1 NATIONAL ELECTRICITY MARKET

The National Electricity Market (NEM) is a wholesale market through 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 the largest interconnected power system in the world, covering a distance of 4500 kilometres.

1.1 Demand and capacity

The NEM supplies electricity to over nine million residential and business customers. In 2010–11 the market generated around 204 terawatt hours (TWh) of electricity, with a turnover of $7.4 billion (table 1.1 and figure 1.1a). Demand levels fluctuate throughout the year, with peaks occurring in summer (for air conditioning) and winter (for heating). Figure 1.1b shows seasonal peaks rose from around 26 gigawatts (GW) in 1999 to 35 GW in 2011. Table 1.2 sets out the regional consumption profile.

1.2 Generation in the NEM

Electricity produced by large electricity generators in the NEM jurisdictions is sold through a central dispatch process that the Australian Energy Market Operator (AEMO) manages. Figure 1.2 illustrates the location of large generators in the NEM.

Table 1.1 National Electricity Market at a glance

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
Regions	Qld, NSW, Vic, SA, Tas
Registered capacity	49 110 MW
Registered generators	305
Customers	9.0 million
Turnover 2010–11	$7.4 billion
Total energy generated 2010–11	204 TWh
Maximum winter demand 2010–11	31 240 MW[1]
Maximum summer demand 2010–11	34 933 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; ESAA, *Electricity gas Australia*, 2011.

Figure 1.1a
National Electricity Market electricity consumption

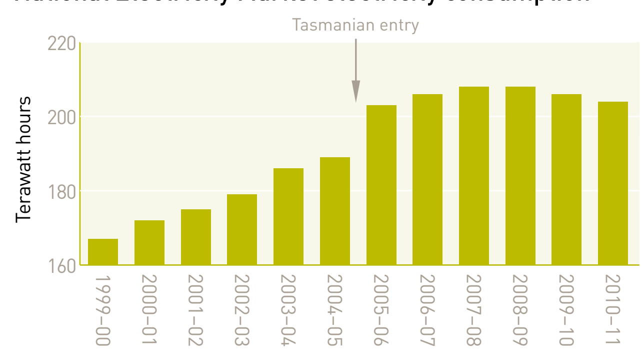
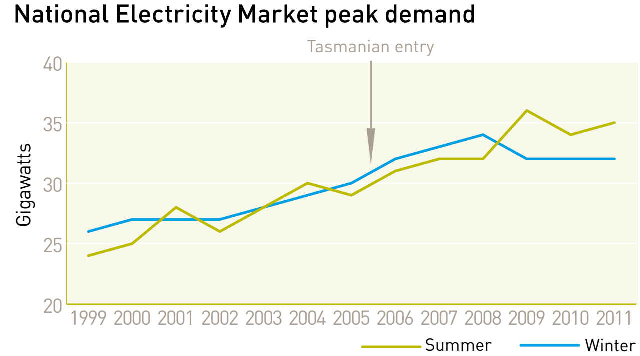


Figure 1.1b
National Electricity Market peak demand



Sources: AEMO; AER.

Figure 1.2

Large electricity generators in the National Electricity Market

Sources: AEMO; AER.

Table 1.2 Electricity supply to regions of the National Electricity Market (terawatt hours)

	QLD	NSW	VIC	SA	TAS[1]	SNOWY[2]	NATIONAL
2010–11	51.5	77.6	50.9	13.5	10.2		203.7
2009–10	53.2	78.1	51.2	13.3	10.0		206.0
2008–09	52.6	79.5	52.0	13.4	10.1		207.9
2007–08	51.5	78.8	52.3	13.3	10.3	1.6	208.0
2006–07	51.4	78.6	51.5	13.4	10.2	1.3	206.4
2005–06	51.3	77.3	50.8	12.9	10.0	0.5	202.8
2004–05	50.3	74.8	49.8	12.9		0.6	189.7
2003–04	48.9	74.0	49.4	13.0		0.7	185.3
2002–03	46.3	71.6	48.2	13.0		0.2	179.3
2001–02	45.2	70.2	46.8	12.5		0.3	175.0
2000–01	43.0	69.4	46.9	13.0		0.3	172.5
1999–2000	41.0	67.6	45.8	12.4		0.2	167.1

1. Tasmania entered the market on 29 May 2005.
2. The Snowy region was abolished on 1 July 2008. The New South Wales and Victorian data subsequently reflect electricity consumption formerly attributed to Snowy.

Note: Estimates based on generation required to meet energy requirements within a region—calculated as regional generation plus net flows into the region across interconnectors.

Sources: AEMO; AER.

1.2.1 Technology mix

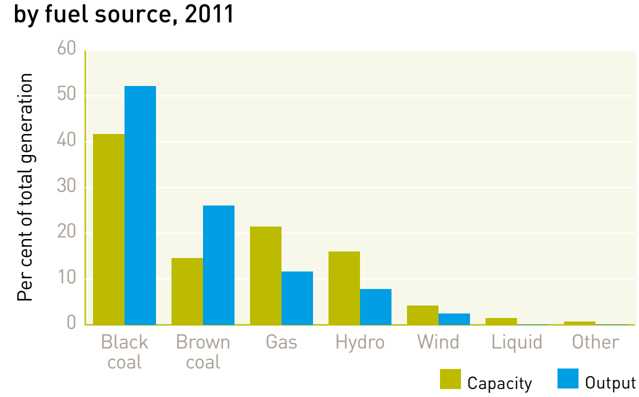
Across the NEM, black and brown coal account for around 56 per cent of registered[1] generation capacity, but this baseload plant supplies around 78 per cent of output (figure 1.3). Victoria, New South Wales and Queensland rely on coal more heavily than do other regions (figure 1.4).

Gas fired generation accounts for around 21 per cent of registered capacity across the NEM but supplies—as intermediate and peaking plant—only around 12 per cent of output. South Australia heavily relies on gas fired generation, and most new investment in other regions over the past decade was also in gas peaking plant.

Hydroelectric generation accounts for around 16 per cent of registered capacity but less than 8 per cent of output. Its contribution to output has increased recently with improved rainfall in Tasmania and eastern Australia. Wind plays a relatively minor role in the market (around 4 per cent of capacity and 3 per cent of output), but its role is expanding under climate change policies. Following significant wind generation investment in South Australia, wind now represents 24 per cent of statewide capacity but has accounted for up to 86 per cent of output.

Non-traditional technologies are also emerging as potential suppliers of electricity, including solar and geothermal generation (section 1.6).

Figure 1.3
Registered generation in National Electricity Market, by fuel source, 2011

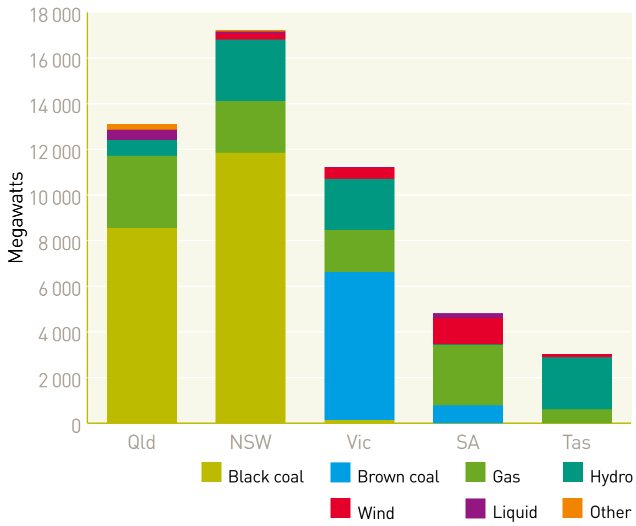


Note: Output is for 2010–11.

Sources: AEMO; AER.

1 Generators seeking to connect to the network must register with AEMO, unless granted an exemption.

Figure 1.4
Registered capacity in regions, by fuel source, 2011



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

The extent of new and proposed investment in weather dependant generation such as wind and solar power raises concerns about system security and reliability. This led to changes in how wind generation is integrated into the market. Since 31 March 2009 new wind generators greater than 30 megawatts (MW) must be classified as 'semi-scheduled' and participate in the central dispatch process. This requirement allows AEMO to manage the output of these generators to maintain the integrity of the power system.

1.2.2 Climate change policies and technological change

The pattern of generation technologies across the NEM is evolving in response to technological change and climate change policies that governments have implemented or proposed. Given Australia's historical reliance on coal fired generation, the electricity sector contributes around 35 per cent of national greenhouse gas emissions.[2]

Climate change policies aim to change the economic drivers for new investment and shift the mix from a reliance on coal fired generation towards less carbon intensive sources. Kogan Creek power station in Queensland is the only major new investment in coal fired generation in the past five years. Gas fired and wind generation have attracted the bulk of new investment.

The Australian Government will introduce a carbon price on 1 July 2012 as part of its Clean Energy Future Plan. The plan 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 will place a fixed price on carbon for three years, starting at $23 per tonne. It will then move to an emissions trading scheme in 2015, with the price determined by the market.

The plan includes assistance of $5.5 billion for emission intensive generators, and contracts for the closure of up to 2000 MW of coal fired generation. The plan also establishes the Clean Energy Finance Corporation, with access to $10 billion over five years for investment in renewable and low emissions energy. The Australian Parliament passed the legislation to implement the plan in November 2011.

The Australian Government also operates a national renewable energy target (RET) scheme, which it revised in 2011. The scheme is designed to achieve the government's commitment to a 20 per cent share of 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 are deemed to generate.

The scheme applies different arrangements for small scale and large scale renewable supply. It has a target of 41 000 gigawatt hours (GWh) of energy from large scale renewable energy projects by 2020. Small scale renewable projects no longer contribute to the national target, but still produce renewable energy certificates that

2 Garnaut Climate Change Review, *Final report*, 2008.

retailers must acquire. Since the 2011 revisions to the scheme, certificates from large scale projects have traded at around $35–40. The price of certificates from small scale projects has been more volatile, trading at $20–40.

1.2.3 Generation ownership

Private entities own the bulk of generation capacity in Victoria and South Australia. While public corporations control a majority of capacity in New South Wales and Queensland, there is increasing private sector activity. The Tasmanian generation sector remains mostly in government hands.

- In *Victoria* and *South Australia*, the major generation players are AGL Energy, International Power, TRUenergy, the Great Energy Alliance Corporation (in which AGL Energy holds a 32.5 per cent stake) and Alinta Energy. Origin Energy owns plant in South Australia and is developing new capacity in Victoria. Vertical integration is significant, with AGL Energy and TRUenergy being key players in both generation and retail. The government owned Snowy Hydro owns about 20 per cent of generation capacity in Victoria, mostly comprising historical investment associated with the Snowy Mountains scheme.[3]
- The *New South Wales* Government in 2011 sold the electricity trading rights of some state owned power stations. TRUenergy acquired the trading rights for the Mount Piper and Wallerawang power stations, while Origin Energy acquired the trading rights for the Eraring and Shoalhaven power stations. While state owned corporations still own around 90 per cent of generation capacity, TRUenergy and Origin Energy now control around one-third of this.
- State owned corporations control around 70 per cent of *Queensland's* generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone and Collinsville power stations). In 2011 the Queensland Government restructured its generation portfolio, with Tarong Energy exiting the market and all state owned capacity being reallocated between CS Energy and Stanwell. Considerable private investment has occurred over the past decade, including investment by Origin Energy, InterGen, AGL Energy, Alinta Energy and Arrow Energy.
- State owned corporations own nearly all generation capacity in *Tasmania*.

Table 1.3 provides information on the ownership of generation businesses in Australia. Figure 1.5 illustrates the ownership shares of the major players in each region of the market.

The New South Wales energy privatisation process in 2011 (and privatisation in Queensland in 2007) continues a trend of vertical integration between electricity generators and energy retailers into 'gentailers'. Origin Energy, AGL Energy and TRUenergy now control almost 30 per cent of generation capacity in the mainland regions of the NEM and jointly supply over 80 per cent of small electricity retail customers. Section B2 of the *Market overview* in this report outlines developments in vertical integration and implications for energy markets.

1.3 Trading arrangements

Generators in the NEM sell electricity through a wholesale spot market in which changes in supply and demand determine prices. The main customers are retailers, which buy electricity for resale to business and household customers. The market has no physical location, but is a virtual pool in which AEMO aggregates and dispatches supply bids to meet demand in real time.[4]

The NEM is a gross pool, meaning all electricity sales must occur through the spot market. In contrast, Western Australia's electricity market uses a net pool arrangement. Unlike some markets, the NEM does not provide additional payments to generators for capacity or availability. Some generators bypass the central dispatch process, including some wind generators, those not connected to a transmission network (for example, embedded generators) and those producing exclusively for their own use (such as remote mining operations).

3 The New South Wales, Victorian and Australian governments jointly own Snowy Hydro.
4 The *State of the energy market 2009* report explained the dispatch process (section 2.2).

Table 1.3 **Generation ownership in the National Electricity Market, July 2011**

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND	TOTAL CAPACITY	12 692	
Stanwell Corporation	Stanwell; Tarong; Tarong North; Swanbank; Barron Gorge; Kareeya; Mackay Gas Turbine; others	4 015	Stanwell Corporation (Qld Government)
CS Energy	Callide; Kogan Creek; Wivenhoe	1 969	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; Mount Stuart; Roma	1 046	Origin Energy
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	760	InterGen (China Huaneng Group 50%; others 50%) 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	275	ERM Group 62.5%; others 37.5% Contracted to AGL Energy
AGL Hydro	Yabulu	235	RATCH Australia Contracted to AGL Energy / Arrow Energy
Stanwell Corporation	Collinsville	187	RATCH Australia Contracted to Stanwell Corporation
RTA Yarwun	Yarwun	146	Rio Tinto Alcan
QGC Sales Qld	Condamine	135	BG Group
AGL Energy	German Creek; KRC Cogeneration; others	78	AGL Energy
Pioneer Sugar Mills	Pioneer Sugar Mill	68	CSR
Ergon Energy	Barcaldine	49	Ergon Energy (Qld Government)
EDL Projects Australia	Moranbah North	46	EDL Projects Australia
CSR	Invicta Sugar Mill	39	CSR
NEW SOUTH WALES	TOTAL CAPACITY	16 742	
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4 839	Macquarie Generation (NSW Government)
Delta Electricity	Vales Point B; Munmorah; Colongra; others	2 648	Delta Electricity (NSW Government)
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2 466	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
TRUenergy	Mount Piper; Wallerawang	2 400	Delta Electricity (NSW Government) Contracted to TRUenergy
Origin Energy	Eraring; Shoalhaven	2 322	Eraring Energy (NSW Government) Contracted to Origin Energy
Origin Energy	Uranquinty; Cullerin Range	670	Origin Energy
TRUenergy	Tallawarra	422	TRUenergy (CLP Group)
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	386	AETV (Tas Government)
Infigen Energy	Capital; Woodlawn	182	Infigen Energy
Marubeni Australia Power Services	Smithfield Energy Facility	160	Marubeni Corporation
Redbank Energy	Redbank	145	Redbank Energy
EDL Group	Appin; Tower; Lucas Heights	108	EDL Group
Eraring Energy	Brown Mountain; Burrinjuck; others	98	Eraring Energy (NSW Government)
AGL Hydro	Copeton; Burrendong; Wyangala; others	74	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

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
VICTORIA	TOTAL CAPACITY	10 791	
LYMMCo	Loy Yang A	2 170	GEAC (AGL Energy 32.5%; TEPCO 32.5%; RATCH Australia 14%; others 21%)
Snowy Hydro	Murray; Laverton North; Valley Power	2 098	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%
TRUenergy Yallourn	Yallourn; Longford Plant	1 451	TRUenergy (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 TRUenergy (CLP Group)
AGL Hydro	Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay; others	596	AGL Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland; Codrington	265	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Energy Brix Australia	Energy Brix Complex; others	160	HRL Group / Energy Brix Australia
Alcoa	Angelsea	156	Alcoa
Aurora Energy Tamar Valley	Bairnsdale	68	AETV (Tas Government)
SOUTH AUSTRALIA	TOTAL CAPACITY	4 430	
AGL Energy	Torrens Island	1 280	AGL Energy
Alinta Energy	Northern; Playford	742	Alinta Energy
International Power	Pelican Point; Canunda	494	International Power / GDF Suez
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	315	International Power / GDF Suez
TRUenergy	Hallet; Waterloo	287	TRUenergy (CLP Group)
Origin Energy	Quarantine; Ladbroke Grove	261	Origin Energy
Infigen Energy	Lake Bonney 2 and 3	198	Infigen Energy
AGL Hydro	Hallett 1 and 2; Wattle Point; North Brown Hill	194	AGL Energy
Origin Energy	Osborne	175	ATCO 50%; Origin Energy 50%
Infratil Energy Australia	Snowtown	99	Infratil
Infigen Energy	Lake Bonney 1	81	Infigen Energy Contracted to Essential Energy (NSW Government)
Meridian Energy	Mount Millar	70	Meridian Energy
TRUenergy	Cathedral Rocks	66	TRUenergy (CLP Group) 50%; Acciona Energy 50%
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Angaston	49	Infratil Contracted to AGL Energy
RATCH Australia	Starfish Hill	35	RATCH Australia Contracted to Hydro Tasmania (Tas Government)
TASMANIA	TOTAL CAPACITY	2 693	
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; Woolnorth; others	2 305	Hydro Tasmania (Tas Government)
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	386	AETV (Tas Government)

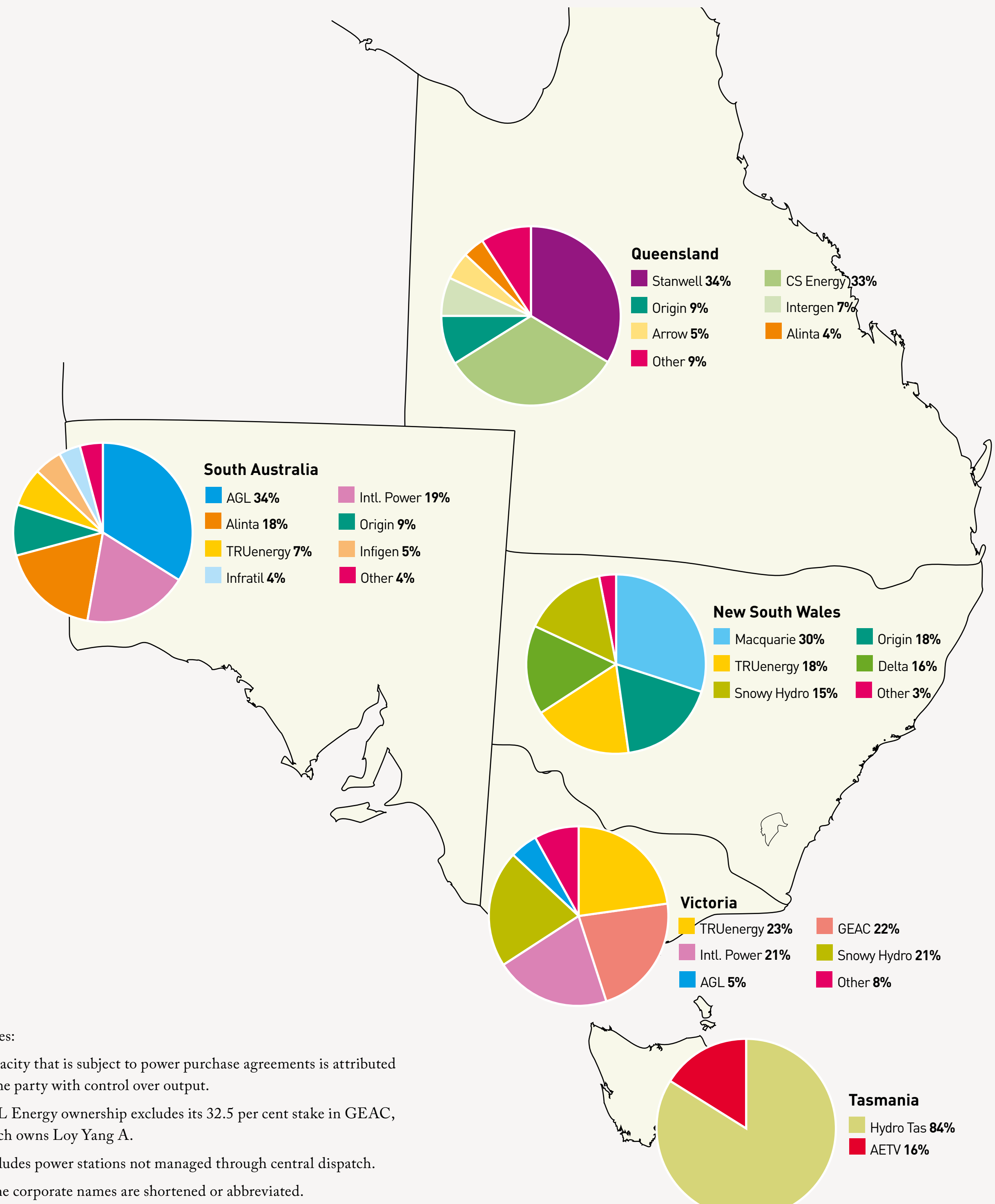
Fuel types: coal; gas; hydro; wind; diesel/fuel oil/multi-fuel; biomass/bagasse; unspecified.

Note: Capacity is as published by AEMO for summer 2011–12.

Source: AEMO.

Figure 1.5

Market shares in electricity generation capacity, by region, 2011



Notes:

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

AGL Energy ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A.

Excludes power stations not managed through central dispatch.

Some corporate names are shortened or abbreviated.

Source: AER.

Figure 1.6
Interregional trade as percentage of regional energy consumption

Sources: AEMO; AER.

The NEM promotes efficient generator use by allowing electricity trade among the five regions. Figure 1.6 shows the net trading position of the regions:

- *New South Wales* is a net importer of electricity. It relies on local baseload generation, but has limited peaking capacity at times of high demand.
- *Victoria* has substantial low cost baseload capacity, making it a net exporter of electricity.
- *Queensland's* installed capacity exceeds the region's peak demand for electricity, making Queensland a significant net exporter.
- *South Australia* imported over 25 per cent of its energy requirements in the early years of the NEM. New investment in generation—mostly in wind capacity—has reduced this dependence since 2005–06.
- In 2010–11 *Tasmania* was a net exporter of energy for the first time since its interconnection with the NEM in 2006. The region's ability to generate hydroelectricity rose due to greater water availability (more than double the levels in 2007). In addition, new gas fired generation was installed in 2009.

1.4 Spot electricity prices

Generators provide AEMO with generation price and quantity offers (bids) for each 5 minute dispatch period. AEMO dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to satisfy demand. In practice, various factors may modify the dispatch order, including generator ramp rates (that is, how quickly generators can adjust their level of output) and congestion in transmission networks.

The dispatch price for a 5 minute interval is the offer price of the highest (marginal) priced MW of generation that must be dispatched to meet demand. A wholesale spot price is then determined for each half hour (trading interval) from the average of the 5 minute dispatch prices. This is the price that all generators receive for their supply during the half hour, and the price that wholesale customers pay for the electricity they use in that period. Spot prices may range between a floor of –\$1000 per MWh and a cap of \$12 500 per MWh. The cap will be increased annually from 1 July 2012 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 1.8).

While the market determines a separate price for each region, prices across the mainland regions are aligned for a majority of the time.[5] Alignment occurred for about 61 per cent of the time in 2010–11, compared with 67 per cent in 2009–10. The rate of alignment has steadily decreased from over 80 per cent in 2001–02. Market separation occurs when a cross-border transmission interconnector becomes congested and restricts interregional trade. This scenario may occur at times of peak demand or when an interconnector undergoes maintenance or experiences an unplanned outage.

The Australian Energy Regulator (AER) monitors the market and reports weekly on activity. It also publishes more detailed analyses of extreme price events. Figure 1.7 charts quarterly volume weighted average prices in each region, while table 1.4 sets out annual prices. Figure 1.8 provides a snapshot of weekly prices since December 2007.

1.4.1 Spot prices in 2010-11

The 2010–11 summer was comparatively mild (with the lowest average maximum temperature across Australia since 2001), resulting in lower than expected electricity demand. Average spot prices fell significantly from the previous year in South Australia, Victoria and New South Wales, and marginally in Queensland, but rose slightly in Tasmania.

As with the previous year, average spot prices in New South Wales ($43 per MWh) and South Australia ($42 per MWh) were higher than in other regions. Victoria ($29 per MWh) and Tasmania ($31 per MWh) recorded the lowest average spot prices in 2010–11, closely followed by Queensland ($34 per MWh). All regions other than Tasmania recorded their lowest average spot prices in at least five years.

In addition to lower average prices, fewer extremely high price events occurred in 2010–11. The NEM recorded 40 trading intervals above $5000 per MWh —the lowest number since 2004–05 (figure 1.9). But while there were fewer events, those that occurred set record prices in New South Wales, South Australia and Tasmania, following an increase in the market price cap on 1 July 2010 to $12 500 per MWh. The maximum price in 2010–11 was $12 400 per MWh, reached on three occasions in Tasmania.

Table 1.4 Volume weighted average spot electricity prices ($ per megawatt hour)

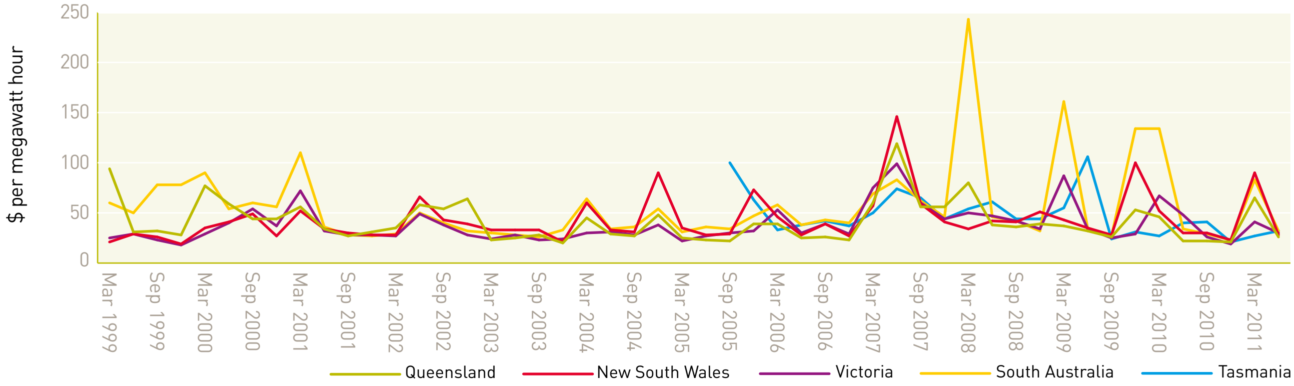
	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
2010–11	34	43	29	42	31	
2009–10	37	52	42	82	30	
2008–09	36	43	49	69	62	31
2007–08	58	44	51	101	57	31
2006–07	57	67	61	59	51	38
2005–06	31	43	36	44	59	29
2004–05	31	46	29	39		26
2003–04	31	37	27	39		22
2002–03	41	37	30	33		27
2001–02	38	38	33	34		27
2000–01	45	41	49	67		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.

5 Even when aligned, prices will exhibit minor disparities across regions, caused by transmission losses that occur when electricity is transported over long distances.

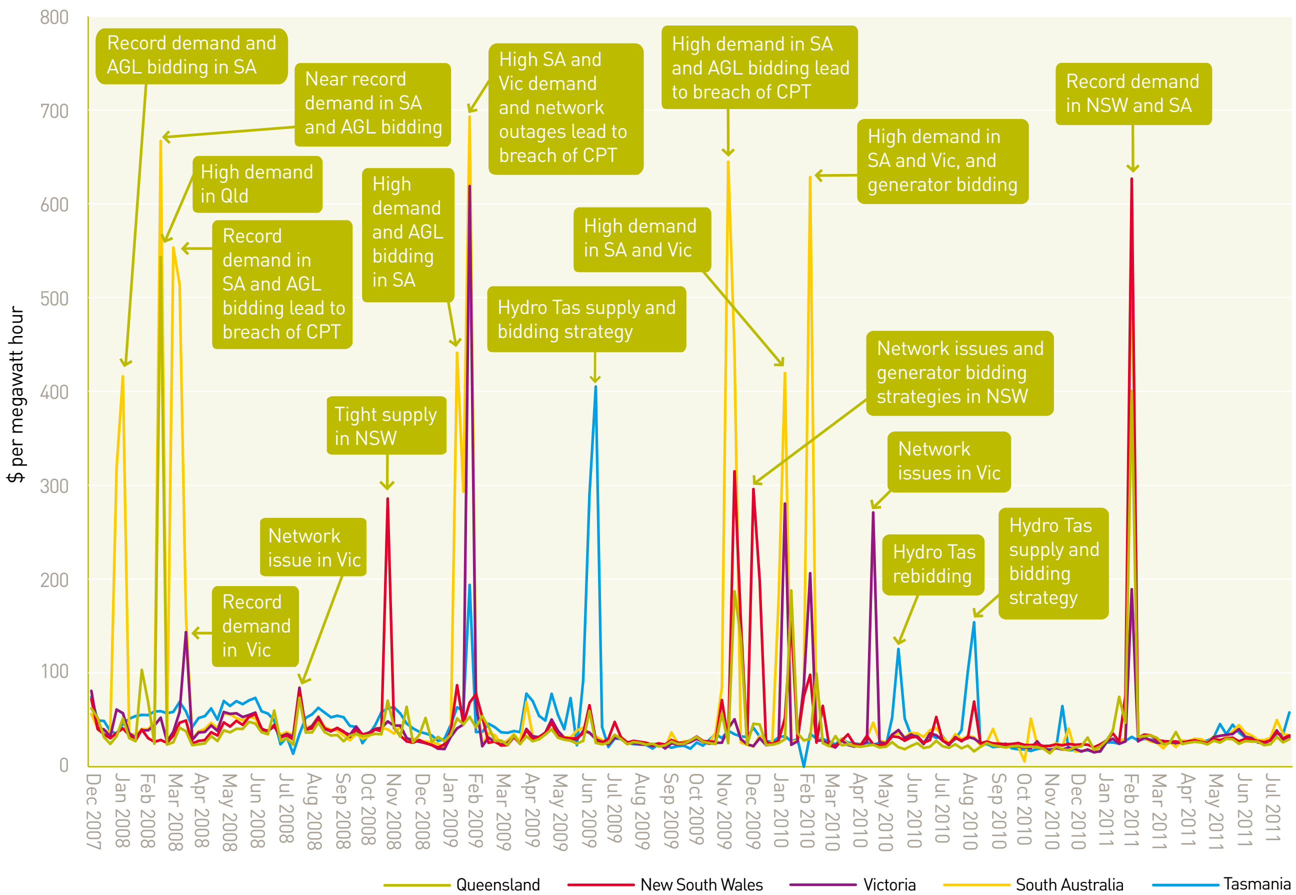
Figure 1.7
Quarterly spot electricity prices



Note: Volume weighted average prices.

Sources: AEMO; AER.

Figure 1.8
Weekly spot electricity prices

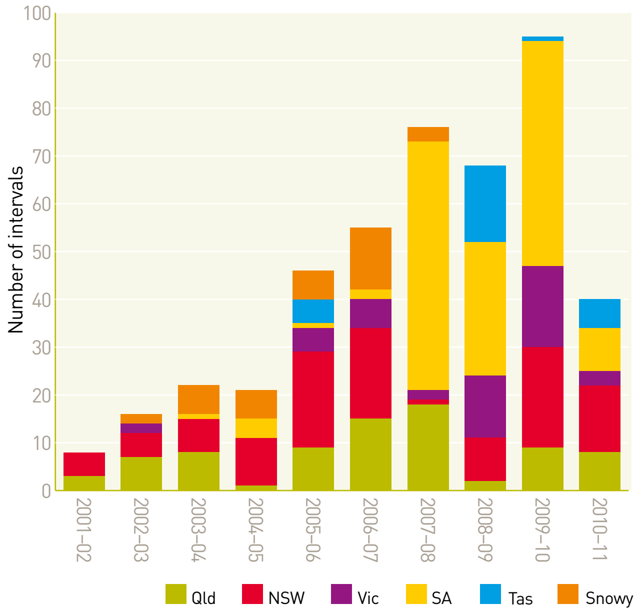


CPT, cumulative price threshold; Hydro Tas, Hydro Tasmania.

Note: Volume weighted average prices.

Source: AER.

Figure 1.9
Trading intervals above $5000 per megawatt hour



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

Table 1.5 summarises all price events above $5000 per MWh in 2010–11, noting the regions in which they occurred and the underlying causes. Eighty per cent of the events occurred during a heat wave from 31 January to 2 February 2011 affecting New South Wales (12 events), South Australia (nine), Queensland (eight) and Victoria (three). The high temperatures led to record demand of 14 598 MW in New South Wales (where the temperature reached 41 degrees on 1 February), and 3378 MW in South Australia (43 degrees on 31 January). Demand was also high in Victoria on 1 February (at 9585 MW), but short of the record 10 445 MW set in January 2009.

The events across the four regions were related, with demand and supply conditions in South Australia on 31 January contributing to high prices in Victoria on that day. Similarly, high demand in New South Wales affected prices in Queensland and Victoria. Floods in Queensland also led to transmission outages and volatile pricing during this period.

NEM turnover for the week covering these days exceeded $2 billion—a 50 per cent increase on the previous record. New South Wales also recorded its highest weekly volume weighted average price of $627 per MWh. The increase in the market price cap contributed to these new records.

Market focus—South Australia

At $42 per MWh, the average spot price in South Australia for 2010–11 was almost 50 per cent lower than in 2009–10. The price exceeded $5000 per MWh in nine trading intervals, down significantly on the previous year (figure 1.9). A mild summer, with only a few days above 40 degrees, affected this outcome.

Another contributing factor was South Australia's 177 trading intervals with negative prices in 2010–11, up from 86 in the previous year and the highest annual number ever recorded for any region. Wind generators sometimes bid negative prices to ensure dispatch, relying on the value of the renewable energy certificates they earn to cover their costs. But several instances of prices near the –$1000 market floor were driven by AGL Energy rebidding large amounts of capacity at times of high wind generation and low demand. The negative prices caused other generators, including wind farms, to shut down (See Section B2, *Market overview*).

The South Australian data contributed to a record number of negative price events (282) for the NEM in 2010–11. As a result, the AER in October 2010 began analytical reporting on spot prices below –$100 per MWh as part of its weekly market updates.

Market focus—Tasmania

Good rainfall allowed for increased hydro generation in Tasmania in 2010–11 and contributed to a second year of relatively low spot prices ($31 per MWh). Tasmania had six extreme price events, compared with one in 2009–10, typically caused by Hydro Tasmania strategically withdrawing its non-scheduled generation to raise prices (as it has periodically done since 2009). There were also instances where the spot price reached the floor (–$1000) when the Victorian spot price was high.

Table 1.5 Price events above $5000 per megawatt hour, 2010–11

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
7 and 8 August 2010	Tas	5	$12 400	In day-ahead bidding, Hydro Tasmania offered significant capacity to the market at high prices. It then reduced output from its small hydro (non-scheduled) generators during peak demand periods on both days. A spot price of $12 400 per MWh in one period set a new record for the NEM, following an increase in the market price cap from $10 000 per MWh to $12 500 per MWh on 1 July 2010. Some demand side response to the high prices appeared to mitigate the price impact in some trading intervals.
10 August 2010	NSW	2	$6 267	Capacity at Delta Electricity's Wallerawang plant was significantly reduced—unit 8 was not operational and Delta delayed unit 7's return to service by several hours. The ratings of the Mount Piper to Wallerawang lines were reduced to allow unit 7 to return to service, contributing to more severe network congestion than expected. This congestion reduced the dispatch of low priced generation and forced electricity flows out of New South Wales, causing prices to significantly exceed the forecast and almost reach the market cap in five dispatch intervals. There appeared to be a demand response to the high prices, with a 300 MW reduction in New South Wales electricity demand.
19 November 2010	Tas	1	$12 400	In day-ahead bidding, Hydro Tasmania offered significant capacity at prices near the market cap for two hours in the morning. On the day, it reduced output from its small hydro (non-scheduled) generators. Due to constraints on Basslink (which limited imports from the mainland) and a lack of alternative local capacity, Hydro Tasmania's high priced scheduled generation was dispatched to meet demand.
31 January 2011	SA	9	$12 200	Record South Australian demand (3378 MW), combined with Alinta Energy pricing around 70 per cent of its capacity at Northern Power Station near the cap, caused spot prices to rise to $12 200 per MWh—a record for the region. Wind generation on the day fell from around 540 MW to an average of 100 MW during the high price period. Had wind generation not fallen, the price impact might have been significantly reduced. The events in South Australia contributed to spot prices exceeding $5000 per MWh in Victoria on the same day.
31 January and 1 February 2011	Vic	3	$9 597	High temperatures led to demand reaching its highest level in Victoria for the summer, peaking at 8924 MW on 31 January and 9585 MW on 1 February. On both days, LYMMCO priced around one-third of its capacity at Loy Yang A at close to the market cap in its day-ahead offers. The tight supply–balance was further aggravated when Newport Power Station tripped on 31 January, causing a 510 MW reduction in available capacity. The combined impact of these factors caused prices to spike above $10 000 per MWh in eight (5 minute) dispatch intervals. The impact was prolonged when Snowy Hydro shifted capacity into negative prices for its Murray generator (located in Victoria) to ensure dispatch and accrue the high Victorian prices. Network constraints did not allow this electricity to flow into Victoria, but instead forced flows into the lower priced New South Wales region. AEMO intervened to reduce exports from Victoria to New South Wales. Record demand and high prices in New South Wales and South Australia also contributed to the high Victorian prices. Rebidding by International Power at Hazelwood and Loy Yang B had an impact on Victorian prices on 1 February.
31 January to 2 February 2011	NSW	12	$12 136	High temperatures led to record New South Wales electricity demand on all three days, peaking at 14 598 MW on 1 February. Sustained high prices over the three days led the weekly cumulative price in New South Wales to increase to $151 025 on 2 February. The events affected neighbouring regions, with prices above $5000 per MWh in Victoria and Queensland on 1 February, and in Queensland on 2 February. Rebidding by Macquarie Generation and Eraring contributed to the high prices.

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
1 and 2 February 2011	Qld	8	$9 044	CS Energy, Millmerran, Stanwell and Callide Power Trading rebid significant amounts of capacity at prices above $9000 per MWh. This rebidding, combined with record demand and high prices in New South Wales, drove a series of extreme price outcomes in Queensland, none of which was forecast.
MARKET ANCILLARY SERVICES				
1 February 2011	SA	35 minutes	$7 591	High Victorian electricity prices drove exports from South Australia into Victoria on a day when a planned transmission outage reduced the capability of the Heywood interconnector between the regions. These conditions led to the need for frequency control ancillary services, and the transmission outage meant these services could be sourced only from South Australia. AGL Energy is the most significant provider of frequency control ancillary services in South Australia, and it offered the majority of its capacity for these services at the price cap. The offers were made through day-ahead offers and rebidding. The combination of high energy prices in the eastern states and AGL Energy's high offers caused prices for lower frequency control services to exceed $5000 per MW for seven (5 minute) dispatch intervals. These services for the seven dispatch intervals, which South Australian customers paid for, cost a total of $441 000 (compared with less than $3000 for the same services on a typical day).

MW, megawatt; MWh, megawatt hour.

Source: AER.

The Tasmanian Government established the Electricity Supply Industry Expert Panel in 2010 to assess the state of the industry. The panel released an issues paper in June 2011 that, in addition to addressing matters core to its terms of reference, questioned Hydro Tasmania's market power and its use of its non-scheduled generation to raise prices. It expected to release its final report in December 2011.

The AER's submission to the issues paper provided evidence of Hydro Tasmania's strategic manipulation of prices (particularly at off peak times) causing inefficient dispatch of open cycle gas turbines and demand side response from large industrial customers. Hydro Tasmania's strategy was not associated with any supply scarcity. The AER concluded Hydro Tasmania's strategic behaviour would, in addition to having negative impacts on market efficiency, pose a major spot market risk for any new retailer in Tasmania.

1.4.2 Rule change proposal on market power

The AEMC began consulting in 2011 on an Electricity Rule change proposal 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 AER noted in a submission to the AEMC that short periods of high prices are necessary in an energy only market to signal underlying supply and demand conditions and the need for investment. Market power concerns arise when high average prices reflect systemic economic withholding of capacity by generators, rather than scarcity pricing. The AER has noted evidence of such behaviour in its reports on extreme prices in the NEM, and in *State of the energy market* reports.

It reported, for example, systemic economic withholding by Macquarie Generation in New South Wales in 2007, by AGL Energy in South Australia between 2008 and 2010, and by Hydro Tasmania between 2009 and 2011.

The AEMC expects to make a draft determination in April 2012, following further stakeholder consultation.[6]

1.5 Electricity futures

Spot price volatility in the NEM can cause significant risk to wholesale market participants. While generators face a risk of low prices affecting earnings, retailers face a complementary risk that prices may rise to levels 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 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 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 Sydney Futures Exchange (SFE). Participants (licensed brokers) buy and sell contracts on behalf of clients that include generators, retailers, speculators such as hedge funds, and banks and other financial intermediaries.

The AER *State of the energy market 2009* described the operation of these markets and the financial instruments traded within them.

Futures trading on the SFE covers instruments for the Victoria, New South Wales, Queensland and South Australia regions. Trading volumes in this market were equivalent to about 284 per cent of underlying energy consumption in 2010–11, up from 204 per cent in 2009–10. New South Wales accounted for 42 per cent of traded volumes, followed by Queensland (29 per cent) and Victoria (28 per cent). Liquidity in South Australia has remained low since 2002, accounting for only 1 per cent of volumes.

1.5.1 Electricity futures prices

Figure 1.10 shows average price outcomes for electricity base futures, as reflected in the national power index.[7] 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.

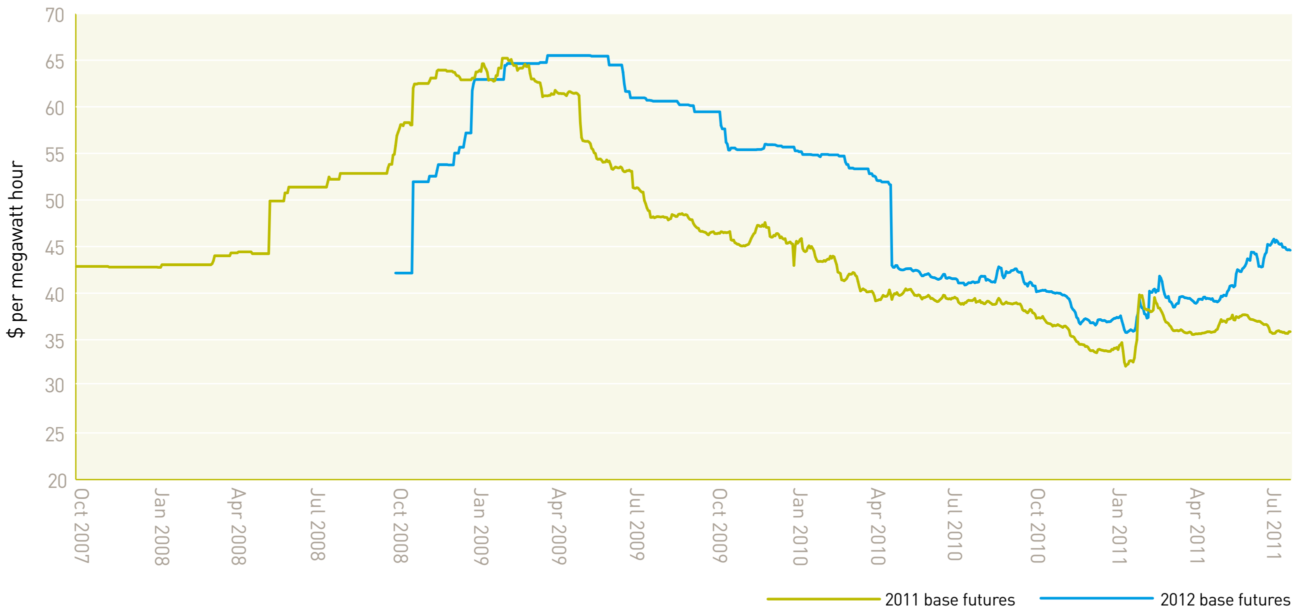
The expected effects of carbon pricing on electricity generation costs led to higher base futures prices in 2008, which then eased following government announcements in 2009 and 2010 to delay new policies in this area. Prices continued to fall throughout 2010, reflecting subdued prices in the electricity spot market. Futures prices were below $40 per MWh in all NEM regions by the end of 2010. They rebounded during the summer of 2010–11 when high temperatures, record electricity demand and record spot prices raised price expectations (especially for 2011 calendar futures).

Prices for 2012 futures continued to rise during 2011 as momentum grew towards the introduction of carbon pricing in 2012. By July 2011 prices for 2012 futures were above $47 per MWh in South Australia and New South Wales, and around $42 per MWh in Victoria and Queensland. Conversely, prices for 2011 futures (which would not be affected by carbon pricing) fell back to around $36 per MWh.

6 AEMC, *National Electricity amendment (potential generator market power in the NEM) Rule 2011, directions paper*, 2011.
7 Base futures contracts cover all trading intervals over the term of the contract.


© Mark Wilson

Figure 1.10
National power index



Source: d-cyphaTrade.

Forward prices

Figure 1.11 illustrates base futures prices at June 2011 for quarters up to two years ahead. For comparative purposes, forward prices at June 2010 are also provided.

Prices in June 2011 for the quarters in 2011–12 eased in most jurisdictions from the levels set in June 2010, reflecting relatively benign spot prices. The largest shift occurred for the Victorian summer, with prices for futures in the first quarter of 2012 falling from almost $60 to $47 per MWh. This fall might have reflected revised perceptions about the state's supply–demand balance, following announcements that new capacity from Origin Energy's 518 MW plant at Mortlake will be operational at that time.

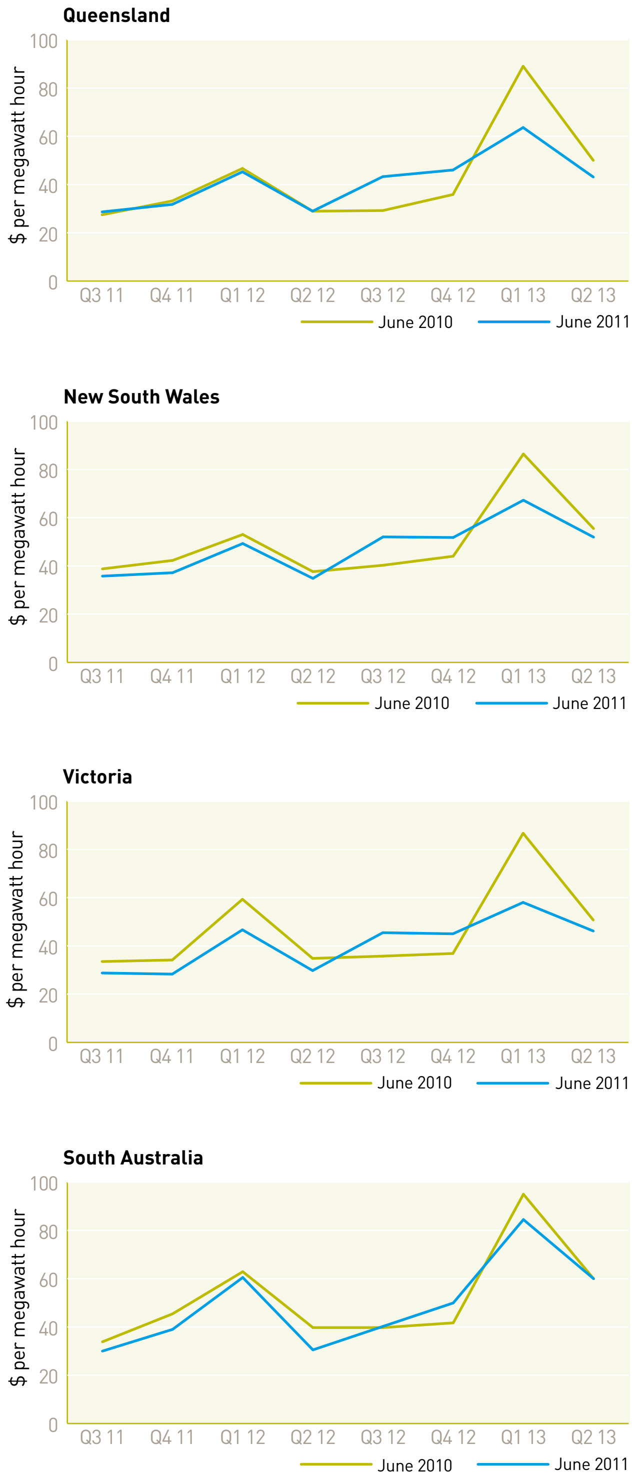
Prices in June 2011 for the late 2012 quarters were generally higher than those set in 2010, reflecting the revised timing for carbon pricing, now expected to take effect from 1 July 2012. Increased certainty around the details of government policy in this area may also explain the significant fall in prices for 2013 futures from the levels set in the previous year.

Forward prices remained higher in South Australia than elsewhere, especially for the summer peak periods. This might have reflected market concerns that periodically high summer prices in South Australia's spot electricity market—as a result of high temperatures, interconnector constraints and market power—remain a potential risk.

While futures contracts typically relate to a specific quarter of a year, contracts are increasingly being traded as calendar year strips, comprising a 'bundle' of the four quarters of the year. This tendency is more pronounced for contracts starting at least one year from the trade date. Figure 1.12 charts prices in June 2011 for calendar year futures strips to 2014. While prices are generally consistent with those evident in the forward curves, they smooth out the impact of seasonal peaks.

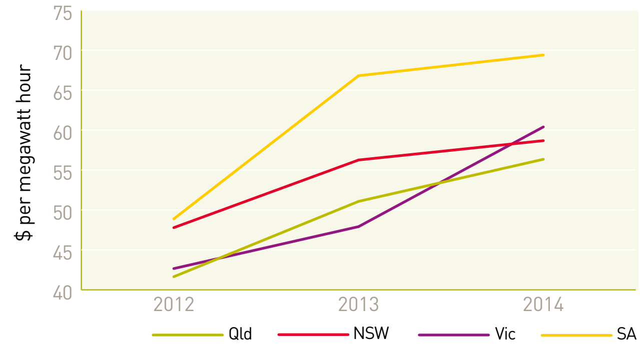
The data indicate a spread of prices across the regions, with New South prices being around $5–8 per MWh higher than those in Victoria and Queensland over the next two years, but with Victorian prices rising above those in New South Wales in 2014.

Figure 1.11
Base futures prices, June 2010 and June 2011



Sources: AER; d-cyphaTrade.

Figure 1.12
Base calendar strip, June 2011



Sources: AER; d-cyphaTrade.

In June 2011 all regions had forward curves in contango —that is, prices were higher for contracts in the later years. This trend might have reflected the expectation of higher generation costs associated with climate change policies, and uncertainty about the effects of those policies on investment. More generally, the market might have factored in assessments of supply adequacy in some regions.

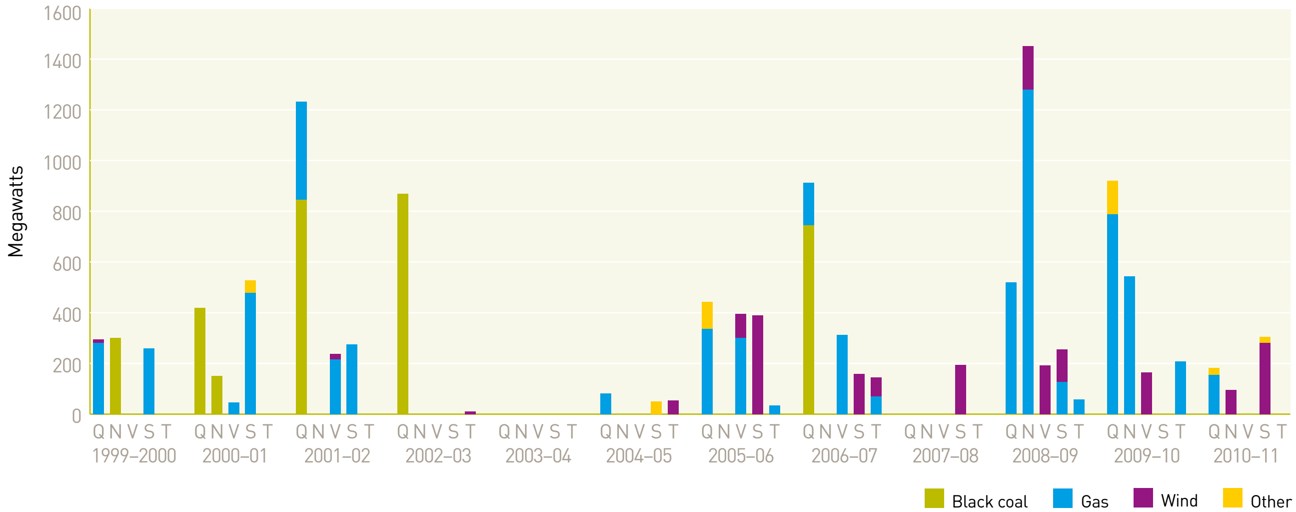
1.6 Generation investment

New investment in the NEM is largely driven by price signals in the wholesale and forward markets for electricity. From the inception of the NEM in 1999 to June 2011, new investment added around 12 600 MW of registered generation capacity.[8] Figures 1.13 and 1.14 illustrate investment since market start.

Tightening supply conditions have led to an upswing in generation investment, with over 4700 MW of new capacity added in the three years to 30 June 2011—predominantly gas fired generation in New South Wales and Queensland. But only 500 MW of this investment occurred in 2010–11, of which over 64 per cent was in wind generation (table 1.6).

8 There has also been investment in small generators, remote generators not connected to a transmission network, and generators that produce exclusively for self-use (such as for remote mining operations).

Figure 1.13
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.

Table 1.7 sets out investment projects in the NEM at June 2011 that were committed but not yet operational. It includes those projects under construction and those for which developers and financiers had formally committed to construction. AEMO accounts for committed projects in projecting electricity supply and demand. At June 2011 the NEM had almost 1300 MW of committed capacity, mostly in gas fired and wind generation. The most significant projects were in Victoria, including the 518 MW Mortlake gas fired power station and the 420 MW Macarthur wind farm (which will be the largest wind farm in the southern hemisphere).

In addition to committed projects, AEMO lists 'proposed' generation projects that are 'advanced' or publicly announced. While some of these projects come to fruition, AEMO considers them to be speculative and thus excludes them from its supply and demand outlooks. At June 2010 it listed over 31 000 MW of proposed capacity in the NEM (figure 1.15). The bulk of proposed investment is in New South Wales and Victoria.

The proposals mostly rely on gas fired and wind technologies. While most of the gas plants adopt open or combined cycle technologies, proposals also include:

- one of the world's first integrated gasification combined cycle plants, with carbon capture and storage, which Stanwell proposes for Queensland by 2017–18. The plant would be capable of capturing 90 per cent of carbon emissions.[9]
- an integrated drying and gasification combined cycle plant proposed for Victoria by 2013–14. The plant would rely on a technology to dry and gasify moist reactive coals (including brown coal), and would reduce carbon emissions by around 30 per cent compared with conventional plant.[10]

9 Wandoan Power, 'Cleaner coal technology moves forward in Australia', Media release, 8 December 2009.

10 Victorian Department of Primary Industries, 'HRL's new coal technology to lower carbon dioxide emissions intensity', Media release, 31 August 2010.

Figure 1.14
Net change in generation capacity since market start, cumulative

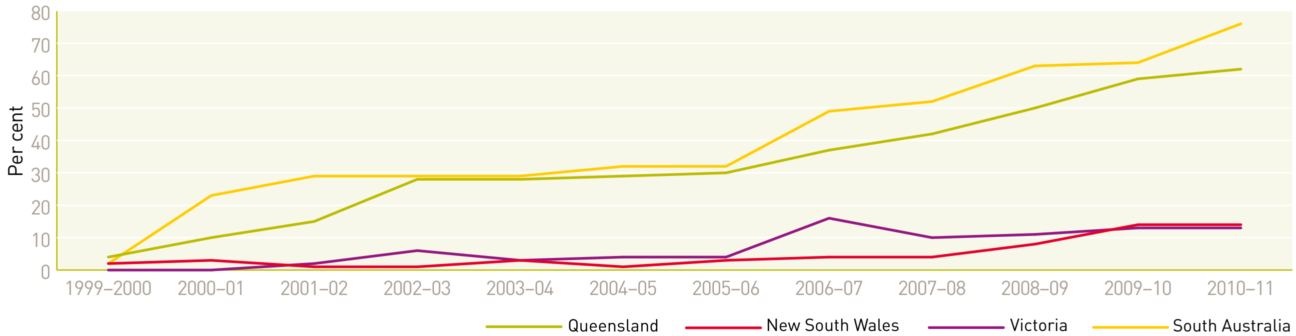


Table 1.6 Generation investment in the National Electricity Market, 2010–11

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED	ESTIMATED COST ($ MILLION)
QUEENSLAND					
Rio Tinto	Yarwun	Gas cogeneration	155	July 2010	200
NEW SOUTH WALES					
Acciona Energy	Gunning	Wind	47	April 2011	147
Infigen Energy	Woodlawn	Wind	48	June 2011	100
SOUTH AUSTRALIA					
Infigen Energy	Lake Bonney 3	Wind	39	July 2010	120
AGL Energy	North Brown Hill	Wind	82	August 2010	334
TRUenergy (CLP Group)	Waterloo	Wind	111	August 2010	300
International Power	Port Lincoln	OCGT	25	November 2010	30

Table 1.7 Committed investment in the National Electricity Market, June 2011

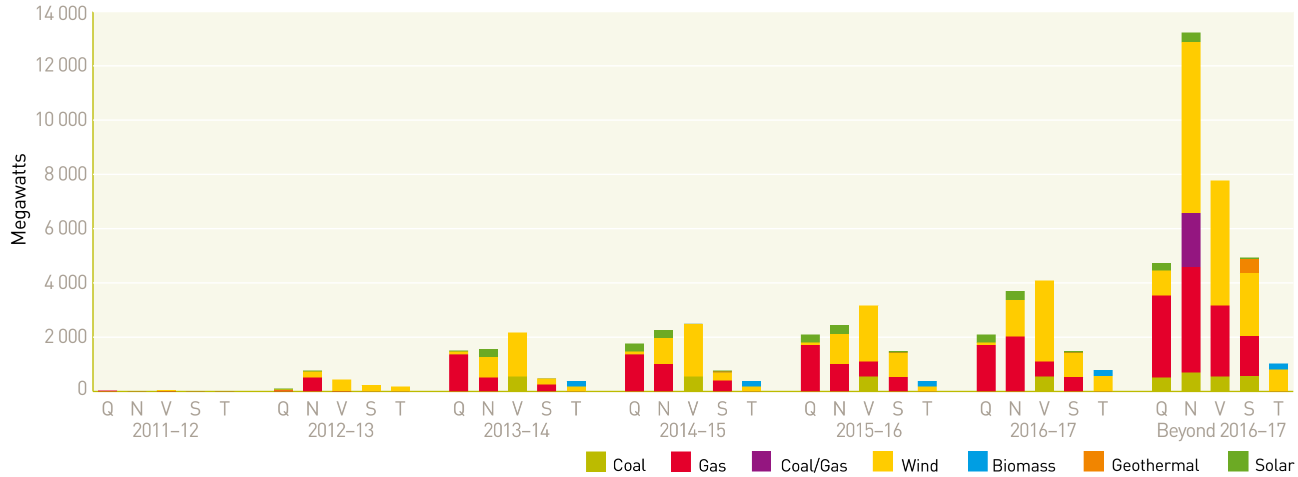
DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
NEW SOUTH WALES				
Eraring Energy	Eraring (upgrade)	Coal fired	240	2012–13
VICTORIA				
Origin Energy	Mortlake	OCGT	518	2011
AGL Energy/Meridian Energy	Macarthur	Wind	420	2011–12
AGL Energy	Oaklands Hill	Wind	63	2011–12
SOUTH AUSTRALIA				
AGL Energy	The Bluff	Wind	34	2011

OCGT, open cycle gas turbine.

Sources (figure 1.14 and tables 1.6 and 1.7): AEMO; AER.

Figure 1.15

Major proposed generation investment in the National Electricity Market, cumulative, June 2011



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

Source: AEMO.

The introduction of the Australian Government's Solar Flagships program has led to several proposals for large scale solar projects, including:

> the world's largest solar thermal gas hybrid plant in Queensland, combining solar generation with a low emission gas boiler back-up system. The 250 MW plant near Chinchilla is proposed for 2014–15.[11]

> Australia's first utility scale solar photovoltaic generation plant. The 150 MW plant at Moree (New South Wales) is proposed for 2013–14.[12] A further four solar plants, with a combined capacity of up to 200 MW, are proposed for New South Wales by 2015–16.

> a 44 MW solar thermal addition to the existing coal fired Kogan Creek power station in Queensland, proposed for 2012–13. The solar project will augment the power station's steam generation system to increase electricity output and fuel efficiency, and will be the world's largest solar integration with a coal fired power station.[13]

There are also plans for geothermal generation. A 525 MW geothermal plant announced for Innamincka (South Australia) is scheduled to connect to the grid in 2018.

1.7 Demand side participation

An alternative or supplement to generation investment is to increase demand side participation—in which energy users contract to reduce consumption at times of peak demand. In 2011 the AEMC was undertaking the third stage of a review into whether the NEM's design allows for effective demand side participation.

In the review's first two stages, the AEMC found the NEM framework does not materially bias against demand side participation. However, it considered some technological barriers, particularly in relation to the flow of information over energy networks, may limit the extent of demand side participation.

Stage three of the review focuses on identifying options for consumers to reduce or manage their energy use, along with the market conditions (including technology, information systems and pricing structures) needed to facilitate uptake of those options. The review will then consider whether those market conditions can be achieved under the current market and regulatory arrangements. The AEMC published an issues paper on stage three in July 2011.[14]

11 Solar Dawn, 'Dawn for proposed Solar Flagships project', Media release, 18 June 2011.
12 Moree Solar Farm, 'Australia's first utility scale solar power station to be built in Moree', Media release, 18 June 2011.
13 CS Energy, 'World's largest solar integration with a coal fired power station gets go ahead', Media release, 13 April 2011.
14 AEMC, 'Information sheet: AEMC review—power of consumer choice', 15 July 2011.

In its 2011 *Electricity statement of opportunities* report, AEMO identified 142 MW of capacity that was 'very likely' to be available across the NEM through demand side participation over the 2011–12 summer. 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).[15]

1.8 Reliability of supply

Reliability refers to the continuity of electricity supply to customers. The AEMC Reliability Panel sets the reliability standard for the NEM. 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 capacity that must be available for each region (including 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 capacity and import capacity from interconnectors. It does not account for supply interruptions in transmission and distribution networks, which are subject to different standards and regulatory arrangements (chapter 2). The standard is equivalent to an annual system-wide outage of 7 minutes at times of peak demand.

1.8.1 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 is $12 500 per MWh.
> 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 must impose an administered price cap. The threshold is $187 500 per MWh, and the administered cap is $300 per MWh.
> a market floor price, set at –$1000 per MWh.

In June 2011 the AEMC finalised a Rule change that provides for the market price cap and cumulative price threshold to be adjusted each year, from 1 July 2012, in line with movements in the consumer price index. The Rule change also provided for a comprehensive review of the reliability standard and settings to occur 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.
> AEMO can use its directions power to require generators to provide additional supply at the time of dispatch to ensure sufficient reserves are available.

The reliability panel finalised a review of the RERT mechanism in April 2011, finding the mechanism was of limited effectiveness and not required to ensure reliability of supply. It recommended the mechanism be closed on 30 June 2013. It also recommended the AEMC review other mechanisms for delivering

15 AEMO, *2011 electricity statement of opportunities for the National Electricity Market*, 2011, pp. 3–50.

capacity and how the NEM's risk allocation framework may affect the reliability of supply. In September 2011 the AEMC commenced a Rule change consultation to implement these recommendations.

1.8.2 Reliability performance

The reliability panel annually reports on the generation sector's performance against the reliability standard and minimum reserve levels set by AEMO. Reserve levels are rarely breached, and generator capacity across all regions of the market is generally sufficient to meet peak demand and allow for an acceptable reserve margin.

Insufficient generation capacity to meet consumer demand occurred only three times from the NEM start to 30 June 2011. 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.[16]

AEMO was not required to issue any directions in 2010–11 to manage local power system issues (compared with seven directions in 2009–10 and 18 in 2008–09).

1.8.3 Security issues

The power system is operated to cope with only credible contingencies. Some 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.

Operating the power system to cope with non-credible events (which are classified as security issues) would be economically inefficient. Likewise, additional investment in generation or networks may not avoid such interruptions. For this reason, reliability calculations exclude security issues.

1.8.4 Historical adequacy of generation

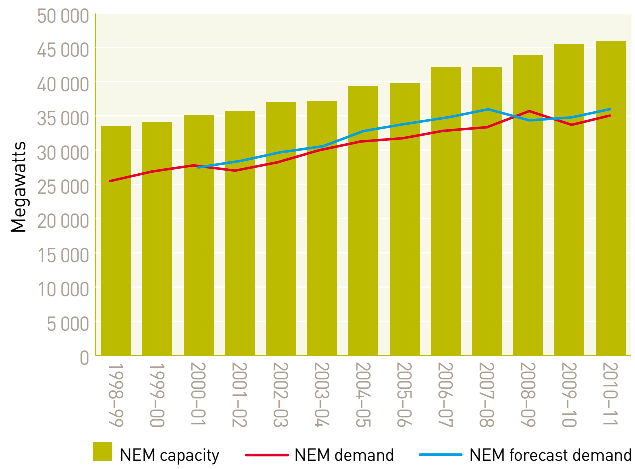
A reliable power supply in the longer term needs sufficient investment in generation to meet customers' needs. A central element of the NEM's design is that spot prices respond to a tightening in the supply–demand balance. Regions with potential generation shortages, therefore, exhibit rising prices in spot and contract markets, which may help attract investment to those regions.

Seasonal factors (for example, summer peaks in air conditioning loads) create a need for peaking generation to cope with periods of extreme demand. The NEM price cap of $12 500 per MWh is necessarily high to encourage investment in peaking plant, which is expensive to run and operates sporadically. Over the longer term, peaking plant plays a critical role in ensuring adequate generation capacity (and thus reliability). Investment in peaking capacity has been significant in most NEM regions over the past few years.

Figure 1.16 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), and provided a safety margin of capacity to maintain the reliability of the power system.

16 AEMC Reliability Panel, *Reliability standard and reliability settings review, final report,* 2010, p. 11.

Figure 1.16
National Electricity Market 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.

1.8.5 Reliability outlook

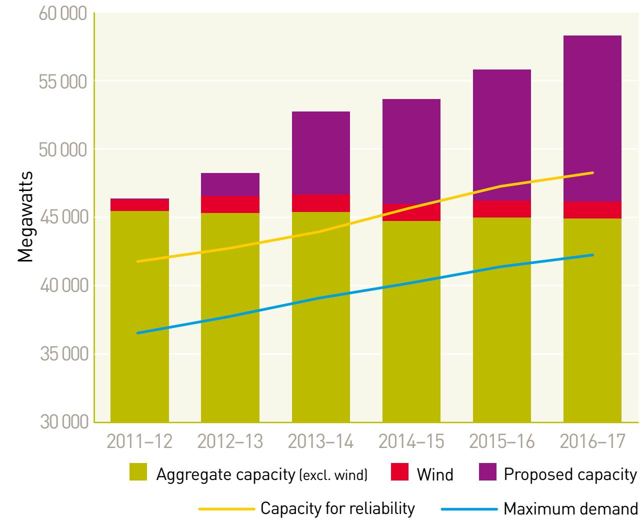
The relationship between future demand and generation capacity will determine electricity prices and the reliability of the power system. Figure 1.17 charts forecast peak demand in the NEM against installed, committed and proposed generation capacity. It indicates the amount of capacity that AEMO predicts will be needed to maintain reliability, given projected demand.

Figure 1.17 indicates installed and committed capacity (excluding wind) across the NEM as a whole will be sufficient until 2013–14 to meet peak demand projections and reliability requirements. Beyond that time, the ability of the market as a whole to meet reliability requirements may require some proposed generation projects to come online.

The required timing of new capacity in particular regions may vary. AEMO's 2011 *Power system adequacy* report found the power system, under expected demand and capacity scenarios, should have sufficient capacity to meet forecast peak demand plus minimum reserve levels for reliability in every NEM region over the two year period to June 2013. Accordingly, AEMO did not expect to invoke its reliability and emergency reserve trader tender process in any region. It identified concerns about the adequacy of frequency control during periods of high wind generation, and is working on this issue.

A sensitivity analysis found an unexpected NEM-wide withdrawal of 1000 MW of generation could lead to Queensland experiencing unserved energy in exceedance of the 0.002 per cent reliability standard in 2012–13; but that other regions would continue to meet the standard.

Figure 1.17
Electricity demand and supply outlook to 2016–17



Notes:

Capacity (excluding wind) is scheduled capacity and encompasses installed and committed capacity. Wind capacity includes scheduled and semi-scheduled wind generation. Proposed capacity includes wind projects.

Wind generation is treated differently from conventional generation for the supply–demand balance. At times of peak demand, the availability of wind capacity as a percentage of total generation supply is assumed to be 5 per cent in South Australia, 7.7 per cent in Victoria and 9.2 per cent in New South Wales.

The maximum demand forecasts for each NEM region are aggregated based on a 50 per cent probability of exceedance and a 92 per cent diversity factor. Unscheduled generation is treated as a reduction in demand.

Reserve levels required for reliability are based on an aggregation of minimum reserve levels for each region. Accordingly, the data cannot be taken to indicate the required timing of new generation capacity within individual NEM regions.

Data source: AEMO, *Electricity statement of opportunities for the National Electricity Market,* 2011.

According to the report, the Australian Government's Clean Energy Future Plan (including carbon pricing and financial assistance to emission intensive generators) is unlikely to impact on power supply reliability or security over the period to 30 June 2013. The reasons are the timing of the policy measures, and initiatives to offset potential reliability impacts.[17]

AEMO's longer term market review found that Queensland, assuming medium economic growth, would be the first region in the NEM to require new generation investment (by 2013–14) beyond that already committed.[18] While Queensland has had substantial new investment over the past decade, the region's economic growth is projected to rise, given an expansion of mining activity in central Queensland and flood related reconstruction. Coal seam gas developments, and growth in supporting infrastructure and services, are also expected to contribute to demand growth.

AEMO projected Victoria and South Australia would require new investment beyond committed capacity by 2014–15 (a year earlier than forecast in 2010). New South Wales would require new investment by 2018–19 (two years later than forecast in 2010). These adjustments largely reflect revised economic growth projections. The New South Wales forecast was also affected by the impact of energy efficiency policies.

AEMO expected Tasmania to have adequate capacity over the 10 year outlook period. The assessment did not account for potential reserve shortfalls due to energy limitations (when there is insufficient fuel to use available capacity). Tasmania's dependence on hydroelectric generation can periodically lead to energy limitations, as in the drought from 2007 to 2009. Basslink, as well as local gas fired and wind generation, safeguarded against supply shortfalls in that period.

AEMO noted climate change policies and the emergence of new technologies would be significant investment drivers over the next few years. In particular, the national RET scheme and carbon pricing would likely shift the generation mix towards less carbon intensive generation sources. AEMO considered wind generation was likely to be the main technology for new developments in the short term. It also noted the potential for new technology such as smart meters, smart grids and electric vehicles, combined with an increased focus on energy efficiency, to alter consumption patterns and mitigate the growth in capacity requirements.[19]

1.9 Compliance monitoring and enforcement

The AER monitors the wholesale electricity market to ensure compliance with the Law and Rules governing the NEM and, where appropriate, takes enforcement action for breaches. 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 (formerly the Ministerial Council on Energy), AEMC, and other bodies.

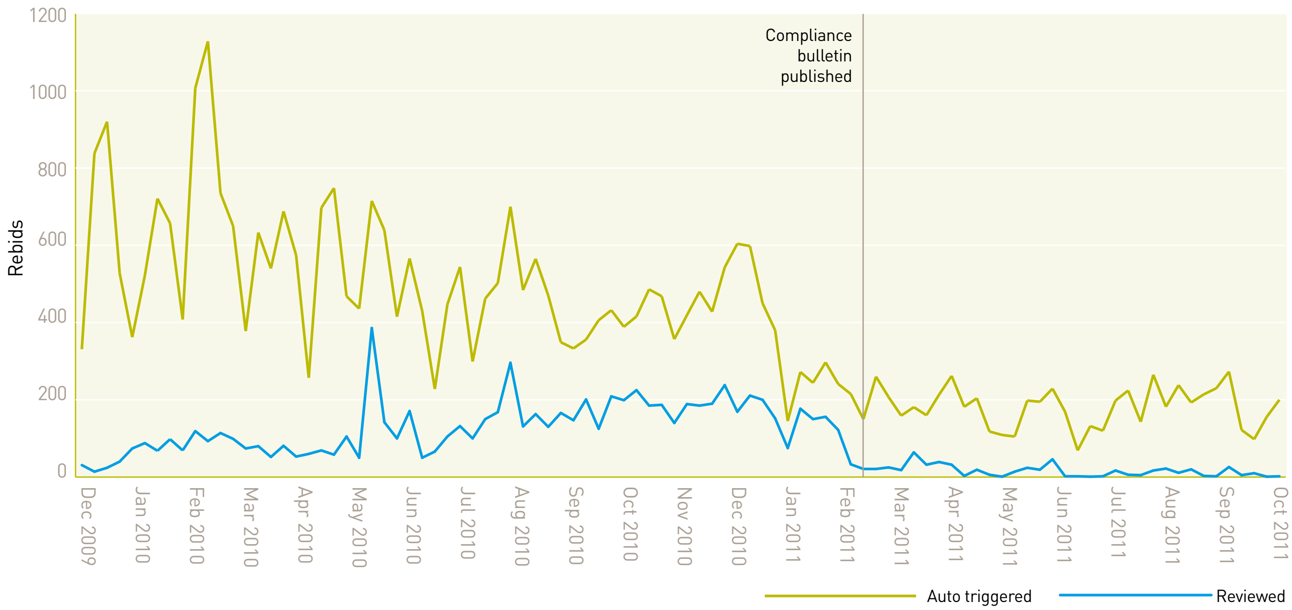
The AER's compliance and enforcement activity includes:

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

17 AEMO, *Power system adequacy*, 2011.
18 AEMO, *Electricity statement of opportunities for the National Electricity Market*, 2011.
19 AEMO, *Electricity statement of opportunities for the National Electricity Market*, 2011, pp. ix and 2–15.

Figure 1.18

Rebids auto-triggered and reviewed by the AER, weekly



Source: AER

The AER considers a number of factors when deciding whether to take enforcement action and which action to adopt. It aims for a proportionate enforcement response taking into account the impact of the breach, its circumstances, and the participant's compliance programs and compliance culture.

1.9.1 Rebidding

A key monitoring project in 2011 focused on generators' provision of accurate rebidding information. Scheduled generators in the NEM submit offers for each of the 48 trading intervals in a day. The initial offers, submitted before the trading day, can be varied through rebidding at any time up to dispatch.

The AER launched a new rebidding enforcement strategy in March 2011 to encourage the provision of more accurate and timely bidding information to the market. Under the strategy, the AER issues two warnings to generators that submit offer and/or rebid information that does not satisfy the Electricity Rules. A third occurrence within six months may lead to the issue of an infringement notice.

Since the strategy was launched, the number of rebids flagged by the AER's internal compliance system and requiring further review has fallen significantly (figure 1.18). Additionally, during the first six months of the strategy's operation, generators contacted the AER on 35 occasions to declare erroneous (or questionable) rebids. This appears to reflect a stronger focus on the quality of rebids and a clearer commitment to compliance within corporate trading teams.

Stanwell compliance with clause 3.8.22A

On another rebidding matter, the Federal Court on 30 August 2011 dismissed the AER's case against Stanwell Corporation (a Queensland generator) for alleged contraventions of the 'good faith' provision in the Rules. The AER alleged Stanwell did not make several of its offers to generate electricity on 22 and 23 February 2008 in good faith, contrary to clause 3.8.22A.

In February 2008 Stanwell controlled more than a quarter of Queensland's registered generation capacity. On 22 and 23 February the spot price for electricity in Queensland exceeded $5000 per MWh on 14 occasions.

Stanwell made 92 rebids over those trading days. More than 50 rebids were made within 15 minutes of dispatch, with around 40 rebids affecting the next 5 minute dispatch interval. The AER alleged Stanwell's reasons for eight rebids failed to identify a change in material conditions and circumstances. It sought orders that included declarations, civil penalties, a compliance program and costs. Justice Dowsett found the rebids did not contravene the Rules.

Generators must offer to supply energy into the market in good faith so AEMO can coordinate efficient dispatch to meet demand. The Rules allow generators to rebid their offers only in response to a change in the material conditions and circumstances on which the offer was based.

The litigation marked the first judicial test of the good faith provision, and the first occasion on which any provision of the Rules has been brought before the courts. Previous AER investigations into compliance with the good faith provision produced insufficient evidence to pursue the matters. Those investigations typically centred on rebids made shortly before dispatch for reasons of financial optimisation rather than technical necessity.

The policy objective of the good faith provision, when introduced in 2002, was to promote firm offers and rebids, and improve the quality of forecast information necessary for an efficient spot market. In particular, the firmness of market offers and rebids affects the quality of forecasts that market participants rely on when making decisions. Rebids submitted shortly before dispatch affect the credibility of these forecasts and limit opportunities for competitive supply and/or demand side response.

The Federal Court's decision calls into question the effectiveness of the good faith provision in achieving these objectives. Together with the AER's previous investigations when insufficient evidence was found, it suggests the provision's effectiveness may need review.