Energy Reform Implementation Group

Impediments to investment in Australia's energy market

The views of investors

November 2006

This report contains 79 pages

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Contents

1 Executive summary

On 10 February 2006 the Council of Australian Governments ("COAG") established a high-level Energy Reform Implementation Group ("ERIG") to develop detailed implementation arrangements for further energy market reforms, if such reforms are required.

ERIG has engaged KPMG to assist it in formulating its views in the financial markets area by examining in further detail, and amongst other issues, the capital market and any impediments to investment in the energy sector.

To undertake the task we have, amongst other things, interviewed twenty existing and potential investors including the major integrated players, independent generators/producers and retailers and a number of major commercial and investment banks. We have also reviewed the evidence in regard to investors' views.

Our review suggests that investors do not believe that there is any impending crisis in relation to investment in the upstream or downstream energy sectors. On the contrary, considerable investment is occurring and is proposed, particularly in the gas sector. In the electricity sector, whilst there is no sense of crisis (ie. there are no major impending reliability issues) there is a basis for some concern, particularly as new baseload capacity becomes necessary.

Investors do believe, however, that that there are impediments to efficient investment in the energy sector, and in the electricity sector in particular. Investors believe that the three key impediments to more efficient investment are:

- Government's continuing ownership of energy businesses;
- Residual electricity price regulation at the wholesale and retail levels; and
- Government policy in regard to greenhouse gas emissions and renewable energy.

In particular, if the major concern of policy makers is whether the market will invest in new baseload electricity generation in a timely manner, then it is imperative that governments address the uncertainty around greenhouse gas emissions policy.

In general, investors do not see major impediments to investment in the areas of market rules, market access and market performance, although some investors had strong views on particular issues. The widespread view is that the energy market works "pretty well", and better than similar markets overseas. Moreover, even where parties had strong views on particular issues, they invariably considered that policy makers should address the major impediments first, where addressing particular issues would represent a major change to the market.

We think the available evidence supports investors' views on the impediments to more efficient investment.

Governments are in a position to address the main impediments, and Section 10 seeks to identify the major policy implications. We acknowledge, however, that many of the changes are likely to be as politically challenging as they are self-evidently in the longer term interests of energy markets and energy consumers.

2 Introduction

On 10 February 2006 the Council of Australian Governments ("COAG") established a high-level Energy Reform Implementation Group ("ERIG") chaired by Mr Bill Scales AO and including industry experts (Mr Geoff Carmody, Mr Alan Rattray and Mr David Swift) to develop detailed implementation arrangements for further energy market reforms.

ERIG must report back to COAG before the end of 2006 with proposed policy measures to:

- Achieve a fully national transmission grid;
- Address any structural issues affecting the competitiveness of the sector; and
- Ensure that there are transparent and effective financial markets to support energy markets.

ERIG's report will set out the case for or against further policy measures.

On July 2006 ERIG published an Issues Paper and it received over forty submissions.

ERIG has engaged KPMG to assist it in formulating its views in the financial markets area by examining three issues in further detail:

- The electricity trading market and any impediments to its development;
- The capital market and any impediments to investment in the energy sector; and
- The gas market and any impediments to its development

This report addresses the second of these issues.

Appendix A contains our terms of reference.

2.1 Approach

To undertake this assignment we have:

- Reviewed the development of the energy sector and the facts regarding investment;
- Reviewed ERIG's Issues Paper and stakeholders' submissions;
- Identified and interviewed key potential investors;
- Documented their views on impediments to investment in the energy sector;
- Examined the evidence in respect of those impediments; and
- Drawn conclusions about the implications for energy sector reform and government policy.

We have interviewed twenty existing and potential investors including the major market players (three), independent generators/producers (six) and retailers (two) and a number of major commercial and investment banks (six). We also interviewed three government owned businesses, which have been amongst the most active in the competitive market.

We conducted the interviews under the 'Chatham House Rule' and therefore do not attribute any comments we report. The interviews followed a semi-structured outline which invited the interviewees to identify what they saw as the major impediments to investment and then sought to investigate the basis for those views and the evidence to support them.

The nature of the process means that we cannot 'prove' the views presented to us are representative of investors generally. In our view, however, the consistency of the views presented on the key impediments to investment, strongly suggests that the views are representative of investors generally.

ERIG has stressed its interest in factual material that supports any assertions made regarding impediments to investment. Our analysis therefore focuses on what investors believe are the most significant impediments and, in particular, on the evidence to support those beliefs. The investors we interviewed often produced strong anecdotal material to support their views, but less analytically verifiable evidence. We do not believe this is surprising given their focus is on finding attractive investments, rather than pondering on those that are unattractive. Some, however, pointed to what they believe is 'hard' evidence, which we have investigated.

The research in this report occurred prior to November 2006. We note that there were a number of recent government policy announcements, particularly in regard to greenhouse gas emissions during November and prior to the finalisation of this report. This report does not document those policy announcements, but given their nature they do not alter its key conclusions.

2.2 Definitions

For the purposes of this task we have defined the 'energy sector' as the electricity and domestic (ie. not export-oriented) gas market. In practice, we focus on the upstream and downstream parts of those markets, and the electricity sector and the National Electricity Market ("NEM") in particular. This is because this is where investors believe the most material impediments exist. We also focus largely on the 'supply side' of the industry as this is the focus of investors.

We do not discuss in detail issues that investors do not believe are material impediments, except market performance.

For the purposes of this project we define 'investment' to be:

- Upstream investment and entry in electricity and gas production (and transmission where it relates to market development); and
- Downstream investment and entry in electricity and gas retailing.

We also discuss changes in ownership in certain cases for the purposes of illustrating the propensity to invest in the sector, at least in relation to existing assets.

We define 'impediments' to be any factor that might be impeding *efficient* investment such as:

- Market failures;
- 'Excessive' transaction costs; and
- Any other issues that might be impeding private sector investment decision (eg. regulation).

The focus on efficient investment is consistent with the NEM market objective:

> To promote efficient investment in, and efficient use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability, and security of supply of electricity and the reliability, safety and security of the national electricity system.

2.3 Outline of report

This report provides the output of our analysis. In particular:

- Section 3 provides some relevant background on energy market ownership and investment;
- Section 4 identifies the potential impediments to investment;
- Section 5 examines government ownership;
- Section 6 examines energy price regulation;
- Section 7 examines government policy on greenhouse gas emissions and renewable energy;
- Section 8 examines uncertainty in government policy and regulation;
- Section 9 examines other potential impediments to investment; and
- Section 10 examines the implications for policy.

There are two appendices:

- Appendix A contains our Terms of Reference; and
- Appendix B summarises some key points about electricity and gas and, in particular, the unique attributes of electricity which are relevant to analysing investment.

2.4 Disclaimer

Inherent Limitations

This report has been prepared as outlined in this section 2. The procedures carried out in preparation of this report constitute neither an audit nor a comprehensive review of operations.

No warranty of completeness, accuracy or reliability is given in relation to the statements and representations made by, and the information and documentation provided by the officers of the Department of Industry Tourism and Resources ("DITR") providing a Secretariat Service to the Energy Implementation Reform Group, who were consulted as part of the process.

KPMG has indicated within this report the sources of the information provided. We have not sought to independently verify those sources unless otherwise noted within the report.

KPMG is under no obligation in any circumstance to update this report, in either oral or written form, for events occurring after the report has been issued in final form.

The findings in this report have been formed on the above basis.

Third Party Reliance

This report is solely for the purpose set out in section 1 of this report and for DITR which includes the use of this information in the Energy Implementation Reform Group's ongoing consultation process. The draft report is not to be used for any other purpose or distributed to any other party without KPMG's prior written consent.

This report has been prepared at the request of the DITR in accordance with the terms of KPMG's contract dated 13 July 2006, proposal dated 8 September and the Form of Order dated 11 October 2006. Other than our responsibility to DITR, neither KPMG nor any member or employee of KPMG undertakes responsibility arising in any way from reliance placed by a third party on this report. Any reliance placed is that party's sole responsibility.

3 Energy sector ownership and investment

This section summarises:

- Energy sector ownership in Australia and changes in ownership over the period 1993-2006;
- Energy sector investment in recent years (ie. 2002-06); and
- Proposed energy sector investment.

This section provides context for the examination of impediments to investment.

3.1 Changes in energy sector ownership

This section summarises the changes in energy sector ownership over the period 1993-2006. In particular, it examines across of the value chain:

- Who owns the assets (ie. the Government or the private sector); and
- The 'type' of private sector investor, where private ownership prevails.[1]

It focuses more on electricity because the private sector has always played a more significant role in gas and particularly in gas production and transmission.

The key points are that:

- The privatisations in Victoria (of electricity and gas) and South Australia (electricity) and to a lesser extent other states (eg. WA gas) have played a key role in increasing private sector involvement across the value chain. But these changes now occurred some time ago;
- The private sector is playing a much larger role in gas than it is in electricity (and always has), but its role has continued to increase faster in gas than it has in electricity;
- The Government sector still dominates the electricity generation, network and retail sectors. By contrast, the Government sector has no ownership role in gas production and its role in the network and retail sectors is modest;
- The types of private owners have changed considerably over the last decade. That is, North American headquartered ownership was the most significant element of private ownership up until 2002, but then these interests progressively sold assets to Australian and Asian headquartered owners; and

[1] We describe owners broadly by where they emanate from. We describe 'investors' as those who have primarily placed the assets in infrastructure funds and often split ownership from operation (eg. Envestra, DUET, Alinta Infrastructure Holdings). All the ownership percentages presented for generation are on capacity, for networks are on Regulated Asset Value and for retail are on customer numbers.

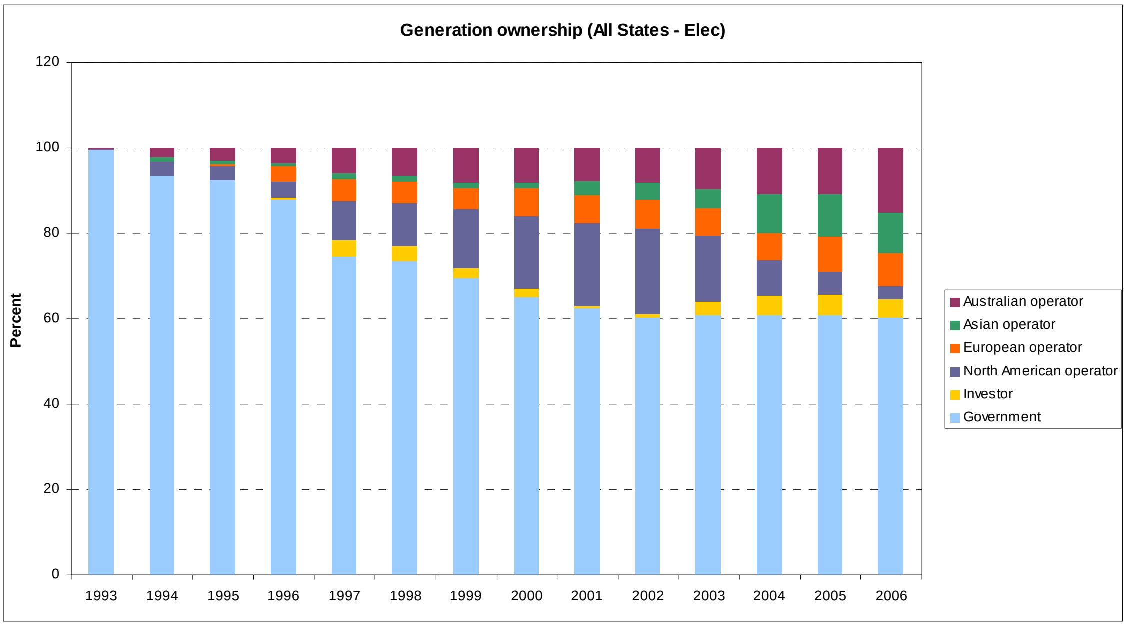
- Investors have emerged with a growing share of ownership, particularly in the network sector. This may well increase with Alinta's acquisition of AGL's infrastructure assets. Investors are also emerging in the generation sector, at least where the assets offer relatively high cash flow certainty (ie. via some form of long term power purchase agreement or "PPA"). For example, two significant floats by Babcock & Brown and Transfield Services of funds comprising electricity generation assets are imminent.[2]

3.1.1 Electricity generation

Figure 1 shows the ownership history of grid connected generation capacity in Australia. In particular, it shows that:

- In 1993 government owned almost all grid connected generation capacity across Australia;
- By 1997 government ownership had fallen to 75% and by 2002 to 60%; and
- Since that time the degree of private involvement in electricity generation has broadly stabilised.

Figure 1: Changes in the ownership of electricity generation by type of owner



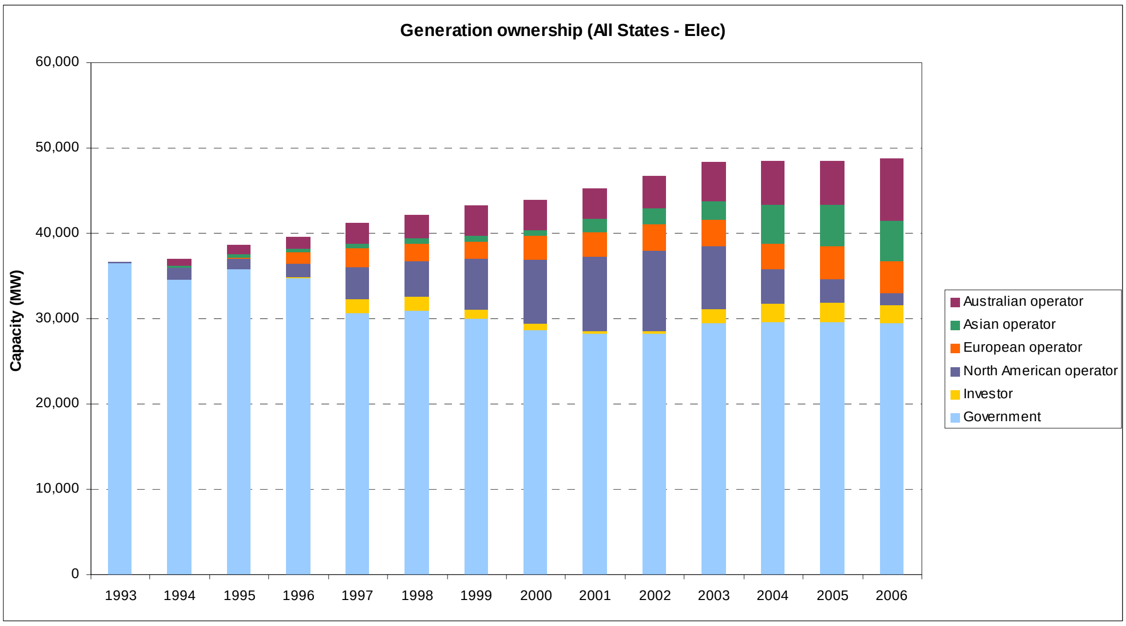
The trend is similar for the NEM jurisdictions only; however, the level of private ownership is more pronounced (ie. in 2002 government ownership in the NEM fell to about 55% and has since broadly stabilised).

[2] Australian Financial Review, 'Hot market powers Babcock & Brown float', 19 October 2006, page 16. Most of the 3,000 MW that the fund is expected to own is contracted to energy suppliers on a long term basis. It includes Braemar and Oakey power stations and projects in Kwinana (WA) and Wagga Wagga (NSW). The new entity is also expected to acquire Redbank and Ecogen from Babcock & Brown Infrastructure Group.

Figure 2 displays the same information as above based on installed capacity. It shows, for example, that:

- In 1993 government owned grid connected generation capacity of 36,000 MW across Australia;
- By 1997 government ownership had fallen to almost 31,000 MW and by 2002 to 28,000 MW; and
- Since that time government owned generation capacity has increased to almost 30,000 MW.

Figure 2: Changes in the ownership of electricity generation by type of owner



3.1.2 Networks

The changes in network ownership follow reasonably closely the changes in the ownership of generation, for the reasons indicated above. However, the degree of private sector involvement is much higher in gas networks than it is in electricity networks. This reflects the initial status of gas networks (which have always involved a greater degree of private ownership, particularly in transmission), and the greater degree of subsequent privatisation.

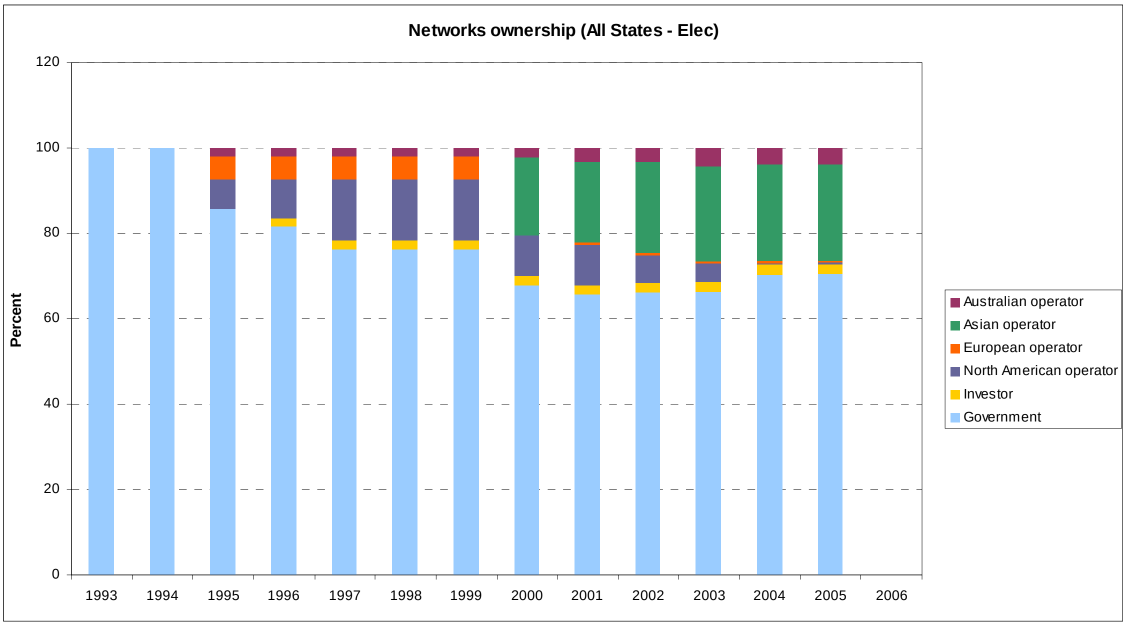
Australia – electricity networks

Figure 3 shows the ownership history of electricity networks across Australia. In particular, it shows that:

- In 1993 government ownership accounted for 100% of electricity network assets;

- By 1997 government ownership had fallen to 76% and by 2002 to 66%; and
- The proportion of government ownership has since stabilised.[3]

Figure 3: Changes in the ownership of electricity networks by type of owner



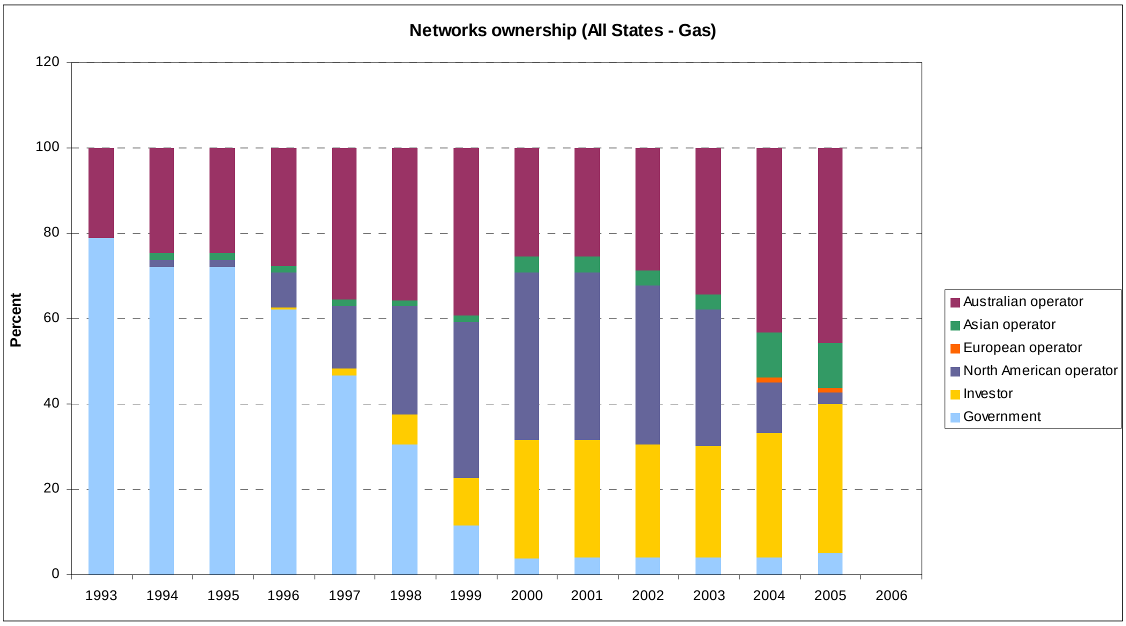
Australia – gas networks

Figure 4 shows the ownership history of gas networks across Australia. In particular, it shows that:

- In 1993 government ownership accounted for 79% of gas network assets across Australia;
- By 1997 government ownership had fallen to 47% and by 2000 to 4%;
- Government ownership has since remained at a very modest level (albeit further reduced most recently by the sale of Allgas in Queensland); and
- Infrastructure funds have become significant owners of gas networks assets (eg. Alinta Infrastructure Holdings, Australian Pipeline Trust, Envestra and DUET). Moreover, this share is likely to increase further if Alinta chooses to securitise the assets it recently acquired from AGL, as seems likely.

[3] The slight increase in recent years is due to the greater expenditure particularly on transmission and distribution networks in Queensland and NSW.

Figure 4: Changes in the ownership of gas networks by type of owner



3.1.3 Retail

The changes in retail 'ownership' in the electricity and gas sectors by the type of owner focuses on who 'owns' the customers in an incumbent sense and therefore shows the proportion of customers whose local retailer is government or privately owned.

In other words, it does not describe precisely the number of customers each type of retailer has under contract.[4] Section 6 describes the available information in terms of what is happening within the competitive retail markets and the degree of switching and new entry between retailers, whether they are government or privately owned. However, due to information constraints the information is necessarily incomplete.

The key points are that:

- Retail ownership across Australia has followed the broad trends outlined above for generation and network assets. That is, high levels of government ownership in 1993 (89%), a stepped decline in the level of government ownership by 1996 (71%) followed by further step declines in 1999 and 2000 (49%). This reflects the privatisations in Victorian (electricity and gas) and South Australia (electricity) respectively;

- Since that time there have been no major changes (although there have been major changes in terms of introducing competition) although significant changes in Queensland are imminent;

[4] So where FRC is in place a significant minority of these customers are likely to have shifted between government and privately owned retailers and vice versa. There are also a couple of jurisdictions which have not introduced FRC (eg. Queensland, although this will soon change for small urban customers, and Tasmania).

- Private ownership is most prevalent for gas retailing, most notably from 1999 onwards. In electricity retailing, government ownership still dominates.

Australian electricity retail ownership

Table 1 shows the ownership history of retail electricity customers. In particular, it shows that:

- In 1993 government owned 100% of electricity retail customers across Australia;
- By 1997 government ownership had fallen to 75% of the retail market, and by 2002 it was down to 66%; and
- Since then the level of government ownership has stabilised at around 66%, although it will soon fall significantly with the sale of Sun Retail and Powerdirect in Queensland.

Table 1: Electricity retail customer ownership

	1993	1996	1999	2002	2005
Government ownership	100%	75%	75%	66%	67%
Private ownership	0%	25%	25%	34%	33%

Australian gas retail ownership

Table 2 shows the ownership history of retail gas customers. In particular, it shows that:

- In 1993 government owned 60% of electricity retail customers across Australia;
- By 1999 government ownership had fallen to around 15% of the retail market, and in the following year accounted for less than 5% of the retail market; and
- It will soon fall slightly further with the sale of Sun Retail, which includes ENERGEX's retail natural gas customers.

Table 2: Gas retail customer ownership

	1993	1996	1999	2002	2005
Government ownership	60%	60%	15%	4%	4%
Private ownership	40%	40%	85%	96%	96%

3.2 Recent investment

This section summarises recent investment in the upstream parts of the electricity and gas value chain by:

- Type of fuel (where relevant);

- Type of investors (government and private sector); and
- Type of private investor. [5]

In relation to the latter we differentiate primarily between those that are 'vertically integrated' and those that are not.[6] This involves a degree of judgement and as a result where appropriate we include numbers at the low and high ends of a reasonable range.

Section 6 discusses investment in the downstream (or retail energy market) in more detail.

The key points are that:

- There appears to have been considerable investment in the upstream gas sector, all of which has been undertaken by the private sector, but some of which has been supported by government subsidies;
- Gas is growing in importance as a fuel source, including as an input into electricity generation, and considerable new investment is occurring;
- The Government remains a significant investor in new electricity generation capacity; and
- The degree of vertical integration is modest presently but it has increased significantly recently, albeit from a low base.

Electricity generation

In the five years from 2002 to 2006 investment in Australia's electricity generation capacity has resulted in a net increase in capacity in the order of 3,600MW. This has included reductions and closures of approximately 1,600MW and gross increases of 5,300MW.

Table 3: Change in generation capacity – Australia

	2002 (MW)	2003 (MW)	2004 (MW)	2005 (MW)	2006 (MW)	Total (MW)
Reductions in capacity	163	331	0	2	1,179	1,675
Increases in capacity	1,723	1,994	141	268	1,186	5,312
Net change in capacity	1,560	1,663	141	266	7	3,637

Examples of the investments include:

- Government: Valley Power (300MW in 2002), Swanbank E (380MW in 2003), Tarong North (450MW in 2003) and Kemerton (260MW in 2005).

[5] Much of the information in Section 3.2 is drawn from ESAA, Electricity Gas Australia 2006, 2006.
[6] We define "vertically integrated" as those assets that are owned or proposed by the major incumbent retailers or their affiliates.

- Vertically integrated: Hallet (220MW in 2002), Somerton (150MW in 2002) and Quarantine (100MW in 2003).

- Remaining private sector: Millmerran (852MW in 2002), 50% of Callide C (210MW in 2003), Yabulu (80MW in 2006) and Thomas Playford B (60MW in 2006). This includes new wind farms at Challicum Hills (53MW in 2004) and Lake Bonney (81MW in 2006).

Figure 5 illustrates the parties responsible for the investment in capacity. It shows that Government accounted for about half.

Figure 5: Major investment in new capacity 2002-06 by owner

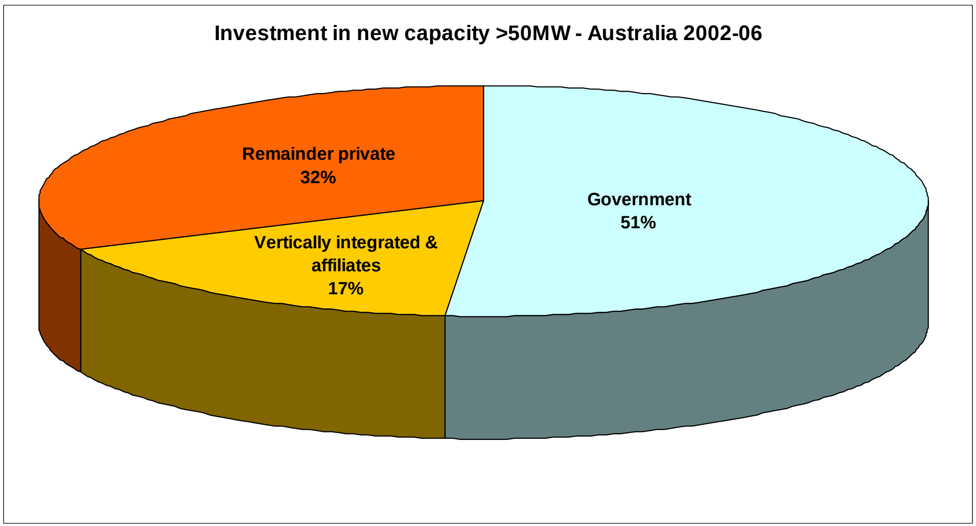
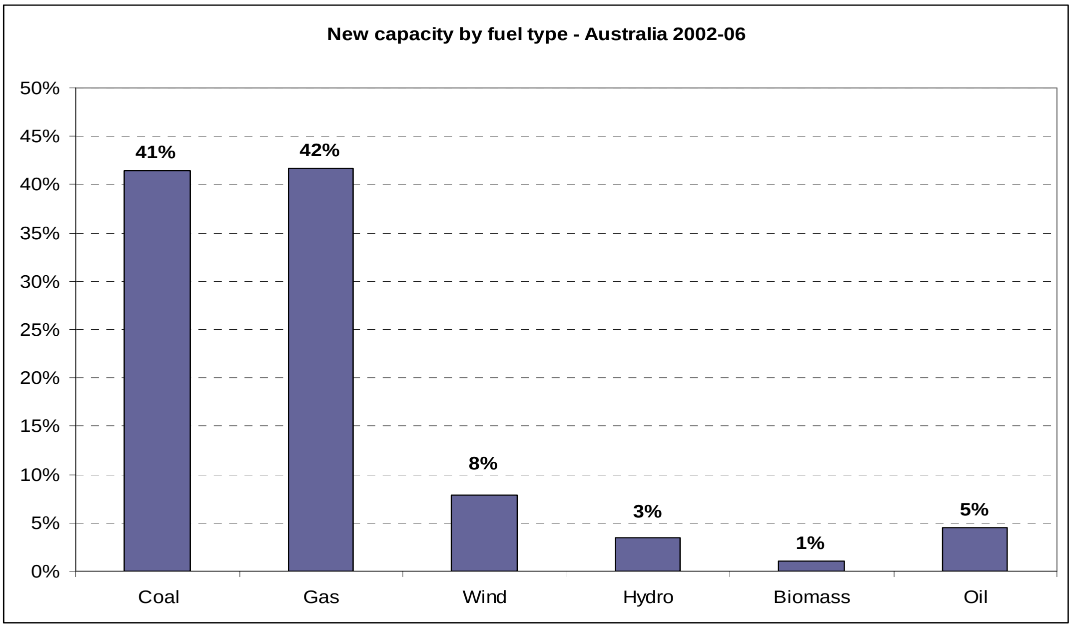


Figure 6 shows that coal and gas have dominated the investment in this new capacity, accounting for over 80%.

Figure 6: Investment in new capacity 2002-06 by fuel



Gas production

There has been and is proposed to be significant investment in the coal seam methane industry.

The energy industry has spent $700 million to date in developing coal seam gas assets and is expecting to spend a further $2 billion over the next 20 years.

Less than a decade ago the coalbed gas industry in Queensland supplied about two petajoules of gas a year; however, now it is producing almost 30 petajoules annually (assisted by the Queensland Government's 13% gas policy – see Section 7.1). Industry estimates suggest that there is more than 15,000 petajoules of recoverable reserve in Queensland alone, enough to provide all the gas needs of Australia's eastern states for 20 years.[7]

Electricity and gas transmission

Recent years has seen the construction of a number of new electricity interconnects. These have included: Directlink; SNI; Murraylink; the upgrade of the Snowy link; and Basslink. Three of these were constructed as non-regulated assets, but two have subsequently become regulated.

The electricity transmission businesses are also spending (and proposing to spend) considerable amounts on greater intra-state investments.

There has also been considerable investment in gas transmission assets – much of it unregulated – and producing the beginnings of an interconnected South Eastern Australian gas market. This

[7] The Weekend Australian, Special Report: Power Generation, 'Abundance, ease of access make methane attractive', 9-10 September 2006, page P7.

includes the Eastern Gas Pipeline, the Tasmanian Gas Pipeline, and the SEA Gas pipeline. For example, TRUenergy notes that the latter:

> ..has the capacity to transfer in excess of 300TJ/day between Victoria and South Australia. This is (very conservatively) equivalent to an electricity interconnector in excess of 1,300 MW.[8]

3.3 Proposed investment

This section summarises proposed investment in the upstream parts of the electricity and gas value chain by:

- Type of fuel (where relevant);
- Type of investors (government and private sector); and
- Type of private investor. [9]

Section 6 discusses investment in the downstream (or retail energy market) in more detail.

The key points are that:

- There are proposals for significant ongoing investment in the upstream gas and electricity sectors;
- Governments propose to remain significant investors in electricity generation capacity; and
- 'Vertically integrated' entities will undertake a significant degree of investment, particularly of private sector investment.

Electricity generation

An analysis of proposed investment in generation capacity in the NEM reveals the following. About 16,000 MW of new capacity is proposed of this 2,200 MW is under construction and a further 2,250 MW is at an advanced planning stage. Of this, about 75 per cent is gas fired.

Of the proposed new capacity:

- Government owned generators represent 42% and the private sector 58% (as Figure 7 illustrates);
- Of the private sector investment:
  - Somewhere between, 38% and 52% can probably be regarded as being proposed by vertically integrated entities;[10]

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8 TRUenergy, Comments on ERIG Issues Paper, 4 August 2006, page 3.
9 Much of the information in Section 3.3 is drawn from ESAA, Electricity Gas Australia 2006, 2006.

- A significant proportion of the remainder (at least 50%) is likely to be subject to PPAs (eg. wind and co-generation plant); and

- What we have assumed are merchant generators are proposing the remaining private sector investment, although in some cases these parties also have retail interests (eg. International Power in its Joint Venture with Energy Australia).

Figure 7: Proposed investment in new capacity – NEM [11]

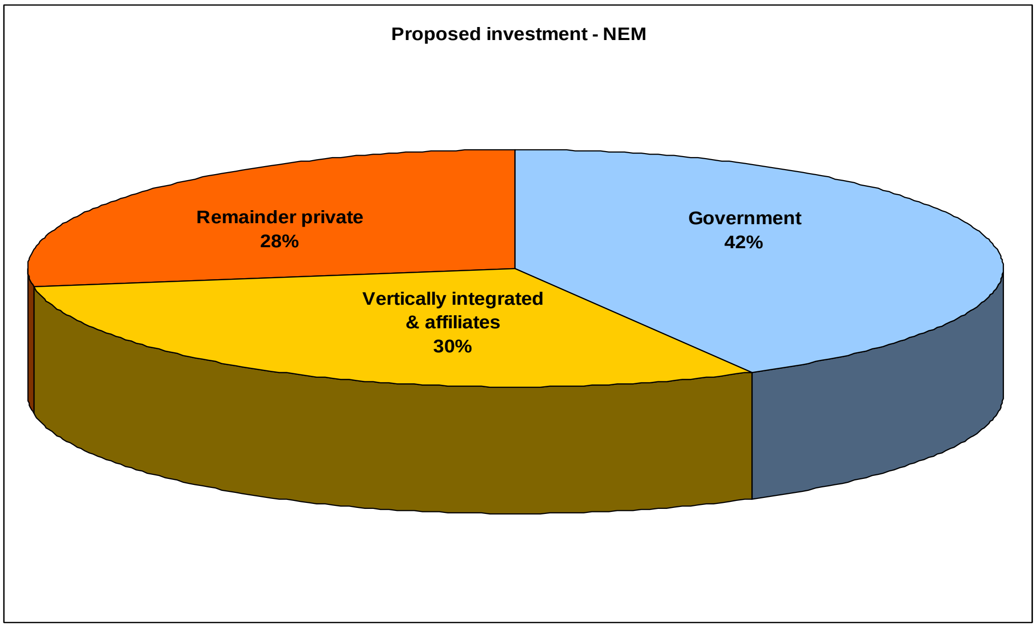
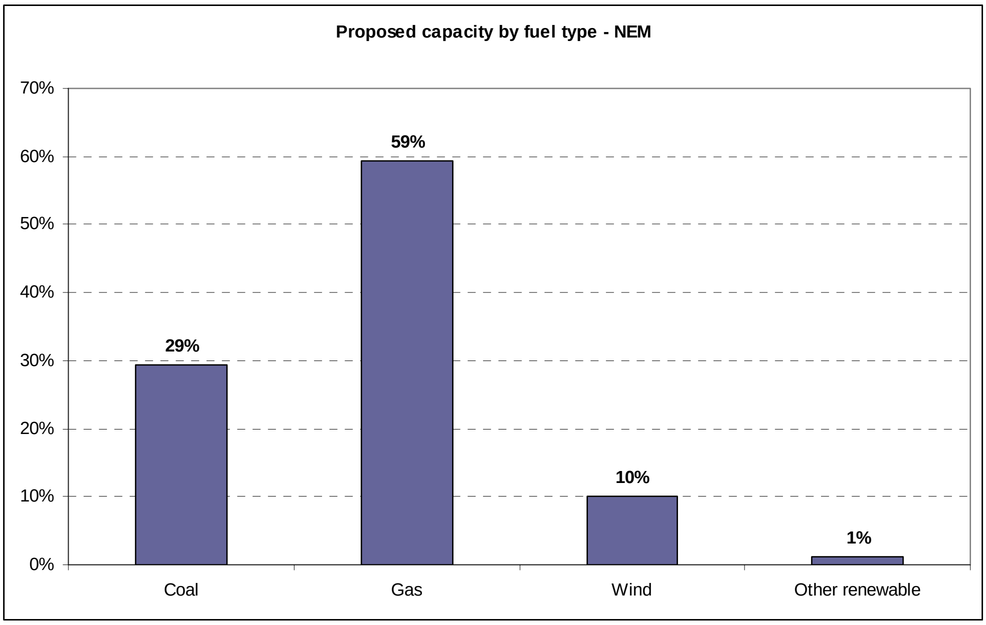


Figure 8 shows that gas fired generation is playing a larger role in the total proposed investment in new capacity, than it has in recently built capacity.

[10] Origin's and AGL's proposed investments in Queensland (Spring Gully at 1,000MW and Townsville at 370MW) are in jurisdictions in which they do not appear to have substantial customer bases at least at the moment, although this may soon change with the sale of some Queensland retail assets. Our range reflects the inclusion and exclusion of these plants.

[11] This includes the two plants mentioned in footnote nine in the vertically integrated category.

Figure 8: Proposed investment in new capacity by fuel – NEM



It is worth noting that in a private market significant differences between what investors propose to build and what they build are likely, as the market responds to developments.

Gas production

As Section 3.2 indicates, investors are proposing a significant amount of new investment in gas production and transmission, particularly in the coal seam methane sector.

3.4 England and Wales

This section briefly summarises investment trends in the UK electricity market, one of the privatised markets with the longest history of competition in its upstream and downstream markets, including the deregulation of retail electricity prices.

Privatisation in England and Wales created two major generation companies and a nuclear generation business which initially remained in public ownership. It also created twelve regional electricity companies with retail franchises. Since privatisation that situation has changed significantly to the extent that there are now six largely vertically integrated entities (as Section 9.3.4) discusses. In the early stages of this process, however, market intervention was used to manage the dominance of the two major private generation businesses.

Since 1994 the amount of generation capacity has increased from about 64 GW to 74 GW or by about 15%. The generation mix has also changed substantially over the period. In 1989 it was dominated by coal (64%) and nuclear (24%). Today the main respective shares are gas (37%), coal (34%) and nuclear (20%).

The UK is likely to need around 25 GW of new electricity generation capacity by 2025, partly because around 8 GW of coal plant must close by 2015 to meet EU environmental legislation, and around 10 GW of nuclear plant is likely to have reached the end of useful life by that time.[12]

There is currently 12 GW of Combined Cycle Gas Turbines either authorised or pending authorisation.[13] This could increase gas's share of the generation mix to 55% by 2020 (without any additional changes to the current market framework).

It can be seen therefore that the privatisation of the UK industry (and certain environmental and competition policy constraints) has lead to major changes in its structure and fuel mix – with these changes being driven (mainly) by market forces.

There is a need for significant new investment, but there does not appear to be major concern about the market's ability to deliver that investment.

3.5 Summary

It seems reasonable to conclude on the basis of the above that:

- There has been considerable corporate takeover activity in the energy market in recent years, but particularly in the regulated networks sector and more recently in the upstream gas sector;

- There is considerable investment occurring in the upstream parts of the electricity and gas value chains; and

- There are proposals to invest considerably more in the upstream parts of the electricity and gas value chains although in the case of electricity governments are proposing to play a key role.

[12] UK Department of Trade and Industry, The Energy Challenge, 2006.
[13] Prospex Research, European Power Trading 2006, page 122.

4 Potential impediments to energy sector investment

This section summarises:

- The need for investment;
- The concerns stakeholders have raised regarding investment; and
- How we assess investors' views regarding these impediments.

4.1 The need for investment

ERIG's Issues Paper highlights that Australia's energy needs are growing rapidly, necessitating large-scale investments to maintain the balance of energy supply and demand in the long term.[14]

The Federal Government's energy white paper notes that:

- The Australian Bureau of Agricultural and Resource Economics estimates that net electricity demand will rise from 186 TWh in 2000 to 284 TWh in 2020.[15] It sees the need for 8,140 MW of new plant to be in operation by 2020;[16] and
- The energy industry has indicated that it will need to invest $30-37 billion over the period to 2020 to meet the growth in electricity demand.[17] We understand that this might more than double the expenditure of the preceding 14 years, although the lack of spending over this period likely reflects the benefits of reform (as Section 5.3.2 discusses).[18]

The investment is needed partly because of growth and the nature of that growth (where peak demand is growing faster than total demand), but also because a significant proportion of existing infrastructure is approaching the end of its useful life.

4.2 Potential impediments

A number of stakeholders have identified potential problems in meeting the need for investment. These problems do not appear to relate to recent investment (ie. reliability has not been a significant problem recently), nor do they appear to relate to what is necessarily proposed in the short term, given expected needs.

The potential problems appear to relate to the investment challenge over the medium term.

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[14] Energy Reform Implementation Group, Issues Paper, July 2006, page 1.
[15] Department of Prime Minister and Cabinet, Securing Australia's Energy Future, 2004, page 68.
[16] The Weekend Australian, Special Report: Power Generation, 'Coal reigns supreme among future fuels', 9-10 September 2006, page P3.
[17] Department of Prime Minister and Cabinet, op. cit., page 69. See also the Weekend Australian, Special Report: Power Generation, 'Coal reigns supreme among future fuels', 9-10 September 2006, page P3. This equates to about 27 per cent of the existing asset value. See The Weekend Australian, Special Report: Power Generation, 'Industry taps into $12b seam', 9-10 September 2006, page P1.
[18] Energy Response, Response to the ERIG Issues Paper, July 2006, page 3.

Based on the views that some stakeholders have put forward during the ERIG consultation process and in the wider energy policy debate, there would appear to be a variety of potential impediments to energy sector investment. In particular, some stakeholders are concerned about:

- Ensuring the magnitude of required investment occurs in a timely fashion;
- Whether the electricity market (in particular) will deliver sufficient and timely capacity;
- Whether the electricity market will deliver particular parts of this capacity (eg. new baseload generation capacity in particular);
- Whether the structure (both horizontal and vertical) and design of the electricity market are causing or exacerbating this risk and/or creating a risk that the market will deliver this investment, but do so inefficiently; and
- Whether the level of liquidity in the markets is sufficient or whether it, in light of industry concentration, becomes part of a 'vicious circle' that:
  - Further reduces liquidity;
  - Thereby further encouraging market concentration; and
  - Deterring new entry and providing more market power to the major players.

4.3 Classifying and assessing potential impediments

The potential impediments stakeholders identify appear to fall into three broad categories; those that are a function of:

- Government polices and uncertainties with those policies;
- Regulation of the market; and
- Characteristics of the market and its performance.

For the purposes of our analysis we analyse seven types of potential impediments to investment:

- Government ownership of the energy production process;
- Price regulation of electricity generation and energy retailing;
- Government policy in regard to greenhouse gas emissions and renewable energy;
- General uncertainty in regard to government policy and regulation;

- Market rules (eg. the 'energy only' market; the level of VoLL; the Reserve Trader; and credit arrangements);

- Market access including access to fuel and the network and the market; and

- Market performance (eg. prices, the depth and liquidity of the financial markets, the willingness to take energy market risk, and the degree of vertical integration).

In the sections below we address each of the above potential impediments. In particular, we:

- Describe the potential impediment;

- Describe the views of investors in relation to it;

- Examine the evidence to support those views; and

- Assess the possible impacts on investment.

We focus on those potential impediments which investors believe present the most material impediments to investment.

5 Government ownership

This section outlines:

- The incidence of government ownership;
- Investors' views on the impediments it creates;
- The evidence to support those views; and
- The impacts of those impediments.

5.1 The incidence of government ownership

Government ownership of the energy production process is a common feature of Australia's energy markets, particularly in the electricity sector. Section 3 illustrates the extent of government involvement in the electricity value chain, and the extent to which governments are proposing to invest.

Government ownership is most apparent in NSW, Queensland and Tasmania. There are, however, some moves to reduce government ownership. In particular, the:

- Queensland Government is in the process of lessening its ownership of energy retailing;
- NSW Government has indicated a preference that all new electricity generation be provided by the private sector; and
- Tasmanian Government has indicated that it is considering selling its electricity transmission (ie. Transend) and distribution (ie. Aurora Energy) businesses, and is encouraging private sector investment in electricity generation.

Despite this, governments still own about half of both generating capacity and the retail market.

5.2 Investors' views

Investors believe that government ownership is a significant impediment to more efficient energy sector investment. Investors consider that it impedes investment decisions by:

- Producing premature investment;
- Deferring or crowding out investment the private sector otherwise would undertake;
- Increasing asymmetric risks (eg. asset stranding);
- Distorting price signals in the market through investment and operating decisions; and

- Generally discouraging new entry because investors typically have an aversion to 'competing' with government owned businesses and will often allocate capital accordingly.

In particular, investors believe government ownership is most likely to impede efficient investment if:

- Governments are proposing new investment;
- Government owned businesses are making inefficient operating and pricing decisions; or
- There is a risk that governments might propose new investment at a later date.

5.3 Evidence

'Hard' evidence of the impediments to investment government ownership creates is difficult to find. This is primarily because the absence of private sector investment - in the face of public sector investment – does not *prove* what would have happened absent the latter (ie. there is no obvious counter-factual).

Nevertheless there is evidence that is indicative of the impediments government ownership can create, even though it is often of a more indirect or anecdotal nature.

5.3.1 Returns on government owned businesses and market expectations

The Productivity Commission's report into the Financial Performance of Government Trading Enterprises 2000-01 to 2004-05 states:

> Government ownership and government borrowing arrangements attenuate the incentives to maximise shareholder return and operational efficiency that flow from appropriate capital structures and market engagement.[19]

It goes on to note that:

> In 2004-05, only eight of the 21 monitored GTEs achieved a return on assets in excess of 8 per cent. Of the remaining 16 electricity GTEs, six failed to achieve the risk free rate of 5.42 per cent (that is, the ten year government bond rate). The median rate of return was 7.3 per cent.[20]

Table 4 illustrates some key financial statistics of the NSW and Queensland government owned businesses. It shows that for the period 2000-01 to 2004-05 the businesses had:

- Average levels of gearing of just below 30%;

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[19] Productivity Commission, Financial Performance of Government Trading Enterprises 2000-01 – 2004-05, 2006, page 2.
[20] Ibid., page 106.

- Average return on assets of just below 8%; and
- Average returns on equity of just below 9%.

There are some discrepancies in the figures (eg. some of the returns on equity are lower than the corresponding return on assets), which appears to be due to how they are measured.[21] But this does not appear to impact on the key point.

Table 4: Government owned generators – key financial statistics

Measure	Year	Eraring Energy	Macquarie Generation	Delta Electricity	Stanwell Corporation	CS Energy	Tarong Energy	Average
Gearing (%)								
	2000-01	18.9	44.5	48.0	20.9	41.9	28.1	33.7
	2001-02	9.9	42.9	46.2	20.3	47.4	34.4	33.5
	2002-03	6.7	47.2	43.5	19.9	41.6	35.4	32.4
	2003-04	11.1	37.0	33.1	14.3	23.8	16.6	22.7
	2004-05	10.6	33.2	30.8	12.7	30.1	16.2	22.3
	Average	11.4	41.0	40.3	17.6	37.0	26.1	28.9
Return on assets (%)								
	2000-01	6.2	10.3	14.8	9.7	6.2	10.5	9.6
	2001-02	4.5	12.3	12.7	5.8	7.4	8.2	8.5
	2002-03	4.8	8.8	9.5	4.7	5.7	6.4	6.7
	2003-04	7.6	8.9	9.1	4.6	4.7	8.1	7.2
	2004-05	8.2	8.6	12.4	3.9	4.1	8.3	7.6
	Average	6.3	9.8	11.7	5.7	5.6	8.3	7.9
Return on equity (%)								
	2000-01	2.7	12.7	23.2	9.4	4.8	10.7	10.6
	2001-02	3.2	17.5	24.3	5.3	10.0	11.3	11.9
	2002-03	3.8	6.1	10.3	4.1	6.6	9.5	6.7
	2003-04	6.2	8.3	9.3	4.0	4.1	10.1	7.0
	2004-05	7.1	8.3	15.4	3.8	4.2	9.2	8.0
	Average	4.6	10.6	16.5	5.3	5.9	10.2	8.9

This information also reveals that returns amongst the Queensland government owned generators is, on average, below those of the NSW generators (i.e. average return on assets of 6.6% versus 9.3% and average return on equity of 7.1% versus 10.6%).

The evidence suggests that:

- The gearing of the government owned businesses is below what one might reasonably expect for private sector businesses in a similar position. Section 9.3.4 discusses the factors that are likely to drive the gearing levels of private sector businesses. The gearing levels are

[21] Productivity Commission, Financial Performance of Government Trading Enterprises 2000-01 to 2004-05, 2006. The Commission draws upon data from the Government Finance Statistics which are the Australian Bureau of Statistics compiles. Gearing is calculated by dividing debt by average total assets, Return on Assets is calculated by dividing Earnings Before Interest and Tax by Average Total Assets, while Return on Equity is calculated by dividing Operating Profit After Income Tax by Average Total Equity.

around the levels that might be expected of pure merchant generators, but it is questionable whether the government owned generators are taking the same degree of market risk.[22]

- The return on assets and equity are significantly lower than what would be expected by a private sector generator. For example, the ACIL Tasman report on generator costs assumes a required return on equity for a new base/intermediate load generator of about 16% and a post-tax nominal WACC of 9%.[23] Our consultations with investors suggest that they are likely to require a return on equity of between 15-20% for stand-alone generation assets.[24]

  To a degree, the comparatively low returns are likely to be a function of the oversupply of baseload generating capacity largely caused by government investment. This has affected the returns achieved by the privately owned generators as well.

  The returns government owned businesses are making would not justify further private sector investment, but do not appear to have been a barrier to further public sector investment.

- There is some evidence that the public sector businesses 'have' or believe they have a lower cost of capital than the private sector, albeit by virtue of the implicit guarantee provided by Government ownership.

5.3.2 Distortions created by government ownership

Some investors noted that the best available 'hard' evidence on the distortions created by government ownership comes from the changes that happened as a result of privatisation and the introduction of more competition into the electricity industry. This evidence relates to:

- Operating efficiency;
- The management of capital expenditure; and
- Investment decisions.

This evidence is unlikely to be of direct relevance to what would happen today if government exited the industry. Different changes would occur today and these might have more modest benefits. They are, however, indicative of the sorts of changes that are likely to occur. They therefore provide, in our view, reliable evidence of the impediments to efficient investment government ownership creates.

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[22] There sales arrangements (eg. ETEF and LEP) would serve to mitigate at least some of this risk. In principle, the lower levels of gearing should increase the required rate of return of these businesses and make them less likely to invest. In practice, it is not obvious that this has been the result.

[23] ACIL Tasman, Report on NEM generator costs (part 2), Prepared for Inter Regional Planning Committee and NEMMCO, page 72. The WACC may be at the low end of the range as ACIL base it on a 60% gearing ratio, which is likely to be too high for a merchant generator, as Section 9.3.4 illustrates.

[24] Section 9.3.4 also contains some evidence on required returns in the UK and international context. However, the absolute numbers may be less relevant to Australian domestic investors.

Access Economics has compiled some of this evidence on the Victorian privatisations.[25] It shows, for example, that employment:

> …in the electricity sector fell by more than 11,000 (or 68 per cent) between June 1991 and June 1999. Much of that fall occurred in the lead-up to privatisation. But employment still fell by 2,200 (or 28 per cent) in the four years after June 1995.[26]

In relation to labour productivity it states:

> …although the estimates are approximate, they paint a picture of dramatic increases in labour productivity (ie. real value added per employee). Productivity growth was especially strong in Victoria which, starting from a similar level in 1990-91, experienced almost twice the productivity growth of NSW over the 1990s.[27]

In relation to multifactor productivity it states:

> According to our estimates, multifactor productivity grew faster in Victoria than in NSW over the 1990s, and from a higher base. The Victorian increase averaged about 6½ percent per annum, whereas the NSW increase was 4½ percent. Productivity growth in NSW was more uneven, with part of the increase in 1995-96 and 1996-97 reflecting apparent write offs in capital assets.[28]

An examination of capital expenditure reveals similar efficiencies:

> The Loy Yang A project, for the construction of four 500MW generators, was budgeted to cost $1 billion in 1980 but ended up costing $4 billion by the time it was completed in 1988. The SECV was unable to manage large capital projects efficiently because it was not subject to commercial disciplines or to a competitive market.[29]

In relation to capital planning:

> … the SECV predicted (on the basis of its published long-term scenarios) that a large number of new generation facilities would need to be built after 2000.[30]

This included an additional 1,000 MW at Loy Yang B by 2000-05. Access Economics notes:

> With more than eleven years having elapsed since the SECV made its predictions, we are now in a position to assess its predictions for electricity consumption and for required investment in generation,…, electricity sales have in fact grown somewhat faster than the SECV predicted under its base or mid-range scenario. However, new base-load generation facilities have not been needed, and there remains an excess of base generation capacity in Victoria.[31]

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25 Access Economics, Impact on Victoria of the privatisation of the state's electricity and gas assets, Prepared for TXU Australia, June 2001.

26 Ibid., page 31. It notes that some of this is likely to have been the result of outsourcing and the splitting of business units and reclassification of staff. In NSW employment fell by a similar amount but from a much higher base and mostly post the Victorian reforms. It also notes that system reliability has improved substantially.

27 Ibid., page 32.

28 Ibid., page 34.

29 Ibid., page 34. It notes, however, that the SECV's performance improved later (eg. with the construction of Loy Yang B).

30 Ibid., page 37.

31 Ibid., page 37.

Access Economics also note:

> There were a number of factors which the SECV did not anticipate, including…
>
> - a marked increase in available capacity factors at Victorian power stations since privatisation;…
> - an extension of plant life at existing Victorian generation plants…[32]

On the first point, one industry participant has noted:

> Plant availability in Victoria and in New South Wales has increased from below 80% in the early 1990s to around 90%. The effect of this increase in availability is equivalent to adding 1800MW of base plant to the system, and thus notionally avoiding $2.7 billion in capital investment, which translates to an annual saving of $216 million in capital carrying costs.[33]

On the second point, Access Economics notes that the SECV incorrectly assumed that a number of existing plants would reach the end of their useful lives after 2000. This included Hazelwood power (1,600 MW) station by 2005. In August 1996, Hazelwood sold for $2.4 billion and it is still in operation (and which government assistance might further extend as Section 7.1 describes).[34]

Access Economics conclude, amongst other things, that:

- There have been "substantial ongoing economic benefits" to Victoria from privatisation (0.5 per cent improvement in gross state product - $700 million – and a 0.25% increase in employment); and

- The improvements have been larger in Victoria than in NSW and that, without Victoria's leadership, the national electricity reform process might have been set back some years. In other words, it would have delayed achieving the broader market wide benefits.

These benefits are not unique to Victoria. A number of other privatisations have produced similar benefits.[35]

5.3.3 Other evidence

There is also evidence of a more anecdotal nature supporting the view that government ownership creates a significant impediment to investment.

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[32] Ibid., page 38.

[33] P., Simshauser, 'The dynamic efficiency gains from introducing capacity payments in the NEM Gross Pool', conference paper No.8, undated, page 5. This may overstate the benefits because they would only accrue for as long as the increases in capacity brought about by improved efficiency deferred the next investment, but the evidence suggests that the new capacity has been deferred for some time.

[34] This included, with the benefit of hindsight, an overestimate of its value, but the investors have borne that cost.

[35] P., Joskow, 'Electricity sector restructuring and competition: Lessons Learned', Latin American Journal of Economics, 40, 121.

The available information suggests that:

- There has been new capacity built in Victoria and South Australia, privately 'owned' markets;
- There has been little new entry in NSW, a publicly 'owned' market (although one significant plant is now under construction albeit aided by greenhouse gas policies); and
- There has been some new capacity built by both parties in Queensland, a largely publicly 'owned' market, although some claim the new public sector investment was not expected and has partly stranded the private sector investment (which greenhouse gas policies also supported). There are, however, new proposals for private sector investment, despite apparent uncertainty about whether the government will continue to invest.

A common sentiment was reflected in the feedback from one Government owned business:

> …the politicians will always want investment before the private sector.

In these circumstances, it is likely that the market:

> …will never get near the price signals that the private sector needs to justify investment.

One government owned generation business argued that

> …its required ROE was about 10% whereas for the private sector it is much higher.

Investors argued that:

- A number of recent government investments in generation could not have been justified on a commercial basis. For example;
    - Particularly the government investments in Queensland which are generating low returns; and
    - Several parties argued that a recent government owned peaking plant had production costs that were considerably higher than the price at which 5 year caps were selling at the time the investment was made. The implication was that the investment "had to be losing money for at least the first five years"

One party claimed that a government investment in generation has materially adversely affected its prior generation investment in three ways:

- By reducing market prices;
- By reducing the quantities it can sell because of the subsequent bidding practices of the Government owned entrant; and

- By reducing the quantities it can sell and cover its contract commitments because of its reduced capacity to get access to the market when it most needs it due to transmission constraints that have emerged with the new entrant.

5.4 Impacts

In our view, what would likely happen absent government ownership the best way to illustrate the impacts on investment. Government's removal from ownership might take several forms perhaps bounded by:

- A firm commitment by governments not to invest further (but retention of the ownership and operation of the existing assets); and

- Privatisation of all assets and a firm commitment not to invest further.

In our view, it is reasonable to expect that in the first case we would see:

- A substantial improvement in the environment for private sector investment because it would remove a substantial degree of uncertainty currently clouding investment decisions, although this might not be sufficient to remove impediments to new baseload investment (see Section 7);

- Significant changes in proposed generation investments and actual investment in terms of the:

  - Quantum;

  - Type of proposed investment; and

  - Timing of that investment.

If Government sold its generation interests, we would see further material improvements in the:

- Capital and operating efficiencies of those businesses and plants; and

- Operating efficiencies of all generators in the NEM as competitive pressures increased across the market. For example, some investors have indicated that substantial efficiency improvements are still available both at publicly and privately owned plants (eg. employment levels).

Quantifying those benefits is always like to be difficult, particularly without a closer analysis of the current situation than this project allows for. It seems likely, however, that absent government intervention there is at least 1,000 MW of new plant entailing an investment of about $1.5 billion, which the private sector would not have built, at least not yet. We base this view on investors' general observations about market developments and their views in regard to two new plants in particular, which a number of respondents highlighted as indicative of premature investment. The combined capacity of these plants is about 1,000 MW.

6 Price regulation

This section outlines:

- The incidence of price regulation;
- Investors' views on the impediments it creates;
- The evidence to support those views; and
- The impacts of those impediments.

6.1 The incidence of price regulation

The energy market varies by jurisdiction both in the degree to which they have introduced Full Retail Contestability ("FRC") and the degree to which they regulate wholesale prices, retail prices or both. In short:

- Queensland and Tasmania are the only jurisdictions of the NEM not to have introduced FRC. Queensland is proposing to introduce FRC for urban (but not rural) customers on 1 July 2007. Tasmania is proposing to introduce it in 2010 subject to a cost benefit analysis;
- NSW uses wholesale electricity price regulation (via ETEF) for loads to customers who have not chosen an alternative supplier;[36]
- Queensland is expected to continue to use wholesale electricity price regulation (via LEP) for loads where it is not planned to introduce FRC; [37] and
- All jurisdictions use retail price regulation in their electricity and gas markets for small (primarily domestic) customers.

In broad terms, retail price regulation affects:

- About 89% of electricity customers and 29% of demand; and
- About 97% of gas customers and 38% of demand.[38]

Wholesale price regulation affects about 24% of system load in NSW.[39] Absent the 'perfect' hedge that this provides it might be reasonable to assume that contracting activity would

[36] The Electricity Tariff Equalisation Fund seeks to manage electricity market price risk between the government owned generators and retailers in NSW.
[37] Queensland uses Long-term Energy Procurement contracts to manage electricity market price risk. Tasmania also uses wholesale electricity price regulation but it has not yet introduced FRC.
[38] These figures assume that price regulation affects all domestic customers and no non-domestic customers and so are approximate. See ESAA, Electricity Gas Australia 2006, 2006. The data is for the 2004/05 year and includes the ACT but excludes Queensland gas customers of which they are about 150,000
[39] We have not been able to ascertain the proportion of retail load LEP accounts for in Queensland and it is likely to change with the sale of ENERGEX's retail interests.

increase by at least a similar amount. The customers and load for which price regulation is in place, is typically also the load that contributes disproportionately to peak demand and therefore the cost of meeting that demand. This might also therefore impact on the amount of trading required to hedge this load.

There are some proposals to remove price regulation in markets where there is FRC. For example, NSW is planning to remove ETEF by 2010 consistent with increasing regulated retail electricity prices to cost reflective levels. In addition, some regulators are questioning either the need for retail price regulation or for how long it might be necessary (eg. in the ACT in the case of electricity and in Victoria).[40]

6.2 Investors' views

Investors believe that wholesale and retail price regulation is a significant impediment to more efficient energy sector investment. Investors consider that the key problem is retail price regulation and they see wholesale price regulation as a second order issue largely made necessary by the former. Investors consider that wholesale price regulation can exacerbate the impediments created by retail price regulation by denying non-incumbents access to the value chain (eg. excluding them from part of the market).

More specifically, investors believe that the key problem is not retail price regulation *per se* (although they would strongly prefer its removal), but rather the levels at which those prices are or potentially could be set.

Investors believe that retail price regulation that is set too low distorts:

- Wholesale and retail markets and discourages new entry; and
- The nature of retail competition, thus undermining its "effectiveness" and making it less price based (including using more cost reflective pricing and thus demand side response).

These views are neither surprising nor controversial. For example, the NSW Government (which investors see as a key offender in regard to retail price regulation) states:

> International and national experience shows that the level of regulated retail tariffs relative to market based prices is the key determinant of how many eligible customers remain on regulated arrangements.[41]

Price regulation likely creates a variety of other distortions, which may exacerbate impediments to investment. These include:

- Artificially low retail price regulation may impose higher costs on unregulated customers;

[40] ICRC, Retail prices for non-contestable electricity customers, April 2006; ESC, Review of effectiveness of retail competition and consumer safety net in gas and electricity: Overview report, 22 June 2004.
[41] NSW Government Terms of Reference as reported in IPART, Review of Regulated Retail Tariffs and Charges for Electricity 2007 to 2010, July 2006, page 29.

- The application of price regulation means that regulated tariffs tend to offer customers additional benefits compared to market tariffs. These include:

  - The flexible term associated with regulated tariffs;[42] and

  - The reversion opportunity associated with regulated tariffs.

  Regulated tariffs therefore provide customers with an *option* to stay on fixed prices for as long as prices are set, but to move for free onto a market contract in the intervening period. Reversion policies provide a further free option to return. Paul Joskow, a US economist, has noted the existence of options in the regulated retail tariffs of US Electricity Service Providers and their importance. He states that:

  > …allowing customers that choose to take service from an ESP to return to a regulated tariff when wholesale prices are high without being charged an appropriate price for this option, seriously undermines the development of retail competition because it effectively provides a subsidised option for retail customers who switch back and forth and a very unstable customer base for ESPs.[43]

- Retail energy markets are price driven markets in the main. By regulating the price, policy makers must make a judgement about when competition is "effective" even though they are controlling the main variable on which competition occurs. This is not required in most other markets and it effectively reverses the burden of proof for the market. It also creates a highly artificial and subjective test, because there is no obvious economic rationale for price regulation. This heightens the risk of getting pricing decisions made politically.

6.3 Evidence

There is strong evidence to suggest that price regulation distorts investment in the energy sector, although distinguishing between the impact of wholesale and retail price regulation is difficult.

The best evidence comes from differences in the:

- Levels at which regulated prices have been set in different jurisdictions;

- Amount of competitive activity and new entry in those jurisdictions; and

- Market expectations on retail margins and those in some regulated retail tariffs.

[42] Market tariffs typically involve a fixed price for a fixed term, sometimes with fees for early termination. By contrast, regulated tariffs typically involve a fixed price for a *flexible* term, with no fees for early termination.
[43] P., Joskow, 'The Difficult Transition to Competitive Electricity Markets in the US', AEI-Brookings Joint Centre for Regulatory Studies, July 2003, page 35.

6.3.1 Differences in the levels of regulated retail prices

There are differences in the levels at which regulated retail prices have been set in different states. Focussing on the allowed electricity retail margins and operating costs per customer in NSW compared to SA and Victoria illustrate this.[44]

We have summarised below recent regulatory decisions on retail margins in Table 5 below.

Table 5: Sample of jurisdictional decisions – electricity margins

	Year	Net margin (%)	Operating cost per customer ($)
SA Electricity	2005	5%[45]	84[46]
NSW Electricity	2004	2%[47]	70[48]
Victoria Electricity	2003	5%[49]	90[50]

These equate to EBIT margins of between $20-50 on a 'typical' customer bill of $1,000.[51]

6.3.2 Market activity and new entry

The evidence shows that there has been more competitive activity and new entry in those markets where regulated margins and operating costs are higher (ie. Victoria and SA).

[44] The overall level of regulated retail prices is also affected by the level of network charges and wholesale prices, which may create further distortions.
[45] ESCOSA, Final report – Inquiry into electricity retail price path, 2005, page 57.
[46] Ibid., page 53.
[47] IPART, NSW electricity regulated retail tariffs 2004/05 to 2006/07- Final report and determination, 2004, page 9.
[48] Ibid., page 10.
[49] Charles River Associates, Electricity and gas standing offers and deemed contracts (2004-07), 2003, page 25. In this case, this is what it recommended not necessarily what was included in the price path for 2004-2007. However, the Government has since sought further reductions in retail prices over the regulated period. See Power Industry News, 'Vic Price Boast', Edition 494, 5 June 2006, page 18.
[50] Charles River Associates, Electricity and gas standing offers and deemed contracts (2004-07), 2003, page 25. In this case, this is what it recommended not necessarily what was included in the price path for 2004-2007. However, the Government to seek further reductions in retail prices over the regulated period. See Power Industry News, 'Vic Price Boast', Edition 494, 5 June 2006, page 18.
[51] For the purposes of this report "gross margin" is the difference between revenues and the direct costs of production of a business (eg. revenues less all electricity – commodity- costs and other pass through costs such as network charges). "Net margin" is the difference between the gross margin and the indirect costs of production of a business (eg. all operating costs, excluding interest and taxes). In addition, this report also uses EBITDA ("Earnings before interest tax depreciation and amortisation") and EBIT ("Earnings before interest and tax") margins because the market often expresses margins in these ways. The latter is broadly consistent with our definition of net margin. In practice, because of the nature of the retail electricity business, the differences between EBITDA and EBIT margins are typically modest.

Competitive activity

There has been considerable competitive activity in the Victorian and SA markets. According to AGL, annual customer churn rates for Victorian and South Australian gas and electricity are all at least 20%. By contrast, for NSW gas and electricity the churn rates are 4% and 9% respectively.[52] Origin Energy reports similar results.[53] The SA figures include retentions whereas the others do not.[54]

The available information on customer numbers by retailer is limited at best, primarily because retailers regard it as commercially sensitive information. AGL provides the best available evidence, as it provides retail customers by state and by fuel. The available statistics show that:

- In South Australia, as at October 2006, 66% and 62% of the small electricity and gas customer base had moved to market contracts;[55]
  - As at June 2006, AGL (the incumbent electricity retailer) data suggests that it had up to 70% of this small electricity customer base.[56] This suggests that other retailers have at least 225,000 small electricity customers. As at June 2006, Origin Energy (the incumbent gas retailer) data suggests that it had up to 18% of this electricity customer base (or 136,000 customers);[57]
  - As at June 2006, AGL had about 14% of the small gas customer base;[58]
- In Victoria, as at September 2006, about 1.5 million small electricity customers (about 70%) had transferred, and transfers were running at over 2,500 per month;[59]
- In NSW, as at September 2006, about 0.76 million small electricity customers (about 26%) had transferred and transfers were running at about 1,500 per month. AGL had 189,000 electricity customers as at 30 June 2006 or about 7% of this customer base (mostly dual fuel customers). Origin Energy had only 14,000 electricity customers as at 30 June 2006. We understand that TRUenergy is not very active in the domestic NSW market.

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[52] AGL, 2006 Full Year Financial Results, 16 August 2006, page 17.
[53] Origin Energy, Final Results Announcement for the Full-year ended 30 June 2006, 30 August 2006, page 32. Both are based on various sources including NEMMCO, VENCorp, ESCOSA and the Gas Market Company and company information. Origin's figures appear to have been taken from slightly earlier in the year.
[54] The SA Government also subsidised customer switching for a time.
[55] ESCOSA, Completed small customer electricity and gas transfers to market contracts: Schedule, October 2006. These are gross transfer figures which therefore include multiple transfers (those that have transferred more than once). Other analysis by ECSOSA in 2003 suggests that the gross transfer rate was about 49% for electricity when the net transfer rate was about 43%. It seems reasonable to assume that the difference may have got larger with time, as more customers shift for a second time.
[56] AGL, 2006 Full Year Financial Results, 16 August 2006, page 17. In practice, the number is likely to be more like 64% of small customers if it is assumed that it has 50% of larger customers.
[57] Origin Energy, Final Results Announcement Full-year ended 30 June 2006, 30 August 2006, page 32, and Origin Energy, Final Results Announcement Full-year ended 30 June 2006, 29 August 2005, page 30.
[58] This figure is likely to be more accurate because there are far fewer larger gas customers. Indeed, other AGL data suggests it has 11% of the total customer base.
[59] http://www.nemmco.com.au/data/ret_transfer_data.htm. NEMMCO statistics only cover those customers who have transferred to another retailer, not those that have entered into a market contract with their incumbent retailer. It will therefore also include those that have transferred more than once.

The Victorian and SA markets are (with the UK) widely considered to be amongst the most competitive in the world.[60]

New entry

- There has been new entry into the Victorian and South Australian markets, primarily via:
  - Victoria Electricity – whose retail business has recently grown to about 115,000 customers since 2002, most of which we understand are in Victoria;[61]
  - Red Energy – which is active in the Victorian electricity market but is understood not to be active in the NSW market;
  - Powerdirect (now incorporating part of Ergon Energy) – which focuses on selling electricity to small and medium sized businesses in the NEM (eg. petrol stations, retail outlets, residential apartments, commercial office buildings and water authorities). It has over 40,000 customers in Victoria, representing 73.5% of total volume sold; and
  - Energy Australia's joint venture with International Power, which we understand might have several hundred thousand customers in Victoria and SA. We also understand that Country Energy has about 3% of the Victorian market.
- By contrast, new entry in the NSW market has been modest, even from Origin Energy and TRUenergy, two of the most likely new entrants.

This suggests that the regulated retail prices in Victoria and SA have been sufficient to encourage switching and new entry. This does not necessarily mean, however, that the allowed margins and operating costs are the sole reason for this. For example, lower than expected wholesale electricity prices would appear to be partly responsible for some of this competitive activity. Our discussions with market participants have confirmed this view, and it would appear to accord with the market evidence (see Section 6.3.3 below).

Anecdotal evidence

Our discussions with investors reflect these facts. Typical views amongst those that have considered entering the NSW market are that "there is no money in it", with limited time and capital it is "just too hard" compared to other opportunities, and the additional risk created by "competing with parties with less incentive to act commercially".

6.3.3 Market expectations on retail margins

There appears to be a discrepancy between the:

[60] Power Industry News, 'Retailers back price move', Edition 513, 16 October 2006, page 9. It refers to research undertaken by the utility research institute, VassaEMG.
[61] This includes growing from 28,000 customers since March 2005. It has also recently made its first positive contribution to the company's first quarter result. See http://www.infratil.com/1/6222.htm.

- Margins the market expects retail businesses to earn and what they are earning; and
- What certain regulated retail margins assume.

Market expectations

In undertaking this work we have reviewed company reports and a sample of the recent stockbrokers' reports available to us.[62]

In terms of market expectations, stockbrokers have suggested the following:

- ABN Amro expected an EBIT margin of 7% for the full year for AGL, broadly in line with the previous calendar period.[63] It also argues that "retail margins are showing signs of being sustainable".
- CitiGroup states in relation to Origin Energy that its medium term expectations for the retail business remain for a stabilised EBIT margin around the 6% level.[64]
- Morgan Stanley values Origin Energy on a future EBITDA/sales margin for its retail business in the 8.2-8.4% range.[65] This suggests an EBIT margin of about 6.8-7.0%.[66]

These expectations would appear to be similar to those expressed by stockbrokers in NZ and the UK. For example, in the case of Contact Energy in New Zealand:

- CitiGroup assumes that retail EBIT margins would fall to an average of 7.5% over the next few years.[67] On CitiGroup's analysis, this would be consistent with a gross margin of about 13.6%.

In the case of Centrica in the UK, various stockbrokers' reports state:

> We assume a long-term average (LTA) EBIT margin of 5.7% for this division;[68]
>
> The key value drivers in our Base Case valuation are (1) Sustainable retail margins of 6%;[69]
>
> Our revised valuation for Centrica is set out below. We are now assuming that stickier customers will mean 8% margins could be sustainable in the energy retail business.[70]

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[62] KPMG has access to two on-line sources of brokers' reports: Thomson and Onesource.
[63] ABN Amro, Australian Gas Light, 'Solid result, but what happens next', 28 February 2006, page 2.
[64] CitiGroup, Origin Energy Limited, 'No Contact', 28 June 2006, page 12. This includes the LPG business.
[65] Morgan Stanley, Origin Energy Ltd., '2006 Interim Result and Merger with Contact', 21 February 2006, page 5.
[66] Origin's interim results for 2006 resulted in EBITDA and EBIT margins from the retail segment falling from 9.8% to 8.8% and 8.4% to 7.4% respectively.
[67] CitiGroup, Origin Energy Limited, 'No Contact', 28 June 2006, page 4.
[68] ABM Amro, 'British Gas Services – upping the ante', 27 June 2006, page 2.
[69] Morgan Stanley, 'Centrica – Recovery Fully Priced', 27 July 2006, page 3. This appears to relate purely to the UK retail energy business. It noted, however, that Centrica has never achieved these margins.
[70] Deutsche Bank, 'Centrica', 23 February 2006, page 4. This appears to be a Profit After Tax margin but appears to include the benefit of some generation assets within that business.

Market performance

The performance of AGL and Origin would appear to be broadly consistent with stockbrokers' views on sustainable margins. For example:

- AGL recent full year results for 2005-06 included for the retail business an increase in EBIT to sales margin to 7.7% from 6.6% (and a 2006 EBITDA of 8%);[71] and

- Origin's final results for 2005-06 suggest that it earned an EBIT margin in its Australian natural gas and electricity retail business (ie. excluding LPG) of 7.8% compared with 7.2% in 2005. This is $110 per customer.[72]

Business valuation

The way the market values retail businesses would also appear to suggest that it expects retailers to earn margins above those implied by regulated margins.

In the capital markets one of the most commonly used measures of the relative cost of acquiring retail businesses is the cost per customer.[73] Most major transactions, many of which occurred some years ago, appear to have valued customers in the $400 to $850 range (with the higher end mainly for customers for whom dual fuel offers are an option). More recently, somewhat higher valuations would appear to be the norm.

For example:

- ABN Amro values AGL's retail business at roughly $925 per customer;[74]

- Morgan Stanley values Origin's retail gas business at $900 per customer and its retail electricity business at $980 per customer.[75]

Goldman Sachs JBWere also recently stated that it expected ENERGEX's retail business to sell for about $600 million, which is about $750 per electricity customer.[76]

In reality, however, a net margin of 2% on an electricity bill of $1000 per annum implies that the retailer earns (before interest and tax) about $20 per customer. The above valuations would suggest that at $900 per customer the market is prepared to pay about 45 times these earnings

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[71] AGL, 2006 Full Year Financial Results, 16 August 2006, page 4. It is not obvious whether this is before or after an allocation of corporate overheads.
[72] Origin Energy, Directors' Review of Results for the full year ended 30 June 2006, 30 August 2006, page 17. These figures appear to be after an allocation of corporate costs.
[73] Australian Financial Review, 'Australian Energy poised', 6 August 2003, page 27. Australian Financial Review, 'AGL needs up to $500m equity for Pulse', 1 July 2002, page 16. See also the Allen Consulting Group, Review of the Gas Code: Commentary on Economic Issues, Report to BHP Billiton, August 2003. The paper provides a summary of Australian retail energy business transactions.
[74] ABN Amro, 'Australian Gas Light', 28 February 2006, page 5.
[75] Morgan Stanley, 'Origin Energy Limited', 21 February 2006, page 5.
[76] Australian Financial Review, 'Alinta-AGL deal to power activity', 23 August 2006, page 33. Although it also has about 50,00 LPG gas customers as well.

(ie. it would take the same number of years to recover the cost of paying this much to acquire a customer). At a net margin of 5%, the market is prepared to pay 18 times these earnings.

It seems unlikely that the market is prepared to pay these multiples of earnings. For instance, ABN Amro suggests that it values AGL's retail business on an expectation that it earns an EBITDA of roughly $100 per customer, and that the market is willing to pay 9 times EBITDA to acquire this performance.[77] Moreover, AGL's most recent results suggest it is earning a gross margin of $184 per electricity mass market customer.[78]

These figures are consistent with net margins above those implicit in regulated tariffs.

6.4 Impacts

In our view, it is highly likely that absent artificially low retail price regulation, the energy market would look quite different to what it looks like today. In NSW, for example, it seems likely, at a minimum, that:

- There would be similar levels of churn and new entry to those experienced in Victoria and SA.
- There would be more new entry in the mass market; in particular, TRUenergy and Origin Energy, both of which have the existing capacity to get involved in the mass market. NSW is the largest retail energy market in Australia and it is highly likely that any retailer with aspirations of being a major player in the Australian mass market would enter the NSW market (notwithstanding the strong position of AGL in the gas market and therefore its ability to offer dual fuel to electricity customers).
- Typical prices would be higher for mass market customers (at least in the short term), but competitive activity would be more widely based and there would be more product innovation.[79] It might also result in some lowering of prices in the unregulated parts of the market.
- There would be wider responses to that competitive activity in the context of improvements in operating efficiency across all retailers. For example, with the demerger and restructure of AGL (with Alinta), it plans to reduce its costs by $60-70M per annum from 2008 onwards. To do this it plans to invest $80-100M in IT to generate annual operating cost savings of $30-40M. It is also proposing to generate $20M from retail process improvement and a further $10M from corporate wide IT efficiencies. It plans a headcount reduction of 40-50%.[80] It is hoping that this will reduce its operating costs per customer from $91 currently to $68 post implementation. Increasing AGL's exposure to competition might

[77] The difference between EBIT and EBITDA for retail businesses is typically modest.
[78] AGL, 2006 Full Year Financial Results: 12 months ended 30 June 2006, page 15. It reports a gross mass margin of $263.4 million over 1.428 million accounts.
[79] The Nordic retail electricity market, for example, displays "considerable product innovation." See S., Littlechild, 'Competition and contracts in the Nordic residential electricity markets', 23 July 2005, pre published paper later published in Utilities Policy. This includes in the residential sector fixed price contracts out to five years as well as spot-related terms. In Norway, about 16% of households are on electricity contracts tied directly to spot prices.
[80] AGL, 2006 Full Year Financial Results: 12 months ended 30 June 2006, page 30.

have made this happen sooner.[81] It is likely that this move will lead to response from TRUenergy and Origin Energy.

- It is likely to drive significant operational efficiency improvements through the incumbent electricity retailers.

- There is more likely to have been new private entry into the generation market, provided that they can also get access to the value chain (ie. wholesale price regulation is removed).

- There would be a chance of at least one of the incumbent electricity retailers in NSW becoming a significant competitor in the national retail energy market for the foreseeable future, provided they can also get access to the value chain.

It is difficult to quantify the overall benefits of removing price regulation in the context of this study, but in our view they are likely to be significant. For example, in the absence of price regulation it would seem reasonable to expect that non-incumbent retailers would have at least 500,000 to 1,000,000 more small customers than they already have.[82] This would have resulted in a number of active new entrants in the NSW and Queensland (including the three major players) in the small customer segment, and quite possibly the development of some peaking capacity by those new entrants. It would also have placed more competitive pressure on the three major retailers' costs and margins.

[81] AGL, A new AGL scheme booklet release (revised), 29 August 2006, page 26.
[82] Based on their success in Victoria where non-incumbent retailers (ie. other than the three major players) have about 500,000 customers.

7 Government greenhouse gas and renewable energy policy

This section outlines:

- The nature of the Federal and State Governments' polices in regard to greenhouse gas emissions and renewable energy;
- Investors' views on the impediments it creates;
- The evidence to support those views; and
- The impacts of those impediments.

7.1 Greenhouse gas and renewable energy policy

Australia currently has a number of policies associated with addressing greenhouse gas emissions and promoting renewable energy. We briefly summarise the key policies below.

7.1.1 Federal Government policies

As at March 2006 the Federal Government claimed to have over eighty policy measures in place to combat climate change.[83] Below we outline the key policies.

- Asia Pacific Partnership

  The Asia Pacific Partnership includes Australia, China, the USA, Korea, Japan and India (which account for about 50% of global emissions) and commenced in January 2006. Its objective is to accelerate the adoption of new technologies, which lower emissions. It has established eight government and business taskforces on: cleaner fossil energy; renewable energy and distributed generation; power generation and transmission; steel; aluminium; cement; coal mining; and building and appliances. Asia-Pacific Partnership Ministers will meet again in 2007.

- Low Emissions Technology Demonstration Fund

  The objective of the $500 million fund established in 2004 is to assist Australian companies to develop new technologies. It is proposing as its first investments to provide $75 million to support the development of a large solar energy electricity generation facility in Victoria and $50 million on new brown coal low emissions technologies (with matching funding of $50 million and $30 million from the Victorian Government for each project).[84]

[83] http://www.orer.gov.au/publications/mret-overview.html
[84] Australian Financial Review, 'Solar power plant grant backfires on Vic Liberals', 26 October 2006, page 3.

- Greenhouse Gas Abatement Programme (GGAP)

  The GGAP aims to reduce Australia's net greenhouse gas emissions by supporting activities that are likely to result in substantial emissions reductions or activities to offset greenhouse emissions, particularly in the 2008-2012 period. It provides subsidies to private initiatives for qualifying projects. There have been three funding rounds. No further rounds are envisaged under this program.

- The Commonwealth Mandatory Renewable Energy Target (MRET)

  The MRET aims to increase renewable electricity generation by encouraging the generation of an additional 9,500 GWh of renewable energy per year by 2010. MRET operates by imposing a legal liability on generally large wholesale purchasers of electricity to buy a certain amount of that electricity from renewable sources. It ends in 2020. The target is expected to be reached in 2007 and the Government is not proposing to expand the program.

- Energy Efficiency Opportunities (EEO)

  EEO requires companies to undertake a detailed review every five years to identify energy efficiency opportunities. Companies will be required to publicly report the findings of their review to the public in order to demonstrate that the company is using energy efficiently.

- Other key policies

  The Federal Government is committed to not introducing a carbon tax or an emissions trading scheme (unless it is comprehensive and international) on the basis that it would damage Australia's economic interests.

  The Federal Government is committed to not ratifying the Kyoto Protocol on the basis that it is an ineffective method of limiting greenhouse gas emissions because it does not include developing countries. The Government expect to meet the target it would have had under ratification.[85]

  The Federal Government is proposing that nuclear energy should be part of the solution to greenhouse gas emissions. Speaking at the 15th Pacific Basin Nuclear Conference Federal Resources Minister, Ian Macfarlane, stated that:

  > The reality is that nuclear technology is here, it is now, and it is available to be introduced into Australia's energy mix to reduce greenhouse gas within 10 years. As third generation plants become a reality, there are forecasts of full-cycle nuclear power costing as little as 5 cents a kilowatt hour. That's in comparison with 3.5 cents an hour for coal, 4.5 cents for gas and 8 cents for wind and 12 cents for solar power.

  He is, however, also of the view that the industry would need to be viable without government support.[86] Meanwhile other members of the Government have warned that

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[85] http://www.deh.gov.au/minister/env/2006/mr23may406.html
[86] ESSA, 'Nuclear debate hots up', ESSA News, Issue 2, 23 October 2006, page 1. See also Australian Financial Review, 'Minister warms to nuclear power', 17 October 2006, page 3.

nuclear power is probably not economically viable in Australia and/or that it would be necessary to subsidise it.

7.1.2 State Government policies

The states are jointly proposing a National Emission Trading Scheme (NETS). In August 2006, the NETS Task Force released a discussion paper outlining possible design options. The NETS would place a cap on the greenhouse gas emissions that a covered sector could emit. The discussions paper suggests that NETS could start as early as 2010 and would in the first instance cover the stationary energy sector.

At the individual level, the key State Government policies are as follows:

- New South Wales

  The NSW Government's objectives are to ensure that emissions in 2025 are no greater than 2000 levels and to reduce emissions by 60% in 2050.[87] It has a variety of policies in place including domestic building standards, a commercial building ratings scheme, an energy savings fund, carbon rights legislation, a Renewable Energy and a Greenhouse Gas Abatement Scheme (GGAS) and a NSW Renewable Energy Target (NRET).

  The GGAS commenced on 1 January 2003. GGAS establishes annual NSW greenhouse gas reduction targets. The scheme requires individual electricity retailers (and some other parties) to meet mandatory benchmarks based on their share of the electricity market. The Government recently announced its intention to extend the scheme from 2012 to 2021 (or until the establishment of a national emissions trading scheme).

- ACT

  The ACT Government introduced a Greenhouse Gas Abatement Scheme on 1 January 2005, which mirrors the NSW Greenhouse Gas Abatement Scheme.

- Queensland

  The Queensland Government's key greenhouse policies involve promoting energy efficiency, and subsidising both the development of clean coal technology and the wider use of gas in electricity generation.

  Under the Gas Electricity Certificate (GEC), Queensland electricity retailers and other liable parties are required to source at least 13% of their electricity from gas-fired generation. The scheme's aim is to encourage the development of new gas sources and infrastructure in Queensland and to reduce greenhouse gas emissions. The scheme commenced in January 2005 and will run until 2020.

[87] http://www.greenhouseinfo.nsw.gov.au/__data/page/927/28-11_FINAL_NSW_GH_Plan_web.pdf

- South Australia

  The Government's objective is to reduce greenhouse gas emissions to 60% of 1990 levels by 2050. It is currently developing a renewable energy program. It is expected to be based on the Victorian Government renewables scheme, and require increasing renewable energy use to 20 per cent of its electricity consumption by 2014.

- Tasmania

  Tasmania recently produced a Draft Climate Change Strategy for public comment. It is amongst other things supporting the development of a national emissions trading scheme.

- Victoria

  The Victorian Government has about 19 policy initiatives in place focussing on producing greenhouse friendly energy, improving energy efficiency and adapting to climate change. The policies in the first two categories include: domestic and commercial building standards; appliance standards and labelling schemes (part of a national initiative); electricity interval meter roll-outs, subsidising clean coal electricity generation projects; requiring large users to develop industry energy efficiency plans; and the Victorian Renewable Energy Target (VRET).[88]

  VRET requires electricity retailers to purchase a minium of 10 per cent of their energy needs from renewable energy by 2016. The targeted start date is 1 January 2007 and it is expected to run until 2025.

7.2 Investors' views

Investors are of the view that the current policies of Australia's governments in respect of reducing greenhouse gas emissions and promoting renewable energy are a significant impediment to more efficient investment.

Their concerns relate more to the execution of those policies rather than the broad policy objective *per se*. The features of these policies that are of most concern to investors include:

- The number of measures being introduced;
- The lack of cohesion between them;
- The limited practicality of some of them;
- The contradictory signals some politicians are sending about them;
- The overt politicisation of the issue; and, most importantly;

[88] http://www.dse.vic.gov.au/ourenvironment-ourfuture/downloads.htm

- The continuing absence of policies most likely to be most effective in reducing emissions (ie. some form of carbon price signal), and therefore the risk that these will be introduced at a later date.

7.3 Evidence

There are three different types of evidence that are relevant to assessing the impediments to investment created by current government policy in relation to greenhouse gas and renewable energy.

- The policies themselves;
- Investors' views about them; and
- Evidence of the impact on investment decisions.

7.3.1 The policies

It is evident from the summary of policies in Section 7.1 that:

- There are a lot of them (eg. the Federal Government claims eighty of its own);
- They are often narrowly based and technology specific (ie. are trying to 'pick winners'). For example, specific measure often disadvantage technologies that are not picked (eg. greater energy efficiency across all end uses), even where in practice they might provide more cost effective reductions in emissions;
- They are overlapping. For example, the Federal Government's proposal to support a solar power plant is also to receive, in effect, subsidies via VRET;[89]
- They are not very cost effective in reducing greenhouse gas emissions (eg. wind but also clean coal technologies);[90]
- Some have become overtly politicised (eg, the orange-bellied parrot and the Victorian election where the opposition has promised to abolish VRET). In relation to the orange-bellied parrot the Australian noted:

  > Campbell's decision, in which, he ignored advice from his own department, has been derided by his political opponents the green lobby and the wind industry. Even the Business Council of Australia says the "baffling" decision to protect the parrot at the expense of the wind farm had the potential to risk future investment in renewable energy. "It demonstrates there needs to be greater

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[89] Australian Financial Review, 'Solar power plant grant backfires on Vic Liberals', 26 October 2006, page 3.
[90] Power Industry News, 'VRET revisited', Edition 513, 16 October 2006, page 9. It refers to work undertaken by McLennan Magasanik Associates which suggests that VRET emission reductions will cost around $71/tonne carbon-dioxide equivalent. However, one investor claims to have investigated low emission clean coal technologies and carbon sequestration and concluded that "at these costs wind becomes cost effective".

clarity around the approvals processes for these projects, otherwise investment that everyone wants in alternative energy, in renewable energy, just won't occur" says spokesman Mark Triffitt.[91]

- They are sometimes of limited duration given the type of investments they are trying to encourage; and, most importantly,

- None address the key 'problem' (ie. that the environmental costs of consuming conventionally produced energy are not transparently reflected in the price of energy).

Investors' views on the policies

Investors almost universally believe that the current policy situation is:

> …a shambles.

Investing in electricity generation at the moment is akin to:

> …gambling on the political environment which is no basis upon which to make investment decisions.

Moreover, investors strongly believe that the Federal Government's current position on greenhouse gas emission is not credible. Therefore, the common view was that:

> …merely removing current policies would not resolve the uncertainty.

Investors 'know' that picking winners typically makes for poor public policy; and they also appreciate that governments know this. As a result, they believe these measures are a 'stop-gap' until more rational policies are developed.

Investors almost universally expect that Australia will soon have to implement some more effective policies to address greenhouse gas emissions. Investors are expecting this to involve some form of carbon price signal. Investors see the Federal Government as the logical party to do this, given the nature of the problem. In this sense, investors are 'ahead' of the policy makers, which they need to be given the term of the investments they are contemplating.

Very recently there has been considerable press commentary on these issues, in the face of greater realisation of the gravity of the drought affecting most of southern Australia. For example, two opinion pieces in the Australian Financial Review have made two of the critical points that investors have been making; that the Federal Government's position is not:

- Sustainable and therefore credible;[92] and

- Providing the certainty investors need.[93]

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[91] The Weekend Australian, Special Report: Power Generation, 'Storm over wind farms', 9-10 September 2006, page P5.

[92] Laura Tingle, Australian Financial Review, 'Weather crisis brings change in political climate', 17 October 2006, page 4.

[93] Jon Stanford, Australian Financial Review, 'Canberra's costly global warming inertia', 17 October 2006, page 63.

The recently published 'Stern Review on the Economics of Climate Change' makes similar points. It identifies as the first of three key elements of policy required for an effective global response to climate change as "carbon pricing". Stern states:

> Clear policy signals, credible over the medium to long term, will help motivate the private investment that will drive down emissions.[94]

One investor interviewed said they potentially have several billion to invest in baseload merchant generation (including coal) but that it had not proceeded on a previous investment opportunity for two reasons:

- It wanted to see prices in the NEM get to efficient new entrant levels; and
- Because of greenhouse policy "we could not value the potential impacts with any degree of certainty".

The same investor suggested than in 1996 it was incorporating a $10/tonne carbon tax in their investment decisions from 2006. In 2006, it argues that there is no more certainty than they had 10 years ago.

Another investor has wind sites in Victoria and South Australia. Its view is that the South Australian site is better on all measures except for the level of government assistance, but because one scheme (ie. MRET) has "run out of funds", it is developing the inferior site.

The critical issue for investors is what price or cost they should factor into their investment models to account for the environmental benefits or costs of their potential investment, which in most cases is likely to have a life of more than twenty years. At the present time, there is very little basis on which to estimate the costs that will be imposed upon more carbon intensive means of production or the benefits that will accrue to those that are less carbon intensive. Assessing any investment opportunity is therefore highly problematic. This is particularly important in getting debt funding because debt providers will expect to see the investor make an assessment of this risk and its impact of the cash flows from the project.

At Origin Energy's recent annual meeting, its chairman, Kevin McCann, said:

> The failure to implement a long term framework for applying a carbon cost is a major impediment to investment in the Australian energy sector.[95]

7.3.2 Investment activity

As with Government ownership, 'hard' evidence of the impediments to efficient investment created by the Governments' greenhouse gas and renewable energy policies is difficult to find because it manifests itself primary in the deferral of investment decisions and/or a failure to invest.

The available evidence is as follows.

[94] N., Stern writing in the Sydney Morning Herald, 'Cost must not put us off the task', 31 October 2006, page 12.
[95] Australian Financial Review, 'Origin seeks leadership on emissions', 26 October 2006, page 22.

The objective of the various renewable energy and gas promotion schemes is to distort investment decisions. Most have been successful in this respect simply because they have made these investments mandatory. For example, there is over 2,000 MW of wind generation either in operation, under construction and proposed. In addition, the reduced capacity to exploit some of these schemes (eg. MRET) quickly led to a reduction in the amount of proposed investment.

By contrast, there has been no new private investment in substantial baseload capacity.[96] Mostly this would appear to be a function of the lack of present need, rather than current policy. But there also appears to have been some delays in the progression of potential large scale gas fired generation investments including Tallawarra (on which construction is just starting) in NSW and Mortlake in Victoria. Again, it is difficult to prove these delays are a function of uncertainty on greenhouse policy, but it is likely to have played a role.

Investors are strongly of the view that the current situation is highly likely to delay investment in new baseload electricity generation, whether that involves using coal or gas and traditional or more carbon efficient forms of generation. The present uncertainty creates an incentive for all parties to defer investment decisions. In particular, the potential:

- Coal fired new entrant will find proceeding problematic without knowing how competitive its plant would be after what they consider to be probable (and sensible) policy changes; and

- Gas fired new entrant is in a similar situation, but may benefit from delaying the investment decision as this encourages more favourable policy changes.

7.4 Impacts

The current policy uncertainty in relation to greenhouse gas emissions is a major impediment to new investment. If the key concern of policy makers about the electricity market is its willingness to invest in new baseload plant, then the single largest impediment to that investment is the current uncertainty regarding greenhouse gas emissions policy.

The current uncertainty is likely to mean that, at a minimum, new baseload capacity comes on line later than it otherwise would and/or be built by governments. This will likely mean:

- Higher electricity prices than otherwise would be the case; and/or

- More issues with the reliability of supply.

It is also likely that it will exacerbate the market response to a sustained period of lower than expected prices, which is to invest more cautiously than it otherwise might.

At a minimum, it is likely to exacerbate the incumbency advantages of the major players in the industry.

[96] Not backed by some form of effective subsidies.

The current policy uncertainty may also have implications for investments by major energy users, particularly given many are currently making major investment decisions. These parties may be more likely to invest offshore in the absence of greater certainty in regard to greenhouse gas policy in Australia.

The risk is that the Federal Government's efforts to avoid sending industries and jobs offshore by refusing to introduce some form of unilateral carbon price signal, will be undermined by the very uncertainty created by a policy that energy sector investors believe is neither credible nor sustainable. The implication is that the cost of trying to protect energy intensive export sectors might well be insufficient investment in electricity generation, which has its own costs.

8 Uncertainty in government policy and regulation

A common theme of the three key impediments identified above is the role of uncertainty in government policy and regulation generally and the impediments to investment this can create.

8.1 Investors' views

Investors believe that policy and regulatory uncertainty distorts investment decisions in a number of ways:

- By creating a higher level of uncertainty than otherwise would be the case;
- By making it more difficult to value project risks and creating asymmetric risks that can be 'deal breakers'; and
- By reinforcing the strengths of those in the strongest position to manage the associated uncertainties (ie. the larger, vertically integrated players who are more likely to make investment decisions on a 'portfolio' basis).

Moreover, investors are of the view that policy and regulatory uncertainty is especially important in electricity markets for the following reasons.

- The nature of electricity (particularly its capital intensity and its demand and price volatility) makes investment highly susceptible to uncertainty. Appendix B summarises the unique attributes of electricity, and compares it to gas.

  Generating electricity is one of Australia's most capital intensive industries. For example:

  > Steven Boulton of Babcock and Brown Infrastructure estimates that it takes $6 in investment to generate $1 in revenues.[97]

  Parts of Australia (most notably South Australia and Victoria) provide some of the most extreme examples in the world of the peakiness of electricity demand. For example, the Federal Government's energy white paper states that peaks lasting for only 3.2 per cent of annual duration account for 36 per cent of total spot market costs.[98] Major energy users argue that in 2005, 0.2% of pool price periods generated 25% of the average pool price.[99]

- Any market interference during those peaks can therefore have a disproportionate impact on average prices. This is, however, precisely the time at which investors' perceive that politicians are most likely to intervene in the market (eg. as price regulation does).

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[97] The Australian, 'Industry taps into $12b seam', Power Generation: Special Report, 9-10 September 2006, page 1. The revenues are presumably annual.

[98] Department of Prime Minister and Cabinet, Securing Australia's Energy Future, 2004, page 70. It also argues that reducing the magnitude and cost of such peaks will reduce overall system costs.

[99] Major Energy Users Inc, Submission to ERIG. 14 August 2005, page 16.

- This creates a risk that prices continue to undershoot new entrant prices, which may then provide 'justification' for further intervention (eg. subsidising new baseload plants).

- The risk is that prices never get to new entrant levels for any sustained period.

Investors consider this to be a serious risk and there is some evidence to support the view that this is one of the causes of the recent history of low prices (in addition a fundamental oversupply of baseload capacity).

Investors are of the view that this type of uncertainty, while difficult to measure, creates a serious impediment to investment, precisely because it is so difficult to measure. Investors by definition have to be prepared to accept risk, but it is asymmetric risks which are difficult to quantify (ie. model) and manage which create the most pervasive impediments to investment.

8.2 Evidence

Investors cite as examples of more general policy and regulatory uncertainty:

- A policy cycle that outpaces the market cycle (ie. the market has not yet been through one investment cycle, but that has not stopped various stakeholders and policy makers forming views about its performance);

- The lack of a unambiguous, time-bound energy policy and a lack of timely implementation of that policy;

- Proposals to tinker with market rules, whilst not dealing with key impediments (which might make the former redundant);

- The re-opening and re-examination of issues (eg. this review and the debate about market structure) and the lack of direction to regulators on these matters. For example, Freehills argues:

  > We have observed widely varying approaches by the ACCC. Having vigorously opposed the acquisition by AGL of a minority and non-controlling interest in Loy Yang A, the ACCC did not object to a number of subsequent acquisitions which presented more significant consolidation. There has been some inconsistency in the ACCC's approach and little guidance from it as to what it regards as the key issues in this industry, exacerbated by undertakings with significant information withheld from the public. There have been improvements in this regard more recently.[100]

- The short term nature of many market transactions (eg, contracting in the retail market), which uncertainty exacerbates;[101]

[100] Freehills, ERIG: Response to Issues Paper of July 2006, page 8.
[101] Most would argue that this is primarily a function of the history of prices (ie. why would an energy user commit to a longer term agreement when prices have 'under-performed'?).

- The history of prices is consistent with these concerns as is the use of the Reserve Trader (which NEMMCO has called but not used on a number of occasions), government responses to high price events and the focus of regulators on investigating all high price events, but not the long history of low prices.[102]

PWC's Utilities Global Survey 2006 asks company leaders about key issues facing the industry and highlights the role of general policy and regulatory uncertainty. In response to the question: Which aspects of regulatory uncertainty provide the greatest disincentive to investment in the energy and utilities sector? – respondents identified the following issues as having either a significant (5) or little (1) impact. The average scores are in brackets.

- Uncertainty about future of environmental schemes that support 'green' investors (3.1);
- Retail price caps (2.9);
- Transmission inter and intra state connection approval processes (2.7);
- Network pricing regimes (2.7);
- Uncertainty about how the national regulator might behave (2.7);
- State interference through mandating of new generation or transmission projects (2.7);
- Changes in wholesale energy market rules (2.6);
- State interference in wholesale market through price arrangements that distort competition (2.4);
- State ownership of energy assets and risk of uncommercial behaviour (2.4);
- Uncertainty about how much power the states will give up to the national regulator (2.4);
- ACCC attitude towards market concentration and market structure (2.4).

These issues are similar those our work has identified, although the relative importance appears to vary. It shows that a broad range of issues are important to industry participants.

The PWC survey also asked a broader question: What do you see as the current impediments to an efficient national energy market in electricity in Australia? This produced a wide range of issues (17) which vary in significance from 3.3 to 2.1. The most important issues identified are: the lack of interconnection between regions, ineffective competition in retail and ineffective market signalling. The least important were: insufficient generation capacity, 'energy only' market rules and the lack of transparency and clarity in government decision making reducing

[102] Most would argue, however, that market fundamentals have played a key role here albeit exacerbated by these impediments.

investment. Other issues identified were: the lack of demand side participation, an insufficient number of market participants and ineffective competition in generation.

A recent University of New South Wales paper argued that:

> …almost all participants see the regulatory risk at both the federal and state government levels as the largest risk they face.[103]

8.3 Impacts

Regulatory uncertainty can have a pervasive, but difficult to measure, effect on investment.

Regardless of the validity of investors' perceptions, they are likely to affect their investment decisions. For example, even if there is no factual basis for private sector concerns about the impact of government ownership on the behaviour of generation businesses, their mere existence is likely to create a perception that their ownership status can or will impact on their behaviour at critical times. This, of itself, creates a risk that a potential investor is likely to consider in assessing an investment opportunity. Other examples include:

- The prevarication on retail price regulation and jurisdiction over it; and
- Statements that imply the Government may invest if the market does not build capacity to its satisfaction. The NSW Energy Minister, Joe Tripodi, recently stated that the Government would prefer investment to come from the private sector "but the government will remain as a provider and investor of last resort."[104]

Investors are likely to respond in a number of ways to this type of asymmetric uncertainty, including by:

- Deferring or delaying investment decisions;
- Requiring a higher rate of return to compensate for the risks; and
- Not investing where the investment does not pass some basic 'screening' type tests.

It is not possible to isolate the impact of general policy and regulatory uncertainty on investment outcomes, but it is likely to be material.

[103] Anderson and Hu, 'Forward Contracts in Electricity Markets: the Australian Experience', 2006.
[104] Australian Financial Review, 'East can take the heat, at least this year', 25 October 2006, page 10. He also stated that the Government did not believe that this created an impediment to private sector investment (as industry claims).

9 Other potential impediments

This section:

- Discusses the other types of potential impediments Section 4 identifies (ie. market rules, market access and market performance issues); and

- Investors' views on whether these are impediments.

In general, investors do not see major impediments to investment in the areas of market rules, market access and market performance, although some investors had strong views on particular issues. The widespread view is that the energy market works "pretty well", and better than similar markets overseas.

Moreover, even where parties had strong views on particular issues, they invariably considered that policy makers should address the major impediments first, where addressing particular issues would represent a major change to the market.

9.1 Market rules

There are several aspects of the market rules that in principle could be potential impediments to investment. The most significant of these are:

- The energy only market;[105]

- The level of VoLL;

- The Reserve Trader; and

- Credit requirements.

The energy only market

The most significant issue raised in relation to the market rules is the market design (ie. the energy only market). A number of parties expressed the view that a capacity market might be a more effective way of ensuring sufficient and timely investment in new generation, particularly baseload generation. Some investors are concerned that the energy only market may not provide the necessary signals to ensure sufficient and timely investment.

Most investors, however, thought that these concerns were largely hypothetical because:

- There is considerable investment in electricity generation currently proposed, albeit largely excluding baseload capacity;

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[105] Another potential issue is whether to use a gross or net pool. However, investors did not indicate that this was a material impediment.

- There is currently limited need for new baseload capacity, although there may be in the next five years; and

- The major constraints on baseload investment in the current situation are the:

  - Level of energy prices for baseload (which is a function of the above); and

  - Uncertainty on greenhouse policy, which creates a major problem in funding any baseload plant.

A number of investors considered, however, that there might be a case for examining alternative market designs *if* the political process never allows the energy only market to operate freely (as Section 8 describes). In other words, if political pressures curb the high price events necessary to get average prices at and above new entrant levels, then it is conceivable that the market never reaches the average prices needed to justify new investment. A number of investors argued that in these very much 'nth' best circumstances, an 'nth' best policy might be necessary.

The level of VoLL

In general, investors do not believe that the current level of VoLL is a material impediment to investment. Some argued that a higher level of VoLL would encourage more demand side management; others argued that a higher level of VoLL would increase the volatility but not necessarily the clarity of price signals (see Section 9.3); others argued that it might merely create a new price point that effectively attracts such prices at times of constraint.

The Reserve Trader

Investors do not believe that the reserve trader is a material impediment to investment. A number of investors have concerns around the conservatism embedded in the decision criteria, the transparency around the decision to invoke the reserve trader and ensuring NEMMCO only invokes it for the purposes of reliability. NEMMCO has recently addressed some of these concerns.[106]

Credit arrangements

Credit arrangements are an issue of particular concern to small retailers. The concern is that the current arrangements constrain new entry because of the relative costs they impose on small new entrants. While these costs are relatively high, we have seen no evidence which demonstrates that they are disproportionately high or that they are not consistent with a reasonable allocation of risk. This issue is addressed in further detail in our report on the electricity trading markets, as are aspects of the credit arrangements that could be improved (eg. to reduce duplication).

[106] Power Industry News, 'New Minimum Standards', Edition 512, 9 October 2006, page 1.

The credit arrangements do not appear to have unduly constrained new entry where the available margins are sufficient, as Section 6 illustrates.

9.2 Market access

There are several aspects of market access that in principle could be potential impediments to investment. The most significant of these are:

- Access to fuel (ie. gas); and
- Access to networks to distribute energy produced.

Access to fuel

Some investors argued that there are some examples (in relation to gas) where potential new entrants have decided not to enter markets because of an apparent inability to get access to fuel (ie. in South Australia and in NSW, albeit some time ago).

We do not address this issue in any more detail in this report because KPMG is addressing this in another report and the issues would appear to be largely circumstance specific.

One investor indicated that the upstream gas market was unwilling to provide longer term contracts that are essential to financing baseload gas plant. This appears to be partly a function of uncertainty in regard to greenhouse gas emissions policy issues.

Access to networks

Some investors expressed major concerns about network access issues particularly in regard to electricity transmission and the firmness of access and the transparency of network businesses operating and investment decisions. In particular, investors are concerned about the capacity for partial asset stranding by virtue of transmission investment decisions and the limited incentives on transmission companies to make commercial investment and operational decisions (eg. when undertaking maintenance).

Investors were less concerned about inadequate levels of interconnection. There is some evidence to support their lack of concern. Both NEMMCO's ANTS and two recent reports by the Australian Economic Regulator put congestion currently at modest levels (in the order of $36-45 million in 2003/04 to 2004/05 respectively on market turnover of about $7 billion).[107] Firecone argues that the level of congestion is consistent with other overseas markets.[108] The lack of concern might also reflect the fact that most private sector investors are likely to benefit from less interconnection in the current market circumstances (ie. the beneficiaries may be those parties that are over-investing).

[107] NEMMCO, Submission to ERIG, 4 August 2006, page 4; and Power Industry News, 'New Congestion Cost Estimates, Edition 513, 16 October 2006, page 12.
[108] Firecone Ventures Pty Ltd, ERIG: A report to the Department of Infrastructure, August 2006, page 19.

In respect of access to networks, for example, one investor indicated that it had taken one year to negotiate a connection agreement (when it has done similar deals in 3 weeks elsewhere), and the network provider twice as long to build the substation as it had taken the investor to build its generating plant. This is despite committing to a connection date (but because of its ownership status one with no penalty clauses). The business lost one year of cash flows and has been unable to meet certain contract commitments. In a separate instance, it attempted to negotiate a major contract (for it) with a government owned business. The deal "sat in a Minister's in tray for over three months", during which time it was unable to provide the market with any guidance. The share price of the company fell 60% over this period.

Over time there may also be a need to address issues that arise between merchant gas transmission and regulated electricity transmission, as the role of gas in the electricity market increases.

We do not address these issues in any more detail in this report because ERIG is addressing these issues in another workstream.

9.3 Market performance

There are several aspects of market performance that in principle could be potential impediments to investment, or reflect other impediments. The most significant of these are:

- The level of prices;
- The depth and liquidity of the financial markets;
- The willingness to take energy market risk; and
- The degree of vertical integration.

In general, investors do not believe that market performance 'creates' a material impediment to more efficient investment. Rather investors are of the view that the market's performance reflects the underlying fundamentals (ie. supply and demand) and the environment in which the market is operating (ie. subject to some major impediments).

There are some market performance issues, however, which some parties (although not typically investors) believe create major impediments to more efficient investment or market outcomes. One of these is vertical integration, which we address in some detail below.

9.3.1 The level of prices

Investors do not regard the level of prices as a material impediment to more efficient investment because:

- Investment decisions are based on a long term view about the prices that the investor could expect to get for its output (eg. usually based on some view about new entrant prices in the case of generation); and

- The financial markets do not look far enough forward to be used for that purpose and reflect shorter term market dynamics.

Many investors are of the view, however, that the level and, in particular, the history of prices has some bearing on investment decisions, or at least their timing. This is because:

- The first few years of cash flow can be important to the viability of an investment even one made on a 20-30 year view;

- Market prices have consistently undershot expectations; and

- The market is getting peakier partly due to the oversupply of baseload, which creates further investment uncertainty (see Section 9.3.2).

For example, many investors argued that few would invest in the expectation of being significantly 'underwater' after the first five years, in the hope that it might turn around thereafter. In particular, investors are unlikely to do this when they have yet to see a period where prices have consistently been at a level that would justify new investment (eg. in baseload). Because of this some investors (who might otherwise be prepared to invest in baseload generation and take market risk) are of the view that it would take a sustained period of prices achieving new entrant levels before they could be in a position to justify investing. In other words, they have seen the losses incurred by the original and some cases second owners of generation plant, and are wary as a result.

In effect, there is a degree to which the market (which is still relatively new and has not yet been through a full investment cycle) is still 'on trial' in the eyes of some investors.

Notwithstanding this, investors are invariably of the view that there are rationale reasons why prices particularly for baseload have undershot expectations, albeit exacerbated by governments historic or more recent investment decisions. It reflects the gradual unwinding of a sustained period of oversupply.

The evidence shows the degree to which prices have undershot expectations. For example:

- In 1997, Loy Yang A (the lowest cost generator in the NEM) sold for an enterprise purchase price $4.9 billion; and

- In 2003, AGL acquired a 32% stake in Loy Yang A on an implied enterprise purchase price of approximately $3.5 billion (a 28% discount).[109]

[109] AGL, Investment in Loy Yang Power Market Briefing, 3 July 2003. Most recently, Transfield acquired a 9.3% stake in Loy Yang A for $115M. Unfortunately, it is not possible to compare these figures with the enterprise purchase prices listed above due to information limitations. Grant Samuel, Independent Expert's Report: Alinta Scheme Booklet, 28 August 2006, Appendix 3 page 1.

The evidence also suggests that up until recently prices have remained below new entrant levels for baseload capacity. The ACIL Tasman's Report on NEM Generator Costs found that the average new entrant cost for coal-fired generators ranged from $31-36/MWh, yet the volume-weighted average pool price for all periods, in most regions in 2005 was less than $30/MWh.[110]

In 2006 there has been some recovery in spot prices which appears to have led to some increases in retail contact prices for large users.[111]

9.3.2 The depth and liquidity of the financial markets

Investors are of the view that the depth of the financial markets (or lack thereof) is not a major impediment to capital investment in the generation sector for the reasons indicated in Section 9.3.1. In other words, the level of prices is only partly relevant and to the extent that it is, it is about the level, not the fluctuation around that level. Investors were of the view that shallow and illiquid markets are likely to increase the volatility of prices which might somewhat increase the degree of uncertainty in regard to price levels.

The depth and liquidity of the financial markets is, however, an issue of significant importance to new retail entrants. Without sufficient depth and liquidity they would find it difficult to compete with the major and more vertically integrated players and it would create a material impediment to new entry and investment. These parties argued that the futures market is critical in providing that liquidity.[112]

Investors were of the view that there was sufficient liquidity at the present time, although more liquidity would be better than less. They also cautioned that policy makers should monitor this issue particularly if the level of vertical integration increased and it started impacting on the level of liquidity.

9.3.3 The willingness to take energy market risk

Some stakeholders have questioned whether the market is willing to take energy market risk (eg. invest in merchant generation particularly baseload) and that, as a result, there is a 'shortage' of capital for this type of investment.

Investors are of the view that there is no 'shortage' of capital at the moment and the buoyant equity markets and the highly competitive debt markets are indicative of this. For example, there is currently a large appetite for energy sector (and other infrastructure) investments with more revenue certainty and stability either by virtue of:

- Regulation (eg. energy network businesses); or
- Long term contracts over outputs (eg PPAs in the case of generation assets or take-or-pay contracts in case of gas production/transmission assets).

110 Energy Supply Association of Australia, ERIG – Issues Paper, 23 August 2006, page 4.
111 Australian Financial Review, 'High power costs spark reform calls', 24 October 2006, page 10.
112 Although others argued that using futures to hedge physical exposures was likely to result in the retailer bearing some market risk.

Australia has been at forefront of securitising these types of infrastructure assets and there has been considerable corporate takeover activity in recent times.[113] The following factors appear to be driving the market's appetite:

- The Federal Government's policy of mandatory superannuation and associated demographic changes (eg. the ageing of Australia's population);
- The relative dearth of alternative investments due to limited government debt and the apparent unwillingness of governments to fund new infrastructure via debt;
- The limited privatisation of government infrastructure assets; and
- The relatively benign interest rate environment, which has supported stocks selling primarily on dividend yields, although this has changed somewhat more recently.

For example, Australia has more money in managed funds per person that any other developed country, and 25% higher than the second ranked country (the United States).[114] We understand that about $1 billion per week currently flows into superannuation funds. These infrastructure funds are increasingly looking overseas to satisfy their investment needs.[115]

Some investors and commentators question whether this is creating a significant distortion in the investment markets.[116]

Notwithstanding these developments investors are of the view that, in principle at least, there is no shortage of capital that might be prepared to take energy market risk (eg. one investor suggested for example that they had "several billion" potentially to invest in baseload, merchant generation).

Investors are also of the view, however, that it is highly unlikely that a stand alone merchant generator would invest in new baseload capacity in the current environment. This is for the reasons indicated above in relation to the uncertainty over the level of prices and greenhouse issues. Even if it were possible to put these issues aside, however, many investors still believe it would be unlikely because this type of investor would struggle to compete with other investors. In particular, this type of investor would struggle to compete in terms of its cost of capital with those who managed market risk either via:

- A PPA with a large end user;
- Vertical integration; or, perhaps,
- Having an internationally diversified generation portfolio.

Section 9.3.4 discusses this issue in some detail in the context of vertical integration.

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[113] Other older funds include Babcock and Brown Infrastructure, Envestra and Hastings Fund Management. See Australian Financial Review, 'Firms set to buy American Utilities', 17 July 2006, page 15.
[114] Sydney Morning Herald, 'Aussies biggest investors in funds', 24 January 2006, page 23 (business).
[115] Sydney Morning Herald, 'Australian funds bid for British utilities, 3 October 2006.
[116] Sydney Morning Herald, 'But Marx didn't mention the fees', Alan Kohler, 16 August 2006.

9.3.4 Vertical integration

A number of stakeholders and policy makers have expressed concerns about the merits or otherwise of vertical integration. These concerns would appear to be from the perspective of:

- The depth and liquidity of the financial markets;
- Encouraging new entry and investment (either directly or indirectly from the above); and/or
- The interests of consumers.

This report focuses on the investment implications of vertical integration.

Investors' views

Investors largely believe that vertical integration is an inevitable and largely benign development because:

- It has occurred in a number of other energy (and electricity) markets (eg. UK, US and NZ);
- It offers material risk management and cost of capital advantages.

There is a considerable body of evidence to support these views.

International developments with vertical integration

In PWC's 2002 Global Utility Survey, it noted that:

> "Vertical integration continued to drive mergers and acquisitions" and that "analysis of the top 40 deals indicates that vertical integration accounted for 40% of all gas and electricity merger and acquisition activity."[117]

PWC's 2003 Global Utility Survey again noted the trend towards vertical integration. It stated:

> …the strength of global utilities in the future will be built upon vertically integrated strategies, rather than the pursuit of multi-utility and specialised portfolios. [118]

<u>The United Kingdom</u>

In the UK there are now:

- Six vertically integrated energy companies: Centrica, Innogy (controlled by German company RWE); London Energy (controlled by French company EdF); Powergen (controlled by German company E. On); Scottish Power; and Southern and Scottish;

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[117] PWC, Survey: Power Deals, 2002.
[118] PWC, Survey: Power Deals, 2003.

- Three primarily merchant generators: International Power (which owns generation assets around the world), the Drax Group and British Energy (the nuclear plant operator); and

- No major independent retailers.

There is therefore a large degree of vertical integration. There are some parties, however, who are 'long' generation (primarily the merchant generators but also some of the more integrated companies) or 'long' retail (e.g. Centrica, which has limited generation assets).

In 2004, the Financial Times noted:

> The merchant generators' dalliance with the UK power market has ended, and vertical integration, more or less, has become the dominant business model.[119]

Developments in the UK market highlight the risk management benefits of vertical integration.

The collapse in UK wholesale electricity prices in 2000-02 provides an illustration. It led to the forced refinancing of British Energy and AES Drax. As noted in Project Finance Magazine:

> The roll call of UK power generating companies that have run into trouble as a result of the situation is a graphic illustration of the importance of vertical integration in this industry. Wholesale prices may be down 40% since NETA was introduced but retail prices certainly are not.[120]

Project Finance noted that British Energy's problems were:

> …exacerbated by the fact that it is a pure generator with no retail supply business to make up the losses it has incurred in generation. This is the problem facing another pure generator AES Drax, which operates a 3960MW coal-fired plant in North Yorkshire – the largest coal-fired plant in Europe.

Project Finance also noted that:

> …the difficulties in the market are by no means universal. Vertically integrated players such as Innogy, Powergen, Scottish Power and Southern can all take advantage of the increased margins on the retail supply side made possible by the drop in wholesale prices. Thus, although they may be facing problems on the generation side they are far better placed to survive the current climate.

More recently, the rapid increase in UK wholesale prices has again highlighted the benefits of vertical integration.

In March 2006, Moody's changed its outlook in respect of Centrica to negative despite its recent announcement to increase its tariffs by 22%. The change in fact highlighted the risk of it losing customers because of weaknesses in its hedging arrangements and thus its retail franchise. Moody's stated that its reassessment:

> …underlines Centrica's current disadvantage over its UK peers from its short generation position and its gas-biased and thus costly fuel mix. As a result, Centrica's residential energy margins are further impacted by the necessity to purchase, at current high prices, power to meet its requirements. Moody's assumes that further acquisitions of power generating capacity (including power purchase

[119] The Financial Times, 'Lex: UK Power', 12 August 2004.
[120] Project Finance Magazine, "Meltdown", 1 November 2002.

> agreements) are inevitable, but that such will come at a high price in the present environment, similarly to any upstream gas assets.[121]

We understand that by June this year Centrica had lost over 400,000 customers in the first half of the financial year.

The United States

There was significant merchant entry into the US generation market in period up until 2001. However, with the Enron collapse and the resulting market turmoil merchant activity has at least stalled. Fitch is quoted as follows:

> …by early 2002 it became "apparent" that volatile cash flows from merchant energy operations – wholesale trading and generation development – were higher than the industry had predicted. "Underlying results refuted the proposition that inherent volatility in wholesale prices would be entirely contained through risk management tools", such as hedging techniques, Fitch said. Even the oil industry, which has a deep and broad market, could not stabilise the swings in natural gas prices through internal hedging, such as vertical integration, or hedging with contracts. Fitch asserted that risk management techniques in the "less mature, less liquid" energy markets proved to be more difficult and less effective.[122]

PWC's 2003 Survey indicated that most of the:

> …US utilities recognise the risk of not owning and controlling your own generation is too high. They've discovered that owning as much generation as you need for your retail load is a good risk management strategy. It also gives you some economies of scale to support the infrastructure.[123]

New Zealand

The New Zealand market is highly vertically integrated and many argue has illiquid hedge markets as a result. In a report for one of the market players, however, NERA argued:

> …vertical integration is often an efficient response to competitive conditions and that the illiquidity of markets for "hedging contracts" is limited by the underlying market conditions in New Zealand, rather than vertical integration alone.[124]

A number of investors familiar with New Zealand expressed similar views.

Australia

All of Fitch's recent credit rating notes on AGL, Contact Energy (NZ), Origin Energy and China Light and Power (TRUenergy), highlight the benefits of vertical integration because of

[121] Moody's Investors Service Press Release, Moody's Changes Outlook on Centrica's Ratings to Negative, 16 March 2006.
[122] Fosters Electric Report, 'Fitch sees tough times ahead for energy companies, but forecasts that core utility assets will continue to save the industry', Report No. 283, 27 November 2002.
[123] Electric Light and Power, 'Utilities moving forward with a more conservative approach', 1 June 2003.
[124] NERA, Hedge Markets and Vertical Integration in the New Zealand Electricity Sector: A Report for Contact Energy, 12 October 2004, http://www.nera.com/Publication.asp?p_ID=2264.

the cash flow stability it provides.[125] Brokers such as, Salomon Smith Barney and Deutsche Bank, have also highlighted the cash flow benefits vertical integration provides (eg. in light of AGL's acquisition of Loy Yang).[126]

In relation to Australia, Fitch Ratings recently noted:

> M&A (mergers and acquisitions) event risk is likely to continue in 2006. Integrated utilities want to strengthen the quality of their internal hedges by combining generation and retail operations through further acquisitions. Moreover, the resulting combination of size, synergies and the increased degree of vertical integration is placing pressure on disaggregated entities such as state government-owned generators and retailers to consider structural and ownership changes to better manage industry risks.[127]

One significant investor indicated that they were currently involved in the construction of about 5,000 MW around the world, all of which PPAs underpin. It is looking at a further six projects in Australia, all of which PPAs (or effective long term agreements) would underpin.

Evidence of the value of vertical integration

It is possible to draw inferences about the value of vertical integration by examining the differences between:

- Merchant generators (or Independent Power Producers – IPPs - who typically sell their output on short term contracts – 3 years – or via spot markets); and

- Contracted generators (i.e. those with long term contracts or PPAs).

The comparison between the two types of generators is instructive because the long term contracts held by the contracted generator is effectively a proxy for the natural hedge obtained through vertical integration. By contrast, a merchant generator bears wholesale market price risk, except over the short term. These two types of generators therefore provide a useful proxy for the valuation implications the market attaches to this risk.[128]

The UK provides the best available market evidence.

- In its valuation of International Power's business, Morgan Stanley disaggregates the earnings from these two types of assets. It states:

  > We view the contracted earnings stream as stable and predictable… In our opinion this is worth a multiple in line with stable, regulated utilities. We apply a 15X PE multiple to gain a fair value for the contracted assets. Merchant assets should be valued differently. We believe the best way is to

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[125] Fitch, Comments on AGL's Acquisition of Loy Yang A, 8 April 2004; Fitch, Contact Energy Limited, 9 January 2006; Fitch; Origin Energy Limited June 2005; Fitch, CLP Australia Holdings Pty Ltd, October 2005.
[126] Deutsche Bank, 'The Australian Gas Light Company: Loy Yang acquisition completed at last', 8 April 2004; Salomon Smith Barney, 'Australian Gas Light Company: Does AGL need to buy Loy Yang?', 20 March 2003.
[127] Fitch, 'Australian Utilities – What's the Mix for 2006', 3 February 2006, page 1.
[128] Observed differences in the valuations of these two types of generators would, however, probably overstate the benefits of achieving vertical integration in a competitive market context. This is because the vertically integrated retailer does not have the same degree of control over its market as the contracted generator, but it has greater control than a merchant generator.

> consider peak merchant earnings and apply a very different, much lower multiple to these. We apply a multiple of 8X to derive a fair value for the merchant assets.[129]

In effect, Morgan Stanley values the earnings from a merchant generator at almost half those from a contracted generator. Consistent with the above, Morgan Stanley took similar issues into account in August 2004 when International Power undertook the business transforming acquisition of the non-US assets of Edison Mission Energy (which included Loy Yang B). The assets acquired where almost entirely contracted. As a result, Morgan Stanley altered its benchmark assumptions in respect of International Power's cost of capital. For example, it altered its benchmark gearing ratio from 30% to 60%.[130]

Morgan Stanley applies different discount rates when valuing pure merchant generators. For example, in respect of International Power, Morgan Stanley applies a "group" weighted average cost of capital of 7.9%. By contrast, in the cases of Drax and British Energy it uses discount rates of 8.75% and 10% respectively.[131] It notes that Drax is a "*higher risk investment than a typical utility because it is not vertically integrated.*"[132] It derives its higher cost of capital than for International Power partly by using a gearing ratio of approximately 20%.

- ABN Amro adopts a similar approach in valuing International Power. It states that:

> IPR's risk profile has changed significantly and it is not as exposed to merchant activities as it once was. Stable PPA assets now comprise 52% of IPR's EV vs 37% in January 2004. As a result, we view IPR's cash flows as more stable, warranting a lower WACC of 7% vs market consensus of 8%.[133]

It assumes IPR's benchmark gearing ratio is 50%, based on an assumed gearing of 70% for contracted assets and 30% for merchant assets. These assumptions imply a cost of capital range of about 8% to 6.2% for merchant and contracted generation assets respectively.

These differences suggest that a merchant generator's cost of capital is likely to be about 2% higher (or about 25-35%) than that of a generator with a long term contract. A vertically integrated player is likely to have a cost of capital somewhere between these two extremes, depending on how well it is vertically integrated.

A number of investors suggested that these estimates are conservative and that the cost of capital advantages of vertical integration might be larger than implied above. One suggested that it is likely to be worth 5% on the cost of equity.[134]

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[129] Morgan Stanley Equity Research, 'International Power: Further to go', 7 March 2006.
[130] This is consistent with the actions of International Power which used 80% debt to fund the contracted assets.
[131] Morgan Stanley Equity Research, 'Drax: Confirming positive outlook', 8 March 2006 and Morgan Stanley Equity Research, 'British Energy – Key Takeaways from Q3 – We still prefer Drax', 24 February 2006. Morgan Stanley uses a higher discount rate for British Energy in part because of its higher operating leverage (ie. higher fixed costs).
[132] Morgan Stanley Equity Research, 'Drax: Discounting US$43 Long-term Oil Price – May Be Conservative', 18 January 2006, page 18.
[133] ABN Amro, 'International Power: Switching the Focus', 13 October 2005, page 1.
[134] The cost of capital referred to for International Power are based either on views about the underlying parameters for the UK or on using an international cost of capital. The absolute level may therefore be less relevant to Australia.

Retailers

As indicated above, some investors (ie. independent retailers) are concerned that vertical integration would create impediments if it resulted in illiquid financial markets. It is not obvious, however, that vertical integration is of itself what is driving the depth of financial markets. There are several reasons for this:

- The evidence suggests that trade has not decreased whilst vertical integration has increased;
- There are good reasons why Australia's financial markets are likely to be less deep than other similar markets (eg. its size, geographic dispersion and relatively modest interconnection);
- Although vertical integration reduces the need to use the financial markets to hedge, vertically integrated players are unlikely to have matched generation and retail portfolios. As a result, they will need to hedge to manage their risks. Vertical integration therefore can change the areas of the market where activity is happening (but also make the markets 'lumpy'). In this way the financial markets are complementary to vertical integration and not a substitute for it; and
- Other similar markets that are highly vertically integrated, also have relatively deep financial markets (eg. oil). As one investor commented: "I don't have any concerns about vertical integration because of my background in the oil industry".

Vertical integration and consumers' interests

The purpose of this report is not specifically to address consumers' interests directly, although more efficient investment is likely to be consistent with them. Equally, it is not the purpose of this report to address directly whether vertical integration is consistent with consumers' interests.

In our view, however, the evidence suggests that there are large efficiency gains to be derived by vertical integration and that absent market intervention the market is likely to become much more vertically integrated over time.

The only question is therefore whether customers will share these gains. In our view, the answer to that question is likely to be a function of the degree of horizontal integration rather than the degree of vertical integration *per se*, and that policy makers should focus on the horizontal market concentration issue.

We think there is strong evidence to support our view.

For example, in a recent paper on vertical integration across industries for the American Bar Association, Paul Joskow provided the results of his review of the vast academic literature and empirical research (over 500 studies) on the reasons for vertical integration.

Joskow's states that:

> The overwhelming conclusion of this large number of empirical studies is that the importance of specific investments and other attributes that affect transaction costs are both statistically and economically important causal factors influencing the decision to vertically integrate. Indeed, it is hard to find many other areas of industrial organisation where there is such an abundance of empirical work supporting a theory of firm or market structure.[135]

Joskow concludes:

> There are many types of market imperfection that could lead transacting parties to turn to vertical integration as an alternative governance arrangement, recognising that vertical integration is one of many governance alternatives to relying on anonymous spot market contracting. Some of the theoretical work supports an efficiency motivation for vertical integration. Some of the theoretical work supports an anticompetitive foreclosure motivation for vertical integration. Overall, I would argue that there is substantial support in the economic literature for various efficiency motivations for vertical integration. There is minimal support for anticompetitive foreclosure motivations. This suggests that there is little empirical support for the antitrust law's traditional suspicion of and hostility toward vertical integration and related non-standard vertical contractual arrangements (Joskow 2002) except under extreme conditions where firms controlling bottleneck monopoly facilities have the incentive and ability to exercise an anticompetitive foreclosure strategy.[136]

Joskow's conclusions stress the importance of keeping transmission separate from generation in the electricity sector.

We are aware of a number of other electricity industry specific studies that express similar views.[137]

Even if it were assumed that a greater degree of vertical integration were a risk to the consumer interest (ie. several vertically integrated players were 'forcing' prices up), then it is not obvious to us that the market does not have some alternatives available to it. It seems to us that it would place energy intensive users (or small groups thereof) in a relatively strong position to use their leverage to underwrite new baseload plant by a party other than one of the incumbents.

They would, however, need to be prepared to enter into long term contracts, which most have shown little inclination to do as yet.[138] The reason for this appears to be that the history of prices has worked in their favour since market start (which, incidentally, is the same reason that has made potential investors in new baseload plant more wary, as Section 9.3.1 discusses).

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[135] Paul Joskow, 'Vertical Integration', Prepared for the American Bar Association Antitrust Section's, Issues in Competition Law and Policy, 15 September 2005, page 27-28.

[136] Ibid, page 28-29.

[137] See, for example: Hung-po Chao, Shmuel Oren, and Robert Wilson, 'Restructured Electricity Markets: A Risk Management Approach', 1 July 2005; Hung-po Chao, Shmuel Oren, and Robert Wilson, 'Restructured Electricity Markets: Reevaluation of Vertical Integration and Unbundling', 1 July 2005; and Erin Mansur, 'Upstream Competition and Vertical Integration in Electricity Markets', (JEL L13 L94).

[138] Some economists have argued that removing the right of customers to choose their retailer would be beneficial to the market because it would facilitate long term contracting which they currently regard as 'insufficient' and thus deliver the benefits that it can provide (ie. lower financing costs, less distortion toward less capital intensive investment and more investment). See for example, K., Neuhoff and L., De Vries, 'Insufficient incentives for investment in electricity generation' Cambridge Working Papers in Economics CWPE 0428, March 2004.

Conclusions on vertical integration

Investors are of the view that, absent government intervention, in ten years the NEM would probably feature:

- Three to four vertically integrated major retailers;
- Several niche players in the upstream and downstream sectors; and
- A highly concentrated and securitised regulated network sector.

The implication is that policy makers should:

- Be less concerned about the degree of vertical integration than currently appears to be the case in some quarters;
- Should remain vigilant in regard to the degree of horizontal integration and seek to ensure that the NEM has several competitors, if large vertically integrated parties come to dominate the market as investors currently expect;
- Ensure that if the Government's of NSW and Queensland privatise their electricity industries they take all reasonable steps to ensure it creates the possibility of at least one new major (vertically integrated) player emerging; and
- Seek better information disclosure and monitor the development of the financial markets to ensure that vertical integration or any other factors are not reducing liquidity to the extent that it might preclude or otherwise distort new entry into the retail market.

10 Policy implications

This section outlines the implications for government policy that flow from investors' concerns.

Investors do not believe that there is an impending crisis in relation to investment in the upstream and downstream energy sectors. On the contrary, considerable investment is occurring and is proposed, particularly in the gas sector. In the electricity sector, whilst there is no impending crisis (ie. there are no major impending reliability issues caused by an absence of generation investment) there is a basis for some concern, particularly as new baseload capacity becomes necessary.

Investors do believe, however, that that there are significant impediments to more efficient investment in the energy sector, and in the electricity sector in particular.

Governments are readily in a position to address the key impediments. We acknowledge, however, that the policy implications in respect of these impediments are likely to be as politically challenging as they are self-evident.

10.1 General

The most important general implications are that Australia's governments and policy markers should:

- Address the key impediments to investment first and resist the urge to 'tinker' with fundamental market rules, before addressing the key impediments. Tinkering with the market rules is unlikely to resolve any fundamental problems, even where it is warranted, absent addressing the key impediments.

- Establish time bound reviews of market performance that might then lead to policy actions (say after 5 years). In other words, give the market time to work to allow the policy cycle to follow the market cycle and be informed by it. There is currently a tendency for the opposite to occur.

- Provide clearer policy direction on key market performance issues. This is particularly important in respect of market structure issues and vertical integration. Investors believe the concerns about vertical integration are misplaced, provided the financial markets retain sufficient liquidity. This is a view we share. If necessary, policy makers should seek the views of the Productivity Commission on this matter.

- Consider ways of generating more information on financial market activity, whilst retaining confidentiality, so that policy makers can monitor activity and, if justified, improve the confidence of all stakeholders in the market. This will provide, for example, the information necessary to assess whether greater vertical integration does in fact lead to insufficiently liquid markets so as to become a material barrier to entry. We address this issue in further detail in another report.

- Further investigate the scope for introducing more transparency into transmission investment and operational decisions and gas access issues. This is also the subject of a separate workstream.

- Establish whether using competition policy payments (or some similar mechanism) could reinvigorate the energy reform process, and encouraging the states to do what is in the interests of the market as a whole.

- Monitor the performance of the WA market over time to see whether its capacity market makes a material contribution to its performance.

10.2 Government ownership

In our view, the key policy implications are:

- Privatisation of the remaining government owned business with a focus on:

  - Creating vertically integrated entities that have some chance of becoming the fourth and, ideally, fifth major players in the market; and

  - Ensuring there is no increase in the degree of horizontal integration.

  This, in our view, provides the prospect of developing the most competitive energy market practically possible. It involves working with the market to deliver practical improvements in market structure rather than working in opposition to it, which is unlikely to be successful. In other words, attempting to impose vertical separation is unlikely to be successful or, if it is, come at excessive cost. This is because market forces are driving vertical integration and it is likely to happen absent major market intervention.

  Privatising assets in the upstream and downstream sectors separately is likely to result in the private sector integrating the assets anyway. In other words, it is likely to play into the hands of the existing vertically integrated businesses and limit the prospects of new entrants (eg. from overseas or established by way of an IPO) participating in the market. Under this approach, the market will likely end up more horizontally integrated than it otherwise might be, but no less vertically integrated. In addition, the proceeds from any privatisation will be lower and the benefits will accrue to the parties that undertake the vertical integration.

- If privatisation is not currently politically feasible, then focus on industry restructuring to allow for vertical integration, and/or seek to 'privatise' the operations of these businesses (eg. perhaps on broadly similar lines to what NSW was proposing with the Trader model).

- If neither of the above is feasible, then at a minimum, a commitment to no new government funded investment in electricity generation is the next most important policy change that governments could make.

- In tandem, it may be necessary to investigate what other ways might exist to provide governments with the additional comfort some appear to want in relation to the security of supply, whilst minimising the impact of providing that greater degree of comfort on investment decisions. This is likely to be a challenging trade-off to meet. The objectives would be to ensure that:

- Governments can decide the level of reliability of supply they want (perhaps beyond what they already have);
- Governments would pay for any new capacity they decide to build; and
- The use of any capacity built for this purpose interferes with market prices (and therefore investment decisions) to the minimum degree possible.

• It might be possible to do this by altering the role of the Reserve Trader. This could, for example, involve governments agreeing to permit state governments to build (or cause to build) additional peaking capacity if they want to, but subject to certain conditions. The most critical are likely to include:

  - NEMMCO deciding how to use capacity under a revised Reserve Trader concept (ie. only to facilitate the reliability of supply). The generator would not be able to contract with any other party;
  - The State Government proposing the investment bearing the cost; and
  - The pool price automatically going to VoLL at any time NEMMCO calls the plant (ie. any time the revised Reserve Trader is used).

• It might also after a suitable lag be possible to release that capacity to the market and make it available for commercial use.

• This approach would need more thorough investigation than this study allows. It would also require significant commitment from all the States. For example, it would not necessarily stop a State building new baseload capacity, if it were inclined to do so (unless it also imposed certain binding obligations in terms of minimum prices for these plants as well, which might not be feasible).

• The other alternatives might include the States agreeing to more punitive arrangements to ensure that they do not increase their absolute level of capacity, perhaps via some form of Intergovernmental Agreement. It is likely that some reasonably complex structuring around the governance of such an agreement would be required to ensure it did not preclude, for example, commercial enhancements to existing capacity or other joint ventures. Alternatively, either:

  - The AEMC could be asked to assess whether any government proposals to build new plant are consistent with the Market Objective; and/or
  - The Australian Government Competitive Neutrality Complaints Office (part of the Productivity Commission) could be given stronger powers to investigate complaints by private sector market participants in relation to public sector investment, which may not

be occurring on a level playing field (and possibly the capacity to recommend fines for breaches).

10.3 Price regulation

The key policy implications in relation to price regulation are to:

- Phase it out as soon as possible; and, if that is not possible,
- Ensure that regulated prices are set at true 'safety net' levels (perhaps by ensuring they increase in excess of CPI each year for an extended period); and
- Use other ways (eg. perhaps through the welfare system) to protect the key customer groups that governments are concerned about (ie. those who cannot pay).

To facilitate this process, policy makers could give consideration to:

- Shifting responsibility for retail price regulation to the national regulator;
- Separating the responsibility for the policy decision (to regulate) and policy implementation (how to regulate); and
- Making the Australian Energy Market Commission (as the MCE recently decided to do) responsible for reviewing the effectiveness of competition and advising on the need for price regulation (rather than State based regulators who are experts in network regulation rather than the performance of competitive markets).

10.4 Government policy – greenhouse gas emissions and renewable energy

As Section 7 notes, if the major concern of policy makers is whether the market will invest in new baseload electricity generation in a timely manner, then it is imperative that governments address the uncertainty around greenhouse gas emissions policy.

Federal and States governments need to work together to develop a more rational approach to greenhouse policy. A more rational approach is likely to involve:

- Agreeing on a simple, broad based but measured and long term carbon price signal, which is:
  - Perhaps phased in over time but provides clear points at which the value might be reset;
  - Provides exemptions (or some form of credits) for energy intensive, trade exposed industries;

- Relying on this as a key component of its greenhouse gas policy perhaps complemented by industry and technology specific initiatives, where policy intervention is necessary to overcome particular impediments to investment in greenhouse gas abatement;

- Where those initiatives are necessary, ensuring that State and Federal policy are consistent.

A Our terms of reference

KPMG has been asked to survey potential investors in the energy sector to identify any impediments to the efficient operation of the capital markets investing in the energy sector, and in particular in the upstream and downstream domestic electricity and gas markets.

The outcomes should provide context for the analysis and any recommendations made to address impediments in the electricity and gas markets (eg. whether any impediments in the financial markets are a function of broader impediments in the physical market).

In particular, ERIG has asked us to examine from the investors' perspective:

- Whether there are any impediments to the capital markets investing in the energy sector;
- What they are and how in practice they impact on investment decisions. ERIG is particularly interested in factual material that supports any investors assertions; and
- What actions governments might take to address the causes of those impediments.

B Key features of electricity and gas

Electricity has a number of important and unusual set of physical and technical attributes that are worth noting in any discussion about investment. There are also a number of important differences between electricity and gas, which the development of the two industries reflects.

Electricity

Paul Joskow has described the unusual attributes of electricity in recounting the difficult transition to competitive electricity markets in the US (a transition that has been much more difficult than in Australia). He states:

> These attributes include:
>
> a. Electricity cannot be stored economically and demand must be cleared with "just-in-time" production from generating capacity available to the network at (almost) exactly the same time that the electricity is consumed.
>
> b. Physical laws governing electricity network operations in real time to maintain frequency, voltage and stability of the network, along with network congestion, interact with non-storability to require that supply and demand be cleared continuously at every location on the network. Creating a set of complete markets that operate this quickly, at so many location, and without creating market power problems is a significant challenge.
>
> c. The short-run demand elasticity of electricity is very low and supply gets very inelastic at high demand levels as capacity constraints are approached. As a result, spot electricity prices are inherently very volatile and unusually susceptible to the creation of opportunities for suppliers to exercise market power unilaterally.
>
> d. Network congestion, combined with non-storability, may limit significantly the geographic expanse of competition by constraining the ability of remote suppliers to compete, further enhancing market power problems.
>
> e. Loop flow, resulting from the physics of power flows on AC networks, introduces additional complex interactions between generators at different points on the network, creating unusual opportunities for suppliers to take actions unilaterally to affect market prices, complicating the definition of property rights, and creating coordination and free riding problems…
>
> f. Electricity demand varies widely from season to season, between day and night, with extreme temperatures, and between weekdays and weekends (and holidays). The difference between the peak demand and the lowest demand over the course of a year is a factor of about three. Because electricity cannot be stored and varies widely over the year, a significant amount of the generating capacity connected to the system operates for a relatively small number of hours during the year to meet peak demands. Historically, there has also been little reliance on real time prices to ration peak demands. This means that the ability of generators that provide services for a small fraction of the year to recover their investment and fixed operating and maintenance costs is heavily dependant on the price formation process during periods when demand (and prices) are at their highest levels.
>
> g. The combination of non-storability, real time variations in demand, and low demand electricity, random real time failures of generation and transmission equipment, the need to continuously clear supply and demand at every point on the network to meet the physical constraints on reliable network operations, means that some source of real time "inventory" is required to keep the system in balance. This "inventory" is generally provided by "standby" generators that respond very quickly to changing supply and demand conditions, though demand side responses can also theoretically provide equivalent services as well. Compatible market mechanism for

procuring and effectively operating these "ancillary services" are therefore necessary. Designing well functioning integrated markets for energy to meet demand and the need for multiple ancillary services to maintain network reliability consistent with all of the other constraints and attributes enumerated above is very challenging.

h. The performance of competitive markets for electricity depend critically on the way the regulated transmission network is operated, access to it priced and scarce transmission capacity is allocated. There are important complementarities between energy markets and transmission operations, especially congestion management and responses to emergencies. Integrating spot energy and ancillary services markets with the allocation of scarce transmission capacity is necessary to wholesale power markets to operate efficiently.

While there are many competitive industries that have one or perhaps two of these attributes, it is hard to think of any commodity market that has all of them,…, Ignoring these unusual attributes of electricity, and ignoring how and why historical governance arrangements evolved for dealing with them, is a very bad mistake.[139]

Gas

In contrast to electricity, for natural gas:

- Production and consumption are not instantaneous, gas transmission can act as a storage and typically gas flows in one direction (ie. point-to-point);
- There is relatively little interdependence in operation of gas transmission networks;
- There are less complicated market and dispatch arrangements due to more predictable long-term flows (due in part to the contracting regime that typically exists);
- Short term flows display less variability; and
- Bilateral contracts for capacity typically underpin pipeline investment.

Electricity is a substitute for gas in virtually all end uses, whereas gas is only a partial substitute for electricity. Gas is, therefore, a fuel of choice. Increasingly, with technological developments in gas turbine technology, gas has became a partial substitute for electricity transmission as it can economically be used to generate electricity to meet base and mid load demands, in addition to its conventional role in supplying peak electricity demands.

As a consequence of these differences the electricity and gas markets have evolved differently both in Australia and overseas. Investment in gas has typically had greater private sector involvement and been underwritten by long term take or pay contracts, whereas in electricity customers have shown a preference for shorter term contracts which limits the capacity of generators to enter into long term contracts to underwrite new generation.

[139] Paul Joskow, 'The Difficult Transition to Competitive Electricity Markets in the US', AEI-Brookings Joint Centre for Regulatory Studies, July 2003, pages 9-11.