Historic and projected energy sector investment

Final Report

Firecone Ventures Pty Ltd

November 2008

Disclaimer

Firecone Ventures Pty Ltd (including the directors and employees) makes no representation or warranty as to the accuracy or completeness of this report. Nor shall they have any liability (whether arising from negligence or otherwise) for any representations (express or implied) or information contained in, or for any omissions from, the report or any written or oral communications transmitted in the course of the project.

Table of Contents

1 Introduction

1.1 Role of this paper

The AEMC is considering the impact of climate change policies on the energy market framework.

Climate change policies are likely to affect the level of annual investment in the Australian electricity sector, and the broader energy sector, in several ways:

- The policies will increase prices. This is likely to reduce demand and so reduce investment requirements

- The policies will alter the variable costs of different generation technologies, in line with their emissions intensity. This may lead to early retirement of some high emissions plant. It will also technology decisions on future generation investments

- The policies will provide a subsidy for eligible renewable generation technologies. This is expected to lead to a rapid increase in the level of installed capacity for these technologies. These plant have high capital costs and low operating costs. As a result the impact on investment requirements may be large.

This note considers the scale of the investment requirement in the Australian energy sector. We look in turn at historical investment over roughly the last ten years, and forecast investment. The forecast investment period depends on the source and is typically up to 2020.

Our main focus is on electricity generation. The impact of climate change policies is likely to be large and there is a reasonable consensus on the nature of the impact. We have also considered electricity networks and gas supply infrastructure in a lower level of detail.

1.2 Summary investment trends

Investment in electricity generation over the last decade has averaged around $390M in real $2008. Investment in electricity generation is likely to increase significantly as a result of climate change policies. The expanded renewable energy target is likely to be mostly met by wind generation. Wind generation has low capacity factors. This means a large volume of installed capacity. In addition the unit costs of wind generation are substantially above other plant.

ACIL Tasman forecast the costs of the expanded RET at $23 billion over ten years. This would require an annual investment of $2.3 billion per year. The Commonwealth Treasury has not provided a cost estimate. However their assumptions on additions to capacity look reasonably comparable.

ACIL Tasman have also forecast $7 to 10 billion of investment in thermal generation over the same period. This forecast reflects their assumption of substantial closure of coal-fired generation over this period. Other forecasts anticipate lower levels of closure.

Capital expenditure on regulated electricity transmission networks over the last three years this time has been around \$4.3 billion, or around \$1.4 billion per year. Forecasts suggest that this expenditure will continue or may increase.

Capital expenditure on regulated distribution networks in recent years has been around \$3 billion per year.

There has been a substantial increase in gas supply networks. Most forecasts suggest a substantial increase in gas-fired generation over the next decade. This may lead to substantially increased investment in gas pipelines. However, the forecast range is very large, reflecting uncertainty over future prices and demand.

2 Historic investment in electricity generation

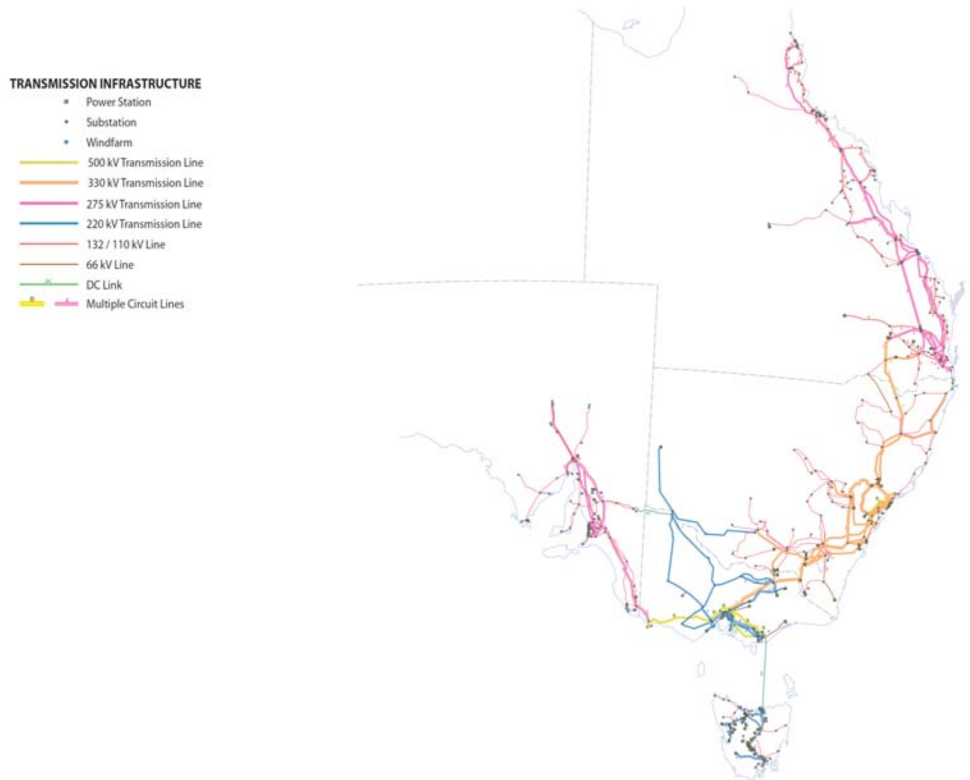
2.1 Major electricity markets

The National Electricity Market (NEM) operates as a wholesale market for the supply of electricity to retailers and end users within Australia's eastern states and territories. The NEM includes South Australia, Victoria, New South Wales, Queensland, Tasmania and the Australian Capital Territory. In geographical span, the NEM is the largest interconnected power system in the world. It covers a distance of 4,500km from Northern Queensland to South Australia and Tasmania[1].

The NEM has around 260 registered generators, six state-based transmission networks (linked by crossborder interconnectors) and 13 major distribution networks that collectively supply electricity to over eight million end-use customers[12]. Figure 1 shows the coverage of the NEM and how the network is connected.

In 2006-2007, approximately 195,000 gigawatts of electricity was traded in the NEM[3].

Figure 1: Networks in the National Electricity Market[4]



[1] *State of the Energy Market Report 2007*, Australian Energy Regulator, 2007, p. 80
[2] *An Introduction to Australia's National Electricity Market*, NEMMCO, 2008 p. 4
[3] *About the NEM – Overview*, NEMMCO, http://www.nemmco.com.au/about/about.html, accessed 6 November 2008
[4] *An Introduction to Australia's National Electricity Market*, NEMMCO, 2008 p. 31

There are three major electricity networks within WA, which are administered by the Independent Market Operator on behalf of the Wholesale Electricity Market:

- The South West Interconnected System (SWIS) is Western Australia's largest electricity network. It provides 5,134MW of the total 6,951MW of installed generation capacity[5], and covers over 322,000 square kilometres. Statewide, approximately 60% of the installed capacity is fuelled by natural gas, with coal (35%), oil (2%) and renewable energy (4.2% - mainly biomass and wind and hydro) providing the remainder[6].

- The North West Interconnected System (NWIS) delivers an additional 400MW of generation capacity to the north-west of the state[6].

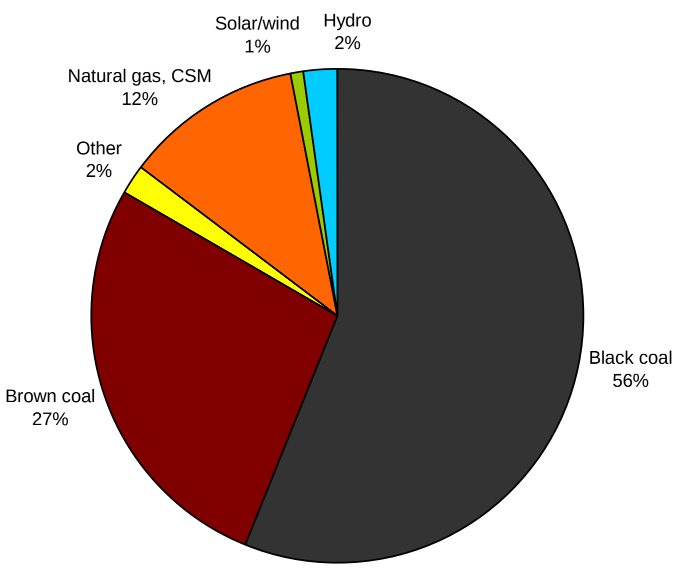
- The Esperence System in southern Western Australia consists of a gas-fired power station running in parallel with a network of wind farms. These plant provide the isolated town of Esperance with 22% of their electricity requirements[7].

The Northern Territories operates an interconnected network. In addition there are a number of isolated networks. The most major isolated networks are those supplying large mining and related loads.

2.2 Fuel consumption for electricity

The total fuel consumption for the production of electricity Australia-wide in 2006/07 is shown in Figure 2.

Figure 2: Total energy consumption for electricity generation in Australia (2006/07)

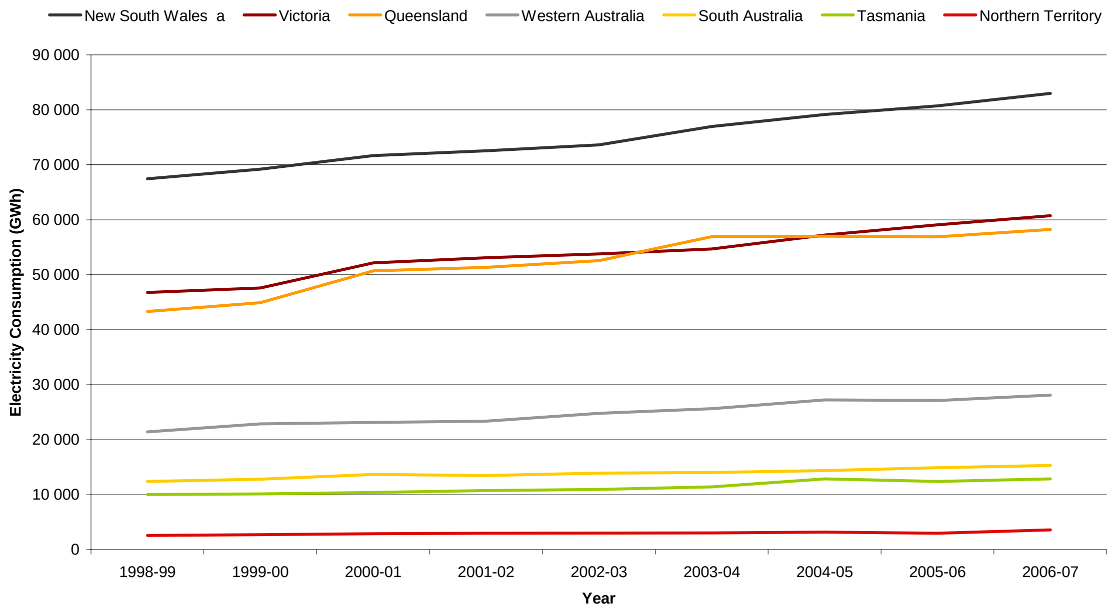


source: ABARE, 2006/07[8]

[5] *State of the Energy Market Report 2007,* Australian Energy Regulator, 2007, p. 204
[6] *State of the Energy Market Report 2007,*Australian Energy Regulator, 2007, p. 205
[7] *Esperance,* Diesel & Wind Systems, accessed 6 November 2008, http://www.daws.com.au/projects/Esperance.html

Figure 3 shows electricity consumption trends by state over this time period. Electricity consumption in Australia has increased by over 28% from 1998 to 2007. The Northern Territory has seen the greatest increase in electricity consumption, consuming 38% more in 2006/07 than in 1998/99. Victoria, Queensland and Western Australia also increased their consumption of electricity by more than 30% over the last 10 years.

Figure 3: Electricity Consumption in Australia from 1998 to 2007



source: ABARE, 2006/07[8]

2.3 Type of generation investment

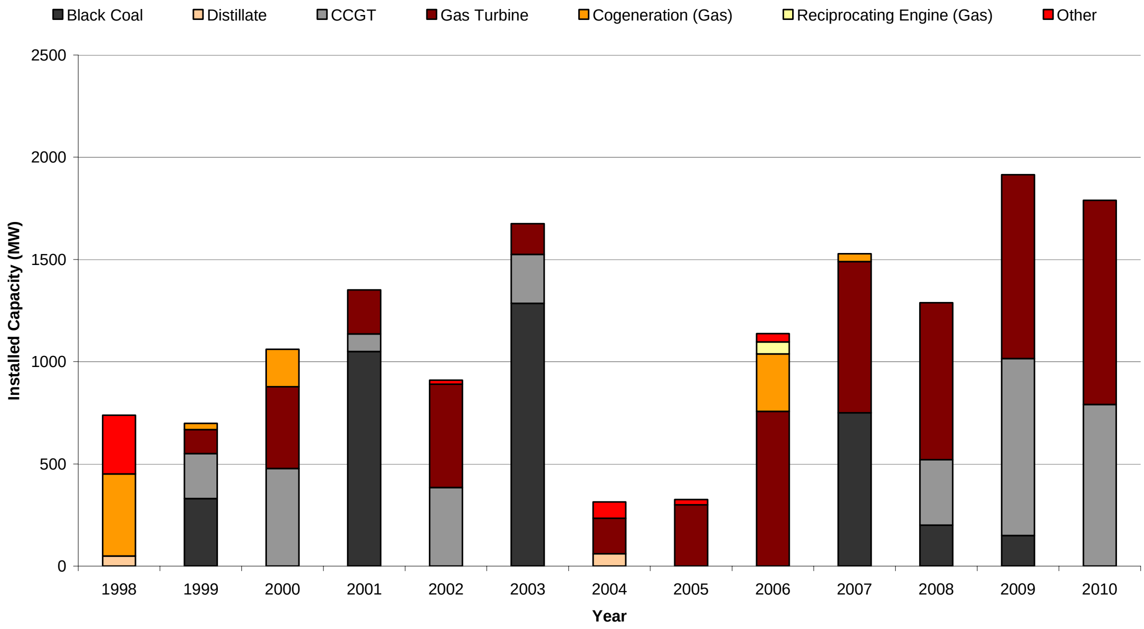
Australia's total installed electricity generation capacity consists of 47,000MW in grid-connected capacity, and a further 4,228MW in embedded and non-grid capacity[9]. Figure 4 shows the generation type and year of commissioning for fossil fuel based electricity generation capacity over the last ten years. The figure shows actual investment and committed investment that will be installed by 2010.

In the last 10 years, over 14,700MW of fossil fuel powered electricity generation capacity has been installed, or is currently under construction, in Australia.

[8]ABARE – Energy Statistics, Historical, data tables, http://www.abareconomics.com/publications_html/data/data/data.html#engHIST, accessed 13 November, 2008.

[9] *Electricity Gas Australia 2008,* Energy Supply Association of Australia, 2008, p. 15

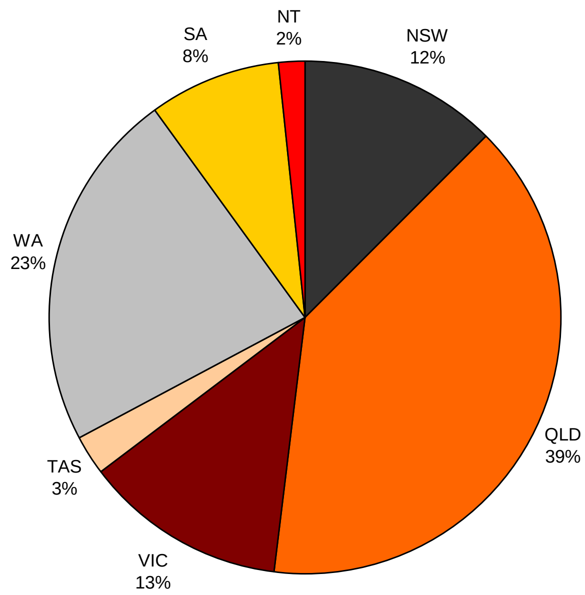
Figure 4: New power generation capacity using fossil fuels in Australia, 1998-2010



Source: Geoscience Australia[10]

The breakdown of new generation investment by state between 1998 and 2010 is shown in Figure 5.

Figure 5: Location of new power generation (installed capacity) using fossil fuels in Australia, 1998 – 2010



Source: Geoscience Australia[10]

[10] *Operating Fossil Fuel Plants,* Geoscience Australia, accessed 3 November 2008, http://www.ga.gov.au/fossil_fuel/

Queensland has installed or currently has under construction, the majority (39%) of new fossil fuelled power generation in from 1998 to 2010. This represents 20 new power generation facilities including four large black coal power stations (averaging 750MW capacity), four CCGT plants (averaging 340MW capacity) – two of which are under construction, seven OCGT plants (averaging 180MW capacity), and five smaller cogeneration and reciprocating engine facilities. Over the same period, Western Australia installed more facilities (22) with the average installed capacity for these facilities being 150MW. A graphical representation of facility type, capacity and year of commission for each state is provided in Appendix 1.

Historically thermal plant using black coal has been the main baseload generation technology used in Australia. Approximately 25% of the new installed capacity commissioned between 1998 and to 2010 is fuelled by black coal. The average installed capacity of each of these facilities is over 525MW. There has also been a small amount of additional investment in upgrading and refurbishing black coal plants since 1998.

The majority of Victoria's electricity generation comes from brown coal power stations. There has not been any new investment in this technology over the last 10 years. There have been upgrades to existing plants to increase their capacity. Upgrades include 30MW of additional capacity in Yallourn (2003), 130MW of additional capacity at Hazelwood (2003 – 2008), and 236MW of additional capacity at Loy Yang (2002-2008).

Combined Cycle Gas Turbine (CCGT) are capable of achieving high thermal efficiencies through the use of waste heat from the gas turbine exhaust. CCGT plants are generally used to supply intermediate or peak load in Australia. They are becoming an increasingly economic option for baseload generation due to the competitive prices of natural gas[11].

There has been 3,384 MW of investment in CCGT plants from 1998 to 2010. This represents 23% of new installed capacity from 1998 to 2010. All of the 16 plants currently operating having been commissioned after 1985. Of these, six have been constructed in the last 10 years. Another five CCGT plants are currently under construction, and are due to be commissioned by 2010. At least three of these plants generate electricity using coal seam gas. The average installed capacity is 380MW.

Gas Turbine or Open Cycle Gas Turbine (OCGT) plants are also reliant on the combustion of gas to generate electricity. These systems use natural gas mixed with compressed air from the atmosphere within a combustion chamber, which is then ignited. The resulting kinetic energy drives a turbine which, in turn, drives a generator which produces electricity.

There has been 6,028 MW of OCGT investment during 1998 to 2010. This includes nearly 2,000 MW of installed capacity which is committed and under construction. This accounts for just over 40% of new power generation facilities commissioned and operating in Australia since 1998. They are used predominantly for peak load power generation. Of the 47 gas turbine plants currently operating in Australia, 25 were commissioned since 1998. The average installed capacity of these plants is 200MW.

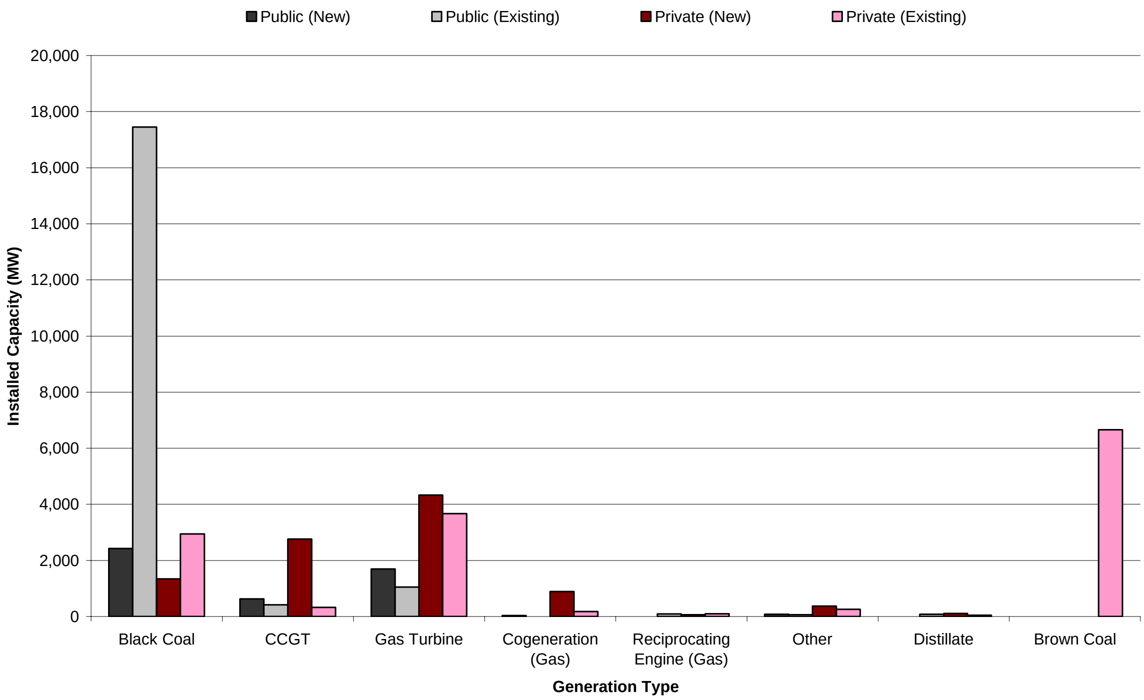
Other facilities installed for power generation over the last 10 years include cogeneration plants, reciprocating engine plants, gas steam turbines and plants which use distillate as their primary fuel source.

[11] *Electricity Generation Technologies*, Energy Supply Association of Australia, accessed 3 November 2008, http://www.esaa.com.au/electricity_generation_technologies.html

2.4 Private and public financing

The private sector is responsible for approximately 67% of the installed capacity of all new fossil fuel powered electricity generation investment since 1998. The breakdown of this investment, and existing installed capacity is shown in Figure 6. Overall, the private sector owns 41% of the installed capacity of fossil fuel powered electricity generation currently operating in Australia.

Figure 6: Ownership of new (1998 - 2010) and existing (pre-1998) generation investment



Source: Simshauser, P., 2008, Geoscience Australia[10]

2.5 Unit costs of generation investment

The cost of investment per kilowatt for each of the three major power generating technologies is shown in Figure 7. Each data point represents a new power generation facility commissioned between 1998 and to 2010. The costs have been converted to 2008 prices using consumer price indices (CPIs) provided by ABS. Trend lines have been included to demonstrate average cost trends over the last 10 years.

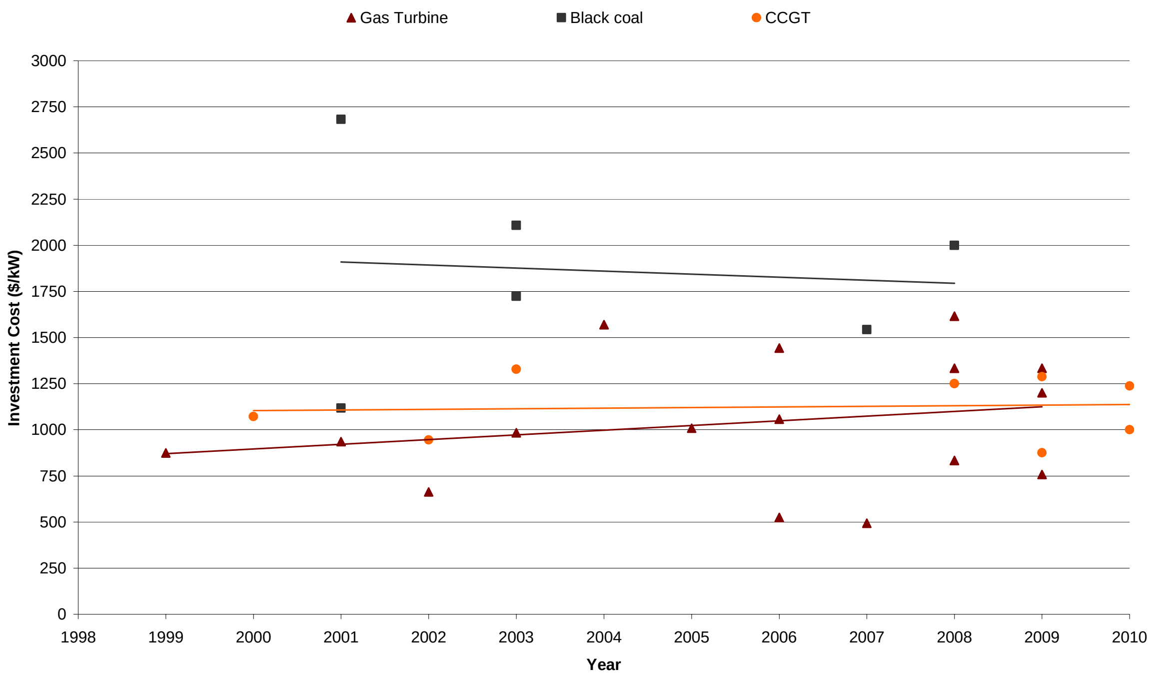
Whilst the overall capital investment costs of building a black coal power station have tended to decrease over the last few years, this type of power plant continues to be the most cost intensive to build. Average capital investment costs for black coal powered stations are currently $1,860/kW[12].

[12] These figure are comparable to those calculated by ACIL Tasman (*Projected Energy Prices in Selected World Regions,* ACIL Tasman, 2008) and Babcock & Brown Power (*The entry cost-shock and re-rating of prices in the power generation industry,* Paul Simhauser, Babcock and Brown Power, 2008): Black Coal power stations - $1,900/kW & $2,250/kW, CCGT - $1,050/kW & $1,550/kW, and Gas Turbine plants - $750/kW & $1,100/kW respectively.

Alternatively, gas turbine plant costs have tended to increase over the same time. Whilst initial investment costs are still quite low, the high running costs of these plants and increasing investment costs may deter future investment in this technology. Average capital investment costs for gas turbine plants are currently $1,040/kW[12].

CCGT plant costs have remained relatively stable over the last 10 years, increasing only slightly. Average capital investment costs for CCGT facilities are currently $1,125/kW[12].

Figure 7: Cost per kW of new power generation using fossil fuels (in 2008 prices)



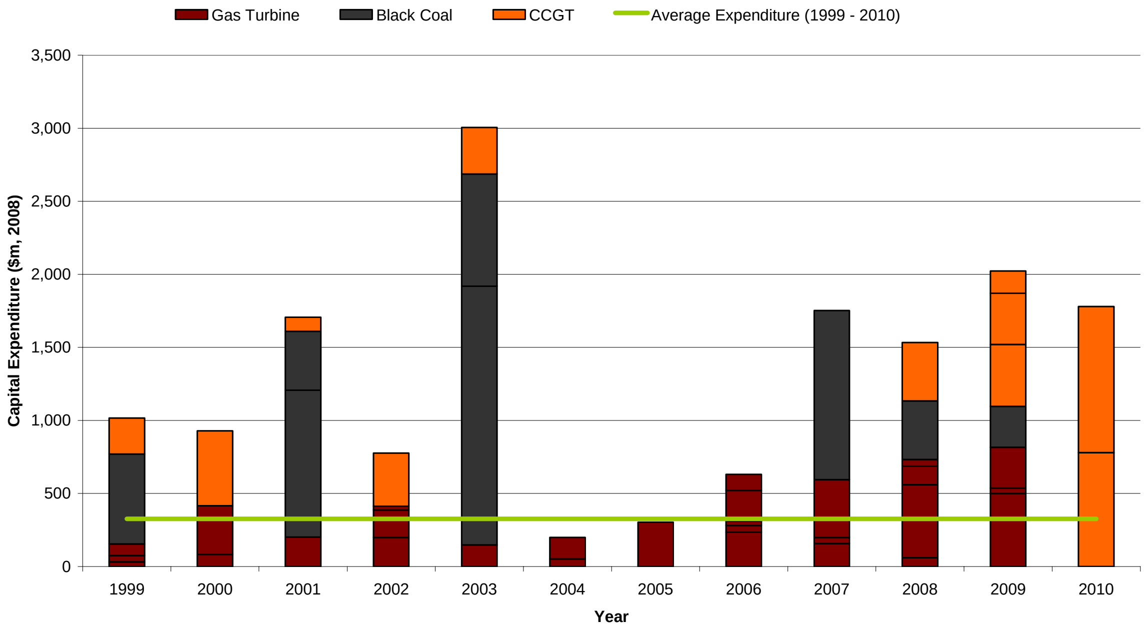
Source: Geoscience Australia[10]

2.6 *Estimated costs of generation investment*

Using the figures determined for average capital investment costs for each of the facilities, it is possible to estimate the total capital expenditure for investment in new generation capacity since 1998. This is shown in Figure 8. The figure shows estimated investment by year, in real $2008, broken down by generation type. The total estimated expenditure over the period is $15.6 billion. The average yearly capital expenditure from 1999 to 2010 is approximately $1,300 million. The average cost per investment is $326 million.

Discussions with industry experts have indicated that the calculated average cost of gas turbine plants may be too high. By interchanging our average calculated cost for gas turbine plants ($1040/kW) with that calculated by ACiL Tasman ($750/kW) the total estimated expenditure over the period reduces to $15.2 million.

Figure 8: Estimated yearly capital expenditure on new fossil fuel powered electricity generation, 1998 - 2010



We note that the investment level over the last decade has been low in relation to the value of installed capacity and the expected life of the plant concerned. Table 1 is taken from a recent article by Paul Simshauser. It shows estimated installed capacity by generation technology, the value of that capacity on a replacement basis, and the depreciated value of that capacity allowing for the average age against the total useful life for the generation technology concerned.

Table 1: Estimated value of installed generation capacity, 2008

TOTAL

Generation Technology	Installed Capacity* (MW)	Replacement Cost# ($/kW)	Replacement Value ($m)	Average Fleet Age* (Yrs)	Total Useful Life# (Yrs)	Remaining Useful Life (Yrs)	Depreciated Value ($m)
Hydro	7,609	2,500	19,023	37.2	100	62.8	11,953
Black Coal	22,601	2,250	50,852	23.5	50	26.5	26,957
Brown Coal	7,335	2,750	20,171	28.1	50	21.9	8,842
Natural Gas	6,539	1,100	7,193	18.1	30	11.9	2,848
CCGT	2,303	1,550	3,570	6.9	30	23.1	2,747
TOTAL	46,387	2,173	100,809	24.9	54	29.5	53,347

Source: Paul Simshauser [check article]

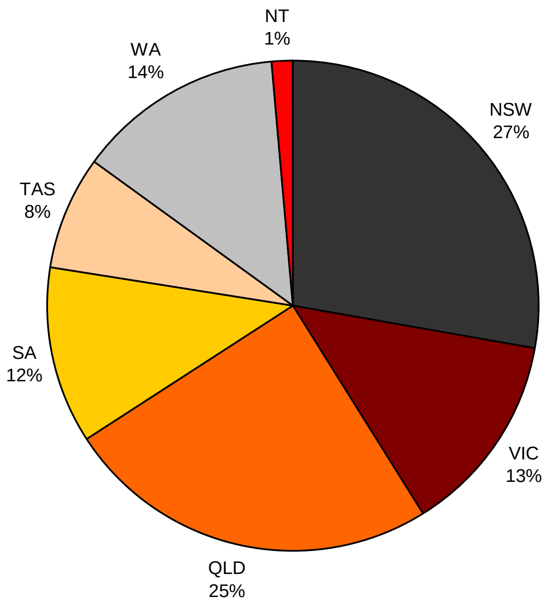
3 Historic investment in electricity networks

3.1 Electricity transmission

Electricity transmission networks transport electricity at high voltages and over long distances. The NEM transmission network is shown in
Figure 1 on page 3. The total transmission network spans over 48,500 km[13].

The overall distribution of transmission lines by state is shown in Figure 9. The figure excludes three DC links, Murraylink, Directlink and Basslink.

Figure 9: Distribution of Australia's transmission network (km)

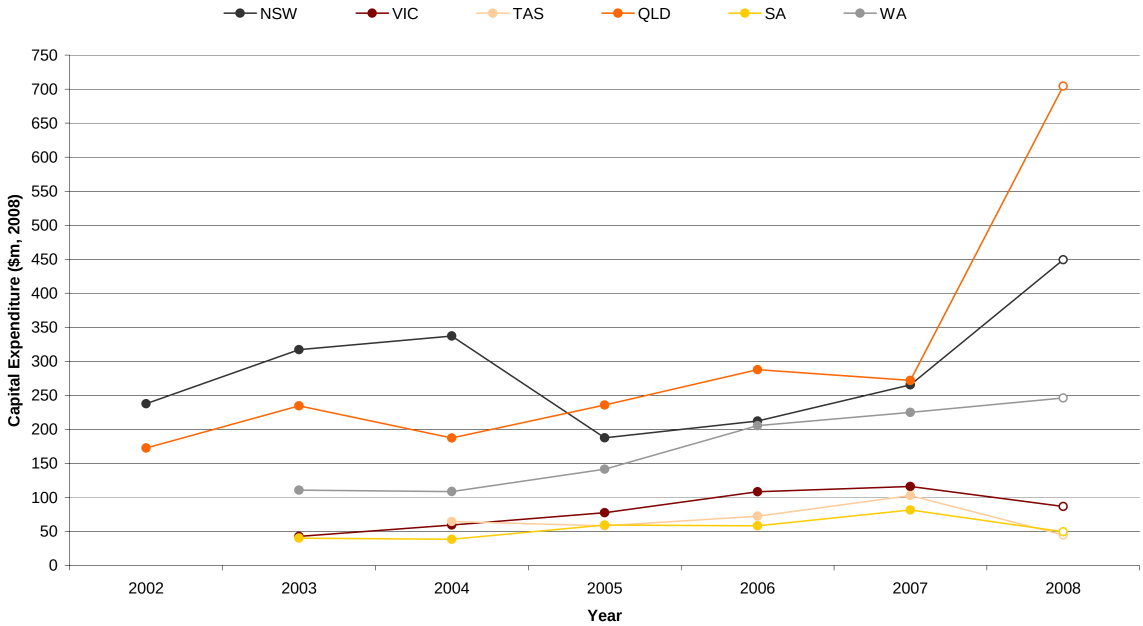


Source: AER, 2008[13]

Capital expenditure in the transmission network has more than doubled, in nominal terms, over the last 3 years, from $759 million in 2005, to $1,580 million expected in 2008. Total capital expenditure over this time has been over $4.3 billion. The majority of this expenditure has occurred in Queensland, with over $1,499 million invested in its transmission network. New South Wales and Western Australia have also invested heavily into their transmission networks since 2005, with $1,114 million and $817 million spent on respective capital investment. Figure 10 demonstrates the trend in capital expenditure in the transmission network over the last 6 years, and expected total expenditure in 2008.

[13] *State of the Energy Market Report 2008*, Australian Energy Regulator, 2008, data tables (AER)

Figure 10: Australia's transmission network capital expenditure[14]



Source: AER, 2008[13]

3.2 Electricity distribution

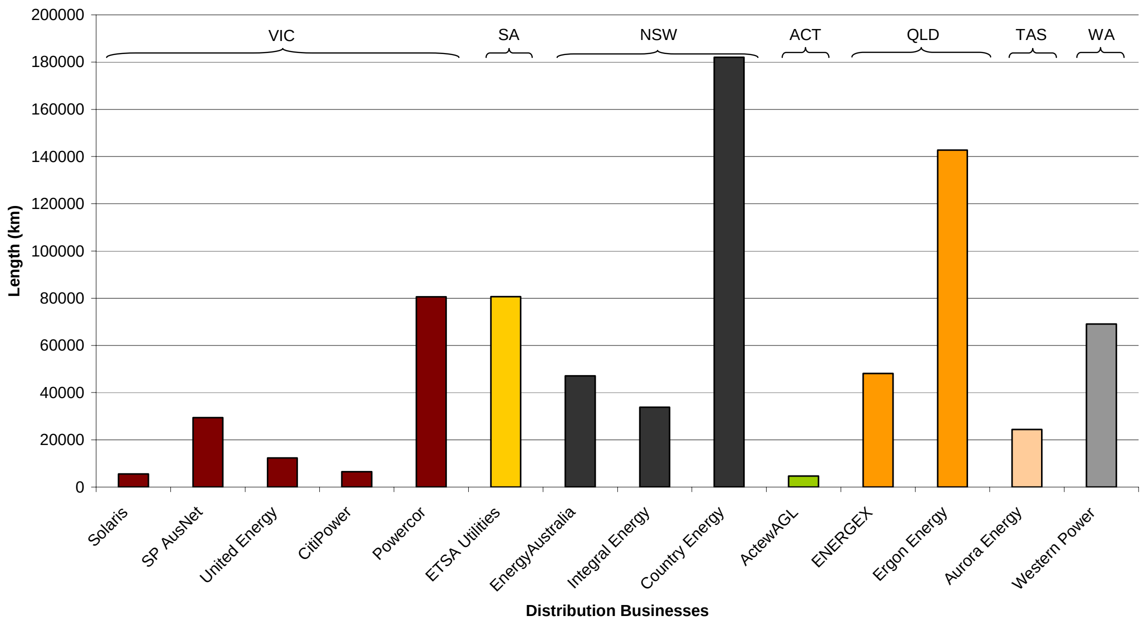
The total length of the distribution network within Australia is over 767,000 km, almost 16 times the length of the transmission network.

As with the transmission network, ownership of the distribution network is predominantly state government based, with the exception of Victoria and South Australia. Western Australia and Northern Territories' distribution networks are owned and maintained by Western Power and Power and Water respectively – the same companies that own and maintain the transmission network. In the NEM, only SP Ausnet and EnergyAustralia own and maintain both transmission and distribution networks. Other distribution businesses include Powercor, CitiPower, United Energy and Solaris in Victoria, ETSA Utilities in South Australia, Integral Energy and Country Energy in New South Wales, ActewAGL in the ACT, Energex and Ergon Energy in Queensland, and Aurora Energy in Tasmania.

Figure 11 shows the current length of distribution network owned and maintained by each of the distribution businesses.

[14] Note: Northern Territory figures are not included due to limited availability of data.

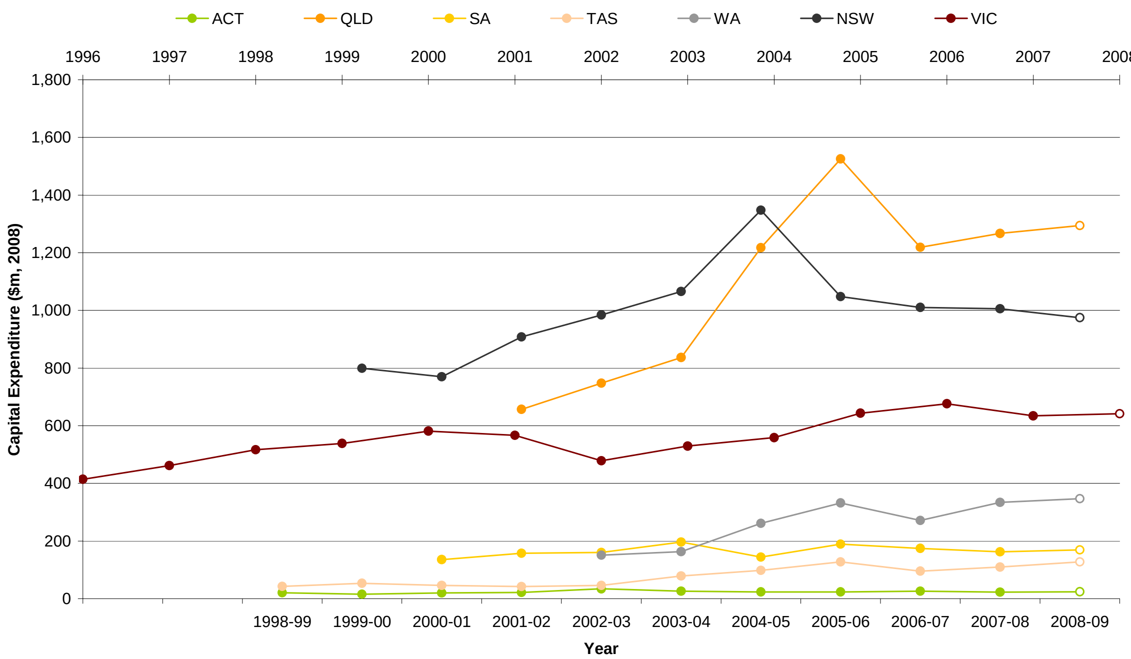
Figure 11: Length of Australia's electricity distribution networks



Source: AER, 2008[13]

Recent capital expenditure in Australia's electricity distribution network has been over $3.4 billion[13]. This is expected to increase slightly over the next couple of years. Capital expenditure in each state over the last decade is shown in Figure 12. As with the transmission network, expenditure in the distribution network over the last 3 years has been predominantly in Queensland and New South Wales, with each state spending over $3 billion during this time.

Figure 12: Australia's distribution network capital expenditure



Source: AER, 2008[13]

4 Historic investment in gas supply

4.1 Background

Australia is a relatively gas-rich country. The largest gas reservoirs located in Victoria (Gippsland Basin), Central Australia (Cooper Basin) and the North West Shelf of Western Australia.

Natural gas is a versatile source of energy, and is used in a variety of industrial commercial and domestic applications, including electricity generation. In Australia, 35% of the natural gas produced is used for electricity generation, predominantly in peaking and intermediate power stations.

There are two main types of natural gas used for electricity generation – naturally occurring methane gas, also called conventional natural gas, occurs naturally in underground reservoirs trapped in rock and is often found in association with oil. Coal seam gas (CSG), also called coal seam methane (CSM) is often extracted when mining coal. Currently in Australia, Queensland is the only state using CSM to generate electricity.

The supply chain for natural gas begins with exploration and development. This involves geological surveying and the drilling of wells to find and verify recoverable resources of gas. This phase of the supply chain is usually in conjunction with the search for other hydrocarbon deposits (for example, coal and oil). Once found, the natural gas enters the production phase, where the gas is extracted, and often requires processing to remove impurities and to separate the methane from other gases that may be present.

Figure 13: Major gas transmission pipelines and proposed pipelines in Australia

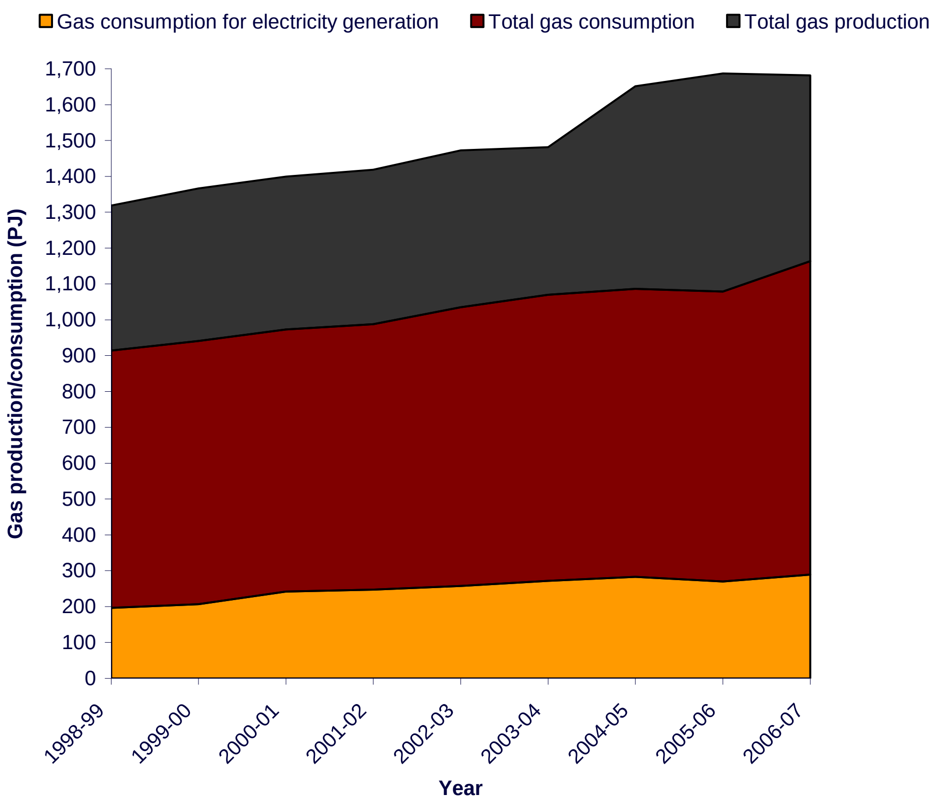
Pipeline	No.
Moomba to Sydney pipeline system (except for Moomba to Marsden)	1
Central West and Central Ranges pipelines	2
Victorian Transmission system	3
Dawson Valley pipeline	4
Queensland Gas pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane pipeline	6
South West Queensland pipeline (Ballera to Wallumbilla)	7
Carpentaria pipeline (Ballera to Mt Isa)	8
Moomba to Adelaide pipeline system	9
Amadeus Basin to Darwin pipeline	10
Goldfields Gas pipeline	11
Dampier to Bunbury Natural Gas pipeline	12
Eastern Gas pipeline (Longford to Horsley Park)	13
Dongara to Perth/Pinjarra	14
SEA Gas pipeline	15
Tasmanian Gas pipeline	16
Palm Valley to Alice Springs	17
Midwest pipeline	18

Unlike electricity, excess gas can be stored for later consumption, either in depleted gas reservoirs, or by converting it to a liquefied form (LNG) for storage in purpose built facilities. LNG can also be readily transported and is fast growing as an important export commodity for Australia.

4.2 Gas consumption and share of gas-fired generation

Natural gas consumption and production in Australia since 1998 is shown in Figure 14. Total domestic consumption has increased by 28% since 1998. Gas consumption for electricity generation has increased by almost 50% over the same period.

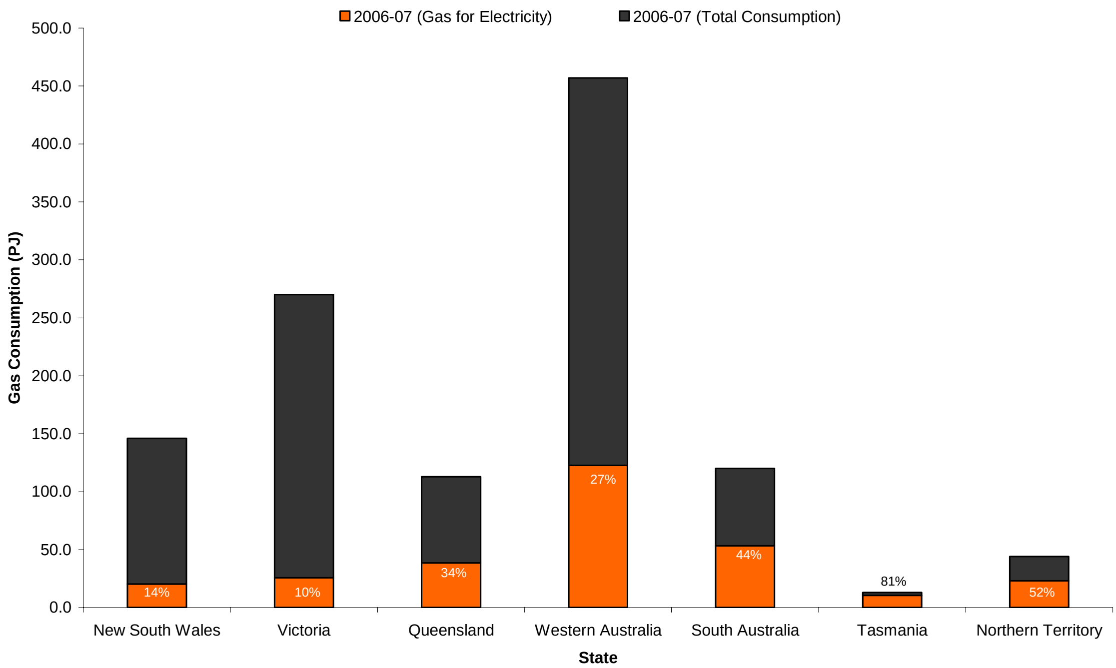
Figure 14: Total gas production and consumption trends, 1998 to 2007



Source: ABARE, 2006/07[8]

The percentage of natural gas consumed for electricity generation varies from state to state. Figure 15 demonstrates each state's consumption of natural gas for electricity generation as a percentage of the total gas consumption.

Figure 15: Total state gas consumption, and gas consumption for electricity generation, 2006/07



Note: Total gas consumption includes ethane, non-commercial natural gas and methane produced from other than natural gas fields

Source: ABARE, 2006/07[8]

4.3 Gas production

At 2007, Australia has 39 operating gas production facilities, 21 of these having been commissioned in the last 10 years. Of the 39 operating gas production facilities, 13 do not produce crude oil (see Table 2), and only 3 focus solely on sales gas.

Table 2: 2007 production figures for gas only production facilities in Australia

Field Name	Operator	Basin	Year	Cost	State	Condensate (barrels)	Sales Gas (PJ)
Palm Valley	Magellan Petroleum	Amadeus	1984		NT		3.426
Denison Trough	Origin Energy	Surat/Bowen	1990		QLD	8,236	11.214
Katnook	Origin Energy	Otway	1991		SA	8,082	0.843
BassGas	Origin Energy	Bass	2005	$ 750m	TAS	813,782	20.579
Casino	Santos	Otway	2006	$ 200m	VIC	73,399	35.559
Geographe Thylacine	Woodside	Otway	2007	$1,100m	VIC		0.535
Minerva	BHPBilliton	Otway	2005	$ 255m	VIC	97,944	35.316
Otway	Santos	Otway	2005		VIC	8,869	12.363
Patricia/Baleen	Santos	Gippsland	2003	$ 120m	VIC		4.437
Beharra Springs	Origin Energy	Perth	1991		WA	7,093	3.628
John Brookes	Apache	Carnarvon	2005	$ 300m	WA	1,008,423	78.315
Wonnich Deep	Apache Energy	Carnarvon	2007		WA	106,945	7.156
Woodada	Arc Energy	Perth	1990		WA	374	1.031

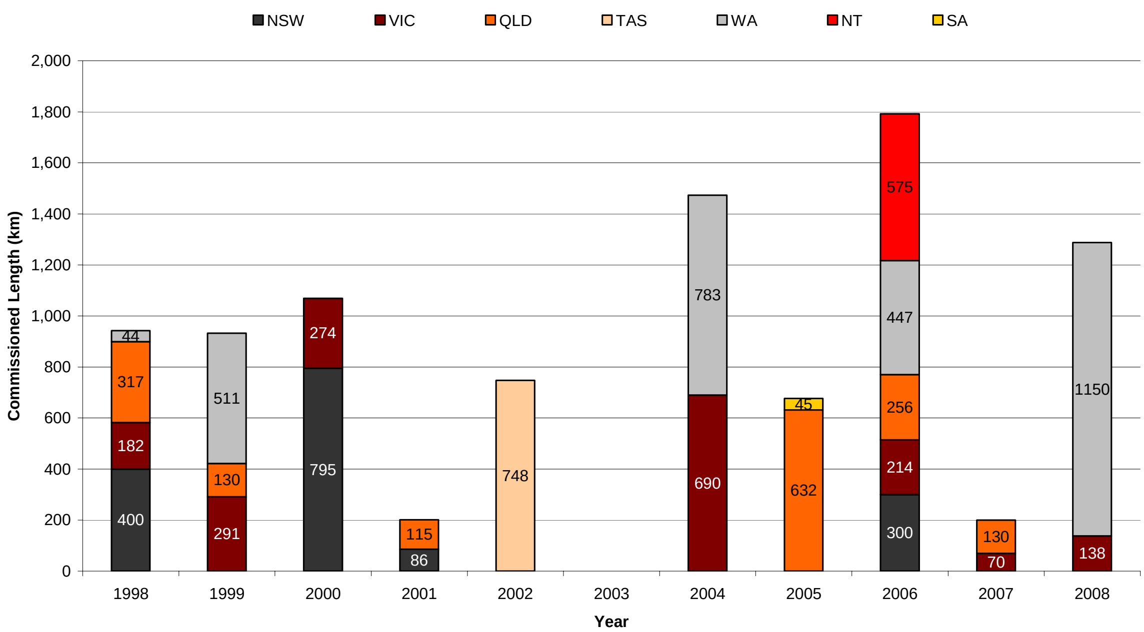
Source: Australian Petroleum Production and Exploration Association of Australia (APPEA), 2008

4.4 Transmission pipelines

Australia's natural gas consumption has almost doubled over the last 16 years, from 655PJ in 1991 to 1,115PJ in 2007[15]. Over the same period, the Australian gas transmission pipeline network has almost trebled in length to over 25,000km, buoyed by the expansion and development of interstate network connections[16]. Between 2000 and 2006, approximately $2.5 billion was invested into the expansion of existing transmission pipelines, and the construction of new pipelines in Australia[17]. This represents approximately 5,960km of additional transmission pipelines Australia-wide.

Figure 16 shows the Australia-wide distribution of new construction since 1998. An additional 1,353km of transmission pipeline is currently under construction. Commissioning of these pipelines is due late 2008 and in 2009.

Figure 16: New gas transmission pipelines commissioned 1998 – 2008



Source: Electricity Gas Australia, 2008

Australia's gas distribution networks expanded 9,000km from a total length of 67,000km in 1997 to 76,000km in 2006, representing an investment of approximately $8 billion (in 2008 prices)[18]. At 30 June 2007, Australia's natural gas distribution network stretches over 81,000km[16].

Investment in the gas distribution sector is currently around $400 million per year (up from $250 million per year as reported in 2005/06). The majority of this investment relates to the

[15] *Electricity Gas Australia 2008,* Energy Supply Association of Australia, 2008, Table 5.2
[16] *Electricity Gas Australia 2008,* Energy Supply Association of Australia, 2008, Table 5.4
[17] *State of the Energy Market Report 2007*, Australian Energy Regulator, 2007, p. 4
[18] *State of the Energy Market Report 2007*, Australian Energy Regulator, 2007, p. 272

expansion of existing networks[19], and is reflective of approximately 1,437km of new distribution pipelines commissioned in 2006/07.

Underlying gas demand in Australia has been forecast to increase at an average of 2.4% per year according to ACIL Tasman in an essay written for the State of the Energy Market Report 2008, *Australia's Natural Gas Markets: The emergence of competition*.

5 Future investment in electricity generation

We have based our information on future investment on analysis undertaken by ACIL Tasman and on the recent Treasury modelling.

The projections correspond to two scenarios for the nature of climate change policies. The two scenarios are for emissions from the Australian electricity sector in 2020 to be reduced by 10% and 20% from 2000 levels. The scenarios assume that this will be achieved through physical reduction within the sector (rather than through trade). An emissions price is determined which will provide this level of response

In addition the analysis includes the expanded Renewable Energy Target (ERET). ACIL Tasman assume that a small level of renewable energy will be viable under Business as Usual. A much higher level of investment is assumed under the two scenarios. The level of investment in renewable energy is the same for both scenarios. It is assumed that the ERET targets are met under both scenarios, but that there is not additional renewable energy investment above those targets. The costs of the ERET are estimated at $23.8 billion for both scenarios, or an average of $2.3 billion per year.

The 20% scenario has an additional $3.2 billion of investment compared with the 10% scenario. This is due to the higher forecast of retirement of coal plant under the 20% scenario.

The forecast average annual generation investment in real 2008 dollars is $1.3 billion under BAU. Under the 10% scenario it is $3.3 billion. Under the 20% scenario it is $3.6 billion. These levels of investment are substantially higher than historic levels.

The annual cumulative investment under BAU and the two scenarios in total, and for renewable generation, is shown in Table 3.

[19] *State of the Energy Market Report 2007*, Australian Energy Regulator, 2008, p. 13

Table 3: ACIL Tasman projections of cumulative capital expenditure by year

	BAU		10% case		20% case	
NEM	Total	Renewable (incl in total)	Total	Renewable (incl in total)	Total	Renewable (incl in total)
2011	$342	$342	$1,755	$1,755	$1,755	$1,755
2012	$972	$342	$4,401	$4,360	$4,401	$4,360
2013	$2,207	$342	$7,243	$6,710	$7,243	$6,710
2014	$3,219	$342	$10,011	$9,079	$12,108	$9,079
2015	$4,166	$342	$13,079	$11,414	$14,736	$11,414
2016	$5,206	$342	$16,638	$14,589	$18,295	$14,589
2017	$5,872	$342	$20,439	$16,958	$21,189	$16,958
2018	$7,380	$342	$23,335	$19,177	$24,964	$19,177
2019	$8,848	$342	$26,636	$21,277	$28,322	$21,277
2020	$10,791	$342	$30,300	$23,282	$33,514	$23,282

Data source: ACIL Tasman modelling

The ACIL Tasman projections of total investment by region are shown in Table 2.

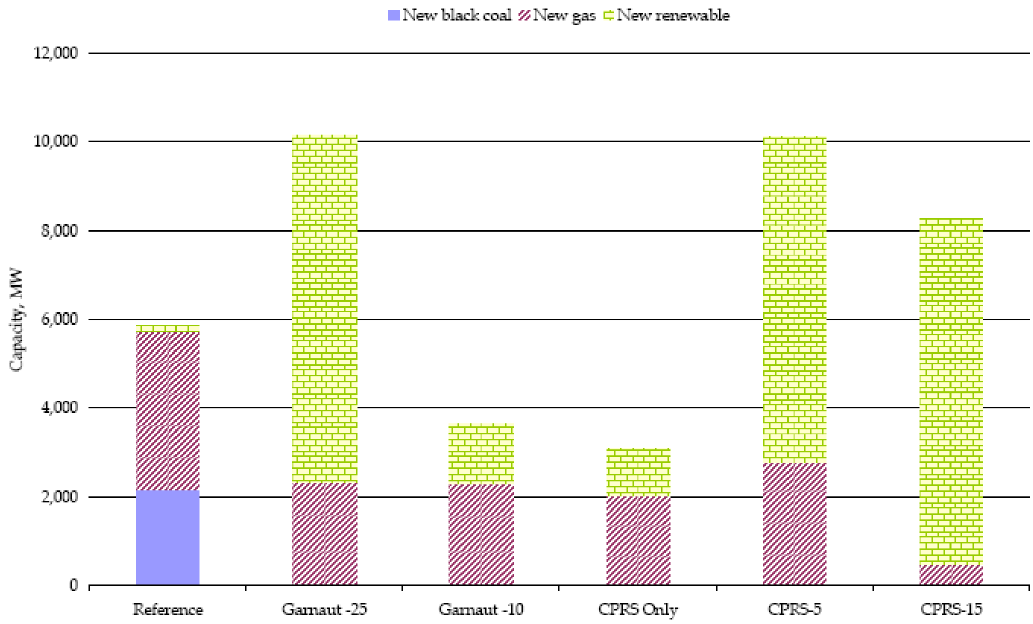
Table 4: ACIL Tasman projections of generation investment (real $2008, millions)

Region	BAU	10% case	20% case
New South Wales	$3,143	$6,033	$6,126
Queensland	$5,057	$6,929	$8,639
South Australia	$266	$5,220	$5,220
Victoria	$2,324	$12,118	$13,529
WA (SWIS)	$2,217	$3,105	$3,006
Total by 2020	$13,007	$33,405	$36,520

Source: ACIL Tasman modelling

Treasury modelling of capacity additions under different scenarios is shown in Figure 17. Under business as usual nearly 6,000 MW of new capacity is required. Under other scenarios there is no coal investment, a reduced level of gas-fired investment and – in all cases which include the expanded RET – a large increase in renewable energy investment.

Figure 17: Treasury forecast of new capacity requirements 2010 to 2020



The Treasury modelling also allows for the ERET under a number of scenarios. The modelling does not provide a separate estimate for capital cost of the ERET. Although there are some differences in the nature of the generation technology it seems likely that total capital costs would be reasonably consistent.

6 Other investment

The studies reviewed do not include robust forecasts of the level of investment in transmission.

The ACIL Tasman analysis concludes additional investment of approximately $4 billion would be required under scenarios with an emissions trading scheme. This investment would be required to connect wind farms and geothermal plant to the grid. It therefore appears this is a forecast of the additional investment requirement.

ACIL Tasman indicate that under climate change scenarios, an additional $500 million might be required for new and upgraded gas transmission pipelines.

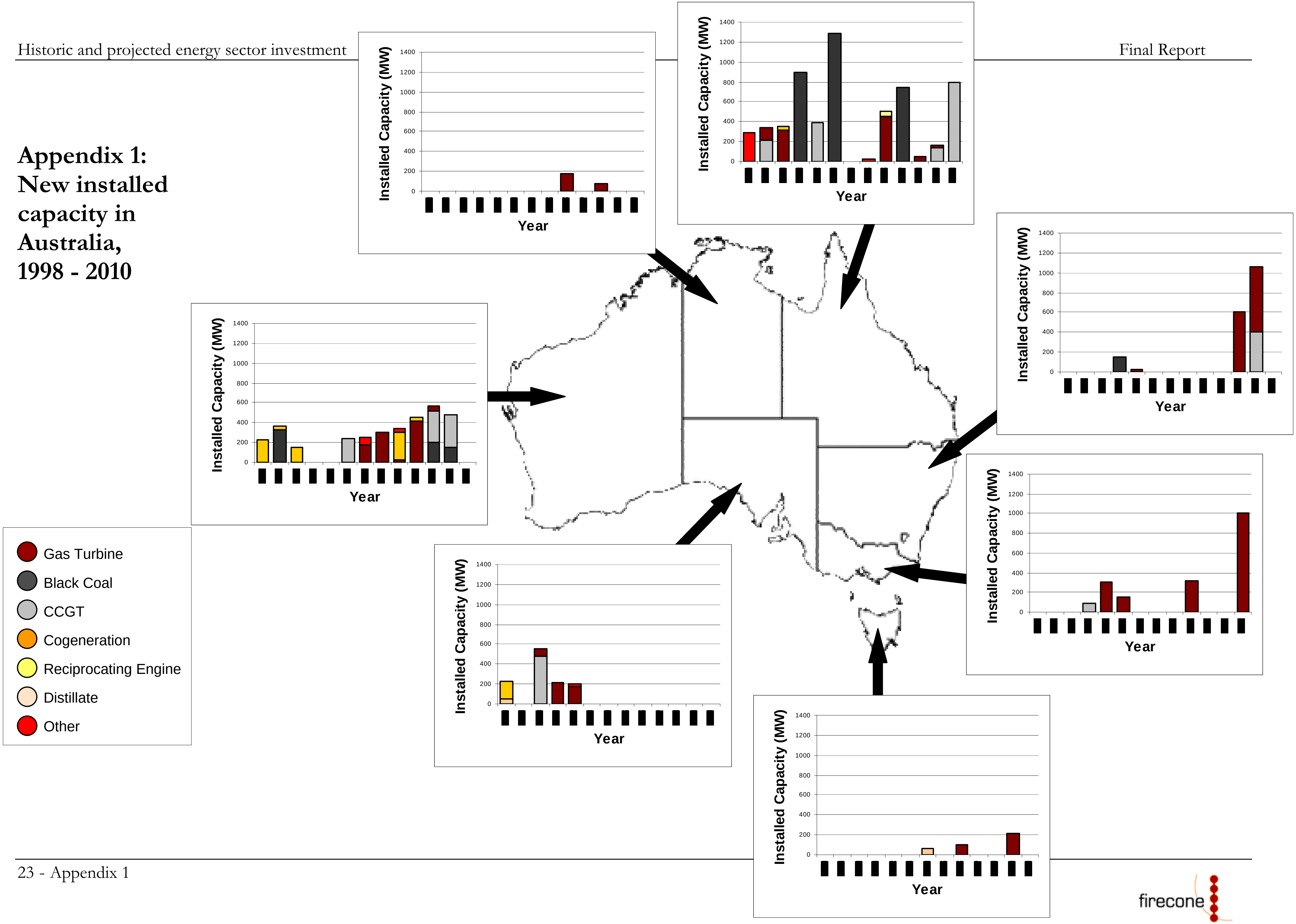
The Treasury modelling has assumed that there is a real 5% increase in investment in electricity transmission.

We note that there could be some tightening of supply markets. Worldwide investment in electricity transmission is expected to reach $867 billion by 2015. An additional $1,239 billion of transmission investment is forecast to be required in the proceeding 15 years, to 2030. Similarly, a large amount of worldwide investment in distribution has also been forecast. To 2015, approximately $1,941 billion of distribution investment is predicated. A further $2,716 billion of distribution investment is thought to be required from 2016 to 2030.[20]

The studies reviewed do not include robust forecasts of the level of investment in gas supply. As noted, there is a consensus of increased demand but a wide range of possible increases.

[20] *World Energy Outlook, 2008*, International Energy Agency, 2008, p. 151. All prices in US dollars, 2007 prices

Appendix 1: New installed capacity in Australia, 1998 - 2010



firecone