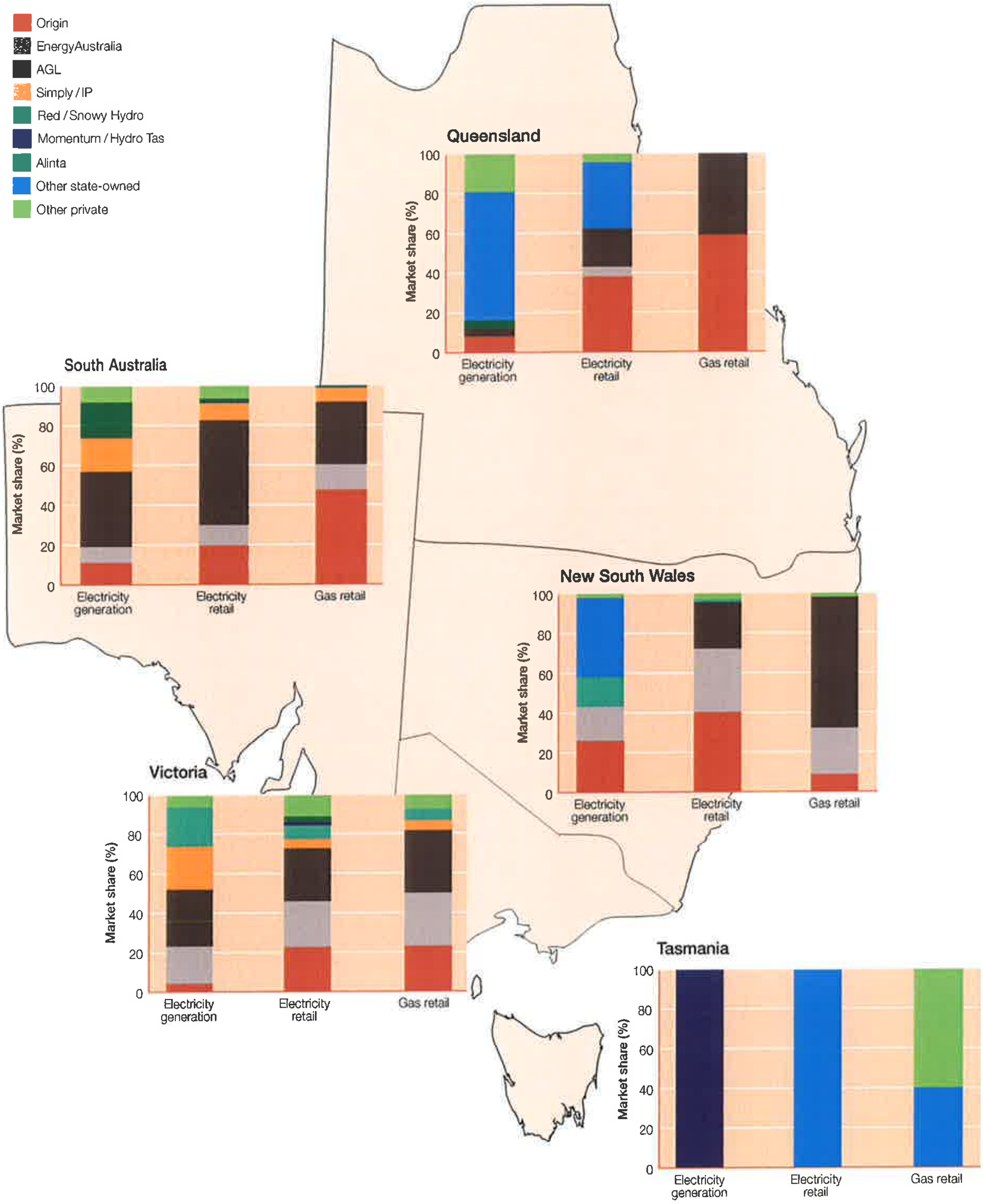
In addition, the Queensland and Tasmanian governments own joint distribution–retail businesses. The ACT Government has ownership interests in both the host energy retailer and distributor. Ring fencing arrangements aim to ensure operational separation of the retail and network arms of these entities. The AER applies jurisdictional ring fencing guidelines to distribution businesses.

5.2.2 Market concentration and vertical integration by jurisdiction

The extent of market concentration and vertical integration in energy markets varies across jurisdictions (figure 5.2).

Queensland has a highly concentrated generation sector but exhibits less vertical integration than most regions do. Electricity generation remains largely in public hands:

Figure 5.2
Vertical integration in National Energy Market jurisdictions, 2013



Note: Electricity generation market shares are based on summer availability for January 2014, except wind, which is adjusted by an average contribution factor. Electricity and gas retail market shares are based on small customer numbers at June 2013.

Source: AER estimates.

state owned corporations control 65 per cent of capacity, including a power purchase agreement over the privately owned Gladstone power station. The degree of market concentration increased in 2011, when the Queensland Government dissolved the state owned Tarong Energy and reallocated its capacity to the remaining two state owned entities.

Origin Energy and (to a lesser extent) AGL Energy are the key players in the retail sector following privatisation in 2007. These entities also account for 12 per cent of statewide generation capacity (mainly new investments in gas fired capacity).

Origin Energy is also one of the leading producers in Queensland's Surat–Bowen Basin, accounting for 17 per cent of the basin's gas production. AGL has a small interest in the basin, accounting for less than 3 per cent of gas production. The basin will soon supply liquefied natural gas projects as well as the domestic market.

EnergyAustralia supplies around 5 per cent of Queensland's retail electricity customers, but has no local generation assets.

The **New South Wales** electricity sector was dominated by government entities until 2011, when Origin Energy and EnergyAustralia acquired assets through the privatisation of retailers and generation contracts. State owned corporations (including Snowy Hydro) still control around 55 per cent of generation capacity.

Origin Energy and EnergyAustralia supply 72 per cent of retail electricity customers, and control 43 per cent of statewide generation capacity (through either direct ownership or contracted trading rights). EnergyAustralia also supplies 23 per cent of gas retail customers.

AGL Energy was the incumbent in gas retail supply, and retains 66 per cent of customers. It fully owns the state's only operating gas producing entity. AGL Energy's position in the gas retail market helped it acquire market share in electricity retail (around 24 per cent of customers).

Victoria's generation sector is disaggregated across a number of private entities. It has no single dominant retailer, with AGL Energy, Origin Energy and EnergyAustralia each supplying around one-quarter of retail electricity and gas customers.

While having reasonable market depth, Victoria has significant vertical integration. The three major retailers control 52 per cent of generation capacity. Victoria's other major generators—International Power and Snowy Hydro—jointly supply around 12 per cent of electricity customers via their ownership of Simply Energy and Red Energy respectively.

Origin Energy has also been active in Victoria's gas supply market. It is a leading player in the Otway Basin (which supplies the Victorian and South Australian markets) and the Bass Basin.

South Australia's electricity sector is concentrated, with AGL Energy supplying over 50 per cent of retail customers. AGL Energy controls 38 per cent of generation capacity, including the Torrens Island power station.

Origin Energy, EnergyAustralia and International Power are significant but minority players in both generation and retail. Alinta too has generation assets, and it entered the electricity retail market in 2011. Gas for electricity generation is sourced mainly from the Cooper and Otway basins; Origin Energy is a producer in both basins.

Tasmania's electricity industry is dominated by government entities. Aurora Energy supplies all small retail customers, while Hydro Tasmania controls nearly all generation capacity. The Tasmanian Government in 2012 announced reforms aimed at encouraging new entry in the retail market (section 5.3).

5.3 Energy market regulation

The Retail Law establishes national regulation of retail energy markets and transfers significant functions from state and territory governments to the AER. The law operates with the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements.

The Retail Law commenced in Tasmania (for electricity only) and the ACT on 1 July 2012, in South Australia on 1 February 2013 and in New South Wales on 1 July 2013. Victoria and Queensland are yet to implement the Retail Law.

The AER's role in national retail regulation 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 (for example, to retirement villages and caravan parks that onsell energy)
- 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

Box 5.1 Types of energy retail contract

'Host' retailers are required to offer a *standard retail contract* to customers without a market contract. A standard retail contract includes model terms and conditions that a retailer may not amend.

Market retail contracts vary from contract to contract, but must reflect minimum terms and conditions. A contract may be widely available or offered to only specific customers. It may offer discounts on the retailer's standard rates, or other inducements (section 5.5.3). Market contracts typically have fixed term durations, with exit fees for early withdrawal. Retailers must obtain explicit informed consent from a customer entering a market retail contract.

The share of customers on market contracts varies significantly across jurisdictions—81 per cent of electricity customers in South Australia, compared with 75 per cent in Victoria, 60 per cent in New South Wales, 46 per cent in Queensland (but 70 per cent in south east Queensland) and 19 per cent in the ACT. Proportions are similar for gas customers in each jurisdiction.

- 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 New South Wales, South Australia and the ACT have access to all of the functions on the Energy Made Easy website. This includes a price comparator tool that provides information on all generally available retail market offers, a benchmarking tool for households to compare their electricity use with that of similar households, and information on the energy market, energy efficiency and consumer protections.

The AER does not regulate retail energy prices, which remain a matter for state and territory governments.

5.4 Retail competition

Queensland, New South Wales, Victoria, South Australia and the ACT have full retail contestability (FRC) in electricity, so all customers can enter a contract with their retailer of choice. These jurisdictions, along with Tasmania, have similar arrangements in gas. Box 5.1 outlines the types of energy contract that a consumer may enter.

In Tasmania, electricity customers using at least 50 MWh per year are free to choose their retailer. Contestability will soon extend to all customers, with the Tasmanian Government planning to introduce FRC from 1 July 2014. To coincide with this introduction, the Tasmanian Government had planned to sell Aurora's retail customer base to private retailers. It abandoned this process in September 2013. But reforms to Tasmania's wholesale market arrangements began in June 2013, to encourage new retail entry (section 1.4.1). The Tasmanian Government will retain retail price regulation until satisfied that competition is fully effective.

5.4.1 Consumer protection in competitive retail markets

Increased competition among retailers for new customers has intensified retailer marketing activity. This activity has been matched by a growth in customer complaints about inappropriate conduct of energy salespersons. The Australian Consumer Law, enforced by the Australian Competition and Consumer Commission (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 also contains marketing provisions that protect customers.

Until recently, door-to-door marketing was the principal method of signing up new customers in the energy industry. It enables energy retailers to target regions and customers that may be open to switching retailers. Additionally, outsourcing sales to door-to-door agents paid on a commission basis can be less expensive than undertaking other forms of marketing.

However, door-to-door marketing is sometimes criticised for involving aggressive sales behaviour. For this reason, and as customers increasingly use energy price comparison and switching websites, the three largest energy retailers—AGL Energy, EnergyAustralia and Origin Energy—committed in 2013 to cease door-to-door marketing.

In September 2011, the ACCC launched the 'Knock! Knock! Who's there?' awareness campaign. The campaign informed consumers about their rights and ability to refuse door-to-door sales. The campaign materials included educational videos, a consumer guide, and 'do not knock' door hangers and stickers. At June 2013, over 95 000 stickers, 39 000 door hangers and 24 000 consumer guide brochures had been distributed.

The ACCC has acted on several alleged breaches of the Australian Consumer Law related to retailers' door-to-door marketing activities:

- In 2012 the ACCC took action against AGL Energy and Neighbourhood Energy, and the marketing companies engaged by them, for misleading and deceptive conduct in door-to-door selling. The Federal Court found each business and its respective marketing companies had breached the Australian Consumer Law. Neighbourhood Energy and its marketing contractor received a penalty of $1 million in September 2012. AGL Energy and its marketing contractor received a penalty of $1.76 million in May 2013.

  The Federal Court further found in October 2013 AGL Energy had breached the Australian Consumer Law when a salesperson failed to immediately leave premises at the request of an occupier. The occupier had requested the salesperson leave by placing a 'do not knock' sign on their door.
- In 2013 the ACCC instituted further proceedings for misleading and deceptive conduct in door-to-door selling against EnergyAustralia, Australian Power & Gas and Origin Energy. The proceedings against Australian Power & Gas and Origin Energy also cover allegations of unconscionable conduct.

  In November 2013 the Federal Court ordered Australian Power & Gas to pay a penalty of $1.1 million for illegal door-to-door selling practices. It found sales representatives acting on behalf of Australian Power & Gas made false or misleading representations while calling on consumers for the purpose of negotiating energy retail contracts, and a sales representative engaged in unconscionable conduct involving a consumer from a non-English speaking background with very limited English skills.

  The proceedings against EnergyAustralia and Origin Energy were continuing at November 2013.
- In July 2013 Lumo Energy provided a three year court enforceable undertaking that it will comply with the Australian Consumer Law. The undertaking followed the ACCC's finding that Lumo Energy's door-to-door sales agents failed to provide consumers with all required information.

The ACCC also took action against energy retailers and energy switching sites for other inappropriate marketing activity:

- In 2012 the Federal Court ordered Energy Watch—a provider of energy price comparison services—to pay $1.95 million for misleading advertising.
- In September 2013 Red Energy paid infringement notices totalling $26 400 and provided a court enforceable undertaking to the ACCC for alleged misleading and deceptive conduct by a telemarketer.
- In December 2013 the ACCC instituted proceedings in the Federal Court against AGL Energy. The ACCC alleged that AGL Energy made false or misleading representations, and engaged in misleading and deceptive conduct, relating to statements to consumers on the level of discount that would be provided under their energy plans.

5.4.2 Customer switching

The rate at which customers switch their supply arrangements can indicate customer participation in the market. 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.

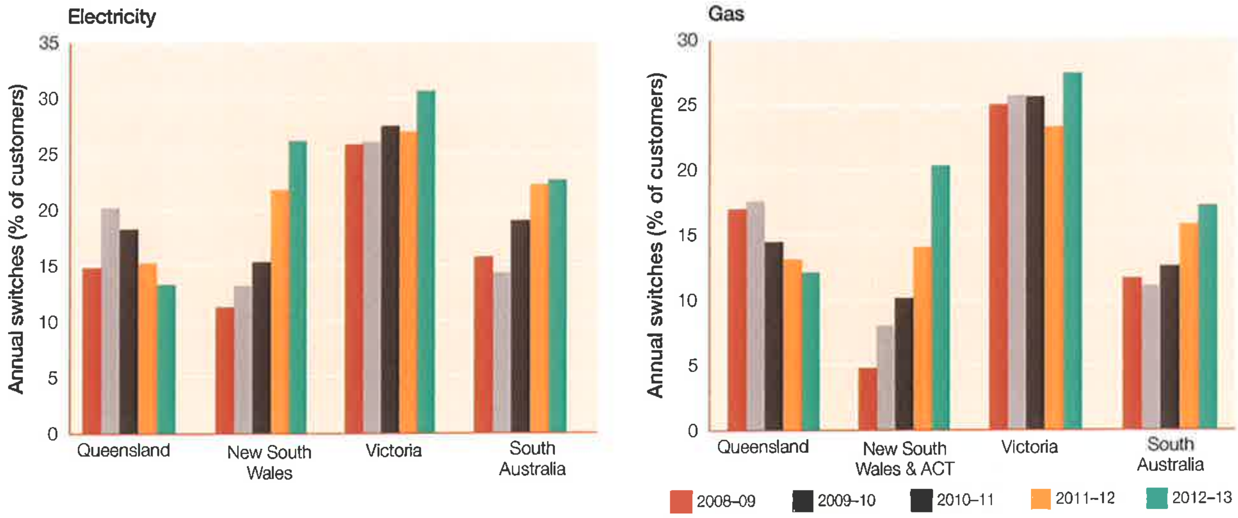
The Australian Energy Market Operator (AEMO) publishes churn data measuring the number of customer switches from one retailer to another (but not customer switches between contracts with the same retailer). Figure 5.3 sets out annual switching data.

Victoria continues to have a higher switching rate than that of other jurisdictions, and in 2013–14 recorded its highest ever switching rates in both electricity (30 per cent of customers) and gas (27 per cent of customers). Switching activity in New South Wales and South Australia rose in each of the past few years, with rates in 2012–13 being the highest recorded in each state for both electricity and gas. Particularly strong growth in New South Wales in 2012–13 led its switching rates to exceed that of South Australia for the first time. And its switching rate for electricity reached a level previously seen only in Victoria.

Queensland's switching rates were once comparable with those in New South Wales and South Australia, but fell in recent years. This fall coincided with a reduction in

Figure 5.3

Customer switching of energy retailers, as a percentage of small customers



Sources: Customer switches: AEMO, MSATS transfer data to July 2013 and gas market reports, transfer history to July 2013; customer numbers: estimated from retail performance reports by the AER, IPART (New South Wales), the ESC (Victoria) and the QCA.

marketing effort by energy retailers in Queensland, reflecting concerns about the process for setting regulated electricity prices. Queensland's electricity switching rate in 2012–13 was its lowest since the introduction of FRC.

Switching levels remain lower in gas than electricity in all jurisdictions, reflecting the lower number of active participants in the gas market.

5.5 Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services. Table 5.2 estimates the composition of a typical electricity retail bill for a residential customer in each jurisdiction. While data for gas are limited, the table includes gas estimates for New South Wales.

The composition of energy bills varies across jurisdictions. In electricity, the cost of using transmission and distribution networks to transport electricity is the largest component (36–57 per cent) of retail bills, followed by wholesale energy costs (21–27 per cent). Retailer operating costs (including margins) contribute 10–15 per cent of retail bills.

Carbon pricing, introduced in July 2012, contributes 3–12 per cent of the final electricity bill. The carbon price impact was lowest in South Australia and Tasmania, which have significant renewable generation. Other green costs—that is, costs associated with schemes to develop renewable or low emission generation, or promote energy efficiency—make up 3–8 per cent of retail bills. The most significant of these costs relate to the renewable energy target (section 1.3.1) and feed-in tariffs for solar photovoltaic installations.

In gas, pipeline charges are the most significant component of retail prices. Transmission and distribution charges account for 48 per cent of gas retail prices in New South Wales. Distribution charges account for the bulk of pipeline costs. Wholesale costs typically account for a similar share of retail gas prices as for electricity. 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.

5.5.1 Retail price regulation

All jurisdictions except Victoria and South Australia apply some form of retail price regulation for electricity supplied under a standard retail contract. In gas, only New South Wales regulates prices for small customers. The regulated prices are set by state or territory government agencies; the AER does not regulate retail prices in any jurisdiction.

Jurisdictions generally apply one of two methods to regulate energy retail prices:

Table 5.2 **Indicative composition of residential electricity and gas bills, 2013**

JURISDICTION	NETWORK COSTS	WHOLESALE ENERGY COSTS	RETAIL COSTS	CARBON COSTS	GREEN COSTS
	PER CENT OF TYPICAL SMALL CUSTOMER BILL				
ELECTRICITY					
Queensland	52	21	15	9	3
New South Wales	51	23	10	7	8
Victoria	36	na	na	8	4
South Australia	55	21	13	4	8
Tasmania	57	27	9	3	4
ACT	43	26	11	12	8
GAS					
New South Wales	48	28	19	5	–

Note: The AEMC did not provide a breakdown of wholesale energy and retail costs for Victoria. These components jointly accounted for 52 per cent of retail bills.

Sources: AEMC, *Electricity price trends, final report*, 2013 (electricity); Determinations and factsheets by IPART (gas).

- a building block approach, whereby the regulator determines efficient cost components (for example, wholesale costs, retail operating costs and costs associated with regulatory obligations) and passes through costs determined elsewhere (for example, network costs). The regulator uses these costs to determine a maximum revenue requirement to be reflected in the prices that the retailer charges. Determinations typically cover a number of years, but some cost components are adjusted annually. Separate pass through provisions cover unexpected costs. New South Wales, Tasmania and Queensland use this approach.
- a benchmark retail cost index, whereby the regulator determines movements in benchmark costs to calculate annual adjustments in retail prices. The ACT uses this approach, which was also previously used in Queensland.

In September 2013 the AEMC completed a review for energy ministers into best practice retail electricity price regulation. Its report sets out the AEMC's preferred methods for estimating each cost component, based on the objective of regulated prices reflecting the efficient costs of providing retail services and facilitating competition. Under the ministerial terms of reference, jurisdictions may adopt the AEMC's proposed method where regulation remains necessary, or transfer regulatory responsibility to the AER.

Australian governments agreed to review the continued use of retail price regulation and to remove it if effective competition can be demonstrated.[4] The Australian Energy Market Commission (AEMC) is assessing the effectiveness of retail competition in each jurisdiction, to advise whether to remove price regulation and, if so, how. State and territory governments make the final decisions on this matter.

The AEMC in 2008 reviewed the effectiveness of competition in the *Victorian* and *South Australian* energy retail markets. It found competition was effective in both markets. In response to the review, the Victorian Government removed retail price regulation on 1 January 2009. South Australia followed in February 2013. While these jurisdictions no longer regulate retail prices, retailers must publish unregulated standing offer prices that small customers can access. The prices can be changed no more than once every six months.

In March 2011 the AEMC found competition in the *ACT's* small customer market was not effective, partly because customers were unaware of their ability to switch retailers. It recommended removing retail price controls from 1 July 2012, in conjunction with running a consumer education campaign to increase awareness of the benefits of competition.[5] However, the ACT Government decided to retain price controls for another two years. It noted the AEMC's finding that removing price controls would increase the average cost of electricity, which would not benefit customers.[6]

4 Australian Energy Market Agreement 2004 (as amended).

5 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT, stage 2, final report*, 2011, p. 11.

6 ACT Government, 'ACT to keep price regulation for Canberra households', Media release, www.chiefminister.act.gov.au/media.php?v=10936&m=53 2011, September 2011.

Table 5.3 Movements in regulated and standing offer prices—electricity and gas

JURISDICTION	REGULATOR	DISTRIBUTION NETWORK	AVERAGE PRICE INCREASE (PER CENT)					ESTIMATED ANNUAL COST ($)
			2009-10	2010-11	2011-12	2012-13	2013-14	
ELECTRICITY								
Queensland	QCA	Energex and Ergon Energy	15.5	13.3	6.6	10.6	20.4	2113
New South Wales	IPART	AusGrid	21.7	10.0	17.9	20.6	3.9	2106
		Endeavour Energy	21.1	7.0	15.5	11.8	1.6	2044
		Essential Energy	17.9	13.0	18.1	19.7	-0.6	2725
Victoria	Unregulated	Citipower	5.7	14.6	3.7	19.9	6.4	2006
		Powercor	5.2	15.4	7.7	23.1	5.8	2389
		SP AusNet	6.0	11.3	23.6	19.7	12.4	2386
		Jemena	7.7	17.7	10.5	23.2	6.1	2339
		United Energy	7.0	11.4	9.7	25.2	4.8	2167
South Australia	Unregulated	ETSA Utilities	3.1	18.3	17.4	12.7	2.8	2510
Tasmania	OTTER	Aurora Energy	6.2	15.3	11.0	10.6	1.8	2205
ACT	ICRC	ActewAGL	6.4	2.3	6.5	17.7	3.5	1577
GAS								
New South Wales	IPART	Jemena	4.4	5.2	4.0	14.8	9.6	922
South Australia	Unregulated	Envestra	5.3	3.1	13.8	17.7	11.6	1072

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 2013.

The Victorian price movements (and estimated annual costs) are for the calendar year ending in that period—for example, the 2013–14 Victorian data are for the calendar year 2013. Victorian price movements (and those for South Australia in 2013–14) are based on unregulated standing offer prices of the local area retailer for each distribution network. The data for South Australia in 2013–14 relates to movements in the standing offer in the six months to December 2013.

The price increase for Tasmania in 2013–14 relates to the period 1 July 2013 to 31 December 2013. A further price adjustment will occur on 1 January 2014.

Sources: Determinations, factsheets and media releases by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

The AEMC in September 2013 found competition was effective in *New South Wales* energy retail markets, with substantial discounts being offered from the regulated price. It recommended the New South Wales Government remove retail price regulation and improve consumer information and ongoing market monitoring. The AEMC provided further advice in October 2013 on how to inform and empower consumers to promote effective competition. The government had not responded to the recommendations at November 2013.

In May 2013 the Standing Council on Energy and Resources recommended to the Council of Australian Governments that the AEMC undertake annual competition reviews covering all NEM jurisdictions, to remove the need for further jurisdictional reviews. Under this review system, individual jurisdictions could request a more detailed assessment of issues that the annual review identifies.[7]

7 AEMC, *Review of competition in the retail electricity and natural gas markets in New South Wales, final report*, October 2013, p. 68.

The *Queensland* Government committed to removing electricity retail price regulation in south east Queensland by 1 July 2015, so long as appropriate consumer protection and engagement policies are in place. Regulated price setting will continue for the Ergon Energy distribution area, pending the development of a strategy to introduce retail competition in regional Queensland.

5.5.2 Trends in regulated prices

Table 5.3 summarises recent movements in regulated and standing offer electricity and gas prices, and estimates the annual bills for customers under these arrangements. The data assume fixed electricity and gas use across all jurisdictions. In practice, average use varies significantly between (and within) jurisdictions for a range of reasons, including climate and the penetration of gas supply. The data on annual cost may not represent a typical household in the jurisdiction.

In New South Wales and Victoria, standing offer electricity prices vary across distribution networks. Prices are highest in those 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 over the past five years. Network costs were the key driver (section 2.x). The carbon price also contributed, leading to price increases of 5–13 per cent in 2012–13, although the impact on low and middle income residential customers was offset by the Australian Government's Household Assistance Package. Cost pressures from other climate change policies also had an impact, but have remained fairly stable since changes to the renewable energy target scheme from 1 January 2011 affected retail prices in 2011–12. Rising prices have led to a greater focus on the issue of energy affordability (section 5.4.5).

Slower growth in network charges contained price rises for 2013–14 to below 4 per cent in New South Wales, South Australia, Tasmania and the ACT. Queensland customers experienced the largest price increases for 2013–14, following the delayed pass through of costs for the previous year (box 5.2).

Box 5.2 Retail energy prices, by jurisdiction—recent developments

Queensland's regulated electricity single-rate tariff for residential customers rose by 20.4 per cent for 2013–14. Almost half of this rise related to higher network costs. Following the Queensland Government's price freeze for this tariff in 2012–13, the price rise for 2013–14 covers two years of network cost increases. Retailers' costs (relating to billing, metering and customer acquisition) pushed up retail prices by 5 per cent, while wholesale costs and solar feed-in tariffs each pushed up prices by around 2.7 per cent.

New South Wales regulated electricity prices were relatively stable for 2013–14, increasing by an average 1.7 per cent. A rise in retailer operating costs (such as for customer service and billing) was the main driver, adding 4.4 per cent to retail charges. Costs associated with green schemes also had a small impact, pushing up prices by 1.3 per cent. But falling wholesale and network costs partly offset these price increases.

Victoria's standing electricity prices rose by 5–12 per cent across the state's five distribution networks in 2013, following increases of 20–25 per cent in 2012. Because prices are unregulated, limited information is available on underlying cost drivers, including the reasons for the price outcomes. But distribution network costs, which increased from 6–30 per cent across the networks, account for a proportion of the retail price increases for most networks. Little information is available on the impact of wholesale energy costs (including hedging costs), retailer costs and retail margins in the Victorian market. A rise in wholesale costs during the year (section 1.7) might have flowed through to retail prices, depending on retailers' hedge positions. The Essential Services Commission of Victoria reported in May 2013 that retailer margins in Victoria have increased since the removal or retail price regulation in 2009.[1]

South Australian retail electricity prices rose by 12.7 per cent for 2012–13. Prices rose by 18 per cent on 1 July 2012, but following the government's decision to deregulate prices, the standing offer fell by 9.1 per cent on 1 January 2013. Retail prices rose a further 2.8 per cent in July 2013. Network costs are the likely main driver, accounting for a 1.7 per cent increase in retail prices.

The regulated electricity price in *Tasmania* rose by 1.8 per cent for 1 July 2013 to 31 December 2013, broadly in line with inflation. A further price determination will reset the standing offer price from 1 January 2014.

ACT electricity prices rose on average by 3.5 per cent for 2013–14. Two-thirds of the increase related to higher network charges. Costs associated with the ACT's energy efficiency scheme, which commenced on 1 January 2013, accounted for the remainder of the increase.

In gas, retail prices in New South Wales rose by an average of 8.5 per cent for 2013–14. Higher network charges were the main contributor, accounting for 60 per cent of the price rise. Gas retail operating costs also rose.

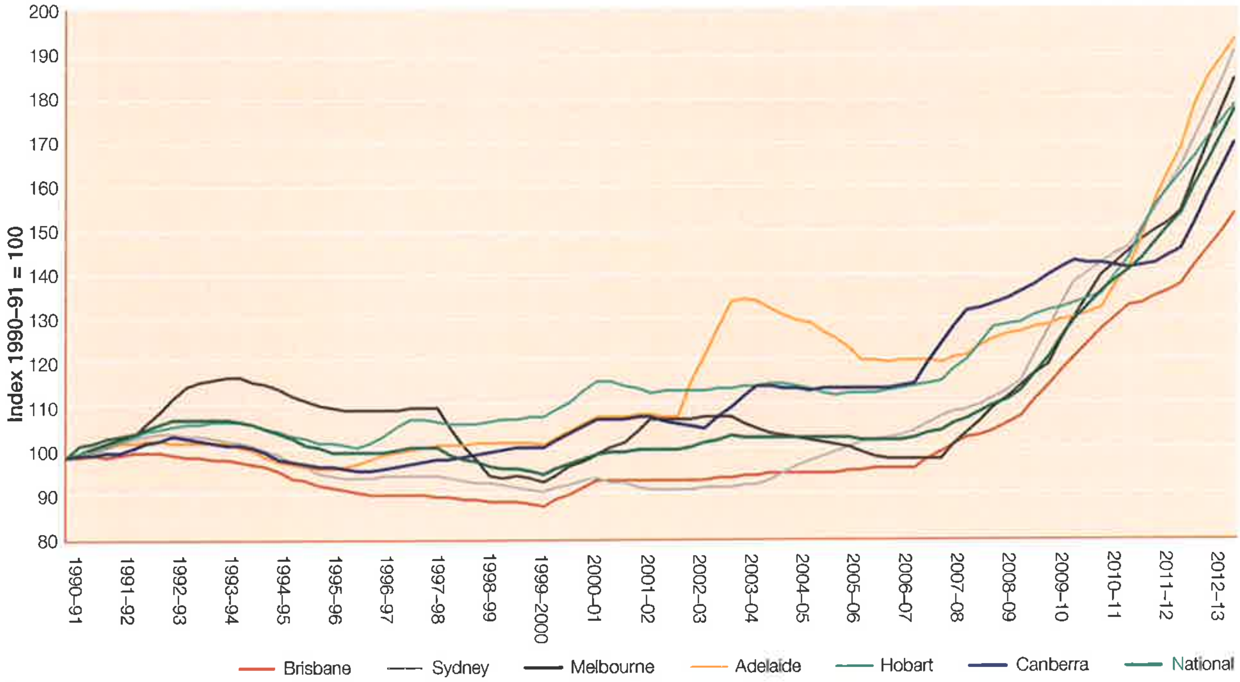
Gas wholesale prices rose in all markets over 2012–13, ranging from around 30 per cent in Melbourne and Adelaide to 70 per cent in Brisbane; these higher wholesale costs are likely to be reflected in current retail gas prices.

1 ESC, *Retailer Margins in Victoria's Electricity Market, discussion paper*, May 2013.

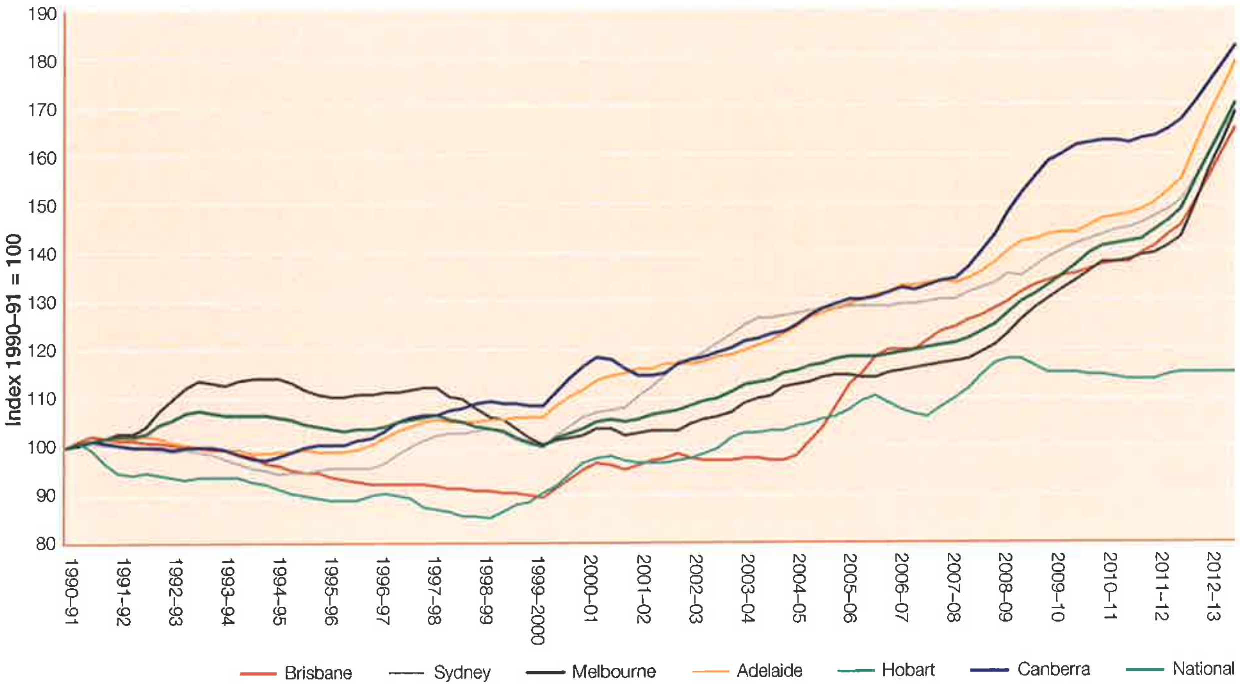
Figure 5.4

Retail price index (inflation adjusted)—Australian capital cities

Electricity



Gas



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.

ABS data on energy prices

Figure 5.4 tracks movements in real energy prices for metropolitan households since 1991, using the electricity and gas components of the ABS consumer price index. Figure 2 in the *Market overview* compares price outcomes for household and business customers. Electricity prices rose nationally over the five years to 2012–13 by 64 per cent in real terms (87 per cent in nominal terms). Gas prices rose by 39 per cent in real terms (59 per cent in nominal terms).

5.5.3 Price diversity

Retailers offer contracts for a range of products with different price structures. The offers may include standard products, green products, 'dual fuel' contracts (for gas and electricity) and packages that bundle energy with services such as telecommunications. Some contracts bundle energy services with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. Additional discounts may be offered for prompt payment of bills, or for direct debit bill payments. These 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 service—Energy Made Easy—to help small customers compare retail product offerings. The website is available for customers in those jurisdictions that implement the Retail Law (at December 2013, New South Wales, South Australia, Tasmania and the ACT). Additionally, the Queensland and Victorian regulators, and a number of private entities operate websites that allow customers to compare available market offers.

Table 5.4 draws on Energy Made Easy and state regulators' price comparison websites to estimate price offerings for residential customers in those jurisdictions with relatively established markets—Queensland, New South Wales Victoria and South Australia. The table provides estimates for August 2012 and August 2013.

The data indicate varying degrees of price diversity. Victoria exhibited the greatest price diversity, with the annual cost under the cheapest contract 35–40 per cent lower than under the most expensive contract. The average discount in annual electricity bills across all contracts in August 2012 was 5–6 per cent below the base offer in Queensland, New South Wales and South Australia, and 8–9 per cent lower in Victoria.[8] The average discount in August 2013 remained relatively unchanged in Queensland, but fell in New South Wales (to below 4 per cent) and South Australia (to 1.5 per cent). The variation in average discounts across Victorian network areas was 7–11 per cent.

In August 2013 the average discount from the base offer cost was lower in gas than electricity—less than 4 per cent in all jurisdictions other than Victoria. The average gas discount in Victoria remained unchanged at 6 per cent in August 2012 and August 2013, although the variation in discounts was greater across the networks. In South Australia and in Queensland's North Brisbane network, gas contract prices on average *exceeded* the base offer price of the local area retailer.

The annual bill spread in August 2013 (measured within a particular distribution network) varied among jurisdictions:

- In electricity, it ranged from $200 in Queensland to around $1000 in Victoria. The spread for most networks was larger in August 2013 than in August 2012.
- In gas, it was around $200 for most networks. The spread for all networks rose between August 2012 and August 2013.

5.5.4 Retail prices and energy affordability

Energy affordability relates to customers' ability to pay their energy bills. While rising energy prices contribute to the number of customers with payment difficulties, affordability also depends on energy consumption levels, household income and financial assistance or concessions.

AER research found average energy costs rose faster than household disposable income during 2012–13 (figure 5.5). For a benchmark low income household that receives energy bill concessions:

- electricity costs accounted for 2.4–7.1 per cent of their disposable income in 2011–12 (depending on region), rising to 2.9–7.9 per cent in 2012–13
- gas costs accounted for 1.2–3.2 per cent of their disposable income in 2011–12, rising to 1.4–3.4 per cent in 2012–13.[9]

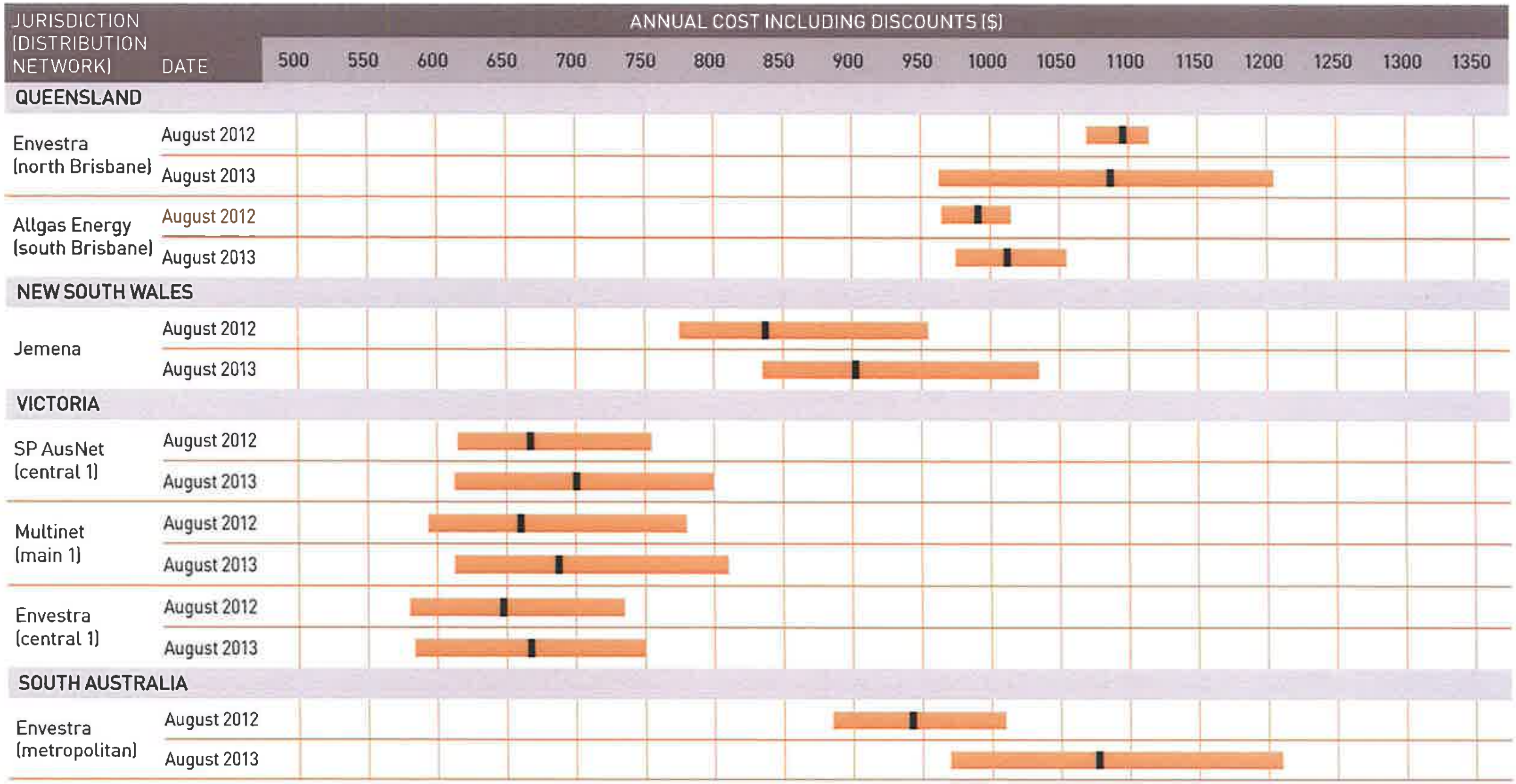
Electricity costs were highest in Tasmania; while charges in that state were lower than in some other jurisdictions, Tasmania's average electricity use for a low income household was 8100 kWh per year (compared with 4700 to

8 Base offers are regulated offers in New South Wales (electricity and gas) and Queensland (electricity). Elsewhere, base offers are the standing offers of the local area retailer for each distribution network.

9 AER, *Annual retail energy market performance report, 2012–13*, 2013.

Table 5.4 Price diversity in retail product offers—August 2012 and August 2013
Electricity

Gas



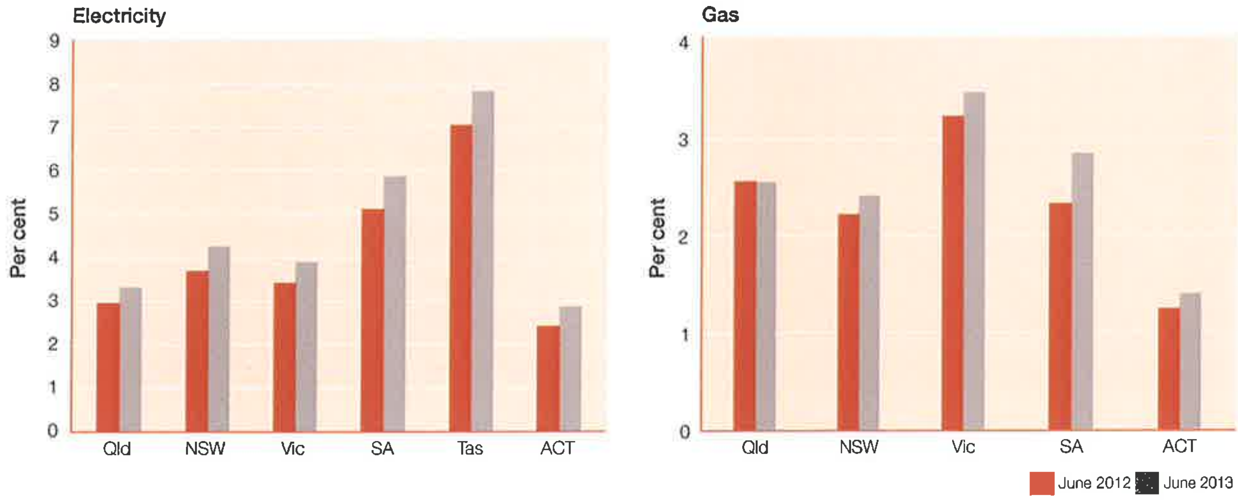
Price spread

Average annual cost

Note: Data are based on market offers (adjusted for discounts) for a customer consuming 6500 kilowatt hours of electricity and 24 gigajoules of gas per year on a peak only (single rate) tariff. Data do not account for Greenpower offers.

Figure 5.5

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 for a household the size of an average low income household. Gas consumption is the average for all households.

Energy charges are based on the median market offer available at June 2012 and June 2013. Charges are adjusted for concessions available to low income households.

Disposable income for a low income household is the average of the second and third income deciles.

Sources: AER; ABS; Price comparator websites operated by jurisdictional regulators.

7000 kWh elsewhere). Gas costs were highest in Victoria, where average use exceeded 60 gigajoules (compared with up to 24 gigajoules for a typical customer in other regions).

Costs for both electricity and gas were lowest in the ACT. While that region's energy consumption is similar for gas and higher for electricity compared with most other jurisdictions, energy charges in the ACT are substantially lower.

This analysis does not account for the impact on bills of falling average domestic electricity consumption, which would offset some of the rise in overall electricity costs.

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 before considering disconnection for non-payment of a bill. Such assistance includes offering access to a hardship program.

Hardship programs aim to provide early assistance to customers. Retailers may offer:

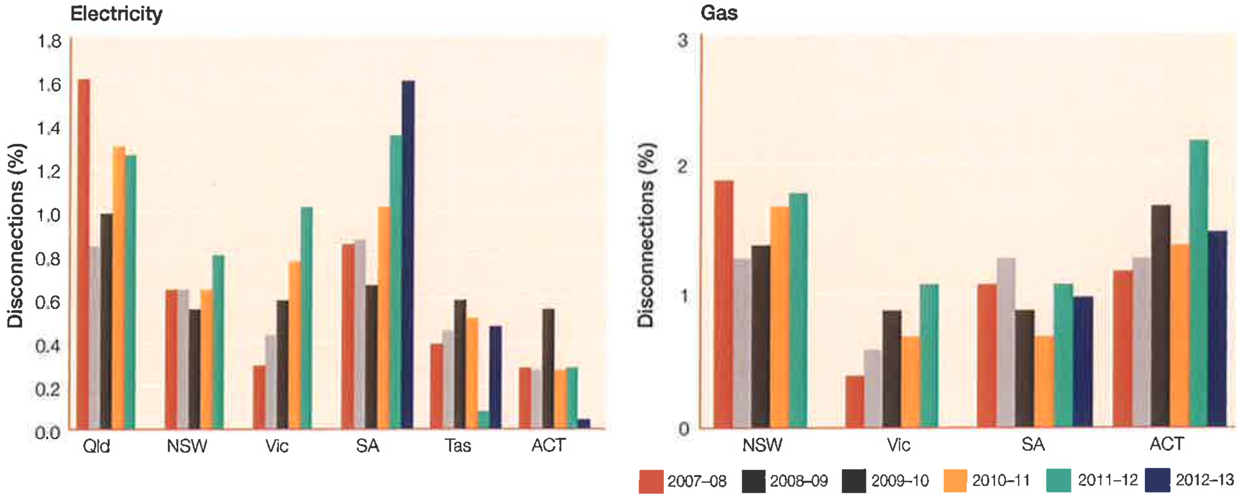
- specialised staff and teams as a dedicated contact for customers
- extensions of time to pay, as well as flexible payment options
- help to identify government concession and rebate programs
- referrals to financial counselling services
- review of a customer's energy contract to make sure it suits 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.

5.6 Quality of retail service

Reporting on retail service quality tends to focus on affordability, access and customer service indicators. A key indicator of affordability and access is the rate of residential customer disconnections for failure to meet bill payments (figure 5.6).

Figure 5.6

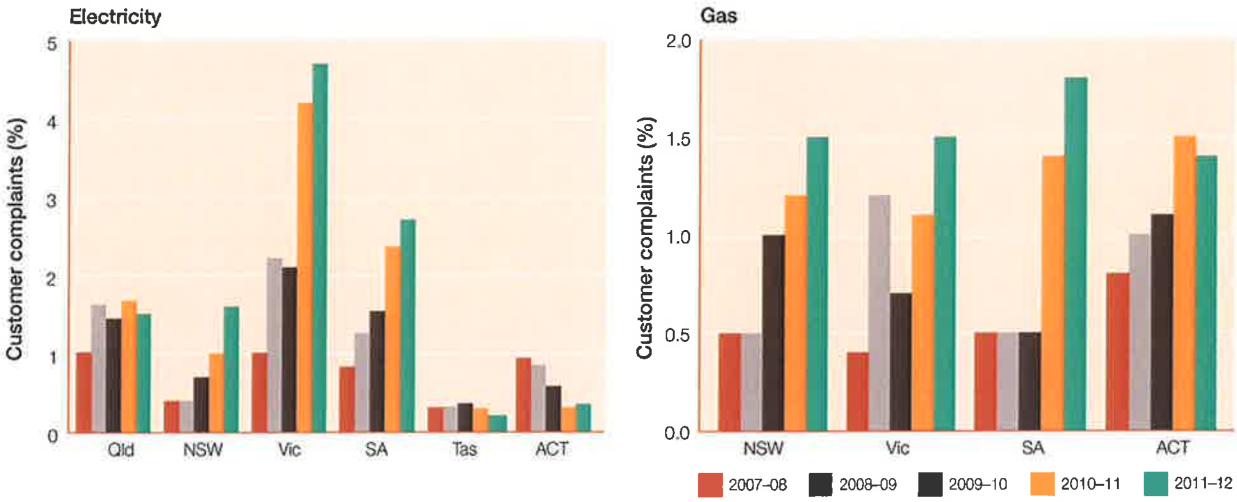
Residential disconnections for failure to pay amount due, as a percentage of customers



Note: 2012–13 disconnection data are available for only those jurisdictions that had implemented the Retail Law in that year (South Australia, Tasmania and the ACT).

Figure 5.7

Retail customer complaints, as a percentage of total customers



Sources for figures 5.5 and 5.6: Reporting against Utility Regulators Forum templates; retail performance reports by the AER, IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA and the Department of Employment, Economic Development and Innovation (Queensland), and the ICRC (ACT).

In 2011–12 the rate of electricity and gas disconnections remained stable or increased in all mainland jurisdictions. Many customers were reconnected within a week, indicating retailers might have resorted to disconnection too quickly; more targeted assistance might have prevented some disconnections.

Aurora Energy (Tasmania) advised it stopped disconnecting customers between October 2011 and June 2012 because it undertook internal restructuring. Its disconnection rate in 2012–13 returned to the rate of previous years.

Figure 5.7 illustrates rates of retail customer complaints in electricity and gas. In 2011–12 New South Wales, Victoria and South Australia experienced record levels of complaints from electricity and gas customers. Consistent with previous years, billing issues accounted for the majority of complaints in all jurisdictions.

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
ASX	Australian Securities Exchange
CCGT	combined cycle gas turbine
CoAG	Council of Australian Governments
CSG	coal seam gas
Electricity Law	National Electricity Law
Electricity Rules	National Electricity Rules
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
EU	European Union
FRC	full retail contestability
Gas Law	National Gas Law
Gas Rules	National Gas Rules
GJ	gigajoule
GSL	guaranteed service level
GW	gigawatt
GWh	gigagwatt hour
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
kW	kilowatt
kWh	kilowatt hour
LNG	liquefied natural gas
MOS	market operator service
MSATS	Market Settlement and Transfer Solution
MW	megawatt
MWh	megawatt hour
NCC	National Competition Council
NEM	National Electricity Market
OCGT	open cycle gas turbine
OTC	over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PC	Productivity Commission
PJ	petajoule
PV	photovoltaic
QCA	Queensland Competition Authority
RAB	regulated asset base
RERT	reliability and emergency reserve trader
RET	renewable energy target
Retail Law	National Energy Retail Law
RIT-D	regulatory investment test for distribution
RIT-T	regulatory investment test for transmission
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCER	Standing Council on Energy and Resources
TJ	terajoule
TW	terawatt
TWh	terawatt hour
WACC	weighted average cost of capital

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