
Origin Energy's Cullerin Range wind farm, New South Wales (Origin Energy)

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 almost nine million residential and business customers. In 2009–10 the market generated around 206 terawatt hours (TWh) of electricity, with a turnover of $9.6 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 have risen from around 26 gigawatts (GW) in 1999 to 34 GW in 2010. Table 1.2 sets out the regional consumption profile.

1.2 Generation in the NEM

About 200 large electricity generators operate in the NEM jurisdictions (figure 1.2).[1] The electricity produced by these generators is sold through a central dispatch process that the Australian Energy Market Operator (AEMO) manages.

1 'Large' refers to generators with capacity greater than 30 megawatts.

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	49 010 MW
Registered generators	299
Customers	8.9 million
Turnover 2009–10	$9.6 billion
Total energy generated 2009–10	206 TWh
Maximum winter demand 2009–10	32 274 MW[1]
Maximum summer demand 2009–10	33 758 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*, 2010.

Figure 1.1a
National Electricity Market electricity consumption

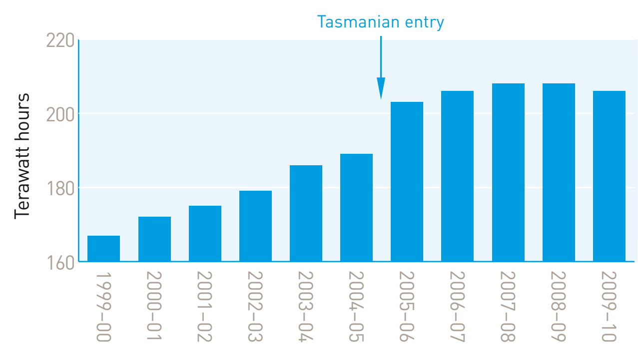
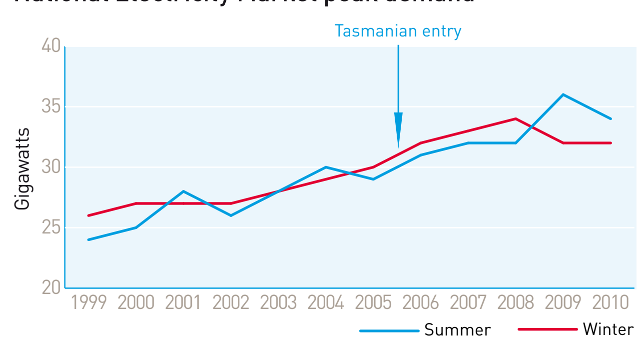


Figure 1.1b
National Electricity Market peak demand



Sources: AEMO; AER.

Figure 1.2
Large electricity generators in the National Electricity Market

Sources: AEMO; AER.

Table 1.2 Electricity consumption in the National Electricity Market (terawatt hours)

	QLD	NSW	VIC	SA	TAS[1]	SNOWY[2]	NATIONAL
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.

Sources: AEMO; AER.

1.2.1 Technology mix

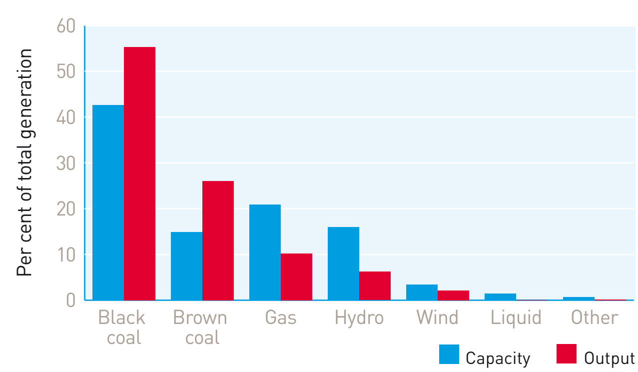
Across the NEM, black and brown coal account for around 58 per cent of registered[2] generation capacity, but this baseload plant supplies around 81 per cent of output (figure 1.3). Victoria, New South Wales and Queensland rely on coal more heavily than do other regions (figure 1.4).

Gas fired generation accounts for around 21 per cent of registered capacity across the NEM but supplies—as intermediate and peaking plant—only around 10 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 6 per cent of output. Its contribution to output fell over the past few years as a result of drought conditions in Tasmania and eastern Australia. Wind plays a relatively minor role in the market (around 3 per cent of capacity and 2 per cent of output), but its role is expanding under climate change policies. There has been significant wind generation investment in South Australia. Wind generation now represents around 20 per cent of statewide capacity.

The extent of new and proposed investment in intermittent generation (mainly wind) has raised concerns about system security and reliability. The integration of wind generation into the market has thus changed. 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 allows AEMO to limit the output of these generators if necessary to maintain the integrity of the power system.

Figure 1.3
Registered generation in National Electricity Market, by fuel source, 2010

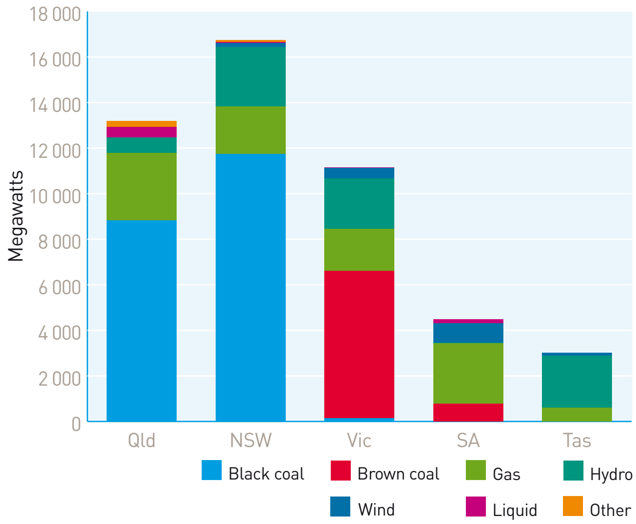


Note: Output is for 2009–10.

Sources: AEMO; AER.

2 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, 2010



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

Sources: AEMO; AER.

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.[3]

The Australian Government's primary emissions reduction policy is a national renewable energy target (RET) scheme, which was expanded in 2010. 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 electricity 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.

From January 2011 the scheme will apply different arrangements for small scale and large scale renewable supply. A target of 41 000 gigawatt hours (GWh) of energy from large scale renewable energy projects has been set for 2020. Small scale renewable projects will no longer contribute to the national target, but still produce renewable energy certificates that retailers must acquire.

The Australian Government in 2009 introduced a Bill to implement an emissions trading scheme—the Carbon Pollution Reduction Scheme (CPRS). The Bill proposed a cap and trade mechanism to meet a carbon reduction target that would increase over time. In April 2010 the Prime Minister announced a delay in implementing the CPRS until at least 2013. The new government elected in late 2010 formed a Climate Change Committee comprising experts and parliamentary members to examine options for introducing a carbon price, including an emissions trading scheme and a carbon tax.

Government proposals and implementation of climate change policies are changing the economic drivers for new investment and shifting the mix from a reliance on coal fired generation towards less carbon intensive sources such as renewable and gas fired generation. Kogan Creek power station in Queensland is the only major new investment in coal fired generation in the past five years. The bulk of new investment has been in gas fired and wind generation.

A number of non-traditional technologies are also emerging as potential suppliers of electricity, including photovoltaic and geothermal generation. South Australia has two publicly announced geothermal projects, including a 525 MW project scheduled to provide local load in 2015 and connect to the grid in 2018.[4]

3 Garnaut Climate Change Review, *Final report*, 2008.
4 AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010, pp. 9–11.

1.2.3 Generation ownership

Across the NEM, around two thirds of generation capacity is government owned or controlled:

- Most generation capacity in *Victoria* and *South Australia* is privately owned. The major 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.[5]
- State owned corporations own around 90 per cent of generation capacity in *New South Wales*, but the government in March 2009 announced plans to contract the right to sell electricity produced by state owned generators to the private sector. The government expected to complete the privatisation process by the end of 2010 (box 1.1).
- State owned corporations control around 67 per cent of *Queensland's* generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone and Collinsville power stations). Considerable private investment has occurred over the past decade, including investment by Origin Energy, InterGen, AGL Energy, Alinta Energy and Arrow Energy. Origin Energy became a significant player in 2010 with the commissioning of its 605 MW Darling Downs plant. Also, public and private entities have formed joint ventures (such as the Tarong North and Callide C power stations).
- 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.

Box 1.1 Privatisation of New South Wales electricity assets

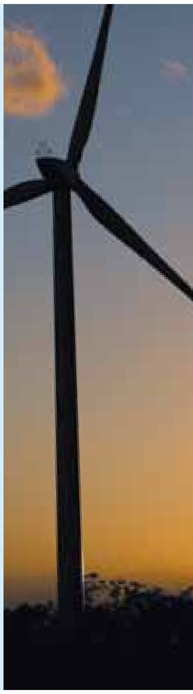
The New South Wales Government has committed to selling its energy assets that operate in contestable segments of the market. The privatisation process will include the sale of:

- the retail arms of the three state owned energy corporations—EnergyAustralia, Integral Energy and Country Energy
- the electricity trading rights of the nine state owned power stations
- seven power station development sites.

The 'gentrader' rights will be sold in four bundles. The generation portfolios of Macquarie (4640 MW) and Eraring (3120 MW) will be offered in their current configurations, while Delta's assets will be split into two bundles—Delta West (2400 MW), which includes the Mount Piper and Wallerawang power stations, and Delta Coast (2588 MW), which includes the Vales Point, Munmorah and Colongra power stations. While the nine development sites are suitable for the construction of new gas fired generation, only two have full planning approval.

The government has reserved the option of bundling a number of assets (including gentrader contracts for Eraring Energy, the retail business of Integral Energy and the Bamarang development site) and divesting them through an initial public offering if the sale process does not result in a new entrant.

The government expected to complete the sale process towards the end of 2010.



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

Table 1.3 Generation ownership in the National Electricity Market, July 2010

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND			
CS Energy	Callide; Kogan Creek; Swanbank	2254	CS Energy (Qld Government)
Tarong Energy	Tarong; Tarong North; Wivenhoe	2343	Tarong Energy (Qld Government)
Stanwell Corporation	Gladstone	1680	Rio Tinto 42.1%; Transfield Services 37.5%; others 20.4% All contracted to Stanwell Corporation (Qld Government)
Stanwell Corporation	Stanwell; Barron Gorge; Kareeya; Mackay Gas Turbine; others	1571	Stanwell Corporation (Qld Government)
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	852	InterGen 50%; China Huaneng Group 50%
ERM Power and Arrow Energy	Braemar 2	462	ERM Power 25%; Arrow Energy 75%
Braemar Power Projects	Braemar 1	450	Alinta Energy
Origin Energy	Mount Stuart; Roma	441	Origin Energy
AGL Hydro	Oakey	275	Alinta Energy 25%; ERM Group 25%; Contact Energy 50% All contracted to AGL Energy
AGL Hydro	Yabulu	232	Transfield Services Infrastructure Fund All contracted to AGL Energy and Arrow Energy
CS Energy	Collinsville	187	Transfield Services Infrastructure Fund All contracted to CS Energy (Qld Government)
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
AGL Energy	German Creek; KRC Cogeneration	32	AGL Energy
Origin Energy	Darling Downs	605	Origin Energy
QGC Sales Qld	Condamine	135	QGC Sales Qld
RTA Yarwun	Yarwun	152	Rio Tinto
Other registered capacity		273	
NEW SOUTH WALES			
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4844	Macquarie Generation (NSW Government)
Delta Electricity	Mount Piper; Vales Point B; Wallerawang; Munmorah; Colongra; others	4547	Delta Electricity (NSW Government)
Eraring Energy	Eraring; Shoalhaven; Brown Mt; Burrinjuck; others	2972	Eraring Energy (NSW Government)
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2336	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Origin Energy	Uranquinty; Cullerin Range	678	Origin Energy
TRUenergy	Tallawarra	417	TRUenergy (CLP Group)
Marubeni Australia Power Services	Smithfield Energy Facility	160	Marubeni Corporation
Redbank Project	Redbank	145	Alinta Energy
Infigen	Capital	140	Infigen Energy
Country Energy	Broken Hill Gas Turbine	50	Country Energy (NSW Government)
Other registered capacity		109	

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

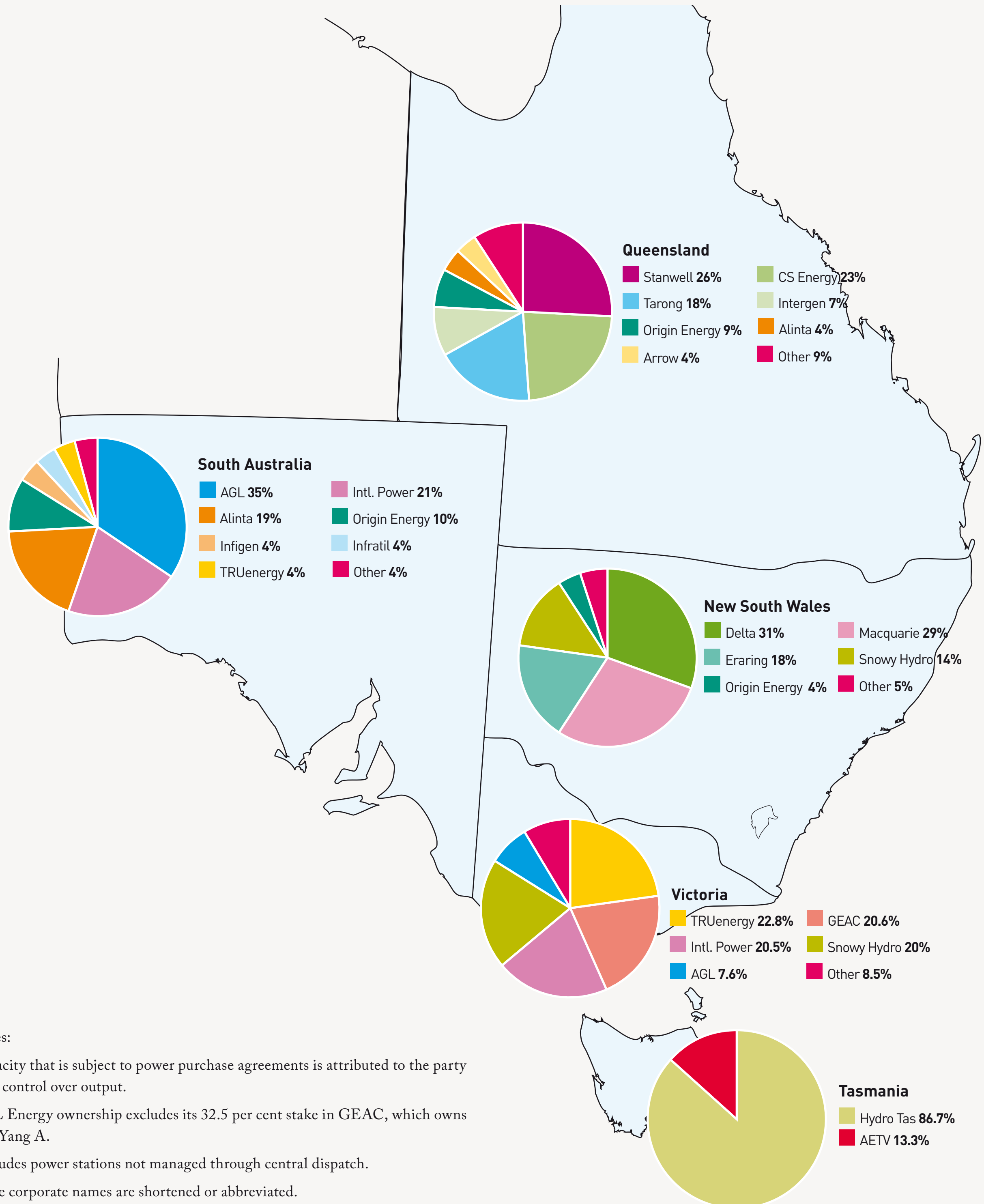
Note: Capacity is as published by AEMO for summer 2010–11.

Source: AEMO.

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
VICTORIA			
LYMMCo	Loy Yang A	2080	GEAC (AGL Energy 32.5%; TEPCO 32.5%; Transfield Services 14%; others 21%)
Snowy Hydro	Laverton North; Valley Power; Murray	1933	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Hazelwood Power	Hazelwood	1580	International Power (91.8%); Commonwealth Bank (8.2%)
TRUenergy Yallourn	Yallourn; Longford Plant	1451	TRUenergy (CLP Group)
International Power	Loy Yang B	975	International Power (70%); Mitsui (30%)
Ecogen Energy	Jeeralang A and B; Newport	891	Industry Funds Management (Nominees) All contracted to TRUenergy (CLP Group)
AGL Hydro	Somerton; Eildon; Kiewa; Dartmouth; McKay; others	550	AGL Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland	247	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Energy Brix Australia	Energy Brix Complex; Hrl Tramway Road	160	HRL Group / Energy Brix Australia
Alcoa	Angelsea	152	Alcoa
Aurora Energy Tamar Valley	Bairnsdale	70	Alinta Energy
Eraring Energy	Hume	58	Eraring Energy (NSW Government)
Other registered capacity		82	
SOUTH AUSTRALIA			
AGL Hydro	Hallett 1 and 2; Wattle Point	257	AGL Energy
AGL Energy	Torrens Island	1256	AGL Energy
Cathedral Rocks Wind Farm	Cathedral Rocks	66	Roaring 40s (Hydro Tasmania (Tas Government) 50%; CLP Group 50%) 50%; Acciona Energy 50%
Infigen	Lake Bonney 1	81	Infigen Energy All contracted to Country Energy (NSW Government)
Infigen	Lake Bonney 2	159	Infigen Energy
Alinta Energy	Northern; Playford	782	Alinta Energy
Origin Energy	Osborne	175	ATCO 50%; Origin Energy 50%
Infratil Energy Australia	Angaston	49	Infratil. All contracted to AGL Energy
International Power	Pelican Point; Canunda	494	International Power
Transfield Services Infrastructure Fund	Mount Millar	70	Transfield Services Infrastructure Fund
Origin Energy	Quarantine; Ladbroke Grove	267	Origin Energy
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Snowtown	99	Infratil
Transfield Services Infrastructure Fund	Starfish Hill	35	Transfield Services Infrastructure Fund All contracted to Hydro Tasmania (Tas Government)
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	275	International Power
TRUenergy	Hallet	150	TRUenergy (CLP Group)
Other registered capacity		25	
TASMANIA			
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	374	AETV (Tas Government)
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; others	2347	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth	140	Roaring 40s (Hydro Tasmania (Tas Government) 50%; CLP Group 50%)
Other registered capacity		100	

Figure 1.5

Market shares in electricity generation capacity, by region, 2010



Notes:

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

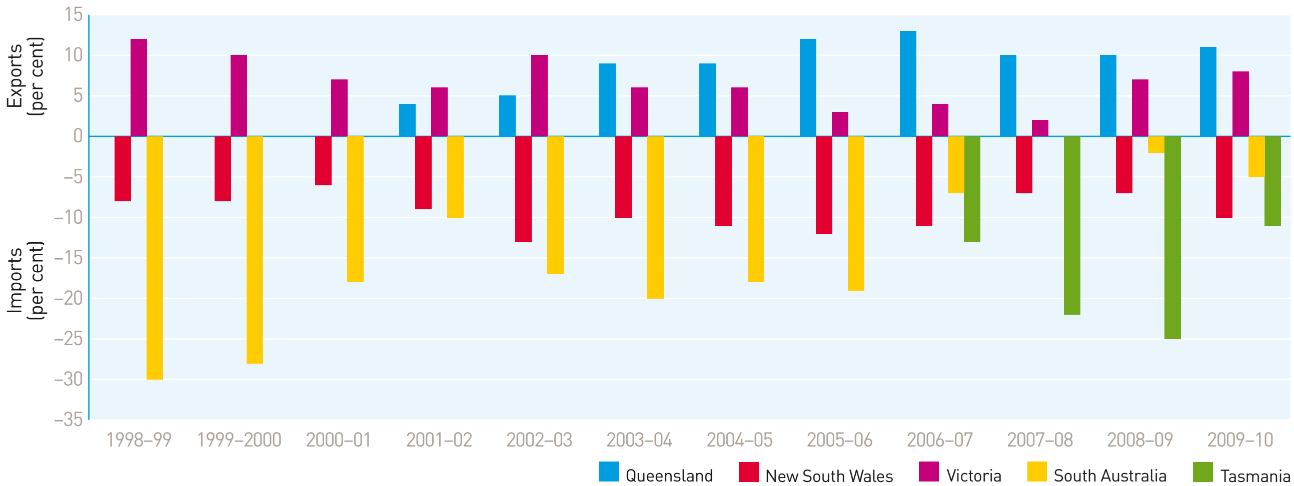
AGL Energy ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A.

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.

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.[6]

The NEM is a gross pool, meaning all sales of electricity must occur through the spot market. In contrast, Western Australia's electricity market uses a net pool arrangement. Unlike some overseas 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,[7] those not connected to a transmission network (for example, embedded generators) and those producing exclusively for their own use (such as in remote mining operations).

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.
- Tasmania has been a net importer since its interconnection with the NEM in 2006, partly because drought has constrained its ability to generate hydroelectricity.

6 The *State of the energy market 2009* report explained the dispatch process in detail (section 2.2).

7 From 31 March 2009 new wind and other intermittent generators must register under the new classification of 'semi-scheduled generator'. These generators must participate in the central dispatch process, which includes submitting offers and limiting their output as requested by AEMO.

1.4 Spot electricity prices

Generators provide AEMO with generation price and quantity offers (bids) for each five 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 five 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 five minute dispatch prices. This is the price that all generators receive for their supply during the half hour, and the price that market 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 was increased from $10 000 per MWh on 1 July 2010.

While the market determines a separate price for each region, the mainland regions typically operate as an 'integrated' market with price alignment for 60–80 per cent of the time. Price alignment occurred for about 67 per cent of the time in 2009–10, compared with 70 per cent in 2009–10. These estimates allow for minor price disparities caused by transmission losses that occur when transporting electricity over long distances. More significant 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 wholesale and forward market 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.

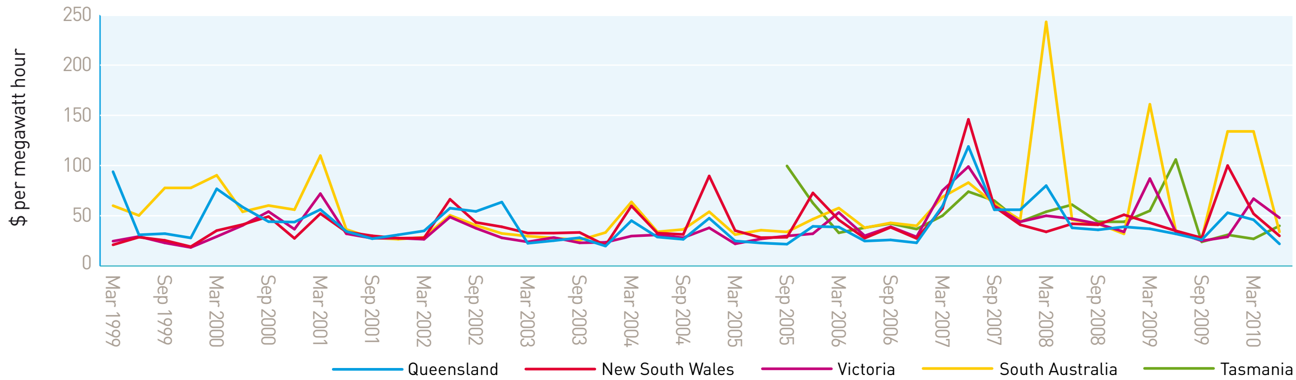
Table 1.4 Volume weighted average spot electricity prices ($ per megawatt hour)

	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
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.

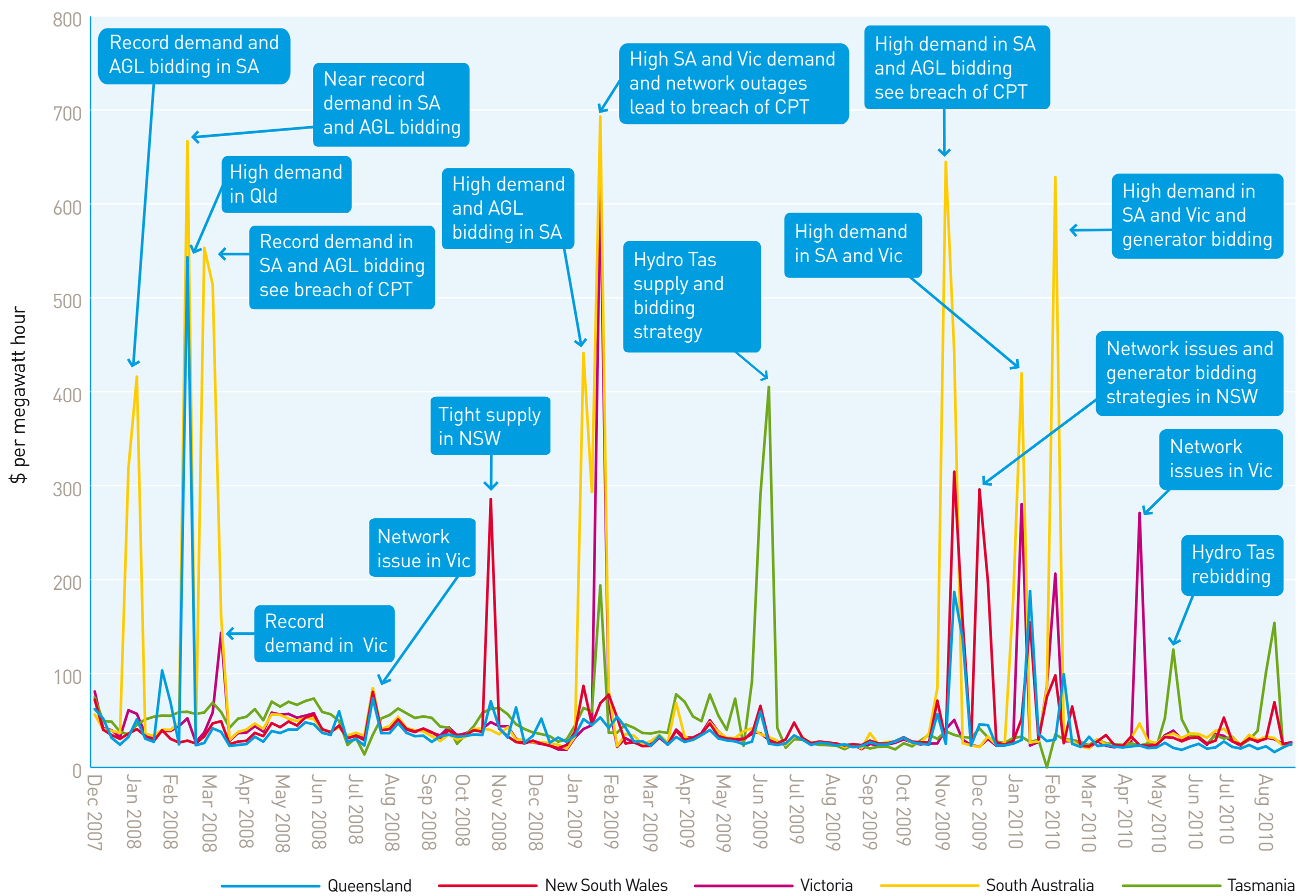
Figure 1.7
Quarterly spot electricity prices



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.

1.4.1 Spot prices in 2009–10

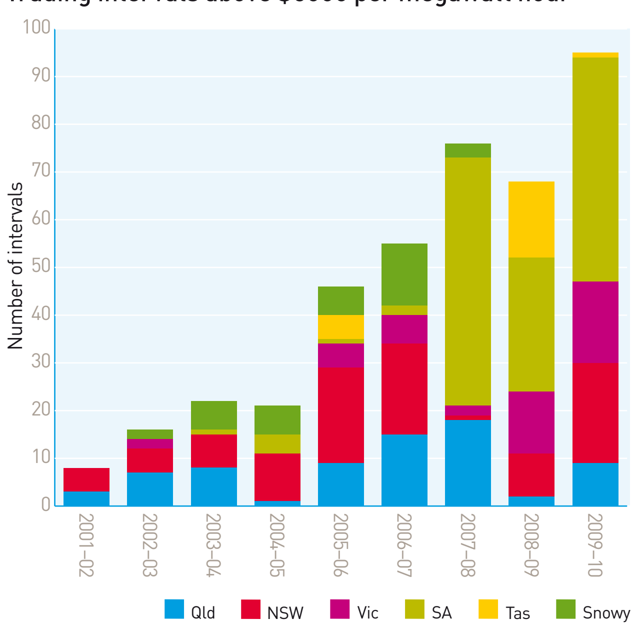
Average spot prices in 2009–10 rose significantly from the previous year in South Australia and New South Wales, and marginally in Queensland. Spot prices fell in Tasmania and Victoria.

Average spot prices in South Australia ($82 per MWh) and New South Wales ($52 per MWh) were higher than in other regions. Tasmania ($30 per MWh) and Queensland ($37 per MWh) recorded the lowest average spot prices in 2009–10, closely followed by Victoria ($42 per MWh). Tasmania recorded its lowest average spot price since joining the NEM.

While conditions were generally benign across much of the market in 2009–10, the spot price exceeded $5000 per MWh in 95 trading intervals—a record number of extreme price events in the NEM (figure 1.9). Price spikes can have a material impact on market outcomes. If prices approach the market cap of $12 500 per MWh for just three hours in a year, then the average annual spot price may rise by almost 10 per cent.

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 extreme price events in 2009–10, noting the regions in which they occurred and underlying causes. The bulk of extreme price events occurred in South Australia and New South Wales, and were associated typically with opportunistic generator bidding. There were also instances of extreme pricing in ancillary services markets in South Australia and Tasmania.

A period of sustained extreme prices may trigger administered pricing at a cap of $300 per MWh.[8] One instance of administered pricing occurred in 2009–10, when several days of extreme prices in South Australia triggered activation of the cap in November 2009.

Market focus—South Australia

Spot prices in South Australia rose by 20 per cent to $82 per MWh in 2009–10, which was the second highest price for any region since the NEM commenced. This outcome reflects that around 50 per cent of NEM prices above $5000 per MWh in 2009–10 occurred in South Australia (table 1.5). Most of these events were associated with opportunistic bidding by AGL Energy, the region's largest electricity generator.

AGL Energy owns the Torrens Island power station, which accounts for around 40 per cent of South Australia's generation capacity. Transmission limits on importing electricity from Victoria mean AGL Energy can, on days of high electricity demand, bid a significant proportion of its capacity at prices around the market cap and drive up the spot price. It adopted this type of bidding strategy during many of South Australia's 47 extreme price events in 2009–10 (table 1.5). The events typically occurred on days of extreme weather, which led to high electricity demand and a tight regional supply–demand balance. There was also evidence AGL Energy engaged in opportunistic bidding in the market for frequency control ancillary services on two days in April 2010, such that the cost of those services to South Australian consumers averaged around $4 million per day, compared with the typical daily rate of less than $3000.

8 AEMO must apply the administered price cap if the sum of half hourly spot prices over a rolling seven days exceeds a cumulative threshold (currently $187 500 per MWh).

Table 1.5 Price events above $5000 per megawatt hour, 2009–10

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
2 November 2009	SA	1	$10 000	Above-forecast demand and import restrictions from Victoria led to a tight market. In addition, around 1000 MW of low priced SA capacity was unavailable, including 730 MW of AGL capacity. These conditions meant high priced capacity offered by AGL for its Torrens Island plant was dispatched and set the spot price.
3 November 2009	NSW and Qld	1 (NSW) 1 (Qld)	$6337 (NSW) $5706 (Qld)	Unseasonally high NSW temperatures combined with planned and unplanned generator outages and reduced import capability from Victoria to create a tight NSW market. This required the dispatch of high priced capacity, which set the NSW spot price. In Queensland, Stanwell responded to high export demand into NSW by rebidding 200 MW of capacity into higher price bands. The high interstate demand led to the dispatch of this high priced generation, which set the Queensland price.
10–13 November 2009	SA	14	$10 000	Extreme November temperatures led to demand exceeding 2800 MW each day. When combined with below-forecast import capability from Victoria, this led to a tight market. AGL anticipated market conditions by bidding 70 per cent of its capacity at Torrens Island power station at over $5000 per MWh. The tight market required the dispatch of this AGL capacity, which set the price at above $9999 per MWh for 80 of 84 dispatch intervals over this four day period. The extreme prices led to administered pricing (with a $300 per MWh cap) being imposed for several days.
19 November 2009	SA	8	$10 000	Record November temperatures led to unseasonally high demand, and imports from Victoria were lower than forecast. AGL anticipated market conditions by offering around 66 per cent of its available Torrens Island capacity (about 30 per cent of South Australia's total available capacity) at above $5000 per MWh. In the tight market, it was necessary to dispatch this capacity, which set the spot price at above $9997 per MWh for 43 of 48 dispatch intervals.
20 November 2009	NSW and Qld	7 (NSW) 3 (Qld)	$9284 (NSW) $8388 (Qld)	Extreme NSW temperatures led to above-forecast demand on a day when around 3000 MW of NSW generation was not offered to the market. In addition, planned network outages in NSW reduced import capability from Victoria. AEMO did not forecast the impact of the outages and allowed them to proceed. As market conditions became apparent during the day, AEMO directed a NSW generator be made available for dispatch and instructed TransGrid to return network equipment to service to increase reserves. The interconnectors between NSW and Queensland were unconstrained during much of this period, which enabled generators to rebid capacity into higher price bands in both regions. This contributed to prices exceeding $5000 per MWh for prolonged periods. There was some demand-side response in NSW to the high prices.
27 November 2009	NSW and Qld	2 (NSW) 1 (Qld)	$8933 (NSW) $8933 (Qld)	Above-forecast demand in NSW and Queensland coincided with a planned network outage in NSW that significantly reduced import capability from Victoria. Generators responded to the tight market by rebidding capacity into higher price bands. These factors combined to raise prices above $1000 per MWh for several trading intervals, including three intervals above $5000 per MWh.
7 December 2009	NSW	6	$9176	Extreme temperatures led to very high demand. Low cost electricity imports from Queensland and Victoria were constrained to manage congestion on the NSW transmission network. These factors, combined with plant outages, led to a very tight NSW market. A number of generators, including Delta Electricity, shifted capacity offers to higher price bands to take advantage of the tight market. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for 5.5 hours.

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
17 December 2009	NSW	3	$8703	Extreme temperatures led to very high demand. Low cost electricity imports from Queensland and Victoria were constrained to manage congestion on the NSW transmission network. These factors, combined with plant outages, led to a very tight NSW market. A number of generators, including Delta Electricity, shifted capacity offers to higher prices to take advantage of market conditions. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for eight hours.
8 January 2010	SA	3	$10 000	Extreme temperatures led to very high demand. Constraints used to manage congestion in the SA transmission network restricted imports from Victoria and constrained off 340 MW of low priced SA generation. AGL anticipated market conditions by bidding two thirds of its available capacity at Torrens Island power station at close to the price cap. The tight market required the dispatch of this AGL capacity, which set the spot price.
11 January 2010	SA and Vic	8 (SA) 6 (Vic)	$9116 (SA) $9201 (Vic)	Extreme temperatures in both regions led to high demand. Import capability into both regions was about 400 MW lower than forecast. In Victoria, day ahead bidding by LYMMCO combined with rebidding on the day by International Power to set high prices. In South Australia, AGL anticipated market conditions by bidding two thirds of its available capacity at Torrens Island power station at over $5000 per MWh. The tight market required the dispatch of this AGL capacity, which set the spot price at above $9100 per MWh for 43 of 54 dispatch intervals.
18 January 2010	Qld	4	$9208	High temperatures led to record Queensland demand. A constraint to manage transmission congestion restricted imports from NSW. Queensland generators anticipated market conditions in their day-ahead bids by offering around 2000 MW of capacity at above $5000 per MWh. They also rebid around 750 MW of capacity on the day from low prices to above $5000 per MWh. In the tight market, these bids set the dispatch prices in four intervals.
4 February 2010	NSW	1	$5541	Planned maintenance on the NSW distribution network led to a potential overload on cables into the Sydney CBD. In response, TransGrid took a 330 kilovolt transmission line out of service. To manage congestion on the NSW transmission network, AEMO constrained low cost electricity imports from Victoria and Queensland. These factors, combined with plant outages, led to a very tight NSW market. A number of generators, including Delta Electricity, rebid their dispatch offers to take advantage of market conditions. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for two hours.
8–10 February 2010	SA and Vic	13 (SA) 4 (Vic)	$10 000 (SA) $7847 (Vic)	High temperatures in South Australia and Victoria led to high demand on all three days. There were also supply issues, including reduced import capability into both regions. On 8 February high temperatures caused a reduction in available generation capacity in Victoria. On 9 February a network reclassification issue forced electricity flows out of South Australia into Victoria, triggering a reserve alert (insufficient reserves to cater for the loss of the largest generator or interconnector) in South Australia. Generators in both regions anticipated market conditions through their day-ahead bids and rebids into high price bands, resulting in a series of extreme prices. On 8–9 February South Australian generators made day-ahead offers to supply over 25 per cent of total SA capacity at above $8900 per MWh. The majority was offered by AGL. Less capacity was offered in this way on 10 February, but AGL rebid 240 MW of capacity from below $50 per MWh to over $9000 per MWh on the day. The threshold for administered pricing was almost reached in South Australia on 10 February.

DATE OR PERIOD	REGIONS	NO. OF PRICES >$5000 PER MWH	MAX PRICE (PER MWH)	CAUSES IDENTIFIED BY THE AER
22 February 2010	NSW	1	$8346	Hot weather drove high electricity demand. In addition, an unplanned outage of a Delta Electricity generator altered flows on the NSW transmission network. This led to restrictions on low priced generators and imports to manage network congestion. These factors led to a tight market. A number of generators, including Delta Electricity, rebid their dispatch offers to take advantage of market conditions. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for 30 minutes.
22 April 2010	Vic	7	$9999	Networks issues restricted Victoria's ability to import electricity. Planned network outages restricted imports from NSW and South Australia, and an unplanned outage of Basslink prevented imports from Tasmania. International Power anticipated a tight Victorian market by pricing significant capacity at close to the price cap in day-ahead bids. A number of subsequent rebids by other generators left Victoria with no capacity priced between $500 and $9000 per MWh. Network issues led to Victoria exporting electricity to the lower priced NSW and South Australian regions. Demand-side response in Victoria cushioned the price impact for about 40 minutes.
22 May 2010	Tas	1	$6750	Cold temperatures led to the highest demand on a Saturday for two years, although demand was close to forecast levels. Day-ahead offers saw 90 per cent of Tasmanian capacity (around 2000 MW) priced below $500 per MWh between 5.30 and 8.30 pm. Hydro Tasmania subsequently rebid almost half of Tasmania's capacity to above $9400 per MWh for this period, which set the dispatch price for about half an hour. The price movements coincided with Hydro Tasmania making significant changes to the output of its non-scheduled generators, which effectively altered the demand that scheduled generators had to meet.
MARKET ANCILLARY SERVICES				
31 December 2009	Tas	90 minutes	$10 000 per MW	Lightning storms in Tasmania led to the reclassification of a number of transmission circuits, which restricted the ability of some generators to provide 'raise six second' frequency control ancillary services (FCAS). The services are used to manage frequency issues arising in the first six seconds of a credible shock to the power system. While AEMO directed Hydro Tasmania to provide additional services, the price remained at the $10 000 cap. Once the storms passed, one reclassification was revoked and the price fell to less than $1 per MW. As a result of this and similar events, the total cost of FCAS in Tasmania for the week to 2 January 2010 was about 20 per cent of total energy turnover in the state (compared with about 1 per cent on the mainland in the same period).
21–22 April 2010	SA	470 minutes over two days		A planned transmission outage in Victoria reduced the capability of the Heywood interconnector. High energy prices in Victoria on both days drove exports from South Australia to Victoria. In combination, these events led to a requirement for local FCAS in South Australia. AGL, the most significant South Australian provider, offered through day-ahead bids and rebidding the majority of its capacity for these services at the price cap. The cost of FCAS totalled more than $8 million, compared with a typical daily rate of less than $3000.

Source: AER.

Market focus—New South Wales

Spot prices in New South Wales rose by 23 per cent to $52 per MWh in 2009–10, which was the largest regional price increase in that year in the NEM. New South Wales recorded 21 price events above $5000 per MWh, which was the second highest number for any region.

At least 11 of these events featured an interplay of factors aggravated by opportunistic generator rebidding (table 1.5). In particular, AEMO was obliged on several summer days in 2009–10 to constrain low cost electricity imports from Queensland and Victoria to manage congestion in the New South Wales transmission network. The congestion resulted from a delayed network upgrade. The constraints typically affected the market on days of high demand and/or infrastructure outages, which led to a tight demand–supply balance. A number of generators, including Delta Electricity, rebid capacity to higher prices to take advantage of the tight market. Generators also rebid their plant ramp rates to prolong the impact, causing prices to stay above $300 per MWh for up to eight hours at a time.

These events contributed to New South Wales experiencing 14 days in 2009–10 when prices exceeded $300 per MWh for one or more trading intervals, including four days on which prices exceeded $5000 per MWh.

Market focus—Tasmania

In 2008–09 opportunistic bidding and output decisions by Hydro Tasmania led to a series of price spikes in the spot electricity market. Tasmania's spot prices were much lower in 2009–10, with only one instance of opportunistic bidding by Hydro Tasmania contributing to prices above $5000 per MWh (table 1.5).

The region also recorded a series of high prices for frequency control ancillary services over three weeks in April 2009. The local market for these services is dominated by Hydro Tasmania, which is always the marginal cost producer.[9] Concerns about high prices led the Office of the Tasmanian Economic Regulator to 'declare' a number of Hydro Tasmania services in December 2009, with a view to setting price caps. The regulator made the declaration to prevent the misuse of substantial market power and to promote competition in the markets for those services. It found Hydro Tasmania had been misusing its market power, extracting monopoly rents and bidding anti-competitively on frequency control ancillary services at high prices.[10]

Tasmania had one instance in 2009–10 of 'raise six second' frequency control ancillary services reaching $10 000 per MW for 90 minutes. These services are used to manage frequency issues arising in the first six seconds of a credible shock to the power system. The total cost of these services in Tasmania for the week to 2 January 2010 was about 20 per cent of total energy turnover in the state (compared with about 1 per cent on the mainland in the same period).

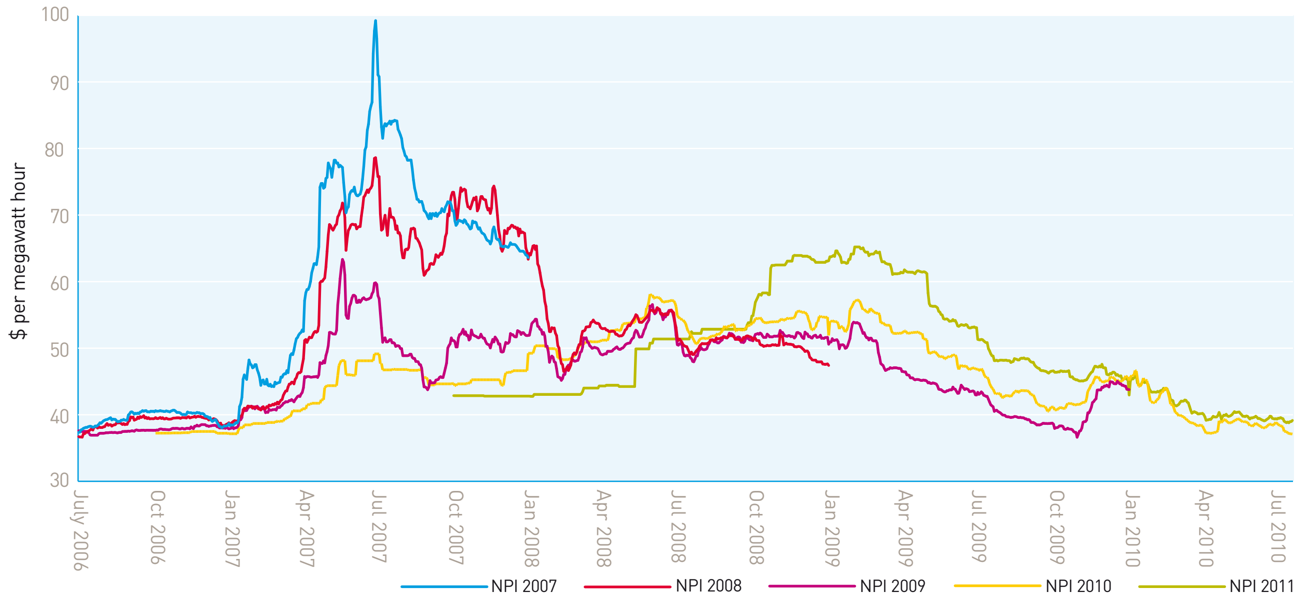
The event occurred when lightning storms in Tasmania led AEMO to identify a heightened risk of unplanned outages in the transmission network. AEMO invoked constraints that restricted some generators from supplying frequency control ancillary services, leading to a shortage during the storm. In 2010 AEMO revised its approach to managing this type of event, to enable more generators to provide the services in similar circumstances.

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 financial contracts (derivatives) that lock in firm prices for the electricity they intend to produce

9 Office of the Tasmanian Economic Regulator, *Declaration of frequency control ancillary services, Statement of reasons*, 2009, p. 4.
10 Office of the Tasmanian Economic Regulator, *Declaration of frequency control ancillary services, Statement of reasons*, 2009, pp. 3, 6.

Figure 1.10
National Power Index



Source: d-cyphaTrade.

or buy. The participants in electricity derivatives markets include generators, retailers, financial intermediaries and speculators such as hedge funds. Brokers facilitate many transactions between contracting participants.

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

- over-the-counter (OTC) markets, comprising direct transactions 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).[11] 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 in d-cyphaTrade products on the SFE is the fastest growing segment of the electricity derivatives market. The market covers futures instruments for the Victoria, New South Wales, Queensland and South Australia regions. Trading volumes in this market in 2009–10 were equivalent to about 204 per cent of underlying energy consumption. Victoria accounted for 36 per cent of traded volumes, followed by New South Wales (33 per cent) and Queensland (30 per cent). Liquidity in South Australia has remained low since 2002, accounting for only 1 per cent of volume.[12]

1.5.1 Electricity futures prices

Figure 1.10 shows average price outcomes for electricity base futures, as reflected in the National Power Index.[13] The index (which d-cyphaTrade publishes for each calendar year) represents a basket of electricity base futures for New South Wales, Victoria, Queensland

11 In 2006 the SFE merged with the Australian Stock Exchange. The merged business operates as the Australian Securities Exchange.

12 d-cyphaTrade, *Energy focus FY 2009–10 review*, 2010, p. 2.

13 Base futures account for most SFE trading volumes and open interest positions. Prices for peak futures tend to be higher than for base futures, but follow broadly similar trends. Base futures cover 0.00 to 24.00 hours, seven days per week. Peak futures cover 7.00 am to 10.00 pm, Monday to Friday, excluding public holidays.

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.

Base futures prices eased significantly from the first half of 2009 through to June 2010, falling to below $40 per MWh. Lower prices reflected relatively benign spot market conditions in Victoria and Queensland, and expectations that new generation plant coming on line in Queensland would ease the risks of price pressure.[14] Government announcements in 2009 and 2010 to delay the implementation of the CPRS also led to carbon being priced out of 2010 and 2011 futures.

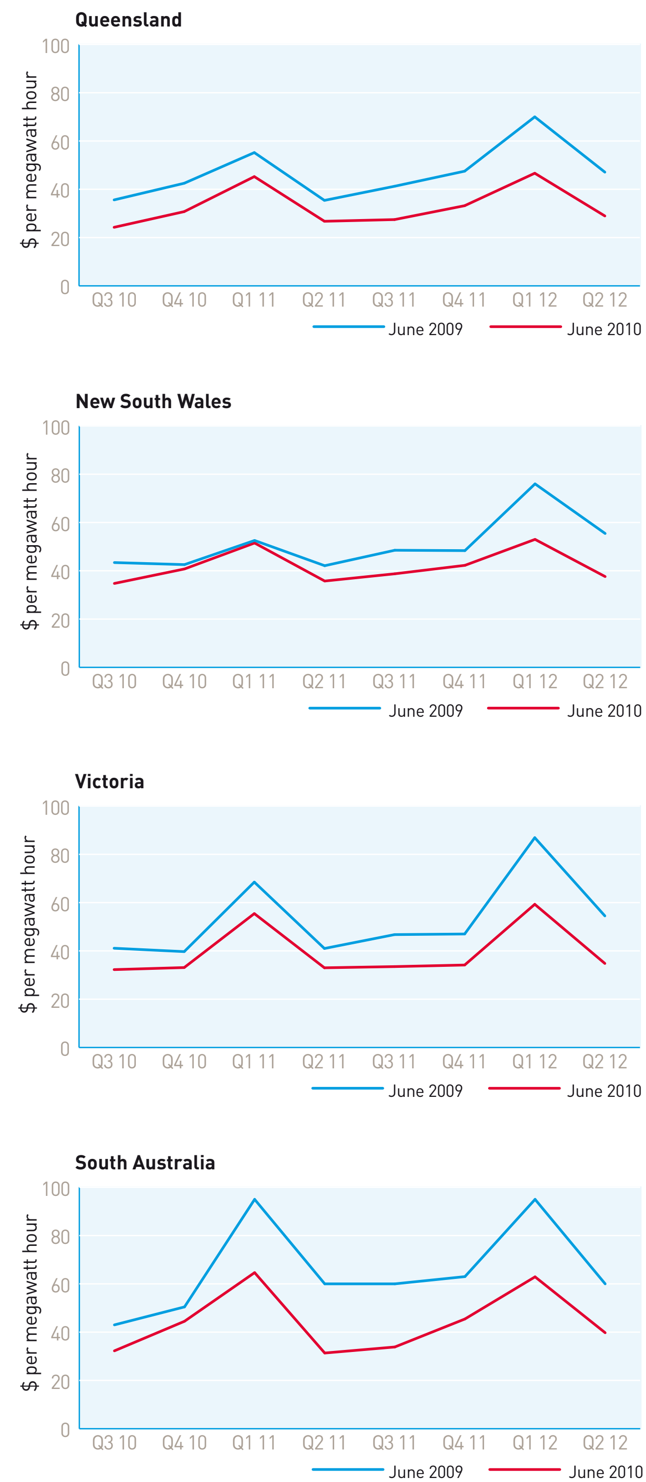
Forward curves

Figure 1.11 provides a snapshot at 30 June 2010 of forward prices for quarterly base futures on the SFE, up to two years from the trading date. These snapshots are often described as forward curves. For comparative purposes, forward prices at 30 June 2009 are also provided.

Forward prices in June 2010 were generally down on the levels of June 2009. This fall was consistent with an easing in spot prices for electricity, and may reflect the commissioning in 2009–10 of around 1600 MW of new generation capacity (mostly in Queensland) and a further 1200 MW of committed capacity beyond 2009–10 (tables 1.6 and 1.7).

Forward prices remained higher in South Australia than elsewhere, especially for the summer peak periods. This may reflect continuing market concerns that high prices in South Australia's physical electricity market over the past three summers—as a result of high temperatures, interconnector constraints and opportunistic bidding by AGL Energy—may recur. But while South Australian forward prices remained higher than elsewhere, they eased off their extreme 2009 levels.

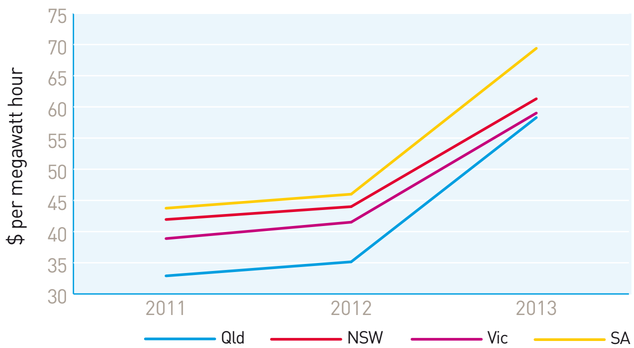
Figure 1.11
Base futures prices, June 2009 and June 2010



Sources: AER; d-cyphaTrade.

14 d-cyphaTrade, *Energy focus FY 2009–10 review*, 2010, p. 3.

Figure 1.12
Base calendar strip, June 2010



Sources: AER; d-cyphaTrade.

Victoria's 'peaky' demand profile can also lead to high summer prices. The market appears to be factoring in concerns that Victoria's supply–demand balance may become tight in summer 2012 unless committed new capacity (such as Origin Energy's 518 MW plant at Mortlake) is operational.

Forward prices for Queensland remain lower than elsewhere. The commissioning of new generation plant in 2010, including Origin Energy's 605 MW Darling Downs power station, has increased regional supply and is expected to mitigate price pressure in the short to medium term. The new plant also increases Queensland's export capacity to New South Wales, which may help ease price pressure in that region.

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 2010 for calendar year futures strips to 2013. While prices are generally consistent with those evident in the forward curves, they smooth out the impact of seasonal peaks.

In June 2010 all regions had forward curves in contango—that is, prices were higher for contracts in the later years. This trend may reflect uncertainty about climate change policies (especially for calendar year 2013), including the effects of policy uncertainty on investment. More generally, the market may be factoring 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 2010, new investment added around 12 100 MW of registered generation capacity.[15] Figures 1.13 and 1.14 illustrate investment since market start.

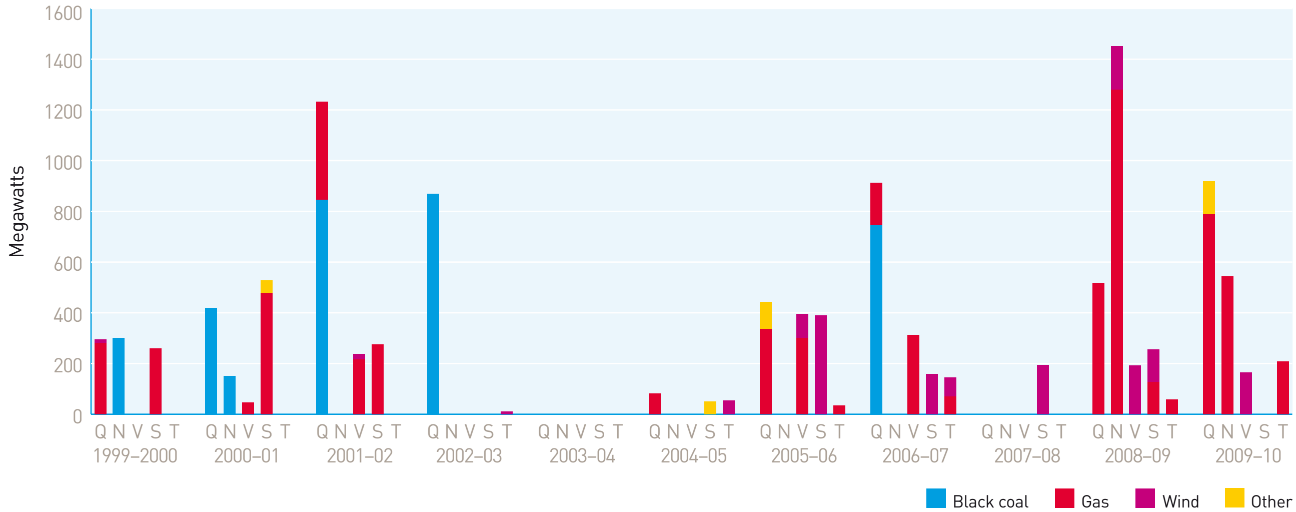
Tightening supply conditions led to an upswing in generation investment from around 2005. The bulk of new investment over the two years to 30 June 2010 was in Queensland (44 per cent of NEM-wide investment) and New South Wales (31 per cent). Developers have committed to further capacity, including major new plant in Victoria. Investment in wind generation has also been significant, especially in South Australia.

Table 1.6 sets out major new generation investment that came on line in the NEM in 2009–10. Around 1800 MW of new capacity was added, following 2500 MW of investment in 2008–09. New gas fired plant in Queensland accounted for over 50 per cent of new investment in 2009–10, including Origin Energy's 605 MW power station on the Darling Downs. In New South Wales, Delta Electricity completed a major expansion of its Colongra plant. Also, in Victoria, investment was made in hydro and wind capacity.

Table 1.7 sets out investment projects in the NEM at June 2010 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 2010 the NEM had over 1200 MW of committed capacity, mostly in gas fired and wind generation. The most significant project was Origin Energy's 518 MW Mortlake power station in Victoria, scheduled for commissioning by the summer of 2010–11.

15 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.

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 40 000 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 (IGCC) plants with carbon capture and storage, which Stanwell proposes for Queensland by 2015–16. The 400 MW plant would be capable of capturing 90 per cent of carbon emissions in the fuel stream for future storage.[16]

> a 600 MW integrated drying and gasification combined cycle (IDGCC) 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.[17]

South Australia has two publicly announced geothermal projects, including a 525 MW project scheduled to connect to the grid in 2018.

1.7 Reliability of supply

Reliability refers to the continuity of electricity supply to customers. The Australian Energy Market Commission (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.

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

17 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

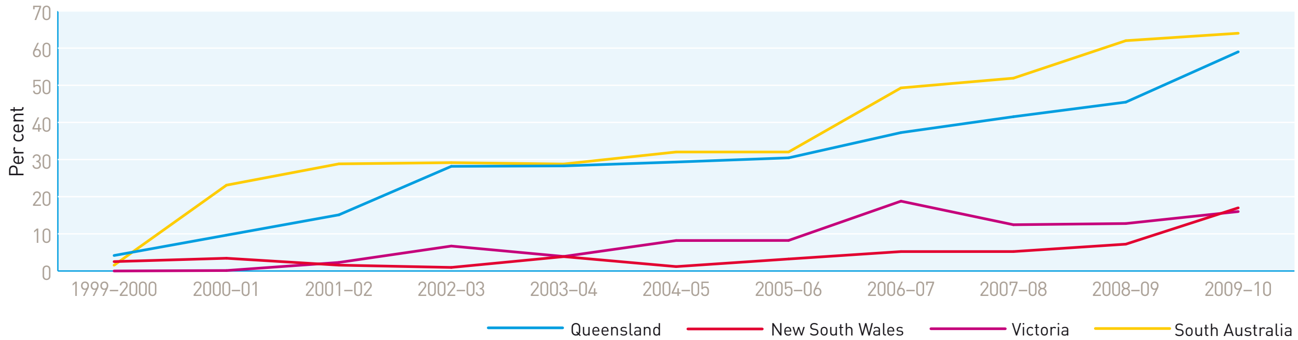


Table 1.6 Generation investment in the National Electricity Market, 2009–10

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED	ESTIMATED COST ($ MILLION)
QUEENSLAND					
Origin Energy	Darling Downs	CCGT	605	December 2009	780
QGC Sales	Condamine	CCGT	135	July 2009	200
Origin Energy	Mount Stuart (expansion)	OCGT	127	October 2009	110
NEW SOUTH WALES					
Delta Electricity	Colongra (units 2–4)	OCGT	471	October 2009	500
VICTORIA					
AGL Hydro	Bogong (part of McKay)	Hydro	140	November 2009	230
Pacific Hydro	Portland	Wind	164	October 2009	330
TASMANIA					
Aurora Energy	Tamar Valley	CCGT	196	July 2009	240

Table 1.7 Committed investment in the National Electricity Market, June 2010

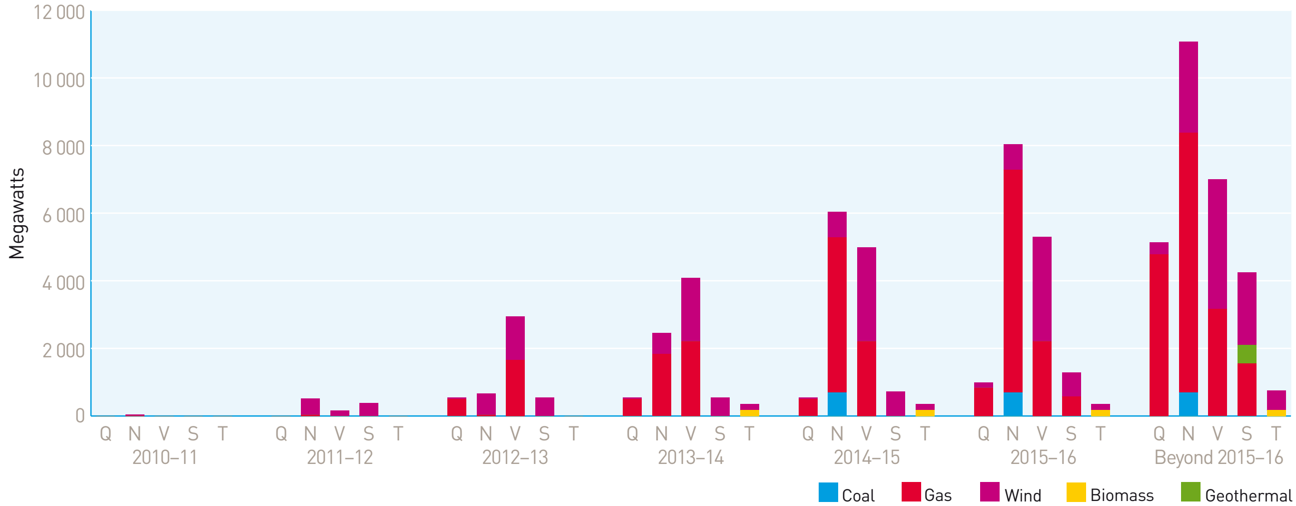
DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND				
Rio Tinto	Yarwun	Gas cogeneration	146	2010
NEW SOUTH WALES				
Eraring Energy	Eraring (upgrade)	Coal fired	240	2012–13
VICTORIA				
Origin Energy	Mortlake	OCGT	518	2010
AGL Energy	Oaklands Hill Wind Farm	Wind	42	2011–12
SOUTH AUSTRALIA				
AGL Energy	North Brown Hill Wind Farm	Wind	82	2010
AGL Energy	The Bluff Wind Farm	Wind	33	2011–12
Infigen Energy	Lake Bonney 3	Wind	39	2010–11
Roaring 40s	Waterloo Wind Farm	Wind	111	2010–11
International Power	Port Lincoln	OCGT	25	2010

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

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

Photo courtesy of TRUenergy

Figure 1.15
Major proposed generation investment in the National Electricity Market, cumulative, June 2010



Source: AEMO.

The current reliability standard for the NEM is that no more than 0.002 per cent of customer demand in each NEM region should be unserved by generation capacity in the region, 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).

1.7.1 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 increased from $10 000 per MWh to $12 500 per MWh on 1 July 2010

> 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

> safety net mechanisms through which AEMO can 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.

1.7.2 Reliability performance

The reliability panel annually reports on the performance of the generation sector against the reliability standard and minimum reserve levels set by AEMO. All regions of the NEM have consistently met the 0.002 per cent reliability standard, which is measured over the long term (based on a 10 year moving average). 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 2010. The most recent instance 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.[18]

AEMO issued seven directions in 2009–10 to manage local power system issues (compared with 18 directions in 2008–09): four directions for Queensland, and one each for New South Wales, South Australia and Tasmania.

1.7.3 Review of reliability settings

Following the unserved energy events in south east Australia in January 2009, the AEMC asked the reliability panel to review whether the current reliability standard and settings remained appropriate. The review (completed in April 2010) recommended:

> retaining the current reliability standard of 0.002 per cent unserved energy per year for each region and across the NEM as a whole. It also proposed performance be assessed against the standard each year, rather than against a 10 year moving average
> annually increasing (from 1 July 2012) the market price cap from $12 500 per MWh, based on movements in the Producer Price Index. The panel considered this change would improve incentives for efficient generation investment. It noted a range of justifications, including rising capital costs for new entrant gas fired generators and 'peakier' electricity demand
> annually increasing (from 1 July 2012) the cumulative price threshold from $187 500 per MWh, based on movements in the Producer Price Index, to mirror increases in the market price cap.[19]

The reliability panel is conducting a separate review of the RERT scheme, which expires in June 2012. Following the unserved energy events in south east Australia during the heatwave in 2009, the panel proposed to make the RERT arrangements more flexible to better address the risk of short term generation capacity shortfalls. The Electricity Rules were amended in October 2009 to implement these changes, which allow more flexibility in contracting under the RERT mechanism. The changes include the establishment of a panel of participants and a short notice contracting process.

In addition, the panel published a review in December 2009 of the operational arrangements to meet the reliability standard. The review recommended refinements to the process for determining minimum reserve levels and obligations on market participants, to provide AEMO with more accurate information on generation availability.

The AEMC in May 2010 completed a review of the effectiveness of the security and reliability arrangements in the light of extreme weather events. The review stemmed from the Ministerial Council on Energy's (MCE) concerns about supply interruptions during the heatwave in south east Australia in January 2009. The report recommended a comprehensive review of arrangements for managing the NEM's technical performance, to be completed by June 2011. It also recommended the AEMC take over (from the Reliability Panel) reviewing the reliability standard and settings, with a review every five years.

The AEMC also supported changing the Electricity Rules to require more accurate reporting of demand-side capability. This proposal aims to minimise AEMO's intervention in the market by improving the quality of reserve assessments.

1.7.4 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. This may involve several credible events occurring simultaneously or in a chain reaction—for example, several generating units might fail or 'trip' at the same time, or a transmission fault might occur at the same

18 AEMC Reliability Panel, *Reliability standard and reliability settings review, Final report*, 2010, p. 11.
19 AEMC Reliability Panel, *Reliability standard and reliability settings review, Final report*, 2010, p. viii.

time as a generator trips. When such events occur, the market operator may need to interrupt customer supply to prevent a power system collapse.

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

While security issues are not reflected in reliability calculations, they may affect the continuity of supply. Five security incidents each disrupted at least 50 MW of customer supply in the NEM in 2009–10, and a number of incidents had more localised impacts.

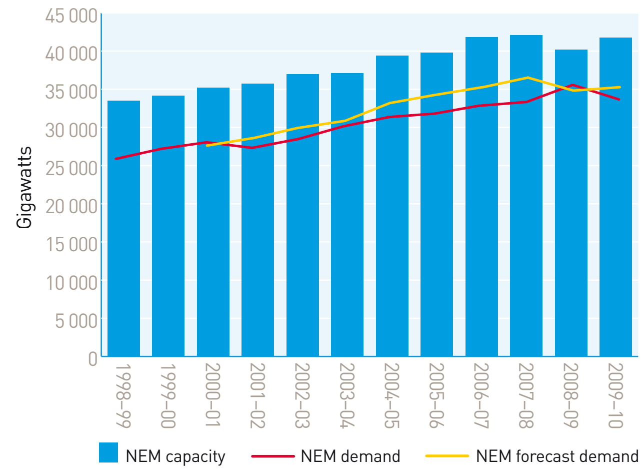
1.7.5 Historical adequacy of generation

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 that 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.

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 a coincidence factor of 95 per cent.

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.

1.7.6 Reliability outlook

The relationship between future demand and available 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 considers would 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. While the uncertain nature of proposed projects means they cannot be factored into reliability equations, the amount of proposed capacity indicates the market's awareness of future capacity needs.

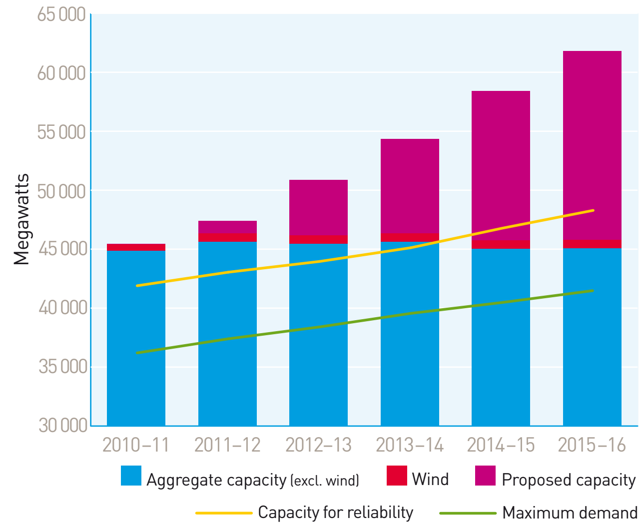
While figure 1.17 indicates longer term capacity requirements in the NEM as a whole, it does not indicate the required timing of new capacity in particular regions. AEMO's 2010 *Power system adequacy* report found the power system should have sufficient supply capacity to meet forecast peak demand plus a minimum reserve level for reliability in every NEM region over the two year period to June 2012. This assessment assumed Origin Energy's committed Mortlake generator in Victoria would be commissioned by summer 2010–11. Accordingly, AEMO did not expect to invoke its reliability and emergency reserve trader tender process in any region over the period to June 2012.[20]

AEMO's longer term market review found that assuming medium economic growth, Queensland would be the first region in the NEM to require new generation investment (by 2013–14) beyond that already committed.[21] While Queensland has had substantial new investment over the past decade, the region's economic growth is projected to rise given buoyant demand in the Surat Basin gas producing area as a result of coal seam gas developments, coal mining developments, and growth in supporting infrastructure and services. Also, installed capacity is expected to fall as the Swanbank B coal fired plant is progressively retired (to be completed by 2012–13).

AEMO projected Victoria and South Australia would require new investment (beyond committed capacity) by 2015–16, as would New South Wales by 2016–17. It expected Tasmania to have adequate capacity until at least 2019–20.

The AEMO report noted climate change policies and the emergence of new technologies would be significant investment drivers over the next few years. In particular, it noted the national RET scheme would likely shift the generation mix towards less carbon intensive generation sources. 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. The report considered the delay in, and associated uncertainty with, the implementation of an emissions trading scheme may pose risks for investment.[22]

Figure 1.17
Electricity demand and supply outlook to 2015–16



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 3 per cent in South Australia, 8 per cent in Victoria and 5 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 95 per cent coincidence 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, *2010 electricity statement of opportunities for the National Electricity Market*, 2010.

20 AEMO, *2010 power system adequacy: two year outlook*, 2010, p. 2.
21 AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010, pp. 3–4.
22 AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010, p. 9.

1.8 AER market investigations and compliance monitoring

The AER monitors activity in the spot market to screen for noncompliance with the Electricity Rules. In addition to reporting on all extreme price events in the NEM, it conducts more intensive investigations if warranted.

1.8.1 Stanwell compliance with clause 3.8.22A

The AER launched an investigation in 2008 into a period of sustained high electricity prices in Queensland in early 2008. It subsequently instituted proceedings in the Federal Court, Brisbane, against Stanwell Corporation Limited (a Queensland generator) for alleged contraventions of the Electricity 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 of the Electricity Rules. The AER sought orders that included declarations, civil penalties, a compliance program and costs. The trial in this matter commenced in Brisbane on 15 June 2010 before Justice Dowsett and concluded on 5 July 2010. In late 2010 the parties were waiting for the judgment.

1.8.2 Babcock & Brown compliance with dispatch instructions

The AER published an investigation report in December 2009 into the compliance of Babcock & Brown Power (BBP, now Alinta Energy) with Electricity Rules provisions relating to the operation of two BBP power stations: Playford in South Australia and Braemar in Queensland.

The AER alleged:

- Playford power station failed on 11 February 2009 to follow dispatch targets issued by AEMO. The AER also alleged BBP failed to notify AEMO of an event likely to change the operational availability of Playford.
- Braemar power station began producing electricity on 17 March 2009 without first receiving a dispatch target from AEMO.

The AER issued infringement notices (totalling $40 000) in September 2009, relating to the alleged failure of Playford and Braemar power stations to follow AEMO's dispatch instructions. While the AER did not issue an infringement notice to BBP for failing to notify AEMO of a change in Playford's operational availability, BBP committed to improve its compliance in this area.