1 ELECTRICITY GENERATION

SPPL Power Station. Rob Homer (Fairfax Images)

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. There are six participating jurisdictions, physically linked by a transmission network—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 geographical distribution, types of generation technology, the life-cycle costs and greenhouse emissions of different generation technologies
- the ownership of generation infrastructure
- investment in generation infrastructure
- the reliability of electricity generation in the National Electricity Market.

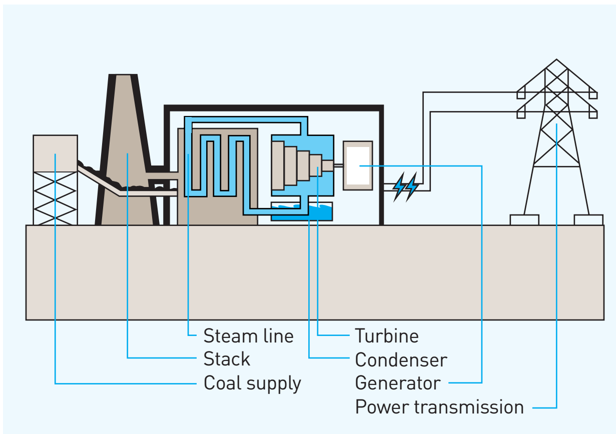
1.1 Electricity generation

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 generators rely on the heat emitted through a nuclear reaction, or renewable energy sources such as the sun, wind or the flow of water down pipes to generate electricity. Figure 1.1 illustrates four types of electricity generation commonly used in Australia—coal-fired, open cycle gas-fired, combined cycle gas-fired and hydro (water) generation.

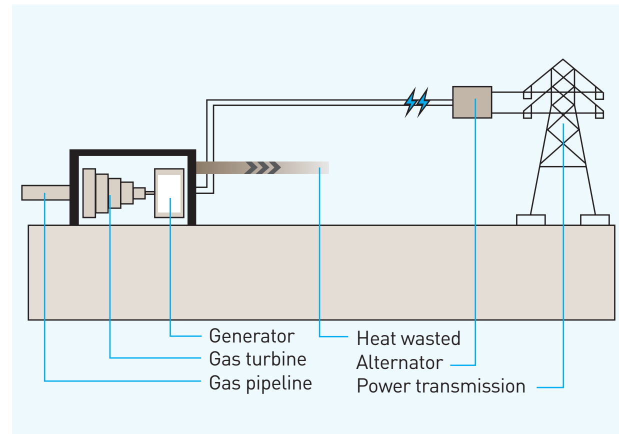
The fuels that can be used to generate electricity each have distinct characteristics (table 1.1). Coal-fired generation, for example, has a long start-up time (8–48 hours), while hydro generation can start almost instantly. Life-cycle costs and greenhouse gas emissions also vary markedly with generator type.

Figure 1.1
Electricity generation technologies

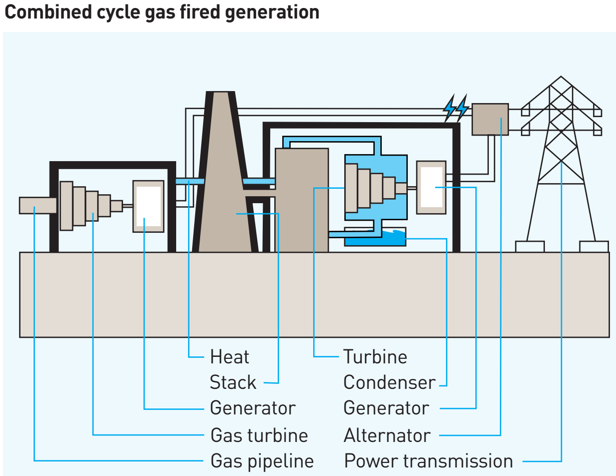
Coal fired generation



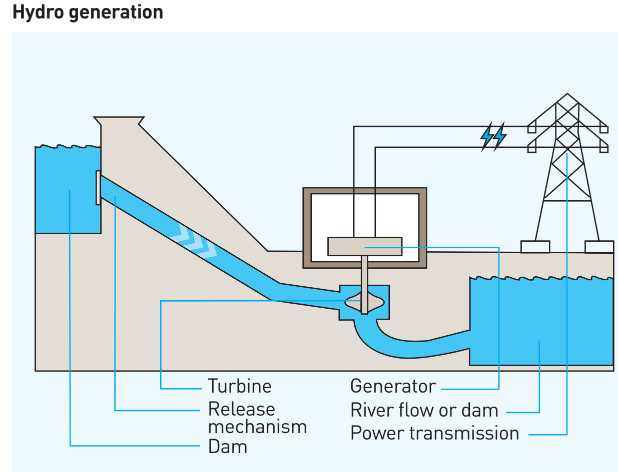
Open cycle gas fired generation



Combined cycle gas fired generation



Hydro generation



Source: Babcock & Brown

Table 1.1 Characteristics of generators

CHARACTERISTIC	GENERATOR TYPE			
	GAS AND COAL-FIRED BOILERS	GAS TURBINE	WATER (HYDRO)	RENEWABLE (WIND/SOLAR)
Time to fire-up generator from cold	8–48 hours	20 minutes	1 minute	dependent on prevailing weather
Degree of operator control over energy source	high	high	medium	low
Use of non-renewable resources	high	high	nil	nil
Production of greenhouse gas	high	medium-high	nil	nil
Other characteristics	medium-low operating costs	medium-high operating costs	low fuel cost with plentiful water supply; production severely affected by drought	suitable for remote stand-alone applications; batteries may be used to store power

Source: NEMMCO, *Australia's National Electricity Market, Wholesale Market Operation, Executive Briefing*, 2005

Life-cycle costs

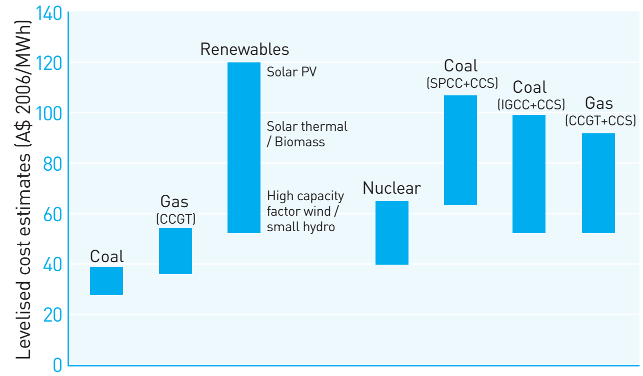
Estimates of the economic life-cycle costs of different electricity generation technologies in Australia are provided in figure 1.2. To allow comparison, the costs of each generation option have been converted to a standardised cost per unit of electricity.[1] Figure 1.2 includes both current generation technologies in Australia, and alternatives such as nuclear energy and carbon capture and storage (CCS) technology.[2] The cost estimates for CCS, which can be used to reduce carbon emissions from fossil-fired generation (coal, gas and oil) technologies, are indicative only.

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

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

Figure 1.2

Life-cycle economic costs of electricity generation



AER note: SPCC is supercritical pulverised coal combustion (in which steam is created at very high temperatures and pressures); IGCC is integrated gasification combined cycle (in which coal is converted into a hydrocarbon vapour at high temperature and is then cleaned, stripped of most pollutants and used as fuel in a combined-cycle generation plant, resulting in significantly reduced carbon emissions); CCGT is combined cycle gas turbine; PV is photovoltaic; CCS is carbon capture and storage (costs are indicative only).

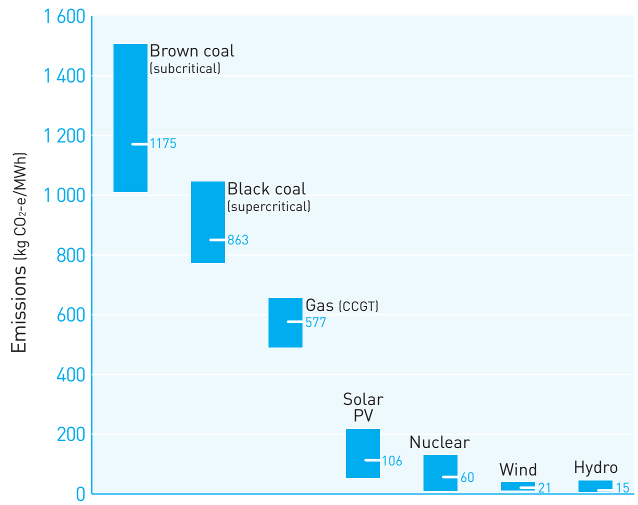
Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?*, Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, December, 2006.

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 produce a cost per unit of electricity (in $ per MWh).

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, or industrial fixation in inorganic carbonates.

Figure 1.3

Life-cycle greenhouse gas emissions of electricity generation



AER note: The figure shows the estimated range of emissions for each technology and highlights the most likely emissions value; includes emissions from the extraction of fuel sources; PV is photovoltaic; CCGT is combined cycle gas turbine.

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, December, 2006.

Greenhouse emissions

Greenhouse gas emissions for different electricity generation technologies, based on current best practice under Australian conditions, are shown in figure 1.3. The data takes account of full life-cycle emission contributions—including from the extraction of fuels—and estimates the emissions per megawatt hour of electricity generated.

Renewables (hydro-electric, wind and solar electricity) and nuclear electricity generation have the lowest carbon emissions of the generation technologies analysed. Of the fossil fuel technologies, natural gas has the lowest emissions and brown coal, the highest. Figure 1.3 does not account for CCS technologies, which can significantly reduce emissions for gas and coal generators.

1.2 Generation in the NEM

Australia has about 230 large electricity generators (figure 1.4), of which around 180 are in National Electricity Market (NEM) jurisdictions in eastern and southern Australia. The electricity produced by major generators in the NEM is sold through a central dispatch managed by the National Electricity Market Management Company (NEMMCO). Chapter 2 of this report outlines the dispatch process.

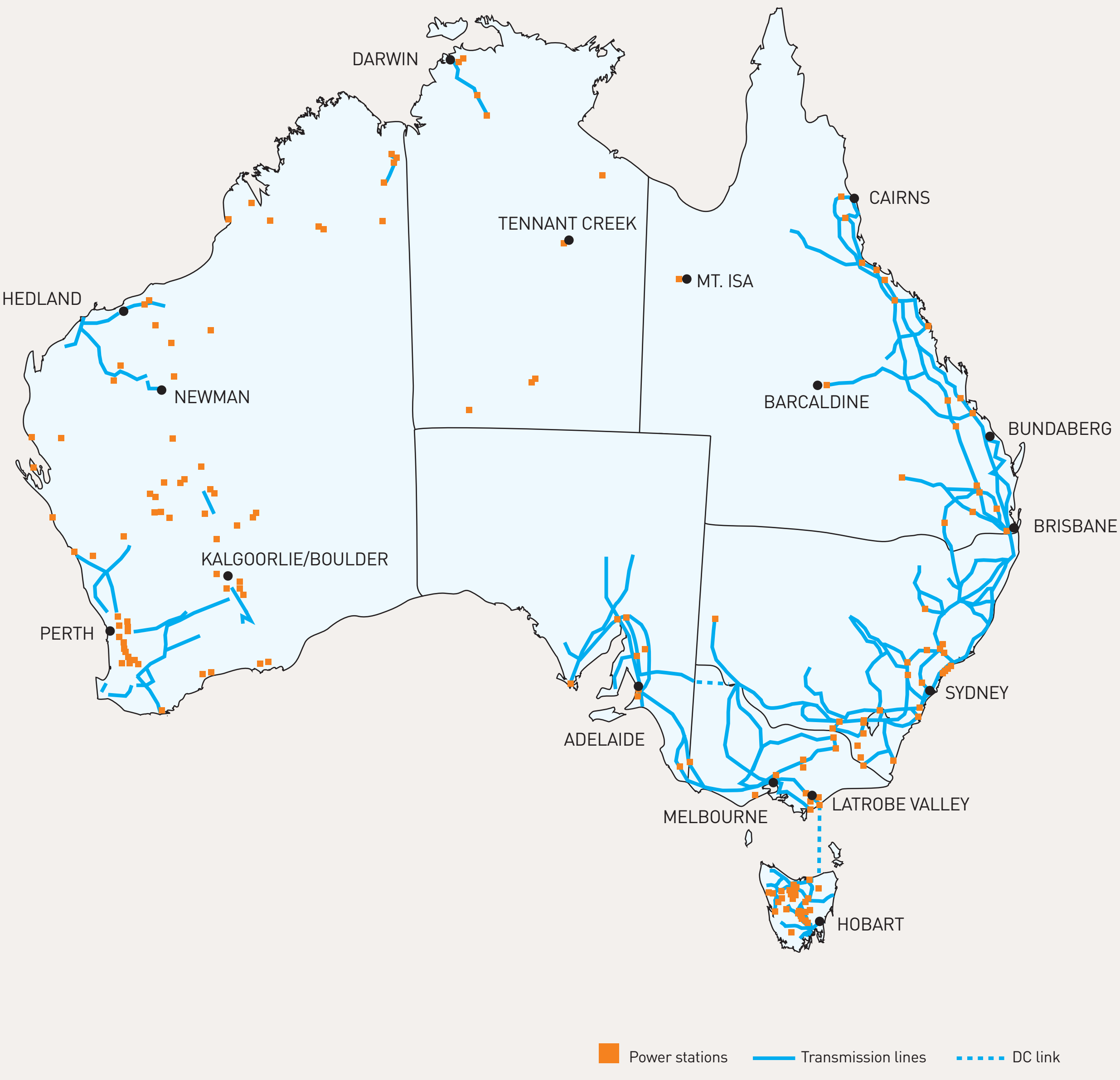
The demand for electricity is not constant, varying with time of day, day of week and ambient temperature. Demand tends to peak in summer (when hot weather drives up air conditioning loads) and winter (when cold weather increases heating requirements). A reliable power system needs sufficient capacity 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 base load, 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 so are used to supplement base load 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 and economical start-up as they may be called upon to operate at short notice. There are also *intermediate* generators, which operate more frequently than peaking plants, but not continuously.

Figure 1.5 sets out the mix of base load, intermediate and peaking generation capacity across the NEM. Most regions rely principally on base load generation, but Victoria and South Australia have a significant share of peaking and intermediate generation. In Victoria, for example, base load consists mainly of coal-fired generation, while most peaking capacity relies on gas. The Snowy and Tasmanian regions produce hydro-electricity, which is classified as intermediate generation.

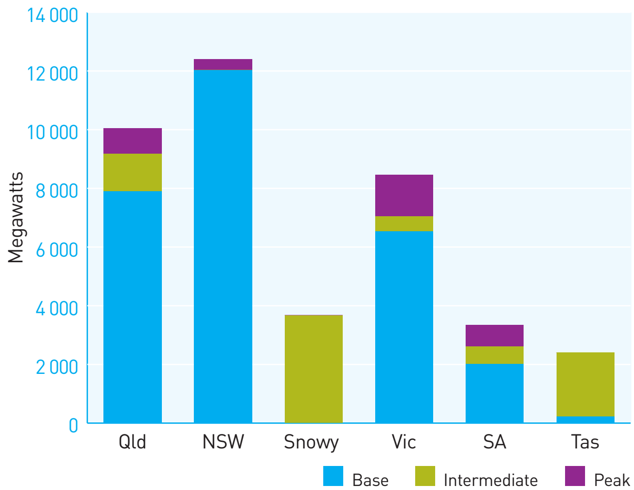
Figure 1.4
Electricity generators in Australia



Locations are indicative only

Source: ABARE 2006

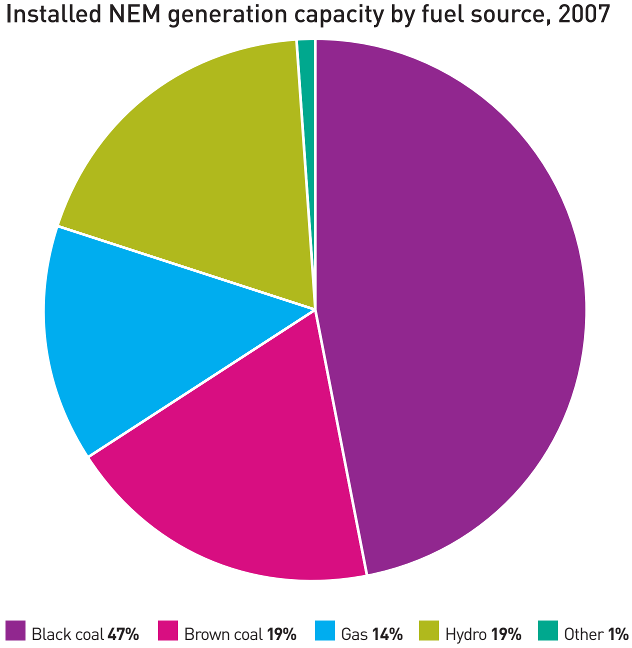
Figure 1.5
Installed NEM generation capacity by region, 2007



Notes: Excludes power stations not managed through central dispatch.
The classifications of 'base', 'intermediate' and 'peak' are based on typical hours of running or capacity factors, and mode and cost of operation. Generation classified as base has a long-term capacity factor (proportion of capacity in use) close to one, and low operating costs, but can take many hours to start. Peak generation has a long term capacity factor closer to zero, and higher operating costs, but can start rapidly. Intermediate generation falls in between. Wind generation is not included in conventional calculations of installed capacity because of the intermittent nature of its generation.

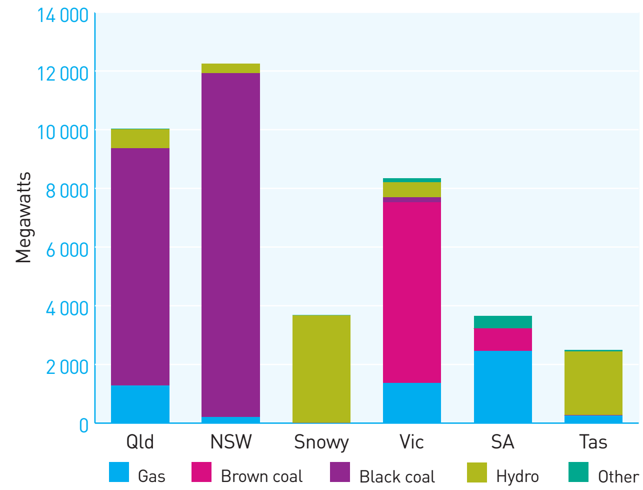
Data source: NEMMCO

Figure 1.6
Installed NEM generation capacity by fuel source, 2007



Data source: NEMMCO

Figure 1.7
Regional generation capacity by fuel source, 2007



Note: Excludes power stations not managed through central dispatch.

Data source: NEMMCO

The NEM generation sector uses a variety of fuel sources to produce electricity (figure 1.6). Black and brown coal account for around 66 per cent of total generation across the NEM, followed by hydro (19 per cent) and gas fired generation (14 per cent). Wind generation accounts for around 1.5 per cent of registered capacity in the NEM. Wind has a significantly higher share at 10 per cent in South Australia.

Figure 1.7 sets out regional data on generation by fuel source. Victoria's base load generation is mainly fuelled by brown coal, supplemented by gas-fired and hydro-electric intermediate and peaking generation. New South Wales and Queensland mainly rely on black coal, but there has been some recent investment in gas-fired generation. Electricity generation in Western Australia, South Australia and the Northern Territory is mainly fuelled by natural gas. Tasmania and Snowy use hydro-electric generation to produce electricity. The Snowy region supports other regions of the NEM with intermediate and peaking requirements.

The future pattern of generation technologies across the NEM may change. As indicated in figure 1.3, coal fired generators produce relatively more greenhouse gas emissions than most other technologies. Australian governments have implemented—and are

Tumut 3 power station, Snowy

developing—initiatives to encourage the development and use of low emission technologies. These include funds for technology development and mandatory targets for greenhouse gas reductions, renewable energy and other low emission generation. Such initiatives result in low carbon emission technologies such as renewables, nuclear and CCS technologies becoming more cost competitive with fossil fuel technologies.

Governments are also considering the introduction of emissions trading or similar policies that would place a price on carbon emissions. In May 2007 the Prime Ministerial Task Group on Emissions Trading recommended that Australia introduce emissions trading, using a 'cap and trade' approach, by 2012.[3] The Government accepted the task force's recommendations in June 2007 and announced that a target or cap for reducing carbon emissions will be set in 2008 following modelling of the economic impact.[4]

Generation ownership

Table 1.2 and figures 1.8–1.9 provide background on the ownership of generation businesses in Australia. Historically, state-owned utilities ran the entire electricity supply chain in all states and territories. In the 1990s, governments began to carve out the generation and retail segments into stand-alone businesses, and allowed new entrants to compete for the first time. Victoria and South Australia privatised their electricity generation businesses. Other NEM jurisdictions retained government ownership, but also allowed new entry. Across the NEM, around 63 per cent of generation capacity is government-owned or controlled.

Victoria and South Australia disaggregated their generation sectors in the 1990s into multiple stand-alone businesses and privatised each business. Several businesses have since changed hands. Most generation capacity in these regions is now owned by International Power, AGL, TRUenergy, the GEAC group (in which AGL holds a 32.5 per cent stake), and Babcock & Brown. International Power, Alinta, AGL, Origin Energy, Snowy Hydro and others have invested in new generation capacity—mainly gas-fired intermediate and peaking plants—since the NEM commenced.

There has been a significant trend in Victoria and South Australia towards vertical integration of electricity generators with retailers. In Victoria, AGL and TRUenergy are now key players in both generation and retail. In South Australia, AGL is both a major generator and the leading retailer. Across Victoria and South Australia, AGL and TRUenergy own around 40 per cent of registered generation capacity.[5] International Power, which controls around 30 per cent of generation capacity in Victoria and South Australia, fully acquired its retail joint venture with EnergyAustralia in 2007.

New South Wales and Queensland disaggregated their generation sectors but retained significant government ownership. Generation capacity in New South Wales is mainly split between the state-owned Macquarie Generation, Delta Electricity and Eraring Energy. Two private sector entrants, Babcock & Brown and the Marubeni Corporation, each own around 1.5 per cent of the state's generation capacity.

In Queensland, the state-owned Tarong Energy, Stanwell Corporation and CS Energy own around 53 per cent of generation capacity. Queensland privatised the Gladstone Power Station in 1994. There has since been private investment in new capacity, including through joint ventures with government-owned entities (Callide C and Tarong North). RioTinto/NRG, Intergen, Transfield, Origin Energy and Babcock & Brown are among the private sector participants. As indicated in table 1.2 and figure 1.9, much of this privately owned generation capacity has been contracted under power purchase agreements to Enertrade, a Queensland Government-owned wholesale energy provider.[6]

Hydro Tasmania owns virtually all generation capacity in Tasmania, while Snowy Hydro (owned by the Australian, New South Wales and Victorian governments) owns all capacity in the Snowy region.[7]

3 The Prime Ministerial Task Group on Emissions Trading, *Report of the task group on emissions trading*, Department of Prime Minister and Cabinet, 2007.
4 Howard, Hon J. W (MP), Address to the Liberal Party Federal Council, The Westin Hotel, Sydney, 3 June 2007.
5 Includes AGL's 32.5 per cent stake in Loy Yang A and TRUenergy's contractual arrangement for capacity owned by Babcock & Brown. See table 1.2.
6 The Queensland Government announced in May 2007 that it would disband Enertrade and transfer its assets to other government corporations.
7 For the non-NEM jurisdictions of Western Australia and the Northern Territory, see chapter 7 of this report.

Table 1.2 Generation ownership in the NEM: June 2007

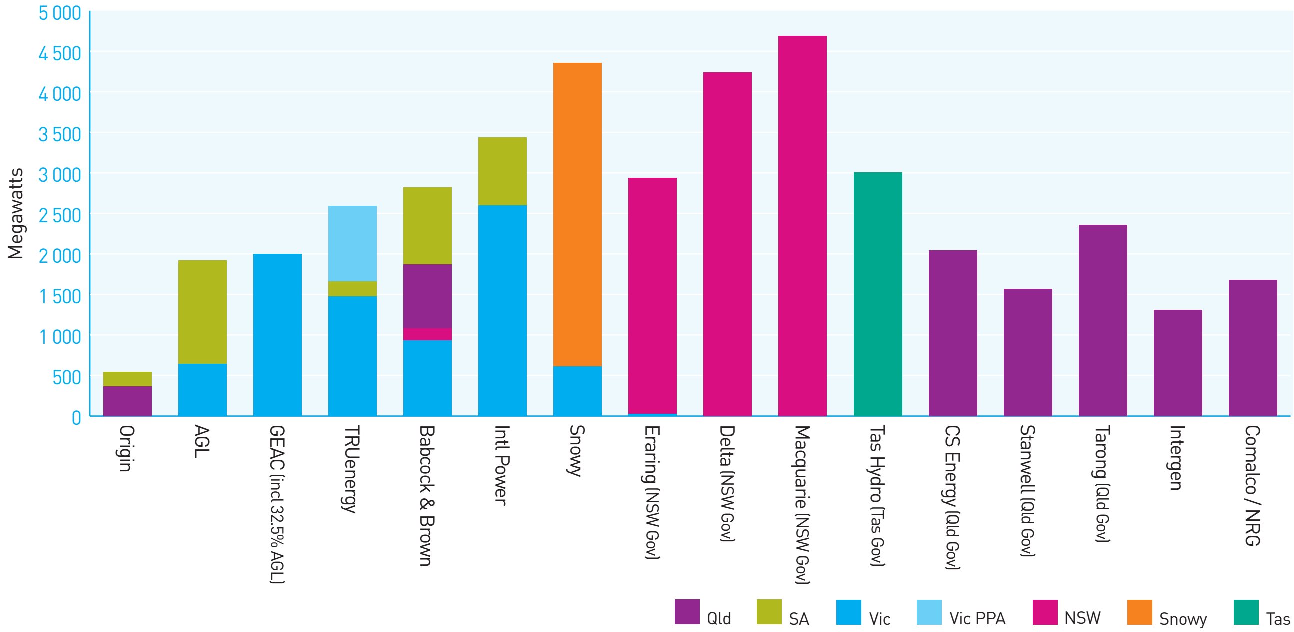
GENERATION BUSINESS	POWER STATIONS	CAPACITY[1] (MW)	OWNER
NEM REGIONS			
NEW SOUTH WALES AND THE AUSTRALIAN CAPITAL TERRITORY			
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4734	NSW Government
Delta Electricity	Vales Point B; Mt Piper; Wallerawang C; Munmorah	4240	NSW Government
Eraring Energy	Eraring; Shoalhaven; Hume	2880	NSW Government
Marubeni Australia Power Services	Smithfield	162	Marubeni Corporation
Redbank Project	Redbank	148	Babcock & Brown
Snowy Hydro	Blowering	80	NSW Govt (58%); Vic Govt (29%); Australian Govt (13%)
Various	Embedded and non-grid	513	Various
VICTORIA			
Loy Yang Power	Loy Yang A	2020	GEAC (AGL Energy (32.5%)
Hazelwood Power	Hazelwood	1580	International Power (98.1%)
TRUenergy	Yallourn	1420	TRUenergy (CLP Power Asia)
IPM Australia	Loy Yang B	1000	International Power (70%), Mitsui (30%)
Ecogen Energy	Newport; Jeeralang A & B	891	Babcock & Brown (73%); Industry Funds Management (Nominees) Ltd (27%) (all contracted to TRUenergy)
AGL Hydro Partnership	McKay Creek; Dartmouth; Somerton; Eildon; West Kiewa	587	AGL
Snowy Hydro	Laverton North; Valley Power	570	NSW Govt (58%); Vic Govt (29%); Australian Govt (13%)
Alcoa	Anglesea	158	Alcoa
Energy Brix Australia	Morwell	139	Energy Brix Australia
Alinta Energy	Bairnsdale	70	Alinta
Eraring Energy	Hume Vic	58	NSW Government
Various	Embedded and non-grid	474	Various
SOUTH AUSTRALIA			
AGL	Torrens Island	1260	AGL[2]
Flinders Power	Northern; Playford B	760	Babcock & Brown
Pelican Point Power	Pelican Point	450	International Power
Synergen	Dry Creek; Mintaro; Snuggery; Port Lincoln	277	International Power
ATCO Power	Osborne	175	ATCO (50%); Origin Energy (50%) (all contracted to Babcock & Brown)
TRUenergy	Hallett	155	TRUenergy (CLP Power Asia)[2]
Origin Energy	Quarantine; Ladbroke Grove	146	Origin Energy
Infratil Energy Australia	Angaston	40	Infratil
Various	Embedded and non-grid	398	Various

GENERATION BUSINESS	POWER STATIONS	CAPACITY[1] (MW)	OWNER
QUEENSLAND			
Tarong Energy	Tarong; Wivenhoe	1900	Queensland Government
Tarong Energy	Tarong North	443	Queensland Government (50%); TM Energy (TEPCO & Mitsui Joint Venture) (50%)
NRG Gladstone Operating Services	Gladstone	1680	Rio Tinto (42%), NRG Energy (37.5%); SLMA GPS (8.5%); Ykk GPS (4.8%); Mitsubishi (7.1%) (all contracted to Enertrade)
Stanwell Corporation	Stanwell; Kareeya; Barron Gorge; Mackay	1608	Queensland Government
CS Energy	Callide B; Swanbank B; Swanbank E	1535	Queensland Government
Callide Power Management (CS Energy 50%; Intergen Australia 50%)	Callide C	900	Queensland Government (50%); Intergen (25%); China Huaneng Group (25%)
Millmerran Power Management	Millmerran	860	Intergen
Braemar Power Projects	Braemer	453	Babcock & Brown (85%); ERM Group (15%)
Transfield Services (Australia)	Yabulla; Collinsville	420	Transfield Services (all contracted to Enertrade)
Origin Energy	Mt Stuart; Roma	342	Origin Energy (all contracted to Enertrade)
Oakey Power Holdings	Oakey Power	276	Babcock & Brown (50%); ERM Group (25%); Contact Energy (25%)
QPTC (Enertrade)	Barcaldine	49	Queensland Government
Various	Embedded and non grid	1002	Various
TASMANIA			
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah, other	2172	Tasmanian Government
Bell Bay Power (Hydro Tasmania)	Bell Bay	336	Tasmanian Government
Various	Embedded and non-grid	29	Various
SNOWY			
Snowy Hydro	Tumut 1, 2 & 3; Murray 1 & 2; Guthega	3676	NSW Govt (58%); Vic Govt (29%); Australian Govt (13%)
NON-NEM REGIONS			
WESTERN AUSTRALIA			
Verve	Maju; Kwinana WPC; Pinjar; Collie; Cockburn; other	3473	Western Australian Government
Various	Independent and remote	2012	Various
NORTHERN TERRITORY			
Power and Water Corporation	Channel Island; Ron Goodin; Berrimah; Katherine; other	418	Northern Territory Government
Various	Embedded and non-grid	230	Various

Notes: 1. Capacity is total capacity for embedded, non-grid, Western Australian and Northern Territory generators; and summer capacity for other generators. An embedded generator is one that directly connects to a distribution network and does not have access to a transmission network. 2. AGL entered agreements in January 2007 to acquire the 1260 MW Torrens Island power station in South Australia from TRUenergy, and to sell its 155 MW Hallett power station to TRUenergy. The transaction was completed in July 2007.

Data sources: NEMMCO; ESAA *Electricity gas Australia, 2006;* and other public sources.

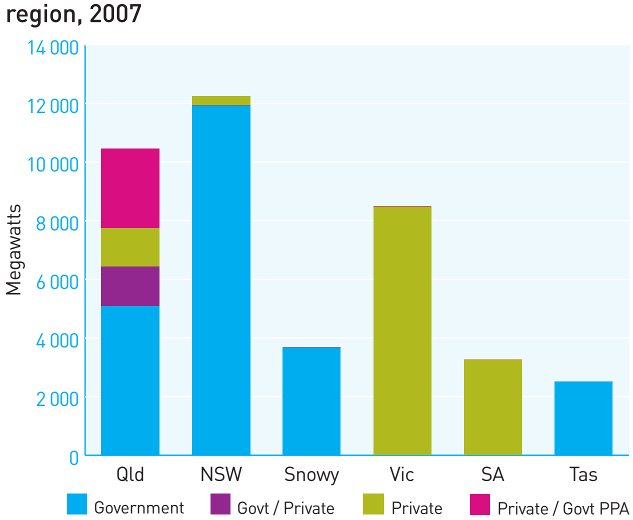
Figure 1.8
Ownership of major power stations in the NEM—major stakeholders, 2007



Notes: 1. Excludes power stations that are not managed through central dispatch. 2. AGL ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A. 3. Ecogen Energy capacity is owned by Babcock & Brown but is included for TRUenergy, which has a power purchase agreement for that capacity. 4. Figure 1.8 does not adjust ownership shares for power purchase agreements held by the Queensland government owned Enertrade over the capacity of some stakeholders. 5. Figure 1.8 accounts for AGL's acquisition of the 1260 MW Torrens Island power station in South Australia from TRUenergy, in exchange for the 155 MW Hallett power station. The transaction was completed in July 2007.

Data source: NEMMCO

Figure 1.9
Private and public sector generation ownership by region, 2007



Notes: 1. Excludes power stations that are not managed through central dispatch. 2. Private/Govt PPA refers to capacity that is privately owned but contracted under power purchase agreements to government owned corporations. 3. Govt/Private refers to joint venture arrangements between the private and government sectors. Tarong North and Callide C generators in Queensland are Govt/Private joint ventures.

Data source: NEMMCO

1.3 Investment in generation infrastructure

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

Some electricity markets (including Western Australia and most markets in the United States) use a capacity mechanism to encourage new investment in generation capacity. This may take the form of a tendering process in which capacity targets are determined by market operators and then built by the successful tenderers. Chapter 7 describes the Western Australian capacity market.

By contrast the NEM is an 'energy only' market in which wholesale price outcomes create investment signals. There are several possible indicators of the effectiveness of the NEM in attracting new generation investment. The indicators include:
> investment since NEM start
> generation capacity compared to demand
> the reliability of generation supply
> committed and proposed investment.

Investment since NEM start

There was investment in almost 5000 megawatts (MW) of generation capacity in power stations managed through central dispatch from the inception of the NEM in 1999 until 2006. This includes investment in new power stations and upgrades. Table 1.3 highlights the net change in generation capacity since the start of the market, taking account of decommissioned plant. The data excludes new investment in plant that was not fully operational in 2006, including Kogan Creek in Queensland. Investment is largely driven by price signals in the wholesale and contract electricity markets (see chapters 2 and 3 of this report).

Table 1.3 **Net change in generation capacity, 1999–2006 (megawatts)**

STATE	BASELOAD AND INTERMEDIATE PLANT	PEAKING PLANT (GAS)	TOTAL CHANGE
Queensland	2091	352	2443
New South Wales	650	–110	540
Victoria	181	583	764
South Australia	631	373	1004
Total	3553	1198	4751

Notes: Excludes power stations that are not managed through central dispatch. There was a net decommissioning of peaking plant in New South Wales over the period 1999–2006.

Data source: NEMMCO

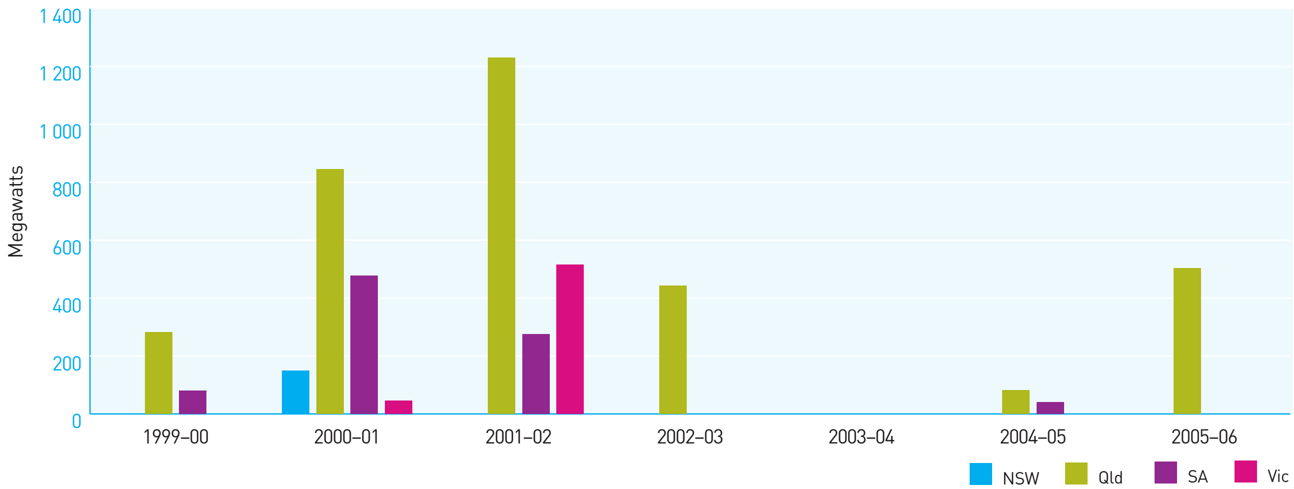
Figures 1.10 and 1.11 illustrate new investment in generation capacity since market start on an annual (figure 1.10) and cumulative basis (figure 1.11). The investment profile has differed between regions. The strongest growth has been in Queensland and South Australia, where capacity has grown by around 32 per cent since the NEM commenced. In South Australia high spot prices around 1999–2000 fuelled new investment, mainly in peaking and intermediate generation. In turn, capacity additions eased spot prices after 2000 and slowed the rate of capacity expansion. Queensland also responded to high spot prices in the late 1990s with significant investment in base load generation.

There has been less investment in New South Wales and Victoria. The bulk of new investment in Victoria has been in peaking capacity to meet summer demand peaks. This followed tight conditions in the late 1990s when it experienced short duration or 'needle' peak demand events totalling around three to four hours a year, where prices touched the market price cap.

There has also been investment in generators that bypass the central dispatch process—for example, small generators, wind generators, remote generators not connected to a transmission network, and generators that produce exclusively for self-use (such as for remote mining operations).

Solar power station

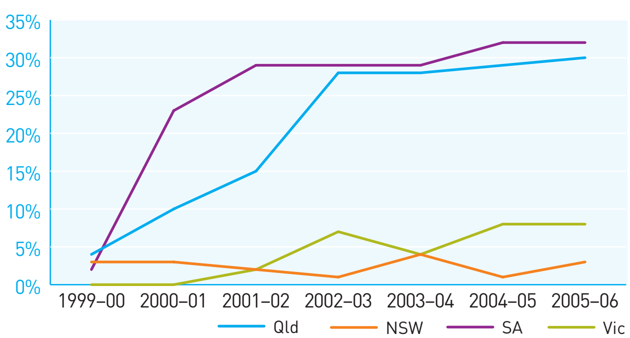
Figure 1.10
Annual investment in new generation capacity



Notes: These are gross investment estimates that do not account for decommissioned plant. Excludes power stations not managed through central dispatch.

Data source: NEMMCO, based on registered capacity data.

Figure 1.11
Cumulative growth in net generation capacity since 1999–2000



Note: Growth is measured from market start in 1998–99. A decrease may reflect a reduction of capacity due to decommissioning or a change in the ratings of generation units.

Data source: NEMMCO, based on registered capacity data.

Generation capacity and demand

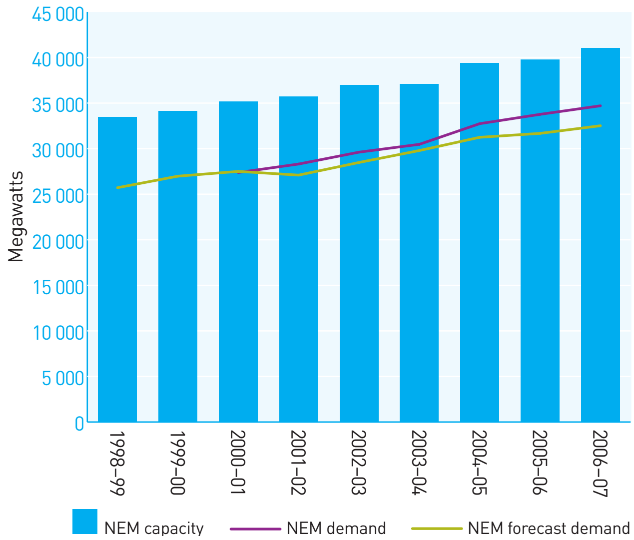
Figure 1.12 compares total generation capacity with national peak demand. The chart includes actual demand and the demand forecasts published by NEMMCO two years in advance. The chart indicates that the NEM has generated sufficient investment in new capacity to keep pace with rising demand (both actual and forecast levels), and to provide a 'safety margin' of capacity to maintain the reliability of the power system.

Reliability of generation supply

Plant failure or inadequate generation capacity can lead to interruptions to electricity supply. The reliability standard adopted in the NEM is that over the long term at least 99.998 per cent of customer demand must be met. To provide this reliability, NEMMCO 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.

In practice generation has proved highly reliable since the NEM commenced. There have only been two instances of insufficient generation capacity to meet consumer demand. The first occurred in Victoria in early 2000 where a coincidence of industrial action, high demand and temporary loss of generating units resulted in load shedding. The second occurred in New South Wales on 1 December 2005, when a generator failed during a period of record summer demand. The restoration of load began within ten minutes.

Figure 1.12
NEM peak demand and generation capacity



Note: Demand forecasts are taken two years in advance, based on a 50 per cent probability that the forecast will be exceeded (due, for example, to weather conditions) and a coincidence factor of 95 per cent.

Source: NEMMCO, *Statement of opportunities for the National Electricity Market* (various years).

Essay B of this report provides an overview of power system reliability in the NEM and the causes of supply interruptions. In summary the essay finds that generation supply is highly reliable and is a minor contributor to electricity supply interruptions.

Committed and proposed investment

Investment in generation capacity needs to respond dynamically to future projections in market conditions. Investors have committed to a number of future generation projects, and have proposed several others.

Committed projects

Committed investment projects include those already being constructed and those where the project developers have formally committed to the project's construction. NEMMCO takes account of committed projects in making future projections of electricity supply and demand.

In 2006, 1600 MW of new capacity had been committed by developers (table 1.4), of which around 75 per cent was in Queensland. The Braemer Stage 1 project became operational in late 2006, and Kogan Creek is expected to be fully operational by late 2007. TRUenergy's Tallawarra project will become the third privately owned major power station in New South Wales.

Proposed projects

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

NEMMCO's annual statement of opportunities for the National Electricity Market (SOO) refers to proposed projects that are 'advanced' or publicly announced. NEMMCO does not include these projects in its supply and demand outlooks as it considers them too speculative. In total, the 2006 SOO referred to around 9200 MW of proposed capacity (excluding wind) in the NEM. The bulk is for New South Wales and Queensland. The significant amount of proposed capacity for New South Wales may reflect that the region is currently the highest net importer in the NEM.

Table 1.4 Major committed generation capacity in the NEM, 2006

REGION	DEVELOPER	POWER STATION	FUEL	CAPACITY IN MW	YEAR OF COMMISSIONING
Qld	CS Energy	Kogan Creek	Coal	750	2007
Qld	Braemar Power Project	Braemar Stage 1	Gas	450	2006
NSW	TRUenergy	Tallawarra	Gas	400	2008

Source: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2006.

Table 1.5 Proposed capacity (excluding wind) in the NEM by region, 2006

DEVELOPER	STATION NAME	FUEL	CAPACITY IN MW	PLANNED COMMISSIONING
NEW SOUTH WALES				
Macquarie Generation	Tomago	Gas	500	–
Delta Electricity	Mt Piper upgrade	Coal	180	2008
Wambo Power Ventures	NewGen Uranquinty	Gas	640	2008–09
Delta Electricity	Bamarang (Nowra)	Gas	400	2010
Wambo Power Ventures	NewGen Bega	Gas	120	2008–09
Wambo Power Ventures	NewGen Cobar	Gas	114	2008–09
Delta Electricity	Munmorah	Gas	600	2009–10
Delta Electricity	Big Hil (Marulan)	Gas	300	2010–11
Delta Electricity	Mt Piper extension	Coal	1500	–
Eraring Energy	Eraring Black Start Gas Turbine	Gas	40	2007
Eraring Energy	Eraring Upgrade	Coal	360	2009
QUEENSLAND				
Stanwell Corporation	Stanwell Peaking Plant	Gas	300	2008
Queensland Gas Company	Chinchilla	Gas	242	2008
Origin	Spring Gully	Gas	1000	2009
Stanwell Corporation	Stanwell Coke Project	Coal	350	2008–09
Wambo Power Ventures	Braemer Stage 2	Gas	450	2008–09
SOUTH AUSTRALIA				
Origin	Quarantine expansion	Gas	70	–
AGL	Hallett expansion	Gas	250	–
International Power	Pelican Point Stage 2	Gas	225	2008
VICTORIA				
Loy Yang Power	Unit 2 upgrade	Coal	25	2009
Loy Yang Power	Unit 4 upgrade	Coal	25	2008
Origin	Mortlake	Gas	1000	2009
AGL Hydro Partnership	Bogong	Hydro	130	2010
SNOWY				
Snowy Hydro	Murray 2 upgrade	Hydro	–	–
Snowy Hydro	Tumut 3 upgrade	Hydro	–	2006–2009

Source: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2006.

Wind power

Planned wind projects are reported separately in the SOO because their capacity is weather dependent and cannot be relied on to generate when required. Wind projects can, however, play an important role in providing energy for future demand growth. The 2006 SOO listed about 5400 megawatts of proposed wind capacity, predominantly in South Australia, Victoria and New South Wales.

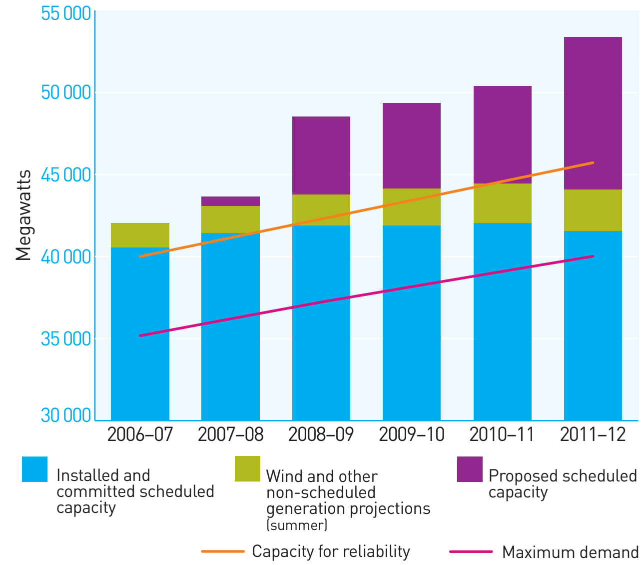
The classification of a particular project may change over time. A project listed as proposed may become committed, and then constructed. Other proposed projects may never come to fruition.

Reliability outlook

The relationship between future demand and capacity will determine both future prices and the reliability of the power system. Figure 1.13 projects future forecast peak demand in the NEM against installed, committed and proposed capacity. The chart indicates the amount of capacity that NEMMCO considers would be needed to maintain the reliability of the power system, given the projected rise in demand. While wind generation is not classified as installed capacity, it is included as a possible source of energy.

Figure 1.13 indicates that new capacity may be needed as soon as 2008–09 to meet NEMMCO's peak demand projections and reliability requirements. Installed wind generation and committed projects provide a margin of safety, but beyond 2009–10 there will be a need for further capacity. The chart indicates the extent of proposed capacity to meet the shortfall. While many proposed projects may never be constructed, only a relatively small percentage would need to come to fruition to address demand and reliability needs into the next decade.

Figure 1.13
Demand and capacity outlook to 2011–12



Notes: The maximum demand forecasts for each region in the NEM are aggregated based on a 50 per cent POE and a 95 per cent coincidence factor. 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: NEMMCO, *Statement of opportunities for the National Electricity Market,* 2006.

While the uncertain nature of proposed projects means they cannot be factored into NEMMCO's reliability equations, they do provide an indicator of the market's awareness of future capacity needs. In particular, they can be seen as an indicator of the extent of competition in the market to develop electricity infrastructure.

Government policies aimed at reducing carbon emissions will likely influence the mix of proposed projects that are constructed. Mandatory renewable energy targets, Queensland's 13 per cent gas scheme, the greenhouse gas abatement scheme in New South Wales and the Australian Capital Territory, and the likely introduction of a national emissions trading scheme will affect investment decisions and increase the viability of low emission technologies.[8]

8 For more information on greenhouse gas emissions policies, see appendix B of this report.