
Hydro Tasmania

1 NATIONAL ELECTRICITY MARKET

The National Electricity Market (NEM) is a wholesale market in which generators sell electricity in eastern and southern Australia. 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	48 311 MW
Number of registered generators	308
Number of customers	9.7 million
NEM turnover 2011–12	$6 billion
Total energy generated 2011–12	199 TWh
National maximum winter demand 2011–12	31 084 MW[1]
National maximum summer demand 2011–12	30 322 MW[2]

MW, megawatt; 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.

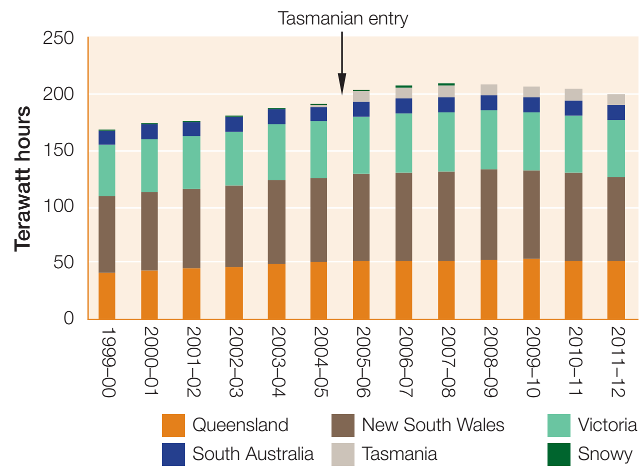
Sources: AEMO; AER.

1.1 Demand and capacity

The NEM supplies electricity to almost 10 million residential and business customers. In 2011–12 the market generated 199 terawatt hours (TWh) of electricity—a 2.5 per cent reduction from the previous year, reflecting a trend of declining energy demand since 2007–08 (figure 1.1). Energy demand has weakened as a result of:

- commercial and residential customers responding to rising electricity costs by reducing energy use and adopting energy efficiency measures such as solar water heating
- moderating rates of economic growth and weaker energy demand from the manufacturing sector
- the increasing use of rooftop solar photovoltaic (PV) generation, which is reducing demand for energy supplied through the grid by the national market.

Figure 1.1
National Electricity Market 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.

The Australian Energy Market Operator (AEMO) projected annual energy demand will be flat in 2012–13 and grow annually by around 1.7 per cent over the next decade.[1] Most of the growth is linked to major industrial projects in Queensland. The growth forecasts are significantly lower than those made 12 months ago, and the national demand forecast for 2012–13 was revised down by 8.8 per cent.

Green Energy Markets estimated rooftop PV generation and solar water heating, supported by the renewable energy target (RET) and energy efficiency schemes, accounted for 53 per cent of the reduction in energy demand since 2008.[2]

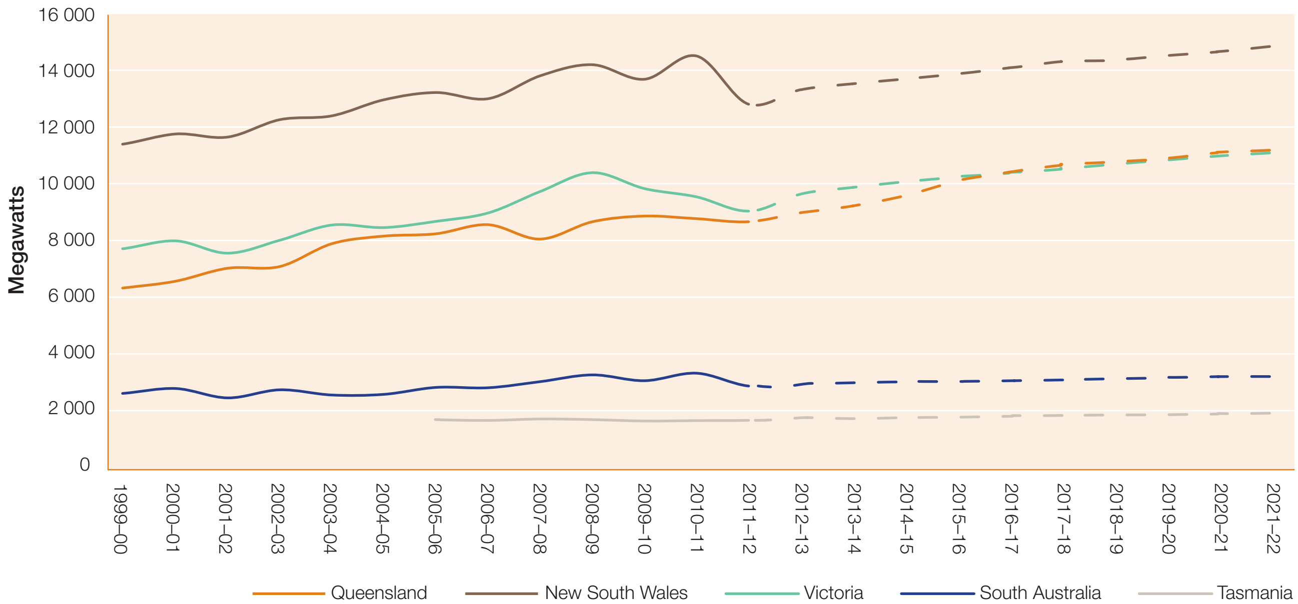
Electricity demand fluctuates throughout the day (usually peaking in early evening) and the season (peaking in winter for heating and summer for air conditioning). Over a year, demand typically reaches its zenith on a handful of days of extreme temperatures, when air conditioning (or heating) loads are highest. Peak demand rose steadily during much of the past decade, reflecting a succession of hot summers and the increasing use of air conditioners (figure 1.2a).

1 AEMO, *National electricity forecasting report 2012*, 2012, p. 3–1.

2 Green Energy Markets, *Impact of market based measures on NEM power consumption: report for the REC Agents Association and the Energy Efficiency Certificate Creators Group*, 2012.

Figure 1.2a

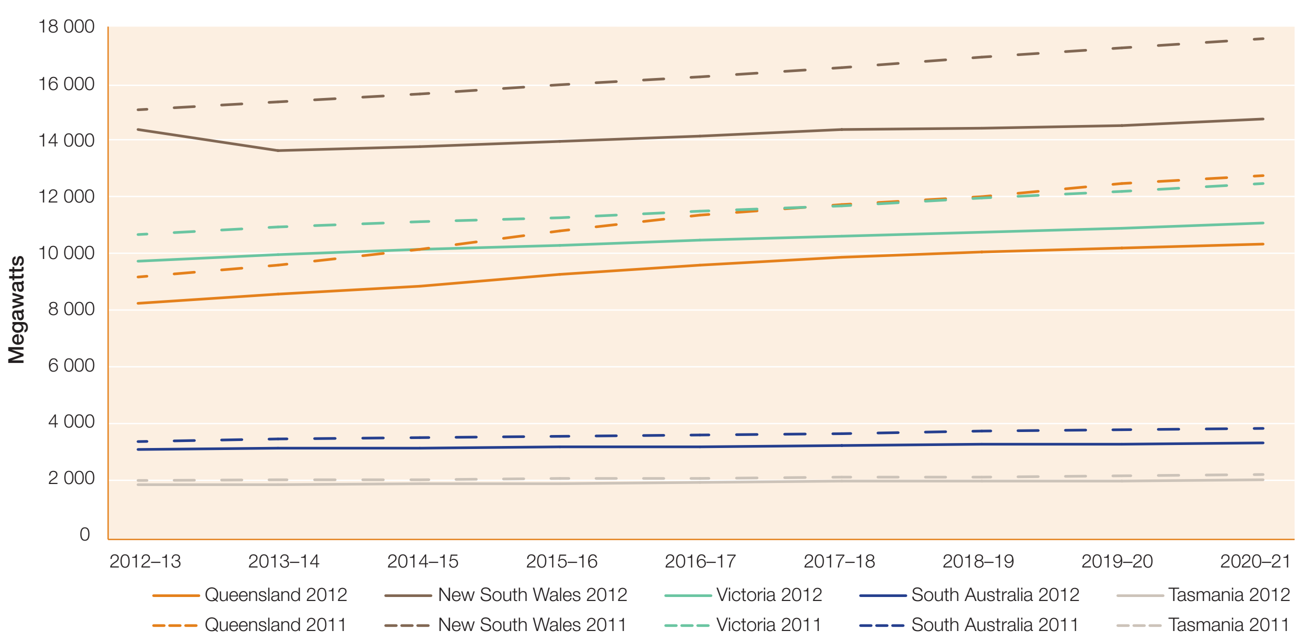
Annual actual and forecast peak demand, by region



Sources: AEMO; AER.

Figure 1.2b

Electricity peak demand, by region—2012 and 2011 forecasts



Sources: AEMO; AER.

Table 1.2 Peak demand growth, by region, 2011–12

	QLD	NSW	VIC	SA	TAS
Change from 2010–11 (%)	–1.2	–11.8	–5.3	–13.5	0.7
Change from historical peak (%)	–2.3	–11.8	–13.1	–13.5	–2.7
Peak year	2009–10	2010–11	2008–09	2010–11	2007–08

Sources: AEMO; AER.

The proportion of Australian households with air conditioning or evaporative cooling rose from 59 per cent in 2005 to 73 per cent in 2011.[3]

A mild summer, combined with the general moderation in energy demand, led to peak demand falling in most regions in 2011–12 (table 1.2). The decrease was most evident in New South Wales (down 11.8 per cent from its 2010–11 record) and South Australia (down 13.5 per cent). Peak demand in Victoria was 13 per cent lower than the state's historical peak set in 2008–09.

AEMO projected that peak demand will return to positive growth from 2012–13 in all regions, but may take several years to return to its historical peaks in New South Wales, Victoria and South Australia (figure 1.2a). More generally, current forecasts of the growth in peak demand are considerably softer than those projected 12 months ago (figure 1.2b).

Subdued electricity demand has flowed through to historically low spot prices (section 1.5). In 2012 it contributed to around 3000 megawatts (MW) of coal plant being shut down or periodically offline (section 1.2.2).

1.2 Generation in the NEM

Most electricity demand in the NEM jurisdictions is met by generators using coal, gas, hydro and wind technologies. The generators sell the energy they produce through a national market that AEMO manages. Figure 1.3 illustrates the location of the major generators in the NEM.

1.2.1 Generation 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 the sun or wind.

Each generation technology has unique characteristics—for example, while coal generators can require up to 48 hours to start up, gas powered and hydroelectric generation can be started relatively quickly. Wind generation relies on weather conditions, so is intermittent. Each type of generator also has significantly different carbon emissions, along with different operating cost structures.

The demand for electricity is not constant, varying with the time of day, the season and the ambient temperature. A mix of generation capacity is thus needed, to respond to these demand characteristics. The mix consists of baseload, peaking, intermediate and intermittent generation.

Baseload plant, which meets the bulk of demand, tends to have relatively low operating costs but high start-up costs, making it economical to run it continuously. *Peaking* generators have higher operating costs and lower start-up costs, and are used to supplement baseload when prices are high (typically, in periods of peak demand). While peaking generators are expensive to run, they must be capable of a reasonably quick start-up because they may be called on to operate at short notice. *Intermediate* generators operate more frequently than peaking plants, but not continuously. *Intermittent* generation, such as wind and solar, can operate only when the weather conditions are favourable.

Across the NEM, black and brown coal account for 57 per cent of registered generation capacity, but this baseload plant supplies 79 per cent of output (figure 1.4). Victoria, New South Wales and Queensland rely on coal more heavily than do other regions (figure 1.5).

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

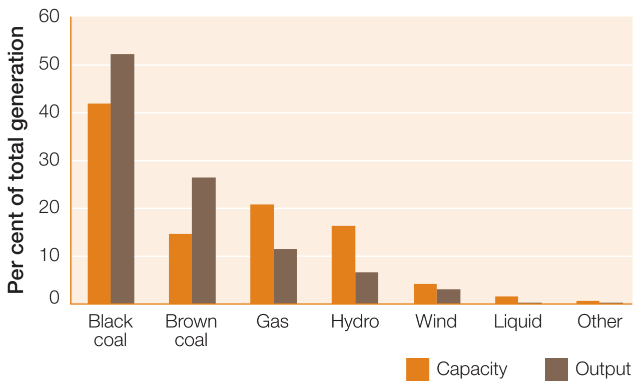
Figure 1.3

Large electricity generators in the National Electricity Market

Sources: AEMO; AER.

Figure 1.4

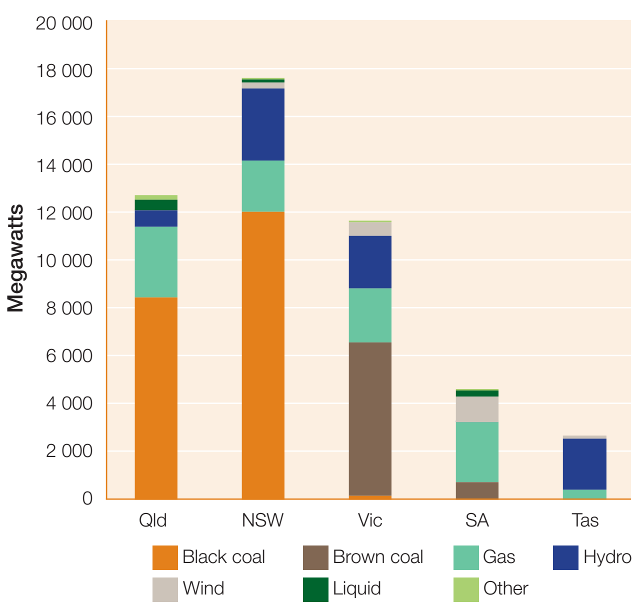
Registered generation, by fuel source, 2011–12



Sources: AEMO; AER.

Figure 1.5

Generation capacity, by region and fuel source, 30 June 2012



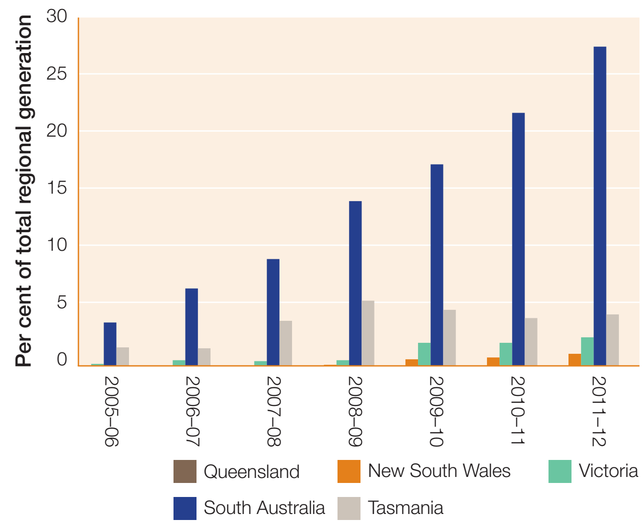
Note: New South Wales and Victoria include Snowy Hydro capacity allocated to those regions.

Sources: AEMO; AER.

Gas powered generation accounts for 21 per cent of registered capacity across the NEM but—as intermediate and peaking plant— supplies only 11 per cent of output. Among the NEM jurisdictions, South Australia is the most reliant on gas powered generation. More generally, 54 per cent of new generation investment over the past decade has been in gas plant.

Figure 1.6

Wind generation share of total generation, by region



Sources: AEMO; AER.

Hydroelectric generation accounts for 16 per cent of registered capacity but less than 7 per cent of output. The bulk of Tasmanian generation is hydroelectric. There is also hydro generation in Victoria and New South Wales (mainly Snowy Hydro).

The role of intermittent wind generation is expanding under climate change policies such as the RET (section 1.2.2). Nationally, wind generation accounts for 4 per cent of capacity and 3 per cent of output. In South Australia, however, it represents 24 per cent of capacity, and it accounted for 27 per cent of output in 2011–12 (figure 1.6).[4] On particular 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).

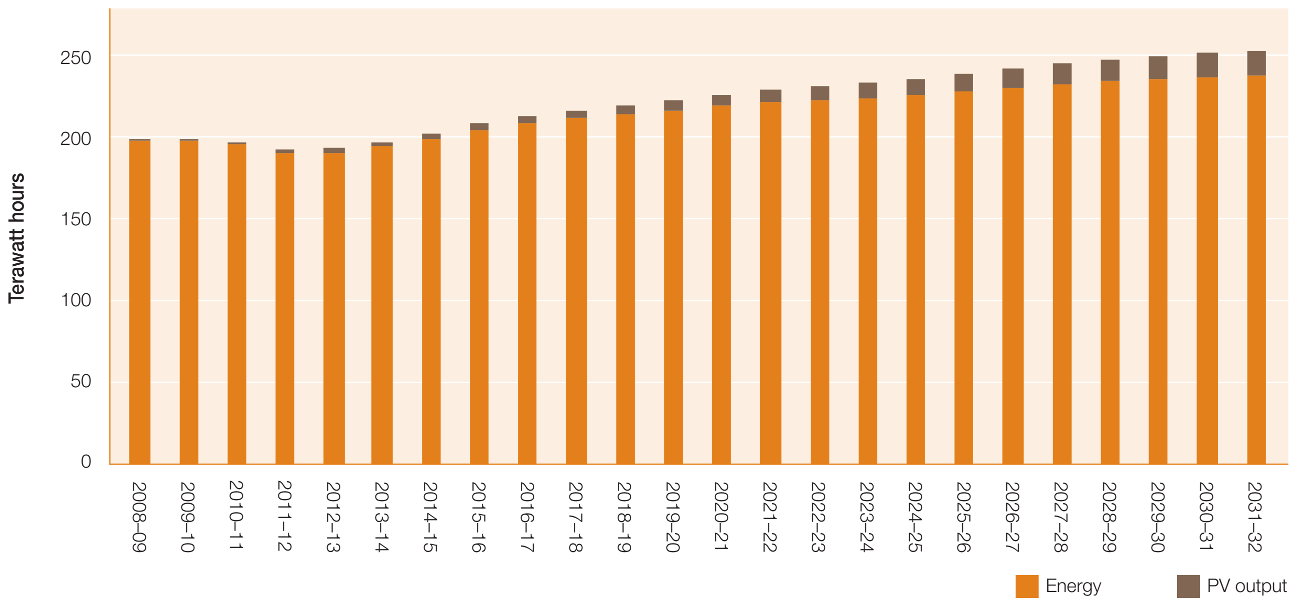
However, wind generation is generally lower at times of peak demand—on average, it contributes to less than 9 per cent of supply at any given time during summer. Yet, there is evidence that wind generation is having a moderating impact on electricity prices in South Australia; spot prices are typically higher at times of low wind.[5]

The extent of new investment in intermittent generation led to changes in how wind generation is integrated into the market. Since 31 March 2009 new wind generators greater than 30 MW have been classified as 'semi-scheduled', and they participate in the central dispatch process.

4 AEMO, *2012 South Australian electricity report*, 2012, p. 16.

5 AEMO, *South Australian wind study report*, 2012, p. 2-1.

Figure 1.7
Forecast contribution of rooftop PV generation to meeting energy demand



Data source: AEMO forecasts.

Rooftop solar generation

Climate change policies, including the RET and other subsidies for rooftop solar PV installations, led to a rapid increase in solar PV generation over the past four 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 subsidies are recovered from energy users through electricity charges.

Rooftop PV generation is not traded through the NEM market. Instead, the installation owner receives a reduction in their energy bills. AEMO measures 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 (figure 1.7).

Installed rooftop PV capacity rose from 23 MW in 2008 to around 1450 MW in February 2012.[6] The contribution of rooftop installations to annual energy requirements is expected 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 sunlight intensity than other NEM jurisdictions. In 2011–12 solar PV installations in South Australia generated around 306 gigawatt hours (GWh), or 2.4 per cent of the state's annual energy requirements.

The contribution of rooftop PV installations to peak demand is generally lower than 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 is operating at 28–38 per cent of capacity. Maximum demand in Tasmania typically occurs on winter evenings, when rooftop PV generation is negligible.

AEMO expects the uptake of rooftop installations to flatten out until 2017, due mainly to a reduction of feed-in tariffs, but then accelerate from 2018.[7] The contribution of rooftop PV generation is forecast to rise to 3.4 per cent of the NEM's energy requirements by 2021–22; in South Australia, it is forecast to reach 6.4 per cent.[8]

1.2.2 Climate change policies

The pattern 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

6 AEMO, *Rooftop PV information paper*, 2012, p. iii.

7 AEMO, *Rooftop PV information paper*, 2012, p. iii.

8 AEMO, *National electricity forecasting report 2012*, 2012, pp. 3-1, 6-1.

greenhouse gas emissions, mainly due to an historical reliance on coal fired generation.[9] 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.

The central plank of Australia's climate change response is the carbon price introduced by the Australian Government on 1 July 2012 as part of its Clean Energy Future Plan. The plan, overseen by the newly created Climate Change Authority, targets a reduction in carbon and other greenhouse emissions to at least 5 per cent below 2000 levels by 2020 (and up to 25 per cent with equivalent international action). The central mechanism places a fixed price on carbon for three years, starting at $23 per tonne of carbon dioxide equivalent emitted. The fixed price will then be replaced by an emissions trading scheme on 1 July 2015, with the price determined by the market. The legislation to establish the scheme included transitional provisions for floor and ceiling prices. Entities would be entitled to acquit up to 50 per cent of their annual carbon liability using international emission reduction units (created through schemes set up under the Kyoto Protocol).

The Australian Government announced changes to the scheme in August 2012 that link the Australian and European Union (EU) emissions trading markets under the floating price scheme to begin in 2015. The changes will permit an Australian entity to use EU emissions allowances to meet up to 50 per cent of its carbon liability. And they will reduce to 12.5 per cent the extent to which an entity can use other international emission reduction units. The government will also abandon the carbon floor price. In effect, from 1 July 2015, the Australian carbon price will be closely linked to the price of EU allowances, which were trading at around $10 per tonne in September 2012.

The Clean Energy Future Plan includes assistance (cash and free carbon permits) for emission intensive generators, estimated at $5.5 billion. It also established the Clean Energy Finance Corporation, with access to $10 billion over five years for investment in renewable and low emissions energy.

A proposal for the Australian Government to contract for the closure of up to 2000 MW of coal fired generation by 2020 did not proceed. The government negotiated terms with the owners of five high emitting coal generators in Queensland, Victoria and South Australia, but the parties could not agree on a price.

9 Garnaut, Professor R, *The Garnaut Review 2011: Australia in the global response to climate change*, Final report of the Garnaut Climate Change Review, 2012.

The Australian Government also operates a national RET scheme, which it revised in 2011. The scheme is designed to achieve the government's commitment to 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 (MWh) 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 and large scale renewable supply. 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 $35–40 (box 1.1). The price of certificates from small scale projects has been more volatile, trading at $20–33.

The Climate Change Authority was reviewing the RET scheme in 2012, including the overall target, the eligibility framework and the scheme's impact on electricity costs, prices and energy security. In a discussion paper in October 2012, it recommended retaining the form and level of the 2020 target for large scale renewable energy projects, and reviewing in 2016 the arrangements for beyond 2020. It also recommended retaining the scheme for small scale installations in its current form. The authority will consider whether the size threshold for these installations should be reduced. A final report is expected in December 2012.

Impacts of climate change policies on electricity generation

The use of black and brown coal for electricity generation peaked in 2008–09 and has since steadily declined (figure 1.9). While energy demand has also declined since 2008–09, gas powered generation rose over the past decade, reflecting new investment in all regions of the NEM. Wind generation has risen strongly, particularly since a 2007 expansion of the RET scheme increased the target and extended it to 2020.

New investment patterns are also changing. In the 10 years to June 2012, electricity generation businesses in eastern Australia invested in 4700 MW of gas powered generation capacity, compared with 750 MW of coal generation

Box 1.1 Certificate prices—renewable energy target

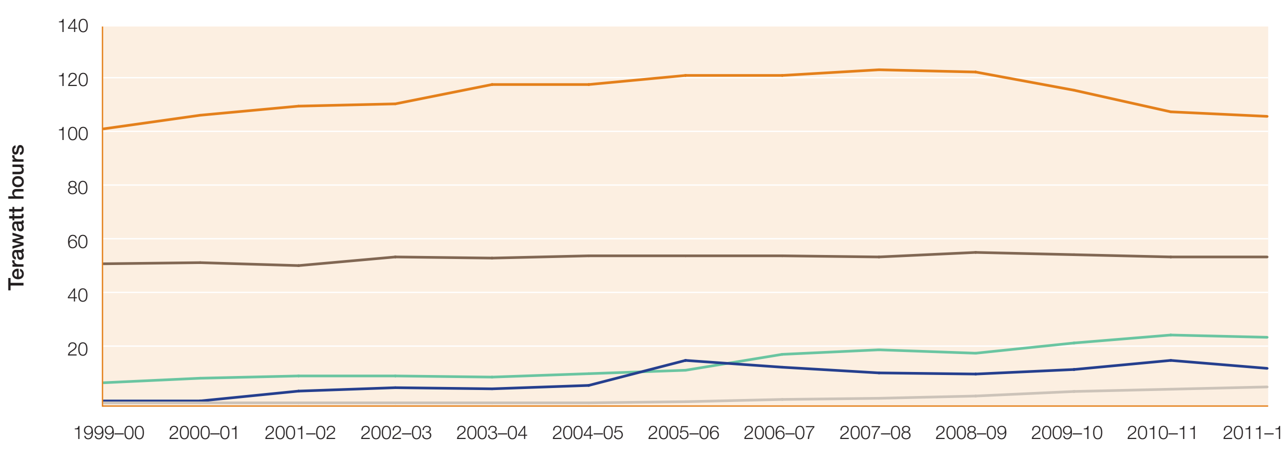
Figure 1.8 illustrates prices of *large generation certificates* (previously renewable energy certificates) issued under the RET scheme, showing prices paid per MWh of generation to wind and other qualifying renewable generators. Wind generators receive both the certificate price *and* the wholesale 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.

Figure 1.8
Large generation certificate prices

Source: Deutsche Bank Markets Research, *Utilities meter*, 5 October 2012.

Figure 1.9
Fuel mix in energy generation, by energy source



Sources: AEMO; AER.

Table 1.3 Generation plant shut down or offline, 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	189	Retired
CS Energy	Gladstone	Coal fired	560	Two units not operating July–December 2012
NEW SOUTH WALES				
Delta Electricity	Munmorah	Coal fired	600	Retired
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
EnergyAustralia	Yallourn (1 unit)	Coal fired	360	Offline July–December 2012
SOUTH AUSTRALIA				
Alinta Energy	Northern	Coal fired	540	April–September 2012
Alinta Energy	Playford	Coal fired	200	From March 2012 until viable

Source: AER.

capacity.[10] Kogan Creek power station in Queensland was the only major new investment in coal fired generation in that period. New investment in wind generation was also significant.

Bloomberg estimated $18 billion will be invested between 2011 and 2018 in wind energy projects, alongside $16 billion in solar PV and $400 million in solar thermal. The estimates do not account for up to $10 billion of project financing that the Clean Energy Finance Corporation may provide.[11]

There are indications that climate change policies affected the generation mix in the NEM during 2012. Notably, over 3000 MW of coal plant was shut down or periodically offline during the year (table 1.3). This reduced capacity was spread across every mainland NEM region, and did not include Victoria's 1450 MW Yallourn power station operating below capacity during winter as a result of flooding.

A number of interrelated factors— flat electricity demand, the introduction of carbon pricing and the impact of the RET in shifting generation away from coal to renewable sources—appear to have contributed to the reduction in coal capacity. Most plant owners cited low energy demand as a key factor in their decisions. The owners of Tarong (Queensland), Munmorah (New South Wales), Morwell and Yallourn (Victoria) cited climate change policies as a contributing factor.

1.2.3 Generation market structure

Private entities own the bulk of generation capacity in Victoria and South Australia, while public corporations own or control the majority of capacity in New South Wales and Queensland. The Tasmanian generation sector remains mostly in government hands. Table 1.4 lists the ownership of generation businesses. Figure 1.10 illustrates the ownership shares of the major players in each region.

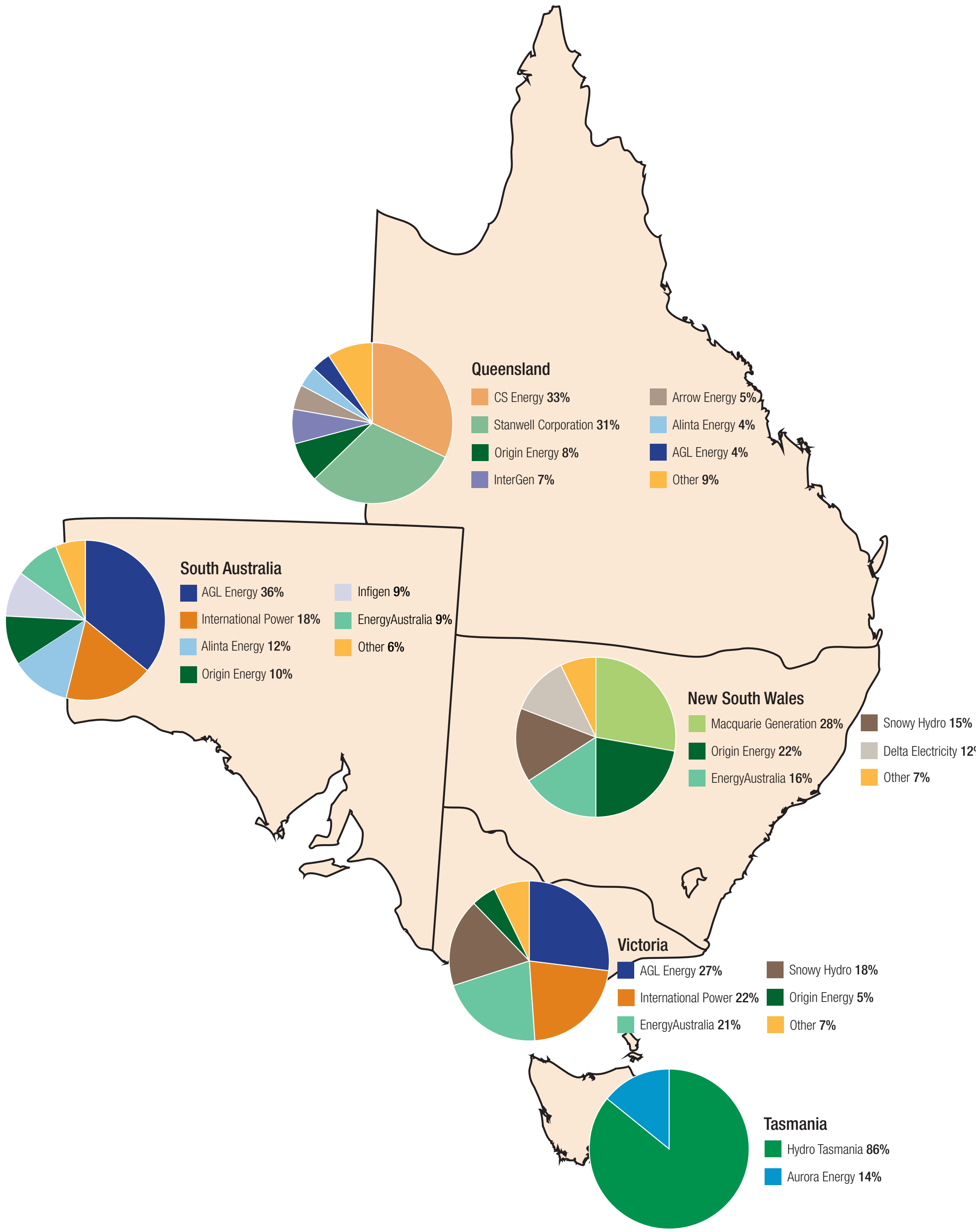
- In Victoria, three private entities are the major players: AGL Energy (27 per cent of capacity), International Power (22 per cent) and EnergyAustralia (formerly TRUenergy, 21 per cent). AGL Energy's acquisition of Loy Yang A power station in June 2012 (after previously owning a one-third minority interest) lifted its market share in Victorian generation from 5 per cent. Origin Energy commissioned new gas peaking plant at Mortlake in 2012—its first plant in Victoria. The government owned Snowy Hydro owns about 18 per cent of generation capacity, mostly comprising historical investment associated with the Snowy Mountains scheme.[12]

10 ACIL Tasman, 'National gas outlook: domestic gas prices and markets', Presentation by Paul Balfe to EUAA conference, 30 May 2012.

11 The Allen Consulting Group, *Client update: renewed energy in renewable energy*, 25 September 2012.

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

Figure 1.10
Market shares in electricity generation capacity, by region, 2012



Notes:

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.

Table 1.4 Generation capacity and ownership, 2012

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
NEM Regions			
QUEENSLAND	TOTAL CAPACITY	12 421	
Stanwell Corporation	Stanwell; Tarong; Tarong North; Swanbank; Barron Gorge; Kareeya; Mackay Gas Turbine; others	3 853	Stanwell Corporation (Qld Government)
CS Energy	Callide; Kogan Creek; Wivenhoe	1 954	CS Energy (Qld Government)
CS Energy	Gladstone	1 680	Rio Tinto 42.1%; NRG Energy 37.5%; others 20.4% Contracted to CS Energy
Origin Energy	Darling Downs; Mt Stuart; Roma	1 038	Origin Energy
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	856	InterGen 50% (China Huaneng Group 50%; others 50%); China Huaneng Group 50%
Arrow Energy	Braemar 2	495	Arrow Energy (Shell 50%; PetroChina 50%)
Braemar Power Projects	Braemar 1	435	Alinta Energy
AGL Hydro	Oakey	282	ERM Group 75%; Contact Energy 25% Contracted to AGL Energy
AGL Hydro	Yabulu	235	RATCH Australia Contracted to AGL Energy / Arrow Energy
RTA Yarwun	Yarwun	155	Rio Tinto Alcan
QGC Sales Qld	Condamine	144	BG Group
AGL Energy	German Creek; KRC Cogeneration; others	78	AGL Energy
Pioneer Sugar Mills	Pioneer Sugar Mill	68	CSR
EDL Projects Australia	Moranbah North	46	EDL Projects Australia
CSR	Invicta Sugar Mill	39	CSR
Ergon Energy	Barcaldine	34	Ergon Energy (Qld Government)
NEW SOUTH WALES	TOTAL CAPACITY	17 035	
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4 824	Macquarie Generation (NSW Government)
Origin Energy	Eraring; Shoalhaven	3 162	Eraring Energy (NSW Government) Contracted to Origin Energy
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2 564	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
EnergyAustralia	Mt Piper; Wallerawang;	2 340	Delta Electricity (NSW Government) Contracted to EnergyAustralia
Delta Electricity	Vales Point B; Colongra; others	2 048	Delta Electricity (NSW Government)
Origin Energy	Uranquinty; Cullerin Range	670	Origin Energy
EnergyAustralia	Tallawarra	420	EnergyAustralia (CLP Group)
Infigen Energy	Capital; Woodlawn	188	Infigen Energy
Marubeni Australia Power Services	Smithfield Energy Facility	162	Marubeni Corporation
Redbank Energy	Redbank	145	Redbank Energy
Eraring Energy	Brown Mt; Burrinjuck; Warragamba; others	116	Eraring Energy (NSW Government)
EDL Group	Appin; Tower; Lucas Heights	108	EDL Group
AGL Hydro	Copeton; Burrendong; Wyangala; others	83	AGL Energy
Essential Energy	Broken Hill Gas Turbine	50	Essential Energy (NSW Government)
Acciona Energy	Gunning	47	Acciona Energy
Infratil Energy Australia	Hunter; Awaba	30	Infratil
VICTORIA	TOTAL CAPACITY	11 531	
AGL Energy	Loy Yang A	2 190	AGL Energy
Snowy Hydro	Murray; Laverton North; Valley Power	2 083	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
International Power	Hazelwood	1 600	International Power / GDF Suez 91.8%; Commonwealth Bank 8.2%

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
NEM Regions			
EnergyAustralia Yallourn	Yallourn; Longford Plant	1 511	EnergyAustralia (CLP Group)
International Power	Loy Yang B	965	International Power / GDF Suez 70%; Mitsui 30%
Ecogen Energy	Jeeralang A and B; Newport	891	Industry Funds Management (Nominees) Contracted to EnergyAustralia
AGL Hydro	Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay; others	810	AGL Energy
Origin Energy	Mortlake	518	Origin Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland; Codrington	265	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Alcoa	Angelsea	156	Alcoa
Energy Brix Australia	Energy Brix Complex; Hrl Tramway Road	104	HRL Group / Energy Brix Australia
Alinta Energy	Bairnsdale	70	Alinta Energy Contracted to Aurora Energy (Tas Government)
AGL Energy	Oaklands Hill	63	Challenger Life Contracted to AGL Energy
SOUTH AUSTRALIA	TOTAL CAPACITY	4 392	
AGL Energy	Torrens Island	1 280	AGL Energy
Alinta Energy	Northern	546	Alinta Energy
International Power	Pelican Point; Canunda	494	International Power / GDF Suez
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	317	International Power / GDF Suez
TRUenergy	Hallet; Waterloo	309	EnergyAustralia (CLP Group)
Origin Energy	Quarantine; Ladbroke Grove	256	Origin Energy
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	147	Infratil
AGL Energy	Hallett 2; Wattle Point	135	Energy Infrastructure Trust Contracted to AGL Energy
AGL Energy	North Brown Hill	82	Energy Infrastructure Investments (Marubeni 50%; Osaka Gas 30%; APA Group 20%) Contracted to AGL Energy
Infigen	Lake Bonney 1	81	Infigen Energy Contracted to Essential Energy (NSW Government)
Meridian Energy	Mount Millar	70	Meridian Energy
EnergyAustralia	Cathedral Rocks	66	EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
AGL Energy	Hallett 1	59	Palisade Investment Partner Contracted to AGL Energy
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Angaston	50	Infratil (all contracted to AGL Energy)
Ratch Australia	Starfish Hill	35	RATCH Australia Contracted to Hydro Tasmania (Tas Government)
AGL Energy	The Bluff	33	Eurus Energy Contracted to AGL Energy
TASMANIA	TOTAL CAPACITY	2 743	
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; Woolnorth; others	2 355	Hydro Tasmania (Tas Government)
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	386	Aurora Energy (Tas Government)
Woolnorth	Woolnorth	140	Shenhua Clean Energy 75%; Hydro Tasmania 25%

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

Note: Capacity as published by AEMO for summer 2012–13, except for wind farms (registered capacity).

Sources: AEMO; AER.

- In South Australia, AGL Energy is the dominant generator, with 36 per cent of capacity. Other significant entities are International Power (18 per cent), Alinta (12 per cent), Origin Energy (10 per cent), EnergyAustralia and Infigen (9 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 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 EnergyAustralia (16 per cent) and Origin Energy (22 per cent).

  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. As in Victoria, Snowy Hydro also has market share in generation (15 per cent).
- In Queensland, state owned corporations Stanwell and CS Energy control around 63 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station).
- In Tasmania, state owned corporations own nearly all generation capacity. The market is highly concentrated, with Hydro Tasmania owning 86 per cent of capacity. The Tasmanian Government in 2012 announced it would establish regulatory control over Hydro Tasmania's wholesale market activity (section 1.5.4).

1.2.4 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. Section 5.2 of the retail chapter details vertical integration in the NEM. In summary, the three leading retailers—AGL Energy, Origin Energy and EnergyAustralia, which jointly supply 76 per cent of retail electricity customers—increased their market share in generation from 11 per cent in 2007 to 35 per cent in 2012. The increase reflects the commissioning of Origin Energy's Mortlake power station and AGL Energy's acquisition of Loy Yang A in Victoria in 2012 (after previously having a one-third minority interest).

The three retailers control around 58 per cent of new generation capacity commissioned or committed in the NEM since 2007. Additionally, many new entrant retailers are vertically integrated with generators—for example, International Power (Simply Energy), Infratil (Lumo Energy), Alinta (Neighbourhood Energy) and Snowy Hydro (Red Energy).

1.3 How the market 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 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.[13] 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 that capacity must be dispatched if regional demand exceeds a certain level. This type of behaviour most commonly occurs at times of peak demand, often accompanied by generator outages or network constraints. More recently, some generators have periodically used strategic bidding to drive negative prices. The Australian Energy Regulator (AER) is monitoring this behaviour to ascertain whether it raises market power issues.

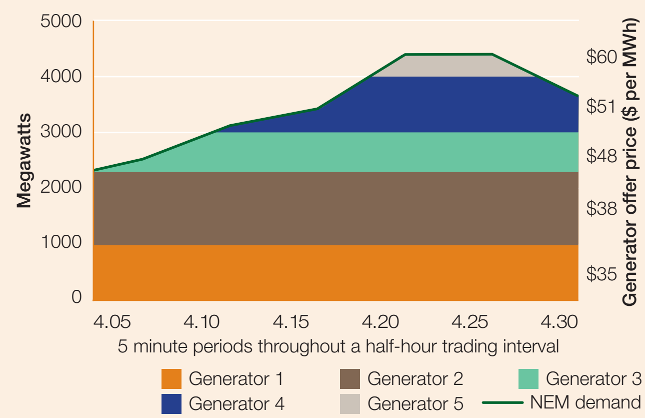
13 The price floor equals –$1000 per MWh.

Box 1.2 Setting the spot price

Figure 1.11 illustrates a simplified bid stack in the NEM between 4.00 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 1.11
Generator bid stack



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 they bid (box 1.2).[14]

The market allows spot prices to respond to movements in the supply–demand balance. Rising prices create signals for demand side response and, in the longer term, new generation investment.

Spot prices may range between a floor of –$1000 per MWh and a cap of $12 900 per MWh (raised from $12 500 per MWh on 1 July 2012). 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 1.9).

The market sets a separate spot price for each of the five NEM regions. Price separation in 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 all other times, prices align across regions, except for minor price disparities due to physical losses in the transport of electricity over long distances. Allowing for these transmission losses, prices across the mainland regions of the NEM were aligned for about 70 per cent of the time in 2011–12, compared with 61 per cent in 2010–11. But the periods of misalignment pose significant issues (section 1.4).

14 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).

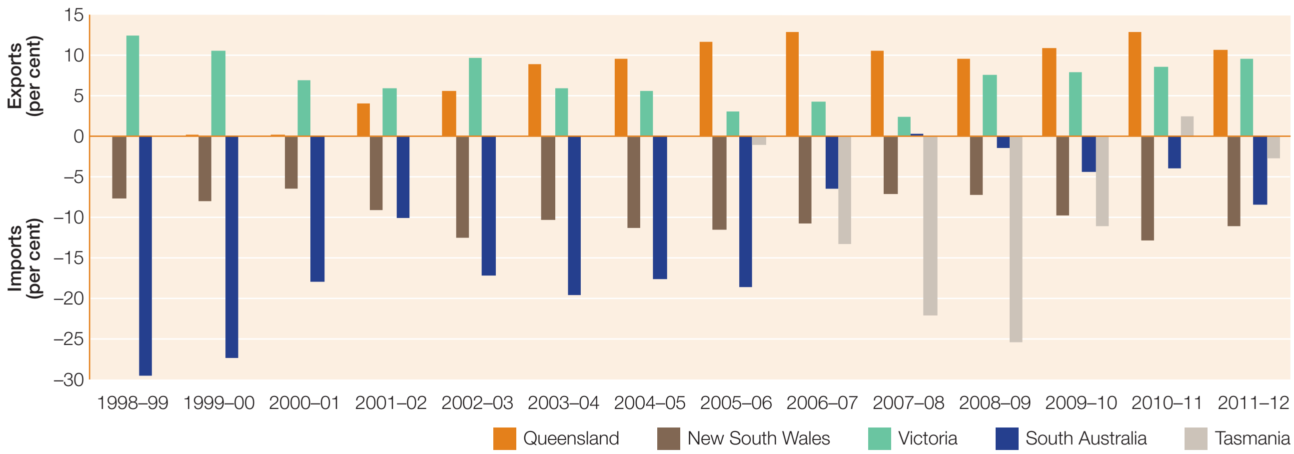
1.4 Interregional trade

The NEM promotes efficient generator use by allowing electricity trade among the five regions, which transmission interconnectors link (figure 1.3). 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 1.12 shows the net trading position of the five regions:

- Victoria has substantial low cost baseload capacity, making it a net exporter of electricity. Its net exports have grown steadily since 2008–09.

Figure 1.12
Interregional trade as a percentage of regional energy demand



Sources: AEMO; AER.

- Queensland's installed capacity exceeds the region's peak demand for electricity, making that state a significant net exporter.
- 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 temporary or longer term shut down of some baseload plant in 2012 caused a rise in net imports.
- Tasmania is typically a net importer of electricity. Its trade dependence was particularly high in 2007–09, when drought affected the region's hydrogeneration.

There is evidence that network congestion is affecting interregional trade, constraining the market from exporting electricity from lower to higher price regions (box 1.3). When spot prices between adjacent regions differ by more than $100 per MWh, trade across some interconnectors is significantly below nominal capacity. For example, while the import links into New South Wales have a nameplate capacity of over 3000 MW (equivalent to almost 20 per cent of the state's generation capacity), network congestion constrains import capacity to about 700 MW at times of high prices. On some interconnectors, power is flowing in the reverse direction to what prices would suggest—that is, electricity is flowing from high price to low price regions. These issues are also influencing risk management arrangements for interregional trade (see box 1.3).

1.5 Spot electricity prices

The Australian Energy Regulator (AER) monitors the spot market and reports weekly on activity. It also publishes detailed analyses of extreme price events. Figure 1.14 provides a snapshot of weekly prices since 2009. Figure 1.15 charts quarterly volume weighted average prices in each region, while table 1.6 sets out annual prices.

Prices across most regions peaked during 2006–08, when drought constrained the availability of water for hydrogeneration 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.[15]

1.5.1 The market in 2011–12

After easing in 2010–11, spot electricity prices fell further in most regions in 2011–12. Queensland and South Australia recorded their lowest average spot price since the NEM commenced, and prices elsewhere were near record low levels. All regional averages were record lows in real terms.

15 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.

Box 1.3 Network congestion, disorderly bidding and interregional trade

In theory, generators can offer contracts to customers in other regions—for example, a Victorian generator might contract to sell power to a South Australian retailer at a fixed price. Such arrangements offer price certainty and strengthen competition and liquidity in contract markets.

But little interregional contracting is occurring because it poses significant risks. While AEMO pays a generator at the spot price in the region in which it operates, retailers pay the price in the region in which they are based. If spot prices are misaligned across the regions, then one party may be at serious financial risk.

In theory, parties to interregional contracts can reduce their exposure to price misalignment by purchasing a share of *settlement residues* that accrue across regions. The residues are a pool of funds equal to the difference between the price paid in an importing region and the price received in the generating region, multiplied by the amount of electricity flow. Electricity typically flows from lower to higher priced regions, resulting in positive residues that accrue initially to AEMO in the market settlement process. AEMO then holds quarterly auctions to sell the rights to future residues up to three years in advance.[16]

Participants can bid for a share of the residues on any cross-border interconnector. The residues can then be used to manage interregional trading risks when prices diverge across regions. Participants make their own assessments of the likely price divergence between two adjacent regions, which feeds into the value of the auction proceeds.

Network congestion affecting interconnector flows can distort the effectiveness of settlement residues as a hedge instrument. In particular, AEMO may need to manage a congestion issue by 'constraining off' a generator to protect the security of energy supply. In turn, the generator may try to avoid this scenario and ensure it gets dispatched by rebidding its capacity at prices below its underlying costs. In some cases, this 'disorderly bidding' can reduce the import capability of an interconnector or result in electricity flowing counter price, reducing the amount of residues available to participants.

An AER study found, when spot prices diverge between adjacent regions, trade across some interconnectors is counter price—electricity flows from high to lower priced regions (table 1.5). The study found when Queensland prices are at least $100 per MWh higher than those in New South Wales, power typically flows counter price *into* New South Wales, causing *negative* settlement residues. This scenario typically occurs when network congestion around Gladstone in central Queensland encourages disorderly generator bidding.

Similar issues have occurred across the Victoria–New South Wales interconnectors (especially in 2009–10) when disorderly bidding by Snowy Hydro (which owns generation on both sides of the border) has caused counter price flows northwards at times, and southwards at other times.

The incidence of counter price flows is reducing the residues returned to participants that purchase them at auction, and causing lower auction proceeds. This development reflects the reduced market valuation of this hedge mechanism, and is most evident for trade flows from New South Wales to Queensland (figure 1.13).

Table 1.5 Interregional settlement residues when prices diverge by more than $100 per MWh

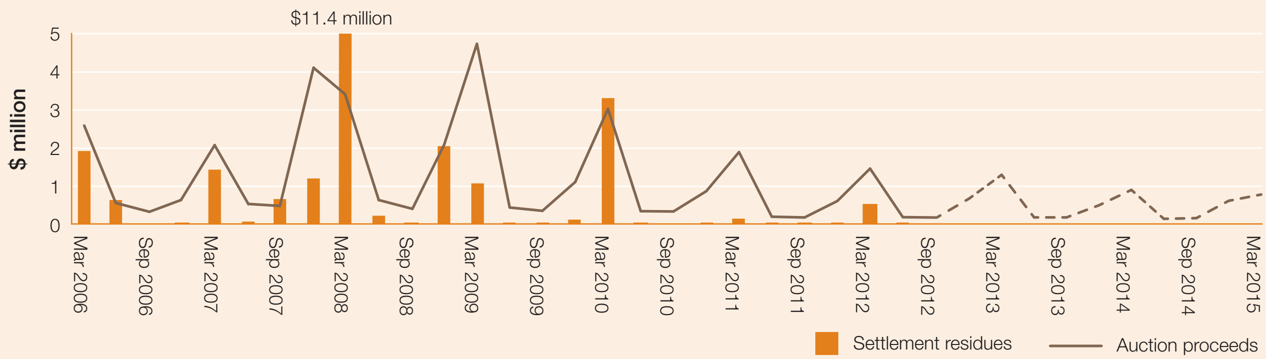
	2009–10		2010–11		2011–12	
RELATIVE REGIONAL SPOT PRICES	POSITIVE RESIDUES ($'000)	NEGATIVE RESIDUES ($'000)	POSITIVE RESIDUES ($'000)	NEGATIVE RESIDUES ($'000)	POSITIVE RESIDUES ($'000)	NEGATIVE RESIDUES ($'000)
Qld > NSW	3 821	857	172	5 775	559	7 318
NSW > Qld	63 218	2 418	60 025	1 190	15 194	2
NSW > Vic	75 977	7 329	50 148	168	14 717	1 765
Vic > NSW	14 371	20 861	873	2 907	742	37
SA > Vic	74 114	608	26 923	147	12 153	517

Source: AER.

16 Negative residues are funded by transmission network businesses and passed on to customers in the importing region.

Figure 1.13

Settlement residues and auction proceeds—trade from New South Wales to Queensland



Source: AER.

A number of workstreams are in place to mitigate issues of congestion, counter price flows and disorderly bidding in the NEM. The AEMC's continuing Transmission Frameworks Review recommended changes to the settlement arrangements for generators located at mispriced connection points, through an optional firm access package.

The model aims to increase the firmness of interconnector availability to improve energy contract liquidity and competition. The issues are complex and reform may take considerable time to implement.

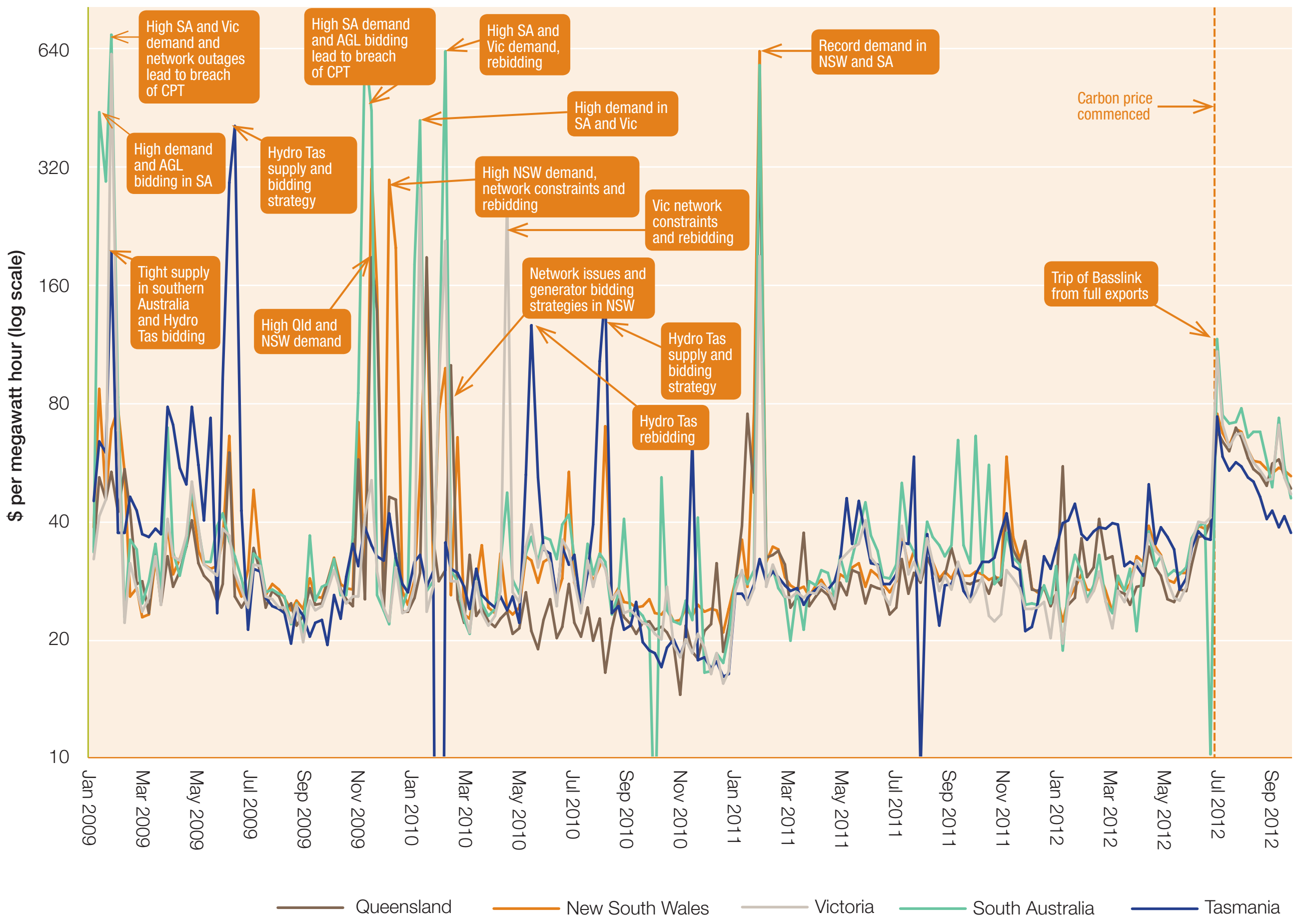
Table 1.6 Volume weighted average spot electricity prices ($ per megawatt hour)

	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
2011–12	30	31	28	32	33	
2010–11	34	43	29	42	31	
2009–10	37	52	42	82	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

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.

Figure 1.14
Weekly spot electricity prices



CPT, cumulative p rice threshold.

Note: Volume weighted average prices.

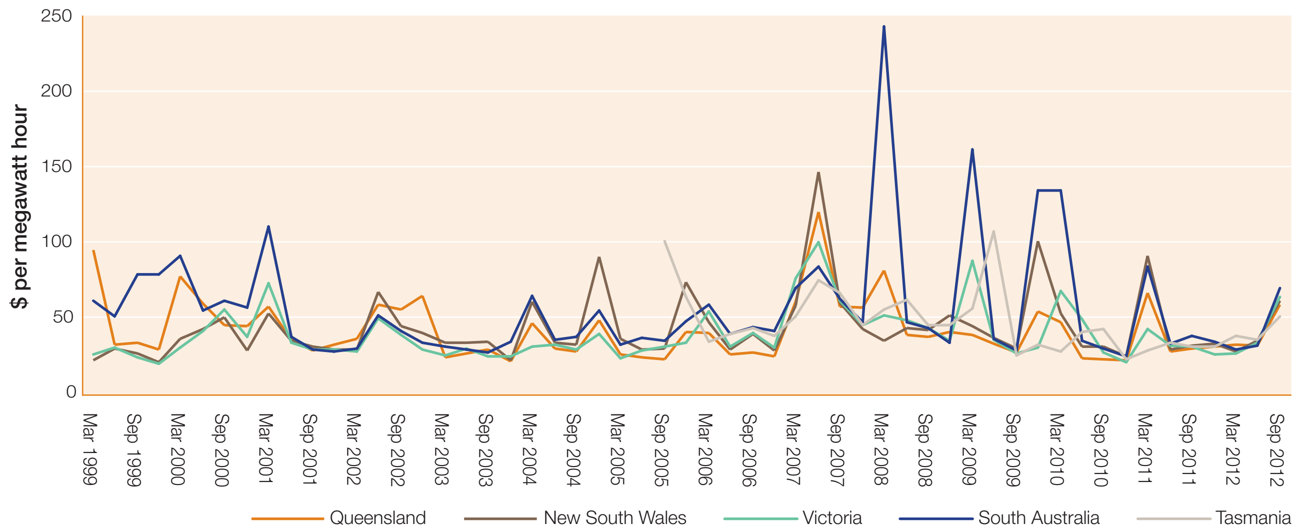
Source: AER.

Average prices fell for the second consecutive year in all mainland regions, with the sharpest reductions occurring in New South Wales (down $12 per MWh) and South Australia (down $10 per MWh). Significant market alignment was also (down $10 per MWh). Significant market alignment was also evident, with average prices ranging from $28 per MWh (Victoria) to $33 per MWh (Tasmania). The small spread in average spot prices was reflected in the mainland market being aligned for 70 per cent of the time in 2011–12.

Low average prices in 2011–12 were mirrored in the small number of very high prices (figure 1.16). Across the NEM, the spot price exceeded $2000 per MWh on 16 occasions, and exceeded $5000 per MWh on only one occasion (when a combination of network issues, generator outages and rebidding caused the New South Wales spot price to reach $6498 per MWh on 9 November 2011).[17] The number of spot prices above $5000 per MWh was the lowest since the commencement of the NEM. Similarly, Victoria's maximum spot price ($133 per MWh) was its lowest since the NEM commenced.

17 One price event above $5000 per MW also occurred in an ancillary services market, when a process failure led to a commissioning test of the Mortlake generator during a planned network outage in Victoria. The test thus created a large requirement for local frequency control ancillary service in South Australia. The cost to South Australian customers was $3.9 million, compared with less than $3000 on a typical day.

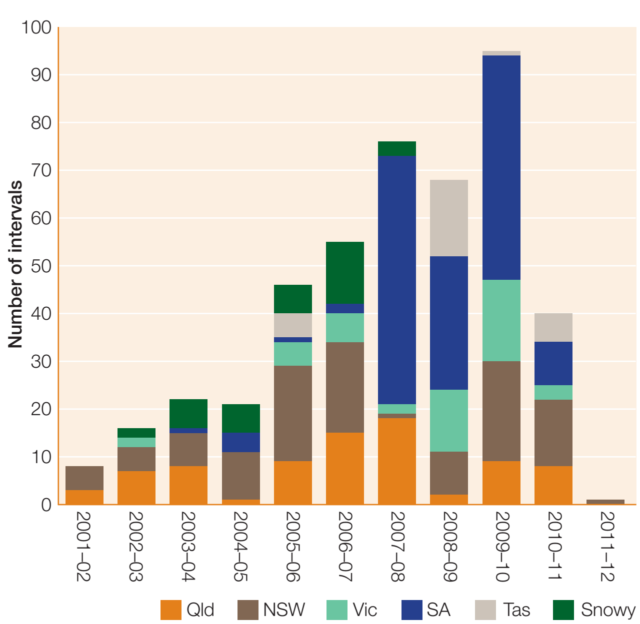
Figure 1.15
Quarterly spot electricity prices



Note: Volume weighted average prices.

Sources: AEMO; AER.

Figure 1.16
Trading intervals above $5000 per megawatt hour



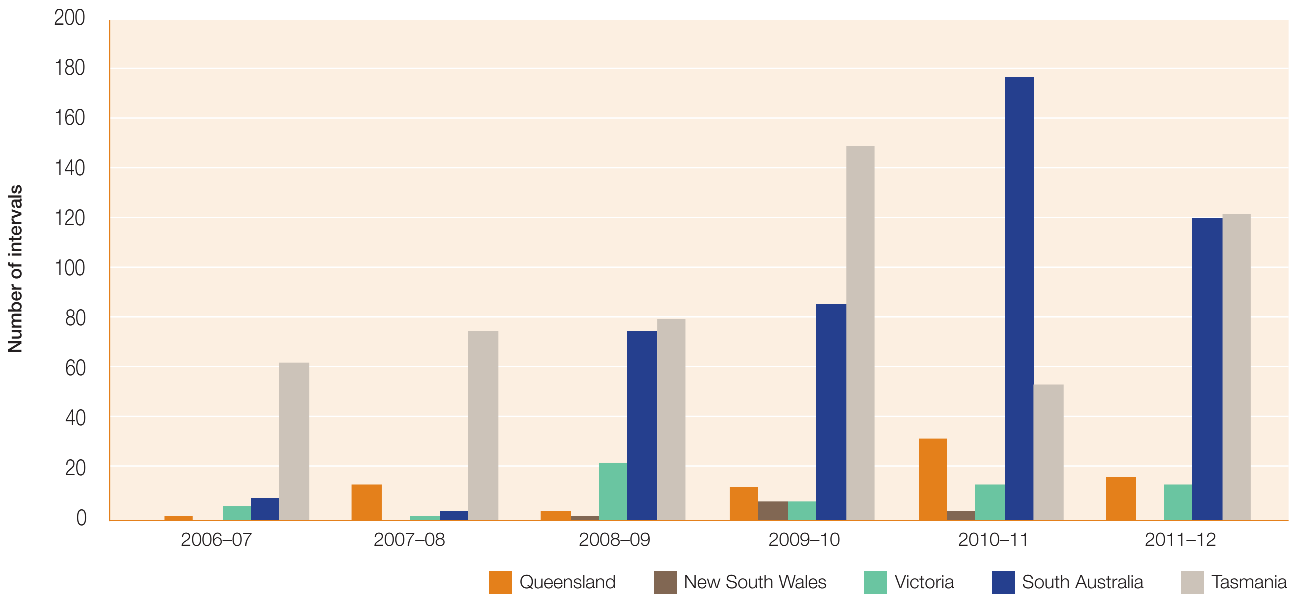
Note: Each trading interval is a half hour.

Sources: AEMO; AER.

A number of demand related factors contributed to lower spot prices. In particular, electricity demand fell by 2.5 per cent in 2011–12, continuing a trend of declining energy use since 2007–08. It reflects weaker demand from the manufacturing sector; the increasing use of rooftop PV generation; and customers responding to rising electricity costs by adopting energy efficiency measures such as solar water heating. Additionally, consecutive summers of below average temperatures capped peak demand by reducing the use of air conditioners (section 1.1). This latter factor helps explain the near absence of extreme prices.

Also contributing to low average spot prices were the 274 negative prices recorded during the year, mostly in Tasmania and South Australia (figure 1.17). The rising incidence of negative spot prices in the past few years can be partly explained by the increasing use of wind generation. Wind generators bid low and often at slightly negative prices to ensure dispatch, because they receive the value of renewable energy certificates in addition to spot market returns. But all instances of South Australian and Tasmanian prices that were *significantly* below zero (including prices at or near the –$1000 market floor) were associated with strategic generator bidding or rebidding. The AER analyses spot prices below –$100 per MWh in its weekly market reports.

Figure 1.17
Negative spot prices



Sources: AEMO; AER.

While average prices were low, price volatility was evident in some regions. Aside from the strategic generator bidding in South Australia and Tasmania, network congestion caused volatility in the Queensland market over summer (section 1.5.5).

1.5.2 Introduction of carbon pricing

The carbon price established under the Australian Government's Clean Energy Future Plan took effect on 1 July 2012 (section 1.2.2). It was introduced at $23 per tonne. Electricity generators are required to purchase and surrender carbon permits to offset their emissions, which increases their operating costs. This cost increase was expected to flow through to generator offers and electricity spot prices.

Market expectations were that the introduction of carbon pricing would increase average spot electricity prices by around $20 per MWh. This expectation was evident from electricity futures prices for the third quarter 2012. But the initial price change was much greater, with average spot prices in the week 1–7 July 2012 ranging from $38 to $84 per MWh above 2011–12 average prices (in New South Wales and South Australia respectively). The average spot price across the NEM rose from $37 per MWh in June 2012 to $67 per MWh in July 2012.

Aside from carbon pricing, various factors contributed to these outcomes—fuel supply and non-carbon related cost issues, plant outages, reasonably strong demand and low wind output. Additionally, network outages contributed to the price peaks in early July. More generally, spot prices in July were coming off very low bases in 2011–12. Nonetheless, the price rises are difficult to reconcile with those factors alone. In particular, a number of 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. By mid-October, the volume weighted average spot price in the NEM (filtered for extreme price events) since the introduction of carbon pricing was in line with market expectations—around $21 per MWh above the average price for June 2012.[18]

1.5.3 Market focus—South Australia

AGL Energy's strategic withholding of generation capacity contributed to average spot prices in South Australia being significantly above those in other NEM regions between 2007–08 and 2009–10. Prices in the state fell significantly in 2010–11, then aligned with prices in other regions in 2011–12.

18 AEMO, *Carbon price—market review*, 8 November 2012.

South Australia's annual average spot price ($32 per MWh) in 2011–12 was the state's lowest since the NEM commenced. Consistent with other regions, flat growth in energy consumption and lower peak demand (due to mild weather) contributed to this outcome.

The spot price in South Australia did not exceed $5000 per MWh at any time in 2011–12. It exceeded $2000 per MWh on nine occasions, with the highest price of $3956 per MWh recorded on 21 October 2011. Most of the high price events were associated with AGL Energy rebidding capacity to near the price cap, often near the time of dispatch.

Additionally, South Australia in 2011–12 recorded its second consecutive year of at least 100 negative spot price events: it recorded 177 negative price events in 2010–11 and 120 in 2011–12. The frequency and magnitude of negative spot prices contributed to South Australia's lower average prices in the past two years. During the week of 24–30 June 2012, the state had 24 negative spot prices lower than –$100 per MWh, including 15 events below –$600 per MWh.

Wind generators bid low and sometimes slightly negative prices, given they earn the value of renewable energy certificates (in addition to spot market returns) to cover costs. For this reason, South Australian wind generation is contributing to lower spot prices for the state. But all instances of prices below –$100 per MWh (including those near the –$1000 per MWh market floor) were driven by AGL Energy bidding or rebidding large amounts of capacity to prices near the floor at times of low demand. On several occasions, this effectively shut down other generators (including wind generators).[19] This type of disorderly market activity can have detrimental longer term consequences for market stability and investment.

1.5.4 Market focus—Tasmania

Tasmania recorded the highest average spot price of all regions in 2011–12, and was the only region in which average spot prices were higher than in 2010–11. Hydro Tasmania continued to influence spot prices during 2011–12 by periodically withdrawing low priced capacity from the market, typically at times of low demand. At other times it engaged periodically in strategic behaviour to drive negative prices.

19 The AER analyses spot prices below –$100 per MWh in its weekly market reports. See, for example, weekly reports for 1–7 April 2012 and 22–28 April 2012.

In 2010 the Tasmanian Government established the Electricity Supply Industry Expert Panel to review the state's electricity supply industry. The panel's final report in March 2012 found the current market structure allows Hydro Tasmania to control regional spot prices, posing a barrier for new entrant retailers. The report proposed major industry reforms, including restructuring Hydro Tasmania's trading functions into three new state owned entities.

The Tasmanian Government in May 2012 responded to the report by announcing major reforms affecting every segment of the industry. It decided on a regulatory solution to address Hydro Tasmania's market power, rather than following the panel's recommendation to restructure the entity. From 1 July 2013, the Office of the Tasmanian Economic Regulator will regulate Hydro Tasmania's wholesale market activities. Tasmanian contract prices will be set by reference to Victorian contract prices, which reflect the opportunity cost of Hydro Tasmania selling into an alternative market.[20]

1.5.5 Market focus—Queensland

Queensland spot electricity prices during summer 2011–12 were periodically volatile, with over 70 spot prices exceeding $100 per MWh between 1 December 2011 and 31 March 2012 (including two prices above $2000 per MWh). Typically, the events were of very short duration. Sixteen negative spot prices (including three *below* –$100 per MWh) followed the short duration high prices. Counter price exports from Queensland into New South Wales occurred during each high price event. Similar incidents of market volatility occurred in August–October 2012.

Initially, the price volatility coincided with the onset of summer and higher energy demand. In January, unexpected changes in the rating of transmission lines in central Queensland (connecting the Gladstone, Stanwell and Callide power stations) led to network congestion, which constrained the use of cheap generation both within and outside Queensland. The bidding behaviour of certain generators, aimed at influencing spot prices, exacerbated network congestion and contributed to market volatility.

Spot price volatility causes market uncertainty and the inefficient dispatch of generation. The incidence of counter price export flows also poses difficulties for retailers and smaller generators seeking to hedge against volatility, especially across regions through settlement residue auctions. Disorderly market activity of this nature can deter new entry and investment in both the generation and retail sectors (box 1.3).

20 Department of Treasury and Finance (Tasmania Government), *Energy for the future: reforming Tasmania's electricity industry*, May 2012.

1.5.6 Rule change proposal on market power

In June 2012 the AEMC published a draft determination on an Electricity Rule change request by Major Energy Users in relation to generators' potential exercise of market power in the NEM. The proponent argued some large generators have the ability and incentive to use market power to increase wholesale electricity prices during periods of high demand. The proposed Rule change would require 'dominant' generators, as determined by the AER, to offer their entire capacity at times of high demand at a price of no more than $300 per MWh.

The AEMC's draft determination found insufficient evidence of the exercise of market power. In its August 2012 submission on the draft, the AER encouraged the AEMC to broaden the range of evidence and analytical tools for assessing market power in the NEM.[21] On 30 August 2012 the AEMC extended the timing of its final determination to 11 April 2013.

1.6 Electricity futures

Volatility in electricity spot prices can pose significant risk for 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 in the future. 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 developed by d-cyphaTrade are traded on the ASX. Participants—including generators, retailers, speculators (such as hedge funds), banks and other financial intermediaries—buy and sell futures contracts.

The terms and conditions of OTC contracts are confidential between the parties. Exchange trades are publicly reported, giving rise to greater market transparency than does OTC contracting. 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 the 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.

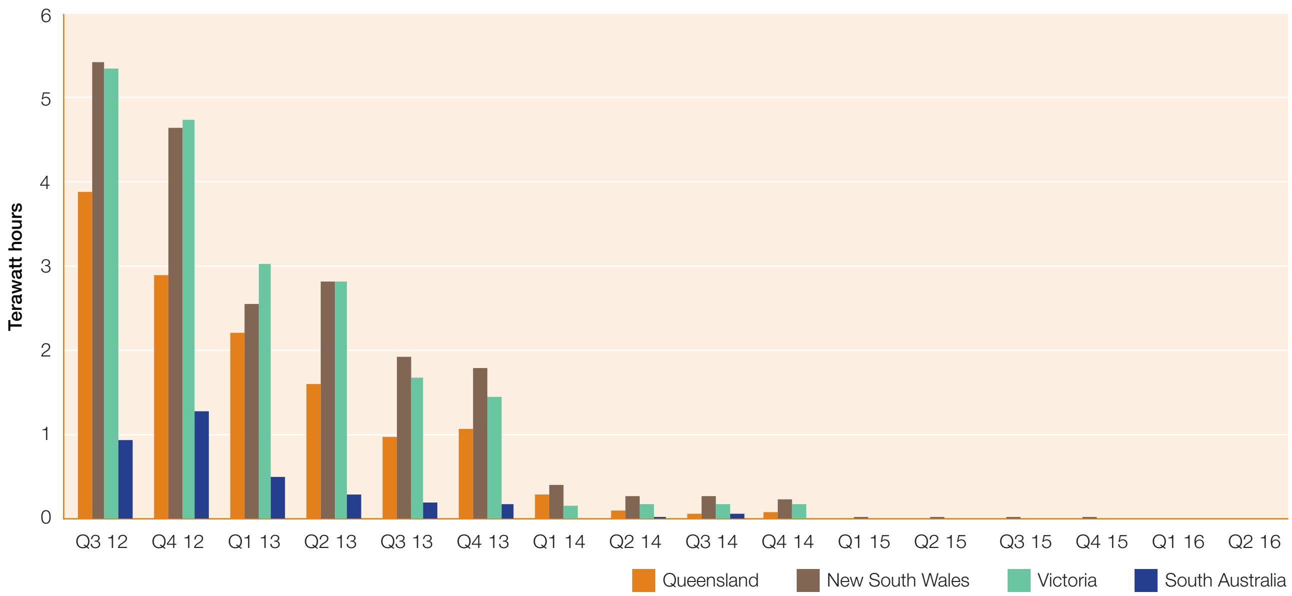
The complex financial relationships between generators, retailers and other businesses create financial interdependency, meaning financial difficulties for one participant can affect others. In November 2012 the AEMC released an options paper on ways to mitigate risk from the financial distress or failure of a large electricity retailer. The paper is the first stage of the AEMC's advice to the Standing Council on Energy and Resources on the resilience of financial markets underpinning the NEM.[22]

21 AER, *Submission on draft determination—potential generator market power in the NEM*, 1 August 2012.

22 AEMC, *NEM financial market resilience*, Options Paper, 9 November 2012.

Figure 1.18

Open interest in electricity derivatives on the ASX, 1 July 2012



Source: d-cyphaTrade.

The Australian Government in 2012 was progressing reforms to implement Australia's G20 commitments in relation to OTC derivatives. The reforms include the reporting of OTC derivatives to trade repositories. They also include obligations on the clearing and execution of standardised derivatives. Some reforms could potentially capture OTC electricity derivatives.

1.6.1 Electricity futures trading on the ASX

Electricity futures trading on the ASX covers instruments for Victoria, New South Wales, Queensland and South Australia. Trading volumes in 2011–12 were equivalent to 231 per cent of underlying energy demand, down from 285 per cent in 2010–11. New South Wales accounted for 38 per cent of traded volumes, followed by Victoria (32 per cent) and Queensland (27 per cent). Liquidity in South Australia is low, accounting for only 3 per cent of volumes.

The most heavily traded products in 2011–12 were base futures (55 per cent of traded volumes), followed by options (32 per cent), $300 cap futures (10 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 2012 was mostly for quarters to the end of 2013, with little liquidity into 2014 (figure 1.18).

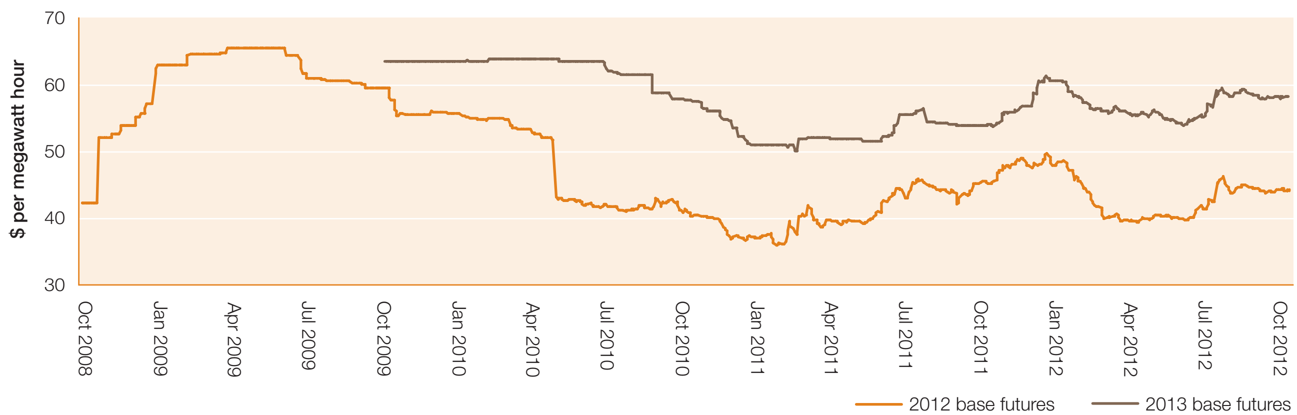
Forward prices

Figure 1.19 shows average price outcomes for electricity base futures, as reflected in the national power index. The index (which d-cyphaTrade 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 around the introduction of a carbon price led to prices fluctuating as the scheme's likelihood was reassessed. Prices peaked towards the end of 2011 when the Senate passed the Clean Energy Future Plan, and rose again in June 2012 when the scheme's introduction was imminent. On 30 June 2012, base load 2013 calendar year prices were $55 in Queensland, $59 in New South Wales, $54 in Victoria and $58 in South Australia. The relatively close alignment across regional prices mirrored the wholesale spot market.

Throughout the measured period, prices for 2013 products were consistently higher than for 2012 products, which cover only six months of carbon pricing.

Figure 1.19
National power index



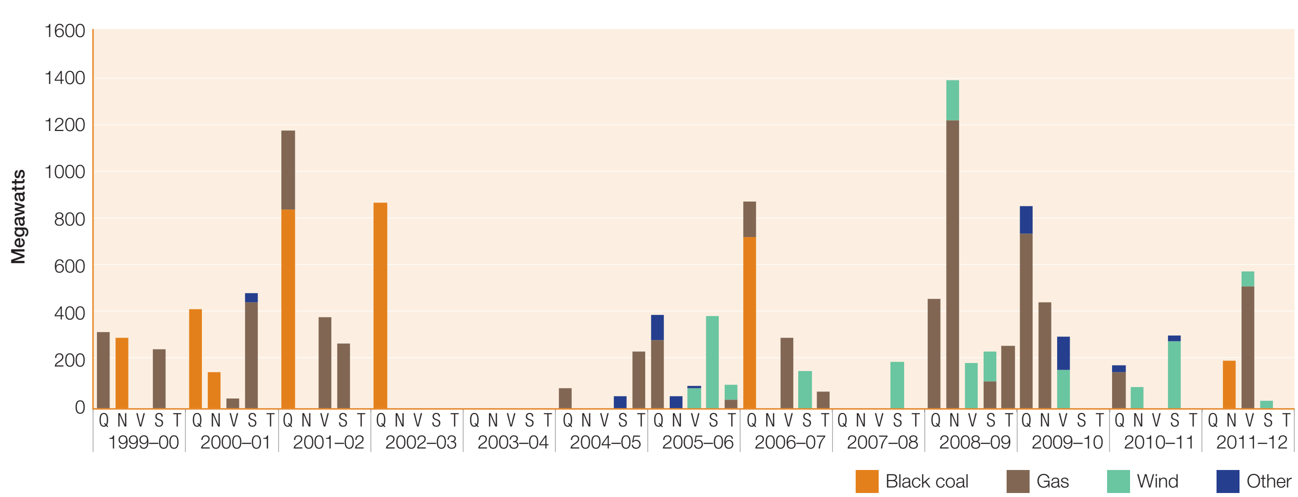
Source: d-cyphaTrade.

1.7 Generation investment

Price signals in the wholesale and forward contract markets for electricity largely drive new investment in the NEM. From the inception of the NEM in 1999 to June 2012, new investment added 13 200 MW of registered generation capacity—around 1000 MW per year. Figures 1.20 and 1.21 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 capacity to at least 2018–19 in all jurisdictions (section 1.9.5). This trend is reflected in flat investment: only 1350 MW of capacity was added over the past two years, of which one-third was in wind generation (which the RET

Figure 1.20
Annual investment in registered generation capacity



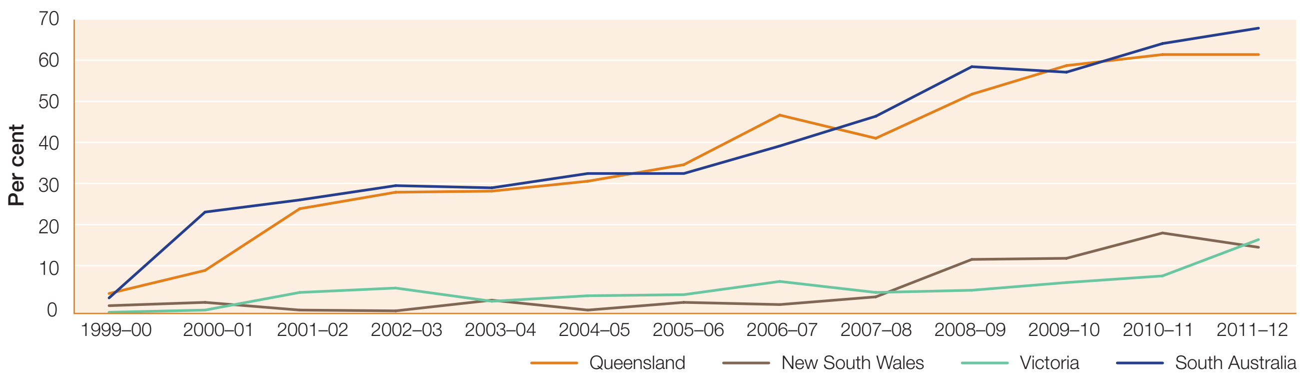
Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.

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

Sources: AEMO; AER.

Figure 1.21

Net change in generation capacity since market start—cumulative



Source: AER.

scheme effectively subsidises). Additionally, weak demand and climate change policies contributed to around 3000 MW of coal plant in 2012 being shut down or periodically offline (section 1.2.2).

Table 1.7 details generation investment since 1 July 2011. The most significant event was the commissioning of stage 1 of Origin Energy's 518 MW gas powered plant at Mortlake (Victoria).

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 2012 the NEM had 700 MW of committed capacity,[23] mostly in wind generation, which (as a result of the RET) may be profitable despite depressed wholesale prices (table 1.8). The most significant committed project is Victoria's 420 MW Macarthur wind farm, which will be the largest wind farm in the southern hemisphere.

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 2012 it listed 32 500 MW of proposed capacity in the NEM (figure 1.22). While 3600 MW of capacity is scheduled to be commissioned before 2017–18, much of this capacity (including 1200 MW of gas powered generation in Queensland) may not be needed by this time, based on current demand forecasts.

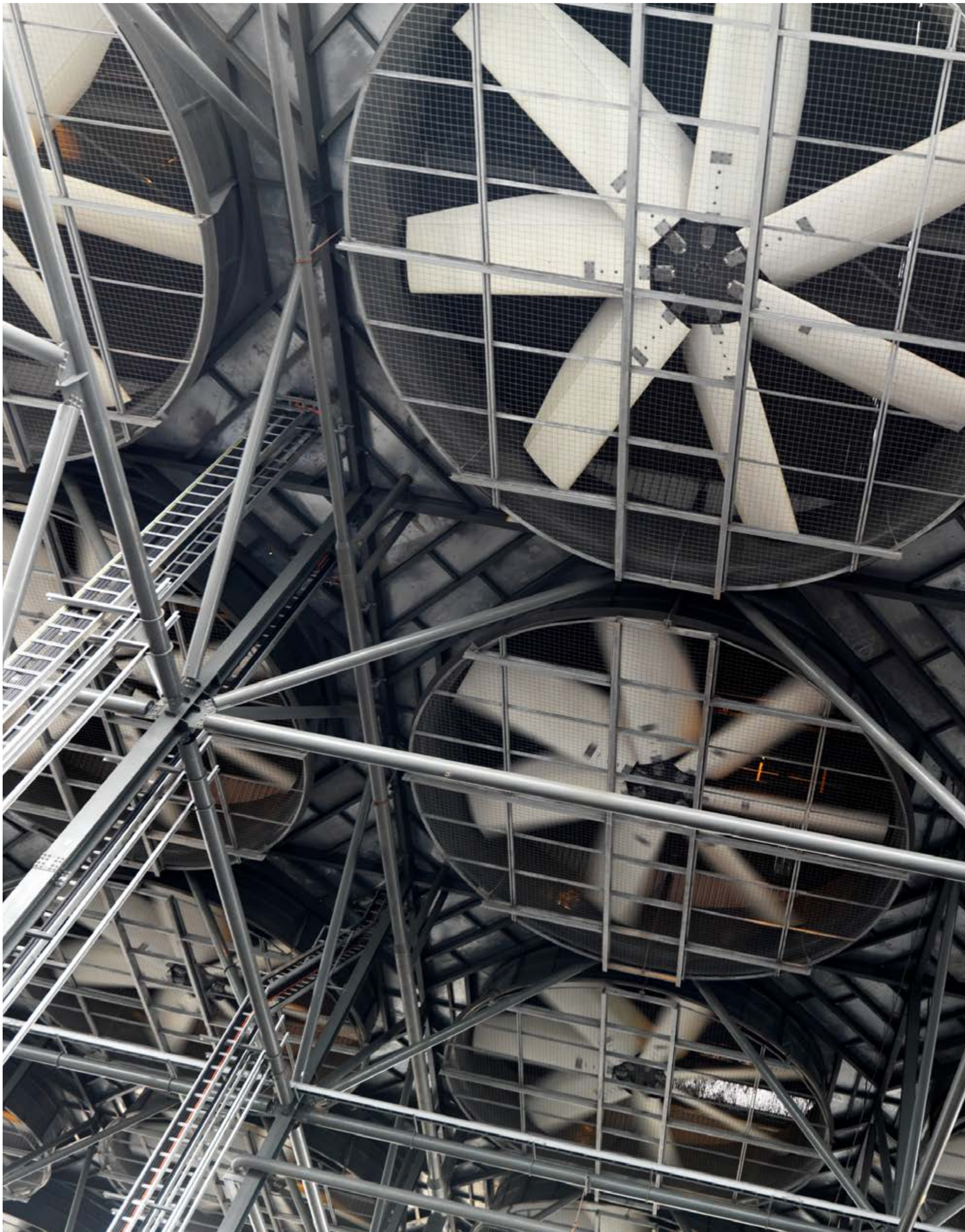
The bulk of proposed capacity is in wind and gas powered generation. While most of the gas plants adopt open or combined cycle technologies, the proposals also include more innovative and experimental approaches. The Australian Government's Solar Flagships program has led to several proposals for large scale solar projects. In June 2012 AGL's 159 MW solar PV project at Broken Hill and Nyngan (New South Wales) was selected to receive funding under the program. A further 1070 MW of major solar projects are proposed for Queensland, New South Wales and Victoria, including:

- a 250 MW solar thermal gas hybrid plant in Chinchilla (Queensland), combining solar generation with a low emission gas boiler back-up system
- two PV projects (180 MW and 154 MW) near Mildura and a 180 MW project in the Mallee (Victoria)
- a 44 MW solar thermal addition to the Kogan Creek power station in Queensland. The solar project will augment the power station's steam generation system to increase electricity output and fuel efficiency.

There are also plans for geothermal generation in South Australia. A 525 MW geothermal plant was announced for Innamincka, with another plant planned for Paralana.

The Australian Renewable Energy Agency, created on 1 July 2012 as part of the Australian Government's Clean Energy Future package, will provide support for renewable energy projects.

23 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.



Origin Energy

Table 1.7 Generation investment, 1 July 2011—31 October 2012

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED	ESTIMATED COST ($ MILLION)
NEW SOUTH WALES					
Eraring Energy	Eraring (upgrade)	Coal fired	180	January 2012	225
VICTORIA					
AGL Energy	Oaklands Hill	Wind	63	August 2011	200
Origin Energy	Mortlake	OCGT	518	August 2011	650
SOUTH AUSTRALIA					
AGL Energy	The Bluff	Wind	34	July 2011	120

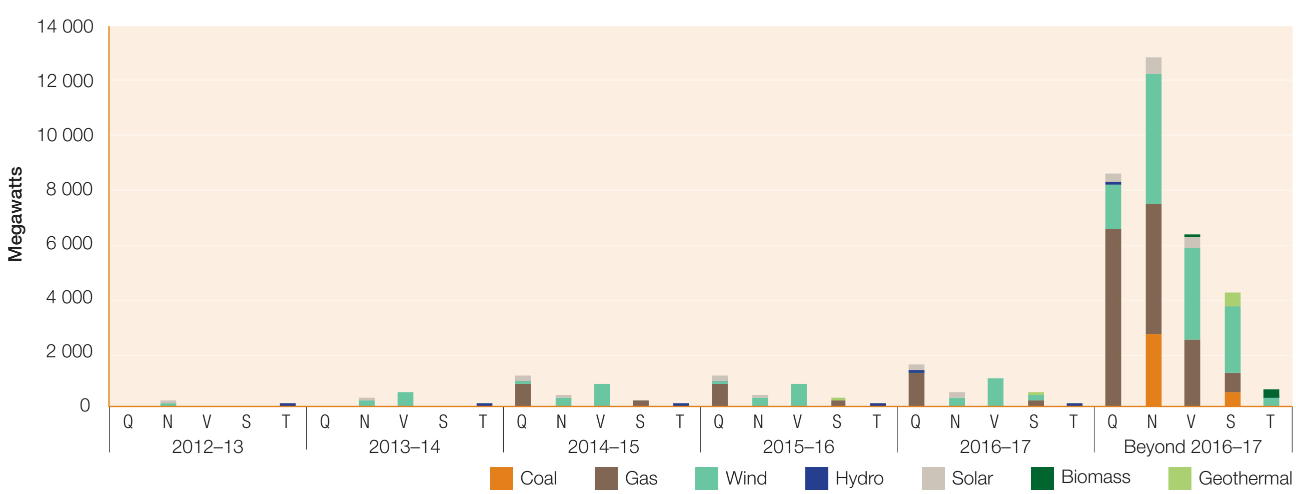
Table 1.8 Committed investment in the National Electricity Market, June 2012

DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
NEW SOUTH WALES				
Eraring Energy	Eraring (upgrade)	Coal fired	60	2012
VICTORIA				
AGL Energy / Meridian Energy	Macarthur	Wind	420	2013
Goldwind / New En	Morton's Lane	Wind	20	2012
Qenos	Qenos Cogeneration Facility	CCGT	21	2012
TASMANIA				
Hydro Tasmania	Musselroe	Wind	168	2013

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

Sources (tables 1.7 and 1.8): AEMO; AER.

Figure 1.22
Major proposed generation investment—cumulative, June 2012



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

Sources: AEMO; AER.

1.8 Demand side participation

An alternative or supplement 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 2012 identified 218 MW of capacity that was 'very likely' to be available across the NEM through demand side participation over the 2012–13 summer (up from 142 MW in 2011–12). It forecast annual growth in demand side participation of 3.2 per cent (for New South Wales) to 5.4 per cent (for Victoria and South Australia).[24]

In November 2012 the AEMC concluded its *Power of choice* review into efficient responses to rising peak demand. While the report's recommendations mainly relate to the network and retail sectors (section 2.6.1), some recommendations relate to generation and wholesale markets. For example, it recommended allowing consumers to participate directly or via their agents in the market, and to receive spot price compensation for reducing their electricity use. Payments would be based on a consumer's reductions in demand against a predetermined baseline for that customer.

1.9 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 due to a lack of available capacity. 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, 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 system wide outage of seven minutes at peak demand.

1.9.1 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 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 $12 500 per MWh to $12 900 per MWh on 1 July 2012.
- 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 $193 900 per MWh on 1 July 2012; 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.

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 give priority to facilities that would least distort wholesale market prices. The AEMC in 2012 extended the operation of the RERT mechanism until 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.

1.9.2 Reliability performance

The reliability panel annually reports on the generation sector's reliability performance. Reserve levels are rarely breached, with generator capacity across all regions of the market usually sufficient to meet peak demand and allow for acceptable reserve margins.

24 AEMO, *National electricity forecasting report 2012*, 2012, appendix D, p. D-3.

Insufficient generation capacity to meet consumer demand occurred only three times from the NEM start to 30 June 2012. The most recent instance, and the only exceedance of the 0.002 per cent reliability standard, resulted from a heatwave in Victoria and South Australia 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.

For the second consecutive year, AEMO was not required to issue any directions in 2011–12 to manage local power system issues (compared with seven directions in 2009–10 and 18 in 2008–09).

1.9.3 Security issues

The power system is operated to cope with only credible contingencies. On rare occasions, power supply interruptions are caused by non-credible (multiple contingency) events. Such interruptions may involve several credible events occurring simultaneously or in a chain reaction—for example, several generating units may fail or 'trip' at the same time, or a transmission fault may occur at the same time as a generator trips.

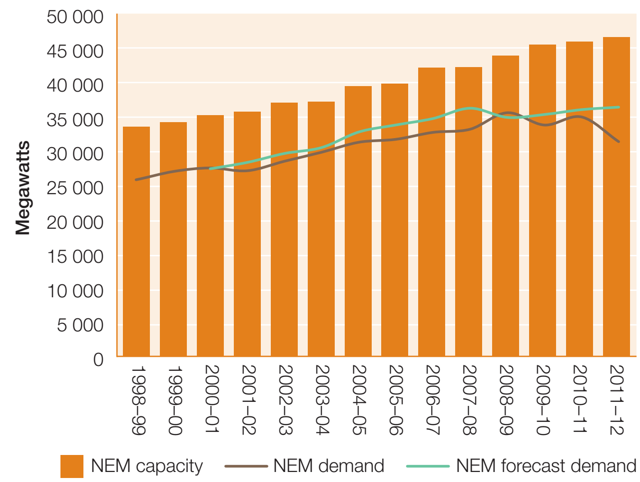
When such events occur, the market operator may need to interrupt customer supply to prevent a power system collapse. That is, while security issues are not reflected in reliability calculations, they can affect the continuity of supply. But operating the power system to cope with non-credible events would be economically inefficient. Likewise, additional investment in generation or networks may not avoid such interruptions.

AEMO reported on 42 security issues in 2011–12 (up from 36 issues in 2010–11); some incidents disrupted customer supply.

1.9.4 Historical adequacy of generation

Figure 1.23 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 over the past decade kept pace with rising demand (both actual and forecast levels), allowing reserve margins of capacity to maintain reliability. With peak demand flattening out from 2008–09, reserve margins have risen significantly, indicating a significant amount of surplus capacity.

Figure 1.23
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.

1.9.5 Reliability outlook

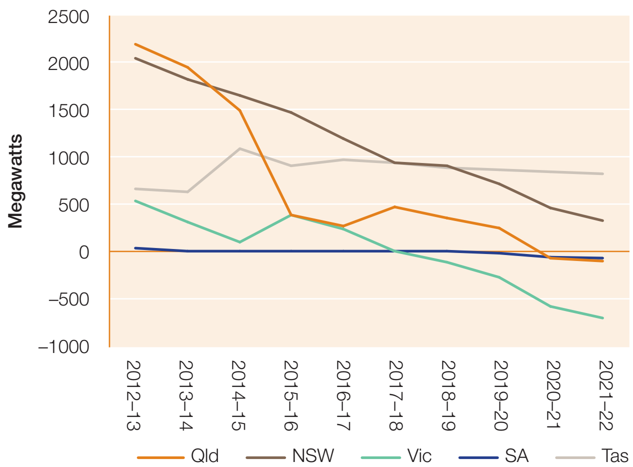
The relationship between demand and generation capacity determines the long term reliability of the power system. Figure 1.24 illustrates the margin of excess generation capacity above peak demand in each NEM region through to 2021–22, based on AEMO forecasts at 30 June 2012. Generation capacity includes wind, but at a factor below its nominal capacity (to reflect its intermittent nature). Forecast generation capacity includes committed capacity but not proposed capacity.

Figure 1.24 indicates the timing of new investment that will be needed to maintain reliability, given projected demand. Victoria will be the first region to require new investment (in summer 2018–19), followed by South Australia (summer 2019–20) and Queensland (summer 2020–21). New South Wales and Tasmania are not forecast to require new generation investment over the next decade.

In 2012, weakening growth in forecast peak demand led to a deferral of new investment requirements by at least four years in all NEM regions, compared with forecasts in 2011 (when AEMO projected Queensland, Victoria and South Australia would all require new investment by 2014–15).

Figure 1.24

Excess reserve capacity, 30 June 2012



Note:

Capacity includes installed and committed regional capacity, demand side participation and import capacity via transmission interconnectors. Wind capacity is included at a reduced factor, based on historical output, to account for its intermittent nature. The data account for rooftop PV generation as a reduction in demand.

Data source: AEMO, *2012 Electricity statement of opportunities*, 2012.

1.10 Compliance monitoring and enforcement

The AER monitors the wholesale electricity market to ensure compliance with the National Electricity Law and Rules governing the NEM, and takes enforcement action if appropriate. It also monitors the market to detect issues such as market manipulation. The AER draws on its monitoring activity to report on the NEM and make submissions and other contributions to the Standing Council on Energy and Resources, the AEMC and other bodies.

The AER's compliance and enforcement activity in the electricity generation sector[25] includes:

- electricity market monitoring to identify compliance issues
- targeted compliance reviews of Electricity Rules provisions—both randomly and in response to electricity market events or inquiries that raise concerns—to identify how participants comply with their obligations
- audits of compliance programs for generators' technical performance standards
- forums and other meetings with electricity industry participants to discuss compliance.
- publication of quarterly compliance reports (outlining the AER's compliance activity) and compliance bulletins (giving additional guidance on the Rules).

When deciding whether and how to act in the case of noncompliance, the AER aims for a proportionate response. It accounts for the impact of the breach, the circumstances and the participant's compliance programs and compliance culture, among other factors. Since 2006 the AER has issued nine infringement notices for electricity matters, and it commenced proceedings in the Federal Court on one occasion (against Stanwell, a Queensland generator, in relation to its compliance with the 'good faith' rebidding provisions of the Rules). Additionally, the AER has issued six compliance bulletins on electricity matters.

The AER's compliance monitoring activity in 2013 will include two new focus areas:

- Recognising the development in customer metering technologies and the importance of transparent market information, the AER will use new metrics to monitor compliance with metering and settlement obligations.
- The introduction of carbon pricing may lead to some coal fired generators being offline more frequently than in the past. The AER will continue to monitor outages and ensure published information about changes in a generator's participation in the market is timely and accurate.

25 The AER's compliance and enforcement activity in gas is considered in section 3.6.