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ELECTRICITY GENERATION



The supply of electricity begins with generation in power stations. This chapter provides a survey of electricity generation in the National Electricity Market, a wholesale market in which generators and retailers trade electricity in eastern and southern Australia. The six participating jurisdictions, physically linked by a transmission network, are Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

1 ELECTRICITY GENERATION

This chapter considers:

- > electricity generation in the National Electricity Market, including geographic distribution and types of generation technology
- > climate change policies and electricity generation
- > the ownership of generation infrastructure
- > new investment in generation infrastructure
- > generation reliability in the National Electricity Market.

1.1 Electricity generation

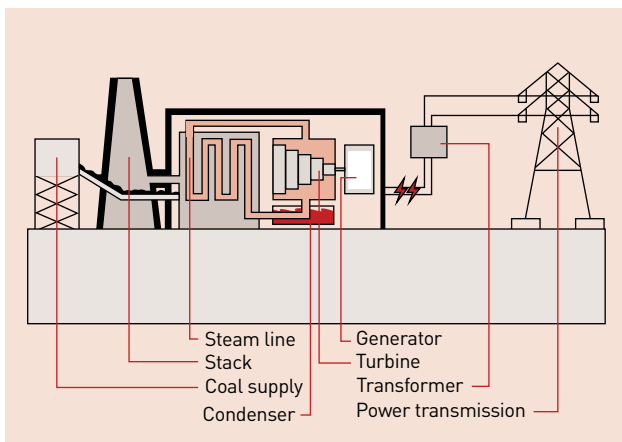
A generator creates electricity by using energy to turn a turbine, which makes large magnets spin inside coils of conducting wire. In Australia, electricity is mainly produced by burning fossil fuels (such as coal and gas) to create pressurised steam. The steam is forced through a turbine at high pressure to drive the generator. Other types of generator rely on the heat emitted through a nuclear reaction, or renewable energy sources such as the sun, wind, geothermal resources (hot rocks)

or water flow to generate electricity. Figure 1.1 illustrates five types of electricity generation most commonly used in Australia: coal fired, open cycle gas fired, combined cycle gas fired, hydroelectric and wind.

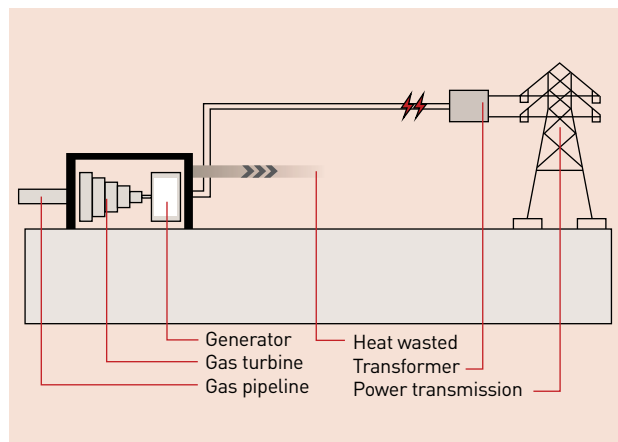
The fuels that can be used to generate electricity each have distinct characteristics. Coal fired generation, for example, has a long start-up time (8–48 hours), while hydroelectric generation can start almost instantly. Lifecycle costs and greenhouse gas emissions also vary markedly with generator type.

Figure 1.1
Electricity generation technologies

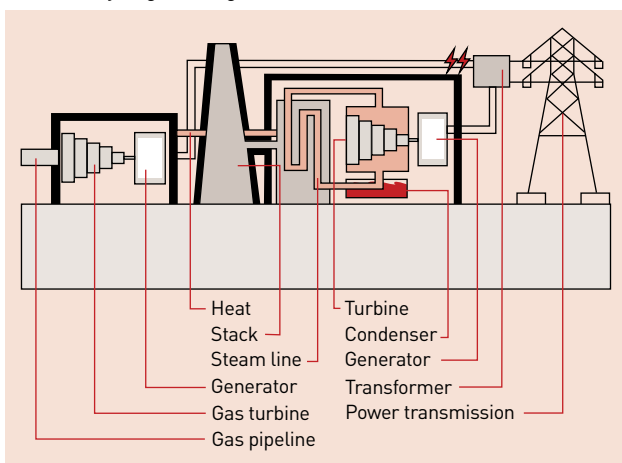
Coal fired generation



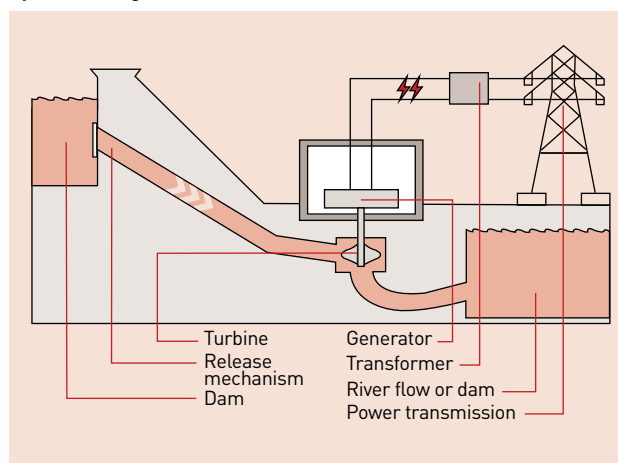
Open cycle gas fired generation



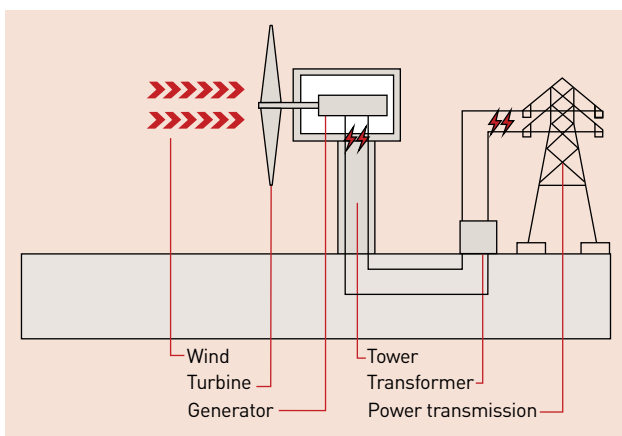
Combined cycle gas fired generation



Hydroelectric generation



Wind generation



Sources: AER (wind); Babcock & Brown (all others).

1.1.1 Lifecycle costs

Figure 1.2 provides estimates of the economic lifecycle costs of different electricity generation technologies in Australia. To allow comparison, the costs of each generation option have been converted to a levelised cost per unit of electricity.¹

Figure 1.2 includes technologies in use, as well as alternatives such as nuclear energy, and fossil fuel fired generators using carbon capture and storage (CCS) technology.² The cost estimates for CCS, which can be used to reduce greenhouse gas emissions from fossil fuel fired generation (coal, gas and oil) technologies, are indicative only.

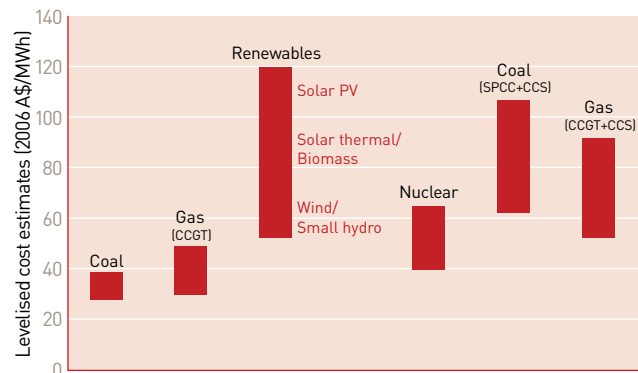
Developing a consistent evaluation of electricity generation costs across different technologies is difficult, given variations in the size and timing of construction costs, fuel costs, operating and maintenance costs, plant utilisation rates and environmental regulations. Site-specific factors can also affect electricity generation costs. Figure 1.2 thus expresses the economic costs for each technology in wide bands.

Coal and gas are the lowest cost fuel sources for electricity generation in Australia. Of the renewable technologies currently used here, wind and hydroelectric generation are cheaper over their lifecycle than biomass and solar. The cost of nuclear generation would fall between that for conventional and renewable generation.

1.1.2 Greenhouse gas emissions

Figure 1.3 shows greenhouse gas emissions for a range of different electricity generation technologies, based on current best practice under Australian conditions. The data account for full lifecycle emission contributions—including those from construction and the extraction of fuels—and estimate the emissions per megawatt hour (MWh) of electricity generated.

Figure 1.2
Lifecycle economic costs of electricity generation



CCGT, combined cycle gas turbine; CCS, carbon capture and storage (costs are indicative only); PV, photovoltaic; SPCC, supercritical pulverised coal combustion (in which steam is created at very high temperatures and pressures).

Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?*, Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, Canberra, December 2006.

Renewable sources of electricity (hydroelectric, wind and solar) and nuclear electricity generation have the lowest greenhouse gas emissions of the generation technologies analysed. Of the fossil fuel technologies, natural gas has the lowest emissions and brown coal has the highest. Figure 1.3 does not account for CCS technologies, which could reduce emissions from gas and coal fired generators.

1.2 Generation in the National Electricity Market

About 200 large³ electricity generators (figure 1.4) operate in the National Electricity Market (NEM) jurisdictions.⁴ The electricity produced by major generators in the NEM is sold through a central dispatch process managed by the Australian Energy Market Operator (AEMO). Chapter 2 outlines this process.

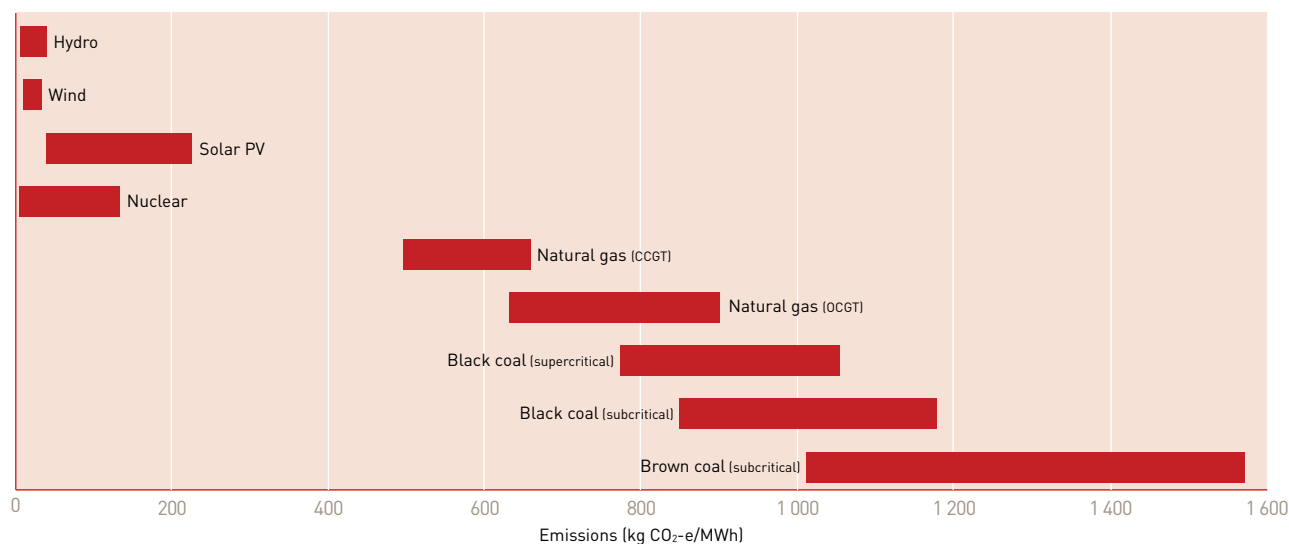
1 The levelised cost of electricity is the real wholesale price of electricity that recoups capital, operating and fuel costs. The present value of expenditures is divided by the electricity generated over the lifetime of the plant to estimate a cost per unit of electricity (in dollars per megawatt hour).

2 Carbon capture and storage, also known as carbon sequestration, is an approach to mitigating carbon dioxide emissions by storing the carbon dioxide. Potential storage methods include injection into underground geological formations, injection deep into the ocean, and industrial fixation in inorganic carbonates. Some industrial processes may use and store small amounts of captured carbon dioxide in manufactured products.

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

4 This chapter does not cover Western Australia or the Northern Territory, which do not participate in the NEM. Chapter 4 provides information on the generation sectors in those jurisdictions.

Figure 1.3
Lifecycle greenhouse gas emissions from electricity generation



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

Notes:

The figure shows the estimated range of emissions for each technology and highlights the most likely emissions value. It includes emissions from power station construction and the extraction of fuel sources.

kg CO₂-e/MWh refers to the quantity of greenhouse gas emissions (in kilograms, converted to a carbon dioxide equivalent) that are produced for every megawatt hour of electricity produced.

Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?*, Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, Canberra, December 2006.

The demand for electricity is not constant, varying with time of day, day of week and ambient temperature. Demand tends to peak in summer (when hot weather drives up air conditioning loads) and winter (when cold weather increases heating requirements). A reliable power system needs sufficient capacity to meet these demand peaks. In effect, a substantial amount of capacity may be called on for only brief periods and may remain idle for most of the year.

It is necessary to have a mix of generation capacity that reflects these demand patterns. The mix consists of baseload, intermediate and peaking power stations.

Baseload generators, which meet the bulk of demand, tend to have relatively low operating costs but high start-up costs, making it economical to run them continuously. Peaking generators have higher operating costs and lower start-up costs and are used to supplement baseload at times when prices are high.

This normally occurs in periods of peak demand or when an issue such as a network outage constrains the supply of cheaper generators. While peaking generators are expensive to run, they must be capable of a reasonably quick start-up because they may be called on to operate at short notice. There are also intermediate generators, which operate more frequently than peaking plants, but not continuously.

The NEM generation sector uses a variety of fuel sources to produce electricity (figures 1.5a and 1.5b). Black and brown coal account for around 60 per cent of registered⁵ generation capacity across the NEM but—as predominantly baseload generators—supply a much larger share of output (85 per cent). Gas fired generation accounts for around 20 per cent of registered capacity but—as intermediate and peaking plant—supplies only around 8 per cent of output.

5 Generators seeking to connect to the network must register with the Australian Energy Market Operator, unless granted an exemption.

Figure 1.4
Large electricity generators in the National Electricity Market



Note: Locations are indicative only.

Sources: AEMO/AER.

Figure 1.5a
Registered generation capacity, by fuel source—
National Electricity Market, 2009

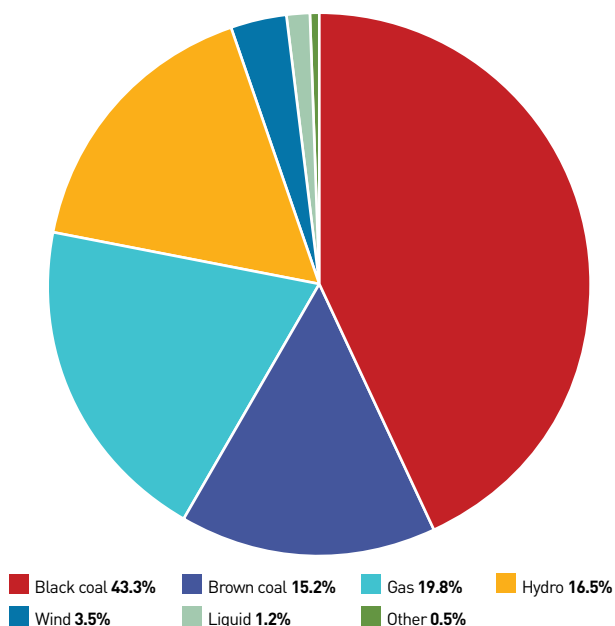
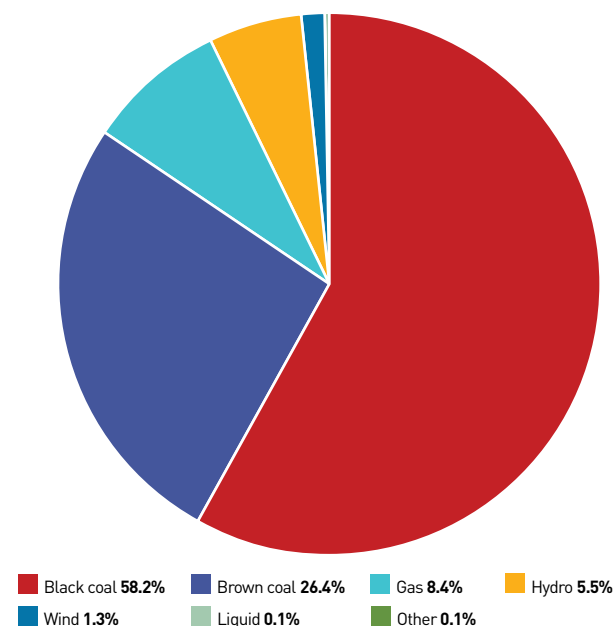


Figure 1.5b
Registered generation output, by fuel source—
National Electricity Market, 2009



Note: Data based on market output published by AEMO. The data exclude output from non-registered generators.

Sources: AEMO/AER.

Hydroelectric generation accounts for around 17 per cent of registered capacity, but less than 6 per cent of output. Hydro's contribution to output has fallen in the past few years as a result of drought conditions in eastern Australia. Wind plays a relatively minor role in the market (around 4 per cent of capacity and 1 per cent of output), but its role is expected to expand under climate change policies. Liquid fuels account for around 1 per cent of capacity.⁶

Figure 1.6 sets out regional data on generation capacity by fuel source. Victoria's generation is fuelled by mainly brown coal, supplemented by hydroelectric and gas fired peaking generation. New South Wales and Queensland rely on mainly black coal, but there has been some recent investment in gas fired generation. New South Wales also has some hydroelectric generation, mainly owned by Snowy Hydro.⁷ Electricity generation in South Australia is fuelled by mainly natural gas. Tasmania relies on hydroelectric generation primarily,

but there has been some recent investment in gas fired generation.

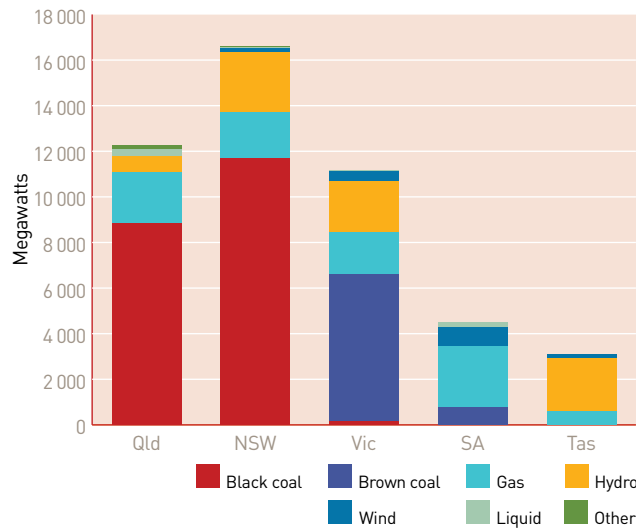
The extent of new and proposed investment in intermittent generation (mainly wind) has raised concerns about system security and reliability. Wind generation grew strongly in the NEM—especially in South Australia—following the introduction of a national mandatory renewable energy target in 2000. That growth led to changes in the way 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 allows AEMO to limit the output of these generators if necessary to maintain the integrity of the power system. While wind accounts for only around 4 per cent of registered capacity in the NEM, it has a significantly higher share in South Australia at 20 per cent (figure 1.7).

⁶ Liquid fuels include diesel, distillates and jet fuel.

⁷ The former Snowy region was abolished on 1 July 2008. It is now split between the Victoria and New South Wales regions of the NEM.

Figure 1.6
Registered generation capacity, by fuel source—
regional, 2009



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

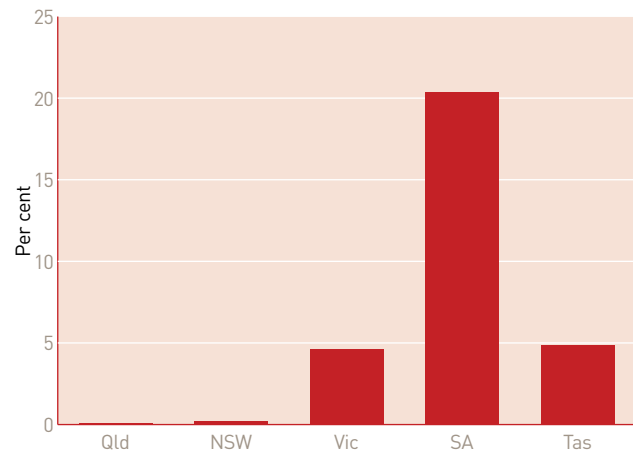
Sources: AEMO/AER.

The pattern of generation technologies across the NEM is evolving. As indicated in figure 1.3, coal fired generators produce relatively more greenhouse gas emissions than produced by most other technologies. The Australian and state and territory governments have implemented (and are developing) initiatives to encourage the development and use of low emission technologies.

The Australian Government's two primary emissions reduction policies are an emissions trading scheme—called the Carbon Pollution Reduction Scheme (CPRS)—and an expanded national renewable energy target (RET).

On 20 August 2009 the Commonwealth Parliament passed legislation to implement the expanded RET scheme. The scheme is designed to achieve the Australian Government's commitment to a 20 per cent share of renewable energy in Australia's electricity mix by 2020. It increases the national target by more than four times to 45 850 gigawatt hours in 2020, then dropping to 45 000 gigawatt hours for the following decade until 2030. The scheme is set to expire in 2030, by which time the proposed CPRS is intended to result

Figure 1.7
Wind generation as a percentage of registered
capacity, 2009



Sources: AEMO/AER.

in a sufficiently high carbon price to drive renewable energy projects.

The expanded scheme aims to encourage investment in renewable energy technologies by providing for the creation of renewable energy certificates. One certificate is created for each megawatt hour of eligible renewable electricity generated by an accredited power station, or deemed to have been generated by eligible solar hot water or small generation units. Retailers must obtain and surrender certificates to cover a set proportion of their wholesale electricity purchases. If a retailer fails to surrender enough certificates to cover its liability, then it must pay a penalty for the shortfall.

The design of the proposed CPRS was set out on 15 December 2008 in the *Carbon Pollution Reduction Scheme: Australia's low pollution future* (white paper). On 4 May 2009 the Australian Government announced a delay in the scheme's introduction by one year, to 1 July 2011.

If introduced, the scheme will create a market for the right to emit carbon by placing a cap on Australia's total emissions. In doing so, it is likely to alter the mix of generation output away from fossil fuel fired

generation technologies (particularly brown coal), which are relatively low cost but high in emissions, in favour of lower emission and renewable energy technologies.

In addition, governments apply a range of other policies that may affect the generation technology mix. These include low emission generation targets (for example, the Queensland Gas Scheme)⁸ and funding for low emission technology development.

1.2.1 Generation ownership

Table 1.1 and figures 1.8 and 1.9 provide information on the ownership of generation businesses in Australia. Across the NEM, around two thirds of generation capacity is government owned or controlled.

In the 1990s Victoria and South Australia disaggregated their generation sectors into multiple stand-alone businesses and privatised each business. Most generation capacity in these jurisdictions is now owned by International Power, AGL Energy, TRUenergy, Great Energy Alliance Corporation (GEAC, in which AGL Energy holds a 32.5 per cent stake) and Snowy Hydro.⁹ Some of these businesses have invested in new generation capacity—mainly gas fired intermediate and peaking plants—since the NEM began.

There has been a significant trend in Victoria and South Australia towards vertical integration of electricity generators with retailers. In Victoria, AGL Energy and TRUenergy are key players in both generation and retail. In South Australia, AGL Energy has the largest generation capacity and the largest retail market share. Across Victoria and South Australia, AGL Energy and TRUenergy own or control around 35 per cent of registered generation capacity.¹⁰

Generation capacity in New South Wales is mainly split between the state owned Macquarie Generation, Delta Electricity and Eraring Energy. Snowy Hydro

also has significant hydroelectric generation capacity in that state. There has recently been some private sector investment in New South Wales. TRUenergy and Origin Energy have entered the generation market with the Tallawarra (417 MW) and Uranquinty (678 MW) power stations. They bring the number of private sector generation businesses in New South Wales to five. (Babcock & Brown Power, Marubeni Corporation and Infigen also have small generation holdings.) In total, the private sector accounts for around 10 per cent of the state's generation capacity.

In March 2009 the New South Wales Government announced it would contract the right to sell electricity produced by state owned generators to the private sector. The government expects to complete the sale process in the first half of 2010. It will offer the contracts in the following five bundles:

- > Liddell power station (2000 MW, owned by Macquarie Generation)
- > Bayswater power station (2640 MW, owned by Macquarie Generation)
- > Mount Piper and Wallerawang power stations (2400 MW, owned by Delta Electricity)
- > Vales Point, Munmorah and Colongra power stations (2588 MW, owned by Delta Electricity)
- > Eraring power station and Shoalhaven pumped storage hydro-electric system (3120 MW, owned by Eraring Energy).¹¹

Queensland has disaggregated its generation sector, but government owned businesses (including Tarong Energy, Stanwell Corporation and CS Energy) control around 75 per cent of the state's generation capacity. This includes some joint ventures with the private sector (such as the Tarong North and Callide C power stations) and power purchase agreements over much of the privately owned capacity (such as the Gladstone and Collinsville power stations).

8 Under the scheme, Queensland electricity retailers must source a prescribed percentage (currently 13 per cent) of their electricity from gas fired generation. The target will increase to 15 per cent in 2010, with an option to increase to 18 per cent by 2020. The scheme will be transitioned into the CPRS as soon as is practicable.

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

10 Includes AGL Energy's 32.5 per cent stake in Loy Yang A and TRUenergy's contractual arrangement for Ecogen Energy's capacity (table 1.1).

11 New South Wales Government, *New South Wales Energy Reform Strategy, delivering the strategy: approach to transactions and market structure*, Sydney, September 2009.

Table 1.1 Generation ownership in the National Electricity Market, July 2009

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
NEM REGIONS			
QUEENSLAND			
CS Energy	Callide; Kogan Creek; Swanbank	2254	CS Energy (Qld Government)
Tarong Energy	Tarong; Wivenhoe	1900	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	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 50%; Arrow Energy 50%
Braemar Power Project	Braemar 1	450	Babcock & Brown Power
Tarong Energy	Tarong North	443	Tarong Energy (Qld Government) 50%; TEPCO 25%; Mitsui 25%
Origin Energy	Mount Stuart; Roma	314	Origin Energy
AGL Hydro	Oakey	275	Babcock & Brown Power 50%; ERM Group 25%; Contact Energy 25%. 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	Barcardine	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
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 Mountain; 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	Babcock & Brown Power
Infigen	Capital	140	Infigen Energy
Country Energy	Broken Hill Gas Turbine	50	Country Energy (NSW Government)
Other registered capacity		109	

GEAC, Great Energy Alliance Corporation; NEM, National Electricity Market.

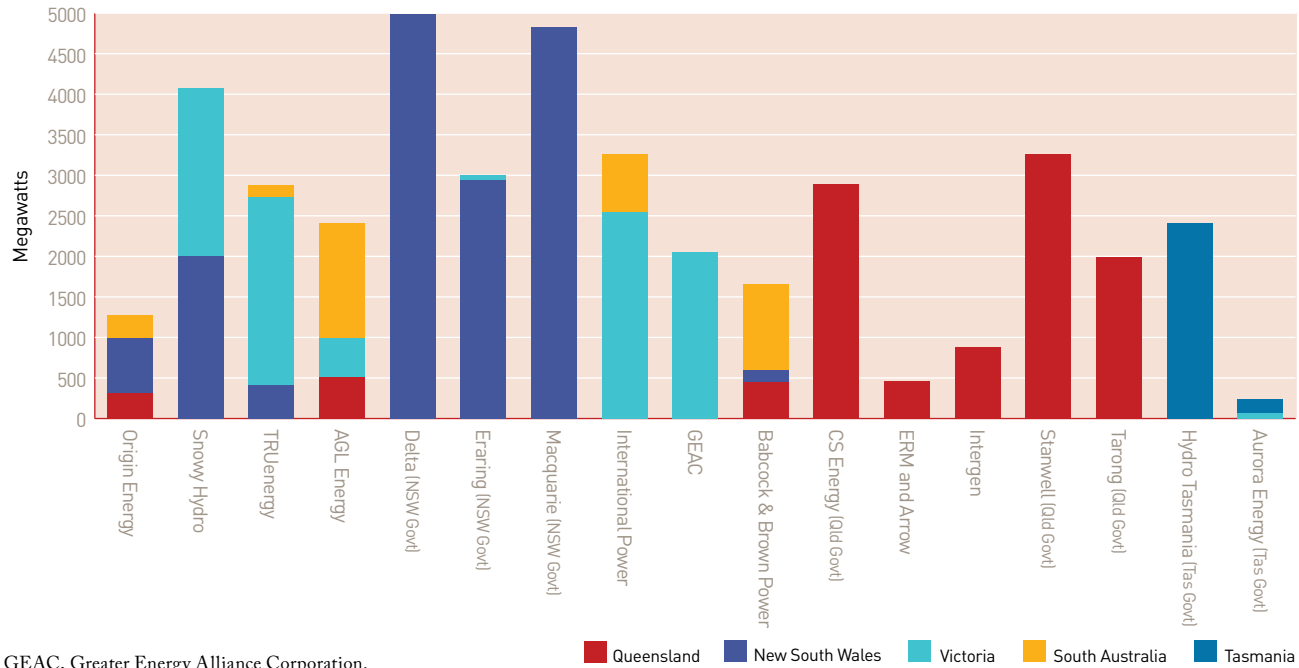
Fuel types: coal; gas; hydro; wind; liquid; biomass/bagasse; unspecified.

Note: Capacity is as published by AEMO for summer 2009-10.

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	Murray; Laverton North; Valley Power	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) Ltd. All contracted to TRUenergy (CLP Group)
AGL Hydro	Mckay; Somerton; Eildon; Clover; Dartmouth; others	423	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
Alcoa	Angelsea	152	Alcoa
Aurora Energy Tamar Valley	Bairnsdale	70	Babcock & Brown Power
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%); Acciona Energy 50%
Infigen	Lake Bonney 1	81	Infigen Energy. All contracted to Country Energy (NSW Government)
Infigen	Lake Bonney 2	159	Infigen Energy
Flinders Power	Northern; Playford	782	Babcock & Brown Power
Flinders Power	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	Hallett	150	TRUenergy (CLP Group)
Other registered capacity		25	
TASMANIA			
Aurora Energy	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 Govt) 50%; CLP Group 50%)
Other registered capacity		100	

Figure 1.8
Major stakeholders in National Electricity Market power stations, 2009



GEAC, Greater Energy Alliance Corporation.

Notes:

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

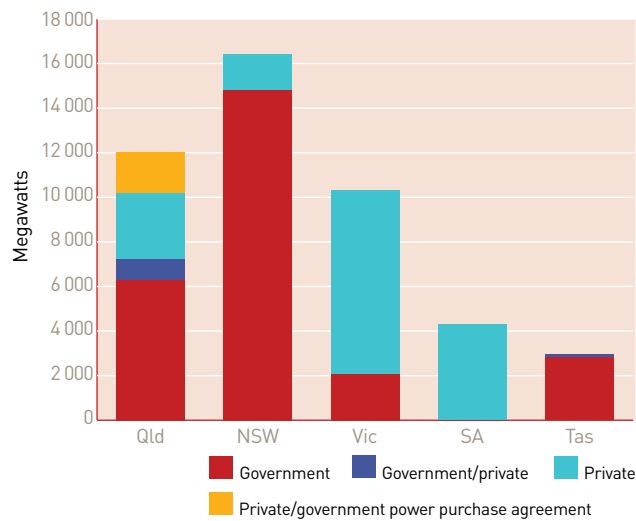
Capacity that is subject to power purchase agreements is attributed to the party with control over output.

Excludes power stations that are not managed through central dispatch.

Some corporate names have been shortened or abbreviated.

Sources: AEMO/AER.

Figure 1.9
Registered generation ownership, by region, 2009



Notes:

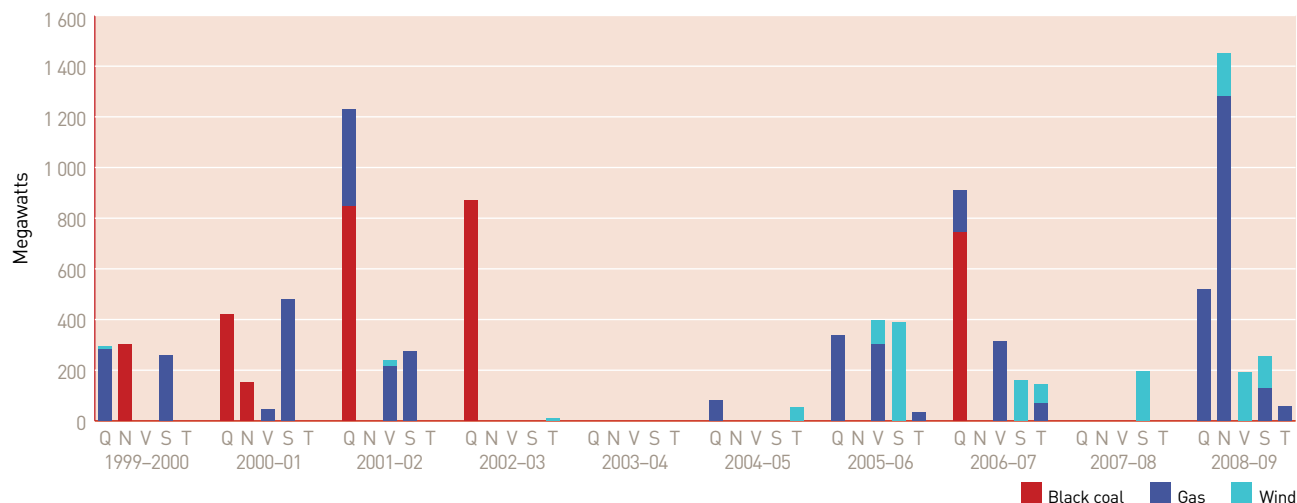
'Private/government power purchase agreement' refers to capacity that is privately owned but contracted under power purchase agreements to government owned corporations.

'Government/private' refers to joint venture arrangements between the private and government sectors.

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

Sources: AEMO/AER.

Figure 1.10
Annual investment in registered generation capacity



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

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

Sources: AEMO/AER.

There has been considerable private investment in new capacity in Queensland, including by Rio Tinto, Intergen, Transfield Services Infrastructure Trust, Origin Energy and Babcock & Brown Power. Most recently, ERM Power and Arrow Energy developed the Braemar 2 power station (462 MW), which began operating in 2009.

State owned enterprises own nearly all of the generation capacity in Tasmania. Hydro Tasmania owns the majority, at 2417 MW. Aurora Energy’s Tamar Valley peaking plant (166 MW) has recently been expanded with the addition of a 196 MW combined cycle gas turbine.

1.3 Investment

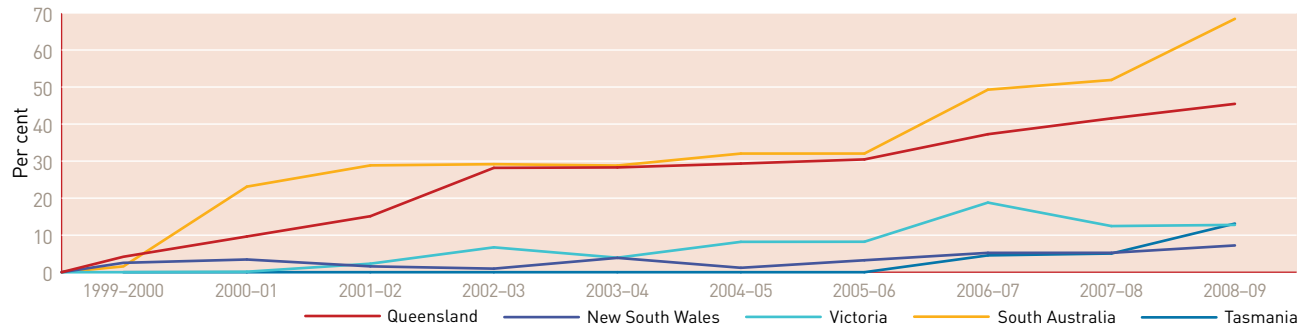
Investment in generation capacity is needed to meet the growing demand for electricity and to maintain the reliability of the power system. It includes the construction of new power stations and upgrades or extensions of existing power stations.

The NEM is an ‘energy only’ market in which investment is largely driven by price signals in the wholesale and forward markets for electricity (see section 1.4). By contrast, most electricity markets across the world (including Western Australia) use a capacity mechanism to encourage new investment in generation capacity. This may involve a tendering process whereby capacity targets are determined by market operators and then built by the successful tenderers. Chapter 4 describes the Western Australian capacity market.

From the inception of the NEM in 1999 to July 2009, new investment added almost 10 300 MW of registered generation capacity, with around 2500 MW occurring in 2008-09.¹² Figures 1.10 and 1.11 illustrate generation investment since market start. There was strong investment in Queensland and South Australia in the early years of the current decade in response to high wholesale electricity prices. Queensland investment was mainly in baseload generation, whereas South Australian investment was mostly in intermediate and peaking generation. There was also some peaking investment in Victoria.

12 There has also been investment in other generators—for example, 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 1.11
Change in net generation capacity since market start



Note: Net change in registered capacity from 1998-99. A decrease may reflect a reduction of capacity due to decommissioning or a reduction in capability of existing generation units.

Sources: AEMO/AER.

There was negligible investment across the NEM in the middle of the current decade. But then tightening supply conditions led to significant new investment in the latter part of the decade. There has been continuing new investment in Queensland and in gas fired plant in New South Wales in 2008-09. South Australia has recorded strong growth in wind capacity over the past few years.

1.3.1 Recent investment

Investment in generation capacity needs to respond to projected market requirements for electricity. Table 1.2a sets out major new generation investment that came on line in the NEM in 2008-09, excluding wind. The bulk of new investment (1240 MW) has occurred in New South Wales, of which around 1100 MW was privately developed by Origin Energy and TRUenergy. Queensland has added around 460 MW of private investment, developed by ERM Power and Arrow Energy. There was new investment by government businesses in New South Wales and Tasmania. All new investment in 2008-09 was in gas fired generation.

Table 1.2b shows almost 500 MW of new wind generation investment in the NEM in 2008-09. The investment occurred in Victoria, New South Wales and South Australia.

Table 1.2c sets out committed investment projects in the NEM at June 2009. It includes those already under construction and those where developers and financiers have formally committed to construction. AEMO accounts for committed projects in projecting electricity supply and demand. There is around 2650 MW of committed capacity in the NEM, of which more than 2200 MW is gas fired generation. Most projects are expected to be commissioned by the end of 2010. There were no major committed projects added in 2008-09.

1.3.2 Proposed projects

Proposed projects include generation capacity that is either in the early stages of development or at more advanced stages but not fully committed. Such projects may be shelved if circumstances change, such as a change in demand projections or business conditions.

The AEMO website lists proposed generation projects in the NEM that are 'advanced' or publicly announced. AEMO considers these projects to be speculative and thus excludes them from its supply and demand outlooks. At June 2009 it listed around 8760 MW of proposed capacity (excluding wind) in the NEM (table 1.3).¹³ There is significant proposed investment in gas fired generation, mainly for New South Wales (possibly because the region is the highest net importer in the NEM) and Queensland.

13 Sourced from AEMO's generator information page (www.aemo.com.au/data/gendata.shtml), viewed 14 August 2009.

Table 1.2a Generation investment in the National Electricity Market, 2008–09 (excluding wind)

REGION	POWER STATION	DATE COMMISSIONED	TECHNOLOGY	CAPACITY (MW)	ESTIMATED COST (\$ MILLION)	OWNER
Qld	Braemar 2	April–June 2009	OCGT	462	546	ERM Power and Arrow Energy
NSW	Colongra (unit 1)	June 2009	OCGT	157		Delta Electricity
NSW	Tallawarra	February 2009	CCGT	435	350	TRUenergy
NSW	Uranquinty	October 2008 – January 2009	OCGT	648	700	Origin Energy
SA	Quarantine	March 2009	OCGT	128	90	Origin Energy
Tas	Tamar Valley Peaking	April 2009	OCGT	58		Aurora Energy

Table 1.2b Wind generation investment in the National Electricity Market, 2008–09

REGION	POWER STATION	CAPACITY (MW)	ESTIMATED COST (\$ MILLION)	OWNER
NSW	Cullerin Range	30	95	Origin Energy
NSW	Capital	140	220	Renewable Power Ventures
Vic	Waubra	192	450	Acciona Energy
SA	Clements Gap	57	135	Pacific Hydro
SA	Hallett 2	71	159	AGL Hydro

Note: Tables 1.2a and 1.2b are based on publicly available information.

Table 1.2c Committed investment projects in the National Electricity Market, June 2009

DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
QUEENSLAND				
Queensland Gas Company	Condamine	CCGT	135	2009–10
Origin Energy	Darling Downs	CCGT	605	2010
Origin Energy	Mount Stuart (extension)	OCGT	127	2009
Rio Tinto	Yarwun Cogen	Gas cogeneration	152	2010
NEW SOUTH WALES				
Eraring Energy	Eraring (extension)	Coal fired	120	2010–11
Delta Electricity	Colongra (units 2–4)	OCGT	471	
VICTORIA				
AGL Energy	Bogong	Hydro	140	2009–10
Origin Energy	Mortlake	OCGT	518	2010
Pacific Hydro	Portland	Wind	164	2009–10
SOUTH AUSTRALIA				
International Power	Port Lincoln	OCGT	25	2010
TASMANIA				
Aurora Energy	Tamar Valley	CCGT	196	2009

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

Note: Capacity is summer capacity for all generators.

Source: AEMO.

Table 1.3 Major proposed generation investment in the National Electricity Market, June 2009

DEVELOPER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING DATE
QUEENSLAND				
Origin Energy	Spring Gully	CCGT	1000	n/a
ERM Power	Braemar 3	Gas	462	2012
ERM Power	Braemar 4	Gas	434	2013
CS Energy	Swanbank F	CCGT	380	2012
NEW SOUTH WALES				
ERM Power	Wellington (Units 1–4)	OCGT	616	2011
Delta Electricity	Mount Piper expansion	Coal	600	2015–16
Macquarie Generation	Tomago Gas Turbine	OCGT	500	n/a
Delta Electricity	Bamarang	CCGT	450	2012–13
Delta Electricity	Marulan gas turbine	CCGT	420	2013–14
AGL Energy	Leaf's Gully	Gas	360	2012
Delta Electricity	Bamarang	OCGT	330	2012–2013
Delta Electricity	Marulan gas turbine	OCGT	330	2013–14
ERM Power	Wellington (Unit 5)	OCGT	280	2012
International Power	Parkes	OCGT	150	n/a
International Power	Buronga	OCGT	120	n/a
Eraring Energy	Eraring upgrade	Coal	60	2011
Eraring Energy	Eraring upgrade	Coal	60	2012
VICTORIA				
Santos	Shaw River	CCGT	500	2012
AGL Energy	Tarrone	Gas	500	2012
HRL Group and Harbin Power Engineering	IDGCC demonstration plant	IDGCC	500	2013
Origin Energy	Mortlake (Stage 2)	CCGT	470	n/a
Solar System	Solar System Victorian Solar Energy Facility (Units 2–51)	Solar Concentrator	100	2012
Solar System	Solar Systems Victorian Solar Energy Facility (Units 52–77)	Solar Concentrator	54	2013
SOUTH AUSTRALIA				
Altona Resources	Arkaringa	IGCC	560	2014
International power	Pelican Point (Stage 2)	Gas	300	n/a
Strike Oil	Kingston	Coal	40	2015
TASMANIA				
Gunns	Bell Bay pulp mill power plant	Biomass	184	2012

CCGT, combined cycle gas turbine; IDGCC, integrated drying and gasification combined cycle; IGCC, integrated gasification combined cycle; OCGT, open cycle gas turbine; n/a, not available.

Note: Excludes wind generation.

Source: AEMO

1.3.3 Wind projects

AEMO reports wind generation investment separately from other proposed investment because wind capacity depends on the weather and cannot be relied on to generate at specified times.¹⁴ At June 2009 it listed around 6730 MW of proposed wind capacity, mainly in Victoria, New South Wales and South Australia (table 1.4).

Table 1.4 Major proposed wind generation investment in the National Electricity Market, June 2009

COMMISSIONING DATE	CAPACITY (MW)					TOTAL
	QLD	NSW	VIC	SA	TAS	
2009				39		39
2010		92	198	129	117	536
2011		1516	564	724		2804
2012		350	760			1110
2013			480			480
2014	101		234		300	635
2015	50			71		121
2016	80	149				229
2017			120			120
2018				109		109
2019		53		80		133
Unknown		30	144	242		416
Total	231	2190	2500	1394	417	6732

Source: AEMO.

1.4 Reliability of the generation sector

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 requires sufficient generation and bulk transmission capacity to ensure, in the long term, no more than 0.002 per cent of customer demand in each NEM region is at risk of not being supplied. To ensure the standard is met, AEMO determines the necessary spare capacity for each region that must be available (either within the

region or via transmission interconnectors). These minimum reserves provide a buffer against unexpected demand spikes and generation failure. The panel also recommends a wholesale market price cap, which is set at a level to stimulate sufficient investment in generation capacity to meet the reliability standard. A review in 2007 of the reliability settings led to a decision to increase the market price cap from \$10 000 per MWh to \$12 500 per MWh, to take effect on 1 July 2010.

The panel reports annually on the performance of the generation sector against the reliability standard and minimum reserve levels set by AEMO. In practice, generation has proved highly reliable. 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.

The performance of generators in maintaining reserve levels has improved since the NEM began in 1998, most notably in South Australia and Victoria. This reflects significant generation investment and improved transmission interconnection capacity across the regions. Table 1.5 sets out the performance of the generation sector in selected regions against the reliability standard. The reliability of all regions falls within the standard.

There have been three instances of insufficient generation capacity to meet consumer demand from the commencement of the NEM to 30 June 2009. The first occurred in Victoria and South Australia in early 2000, when a coincidence of industrial action, high demand and temporary loss of generating units resulted in load shedding. The scope of the reliability standard was amended following the release of the AEMC's *Comprehensive reliability review—final report* in December 2007, to exclude unserved energy associated with power system incidents resulting from industrial action or 'acts of God' at transmission facilities.¹⁵ Accordingly, revised calculations of unserved energy exclude the event in 2000.

14 The Australian Energy Market Commission published a final Rule determination on 1 May 2008 that requires new intermittent generators to register under the new classification of 'semi-scheduled generator'. These generators must participate in the central dispatch process. Additionally, in 2004 the South Australian regulator, the Essential Services Commission of South Australia (ESCOSA), implemented licence conditions preventing wind farms from being classified as non-scheduled. Accordingly, all wind farms commissioned in South Australia since that date are classified as scheduled generation. Some pre-existing South Australian wind farms also have changed classification, from non-scheduled to scheduled.

15 AEMC Reliability Panel, *Reliability standard and settings review, issues paper*, Sydney, June 2009.



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The second event occurred in New South Wales on 1 December 2004, when a generator failed during a period of record summer demand. The restoration of load began within 10 minutes. The most recent instance of insufficient generation occurred on 29 and 30 January 2009 in Victoria and South Australia. Extremely high temperatures led to record demand in Victoria and near record demand in South Australia. Unplanned outages on Basslink on each day exacerbated the tight supply conditions in Victoria and South Australia. This led to supply interruptions on two days in South Australia (for 90 minutes and 165 minutes respectively) and Victoria (for 160 minutes and 230 minutes respectively).¹⁶

Table 1.5 Unserviced energy—long term averages, December 1998 to June 2009

REGION	UNSERVED ENERGY (%)
Queensland	0.00000
New South Wales	0.00010
Victoria	0.00044
South Australia	0.00051

Note: There has been no breach of the reliability standard in Tasmania since it joined the NEM in 2005.

Source: AEMC Reliability Panel, *Reliability standard and settings review, issues paper*, Sydney, June 2009.

1.4.1 Excluded events

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 time as a generator trips. It would be inefficient to operate the power system to cope with non-credible events. Likewise, additional investment in generation or networks may not necessarily avoid such interruptions. For this reason, these events are excluded from reliability calculations.

1.4.2 Reviews of the reliability settings

The AEMC Reliability Panel is required to review the reliability standard and mechanisms every two years. The next review is to be completed by 30 April 2010, with any changes to apply from 1 July 2012. In addition, the AEMC is reviewing the effectiveness of the NEM security and reliability arrangements in the light of extreme weather events. The review, also to be completed by April 2010, will assess:

- > whether the current reliability standard conforms with public expectations of supply reliability
- > the impact of a range of market price caps on reliability and costs to customers
- > whether the process of determining the reliability standard and market price cap requires change.

Further, in June 2009 the panel began a review of the operational arrangements to meet the reliability standard. The review is considering the process for determining minimum reserve levels and obligations on market participants to provide AEMO with accurate information on generation availability.

The NEM combines a number of mechanisms to ensure high levels of reliability in supply. AEMO publishes forecasts of electricity demand and generator availability to allow generators to respond to market conditions and determine the scheduling of maintenance outages. It can intervene in the market when generation capacity forecasts indicate capacity is unlikely to be sufficient to meet minimum reserve levels. The reliability and emergency reserve trader (RERT) mechanism allows AEMO to enter reserve contracts with generators to ensure sufficient reserves to meet the reliability standard. When entering these contracts, AEMO must give priority to facilities that would least distort wholesale market prices. Reserves were contracted through the reserve trading mechanism for the first time in Victoria and South Australia in February 2005 and again in February 2006, but were ultimately not required on either occasion. AEMO can also intervene in the market through its directions power, requiring

¹⁶ There were further network outages in Victoria on the evening of 30 January, leading to localised interruptions to customers. The interruptions were not related to a shortfall in generation supply.

generators to provide additional supply at the time of dispatch to ensure sufficient reserves.

In 2008 the AEMC commenced a review of the energy market frameworks to determine their adequacy to accommodate climate change policies, particularly the CPRS and expanded RET. The final report (published 8 October 2009) raised concerns that the current reliability mechanisms—including the RERT mechanism and directions power—do not adequately address the risk of short term generation capacity shortfalls. Addressing this concern, the AEMC Reliability Panel proposed changing the Electricity Rules to allow more flexibility in contracting under the RERT mechanism, including the establishment of a panel of participants and a short notice contracting process.

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.

1.4.3 Investment in generation and long term reliability

While the NEM combines a number of mechanisms to manage short term generation capacity issues, a reliable power supply in the longer term needs sufficient investment in generation to meet the needs of customers.

A central element in the design of the NEM is that spot prices respond to a tightening in the supply–demand balance. Wholesale prices and projections of the supply–demand balance are also factored into forward prices in the contract market (see chapter 3). Regions with potential generation shortages (which could lead to reliability issues), therefore, will exhibit rising prices in the spot and contract markets. High prices may help attract investment to areas where it is needed, and may lead to some demand-side response if suitable metering and price signals are available to customers—for example, retailers may offer financial incentives

for customers to reduce consumption at times of high system demand, to ease pressure on prices.

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 \$10 000 per MWh is necessarily high to encourage investment in peaking plant, which is expensive to run and may operate only rarely. Over the longer term, peaking plant plays a critical role in ensuring there is adequate generation capacity (and thus reliability). There has been significant investment in peaking capacity in most regions of the NEM over the past few years.

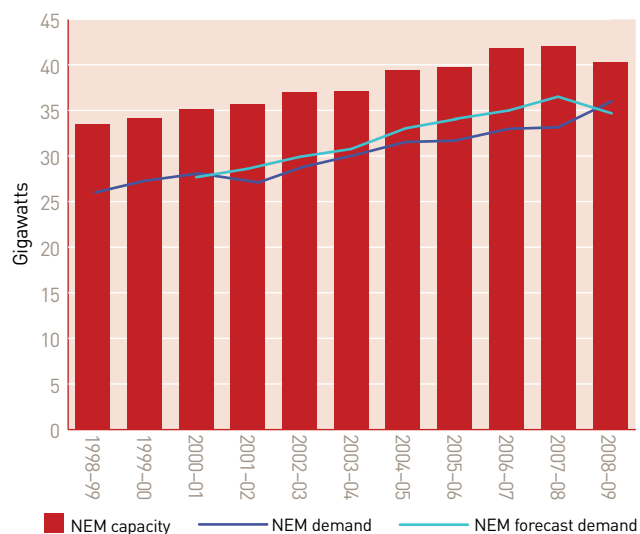
Historical adequacy of generation to meet demand

Figure 1.12 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 has kept pace with rising demand (both actual and forecast levels), and has provided a safety margin of capacity to maintain the reliability of the power system. In 2008–09 actual demand was above forecast demand for the first time since 2000–01.

Reliability outlook

The relationship between future demand and available capacity determines electricity prices and the reliability of the power system looking ahead. Figure 1.13 charts forecast peak demand in the NEM against installed, committed and proposed capacity. It indicates the amount of capacity that AEMO considers would be needed to maintain reliability, given projected demand. Wind generation is treated differently from conventional generation for the purpose of the supply–demand balance. In South Australia, for example, a figure of 3 per cent of installed wind capacity is used to represent the contribution to overall generation supply at times of peak demand; 8 per cent is used in Victoria.

Figure 1.12
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.

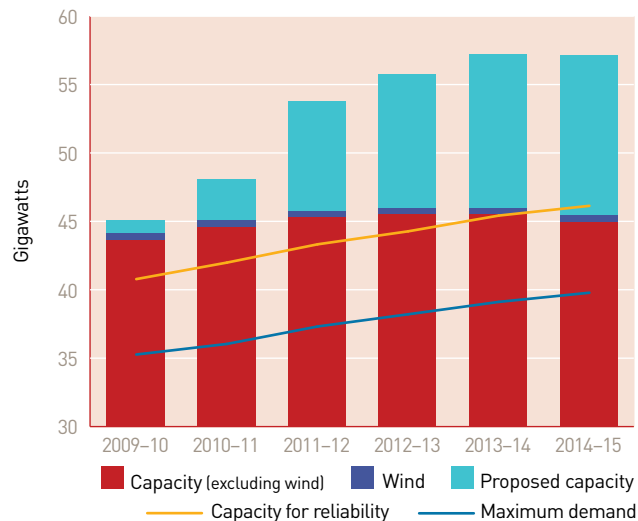
NEM capacity excludes wind generation and power stations not managed through central dispatch.

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

Figure 1.13 indicates that current installed and committed capacity will be sufficient to meet peak demand projections and reliability requirements until at least 2012-13.

While the uncertain nature of proposed projects means they cannot be factored into AEMO’s reliability equations, they indicate the market’s awareness of future capacity needs. In particular, they indicate the extent of competition in the market to develop electricity infrastructure. Figure 1.13 indicates the possible extent of proposed capacity required to be constructed to meet projected shortfalls beyond 2012-13. While many proposed projects may never be constructed, only a relatively small percentage would need to occur to meet demand and reliability requirements into the next decade.

Figure 1.13
Demand and generation capacity outlook to 2014-15



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 (see tables 1.3 and 1.4).

The maximum demand forecasts for each region in the NEM 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, *Electricity statement of opportunities for the National Electricity Market*, Melbourne, 2009.