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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.

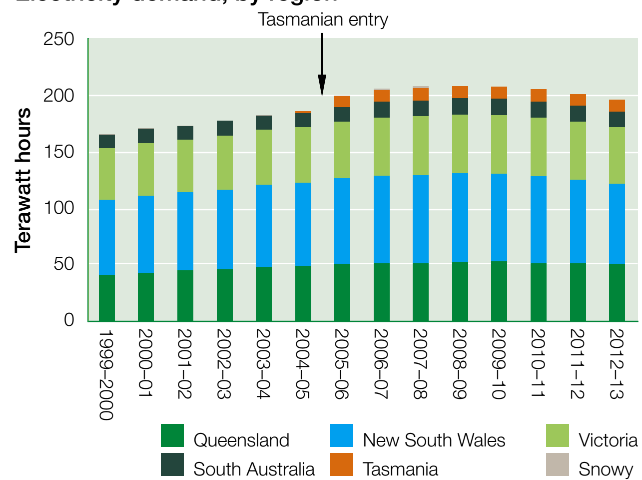
2 The maximum historical summer demand of 35 551 MW occurred in 2009.

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]

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:

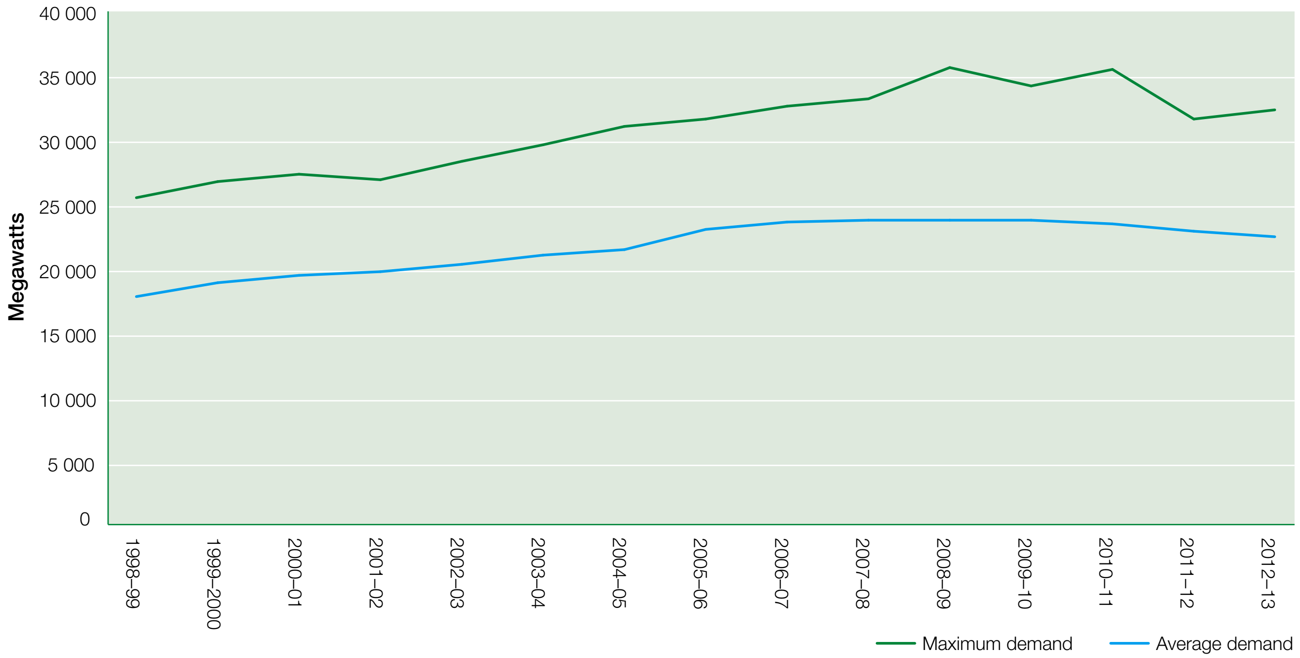
- commercial and residential customers responding to higher electricity costs by reducing energy use and adopting energy efficiency measures such as solar water heating. New building regulations on energy efficiency reinforce this trend.
- subdued economic growth and weaker energy demand from the manufacturing 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]

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

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).

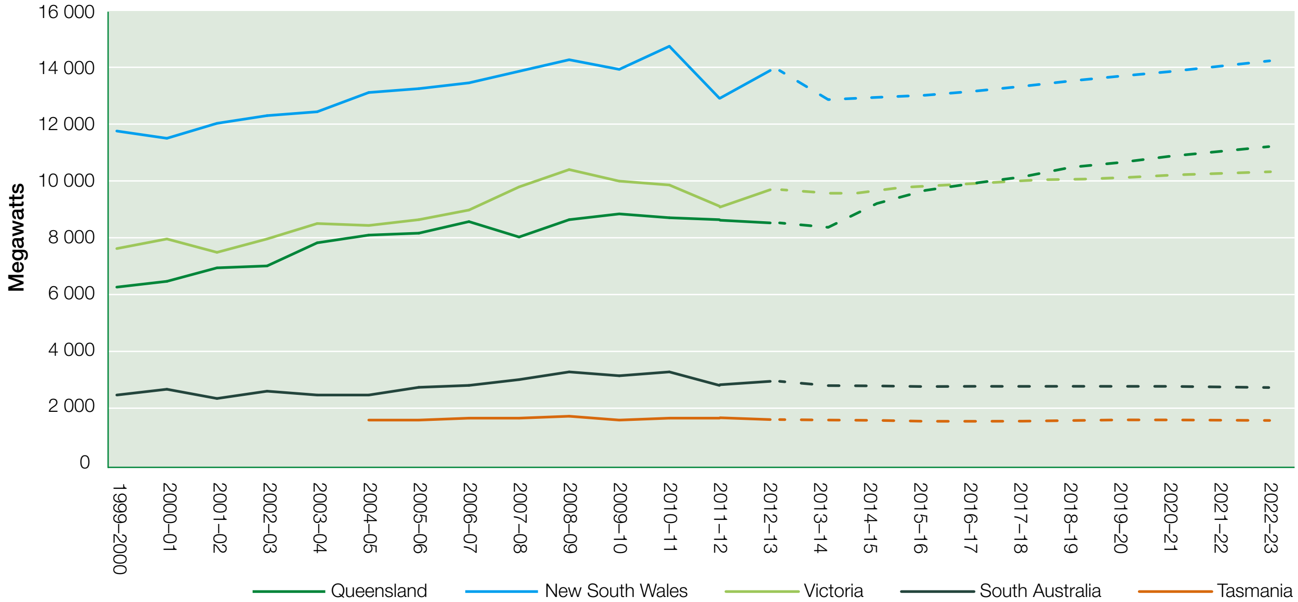
Maximum demand over the next decade is expected to remain below previous highs in most regions (figure 1.3). The exception will be Queensland, where the commencement of LNG projects will result in maximum demand rising by 10 per cent in 2014–15, then annually by around 2.4 per cent. In other regions, 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

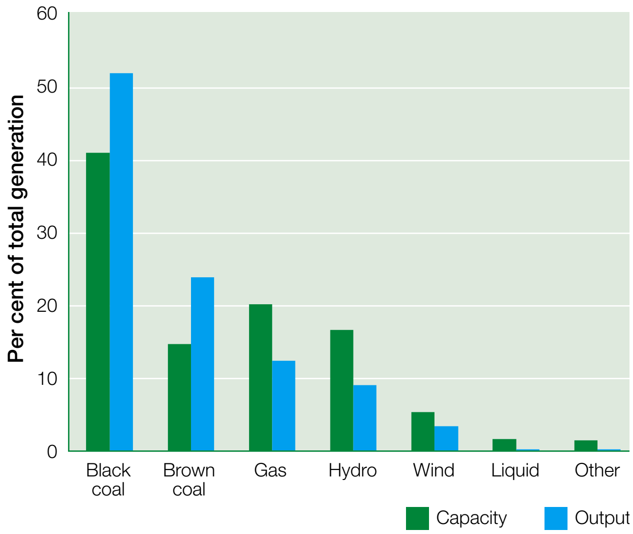
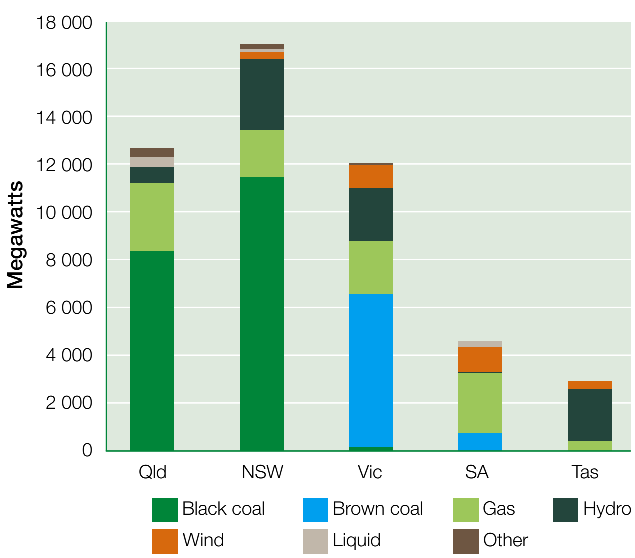


Figure 1.6

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

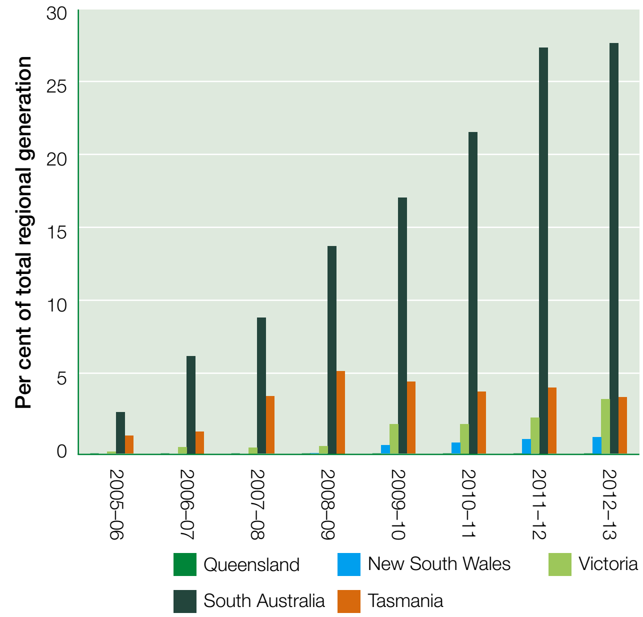


and solar, can operate only when the weather conditions are favourable.

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.

Figure 1.7

Wind generation share of total generation, by region



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

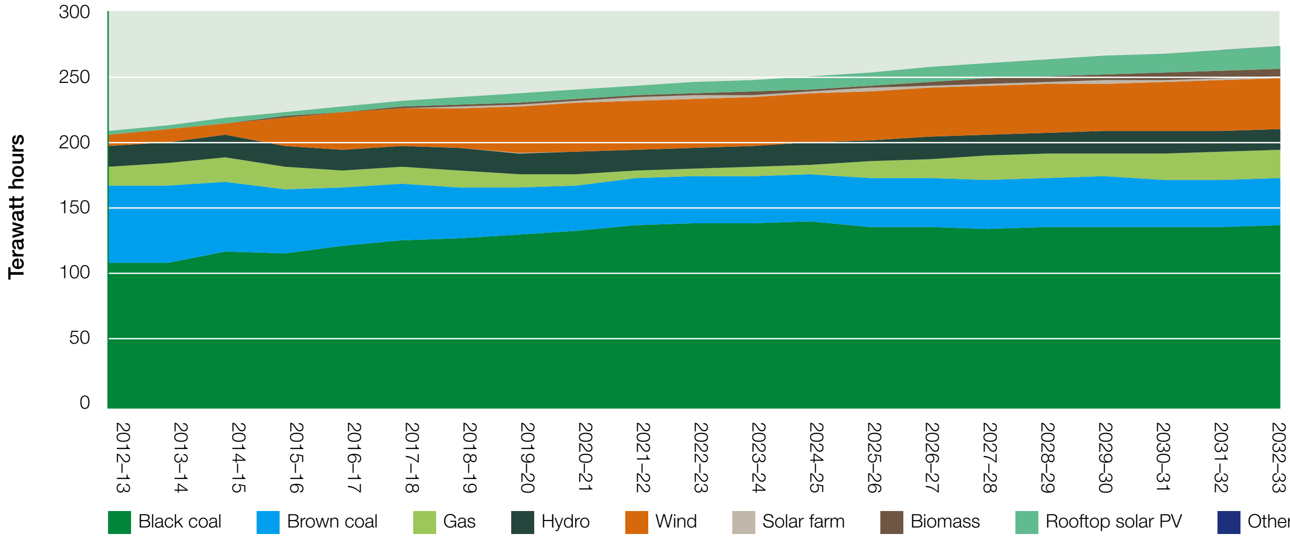
Gas powered generators account for 20 per cent of registered capacity across the NEM, but they supply only 12 per cent of output. Among the NEM jurisdictions, South Australia is the most reliant on gas powered generation. More generally, 55 per cent of new generation investment over the past decade was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

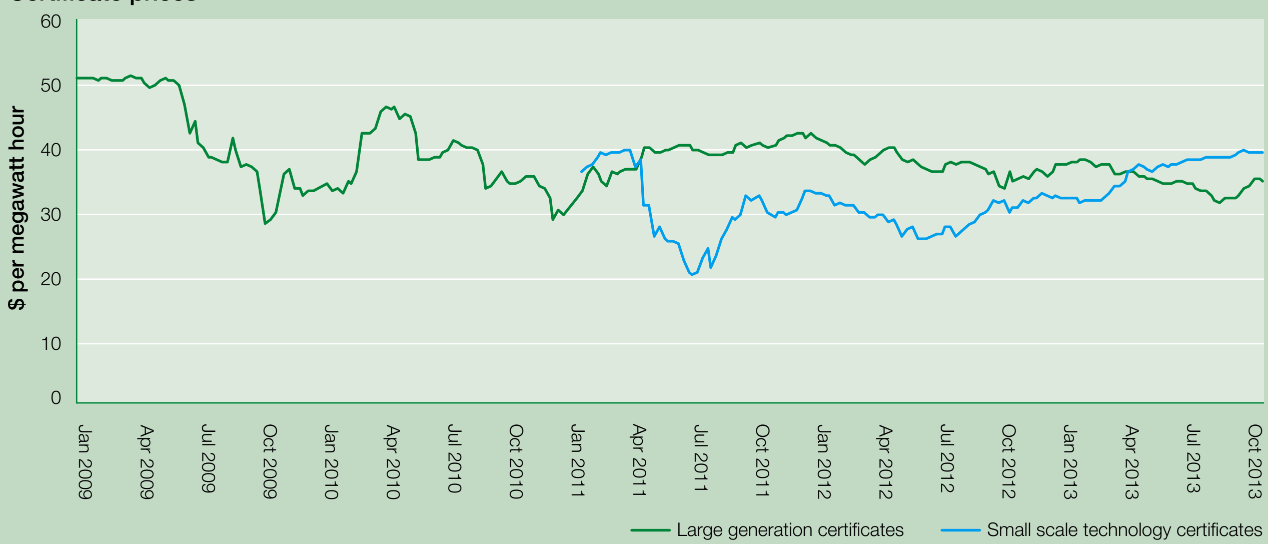
16 AEMO, *Power system adequacy 2013*, p. 1–2.

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.

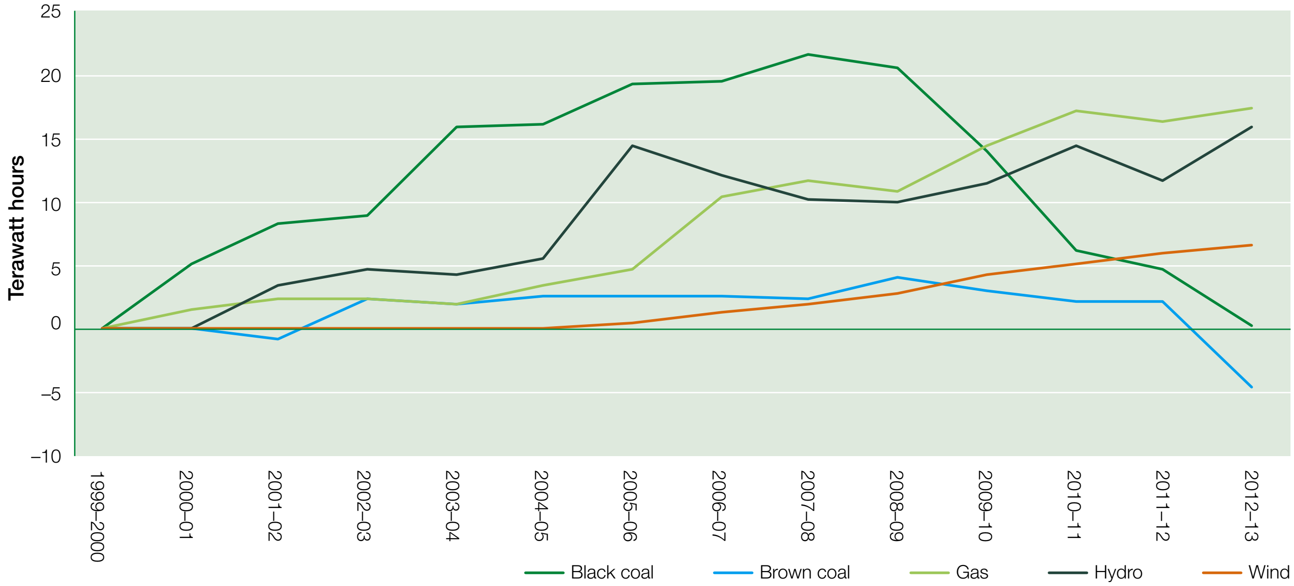
Conversely, the introduction of carbon pricing enhanced the competitiveness of hydro generation, contributing to a 36 per cent rise in output in 2012–13 to supply 9 per cent of electricity in the NEM. The increased hydro generation consumed water faster than it could be replenished, causing storage to 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

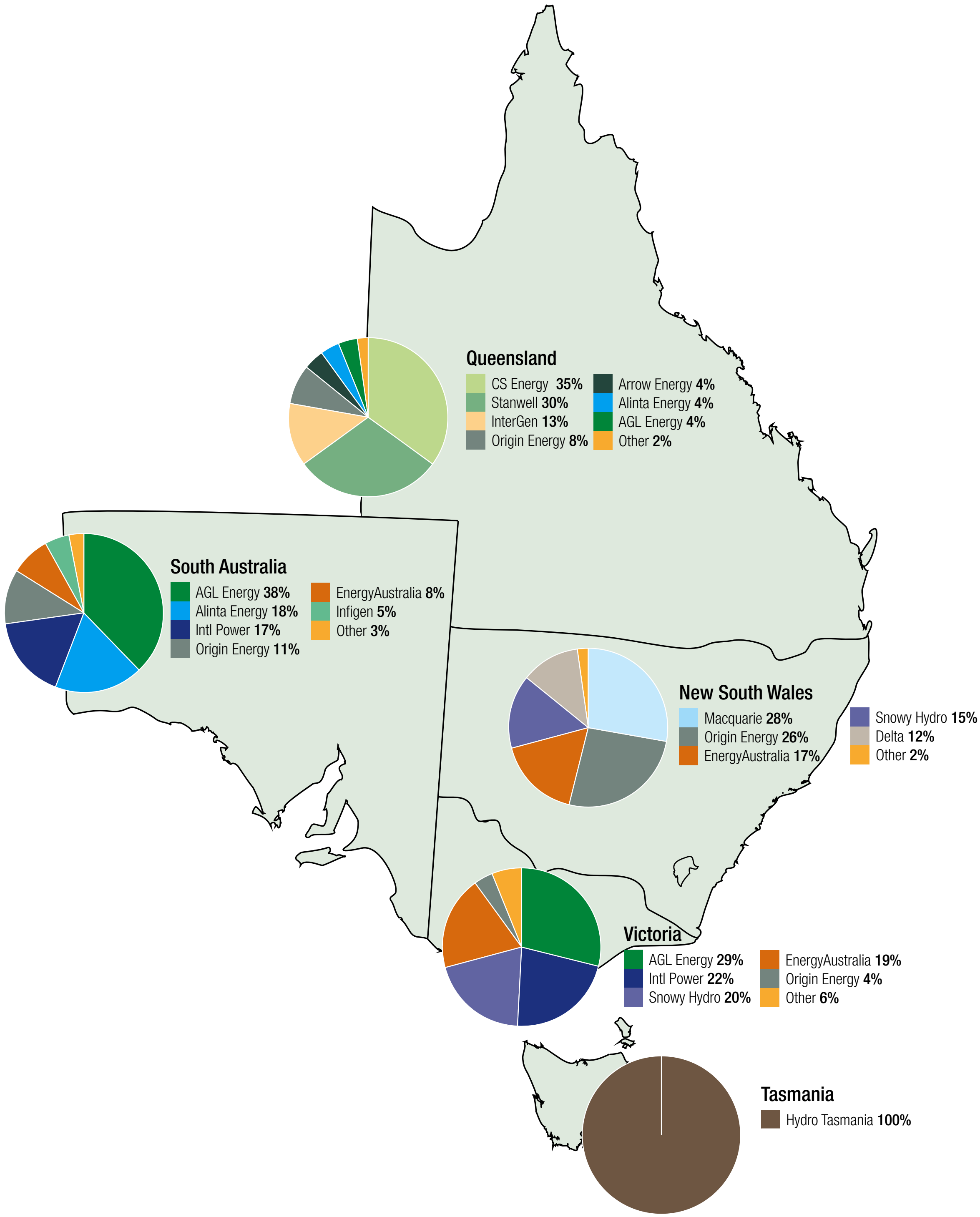
Fuel types: coal; gas; hydro; wind; diesel/fuel oil/multi-fuel; biomass/bagasse; unspecified

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.

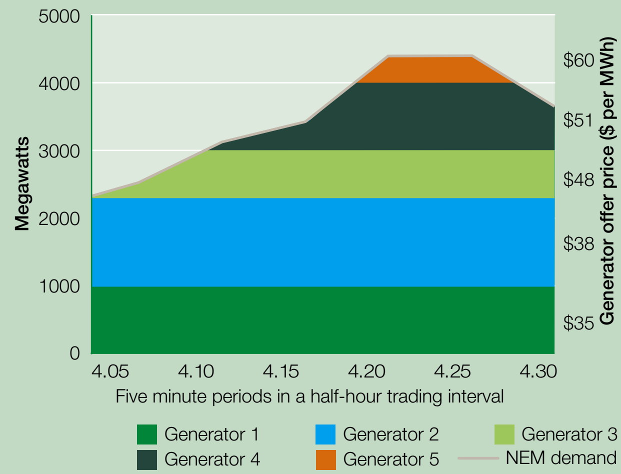
24 Some generators bypass this central dispatch process, including some older wind generators, those not connected to a transmission network (for example, solar rooftop installations) and those producing exclusively for their own use (such as remote mining operations).

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:

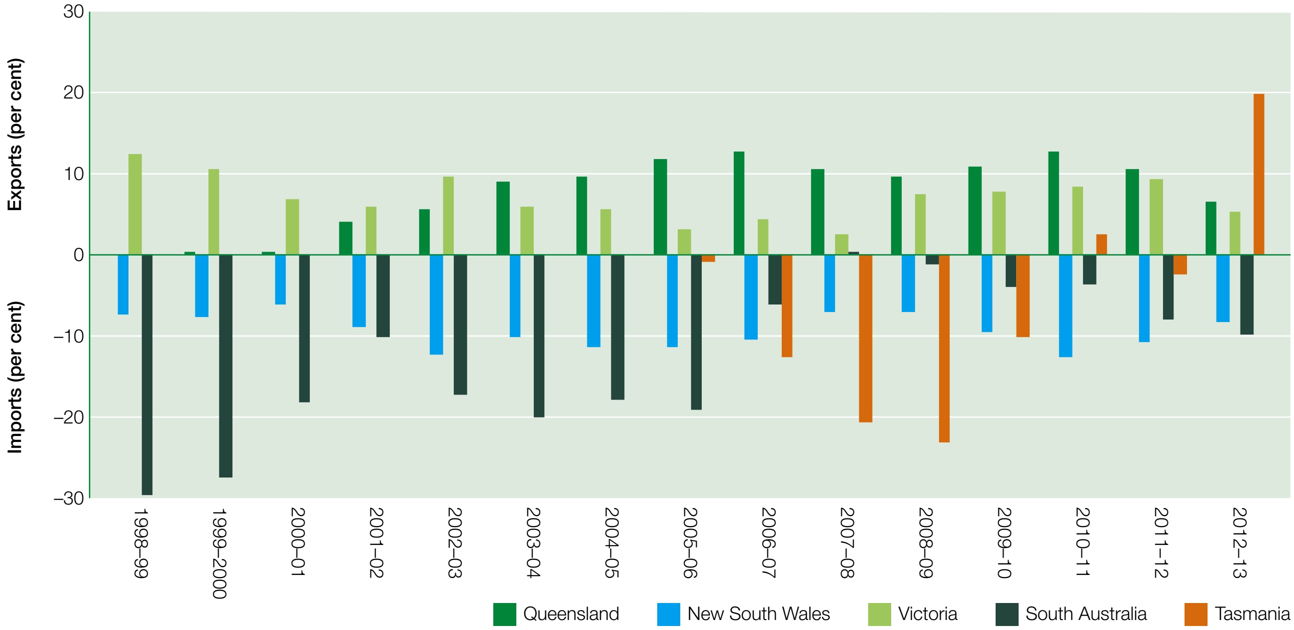
- Victoria has substantial low cost coal fired generation, making it a net exporter of electricity (particularly to New South Wales and South Australia). However, its exports to those regions in 2012–13 were partly offset by a significant increase in hydro generation imports from Tasmania.
- Queensland's 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]

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.

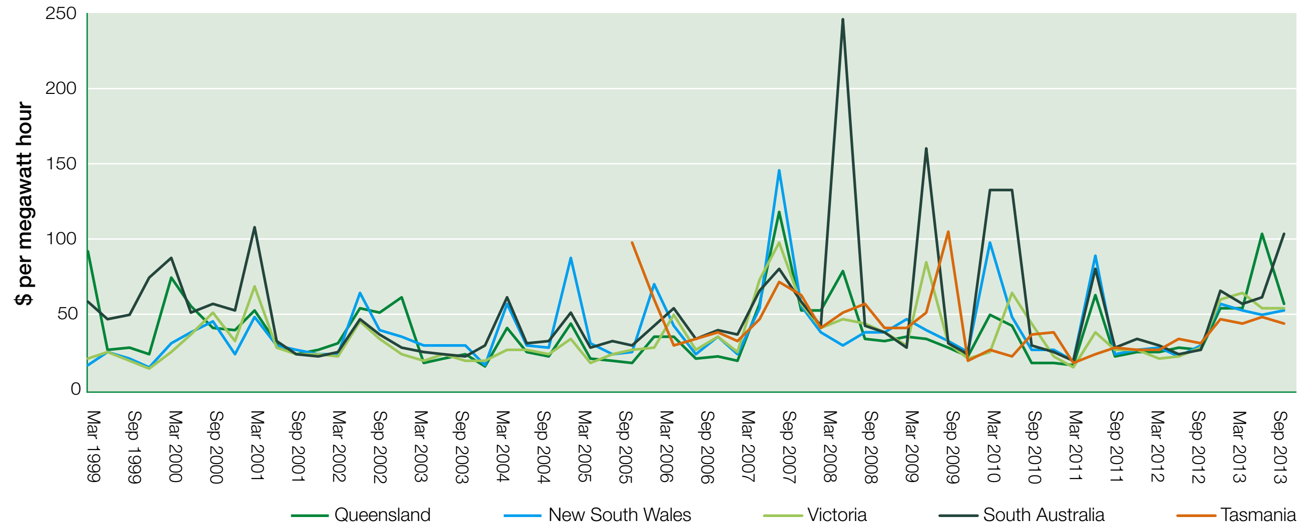
1.7.1 The market in 2012–13

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

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):

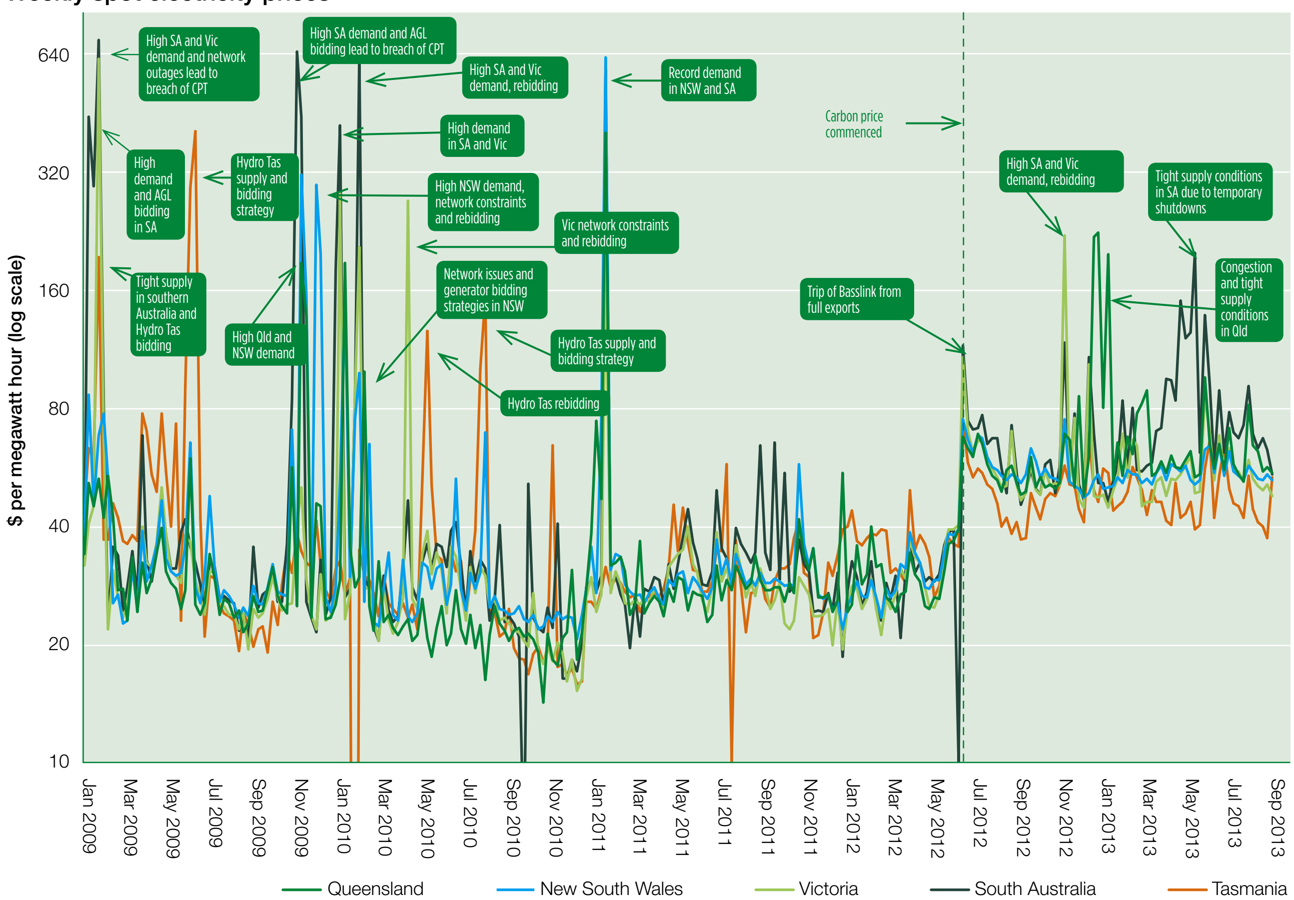
- three events in Victoria on 29 November 2012, with the peak of $9974 per MWh at 4.30 pm. The prices were driven by higher than expected temperatures causing Victorian electricity demand to significantly exceed forecasts and reach its highest level since February 2011. Several generators reacted to 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]

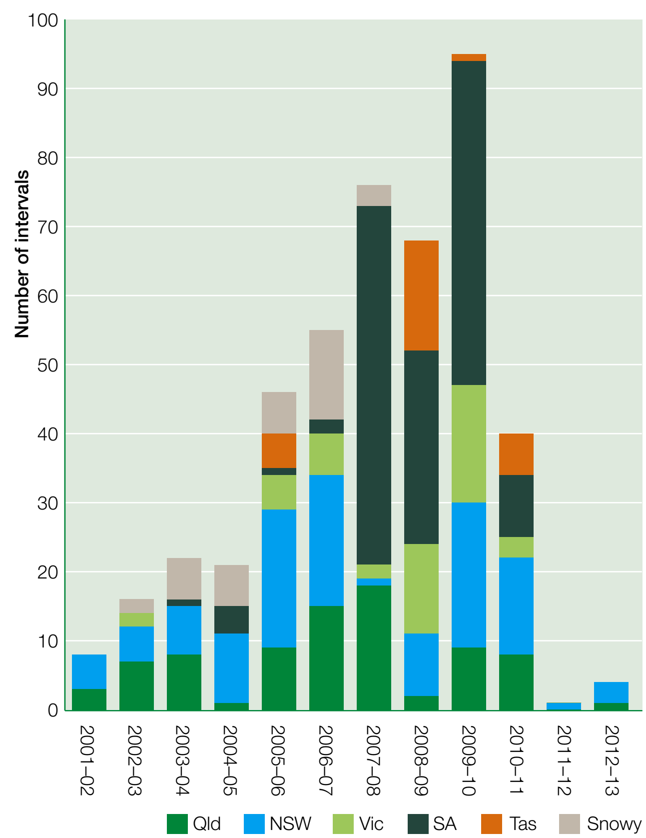
The sharp decline in the number of extreme prices reflects changing market conditions. In particular, energy use has been falling and peak demand has plateaued (section 1.1), causing surplus installed capacity in most regions. Additionally, recent summers have had few prolonged heatwaves, avoiding the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



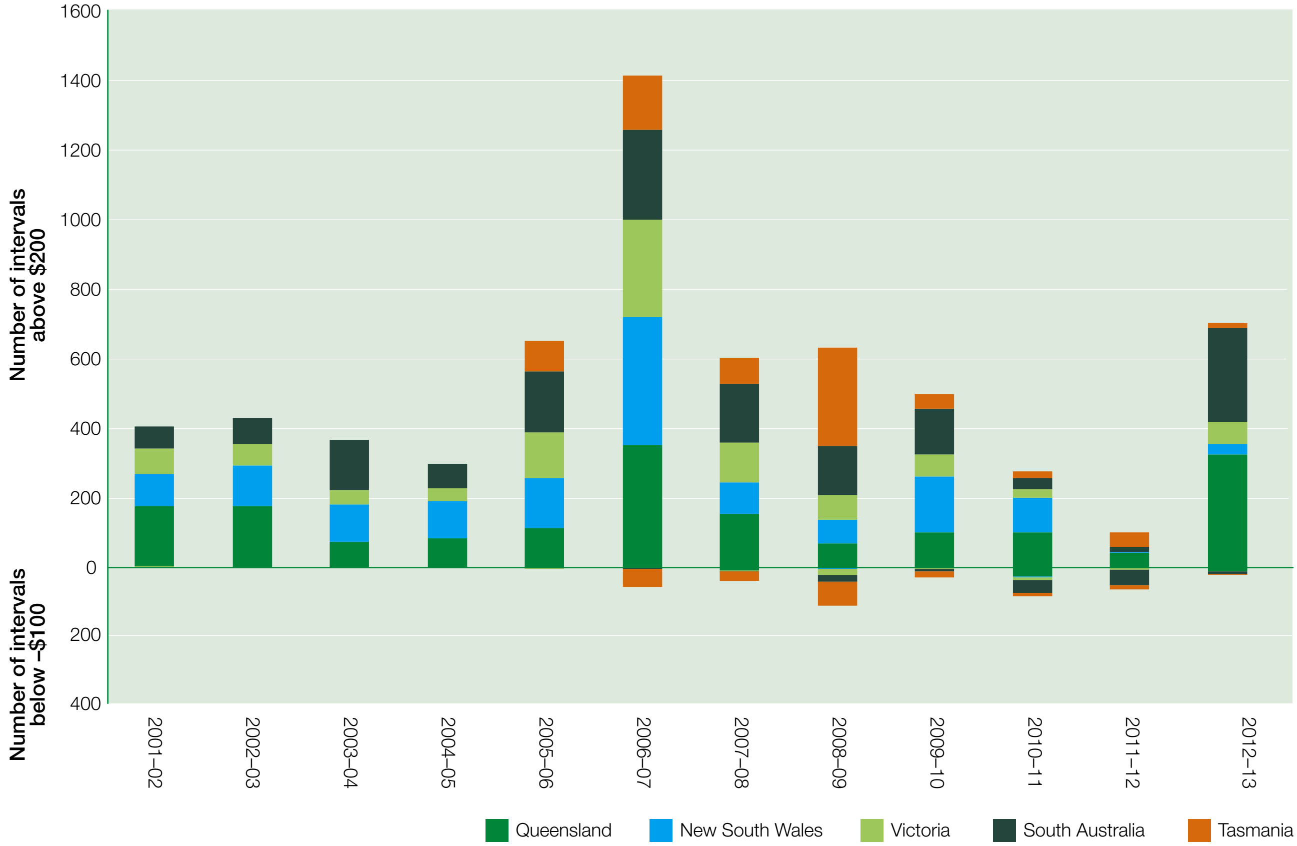
Note: Each trading interval is a half hour.

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.

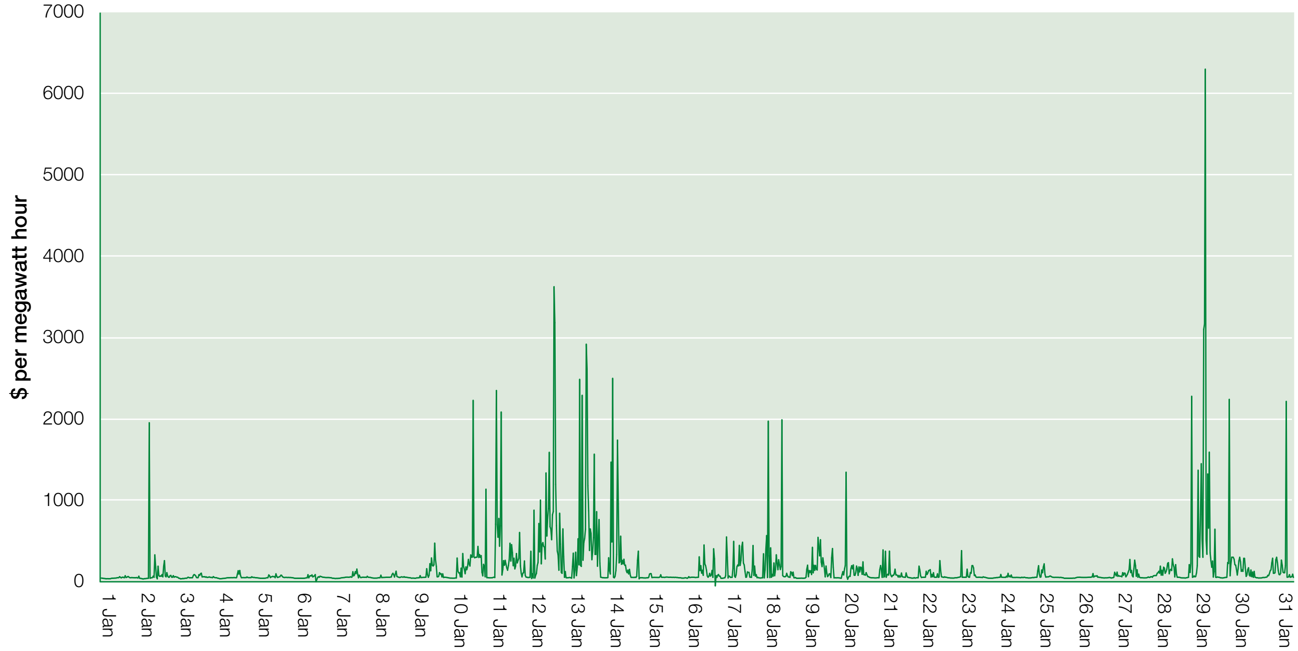
Queensland's supply–demand balance was relatively tight in the first quarter of 2013, with generators offering 12 per cent less capacity (around 1320 MW) into the market than during the same quarter in 2012 (figure 1.19). These conditions were aggravated during much of January by transmission network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

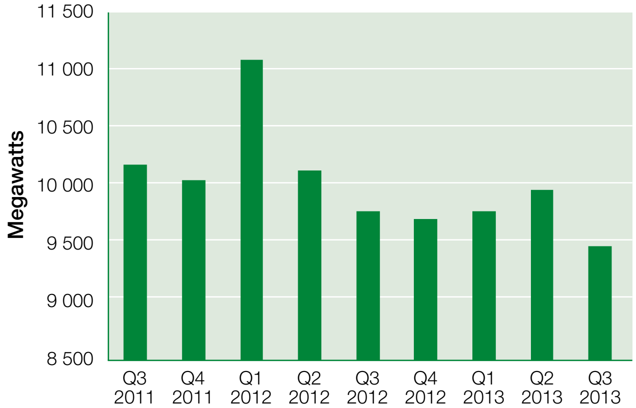
Additionally, the effects on interregional trade flows are significant. When electricity flows counter-price across state borders, the market operator pays out more to generators in the exporting region than it receives from importing customers. The cost of this negative settlement residue falls on the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

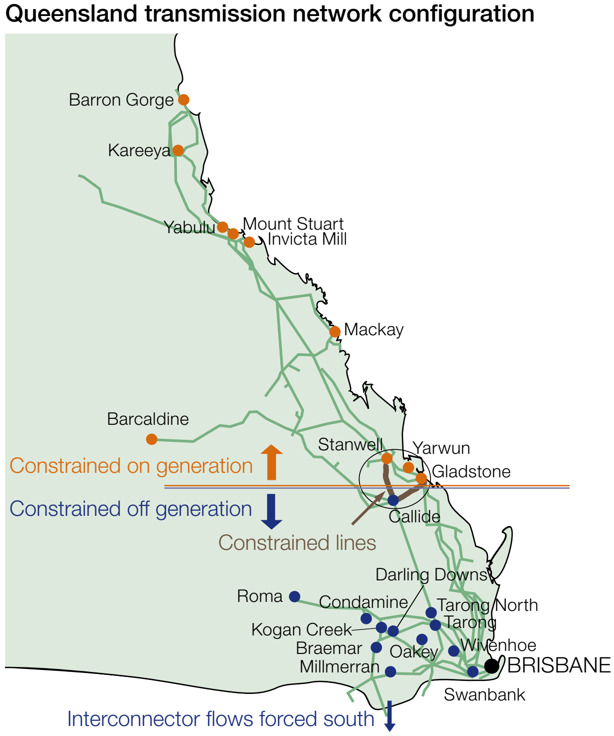
Maximum available generator capacity, Queensland



Source: AER.

Figure 1.20

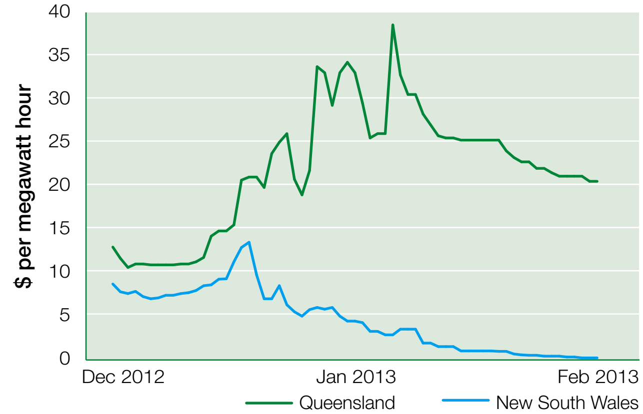
Queensland transmission network configuration



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).

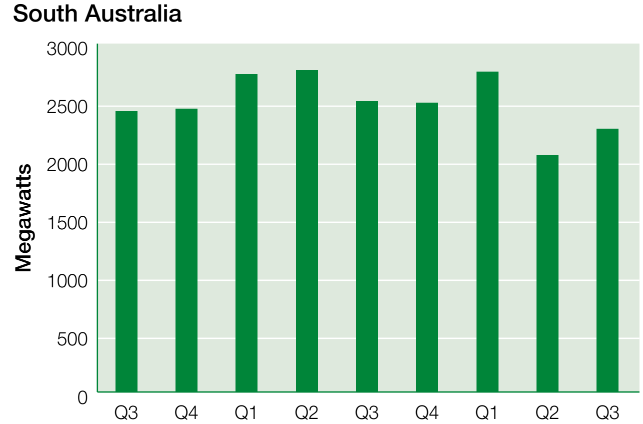
The high prices were driven by tight supply conditions, evidenced by the lowest reserves for four years. During this period, AEMO issued market notices forecasting a lack of reserve conditions for 41 days. South Australia narrowly avoided interrupting customer load. The supply conditions were the tightest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

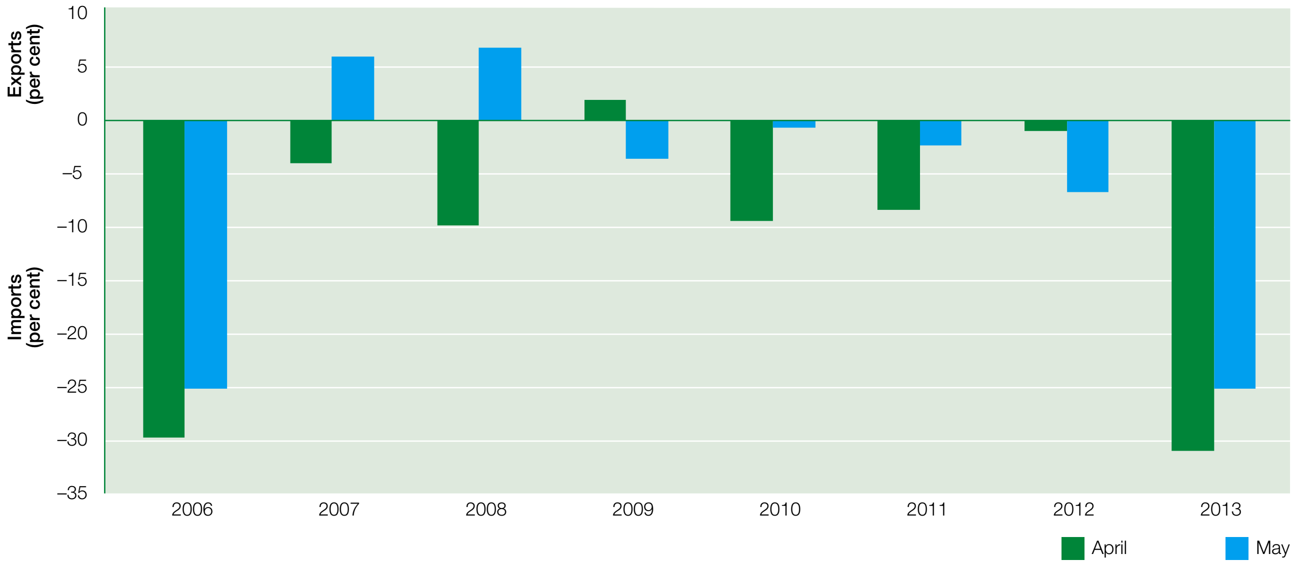
Average half hourly maximum generation availability, South Australia



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]

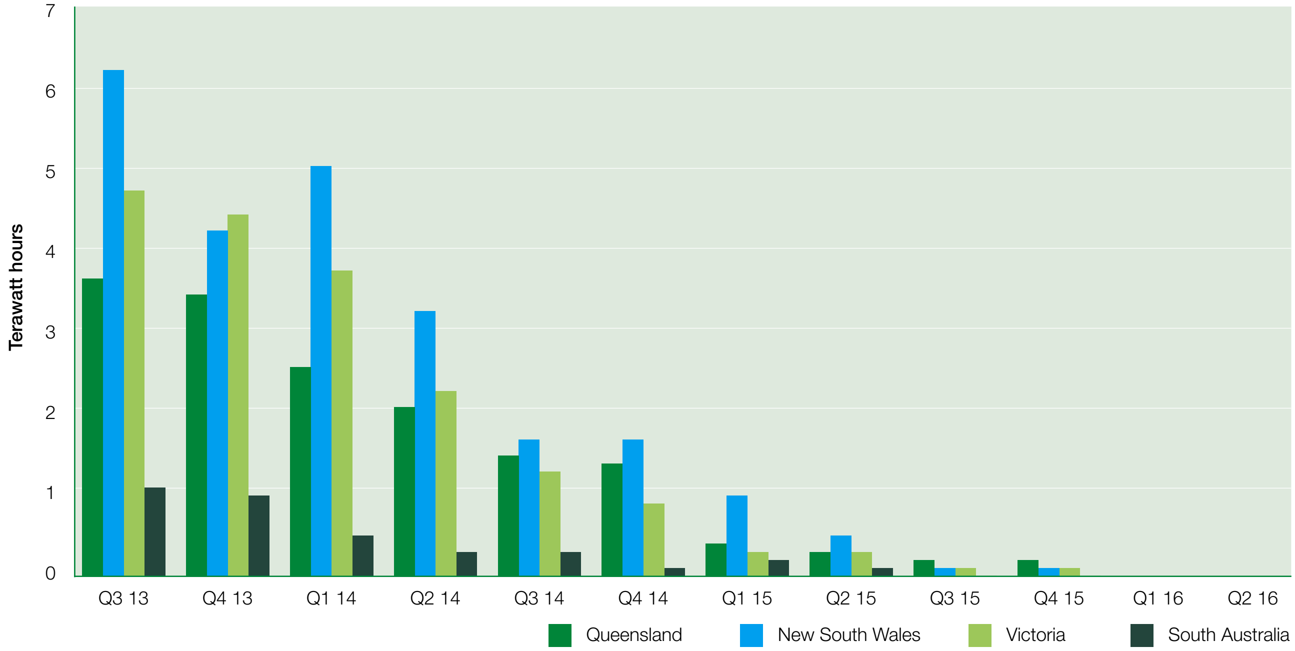
1.8.1 Electricity futures trading on the ASX

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).

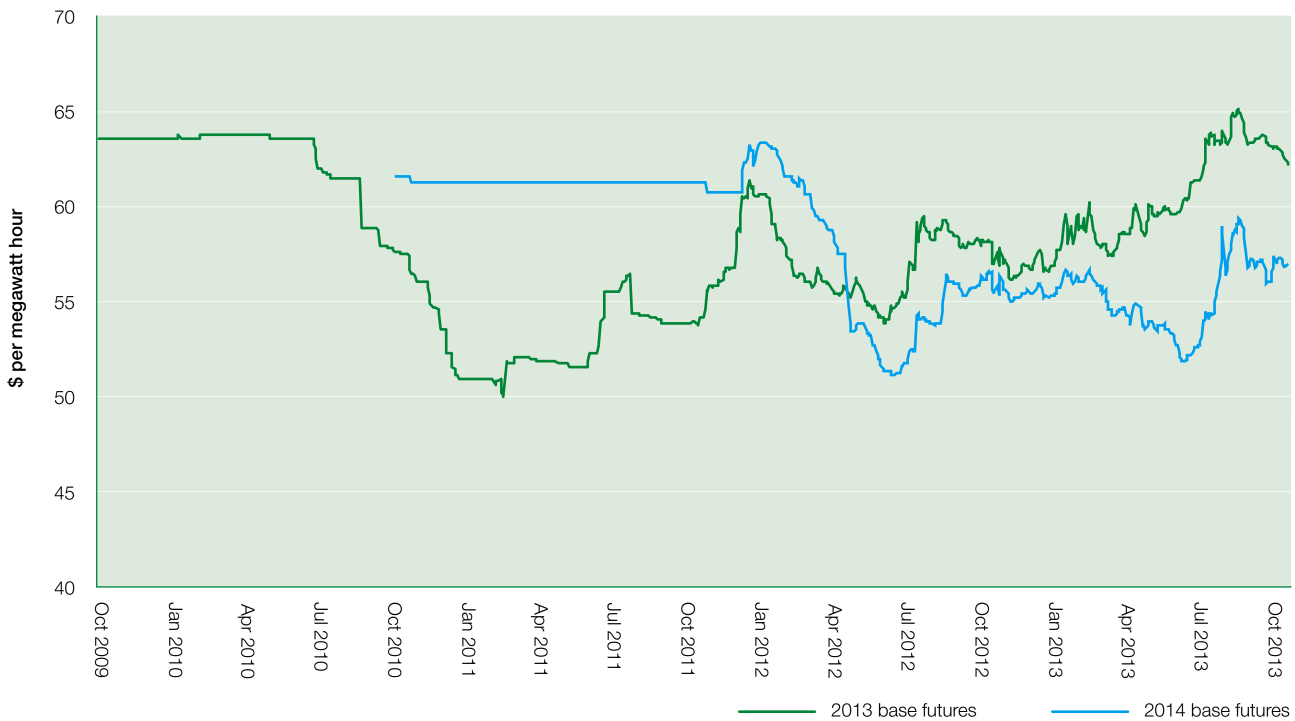
35 AEMC, *NEM financial market resilience, Stage 2 options paper*, November 2013.

Figure 1.24
Open interest in electricity derivatives on the ASX, September 2013



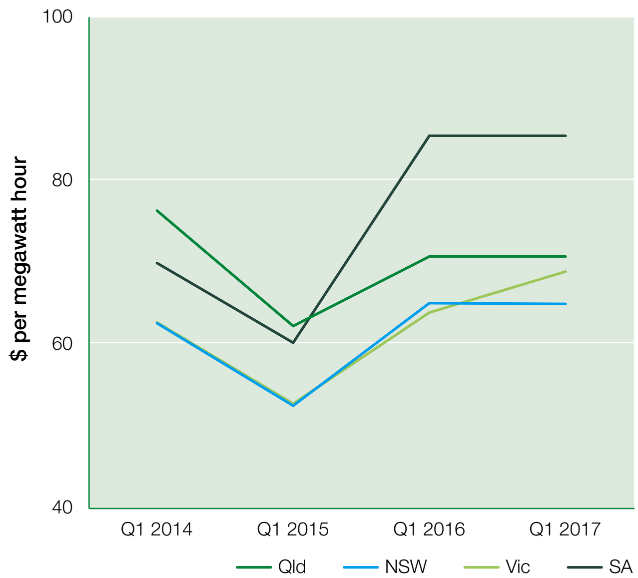
Source: ASX Energy.

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

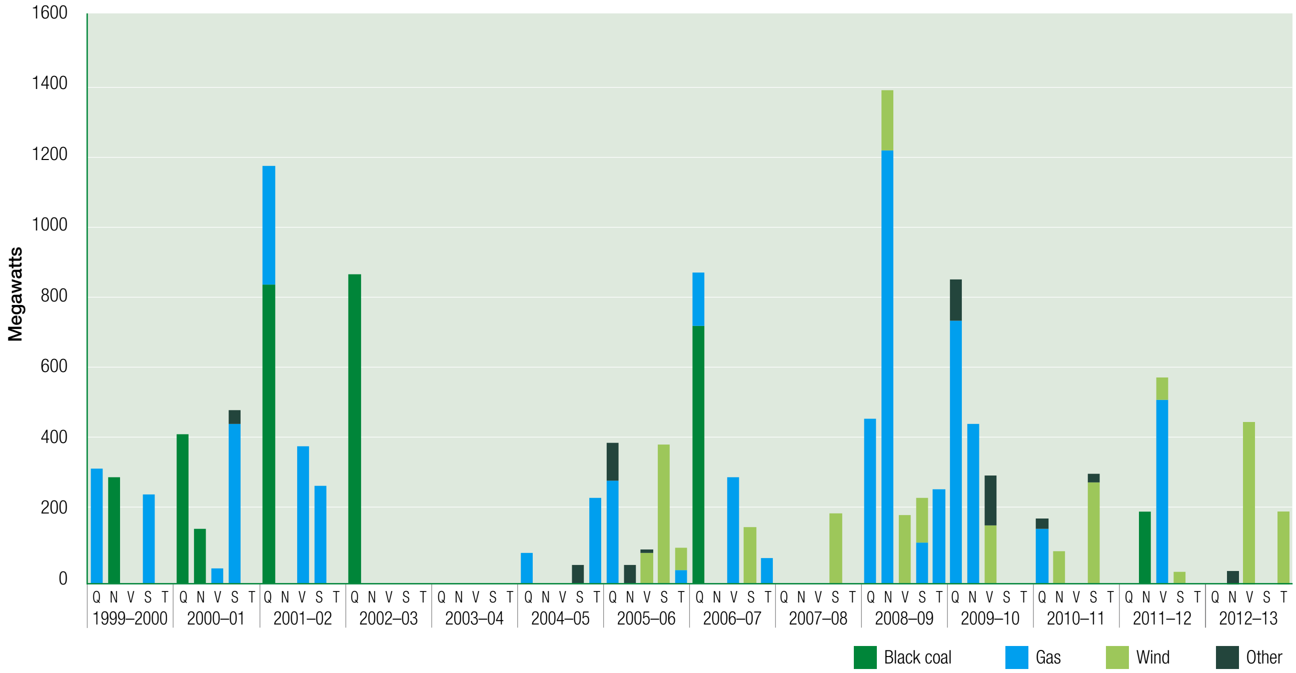
Price signals in the wholesale and forward contract markets for electricity largely drive new investment in the NEM. From the start of the NEM in 1999 to June 2013, new investment added 13 850 MW of registered generation capacity—around 1000 MW per year. Figures 1.27 and 1.28 illustrate investment in 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

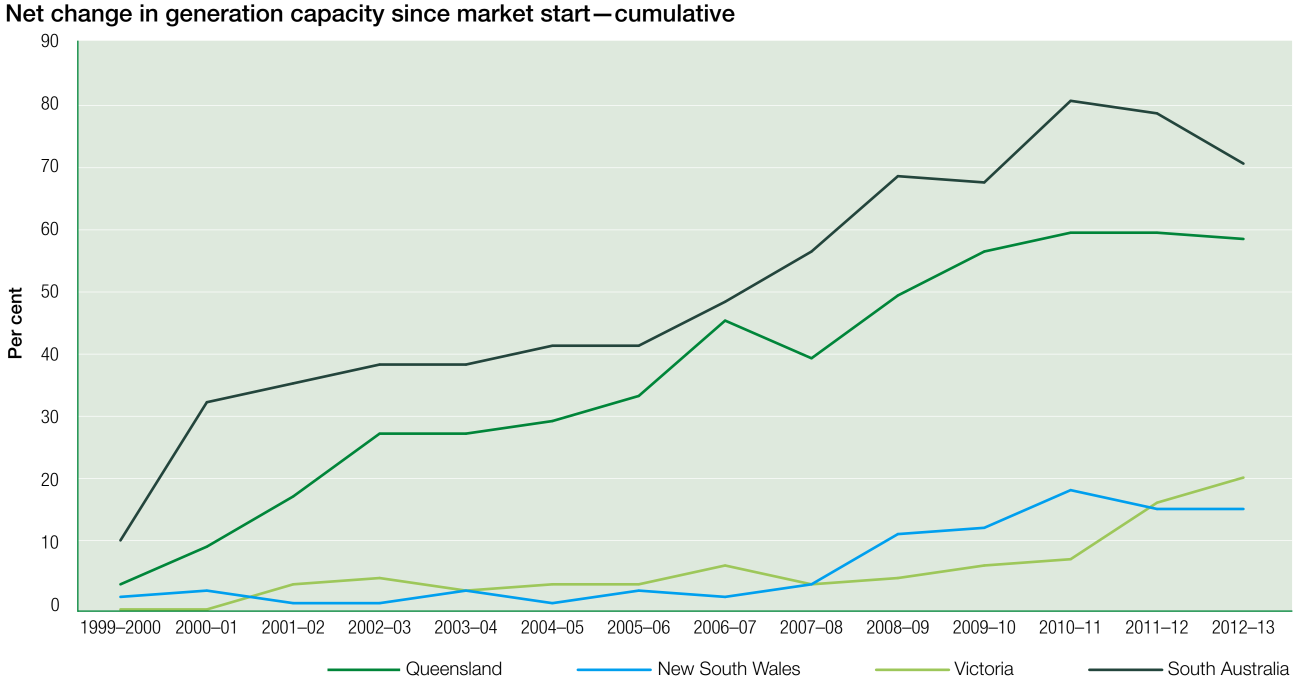


Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.

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

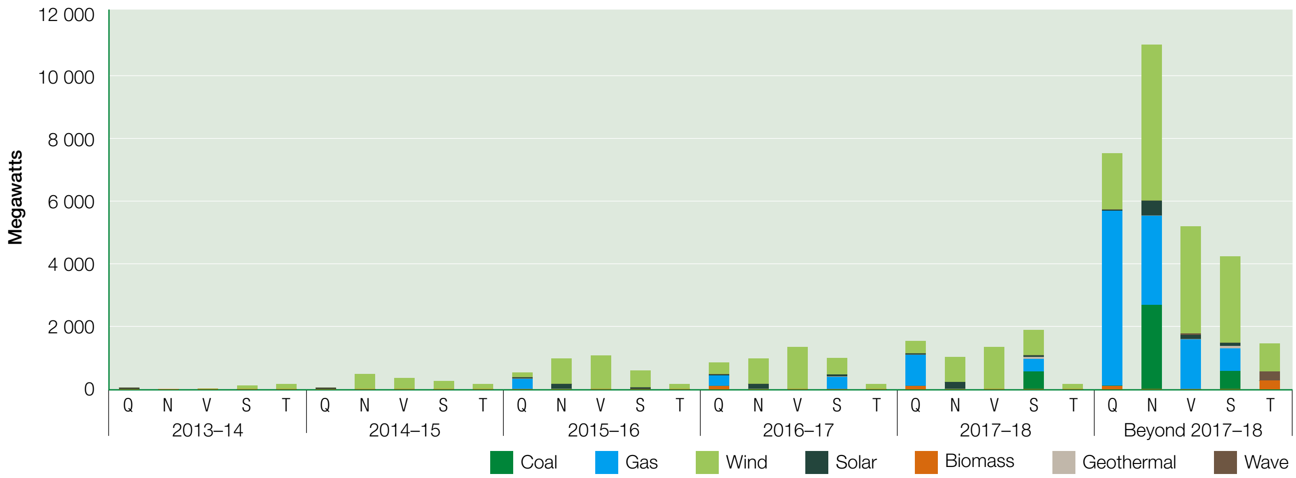
Generation investment (other than in wind) is likely to be limited over the next few years, with only a small number of projects in development. At June 2013 the NEM had around 800 MW of committed capacity[37]—mostly in wind generation, which the RET may make profitable despite depressed wholesale prices (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:

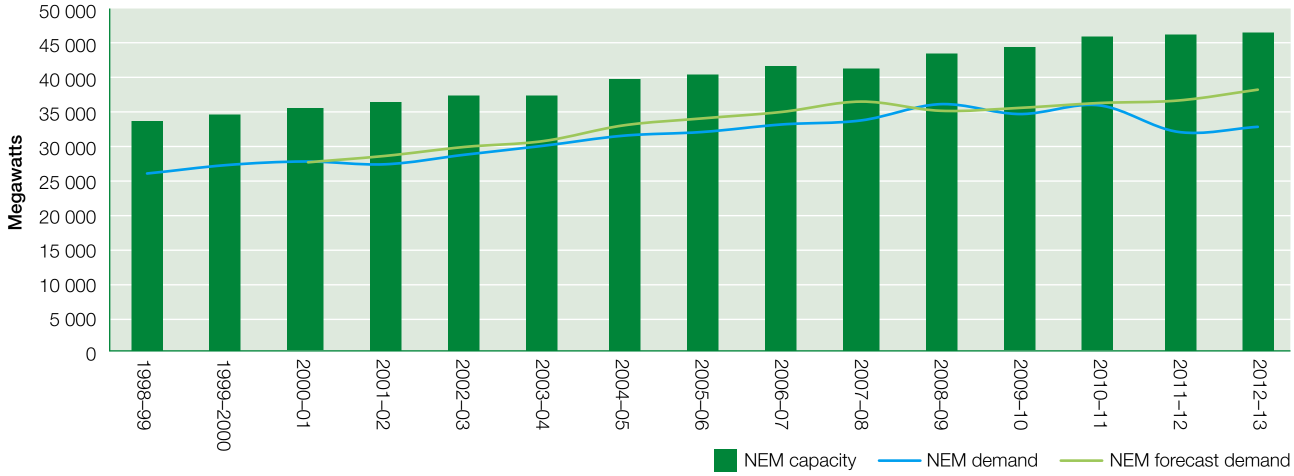
- AEMO can enter reserve contracts with generators under a reliability and emergency reserve trader (RERT) mechanism to ensure reserves are available to meet the reliability standard. When entering these contracts, AEMO must prioritise facilities that would least distort wholesale market prices. It does 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

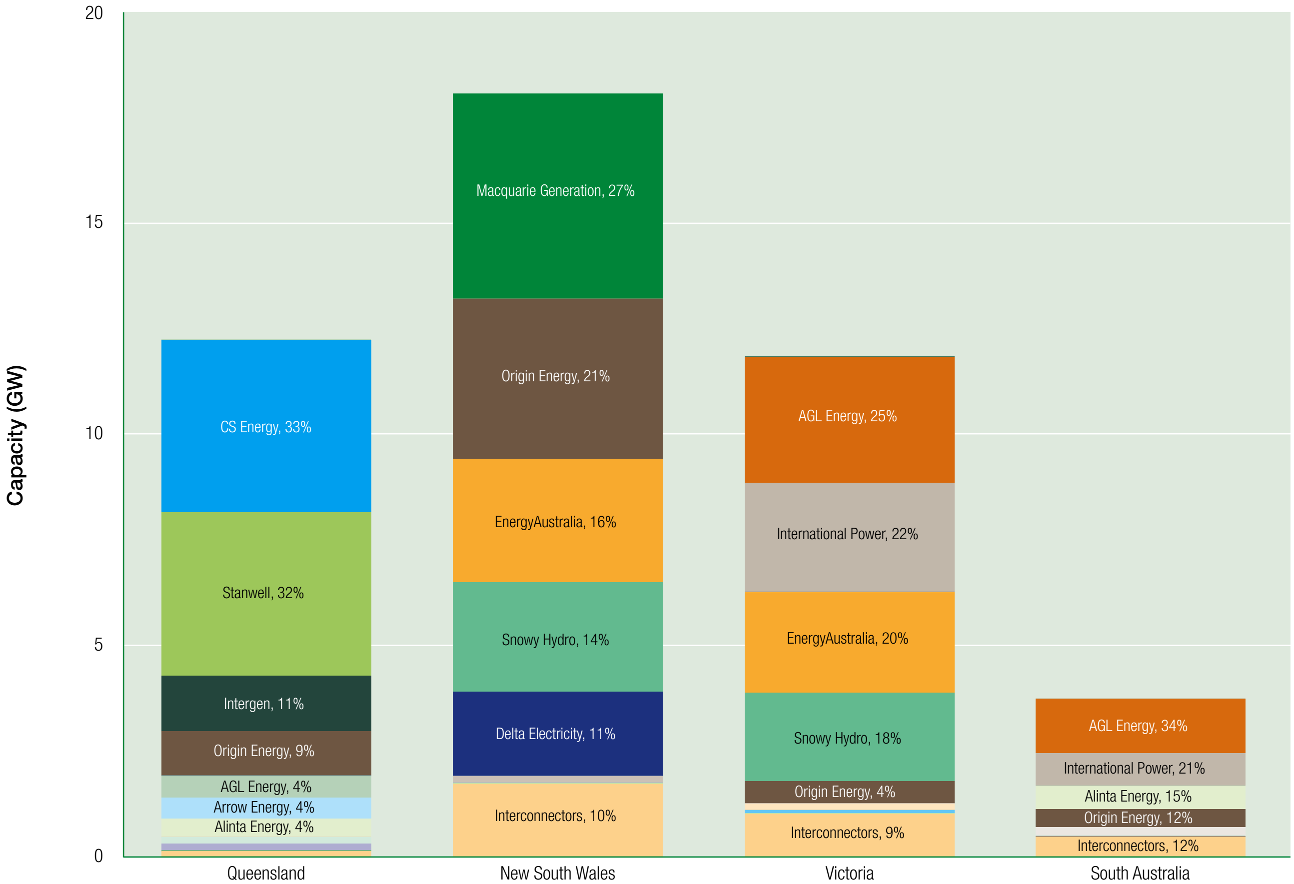
The two largest generators in Queensland, CS Energy and Stanwell, held a combined market share of 65 per cent in 2012–13. The indicators suggest an improvement in competitive conditions in the Queensland market between 2008–09 and 2010–11, when private investment in new capacity drove down the market 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

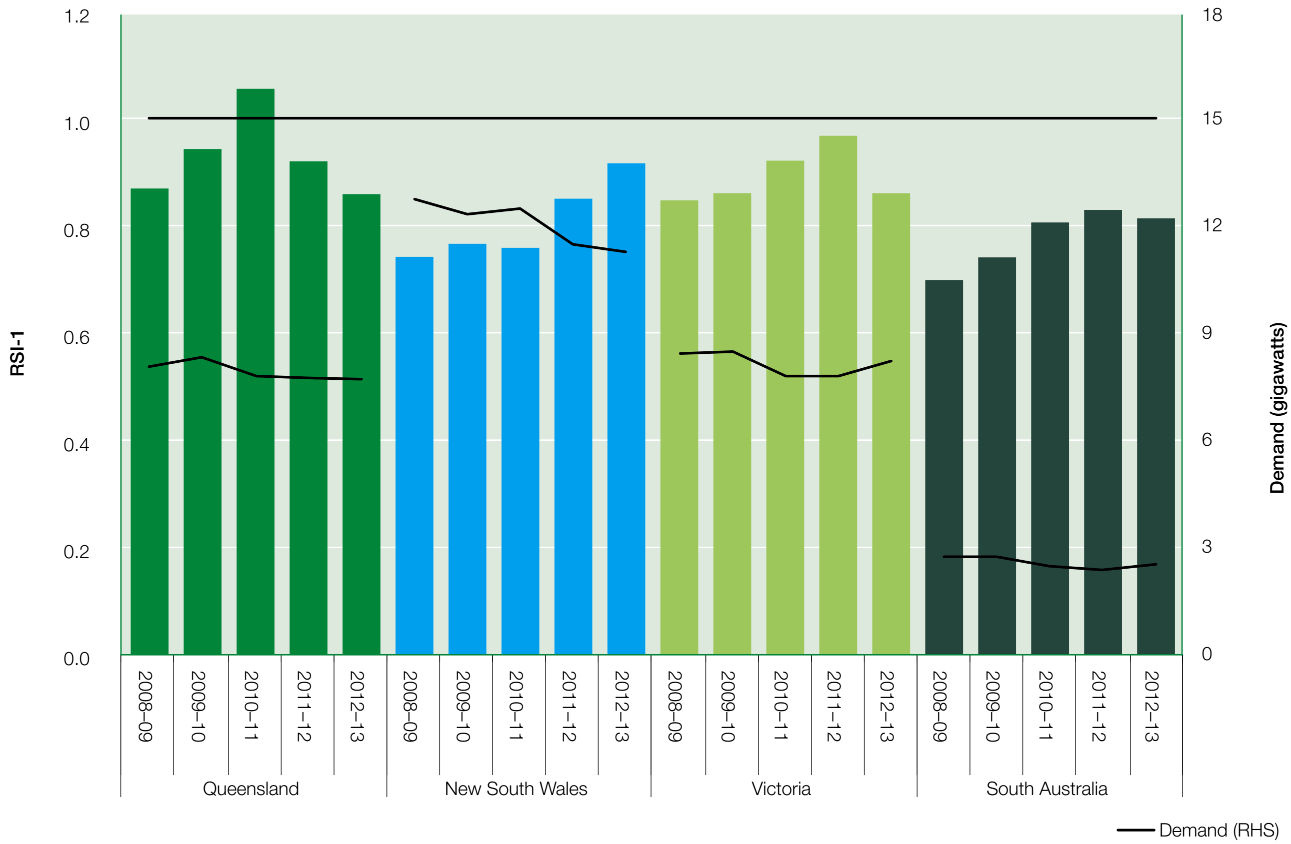


Source: AER.

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)

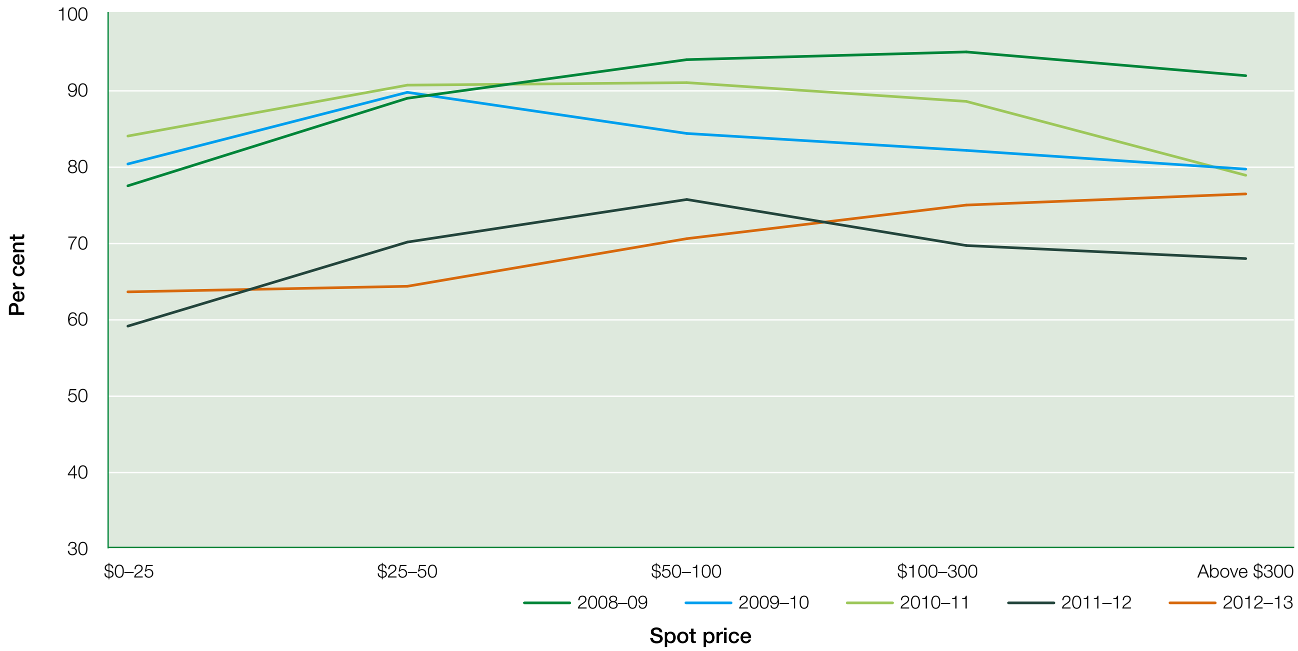


Figure 1.35
Average annual capacity utilisation, Macquarie Generation (New South Wales)

Figure 1.36
Average annual capacity utilisation, International Power (Victoria)

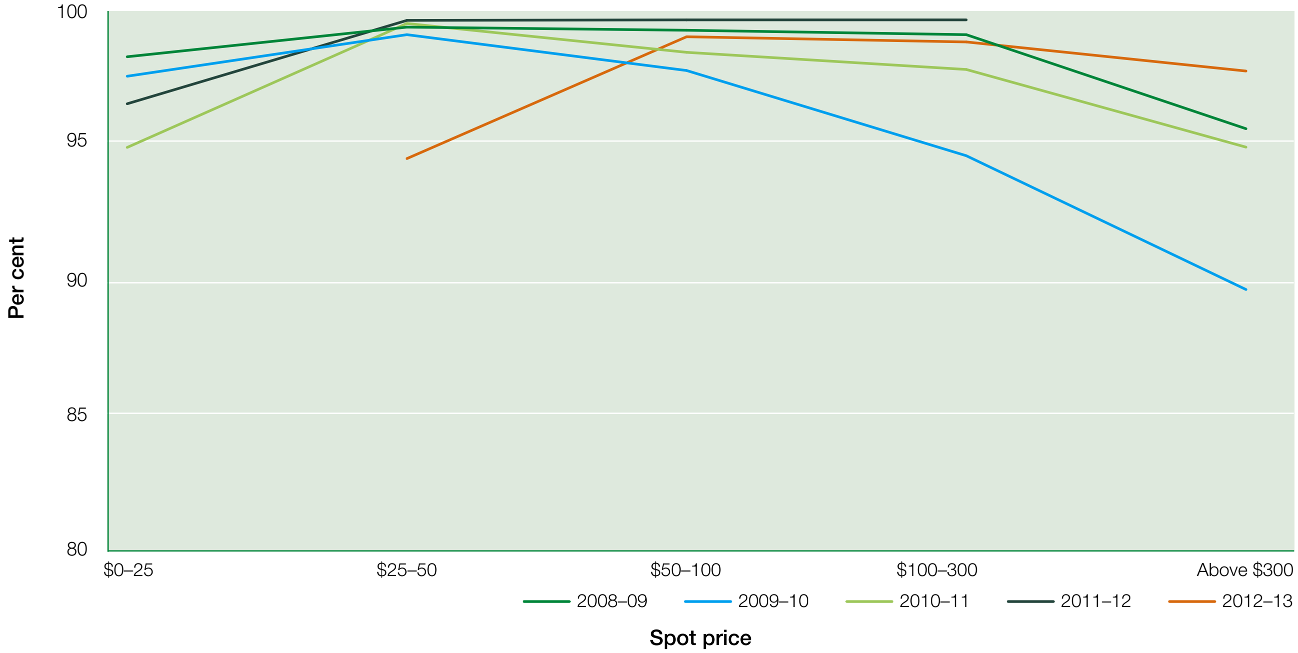
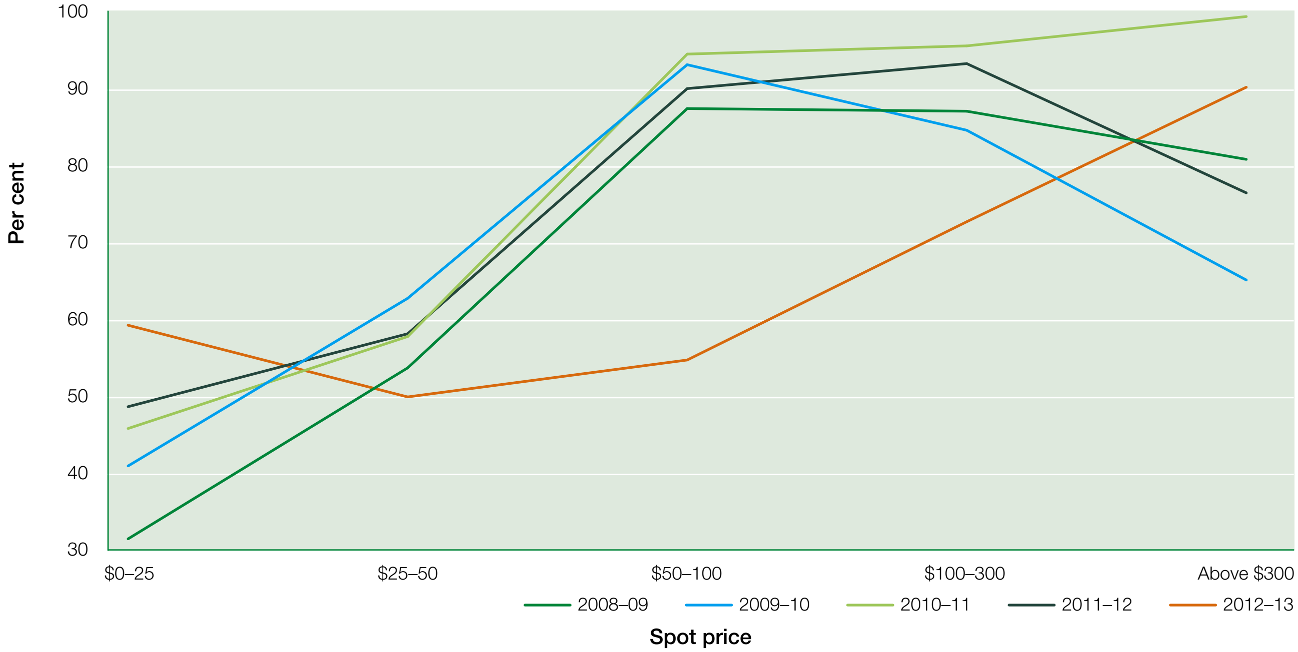


Figure 1.37
Average annual capacity utilisation, AGL Energy (South Australia)



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