Energy security 2010-20
Overcoming investor uncertainty in power generation

August 2010
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- **Power generation in a carbon constrained world: implications for the resources sector** (June, 2009)
- **Doing business in a carbon constrained world: helping you understand the Carbon Pollution Reduction Scheme** (November, 2008).

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Executive summary

As in other developed economies, electricity supply in Australia is regarded as an essential service. While failure of supply is inconvenient for householders, it can be costly and even destructive for business sectors of the economy.

As well as reliability and security of supply, the cost of electricity is important, both to residential users confronted by a range of rising demands on their income and to energy-intensive industries exposed to international trade pressures who are large employers and vitally important to the health of the economy overall.

However, in the last 18 or so months the Australian electricity generation sector has entered a period of unprecedented uncertainty after 14 years of operating in a relatively constant investment climate, and producing and supplying power at very competitive costs by international standards.

The main cause of this situation is a protracted and increasingly polarised domestic debate about national carbon policy, set against the inability of governments globally to achieve a binding agreement on reducing world-wide greenhouse gas emissions after the Kyoto treaty expires in 2012.

The Australian Government’s inability to achieve passage of its emissions trading scheme (ETS) through the Senate, along with the challenges arising from the enlarged renewable energy target (RET) as a consequence of a collapse in the value of RET certificates, has created an uncertain domestic environment for investors.

Both existing and potential investors were already finding it difficult to implement plans to sustain value in existing assets, or to finalise decisions on long-term development projects. As a result, there has been limited investment in new Australian base load capacity over the past two years as investors adopt a wait-and-see approach.

Uncertainty has further increased following the recent announcement by the Federal Government that it will defer pursuing parliamentary consideration of the ETS until after the expiration of the Kyoto Protocol’s first commitment period – at the end of 2012 – meaning the implementation of the Scheme would be delayed until at least 2013. This, coupled with the Government’s decision not to pursue its Energy White Paper – intended to “set durable policy directions to ensure long-term economic prosperity and energy security” – has further contributed to what many in industry are describing as a policy vacuum. For while the publication of the Australian Energy Resource Assessment (AERA) – a joint undertaking by Geoscience Australia and the Australian Bureau of Agricultural and Resource Economics (ABARE) commissioned by the Federal Government – has provided an important technological platform for policy makers, it has not resolved the issues concerning investors.

The deferral of the ETS will not make the debate go away. In January this year, in response to the Copenhagen Summit, the Australian Government committed to reducing emissions by at least five per cent on 2000 levels by 2020. This means Australia will need to implement measures to encourage a shift from our fossil fuel dependent generation fleet to cleaner alternatives – sooner rather than later. This shift will not occur under the current policy and regulatory frameworks, because lower emissions alternatives are simply too expensive.

1 Announcement by the Hon. Kevin Rudd MP, Prime Minister of Australia, 27 April 2010
In the absence of an ETS, there has been a clear shift towards supporting selected renewable technologies through both the expanded RET Scheme and Government funded initiatives (such as the recently announced Renewable Energy Future Fund and the existing Clean Energy Initiative). Despite this, it remains doubtful whether sufficient price signals and certainty exist to deliver investment on the scale required to meet Australia’s emerging energy needs.

At the same time, investors do not have sufficient certainty to invest in existing coal and even gas generation technologies, given the impact a price on carbon (or other climate change policy response) is likely to have on future returns.

The broader policy framework has also become less certain, given the drive to bi-partisan policy agreement has been replaced with significantly different proposals, with likely very different impacts. While the Coalition has committed to the reduction targets set out in the Copenhagen Accord, the details of its energy policy beyond its proposed Renewable Energy Future Fund, is as yet unknown.

The longer policy uncertainty continues and investment decisions are deferred, the closer the National Electricity Market (NEM) moves towards demand/supply balance as consumption growth erodes excess generation capacity and some of the oldest plant is retired.

Irrespective of the demands of climate change policy, a growing portion of national capital stock – both generation and networks – is reaching its use-by date and will need to be replaced or enhanced this decade. Recent estimates suggest that close to $40 billion worth of investment in new generation, and in refinancing or augmenting existing generation, will be required by 2014. This represents the likely financing task, before considering any additional capacity that may be required if Australia is to transition to a lower emissions generation fleet.

The appetite of investors to commit such funding is affected significantly by boardroom perspectives of whether the likely returns from investment are commensurate with the risks involved. This is not least because substantial opportunities for new ventures exist in the rest of Asia and further afield. Factors influencing decision-makers include uncertainty over how earnings may be compromised by uncertain carbon price increases, the emergence of new technologies offering lower emissions, and the prospect that governments may change policies affecting some existing technologies under political pressure.

These uncertainties come on top of other significant risks that will need to be overcome if investors are to commit significant capital to new investment of generation assets. These include:

- Access to and cost of capital following the Global Financial Crisis (GFC)
- Demand side risks such as the impact of energy efficiency and demand side management, the potential future use of electric cars and predicted population growth
- Access to transmission networks (the ability of generators to take their product to market in a congested network); and
- Regulatory uncertainty, including potential changes to market rules and retail price regulation to accommodate any climate change policies that are introduced.

The difficulty to date of the New South Wales Government to resolve the sale of production by three State-owned generators in the largest electricity market in the country, where the need for new base load power is essential, is indicative of the downbeat investment sentiment.

In addition, the unwillingness of most States and the Australian Capital Territory to give up retail price regulation creates a reaction back through the electricity supply chain, with any dampening of price signals, especially those related to carbon costs, increasing the risks to generators.
The time it is taking governments, working collectively, and the market regulatory agencies to resolve the need to change the transmission approvals framework is also a discouraging signal for investors in generation.

Timing is now a critical issue for generation development and for consumers concerned about both supply reliability and costs because base load capacity cannot be installed overnight. Typically, a coal-fired power station can take up to five years to be completed while a combined cycle gas-fired plant may require a construction period of up to three years, depending on approval processes and the availability of equipment.

Based on these dynamics, only a narrow window is available to resolve the policy and regulatory issues impacting on generation investment this decade if power supply constraints are to be avoided. The need for policymakers to act decisively to ensure that there is sufficient certainty for investors in base load generation to have confidence that they can identify, price and manage their risks is obvious.

Yet with elections looming in two of the three largest electricity demand regions – Victoria and New South Wales – as well as federally, it is clear that there is unlikely to be any resolution on a range of policies impacting investment decisions any time soon. While the situation may not yet be dire, it certainly supports a perception that power supply security in eastern Australia is more uncertain now than it has been since the 1970s.

While the current environment poses considerable challenges to the industry, it also presents opportunities. At a recent event held for Energy Supply Association of Australia (esaa) member CEOs, Federal Energy Minister Martin Ferguson acknowledged that the energy market policy agenda needs refocusing to ensure Australia gets the investment needed in networks and generation in order to guarantee the high supply reliability expected by the community. In his view, there are three policy priorities:

• Integrating new renewable generation into the grid
• Market arrangements to ensure infrastructure investment occurs to meet demand and maintain supply reliability; and
• Energy efficiency initiatives.

There is no doubt that the Federal Government is leading a coordinated shift to a national reform agenda, as outlined in its Blueprint for Reform of Australian Government Administration released on 29 March 2010. The Policy contains nine recommendations, including Recommendation 3: Enhancing policy capability which comprises strengthening strategic policy, building partnerships including with the private sector, and improving policy implementation.

Within this context, the energy sector has an unprecedented opportunity to genuinely influence the future policy framework and ultimately the structure of Australia’s future electricity industry as governments, both at Federal and state levels, prepare to act to transition Australia to a low emissions economy.

Some industry players are already taking the opportunity to become ‘shapers’ of the future industry. They recognise that the climate change debate is unlikely to simply fade away and are actively seeking to influence the debate. Even without a carbon price signal, there is strong activity in a number of areas that have the potential to assist in transitioning Australia to a low carbon economy.

In the absence of an ETS, there has been a clear shift towards supporting selected renewable technologies
Organisations looking to shape the future direction of the industry are focusing efforts on:

- Developing energy efficiency initiatives and demand-side management strategies
- Leveraging funding opportunities by seeking to access:
  - Government supported initiatives for the development and deployment of renewable technology (including the recently announced $652.5 million Renewable Energy Future Fund as well as existing programs, such as the $2 billion Carbon Capture and Storage Flagships Program and the $1.5 billion Solar Flagships Program)
  - The venture capital sector for clean energy projects
- Calling for the Government to reconsider new policy options to support investment, including those common internationally, such as loan guarantees, subordinated debt funds and accelerated depreciation to support private sector financing.

While investors may not have the requisite comfort to fund new projects in the current uncertain climate, many are taking the opportunity to gain a deep understanding of the emerging market dynamics. There is awareness that those investors with a strong understanding of the risks and opportunities of operating in a carbon constrained economy will be well placed to not only shape the future direction of the sector, but to move ahead of the competition once the conditions for investment are restored.

Based on these dynamics, only a narrow window is available to resolve the policy and regulatory issues impacting on generation investment this decade if power supply constraints are to be avoided.

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2 As announced in the Federal Budget, 11 May 2010
The focus of this paper is on investment in base load electricity generation in the context of the uncertain requirements to de-carbonise Australia’s electricity supply. This context raises significant challenges for investors in base load generation in addition to existing investment challenges and these are discussed in some detail. There is also some discussion of the issues relating to investment in new transmission infrastructure and in intermediate and peaking capacity, where relevant to the broader issue of energy security.

The paper is structured as follows:

- **Section 1** provides an outline of the context for investment in generation in Australia
- **Section 2** addresses the base load generation investment task, including the likely shift in the generation landscape as we move to a carbon constrained economy
- **Section 3** considers investor appetite for the financing task ahead
- **Section 4** looks at the likely returns to investors
- **Section 5** considers a number risks facing investors in base load generation, including carbon price uncertainty, technology risk and other risks that may affect investment decisions
- **Section 6** considers the need to resolve current uncertainties through policy clarity
- **Section 7** provides some conclusions and recommendations for current and potential investors in the Australian power generation sector.
In this section:

This section outlines the role which relatively cheap electricity has played in developing Australia’s economy as well as the changing pattern of investment in generation and the investment required to meet future short to medium term demand requirements. It also contrasts the profile of Australia’s generation plant with elsewhere globally.

Key points

• Reliable and comparatively cheap electricity underpins Australian living standards and the international competitiveness of key industries

• The trend to greater private sector funding of generation continues, a significant proportion of which is from international sources

• There is a narrow window within which new generation investment must occur if energy supply is to continue to meet reliability standards

• Historical reliance on fossil fuels and therefore comparatively high carbon intensity poses significant challenges and costly structural adjustment for Australia moving forward.
1. The context for investment in generation in Australia

1.1 Electricity and its role in developing Australia’s economy

In Australia, as with most developed economies, electricity supply is regarded as an essential service. We take it for granted that when we walk into our houses and flick a switch, the lights will come on. While blackouts, or the failure of supply, are inconvenient for households, they can be costly and even destructive in other sectors of the economy. Industries operating expensive equipment or working to a ‘just in time’ schedule can face substantial costs if production is interrupted due to an unreliable energy supply.

As well as reliability and security of supply, the cost of electricity is important. Australia has benefited from the availability of vast reserves of black and brown coal which has allowed electricity to be produced and supplied at a very competitive cost by international standards.

Not only does relatively low-priced energy allow Australian households to spend more on other goods and services that contribute to our high living standards, but it underpins the international competitiveness of some important Australian industries.

It is not only industries such as aluminium, which used to be characterised in the 1980s as ‘congealed electricity’, that have benefited from this. Most manufacturing industries are now facing strong and increasing competitive pressures from countries such as China. Any increase in their cost base relative to their overseas competitors reduces their ability to compete.

Any significant rise in the relative cost of their electricity would be likely to adversely affect Australia’s global competitiveness in the future.
1.2 Investment patterns in Australian generation

Traditionally in Australia, State governments have been responsible for building power stations and transmission networks. Despite the introduction of the National Electricity Market (NEM) in the mid-1990s and significant privatisations in Victoria and South Australia, governments still own the majority of electricity assets in Australia.

Although the operations of the NEM are now carried out at arm’s length from governments, it is unlikely that Australians will blame the Australian Energy Market Operator (AEMO) if the lights go out, or the Australian Energy Regulator or the Stated-based regulators if the price of electricity increases. They will, almost universally, blame ‘the government’.

For this reason, governments have generally ensured that investment in new capacity occurred in plenty of time to meet increased demand. Constructing new power stations was also popular and created jobs in regional areas. When the NEM commenced operations, it therefore had to accommodate significant surplus capacity, particularly in base load generation across all States (with the exception of South Australia). This has tended to keep prices low and has also meant that very little new base load plant has been commissioned in the last decade.

However, the past may not be a good guide as to where investment will need to come from in the future. The creation of the NEM (with private entrants and the corporatisation of government held assets) as well as increased pressures on State budgets has brought about a change in this approach.

Given the changing ownership structure of the generation sector, it is almost certain that the private sector will need to play a critical role in providing a significant portion of the investment required, including the vital transition to a fleet of lower emission energy assets. The capital intensive nature of energy assets and the burden that continued investment places on State balance sheets means that the States are looking to the private sector to meet future investment requirements. Victoria and South Australia have already passed the baton to the private sector in electricity markets. New South Wales is still attempting to sell some of its electricity businesses, while the recent downgrading of Queensland’s credit rating has meant that it no longer has the funding capacity it once had to invest heavily in this sector. State Governments are no longer able or willing to continue funding new infrastructure, particularly if it comes at the expense of other service delivery priorities, such as health and education.

In further support of this, the industry has estimated that the private sector accounts for 78 per cent³ of the current refinancing requirements for existing plant. This measure does not include private sector financing of new generation assets going forward. Of the total debt funding, it is estimated that 45 per cent is currently sourced from international sources. It is expected this trend towards private sector investment in generation will continue as a gradual withdrawal by State governments from the sector continues in the next few years. This withdrawal may be either explicit through sell down of assets or through the dilution of State ownership through a future non-investment policy for new assets and retirement and non-replacement of existing assets.

Given these factors, it is critical that strong investment signals are in place to ensure the much needed investment occurs in a timely manner to maintain security and reliability of electricity supply across Australia.

³ Energy Supply Association of Australia Global Financial Crisis and the energy supply sector, 2009
1.3 Capacity outlook in the NEM

To help inform existing and future investors in the sector, the Australian Energy Market Operator (AEMO) releases an annual *Electricity Statement of Opportunities* (ESOO), which provides details of the future adequacy of electricity supplies in the NEM to meet the Reliability Standard for the next 10 years.\(^4\)

To illustrate emerging supply constraints, the ESOO estimates when additional capacity may be required across each state in the NEM. Below are extracted graphs predicting when supply constraints are expected to emerge for South Australia, Victoria, Queensland and New South Wales. The supply constraint point indicates the first year that the reserve margin is projected to fall below the Minimum Reserve Level set by AEMO to ensure sufficient capacity and reliability of the supply of energy.

![Graph](image-url)

**Figure 1.1 Victoria and South Australia: Forecast emerging supply constraints and latest dates for required investment**

Source: AEMO, 2009; Deloitte Economics

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\(^4\) *Australian Energy Market Operator (AEMO) Electricity Statement of Opportunities for the National Electricity Market, 27 August 2009*
Figure 1.2 Queensland: Forecast emerging supply constraints and latest dates for required investment

Figure 1.3 New South Wales: Forecast emerging supply constraints and latest dates for required investment

Source: AEMO, 2009; Debashe Economics
The Minimum Reserve Level calculations for the NEM were last recalculated in 2006. AEMO has recently released draft Minimum Reserve Levels for 2010 based on a revised calculation methodology. This new approach, which is currently open for consultation, has the effect of bringing forward capacity requirements in some States (particularly in Queensland), further narrowing the potential investment window.

Given the 2010 Minimum Reserve Levels remain in draft form the following assessment has been based on the 2006 ESOO methodology.

**Forecast emerging supply constraints**

While the position varies from State to State, based on the ten year outlook it appears that Australia’s current reserve capacity for generation is adequate to meet the future supply demands for the next few years at least. The ESOO does, however, highlight the window within which new generation investment will need to occur, if Australia’s security of supply is to meet current reliability standards.

This position is underlined further by the recent announcements to postpone the Energy White Paper and to defer reconsideration of the ETS until after the expiration of the Kyoto Protocol’s first commitment period, at the end of 2012, meaning under the current Federal Government the implementation of the Scheme would be delayed until at least 2013. This makes it nearly impossible for investors to currently factor into their financial models credible estimates of future carbon prices or other factors.

Figures 1.1 - 1.3 highlight, by State, the narrowing windows for investment assuming that there is Scheme certainty some time in 2013. The figures show the lead time for commissioning both gas and coal fired plant, although it is acknowledged that it may be unlikely that Australia will see a new coal fired plant given the current policy frameworks in place in many states.

When the lead times are taken into account, there may be very tight timeframes to install sufficient capacity to ensure reliability of supply in the NEM. This is because new plant may take up to three years for gas (combined cycled gas turbine) – and up to five years for coal – before being commissioned. These timeframes could potentially be longer in some cases, depending on a range of factors including approval processes and availability of equipment.

The position in South Australia (2012/13) and Victoria (2014/15) appears to be pronounced based on existing data, with strong concerns about the ability to deliver sufficient capacity in the absence of new investment. Queensland may have an emerging supply shortfall, some time from 2014/15 onwards, depending on the commissioning of new plant. In NSW the potential supply constraint emerges in 2015/16 onwards, although potentially there may be sufficient lead time if gas plant is able to be commissioned in late 2012.

Figure 1.4 summarises these projections, highlighting the expected supply deficit in the year in which the state falls below required capacity levels.

This assessment would indicate that while there is some breathing space, based on existing capacity, the continuing policy uncertainty is starting to raise genuine concerns about future capacity, underlining the need for the Government to act sooner rather than later.
The Australian electricity generation sector has entered a period of unprecedented uncertainty after 14 years of being a stable business operating in a relatively constant investment climate and producing and supplying power at very competitive costs by international standards.
Interestingly, the current record low prices being seen in parts of the NEM may not be reflective of the emerging risk. For example, in Queensland price signals are being significantly dampened by excess supply of energy from gas-fired plant in the lead up to the commencement of the liquefied natural gas (LNG) export industry in 2014 (at the earliest) although this may be impacted by the Resources Super Profits Tax (RSPT) announced on 9 May 2010 as part of the Henry Tax Review. This is discussed in more detail in section 2 of this paper.

If these cheap interim gas supplies are re-directed to the export market, pool prices can be expected to recover. Strong LNG exports are expected from 2014 onwards, which should in turn produce higher pool prices and stronger price signals to encourage further investment. Pool prices will also be impacted by additional industry requirements estimated to be in the order of 1000MW. The impact on pool prices will be driven by whether supply is sourced through existing capacity (ie a contract based solution) or whether players build their own plant. It may also be affected by the impacts of RSPT for project viability in this sector going forward. Either way, the emerging LNG industry is distorting traditional energy supply price signals, adding to the complexity of investment decisions.

There have recently been other announcements in various states which may push out the time for new capacity and which will be reflected in the 2010 ESOO when it is released later in 2010. For example, in response to the decision to defer the CPRS until 2013 and therefore the uncertainty over a carbon price, Santos announced that it will not be building its proposed $800 million 1500 MW gas-fired plant at Shaw River in Victoria.5

It is worth noting that the 2010 ESOO will reflect revised demand projections, which may increase as Australia recovers from the decreased demand for electricity (reduced production) as a result of the GFC. Any increase in demand above assumed levels will put further pressure on reserve capacity and indicate the need for earlier investment in generation. New capacity requirements will also be impacted by AEMO’s new reserve margin calculation, which is expected to further close the gap for new plant (particularly in Queensland).

Security of supply is not an issue unique to Australia. A study by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA) entitled Projected Costs of Generating Electricity6 has concluded that security of supply is now an issue for most OECD countries, highlighting the need for Government policies to stimulate required investment in generation assets going forward more broadly.

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5 Announcement by David Knox, Chief Executive of Santos, 28 April 2010

1.4 Australia’s generation profile in a global context

Australia’s heavy reliance on fossil fuels, and in particular coal, for most of its base load generation is illustrated in Figure 1.5.

Past investment in coal-based generation has largely been driven by economically sound investment decisions coupled with a lack of recognition of environmental externalities (which have not been priced), rather than any specific moral failure on the part of plant owners.

The reality is that the production cost of open cut mined coal has until now been extremely cheap in Australia, particularly where there has been no alternative export prospects due to fuel quality or distance to export infrastructure. By way of example, the brown coal used in the Latrobe Valley generators is available at around one quarter of the cost of the similar lignite used for electricity generation in Germany.

In the absence of a carbon price, coal has been too cheap for too long in eastern Australia to allow a rational investor to opt for any other base load technology. The alternative fossil fuel base load technology – combined cycle natural gas – has historically been unable to compete with coal in the eastern States, despite a relatively low gas price.

As a result, the Australian power generation sector has one of the highest carbon intensities by comparison in the global context.

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7 ABARE, Electricity Generation Major Development Projects, October 2009
Overcoming investor uncertainty in power generation

Figure 1.6 Carbon intensity of electricity generation in G20 countries, 2007

Australia’s comparatively high carbon intensity is likely to pose significant challenges if Australia is required to significantly reduce its emissions as part of its response to climate change.

While most countries have significantly lower carbon footprints than Australia in their electricity sectors, this has not necessarily arisen because they have any greater commitment to addressing climate change. France sources all its base load power from nuclear reactors as result of a legacy of the oil shocks of the 1970s and a consequential focus on energy security. The extensive use of gas in many European economies is as a result of a commercial decision to seek alternative fuel sources due to the rising cost of coal in the last quarter of the twentieth century and further investment in nuclear power being put on hold for twenty years following the Chernobyl disaster in 1986. For example, the UK was one of a number of countries that underwent a ‘dash for gas’ in the 1990s taking advantage of the abundance of gas from the North Sea fields and the tribulations of the British coal industry in the 1980s.

Over time, an important objective of climate change policy must be to decarbonise the world’s electricity supply and Australia, as a developed economy with a comparatively high carbon intensity, will need to play its full part.

Any climate change response that introduces any considerable cost to carbon is likely to significantly influence investment decisions for fuel and technology choices going forward. This will, in turn, lead to structural adjustment to the Australian generation landscape over the medium to long term.

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Figure 1.6 provides estimates for carbon intensity of electricity generation in the G20 economies in 2007.

Australia’s carbon intensity in power generation is clearly the highest of the developed countries in the G20. Only one country (South Africa) has a higher carbon intensity in its electricity sector than Australia. However since it is not an Annex 1 (that is, 'developed') economy, South Africa is likely to face an emissions reduction task that is significantly less than that of Australia under any future global agreement. Both China and India, which are frequently characterised as major users of coal, register a carbon intensity only slightly lower than that of Australia. However China and India – as well as South Africa – have significant nuclear power programs. The next ranked developed economies, Germany and the US, register carbon intensities of nearly one-third lower than Australia.

Australia’s economy has until now benefited from low-cost fossil fuels to produce electricity

Source: IEA, 2009

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8 International Energy Agency, 2009

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In this section:

This section considers the investment task and the issues impacting decision-making given the currently uncertain local and global commitment to emissions reduction.

Key points

• Even before the climate change challenge, the combination of the ageing of Australia’s electricity infrastructure, the erosion of historical excess capacity in the NEM, and the growth rate of Australia’s population and economy generally, combine to create a considerable future investment task.

• Climate change is likely to pose a further and significant investment challenge in addition to the already significant levels of investment required.

• Despite the emerging needs for future investment, the uncertainty surrounding climate change and its likely impacts has meant that significant investment in base load generation has largely been put on hold.

• Investor response to the uncertainty has been to avoid investment in base load coal-fired generation and in favour of intermediate and peaking load plant, in particular gas and renewables, especially wind.
2. Base load generation: the investment challenge

2.1 To maintain the energy security status quo

It is widely recognised that the Australian energy sector is facing a significant investment task in the coming years, even putting climate change imperatives to one side.

The considerable investment task in the sector reflects a number of factors:

- The ageing of Australia’s electricity infrastructure, much of which was installed in the 1950s and 1960s
- The fact that, after a decade where there was significant excess capacity in the NEM, the supply/demand situation is now approaching equilibrium9.
- A projected high rate of growth in Australia’s population and the economy generally.

A recent study based on an industry survey undertaken by esaa has estimated that the financing task (for both network and generation assets) over the next five years is approximately $100 billion10. Of this, it is estimated that approximately 40% or around $37 billion will be needed to meet the refinancing and capital investment on new and existing generation assets. Capital expenditure on existing generation assets is estimated at more than $6 billion, while the expenditure expected for new generation assets is almost double at around $12 billion.

This presents a considerable financing challenge for existing and future investors in the energy sector.

Table 2.1 Energy sector capital requirements, 2010-14

<table>
<thead>
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<th>$ billion</th>
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<tbody>
<tr>
<td>Transmission</td>
<td>60</td>
</tr>
<tr>
<td>Generation</td>
<td></td>
</tr>
<tr>
<td>• Refinancing – generation</td>
<td>19</td>
</tr>
<tr>
<td>• Capital expenditure on existing generation assets</td>
<td>6</td>
</tr>
<tr>
<td>• Capital expenditure on new generation assets</td>
<td>12</td>
</tr>
<tr>
<td>Total</td>
<td>97</td>
</tr>
</tbody>
</table>

Source: esaa, 2009

2.2 To take account of a price on carbon

The public policy response to climate change could potentially have a profound impact on the energy sector, resulting in considerable structural change over time. This is likely to require wide-ranging changes which will need to be funded.

The industry will need to be able to fund new investment to meet not only the underlying energy requirements, but also to replace the load from existing generators that will become economically unviable and displaced over time by lower emission plant.

The size of the actual investment requirement will be driven by both the approach of the Australian Government and the global response to climate change. The speed at which the generation sector will need to transition to lower emission technologies will be determined ultimately by the commitment to reduce emissions, including the reductions trajectory and the agreed mechanism to achieve this.

The industry has released data estimating the likely impact of a move to reduce emissions, based on the Australian Government’s proposed CPRS and the expanded Renewables Energy Target11. The above-mentioned esaa study estimates the total capital requirement for new generation assets to 2020 is likely to be $21 - $23 billion in order to accommodate climate change.12 That is, it could potentially add a further $11-12 billion to the new generation asset investment task13, assuming one third of this is required in the next five years.

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9 AEMO Electricity Statement of Opportunities, 2009
10 esaa, Global Financial Crisis and the energy supply sector, 2009
11 The Renewable Energy Target (RET) Scheme requires that 20 per cent of Australia’s electricity supply will come from renewable sources by 2020. The RET expands on the existing Mandatory Renewable Energy Target (MRET), which commenced in 2001 and expanded in 2009
12 esaa, Global Financial Crisis and the energy supply sector, 2009
13 On the basis that the survey data was incomplete for new generation investment.
The size of the actual investment requirement will be driven by both the approach of the Australian Government and the global response to climate change.

Esaa further estimated that the generation sector would require an additional $20 billion of credit facilities over five years to finance Australian emissions units (AEUs) under the proposed CPRS to enable forward contracting.14

The adjusted financing task in relation to generation assets, taking into account potential impacts from the expanded RET and the proposed CPRS, is summarised below:

### Table 2.2 Generation capital requirements (including climate change), 2010-14

<table>
<thead>
<tr>
<th></th>
<th>$ billion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Refinancing – generation</td>
<td>19</td>
</tr>
<tr>
<td>Capital expenditure on existing generation assets</td>
<td>6</td>
</tr>
<tr>
<td>Capital expenditure on new generation assets</td>
<td>12</td>
</tr>
<tr>
<td>Climate change related capital expenditure on existing &amp; new generation assets</td>
<td>11-12</td>
</tr>
<tr>
<td>Financing permits</td>
<td>20</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>68-69</strong></td>
</tr>
</tbody>
</table>

Source: esaa, 2009

Of course, these estimates may have less currency following events subsequent to the study, including the inconclusive outcome from the Copenhagen Summit15, announced revisions to the RET scheme, the deferral by the current Government of its CPRS legislation, and the proposed alternative mechanisms for reducing emissions proposed by the Federal Opposition.

In the end, the actual financing requirement will depend on the climate change policies that are implemented to transition Australia to a low emission economy. This will affect not only the size and nature of future capital expenditure required in Australia in the medium to longer term, but also the financing requirement for permits.

### 2.3 Predicting the task ahead – navigating a world of regulatory uncertainty

The deferral of the implementation of an ETS to 2013 has not alleviated the need to transition to a lower carbon generation fleet unless a future government were to rescind the non-binding commitments made under the Copenhagen Accord. The commitments by the Australian Government under the Copenhagen Accord mean that Australia will need to reduce its emissions by five per cent on 2000 levels by 2020 and up to 25 per cent if an international agreement is secured. Moreover, as a member of the G20, Australia’s agreement alongside many other nations at the Copenhagen Summit to an ambitious objective of restricting average increases in global temperatures to two degrees celsius, implies that emissions would need to be reduced by around 80 per cent by 2050. This would require virtually the total decarbonisation of the global – and Australian – electricity generation sector by 2050.

To do this will necessitate either a regulatory requirement to shift to alternative technologies, or the introduction of market mechanisms or price signals. This is likely to be achieved through a combination of existing schemes, as well as additional new initiatives designed to give effect to the Australian Government’s climate change policy.
Existing mechanisms supporting transition to a lower emissions generation fleet

There are a number of mechanisms already in place in Australia which aim at supporting the transition to lower emissions technologies. The most significant at present is the expanded Renewable Energy Target Scheme (RET) originally designed to reduce emissions by encouraging additional generation from renewable energy sources. The Scheme places a liability on wholesale purchasers of electricity to purchase energy from renewable sources. This is effected through a mechanism by which renewable energy certificates (RECs) are issued and traded at a market price. The Scheme was recently expanded so that 20 per cent of Australia’s electricity will have to be generated from renewable energy sources by 2020, up from 9,500GWh to 45,000GWh.\(^\text{16}\)

While there is evidence that it has encouraged increased investment in renewables, the Scheme has not been without problems. The fall in the spot market for RECs has largely been driven by an oversupply of RECs, principally as a result of the inclusion in the Scheme of household incentive programs for solar hot water units and heat pumps. This has prompted concerns that the REC market is unlikely to be sufficient to encourage deployment of large-scale projects, such as wind farms. This has been recognised by the Government, which recently announced changes to the Scheme following a review\(^\text{17}\).

The Scheme, if implemented, is to be split in two from 1 January 2011, with small-scale and large-scale targets being set. These changes are aimed at providing sufficient price signals to encourage investment in large-scale renewable projects.

There is also a range of complementary State-based measures designed to encourage investment in non-coal generation alternatives. These include the Queensland Gas Scheme and the Greenhouse Gas Abatement Schemes in New South Wales and the Australian Capital Territory.

These schemes are currently the subject of review. Given the potential for any misalignment between State-based and federal policies to create market distortions and potentially undermine the impact of an ETS, the current Federal Government has proposed that the State based Schemes terminate upon the commencement of the CPRS, should it proceed.

The recent uncertainties surrounding the RET Scheme and the State-based Schemes have served to undermine investor confidence. While the recent splitting of the RET Scheme into large-scale and small-scale targets is aimed at providing more reliable price signals to encourage investment in large scale projects such as wind farms, it also sends another message. That is, it reconfirms the risks that investors face under any regulatory scheme of policy interference. Ultimately, investors looking to invest in renewables will need to make their own judgments.

Even if the revised RET Scheme and State based measures are successful in encouraging further investment in the gas and renewables sectors, it is likely that more will need to be done if Australia is to significantly reduce its emissions.

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16 That is, the Renewable Power Percentage (RPP) is 10% in 2010

17 The legislation is due to come before the Senate in the week commencing 21 June 2010, following an inquiry by the Senate Environment, Communications and the Arts Legislation Committee which recommended the legislation be passed during the 2010 winter Parliamentary sittings.
The two key determinants of the speed with which the Australia generation sector will need to shift to and invest in lower emission technologies will be the agreed trajectory for reducing emissions and the mechanism(s) used to achieve this. However Australia’s current position in relation to both of these policy levers remains far from clear.

On 27 January 2010, the Australian Government through its submission to the Copenhagen Accord confirmed its existing emissions reduction target range (five per cent unconditional by 2020 on 2000 levels, with up to 15 per cent and 25 per cent both conditional on the extent of action by other countries).

The Australian Government hoped that the Copenhagen Summit would provide the basis of a binding global agreement on climate change with firm reductions targets to 2050. However, while the Copenhagen Accord set a goal of limiting global warming to a maximum of two degrees celsius, the non-binding commitment for member countries did not specify any longer term emissions reductions target or a method of how to achieve this.

Given the uncertainty in the global context, some, including the Australian Chamber of Commerce and Industry, had suggested that Australia defer any decisions until the design and timing of any ETS in the United States. This position was based on concerns that Australia may put its economic competitiveness at risk by unilaterally moving to cut emissions by at least five per cent by 2020 ahead of any global commitment.

Having been rejected twice by the Senate the Government has now advised that the issue of its proposed CPRS will not be decided before 2013.

Irrespective of the merits of either policy approach, the issue is unlikely to be revisited until after the next federal election and, in the case of the current Government’s CPRS legislation, not until the end of the Kyoto protocol after 2012. The uncertain global position together with the challenges being faced domestically will mean investors in base load generation assets are likely to face considerable uncertainty for some time yet.
Other regulatory proposals and changes

The Henry Review
On 2 May 2010 the Australian Government released the Report on Australia’s future tax system by Treasury head, Ken Henry20. Within the report are three recommendations related to environmental taxes and the environment for investment in power generation. Two of these concern the CPRS while a third recommends a general monitoring of tax concessions21.

As with a lot of the earlier work and reports on the climate change debate, Henry concurs that a market-based mechanism allows for the lowest-cost means of emissions abatement. Like the Productivity Commission before it, the review recommends that, once the CPRS is operational, existing emission reduction measures that are not justified should be phased out22, and the transitional measures under CPRS be independently reviewed23.

The Government has not (yet) responded to the Henry Review recommendations. However for a significant period, business has lacked a carbon price signal and this has created much uncertainty in the investment community about where to direct scarce capital.

The shelving of the ETS means that the central plank of a carbon price signal is now missing from the Government’s climate change policy, until at least 2013. This suggests that the Government needs to take other measures in order to provide more certainty to investors in energy markets, particularly electricity.

In response to the Henry review, the Government has however announced a Resources Super Profits Tax (RSPT), which seeks to impose a 40 per cent tax on mining profits in addition to the usual company income tax. This tax has the potential to increase the cost of fossil fuel based generation relative to renewable generation alternatives, which may provide further incentives for the generation sector to move away from its current level of fossil fuel dependency.

The Government has also announced further support for geothermal energy exploration, through its new Resource Exploration Rebate, within the company income tax system, from 1 July 2011. This will also provide further incentives to move towards renewable energy sources.

2010-11 Federal Budget announcements
To help fill the void left by the deferral of the CPRS, the Federal Government announced in its Budget on 11 May 2010 that it will commit a further $652.5 million over four years to establish a Renewable Energy Future Fund (REFF) to support Australia’s response to climate change.

The Fund will provide additional support for:
- The development and deployment of large and small scale renewable energy projects, including investments in geothermal, solar and wave energy
- Industrial, commercial and residential energy efficiency to reduce energy consumption.

The aim of the REFF is to leverage private sector investment to support the commercialisation of renewable technologies. Its announcement signals a shift in policy direction away from a market-based mechanism to measures that support selected generation technologies to assist Australia in transitioning to a lower emission future.

The REFF will complement the existing $5.1 billion Clean Energy Initiative (including the $2 billion Carbon Capture and Storage Flagships Program and the $1.5 billion Solar Flagships Program) as well as the expanded Renewable Energy Target (20 per cent by 2020).

20 Australian Government, Report on Australia’s Future Tax System, 2 May 2010
21 op cit, Part 1: Overview, Chapter 12: List of Recommendations, Part 2 - Detailed Analysis, E2 - Taxes to improve the Environment, Recommendation 60
22 ibid, Recommendation 58
23 ibid, Recommendation 59
2.4 Investor response to the challenge to date

While the policy framework to de-carbonise Australia’s electricity supply appears to be a long way from being resolved, there is clear evidence that some investors are navigating the uncertainty and forging the early pathway towards a lower emission technological base.

According to Australian Bureau of Agricultural and Resource Economics’ (ABARE) data, Australia has 15 projects at an advanced stage of development, with an estimated cost of $4.9 billion and a total capacity of 2687 megawatts (MW).

Of the 15 projects in development, coal-fired projects make up a small proportion, representing approximately 9% of the total capacity of advanced projects. Significantly, this includes only one new coal-fired development.

Of the remaining 14 projects in development, five (or 57% of capacity) are gas-fuelled. This includes natural gas-fired projects, which account for 33.4% of the announced capacity, and coal seam gas-fired projects, which account for a further 23.6%. The remaining 9 projects are renewables which, combined, account for approximately 34.1% of the total capacity of advanced projects.

While almost two-thirds of the planned projects are comprised of renewables, the total capacity of these is only a little more than a third of the total planned new generation capacity. This is because the average capacity of wind projects being developed is 102MW. By contrast the average for gas non-renewable plant is significantly more (295.5MW).

A clear trend emerging from the planned advanced stage projects is the replacement of coal-fired capacity with lower emission fossil fuel projects such as natural and coal seam gas, and the strong emergence of renewables, and in particular wind generation.

This early trend – combined with widely accepted comparative fuel source cost – appears to suggest that natural gas will be the fuel source that replaces coal for base load generation in the short to medium term.

While these signs are encouraging, significant investment in baseload capacity is likely to remain constrained until the climate change policy framework is clarified.

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24 ABARE, Electricity generation: major development projects – April 2010
25 Defined as “committed or under construction”
In this section:

This section assesses likely investor appetite for the financing task ahead.

**Key points**

- Given the size of the domestic financial sector it is unlikely that the required need for capital can be met without support from global markets.
- As a consequence of the global financial crisis, capital markets are constrained placing a disproportionate burden on equity providers to fund projects.
3. Investor appetite: the attractiveness of generation as an investment

As a general principle, in order to attract sufficient investment into the sector, the returns must be at least commensurate with the risks involved.

The Australian generation sector will need to attract significant amounts of debt and equity funding in the market in order to meet the required demand for capital in the short to mid-term. It is unlikely, given the size of the domestic market, that this can be met without support from the global capital market.

The depth of the challenge in sourcing the required capital may be understated if it is assumed that remaining Government-owned generators (supported by existing State balance sheets) will meet demand in some States. Given the current pressure on States’ finances, this appears unlikely at least in the short to medium term.

The fundamental question then is whether the power generation industry in Australia remains an attractive proposition for investors, or whether the risks involved will result in a lack of availability of capital for this industry.

Typically, private generation projects have been financed through a combination of debt and equity, resulting in an efficient cost of capital. Equity providers have geared projects to optimal levels, based on the appetite of the financier to assume project risk. Debt providers by their nature are risk averse and funding arrangements are structured in a way to ensure the ability to repay debt is not compromised. As an unregulated business, a generator’s ability to repay debt will depend on its ability to derive revenue (through pool revenues and/or the contract market) which exceeds its costs (including any future cost of carbon).

The GFC clearly demonstrated that global capital markets respond negatively to high levels of uncertainty by rapidly withdrawing available funds. The reduction in gearing structures for infrastructure assets will create a greater focus on equity returns as new funding will need to be skewed towards a greater proportion of equity funding than previous years.

However as is examined later in this paper, there are significant risks and uncertainties surrounding the capacity of Australia’s generation businesses to generate the required revenue in an emerging carbon constrained economy.

The Australian generation sector will need to attract significant amounts of debt and equity funding in the market in order to meet the required demand for capital. It is unlikely, given the size of the domestic market, that this can be met without support from the global capital market.
Leaving aside climate change considerations for the moment, the sector is also undergoing significant structural change and uncertainty, which already pose risks to investors:

- **Government asset sales and/or continued ownership**
  The proposed disposal by New South Wales of certain energy assets provides a current example of the risks for investors in the market. The New South Wales Government has twice pushed back the sales process for its ‘Gentrader’ model citing complexities around the due diligence process and these complexities clearly present significant challenges for potential investors. There is also the risk that other States, such as Queensland, may also decide to sell energy assets. Conversely continued State ownership includes the potential for Government shareholders to respond to factors other than pure market dynamics.

- **Demand-side risk – the impact of LNG**
  The emerging liquified natural gas (LNG) industry in Australia, particularly in Queensland, has the potential to impact both the demand and supply balance in Queensland, with potential knock-on effects across the NEM due to the inter-connectedness of the market. Currently, Queensland has seen a significant dampening of pool prices as a result of the ramp up in gas being produced. The longer term impacts, once the industry is in full operation, remain uncertain however. This is because, while the industry will require significant additional energy capacity, it is unclear whether this is likely to be sourced from existing providers (i.e. through contract) or whether providers are likely to invest in their own plant. Either way, there will be a direct impact on pool prices correlated to the demand/supply balance.

- **Increasingly illiquid wholesale markets**
  Vertical integration between retail and generation is expected to continue. This will have considerable impacts on the wholesale energy markets which, in turn, will affect investor returns to generators by potentially smoothing volatility in the cost of energy (in particular the high priced events which have historically underpinned generator returns).

- **Cost pressures**
  The commodity boom and now the RSPT have the potential to impose further cost pressures on fossil fuel reliant generation assets, further eroding the cost competitiveness of these businesses.

- **Demand-side management**
  Pressures by regulators and consumers to minimise network and retail costs through better demand-side management strategies aim at smoothing the peak demand for electricity. While this may produce efficiencies, it also poses risks to the generation sector, which typically derives profitability through revenues earned during peak or high priced events.

These uncertainties and constraints are further compounded by the challenges resulting from the notable contraction in the debt market as a result of the GFC. It is clear that there are fewer banks actively lending in global terms (leaving aside those international players who have recently retreated from the Australian market in an effort to consolidate their own domestic balance sheets). Of those participating, debt providers have lowered their lending limits significantly compared to historical levels, shortened lending terms and are charging significantly higher debt margins reflecting increases in their own costs of funds, as well as a declining appetite for genuine risk26.

While it is recognised that the debt markets were starting to show signs of recovery, the recent European debt crisis is making already fragile global capital markets less stable again. Organisations seeking to invest in new generation capacity in the short to medium term face a significant task in attracting funding in a constrained market. It is not surprising, that a disproportionate burden may therefore fall on the equity investors. The willingness of equity investors to undertake new investments will be partially affected by their ability to secure adequate debt funding at an efficient cost, to maintain an optimal capital structure.

The implication of these risks is that it has become extremely difficult to accurately predict the breakeven point for new investment. In an environment where significant uncertainty remains, debt and equity providers may not be prepared to fund new investments in the generation sector on the basis that they are simply unable to price project risk.

Existing players with strong balance sheets and strategic incentives to take advantage of short term market conditions (such as acquisition of weaker rivals or for vertical integration) may have the short term ability to fund new projects within existing facilities, particularly where they have been de-risked through the backing of proven and viable plant, secure fuel supply arrangements and off-take agreements where any future carbon risk is fully passed through to end customers.

While this approach may fill some short term gaps, it is not an efficient or sustainable solution for energy certainty for Australia going forward. The solution to addressing the problem will ultimately come down to an assessment by investors as to whether the potential returns from generation assets in Australia outweigh the likely risk of investing in the sector, relative to other investment opportunities.
In this section:

This section looks at the likely returns to investors in base load generation.

Key points

• To date returns to private investors suggest investment in baseload generation is already riskier than had been allowed for, resulting in unsatisfactory financial performance for some players

• Any asset impairment and failure to compensate adequately arising from structural incentives to transition to lower emissions plant will diminish capital available to incumbents

• Compensation for affected players will be critical to providing a supportive environment to continued investment by incumbents especially global investors

• Disaffected incumbents may not only be deterred from further investment but employ other strategies to recover their investment in existing assets which could be highly disruptive to the market.
Overcoming investor uncertainty in power generation

4. The likely returns to investors in base load generation

Historically, investors in base load electricity generation have not required a high rate of return. In corporate finance-speak, the business has a relatively low Beta because base load generators tend to supply electricity in good economic times as well as in bad. The theory has been that price should be relatively easy to predict, as is long term demand.

In fact, the returns to private investors in the industry in Australia suggest that the generation business is rather more risky than has previously been priced by investors, which has resulted in some unsatisfactory financial performances over recent years.

4.1 Recent history

In assessing returns to investors in base load generation, it is helpful to consider the experience of the private sector entering the energy market in the Australian context. In the mid-1990s, Victoria’s four large brown coal generators – Loy Yang A, Loy Yang B, Hazelwood and Yallourn – were privatised. Prices paid were regarded as being high at the time and subsequent returns tend to confirm that judgment. Leaving aside that buyers may have paid insufficient attention to the risks from a future carbon price – to which brown coal generation would be particularly exposed – the future pool prices projected in the due diligence process failed to materialise. In hindsight, it would appear that this was partially because of ongoing excess capacity in the NEM and partially because the efficiency gains created as a consequence of private ownership drove down the marginal cost curves of the generators.

Currently market conditions vary across each jurisdiction, with each State having its unique challenges:

• Queensland is currently experiencing considerably low pool prices and increased uncertainty due to the emergence of the LNG industry and new efficient gas fired plant coming on line

• New South Wales has continued uncertainty as the State Government’s asset sales program is further delayed

• Victoria has significant exposure to high polluting brown coal assets, coupled with an emerging demand/supply constraint.

While each has separate challenges, the operation of the NEM means there are interdependencies, which in turn have the ability to impact sectoral asset values.

While the private sector has continued to invest in generation assets post the privatisations, the generation sector’s investment track record to date does not set a positive backdrop for new entrants to the Australian market.
4.2 Impacts of an emissions trading scheme on returns for incumbents

Returns

The intention of an ETS is to lead to changes in the merit order, that is the order in which plant is dispatched into the NEM. This is aimed at incentivising a shift from existing fossil fuel based generators to lower emission plant to contribute to the emissions reduction tasks. If it operates in the way it is intended, higher emission generators will be displaced by plant with a lower marginal cost of dispatch. This bid and dispatch mechanism will most likely prevent a full pass through of carbon costs for some players, particularly those with higher levels of emissions. This implies that existing generators will suffer a loss in asset values to the extent that they are unable to recover their full cost of operations (including any carbon-related costs) through the pool price dispatch, or in combination with a trading-led (derivatives based) solution.

Any resulting asset impairments created by the decline in financial performance will cause a diminution in available capital and negatively impact investors with exposure to brown and black coal-fired generation looking to invest further in the sector. The extent of this constraint will be directly impacted by the design of the Scheme and, in particular, any compensation arrangements that would be provided to the owners of affected plant.

Australia’s ability to de-carbonise its generation supply in a seamless and timely manner, while minimising impacts on industry and consumers, will depend on its ability to attract new investment in lower emission generation assets. This will rely on incumbents – both privately owned as well as government owned generators – being at the forefront in making investment in new base load generation assets, despite their existing asset bases and balance sheets potentially being compromised.

Compensation

If any ETS is introduced, compensation for affected players will be critical to providing a supportive environment for continued investment by incumbents in the sector.

However compensation arrangements such as the Electricity Sector Adjustments Scheme (ESAS) proposed under the current Australian Government’s CPRS27 are unlikely to fully offset the loss in asset value for coal-fired generators.

The Federal Government’s original package committed to providing limited compensation totalling $3.9 billion over five years to the industry in the form of free emission permits.28 While some commentators, including the Government’s adviser on climate change, Professor Ross Garnaut, argue against the need for compensation, the industry contends that this compensation is insufficient. The critics tend to argue from an ethical or theoretical standpoint, namely that ‘polluters’ have caused the greenhouse problem and that they should not be compensated for reducing their pollution. More contentiously, Garnaut has argued that traditionally in Australia companies have not been compensated for policy changes detrimental to their interests.

These arguments ignore the fact that coal-fired generation assets were constructed before there was a cost to emissions and, in most cases, at a time when there was no clarity in terms of how such a cost may be introduced. They also ignored the historical benefit that consumers (both householders and commercial and industrial users) have derived through low cost electricity.

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27 As set out in the CPRS White Paper, 15 December 2008
28 Based on the scheme design as at the Government’s announced delayed introduction April 2010
Leaving aside the moral arguments, compensation remains a complex issue under any ETS proposal because of the difficulty in assessing the likely impact under any ETS proposal on asset values. This was demonstrated by the three very different compensation estimates for a single black coal-fired power station presented as part of the CPRS White Paper in relation to the impacts of an ETS. The estimated modelled changes (summarised below) indicate a range of $1.8 billion for affected values for “Black coal plant #11” – ranging from a positive impact on asset values of $923 million to a decrease in values of $915 million.

Table 4.1 Impact of CPRS on generation asset values: range of estimates

<table>
<thead>
<tr>
<th>Plant</th>
<th>McLennan Magasanik Associates</th>
<th>ACIL Tasman</th>
<th>ROAM Consulting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black Coal plant #11</td>
<td>$923 million</td>
<td>-$414 million</td>
<td>-$915 million</td>
</tr>
</tbody>
</table>

Given the need for substantial investment in electricity generation in the next few years, it seems prudent not to alienate some of the global power companies that Australia will be looking to as major investors in cleaner generation technologies.

Certain incumbents have alluded to sovereign risk issues being raised by the compensation matter. While these players may be perceived as having ‘vested’ interests, the views of global companies that have major investments in Australia should not be summarily dismissed. In its submission to the Federal Government’s CPRS White Paper, International Power argues that:

“Instead of encouraging new investment in the stationary energy sector, the CPRS is acting as a major impediment to new investment. The willingness being displayed by Government to deliberately destroy the value of existing generating assets has been noticed by international investors. Investment in the Australian energy sector is now viewed as more risky than that of developing countries. Some Australian businesses and banks are in the process of exiting the sector.”

Not surprisingly, the issue of compensation was the focus of rigorous debate between the Government and the Coalition (under Turnbull) as they attempted to agree changes to the final Scheme design in the lead up to the bill being put to the Senate for the second time in December 2009.

In response to continuing industry concerns and to assist in informing its revised position, the Government commissioned a confidential report by Morgan Stanley (completed in late 2009) on the likely financial impacts of the CPRS Scheme on a group of emissions-intensive generation assets. While the Government has refused to release details of the report (on the basis of being commercial in confidence), it is likely that the analysis has served to highlight the considerable adverse impact on parts of the generation sector and to raise genuine concerns in the Government’s mind about security of supply going forward.

Following negotiations, the “Turnbull agreement” was reached, which resulted in a compensation package for generators being increased from $3.9 billion over five years to $7.3 billion over ten years. At the time this attracted considerable criticism and was labelled as “polluters’ pay day” by the Greens. While there is strong debate on the ‘morality’ of the issue, it is critical to note that the compensation is still well below the amount originally sought by Turnbull (which was $11.7 billion for the top 20 industry players over five years) and significantly below that being sought by the industry.

Under the workings of the proposed emissions reduction fund announced by new Coalition Leader, Tony Abbott, compensation to owners of existing coal-fired plant is unlikely to be a critical issue as this Scheme is incentives-based.
The ‘wounded bull’ scenario
Existing generators, both publicly and privately owned, are unlikely to stand by idly while value erosion takes place through an increasing carbon price. In a scenario where coal generators consider their compensation is inadequate, not only may they be deterred from investing further in the industry, but they may attempt to use other legitimate means to recover their investment in existing assets.

A combination of the NEM rules with the fact that excess capacity is now disappearing from the market may allow generators some scope for ‘gaming’ the market. Simshauser and Doan have demonstrated how individual brown coal generators could shut down one or more units so as to withhold supply and then bid high prices to bring them back into operation (the ‘wounded bull’ scenario).31

By using this approach aggressively over a period of time, generators could recover the cost of their investments in a relatively short period. This could be highly disruptive to the market in terms of prices, with the potential for increases in pool prices estimated to be as high as 300%. It could also provide unsustainable price signals to new entrants and cause severe financial distress to electricity retailers in circumstances where there are limitations on tariffs charged to retail customers.

How likely is the ‘wounded bull’ scenario?
While this approach represents a key risk to the market, there may be some practical challenges:

- It is unclear how regulators would address this issue
- Depending on the market power of the participant, it may be difficult to single-handedly shift the market
- Other players, particularly those after market share, are likely to fill the requirement, with the ‘gaming’ generator remaining undispatched (thereby earning nil revenue)
- Even if the approach were to be effective in the short term, it does not represent a long term strategy, as sustained increasing pool prices will ultimately provide a price signal to encourage additional investment, resulting in additional capacity and a longer term lowering of returns.

Whatever the outcome, it seems clear that bidder behaviour will change in response to any carbon constraint, posing additional risks for new entrants.

In this section:

This section deals with the key risks likely to concern investors in base load generation:

Key points

• The bipartisan support of Australia’s commitment to reductions of a minimum of five per cent of 2000 levels by 2020 presents a significant challenge, with no current agreed mechanism to achieve this.

• In the absence of policy certainty on the delivery mechanism, carbon price risk presents a considerable risk for an investor considering investing scarce capital in long-lived generation assets.

• This uncertainty is compounded by the linking of Australia’s reduction commitment to global efforts.

• Investors must also make a determination on what the most economically viable base load power generation will be in light of possible carbon prices.

• There are limited economically viable, low or zero emission technology options, presenting significant challenges for Australia once gas is displaced as a transitional fuel under higher carbon prices.

• Investors face other significant risks, including demand side risks (energy efficiency, transport and population growth), transmission access risk, regulatory risk and the ongoing role of the Governments as plant owners.
5. The likely risks for investors in base load generation

5.1 Carbon risk

There are two key factors that are contributing to the current carbon emissions uncertainty in Australia.

- How and whether Australia will deliver on its commitments under the Copenhagen Accord; and
- The global economic and policy context, including the impacts on the likely trajectories to be adopted in Australia and those adopted in other countries.

**Delivering on Australia’s commitment under the Copenhagen Accord**

In its submission in response to the Copenhagen Accord, Australia reaffirmed its commitment to reducing emissions by between five per cent and 25 per cent (depending on global agreement) on 2000 levels by 2020.

In absolute, if not relative, terms a five per cent reduction represents a considerable challenge. It is equivalent to a reduction in emissions from business-as-usual (BAU) projections of around 22 per cent. A 25 per cent cut would represent an even more considerable challenge – a reduction from BAU of around 42 per cent.

The wide range for the reductions task, which is dependent on global factors as well as equally uncertain domestic policy outcomes, presents a practical challenge for the local industry, as well as significant uncertainty for investors.

Despite its deferral, the CPRS is the current Government’s proposed instrument to deliver on its Copenhagen commitment. Not only is it designed to deliver on the existing reduction commitment of five per cent, but it also has the ability to scale up (at least in theory) the reductions task rapidly by reducing caps on emissions. The mechanism driving the reduction is the resulting carbon price, which will encourage the displacement of emission intensive plant or supply in favour of lower emission alternatives.

By contrast the Coalition’s current policy response aims to deliver a five per cent reduction in emissions in line with the Australia’s Copenhagen commitment through incentives rather than through introducing a cost to carbon. While the Coalition has stated that its proposed incentives have the ability to deliver reductions of more than five per cent, it has not at this stage released details on how this would be achieved.

Given the Coalition’s current policy stance and the deferral of consideration of the CPRS, it is clear that the mechanism to deliver on the Government’s commitment under the Copenhagen Accord will not be resolved any time soon.

Unfortunately, this will only make the ultimate task of meeting the reduction commitments under the Copenhagen Accord more challenging. This is because the window for switching technologies will be shorter and more difficult in practical terms.
Impact of global commitment: Copenhagen and beyond

Even if certainty is achieved through an established scheme domestically, the global context will continue to be a significant factor impacting the reductions task in Australia. As such, certainty in terms of a global response to climate change is critical to establishing investment certainty domestically.

Despite earlier hopes, the Copenhagen Summit failed to deliver a clear global position on climate change. Not long before his resignation, the Executive Secretary of the UN Framework Convention on Climate Change, Yvo de Boer agreed, stating that “Copenhagen did not deliver the full agreement that the world needs to address the collective climate change challenge”. His view was that “Copenhagen didn’t produce the final cake, but it left countries with all the right ingredients to make a new one in Mexico.”

While the Copenhagen Accord is not as conclusive as many would have liked, setting a goal of restricting the average temperature rise this century to two degrees Celsius provides a starting point for participating countries.

Even with this important first step, Australia’s commitment to greater emissions reductions linked to future global commitments is problematic. This is because it introduces significant uncertainty by exposing investors to the future action of other countries, presenting an open and uncontrollable risk. Australia will now need to look ahead to the next major UN climate talks – which will be held in Mexico in December 2010 – at the earliest and more likely post the expiry of the Kyoto Protocol’s first commitment period, at the end of 2012 – to see if a much anticipated legally-binding treaty is implemented.

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32 Yvo de Boer, Executive Secretary UN Framework Convention on Climate Change.
Carbon risk as a project risk

In practical terms, carbon price risk translates into a number of specific project risks that will arise as a result of the market’s response to a price on carbon and an ETS.

• **Contract market risk** – the ability of generators to manage forward energy price risk is significantly inhibited in the current market, which is largely illiquid in the outyears (particularly post 2012) due to carbon uncertainty. This poses significant problems, particularly to high emitting generators who will look to a trading-led solution to manage their carbon risk.

• **Relative competitiveness risk** – the level and volatility of wholesale prices under an ETS (including the likely retaliatory response of generators who are displaced in the merit order). Even a relatively modest emissions reduction target is likely to give rise to a change in the merit order for dispatch, which is likely to lead to modified bid/dispatch strategies by generators.

• **Permit price risk** – the higher the carbon price, the more capital that will need to be committed for purchasing permits. Even at a low price of $17.50/tonne CO2-e, “a 2000MW brown coal generator in Victoria would have to finance $324 million worth of acquisitions per annum, equivalent to 10 per cent of its aggregate asset value or 55 per cent of its annual revenue, in order to pay for permits.” At a more likely permit price of $35, the impact would double.

• **Pass through risk** – the ability to pass through the full cost of carbon (which is likely to be less than 100% given the dynamics of the pricing and dispatch mechanisms of the NEM). It has been estimated that even with relatively modest carbon prices, brown coal generators, for example, may be able to pass through only around 78 per cent of the cost of emissions permits initially, falling to 60 per cent as new gas generation enters the market. The rate of pass through will ultimately depend on the prevailing generation mix and the ability of the market to displace high emissions plant with cost competitive lower emission supply alternatives.

Carbon price uncertainty does not just affect investment in new projects. It also has the ability to affect existing players, the impact of which should not be underestimated.

Evidence of the impact can be seen by Standard & Poor’s downgrading of the credit rating of a number of corporates and their difficulty in refinancing maturing debt. All of these factors will need to be assessed and priced before any investment is likely to be made.

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34 Ibid, page 75.
5.2 Technology risk

Investors not only must form a threshold level of comfort in terms of the climate change policy environment, and make a broad decision to invest, but they must also determine which is likely to be the most economically viable base load power generation technology in light of the possible carbon price paths.

This is perhaps the most critical issue, given that base load plant tends to be highly capital-intensive, has an economic life of up to forty years and generally comes with a pay-back period of at least fifteen years. An ill-judged decision in terms of choosing the wrong technology could lead to the pay-back period being pushed out well beyond fifteen years, credit metrics being breached and the asset becoming stranded well before the end of its theoretical economic life.

New generation technologies: the pathway to a lower emissions future

Technologies for electricity generation, as with most other industrial processes, tend to be global in their application. Some countries, like Australia, have the advantage of access to particularly cheap fossil fuels, while others have an abundance of hydro resources, sunshine or wind. Fundamentally, however, most countries face similar choices between low and zero emissions base load technologies.

While Australia has the most carbon-intensive economy in the developed world, both Professor Garnaut and some ministers have suggested that, in some way, Australia has advantages in terms of low emissions energy choices that are denied to other countries. This may, however, over-simplify the true position.

A previous paper by Deloitte Economics discussed the various low emissions technologies available for base load generation and provided estimates of relative costs. This paper found that in the medium to longer term, the practical options in Australia for transitioning to low or zero emissions base load generation are limited for a range of availability policy and technological challenges. These are outlined in more detail in the remainder of this section.

Carbon price as a driver for new technology

A key determinant of the speed with which Australia makes the transition to a lower emission technology base will be the price attaching to carbon.

Table 5.1 compares the long run marginal cost ($/MWh) of base load electricity generation technologies in Australia in 2008 with, and without, a $50/tonne carbon price.

### Table 5.1 Long Run Marginal Cost (A$/MWh)

<table>
<thead>
<tr>
<th>Technology</th>
<th>2008 (with $50/t CO2e price)</th>
<th>Projection (with $50/t CO2e price)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black coal ultra super critical</td>
<td>54</td>
<td>96</td>
</tr>
<tr>
<td>Gas-fired (CCGT)</td>
<td>58</td>
<td>76</td>
</tr>
<tr>
<td>Nuclear</td>
<td>76</td>
<td>76</td>
</tr>
<tr>
<td>Hydro</td>
<td>72</td>
<td>72</td>
</tr>
<tr>
<td>Solar</td>
<td>224</td>
<td>146</td>
</tr>
<tr>
<td>Wind</td>
<td>93</td>
<td>65</td>
</tr>
<tr>
<td>Geothermal</td>
<td>87</td>
<td>73</td>
</tr>
<tr>
<td>Black coal + CCS*</td>
<td>145</td>
<td>100-150</td>
</tr>
</tbody>
</table>

Source: ACIL Tasman, Projected Energy Prices In Selected World Regions, May 2008; * Deloitte Economics

Table 5.1 illustrates a number of important points:

- Traditional fossil fuel based technologies, even gas, will ultimately be displaced by emerging technologies as the cost of carbon increases
- Nuclear, geothermal and hydro are competitive with gas CCGT at a $50/t CO2e price, demonstrating the likely tipping point at which gas begins to become uncompetitive and will be replaced with alternative baseload options
- Solar thermal and black coal with CCS will require significant carbon price if they are to become commercially viable in their own right.

One other thing is also clear. Irrespective of which technologies emerge as winners in terms of their role in contributing to Australia’s emission reduction task, any introduction of a carbon price, or similar mechanism, will mean that electricity prices will rise significantly. The level of increase will depend on the rate at which technology can be scaled up to provide commercially viable solutions in the Australian environment.

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36 Deloitte Economics, Power Generation in a Carbon Constrained World: Implications for the Resources Sector, June 2009
The Australian Energy Resource Assessment (AERA)

To inform future policy settings, the Federal Government commissioned the AERA. According to this report, the projected annual growth rate in Australian electricity generation is expected to be 1.8 per cent (366TWh) between 2007-08 and 2029-30, assuming the introduction of the CPRS and the revised RET Scheme.

The study indicates there is likely to be a key change in the projected generation landscape with a substitution of coal-fired generation for gas-fired generation. The following figure illustrates the shift.

In any case, it is interesting to note that the 2030 prediction for fuel mix still includes almost 80% of fossil fuels, with only minor contributions from renewables. This raises concerns about the Australian Government’s ability to achieve its commitments under the Copenhagen Accord of a five per cent reduction by year 2020 on 2000 emissions, based on the assumed fuel mix. This is because five per cent represents a reduction of approximately 22 per cent on business as usual projections. At the top end of the target reduction range, a 25% reduction on 2000 levels represents a reduction of around 42 per cent on business as usual in Australia.

By the time horizon of 2030 assumed in AERA study, it is likely that the targeted reduction would be above the five per cent, raising further concerns about available technology to deliver on the emissions reduction task. As discussed later in this section, the immaturity of most renewable energy technologies means that renewables will most likely not be able to fill this gap, leaving Australia in a difficult position with regard to low-emission base load generation, which excludes fossil fuels by necessity. Although Australia has abundant and widespread renewable energy resources, the projected major shift to renewables will depend on the rate of technological advances and demonstration of commercial viability, with attendant reduction in the cost of the technologies37.

The more likely scenario is that Australia will meet this task through importing permits internationally, rather than removing reliance domestically on fossil fuels.

The following section discusses the range of potential generation options that may emerge as we enter into a carbon constrained economy.

37 AERA
Renewables
Renewables are likely to be an important part of the future generation landscape in Australia. This shift is currently being driven by the RET policy which incentivises purchasers of energy to source a proportion of their supply from renewable sources.

In the absence of a carbon price or similar mechanism to encourage investment in renewables, it appears the Government is looking to other mechanisms to encourage this sector. The recent announcement in the Federal Budget of the $652.5 million Renewable Energy Future Fund is aimed at encouraging private sector investment to support the commercialisation of renewable technologies.

This however may not be enough to stimulate investment on the scale required to meet emerging energy needs. This is because most renewable solutions have significant challenges. Many are derived from interruptible sources (such as wind and solar) and for this reason have been overwhelmingly used for peak load and intermediate duty rather than for base load.

The interruptibility of renewable supply means that they require significant fossil fuel back-up, generally from gas peaking plant. When the fossil fuel back-up is taken into account, the costs of renewables are sometimes significantly more, and their contribution to reducing emissions often less, than typically accounted for on a stand-alone basis.

The only types of renewables that are suitable for base load power and have the potential to be produced at an acceptable cost are hydro and geothermal.
Despite the enthusiasm in the community and the optimism in the renewables sector, it is difficult to see how renewable energy could provide a significant contribution to Australia’s base load generation requirements in the short to medium term. This is because:

- **Solar thermal** remains an interruptible technology and is comparatively very expensive (although the cost disadvantage should erode over time as solar panels are produced on a greater scale)
- **Wind** remains interruptible and poses some technology risks. Anecdotal evidence from the industry suggests that many of the early wind turbines installed in Australia have had a significantly shorter life than was expected when the investment decisions were taken
- **Hydro** offers limited scope for significant development in Australia due to drought and environmental constraints
- **Hot dry rocks (geothermal)** remain unproven and in general are located large distances from transmission networks. They do, however, provide promising prospects in terms of availability, cost and capacity and therefore have the potential to provide a renewable base load solution longer term.

In summary, renewables simply do not offer an affordable, low risk and mature base load technology in the short to mid term. As highlighted in the AERA, most renewables are high cost, longer term options for base load power.

Figure 5.2 illustrates the technological phase attributable to renewable technologies.

Of those available in Australia, only hydro is considered an affordable and mature technology option. The majority of renewables remain in research, development and demonstration phases meaning immediate low cost renewable options are simply not available at this stage.

To encourage a strong shift towards renewables, further investment in these technologies coupled with effective price signals (such as a price on carbon or other supportive mechanisms) will be required.

Given these challenges, while they will clearly be part of the generation landscape going forward, renewables are unlikely to be suitable for base load generation at this stage due to their maturity.
Natural gas

Is a mature, low risk and relatively low cost generation solution. It provides one proven solution to the problem of de-carbonising power generation. Combined cycle gas turbine plant (CCGT) have a carbon footprint of around 400 kg of CO2/MWh, less than half that of black coal, have moderate capital requirements, can be built relatively quickly and are capable of providing continuous supplies of electricity at a moderate cost premium to coal.

As can be seen from Figure 5.3, many countries derive a significant amount of their electricity supplies from natural gas.38

Figure 5.3 Gas as a percentage of power generated: international comparison and State breakdown

In the Australian context, gas has a number of advantages. It used to be said that natural gas was abundant in Australia but that it was in the ‘wrong place’. This was because the main gas resources were offshore in the north-west of Australia while the main markets were in the east. This has all changed in the last few years. The enormous reserves of coal seam gas discovered in Queensland and New South Wales in recent years provide ample supplies for domestic gas users as well as a new LNG industry on the east coast.

One disadvantage with gas for base load generation is that the operating costs of a CCGT generator are highly sensitive to the gas price. According to one industry contribution to the Energy White Paper, a rise in gas prices from $4/GJ to $10/GJ on global markets would increase electricity prices by between $40 and $50 per MWh in Australia.39 Depending on the nature of the competing plant, a gas price rise of this magnitude could well threaten the commercial viability of CCGT plant as well as increasing the cost of electricity in Australia to internationally uncompetitive levels.

It is frequently suggested that the growth of an export LNG industry in Queensland and NSW will lead to domestic gas prices rising to world parity. More detailed analysis, however, suggests this is unlikely to occur. ACIL Tasman suggests that there is plenty of gas to serve both domestic and foreseeable global markets in the future, with different price pressures prevailing in each market. Their modelling suggests that the domestic gas price is unlikely to exceed around $5/GJ at 2009 values until at least 2030.40

Given it is a proven technology with (at least currently) acceptable fuel supply costs, it is clear that gas is likely to be the transitional generation solution as Australia seeks to lower its emissions in the short to medium term.

38 Santos, Submission to the Energy White Paper, 2009, page 13
39 Rio Tinto Australia, Submission to the Energy White Paper, June 2009, page 2
40 Paul Raffe, ‘How far can gas dash?’, paper delivered at Powering Australia conference, Brisbane, 10 November 2009
Coal with and without carbon capture and storage (CCS)

Currently, coal-fired generation plays the main role in producing electricity for the world. It is also the major source of greenhouse gas emissions. Rapid growth in China and other Asian countries has largely been underpinned by coal-fired electricity. It is unlikely that new investment in current technology coal generation will decline in developing countries in the near future. In fact, current plans for additional coal-fired generation capacity to 2020 can be seen in Figure 5.4\textsuperscript{41}:

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure5.4.png}
\caption{Plans for additional coal-fired generation capacity to 2020}
\end{figure}

Depending on the commitments by member countries following Copenhagen, and at Mexico in December 2010, these plans may change. Already developed countries are moving away from current technology coal generation, particularly for plant that are not ‘CCS ready’.

It is widely considered that, primarily because of its abundance, coal will have to play an ongoing role in power generation for much of the rest of this century. If this is to occur, however, coal drying techniques together with the sequestration of the CO\textsubscript{2} underground will need to be commercially viable.\textsuperscript{42}

The major hurdle facing clean coal with CCS is its cost. A recent report by the Global Carbon Capture and Storage Institute (GCCSI) suggested that a carbon price of approximately $90/tonne of CO\textsubscript{2}-e would be required before the technology was commercially viable. The report also suggested that the world would need to allocate funding of $100 billion per year in order to make the technology viable.

Industry players interviewed in the course of developing this paper were similarly pessimistic over the current costs of clean coal with CCS. CCS also poses risks arising from leakage of carbon dioxide. There is likely to be a need to guarantee the integrity of storage basins, particularly onshore reservoirs. To de-risk projects, governments may need to assume liability for onshore carbon storage from the commencement of a project. Even so, fulfilling any generator’s duty of care in assuring that every possible precaution was taken is likely to raise concerns in the eyes of debt and equity holders and could add significantly to costs. These costs and the associated contingent liabilities do not appear to be fully factored into the GCCSI cost estimates.

Taking all of these factors into account, CCS technology has a number of hurdles to clear before it offers a viable solution for base load generation in a carbon constrained world.

\begin{itemize}
\item[\textsuperscript{41}] International Energy Agency, quoted in Australian Coal Association, Submission to Energy White Paper, June 2009, page 8
\item[\textsuperscript{42}] Global Carbon Capture and Storage Institute, Strategic Analysis of the Global Status of Carbon Capture and Storage, October 2009, paragraph 1.5.11
\end{itemize}
Nuclear power is the only proven, near-zero emissions base load generation technology that is widely available and generates electricity at a relatively competitive cost. It delivers very low carbon base load electricity at costs that are stable over time.

Australia has a ‘no nuclear’ policy. While Federal Resources and Energy Minister Martin Ferguson acknowledges “nuclear power globally is part of the climate change solution,” he has reaffirmed the ‘no nuclear’ policy by stating that “it is the view of the Australian community that we should pursue all energy options other than nuclear.”

While most Australians are aware of the ‘no nuclear’ stance, many are unaware of what former British Prime Minister Gordon Brown referred to as the ‘nuclear renaissance’, namely the global shift towards nuclear power as a response both to energy security concerns and climate change. Of the G20 nations, only Australia does not already have nuclear power or is not actively planning a nuclear program. Indeed former Executive Secretary of the UN Intergovernmental Panel on Climate Change (IPCC), Yvo de Boer, has said that he has “never seen a credible emissions reduction strategy that does not include nuclear power”.

In the United States for example, President Obama has announced the construction of a new generation of nuclear power plants. The aim of the Obama administration’s energy policy, which may increase nuclear energy supply to 60 per cent of electricity in the United States by 2030, is to address climate change concerns while seeking to satisfy the nation’s growing energy needs. Meanwhile, in the United Arab Emirates, a South Korean consortium was recently awarded a contract worth $US20 billion to build four nuclear power plants to be operational by 2020.

Nuclear power has, however, a number of drawbacks, apart from proliferation. Capital costs are extremely high and development timeframes are long. Loads need to be around 1,000 MW at a minimum, although this may be changing. A high level of government involvement is generally required in terms of providing an appropriate regulatory framework and also in assisting with development planning and insurance. De-commissioning costs can also be high.

There are also the technical risks which invariably arise with any new or re-emerging technology. Finland is currently seeing that building the first nuclear plant for twenty years is a difficult undertaking with both costs and timelines having blown out significantly.

Most importantly of course there is still no clear resolution of the key risk – how to deal with nuclear waste.

Clearly, replacing all existing coal generators with nuclear plant would represent a major endeavour and would require a supportive change in government policy, a suitable solution to disposing of nuclear waste, and potentially loan and insurance guarantees, although the required support may arguably be less than that presently afforded renewables. Coming off a zero base, France built 56 nuclear plants in 15 years and within five years had reduced its emissions from electricity generation by 80 per cent. France now has some of the cheapest electricity in the European Union.

By contrast, on the basis that Australia will not be accessing nuclear as a relatively low cost zero emission technology, treasury modelling suggests that electricity prices are likely to rise at a rate five times higher than that of countries that employ natural gas and nuclear power to produce their electricity.

43 “Going fission”, The Age, 13 October 2009
44 Australian Financial Review, 8-9 December 2007, page 22
45 Australian Government, Australia’s Low-Pollution Future: the Economics of Climate Change Mitigation, Canberra, 2008, page 128
Low emissions generation technologies: the likely solution, the dash for gas and beyond

Given the uncertainties both in terms of the climate change policy and the technological advancement necessary to deliver the emission reduction task, it is not possible to accurately predict what the generation landscape will look like going forward.

What does seem apparent is there is likely to be two distinct stages in the transition towards low emissions technologies in Australia:

• An intermediate solution based on gas
• A longer term (and less clear) solution beyond gas.

Australia’s ‘dash for gas’

Apart from investment in renewables to meet the 20 per cent target, the bulk of investment in new generation capacity in the medium term will be in natural gas CCGT plant.

If an imposed carbon price is sufficiently high to displace all coal generation by gas, Australia’s carbon footprint from the production of electricity could fall by more than half. This is likely to be the first phase of Australia’s response and will provide a breathing space while lower emissions options are further developed.

While gas is seen as an excellent transition solution to reducing emissions, it is not without risks and is likely to be superseded in the longer term. This is because:

• While gas has lower emissions than coal, it is far from being a zero emissions technology. As the carbon price rises over time this will make gas generation uncompetitive with some zero emissions technologies such as nuclear
• Carbon capture and storage (CCS) technologies for gas are presently considerably more expensive than for coal, and may not be commercially viable for at least ten years, “and most likely not for 20 years”

• The cost of power generated from a CCGT is highly sensitive to the gas price. As the demand for natural gas rises and international trade in gas increases, significant price rises may occur to the extent that gas supply at certain (non market linked) prices has not already been secured.

The ‘window of opportunity’ for gas, however, is not clear. If ambitious emissions reductions targets are agreed and the costs of CCS for gas do not fall substantially, new investment in gas generation may become unattractive as early as 2020 because of the carbon footprint, leaving insufficient payback time.

Beyond the ‘dash for gas’

Greater technological difficulties are likely to come with phase two of Australia’s response, when further reductions in emissions need to be made and near zero emissions technologies are required. This may arrive around 2020, depending on climate change policy initiatives and pricing mechanisms.

Without nuclear power, and with only limited recourse to renewables such as geothermal for base load generation, the only remaining option is clean coal with CCS. There is clearly a considerable risk that electricity from clean coal with CCS will not become available at a commercial cost within an acceptable timeframe. Should this occur, Australia has nowhere to go in terms of very low emissions generation technologies.

The implication for investors is that they will potentially face a significant risk if Australia becomes subjected to a tougher emissions reduction target for 2020 (i.e. above the unconditional commitment of five per cent). This is because it is almost impossible to accurately predict what technology choices will be viable at that time.

While gas is likely still to make the best commercial sense at that stage, the asset may not be paid off until the early 2030s. The difficulty is that while nuclear energy is currently banned in Australia, investors in non-nuclear technologies will face an ongoing risk that government policy will change.

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46 Origin Energy Limited, Presentation to the Committee for Economic Development of Australia’s CEO Vision Series, Fuelling growth: Australia’s energy options, Grant King, April 2010

47 Clean coal with CCS is not a zero or near zero technology. Emissions are likely to be around 150-200kg of CO2/MWh
If the gas price rose moderately and carbon prices went above $50/tonne, nuclear power could undercut CCGT generation in Australia. A number of submissions to the CPRS White Paper, for example those from the Business Council of Australia and the esaa, suggested that the government should reconsider its ban on nuclear power. A recent opinion poll in The Age, in the absence of any campaign for nuclear power, showed a slight majority of the public in favour. Confronted with the climate change imperative, other governments around the world have changed their policies on nuclear power. In this regard, it would be a courageous investor who would say anything other than ‘never say never’. Discussions with the industry confirmed that this is a real issue both for project proponents and their financial supporters.

5.3 Other risk

Investors in base load generation will face a number of other areas of uncertainty in the coming decades that have the potential to increase the risk of deriving adequate returns on their investment in generation assets. Some of these risks will also have wider application to the community generally.

Demand side: energy efficiency, transport, population growth

Energy efficiency

Significant uncertainties exist in terms of the future demand for electricity in Australia. One very important area is energy efficiency.

The importance of this was reflected in the changes to the CPRS draft legislation in late 2009, which included more resources for energy efficiency measures to incentivise households to do their bit in the reduction task.

A number of projections of global emissions from electricity to the middle of the century and beyond suggest that around half of the required reduction in emissions will be derived from increased energy conservation and efficiency in its use. Indeed, some projections of electricity demand to 2020 in Australia suggest that, in contrast to the assumptions used in this paper, no additional investment in base load generation for the NEM will be required in the next decade.

The Australian Government appears to be focussing on the issue of energy efficiency now that the ETS has been deferred. There is an Energy Efficiency Taskforce, which is expected to report to Government in the middle of 2010.
There have also been renewed calls to focus on energy efficiency to fill the void left by the deferral of the ETS. One property and construction company has urged the Government to reconsider its proposed energy efficiency scheme for commercial buildings, under which building owners can buy and sell credits set against an industry energy efficiency benchmark. It has been suggested that such a scheme could double the energy efficiency of the commercial building sector by 2020, thereby enabling the country to meet its targets under the Copenhagen Accord.

While Australian governments are committed to securing increased energy efficiency in the community, the impact of this on demand is difficult to forecast. The demand for electricity has proven to be relatively inelastic and so long as energy bills account for only a relatively small proportion of households’ and businesses’ budgets, the impact of higher prices on consumption may well be muted.

There is also a risk that load profile may also change, as pressure builds to create greater efficiencies by shaving peak load demand to improve network efficiencies and lower electricity prices. The importance of achieving greater efficiencies has now been recognised by the AER in recent determinations, which provides for a demand side management incentive scheme to better encourage demand side management strategies. Any decline in pool prices and/or voratility may directly impact investor returns.

Investors will need to make judgments as to the likelihood of any significant change in energy consumption patterns as a result of energy efficiency and demand side management measures, and any likely negative impact on the potential returns on their investment.

48 “Call to renew energy plan”, Australian Financial Review 30 April 2010, page 12
49 Final determination for Queensland’s electricity distribution network service providers, Energex and Ergon Energy, for the period 1 July 2010 to 30 June 2015 released on 6 May 2010

Transport
Until recently, there has been considerable uncertainty as to which technologies will emerge as the means of reducing emissions from the transport sector. For many years, hydrogen fuel cells were regarded as the most prospective emerging technology. Recently, however, with rapid advances in battery technology, electric vehicles seem most likely to succeed in the market place. Electric vehicles generally require regular charging by attaching them to the electricity supply. Depending on the take-up rate of electric vehicles, this could mean that the demand for electricity will be up to 10 per cent higher by 2020 than it otherwise would have been. Regulation will need to address the trade-off between the potential emissions reductions from the use of these vehicles with the electricity supply required to support the recharge process (for example price incentives for off-peak recharging).

Again, there are substantial uncertainties around this projection, decreasing the ability to accurately predict future demand side forecasts for energy and likely returns.

Population growth
Recent projections have suggested that Australia’s population may reach 35 million by 2050, an increase of over 60 per cent in the next four decades.

While this may lead to a rapid increase in the overall energy demand, this factor could also mean that we will need to move to very low emissions generation technologies more quickly than originally thought, thereby increasing the difficulty of the reduction task ahead.

50 As predicted by Ken Henry, Secretary of the Commonwealth Treasury QUT Leaders Forum, Brisbane, 23 October 2009
Transmission access
It is also widely acknowledged that the current regulatory framework may not be sufficient to encourage economic investment in new generation assets.

Australia’s transmission systems evolved on a state-by-state basis and the network is not optimal from a national perspective. Currently, parts of the transmission network in the NEM are becoming congested. A notable feature of a number of submissions from generators to the now deferred Energy White Paper is some concern over their ongoing ability to access the network.

The market mechanisms in the NEM have not been fully tested in terms of demonstrating their ability to bring about the timely investment required to augment the capacity of the network when it is needed. Yet investors need to be fully confident that they will be able to bring their full production to market.

This is likely to be a problem for emerging renewable electricity suppliers, as well as for base load incumbents. The commercial case for building a costly transmission line to remote areas where the winds are strong may be difficult to justify. Given the relatively low loads and interruptible nature of wind generation, either the payback periods for the transmission investment may be too long, or the tariff required to provide an economic return could push the cost of the delivered wind power to an uncompetitive level.

A similar argument may apply to base load geothermal power from central Australia. While generation would be continuous in this case, a substantial load may be required to justify the investment in transmission. Such a load may not be available for some time.

Any constraint to dispatch will pose considerable risks to a new investor. This is currently being considered by the Ministerial Council on Energy, which has released its policy response to the Australian Energy Market Commission’s (AEMC’s) Review of Energy Market Frameworks in light of climate change policies. It has largely supported the AEMC’s finding that the market frameworks are largely robust, but has acknowledged that a number of rule changes will be required to support impending climate change policies. A timeline will be developed for the AEMC to deliver periodic Review updates of energy markets in light of the changing policy environment.
Regulatory: retail price regulation and the ongoing role of public sector

*Retail price regulation*

While generators themselves are not subject to price regulation, they are nevertheless affected by the regulatory framework.

Most States still maintain retail price regulation. Governments generally regulate retail prices because they are concerned with the welfare of the more vulnerable members of the community and to guard against the potential misuse of market power. Given the indirect impacts of the retail price caps back through the supply chain, price regulation can be highly distortionary in terms of preventing the effective transmission of price signals in the market place. Any dampening of price signals could ultimately affect the timing of investment decisions. The risk of price distortion is likely to increase given the significant impact of a cost of carbon to retail pricing and any failure to pass through the full cost would pose significant risks to investors in generation assets.

*Ongoing role of public sector*

There may be a role (even in a transitional capacity) for the Commonwealth to support the move towards a low emissions environment. This could include, for example, support for investment in the transmission system to remote locations when such investment may be uneconomic.

The market may also look to Government to build the infrastructure for CCS before it is required in any volume or even accept liability for leakage of CO2 from underground storages.

State governments will also need to decide what, if any, role they will play in future investment in generation assets. The continued presence of Government-owned generation assets in the market has raised concerns in the past by industry players as to the risks of intrusion by Government shareholders that may result in non-commercial behaviour which can undermine efficient and effective market operation. The New South Wales’ asset sales and the Queensland Government’s current fiscal challenges mean that a question mark is likely to remain, for at least some time, as to whether the current ownership structures will continue in these states.

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In this section:

This section considers the need for current uncertainties negatively impacting investment in base load generation to be urgently resolved.

Key points

• Currently there is no assurance that capital expenditure will occur when and where it is required in order to guarantee security of supply.

• Given emerging supply constraints in the medium term, policy makers must act now to resolve current uncertainty to stabilise the environment for investors.

• The deferral of the emissions trading scheme, together with the reopening of the climate change debate presents an unprecedented opportunity for the industry to actively influence the future policy direction on this critical issue.
6. Reduction of uncertainty through policy clarity

In light of the current policy uncertainty, there is no assurance that capital expenditure will occur when and where it is required in order to guarantee an ongoing security of supply of electricity to Australian homes and businesses.

The resolution of much of the uncertainty will necessarily be left to future global and domestic policy decisions, technological advancement and market forces. However, there are some issues that must be resolved quickly by Governments (both Federal and State) in the short term.

This was recognised by the Commonwealth Government, which was preparing an Energy White Paper, focussing in part on security of supply.

As recognised in one of the Discussion papers, investment in electricity generation has slowed in recent years, tightening the supply-demand balance\(^{52}\). This poses risks to energy security to the extent that investment in new generation is either delayed or does not occur. It is also recognised that the market’s ability to respond to a supply shortfall is limited, due to the long investment lead times.

Aspects of government policies, market operations and rules, and international economic circumstances have the ability to impact on Australia’s ability to securely, reliably and affordably meet its power generation needs\(^{53}\).

The purpose of this energy policy framework was to ensure long-term energy security exists in Australia “to set durable policy directions to ensure Australia’s long-term economic prosperity and energy security”\(^{54}\). Unfortunately, the Government recently announced the Energy White Paper process will be deferred indefinitely. Policy settings that create uncertainty or have the potential to distort the market affect the confidence and the appetite of investors, as evidenced by the lack of recent investment.

The timing for resolution of these critical issues now remains uncertain. While the recent publication of the AERA has provided an important technological platform for policymakers, it has not resolved the issues for investors.

Policy measures to reduce emissions

The most critical and urgent issue that requires resolution is the policy framework that will be introduced to reduce emissions and meet Australia’s commitment under the Copenhagen Accord (albeit non-binding). This is critical to providing investors with more certainty as to the likely mechanism to effect reductions, the future carbon prices (if any) and ultimately the risks that may be faced by investors.

The first hurdle is set with the Government reaffirming its targets of between five and 25 per cent under the Copenhagen Accord. What is needed now is for the Government to legislate a policy framework and mechanism to help clear the hurdles that are now in place.

Nuclear policy

While the government may continue to prohibit investment in nuclear power, the corollary is that it needs to be able to give the market confidence that other technologies will be commercially attractive. Potential investors in, say, clean coal with CCS or even gas CCGT, will also need to be confident that their very costly investment will not be undercut a few years down the track by a change in policy on nuclear energy. While this issue has been something of a ‘sleeper’, it will be of critical importance before long and will need to be addressed when the White Paper is back on the table – especially if the five per cent reduction in year 2000 emissions is increased due to any binding future global agreement.

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\(^{52}\) “Investment, Competitive Markets and Structural Reform” in Energy White Paper, April 2009, page 18

\(^{53}\) Ibid, page 19

\(^{54}\) Energy White Paper

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Planning approvals
Planning approvals processes can be considerably long in certain parts of Australia. It can take up to three years to gain approval to build a CCGT generator, for example. Because of the considerable investment task and the compressed time period in which it needs to be completed, there is a case for significantly shortening approvals processes where the necessary safeguards can be maintained, as is currently occurring in Victoria. In Britain, the government has reduced the approvals period from up to seven years to just one year, including for nuclear power plants, and will not allow local authorities any right of veto over the location of new generation plant. This issue may become more critical if the current lag in triggering new investment in generation persists to the point of creating a capacity shortfall.

Complementary State measures
There are a range of State-based measures that will need to be considered to ensure they align with the Commonwealth’s CPRS (if implemented) and the expanded RET scheme. These include the Queensland Gas Scheme and the Greenhouse Gas Abatement Schemes in New South Wales and the Australian Capital Territory. Any misalignment of State-based (and indeed other Federal) policies has the ability to further distort the market and potentially undermine the impact of an ETS. This presents a further opportunity for the Federal and State Governments to demonstrate cooperative federalism by ensuring a clear alignment of policy to contribute to achieving Australia’s emission reduction task.

While policy certainty will not remove all of the risks facing investors in generation assets, it may provide a more stable and supportive environment to tip the equation back in favour of attracting sectoral investment.
Overcoming investor uncertainty in power generation
Investors that have a strong understanding of the risks of operating in a carbon constrained economy should be well placed to move ahead of the competition by timely investment.
Australia has a significant challenge ahead. It must resolve the climate change challenge in a timely and considered manner so that investors have adequate incentives and certainty to support the significant investment task ahead. This is in order to both replace and expand generation capacity at the same time as enabling Australia to transition to a low emission economy in the most cost-effective way.

With the CPRS legislation being off the table until at least 2013, and the date for the release of the White Paper deferred indefinitely, it seems unlikely that there will be any resolution of many of these issues in the short term. Notwithstanding these challenges, it is clear that policy makers must act quickly in concert with industry to ensure that there is sufficient certainty to enable investors in base load generation to do their part in transitioning Australia to a low emissions future as quickly and efficiently as possible.

While the outlook in the interim may appear daunting, the prevailing uncertainty provides an unprecedented opportunity to shape the policy that will ultimately determine the future generation landscape. Investors in the sector and industry more broadly should be using this period to influence policy makers and capitalise on emerging opportunities as the sector undergoes what will inevitably be a major structural adjustment.

This structural adjustment is likely to affect:

- How electricity is made, including the evolution of newer and greener generation technologies
- How electricity is transmitted, including transporting power from more remote areas as Australia moves to harness new renewable resources
- How electricity is used, including the amount that is used and when it consumed, as Australia seeks to not only reduce overall demand, but also manage peak loads.

These changes have already signalled a shift away from the traditional methods of producing and using electricity. As Australia starts to transition towards a new carbon constrained economy, some early movers in the sector are already rewriting some of the underlying fundamentals on which the industry has been traditionally based. As this transition gathers pace, industry must not wait but instead invest its effort and resources into:

- Influencing the policy debate, both at State and Federal levels to ensure measures are aligned and effective from both a community and an industry perspective to encourage much needed investment by the private sector
- Capitalising on Government funding support (both at State and Federal levels) to render non-commercial projects viable
- Working with the banking and finance sector to encourage the flow of capital under adequate terms which allow the sector to make this transition, while at the same time recognise the risks to lenders
- Using investment funds (both public and private) to further develop immature technologies to ensure that Australia is left with viable low cost low emission generation options
- Transitioning the sector to meet emerging opportunities to create new skills and jobs to ensure the industry remains an innovative, responsive and attractive option in a resource constrained skills market.

At such a critical juncture in the sector’s future, organisations with an understanding of the risks and opportunities of operating in a carbon constrained economy will have a rare opportunity to influence the future generation and investment landscape. Perhaps equally importantly, these players will be well placed to move ahead of the competition by timely investment in new generation assets once the uncertainty is addressed and the conditions for investment are restored.

While policy certainty will not remove all of the risks facing investors in generation assets, it will provide a more stable and supportive environment to tip the equation back in favour of attracting sectoral investment. Then industry may be left to identify, price and manage its risks, as it has always done in the past.

7. Conclusion
<table>
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<tr>
<th>Term</th>
<th>Description</th>
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<tbody>
<tr>
<td>AEMC</td>
<td>Australian Energy Market Commission</td>
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<td>AEMO</td>
<td>Australian Energy Market Operator</td>
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<td>AER</td>
<td>Australian Energy Regulator</td>
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<td>AERA</td>
<td>Australian Energy Resource Assessment</td>
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<td>AEU</td>
<td>Australian emissions units</td>
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<tr>
<td>Base load power plant</td>
<td>Low cost plant that provides a steady flow of power regardless of total power demand by the grid.</td>
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<td>BAU</td>
<td>Business as usual</td>
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<tr>
<td>ERF</td>
<td>Emissions Reduction Fund</td>
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<td>ESAS</td>
<td>Electricity Sector Adjustments Scheme</td>
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<td>ETS</td>
<td>Emissions Trading Scheme</td>
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<tr>
<td>CoP</td>
<td>Conference of Parties</td>
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<tr>
<td>Copenhagen Accord</td>
<td>The non-binding agreement arising from the CoP on 18 December 2009 under which certain delegate countries attending the United Nations Climate Change Conference committed to take action on climate change in order to limit the increase in global temperatures to below two degrees Celsius</td>
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<tr>
<td>CPRS</td>
<td>Carbon Pollution Reduction Scheme proposed by the Federal Government</td>
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<td>esaa</td>
<td>Energy Supply Association of Australia</td>
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<td>ESOO</td>
<td>Electricity Statement of Opportunities published annually by AEMO to provide information about the projected adequacy of electricity supplies in the NEM to meet projected demand for the next ten years</td>
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<tr>
<td>GCCSI</td>
<td>Global Carbon Capture and Storage Institute</td>
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<td>Gentrader model</td>
<td>The New South Wales Government’s proposed sale structure for the disposal of its interests to the private sector in nine State-owned power stations through the contracting of the electricity trading rights relating to the output from the relevant plant</td>
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<td>GFC</td>
<td>Global Financial Crisis</td>
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<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>IPCC</td>
<td>UN Inter-governmental Panel on Climate Change</td>
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<tr>
<td>Merit Order</td>
<td>Order in which generation plant supply is dispatched into the NEM</td>
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<tr>
<td>MW</td>
<td>Megawatt</td>
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<td>MWh</td>
<td>Megawatt hour</td>
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<td>NEM</td>
<td>National Electricity Market</td>
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<td>REC</td>
<td>Renewable Energy Certificate</td>
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<td>RSPT</td>
<td>Resources Super Profits Tax</td>
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<td>Scheme</td>
<td>The Federal Government’s proposed CPRS</td>
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About the author

Jon Stanford is a former partner in Deloitte Economics and now Senior Economics Adviser to Deloitte’s Energy & Resources, Manufacturing and Defence practices. Following a distinguished career in the Australian Public Service specialising in industry and resources policy and culminating as head of the Energy, Infrastructure & Resource division within Prime Minister & Cabinet, Jon has spent the last 15 years consulting across many areas of industry, competition and climate change policy and advice. His contributions to the energy sector have included variously, gas and water reform under COAG, the establishment of the National Gas Code, more than ten years of research and modelling into the impacts of climate change including the first ever report for Government, and both program reviews and projects assessments across LNG, renewables, uranium and the options for base load generation under carbon constraints.
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