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Economic assessment of combined cycle gas turbines in Australia

Some effects of microeconomic reform and technological change

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Australian electricity markets and natural gas markets are undergoing rapid reform. Choosing among electricity generation modes is a key issue. Such choices are affected by expectations about the future structure of these markets and future technologies, and how they affect costs and emissions. In the research reported in this paper, the MARKAL model of the Australian energy system is used to evaluate the competitive position of natural gas fired combined cycle gas turbines (CCGTs) in the energy sector as a whole. Competing in the sector are large scale electricity generation technologies such as refurbished existing coal fired stations and advanced forms of coal fired generation. The modeling incorporates new data on electricity supply technologies and options. Least cost configurations of the energy system that would be required to abate energy sector greenhouse gas emissions are not considered in the paper. However, some directions in establishing a baseline for such an analysis are implied.

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Introduction

A major issue for investment decision makers in the Australian electricity supply industry is the choice between large scale technologies in base load generation — specifically, that between coal fired steam turbines and gas fired combined cycle gas turbines (CCGTs). A similar choice arises in many other countries that have significant sunk costs in coal fired capacity but have natural gas available for use in the CCGT technology.

At least three key sets of factors are involved in the choice: the influence of energy market reform, differential rates of technological change and greenhouse gas emissions abatement (especially carbon dioxide emissions). The focus in this paper is on the first and second of these themes. The potentially important role of CCGTs in reducing energy sector carbon dioxide emissions by displacing coal fired base load electricity generation is not covered in the analysis but information that is useful in establishing a baseline for such analyses is provided.

The organisation of the paper is as follows. Background information on the choice between coal and CCGT technologies, noting some similarities and some differences between the Australian context and recent international experience, is provided first.

The MARKAL modeling approach is then introduced. It is used to make economic assessments of technologies in a least cost, energy sectorwide context. That analytical approach is briefly prefaced by a consideration of simpler 'technology by technology' comparative approaches. These are not capable of representing important market based interactions that can be modeled in MARKAL.

The energy sector context is reviewed in the third section. Equally relevant are technological progress and deregulation of the electricity and gas sectors, referred to here as 'energy sector microeconomic reform'. It turns out that each of these two sets of factors has both positive and negative effects on the prospects of CCGTs relative to coal fired capacity. The model based analysis, including discussion and evaluation of the results, is then presented.

In the final section, a summary of the modeled effects of technological change and microeconomic reform on the cost effectiveness of CCGTs is provided. The conclusion is not clear cut. Regional variation aside, the CCGT share of electricity output at the national aggregate level by 2030 can vary between 5 per cent and 46 per cent in scenarios not including a carbon dioxide constraint. Perhaps one of the more plausible scenarios has the share of electricity output at 10 per cent attributable to CCGT alone and 18 per cent to both CCGT and OCGT (open cycle gas turbines) together. The assumptions underlying these scenarios are clarified in the paper.

Background on the choice between coal fired and CCGT technologies internationally

Coal fired capacity has retained its position as the major source of electricity generation internationally, being remarkably stable at around 38 per cent since at least 1975. The International Energy Agency projects that this share will be maintained to 2010, with strong growth expected in countries such as India and China (IEA 1998, p. 79; table 1).

The oil based share of generation has continued the decline that was initiated by the oil shocks of the 1970s. While nuclear based output increased significantly in the 1980s, its share seems now to have peaked following the few, but serious, 'safety shocks' that have precluded new capacity in many countries. Expansion of nuclear capacity, a capital intensive technology, is also not favored by the higher required rates of return in restructured and privatised electricity sectors.

The gas based share has increased by 2.5 percentage points since 1975 to reach around 15 per cent. Factors favoring an accelerating increase in the gas based share have included greatly expanded natural gas reserves and pipeline delivery systems around the world.

Policy perceptions also changed during the late 1980s and 1990s. Natural gas now appears not to be (as hitherto thought) a scarce 'premium' fuel subject to supply security risks. Rather, it is now viewed as a moderately low cost, plentiful and generally secure fuel that is also cleaner than coal in terms of both local air pollution as well as carbon dioxide emissions. Accordingly, the IEA projects continued strong growth in its share, overtaking hydro and nuclear power to take second place to coal based electricity by 2010.

The natural gas fired CCGT technology is a relatively recent entrant. In 1995, CCGT capacity was only 4 per cent of the grand total capacity of all types (Claeson 1999). At that time, the technology was thought to be enjoying rapid progress whereas the coal fired

Table 1: **Electricity generation: output shares, by fuel type**

	World						Australia					
	1975	**1980**	**1985**	**1990**	**1995**	**2010**	**1975**	**1980**	**1985**	**1990**	**1995**	**2010**
	%	%	%	%	%	%	%	%	%	%	%	%
Coal	36.7	38.1	38.9	38.2	37.8	38.2	68.8	73.3	74.7	77.1	77.1	77.3
Oil	22.2	19.7	12.1	11.3	9.6	8.0	6.6	5.4	3.9	2.7	1.7	1.4
Natural gas	12.3	12.0	12.7	13.8	14.8	24.3	4.0	7.3	9.6	10.6	10.3	12.2
Nuclear	5.9	8.6	15.2	17.0	17.6	12.3	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	22.3	20.9	20.3	18.3	18.8	16.5	20.0	13.6	11.4	9.2	9.2	7.0
Other renewables	0.7	0.7	0.8	1.5	1.4	0.7	0.7	0.4	0.4	0.4	1.7	2.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: IEA (1998).

option was perceived to be mature. The worldwide trend to private sector involvement in electricity supply associated with market reforms was also expected to favor the less capital intensive and more ‘modular’ CCGT technology.

There were indeed some major instances in which new CCGTs displaced new coal capacity — notably in the United Kingdom’s ‘dash for gas’ of the early 1990s and in the unified Germany. However, there has been something of a reappraisal recently, suggesting that these two particular cases are not necessarily a guide to a general trend, at least for generation shares. Both of these instances involved high coal prices, substantial increases in gas availability and the aging of coal fired capacity. The option of refurbishment was not considered favorably at the time.

In the United States, despite the removal in 1990 of legislative bars on the use of natural gas in electricity generation and gas’s low delivered cost from a deregulated and highly integrated national pipeline system, there has been an expansion in the share of coal fired generation from existing capacity. This has occurred despite CCGT’s dominance of the new capacity that has been committed (Ellerman 1997).

Historically, Australian electricity generation has been dominated by low cost coal with a low content of sulfur and other pollutants. Coal (black, sub-bituminous and brown) currently accounts for 87 per cent of fossil fuel based electricity generation in Australia. Plentiful supplies of natural gas are available but no new CCGTs were commissioned in the 1990s and only two, or possibly now three, are committed as at 2000. On the other hand, significant new coal fired capacity has recently been committed in Queensland in the face of a strong prospect of major pipelined natural gas imported from Papua New Guinea requiring major loads to be viable.

Approaches to economic assessment of technologies

Results of the economic assessment of technologies (as projects) are often expressed using summary indicators such as net present values (NPVs) or unit output costs (long run average costs).

As an example of the latter, table 2 contains calculations based largely on data provided by ABARE’s consultant on fossil fuel technologies (Sinclair Knight Merz 2000). It incorporates a comparison of CCGTs and both new and refurbished coal fired capacity (under New South Wales cost assumptions but also including Victorian brown coal). The summarised comparison is expressed in terms of unit output costs ($ / MWh or $ / PJ). These unit costs incorporate a capital charge calculated to cover real interest charges (at a real rate of 8 per cent a year) and assuming repayment of capital in equal annual instalments over the designated lifetime of each type of power station.

Table 2: **Unit costs for base load electricity generation capacity: coal fired capacity versus natural gas fired combined cycle gas turbines (CCGT) a**

		Conventional brown coal (Victoria)		Conventional black coal (NSW) b		CCGT: standard, technical progress			CCGT: cost premium, high efficiency, technical progress c		
		Refur-bished	New	Refur-bished	New						
Earliest start year		2005	2010	2005	2010	2005	2010	2020	2005	2010	2020
Life	yrs	15	40	15	40	25	25	25	25	25	25
Construction period	yrs	2.0	4.0	2.0	3.5	1.3	1.3	1.3	1.3	1.3	1.3
Energy efficiency	%	23.8	27.8	35.3	38.0	40.0	45.0	52.1	41.0	46.1	52.9
CO_2 coefficient (contained carbon)	t/GJe	0.109	0.094	0.071	0.066	0.038	0.033	0.029	0.037	0.033	0.028
Fuel cost											
– case 1 **d**	$ / GJ	0.64	0.64	1.78	1.66	3.1	3.1	3.1	3.1	3.1	3.1
– case 2 **d**	$ / GJ	1.00	1.00	1.78	1.66	4.0	4.0	4.0	4.0	4.0	4.0
Capital cost											
– excluding interest during construction	$ / kW	600	2000	600	1199	750	750	750	765	765	765
– including interest during construction	$ / kW	674	2433	674	1430	821	821	821	837	837	837
Operating cost											
– variable	$ / GJ	0.73	0.67	0.61	0.56	0.79	0.79	0.79	0.83	0.83	0.83
– fixed	$ / kW	21.6	18.0	18.0	15.0	10.6	10.6	10.6	11.13	11.13	11.13
Annual capital charge **e**	$ / MWh	10.0	25.9	10.0	15.2	9.8	9.8	9.8	10.0	10.0	10.0
Operating cost											
– variable	$ / MWh	2.6	2.4	2.2	2.0	2.8	2.8	2.8	3.0	3.0	3.0
– fixed	$ / MWh	2.7	2.3	2.3	1.9	1.3	1.3	1.3	1.4	1.4	1.4
Case 1											
Delivered fuel cost	$ / MWh	9.7	8.3	18.1	15.7	27.9	24.8	21.4	27.2	24.2	21.1
Total unit cost	$ / MWh	25.1	38.9	32.6	34.9	41.8	38.7	35.4	41.6	38.6	35.4
Total unit cost	$ / GJ	7.0	10.8	9.0	9.7	11.6	10.8	9.8	11.5	10.7	9.8
	index **f**	*0.72*	*1.12*	*0.93*	*1.00*	*1.2*	*1.11*	*1.01*	*1.19*	*1.11*	*1.02*
Case 2											
Delivered fuel cost	$ / MWh	15.3	13.1	18.1	15.7	36.0	32.0	27.6	35.1	31.2	27.2
Total unit cost	$ / MWh	30.6	43.7	32.6	34.9	49.9	45.9	41.6	49.5	45.6	41.6
Total unit cost	$ / GJ	8.5	12.1	9.0	9.7	13.9	12.8	11.6	13.7	12.7	11.5
	index **f**	*0.88*	*1.25*	*0.93*	*1.00*	*1.43*	*1.32*	*1.19*	*1.42*	*1.31*	*1.19*

a Illustrative data for New South Wales, except for Victorian brown coal: MARKAL database revised on advice from Sinclair Knight Merz. **b** The Australian MARKAL database also contains Sinclair Knight Merz supplied data for supercritical conventional coal fired capacity and two forms of advanced coal fired generation capacity (IGCC and PFB). **c** The assumption here is that an additional investment cost premium of 2 per cent (and higher operation and maintenance costs) delivers a 0.8–1.0 percentage point improvement in efficiency. **d** Data from ABARE sources, not Sinclair Knight Merz. **e** Calculated assuming an availability factor of 0.90 and that capacity is operated up to the limit indicated by the availability factor — that is, the capacity factor is equal to the availability factor; a real interest rate of 8 per cent and an equal annual annuity to amortise the project over its defined life.
f Relative to New South Wales conventional coal new standard.

However, the rigorous economic assessment of applied technologies often requires that they be analysed in the context of larger market systems. This is so, for example, if these technologies or projects can play a large part within these systems, implying significant market interactions. An example is the case of an expanding energy technology using a fuel in short supply where the rate of its expansion may be limited by consequent increases in the price of that energy input. Other important trends may be determined systemwide — for example, rates of capacity utilisation over the life of a project. Fuels such as natural gas can be both an input to generation of electricity and its competitor in many end uses. For these sorts of reasons, a least cost energy systemwide analysis provides a more robust economic assessment of technologies such as CCGT and its competitors.

Extension of the analysis to include the energy market context requires a model incorporating a simulation of relevant markets, technologies and energy flows. MARKAL, the framework used here, was originally developed by the International Energy Agency for economic assessments of technologies in national energy systems (Fishbone and Abilock 1981). At that time (the early 1980s) the main focus was on technologies likely to be favored by then current expectations of continuing high and rising real prices for crude oil. More recently the focus has been on analysis of the consequences of least cost abatement of greenhouse gas emissions.

The MARKAL modeling approach

The MARKAL model involves an intertemporal, linear programming approach adapted to the major features of national energy systems. Its data structure is shown in the Australian MARKAL version illustrated schematically in figure 1. There are four blocks of technologies:

(1) energy imports and resources such as coal mines and gas extraction;

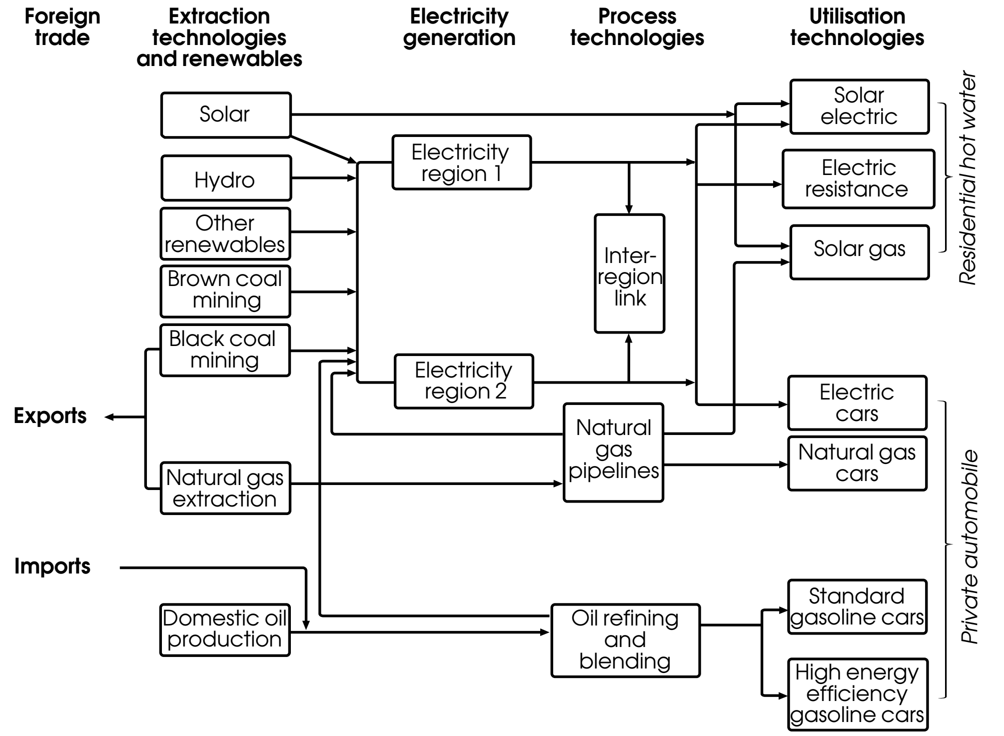
(2) electricity generation and transmission;

(3) other process technologies, including oil refining and various forms of energy transport — for example, gas pipelines; and

(4) utilisation technologies competing to meet the levels of consumption of energy services (‘energy services’ are the outputs of ‘demand devices’: for example, billion kilometres a year of road passenger transport provided by various sorts of cars and buses represented in the database; lighting; space heating; airconditioning etc.) The forecasts of energy services are exogenously given and hence the model is sometimes described as ‘demand driven’.

The nodes in this ‘reference energy system’ (generally ‘technologies’) are all connected by flows of ‘energy carriers’ (a generic term including primary energy forms and secondary energy forms such as electricity).

Figure 1: **Schematic representation of energy system in Australian MARKAL**



* Australian MARKAL was formerly known as 'MENSA' (Stocks and Musgrove 1984). However, it now seems appropriate to revert to the original, generic and internationally recognisable terminology.

In the standard version of MARKAL used in this analysis, markets are simulated by minimising an objective function incorporating the costs of energy technologies and resources. The cost related parameters for each technology include unit investment costs (for example, $/kW), constant and variable operation and maintenance costs, and fuel delivery costs. Decision variables include capacity (GW or PJa), activity (PJ output which, for electricity, is defined for separate seasonal and diurnal periods). There are many other specific parameters, including emission coefficients (for example, carbon dioxide emissions per unit output) for each technology.

The objective function to be minimised is discounted over time at a rate chosen by the user and, for Australian MARKAL, this has been a value of 8 per cent in real terms. The process modeled has been described as representing an assumption of 'perfect foresight' in the sense that actions, such as investment decisions, taken early in the period are determined simultaneously with later systemwide consequences.

MARKAL is a deterministic model in the sense that the variables (as in a standard NPV calculation) are not stochastic. However, this does not remove scope for using MARKAL to model the consequences of risk or uncertainty in investment decisions. This can be represented by technology specific 'hurdle' rates of return, where these rates include an additional risk premium. This is analogous to the modeling choice described by Johnson (1994) where he contrasts a standard deterministic NPV calculation (where the discount rate can include a risk premium) with a stochastic NPV calculation that includes uncertainty bands, or measures of dispersion, in the cash flows themselves. In the latter case, he argues that the discount rate should be reduced to avoid any double counting of risks represented in this way. Technology specific hurdle rates form a key part of the model based analysis in this paper.

Australian MARKAL incorporates a subnational regional structure (Stocks and Musgrove 1984). This structure allows representation of many regional or state specific features on the supply and consumption sides, together with interstate electricity transmission and natural gas pipelines. A review of Australian MARKAL's development and research applications by ABARE since 1991 is available in Matthewson, Naughten, Jacobs, Noble and Tulpulé (1998).

Impact of microeconomic reform and technological change on the choice of CCGT versus coal fired capacity

A number of factors identified below as important influences on this investment choice involve both microeconomic reform ('structural change') in the electricity and natural gas sectors and expected future technological trends in both types of electricity generation. It is not always easy to disentangle these influences. For example, technological change might be partially induced by microeconomic reform, by reducing 'X-inefficiency' (Stiglitz 1994). The original assessment (and subsequent critiques) of the benefits of microeconomic reform to the electricity industry in Australia assumed that these benefits result largely from such a reduction in X-inefficiency and then determined the economywide effects using a general equilibrium model of the Australian economy (Hilmer, Rayner and Taperell 1993; Quiggin 1997; Whiteman 1999).

Emphasis on industry based research and development may, in some cases, have been more prominent within the sector prior to microeconomic reform, and especially prior to privatisation where that has occurred. However, as pointed out by Button and Weyman-Jones (1992) in their discussion of 'X-inefficiency' and deregulation, in-house research and development can be become an end in itself and, at worst, can distort investment decisions:

> 'The emphasis of regulation (in Great Britain) has moved from the confiscation of profits for allocative efficiency reasons to maximising the incentive to reduce costs. The immediate consequences have been substantial reductions in labour input used and, in the case of electricity, a switch from high profile and complex capital-intensive technologies like nuclear power, which offer status and prestige to the industry's engineering management, to small-scale, low-capital-cost technologies such as gas turbines.'

Several mechanisms associated with energy sector microeconomic reform have been postulated as leading to increased use of natural gas in electricity generation in general, and through CCGT capacity in particular (Ellerman 1996; Eklund 1996; Söderholm 1996).

Aspects of microeconomic reform apparently favoring CCGT based electricity generation

At least two consequences of energy sector microeconomic reform have been expected to favor CCGTs. Other aspects, to do with competitive access to the grid system, are expected to favor the use of gas in 'embedded' industrial cogeneration (Naughten and Dlugosz 1997). These two mechanisms are, first, higher real rates of return subsequently required by investors in some forms of electricity generation and, second, the appearance of increasingly competitive and integrated gas markets.

Higher real rates of return required by private or corporatised investors in electricity capacity

Real rates of return required by private or corporatised investors in electricity capacity may tend to be higher than when the industry was largely government owned and operated in centralised, monopolistic and vertically integrated structures. This would not be surprising given that the relevant private or corporatised entities now have to voluntarily bear risks that were previously borne by taxpayers and electricity consumers generally or were spread among the entire population. A key example is the risk associated with mismatching planned supply and realised demand (or consumption) of electricity. This risk is significant given that generation has typically been capital intensive, planning / construction lead times are often lengthy and the forecasting of electricity consumption (and peak demand) is an inexact science. Objectively, such uncertainties may be no greater after microeconomic reform — in fact they may be less — but the extent to which the associated risks are borne by the investor is greater.

As noted by Dixit (1992), the essential ideas of economic investment under competitive conditions require a revision to the standard Marshallian investment criterion that investment is warranted when (expected) price exceeds long run average cost. He lists three important features as follows: the inevitable presence of some irreversibility ('sunk cost') in an investment process; that the future is uncertain but with relevant information arriving gradually; and that waiting is often possible so that the decision is not only on whether (and in what) to invest but when to invest. As will be seen, these features are of central relevance to investment in electricity generation. To meet the Marshallian investment criterion, the required rate of return on capital may need to be adjusted upwards to take account of these features: this is the so-called 'hurdle' rate. Dixit's theoretical analysis shows that plausible hurdle rates can exceed the (risk-free) cost of capital by a factor of 2 or 3. The potential importance of these hurdle rates in the investment decision is discussed by other authors (Pindyck 1991; Hassett and Metcalfe 1993).

Table 3: **Unit costs for base load capacity in New South Wales, revised MARKAL data-base: coal fired capacity vs CCGT**

	Discount rate	Brown coal based Standard (2000)	Black coal based Standard (2000)	CCGT New conventional (2005)	CCGT Advanced (2020)
	%	$/MWh	$/MWh	$/MWh	$/MWh
Annual capital charge	5	18.0	10.6	7.4	7.5
	8	25.9	15.2	9.8	10.0
	12	37.4	22.0	13.3	13.5
Total unit cost	5	31.0	30.2	45.1	37.2
	8	38.9	34.9	47.4	39.7
	12	55.2	41.6	50.9	43.2
	%	index	index	index	index
Total unit cost	5	*1.03*	*1.00*	*1.49*	*1.23*
	8	*1.12*	*1.00*	*1.36*	*1.14*
	12	*1.33*	*1.00*	*1.22*	*1.04*

Source: Based in part on data provided by Sinclair Knight Merz (under New South Wales assumptions) and extending certain results from table 1.

Such higher required real rates of return will tend to favor the less capital intensive technologies such as CCGTs rather than the more capital intensive coal fired stations that were favored by the pre-existing structures and practices. This is simply illustrated in table 3 in which long run average costs of selected CCGT technologies are compared with those of major coal fired technologies at three different real interest rates.

Again, such simple ‘technology by technology’ comparisons abstract from important trends over time in fuel prices and capacity utilisation factors. The latter changes over time (typically declining with the age of the facility) and differentially (coal capacity, to the extent that its marginal variable cost are lower than that of CCGTs, will tend to have a higher capacity factor than CCGTs, but this is not reflected in table 3).

The relative size of the capital charge component is also influenced by the inclusion of interest during construction in the capital cost. At higher required rates of return this also gives a correspondingly greater premium to technologies (such as CCGTs) with shorter lead times in construction.

Technology specific ‘hurdle’ rates of return

The above argument can be extended. Not only are investor borne risks likely to be higher as a result of microeconomic reform, but these risks are also likely to be specific to different types of electricity generation technology. For example, because of uncertainty about matching capacity and future consumption, technologies with shorter lead times and of a more modular nature have an advantage that is evident from Dixit’s theoretical analysis.

That is, such technologies allow the decision to invest to be deferred to a time closer to the expected commissioning date, thus enabling the more timely gathering of relevant information, for example about future levels of consumer demand, relative fuel prices etc.

To the extent that flows of value in a deterministic model such as MARKAL cannot be used to reflect technology specific risks, it is appropriate to capture such effects using technology specific ‘hurdle’ rates. For example, lower hurdle rates may be attributed to investment in technologies that are more modular (that is, smaller sized units with acceptable scale economies) and with shorter lead times compared with conventional base load electricity technologies. Other factors potentially influencing hurdle rates are discussed below.

Given that the hurdle rate appropriate to CCGT capacity is lower than that for new coal fired capacity it is clear from table 3 that the choice of technologies could be dramatically affected. However, as will be seen below, in practice this investment choice is generally not a simple two-way one.

Hassett and Metcalfe (1996) noted that rigorous econometrically based estimates of hurdle rates (for energy conserving investment) were not yet available. Although this may also be the case for the technologies considered here, MARKAL can be used to investigate implications of plausible or conservative assumptions about these rate differentials.

As just noted, ‘modularity’ is an important aspect of investment in electricity generation technologies. Its significance to the choice of modes is best understood in the context of the revised theory of investment just described, and the notion is helpful in understanding the influence of both microeconomic reform and technical change on this choice. However, before considering modularity in more detail it is useful to first note some further effects of microeconomic reform and technical change.

More competitive gas markets and expanded gas supplies through a fully integrated network

With microeconomic reform in gas markets, and with the expanded availability of gas supplies to a fully integrated supply network, regional gas prices should tend to both converge and to fall, or at least to increase less markedly in the face of any increases in demand. Examples of those supply side forces include gas supply augmentation through Duke Energy’s new pipeline from Longford (Gippsland, Victoria) to Sydney competing with AGL’s existing supply through the Cooper Basin, South Australia (Myatt 2000).

A potentially even more important factor expanding supply and thereby moderating price increases is increased gas from Papua New Guinea through a pipeline to southern Queensland. In an increasingly integrated system, this gas could eventually be made available through the Moomba node to markets in New South Wales and the other south eastern states. Scope also exists for major augmentation from Timor Sea gas sources (Harman 2000). The position is similar in the case of a Western Australian natural gas grid, whether linkage to the eastern Australian system proves cost effective during the 2000–30 projection period or not.

Aspects of microeconomic reform that may not favor CCGT based electricity generation

The outcomes of microeconomic reform need not wholly favor natural gas, and CCGTs in particular, over coal fired generation. Possible offsetting factors include opportunities for making greater and more efficient use of sunk capital (existing assets). These opportunities can arise from a combination of microeconomic reform and technological change. More intensive or extended use of sunk capital tends to prolong inherited fuel use patterns (Ellerman 1998). However, these patterns can also be changed, at a cost, through approaches to 'repowering' discussed later.

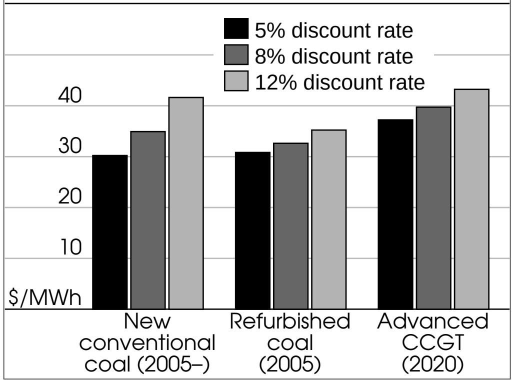
Refurbishment of existing coal fired capacity

In large part, a stronger preference for investment in refurbishment of existing coal fired capacity rather than in new coal fired capacity can be a result of a mechanism just noted: the higher required rates of return as a consequence of microeconomic reform. This effect will exist even in the absence of differentially higher hurdle rates on new coal fired capacity, because the capital cost of refurbishment is typically much less than that for the construction of new coal fired capacity. This is especially so when the latter is on a greenfields site, with consequent expenses related to site approvals, preparation and infrastructure. This argument is reinforced by the much shorter construction times for refurbishment when compared with new coal fired capacity, implying less capital tied up in interest during construction in the former case.

Further reinforcing this effect is the likelihood of a lower hurdle rate for refurbishment than for investment in new coal fired capacity. Later discussion will suggest that while refurbishment may have a lower hurdle rate than new coal fired capacity because it is more modular, its hurdle rate may well be higher relative to the rate for CCGT.

A three-way comparison of long run average costs of new coal fired capacity, refurbished coal capacity and CCGT is illustrated in figure 2. This comparison is to be taken with the same caveats as before. Again, the effect of assuming application of technology specific hurdle rates can be noted: for example, CCGT at an 8 per cent required rate of return appears

Figure 2: **Effect of various 'hurdle' rates on long run average costs**



to be competitive with new coal at 12 per cent. However, refurbishment appears to dominate at most rates in this range.

A relationship between electricity sector microeconomic reform and an increasing preference for power station refurbishment has been observed internationally (Ellerman 1998). Moreover, Ellerman notes that technological progress in operation and maintenance may also be important in lengthening the lives of existing capacity.

Higher availability factors and longer lives for existing and new conventional coal fired capacity

Another feature favoring existing and refurbished (and to some extent, new) coal fired generation is the result of more effective operation and maintenance. This leads to at least two cost saving effects:

- enhanced availability factors of existing and new coal fired capacity: these availabilities are now much higher than 15–20 years ago, reflecting less ‘down time’ for both planned and unplanned maintenance; accordingly, in the updated Australian MARKAL database, all the availability factor values for base load capacity are now set equal to or in excess of 90 per cent, compared with 80 per cent in the pre-existing Australian MARKAL database, mainly reflecting the experience of the 1980s;

- prolonged lifetimes of both existing and new coal fired technologies: these lifetimes are now assumed to be 40 years rather than the 30 years used in the pre-existing Australian MARKAL database for this type of capacity.

Such trends are at least partly the result of competitive forces associated with microeconomic reform but also technological change, especially innovations in information technology, reducing operation and maintenance costs of existing as well as new capacity (Ellerman 1998).

Shorter construction lead times with some convergence between generation modes

There is some evidence of a trend to shorter construction lead times generally. This may be an example of technical change partly ‘induced’ by recognising the advantages of deferral pointed out by Dixit and others, and perhaps partly a spur provided by a greater role for market forces. Construction lead time values in the pre-existing Australian MARKAL database (reflecting estimates as at 1991) are compared with Sinclair Knight Merz’s current advice in table 4. This confirms markedly shorter construction periods, although the CCGT index relative to coal is unchanged at 0.92.

Fuel price effects of microeconomic reform adverse to prospects of natural gas

Microeconomic reform (or ‘structural change’) in that part of the coal industry supplying the domestic electricity industry has the potential to reduce coal costs. Western Australia

Table 4: **Trends in construction lead times and implications for interest during construction**

	Sinclair Knight Merz advice (April–May 2000)				Pre-existing Australian MARKAL database a			
	Construction period		IDC factor b	Index relative to black coal	Construction period		IDC factor b	Index relative to black coal c
	months	years			months	years		
Plant type								
Black coal steam	42	3.5	1.19	1.00	60	5	1.27	1.00
Brown coal steam	48	4.0	1.22	1.03	60	5	1.27	1.00
Coal plant refurbishment	24	2.0	1.12	0.94	**d**	**d**	**d**	**d**
Gas turbine open cycle	12	1.0	1.08	0.91	24	2	1.12	0.89
Gas turbine combined cycle	16	1.3	1.09	0.92	36	3	1.17	0.92
Reciprocating engines	14	1.2	1.09	0.92	**d**	**d**	**d**	**d**
Nuclear (lower bound)	**d**	**d**	**d**	**d**	72	6	1.32	1.04
Nuclear (upper bound)	**d**	**d**	**d**	**d**	90	7.5	1.41	1.11

a Estimates as at (Intelligent Energy Systems 1991). **b** Using a discount rate of 8 per cent. **c** Index for black coal fired capacity = 1.00. **d** Not included.

and South Australia provide important examples of opportunities for CCGTs, because the relative prices of coal and gas in both states are most favorable to gas and hence to CCGTs.

In Western Australia the main coal field is at Collie. Until recently this black coal was sourced only from labor intensive underground mining. However, this deposit has now been made accessible to lower cost opencut mining. This is associated with both a fall in unit costs and an increase in economic reserves, and occurred in the mid-1990s following a multiparty agreement to use underground Collie coal in a station constructed in preference to a CCGT using gas from the North West Shelf (Roberts 1996). Similar productivity improvements have been secured in South Australia (Jemison 1994; *Australia's Mining Monthly* 1996). The comparison between pre-existing and revised MARKAL data specification of Western Australian and South Australian coal is indicated in table 5.

The expected price of black steaming coal used in domestic electricity generation in committed Queensland power stations may similarly be lower than had earlier been projected relative to natural gas (Zauner and Coddington 1999). The production costs and price of such coal need not be tightly related to the price of exported steaming coal. The latter tends to be located near to ports or existing transport, to be of high energy content etc, whereas coal deposits attractive for domestic electricity generation, often on site, tend to have different locational and quality characteristics.

In specifying costs of coal inputs to electricity generation it is important to avoid double counting in the vertically integrated activities. For example, capital costs of coal extraction may sometimes be accounted for in power station investment costs, with only the marginal operating costs of coal extraction being reported as the unit cost of coal.

Table 5: **Parameters for South Australian sub-bituminous coal and Western Australian steaming coal** [a]

	Unit cost	Economic reserves	Annual capacity	Implied lifetime [b]	Energy content	Unit cost	Economic reserves
	$/GJ	PJ	PJ	years	GJ / t	$/t	Mt
South Australian coal							
Pre-existing Australian MARKAL database							
– 1st tranche	3.05	2 000	80	25	13.5	41	148
– 2nd tranche	3.66	4 000	50	80	13.5	49	296
Revised database [c]	2.07	824		20	13.5	28	61
Western Australian coal							
Pre-existing Australian MARKAL database	1.83	7 000			19.7	36	355
Revised database [c]	1.52	21 769			19.7	30	1 105

a For price data on coal in other states, see table 11. **b** At full capacity. **c** Based on information provided by the Australian Geological Survey Organisation, personal communication, May 2000.

Technological progress and productivity improvement in supply and use of combined cycle gas turbines

CCGT technology consists of an open cycle gas turbine combined with a steam turbine in which steam is produced by using the exhaust heat of the gas turbine. Productivity improvements have included developments in the gas turbine stage, in turn reflecting advances in jet aero engines. More recently, there have also been advances associated with their application in electricity generation. These include economies of scale in manufacture, use of advanced metals, new blade designs, high compression ratios, steam injection.

Technological progress projected for CCGTs compared with advanced coal fired technologies

Technological progress in CCGTs could both reduce investment cost relative to competitors and increase their thermal efficiency advantage relative to coal fired capacity. (CCGTs are already less labor intensive than other baseload fossil fuel generation modes.) As the more mature technology, conventional coal fired generation appears to provide fewer opportunities for such progress (Joskow 1987). However, the case of ‘advanced coal fired generation’ is a qualification to this. These technologies include pressurised fluidised bed (PFB) and integrated gasification combined cycle (IGCC). They present opportunities for considerable improvement in energy efficiency but at a relatively high cost premium. With their benefits in fuel savings, the high capital cost but advanced coal technologies will have the most evident potential economic importance where the unit costs of imported or indigenous coal are high. This occurs (for example) in parts of Europe, where available coal is also often of poor quality and with consequences for local pollution that can be addressed with these technologies.

Since ‘advanced coal’ options are associated with significant capital cost premiums, they are much less attractive in east Australian conditions, where coal is both clean and very low cost by world standards. However, both advanced coal technologies are included as options in the Australian MARKAL database. An intermediate case that does appear to be economically viable under Australian conditions is that of ‘supercritical’ coal based steam generation. This involves steam generating plants operating at up to 340 atmospheres (34 MPascals) or more (Glasstone 1983). The water is then converted to steam with the same density as the liquid. Committed Queensland power stations (Tarong North, Millmerran and Callide) are of this type.

Scope for productivity improvements in CCGTs: overstated by some commentators?
Over the past 20–30 years since their original development, CCGTs have shown significant improvements in productivity in the two key dimensions of unit investment cost ($/kW installed) and thermal efficiency (electricity sent out divided by primary energy input).

There are several potential difficulties in assessing the available evidence. First, on capital cost per kilowatt, there is a need to distinguish recent short term fluctuations in market prices for CCGTs from their ‘equilibrium’ unit costs. Claeson (1999) draws a distinction between current actual market prices for CCGTs and production costs. She suggests that a market shake-out at the end of the 1990s following a period of oversupply may mean that recent price falls are atypical and will not be prolonged into the 2000s. This view (related to the international ‘reassessment’ noted above) is also taken by Sinclair Knight Merz and is reflected in the revised Australian MARKAL database.

Second, on performance (here, energy efficiency), there is a significant discrepancy between the design efficiency claims of manufacturers versus the evidence of actual performance on site. Sinclair Knight Merz advise that energy efficiency data in manufacturers’ catalogues are often 5–6 percentage points higher than can be achieved on site. This is because the former data are calculated on a ‘lower heating value’ basis, while it is the ‘higher heating value’ that equates to a ratio of energy input to electricity sent out. This can account for values of 60 per cent quoted when only 54–55 per cent may be realisable. Further, it is necessary to take account of the dependence of performance on local conditions. Factors relevant to in situ energy efficiency may include temperature and (to a lesser extent) humidity, which can entail lower operational energy efficiencies in parts of Australia than may be experienced in the climatic conditions of, say, northern Europe, especially under part load conditions.

In the early 1990s, a particularly optimistic view existed on the scope for early and significant technological progress in CCGTs. For example, one source (Flavin and Lensson 1995) refers to CCGTs with 53 per cent efficiency at $700 / kW for a UK plant in 1992, compared with efficiencies of more than 40 per cent in the late 1980s. The same source referred to efficiencies for the GT cycle alone reaching 39 per cent but ‘expected to close on 60 per cent by 2000'. Similarly, the International Energy Agency refers to CCGT energy efficiencies of 52 per cent in 1995 and 60 per cent in 2020 for OECD North America and OECD Europe, but again these may be 'lower heating values' (IEA 1998, p. 74).

It is important also to take into account manufacturers' scope to provide a range of CCGT variants available for sale to generators who can trade off capital and energy efficiency. This opportunity allows improved efficiency to be obtained for a premium on investment cost and possibly on operation and maintenance costs. For purchasers of the technology, this choice will be influenced by their expected relative prices of natural gas or other fuels over the life of the project.

Induced technological progress for CCGTs

'Autonomous' technological progress is normally correlated simply with time. By contrast, 'induced' technological progress implies particular mechanisms. Examples can include relative price changes such as increases in fuel cost or the dispelling of X-inefficiency by competitive market forces more generally. Another such mechanism is that of 'learning by doing' (Arrow 1962). The proximate cause of technological progress in that case is simply the level of capacity of the technology concerned, and hence production experience, as this increases over time. This 'internationally induced' notion of technological progress was outside the brief of ABARE's engineering consultants Sinclair Knight Merz and hence required use of other information sources.

For a given technology, 'experience curves' (Mattson 1997; IEA 1999) have been presented as a way of representing an inverse relation between the investment cost for the purchase and installation of that technology and the increased experience in its production. In developing these curves, increased experience in production has been proxied by worldwide cumulatively installed capacity. So far, investigation of experience curves has focused on productivity improvement as cost reduction rather than as improvement in quality of performance: that is, in energy efficiency.

From this historical relationship is defined a 'progress ratio' relating the reduction in unit investment cost ($/kW installed) to the unit increase in experience (cumulative installed capacity). A recent study of experience curves for CCGTs indicated a progress ratio of 0.75 during the 1990s (Claeson 1999). Historically, this result implies that unit cost has been reduced by 25 per cent for every doubling of international cumulative installed capacity.

However, these results cannot be accepted uncritically as a guide to future trends. First, the data underlying 'experience curves' may reflect a combination not only of true technological progress (for example, of the induced 'learning by doing' type) but of the effects of economies of scale in production, price induced changes in factor combinations etc. As a more rigorous basis for forecasting, historical analysis would seek to disentangle these elements. Second, the continued validity of an exponential relationship summarised by 'progress ratios' should be seriously questioned. For good physical reasons, phenomena with a history of exponential growth usually indicate saturation at some point with the result that an 'S-shaped' or logistic curve is a better mathematical description of the trends. The difficulty with using this type of functional form to forecast is to judge, in advance, the level and timing of any such saturation effects.

We can avoid simply extrapolating an exponential relation but still postulate a decline in unit cost arising from such an increase in international capacity. MARKAL can then be used to assess the effect on penetration of CCGTs under Australian conditions.

Technological change: implications for uncertainty, irreversibility, fuel choice and hurdle rates

Projecting technological change involves uncertainty and irreversibility. If particular (even random or accidental) factors lead to expansion in a technology where economies of scale or 'learning by doing' is involved, this advantage can be reinforced, eliminating (potentially more cost effective) competitors without such an initial advantage. In introducing these ideas of 'locking in' and 'path dependence', Arthur (1989) refers to the historical case of the light water reactor (LWR) variant of nuclear power — with its infrastructure — as a possible example.

There is no suggestion that CCGT is an inefficient technology standing to gain in this sense from any 'locking in' mechanism. However, central to the case of CCGTs are the possibilities for 'locking in' the complementary network infrastructure with its scale economies. Arthur (1990) notes the applicability of this argument to networks. Here, the relevant network infrastructure is the natural gas pipeline system with its potentially multiple nodes of supply and consumption with associated 'network externalities' of production. The latter can occur where gas consumers entering the market at a later time enjoy benefits — in terms of infrastructure availability and hence lower gas costs — stemming from the actions of earlier large consumers that have made the commitments inducing the initial large trunk pipelines. Uncorrected externalities are involved to the extent that these benefits are not captured by the large gas consumers making the early commitments. Hence there is scope for beneficial coordinating and risk reducing government intervention to encourage these early consumers and thereby internalise this market imperfection.

The revised theory of investment and associated notion of hurdle rates can also offer insights. Not all of the new investment in conventional coal fired technologies, with their lengthened (even 'indefinite') lifetimes, is completely irreversible[1] ('sunk' in Dixit's sense) — for example, the 'repowering' options discussed below.

[1] Ellerman (1996) notes that 'plants built initially for coal can be converted to oil or gas use with relatively little additional capital expenditure, whereas the converse is not true.' However, if 'gas' means simply a steam thermal station there is an efficiency penalty compared with a CCGT.

On the other hand, if expected progress in an (as yet) uninstalled technology is very rapid, it may be advantageous to delay investment – for example, in the case of personal computers and possibly some energy conservation technologies. However, it is unlikely that expected technical progress in CCGTs will be so rapid as to be a factor tending to defer its installation as investors ‘wait’ for later, more energy efficient variants — and so we would not expect such an effect to induce an increase in its hurdle rate.

Also relevant may be the common view since 1990 that natural gas is a ‘fuel of the future’, a popular perception that cannot be divorced from expectations about future greenhouse gas emissions policies.

Modularity in electricity generation investment

Greater modularity of competing forms of generation capacity is based on smaller economic unit sizes[2] and shorter installation lead times.

In contrast with coal fired capacity — where economies of scale are achieved on site with larger units — CCGTs are, to a greater extent, factory built. Hence, there is scope for economies of scale to be achieved within the factory, as assembly line run sizes increase, without these economies being as dependent on unit size in the construction phase.

Compared with coal fired steam turbines, CCGT’s greater modularity can reduce cost penalties associated with the uncertainty of future levels of electricity consumption (Boyd and Thompson 1980; Loose and Flaim 1980).

New coal fired capacity is the least modular of the technologies considered here. This is because of its large economic plant size and long construction lead times. Unit sizes are dictated by the tradeoff between the advantages of economies of scale in manufacture and construction of a generating unit under Australian conditions and some offsetting factors. The latter include system reliability criteria which restrict the largest possible generating unit size to no less than a given fraction of total system capacity. This choice relates to a NEMMCO rule concerning the ‘minimum reserve trigger’ (Sinclair Knight Merz 2000). Unit sizes for new capacity under Australian conditions are indicated in table 6.

On the other hand, the unit sizes for coal fired capacity suitable for refurbishment will be limited by the size and number of such existing units reaching the end of their usual lifetimes (of around 40 years) in any given period. The unit sizes in table 6 indicate the applicable range in current Australian circumstances. Clearly, on this criterion, the initial levels

[2] Economies of scale or ‘lumpiness’ in investment can be dealt with in MARKAL by using integer programming. That approach is required in modeling natural gas pipelines but is not practicable or as necessary in electricity generation. Issues can be dealt with by inspection. For example, costs attributed to a given technology may be based on a unit size of 500 MW, so that model reported additions to capacity substantially less than this have to be viewed critically and may be rejected as understating true cost or of negligible importance.

Table 6: **Modularity of new and refurbished coal fired generation units a**

	New generating units		Potentially refurbishable units b	
	MW		MW	
New South Wales	660	Mt Piper	300–350	Munmorah
Victoria	500	Loy Yang, Mission Energy	350	Yallourn W
Queensland	434	Millmerran	6 * 66	Swanbank A
South Australia	260	Northern	2 * 60	Thomas Playford B
Western Australia	300	Collie	4 * 60	Muja A, B

a Source: Sinclair Knight Merz, personal communication, 2000. **b** In the short to medium term.

of refurbishable capacity units are significantly smaller than new capacity and therefore more modular in this sense. However, these relatively few old and small units will be fairly quickly exhausted over time, implying that unit sizes for refurbishment in the later years (in which there is significant requirement for capacity additions) will more closely reflect the typically much larger unit sizes for new units.

Closely associated with modularity is the issue of installation lead times. As set out in table 4, these are significantly greater for new coal fired capacity than for refurbished coal, which in turn is greater than for CCGT, and in turn, OCGT.

Moreover, CCGT has an additional advantage over both new and refurbished coal in that it can be constructed in two phases: first, the OCGT component (which accounts for two-thirds of final capacity but has a very short lead time) and then the steam turbine unit, which can then be installed as required. Comparatively little capital is tied up in the first stage; it is the steam generation component that adds significantly to the capital cost of the project, but providing a return from the considerably improved overall energy efficiency then applicable for the remainder of the completed CCGT project's lifetime. Again, in Dixit's terms, options in this two stage approach are kept open or deferred, with consequent potential economic benefits in the presence of uncertainty and irreversibility.

Repowering

There are proposals for integrating OCGTs with existing steam generating capacity in coal fired units that have been converted to gas (or in the few remaining gas fired steam generators). This approach involves scrapping existing specialised coal fired boilers but retaining the turbines and other equipment. It entails simultaneous 'repowering' and enhancement of existing capacity from coal to gas fired operation to again arrive at a CCGT. However, this is by an alternative route that, by making use of 'sunk' capacity, saves capital and therefore is more likely to be favored where rates of return are required to be high. Again, a qualification arises from the ratio of approximately 2:1 in the contribution of the gas turbine and steam turbine respectively — thereby restricting the level of existing steam turbine capacity convertible in this way at any given time and reducing the modularity of CCGTs obtained through this route.

Flexibility in operation

CCGTs have the advantage of greater flexibility in operation in that they can, with less cost penalty than large coal fired power stations, follow instantaneous changes in electricity requirements in the diurnal cycle or where sudden supply outages or demand increases occur. However, meeting these consumption changes is essentially the function of dedicated peaking or emergency capacity (for example, open cycle gas turbines or hydro) rather than base load capacity. (This will be the case as long as base load capacity is inflexible in this sense. But if the technology exists to provide base load capacity from flexible plants, the requirement for dedicated peaking plants will be reduced.) The MARKAL database includes a parameter capturing some of this load following advantage in the case of base load capacity such as CCGTs, as well as incorporating the distinction between base load and peaking capacity.

Decentralised, 'embedded' or 'distributed' generation

One advantage of decentralised but grid connected modes of electricity generation is that increases in the costs of electricity transmission normally associated with additions to generation capacity do not apply to these technologies. MARKAL allows scope to recognise this feature and currently does so in the case of both industrial cogeneration (which in some cases may be CCGTs or OCGTs) and photovoltaic cells. However, there are other potential advantages of decentralised generation — for example, increased supply reliability through avoidance of some risks associated with transmission systems. This is another uncertainty effect that could be held to favorably influence hurdle rates for these types of capacity.

For the purposes of this MARKAL analysis, CCGTs and OCGTs have both been assumed to be conventional centralised technologies. However, in reality their location may be more flexible than sites on coal fields, often mandatory for large coal fired stations, especially brown coal. In addition, these gas fired technologies can form part of 'distributed' industrial cogeneration options (Sinclair Knight Merz 2000). The risk abatement opportunities that can be involved in 'distributed' generation are discussed in Huff, Wenger and Farmer (1996).

The Australian MARKAL analysis

The updated MARKAL database: characterising CCGTs and competing technologies

The updated MARKAL database reflects the revised characterisation of fossil fuel electricity generation technologies, and CCGTs in particular, including the important issues identified above. The consultant complied with a request for particular treatment of issues such as refurbishment, technical change and capital / energy tradeoffs (Sinclair Knight Merz 2000).

Technical progress

The consultant's advice is illustrated by the examples in table 2. In no case (that is, neither CCGT nor competing coal fired technologies) is 'autonomous' technical progress in the 2000–30 period assumed to include further reductions in investment cost. However, it is assumed that further progress in improving energy efficiencies is possible without any increase in investment cost. For example, the table indicates that without any increase in investment cost, energy efficiencies of 'efficient' CCGTs are assumed to improve by a factor of 1.29 between 2005 and 2020 (from 41 per cent to 52.9 per cent). This improvement is clearly very significant but from a lower base and to a lower end point than is implied by other commentators noted above.

Capital versus energy efficiency tradeoff

The 'efficient' CCGT technologies can be taken as an example of the capital versus energy efficiency tradeoff: over the period 2005–20, the investment cost premium over the 'standard' technology is 2 per cent and the energy efficiency improvement thus obtained is 2.5 per cent, falling to 1.5 per cent. Over this period, the ratio of energy efficiency improvement factor to the cost increase factor tends to be somewhat lower for the coal fired technologies than for the CCGTs.

Characterising the MARKAL model scenarios

As a matter of terminology, 'scenarios' refer to variants of the database, while 'cases' refer to the model's least cost solutions (and the detailed results) that may be associated with each of these scenarios.

The reference scenario

Scenarios in MARKAL are defined by comprehensive specification of actual and future energy sector technologies, resources and energy flows as well as projected values of energy services consumption over the full projection period 2000–30. Simulations were all carried out over the period 2000–35 to minimise 'end condition' errors and retain sufficient robustness for results occuring later in the projection period.

In minimising total resource costs, the discount rate is 8 per cent real[3], the rate normally used in Australian MARKAL. The reference scenario in this instance includes no policies to reduce carbon dioxide emissions. As will become evident, this scenario should not be interpreted as a 'business as usual' case or a forecast.

[3] The Victorian Regulator-General has recently calculated that distribution companies would generate a nominal return on equity of 12 per cent and that capital markets would be satisfied with a 12 per cent rate of return (Bartholomeusz 2000). Such a nominal rate, before tax for the relatively lower risk associated with distribution seems consistent with the 8 per cent real used in MARKAL as both a systemwide discount rate and as a benchmark hurdle rate for lower risk technologies.

Table 7: **The key MARKAL scenarios: variations relative to the reference scenario**

Scenario assumptions	**Case**
Hurdle rates	
Applied to investment in *new* coal fired capacity **a**	
9 per cent, 10+ per cent	1[9], 1[10]
Applied to investment in *all* coal fired capacity *including* refurbished capacity	
10 per cent, 11+ per cent	2[10], 2[11]
Cost cutting productivity improvement	
in production of CCGTs and OCGTs	3
Favorable assumptions for CCGTs b	
– low gas price	4[low]
– high gas price	4[high]

a The default hurdle rate on all other electricity generation technologies is that of the energy sectorwide discount rate of 8 per cent.
b 10 per cent hurdle rate on *both* refurbishment and on new coal capacity plus cost-cutting productivity improvement for CCGTs.

The 'reference scenario' used in this analysis incorporates upper limits to the output (PJ) of natural gas fired industrial cogeneration. These limits are specified exogenously rather than through the model's optimisation process. This is necessary because of the complexity of factors determining future penetration of industrial cogeneration — for example, factors influencing long term future opportunities for the industrial use of process steam in particular highly specialised market situations.

Other scenarios

The other selected scenarios illustrate the influence of several of the technical issues and policy relevant factors considered above. The assumptions underlying the main non-reference scenarios are indicated in table 7.

Additional scenarios were used to investigate several other issues: the effect of lower coal prices in South Australia and Western Australia (now in the reference case) and in Victoria; the timing of CCGT penetration in South Australia and Queensland in the absence of current commitments.

Results and discussion

Key results

The first key result is the wide range of the outcomes for CCGT output if the reference case is compared with others such as the 'favorable assumptions' case (case 4[low]). This contrast is illustrated in figures 3 and 4. These compare contributions from each type of technology to electricity output in each case.

In the reference case (figure 3), by 2030, electricity output from new coal fired capacity (that is, capacity so far uncommitted but commissioned during the projection period) is

26 per cent of the total. Electricity output from all coal fired capacity is 64 per cent of the total. Apart from the supercritical coal fired capacity already committed in Queensland, this coal fired capacity does not include any 'advanced' forms. Output of gas fired capacity (CCGT and OCGT but excluding cogeneration) is 13 per cent, of which CCGT output is only 5 per cent of total electricity generated. Apart from South Australia, where CCGT technology becomes dominant early (along with electricity imports) there is no new CCGT capacity in this reference case, except in Victoria where 0.7 GW appears but not until 2030.

Results from the least cost solution derived from case 4[low] are indicated in figure 4. This scenario includes the effect of three 'favorable assumptions': low priced gas, productivity improvement cutting CCGT capital cost by 26 per cent by 2030 and a moderate increment to the hurdle rate applied to both new coal fired capacity and refurbishing coal fired capacity (an additional 2 percentage points). Each of these assumptions is more precisely defined below.

In this 'favorable assumptions' case, new coal fired capacity is found to be not cost effective in any state and in fact does not appear at any period in the least cost solution. The same applies to refurbished coal fired capacity. The total coal fired share of only 25 per cent as at 2030 is therefore entirely accounted for by currently existing and committed capacity. On the other hand, the share of national electricity output from gas fired capacity in 2030 (that is CCGT and OCGTs but excluding gas fired cogeneration) is as high as 53 per cent, of which CCGT output is 46 per cent of total electricity output and 7 per cent is OCGT.

Figure 3: **Electricity output – reference case**

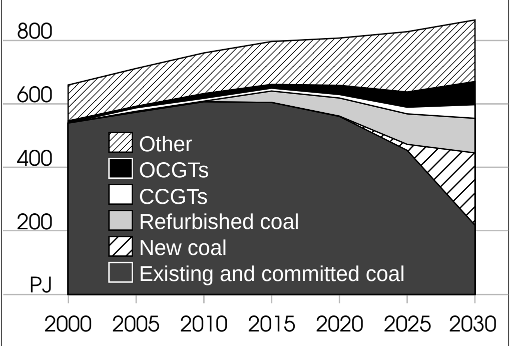
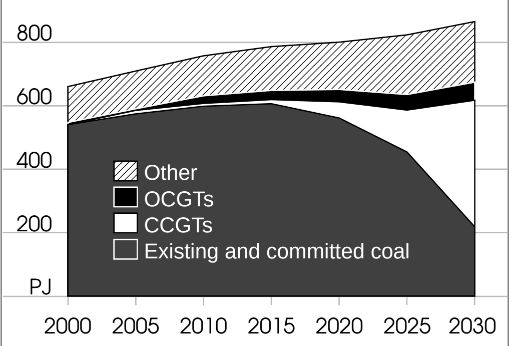
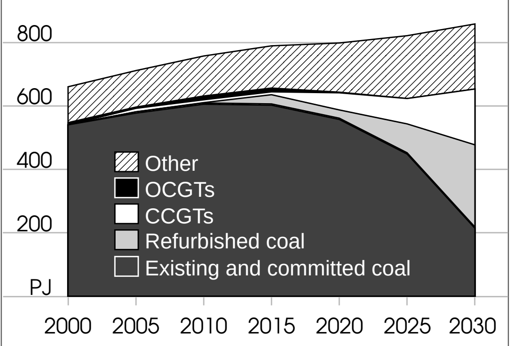


Figure 4: **Electricity output – favorable case for CCGTs a**



a Higher hurdle rates on new and refurbished coal fired capacity; low gas price.

Figure 5: **Electricity output – higher hurdle rates; higher gas prices a**



a Higher hurdle rates on new and refurbished coal fired capacity.

One plausible midrange scenario (case 1[10]) involves the following assumptions:

- a 'hurdle' rate of return on new coal fired capacity of 10 per cent (or higher) — that is, (at least) 2 percentage points above the 8 per cent default rate; and
- only moderate upward pressure on natural gas prices, in the face of demand shifts resulting from increased gas requirements from the electricity sector and other sectors.

In this midrange scenario, the electricity output share of new coal fired capacity again turns out to be zero, but the share attributable to refurbished coal is as much as 34 per cent, implying a total coal fired share of 59 per cent. CCGT capacity accounts for 10 per cent and both CCGT and OCGT together for 18 per cent.

State level detail

In the 'favorable' case 4[low], significant CCGT capacity is cost effective in all five mainland states by 2025 and 2030 (table 8).

Table 8: **Regional distribution of CCGT capacity: favorable assumptions case *versus* reference case**

	2005	2010	2015	2020	2025	2030
Electricity output	PJ	PJ	PJ	PJ	PJ	PJ
Reference case						
Queensland				2	4	
South Australia	11	9	9	9	17	24
Victoria						19
Total	11	9	9	11	21	43
Favorable assumptions case (case 4[low])						
New South Wales					15	180
Queensland				4	5	33
South Australia	11	9	13	18	26	44
Victoria				9	63	97
Western Australia				20	22	46
Total	11	9	13	51	132	399
Capacity	GW	GW	GW	GW	GW	GW
Reference case						
Queensland	0.3	0.3	0.3	0.3	0.3	
South Australia	0.5	0.5	0.5	0.5	0.8	0.9
Victoria						0.7
Total	0.8	0.8	0.8	0.8	1.0	1.6
Favorable assumptions case (case 4[low])						
New South Wales					0.6	6.3
Queensland	0.3	0.3	0.3	0.3	0.3	1.3
South Australia	0.5	0.5	0.5	0.8	1.3	1.9
Victoria				0.3	2.2	3.4
Western Australia				0.7	0.8	1.6
Total	0.8	0.8	0.8	2.1	5.1	14.6

Detailed discussion

The model results for CCGT in each case at an aggregated national level are set out in table 9 indicating capacity installed (GW), electricity output (PJ) and its share of total electricity output. In seeking to understand these results, it is also necessary to explore the state level detail. The scenarios and the relevant results are now considered in turn, and comparatively.

Table 9: **CCGT capacity and output: summary of results from Australian MARKAL scenarios**

		2005	2010	2015	2020	2025	2030
CCGT installed capacity		GW	GW	GW	GW	GW	GW
Reference scenario		0.75	0.75	0.75	0.75	1.03	1.55
9% hurdle rate on new coal capacity	Case 1[9]	0.75	0.75	0.75	0.77	1.09	2.65
10% hurdle rate on new coal capacity **a**	Case 1[10]	0.75	0.75	0.75	0.77	1.08	3.17
‘No new coal or refurbishment’ **b**	Case 2[11]	0.75	0.75	0.75	1.83	4.29	13.48
CCGT cost cut from productivity improvement	Case 3	0.75	0.75	0.75	1.12	1.62	3.78
10% hurdle rate, all coal cap. + low gas price	Case 4[low]	0.75	0.75	0.75	2.13	5.06	14.61
10% hurdle rate, all coal cap. + high gas price	Case 4[high]	0.75	0.75	0.75	2.79	4.04	7.71
CCGT energy output		PJ	PJ	PJ	PJ	PJ	PJ
Reference scenario		10.8	9.4	9.2	10.8	21.1	43.0
9% hurdle rate on new coal capacity	Case 1[9]	10.8	9.4	9.2	10.8	23.9	70.4
10% hurdle rate on new coal capacity **a**	Case 1[10]	10.8	9.4	9.2	10.8	23.9	84.5
‘No new coal or refurbishment’ **b**	Case 2[11]	10.8	9.2	13.0	41.7	114.9	375.7
CCGT cost cut from productivity improvement	Case 3	10.8	9.2	9.2	18.9	33.9	90.1
10% hurdle rate, all coal cap. + low gas price	Case 4[low]	10.8	9.21	3.0	51.0	132.0	398.9
10% hurdle rate, all coal cap. + high gas price	Case 4[high]	10.7	9.2	9.2	54.3	79.7	176.0
CCGT share of total electricity output		%	%	%	%	%	%
Reference scenario		1.5	1.2	1.2	1.3	2.5	5.0
9% hurdle rate on new coal capacity	Case 1[9]	1.5	1.2	1.2	1.3	2.9	8.2
10% hurdle rate on new coal capacity **a**	Case 1[10]	1.5	1.2	1.2	1.3	2.9	9.8
‘No new coal or refurbishment’ **b**	Case 2[11]	1.5	1.2	1.6	5.2	14.0	43.6
CCGT cost cut from productivity improvement	Case 3	1.5	1.2	1.2	2.3	4.1	10.4
10% hurdle rate, all coal cap. + low gas price	Case 4[low]	1.5	1.2	1.6	6.4	16.0	46.1
10% hurdle rate, all coal cap. + high gas price	Case 4[high]	1.5	1.2	1.2	6.8	9.7	20.5

a A hurdle rate of 10 per cent or above on new coal fired capacity is sufficient to prevent its construction in all states. **b** In this case, the 11 per cent hurdle rate is applied to investment in all coal fired capacity including both new coal capacity and refurbishment of existing coal fired capacity — that is, ‘no new coal or refurbishment’ is a *result* of this assumption, not merely an exogenously imposed constraint.

Effect of existing CCGT capacity commitments

The revised database specifies that CCGT capacity is committed for installation in the period to 2005 in both Queensland (260 MW, Mica Creek) and South Australia (487 MW, Pelican Point). The committed Queensland capacity is found in the reference case to be scarcely used under ‘least cost’ assumptions. In understanding the failure of (additional) CCGT capacity to appear in Queensland, it is important to recall here not only the absence of a maximum carbon dioxide constraint and higher hurdle rates in this analysis, but also that in Queensland coal is extremely low cost, implying very low running costs. In that state, coal fired base load capacity, existing and committed for construction, is in ample supply. Consistent with this, a hypothetical case without these two existing CCGT commitments indicates that, in a least cost analysis, no CCGT capacity at all is installed in Queensland during the projection period.

As seen in table 10, the situation is very different in South Australia, where coal is more costly and CCGT becomes the dominant base load supply source by 2030. But even in South Australia, installation is still deferred somewhat compared with the reference case. This case includes the existing CCGT installation commitments. In this hypothetical South Australian case, CCGT first appears in 2020 at 330 MW. CCGT shares of electricity consumption are also given in table 10, reflecting the significant level of electricity imports into South Australia from Victoria.

Table 10: **Penetration of CCGT in South Australia: reference scenario** **a**

		2005	2010	2015	2020	2025	2030
Energy output of CCGTs	PJ	10.8	9.6	9.2	10.8	19.2	32.2
Share of generation	%	35	37	26	28	45	71
Share of consumption	%	24	27	26	27	37	71

a Coal costs and reserves revised in line with advice from the Australian Geological Survey Organisation, May 2000 (see p. 6).

Input prices for natural gas relative to coal

Trends in coal prices

In the eastern mainland states (New South Wales, Queensland and Victoria), supplies of low cost coal are effectively unlimited in the projection period. Hence, increasing domestic consumption of coal over time will not put marked upward pressure on price and this is reflected in the modeling as is evident from the coal price trends in (table 11). A mild exception is the case of South Australia, where limits on coal availability lead to a bidding up of its price in that state.

Lower cost coal from mine restructuring in Western Australia and South Australia

The price of South Australian coal at \$2.2 / GJ, rather than the early 1990s specification of \$3 / GJ, is still well above that in the eastern states. However, coal supplies at this lower

Table 11: **Trends in price of steaming coal for electricity generation: reference scenario**

	2000	2010	2020	2030	2000	2010	2020	2030
	$ / GJ	$ / GJ	$ / GJ	$ / GJ	index	index	index	index
Victoria (brown coal)	1.0	1.0	1.0	1.0	*1.00*	*1.01*	*1.02*	*1.02*
New South Wales	1.6	1.6	1.6	1.7	*1.00*	*1.00*	*1.01*	*1.02*
Queensland	1.6	1.6	1.6	1.7	*1.00*	*1.00*	*1.01*	*1.02*
South Australia	2.2	2.2	2.4	2.7	*1.00*	*1.03*	*1.11*	*1.25*
Western Australia	1.6	1.6	1.6	1.6	*1.00*	*1.01*	*1.02*	*1.02*

price are limited (20 years at an average output of about 40 PJ a year). Model results indicated a negligible effect on penetration of CCGT in South Australia arising from this lower coal price assumption.

Coal price trends in New South Wales, Queensland and Victoria

There have been suggestions that the price of coal for domestic electricity generation is declining in all three eastern mainland states (Zauner and Coddington 1999). This is not critical to the simulation results for New South Wales and Queensland since new CCGT capacity does not appear in any event. A sensitivity test using a lower price for coal in Victoria ($0.62/GJ compared with $1.0 /GJ) did not result in reduced penetration of CCGT in that state.

Price trends for natural gas

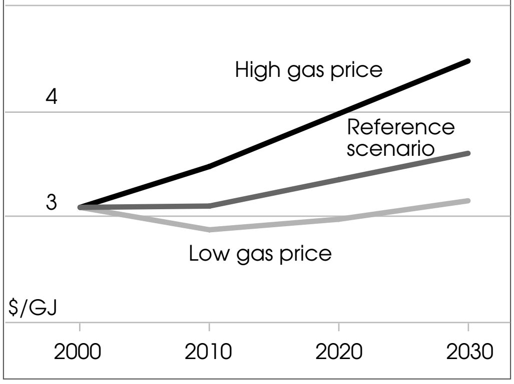
The mechanisms of the supply of natural gas and its representation in the Australian MARKAL database are more complex than for coal used in domestic power stations. Natural gas is supplied through an increasingly complex and integrated grid system of pipelines that cross state boundaries. By contrast, in many cases, coal fired electricity capacity is located adjacent to the coal field. As a result, coal prices (as in table 12) are measured at that point.

Alongside the increasing role of competitive gas markets, the network externalities referred to above may justify a role for state governments in assuring significant initial loads for major new gas grid extensions. Such loads include CCGTs. This government role is possible where they have residual influence in the choice of electricity supply technologies, as in the case of recent decisions of the Queensland government favorable to CCGT capacity in that state[4].

[4] The Queensland government was reported (in June 2000) to have approved the deferral of the Kogan Creek coal fired power station (of 0.7 GW) in favor of constructing a second CCGT power station in that state, Swanbank E (0.35 GW). The latter station will actually use coal bed methane piped through the existing natural gas grid (McCarthy 2000). While this increment may be an important contribution, it may not change the MARKAL results significantly as at 2030, given that both these Queensland CCGTs (Mica Creek and Swanbank E) will have reached the end of their designated lifetimes by that time.

For the more immediate purposes of the modeling for this paper, three alternative sets of assumptions for the city gate price of natural gas (reflecting pipelining costs) are used. These define scenarios to illustrate the combined effect of gas market reform and supply augmentation. 'City gate' prices are equated to the price of gas available for electricity generation.

Figure 6: **City gate gas price trends: eastern states**



Both the reference case assumption and the sensitivity tests on low and high gas price paths over the projection period scenarios are given in table 12. The reference scenario assumption is that a combination of microeconomic reform and major augmentation from major new gas sources (and risk management from state governments) will ensure that supply can be expanded to meet requirements without significant price increases. The high gas price case reflects a bidding up of the price in response to supply limitations and expanded demand. Broad trends in gas prices under each assumption are shown in figure 6.

Of the scenarios modeled here, that with the highest consumption of natural gas is case 4[low], which includes an assumption that gas prices can be maintained at the low price as

Table 12: **Trends in 'city gate' price of natural gas: high, medium and low growth cases**

	2000	**2010**	**2020**	**2030**
	$ / GJ	$ / GJ	$ / GJ	$ / GJ
Reference scenario				
Adelaide	3.05	3.1	3.4	3.7
Brisbane	3.4	3.4	3.7	3.9
Melbourne	2.8	2.8	3.0	3.2
Perth	2.9	2.9	3.1	3.3
Sydney	3.1	3.1	3.3	3.6
High gas price assumption (case 4[high])				
Adelaide	3.05	3.5	4.0	4.5
Brisbane	3.4	3.9	4.4	4.9
Melbourne	2.8	3.1	3.6	4.0
Perth	2.9	3.2	3.7	4.1
Sydney	3.1	3.4	3.9	4.5
Low gas price assumption (case 4[low])				
Adelaide	3.05	2.85	2.95	3.2
Brisbane	3.4	3.1	3.2	3.3
Melbourne	2.8	2.65	2.75	2.9
Perth	2.9	2.75	2.85	2.95
Sydney	3.1	2.9	3.0	3.2

Sources: Business Council of Australia (2000); Australian Gas Association (1999); miscellaneous gas price sources; Harman (2000).

Table 13: **Natural gas used in electricity generation and total gas for domestic supply**

	2010	2015	2020	2025	2030
Reference case	PJ	PJ	PJ	PJ	PJ
Use in electricity sector	133	164	273	391	540
Total gas for domestic supply	769	789	831	941	1 045
Proportion of total domestic gas supply used in:	%	%	%	%	%
– CCGTs	3	3	3	5	12
– electricity supply	17	21	33	42	52
Favorable assumptions case (case 4[low])	PJ	PJ	PJ	PJ	PJ
Use in electricity sector	169	221	382	611	1 137
Total gas for domestic supply	817	839	937	1 200	1 725
Proportion of total domestic gas supply used in:	%	%	%	%	%
– CCGTs	3	4	11	22	44
– electricity supply	21	26	41	51	66

a result of microeconomic reform and the augmentation of supply including the grid system. It is of interest to note the impact of this scenario on total gas requirements, both as input to electricity and nonelectricity uses. These are summarised in table 13 in comparison with the reference case.

Refurbishing existing coal fired capacity

The aggregate national levels of refurbished coal fired capacity that are cost effective in all the major cases are set out in table 14. It is evident that, in the reference case, refurbished coal fired capacity plays a significant role in a least cost solution, its total capacity being somewhat more than that of CCGT throughout the period. In the reference case, refurbishment's first major appearance is not until 2015 (1.3 GW) but increases to 3.9 GW by 2030 compared with 1.6 GW of CCGT by 2030.

The total potential for refurbished coal is outlined in table 15. This simply reflects the fact that existing capacity cannot become available for refurbishment until the end of its designated (40 year) lifetime and those capacity levels cannot be exceeded. Table 14 also includes the levels of refurbishment indicated as cost effective in the reference case, as well as a case (discussed in the next section) in which new coal fired capacity is excluded due to a high hurdle rate.

In the reference case, cost effective refurbishment is indicated as occuring in Victoria (from 2015) and in Western Australia (from 2025), with a minor amount already committed in New South Wales. When a higher hurdle rate is applied to new coal fired capacity (Case 1[10], as discussed in the next section), major refurbishment is also cost effective in New South Wales by 2030.

Table 14: **Refurbished coal capacity and output: summary of results from Australian MARKAL scenarios**

		2005	2010	2015	2020	2025	2030
Refurbished coal installed capacity		GW	GW	GW	GW	GW	GW
Reference scenario		0.10	0.10	1.31	1.99	3.39	3.85
9% hurdle rate on new coal capacity	Case 1[9]	0.10	0.10	1.31	1.99	3.88	10.19
10% hurdle rate on new coal capacity **a**	Case 1[10]	0.10	0.10	1.31	1.99	3.88	10.21
‘No new coal or refurbishment’ **b**	Case 2[11]	0.10	0.10	0.10	0.00	0.00	0.00
CCGT cost cut from productivity improvement	Case 3	0.10	0.10	1.31	1.96	3.39	3.85
10% hurdle rate, all coal cap. + high gas price	Case 4[high]	0.10	0.10	1.02	0.92	3.21	9.13
Refurbished coal, units generated		PJ	PJ	PJ	PJ	PJ	PJ
Reference scenario		1.8	0.8	25.2	47.6	91.2	114.1
9% hurdle rate on new coal capacity	Case 1[9]	2.8	0.8	36.6	56.6	110.0	289.4
10% hurdle rate on new coal capacity **a**	Case 1[10]	2.8	1.8	35.8	56.6	110.0	289.9
‘No new coal or refurbishment’ **b**	Case 2[11]	2.8	1.8	2.0	0.0	0.0	0.0
CCGT cost cut from productivity improvement	Case 3	2.8	1.8	35.5	55.7	96.2	109.3
10% hurdle rate, all coal cap. + high gas price	Case 4[high]	0.0	0.8	29.0	26.2	91.0	259.1
Refurbished coal, share of total electricity output		%	%	%	%	%	%
Reference scenario		0.2	0.1	3.2	5.9	11.0	13.2
9% hurdle rate on new coal capacity	Case 1[9]	0.4	0.1	4.6	7.0	13.3	33.6
10% hurdle rate on new coal capacity **a**	Case 1[10]	0.4	0.2	4.5	7.0	13.3	33.7
‘No new coal or refurbishment’ **b**	Case 2[11]	0.4	0.2	0.3	0.0	0.0	0.0
CCGT cost cut from productivity improvement	Case 3	0.4	0.2	4.5	6.9	11.6	12.6
10% hurdle rate, all coal cap. + high gas price	Case 4[high]	0.0	0.1	3.7	3.3	11.1	30.2

a A hurdle rate of 10 per cent or above on new coal fired capacity is sufficient to prevent its construction in all states. **b** In this case, the 11 per cent hurdle rate is applied to investment in all coal fired capacity including both new coal capacity and refurbishment of existing coal fired capacity — that is, ‘no new coal or refurbishment’ is a *result* of this assumption, not merely an exogenously imposed constraint.

Higher required ‘hurdle’ rates of return on electricity capacity investment

As discussed above, a key effect of microeconomic reform could be to increase required hurdle rates of return on certain forms of electricity capacity investment — for example, to reflect the greater private bearing of risk associated with those technologies. Apart from applying the hurdle rates themselves, modeling requires adjustments to the interest during construction component in unit investment costs. This is calculated at the relevant ‘hurdle’ rate. In these instances, the higher hurdle rates replace the 8 per cent rate used in Australian MARKAL, given that this rate is also the default value for investment decisions.

This default 8 per cent rate is not assumed to be a risk free rate, but hurdle rates above this rate are an attempt to capture additional risks specific to the sector subsequent to microeconomic reform and differentially among technologies. An empirical basis for hurdle rates (or hurdle rate increments) could be obtained from econometric estimates or otherwise. Given information about the capacity, capital cost and expected lives of plant; and data on price distributions of electricity and capacity, it should be possible to derive

Table 15: **Refurbished coal capacity: specified maximum levels versus cost effective levels**

	Unit	2005	2010	2015	2020	2025	2030
Database limits to refurbished capacity							
New South Wales (lower bound)	GW	0.1	0.1	0.1	0.0		
New South Wales	GW	0.1	0.1	2.0	3.6	4.9	8.2
Queensland	GW		0.8	1.2	2.9	2.9	3.1
South Australia	GW	0.1	0.1	0.1		0.5	1.0
Victoria	GW		0.8	1.8	2.5	2.9	3.0
Western Australia	GW		0.2	0.5	0.9	0.6	1.2
Total	GW	0.2	2.1	5.6	9.9	11.8	16.5
Model results (index relative to specified limit = 1.00)							
Reference scenario							
New South Wales	index	*1.00*	*1.00*	*0.05*			
Victoria	index			*0.68*	*0.54*	*0.94*	*0.93*
Western Australia	index				*0.73*	*1.00*	*0.92*
Total	GW	0.1	0.1	1.3	2.0	3.4	3.9
Hurdle rate, new coal = 10% (case 1[10])							
New South Wales	index	*1.00*	*1.00*	*0.05*		*0.10*	*0.77*
Victoria	index			*0.68*	*0.54*	*0.94*	*0.93*
Western Australia	index				*0.73*	*1.00*	*0.92*
Total	GW	0.1	0.1	1.3	2.0	3.9	10.2

these estimates. In their absence, the approach was experimental. For example, we can determine the smallest increment to hurdle rates at which significant resource allocation effects occur, such as the absence of new coal investment or coal refurbishment from the least cost solution.

Electricity supply sector specific hurdle rates

If a higher hurdle rate is applied equally to all electricity generation technologies subsequent to microeconomic reform, the results are not favorable to CCGT despite its lower capital cost and shorter construction lead time than new coal fired capacity. The explanation is simply that other technologies are even less capital intensive and hence more favored by this high rate than is CCGT. The latter has a unit investment cost (excluding interest during construction) of $750 or $765/kW and a construction lead time of 1.3 years, compared with $1200/kW and 3.5–4.0 years for a new coal fired power station. But other competing technologies with even lower capital intensity and also short lead times dominate CCGT in this 10 per cent sector specific hurdle rate scenario, for example:

- refurbished coal fired capacity ($600/kW and 2.0 years to construct): by 2030 this predominates in New South Wales, whereas no refurbishment is indicated in this state when the standard rate of return of 8 per cent applies);

- open cycle gas turbines (OCGTs, $337/kW, 1.0 year to construct) which squeeze out both CCGT and refurbished coal to dominate in Victoria by 2030 — total capacity being as high as 13.2 GW by 2030; 36 per cent of national electricity generation, higher than in any other scenario.

Technology specific higher hurdle rates: new coal fired capacity

For reasons discussed above, hurdle rates are more likely to differ significantly among electricity generation technologies because comparisons are being made in an investment context characterised by uncertainty, irreversibility and the benefits from 'waiting' or deferring investment. And the above discussion of modularity indicated that, on these grounds alone, the hurdle rate on investment would be correspondingly higher in the case of new coal fired capacity, possibly followed by refurbished coal and then CCGTs and OCGTs at lower hurdle rates.

In the relevant scenarios initially examined, the higher hurdle rate was attributed to investment in new coal fired capacity alone, with investment in the other technologies being at the default rate of 8 per cent. The higher hurdle rates tested in this way were 9, 10 and 12 per cent.

Results for CCGTs and for refurbished coal are summarised in tables 9 and 14. It was found that the least cost solution for the 12 per cent hurdle rate case was identical to that for the 10 per cent rate, the explanation being that investment in new coal fired capacity was in no instance cost effective at the 10 per cent rate. Such investment was also reduced, but not eliminated, at the 9 per cent rate.

A marked difference from the sectorwide higher hurdle rate case was that CCGT was significantly favored in these two cases (case 1[9], case 1[10]) with technology specific hurdle rates — rather than being completely squeezed out by other technologies with even lower capital costs. For example, in the case with a 10 per cent technology specific hurdle rate on new coal fired capacity, CCGT capacity reaches 3.2 GW in 2030 (and 10 per cent of electricity generated) compared with 1.6 GW (and 5 per cent) in the reference case. However (as indicated in table 14), refurbished coal benefits even more, with penetration as at 2030 increasing from 4 GW (and 13 per cent of generation) in the reference case to 10 GW (and 34 per cent) in the 10 per cent hurdle case. By contrast with the sectorwide hurdle rate case, this technology specific hurdle rate case entails no increase in OCGT compared with the reference case.

Technology specific higher hurdle rates: refurbished coal fired capacity

The next set of simulations attributed a higher hurdle rate also to refurbished coal capacity (case 2). The possible arguments based on modularity that might support such a hurdle rate differential were discussed earlier, notably that increment sizes later in the forecast period will tend to be tied to the larger generating unit sizes of currently existing power stations of the 20–25 year vintage.

Quite distinct from the modularity criterion, refurbishment does not entail the same risk abating advantages, with respect to the transmission sector, that accompany relatively 'footloose' or 'embedded' technologies such as CCGT and others such as gas fired industrial cogeneration.

Another key risk factor potentially having an adverse impact on the refurbishment option is that of community expectations about the future imposition of carbon constraints. As pointed out by Manne and Richels (1992) among others, considerations of risk and the logic of 'waiting' are highly relevant to investment that may be affected by 'gradually arriving' information about global climate change and associated policy responses. In terms of the MARKAL modeling, hurdle rates can be a way of reflecting these risk factors, where it is not possible or appropriate to apply energy sectorwide emission constraints directly. In MARKAL, actually existing or hypothetical greenhouse gas emissions or carbon dioxide targets would of course be modeled separately by imposing upper bounds on such emissions in the future periods involved. In those circumstances (not applicable here) it would be important to avoid double counting in the form of a hurdle rate adjustment based on this risk.

On the basis of the standard reference case assumptions, it was found that a hurdle rate of return of 11 per cent on investment in refurbished coal fired capacity (3 percentage points above the default rate) was sufficient to exclude it from the least cost solution in all states. As already noted, this same rate is more than sufficient to exclude new coal fired capacity. The result is that the share of CCGT to total electricity output (in this case 2[11]) is as high as 43 per cent by 2030.

Effect of cost-cutting productivity improvement in CCGT manufacture

On the specification of CCGTs and other fossil fuel based electricity technologies, the Australian MARKAL database (as revised following advice from Sinclair Knight Merz) includes scope for considerable 'autonomous' technical progress in energy efficiency and also modest scope for purchasing additional efficiency at a cost premium. However, the database thus revised does not embody scope for any cost-cutting productivity improvement in CCGTs over this projection period. As noted above, consideration of internationally induced technical change was outside the consultant's brief. Hence, no such possibility has been included in the reference scenario.

However, as a sensitivity test, a cost-cutting effect was included in one scenario based on the possible mechanisms discussed earlier. Those mechanisms include the possibility that productivity improvement in CCGT manufacture might be induced by widespread international adoption of the technology — for example, following international compliance with greenhouse gas emissions targets. The mechanisms could include production line economies of scale and 'learning by doing'. Accordingly, the relevant MARKAL test scenario included an assumption that the unit investment cost of CCGT would decline smoothly from 2010 to 26 per cent at the end of the projection period in 2030. A similar assumption was made in the case of OCGTs. This is a significantly more cautious assumption than would be implied by the International Energy Agency's projected global capacity expansion at the 'progress ratio' (0.75) cited earlier for the CCGT technology.

For the least cost solution (case 3), compared with the reference case, the effect is to increase the national level of CCGT capacity by 2030 from 1.6 GW to 3.8 GW, again occuring mainly in Victoria. The total capacity of CCGT and OCGT together increases from 6.5 GW in the reference case to 8.9 GW. However, there was still no CCGT penetration in New South Wales and Queensland solely based on this cost reduction.

The scenario combining factors favorable to CCGTs: robustness to changes in key assumptions

A plausible scenario favorable to CCGTs (case 4[low]) combines three of the features just discussed: use of a technology specific hurdle rate of 10 per cent for both new coal capacity and refurbishment; price elastic gas supplies and the cost-saving productivity improvement. As already noted (figure 4) the results for electricity generation, indicate a 46 per cent output share from CCGT capacity by 2030.

The robustness of this scenario result favorable to CCGT capacity can be noted in two ways. First, this share is only 3 percentage points above that without the cost saving productivity improvement and with the midrange (rather than the low) gas price assumption — that is, case 2[11], but note that the hurdle rate in case 2[11] (higher by a percentage point, at 11 per cent) is sufficient to exclude refurbishment.

Second, it was tested by substituting the high gas price assumption. In this case (4[high]), the adverse effect on the cost effectiveness of CCGT capacity is considerable — even when this technology is advantaged by lower hurdle rates than its coal based competitors. As illustrated in figure 5, the CCGT share of electricity output as at 2030 falls from 46 per cent in the favorable scenario to 21 per cent (still four times the reference case share) and the share of OCGT disappears completely (compared with 8 per cent in the reference case). Despite the 10 per cent hurdle rate on investment in both refurbished coal and new coal fired capacity, the share of refurbished coal fired capacity increases to 30 per cent. This compares with a 13 per cent share in the reference case and a 34 per cent share where refurbishment enjoys the same hurdle rate as CCGTs. But again, with the 10 per cent hurdle rate applicable, no new coal fired capacity is cost effective in this scenario despite higher prices for natural gas.

Clearly, the modeled shares of CCGT capacity and output are sensitive to key assumptions, such as hurdle rates and future gas prices.

Conclusions

This paper commenced with an argument that a least cost energy systemwide analysis can provide a more robust economic assessment than a simple 'technology by technology' approach. The optimising, systemwide approach has been adopted in this analysis of the CCGT technology against its competitors in the circumstances of the Australian energy system. The analysis incorporated reliable data, including technically informed projections of relevant cost and performance parameters, not only for CCGTs themselves but for their major competitors. This was achieved through a major update to the Australian MARKAL database for the electricity supply sector, using reputable engineering consultants.

The model results confirmed that both microeconomic reform in energy markets and technological progress can have mixed effects for CCGTs.

An aspect of microeconomic reform is that the investment process tends to proceed as if in private hands (even where strict privatisation has not occurred). An important feature of investment under these circumstances is that much less of its substantial risk is now borne or subsidised by electricity consumers and taxpayers. Hence, uncertainty and irreversibility must be incorporated in the analysis. Increased risks are associated, for example, with relatively large and 'lumpy' investments with long lead times and lifetimes and uncertain revenues owing to the difficulties of projecting consumption and volatile/uncertain prices for both outputs and fuel inputs. Market driven responses, internationally and in Australia, have been at least twofold:

- where possible, cost effective increases in production from existing capacity: increased levels of electricity generation from sunk capital using coal are in part the result of microeconomic reform and in part from technological progress — for example, in information technology — the same is true for life extension and higher utilisation factors for existing coal fired capacity;
- to the extent that new investment is unavoidable, technologies sought are less capital intensive with shorter lead times and are less lumpy, more modular and more reversible (for example, through 'building in' the possibility of repowering).

The MARKAL analysis confirmed that in Australia the important 'new' competitor with CCGT is refurbishment of existing coal fired capacity. It has some features of each of these 'market driven responses': it is extending the life of an existing facility and it is a new investment that has a shorter lead time than a completely new station and involves much less capital expenditure. However, doubts remain about the extent to which it should be attributed higher hurdle rates than CCGT on criteria including not only modularity but other factors such as being locationally tied to existing coal sites and 'climate change policy' risk.

The MARKAL modeling suggested that further cost-effective refurbishment of coal fired capacity would occur, especially in Victoria and Western Australia (additional to the Hazelwood example already seen in Victoria). By 2025, major refurbishment would be cost effective also in New South Wales to the extent that higher hurdle rates indeed apply to new coal capacity only. If the market were to reflect higher hurdle rates on refurbishment for the reasons suggested above, then the option could tend to be displaced by CCGT capacity.

A second key impact of microeconomic reform is on the future price of gas. An important, if not surprising, conclusion of the modeling is that the price of natural gas input can be a key determinant of CCGT's prospects of taking a major role in electricity generation by 2030. This is most evident if CCGT takes a significant role for other reasons — that is, if the refurbishment option is also less attractive to the market.

Understanding the factors influencing the future price of gas has important implications for both policy and for ABARE's research program for Australian MARKAL. Policy issues affect the conditions for supply augmentation and the working out of microeconomic reform and structural change in the gas industry. But there are important issues on the demand side, including a residual role for government in reducing risk. This can include influencing electricity sector generation investment choices.

The research task on the price of gas is to revise Australian MARKAL's representation of the deregulated, integrated gas supply system to enable the accurate endogenous treatment of these processes over the projection period. This revision has to take account of conditions that could include a very large favorable shift in the demand for gas. Again, this includes treatment of key consumption loads, including potential large nonelectricity industrial users of gas.

Large scale international expansion in the use of CCGTs (say, as a result of the international adoption of targets for greenhouse gas emissions) could be associated with a significant fall in their cost per kilowatt — for example, through 'learning by doing' and scale economies. This assumption, along with the possible effects of higher hurdle rates on technology choice and a low gas price assumption was the basis for a plausible scenario in which CCGT capacity accounted for as much as 46 per cent of electricity output by 2030. However, this proportion could markedly fall if either the hurdle rate on refurbishment turns out to be closer to that for CCGT or there is not sufficient moderation to gas price increases.

The carbon dioxide coefficient associated with electricity generation from (for example) refurbished brown coal fired capacity is almost four times that of the most energy efficient CCGT in the MARKal database. Hence, least cost policies to abate greenhouse gas emissions are likely to significantly encourage CCGT penetration, especially under Australian conditions. Although this question requires a separate analysis, the results reported here offer guidance in establishing a suitable base line.

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