8. Present and Future Fossil Fuel Technologies

This Chapter reviews the current status and likely future development of fossil fuel technologies. It considers resources, technology development pathways, present and future costs, and limitations on deployment and operation. It is based on recent review articles, data both new and old, and interviews with several leaders in R & D and business in each of the technologies.

First, existing coal-fired power stations and possible improvements to coal burning technologies are considered. An important indicator of performance of power stations is the thermal efficiency, which is the electrical energy sent out from the power station divided by the chemical energy stored in the fuel, expressed as a percentage. The best thermal efficiencies obtained by Australian conventional black coal-fired power stations up to 2001 were about 36% (HHV).

Another important power station operating parameter is the capacity factor, which is total annual generation divided by total annual generation that it would have achieved if it had operated at its nameplate capacity for the full year, usually expressed as a percentage. Capacity factor of thermal power stations measures both performance and operating strategy. For instance, base-load power stations are operated as much as possible at full power because of high capital costs and low fuel costs. Gas turbine peak-load stations have low capital costs, are operated as little as possible because of high fuel costs, and so have low capacity factors, typically 2-10%. In the case of hydro-electric peak-load stations, there are also constraints on operation because the amount of stored water is limited. Intermediate-load stations are operated just as the name suggests and so have capacity factors falling between those of base-load and peak-load.

At current rates of consumption and export, Australia has 200-300 years of steaming coal, probably 50-100 years of natural gas (depending on the quantity to be exported) and probably only two decades of cheap oil.

8.1. Conventional (pulverised fuel) coal-fired power stations

The combustion of coal is by far the largest contributor to Australia’s greenhouse gas emissions, producing 186 million tonnes of CO_2 in 2000. The vast majority of this, about 170 Mt, was emitted by coal-fired power stations. Coal is also the fuel with the highest greenhouse intensity.

With the restructuring of the electricity industry in the mid-1990s, it has become much more difficult to obtain data on the performance and costs of power stations. The following data have been collected from public sources, some extrapolated from before restructuring, and current expert opinion. Different sources use different methods and obtain different results, even disagreeing on whether electricity from black coal is dearer than from brown -- e.g. compare ACIL Tasman (2003) with SKM (2003).

A typical modern black coal-fired power station, rated at (say) 2000 MW (2 GW) and put into operation in the 1990s, has a thermal efficiency of about 36%, a capacity factor of 75-85%, sends out about 14,000 GWh p.a. of electricity and consumes about 6 million tonnes of black coal in the process. Its greenhouse gas intensity is typically 0.85-1.0 Mt CO_2 emitted per TWh of electricity sent out. Its capital cost in 2001 Australian dollars was about $1400/kW installed, including interest during construction. Its fuel cost is about $1/GJ[1] or 1 c/kWh and its other operation and maintenance costs amount to about 0.39 c/kWh. With refurbishment, its operational life may be extended to about 40 years. However, since refurbishment is not included in the above costings, an economic lifetime of 30 years has been assumed. With a discount rate of 8% and 10% real and using the levelised annuity formula, the cost of electricity including all fixed and variable costs becomes 3.6 and 4.0 c/kWh, respectively.

The typical modern brown coal-fired power station, rated at (say) 2000 MW (2 GW) and put into operation in the 1990s, has a thermal efficiency of about 28%, a capacity factor of about 85%, sends out about 15,000 GWh p.a. and consumes about 19 million tonnes of brown coal in the process. Its greenhouse gas intensity is typically 1.2-1.45 Mt CO_2 emitted per TWh of electricity sent out. Its capital cost in 2001 Australian dollars was about $1800/kW installed, including interest during construction. Its fuel cost is about 0.4 c/kWh and its other operation and maintenance costs amount to about 0.37 c/kWh. With refurbishment, its operational life may be extended to about 45 years. However, since refurbishment is not included in the above costings, an economic lifetime of 30 years has been assumed. With a discount rates of 8% and 10% real and using the levelised annuity formula, the costs of electricity including all fixed and variable costs become 3.6 and 4.1 c/kWh, respectively.

The lower capacity factors of black coal power stations compared with brown reflect the situation that the output of the former can be varied within bounds, allowing the stations to follow variations in demand on timescales of an hour or two. Thus black coal stations can be operated as both base-load and intermediate load. In Victoria, the brown coal stations are strictly base-load and natural gas stations fill the role of intermediate load.

The greatest uncertainties seem to be the magnitudes of capital costs of coal-fired power stations. There is also uncertainty about whether the usually quoted capacity factors are typical of 'normal' operating conditions or whether they reflect lifetime averages in which there may be occasionally long breakdowns in 'abnormal' years. In practice, there also will be variations in the costs depending upon how the power stations are financed – e.g. how much debt and how much equity.

Within the category of pulverised fuel coal-fired power stations, the main pathway to improvements in thermal efficiency and hence reductions in greenhouse gas emissions is to increase the steam temperature and pressure in the boilers. The first power stations with *supercritical* boilers, having steam temperature around 538˚C and pressure around 24 MPa, were installed in Queensland in 2002-2003. The generators expect thermal efficiency of around 40% and greenhouse intensity of about 0.8 Mt CO_2/TWh sent out. *Ultra-supercritical* boilers, with temperatures around 600˚C and pressure around 36 MPa, are beginning to be installed overseas. These have thermal

[1] One of the new coal-fired power stations commissioned recently in Queensland, Millmerran, is located inland and has considerably cheaper coal. However, because it is air-cooled rather than water-cooled, its capital cost is higher.

efficiencies of 42-45% and manufacturers claim that they will soon be able to reach 50% in the foreseeable future. However, none of these new coal-fired power stations can reduce greenhouse gas emissions to anywhere near that of today's combined cycle natural gas-fired power stations.

8.2. Combined cycle gas-fired power stations

Combined cycle power stations use a gas turbine, fuelled by liquid or gaseous fuels, to generate electricity and take the waste heat from that process to generate steam to drive a steam turbine to generate additional electricity. Because they waste less heat than conventional steam or turbine power stations, combined cycle power stations have one of the highest thermal efficiencies of all non-renewable generating plant currently available. (Cogeneration is currently the most efficient way of generating electricity and usable heat together -- see Section 8.6.) Pelican Point in South Australia is the largest Australian combined cycle power station fuelled by natural gas. Such power stations currently have thermal efficiencies around 50 – 55% -- new models are just coming onto the market with thermal efficiencies of 60% and these will become state-of-the-art by 2010. Greenhouse intensities are currently around 0.4 Mt CO_2/TWh of electricity sent out and declining. In base-load operation capacity factors should be 85-90%, i.e. slightly better than those of base-load coal. It is possible to fuel combined cycle power stations with biogas or coal bed methane.

According to Geoscience Australia (2002), natural gas reserves on 1 January 2001 amounted to 157,343 PJ, of which about 20% is economically recoverable in today's market. The gas industry is confident that the major gas fields of the North-West Shelf and in other remote locations have the capacity to supply both very large export contracts of liquefied natural gas and, as required by our clean energy scenarios, greatly expanded domestic supplies of natural gas. To utilise these fields, pipelines would have to be built to connect remote gas supplies to the existing transmission pipeline networks of the eastern States.

In addition, most black coal seams contain methane gas, naturally held within pores and tiny fractures of the coal. In Queensland and NSW there are substantial reserves of this coal-bed methane in coal seams which are too deep or otherwise considered to be uneconomic or unsuitable for mining. These gas reserves could become a substantial source of gas supply in each of these states. However, only a small fraction of the reserves is actually recoverable and most of this at a higher price than conventional natural gas. In Queensland coal-bed methane is already being produced commercially at several separate fields and is connected to the state-wide pipeline network. In NSW there is active exploration but as yet no commercial production. In both States there are plans to expand the production of this gas.

Coal seam methane must be distinguished from waste coal mine methane, which is methane extracted from coal seams during or just prior to mining. Mine safety and productivity are usually the main drivers for waste coal mine methane collection, but this methane, if not collected, is also a significant source of fugitive energy greenhouse emissions (see Section 6.7). There are projects in both NSW and Queensland which collect waste coal mine methane and use it to produce useful energy in various ways, including one that has been operating since the early 1990s in NSW, generating about 100 MW of electricity.

8.3. Integrated gasification combined cycle (IGCC) coal-fired power stations

IGCC is a combined cycle process fuelled by gasified coal. Coal is gasified by heating it in a gasifier in the presence of steam and oxygen. This produces a fuel gas made up mainly of hydrogen and carbon monoxide. The fuel gas is cleaned of impurities and burnt in a gas turbine, producing electricity, carbon dioxide and water vapour. The waste heat from the gasification process is partially recovered and used to generate steam to drive a steam turbine, thus providing a second 'cycle' to generate electricity. There are currently no coal-fired combined cycle power stations in Australia, although there are several demonstration plants overseas[2].

In our future energy scenarios, we consider that any black coal-fired power stations existing in 2040 will use IGCC with thermal efficiency of about 43% HHV. However, even these stations are expected to have a greenhouse intensity of about 0.7 Mt CO_2/TWh of electricity sent out. Since the gasification of coal is a low efficiency process that produces CO_2, the reduction of greenhouse intensity achieved by burning coal gas is partially offset by the emissions from gasification. The net result is that building an IGCC power station makes little sense unless it is combined with the capture of CO_2.

8.4. Geosequestration of CO_2

One technically possible way of substantially reducing greenhouse gas emissions from coal-fired power stations would be to capture the CO_2, compress it and transport it by pipeline and/or ship to a secure storage location. Capture of the CO_2 can in principle be done in two different ways:

- after the gas turbine 'cycle' in an IGCC power station; or
- after fuel combustion in a conventional (pulverised coal or natural gas) power station, by extraction of CO_2 from flue (exhaust) gas as it passes up the chimneys.

The CO_2 produced in the gasification process is more concentrated than in the flue gas and so is easier to extract.

The main option for storage of CO_2 from a large point source such as a power station is deep underground, either in depleted oil and gas fields, or in un-minable coal mines or in saline aquifers located in sedimentary rocks. In Australia, oil and gas fields will not be sufficiently depleted to be used before about 2030 and deep un-minable coal mines would not absorb the CO_2 fast enough to be effective. Therefore, the principal option for the period up to 2030 or 2040 is saline aquifers (Bradshaw et al., 2002). For secure storage suitable saline aquifers have to have caps composed of rock that is impervious to CO_2 and have no exit holes. Saline aquifers are not well mapped and the science of storing CO_2 in them is not fully understood.

The main concerns about geosequestration are:

- the amount of CO_2 that could be stored annually;
- ensuring secure storage of CO_2;

[2] The first full-size IGCC (253 MWe) based on coal is in trial operation in Buggenum (the Netherlands) with a thermal efficiency of about 43 %.

- the environmental and health impacts of an escape of CO_2;
- the cost.

According to a preliminary study by the GEODISC group of the Australian Cooperative Research Centre for Greenhouse Gas Technologies, the largest storage potential is in Western Australia but almost all of the biggest point sources emitters are in eastern Australia. As a result Australia only has the potential to store 100-115 Mt per year of CO_2, corresponding to 27%-31% of total annual CO_2 emissions (Bradshaw et al., 2002). Therefore geosequestration is at best a partial solution and Australia would do well to continue with and expand the development of efficient energy use and renewable sources of energy.

The risks of escape comprise the hazards of global climate change; the danger of CO_2 (which is heavier than air) filling a valley near the escape point and asphyxiating every person who is submerged in it[3]; and local environmental impacts on soil and waterway ecosystems. These risks can be reduced at a price.

The cost of capture and geosequestration of CO_2 from fossil fuelled power stations has been calculated by the International Energy Agency (Davison, Freund & Smith, 2001; Freund & Davison, 2002). At the rate of exchange of 1 AUD = 0.67 USD and fuel costs of 1.0 AUD per GJ of black coal and 3.1 AUD per GJ of natural gas, the estimated cost of avoiding CO_2 emissions through geosequestration is US$45/t CO_2 (A$67.5/t) for IGCC, US$55/t CO_2 (A$82.5/t) for conventional (pulverised) coal power stations and US$45/t CO_2 (A$67.5/t) for natural gas combined cycle. Other international studies, such as US Department of Energy, give higher costs. Therefore, it is surprising that the Prime Minister's Science, Engineering and Innovation Council (PMSEIC) is claiming costs of only A$10/t CO_2, without providing any published study to support this extraordinary result. Recent presentations of this claim indicate that it may only represent the geosequestration part of the costs, but not the gasification, combustion or collection of the CO_2 parts. It is unclear whether the cost of transporting CO_2 is included. However, it should be noted that these recent presentations compare the partial cost of so-called 'clean coal' electricity with the full costs of gas fired and renewable sources of electricity.

Continuing with the IEA calculations, the above costs of geosequestration translate into electricity costs in Australian currency of about 10 c/kWh for IGCC and conventional coal-fired power stations and about 7 c/kWh for combined cycle natural gas. Since the projected coal electricity plus geosequestration costs are well above current biomass and wind electricity prices, we do not consider this option as part of our principal scenarios to 2040. However, natural gas combined cycle generation plus geosequestration seems to be a real option for Victoria and Western Australia. We also consider that all new natural gas production at the North-West Shelf, such as the proposed Gorgon field, must capture and store securely the CO_2 that comes up with the gas.

A more detailed discussion of CO_2 emissions from Australia's coal-fired power stations and the limitations of geosequestration is given by Diesendorf (2003).

[3] In 1986 a large amount of CO_2 that had been produced by volcanic action escaped from Lake Nyos in the Cameroons. It filled neighboring valleys out to a distance of nearly 30 km and killed 1700 people.

8.5. Oil substitutes from oil sands, shale and coal

The vast majority of liquid fuels from petroleum – such as petrol, diesel and LPG -- are used for transport. A small fraction is used to supply stationary energy in mines, farms, factories and remote homes, and a somewhat larger fraction to power mobile machinery, such as tractors and earth moving equipment, in the Mining, Construction and Agriculture, etc. sectors. Liquid fuels can also be used to generate electricity in power stations with boilers or gas turbines and are widely used for that purpose in many countries, but in Australia, where coal and natural gas are readily available and much cheaper, use of petroleum for electricity generation is limited to small power plants such as diesel and petrol generators.

As oil becomes scarcer and more expensive over the next few decades, non-renewable substitutes in the form of liquid fuels could be obtained from oil sands, shale oil and oil from coal processes, as is currently happening in some other countries, such as Canada (oil sands) and South Africa (oil from coal). In addition, a product called Ultra-Clean Coal, which is a solid fuel with very low ash content made from coal, has been developed in Australia for direct firing, as a very fine powder, in gas turbines.

The production and combustion of each of these potential oil substitutes emits much greater total amounts of CO_2 than the equivalent quantity of oil. Therefore, we do not consider that they will ever be used in significant quantities in Australia. Rather, we envisage liquid fuels from biomass – methanol, ethanol and bio-oils – being used increasingly as oil prices increase (see Chapter 7).

8.6. Cogeneration of heat and electricity

Cogeneration, also termed combined heat and power or CHP in many countries, is the simultaneous production of electricity and useful heat from the same energy source. The energy source is normally combustion of a fossil or biomass fuel. Cogeneration is a means of maximising the useful energy extracted from the combustion process and thereby maximising the efficiency of energy use in terms of both the First and Second Laws of Thermodynamics (see Glossary).

For this reason, cogeneration has long been recognised as a most important and effective means of increasing overall energy efficiency, and thereby reducing the level of greenhouse gas emissions per unit of fossil fuel consumed and of useful energy services delivered. Indeed, like distributed generation in general, cogeneration is a technology which was once much more widespread, and over the last 50 or 60 years has been driven out of the electricity supply mix by the shift to very large centralised power stations and long distance electricity transmission. One way of looking at the long historical trend is to regard the cost of cogeneration as broadly constant over the long term, having been displaced by large, low-cost coal fired power stations, and coming into its own again in the future as environmental considerations and other factors force up the costs of coal-fired generation.

Cogeneration can be used where there is a combined need for both electricity and process heat, the latter normally being supplied as steam, though not necessarily so. The combined need may either be at a single site or simultaneously at several neighbouring sites which are sufficiently close to allow economic and efficient transportation of the steam generated. If electricity can be sold into the wholesale market at a high enough price, a large heat load alone can suffice to support a cogeneration installation. Typical sites for large cogeneration projects include chemical plants, oil refineries, pulp mills, sugar mills and mineral processing plants which use aqueous phase digestion processes, such as alumina and nickel refineries. Smaller cogeneration projects are suitable for hospitals, larger educational institutions, leisure facilities and office buildings. In the case of office buildings, widespread adoption of absorption chillers (instead of compression cycle chillers, which are the norm today) would combine well with gas engine cogeneration. At present, most cogeneration capacity in Australia is at large industrial sites.

There are a number of different types of cogeneration technology. For many years, all cogeneration installations were based on the use of conventional fuel fired boilers, with steam turbines as the prime mover used for electricity generation. Two alternative configurations are possible: the so-called topping cycle[4], in which steam is passed first through a back pressure turbine[5] before going to the thermal load, and the so-called bottoming cycle, in which the sequence of the two components is reversed. The topping cycle is far more common than the bottoming cycle. The latter may be associated with either a boiler installation or a high temperature thermal process, such as a kiln or furnace, where the high temperature exhaust gases are passed through a heat exchanger to generate steam. There are currently a number of these projects associated with furnaces or kilns in Australia.

In recent decades a diversity of new technologies have emerged, as summarized in Table 8.1, and today gas turbine technology has largely superseded steam turbine technology for medium size installations.

Typical or representative characteristics of these various configurations are shown in Table 8.2, taken from a Canadian report (Strickland, 2002). It should be noted that ‘high thermal quality’ refers to high temperature/pressure steam, ‘medium’ thermal quality’ to low temperature/pressure steam, and ‘low thermal quality’ refers to hot water.

Table 8.1: Types of cogeneration

[4] This terminology derives from thermodynamics; the passage of energy through a total process from high temperature/high quality to low temperature/low quality. It is described as moving from the “top” to the “bottom” in thermodynamic terms, so “topping” means taking energy out at the high temperature end and “bottoming” to taking energy out at the low temperature end.
[5] A back pressure turbine is one in which steam exits from the turbine at a significant positive pressure, and thus still contains considerable energy, to be used in thermal processes.

Generation prime mover	Thermal energy carrier	Thermal energy source	Typical size range (indicative only)	Typical host industry or sector
Back pressure steam turbine	Steam	Steam turbine exhaust	5-50 MWe	Manufacturing (various)
Condensing steam turbine	Steam or high temperature combustion gases	Boiler or kiln/furnace	5-50 MWe	Manufacturing (various)
Open cycle gas turbine	Steam	Exhaust gas heat exchanger	5-100 MWe	Manufacturing, large commercial
Reciprocating engine	Hot water or steam	Engine cooling water or exhaust gas heat exchanger	< 2 MWe	Commercial/ buildings, small industrial
Combined cycle gas turbine	Steam	Exhaust gas heat exchanger and/or Steam turbine exhaust	> 100 MWe	Large industrial/ manufacturing
Microturbine	Steam	Exhaust gas heat exchanger	< 100 kWe	Commercial/ buildings
Fuel cell	Steam or hot water	Cooling water	< 500 kWe	Demonstration stage only

Table 8.2: Typical performance characteristics of various types of cogeneration configuration

Cogeneration System	Electrical energy output (% of fuel input)	Overall efficiency (%)	Heat-to-power ratio	Thermal qualities
Back-pressure steam turbine	14-28	84-92	4.0-14.3	High
Condensing steam turbine	22-40	60-80	2.0-10.0	High
Gas turbines	24-42	70-85	1.3-2.0	High
Reciprocating engine	33-53	75-85	0.5-2.5	Low
Combined cycle gas turbine	34-55	69-83	1.0-1.7	Medium
Fuel Cells	40-70	75-85	0.33-1	Low to High
Microturbines	15-33	60-75	1.3-2.0	High

Source: Strickland (2002)

It is important to appreciate “that inherently, different types of configurations provide different natural quantities of steam and electricity” (Cogeneration Ready Reckoner Manual, p. 14), as Table 8.2 implies. They are also inherently suited, or most economically efficient, in different size ranges. Broadly speaking, reciprocating engines are the current optimal technology for installations of up to about 2 MWe capacity where relatively low grade heat is typically required. In coming years they will probably be superseded in that role by microturbines (which are very small gas turbines) and fuel cells. Fuel cells in particular may also become economic at sizes smaller than any current cogeneration installations (suitable for an individual house). However, since they are as yet not a fully commercially proven technology, we have not included fuel cells in our 2040 scenario.

At larger sizes, steam turbines and/or gas turbines come to the fore. The choice between the two will depend on a number of factors, including the balance of steam, the pressure and temperature of the heat/steam required, and electrical output desired. In general, a CHP system is designed to meet the heat needs of the host. Then, if a relatively small electrical output is required, as for example an establishment wishing to become partially self sufficient in electricity, but not a significant exporter, steam turbines would be the technology of choice. Otherwise, reciprocating engines would be used in small to medium installations and combined cycle gas turbines (CCGT) would be used in very large installations, where the objective is to maximize electrical production for export, relative to a large on-site steam load.

Looking at cogeneration as a whole, the mix of the different types of fully commercial technology, i.e. not including fuel cells and microturbines, across the whole potential size range for cogeneration installations is still a cost curve which declines with size. For example, a report by Sinclair Knight Merz (2001, pp. 56-7) estimates that the cost of cogenerated electricity for plants of 5 MW capacity or smaller is above $60 per MWh, falling to around $50 per MWh at sizes around 50 MW and flattening out at about $40 per MWh above 200 MW capacity. As fuel cells become fully commercially mature technologies, their costs will fall, but it seems probable that the foreseeable future they will be more costly than large steam and gas turbine plant in terms of $ per MW of capacity or per MWh of electricity generated. However, being much closer to the electrical loads, small plants can compete on a more equal basis when transmission and distribution costs are taken into account.

As the cost data above demonstrates, medium and larger cogeneration is currently more costly than coal-fired base-load electricity, but not greatly so, and full consideration of avoided transmission, distribution and greenhouse costs could tip the balance in favour of cogeneration. Technology improvements can be expected to reduce the cost of smaller cogeneration installations. Accordingly, our scenario includes widespread use of cogeneration in industries with a requirement for thermal energy in the form of steam (including both manufacturing and also hospitals, educational institutions etc. in the Commercial/Services sector). We also assume widespread use of absorption chillers and small cogeneration in commercial buildings, but do not include use of topping cycle installations in industries that make extensive use of kilns, such as cement and glass. It is assumed that all these installations will be fuelled by natural gas, except in the sugar and pulp and paper industries, which produce large quantities of biomass waste. It is assumed that all sugar mills will be associated with new, technologically optimised cogeneration plants, which can meet the in-house requirements of the mills for steam and electricity from only half the available quantity of biomass, leaving the remaining bagasse available to fuel additional electricity generation. The total electrical energy produced from this group of plants will of course depend on the total size of the sugar industry.

8.7. Phase-out of existing fossil fuelled power stations

One of the constraints on transforming the electricity industry into a much cleaner industry, both in terms of greenhouse gas emissions and other forms of pollution and land degradation, is the long lifetimes of existing power stations. Without a major refurbishment, power stations can be expected to run for 30-35 years. We assume that henceforth any proposal for a major refurbishment or for a new power station would have to meet very stringent conditions on greenhouse intensity: specifically that such stations would be required to have greenhouse intensities less than or equal to those of the best combined-cycle natural gas power stations in 2003. In practice this is likely to entail that all existing coal-fired power stations, with the possible exception of those commissioned on or after 2000, would have been closed down by 2040.

Table 8.3 lists all Australia's large power stations in order of decreasing total CO_2 emissions, giving their dates of commissioning. The data suggest that, on the basis of our assumed greenhouse constraint, only three existing coal-fired power stations may be still operating in 2040: Millmerran, Tarong North and Callide C. All are located in Queensland and together have a total generating capacity of 2130 MW. At the time of writing, a full year's energy generation data is not available for these stations. Nevertheless, an approximation can be obtained by assuming an average capacity factor of 86%, giving total annual electricity generation of about 16 TWh, which is about 8% of total Australian generation in 2001. Our principal scenario considered in Chapter 10 retains these three power stations.

Table 8.3: Dates of commissioning and greenhouse gas emissions of major existing power stations (Year 2000 or Financial Year 2000-01)

Power station	State	Type of power station[a]	Year of commission	Capacity (MW)	Generating units (no. x MW)	Approx. CO_2 emissions[b] (Mt)	Approx. greenhouse intensity[c] (Mt CO_2/ TWh sent out)
Loy Yang A	Vic	brown	1984/87	2,000	4x500	17.3*	1.28
Hazelwood	Vic	brown	1964/71	1,600	8x200	16.3*	1.46
Bayswater	NSW	black	1982/84	2,640	4x660	15.8*	0.93
Yallourn W	Vic	brown	1973/75	1,450	2x350 + 2x375	13.4*	1.43
Eraring	NSW	black	1982/84	2,640	4x660	12.4	0.9
Stanwell	Qld	black	1993/96	1,400	4x350	10.1	1.0
Gladstone	Qld	black	1976/82	1,680	6x280	9.8	1.0
Loy Yang B	Vic	brown	1993/96	1,000	2x500	9.7	1.15
Tarong	Qld	black	1984/86	1,400	4x350	9.4*	0.84
Mt Piper	NSW	black	1992/93	1,320	2x660	9.4	0.9
Liddell	NSW	black	1971/73	2,000	4x500	8.8*	0.98
Vales Point	NSW	black	1978	1,320	2x660	6.8	1.03
Muja	WA	black	1965,81,85/86	1,040	4x60+4x200	6.0	
Callide B	Qld	black	1988/89	700	2x350	5.6	1.0
Northern	SA	brown	1985	520	2x260	4.8	1.1
Wallerawang C	NSW	black	1976/80	1,000	2x500	4.3	1.0
Callide C	Qld	black	2001 2001	840	1x420 1x420	3.0 N/A	0.95
Swanbank A & B	Qld	black	1970/73 1966/69	908	4x125 + 6x68	2.8	1.06
Collie	WA	black	1999	330	1x330	2.5	
Torrens Island[e]	SA	gas		1280		1.9 (e)	0.56 (e)
Kwinana[d] A & C	WA	black	1970, 76	880	4x200 + 4x120	1.8	
Munmorah	NSW	black	1969	600	2x300	1.6	1.1
Pelican Point	SA	gas CC	2000	478	2x160+1x158	1.1	
Kwinana[d] B	WA	gas	1970	240		0.3	
Millmerran	Qld	black	2003	840	2x420	N/A	N/A
Tarong North	Qld	black	2003	450	1x450	N/A	N/A

Sources: ESAA (2003), websites of generators where they exist, and personal communications from some generators
Notes:

a. 'Brown' and 'black' denote boiler-type base-load power stations burning brown and black coal respectively; 'gas' denotes boiler-type natural gas-fired; 'gas CC' denotes combined-cycle natural gas.
b. CO_2 emissions with asterisk are obtained from company's published reports. The others are our estimates.
c. CO_2 intensity is given here in terms of Mt CO_2 produced divided by TWh of electricity sent out from the power station. Electricity generated is typically 6-8% higher than electricity *sent out*. The difference is used to operate the power station.
d. Here we assume that Kwinana units A & C burn coal, and unit B burns mainly gas.
e. Year 2000 data. CO_2 emissions from personal communication from TXU.