Fuel and capital costs in the NEM

Greenfield cost data for the calculation of the 2009/10 BRCI

Prepared for Queensland Competition Authority

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ACIL Tasman

Economics Policy Strategy

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Glossary

BRCI	Benchmark Retail Cost Index
CCGT	Combined Cycle Gas Turbine
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSG	Coal Seam Gas
EPC	Engineering Procurement and Construction
FOB	Free on board
FOM	Fixed Operation and Maintenance
GDP	Gross Domestic Product
GT	Gas turbine
GW	Gigawatts
HHV	High Heat Value
IDC	Interest During Construction
LNG	Liquefied Natural Gas
LRMC	Long-run Marginal Cost
MW	Megawatts
NEM	National Electricity Market
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
PPP	Purchasing Power Parity
ROM	Run of Mine
SRMC	Short-Run Marginal Cost
VOM	Variable Operating and Maintenance
WACC	Weighted Average Cost of Capital

Executive summary

ACIL Tasman has been engaged by the Queensland Competition Authority (QCA) to provide estimates of new build generation and fuel costs across the five regions of the National Electricity Market (NEM). The purpose of our engagement is to provide the fuel and other generator cost information to inform the calculation of the Benchmark Retail Cost Index (BRCI) for the 2009/10 tariff year to be undertaken by CRA International (CRA).

Capital costs

Our analysis of actual capital costs to date suggests there is clear evidence of a step like change in capital costs over the past 24 months – mainly driven by a changes in steel prices, and to a lesser extent, labour costs. Interestingly, the tightening demand/supply balance for turbines, due to strong global economic growth and even stronger growth from developing economies such as China and India, does not appear to have resulted in the small number of major turbine suppliers lifting prices excessively in the Australian market. The exception to this is wind turbine manufacturers who appear to have benefited from the strong demand for wind turbines.

We have identified and presented other published studies on capital costs and all of the studies suggested there has been a step like change, although there is some slight variation in opinion as to the extent to which this has occurred.

However, a further and important question to consider is whether these price increases are temporary or permanent? That is, have we experienced a step change and reached a new equilibrium level for capital costs that will be maintained for the next 10 years?

Supply and Demand

The CCGT market is dominated by four major suppliers being GE, Siemens, Alstom and MHI. The major manufacturers in the steam turbine market includes the same four players along with Toshiba, Shanghai Electric, Harbin and Dongfang in China and BHEL in India.

While these markets are relatively concentrated in terms of supply, we expect that most of the major suppliers will increase manufacturing capacity over the next few years. This is expected to alleviate supply constraints and gradually reduce the backlog of orders over the next five to 10 years.

Demand for power plant is largely linked to world economic growth and in particular, economic growth in developing countries undergoing rapid industrialisation such as China and India. However additional considerations are the aging generator fleet in the OECD which will increasingly need to be replaced and increasing environmental restrictions that will lead to replacement of some existing infrastructure and limitations on the types of future investments.

Demand growth for turbines is expected to moderate over the next few years with the effect of the current turmoil in financial markets slowing growth, and leading to inflationary pressures, particularly in the OECD and the developing countries undergoing rapid industrialisation.

However the growth in demand for turbines coupled with supply constraints has led to a number of manufacturers facing order backlogs. Even if demand was to abate rapidly, over the next couple of years, we expect that it would take several years to return the backlog to equilibrium. Hence we expect that supply/demand disequilibrium will exist until at least 2011 when new supply comes online, and possibly as far away as 2013 to 2015 as order backlogs are returned to normal levels.

Financial analysis of major suppliers

We undertook an assessment of the financial performance of major suppliers to ascertain whether they were enjoying increased profit margins as an indication of the long run supply/demand disequilibrium. We analysed the results of Siemens, Alstom, MHI and GE. Our analysis showed that profit margins were up marginally and that the increases in prices being charged for plant were largely about recovering higher input costs. This supports the view that a significant portion of recent price increases are likely to be sustained over time.

Steel prices

After years of decline in real terms, steel prices have experienced sharp changes in both 2004 and 2008. We note that there are several short term factors in play in the 2008 price rise. We expect prices to return to pre 2008 levels by 2011 and then escalate at around 3% per annum, consistent with the price growth rate between 2004 and 2007.

Our analysis also indicates that steel price changes tend to have a one to two year lag in terms of the impact on power station capital costs. Hence we expect that steel cost pressures on power plant will not abate until 2012 to 2013.

In the event that demand from China and India is maintained and global steel production is not increased significantly, we would expect that the 2008 price increases would be sustained with further annual increases of around 3% per annum.

Labour costs

We consider that labour costs contribute between 50 and 70% of the total cost of the total EPC contract price. Australian labour costs have increased markedly in recent years, growing at an average of 5% per year since 2004.

Growth in labour costs in other parts of the world have not been as significant, however they have generally been growing faster than the rate of inflation. These input cost increases flow through to manufacturing costs and higher plant capital costs.

Third party capital cost estimates

We included a review of third party estimates of capital costs. These are summarised as follows:

- The Edison Foundation estimates that the cost of gas turbines increased by around 16% and conventional coal station costs by about 12% in 2007
- CERA records a step up in costs in 2006 and returning to the long term growth trend in 2007 with no reversion to pre 2006 prices
- Energy Information Administration estimates in their Annual Energy Outlook show a cost increase in plant of around 15% between 2007 and 2008
- The Cooperative Research Centre for Coal in Sustainable Development (CRC-CCSD) provided a report titled: *Options for Electricity Generation in Australia – 2007 Update*, in March 2008, in which it provided estimates of future capital costs and learning rates
- SKM data provided to an EUAA conference in June 2008 indicates a step up in prices between 2006 and 2008.

ACIL Tasman estimates of capital costs

Our analysis concludes that about 50% of the price increases observed in capital costs over the past 24 months is fundamental and long term. Steel costs experienced a sharp increase in 2004 and this has taken one to two years to filter through to the capital costs of power plant. There has been another recent sharp increase in steel costs in 2008 (50% above 2007 levels) and we conclude that this is not sustainable and steel prices will decline and return to pre 2008 levels over the next few years, by 2011. This assumes that supply catches up with demand as a consequence of slower demand growth, and increases in supply as China increases steel production.

The table below shows ACIL Tasman's projected capital costs by technology. The projection shows that the recent price increases are likely to increase further over the next one or two years before softening. However, given that price increases for steel in 2004 have been sustained since that time, we consider that 50% of the recent capital costs increase represents a fundamental step change and will be sustained in the long term.

Table ES 1 **Projected capital costs by technology (nominal AUD/kW) – 2008 - 2018**

Year ending June	CCGT	Black coal supercritical	Brown coal supercritical	OCGT	Wind	Geothermal
2008	$1,200	$2,200	$2,420	$900	$2,300	$5,000
2009	$1,404	$2,330	$2,563	$1,053	$2,646	$5,163
2010	$1,314	$2,291	$2,520	$985	$2,525	$5,330
2011	$1,255	$2,268	$2,495	$941	$2,406	$5,504
2012	$1,284	$2,284	$2,512	$963	$2,415	$5,569
2013	$1,292	$2,301	$2,531	$969	$2,394	$5,635
2014	$1,308	$2,344	$2,578	$981	$2,450	$5,701
2015	$1,336	$2,387	$2,626	$1,002	$2,504	$5,769
2016	$1,365	$2,444	$2,688	$1,024	$2,557	$5,837
2017	$1,395	$2,501	$2,751	$1,046	$2,608	$5,907
2018	$1,424	$2,559	$2,815	$1,068	$2,658	$5,977

Data source: ACIL Tasman analysis

Impact of the global financial crisis

Global financial markets have recently experienced a period of extreme volatility and uncertainty. What began more than a year ago with market turmoil surrounding U.S. sub-prime mortgages, has since escalated to a broader financial crisis, which will have a negative effect on economies around the world. A number of international bodies and government agencies have recently lowered economic growth expectations considerably, and now anticipate that some large developed economies (such as the US and UK) may enter a period of recession.

This development is likely to have a suppressing effect upon electricity demand, which is turn is likely to ease the current global supply-side conditions for generation equipment. This may result in a faster easing of cost pressures on generator manufacturers, however the length and severity of any global economic downturn is unknown and cannot be forecast reliably.

Other LRMC inputs

We set out the other relevant LRMC inputs in section 3 of the report as follows.

We have assumed a post tax real WACC of 6.81%. Details of our WACC analysis are included in the report.

Assumed build times and project lives for each type of plant are set out in Table ES 2.

Table ES 2 **Construction profile (% of project capital cost)**

Technology	Year -4	Year -3	Year -2	Year -1
CCGT	0%	0%	40%	60%
Supercritical – black	10%	20%	35%	35%
Supercritical – brown	10%	20%	35%	35%
OCGT	0%	0%	0%	100%

Data source: ACIL Tasman analysis

Assumed fixed O&M costs for each type of plant are shown in Table ES 3.

Table ES 3 **Estimated fixed O&M cost (AUD per MW of installed capacity) in 2007-08 and escalation rate**

Technology	AUD$/MW/year	Escalation rate (% of CPI)
CCGT	$12,800	100%
Supercritical – black coal	$40,000	100%
Supercritical – brown coal	$40,000	100%
OCGT	$7,500	100%
Geothermal	$40,000	100%
Wind	$20,000	100%

Data source: ACIL Tasman analysis

Variable O&M costs for each type of plant are shown in Table ES 4.

Table ES 4 **Variable O&M cost (AUD/MWh, sent-out) in 2007-08 and escalation rate**

Technology	AUD$/MWh	Escalation rate (% of CPI)
CCGT	$4.85	100%
Supercritical – black coal	$1.20	100%
Supercritical – brown coal	$1.20	100%
OCGT	$7.50	100%
Geothermal	$2.00	100%
Wind	$1.60	100%

Data source: ACIL Tasman analysis

Auxiliary usage for each type of plant are shown in Table ES 5. Where not shown auxiliary usage is assumed to be zero.

Table ES 5 **Auxiliary usage (%) for new entrants**

Technology	Auxiliary usage
CCGT	2.4%
Supercritical – black coal	7.5%
Supercritical – brown coal	9.5%
OCGT	2.0%

Data source: ACIL Tasman analysis

Thermal efficiency for each type of plant are shown in Table ES 6.

Table ES 6 **Thermal efficiency (HHV, as sent out) for new entrants by build year**

Year ending June	CCGT	Black coal	Brown coal	OCGT
2008	52%	42%	34%	31%
2009	52%	42%	34%	31%
2010	53%	42%	34%	31%
2011	53%	42%	34%	32%
2012	54%	42%	34%	32%
2013	54%	43%	34%	32%
2014	54%	43%	35%	32%
2015	55%	43%	35%	33%
2016	55%	43%	35%	33%
2017	56%	43%	35%	33%
2018	56%	43%	35%	33%

Data source: ACIL Tasman analysis

We have assumed plant availabilities of 90% for coal plant, 92% for CCGT and 97% for OCGT. Availabilities for other technologies have been adopted from the CRA draft report.

Gas costs

The last 18 months has seen a significant move in gas prices in Australia caused by rising demand for energy both domestically and internationally and rising costs including both capital and labour costs. The large number of East coast LNG proposals have placed additional pressure on gas prices. The sheer size and scale of the potential LNG industry has the potential to influence the availability of gas for domestic use.

Hence we have included two LNG export facilities of 4 Mtpa each, with assumed start-up in 2014 and 2018 in our analysis.

Within the report ACIL Tasman has provided updated gas price projections, and has attempted to construct a gas price curve for varying levels of gas consumption. The key objective for this analysis is to recognise that as gas consumption changes, so to will the prevailing price level. Hence we developed price projections constructed over a range of consumption levels, relative to aggregate NEM demand. Annual regional gas prices were projected for the following fuel mix scenarios:

- 10% gas
- 25% gas
- 50% gas
- 75% gas
- 90% gas.

Prices are taken from representative nodes of the Eastern Australian gas grid, deemed most likely to support bulk gas-fired power generation. The prices therefore include applicable gas transmission tariffs.

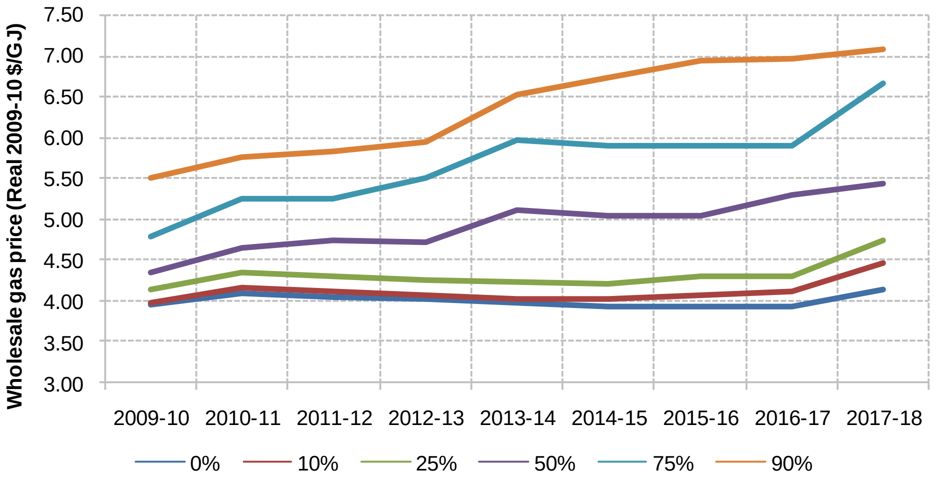
The representative nodes selected for each NEM region are:

- Queensland: Dalby
- New South Wales: Bayswater
- Victoria: Latrobe Valley
- South Australia: Adelaide
- Tasmania: Bell Bay.

For low levels of NEM-scheduled gas consumption, the reported prices are reflective of long-run supply costs from various fields throughout Eastern Australia. However, as the demand from NEM-scheduled generation increases and the available supply capacity is exhausted, prices begin to reflect price tolerances of other domestic users who have been displaced by the additional demand. In the scenarios where gas accounts for the majority of NEM generation, prices – particularly toward the end of the projection – begin to reflect full LNG export netback parity, as the aggregate production capacity is insufficient to support both the entire NEM *and* 8 Mtpa of export capacity simultaneously.

Projected gas prices for Queensland for each level of gas consumption modelled are shown in Figure ES 1.

Figure ES 1 **Projected gas prices for Queensland at varying levels of gas in the NEM fuel mix**



Data source: ACIL Tasman GasMark modelling

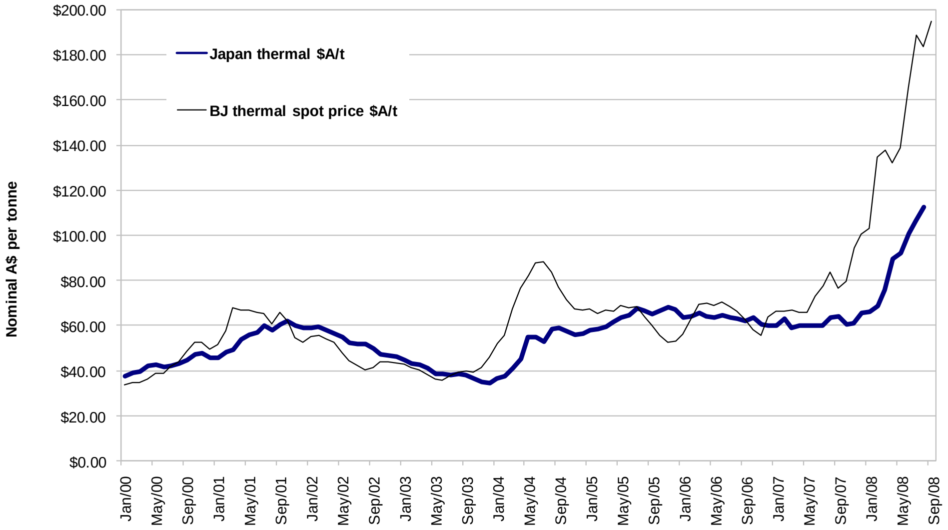
Coal costs

Examination of the quality and location of coal resources suggests there are potentially seven areas within the NEM regions where coal resources are sufficient to support new coal fired capacity; three in Queensland, three in NSW, and one in Victoria.

The FOB price for thermal coal is an important consideration in the price formation for new coal fired generation in QLD and NSW. It is the projection of these prices which underlies the future export parity value of the ROM coal at each location which in some cases sets the delivered price into local power stations using that coal.

Thermal coal spot and contract prices have increased markedly in the past twelve months as shown in Figure ES 2. ACIL Tasman predicts that the price will abate in the coming one to two years as new mines are brought into production and export infrastructure bottle necks are eased.

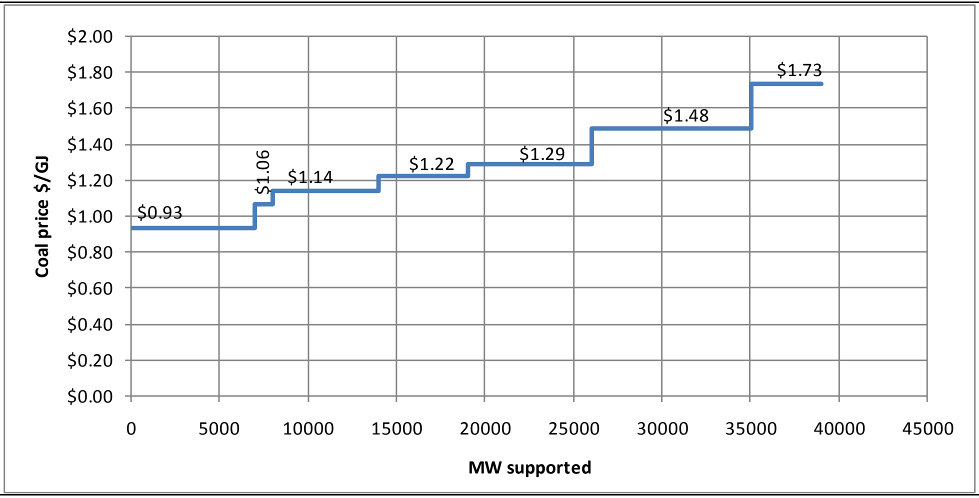
Figure ES 2 **Spot and contract prices for thermal coal exports (nominal A$/t)**



Data source: Australian Coal Report

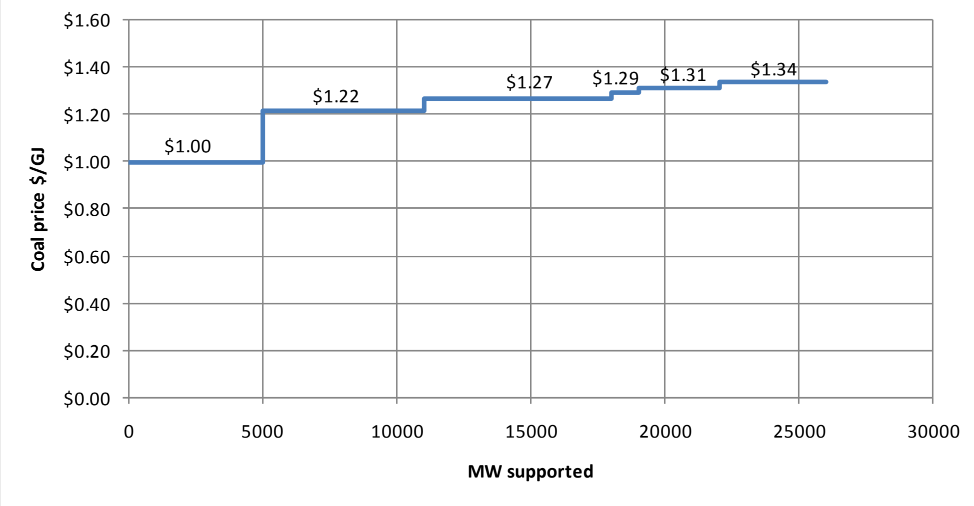
The projected coal prices and potential plant capacity for 2009/10 for Qld and NSW are shown in Figure ES 3 Figure 51and Figure ES 4.

Figure ES 3 **Coal prices and potential MW for Qld in 2009/10 ($/GJ)**



Data source: ACIL Tasman analysis

Figure ES 4 **Coal prices and potential MW for NSW in 2009/10 ($/GJ)**



Data source: *ACIL Tasman analysis*

1 Introduction

ACIL Tasman has been engaged by the Queensland Competition Authority (QCA) to provide estimates of new build generation and fuel costs across the five regions of the National Electricity Market (NEM). The purpose of our engagement is to provide the fuel and other generator cost information to inform the calculation of the Benchmark Retail Cost Index (BRCI) for the 2009/10 tariff year to be undertaken by CRA International (CRA).

ACIL Tasman understands and accepts that the finalised report we provide may be released in the public domain.

The projected cost data requirements are set out below:

1. The data is to be estimated in the context of the methodological framework adopted by the QCA for greenfield plant
2. The data is to be provided on an annual basis for 2007/08 to 2017/18 inclusive
3. The data is to be provided for each region of the NEM, but not for subsets of each region (that is, a single estimate will be provided for a given region for a given year)
4. The fuels to be covered are gas and coal – with a single representative delivered cost projected for each region and where appropriate, each technology type (for example, a separate gas price for CCGTs and OCGTs will be provided to reflect the different load factors)
5. Identification of short term gas resource constraints – the limit on annual gas consumption for the first five years of the projection period
6. Capital costs for a greenfield development for the following technologies:[1]
   - Black coal
   - Brown coal
   - CCGT
   - OCGT
   - Wind
   - Geothermal.
7. The inputs for calculating the annualised capital cost for each of the technologies identified in the previous bullet point, including:
   - Capital cost

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[1] We assume other renewable technologies such as Biomass will have a very minor role in the overall plant mix and therefore we have not exerted effort and budget in the estimation of their capital costs.

- Construction profile (fall of capital during the construction period)
- WACC and its components

8. Fixed Operations and Maintenance (O&M) costs assuming a normal capacity factor for each of the technologies identified in bullet point 6
9. Variable O&M costs for each of the technologies identified in bullet point 6
10. Thermal efficiency and auxiliary load for each of the technologies identified in bullet point 6.

We have attempted to make our analysis as transparent as possible. However, given our experience in the NEM we have access to useful and informative market intelligence which we have chosen not to ignore in this particular analysis, for which we are unable to divulge the source. Therefore some of our analysis will include data that we cannot attribute to a particular public source.

Two members of the ACIL Tasman team have been previously engaged in assisting AGL with their submissions to the QCA for the 2008/09 BRCI. We accept that this may raise the issue of independence and/or conflict with other stakeholders during our engagement with QCA. ACIL Tasman takes these matters very seriously. Therefore, we have included an internal peer review by a senior ACIL Tasman consultant who has not been involved in previous work with AGL or the QCA.

2 Capital costs

2.1 Introduction

One of the major issues for the 2008/09 BRCI was the estimate of capital costs. ACIL Tasman was engaged by AGL in the first half of 2008 to undertake a separate study of estimate capital costs for coal and gas-fired plant in 2008/09. The estimates were based on published data and analyses. In our study for the QCA we are providing a projection of capital costs out to 2017/18.

In our study for AGL we suggested there was clear evidence of a step change in capital costs over the past 24 months. We still believe this to be the case and this issue is discussed further in this chapter of the report. However a further and an important question to consider is whether these step changes are temporary or permanent? That is, have we reached a new equilibrium for plant capital costs that will be maintained for the next 10 years?

This is a difficult question to answer and we attempt to answer it in this chapter by considering the drivers likely to be responsible for the recent step change and whether these drivers are likely to change in the near future. These drivers include (in no particular order of importance):

- Supply of turbines:
  - We will assess the supply situation for turbines and whether supply constraints are contributing to the increase in costs and any likely supply expansions in the future which may alleviate any supply constraints
- Demand for turbines (in Australia, but more importantly, overseas):
  - We will assess the demand for turbines to get a sense of the demand/supply balance for turbines and wheter this has contributed to the cost increase and whether the outlook for the demand for turbines is likely to change
- Financial analysis of the major turbine suppliers:
  - It is worth investigating whether turbine manufacturers are gouging the market and hence inflating the cost for turbines.
- Input costs for turbines (steel prices and wages etc)
  - We will assess the impact that rising steel prices and labour costs have on turbine costs and consider the future outlook for stell prcies and labour costs.

Given the dominance of coal and gas in the plant mix of previous BRCI determinations and of gas in the current draft analysis by CRA, our analysis of the step change in capital costs focuses on coal plant and CCGT plant. However, we provide capital cost estimates of OCGT, wind and geothermal plant.

Our analysis starts with developing a sense of the contribution of these drivers to the step change (that is, to what extent is the step change a result of the increase in input costs and/or the change in the demand/supply balance). It is important to get a sense of the current demand/supply balance and the turbine back log. We then need to project forward the demand and supply of turbines. The demand will largely be influenced by India and China and we make use of published data on projected demand. The supply side will be largely influenced by the ability and intent of existing turbine manufacturers to ramp up (or expand) production. We also consider the possibility of new manufacturers coming on line.

Input costs are estimated by obtaining projections of steel price. To the extent possible we have drawn upon public statistics and indices.

Naturally, there are limitations to what we can and cannot do in this type of study and we make these limitations very clear in our report. For example, we do not undertake our own projection of steel prices as this would require substantial time and budget. Further, the estimation of the demand/supply balance of turbines is exactly that – an estimate, we have not developed a complex and detailed turbine demand/supply balance model nor have we undertaken a detailed analysis and projection of the global economy using tools such general equilibrium modelling (again, for time and budget constraints). Instead, we have assessed each of the major drivers drawing on published information to as great extent as possible and have made our conclusions and justified these conclusions. Undertaking a detailed modelling exercise of the global economy and the turbine sector may or may not deliver a more accurate projection of capital costs, it is difficult to say, but it is clear that such a detailed modelling exercise would certainly require a far greater number of more detailed input assumptions which will create more debate and produce a result that is no more justifiable than that of our analysis.

As with any analysis of this sort, quite naturally there are differing views and we have included independent views from public sources to allow a comparison with our conclusions. However, we are required to make an independent assessment on the future capital costs as well as the current capital costs and this inevitably requires, to some extent, judgement on our behalf.

Our estimates of project capital costs for a new power station include the following:

- engineering, procurement and construction (EPC)
- planning and approval

- professional services
- land acquisition
- infrastructure costs (incl. water)
- spares and workshop etc and
- connection to the electricity network
- fuel connection, handling and storage.

Our estimates of project capital costs exclude interest during construction (IDC).

2.2 Supply

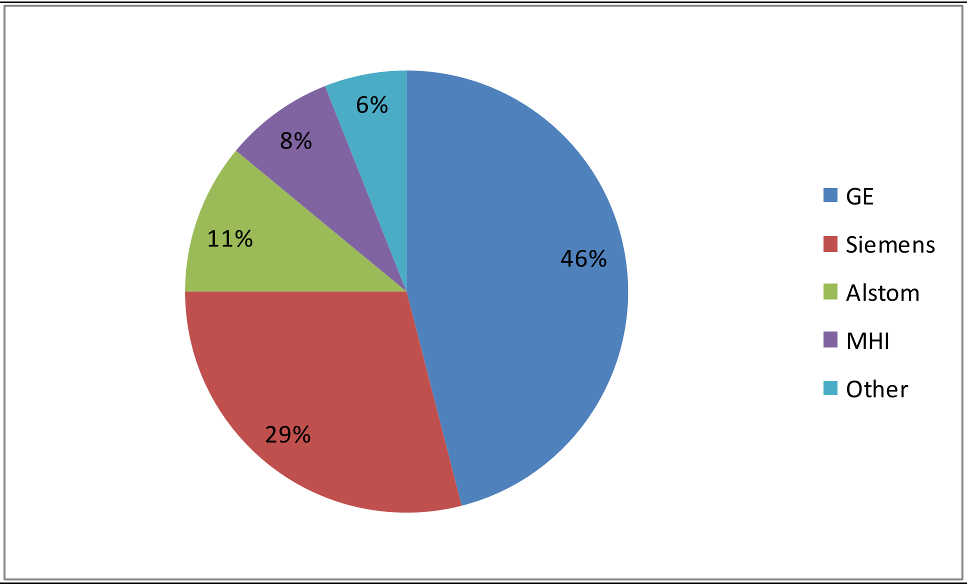
It has been suggested that supply constraints are contributing to the increase cost of turbines. Therefore, it is worth reflecting on the status of supply for turbines to get a sense of the number and concentration of suppliers, as well as any plans for future supply expansions. Concentration of suppliers could contribute to higher price though gaming the market and conversely future supply expansions could alleviate supply constraints and gaming.

2.2.1 Current supply

CCGTs

Figure 1 shows the current global market share by supplier of CCGTs. The market is dominated by four suppliers, namely, GE, Siemens, Alstom and MHI, and therefore very concentrated, with these four suppliers making up 94% of the market.

Figure 1 **Average global market share of CCGT suppliers – 2005-2007**



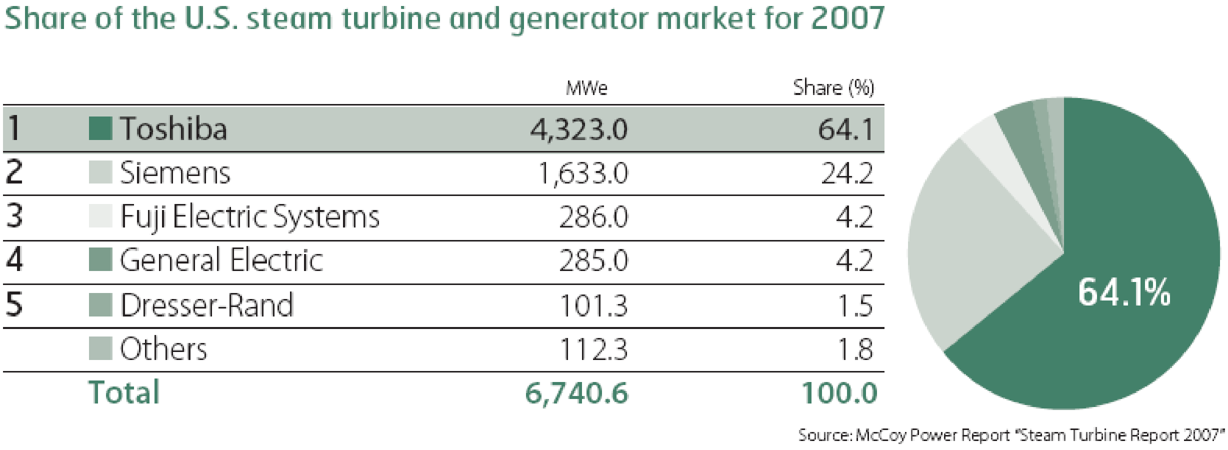
Data source: MHI (May 2008)

Coal plant

In the steam turbine market, the main global suppliers are Alstom, Siemens, MHI, Toshiba and GE. However, supply also comes from Shanghai Electric, Harbin and Dongfang in China, and BHEL in India.

It was not possible to estimate the global market share of the different steam turbine manufacturers. However, Figure 2 shows that in the US, the market is dominated by Toshiba and Siemens, which suggests that the steam turbine market is similar to the CCGT market in terms of supply concentration.

Figure 2 **Toshiba's share of the US steam turbine market - 2007**



Share of the U.S. steam turbine and generator market for 2007

		MWe	Share (%)
1	■ Toshiba	4,323.0	64.1
2	■ Siemens	1,633.0	24.2
3	■ Fuji Electric Systems	286.0	4.2
4	■ General Electric	285.0	4.2
5	■ Dresser-Rand	101.3	1.5
	■ Others	112.3	1.8
	Total	6,740.6	100.0

Source: McCoy Power Report "Steam Turbine Report 2007"

Data source: Toshiba 2008 Annual Report

2.2.2 Future supply

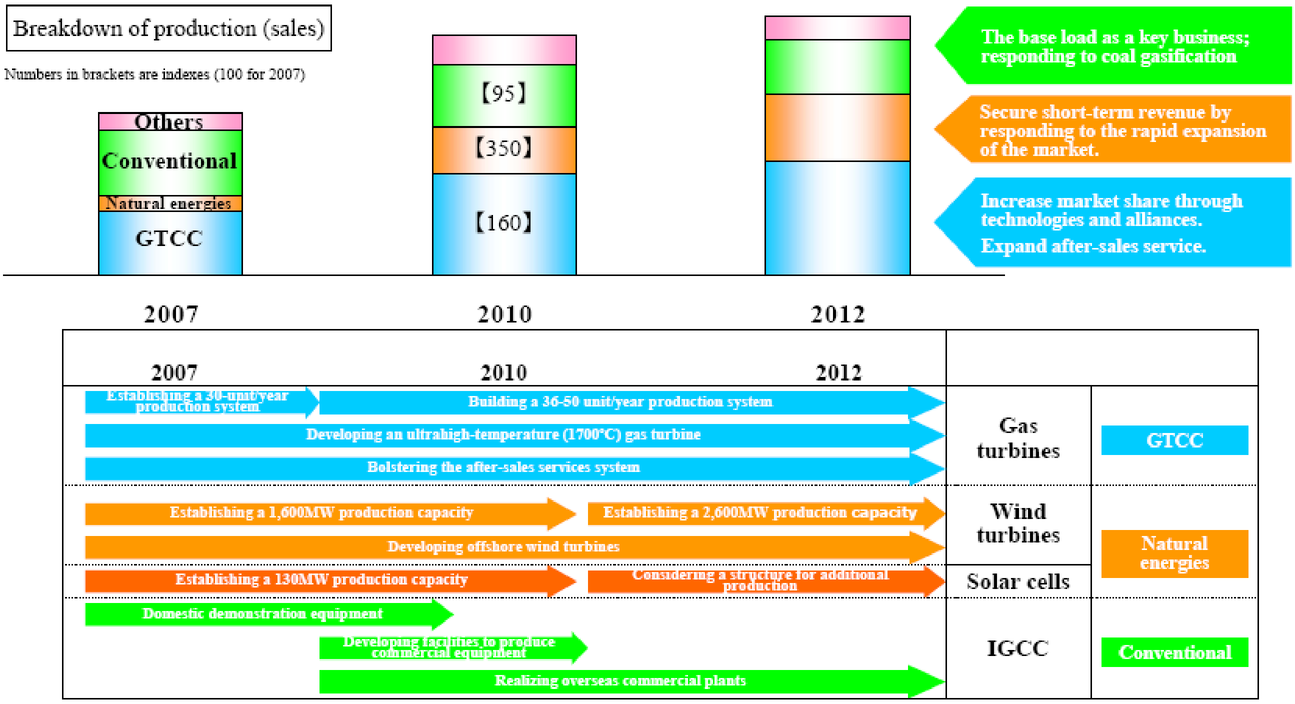
The rising demand for turbines is expected to result in an increase in production capacity by the major manufacturers. The decision to expand production capacity depends on the long-term views of the manufactures in terms of future demand for turbines. Section 2.3 sets out a reasonably unanimous expectation of the future global demand for turbines.

There appear to be some committed plans by the large suppliers to expand turbine production capacity.

At the end of 2007, Alstom committed to building a new facility in Chattanooga, Tennessee, USA, to manufacture steam turbines for nuclear and thermal power plants, gas turbines, generators and related equipment. The project will represent an investment more than $200 million. It is reported that the new plant will increase the company's worldwide manufacturing capacity by 10 to 15 percent and is targeted to commence operations in 2010/2011.

MHI in a recent investor presentation has indicated its intentions to expand its production facilities by as much as 100% for CCGTs between 2010 and 2012 (see Figure 3). A press release in mid 2007 stated: "*Currently MHI is planning a large-scale investment in its Takasago Machinery Works, the company's core production plant for gas turbines, in order to boost in-house turbine production capability in anticipation of strong demand. The company also aims to further expand its gas turbine production capacity to meet sharp increases in demand expected in North America, Europe and Asia*". The current production capacity of Takasago is 2,400MW of steam turbines for thermal and nuclear power plants and 4,800MW of gas turbines.

Figure 3 **MHI Business Operation Plan - Breakdown of production sales**



Data source: MHI, 2008

It is unclear whether Siemens has further expansion plans. In 2002 Siemens was reportedly doubling its gas-turbine production capacity to over 100 units per year to meet its backlog, which at that time extended to at least 2004. In a September 2008 investor presentation, Siemens indicated plans to expand its gas turbine production facilities from 60 GTs per year to 120 GTs per year by 2010.

China

New production capability appears to be coming online in China, but it is difficult to get a sense of the extent of the capacity expansion. However, it is usually in the form of a Chinese manufacturer licensing the technology of one of the larger manufacturers. For example, in 2002, MHI signed an agreement to license large-size gas turbine technology to China's Dongfang Steam Turbine Works.

2.3 Demand

Demand for new turbines is an important consideration in the context of capital costs. If demand for turbines has outpaced supply then this would contribute to a tightening demand/supply balance which in turn could contribute to the increase in capital costs.

We have focused on global demand, rather than domestic demand for turbines. In the NEM the most recent coal plant constructed was Kogan Creek (750 MW), completed in 2007, prior to that it was the tranche of capacity made up by Callide C (930 MW), Millmerran (850 MW) and Tarong North (443 MW) around 2003. This compares with about 150,000 MW of capacity added each year globally.

Global demand for new investment in power stations, and the type of technology, is driven largely by the following factors:

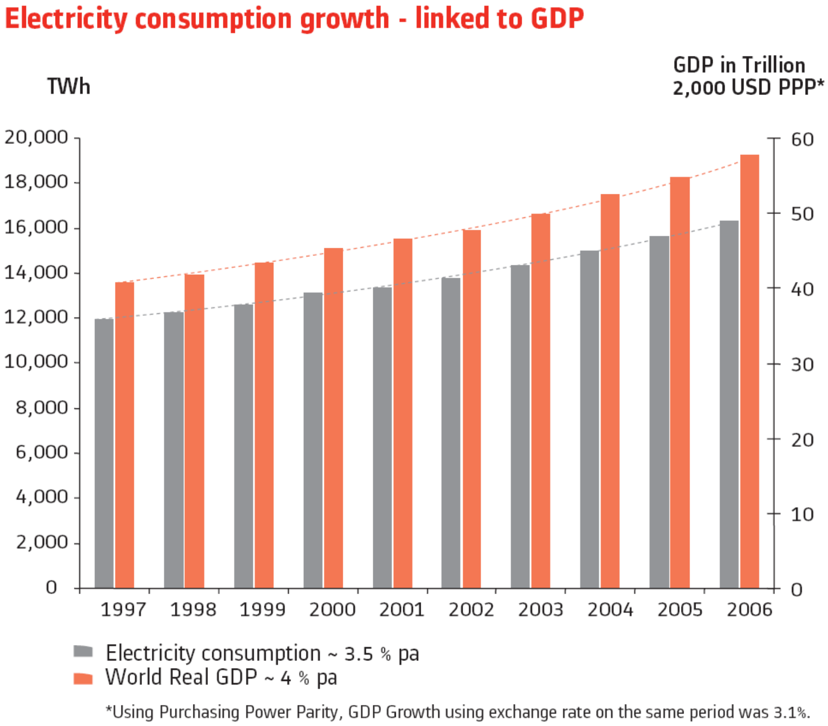
- World economic growth
- Growth in energy demand
- An ageing generator fleet
- Environmental concern.

2.3.1 Economic growth

Power consumption and GDP are tightly linked. Economic development is driving consumption of electricity, particularly in countries with rapid industrialisation. In China for example, power consumption growth has outpaced GDP growth, driven by strong production from heavy industry and growing electrification in rural areas. In developed countries, the ratio of electricity consumption to GDP, known as electricity intensity, is progressively declining due to a shift of the economy from more energy intensive primary and secondary manufacturing to less energy intensive tertiary industries and services.

The graph below shows that world GDP has averaged 4% per annum over the past decade compared with 3.5% for electricity consumption growth.

Figure 4 **Growth in global GDP and electricity consumption: 1997 - 2006**



*Using Purchasing Power Parity, GDP Growth using exchange rate on the same period was 3.1%.

Data source: Alstom 2007/08 Annual Report

The World Bank

The latest global outlook available on the World Bank website makes the following points:

- Turmoil in financial markets, slower growth in high-income countries, and rising inflation have all adversely affected growth prospects for developing countries over the near term. Most countries have shown impressive resilience in this turbulent environment. Growth in developing countries as a group is expected to moderate slightly, with GDP outturns likely to differ substantially across regions, and vulnerable countries that depend on foreign capital flows likely to experience a sharper slowdown.
- Most countries have shown resilience in this turbulent environment, and growth for developing countries as a group is expected to moderate from 7.8 percent in 2007 to a still strong 6.5 percent in 2008.
- However, vulnerable countries that depend on foreign capital flows are likely to experience a sharper slowdown.

The latest forecast of world GDP growth from the World Bank is detailed in Table 1.

Table 1 **World Bank GDP growth projection (%)**

Real GDP Growth	2006	2007e	2008f	2009f	2010f
World	4	3.7	2.7	3	3.4
World (PPP weights)	5.4	5.4	4.3	4.5	4.8

Data source: The World Bank website, June 2008

Energy Information Administration

The Energy Information Administration (EIA) in its latest publication, *International Energy Outlook 2008* (September 2008) projects that the global real GDP on a purchasing power parity basis will average 4.0 percent annually to 2030 in its reference case. This is higher than the 3.5% observed historically, but the EIA suggest that the countries that are expected to see more rapid growth, such as China and India, are increasing their share of world GDP.

The data in Table 2 suggests that GDP growth assumed by EIA will be about 4.4% between 2008 and 2015, which is not dissimilar to the projection provided be the World Bank in Table 1. Growth in China and India are noticeably higher at about 7.3% and 7.1% respectively during the same period.

Table 2 **Projected annual growth in World GDP**

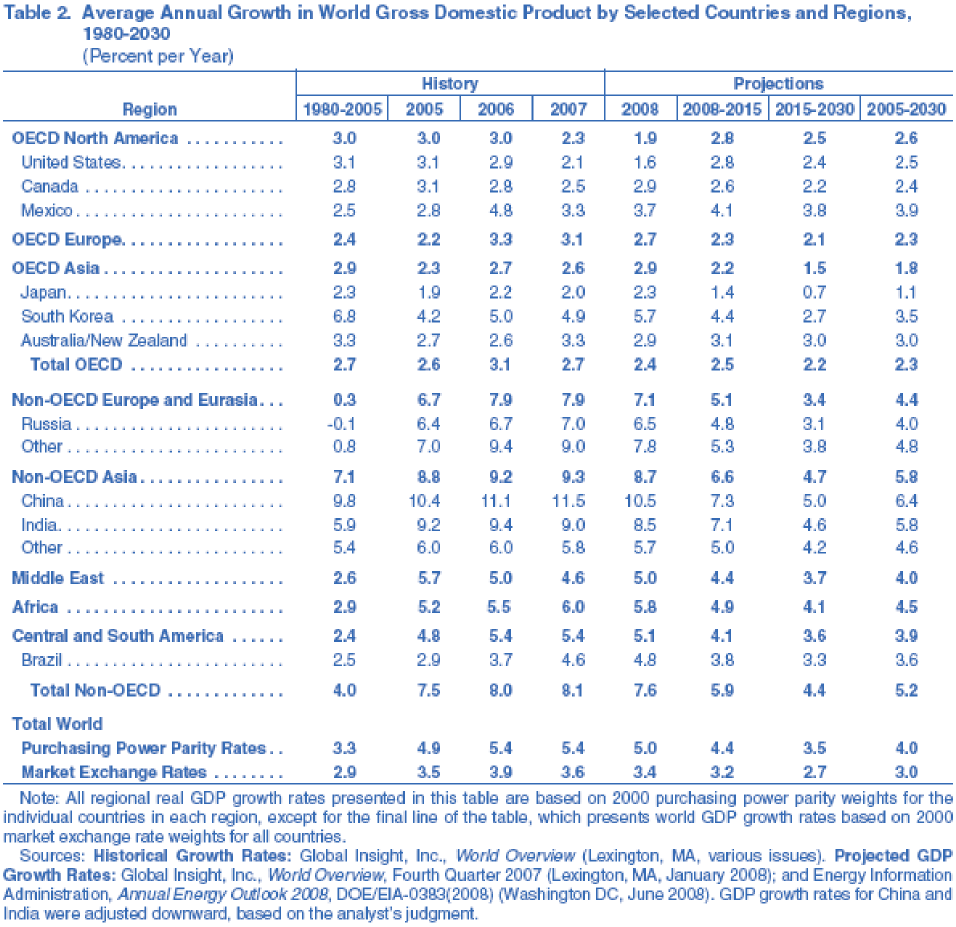


Table 2. Average Annual Growth in World Gross Domestic Product by Selected Countries and Regions, 1980-2030
(Percent per Year)

Region	History 1980-2005	2005	2006	2007	Projections 2008	2008-2015	2015-2030	2005-2030
OECD North America	**3.0**	**3.0**	**3.0**	**2.3**	**1.9**	**2.8**	**2.5**	**2.6**
United States	3.1	3.1	2.9	2.1	1.6	2.8	2.4	2.5
Canada	2.8	3.1	2.8	2.5	2.9	2.6	2.2	2.4
Mexico	2.5	2.8	4.8	3.3	3.7	4.1	3.8	3.9
OECD Europe	**2.4**	**2.2**	**3.3**	**3.1**	**2.7**	**2.3**	**2.1**	**2.3**
OECD Asia	**2.9**	**2.3**	**2.7**	**2.6**	**2.9**	**2.2**	**1.5**	**1.8**
Japan	2.3	1.9	2.2	2.0	2.3	1.4	0.7	1.1
South Korea	6.8	4.2	5.0	4.9	5.7	4.4	2.7	3.5
Australia/New Zealand	3.3	2.7	2.6	3.3	2.9	3.1	3.0	3.0
Total OECD	**2.7**	**2.6**	**3.1**	**2.7**	**2.4**	**2.5**	**2.2**	**2.3**
Non-OECD Europe and Eurasia	**0.3**	**6.7**	**7.9**	**7.9**	**7.1**	**5.1**	**3.4**	**4.4**
Russia	-0.1	6.4	6.7	7.0	6.5	4.8	3.1	4.0
Other	0.8	7.0	9.4	9.0	7.8	5.3	3.8	4.8
Non-OECD Asia	**7.1**	**8.8**	**9.2**	**9.3**	**8.7**	**6.6**	**4.7**	**5.8**
China	9.8	10.4	11.1	11.5	10.5	7.3	5.0	6.4
India	5.9	9.2	9.4	9.0	8.5	7.1	4.6	5.8
Other	5.4	6.0	6.0	5.8	5.7	5.0	4.2	4.6
Middle East	**2.6**	**5.7**	**5.0**	**4.6**	**5.0**	**4.4**	**3.7**	**4.0**
Africa	**2.9**	**5.2**	**5.5**	**6.0**	**5.8**	**4.9**	**4.1**	**4.5**
Central and South America	**2.4**	**4.8**	**5.4**	**5.4**	**5.1**	**4.1**	**3.6**	**3.9**
Brazil	2.5	2.9	3.7	4.6	4.8	3.8	3.3	3.6
Total Non-OECD	**4.0**	**7.5**	**8.0**	**8.1**	**7.6**	**5.9**	**4.4**	**5.2**
Total World								
Purchasing Power Parity Rates	**3.3**	**4.9**	**5.4**	**5.4**	**5.0**	**4.4**	**3.5**	**4.0**
Market Exchange Rates	**2.9**	**3.5**	**3.9**	**3.6**	**3.4**	**3.2**	**2.7**	**3.0**

Note: All regional real GDP growth rates presented in this table are based on 2000 purchasing power parity weights for the individual countries in each region, except for the final line of the table, which presents world GDP growth rates based on 2000 market exchange rate weights for all countries.

Sources: **Historical Growth Rates:** Global Insight, Inc., *World Overview* (Lexington, MA, various issues). **Projected GDP Growth Rates:** Global Insight, Inc., *World Overview*, Fourth Quarter 2007 (Lexington, MA, January 2008); and Energy Information Administration, *Annual Energy Outlook 2008*, DOE/EIA-0383(2008) (Washington DC, June 2008). GDP growth rates for China and India were adjusted downward, based on the analyst's judgment.

Data source: International Energy Outlook 2008, Energy Information Administration, September 2008

Chinese growth policy

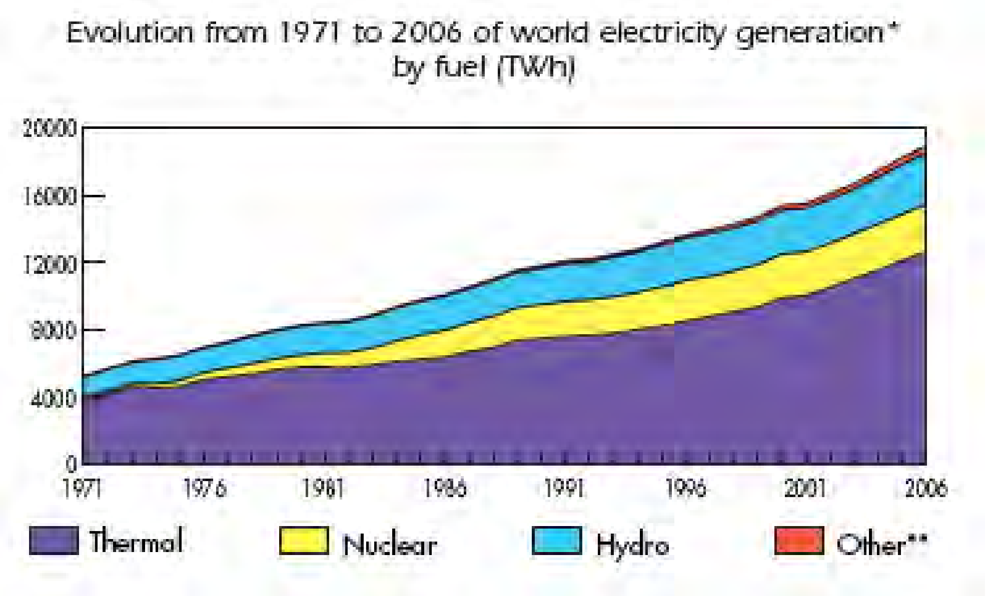
Recent action by the Chinese central bank to ease interest rates, reversing a tightening of rates over the last year, suggests that China is shifting monetary policy efforts from fighting inflation to supporting economic growth. Further easing of interest rates over the next twelve months is expected, in an attempt to maintain current growth levels where possible. This is consistent with the views of Consensus Economics above.

2.3.2 Growth in energy demand

International Energy Agency

Figure 5 and Figure 6 show that historical growth in electricity consumption over the past 30 or so years has largely been met by an increase in thermal generation and to a lesser extent nuclear generation. Thermal generation has doubled over the past 30 years. Within thermal generation, there has been a reduced dependence on oil-fired generation and an increase dependence on gas-fired generation.

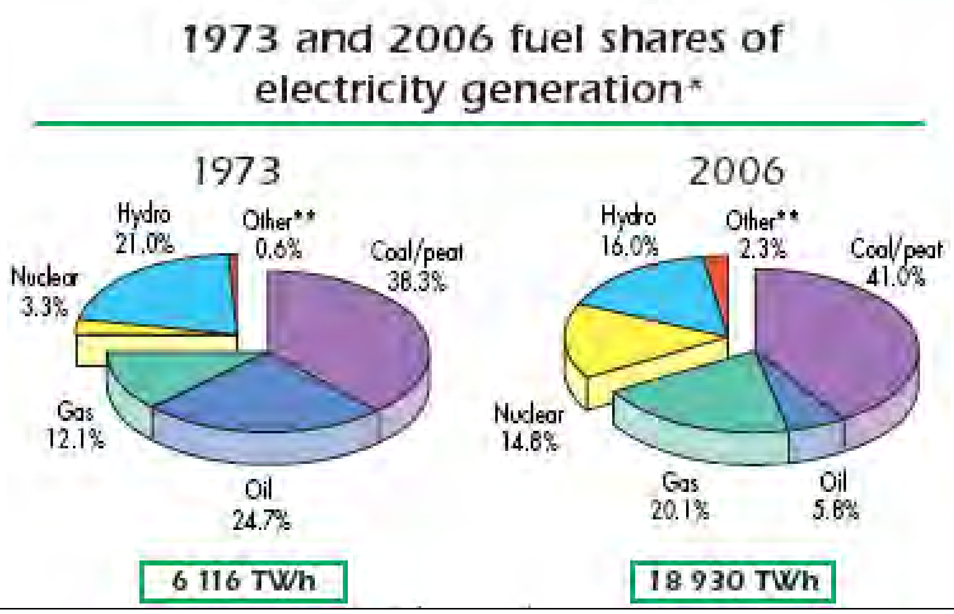
Figure 5 **Historical global electricity consumption (TWh) by type – 1971 - 2006**



Note: "Other" includes renewables.

Data source: Key World energy Statistics, International Energy Agency, 2008

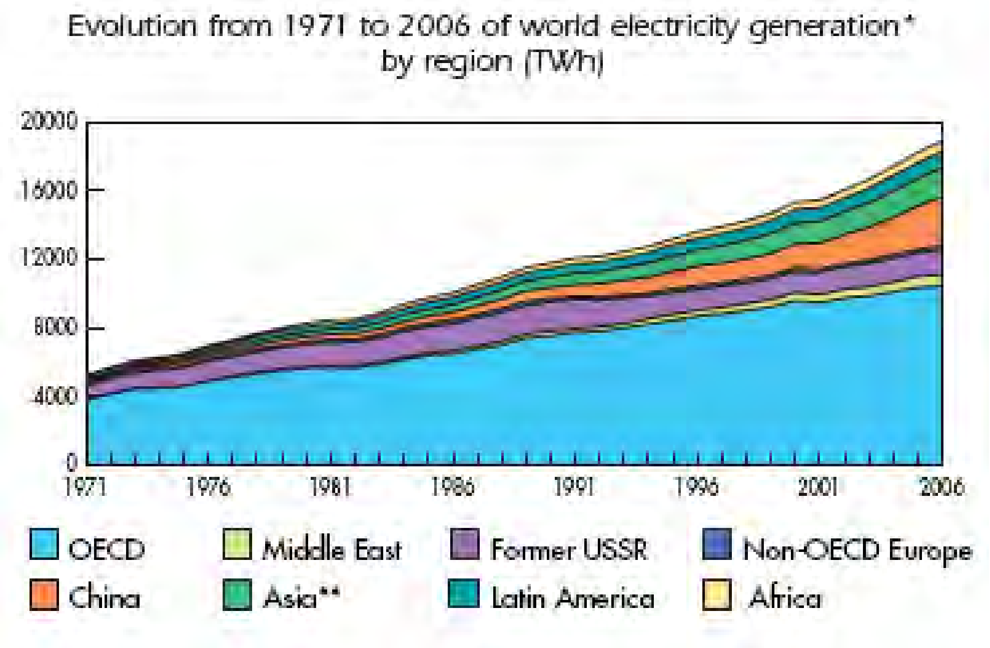
Figure 6 **Historical global electricity consumption (TWh) by type – 1973 and 2006**



Data source: Key World energy Statistics, International Energy Agency, 2008

Figure 7 shows that growth in developed countries over the past 30 years has been relatively steady and that the up-turn in overall electricity growth over the past five years is largely a result of growth in Asia and in particular, China.

Figure 7 **Historical global electricity consumption (TWh) by region – 1971 - 2006**

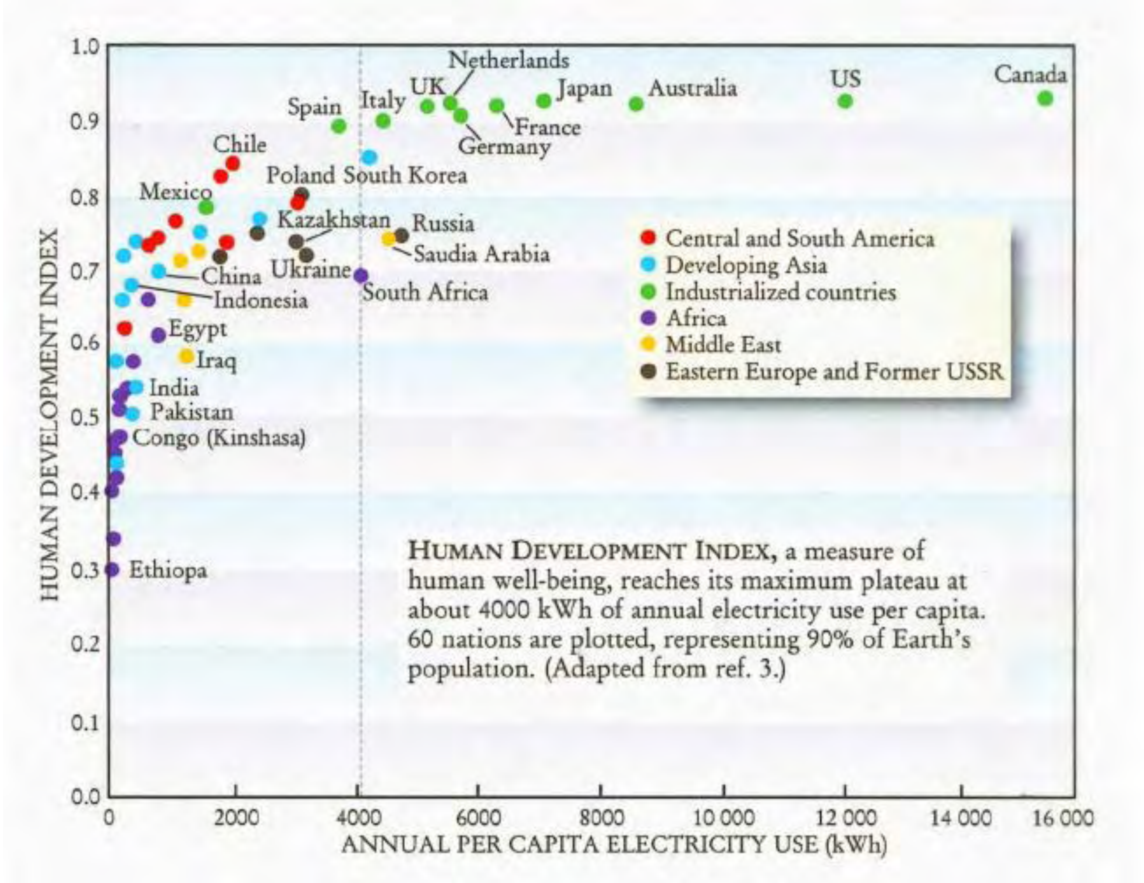


Data source: Key World energy Statistics, International Energy Agency, 2008

MIT Energy Initiative

The MIT Energy Initiative (MITIE) in a presentation to the EIA in April 2008 showed that the electricity consumption per capita of China and India was about a tenth of that of the US and other developed countries. Clearly there is a large potential for further and substantial growth in these two countries as their economies develop.

Figure 8 **Per capita electricity use by country**



Data source: MIT Energy Initiative presentation to EIA, April 2008.

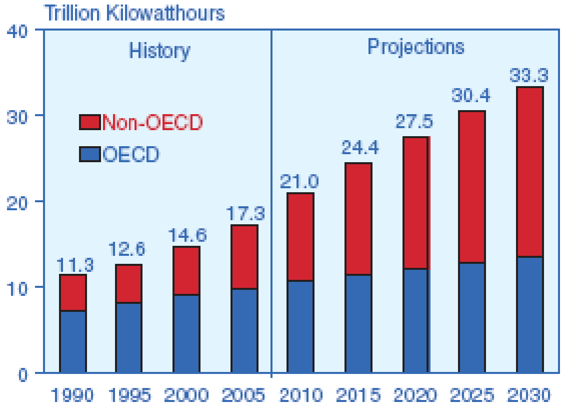
Energy Information Administration (and International Energy Agency)

The EIA suggests that electricity is expected to remain the fastest-growing form of end-use energy worldwide through 2030. Generation is projected to increase at an average annual rate of 2.6% through 2030, in the reference case, and 2% for 2005 to 2015.

The graph below shows that the growth in electricity consumption is clearly coming from developing countries.

Figure 9 **Projected annual electricity consumption – 2010 to 2030**

Figure 53. World Net Electric Power Generation, 1990-2030



Sources: **History:** Energy Information Administration (EIA), *International Energy Annual 2005* (June-October 2007), web site www.eia.doe.gov/iea. **Projections:** EIA, System for the Analysis of Global Energy Markets/Global Electricity Module (2008).

Note: Reference case

Data source: International Energy Outlook 2008, Energy Information Administration, September 2008

The International Energy Agency (IEA) in its World Energy Outlook 2007 provides projections comparable with those in the EIA International Energy Outlook 2008.

In the 2005 to 2015 projection period, the IEA reference scenario is about 0.3 of a percentage point higher than the EIA reference case. This difference appears reasonably consistent across all regions as shown in Table 3.

Both outlooks project much faster growth in energy demand among the non-OECD nations than in the OECD.

For China, IEA projects much faster growth than EIA from 2005 to 2015.

Table 3 **Projected annual electricity consumption – 2005 to 2015 by region**

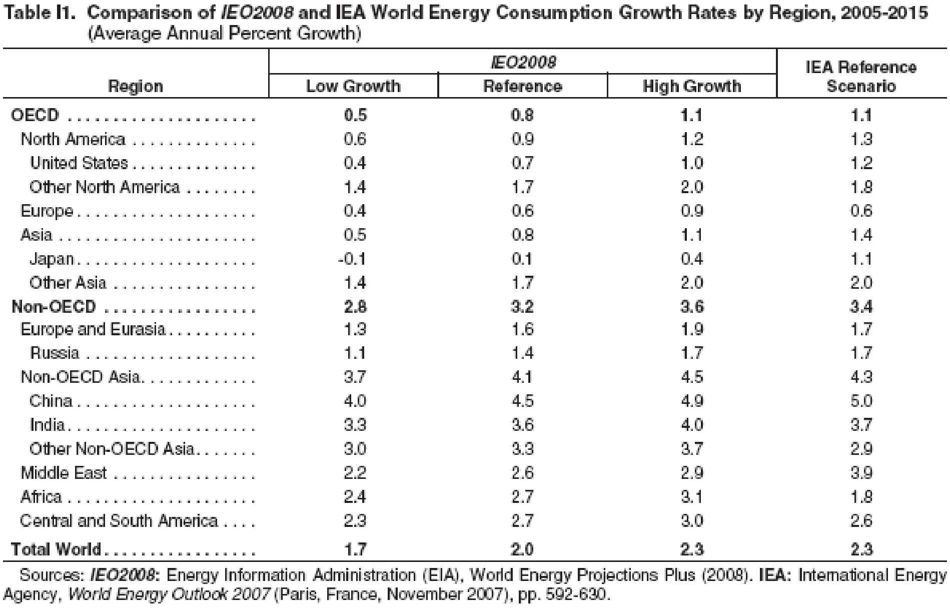


Table I1. Comparison of *IEO2008* and IEA World Energy Consumption Growth Rates by Region, 2005-2015
(Average Annual Percent Growth)

Region	*IEO2008* Low Growth	*IEO2008* Reference	*IEO2008* High Growth	IEA Reference Scenario
OECD	**0.5**	**0.8**	**1.1**	**1.1**
North America	0.6	0.9	1.2	1.3
United States	0.4	0.7	1.0	1.2
Other North America	1.4	1.7	2.0	1.8
Europe	0.4	0.6	0.9	0.6
Asia	0.5	0.8	1.1	1.4
Japan	-0.1	0.1	0.4	1.1
Other Asia	1.4	1.7	2.0	2.0
Non-OECD	**2.8**	**3.2**	**3.6**	**3.4**
Europe and Eurasia	1.3	1.6	1.9	1.7
Russia	1.1	1.4	1.7	1.7
Non-OECD Asia	3.7	4.1	4.5	4.3
China	4.0	4.5	4.9	5.0
India	3.3	3.6	4.0	3.7
Other Non-OECD Asia	3.0	3.3	3.7	2.9
Middle East	2.2	2.6	2.9	3.9
Africa	2.4	2.7	3.1	1.8
Central and South America	2.3	2.7	3.0	2.6
Total World	**1.7**	**2.0**	**2.3**	**2.3**

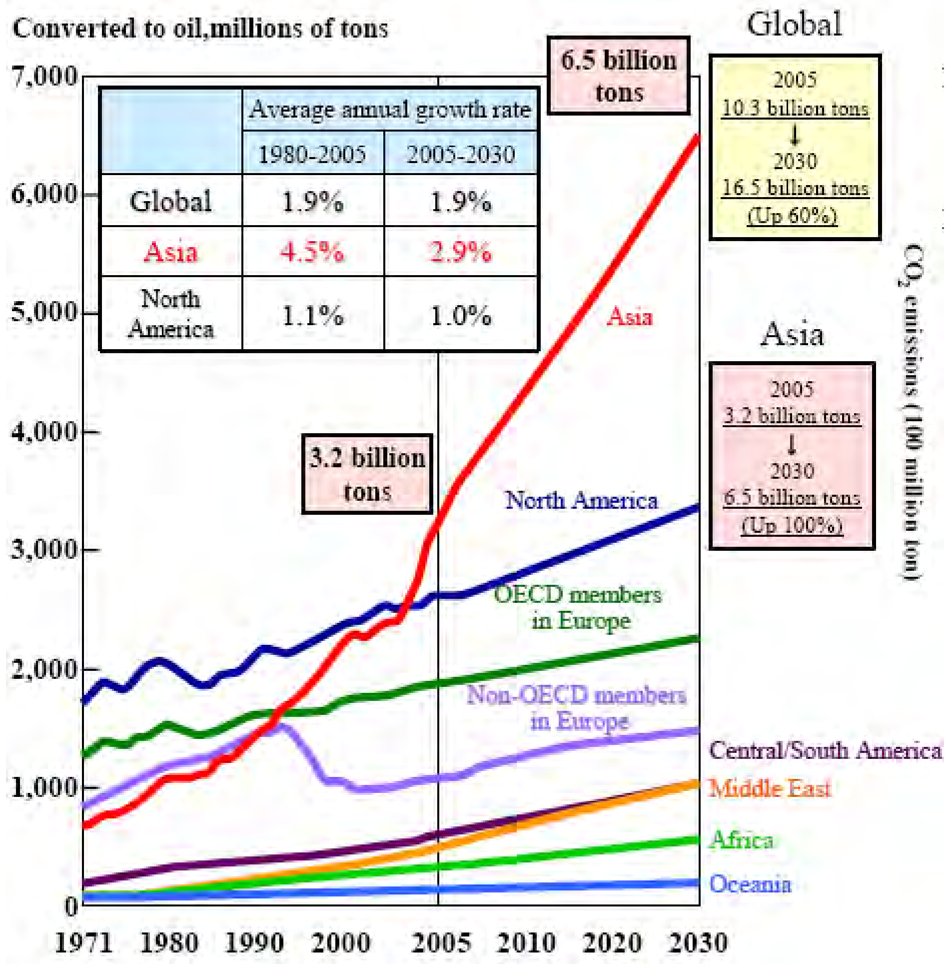
Sources: ***IEO2008*:** Energy Information Administration (EIA), World Energy Projections Plus (2008). **IEA:** International Energy Agency, *World Energy Outlook 2007* (Paris, France, November 2007), pp. 592-630.

Data source: International Energy Outlook 2008, Energy Information Administration, September 2008

Mitsubishi Heavy Industries

As one would expect turbine manufactures are very interested in the outlook for electricity growth. Mitsubishi Heavy Industries (MHI) in an investor presentation in May 2008 also noted the growing demand for electricity, particularly in Asia – specifically India and China.

Figure 10 **Historic and projected primary energy consumption – 1971 to 2030**



	Average annual growth rate	
	1980-2005	2005-2030
Global	1.9%	1.9%
Asia	4.5%	2.9%
North America	1.1%	1.0%

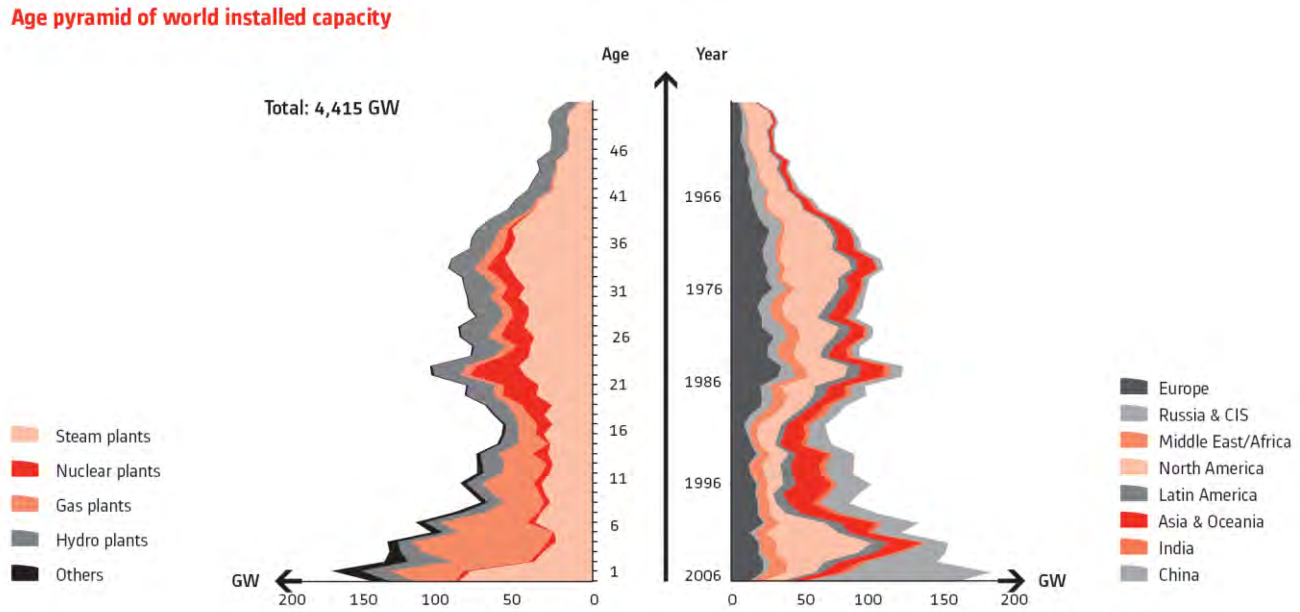
Data source: MHI investor presentation, May 2008 using IEEJ (2007)

2.3.3 Ageing generator fleet

An important consideration for future demand of generator capacity is not only the demand for electricity but the replacement of older existing power stations. Figure 11 is taken from the Alstom 2007/08 Annual Report which uses Utility data Institute (UDI) data and shows the age distribution of the existing world generator fleet.

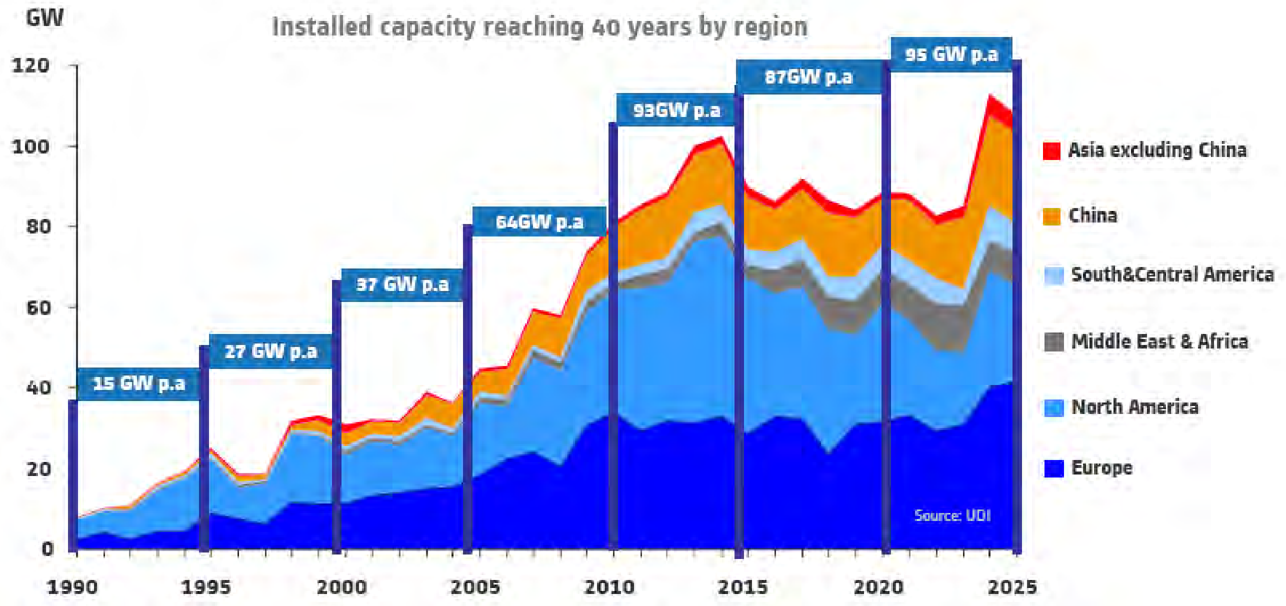
During the next 10 years, just under 1,000GW of plant will be at least 40 years of age. The majority of this plant is coal-fired, baseload, and located in Europe and North America. The increasing number of old plants reaching retirement age will contribute to the demand for new equipment in order to maintain current levels of installed capacity. The annual reports and associated investor presentations of the main turbine suppliers suggest they are fully aware of this outlook.

Figure 11 **Ageing generator fleet**



Data source: Alstom 2007/08 Annual Report

Figure 12 **Installed capacity 40 years of age by region**



Data source: Alstom analyst presentation 2008 (data source: UDI)

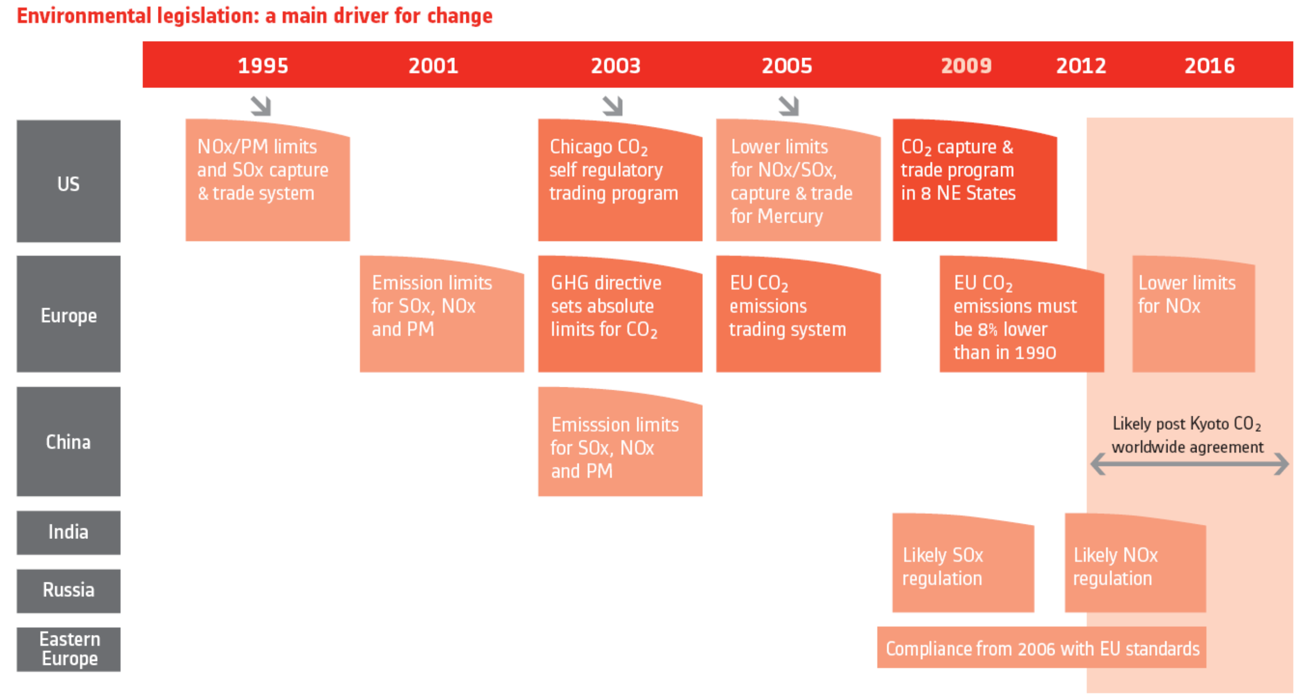
2.3.4 Environmental concerns

Environmental concerns have been the most widely debated topics over recent years in the energy sector. A real change in attitude and behaviour is visible, with more stringent regulations being implemented particularly in developed economies.

Legislators are starting to put in place a raft of policies to reduce CO_2e emissions in the medium- to long-term. These policies have created increased interest in gas-fired and nuclear technology over the past decade and more recently in various clean-coal technologies. The ageing fleet and changes to environmental legislation and policies have resulted in increased refurbishment and the integration of environmental control systems into existing power plants.

We can see this influence in the NEM; greenhouse policy has postponed or removed future coal plant development and made gas-fired plant more economic. However, large developing economies such as China and India do not have as stringent greenhouse policies in place at present which is therefore maintaining demand for coal plant.

Figure 13 **Environmental legislation – by region and date**



Data source: Alstom 2007/08 Annual Report

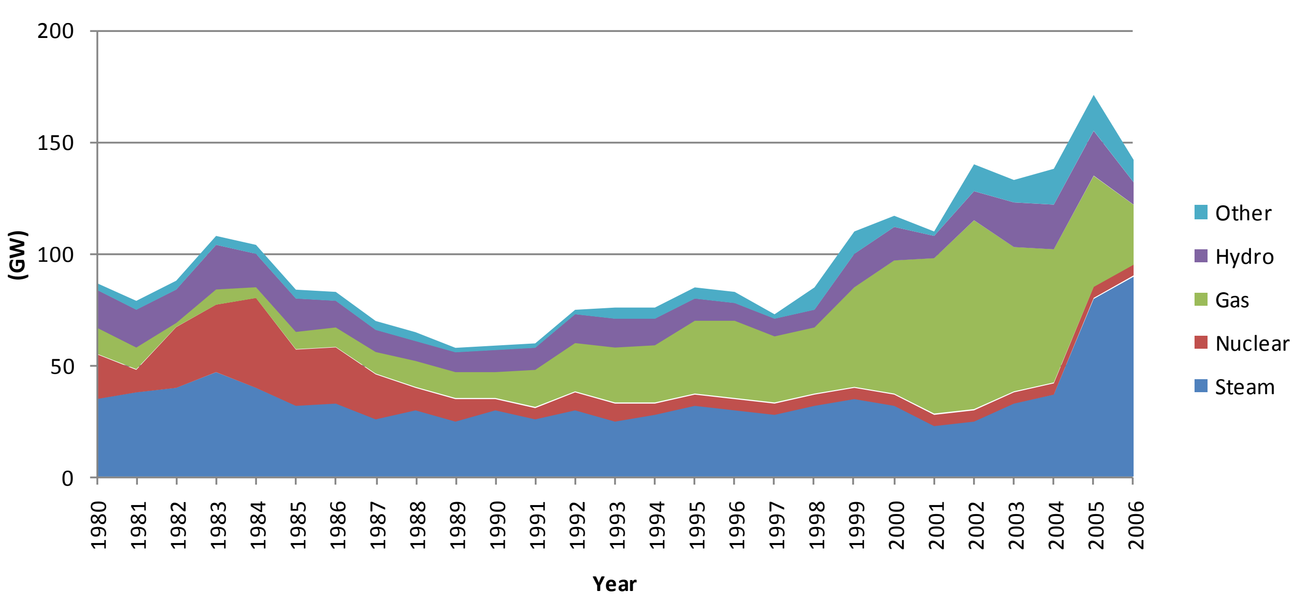
2.3.5 Future turbine demand

The global mix of primary fuels used to generate electricity has changed over the past two decades. Coal continues to be the fuel most widely used for electricity generation, although generation from nuclear power increased rapidly from the 1970s through the 1980s, and natural-gas-fired generation grew rapidly in the 1980s and 1990s.

Rising oil prices in the mid 2000s appears to have halted the strong growth in gas-fired capacity which has been substituted by coal-fired capacity in recent years – particularly in China.

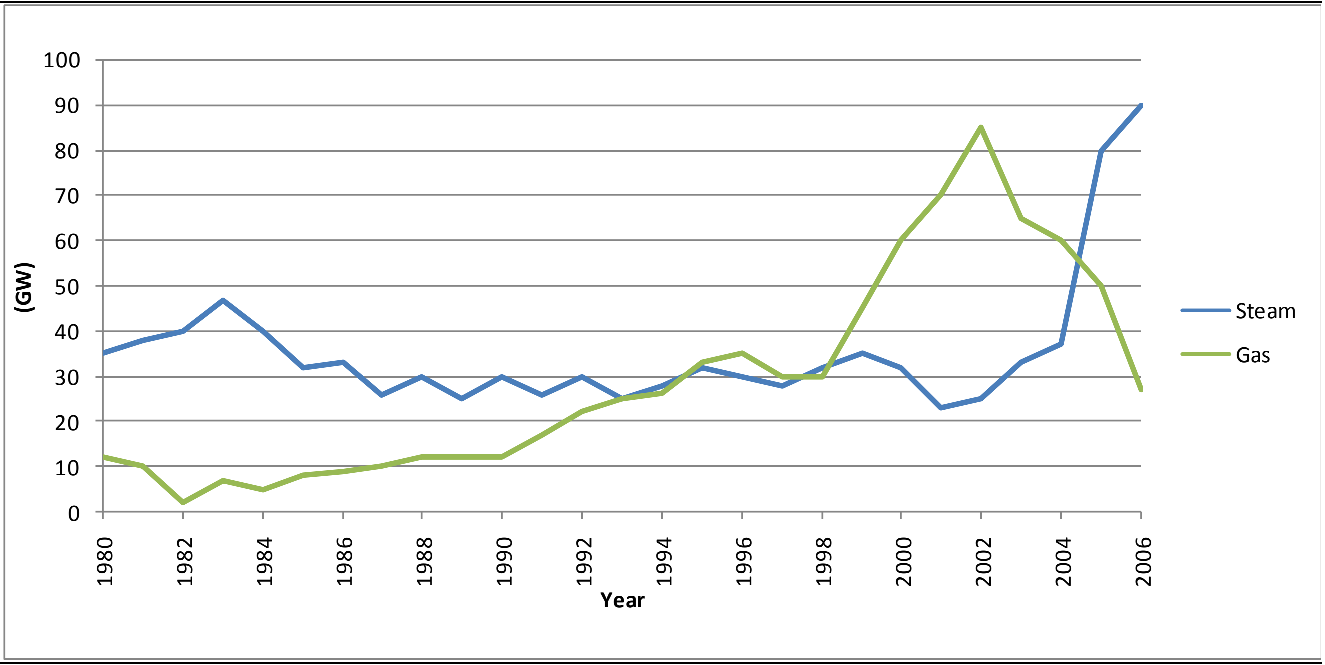
Figure 14 and Figure 15 summarise the capacity added annually to the global generator fleet between 1980 and 2006. It is clear that over the last decade there has been substantial growth in the capacity additions.

Figure 14 **Global generator capacity added annually – 1980 - 2006**



Data source: ACIL Tasman analysis of various sources

Figure 15 **Global steam and gas generator capacity added annually – 1980 - 2006**



Data source: ACIL Tasman analysis of various sources

We found a number of sources that provide projections of global demand for generator capacity by type which are worth considering.

Energy Information Administration

The EIA projects natural gas to be the fastest-growing energy source for electricity generation worldwide. However, coal continues to have the largest share. In 2005, coal-fired generation accounted for 41% of world electricity supply; in 2030, its share is projected to be 46%. High prices for oil and natural gas make coal-fired generation more attractive, particularly in economies that are rich in coal resources, such as China, India, and the US.

The EIA also note that natural-gas-fired combined-cycle capacity is an attractive choice for new power plants because of its fuel efficiency, operating flexibility (it can be brought on line in minutes rather than the hours it takes for coal-fired and some other generating capacity), shorter planning[2] and construction times, and capital costs that are lower than those for other technologies.

Table 4 and Table 5 summarise the projected installed capacity for gas-fired and coal-fired plant for the EIA's reference case. Gas-fired capacity is expected

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[2] Although, these times are blowing out for CCGTs to about 36 months construction time.

to grow on average at 3.6% per year and coal-fired capacity is expected to grow at 2.6% per year between 2005 and 2030. Between 2010 and 2015, gas-fired capacity is projected to grow by 60GW per year and coal-fired capacity is projected to grow at 42GW per year. We assume that gas-fired capacity refers to CCGTs and GTs.

Table 4 **EIA Reference Case Electricity Capacity – Gas-fired**

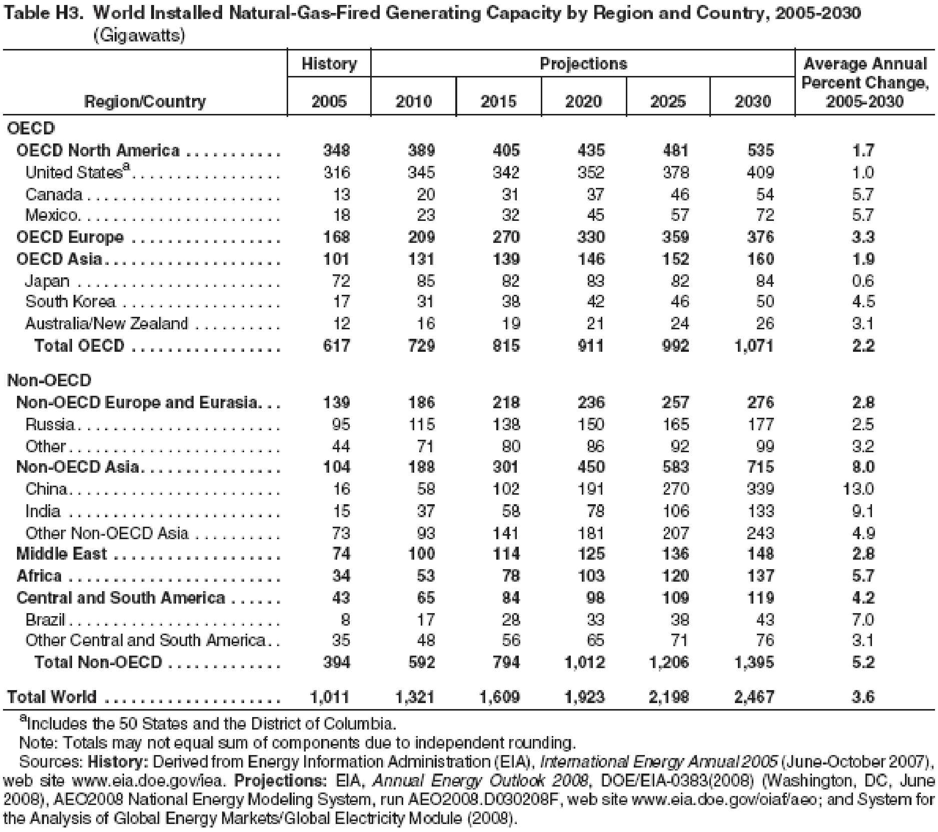


Table H3. World Installed Natural-Gas-Fired Generating Capacity by Region and Country, 2005-2030
(Gigawatts)

	History	Projections					Average Annual Percent Change, 2005-2030
Region/Country	2005	2010	2015	2020	2025	2030	
OECD							
OECD North America	**348**	**389**	**405**	**435**	**481**	**535**	**1.7**
United States[a]	316	345	342	352	378	409	1.0
Canada	13	20	31	37	46	54	5.7
Mexico	18	23	32	45	57	72	5.7
OECD Europe	**168**	**209**	**270**	**330**	**359**	**376**	**3.3**
OECD Asia	**101**	**131**	**139**	**146**	**152**	**160**	**1.9**
Japan	72	85	82	83	82	84	0.6
South Korea	17	31	38	42	46	50	4.5
Australia/New Zealand	12	16	19	21	24	26	3.1
Total OECD	**617**	**729**	**815**	**911**	**992**	**1,071**	**2.2**
Non-OECD							
Non-OECD Europe and Eurasia	**139**	**186**	**218**	**236**	**257**	**276**	**2.8**
Russia	95	115	138	150	165	177	2.5
Other	44	71	80	86	92	99	3.2
Non-OECD Asia	**104**	**188**	**301**	**450**	**583**	**715**	**8.0**
China	16	58	102	191	270	339	13.0
India	15	37	58	78	106	133	9.1
Other Non-OECD Asia	73	93	141	181	207	243	4.9
Middle East	**74**	**100**	**114**	**125**	**136**	**148**	**2.8**
Africa	**34**	**53**	**78**	**103**	**120**	**137**	**5.7**
Central and South America	**43**	**65**	**84**	**98**	**109**	**119**	**4.2**
Brazil	8	17	28	33	38	43	7.0
Other Central and South America	35	48	56	65	71	76	3.1
Total Non-OECD	**394**	**592**	**794**	**1,012**	**1,206**	**1,395**	**5.2**
Total World	**1,011**	**1,321**	**1,609**	**1,923**	**2,198**	**2,467**	**3.6**

[a] Includes the 50 States and the District of Columbia.

Note: Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 2005* (June-October 2007), web site www.eia.doe.gov/iea. **Projections:** EIA, *Annual Energy Outlook 2008*, DOE/EIA-0383(2008) (Washington, DC, June 2008), AEO2008 National Energy Modeling System, run AEO2008.D030208F, web site www.eia.doe.gov/oiaf/aeo; and System for the Analysis of Global Energy Markets/Global Electricity Module (2008).

Data source: International Energy Outlook 2008, Energy Information Administration, September 2008

Table 5 **EIA Reference Case Electricity Capacity – Coal-fired**

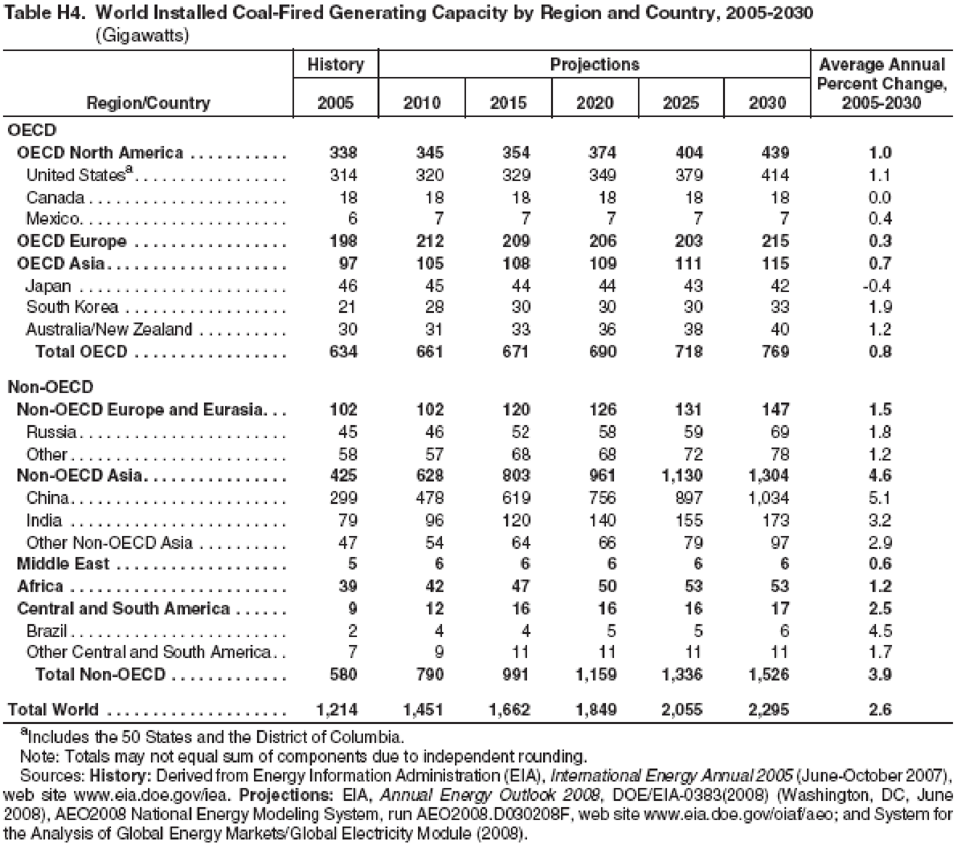


Table H4. World Installed Coal-Fired Generating Capacity by Region and Country, 2005-2030
(Gigawatts)

Region/Country	History	Projections					Average Annual Percent Change, 2005-2030
	2005	2010	2015	2020	2025	2030	
OECD							
OECD North America	**338**	**345**	**354**	**374**	**404**	**439**	**1.0**
United States[a]	314	320	329	349	379	414	1.1
Canada	18	18	18	18	18	18	0.0
Mexico	6	7	7	7	7	7	0.4
OECD Europe	**198**	**212**	**209**	**206**	**203**	**215**	**0.3**
OECD Asia	**97**	**105**	**108**	**109**	**111**	**115**	**0.7**
Japan	46	45	44	44	43	42	-0.4
South Korea	21	28	30	30	30	33	1.9
Australia/New Zealand	30	31	33	36	38	40	1.2
Total OECD	**634**	**661**	**671**	**690**	**718**	**769**	**0.8**
Non-OECD							
Non-OECD Europe and Eurasia	**102**	**102**	**120**	**126**	**131**	**147**	**1.5**
Russia	45	46	52	58	59	69	1.8
Other	58	57	68	68	72	78	1.2
Non-OECD Asia	**425**	**628**	**803**	**961**	**1,130**	**1,304**	**4.6**
China	299	478	619	756	897	1,034	5.1
India	79	96	120	140	155	173	3.2
Other Non-OECD Asia	47	54	64	66	79	97	2.9
Middle East	**5**	**6**	**6**	**6**	**6**	**6**	**0.6**
Africa	**39**	**42**	**47**	**50**	**53**	**53**	**1.2**
Central and South America	**9**	**12**	**16**	**16**	**16**	**17**	**2.5**
Brazil	2	4	4	5	5	6	4.5
Other Central and South America	7	9	11	11	11	11	1.7
Total Non-OECD	**580**	**790**	**991**	**1,159**	**1,336**	**1,526**	**3.9**
Total World	**1,214**	**1,451**	**1,662**	**1,849**	**2,055**	**2,295**	**2.6**

[a] Includes the 50 States and the District of Columbia.

Note: Totals may not equal sum of components due to independent rounding.

Sources: **History:** Derived from Energy Information Administration (EIA), *International Energy Annual 2005* (June-October 2007), web site www.eia.doe.gov/iea. **Projections:** EIA, *Annual Energy Outlook 2008*, DOE/EIA-0383(2008) (Washington, DC, June 2008), AEO2008 National Energy Modeling System, run AEO2008.D030208F, web site www.eia.doe.gov/oiaf/aeo; and System for the Analysis of Global Energy Markets/Global Electricity Module (2008).

Data source: International Energy Outlook 2008, Energy Information Administration, September 2008

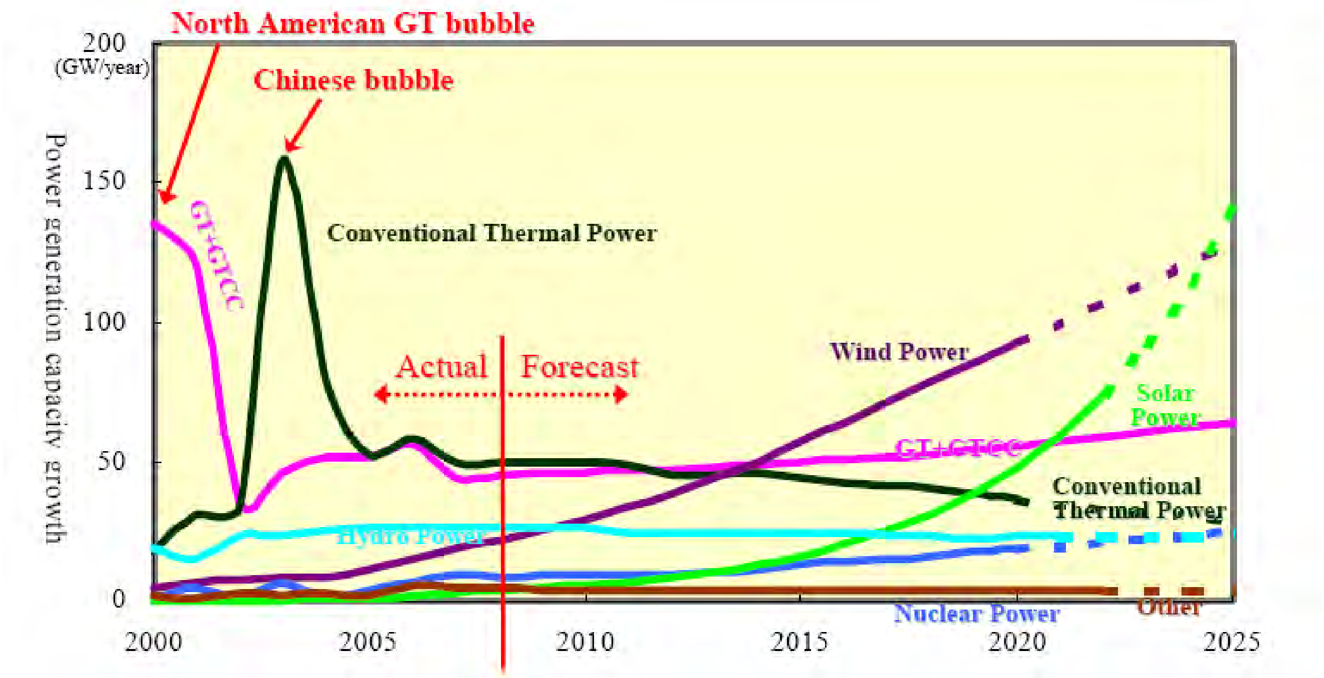
Mitsubishi Heavy Industries

MHI in a recent investor presentation projects that demand for gas-fired capacity (GTs and CCGTs) will grow steadily at a rate of around 50GW per year, between now and 2025 which is slightly less than the 60GW per year projected by EIA.

Conversely, MHI projects conventional thermal capacity (which we assume to be predominantly coal) will be about 50GW per year between now and 2015 compared with the 42GW projected by EIA.

Both the EIA and MHI projections are similar in terms of the decline in demand for conventional thermal power generation facilities because of greenhouse emissions policies and legislation.

Figure 16 **MHI Business Operation Plan - Demand forecast for major power generation facilities**



Data source: MHI (May, 2008)

Alstom

Alstom in its 2007/08 Annual Report made the following observations regarding historical demand for power generation equipment:

- Following a period of intense growth in power infrastructure investment in the United States from the late 1990s, 2002 saw a sharp drop in the level of new orders.
- Since 2003, the world economy has been driven by unprecedented growth in Asia – especially China and India – where there is a buoyant demand for new power plants.
- 2007 also saw a high level of gas plant orders. Strong demand for gas-fired technologies in the Middle East and Europe resulted in a fairly balanced technology split.
- 2007 itself has been buoyant, with strong and simultaneous demand for almost all technologies and in almost every region in the world.

In terms of future demand, Alstom make the following projections:

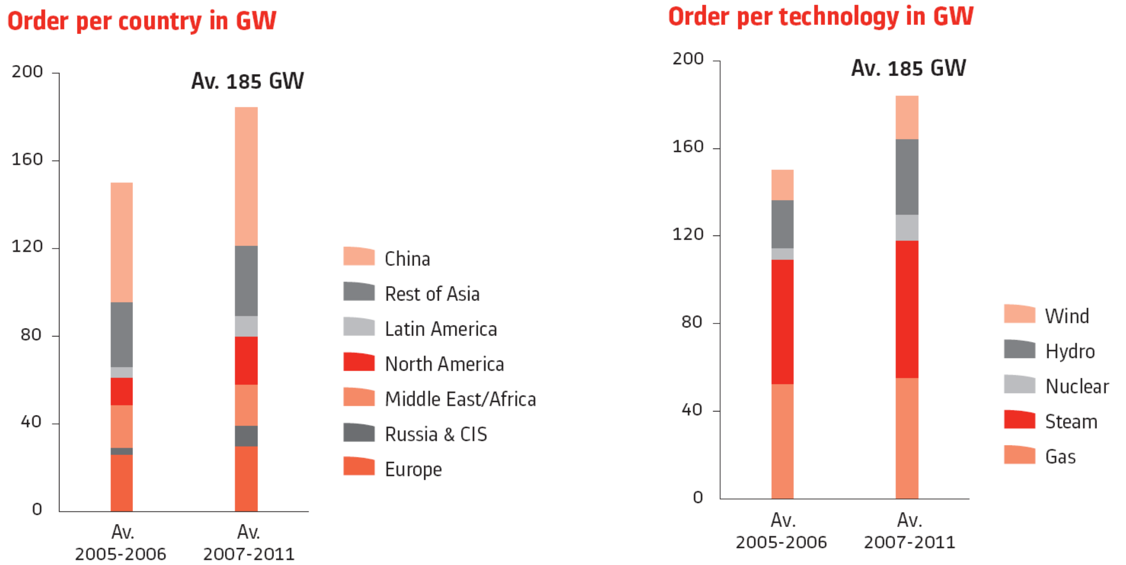
- In the medium term, a balanced technological mix of the power plant, with at least two-thirds being fossil power plants, a strong hydro market, a nuclear revival and a growing demand for wind.

- In the light of CO2 concerns and continued portfolio balancing, several countries in the Middle East, Africa, Asia, Europe and the Americas have expressed nuclear intentions.
- Asia is likely to remain the biggest market globally, with China and India representing key parts of it. The rest of the world market will be distributed among the Middle East, Europe – will be gas dominated, a strong coal market in Germany and significant investment plans in Russia. Markets will also grow in the Americas, with growing needs in Latin America and a new investment cycle to start in North America.

The graph below suggests that Alstom is expecting demand for gas-fired capacity (GTs and CCGTs) will grow at a rate of around 55GW per year, between 2007 and 2011, which is between the 60GW per year projected by EIA and 50GW per year projected by MHI.

Alstom appears to be expecting demand for steam capacity to grow at about 60GW per year between 2007 and 2011, which is higher than the 50GW per year projected by MHI and the 42GW projected by EIA.

Figure 17 **Evolution of the large power plant market by region and by technology over the 2007-2011 period**



Note: order forecasts include large gas power plants, large conventional steam power plants, combined cycle power plants, nuclear, hydro and wind plants.

Note: order forecasts include large gas power plants, large conventional steam power plants, combined cycle power plants, nuclear, hydro and wind plants.

Data source: Alstom 2007/08 Annual Report

Order backlog

The above analysis provides a view on historical additions of capacity and projected demand for capacity. What is unclear, however, is the current extent of unmet turbine demand. Order back-logs can provide some sense of unmet demand or at least the tightening or relieving of the demand/supply balance.

Further, it is unclear as to how the EIA treats backlogs in its projection of turbine expansion – we suspect the values provided are actual expansions as opposed to turbine demand.

According to the 2007/08 Alstom Annual Report: "*2007/08 has been extremely positive for the power generation market with volumes moving up in most countries. In addition, China and India have been through a booming demand this year. Asia remains the dominant market with more than half of the world demand for new equipments. Coal in Europe, China and India, and hydro in China, India and South America will remain leading sources of energy, together with gas.*

Orders received by the Sector *in 2007/08 amounted to €11,569 million,* ***a 21% increase over last year*** *(22% on an organic basis). Overall, Power Systems booked a total of 38 gas turbines (including 18 GT26™) compared to 20 the previous year.*"

This suggests that gas turbine orders at Alstom increased by 80% in 2007/08.

Siemens in a presentation in 2008 shows an **increase in the backlog for its power division of 18%** between 2006/07 and 2007/08.

Similarly, MHI presented a 20% increase in the backlog for its Power Systems Division between 2007 and 2008.

Of course, it should be kept in mind that the backlogs are measured in dollar values which makes it difficult to separate the number of orders (in MW terms) from the price of the orders. However, the change in backlog in MW terms can be estimated providing the change in price per unit (or MW) is assumed. For example, if we assume broadly a 15% increase in the price for an EPC between 2007 and 2008 (which is not unreasonable given the evidence[3]) then a 20% increase in the backlog (in dollar terms) converts to a 17% increase in MW terms. That is, **the backlog for turbines, in MW terms, is estimated to have increased by 17% between 2007 and 2008, which confirms the existence of a supply constraint.**

The supply constraint is likely to continue at least until production capacity ramps up by 2011. When taking into account the time required to clear the backlog of orders (which will be at least two to four years[4]) it is more likely that the supply constraint will be relieved at earliest 2013 to 2015. Even then it is

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[3] Discussed in Section 2.5.

[4] When taking into account that the current backlog equates to a two and four year delay for CCGTs and coal plant respectively

unclear whether the additional production capacity will be sufficient to meet demand since we are unsure of the extent of unmet demand.

2.4 Financial analysis of major suppliers

It is worth analysing the financial performance of the main turbine suppliers to get a sense of whether the suppliers are taking advantage of the tight demand/supply balance for turbines in the pricing of EPC contracts.

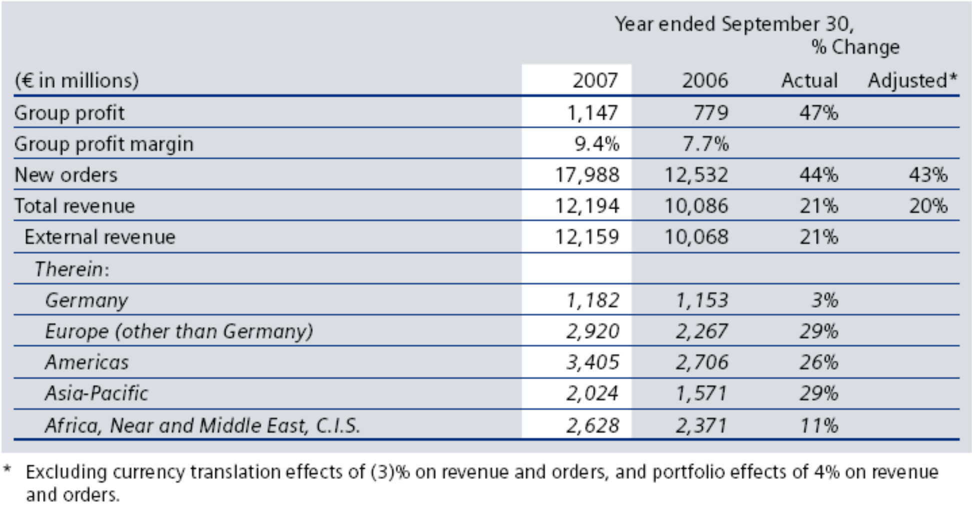
2.4.1 Siemens

Table 6 provides a summary of the financial performance of the Siemens Power Generation Division in 2007. Table 6 summarises the profit margins back to 2004. The profit margin increased from 7.7% in 2006 to 9.4% in 2007, but these are lower than the profit margins of 2005 and 2004 (which were before the step change in capital costs). These are not extravagant profit margins and do not suggest that the suppliers of turbines are gouging the market in response to the tight demand/supply balance for turbines, although Siemens does acknowledge some benefit of the tight demand/supply balance. The profit margins also suggest that the manufacturers have been caught short somewhat due to increasing input costs and not passing on these costs fully within the EPC contracts.

The following comments from the Siemens 2007 Annual Report are worth noting:

- *While PG faced higher materials costs compared to fiscal 2006, strong demand enabled the Group to offset the increase with higher prices.*
- *Fiscal 2007 orders for PG overall climbed to €17.988 billion, up 44% year-over-year, and are expected to increase the earnings quality of PG's order backlog as they replace older, lower margin orders that are being fulfilled in coming quarters.*

Table 6 **Siemens annual profit margins for its power generation division**



(€ in millions)	Year ended September 30, 2007	2006	% Change Actual	Adjusted*
Group profit	1,147	779	47%	
Group profit margin	9.4%	7.7%		
New orders	17,988	12,532	44%	43%
Total revenue	12,194	10,086	21%	20%
External revenue	12,159	10,068	21%	
Therein:				
Germany	*1,182*	*1,153*	*3%*	
Europe (other than Germany)	*2,920*	*2,267*	*29%*	
Americas	*3,405*	*2,706*	*26%*	
Asia-Pacific	*2,024*	*1,571*	*29%*	
Africa, Near and Middle East, C.I.S.	*2,628*	*2,371*	*11%*	

* Excluding currency translation effects of (3)% on revenue and orders, and portfolio effects of 4% on revenue and orders.

Data source: Siemens 2007 Annual Report, p129

Table 7 **Siemens annual profit margins: 2004 – 2007 (Euro million)**

	2007	2006	2005	2004
Group profit	1,147	779	951	961
Group profit margin (%)	9.4%	7.7%	11.8%	12.8%
New orders	17,988	12,532	10,964	9,243

Data source: Siemens 2005, 2006 and 2007 Annual Reports

In its 3rd quarter report for 2008, Siemens noted that the profit margin was 6.1%, down from about 8.5% for the same period in 2007, citing:

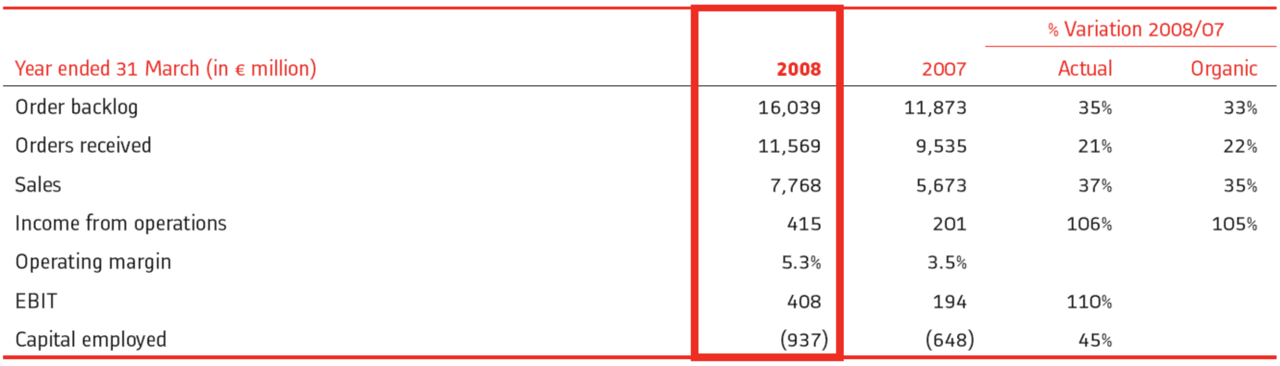
> *The change was due to the Division's turnkey solutions business, where a review of major projects identified resource constraints leading to project delays, expiring supplier price agreements, and significantly higher commodity prices.*

2.4.2 Alstom

Similarly, Table 8 shows that Alstom recorded a profit margin in 2008 of 5.3%, an improvement over the 3.5% of 2007. In 2006 the profit margin was 1.8%. Alstom made the following comments:

- *The operating margin increased from 3.5% to 5.3%, driven by the increase in sales volume with a constant focus on project execution and cost control.*
- *Given the strong and healthy backlog, the Group's operating margin in March 2010 should exceed the previous forecast and reach around 9%, with an operating margin between 10% and 11% for the combined Power Sectors. Based on current market conditions and trends (as described above), the Group's operating margin should further increase beyond 2009/10.*

Table 8 **Alstom - key financial data for the Power Systems – 2007/08**



			% Variation 2008/07	
Year ended 31 March (in € million)	**2008**	2007	Actual	Organic
Order backlog	16,039	11,873	35%	33%
Orders received	11,569	9,535	21%	22%
Sales	7,768	5,673	37%	35%
Income from operations	415	201	106%	105%
Operating margin	5.3%	3.5%		
EBIT	408	194	110%	
Capital employed	(937)	(648)	45%	

Data source: Alstom 2007/08 Annual Report

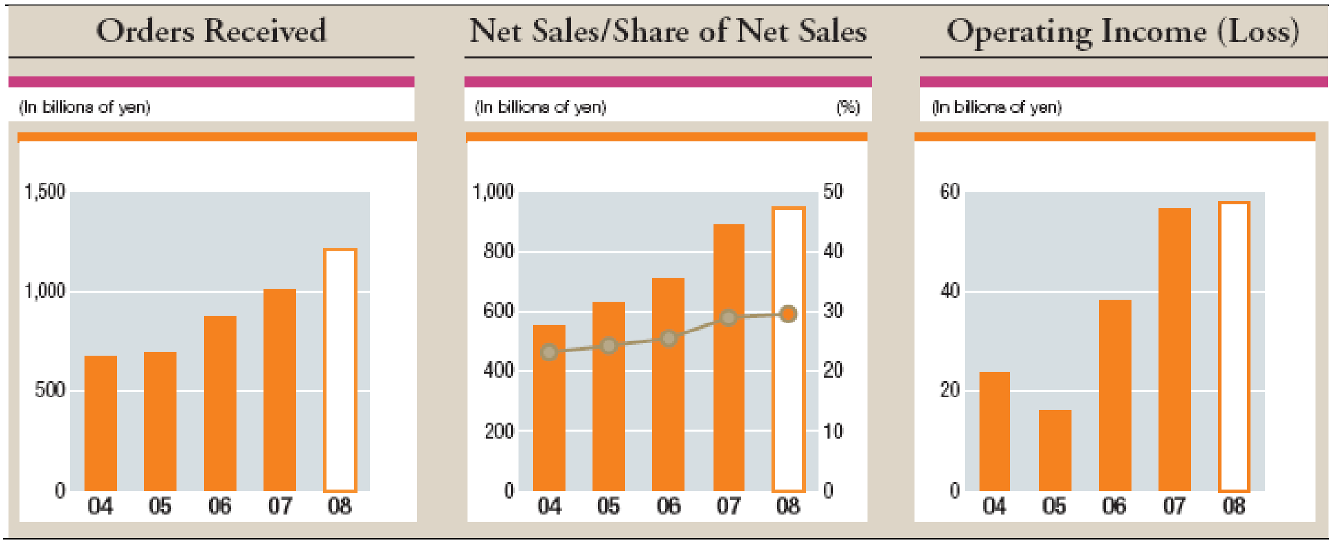
2.4.3 MHI

MHI in its 2008 annual report summarise the Power Systems Division performance as per Figure 18. The implied gross margin in 2008 was about 6%, compared with about 6.5% in 2007 and 4.5% in 2004.

MHI made the following comments in the 2008 Annual Report (page 46):

- *Prices for materials such as steel products, non-ferrous metals and crude oil are rising, which is also driving up the cost of finished materials used to manufacture products. There is also a concern about the potential impact from delayed supplies of necessary materials. In response, the MHI Group is working harder to reduce costs by promoting design standardization, increasing its utilization of common components, employing standardized parts, signing comprehensive procurement contracts, and expanding its overseas production activities. The MHI Group also intends to pass the price rises of materials on to customers as much as possible.*

Figure 18 **Historical performance of MHI Power Systems Division – 2004 to 2008**

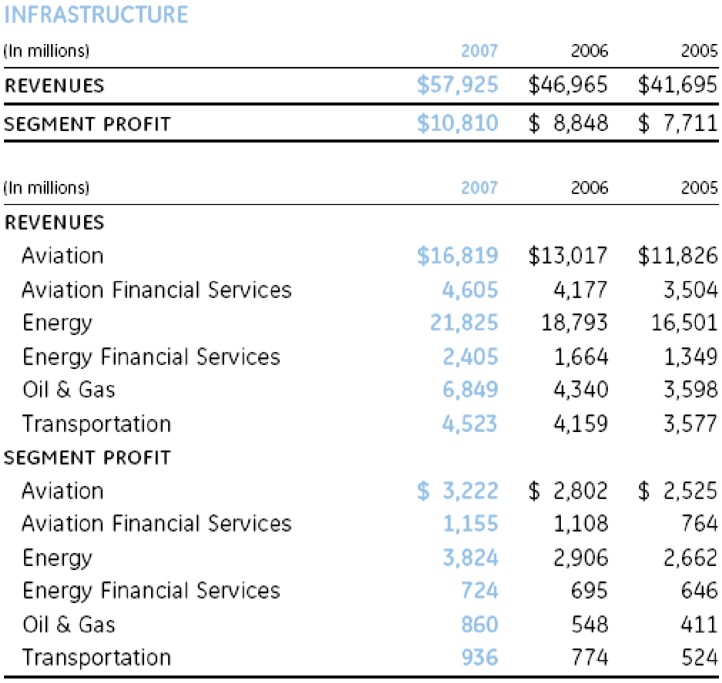


Data source: MHI 2008 Annual Report

2.4.4 GE

GE provided the following table in its latest annual report. It appears that the gross margin of the GE Energy Division is about 14.8% in 2007 which is somewhat higher than Siemens and Alstom and may be due to different reporting procedures. In any case, the gross margin in 2005 was about 13.6% which suggests a similar trend to the other suppliers – a marginal increase in profits during the period of the capital cost increases.

Table 9 **Performance of GE Infrastructure Division**



INFRASTRUCTURE

(In millions)	2007	2006	2005
REVENUES	$57,925	$46,965	$41,695
SEGMENT PROFIT	$10,810	$ 8,848	$ 7,711

(In millions)	2007	2006	2005
REVENUES			
Aviation	$16,819	$13,017	$11,826
Aviation Financial Services	4,605	4,177	3,504
Energy	21,825	18,793	16,501
Energy Financial Services	2,405	1,664	1,349
Oil & Gas	6,849	4,340	3,598
Transportation	4,523	4,159	3,577
SEGMENT PROFIT			
Aviation	$ 3,222	$ 2,802	$ 2,525
Aviation Financial Services	1,155	1,108	764
Energy	3,824	2,906	2,662
Energy Financial Services	724	695	646
Oil & Gas	860	548	411
Transportation	936	774	524

Data source: GE 2007 Annual Report

2.5 Steel prices

Figure 19 shows steel prices actually declined slightly between 1994 and 2003, and then increased substantially in 2004 and again in 2008. Despite its potential outlying magnitude, the 2004 increase has been sustained over the past five years. Steel prices have jumped again recently as the increase in the cost of iron ore and coking coal forces steel firms to raise prices.

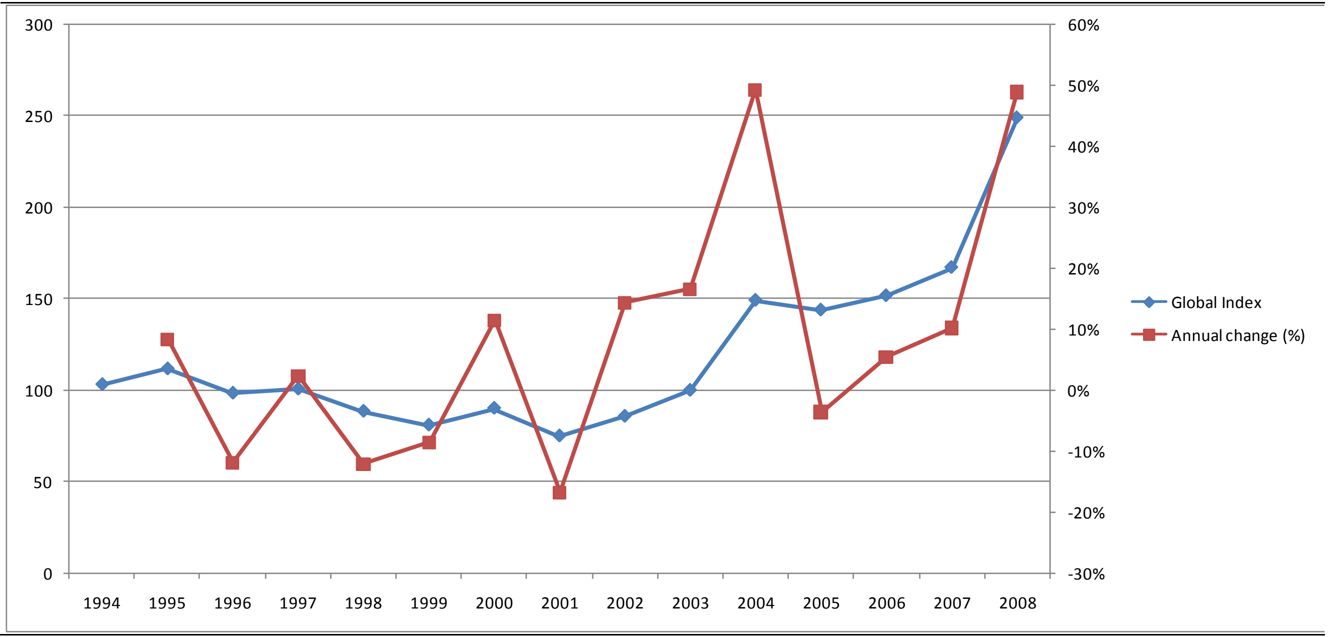
The 2008 increase occurs despite the US slowdown, and is driven by developing country demand and iron ore and coal shortages, which have limited Chinese and other countries' production growth. Further, the Chinese government policies to restrict exports may drive prices higher.

It has been suggested that the price increase in 2008 is also a result of heavy destocking in 2007 by steel buyers in anticipation of lower 2008 prices, which then led to panic buying as shortages appeared.

The high prices provide incentives to develop new resources, but it will take time for markets to return to surplus levels.

It is interesting to note that the increase in 2004 appears to have a one to two year lag in terms of impact on power station capital costs. This is consistent with the turbine manufacturers noting some lag in their annual reports.

Figure 19 **Global steel price index – 1994 to 2008**



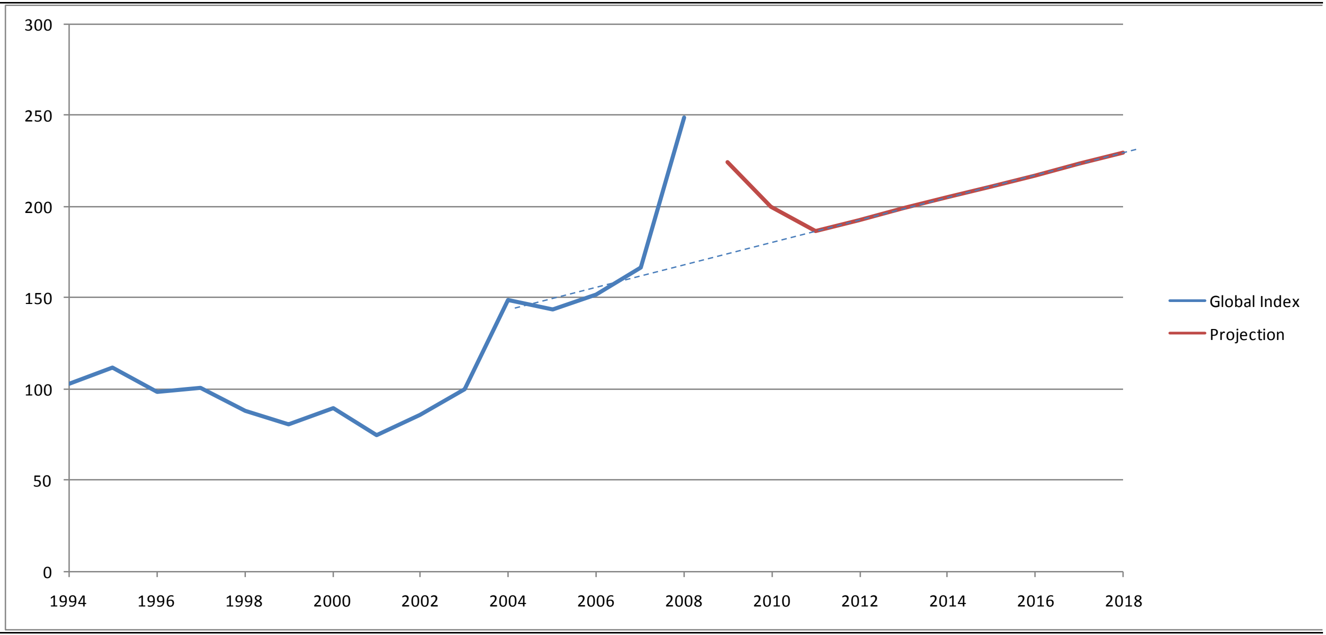
Note: Values for 2008 are based on data for January to September 208.

Data source: ACIL Tasman analysis of data from www.CRUgroup.com

The graph below summarises our projection for steel prices over the next decade. The projection shows that steel prices return to pre 2008 levels over the next few years, by 2011, assuming that supply catches up with demand, due to slower demand growth and supply constraints becoming relieved as China increases steel production. Post 2011, we assume prices will continue to escalate at a similar rate as occurred between 2004 and 2007, about 3% per year. We have incorporated the steel price projection into our projection of power station capital costs which is explained in Section 2.8.

Post 2011 if demand from China and India is maintained and more importantly, production is not stepped up then it is likely that steel prices will not reduce below current levels and will continue to escalate at a similar rate as occurred between 2004 and 2007, about 3% per year, until supply does catch up with demand.

Figure 20 **Global steel price index – 1994 to 2018**



Data source: ACIL Tasman analysis of various sources

2.6 Labour costs

Labour costs affect power station capital costs particularly in terms of the manufacturing of turbines and boilers, and local labour costs for the erection, construction and site works. Of course, labour costs also affect the costs of the actual resources used in the manufacturing of power plant.

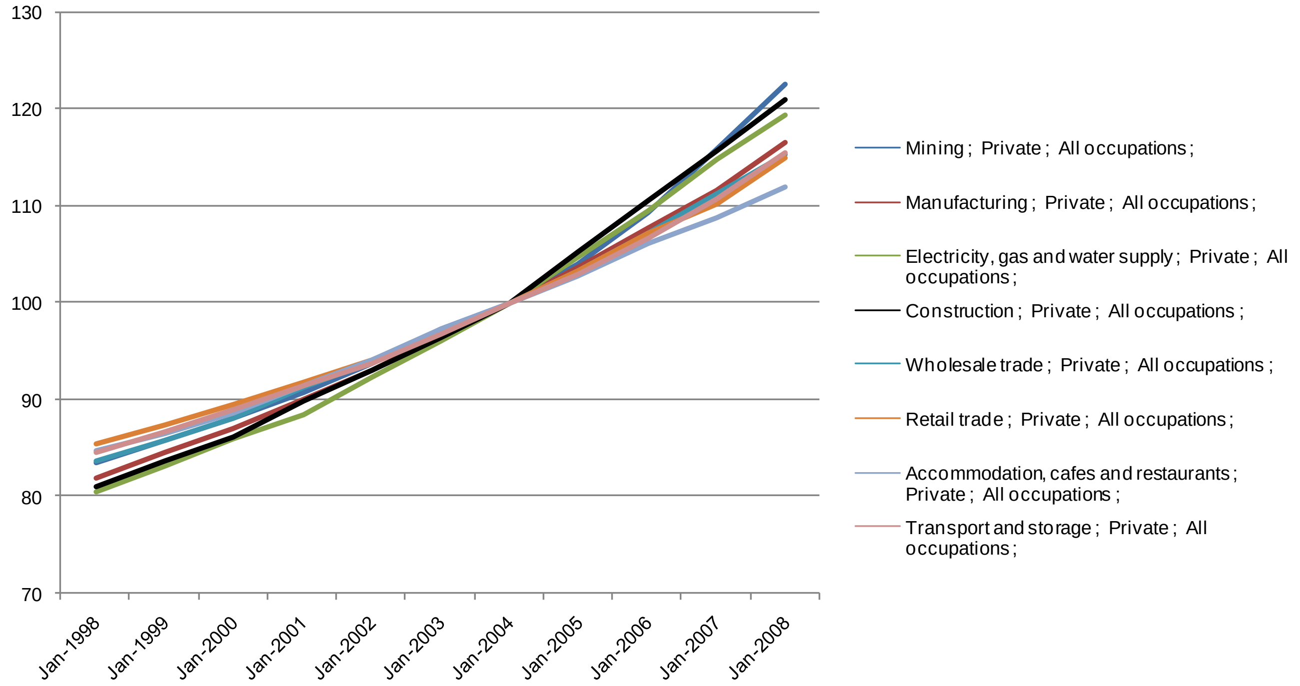
ACIL Tasman has had access to a number of power station project EPC contracts in past years both in Australia and Asia. We estimate that labour costs contribute between 50%-70% of the total EPC contract cost.

2.6.1 Australia

Figure 21 shows the trend in labour costs in Australia from 1998 to 2008. Labour costs increased on average by about 3% per year between 1998 and 2004. Post 2004 there has been an average increase of 5% per year, peaking at about 6% per year in 2007/2008. The graph shows that mining and constructions sectors have seen the strongest growth – as one would expect given the strong demand in these sectors due to the resource boom.

The higher growth in Australian labour costs observed over the past two or so years coincides with the increase in capital costs.

Figure 21 **Trend in labour costs - Australia**



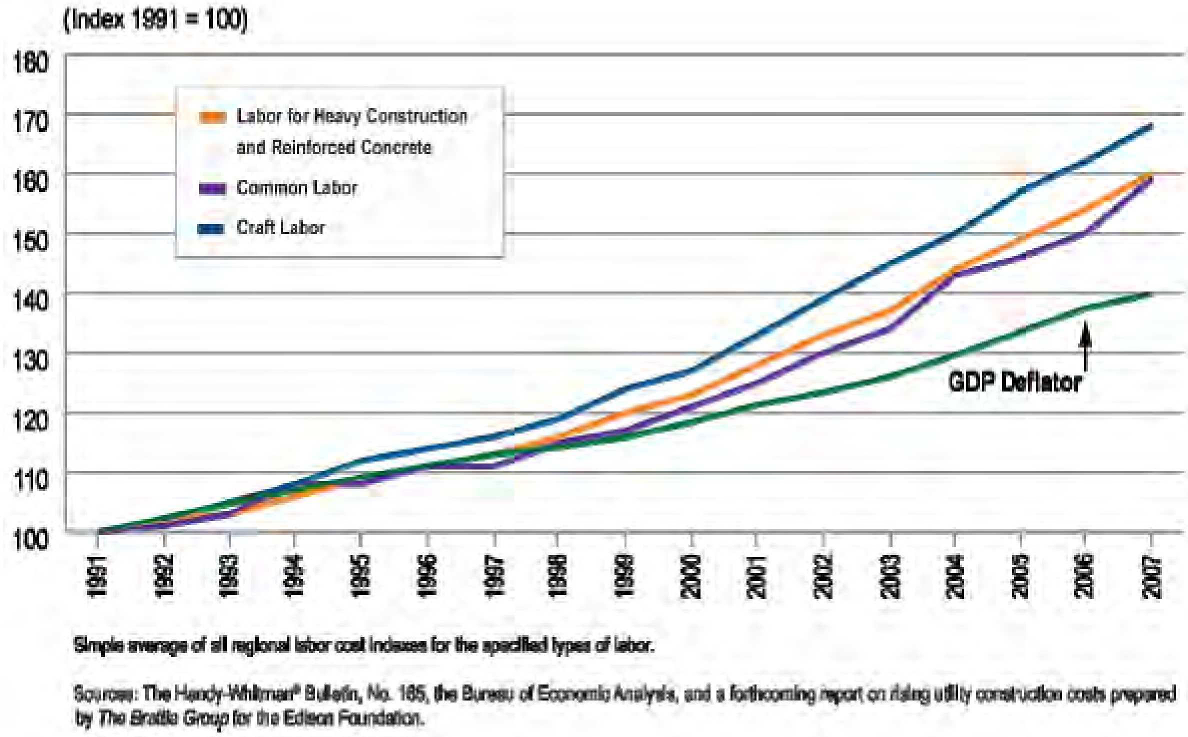
Note: June 2004 set as base (i.e. 100)

Data source: Australian Bureau of Statistics

2.6.2 Global

The graph below shows the trend in labour cost in the US. This suggests that labour costs have not increased as much over the past few years as in Australia, although costs have been escalating at a higher rate than CPI.

Figure 22 **Labour costs - US**



Data source: Edison Electric Institute presentation, February 2008

2.7 Third party capital cost estimates

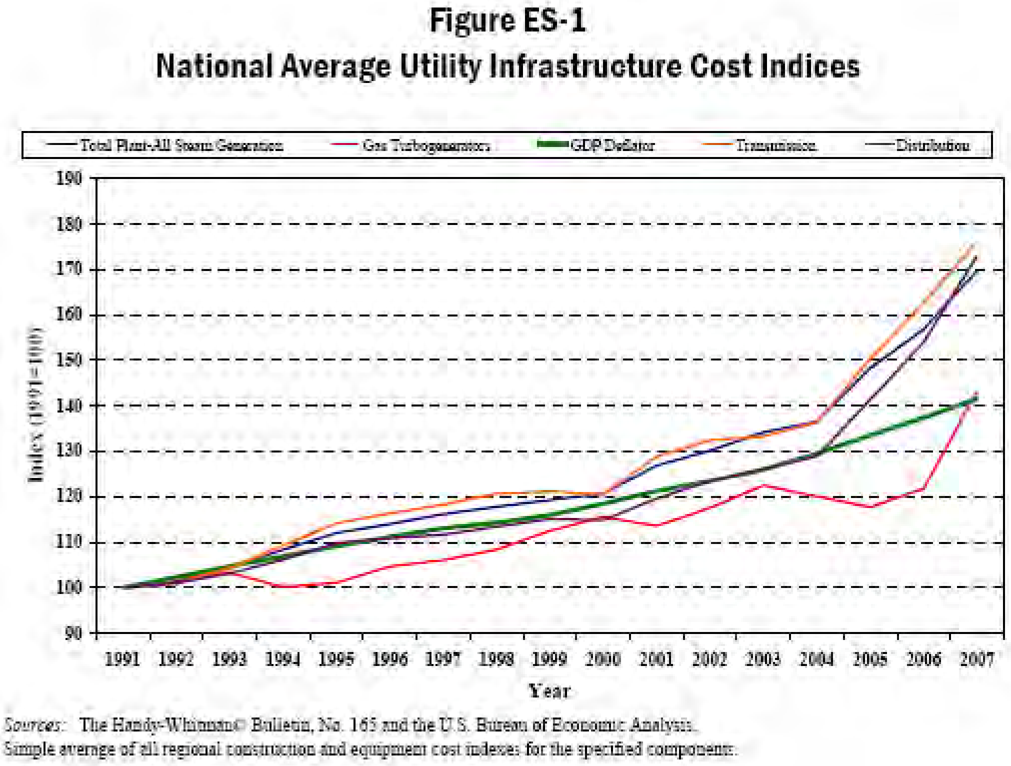
Provided below is a summary of commentary and analysis of capital costs from a number of different public sources.

2.7.1 The Edison Foundation

The Edison Foundation report titled, *Rising Utility Construction Costs: Sources and Impacts*, September 2007, provides a useful analysis of the increase in capital costs in the electricity sector and examines reasons for the increase.

Figure 23 shows the increase in capital costs in the US for the power sector, using 1991 as the base. The indices are based on the Handy-Whitman Index data series. The graph shows prior to 2006, the increase in capital costs generally followed inflation. However, in 2006 and 2007 the increase in capital costs deviated quite noticeably above the general inflation rate. For example, the cost of gas turbines increased by about 16% in 2007 and conventional coal station project capital costs increased by about 12% in 2007.

Figure 23 **Capital costs indices for US power sector – 1991 to 2007**



Data source: Rising Utility Construction Costs: Sources and Impacts, Edison Foundation, September 2007

The Edison report makes the following observations with regard to the increase in capital costs:

- *Dramatically increased raw materials prices (e.g., steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.*
- *Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or projected supply.*
- *There also is a growing backlog of project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC firms,* ***it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue****.*

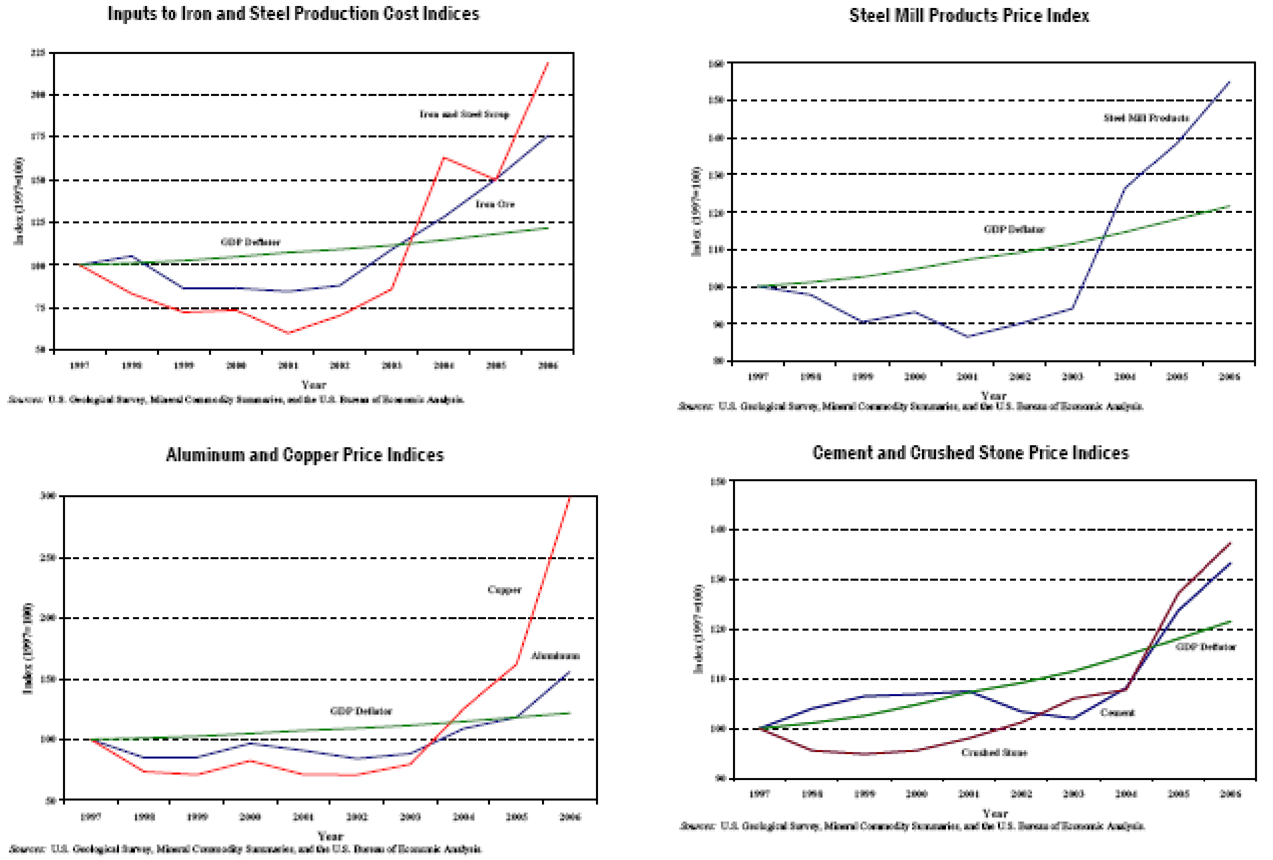
The Edison report also makes the interesting (and we think, valid) observation that the full impact of rising input costs will have a more dramatic impact on the estimated cost of proposed utility infrastructure projects, since completed projects have not been fully exposed to the recent price trends due to project lead times.

It is worth noting that the Edison Foundation report makes reference to the US Energy Information Administration's 2007 *Annual Energy Outlook* (AEO) and makes a similar observation to that of CRA, that is – "*capital costs of all technologies are assumed to grow at the general price level* [in the AEO] – *a pattern that contradicts the market evidence presented in this report*" (page 3 of *Rising Utility Construction Costs: Sources and Impacts*, September 2007, Edison Foundation). The AEO is discussed further in Section 2.7.3.

The Edison report provides three primary sources of the increase in construction costs:

- material input costs, such as steel and cement, as well as increased costs of components manufactured from these inputs, do exhibit a step change in recent years (which are provided in Figure 24)
- shop and fabrication capacity for manufactured components (relative to current demand)
- cost of construction field labour – which has increased but not to the same extent as the material inputs (as shown in Figure 25).

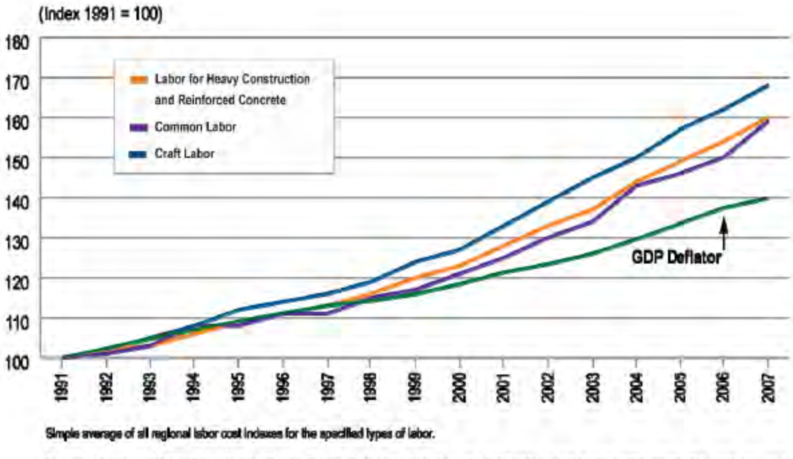
Figure 24 Material input costs - US



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Data source: Rising Utility Construction Costs: Sources and Impacts, Edison Foundation, September 2007

Figure 25 Labour costs - US



Simple average of all regional labor cost indexes for the specified types of labor.

Sources: The Handy-Whitman® Bulletin, No. 165, the Bureau of Economic Analysis, and a forthcoming report on rising utility construction costs prepared by *The Brattle Group* for the Edison Foundation.

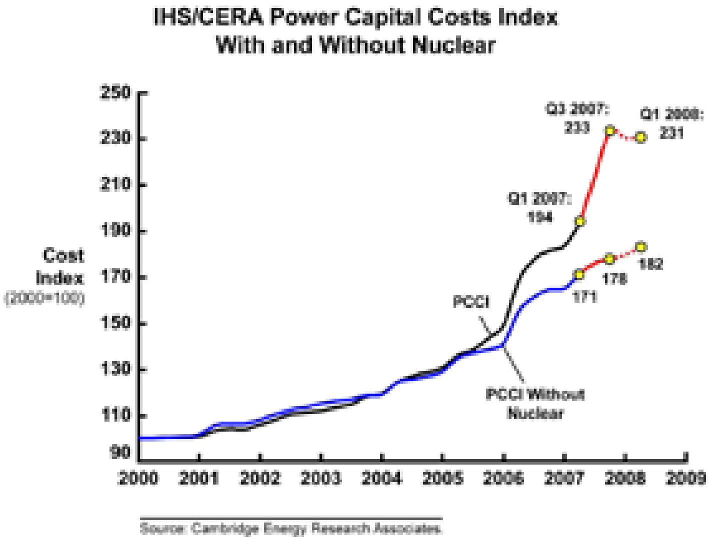
Data source: Edison Electric Institute presentation, February 2008

2.7.2 CERA Power Capital Costs Index (PCCI)

CERA maintain and publish their Power Capital Costs Index (PCCI) – which tracks the costs of building coal, gas, wind and nuclear power plants in North America indexed to the year 2000.

Figure 26 shows the latest PCCI from the CERA website. Again, the step change from 2006 onwards is apparent. However, when separating nuclear plant from the sample, the cost index does appear to revert back to the long term growth trend in 2007. Further, the implied projected trend is that the CERA does not expect the costs to downturn to pre-2006 levels in 2008 or 2009.

Figure 26 **CERA Power Capital Costs Index**



Data source: IHS website – May, 2008

The following comments were obtained from the CERA website in relation to the latest index:

- *Wind has shown the largest increase at six percent since the third quarter of 2007 and 108 percent since 2000 in response to increased demand for wind turbines which has pushed up equipment costs and time to deliver, and is compounded with increasing labour and construction costs.*
- *Gas has increased by three percent since the third quarter of 2007 and 92 percent since 2000. This has been driven by manufacturers' response to increased demand for gas turbine costs, as costs increase and lead times continue to extend for equipment delivery. Additional escalation can be attributed to continued increases in labour, engineering and construction costs.*
- *Coal has increased in cost by 2.3 percent since the third quarter of 2007 and 78 percent since 2000. Strong international demand for boilers has sustained high cost levels. There*

> *has also been high demand for scrubbers in the United States as clean air provisions push utilities to retrofit their coal facilities in order to comply with the 2010 regulations.*

As well as the expected continued high demand for turbines and the tight demand/supply balance, **CERA also suggest continuing pressure on capital costs into the future,** due to factors such as the ageing engineer workforce resulting in an actual contraction in the pool of engineers.

Recent cancellations of proposed coal plants in the United States due to uncertainty over environmental regulations and a recession has provided some slowing in cost increases in the U.S. However international demand for coal boilers, particularly in Southeast Asia, is maintaining a tight demand/supply balance.

2.7.3 Energy Information Administration

The EIA has recently released its 2008 Annual Energy Outlook (AEO 2008). It is an annual publication which provides long-term projections of energy supply, demand, and prices through 2030 for the US.

As discussed in Section 2.7.1, the Edison Foundation was critical of the AEO 2007 in terms of the capital cost input assumptions suggesting that the costs needed to be revised upwards to reflect the recent step change in capital costs. The AEO 2008 has in fact revised the capital cost estimates:

> The base costs for all technologies in the reference case were increased by 15 percent relative to AEO2007 to reflect recent cost increases (page 93, AEO 2008 Assumptions to Annual Energy Outlook).

The EIA released a focus article discussing the capital costs assumed in the AEO 2008 focus article about capital costs and the drivers of the increase, including steel, cement and concrete prices.

Table 10 summarises the capital cost assumptions adopted by EIA in the AEO 2008. The costs reflect the 15% step change when compared with the AEO 2007. Despite the inclusion of the step change, ACIL Tasman is of the opinion that the absolute costs assumed by EIA are too low due to a low base, as will be demonstrated in Section 2.8. However, it is worth noting that the step change is maintained in the longer term projection of capital costs to 2030, suggesting that either EIA assumes the step change is long term or EIA did not consider implications of the step change.

Table 10 **EIA – Capital cost assumptions for the AEO 2008**

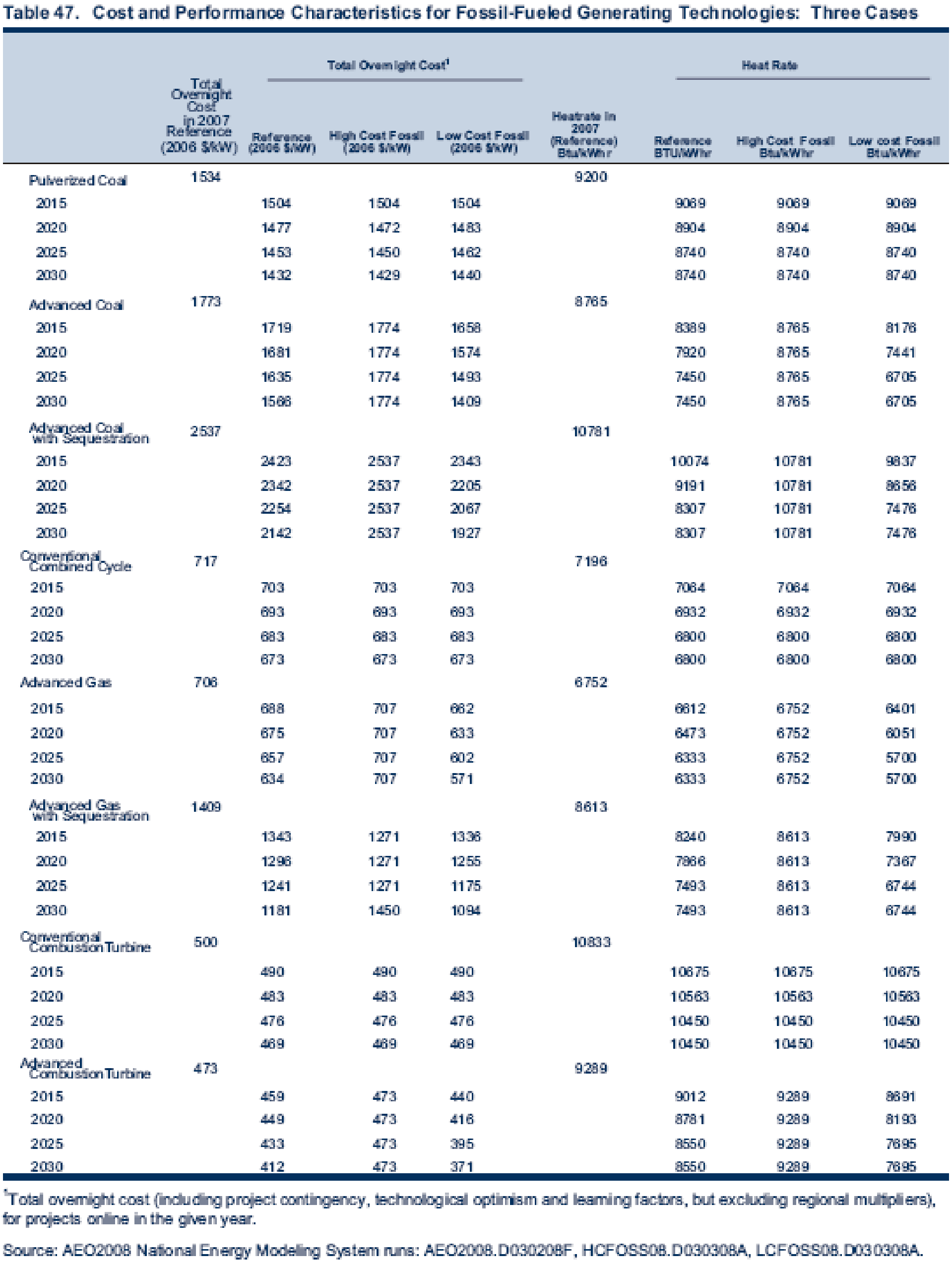


Table 47. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

		Total Overnight Cost[1]				Heat Rate		
	Total Overnight Cost in 2007 Reference (2006 $/kW)	Reference (2006 $/kW)	High Cost Fossil (2006 $/kW)	Low Cost Fossil (2006 $/kW)	Heatrate in 2007 (Reference) Btu/kWhr	Reference BTU/kWhr	High Cost Fossil Btu/kWhr	Low cost Fossil Btu/kWhr
Pulverized Coal	1534				9200			
2015		1504	1504	1504		9069	9069	9069
2020		1477	1472	1483		8904	8904	8904
2025		1453	1450	1462		8740	8740	8740
2030		1432	1429	1440		8740	8740	8740
Advanced Coal	1773				8765			
2015		1719	1774	1658		8389	8765	8176
2020		1681	1774	1574		7920	8765	7441
2025		1635	1774	1493		7450	8765	6705
2030		1566	1774	1409		7450	8765	6705
Advanced Coal with Sequestration	2537				10781			
2015		2423	2537	2343		10074	10781	9837
2020		2342	2537	2205		9191	10781	8656
2025		2254	2537	2067		8307	10781	7476
2030		2142	2537	1927		8307	10781	7476
Conventional Combined Cycle	717				7196			
2015		703	703	703		7064	7064	7064
2020		693	693	693		6932	6932	6932
2025		683	683	683		6800	6800	6800
2030		673	673	673		6800	6800	6800
Advanced Gas	706				6752			
2015		688	707	662		6612	6752	6401
2020		675	707	633		6473	6752	6051
2025		657	707	602		6333	6752	5700
2030		634	707	571		6333	6752	5700
Advanced Gas with Sequestration	1409				8613			
2015		1343	1271	1336		8240	8613	7990
2020		1296	1271	1255		7866	8613	7367
2025		1241	1271	1175		7493	8613	6744
2030		1181	1450	1094		7493	8613	6744
Conventional Combustion Turbine	500				10833			
2015		490	490	490		10675	10675	10675
2020		483	483	483		10563	10563	10563
2025		476	476	476		10450	10450	10450
2030		469	469	469		10450	10450	10450
Advanced Combustion Turbine	473				9289			
2015		459	473	440		9012	9289	8691
2020		449	473	416		8781	9289	8193
2025		433	473	395		8550	9289	7695
2030		412	473	371		8550	9289	7695

[1] Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.

Source: AEO2008 National Energy Modeling System runs: AEO2008.D030208F, HCFOSS08.D030308A, LCFOSS08.D030308A.

Data source: Annual Energy Outlook 2008, EIA June 2008

Table 11 **EIA – Capital cost learning parameter assumptions for the AEO 2008**

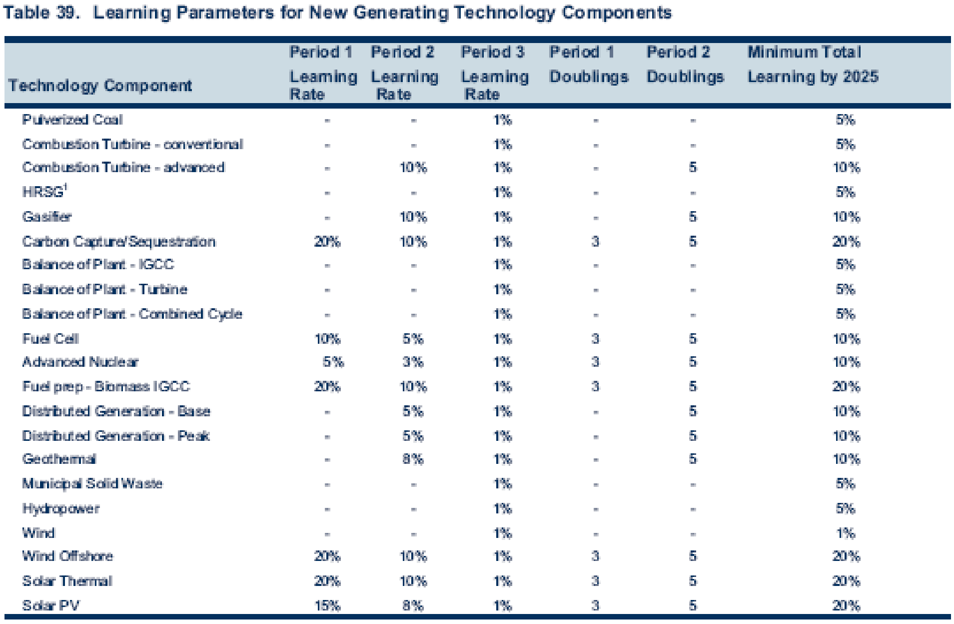


Table 39. Learning Parameters for New Generating Technology Components

Technology Component	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2025
Pulverized Coal	-	-	1%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG[1]	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	10%	5%	1%	3	5	10%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass IGCC	20%	10%	1%	3	5	20%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	1%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	20%
Solar PV	15%	8%	1%	3	5	20%

Data source: Annual Energy Outlook 2008, EIA June 2008

2.7.4 CRC – CCSD

The Cooperative Research Centre for Coal in Sustainable Development (CRC-CCSD) released its report titled: *Options for Electricity Generation in Australia – 2007 Update*, in March 2008, as part of its research program into the potential generation mix in Australia.

The report includes CRC-CCSD estimates of future capital costs and learning rates and notes the current surge in demand for new power plants has occurred together with a period of strong demand growth for metals and other plant input material.

Table 12 summarises the CRC-CCSD capital cost estimates.

Table 12 **Technology cost and performance assumptions for 2010 – CRC-CCSD**

	Install Capital Cost (2008 AUD$/kW) (2010)	Thermal efficiency (%)	Capacity factor (%)	Total O&M (AUD/MWh)
Brown coal	$2,050	31%	87%	$6.00
Black coal	$1,850	40%	80%	$6.00
CCGT	$1,200	49%	80%	$7.80
OCGT	$700	20%	20%	$23.50
Wind	$1,925	na	29%	$7.90
Geothermal	$5,290	na	80%	$17.80
Large Hydro	$3,010	na	20%	$28.50
Biomass	$2,975	26%	55%	$6.00

Data source: Options for electricity generation in Australia – 2007 update, CRC-CCSD, March 2008

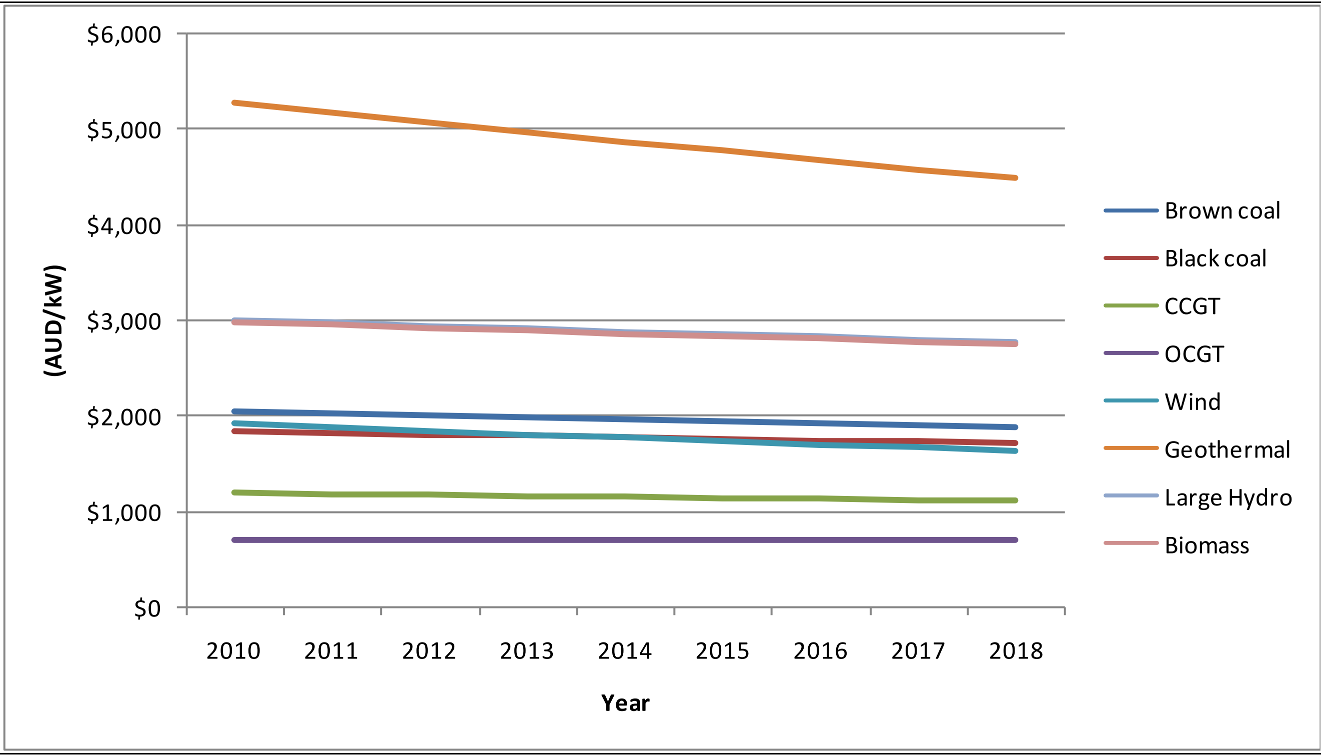
The report also provides a projection of plant capital costs accounting for the three following factors:

1. Resource constraints
2. Volatility of generation plant markets
3. Technological improvement.

CRC-CCSD assumed an average annual learning rate of 0-5% for mature technologies between 2010 and 2050. The report provides a graph of projected capital costs by technology, but no detailed table of values. ACIL Tasman has reproduced the graph to estimate the assumed capital costs adopted in the report. It appears that the learning rates assumed are about 1% for coal and CCGT plant, 0% of OCGT plant, 2% for wind and geothermal plant and 1% for hydro and biomass plant between 2010 and 2020.

It also appears that the analysis assumes, implicitly at least, that the higher capital costs observed recently are not temporary and remain in play over the next decade. However, no discussion on this matter is provided in the report.

Figure 27 **Inferred projected capital costs (real 2008 AUD/kW) – CRC-CCSD**



Note: The data points in the above graph are inferred visually from the source report

Data source: Options for electricity generation in Australia – 2007 update, CRC-CCSD, March 2008

Table 13 **Inferred projected capital costs (real 2008 AUD/kW) – CRC-CCSD**

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Brown coal	$2,050	$2,030	$2,009	$1,989	$1,969	$1,950	$1,930	$1,911	$1,892
Black coal	$1,850	$1,832	$1,813	$1,795	$1,777	$1,759	$1,742	$1,724	$1,707
CCGT	$1,200	$1,188	$1,176	$1,164	$1,153	$1,141	$1,130	$1,118	$1,107
OCGT	$700	$700	$700	$700	$700	$700	$700	$700	$700
Wind	$1,925	$1,887	$1,849	$1,812	$1,776	$1,740	$1,705	$1,671	$1,638
Geothermal	$5,290	$5,184	$5,081	$4,979	$4,879	$4,782	$4,686	$4,592	$4,501
Large Hydro	$3,010	$2,980	$2,950	$2,921	$2,891	$2,862	$2,834	$2,806	$2,777
Biomass	$2,975	$2,945	$2,916	$2,887	$2,858	$2,829	$2,801	$2,773	$2,745

Note: The data points in the above graph are inferred visually from the source report

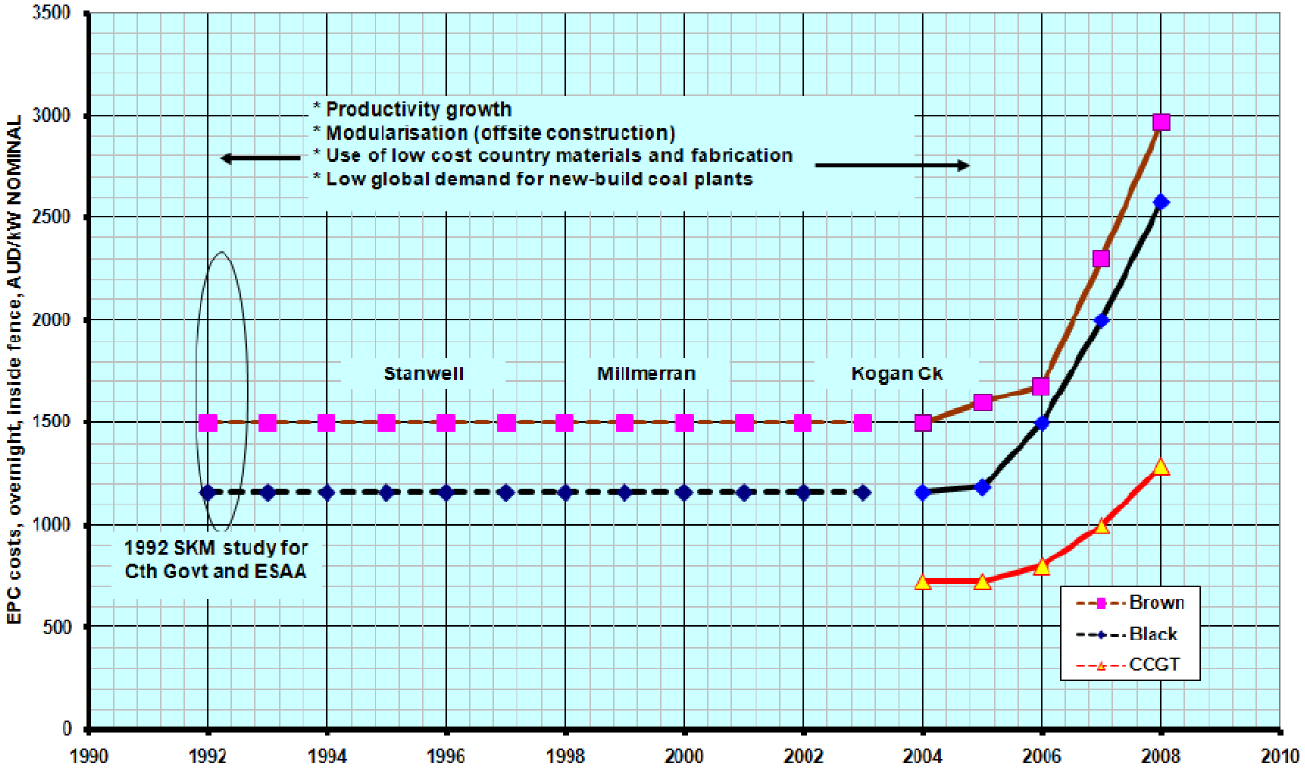
Data source: Options for electricity generation in Australia – 2007 update, CRC-CCSD, March 2008

2.7.5 Other sources

SKM

SKM provided a presentation to the 2008 EUAA Energy Price & Market Update in June 2008. The following graph is an extract from the presentation and again suggests the step change in capital costs post 2006.

Figure 28 **Graph from SKM Presentation to 2008 EUAA Conference on capital costs**



Data source: "New entrant prices & wholesale price projections", 2008 EUAA Energy Price & Market Update, Rohan Zauner, Sinclair Knight Merz Pty Ltd, June 2008

2.8 Pulling the pieces together - ACIL Tasman estimates of capital costs for coal plant and CCGT plant

Provided in this section is our estimate of current capital costs as well as a projection of future capital costs taking into account the analysis presented above.

2.8.1 CCGT

In the 2007 NEMMCO report our estimate of project capital costs for CCGT plant for 2007/08 was AUD$1,050/kW installed. It is important to note that this estimate was based on data and information available as at the last quarter of 2006.

Since the NEMMCO report there has been a small number of projects in Australia and New Zealand as shown below. It is quite apparent that costs have continued to increase during the past 12-18 months.

Table 14 **Project capital costs for recently announced CCGT projects in Australia and New Zealand**

Project	Cost (AUD$/kW, 2007/08 $)	Source	Comments
Condamine, 140MW	$1,214/kW	Various QGC ASX announcements	
Tamar Valley, 210MW	$1,095/kW	Various Alinta ASX announcements	Brownfield site
Huntly, NZ, 385MW	$1,148/kW	http://www.power-technology.com/projects/#top	
Darling Downs, 630MW	$1,238/kW	Origin Energy website	

Data source: ACIL Tasman analysis of various sources

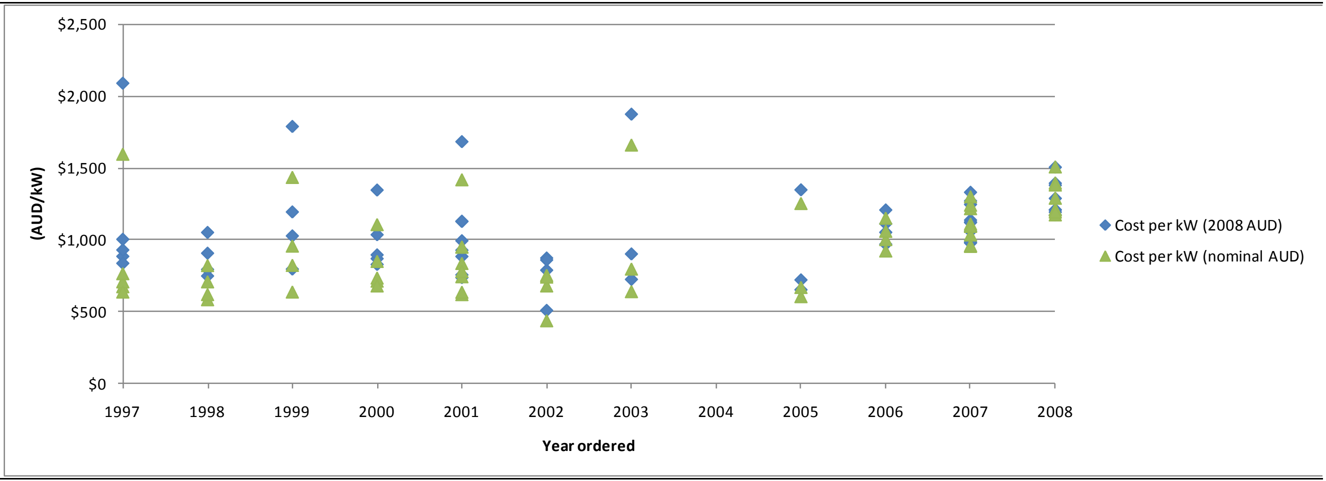
ACIL Tasman has updated the international database of project capital costs for new entrant CCGTs to take into account recently announced projects (such as those in Table 14) to populate the time series for 2007 and 2008.

Figure 29 plots the historical project capital costs for CCGT projects over the past decade. There are 55 individual projects included in the graph, representing projects from Europe, USA, Asia and Australia. The costs have been plotted two ways – in nominal terms (costs of the day) as well as in real terms (in 2008 dollars assuming an inflation rate of 2.5% per year). The step change in costs from 2006 onwards is quite apparent.

Figure 30 plots the annual median of the historical capital costs for CCGT plant. The reason for presenting such a plot is to reduce the influence of outliers in the analysis.

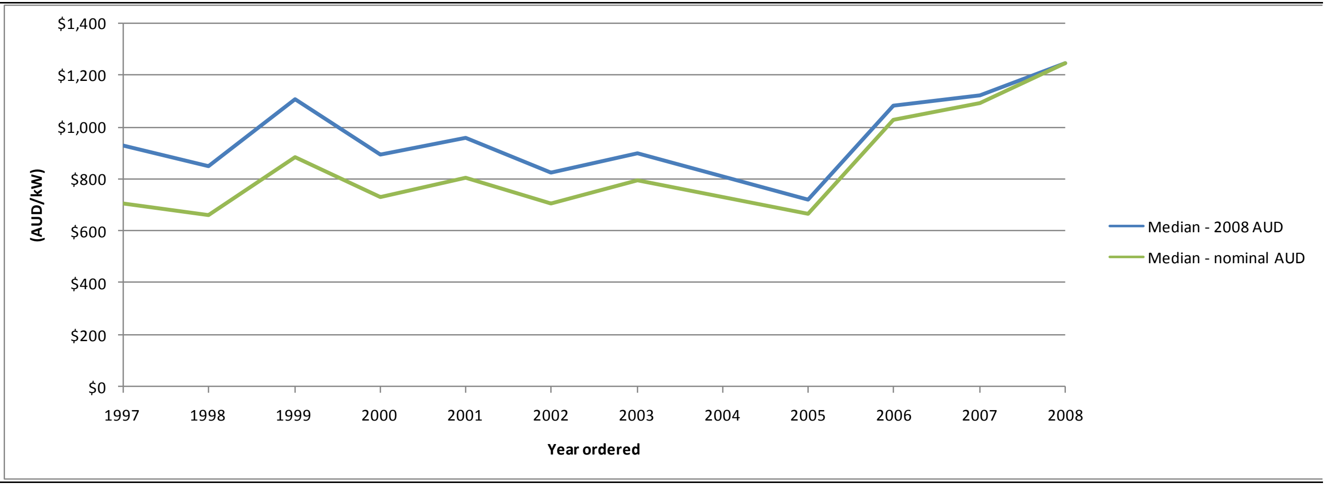
Based on this analysis, **we estimate that the cost for a greenfield CCGT project is AUD$1,200/kW for 2007/08**. This represents about a 14% increase from our estimate published in the 2007 NEMMCO report, which at the time assumed the capital costs had reached a steady state and did not include the latest data now available. The analysis associated with the 2007 NEMMCO report also produced an estimate of AUD$1,030/kW for 2006/07 and when we include the additional up to date data, this estimate is revised to AUD$1,050/kW – using this as a base, the current estimate of AUD$1,200/kW for 2007/08 represents a 14.3% increase in capital costs between 2006/07 and 2007/08.

Figure 29 **Historical project capital costs (AUD/kW) for a new build CCGT power station by year of project**



Data source: ACIL Tasman analysis of various sources

Figure 30 **Median project capital costs (AUD/kW) for a new build CCGT power station by year of project**



Data source: ACIL Tasman analysis of various sources

ACIL Tasman notes that in Singapore in early 2007, the regulator (the Energy Market Authority (EMA)) as part of its determination into the LRMC of generation revised the capital cost of a CCGT by an increase of 33% between 2005-2006 and 2007-2008 – about a 16.5% increase per year (or 15.3% compounded), which is slightly higher than the 14.3% increase we estimate for Australian projects. In mid 2008 the EMA is suggesting an increase in capital costs of a new CCGT of 12.5% for its 2009-10 draft determination.

Similarly, the Edison Foundation estimates that gas turbine costs increased by about 16% in 2007, which is again is slightly higher with our estimated 14.3% increase.

Finally, the EIA in its AEO 2008 increased the base costs for all technologies by 15% compared with the AEO 2007.

However, despite the 15% increase applied in the EAO 2008, the estimate of capital costs for a CCGT by the EIA is substantially lower than our estimate and the estimates of others. Table 15 compares the estimates of capital costs for CCGTs made in 2008 and there is close agreement between our estimate and that of CRC-CCSD, SKM and EMA.

Both the absolute estimates and the percentage increases are important in the BRCI calculation, given that it is an index.

Table 15 **Comparison of capital costs estimates for a new entrant CCGT in 2007/08**

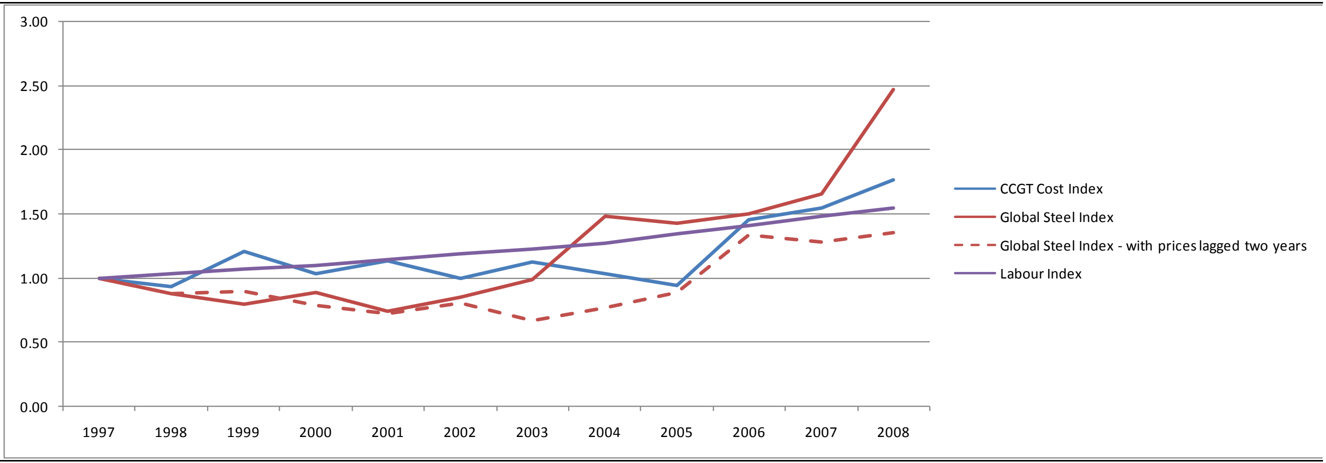
Source	Estimate (AUD/kW)	Percentage increase over 2007
ACIL Tasman, October 2008	$1,200	14.3%
CRC-CCSD, March 2008	$1,200	NA
EIA, AEO 2008, September 2008	$890	15% (thermal plant in general)
SKM, EUAA presentation, June 2008	$1,250	25%
IHS/CERA, May 2008	NA	4% (thermal plant in general)
Singapore EMA, July 2008	$1,208	12.5%

Data source: Various

Future capital costs for CCGTs

ACIL Tasman has used the historical relationship between CCGT costs and its two major inputs, being steel and labour, to produce a projection of future CCGT costs. Figure 31 shows the historical correlation between the CCGT cost index and the steel and labour cost indexes.

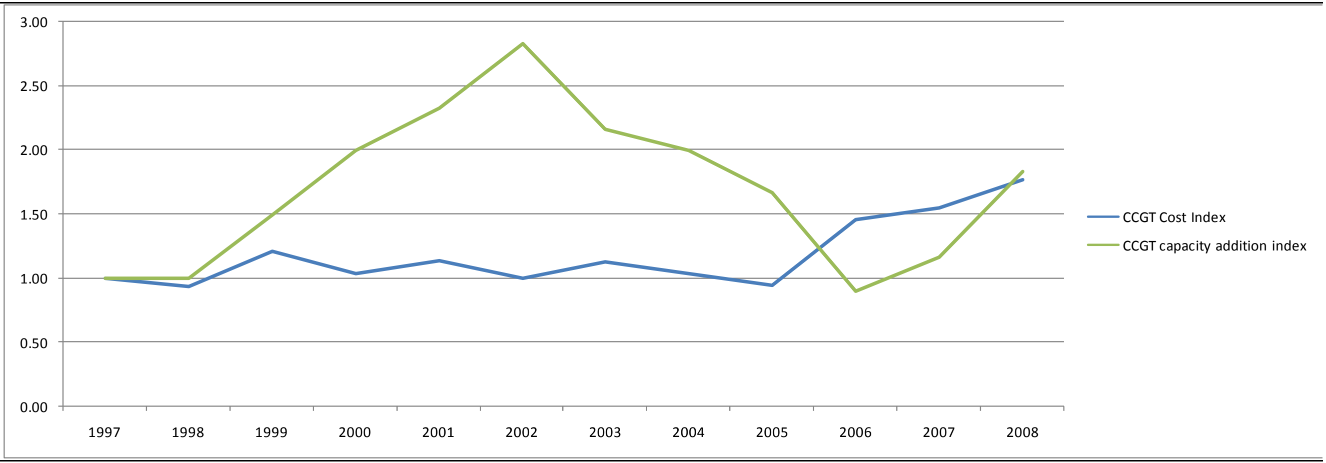
Figure 31 **CCGT capital cost, steel cost and labour indexes (nominal) – 1997 - 2008**



Data source: ACIL Tasman analysis of various sources

Demand for CCGTs declined between 2002 and 2006 as shown in Figure 32, but this decline does not seem related to the cost of CCGTs. Further, the demand for CCGTs has increased in recent years. We noted earlier, the potential for supply expansions for CGGT manufacturing facilities but these expansions are not likely to occur before 2011. Therefore we can imagine a supply constraint to at least 2011.

Figure 32 **CCGT capital cost index (nominal) and capacity addition index – 1997 - 2008**



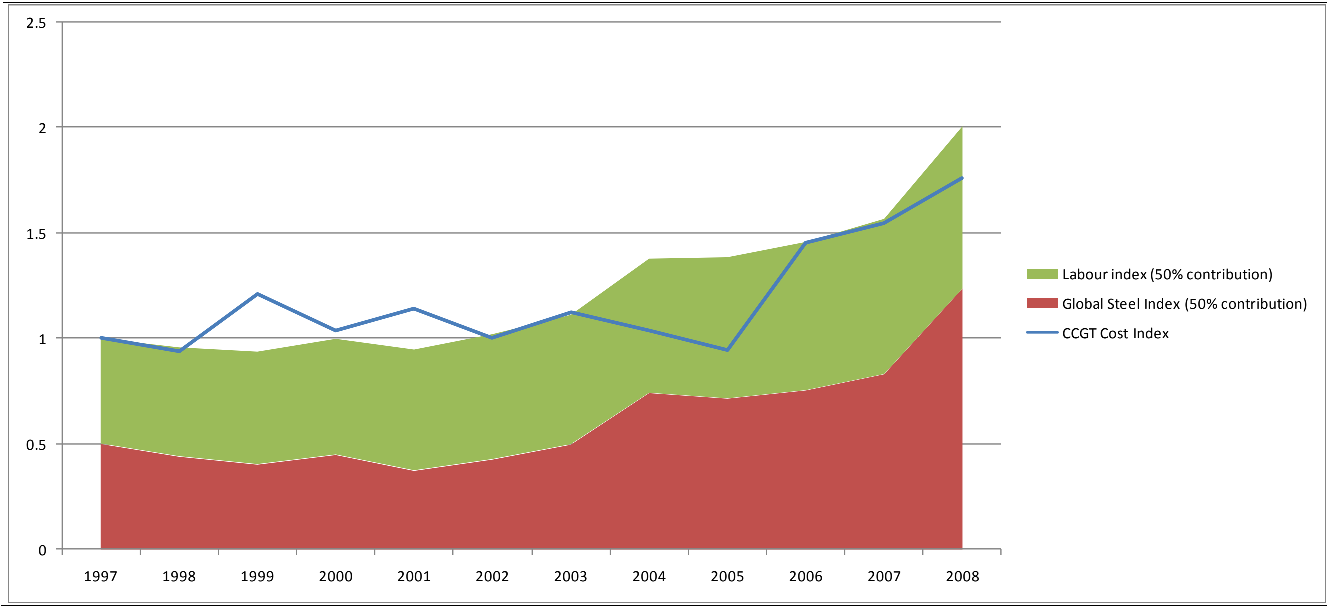
Data source: ACIL Tasman analysis of various sources

Despite the supply constraint, our analysis of the financial performance of the turbine suppliers shows that there does not appear to be any gouging of the market and therefore, the tight demand/supply balance and market concentration of the suppliers does not appear to be a significant factor in the increasing capital costs of CCGTs.

Aggregating the two cost components provides an aggregate index that matches the CCGT cost index reasonably well when considering the lag impact of steel prices on CCGT costs. This suggests that a reasonable method of projecting the capital cost index of CCGT is to use the projections of steel and labour as dependent variables.

The CCGT cost index declines slightly in the earlier years relative to the component indexes but this may be explained by the "learning" effect.

Figure 33 **CCGT capital cost index (nominal) with major components – 1997 - 2008**

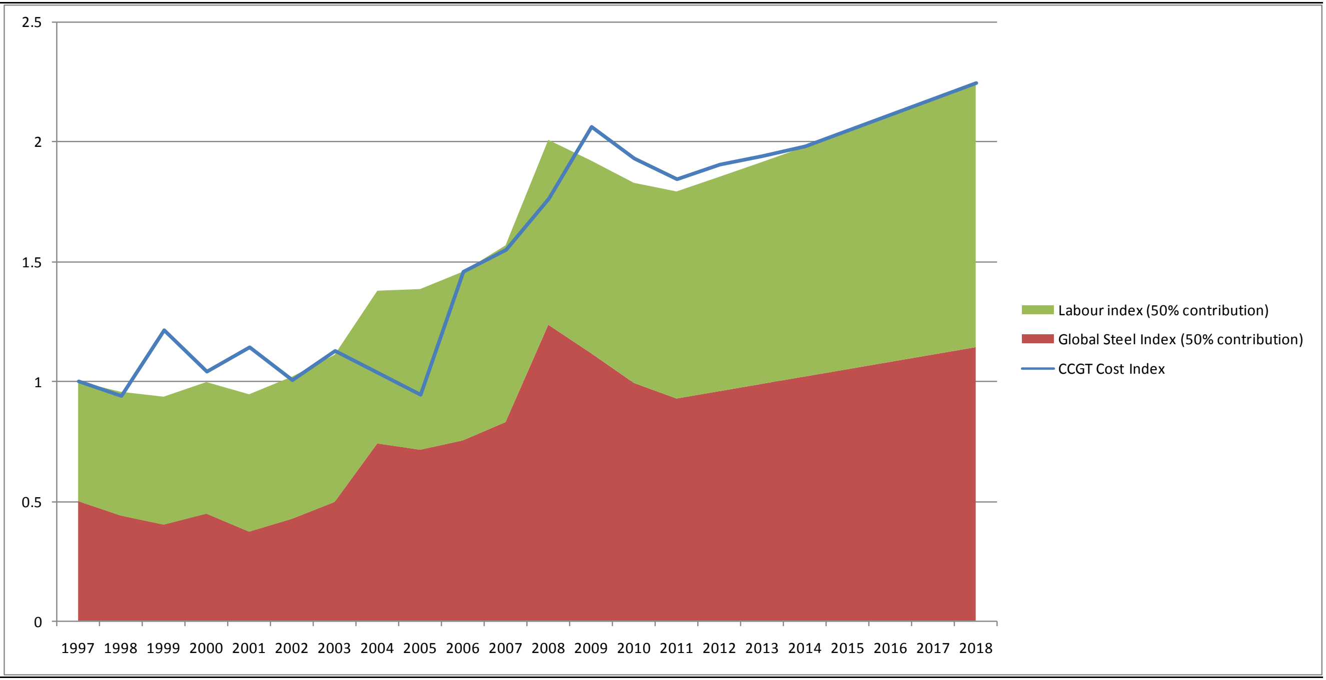


Data source: ACIL Tasman analysis of various sources

Figure 34 shows our projection of the CCGT index using a projection of the two major components, steel and labour, based on the following assumptions:

- Steel and labour make up 50% of the CCGT capital cost respectively. Obviously this is a simplified assumption, but one that we believe to be reasonable.
- Steel prices return to pre 2008 levels over the next few years, by 2011, as supply catches up with demand. Post 2011 if demand from China and India is maintained then it is likely that steel prices will continue to escalate at a similar rate as occurred between 2004 and 2007, about 3% per year.
- The impact of steel prices on CCGT costs is lagged by about two years
- Labour costs contract slightly back to long term averages of 3.5% per year post 2011 assuming labour supply shortages are relieved partly due to a slight slowdown in the global economy.
- CPI is assumed to be 2.5%.

Figure 34 **CCGT capital cost index with major components – projected to 2018**



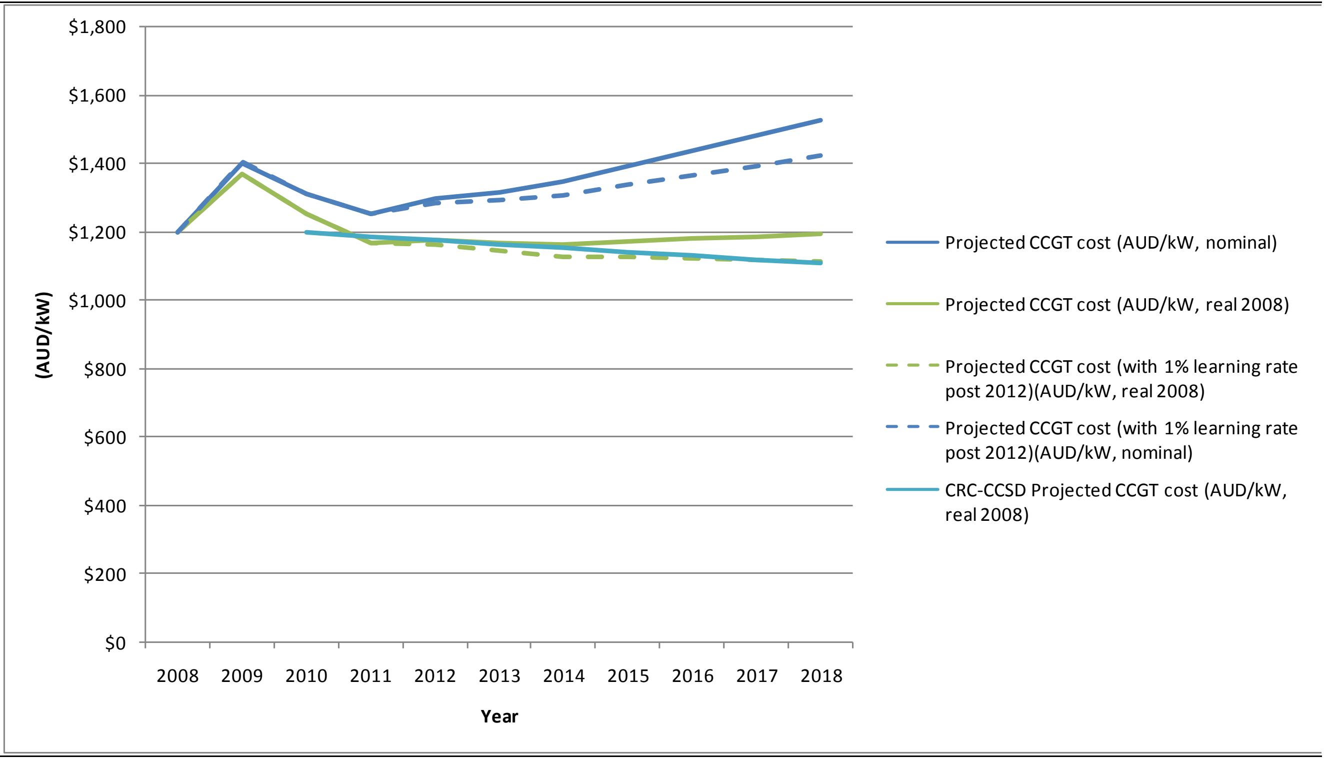
Note: Actual estimates to 2008 and projection post 2008.

Data source: ACIL Tasman analysis of various sources

The CCGT capital costs projection shows that the step change is likely to continue to increase for the next one or two years before softening. This softening is a result of the assumption that steel prices will decline back to 2004-2007 levels over the coming few years. In other words, about 50% of the step change, observed in capital costs over the past two years and projected for the next two years, is projected to be temporary. However, given that the step change in steel price in 2004 has been sustained, we think that the "other" 50% of the step change in capital costs is fundamental and long term.

The projection above does not include the "learning" factor. Figure 35 shows the projected capital costs with and without a learning factor. If we assume a 1% learning rate as suggested in the 2008 CRC-CCSD report and which we think is reasonable, the projected capital costs line up very closely with the CRC-CCSD capital cost projections. The main difference between our projection and the CRC-CCSD projection is the temporary "hump" in costs in 2009 and 2010 due to higher steel prices and labour costs.

Figure 35 **Projected capital costs for CCGTs – 2008 - 2018**



Data source: ACIL Tasman analysis of various sources and *Options for electricity generation in Australia – 2007 update*, CRC-CCSD, March 2008

The two right columns in Table 16 summarise ACIL Tasman's base case projection for CCGT capital costs for 2008 to 2018 in real and nominal terms.

Table 16 **Projected capital costs for CCGTs – base case, 2008 - 2018**

Year ending June	Projected CCGT cost (AUD/kW, nominal)	Projected CCGT cost (AUD/kW, real 2008)	Projected CCGT cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected CCGT cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$1,200	$1,200	$1,200	$1,200
2009	$1,404	$1,370	$1,404	$1,370
2010	$1,314	$1,250	$1,314	$1,250
2011	$1,255	$1,165	$1,255	$1,165
2012	$1,296	$1,175	$1,284	$1,163
2013	$1,318	$1,165	$1,292	$1,142
2014	$1,348	$1,162	$1,308	$1,128
2015	$1,391	$1,170	$1,336	$1,124
2016	$1,436	$1,178	$1,365	$1,121
2017	$1,481	$1,186	$1,395	$1,117
2018	$1,527	$1,193	$1,424	$1,112

Data source: ACIL Tasman analysis

As a sensitivity, Table 17 shows the projected CCGT capital costs if the steel prices were to be sustained at current levels.

Table 17 **Projected capital costs for CCGTs – permanent high steel price sensitivity, 2008 - 2018**

Year ending June	Projected CCGT cost (AUD/kW, nominal)	Projected CCGT cost (AUD/kW, real 2008)	Projected CCGT cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected CCGT cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$1,200	$1,200	$1,200	$1,200
2009	$1,404	$1,370	$1,404	$1,370
2010	$1,449	$1,379	$1,449	$1,379
2011	$1,495	$1,389	$1,495	$1,389
2012	$1,543	$1,398	$1,528	$1,384
2013	$1,593	$1,408	$1,561	$1,380
2014	$1,644	$1,417	$1,595	$1,375
2015	$1,696	$1,427	$1,629	$1,371
2016	$1,750	$1,437	$1,665	$1,366
2017	$1,806	$1,446	$1,701	$1,362
2018	$1,864	$1,456	$1,738	$1,357

Data source: ACIL Tasman analysis

2.8.2 Black coal plant

In the 2007 NEMMCO report our estimate of project capital costs for black coal supercritical plant for 2007/08 was AUD$1,700/kW installed.

Unfortunately, with the prospect of emissions trading and the proliferation of CSG resources, there are no new data on supercritical project costs in eastern Australia in the public domain. Griffin Energy is developing the 208MW Bluewaters I project in Western Australia at a cost of AUD$400M (according to the Griffin Website in 2007), which is equivalent to AUD$1923/kW – however, the EPC for this project was probably signed at least two years ago. We note that in May 2008 a press article quotes Bluewaters I and II will cost AUD$1 billion – back solving this suggests that Bluewaters II is AUD$2,700/kW or an average of the two units is AUD$2,270/kW. One could argue that these prices are higher due to the smaller unit sizes of Bluewaters compared with the typical size of coal fired units in the NEM, however, our previous analysis for NEMMCO suggests little relationship between price and unit size for units above 200MW.

In September 2008, Perth-based Aviva Corporation announced that it was developing a 400 megawatt power project at a cost of about $1 billion –this equates to AUD$2,500/kW.

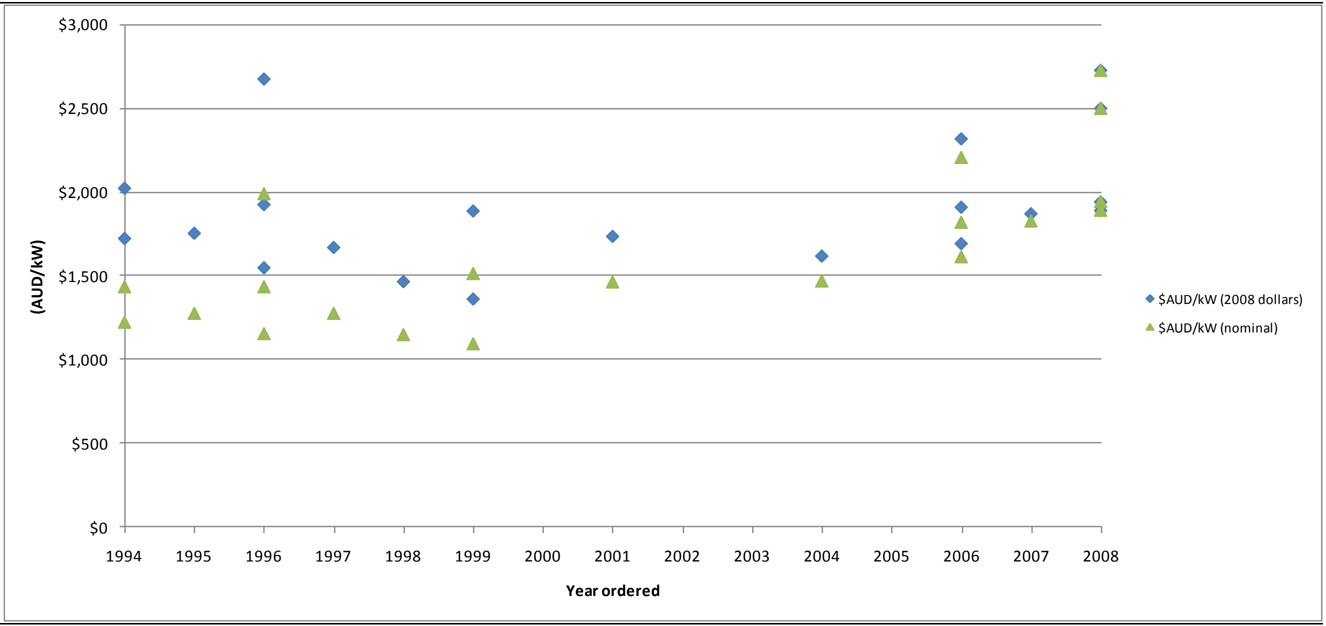
ACIL Tasman has also updated the international database of project capital costs for new entrant coal plant to take into account recently announced projects as well as drawing on confidential information for new coal fired projects in Asia to populate the time series for 2007 and 2008.

Figure 36 plots the historical project capital costs for coal projects over the past decade. There are 20 individual projects included in the graph, representing projects from Europe, USA, Asia and Australia. The costs have been plotted two ways – in nominal terms (costs of the day) as well as in real terms (in 2008 dollars assuming an inflation rate of 2.5% per year). The step change in costs from 2006 onwards is quite apparent.

Figure 37 plots the annual median of the historical capital costs for coal plant.

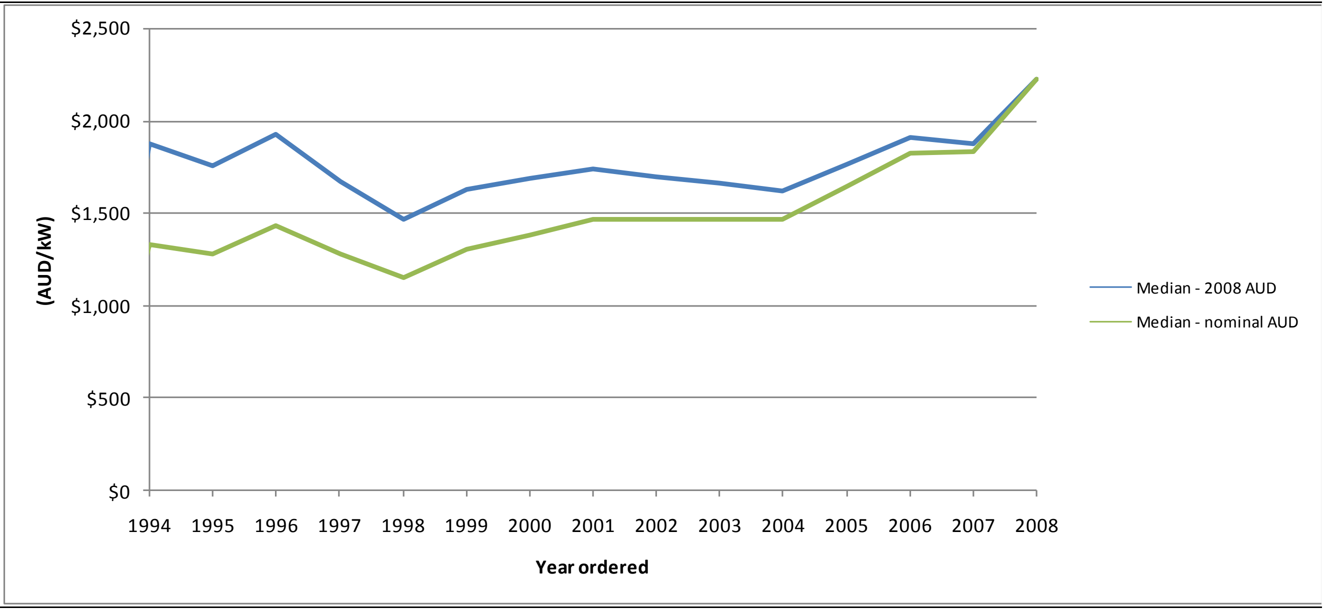
Based on this analysis, **we estimate that the cost for a greenfield supercritical coal project is AUD$2,200/kW for 2007/08.** This represents about a 29% increase from our estimate published in the 2007 NEMMCO report, which at the time assumed the capital costs had reached a steady state and did not include the latest data now available. The analysis associated with the 2007 NEMMCO report also produced an estimate of AUD$1,500/kW for 2006/07 and when we include the additional up to date data, this estimate is revised to AUD$1,800/kW – using this as a base, the current estimate of AUD$2,200/kW for 2007/08 represents a 22% increase in capital costs between 2006/07 and 2007/08.

Figure 36 **Historical project capital costs (AUD/kW) for a new build coal power station by year of project**



Data source: ACIL Tasman analysis of various sources

Figure 37 **Median project capital costs (AUD/kW) for a new build coal power station by year of project**



Data source: ACIL Tasman analysis of various sources

Table 18 compares the estimates of capital costs for coal plant made in 2008 and there is close agreement between our estimate and that of CRC-CCSD and EIA. Our estimate is below the estimate of SKM.

Table 18 **Comparison of capital costs estimates for a new entrant super-critical coal plant in 2007/08**

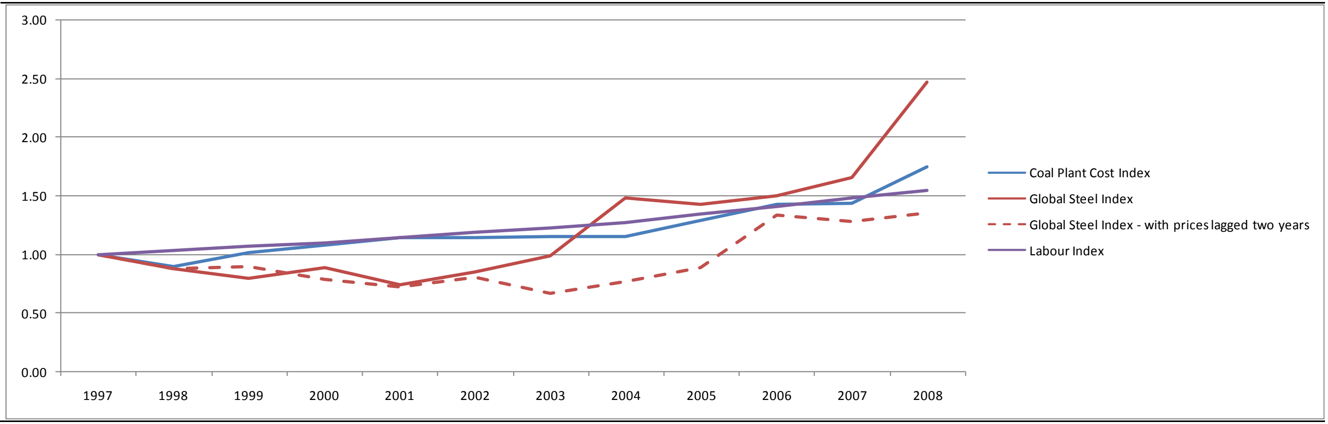
Source	Estimate (AUD/kW)	Percentage increase over 2007
ACIL Tasman, October 2008	$2,200	22%
CRC-CCSD, March 2008	$1,850	NA
EIA, AEO 2008, September 2008	$2,200	15%(thermal plant in general)
SKM, EUAA presentation, June 2008	$2,600	30%
IHS/CERA, May 2008	NA	4% (thermal plant in general)

Data source: Various

Future capital costs for coal plant

ACIL Tasman has used the historical relationship between coal plant costs and its two major components, steel and labour, to produce a projection of future coal plant costs. Figure 38 shows the correlation between the coal plant cost index and the steel and labour cost indexes.

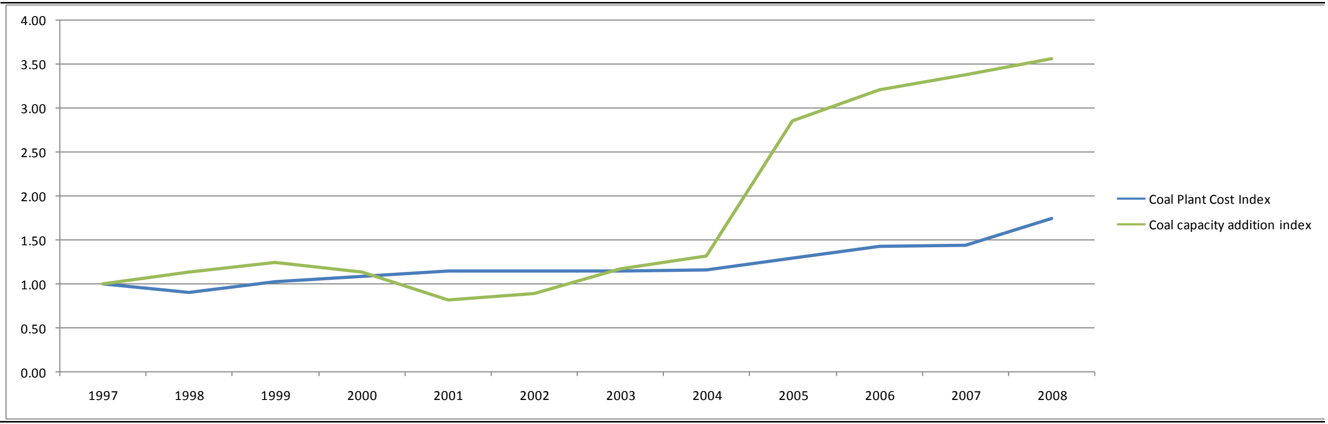
Figure 38 **Coal capital cost, steel cost and labour indexes (nominal) – 1997 - 2008**



Data source: ACIL Tasman analysis of various sources

Demand for coal plant has not declined over the past few years as shown in Figure 39, despite the increase in capital costs.

Figure 39 **Coal capital cost index (nominal) and capacity addition index – 1997 - 2008**



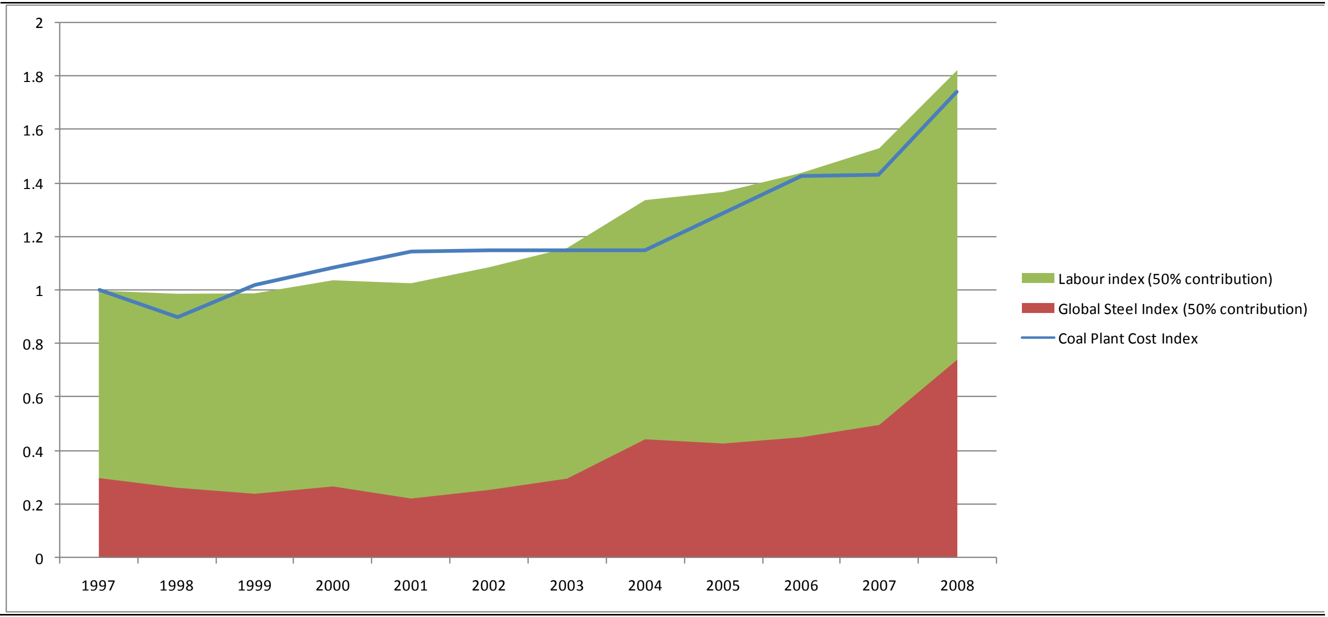
Data source: ACIL Tasman analysis of various sources

Despite the supply constraint, our analysis of the financial performance of the turbine suppliers shows that there does not appear to be any gouging of the market and therefore, the tight demand/supply balance and market concentration of the suppliers does not appear to be a significant factor in the increasing capital costs of coal plant.

Aggregating the two cost components provides an aggregate index that matches the coal plant cost index reasonably well when considering the lag effect of steel prices on coal plant costs. This suggests that a reasonable method of projecting the capital cost index of coal plant is to consider the projections of steel and labour.

Unlike the CCGT index, the coal plant cost index does not decline slightly in the earlier years relative to the component indexes - this may be explained by the increased demand for coal plant.

Figure 40 **Coal plant capital cost index (nominal) with major components – 1997 - 2008**



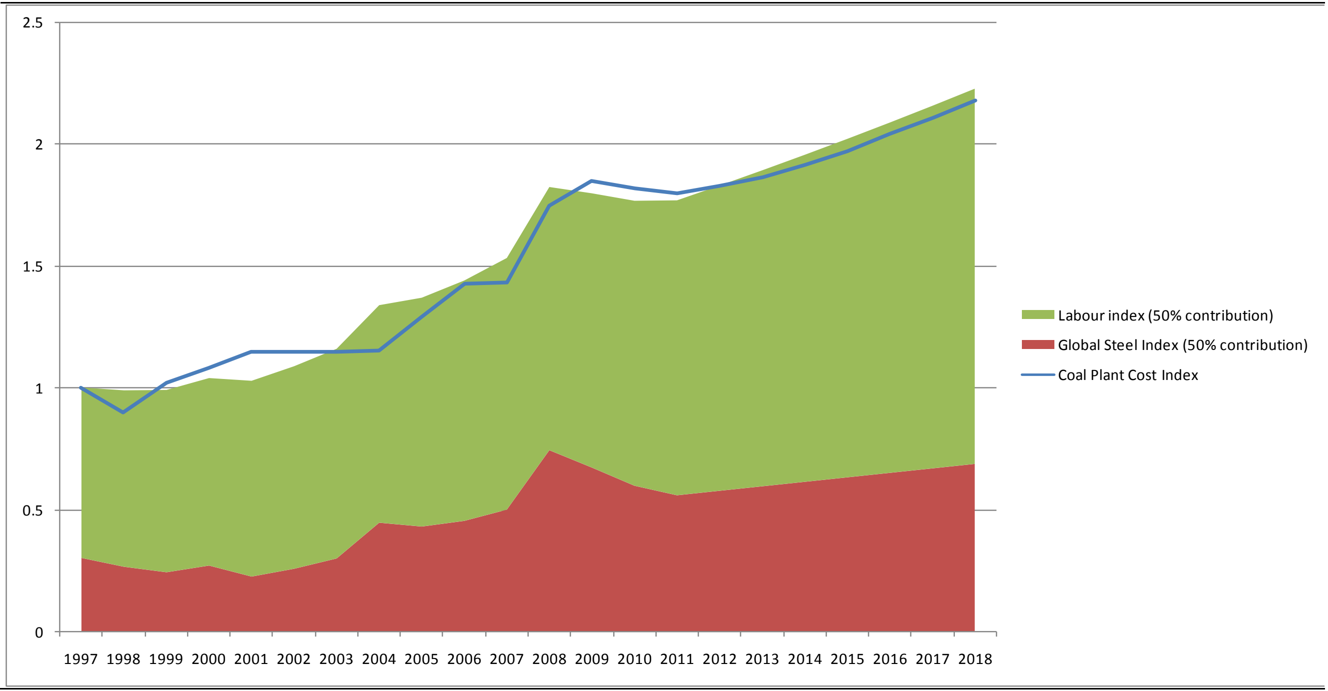
Note:

Data source: ACIL Tasman analysis of various sources

Figure 41 shows our projection of the coal plant index using a projection of the two major components, steel and labour, based on the following assumptions:

- Steel and labour make up 30% and 70% of the coal plant capital cost respectively. Obviously this is a simplified assumption, but one that we consider to be reasonable.
- Steel prices return to pre 2008 levels over the next few years, by 2011, as supply catches up with demand. Post 2011, if demand from China and India is maintained then it is likely that steel prices will continue to escalate at a similar rate as occurred between 2004 and 2007, about 3% per year.
- The impact of steel prices on coal plant costs is lagged by about two years
- Labour costs contract slightly back to long term averages of 3.5% per year post 2011 assuming labour supply shortages are relieved partly due to a slight slowdown in the global economy.
- CPI is assumed to be 2.5%.

Figure 41 **Coal plant capital cost index with major components – projected to 2018**



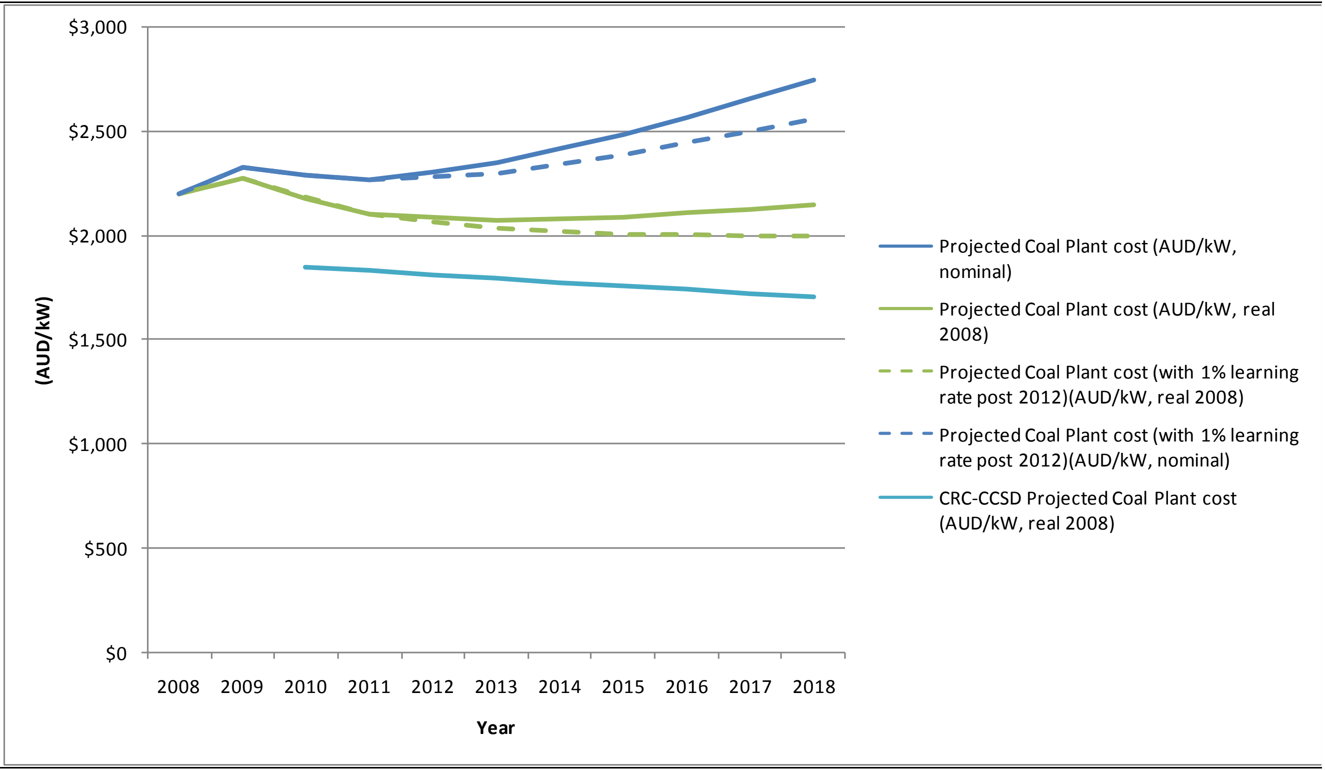
Note: Actual estimates to 2008 and projection post 2008.

Data source: ACIL Tasman analysis of various sources

Similar to CCGTs, the capital cost projection for black coal plant shows that the step change is likely to continue to increase for the next one or two years before softening. This softening is a result of the assumption that steel prices will decline back to 2004-2007 levels over the coming few years. In other words, about 50% of the step change, observed in capital costs over the past two years and projected for the next two years, is projected to be temporary. However, given that the step change in steel price in 2004 has been sustained, we think that the “other” 50% of the step change in capital costs is fundamental and long term.

The projection above does not include the “learning” factor. Figure 42 shows the projected capital costs with and without a learning factor. If we assume a 1% learning rate as suggested in the 2008 CRC-CCSD report and which we think is reasonable, the trend in the projected capital costs line up very closely with the CRC-CCSD capital cost projections. However, our projection remains higher than the CRC-CCSD projection. The analysis of the historical data shows that after periods of price increases plant costs stabilise but do not appear to decrease.

Figure 42 **Projected capital costs for black supercritical coal plant – 2008 - 2018**



Data source: ACIL Tasman analysis of various sources and *Options for electricity generation in Australia – 2007 update*, CRC-CCSD, March 2008

The two right columns in Table 19 summarise ACIL Tasman's base case projection for black coal plant capital costs for 2008 to 2018, both in real and nominal terms.

Table 19 **Projected capital costs for black coal supercritical plant – base case, 2008 - 2018**

Year ending June	Projected coal plant cost (AUD/kW, nominal)	Projected coal plant cost (AUD/kW, real 2008)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$2,200	$2,200	$2,200	$2,200
2009	$2,330	$2,273	$2,330	$2,273
2010	$2,291	$2,181	$2,291	$2,181
2011	$2,268	$2,106	$2,268	$2,106
2012	$2,307	$2,090	$2,284	$2,069
2013	$2,348	$2,075	$2,301	$2,034
2014	$2,415	$2,083	$2,344	$2,021
2015	$2,485	$2,091	$2,387	$2,008
2016	$2,570	$2,109	$2,444	$2,006
2017	$2,657	$2,127	$2,501	$2,003
2018	$2,745	$2,145	$2,559	$1,999

Data source: ACIL Tasman analysis

As a sensitivity, Table 20 shows the projected black coal plant capital costs if the steel prices were to be sustained at current levels.

Table 20 **Projected capital costs for black coal supercritical plant – permanent high steel price sensitivity, 2008 - 2018**

Year ending June	Projected coal plant cost (AUD/kW, nominal)	Projected coal plant cost (AUD/kW, real 2008)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$2,200	$2,200	$2,200	$2,200
2009	$2,330	$2,273	$2,330	$2,273
2010	$2,404	$2,288	$2,404	$2,288
2011	$2,481	$2,304	$2,481	$2,304
2012	$2,561	$2,320	$2,535	$2,297
2013	$2,642	$2,336	$2,590	$2,289
2014	$2,727	$2,352	$2,646	$2,282
2015	$2,814	$2,368	$2,703	$2,274
2016	$2,904	$2,384	$2,762	$2,267
2017	$2,997	$2,400	$2,822	$2,260
2018	$3,093	$2,416	$2,883	$2,252

Data source: ACIL Tasman analysis

2.8.3 Brown coal plant

As in our 2007 NEMCO report, we assume 10% additional project capital costs for a brown coal fired new entrant project to account for additional coal handing requirements etc. This means that the project capital cost for brown coal fired plant in the NEM would be around $2,420/kW for 2007/08. This cost assumes access to third party coal. It is difficult to obtain other estimates of brown coal capital costs, although the SKM presentation (see Section 2.7.5) appears to suggest about AUD$2,900/kW for 2007/08, which is about a AUD$300/kW premium on black coal. CRC-CCSD assumes a AUD$200/kW premium for brown coal when compared with their black coal estimate.

The two right columns in Table 21 summarise ACIL Tasman's base case projection for brown coal plant capital costs for 2008 to 2018. Similar to the CCGT and black coal plant, we have assumed a 1% learning rate for brown coal plant.

Table 21 **Projected capital costs for brown coal supercritical plant – 2008 - 2018**

Year ending June	Projected coal plant cost (AUD/kW, nominal)	Projected coal plant cost (AUD/kW, real 2008)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$2,420	$2,420	$2,420	$2,420
2009	$2,563	$2,500	$2,563	$2,500
2010	$2,520	$2,399	$2,520	$2,399
2011	$2,495	$2,317	$2,495	$2,317
2012	$2,538	$2,299	$2,512	$2,276
2013	$2,582	$2,282	$2,531	$2,237
2014	$2,657	$2,291	$2,578	$2,223
2015	$2,734	$2,300	$2,626	$2,209
2016	$2,827	$2,320	$2,688	$2,206
2017	$2,922	$2,340	$2,751	$2,203
2018	$3,020	$2,359	$2,815	$2,199

Data source: ACIL Tasman analysis

As a sensitivity, Table 22 shows the projected brown coal plant capital costs if the steel prices were to be sustained at current levels.

Table 22 **Projected capital costs for brown coal supercritical plant – permanent high steel price sensitivity, 2008 - 2018**

Year ending June	Projected coal plant cost (AUD/kW, nominal)	Projected coal plant cost (AUD/kW, real 2008)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected coal plant cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$2,420	$2,420	$2,420	$2,420
2009	$2,563	$2,500	$2,563	$2,500
2010	$2,645	$2,517	$2,645	$2,517
2011	$2,729	$2,534	$2,729	$2,534
2012	$2,817	$2,552	$2,788	$2,526
2013	$2,907	$2,569	$2,849	$2,518
2014	$3,000	$2,587	$2,911	$2,510
2015	$3,096	$2,604	$2,974	$2,502
2016	$3,195	$2,622	$3,038	$2,494
2017	$3,297	$2,640	$3,104	$2,486
2018	$3,403	$2,658	$3,171	$2,477

Data source: ACIL Tasman analysis

2.8.4 OCGT

In the 2007 NEMMCO report our estimate of project capital costs for OCGT peaking plant for 2007/08 was AUD$720/kW installed.

Since the NEMMCO report there has been a small number of projects committed in Australia as shown below. It is quite apparent that costs have continued to increase during the past 12-18 months.

Given the information in the table below, **we estimate that the cost for a greenfield OCGT project is AUD$900/kW in 2007/08.** This represents about a 20% increase from our estimate published in the NEMMCO report.

Table 23 **Project capital costs for recently announced OCGT projects in Australia**

Project	Cost (AUD$/kW, 2007/08 $)	Source	Comments
Braemar OCGT - Stage 2	$1,011	Courier Mail Feb 2008	Removed AUD$90M for pipeline.
Mt Stuart expansion	$730	Origin ASX release - Feb 2008	Expansion.
Neerabup	$1,091	Babcock & Brown website	Removed AUD$65M for pipeline.
Colongra	$610	Platts	EPC only.
Tamar Valley OCGT	$891	Alinta website	Brownfield site

Data source: ACIL Tasman analysis of various sources

Table 24 compares the estimates of capital costs for OCGT plant made in 2008 and our estimate is somewhat higher than that of CRC-CCSD, EIA and the Western Australia ERA-IMO.

Table 24 **Comparison of capital costs estimates for a new entrant OCGT plant in 2007/08**

Source	Estimate (AUD/kW)	Percentage increase over 2007
ACIL Tasman, October 2008	$900	20%
CRC-CCSD, March 2008	$700	NA
EIA, AEO 2008, September 2008	$618	15%(thermal plant in general)
Western Australia ERA-IMO, January 2008	$708	NA
IHS/CERA, May 2008	NA	4% (thermal plant in general)

Data source: Various

The two right columns in Table 25 summarise ACIL Tasman's base case projection for OCGT plant capital costs for 2008 to 2018 both in real and nominal terms. The projection takes our estimate for 2007/08 and escalates this value at the same rate as implied by our projection of CCGT capital costs.

Table 25 **Projected capital costs for OCGT plant – base case, 2008 - 2018**

Year ending June	Projected OCGT plant cost (AUD/kW, nominal)	Projected OCGT plant cost (AUD/kW, real 2008)	Projected OCGT plant cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected OCGT plant cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$900	$900	$900	$900
2009	$1,053	$1,027	$1,053	$1,027
2010	$985	$938	$985	$938
2011	$941	$874	$941	$874
2012	$972	$881	$963	$872
2013	$989	$874	$969	$856
2014	$1,011	$872	$981	$846
2015	$1,043	$878	$1,002	$843
2016	$1,077	$884	$1,024	$841
2017	$1,111	$890	$1,046	$837
2018	$1,146	$895	$1,068	$834

Data source: ACIL Tasman analysis

As a sensitivity, Table 26 shows the projected OCGT plant capital costs if the steel prices were to be sustained at current levels.

Table 26 **Projected capital costs for OCGT plant – permanent high steel price sensitivity, 2008 - 2018**

Year ending June	Projected OCGT plant cost (AUD/kW, nominal)	Projected OCGT plant cost (AUD/kW, real 2008)	Projected OCGT plant cost (with 1% learning rate post 2012)(AUD/kW, nominal)	Projected OCGT plant cost (with 1% learning rate post 2012)(AUD/kW, real 2008)
2008	$900	$900	$900	$900
2009	$1,053	$1,027	$1,053	$1,027
2010	$1,087	$1,034	$1,087	$1,034
2011	$1,121	$1,041	$1,121	$1,041
2012	$1,157	$1,049	$1,146	$1,038
2013	$1,194	$1,056	$1,171	$1,035
2014	$1,233	$1,063	$1,196	$1,031
2015	$1,272	$1,070	$1,222	$1,028
2016	$1,313	$1,077	$1,248	$1,025
2017	$1,355	$1,085	$1,276	$1,021
2018	$1,398	$1,092	$1,303	$1,018

Data source: ACIL Tasman analysis

2.8.5 Wind

ACIL Tasman has not previously provided capital costs for wind farm projects to NEMMCO. Table 27 summarises recently announced wind farm projects in Australia.

Table 27 **Project capital costs for recently announced wind projects in Australia**

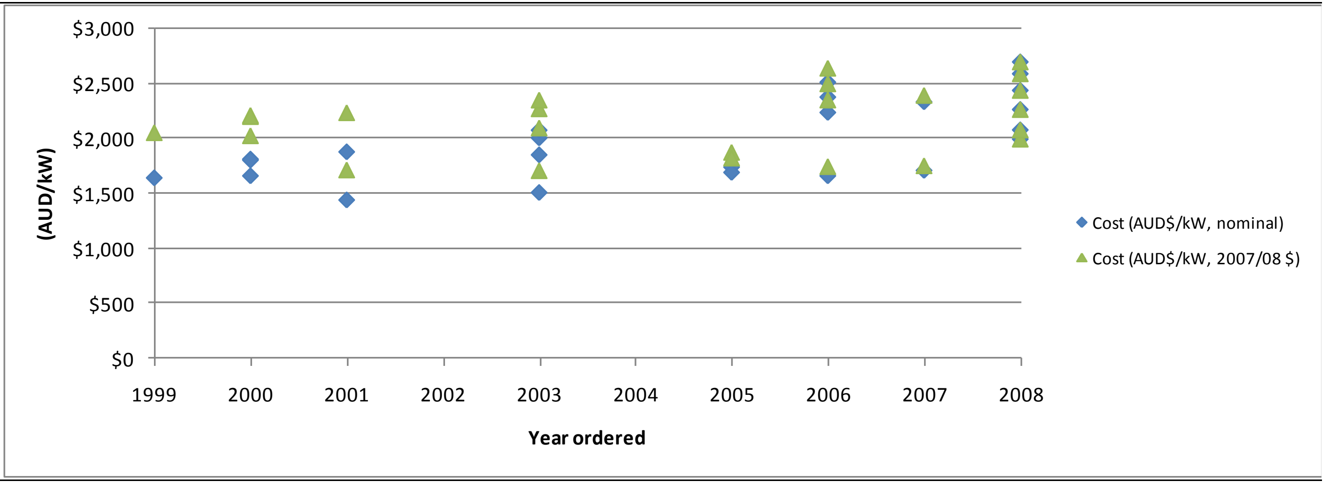
Project	Cost (AUD$/kW, 2007/08 $)	Source
Hallett Hill 2	$2,300	AGL ASX release - Nov 2007
Collgar	$2,600	Investec press release – September 2008
Coopers Gap	$2,300	Investec press release – September 2008
Oaklands Hill	$2,600	Investec press release – September 2008

Data source: ACIL Tasman analysis of various sources

Unlike the other technologies, there is a good set of historical wind farm capital cost data available for Australian wind farms, as well as for proposed projects. Figure 43 plots the historical project capital costs for wind projects over the past decade. There are 24 individual projects included in the graph. The costs have been plotted two ways – in nominal terms (costs of the day) as well as in real terms (in 2008 dollars assuming an inflation rate of 2.5% per year). Again, the step change in costs from 2006 onwards is quite apparent.

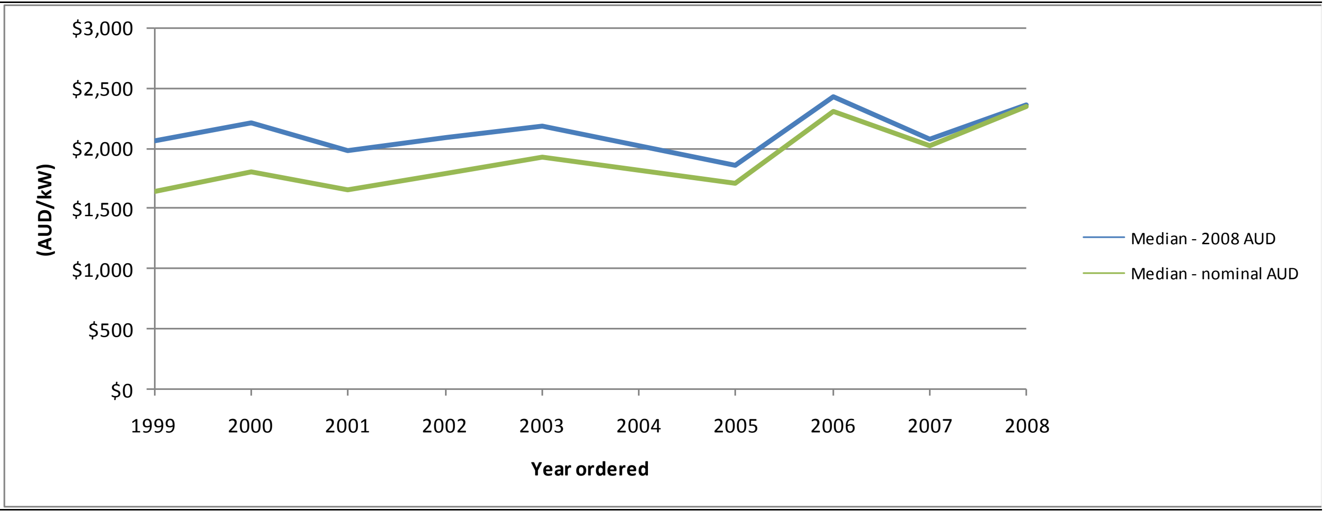
Figure 44 plots the annual median of the historical capital costs for wind farm plant.

Figure 43 **Historical project capital costs (AUD/kW) for a new build wind farm by year of project**



Data source: ACIL Tasman analysis of various sources

Figure 44 **Median project capital costs (AUD/kW) for a new build wind farm by year of project**



Data source: ACIL Tasman analysis of various sources

The table below shows the annual profit margin for Vestas, one of the main suppliers of wind turbines, for 2003 to 2008. The increase in profit margin in 2006 is noticeable and lines up with the increase in turbine price. Indeed, the Vestas Annual Report 2007 makes the comment: "*the progress is attributable to improved in-house procedures and better prices and conditions*". There seems to be more of a coincidence in an increase in profit margins and increased prices in the wind sector when compared with gas and coal fired plant. It will be recalled there were only some minor increases in profit margins from the likes of Siemens, MHI, Alstom and GE during this period of capital cost increases. It might also be that the lead times for wind farms are shorter and so manufactures are able to pass the cost increases more quickly due to shorter contract periods. The table also shows the demand for wind turbines has increased over the past two or so years.

Table 28 **Vestas profit margin: 2003 - 2008**

Year	2003	2004	2005	2006	2007	2008 H1
Gross margin (%)	9.1%	5.1%	2.4%	12%	17%	19.6%
MW delivered – by Vestas	2,667	2,784	3,185	4,239	4,502	NA
MW delivered – by all suppliers			11,407	15,016	19,574	

Data source: Vestas Annual Report 2007 and investor presentations

Based on this analysis, **we estimate that the cost for a greenfield wind farm project is AUD$2,300/kW in 2007/08.**

Table 29 compares the estimates of capital costs for wind farm plant made in 2008 and our estimate is somewhat higher than that of CRC-CCSD and EIA.

Table 29 **Comparison of capital costs estimates for a new entrant wind farm in 2007/08**

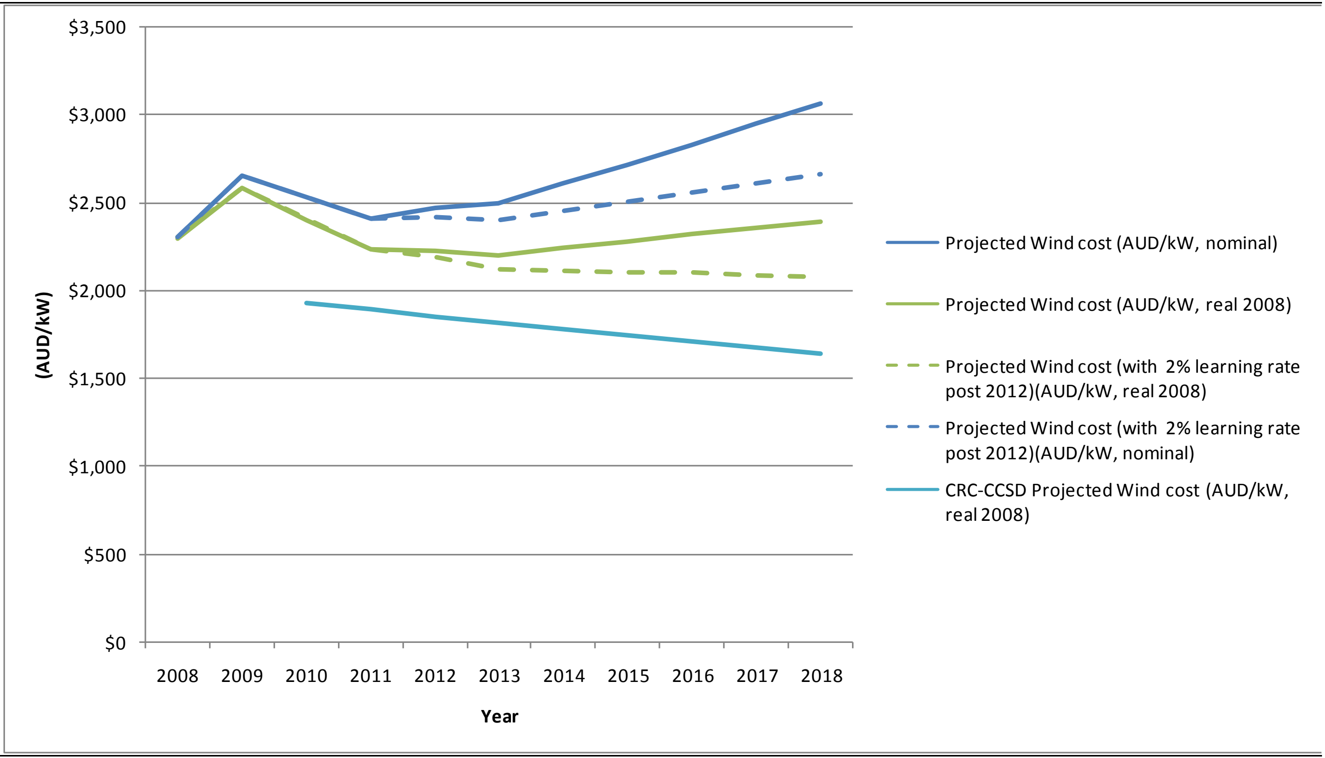
Source	Estimate (AUD/kW)	Percentage increase over 2007
ACIL Tasman, October 2008	$2,300	15%
CRC-CCSD, March 2008	$1,925	NA
EIA, AEO 2008, September 2008	$1,770	19%

Data source: Various

Figure 45 shows our projection of the wind farm index using a similar trend to the projected CCGT index but by accounting for the strong demand for turbines likely to be seen between now and at least 2012.

If we assume a 2% learning rate as suggested in the 2008 CRC-CCSD report, the trend in projected capital costs line up very closely with the CRC-CCSD capital cost projections, however our estimates remain above those of CRC-CCSD.

Figure 45 **Projected capital costs for Wind farms – 2008 - 2018**



Data source: ACIL Tasman analysis of various sources and *Options for electricity generation in Australia – 2007 update*, CRC-CCSD, March 2008

The two right columns in Table 30 summarises ACIL Tasman's projection for wind farm capital costs for 2008 to 2018, both in real and nominal terms.

Table 30 **Projected capital costs for Wind farms – base case, 2008 - 2018**

Year ending June	Projected Wind plant cost (AUD/kW, nominal)	Projected Wind plant cost (AUD/kW, real 2008)	Projected Wind plant cost (with 2% learning rate post 2012)(AUD/kW, nominal)	Projected Wind plant cost (with 2% learning rate post 2012)(AUD/kW, real 2008)
2008	$2,300	$2,300	$2,300	$2,300
2009	$2,646	$2,581	$2,646	$2,581
2010	$2,525	$2,403	$2,525	$2,403
2011	$2,406	$2,234	$2,406	$2,234
2012	$2,464	$2,233	$2,415	$2,188
2013	$2,492	$2,203	$2,394	$2,116
2014	$2,603	$2,244	$2,450	$2,112
2015	$2,715	$2,284	$2,504	$2,106
2016	$2,828	$2,321	$2,557	$2,098
2017	$2,944	$2,357	$2,608	$2,088
2018	$3,061	$2,391	$2,658	$2,076

Data source: ACIL Tasman analysis

We do not think the increase in steel prices has the same degree of influence of wind turbine prices as it does for CCGTs and coal plant and therefore we have not provided a capital cost projection based on a high steel price sensitivity.

2.8.6 Geothermal

Our estimate of geothermal plant capital costs is AUD$5,000/kW for 2007/08.

Table 31 compares the estimates of capital costs for geothermal plant in 2008 and our estimate is in-line with that of CRC-CCSD but higher than that of EIA. However, it is unclear what type of geothermal plant is assumed by EIA – presumably this figure relates to conventional geothermal rather than hot dry rock technology.

Table 31 **Comparison of capital costs estimates for a new entrant geothermal plant in 2007/08**

Source	Estimate (AUD/kW)	Percentage increase over 2007
ACIL Tasman, October 2008	$5,000	NA
CRC-CCSD, March 2008	$5,290	NA
EIA, AEO 2008, September 2008	$1,370	NA

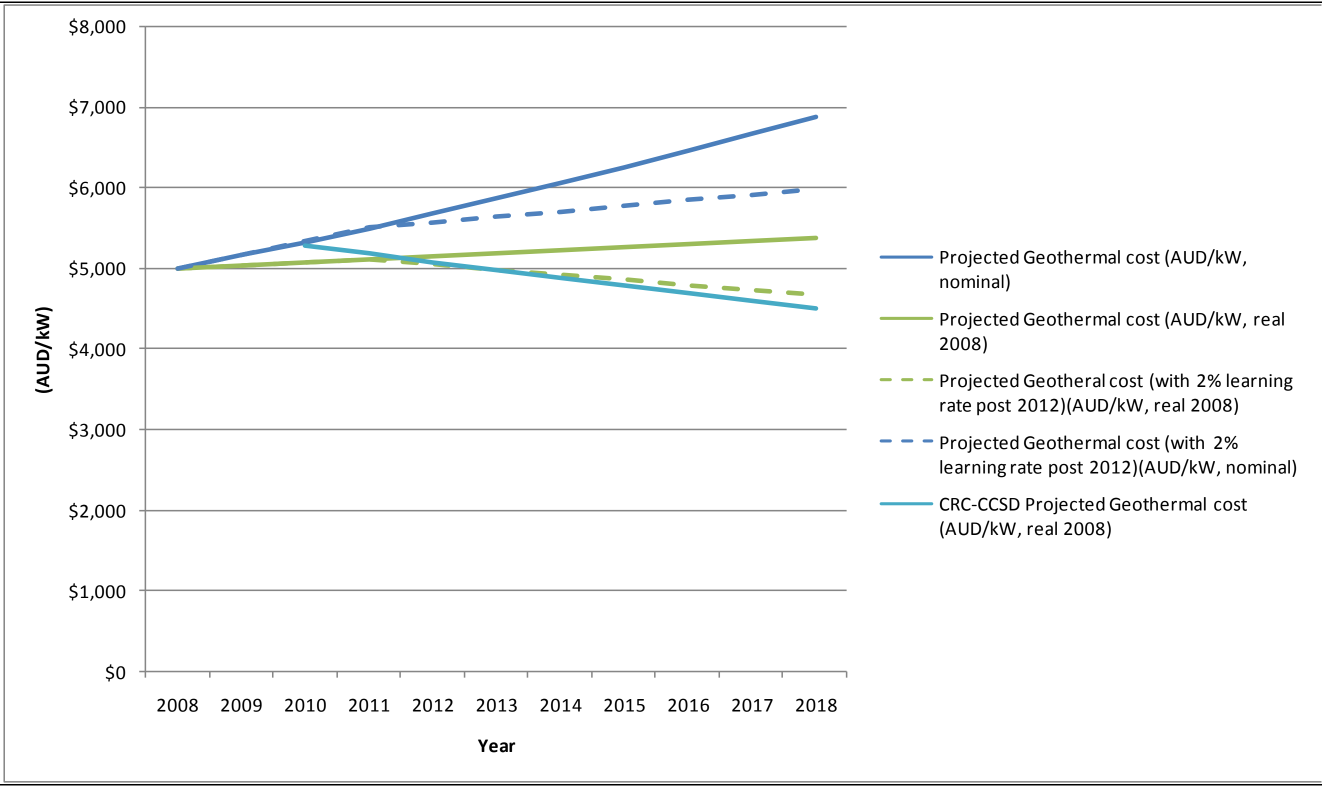
Note: It is difficult to discern the type of geothermal plant assumed in the AEO 2008.

Data source: Various

Figure 46 shows our projection of the geothermal index which assumes some increases over the next few years based on increased input costs.

If we assume a 2% learning rate as suggested in the 2008 CRC-CCSD report, the trend in projected capital costs line up very closely with the CRC-CCSD capital cost projections, however our estimates remain above those of CRC-CCSD.

Figure 46 **Projected capital costs for Geothermal plant – 2008 - 2018**



Data source: ACIL Tasman analysis of various sources and *Options for electricity generation in Australia – 2007 update*, CRC-CCSD, March 2008

The two right columns in Table 32 summarise ACIL Tasman's projection for geothermal capital costs for 2008 to 2018, both in real and nominal terms.

Table 32 **Projected capital costs for Geothermal plant – 2008 - 2018**

Year ending June	Projected Geothermal plant cost (AUD/kW, nominal)	Projected Geothermal plant cost (AUD/kW, real 2008)	Projected Geothermal plant cost (with 2% learning rate post 2012)(AUD/kW, nominal)	Projected Geothermal plant cost (with 2% learning rate post 2012)(AUD/kW, real 2008)
2008	$5,000	$5,000	$5,000	$5,000
2009	$5,163	$5,037	$5,163	$5,037
2010	$5,330	$5,073	$5,330	$5,073
2011	$5,504	$5,111	$5,504	$5,111
2012	$5,682	$5,148	$5,569	$5,045
2013	$5,867	$5,186	$5,635	$4,980
2014	$6,058	$5,224	$5,701	$4,916
2015	$6,255	$5,262	$5,769	$4,853
2016	$6,458	$5,300	$5,837	$4,791
2017	$6,668	$5,339	$5,907	$4,730
2018	$6,884	$5,378	$5,977	$4,669

Data source: ACIL Tasman analysis

Given the lack of historical data on geothermal plant capital costs, it is not possible to assess the impact of the increase in steel prices therefore we have not provided a capital cost projection based on a high steel price sensitivity.

2.8.7 Biomass and hydro

The QCA also requested that ACIL Tasman provide comment on estimates for the capital costs of hydro and biomass plant.

Given that each biomass and hydro project is unique and influenced by location, source of energy inputs, etc it is difficult to provide a projection of capital costs.

We note that CRA in its draft analysis to the QCA has used the CRC-CCSD as the source for estimating the capital costs for hydro plant and the AEO 2007 and AEO 2008 as the source for estimating the capital costs for biomass plant. Given the lack of other sources we think this is a reasonable approach.

The CRC-CCSD report has been updated since CRA undertook its draft analysis, and we suggest using the latest estimates from the 2008 CRC-CCSD report.

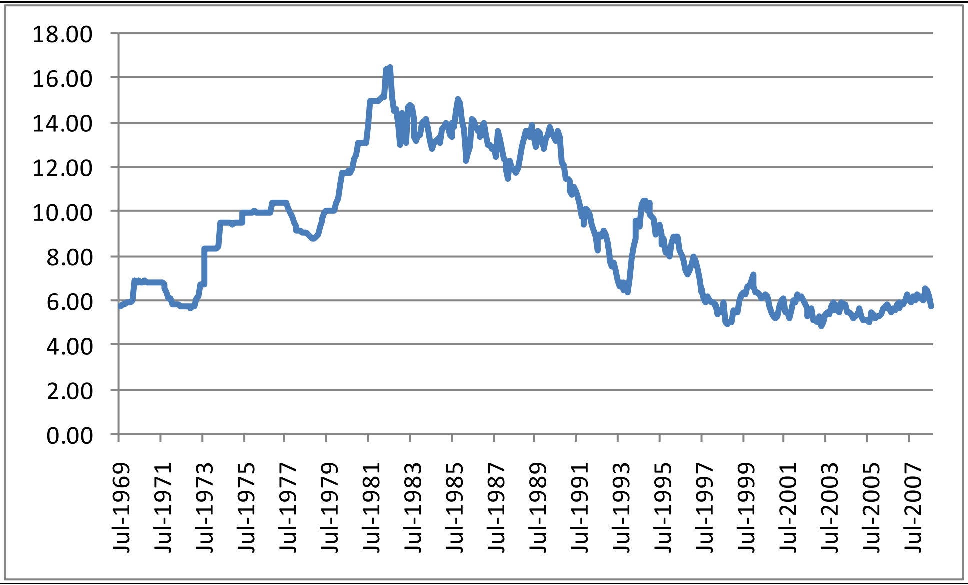
As we mentioned in the introduction to this chapter, the contribution to the plant mix of these two technologies is very small and the lower accuracy of estimates will have negligible impact on the overall BRCI.

3 Other LRMC inputs

3.1 Discount factor – WACC

The discount factor (or WACC) is derived using the components shown in the table below. The only change in the inputs, when compared with our 2007 estimates, is the Treasury T-bond rate which is assumed to be 6.00% (based on the long term average rate over the past eight years) compared with the 2007 assumption of 5.7%.

Figure 47 **Monthly Treasury Bond rates (%)**



Note:
Data source: RBA website

We estimate the current post tax real WACC to be 6.81%, an increase from the 2007 estimate which was 6.58%. We note that CRA continue to use our 2007 estimate.

Table 33 **WACC parameters**

	Parameter	Value
D+E	Liabilities	100%
D	Debt	60%
E	Equity	40%
rf	Risk free RoR	6.00%
MRP = (rm-rf)	Market risk premium	6.00%
rm	Market RoR	12.00%
T	Corporate tax rate	30%
Te	Effective tax rate	22.5%
Tc	Imputation adjusted tax	15.0%
	Debt basis point premium	200
rd	Cost of debt	8.00%
G	Gamma	0.50
ba	Asset Beta	0.80
bd	Debt Beta	0.16
be	Equity Beta	1.75
re	Required return on equity	16.50%
F	Inflation	2.50%
	Post tax real WACC (Officer)	6.81%

Data source: ACIL Tasman and various sources

3.2 Build time and project life

For the purpose of calculating the long run marginal cost of a new plant a project life of 30 years has been assumed. The build time assumed for each type of technology is shown in the table below. These assumptions are the same as in the 2007 NEMMCO report.

Table 34 **Construction profile (% of project capital cost)**

Technology	Year -4	Year -3	Year -2	Year -1
CCGT	0%	0%	40%	60%
Supercritical – black coal	10%	20%	35%	35%
Supercritical – brown coal	10%	20%	35%	35%
OCGT	0%	0%	0%	100%

3.3 Fixed O&M costs

Fixed O&M costs include maintenance, operating, and overhead costs that are not dependent on the hour-by-hour level of generation from the station.

ACIL Tasman's estimates of fixed O&M costs are provided in the table below. Our view on the fixed costs for the existing technologies has evolved over time and has been subjected to review from a large number of clients. These estimates are unchanged from the 2007 NEMMCO report.

Note that these estimates are presented as a cost per MW of installed capacity (not sent-out capacity).

Table 35 **Estimated fixed O&M cost in 2007-08 and escalation rate**

Technology	AUD$/MW/year	Escalation rate (% of CPI)
CCGT	$12,800	100%
Supercritical – black coal	$40,000	100%
Supercritical – brown coal	$40,000	100%
OCGT	$7,500	100%
Geothermal	$40,000	100%
Wind	$20,000	100%

Data source: ACIL Tasman analysis

ACIL Tasman has not provided fixed O&M costs for biomass and hydro plant due to the unique characteristics of such plant. CRA in its draft analysis to the QCA has used $153,638/MW/year for biomass and $52.531/MW/year for hydro plant (both 2009-10 dollars). These numbers were reportedly sourced from the US Annual Energy Outlook. ACIL Tasman is willing to accept these figures as given.

3.4 Variable O&M costs

ACIL Tasman's estimates of variable O&M costs are provided in the table below. The estimates for variable costs for the existing technologies has evolved over time and incorporates analysis of NEM offer curves to deconstruct the SRMC cost components. Our estimates have been subjected to review from a large number of clients. These estimates are unchanged from the 2007 NEMMCO report.

It is important to note that the variable O&M cost for a CCGT is based on a 65% capacity factor – the typical capacity factor observed for CCGTs in the NEM to date. The Connell Wagner report to the recent Owen Inquiry suggests that our estimate was too high, but Connell Wagner made the incorrect assumption that our estimate was based on a 90% capacity factor. ACIL Tasman has recent experience consulting in other electricity markets in which CCGTs operate in baseload mode and consequently have a lower variable O&M of about $1/MWh, with correspondingly higher fixed O&M. Therefore, ACIL Tasman is comfortable with the assumed O&M costs reported in this document.

Note that these estimates are presented as a cost per MWh sent-out.

Table 36 **Variable O&M cost (sent-out) in 2007-08 and escalation rate**

Technology	AUD$/MWh	Escalation rate (% of CPI)
CCGT	$4.85	100%
Supercritical – black coal	$1.20	100%
Supercritical – brown coal	$1.20	100%
OCGT	$7.50	100%
Geothermal	$2.00	100%
Wind	$1.60	100%

Data source: ACIL Tasman analysis

ACIL Tasman has not provided variable O&M costs for biomass and hydro plant due to the unique characteristics of such plant. CRA in its draft analysis to the QCA has used $4.60/MWh for biomass and $7.35/MWh for hydro plant (both 2009-10 dollars). These numbers were reportedly sourced from the US Annual Energy Outlook. ACIL Tasman is willing to accept these figures as given.

3.5 Thermal efficiency and internal usage (auxiliaries)

ACIL Tasman's estimates of auxiliaries are provided in the table below. The estimates have been based on published sent-out and generated output by existing NEM generators and from feedback from clients.

Table 37 **Auxiliary usage (%) for new entrants**

Technology	Auxiliary usage
CCGT	2.4%
Supercritical – black coal	7.5%
Supercritical – brown coal	9.5%
OCGT	2.0%

Data source: ACIL Tasman analysis

It should be noted that plants which are air cooled incur an auxiliary penalty of around 2% over the figures shown in Table 37. Most new coal plant in the NEM are likely to be air cooled.

ACIL Tasman's estimates of thermal efficiency are provided in the table below. Our view on the thermal efficiency for the existing technologies has evolved over time and includes analysis of offer curves of existing plant to deconstruct the SRMC cost components. The estimates have been subjected to review from a large number of clients. These estimates are unchanged when compared with the 2007 NEMMCO report

Table 38 **Thermal efficiency (HHV, as sent out) for new entrants by build year**

Year ending June	CCGT	Black coal	Brown coal	OCGT
2008	52%	42%	34%	31%
2009	52%	42%	34%	31%
2010	53%	42%	34%	31%
2011	53%	42%	34%	32%
2012	54%	42%	34%	32%
2013	54%	43%	34%	32%
2014	54%	43%	35%	32%
2015	55%	43%	35%	33%
2016	55%	43%	35%	33%
2017	56%	43%	35%	33%
2018	56%	43%	35%	33%

Data source: ACIL Tasman analysis

3.6 Plant availability

In 2005, ACIL Taman undertook an availability analysis of coal fired plant in the NEM spanning 1999 to 2004 using published NEMMCO data. The availability analysis grouped planned maintenance and forced outages together.

The analysis found that in Queensland the average outage days per year across all coal plant was 41 and the median was 37 – this equates to an availability of 88% and 90% respectively. The median was reported in an attempt to remove anomalous outages – such as the well recognised difficulties experienced by Millmerran – although it gave only a slightly lower result than the average.

The 75th percentile of the outage distribution was 60 days, which equates to 84% availability.

ACIL Tasman proposes to use an availability of 90% for coal plant.

There is not as much long term data available on CCGT plant in Queensland, but ACIL Tasman in its market modelling of the NEM and Singapore routinely assumes CCGTs experience 15 days per year of planned maintenance (which equates to 4%) and a 3% forced outage rate. **Therefore, ACIL Tasman proposes to use an availability of 92% for CCGT plant**.

ACIL Tasman assumes a 3% forced outage rate for peaking plant. Although peaking plant undergo planned maintenance, we assume that this maintenance is scheduled during the off-peak months when the plant are rarely used. Given these plants typically have annual capacity factors of less than 5%, it appears reasonable to assume that their planned maintenance can be scheduled during periods when there is a very low probability of high priced outcomes in the NEM.

Therefore, ACIL Tasman proposes to use an availability of 97% for OCGT plant.

Table 39 summarises the availability factors recommended for use in the calculation of the BRCI. Note that ACIL Tasman has adopted the values used for Geothermal, Wind, Biomass and Hydro from the CRA draft report.

Table 39 **Availability by new entrant technology**

Technology	Availability
CCGT	92%
Supercritical – black coal	90%
Supercritical – brown coal	90%
OCGT	97%
Geothermal	90%
Wind	93.4%
Biomass	85%
Hydro	92.2%

Data source: ACIL Tasman analysis

4 Gas costs

The section examines the Eastern Australian gas market and projections of wholesale gas prices ACIL Tasman believes to be appropriate for use in the calculation of the BRCI.

4.1 Introduction

It would be fair to say that over the last 18 months there has been significant movement in the outlook for gas prices, driven by a number of factors including:

- Steeply rising prices and widening specifications for internationally traded thermal coal which is starting to impact on domestic coal prices (the main competitor for domestic gas)
- Dramatic increases in mining, petroleum development and construction cost indices over the last 18 months. This has implications for the development of new fuel resources (particularly coal and offshore gas developments)
- Policy developments relating to the imminent commencement of the Carbon Pollution Reduction Scheme (CPRS) and the announced increase of the Mandated Renewable Energy Target to 60,000 GWh
- Announcement of a number of proposals to export LNG using Coal Seam Gas (CSG) as feedstock from Gladstone. If proponents prove to be successful, this may link domestic gas sales to international gas prices which are around 2-3 times higher than those historically seen in domestic markets.
- The entrance of a number of major international oil and gas companies such as Shell, ConocoPhillips, and BG Group entering into joint ventures with local CSG producers in a significant vote of confidence in the local industry
- Varied production results from a number of CSG producers – some positive and some negative – which may have implications for the resources ultimately available for domestic generation, coupled with large increases in certified reserves and contingent resources in Queensland and NSW CSG developments.

Arguably, the development that will ultimately have the largest impact upon domestic prices is the potential for the development of an East coast LNG industry. With the prospect of being able to achieve high netback prices by directing production into LNG manufacture, Queensland CSG producers are now much less likely than in the recent past to discount prices in order to attract domestic customers, either locally or in southern states.

The following section examines the proposed LNG projects and their potential impact upon domestic prices.

4.2 Potential for LNG export

Until recently, Eastern Australia has not been considered a prospective location for LNG manufacture, principally because uncommitted conventional gas resources in the region are inadequate to support a world-scale LNG facility. However, the recent surge in international energy prices together with the identification of large resources of CSG in southern and central Queensland has changed the prospects for East Coast LNG. Since early 2007, six LNG proposals based on coal seam gas (CSG) feed from the Bowen and Surat Basins have been announced as detailed in Table 40.

The projects range in size from 0.5 to 4 million tonnes per year, with potential in each case for increased production with the replication of the initial liquefaction plant. Total proposed capacity is initially 16.8 Mtpa, rising to 40.6 Mtpa if plans are fully developed to their ultimate potential.

While posing many technical and commercial challenges for the proponents, in the current oil price environment (which has flowed on to high prices for internationally traded LNG) there is a compelling logic to the attempts of the proponents to access large, high value international markets at a time of burgeoning demand and tight supply. LNG prices in the Asia-Pacific region are linked formulaically to crude oil prices. With oil selling hovering around US$100 per barrel, the delivered price of LNG under current price arrangements can be expected to lie in a range from US$12 to $17/GJ. After allowing for the cost of liquefaction, shipping and regasification, the netback value of gas delivered to the LNG plant currently stands in excess of A$7.50/GJ. At these prices, and based on proponent estimates of capital costs, ACIL Tasman analysis suggests that the economics of the projects may well be comparable to conventional gas fed LNG projects, many of which are based on large offshore gas fields for which development costs continue to rise rapidly.

Table 40 Overview of Queensland LNG export proposals

Proponent	Announced	Capacity	Schedule for first cargoes	Gas feed required	Liquefaction Technology	Comments
Arrow Energy – Shell/LNG Limited	May 2007	1.3 Mtpa	2011	78 PJ/a	Unknown	Project located at Fisherman's Landing Gladstone. Interests in the LNG plant are anticipated to be 60% LNGL; 20% Arrow; 20% LNG buyer. Estimated capital costs of US$400 million. Potential for a second train of the same size. FID anticipated late 2008.
Santos/Petronas	July 2007	3-4 Mtpa	Early 2014	170-220 PJ/a	ConocoPhillips Optimised Cascade	Target Final Investment Decision by the end of 2009. The project will initially produce 3 to 4 Mtpa, with a maximum potential production of 10 Mtpa. Reported capital cost of $7.7 billion. In May 2008 Santos sold a 40% interest in the GLNG project to Petronas for US$2.008 billion plus US$500 million upon FID of GLNG Train 2 using JV gas
Sunshine Gas/Sojitz	December 2007	0.5 Mtpa	Early 2012	30 PJ/a	Unknown	Proposed ownership 70/30 Sojitz/Sunshine for LNG plant at Fisherman's Landing Gladstone. FID intended for end 2008, with first cargoes in early 2012. Train size of 0.5 Mtpa which can be developed as modules. Proposed takeover of Sunshine Gas by QGC may result in gas being utilised by QGC for other means.
Queensland Gas Company/ BG	February 2008	3-4 Mtpa	Early 2014	170-220 PJ/a	ConocoPhillips Optimised Cascade	Final investment decision scheduled for early 2010. Initial design for 3-4 Mtpa, with potential expansion to up to 12 Mtpa subject to additional gas reserves. Estimated capital cost of $8 billion including 380km pipeline. QGC and BG Group entered into a three-part joint venture with respective ownership of 80/20 for the upstream tenements (moving to 70/30), 50/50 for the pipeline and 30/70 for the LNG plant and port assets.
LNG Impel	May 2008	0.7-1.3 Mtpa	2013	42-78 PJ/a	Unknown	To be constructed in modules of between 0.7 and 1.3 Mtpa. Site at Curtis Island has been scoped for up to 3 trains. Open-access LNG plant projects to be designed on a toll for service basis with 15 to 20 year contracts
Origin/ConocoPhillips	September 2008	3.5 Mtpa x 2	Early 2014	195 PJ/a x 2	ConocoPhillips Optimised Cascade	ConocoPhillips to invest A$9.6 billion for a 50% share in CSG to LNG project proposed for Gladstone. Plans for ultimately up to 4 x 3.5 Mtpa LNG trains. 50/50 joint venture alignment for whole project.

Data source: ACIL Tasman based on company announcements

The proposed LNG developments have the potential to influence the availability of gas for domestic use. A 4 Mtpa LNG plant would require gas supply of between 225 and 250 PJ/a (after allowing for gas used in processing and transportation). In order to provide a twenty year reserve backing, such a development would therefore require dedication of up to 5,000 PJ of proven and probable gas (2P) resources. Given the rate of reserves build up over the past five years, there is every reason to believe that significantly more CSG reserves can be established. However, it is clear that the LNG proposals have the potential to divert to exports significant quantities of gas that might otherwise be available to domestic markets. This does not necessarily mean that the domestic market will be left short of supply. However it does mean that domestic supply will have to rely on higher cost, less productive sources of CSG supply sooner than would be the case in the absence of the LNG projects, which in turn has implications for domestic gas prices.

Whether or not any of these proposals proceed to development, the fact that they offer a credible alternative market pathway for local gas suppliers means that they are already starting to impact on domestic gas prices.

4.3 Assessment of gas prices for generation

Within the draft report[5] for the calculation of the BRCI for 2009-10, CRA used gas prices based upon historic Victorian spot market outcomes for the period 2002-03 through to 2006-07. These historical prices were projected forward based on this historical trend and $0.50/GJ was added for transport costs. These prices were used for new entrant CCGT plant located in Victoria. Gas prices for other NEM regions were derived based upon the relativities between regions within the ACIL Tasman 2007 cost report for NEMMCO.

These gas prices were then used to calculate the ‘greenfield’ estimate for Queensland’s LRMC of energy for 2009-10. This involved ‘re-building’ the entire NEM’s generation capacity in a least cost framework over the period 2009-10 through to 2017-18. The results of this analysis suggested that a plant mix for Queensland in which gas-fired generation accounted for over 90% of generation was the least cost option. Although not stated within the CRA report, presumably other NEM regions also had a large proportion of electricity demand being met by gas-fired plant.

Clearly, an efficient plant mix consisting of 90% gas-fired generation is very different from the current reality and one must question the usefulness of historic gas price outcomes as an input to such a scenario. Indeed, it may be

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[5] CRA International, *Calculation of the Benchmark Retail Cost Index 2009-10*, 15th August 2008

the case that even in the long-run, Eastern Australia's gas market is simply not capable of supporting such levels of consumption.

The wholesale gas market, while illiquid and non-transparent, still behaves as a normal market in which prices are a result of the interaction of supply and demand. ACIL Tasman's view is that given the methodological framework, gas price inputs to the LRMC estimation process need to broadly reflect the level of gas consumption.

Within this report ACIL Tasman has not only provided updated gas price projections, but also attempted to construct a gas price curve for varying levels of gas consumption. The key objective for this analysis is to recognise that as gas consumption changes, so to will the prevailing price level.

Rather than create an iterative process between CRA's models and ACIL Tasman on gas consumption and price level, it was decided that price projections would be constructed over a range of consumption levels, relative to aggregate NEM demand. Annual regional gas prices were projected for the following fuel mix scenarios:

- 10% gas
- 25% gas
- 50% gas
- 75% gas
- 90% gas.

Table 41 details the estimated gas required to fuel each of the NEM regions entirely by gas-fired CCGT plant operating at 50% thermal efficiency over the period 2009-10 through to 2017-18.[6] Underlying energy for each region over this period is sourced from NEMMCO's 2008 medium economic growth sent-out energy forecast.[7]

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[6] It must be recognised that energy during peak periods is most economically met by OCGT plant which operate at significantly lower thermal efficiencies, however the simplifying assumption of 50% is used throughout.

[7] NEMMCO, 2008 Energy & Maximum Demand Projections, July 2008

Table 41 **Gas required to fuel 100% of NEM scheduled generation (PJ)**

	QLD	NSW	VIC	SA	TAS	NEM
2009-10	388	548	320	95	75	1,427
2010-11	403	549	316	95	73	1,437
2011-12	416	553	314	96	75	1,455
2012-13	428	560	307	99	76	1,470
2013-14	442	565	310	101	76	1,494
2014-15	455	568	316	104	75	1,518
2015-16	469	576	323	105	73	1,546
2016-17	484	579	330	108	74	1,574
2017-18	500	585	336	110	75	1,606

Note: Assumes all generation occurs with a sent-out thermal efficiency of 50% (7.2 GJ/MWh)

Data source: ACIL Tasman based on forecast annual energy from NEMMCO 2008 Energy & Maximum Demand Projections

Aggregate volumes required rise from over 1,400 PJ in 2009-10, up to just over 1,600 PJ by 2017-18. To put these gas volumes in context, the aggregate figure for 2009-10 of 1,427 PJ is equivalent to the feedstock requirement for approximately 26 Mtpa of LNG export capacity.

4.4 Scenario construction

In projecting gas prices available for generation, ACIL Tasman has utilised its proprietary *GasMark* model. GasMark incorporates a complete input database containing input data and assumptions for every gas producing field, transmission pipeline and major load/demand centre in Australia.

The scenario used for this exercise represents ACIL Tasman's base case view on supply and load developments throughout Eastern Australia over the period 2009-10 to 2017-18. It includes the development of two LNG export facilities of 4 Mtpa each, with assumed start-up in 2014 and 2018.

On the demand-side the scenario includes assumed growth in domestic demand, both through large industrial loads and general growth in reticulated gas to residential and commercial premises. The total assumed gas demand excluding NEM-scheduled power generation is detailed in Table 42. Aggregate growth over the period is relatively modest at around 130 PJ/a (growth rate of 2.6% per annum).

Table 42 **Gas demand excluding NEM-scheduled power generation (PJ)**

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
QLD	137.2	141.5	149.1	154.0	158.8	159.6	160.6	161.4	162.2
NSW/ACT	134.3	136.7	139.2	141.5	143.8	146.3	148.6	151.1	153.6
VIC	236.6	241.6	246.7	251.9	257.1	262.5	268.1	273.7	279.5
SA	48.4	68.6	79.7	83.8	85.0	86.1	87.6	88.8	90.0
TAS	7.4	7.6	7.7	7.8	7.9	8.0	8.1	8.2	8.3
	563.8	**596.0**	**622.3**	**638.9**	**652.6**	**662.5**	**673.0**	**683.1**	**693.6**

Note: Includes gas demand from non-NEM connected and non-NEM scheduled power generation

Data source: ACIL Tasman GasMark database

The gas demand arising from NEM-scheduled generation is varied under the scenarios as outlined in section 4.3.

The supply assumptions used for this exercise are somewhat theoretical in nature due to the ‘greenfield’ LRMC methodology as used in the calculation of the BRCI. Rather than our normal assumptions which include new supply developments occurring over time in response to market conditions, the scenario assumes all new supply developments are available from 2009-10. For example, in Victoria the offshore Kipper development which is scheduled to commence production in 2011 is assumed to be available at full capacity in July 2009. Similarly, ACIL Tasman’s assessment of the ultimate production potential from Queensland and NSW coal seam gas resources are also assumed to be available from July 2009.

In addition, transmission pipeline capacity is assumed to be infinite at the current tariffs. While ACIL Tasman generally expects pipeline augmentations to be at a higher cost relative to the original pipeline tariff (a result of the higher steel and construction costs environment which now prevails), the economies of scale derived from the larger volumes may offset this to some degree within the theoretical scenarios.

4.5 Gas price projections for CCGT plant

Table 43 through to Table 47 detail the price results from the gas market analysis. These prices can be interpreted as the LRMC of gas supply in each year given the level of gas consumption from NEM-scheduled power stations.

Prices are taken from representative nodes of the Eastern Australian gas grid, deemed most likely to support bulk gas-fired power generation. The prices therefore include applicable gas transmission tariffs.

The representative nodes selected for each NEM region are:

- Queensland: Dalby

- New South Wales: Bayswater[8]
- Victoria: Latrobe Valley
- South Australia: Adelaide
- Tasmania: Bell Bay.

For low levels of NEM-scheduled gas consumption, the reported prices are reflective of long-run supply costs from various fields throughout Eastern Australia. However, as the demand from NEM-scheduled generation increases and the available supply capacity is exhausted, prices begin to reflect price tolerances of other domestic users who have been displaced by the additional demand. In the scenarios where gas accounts for the majority of NEM generation, prices – particularly toward the end of the projection – begin to reflect full export netback parity, as the aggregate production capacity is insufficient to support both the entire NEM *and* 8 Mtpa of export capacity simultaneously.

Table 43 **Projected gas prices for Queensland (2009-10 $/GJ)**

	Proportion of NEM generation met by gas					
	0%	10%	25%	50%	75%	90%
2009-10	3.94	3.98	4.14	4.36	4.79	5.51
2010-11	4.11	4.15	4.35	4.66	5.24	5.76
2011-12	4.06	4.11	4.29	4.74	5.26	5.83
2012-13	4.02	4.07	4.25	4.73	5.50	5.95
2013-14	3.98	4.03	4.24	5.11	5.97	6.52
2014-15	3.94	4.03	4.22	5.05	5.90	6.74
2015-16	3.93	4.07	4.31	5.04	5.90	6.94
2016-17	3.93	4.12	4.30	5.29	5.90	6.98
2017-18	4.15	4.46	4.74	5.43	6.66	7.09

Data source: ACIL Tasman GasMark modelling

Figure 48 displays the projected Queensland prices in graphical form. As one would expect, the higher the proportion of gas within the NEM's fuel mix, the higher the prevailing market prices. However, within each price series there are a few general trends which require further explanation:

- The initial rise in prices from 2009-10 to 2010-11 is a result of some factoring in of the benefit derived from the commencement of the CPRS – both to suppliers and end-users
- Steady downward trend in real terms beyond this point in the 0%, 10% and 25% cases. This is a result of production costs declining in real terms
- Sharp upward movements in 2013-14 and 2017-18 in a number of series relates the commencement of the LNG production trains, which are in effect, large step changes in gas demand.

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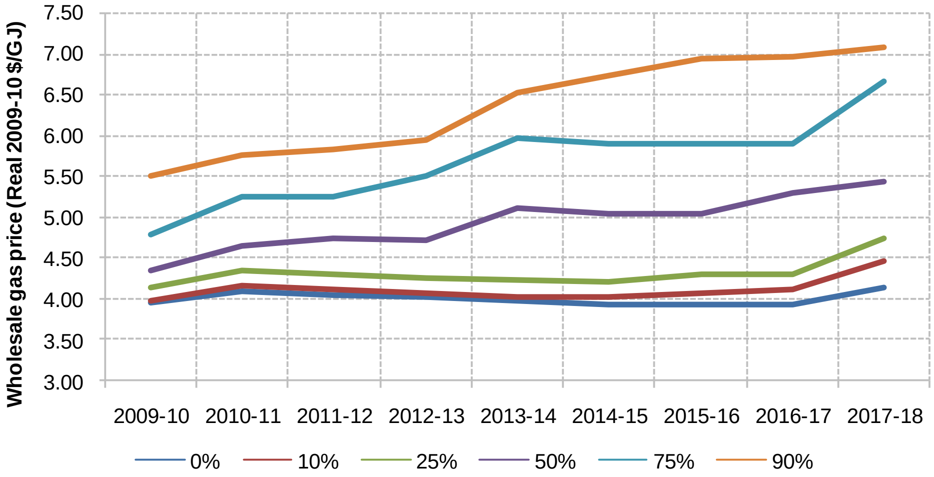
[8] Scenario assumes gas transmission infrastructure is in place to service Bayswater.

Figure 48 **Projected gas prices for Queensland at varying levels of gas in the NEM fuel mix**



Data source: ACIL Tasman GasMark modelling

Similar price paths are also seen in other NEM states (albeit starting at different price points), as detailed within Table 44 through to Table 47. For other regions, the impact of the LNG plant start-ups is a little more subtle.

Table 44 **Projected gas prices for New South Wales (2009-10 $/GJ)**

	Proportion of NEM generation met by gas					
	0%	10%	25%	50%	75%	90%
2009-10	4.53	5.15	5.27	5.32	5.72	5.99
2010-11	4.79	5.39	5.42	5.62	6.00	6.55
2011-12	4.86	5.35	5.45	5.70	6.22	6.70
2012-13	4.83	5.32	5.41	5.70	6.47	6.79
2013-14	4.78	5.28	5.49	6.10	6.80	7.37
2014-15	4.85	5.27	5.46	6.14	6.86	7.79
2015-16	5.03	5.31	5.55	6.17	7.10	7.82
2016-17	5.03	5.36	5.55	6.39	7.14	7.86
2017-18	5.03	5.95	6.16	6.79	7.90	7.90

Data source: ACIL Tasman GasMark modelling

Table 45 **Projected gas prices for Victoria (2009-10 $/GJ)**

	Proportion of NEM generation met by gas					
	0%	10%	25%	50%	75%	90%
2009-10	4.14	4.14	4.27	4.58	5.03	5.29
2010-11	4.42	4.42	4.54	4.98	5.31	5.85
2011-12	4.46	4.49	4.76	5.06	5.53	6.01
2012-13	4.50	4.53	4.80	5.13	5.78	6.11
2013-14	4.53	4.57	4.92	5.42	6.12	6.69
2014-15	4.58	4.71	4.97	5.47	6.19	7.11
2015-16	4.62	4.74	5.03	5.50	6.44	7.16
2016-17	4.65	4.78	5.08	5.72	6.48	7.19
2017-18	4.70	5.13	5.48	6.13	7.24	7.24

Data source: ACIL Tasman GasMark modelling

Table 46 **Projected gas prices for South Australia (2009-10 $/GJ)**

	Proportion of NEM generation met by gas					
	0%	10%	25%	50%	75%	90%
2009-10	4.99	4.99	4.99	5.31	5.72	5.72
2010-11	5.27	5.27	5.32	5.80	6.01	6.68
2011-12	5.30	5.30	5.58	5.88	6.26	6.83
2012-13	5.34	5.34	5.57	5.86	6.60	6.92
2013-14	5.38	5.38	5.64	6.12	6.93	7.50
2014-15	5.42	5.42	5.61	6.15	6.99	7.91
2015-16	5.45	5.45	5.69	6.20	7.23	7.95
2016-17	5.49	5.49	5.67	6.44	7.27	7.98
2017-18	5.53	5.91	6.26	6.92	8.02	8.02

Data source: ACIL Tasman GasMark modelling

Table 47 **Projected gas prices for Tasmania (2009-10 $/GJ)**

	Proportion of NEM generation met by gas					
	0%	10%	25%	50%	75%	90%
2009-10	5.01	5.01	5.13	5.45	5.90	6.16
2010-11	5.29	5.29	5.41	5.85	6.18	6.72
2011-12	5.33	5.35	5.63	5.93	6.40	6.88
2012-13	5.37	5.40	5.67	6.00	6.65	6.98
2013-14	5.40	5.44	5.79	6.29	6.99	7.56
2014-15	5.45	5.58	5.84	6.34	7.06	7.98
2015-16	5.49	5.61	5.90	6.37	7.31	8.03
2016-17	5.52	5.65	5.95	6.59	7.35	8.06
2017-18	5.57	6.00	6.35	7.00	8.11	8.11

Data source: ACIL Tasman GasMark modelling

4.6 Gas price projections for OCGT plant

Due to the relatively small volumes consumed by OCGT in an optimised system, ACIL Tasman does not think it necessary to constrain gas volumes for OCGT plant. In making this assumption, we took into account that fuel costs are generally a very small portion of the LRMC for OCGT units.

Due to their intermittent nature OCGT plant generally pay a significant premium for fuel and pipeline capacity relative to CCGT plant. Within the 2007 NEMMCO cost report, ACIL Tasman recommended that a premium of 25% over delivered CCGT costs would be sufficient to cover these additional charges. Since that time however, ACIL Tasman has taken the view that a premium of 50% may be more appropriate to reflect supply and transport cost premiums for intermittent loads.

As OCGT plants generally rely upon 'as available' pipeline capacity, this price premium can still be considered conservative. This is due to the fact that spare pipeline capacity is scarce during high electricity price periods and OCGT are usually forced on to much more expensive liquid fuels during such times.

ACIL Tasman therefore recommends the use of a 50% price premium for gas costs faced by OCGT relative to CCGT units.

5 Coal costs

Examination of the quality and location of coal resources suggests there are potentially seven areas within the NEM regions where coal resources are sufficient to support new coal fired capacity; three in Queensland, three in NSW, and one in Victoria. This is illustrated in Table 48.

Analysis revealed that in those areas where there is well developed export infrastructure, such as in the much of the Bowen Basin in Qld and the Hunter Valley in NSW, the netback export parity prices for raw thermal coal is noticeably higher than ROM mining costs in all areas. Hence these export oriented areas are not considered as potential sources of coal for local power stations. There are some deposits of lesser quality in these exporting areas (Callide in Qld and Ravensworth-Namara in NSW)but these deposits have already been heavily extracted and would not have sufficient remaining economically mineable resources to support a large new coal fired base load station.

Table 48 **Areas where economic coal fired generation is an option**

Area	Coal source	Assumed power station locations within 100km of transmission	Potential
North Qld	Northern Bowen Basin (Lake Elphinstone, Nebo West, Bee Creek, and others)	Mine mouth	Several economic coal deposits which could support further new base load generation but would compete with export rrarket
	Northern Galilee Basin (Pentland)	Via Strathmore (260km from mine)	Significant open cut resource with no export infrastructure
Central Qld	Central Bowen Basin (Minerva, Togara, Valeria, Ensham, Cullin-la-ringo, and others)	Mine mouth	A number of econonic coal deposits which could support further new base load generation but would compete with the export market
	Southern Galilee Basin (Alpha, Kevins Corner)	via Lilyvale (210km from mine)	Significant low strip-ratio resource with no coal export infrastructure
South West Qld	Surat Basin (Felton and New Acland, Kogan and Wilkie Creek in the east and around Chinchilla and Wandoan in the west and others in between)	Mine mouth for eastern deposits and via Braemar (150km from western deposits)	Extensive low cost coal reserves which could support significant additional new base load generation and only very linited export Infrastructure
Northern NSW	Gunnedah Basin (Maules Creek, Boggabri)	Mine mouth	Extensive undeveloped mainly underground thermal coal deposits with limited export infrastructure
Central NSW	Hunter and Western (Ulan, Bylong, Mooraben, Saddlers Creek and others)	Mine mouth	Many well located undeveloped coal deposits which could support additional new base load generation
South West NSW	Oaklands	Mine mouth	Large low strip ratio deposit suitable for large power station development
Latrobe Valley	Latrobe Valley	Mine mouth	Estimated useable reserve of 500,000 million tonnes which could support significant additional new base load generation

Data source: *ACIL Tasman assessment*

Table 49 identifies the potential for an economically sized base load coal fired capacity in each of the black coal areas identified in Table 48. The areas with greatest potential for additional coal fired generation are:

- South West Qld based on the extensive low cost black coal deposits in the Surat Basin
- Northern NSW based on vast unused coal resources in the largely untouched Gunnedah Basin
- and Latrobe Valley in Victoria based on an estimated 50,000 million tonnes of usable brown coal resources.

North Qld, Central Qld and Central NSW also contain large deposits of coal that could support significant coal-fired generation.

Undeveloped deposits in North SA around Leigh Creek and central Eyre Peninsula, because of their location, quality and mineability, are regarded as non-economic as a fuel source for a new base load station in the NEM.

Table 49 shows the most likely coal deposits which could economically supply coal to a major base load generator and the potential capacity which could potentially be supported.

Table 49 **A selection of potential coal deposits suitable for large scale base load generation**

Area	Deposit	Location	Resource (Mt)	Estimated future exports	Specific energy (GJ/t as)[1]	Resource available to power station (PJ)	Strip ratio (bcm:ROMt)	Mining method	Approximate potential MW supported [2]
North Qld	Pentland[3]	220km SW Townsville	645	0	18.0	11610	4.7	OC	4000
Central Qld	Alpha	55km N Alpha	665	0	25.7	17100	2.6	OC	6000
	Kevins Corner[3]	70km N Alpha	910	0	24.8	22612	4.2	OC	7000
South West Qld	Felton[3]	40km SW Toowoomba	1090	0	15.5	16910	3.4	OC	5000
	Existing Surat mines	NW to SW of Toowoomba	1500	200	19.0	24700	2.5	OC	7000
	Horse Creek[3]	25km N Chinchilla	295	100	24.6	4797	7.7	OC	1000
	Wandoan[3,4]	60km N Miles	1893	600	20.5	26443	4.1	OC	9000
North NSW	Maules Creek	20km NE Boggabri	520	200	27.9	8928	na	OC	3000
	Boggabri	17km NE Boggabri	576	200	28.3	10641	na	OC & UG	3000
	Caroona	256km S Gunnedah	930	500	27.6	11868	na	OC & UG	4000
	Narabri	SW Narrabri	1205	500	27.9	19670	na	UG	6000
Central NSW	Moorlarben	45km NE Mudgee	453	250	23.0	4669	na	OC & UG	1000
	Ulan	40km NE Mudgee	847	250	23.0	13731	na	OC & UG	4000
South West NSW	Oaklands	100km W Albury	880	0	17.5	15400	4.0	OC	5000

Notes: SE (a.s.) = specific energy (as supplied); ROM = 'Run of mine' (raw)

1. SE (a.s.) = specific energy (as supplied); ROM = 'Run of mine' (raw)
2. Based on power station life of 40 years @ 85% CF and 9.5GJ/MWh
3. Resource based on "Measured" + "Indicated"
4. Austinvale, Woleebee and Summer Hill (640Mt) - additional 165Mt for Frank Creek, Wubagul and Glen Laurel

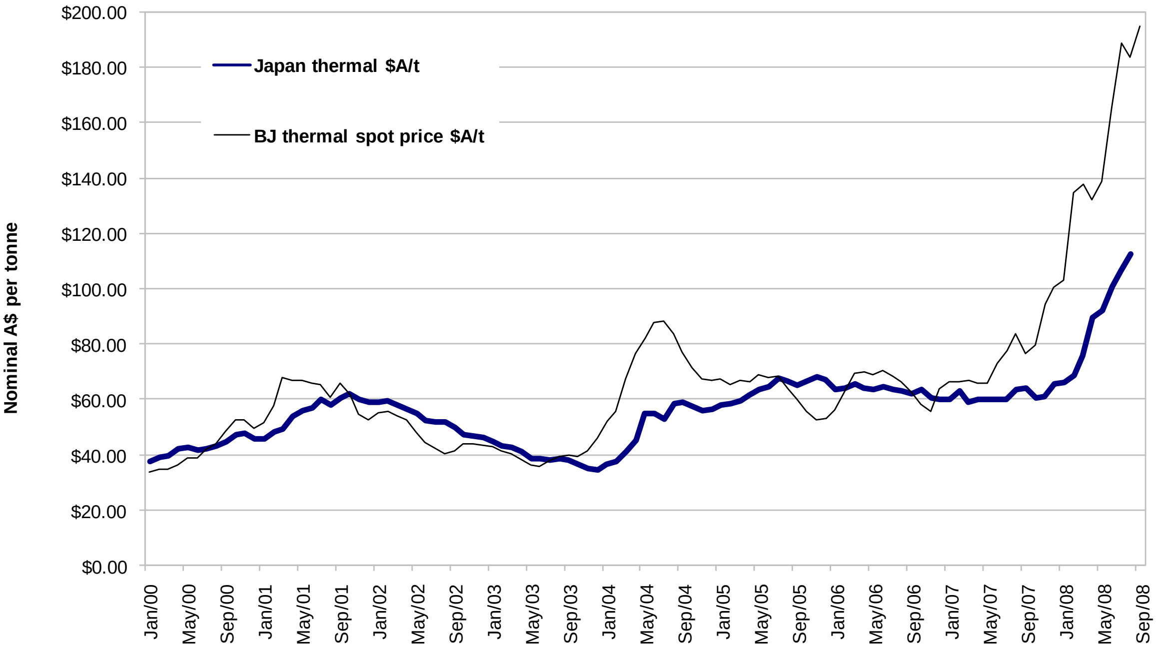
Data sources: *Queensland Coals 13th edition, 2005 NSW Coal Profile and ACIL Tasman assessment*

5.1 Projection of export prices for thermal coal

The FOB price for thermal coal is an important consideration in the price formation for new coal fired generation in QLD and NSW. It is the projection of these prices which underlies the future export parity value of the ROM coal at each location which in some cases sets the delivered price into local power stations using that coal.

Thermal coal spot and contract prices have increased markedly in the past twelve months as shown in Figure 49. ACIL Tasman predicts that the price will abate in the coming one to two years as new mines are brought into production and export infrastructure bottle necks are eased.

Figure 49: **Spot and contract prices for thermal coal exports (nominal A$/t)**



Data source: Australian Coal Report

Projecting thermal coal export prices, particularly in the current volatile world economic environment is necessarily subject to a great deal of uncertainty. The future price trend is dependent on many factors including *inter alia*:

- Demand and supply balance in the coal market;
- World economic growth;
- Cost of coal of production;
- Price and availability of substitutes such as oil and gas;
- Technology changes in coal usage;
- Environmental policies potentially affecting coal usage; and
- Increasing low cost production, including that from Australia, China and Indonesia.

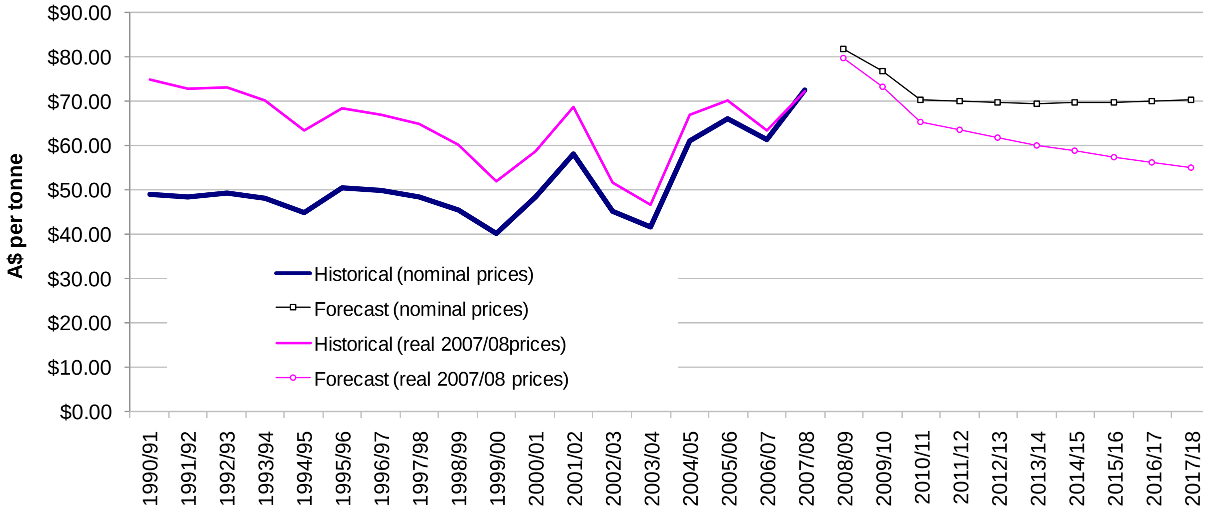
ACIL Tasman expects that the past trends of gradually declining nominal coal prices and declining real prices in A$ are likely to continue. Initially, with the time required to bring on new production and to ease infrastructure bottlenecks, coal prices are expected to remain strong for one to two years. However in the longer term as supply and demand move towards balance ACIL Tasman predicts that thermal coal export prices will return to a trend of real price reductions. Additional pressure on export coal prices would occur with the widespread introduction of carbon trading where coal is disadvantaged against other fuel options including gas and renewable sources.

An ongoing gradual decline in real coal prices can be expected on the basis of:

- On-going real reduction in production costs due to:
  - Continued technological improvements
  - Improving economies of scale
  - On-going development of new lower cost developments
  - Continued availability of low cost resources over the period of interest.
- Subdued growth in demand for thermal coal because of:
  - Increased use of alternative fuels including renewable
  - Reducing energy intensity in industry due to innovation and cleverer use of material inputs
  - Technology developments in coal usage
  - Electricity demand management
  - Widespread introduction of emissions trading.

The ACIL Tasman expectation of annual coal prices in nominal and real terms is illustrated in Figure 50.

Figure 50 **Forecast of average annual export thermal coal prices (A$/tonne FOB in nominal and real 2007/08 prices)**



Data source: AT analysis based on in-house information

5.2 Projected delivered coal prices to new power stations

The approximate delivered coal prices in each of seven areas and in the Latrobe Valley are presented in Table 50 (nominal prices) and Table 51 (real 2009/10 prices). The delivered coal prices are as projected for each year and have not been levelised over power station life.

The delivered coal prices shown in Table 50 and Table 51. The coal prices depend upon whether the coal can be exported and whether the power station is located as a mine mouth or remote from the mine from which it is supplied. Where coal is exportable, we assume that the power station would receive a 20% discount over the export parity value of the coal mined to the ROM. Hence the coal prices are one of the following.

- **ROM coal mining costs** where 80% of the export parity value of the ROM coal is less than the mining costs and the coal is delivered to a mine-mouth power station – this usually applies to deposits which are relatively inferior in quality and/or some distance from export terminals while being relatively close to major transmission links (Felton, New Acland, Ulan etc)
- **ROM coal mining costs plus transport costs** to a power station site remote from the mine but closer to transmission infrastructure and where 80% export parity value of the ROM coal is again less than the mining costs but where the deposit is greater than 100km from the transmission system (Wandoan, Alpha, Pentland)
- **80% of the export parity value of the ROM coal** where it is greater than the ROM coal mining cost - this generally applies to deposits which are higher quality coal and/or are generally closer to the export terminals.

The delivered prices can switch from one basis to another as export prices and ROM coal mining costs vary. This is particularly the case as export prices are projected to fall in real terms while mining costs are projected to remain constant in real terms. CPI is projected at 2.5%.

Based on a high level assessment of the potential coal resources and associated mining costs, and using industry knowledge and deposit information, the projected nominal delivered costs of coal to new power stations are shown in Table 50 with the real costs in $2009/10 shown in Table 51.

Table 50 **Projection of delivered coal prices for selected coal mines (nominal $/GJ)**

Area	Deposit	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Approximate potential MW supported
North Qld	Pentland	$1.73	$1.77	$1.82	$1.86	$1.91	$1.96	$2.00	$2.05	$2.10	4000
Central Qld	Alpha	$1.14	$1.17	$1.19	$1.22	$1.25	$1.28	$1.32	$1.35	$1.38	6000
	Kevins Corner	$1.29	$1.32	$1.35	$1.39	$1.42	$1.45	$1.49	$1.53	$1.56	7000
South West Qld	Felton	$1.22	$1.25	$1.28	$1.31	$1.35	$1.38	$1.41	$1.45	$1.49	5000
	Existing mines Surat	$0.93	$0.89	$0.92	$0.94	$0.96	$0.99	$1.01	$1.04	$1.06	7000
	Horse Creek	$1.06	$1.09	$1.12	$1.14	$1.17	$1.20	$1.23	$1.26	$1.30	1000
	Wandoan	$1.48	$1.52	$1.55	$1.59	$1.63	$1.67	$1.71	$1.75	$1.80	9000
North NSW	Maules Creek	$1.27	$1.22	$1.20	$1.18	$1.17	$1.16	$1.15	$1.13	$1.12	3000
	Boggabri	$1.31	$1.27	$1.24	$1.22	$1.21	$1.20	$1.19	$1.18	$1.17	3000
	Caroona	$1.34	$1.29	$1.27	$1.25	$1.24	$1.23	$1.22	$1.21	$1.20	4000
	Narabri	$1.22	$1.17	$1.15	$1.12	$1.11	$1.10	$1.13	$1.15	$1.18	6000
Central NSW	Moorlarben	$1.29	$1.25	$1.23	$1.21	$1.20	$1.19	$1.18	$1.17	$1.16	1000
	Ulan	$1.27	$1.22	$1.20	$1.18	$1.17	$1.16	$1.16	$1.15	$1.13	4000
South West NSW	Oaklands	$1.00	$1.02	$1.05	$1.07	$1.10	$1.13	$1.15	$1.18	$1.21	5000
Victoria	Latrobe Valley	$0.57	$0.58	$0.60	$0.61	$0.62	$0.64	$0.65	$0.67	$0.68	>10000

Data source: ACIL Tasman analysis

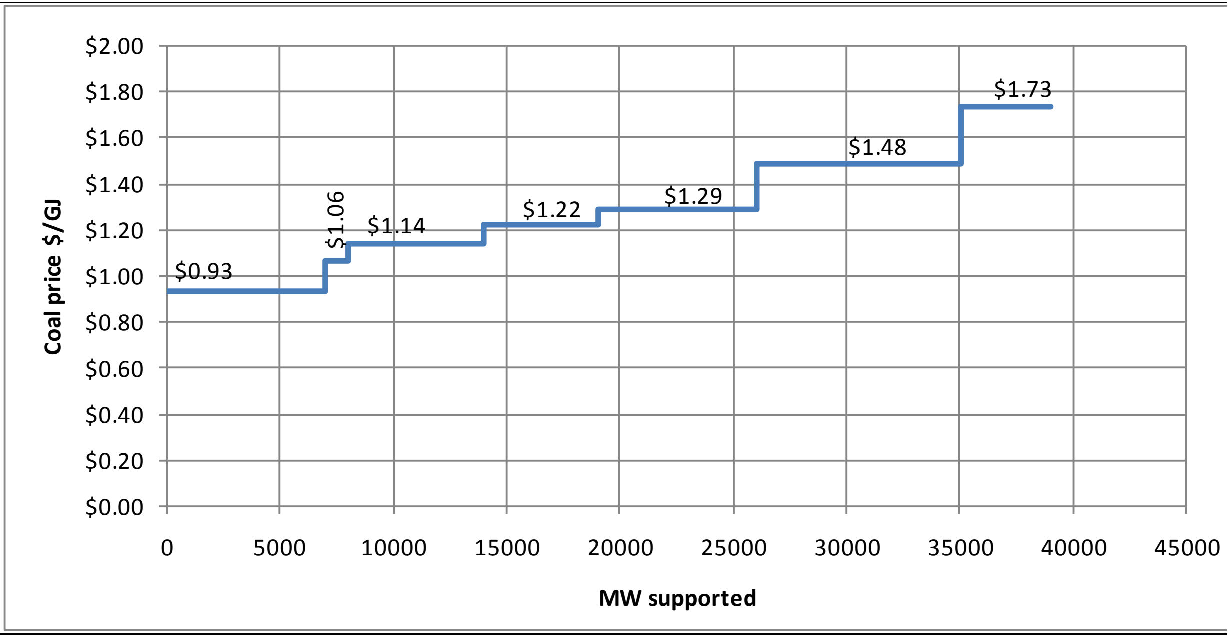
Table 51 **Projection of delivered coal prices for selected coal mines (real 2009/10 $/GJ)**

Area	Deposit	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Approximate potential MW supported
North Qld	Pentland	$1.73	$1.73	$1.73	$1.73	$1.73	$1.73	$1.73	$1.73	$1.73	4000
Central Qld	Alpha	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.13	$1.13	$1.13	6000
	Kevins Corner	$1.29	$1.29	$1.29	$1.29	$1.29	$1.29	$1.28	$1.28	$1.28	7000
South West Qld	Felton	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	5000
	Existing mines Surat	$0.93	$0.87	$0.87	$0.87	$0.87	$0.87	$0.87	$0.87	$0.87	7000
	Horse Creek	$1.06	$1.06	$1.06	$1.06	$1.06	$1.06	$1.06	$1.06	$1.06	1000
	Wandoan	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	$1.48	9000
North NSW	Maules Creek	$1.27	$1.19	$1.14	$1.09	$1.06	$1.02	$0.99	$0.95	$0.92	3000
	Boggabri	$1.31	$1.23	$1.18	$1.13	$1.10	$1.06	$1.03	$0.99	$0.96	3000
	Caroona	$1.34	$1.26	$1.21	$1.16	$1.13	$1.09	$1.06	$1.02	$0.99	4000
	Narabri	$1.22	$1.14	$1.09	$1.04	$1.01	$0.97	$0.97	$0.97	$0.97	6000
Central NSW	Moorlarben	$1.29	$1.22	$1.17	$1.12	$1.09	$1.05	$1.02	$0.99	$0.96	1000
	Ulan	$1.27	$1.19	$1.14	$1.10	$1.06	$1.03	$1.00	$0.96	$0.93	4000
South West NSW	Oaklands	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	5000
Victoria	Latrobe Valley	$0.57	$0.57	$0.57	$0.57	$0.57	$0.56	$0.56	$0.56	$0.56	>10000

Data source: ACIL Tasman analysis

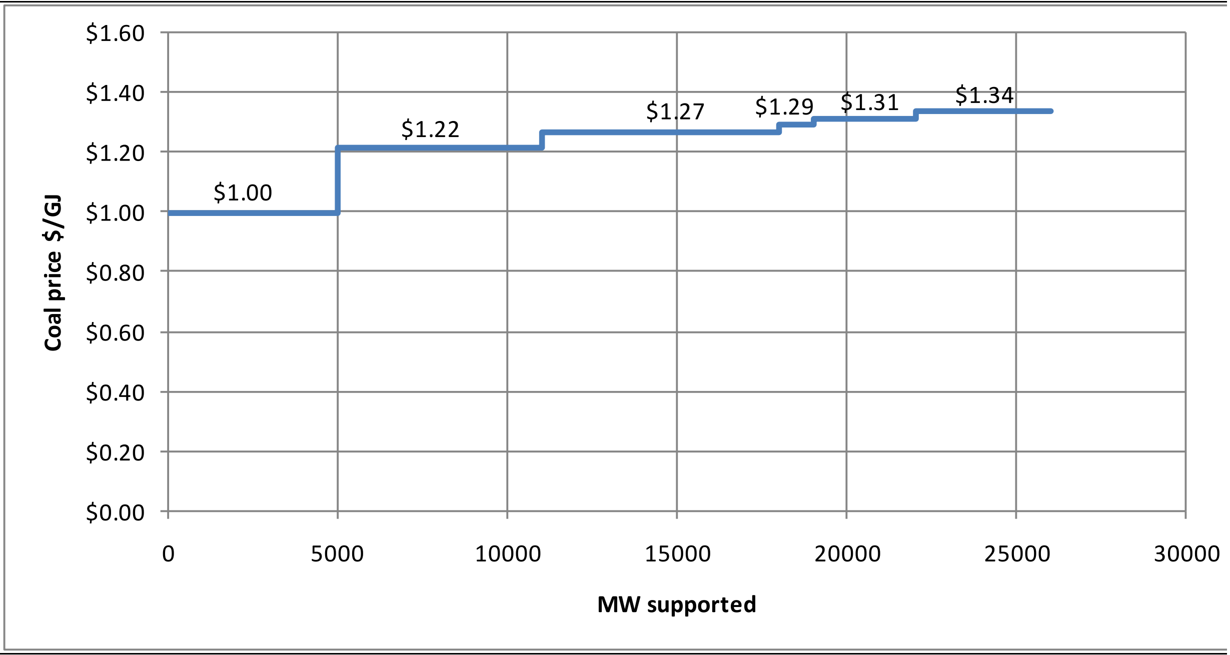
Based on the data provided in Table 50 and Table 51, the coal prices and potential plant capacity for 2009/10 for Qld and NSW are shown in Figure 51and Figure 52.

Figure 51 **Coal prices and potential MW for Qld in 2009/10 ($/GJ)**



Data source: ACIL Tasman analysis

Figure 52 **Coal prices and potential MW for NSW in 2009/10 ($/GJ)**



Data source: ACIL Tasman analysis

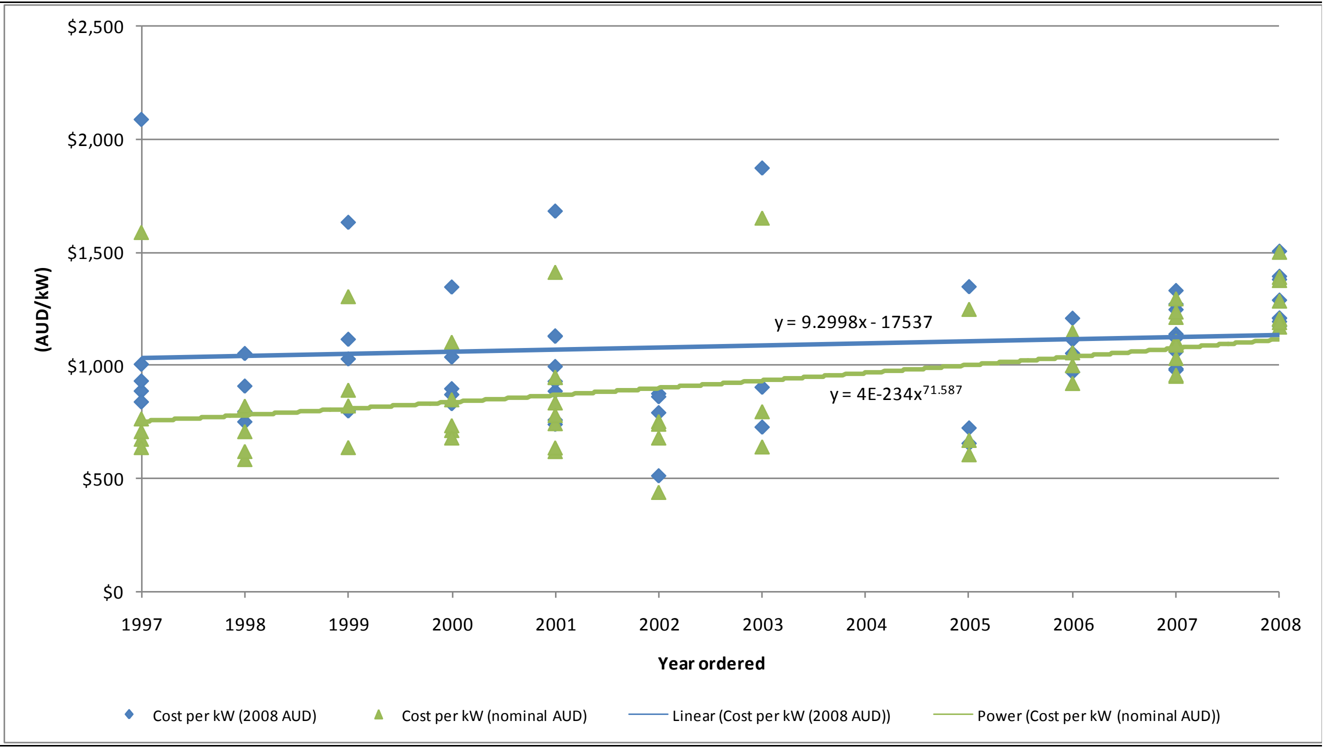
A Capital cost regression analysis

In past analysis, ACIL Tasman has used regression equations to project plant capital costs. As noted in the report, capital costs have experienced step like changes in the last two years which means that the use of regressions are not suitable to project forward prices. However for completeness we have included the regressions for coal and CCGT capital costs in Figure A1 and Figure A2 below.

Based on the linear trendline function the CCGT costs for 2010 (in real 2008 dollars) would be $1,156/kW. Inflating this value by two years at the assumed long-run CPI of 2.5% yields a price of $1,214/kW in 2010 dollars for CCGT.

Our estimate for comparison used in the report is $1,200/kW (in real 2008 dollars).

Figure A1 **Historical project capital costs ($/kW) for new build CCGT by year of project**

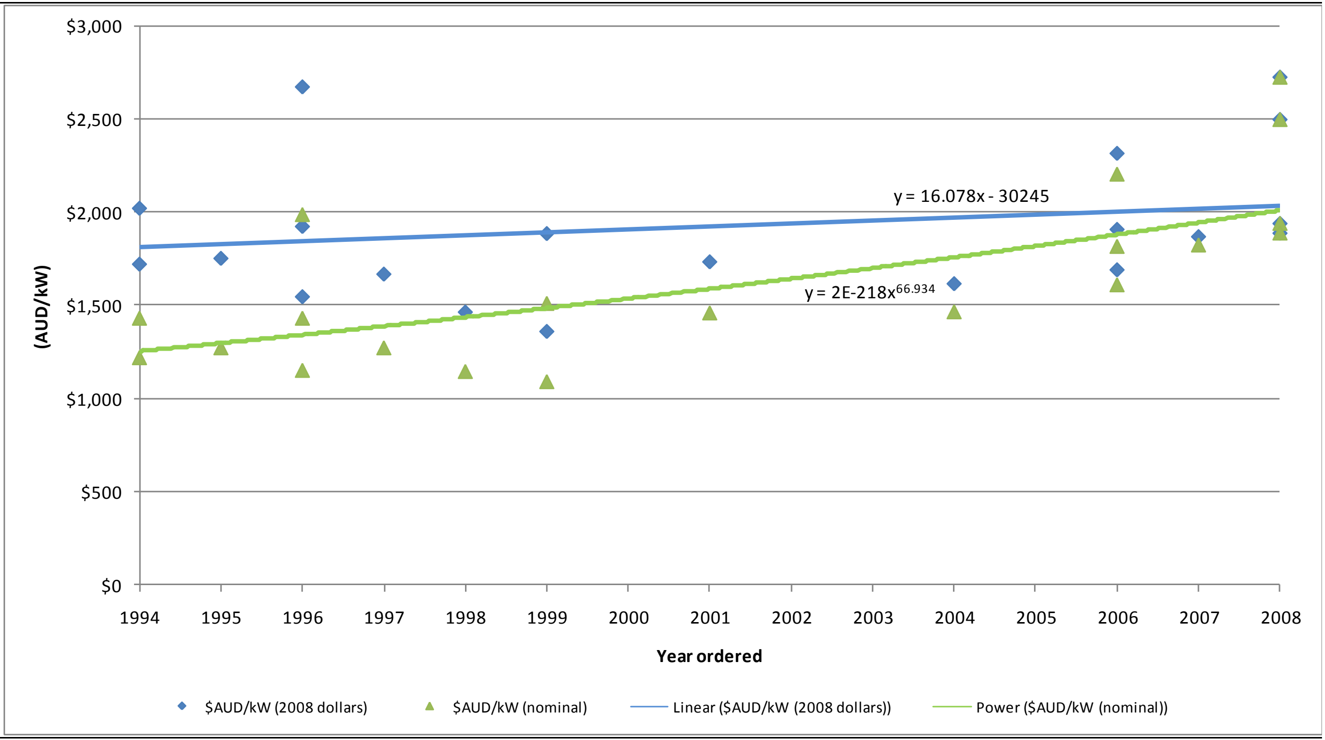


Data source: ACIL Tasman analysis of data from http://www.power-technology.com/projects/#top and various generator company websites

Based on the linear trendline function the coal-fired power station costs for 2010 (in real 2008 dollars) would be $2,072/kW. Inflating this value by two years at the assumed long-run CPI of 2.5% yields a price of $2,177/kW in 2010 dollars for coal-fired plant.

Our estimate for comparison used in the report $2,200/kW (in real 2008 dollars)

Figure A2 **Historical project capital costs ($/kW) for new build coal-fired power station by project year**



Note: Estimates exclude mine development costs

Data source: ACIL Tasman analysis of data from http://www.power-technology.com/projects/#top and various generator company websites