20 THE ENERGY TRANSFORMATION

Key points

Australians have become accustomed to low and stable energy prices. This is being challenged by rapidly rising capital costs and large price increases for natural gas and black coal. These cost effects will be much larger than the impact of the emissions trading scheme for some years.

Australia is exceptionally well endowed with energy options. Support for research and development and for structural change in transmission infrastructure will allow Australia's natural endowments in renewable energy to be efficiently brought to account.

The interaction of the emissions trading scheme with support for research, development and commercialisation will assist transition to a near-zero emissions energy sector by mid century.

The future for coal-based electricity generation, both domestic and exported, and for mitigation in developing Asia depends on carbon capture and storage becoming commercially effective. Australia should lead a major international effort towards the testing and deployment of this technology.

Specific support for emissions-reducing investment in the coal-based electricity-generating regions is warranted, for smooth energy sector adjustment and established generating regions.

If the world is able to meet the challenge of climate change, there will be a transformation in Australia's stationary energy sector in the context of adjustment to its mitigation policies. The story will unfold over the next 40 years. We will see the emergence of something close to a zero-carbon energy sector in Australia and in all developed and substantial developing countries.

The transformation as described in this chapter will be a response to the forces and actions that we know today and can reasonably expect in the future. The Review acknowledges that there is great uncertainty—about the climate science, the development of technologies and, most critically, the capacity for human ingenuity to adapt to changing circumstances.

Key forces that will drive the Australian energy transformation include:

- the global response as it evolves from the current ad hoc and partial arrangements to a comprehensive global commitment
- adaptation to unavoidable climate change

- the impact of the emissions trading scheme
- the impact of other policies that address market failures, including transitional support for trade-exposed, emissions-intensive industries, and assistance for research, development and commercialisation of new technologies
- the economics of key energy supply chains, particularly related to coal, gas and oil
- the speed and extent of changes in energy demand.

The transformation of the stationary energy sector will have three broad phases:

- an initial adjustment phase involving a transition from high-emissions growth to greater use of known lower-emissions technologies
- a technology transition phase as new technologies, some of which may exist through this phase only, emerge and then facilitate and accelerate the restructuring of the sector
- a long-term emergence phase to sustainable, low- and zero-emissions technology platforms.

As the results of the global and domestic modelling that will translate this story into more precise economic relationships are not yet complete, this chapter is necessarily more qualitative than the Review's final report.

20.1 The role of energy and the basis for transformation

The current reliability and low price of energy have been largely taken for granted by the Australian community. The realities are changing rapidly.

Australia has been able to source its energy from an abundance of domestic primary fuels. This has resulted in a domestic energy price that has been very low on a global basis.

The energy sector, driven by the reforms of national competition policy and progressive privatisation, has been evolving to the point that it represents a physically and financially sophisticated and increasingly national sector, delivering security of supply, competitive prices and new investment. This evolution remains unfinished, with regulatory responsibility for monopoly sub-sectors still to make the full transition to national bodies. Several jurisdictions retain government ownership, and economic regulation is still in place where competition should be capable of delivering greater consumer benefits.

The energy sector makes a larger contribution in Australia than in other developed countries to greenhouse gas emissions (Chapter 8).

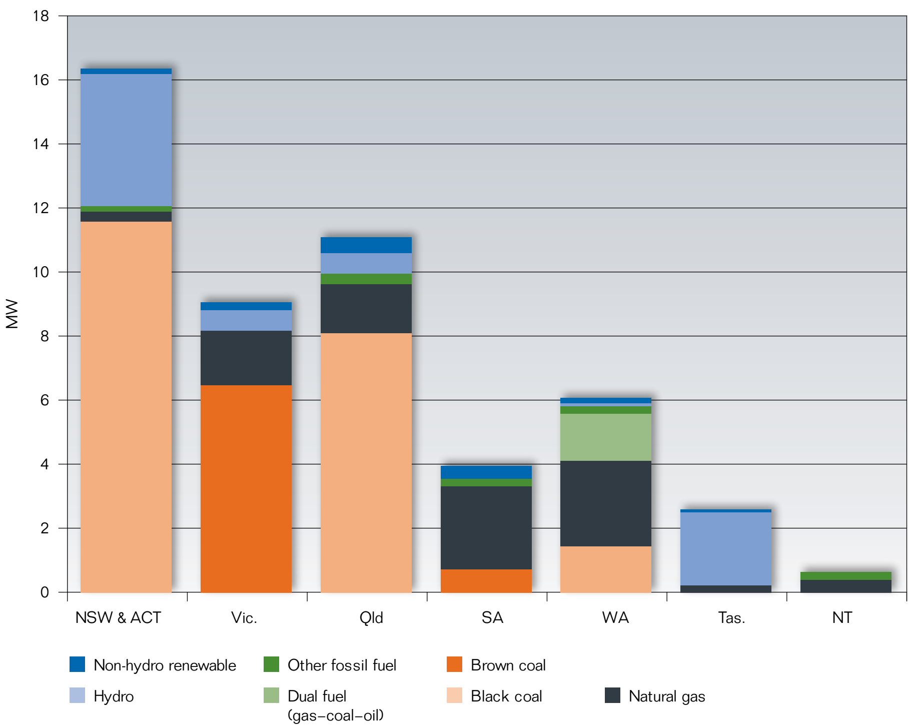
An energy sector that addresses the mitigation issue will therefore need to establish a balance between driving change towards a low-emissions future, building on the underlying national reform agenda, and preserving as much as possible of the energy sector's positive contribution to the Australian economy.

20.1.1 Australia's energy sector in the economy

Energy-related sectors such as electricity, mining and transport account for some 11 per cent of GDP and around half of total exports (ABARE 2006). Growth in energy consumption has historically moved closely with GDP, with a tendency for this growth to be slightly below GDP since the early 1990s.

The stationary energy sector is dominated by electricity generation and manufacturing processes. The total level and fuel mix varies across the country and reflects different regional economic structures and local fuel sources (see Figure 20.1).

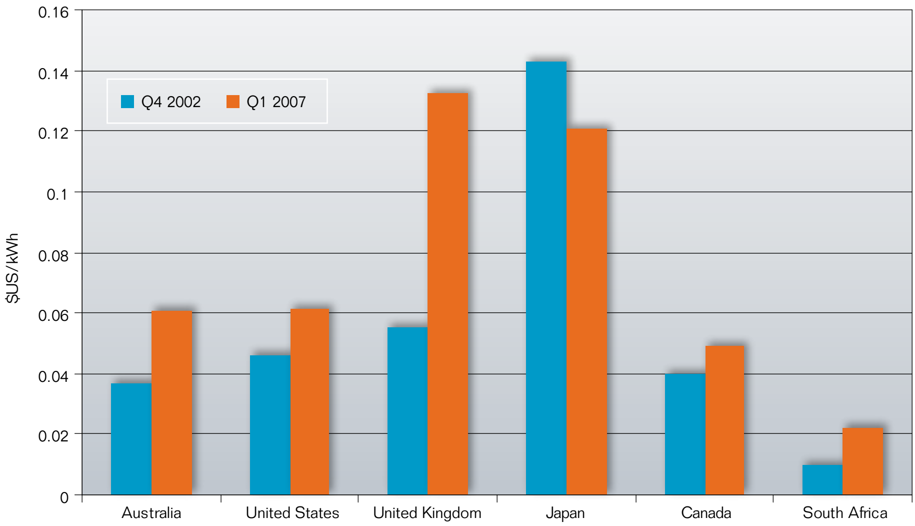
Figure 20.1 Installed electricity generation capacity



Source: Energy Supply Association of Australia (2007).

Nationally, the availability of large and accessible coal and gas resources has delivered electricity and gas prices that have been low in comparison with those of comparable countries. Substantial recent movements in domestic electricity prices have not been unique to Australia (see Figure 20.2).

Figure 20.2 Comparison of industrial electricity prices



Note: Exchange rate movements have been significant sources of changes in relativities 2002–07.
Source: IEA (2003, 2008).

20.1.2 The process of evolution in the absence of climate change

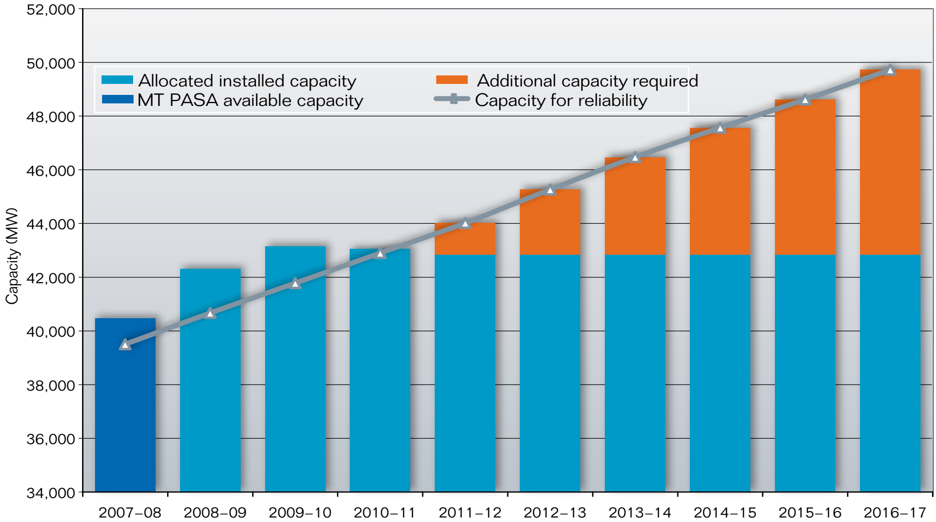
The last decade or so has witnessed a remarkable era of change in Australia's electricity sector. In the early 1990s, the sector was largely publicly owned, with vertically integrated gas or electricity monopolies operating in individual states and little or no interaction between fuel sources. Since then, competition policy has led to a fundamental restructuring of the retailing and generation sectors towards a variety of business models. The integrated generator–retailer across both electricity and gas is taking an increasingly dominant role.

The distribution and transmission pipeline sectors in gas are entirely, and electricity partially, privately owned. The electricity transmission grid remains largely government-owned. Distribution and transmission assets generally exhibit natural monopoly characteristics and are subject to economic regulation, for which responsibility is gradually passing to the national Australian Energy Regulator.

Progressive privatisation has led to new investment and new market participants across all sectors. The result is a highly competitive, increasingly national market with considerable regional interconnection, sophisticated financial structures and flexible fuel substitution. This era of change has delivered choice and broadly stable prices for customers and an attractive climate for investors, while maintaining and increasing supply security.

Power generation based on black and brown coal for baseload supply, transmission interconnection for flexibility and additional security, and gas-fired plant to meet the growing demand for peak and intermediate demand have all been important in this period of rapid change. Almost 5000 MW of net additional generation capacity was added between 1999 and 2006, with further capacity either under construction or planned in response to the consistent and ongoing growth in demand (Figure 20.3).

Figure 20.3 National Electricity Market: summer supply–demand outlook



Note: MT PASA = medium-term projected assessment of system adequacy. This is NEMMCO's forecast of demand and supply to identify gaps and opportunities for new investment.

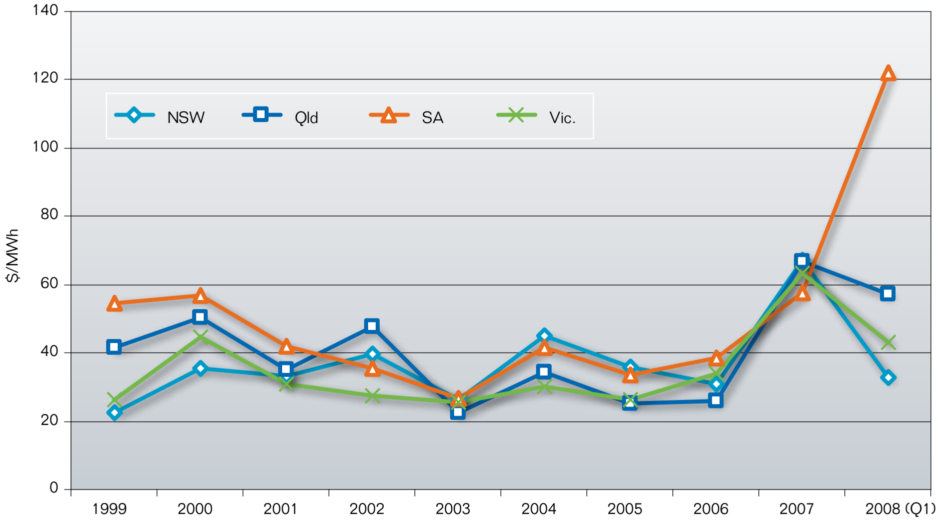
Source: National Electricity Market Management Company (<www.nemmco.com.au/data/markets_data.htm>).

During this period, the supply and demand for both gas and electricity have grown steadily, and prices have been generally stable. Domestic prices for thermal coal were relatively low and steady. In the case of gas, the market has witnessed a growth in the depth and breadth of supply sources in response to renewal cycles of long-term contracts, the requirements of the Queensland Government that a minimum proportion of electricity be generated from gas, the increasing role for gas in meeting peak electricity demand, the development of new gas fields, and the emergence of coal-seam gas as a major new supply source. The electricity market has been characterised by strong growth, which has been met by:

- the construction of inter-regional transmission to balance over- and under-supply
- increases in the operability of existing plant
- construction of new plants.

It is only since 2006 that the market has seen some price uplift (see Figure 20.4). Announced price increases have been large in 2008, and are likely to continue independently of any emissions trading scheme impacts.

Figure 20.4 Average electricity market prices, 1999–2008



Source: NEMMCO (2008).

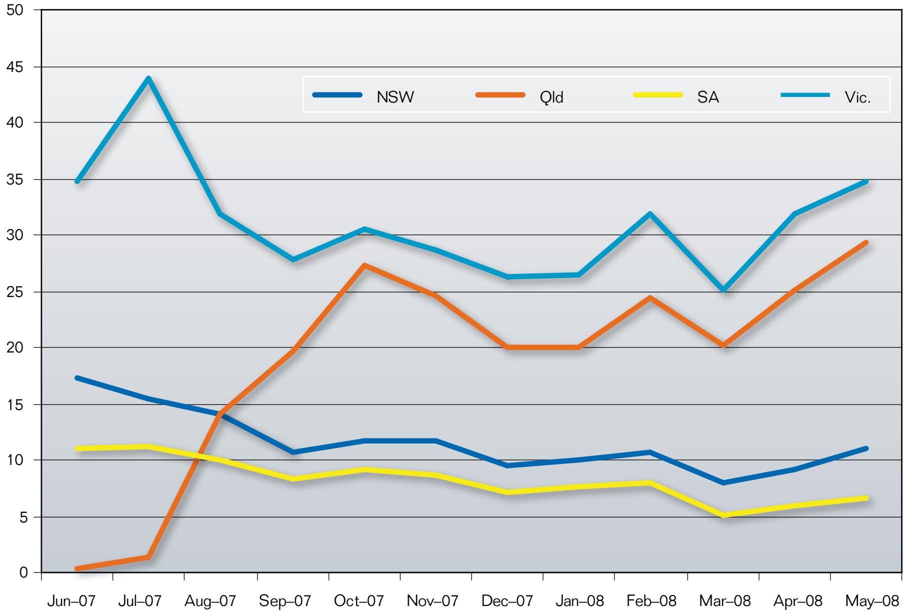
The National Electricity Market operates through the National Electricity Market Management Company (NEMMCO). This entity, owned by the relevant governments and funded by the industry, is responsible for:

- operating the power system within technical requirements
- registering participants in the National Electricity Market
- meeting demand in the lowest-cost way
- maintaining prudential standards for participants
- financially settling the market on a weekly basis
- coordinating inter-regional transmission planning.

With the trend to a seamless gas and electricity energy market, there has been agreement across the industry to bring both markets into a common structure with a single central operating entity, the Australian Energy Market Operator. The process for establishing this body is under way.

The most significant remaining step in the implementation of competition policy reform is the removal of retail price regulation. State and territory governments have been cautious about relaxing the regulatory process. At the same time, the market has been evolving through competitive activity, as evidenced by the number of customers switching their retailer as full retail competition has been introduced (see Figure 20.5).

Figure 20.5 Electricity customer transfers—annualised monthly proportion of market



Source: NEMMCO (2008) and Energy Supply Association of Australia (2007).

Through the Ministerial Council on Energy, there is now agreement for the Australian Energy Market Commission to review the status of competition in each jurisdiction with a view to opening up the market to full competition, while maintaining structures that protect consumers who are in financial hardship. There has been a general move away from cross-subsidies and towards directly funded community service obligations. Subject to this review, the commission will recommend on the appropriateness of and approach to the removal of remaining retail price controls.

The first step in the review was carried out in the second half of 2007 for Victoria. The commission concluded that gas and electricity competition is effective. Further, and as part of its remit, the commission has made a recommendation to the Ministerial Council on Energy and the Victorian Government to continue the phasing out of retail price regulation. This is accompanied by recommendations to maintain and enhance the existing customer protection framework.

Privatisation of energy sector businesses began with Victoria in the early 1990s. Competitive retail electricity businesses in Queensland were sold in 2006–07. The former Commonwealth government blocked a move by the New South Wales and Victorian state governments to sell Snowy Hydro (currently jointly owned by the three governments) into the private sector in 2006. There is considerable tension in New South Wales as the state government grapples with privatisation of the retail sector and some form of transfer of economic responsibility for its generation assets to the private sector.

These structures and processes generally allow the private sector's assessment of supply and demand to determine the need for additional capacity and to deliver this capacity in a timely fashion. They have generally been successful for gas exploration, production and transportation. They have also been successful for electricity generation, although some jurisdictions have experienced discomfort with the process. There are mixed views across the industry as to whether there are appropriate mechanisms to deliver the most efficient and timely investment in electricity transmission (see Chapter 17).

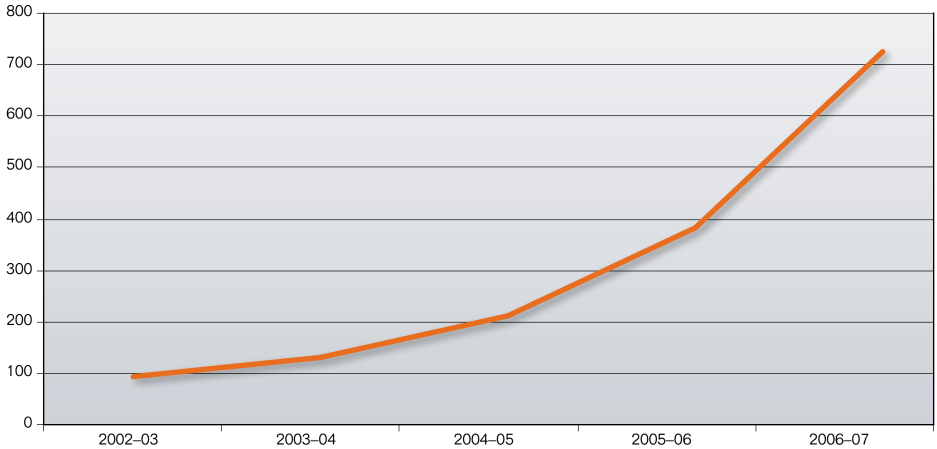
20.1.3 Nature's revenge

Although Australia is likely to meet its Kyoto Protocol commitment of 108 per cent of 1990 emissions by 2008–12, this will be achieved despite a high underlying trend in emissions growth from fossil fuel combustion. Significant reductions in Australia's greenhouse gas emissions will require a fundamental transformation in the way Australians consume and produce energy. The strengthening commitments of other governments to mitigation policies raises risks for Australia's large coal exports unless Australia and the international community can find an economically efficient means of sequestering emissions from fossil fuel combustion.

In the last several years, there have been three major developments in the Australian energy sector's response to the climate change challenge.

First, a mixture of federal and state policies has driven investment in a specific set of lower-emissions technologies. The federal government's Mandatory Renewable Energy Target (MRET), the NSW Greenhouse Gas Abatement Scheme (GGAS) and the Queensland Gas Scheme have been the principal instruments. Second, the increasing public awareness of climate change has seen the emergence of a voluntary market exemplified by the continuing rapid growth in Green Power (see Figure 20.6). Finally, there has been a general hesitancy to invest in new power generation assets outside existing schemes in the absence of a clear, broad and stable policy framework.

Figure 20.6 Green Power customers, 2002–03 to 2006–07



Source: Green Power, June 2008 (<www.greenpower.gov.au/audits_and_reports.aspx>).

20.2 Drivers of the transformation

The energy industry is not new to change in the face of external pressures. Different societies at different times have moved away from gathering trees for firewood and charcoal; from burning coal in homes and commercial buildings for heating; and from 'towns gas' made from coal to natural gas. The key to these changes has always been the interaction between economic and environmental factors. One driver has been increased scarcity of resource bases, which in due course would underpin a transition from fossil fuels. With the challenge of climate change, the introduction of a price on greenhouse gas emissions will accelerate the transition by bringing down the relative cost of alternatives to fossil fuels.

Two primary sets of drivers will dictate the pace and direction of the energy transformation as envisaged by the Review. They are the dynamics of the supply and demand surrounding key fuel sources; and the global and domestic policy response to mitigation of climate change.

20.2.1 Global fuel dynamics

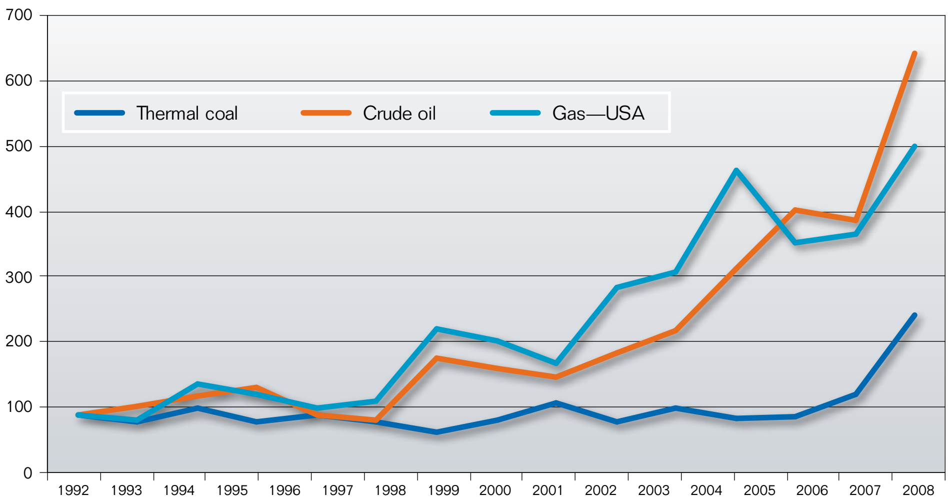
In the last few years, the dynamics of what had been a relatively benign environment for the domestic energy sector has been challenged:

- A major escalation in capital costs across sectors, with particular impact on capital-intensive industries. Industry advice to the Review indicates there have been increases of 60 per cent in construction costs per installed kilowatt of power plants since 2004.

- A major uplift in global coal prices—180 per cent over the past three years and 118 per cent over the past year—has been driven by recent strong demand in China and India and a supply system that takes some time to respond with new infrastructure and transport capacity.
- Increases in global prices for traded natural gas, which have not kept pace with even greater increases in oil prices.

These movements in energy commodity prices are illustrated in Figure 20.7.

Figure 20.7 Energy commodity prices indexed to 2000 (2000=100)



Source: ABARE (2008), State of Nebraska (2008) and Government of Western Australia (2008).

In Australia, the first of these forces, rising capital costs, is starting to affect electricity prices. Those effects were exacerbated from early 2007 with the effect of drought on the availability of water for hydroelectric generation and power station cooling. The existence of long-term domestic contracts for black coal, the unsuitability of brown coal for export and the absence of liquefied natural gas (LNG) export infrastructure on the east coast have largely cushioned Australian prices from the other two forces.

This position is not sustainable: contracts will be renegotiated, new coal export infrastructure is being developed and several east coast LNG export projects have been announced. To put these price increases into perspective, a $10/t price on carbon dioxide could add $8–10/MWh to the wholesale electricity price. An increase of $3/GJ in the gas price, to somewhere closer to but still short of export parity would add more than $20/MWh to gas-fired electricity. An increase of $100/t to black coal prices would add approximately $53/MWh to coal-fired electricity.

While there is clearly considerable scope for substitution across fuel types, the cost of fuels will largely determine the response of the energy sector over the coming decades. In the discussion of the four broad fuel types in the Australian energy sector that follows, the outlook for oil, with traditional sources becoming increasingly constrained by resource availability or increasing extraction costs, will tend to act as an external determinant of prices for the other fuels, at least in the long periods required for large expansion of production and transport capacity for the more abundant fossil fuels.

Coal

The following assessment flows from considering three distinct coal types: brown coal, thermal black coal and coking black coal. Coal sources generally get to the point of consumption in one of three ways:

- as part of an integrated coal supply/power generation entity
- through commercial contracts with generators
- through export contracts.

The first of these recognises the favourable integrated economics that can come from optimising around a single financial unit when the resource is at the low end of the value range and coal prices are relatively low. This model generally applies in Victoria and Queensland, including the recently established plant at Kogan Creek.

The second is characterised by relatively long-term contracts. The most obvious example is in New South Wales, where the government established these structures, separating mining rights from electricity generation, when it corporatised the energy sector some years ago. In the past they have provided some flexibility for competitive market forces to optimise outcomes and keep domestic prices low. However, firms within such structures are highly vulnerable to the continuation of high export prices combined with tendencies towards internationalistion of low-quality black coal markets. Coal generators relying on the purchase of exportable coal will be at an increasing disadvantage in competing with generators with tied access to coal in Victoria and Queensland. A tight global market for thermal coal has made much lower quality black coal exportable.

The third arrangement underpins the export market, where annual contracts apply and where prices reflect the dynamics of global supply and demand.

Coal demand is experiencing a period of unprecedented growth, driven by China and India (Chapter 4). This has resulted in contract price increases of more than 100 per cent over a short period. As contracts for the domestic supply of thermal coal expire and where the supplier has the potential to access this export market, there is upward pressure on these prices also. Such prices, if they hold up for an extended period, have the potential to encourage coal-drying technologies and underpin an enhanced economic outlook for Australia's brown coal resource.

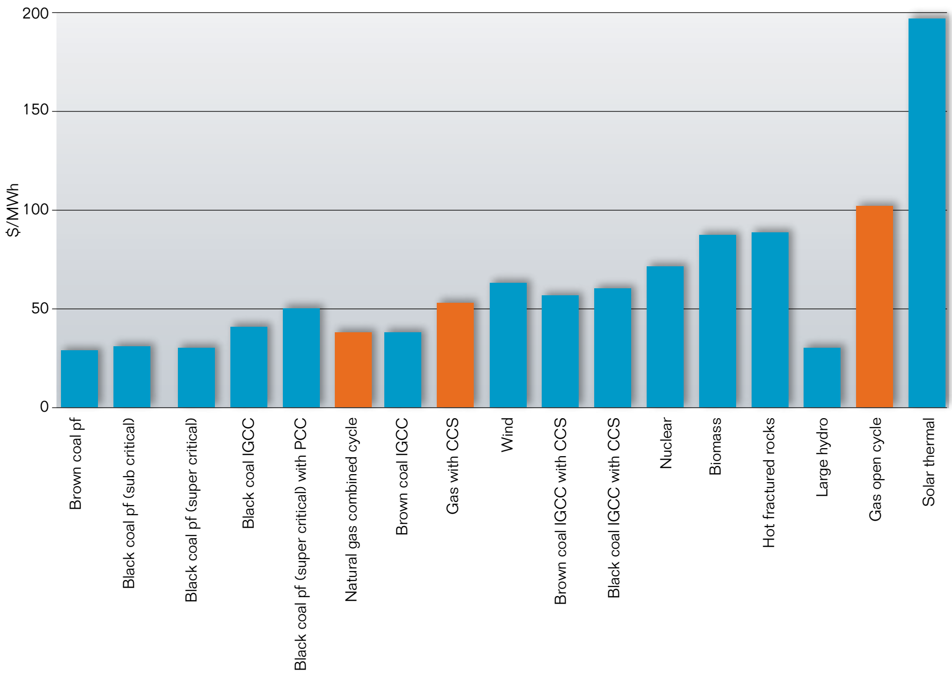
In the absence of any expectation of a significant slowing of Chinese growth (see Chapter 4), the likely longer-term outlook is for prices in real terms to remain well above the levels of the late 20th and early 21st centuries, but to come down from current peaks as supply expands. There is no foreseeable constraint on coal resource availability, although the exploitation of deeper and more distant deposits is likely to keep prices on a rising trend in the long term.

Gas

Natural gas in Australia has two physical markets. The east coast has gas coming from the Cooper Basin in Central Australia and the Gippsland Basin in the south east. The North-West Shelf supplies the local West Australian market but also provides increasing and large volumes of liquefied natural gas for export. Over the last decade or more, gas prices in Australia have been relatively stable, with no significant new sources of supply or demand being developed.

Gas for power generation has remained confined to a relatively small peaking demand, where the higher fuel cost could be offset by lower capital costs. Figure 20.8 indicates the cost of gas-fired power generation relative to other sources and uses 2006 estimates for the costs of fuels and capital in the absence of an emissions price.

Figure 20.8 Estimated electricity generation costs of selected electricity generation technologies, 2006



Notes: pf = pulverised fuel; IGCC = integrated gasification combined cycle; PCC = post-combustion capture; CCS = carbon capture and storage.

Source: Wright (2007).

As long-term contracts came to an end, new sources of supply emerged, as did an increase in the gas transmission network to provide greater security of supply and competition between basins. The uptake of gas for power generation to meet increasing peak and intermediate demand and the introduction of the Queensland Gas Scheme have further influenced these developments. The most notable has been the growth in the coal-seam gas sector. This growth has been rapid and is likely to increase explosively over the period immediately ahead.

Recent and rapidly increasing global demand has resulted in a lift in prices in Western Australia.

The increasing confidence in large coal-seam gas reserves in Queensland has led to recent announcements of liquefied natural gas export infrastructure in the east. The potential to access the global market has then resulted in upward price pressure on natural gas prices, at the same time as the potential to gain commercial value from the lower-emissions intensity of gas-fired power generation relative to coal is being recognised.

Domestic gas prices can be expected to rise rapidly towards export parity and remain at that level over the longer term.

Nuclear

The global uranium industry has recently seen signs of a surge in demand. China and India have committed themselves to programs that are immense by any previous standards anywhere. In China, with the larger of the expansions, nuclear will still account for no more than 6 per cent of total power in 2020. Some countries which have not been installing new capacity for many years, including the United Kingdom, have decided that, on balance, nuclear power stations should have a role to play alongside other low-carbon electricity sources (HM Government 2008). This renewed demand arises from a combination of influences from climate change, energy security and relative costs. With more than one-third of currently estimated global uranium resources, Australia is well placed to benefit from this growth.

The 2006 Uranium Mining, Processing and Nuclear Energy Review for the Commonwealth Government concluded: 'Although the priority for Australia will continue to be to reduce carbon dioxide emissions from coal and gas, the Review sees nuclear power as a practical option for part of Australia's electricity production, (Commonwealth of Australia 2006:1). This conclusion was based on a cost of nuclear power of $40–65/MWh, which is within the range of the $35–80/MWh estimate of the Nuclear Energy Agency and the International Energy Agency from 2005, but below ranges specified in the more recent official UK publications of $60–80 MWh. Nuclear power stations will have been disproportionately affected by the recent increases in capital costs on account of their exceptional capital intensity, and will have been rendered less competitive by this development. Newer-generation nuclear technologies indicate potentially lower costs.

Australia has better non-nuclear low-emissions options than other developed countries, especially (but not only) if carbon capture and storage is commercialised within the range of current cost expectations. Australia is a major net exporter of a wide range of energy sources, notably coal, liquefied natural gas and uranium. Transport economics should favour local use of those fuels in which the gap between export parity and import parity price is greatest (first liquefied natural gas, then coal). As a consequence, Australia is not the logical first home of new nuclear capacity on economic grounds.

In Australia, as well as in most other developed and developing countries, public acceptability is an important barrier, that would need to be recognised as a constraint and a source of delays and increased costs by any government committed to implementation of a nuclear power program. The Australian Government is firmly against Australian nuclear power generation, and the Coalition parties retreated quickly from nuclear advocacy in the face of community antipathy during the 2007 federal general election. It would be imprudent, indeed romantic, to rely on a change of community attitudes as a premise of future electricity supply for the foreseeable future.

Given the economic issues and community disquiet about establishing a domestic nuclear power capacity, Australia would be best served by continuing to export its uranium and focusing on low-emissions coal, gas and renewable options for domestic energy supply. However, it would be wise to reconsider the constraints if:

- future nuclear costs come in at the low end of the estimates provided above
- developments in technologies reduce the need for long-term storage of high-level radioactive waste
- there is disappointment with technical and commercial progress with low-emissions fossil fuel technologies, and
- community disquiet eases.

Renewable energy

In recent years, power generated from non-hydro renewable sources has increased as a result of MRET and, to a lesser extent, Green Power demand. It represented 8 per cent of capacity and 5 per cent of delivered electricity in 2005–06. The design of MRET and the prevailing relative cost of renewable technologies mean that this additional capacity has been dominated by wind, with contributions from solar hot water and biomass. Other potential forms of additional renewable energy include solar (photovoltaic and thermal), geothermal and wave/tidal power. Each of these technologies faces its specific challenges of relative costs, community acceptability, technical feasibility and intermittency.

While all forms of low and near-zero emissions technologies will benefit from the price uplift of the emissions trading scheme, and renewables are receiving an initially much larger boost from the increase in fossil fuel prices within Australia, genuinely new technologies will require support for research, development and commercialisation (see Chapter 16).

There is little likelihood of expansion in storage-based hydroelectric generation in Australia, although there is scope for much better utilisation of existing storage capacity in the new environment in which renewable power has greatly increased value. The anticipated growth in intermittent supply technologies (wind and solar) and ongoing, above-average growth in peak demand mean that existing hydroelectric infrastructure will play an enhanced role as a provider of flexible and readily available stored energy to meet short-term demand peaks.

This role could be substantially expanded through judicious investment aimed at making the hydro-electricity assets important balancing components in the eastern Australian system. Australia's main hydroelectric assets—in the Snowy Mountains and Tasmania—will have increased value, far beyond that suggested by their installed capacities (3676 MW and 2278 MW respectively) alone. Power from intermittent sources at times of low demand and price can be used to pump water into hydroelectric storage for use at times of greater demand and value. Public ownership, and in the case of Snowy Hydro ownership by three governments, have applied constraints on the supply of capital to the optimisation of the value of these major national assets. These constraints have high opportunity costs in the emerging environment. It is important that the constraints be removed.

What might have been

In the absence of climate change, global and domestic forces would drive significant change in the Australian economy and the energy sector in particular.

The first key force for change is global demand for Australia's commodity exports, driving rising terms of trade and a GDP that roughly trebles to 2050 (Garnaut–Treasury reference case). Population and Australian household incomes both rise strongly. In the longer term, the depletion of relatively low-cost resources leads to modest increases in energy prices, accelerated by a progressive shift towards electricity as the central energy source. In this scenario greenhouse gas emissions grow without constraint, with Australia's emissions projected to double by 2050 through rising energy consumption and ongoing dependence on fossil fuels.

Chapter 9 describes the impact of unmitigated climate change on the Australian economy. It is worth dwelling briefly on this scenario before focusing on how it will change in the course of successful transition to a low-emissions economy.

Adverse climate change impacts lead to a deterioration in demand for Australia's commodity exports, such as coal and other minerals. Agriculture is further affected as increased temperatures and reduced rainfall are likely to reduce output.

Storm, wind, bushfire damage and increased levels of materials degradation are likely to lead to additional transmission and distribution losses across the gas and electricity networks.

The most significant impact that will require adaptation planning in the energy sector is that of urban water supply (Chapter 7 and Box 20.1).

There will also be an impact on energy infrastructure demand through reinforcing ongoing growth in the peak summer period.

Box 20.1 Energy and water—joined at the hip

Changes in water availability will affect the energy sector in three ways.

In 2007, the drought exposed the obvious dependence of part of the market, the hydro generators, on water supply.

However, it also exposed the extent to which generators depend on water for cooling. This is likely to lead to a move towards air-cooled plant in future, with an associated reduction in efficiency.

Finally, the move to desalination plants to supplement water supplies will impose a significant additional demand for power of about 3–5 kWh per kilolitre.

The specific risk to electricity transmission and distribution networks that arises from the increased frequency of extreme weather events is illustrated by the power supply outages experienced in January 2007, when a bushfire caused disruption to the transmission system between New South Wales and Victoria.

These challenges amplify the need to maintain momentum towards a truly national energy market at the same time as responding to the structural adjustment imposed by the mitigation task.

20.2.2 The domestic emissions trading scheme

The implementation of an emissions trading scheme will unleash far-reaching change, as the market responds to the emissions reduction trajectory and delivers an assessment of consequent short- and long-term pricing expectations. In the energy market, the short-term price implications will cause a direct adjustment in marginal cost structures and asset values. The long-term price expectations will provide long-needed clarity to frame major investment decisions for new energy infrastructure, including, but not limited to, baseload power generation. In addition to investment in technologies with known operating and cost characteristics, this longer-term perspective, is expected to facilitate research, development and commercialisation of technologies assessed to have greater mitigation potential in the future. The Review's recommended support for research, development and commercialisation of low emissions technologies will have a powerful effect in accelerating innovation—in ways that were not present with MRET, GGAS and the EU emissions trading scheme. The overall domestic mitigation policy suite suggested by the Review (Chapters 14 to 18) provides the necessary and sufficient policy conditions to unleash the transformation described below.

20.3 The path to transformation

In considering the way forward, it is possible to identify three broad phases over time. These are not prescriptive or precise, but separate the ebb and flow of particular developments as they unfold, especially future changes in technology.

From the perspective of 2008, the first phase could be expected to apply over its initial 5–10 years, the second over the next 10–15 years and the third beyond that.

In this draft report, the phases are described qualitatively. The economic modelling results for the mitigation scenarios will enable the supplementary draft and final reports to significantly expand on these descriptions.

It is clear that Australia is ideally placed for this transformation with abundant coal, gas, uranium, geothermal, solar and other renewable sources, alongside exceptional opportunities for geosequestration and biosequestration of carbon dioxide.

Therefore, while major structural change is never without its challenges, energy supply security is not likely to be one of them.

20.3.1 Phase 1—commitment and adjustment

The first few years from the beginning of the emissions trading scheme may generate relatively low prices as the trajectory follows Australia's Kyoto commitment. Whether or not there is a separate transition period, the primary and secondary markets will quickly establish a spot and forward price curve for emission permits beyond 2012.

As the constraints tighten from early 2013, low-cost mitigation opportunities and expectations of tightening of trajectories in response to international agreement are likely to lead to some hoarding of permits.

As this phase evolves, with divergence of the trajectory from the business-as-usual path, the next set of responses is likely to involve some fuel switching, constrained by transmission interconnection and gas availability and cost, involving existing gas-fired open-cycle plants being operated more intensively. Competitive tensions will derive from the relative emissions intensities of existing coal-fired plants as the merit order moves quickly to incorporate the permit price into short run marginal costs. Increased price volatility is likely to be a feature of this period—around a rising tendency in prices driven by factors outside the emissions trading scheme, but augmented by the emissions price.

The fuel mix and cost implications will be strongly influenced by the extent to which new black coal contracts in the domestic electricity sector are negotiated at higher prices and the speed with which domestic gas prices move towards global price parity. The implications for brown coal generators will, in the short term, be dominated by these factors affecting their competitors and the east coast electricity prices, and therefore their capacity to recover lost volume in prices. After that, either partial fuel substitution within coal-based generators, or other changes to existing plant to reduce emissions intensity will have major effects. In the still shorter term, it is possible that some existing, coal-fired generators with captive coal supply will stand to reap significant benefits from the higher price environment driven by increases in capital costs and gas and black coal prices. There will be a vigorous search for in-plant mitigation. Beyond the commercial limits of in-plant emissions reduction, it may be economical for such generators to purchase domestic offset credits or international permits to maintain production despite high emissions intensity, in an environment in which high gas and black coal prices are underpinning higher electricity prices.

Box 20.2 Will the National Electricity Market survive?

The National Electricity Market (NEM) has evolved over a number of years and industry has simultaneously evolved business strategies to optimise commercial outcomes within the current market and policy framework.

The emissions trading scheme has major implications for NEM participants and these business models and strategies, including substantial changes in bidding and contracting behaviour. However, the NEM and its participants are expected to draw on the experience to date, enhanced by that of coping with MRET, GGAS and the Queensland Gas Scheme, to rapidly develop new strategies and structures.

Chapter 17 of this report highlighted a specific issue that relates to the development of network infrastructure to support efficient technology responses to the emissions trading scheme. Outside that issue, the structure, policies, procedures and governance mechanisms of the NEM are expected to accommodate the implementation of the emissions trading scheme.

This process will require close involvement of the key industry agencies with business to ensure any unforeseen consequences are identified and addressed early.

An added complexity arises from the fact that these changes will occur at the same time that the NEM is evolving to become the Australian Energy Market as described in this chapter.

In this phase, new baseload generation capacity is likely to be based on established, combined-cycle gas turbine technology, ideally designed for post-combustion capture of carbon dioxide. It is possible that the rising permit price will shadow the gas price over this period—a possibility that will be explored in the light of the modelling to be discussed in the supplementary draft report.

Offsets, trade in permits, and hoarding and lending of permits would all provide the flexibility necessary to avoid unacceptably high permit prices and flow-through to delivered energy prices deriving from short-term disruption of supply or demand expectations.

The Review recognises that this period will generate acute pressures for owners and operators of existing coal-fired plants, some of which have been optimised to run efficiently in a mode that will be challenged in this new world. As described in Chapter 14, the Review has concluded that compensation in such circumstances is a low priority. Appendix 20A addresses in some detail the specific arguments raised in relation to emissions-intensive electricity generation. However, a range of other factors will tend to ameliorate the otherwise negative consequences for well-managed coal-based generators:

- There will be opportunities for some relatively low-cost reductions in emissions, including through coal drying.
- There will be capacity to recover volume loss through price. The strong upward pressure on competitors' costs for reasons beyond the mitigation regime will strongly favour established producers with sources of non-tradable coal including some of these generators most affected by the emissions trading scheme. Some of these generators will not see a loss in cash flows for several years, and may well see opportunities for increasing profit in the early years.

Near-zero emissions coal technologies

For Australia, the importance of reducing emissions from coal combustion is of large national importance.

Coal underpins Australia's domestic electricity supply sector, and is by far our biggest export commodity. The $22 billion contribution to exports in 2007 is set to leap dramatically in 2008–09 to almost $50 billion, mainly through much higher prices.

Under any realistic scenario, Australia's response to climate change, both internationally and domestically, will be inextricably intertwined with the role of the coal industry. If this industry is to have a long-term future in a low-emissions economy, then it will have to be transformed to near-zero emissions, from source to end use, by the middle of this century. A range of technical, environmental and economic challenges must be addressed effectively to achieve this objective, in a time frame consistent with a global agreement on climate change and Australia's own domestic commitment (Box 20.3).

The relevant industry sectors, namely the domestic coal-fired generation sector and the domestic and export mining sectors, as well as the communities who live and work in centres of coal mining and coal-fired power generation, all have a vital stake in the development of low-emissions ways of using coal in electricity generation and in manufacturing processes.

The Review has identified five key reasons why Australia has a strategic interest in the future of near-zero coal technologies.

First, the central role that coal-fired power generation has played in Australia's energy sector over many decades and its major contribution to our emissions are described in Chapter 8 and earlier in this chapter. An early resolution of the future role of coal-fired generation will be critical in shaping a smooth transition for Australia's energy sector into a component of a low-emissions economy.

Second, the significant role that coal plays as Australia's biggest export means that we have a major economic interest in working with other coal-exporting countries and the importing countries themselves to determine as quickly as possible how and when low-emissions coal technologies can assist these countries to follow lower-emissions development paths. It is in our interest for other countries to have a way of utilising coal on a long-term sustainable basis. The coal export industry is at risk, sooner or later, unless low-emissions ways of using coal are applied successfully in our major Asian markets.

Third, a number of Australia's rapidly expanding neighbours in developing Asia also have a high and increasing dependence on coal for their electricity generation and for key manufacturing industry sectors. The trend in the large developing countries, including China, India and Indonesia, is described in Chapter 4, where the recent end to a period of falling emissions intensity of growth is highlighted. The heavy reliance on coal is expected to continue for some time and will be exacerbated by any shift towards coal for the production of transport fuels in the face of continued high oil prices (Garnaut–Treasury reference case). The coal dependence of such rapidly growing regional neighbours provides an additional national interest rationale for giving priority to this work. Australia has a strong interest in continued economic growth in its Asian neighbours.

Fourth, the successful participation of China, Indonesia and India, amongst other major developing countries, in effective global emissions reduction will be difficult without the development on low-emissions technologies for using coal. At the same time, the effective participation of these countries in ambitious emissions reduction is essential for the success of the global mitigation effort.

Fifth, there are possible scenarios in which significant adverse impacts arise for communities dependent on coal and coal-fired power generation, notably those in the Latrobe Valley, the Hunter Valley and Central Queensland. In these cases, there is good reason and well-established policy precedents for government to provide assistance to individuals and communities. The continued health of the industry could obviate the need for other assistance measures. If the new low-emissions technologies are not successful, it is likely that governments will need to apply, in the coal-based electricity generating regions, such measures as the retraining of workers for new employment (as with textile and steel workers in the 1980s after reductions in protection); and grants to communities to support improvements in infrastructure that would be helpful to the attraction of alternative industries;

The priority that should be given to the transition to low emissions in the coal industry is further accentuated by the need to resolve whether a near-zero coal future is even feasible, either partially or in total. If it is not, then Australia needs to know as soon as possible, so that all who depend on the coal industry can begin the process of adjustment, and so that adequate and timely investments are made in other industries.

The Review has identified three key funding initiatives that would provide the necessary momentum:

1. Technology innovation in the sector will benefit from the early research funding described in Chapter 16, as will investment in demonstration and commercialisation from the suggested matched funding scheme. This large source of funding will be available across all emissions-reducing technologies on an even-handed basis. It is proposed that this facility be financed out of 20 per cent of the receipts from sales of emissions trading scheme permits.
2. A specific allocation of additional funding, of the order of $1–2 billion, is proposed to accelerate structural adjustment in the industry. This would match industry funding on an equal basis, and would be available to support new investment in reducing emissions in coal-based generation, in existing and new plant related to reduced emissions from power generation in established areas of coal-based generation.

   For example, funding could be provided to retrofit a facility with low-emissions technologies to support drying of brown coal and restructuring of boilers to use the product, or improve use of materials and logistics. Such investment is seen as a pre-emptive form of structural adjustment assistance, and will be more cost effective than assisting communities only after they are under stress.

   Such assistance to industries would be provided in cases where business investment commitments indicate that there are prospects for improved commercial performance through reductions in emissions.

   This facility is directed at forward-looking structural adjustment, and not at compensation for loss.

   A number of arguments have been made for compensation to electricity generators. The Review has considered them and summarised its response in 20A.

3. Australia has the opportunity and the interest to play a leadership role in leading and coordinating a major global effort to develop and deploy carbon capture and storage technologies, and to transfer those technologies to developing countries. The core of this funding could come from a large expansion of the allocations already committed by the federal, state and territory governments, and by the coal industry. The Review understands that a number of governments of other developed countries would be prepared to make complementary commitments to the program. Australia's roles as the world's largest exporter of coal, and as a coal supplier and close economic partner to major Asian developing countries, would make it the natural leader of such an effort. The Review will explore this concept more fully for the final report,

   Australia's expenditures under initiatives 1 and 3, but not 2, would contribute to acquittal of its obligations under the International Low Emissions Technology Commitment proposed in Chapter 13.

In this phase, the assessment of low-emissions coal technologies, and their potential contribution, will be determined. From today's perspective it is possible to identify the challenges and issues central to this assessment, and these are described in Box 20.3.

A rising permit price will provide increasingly strong support for incremental technology enhancements, with higher capital costs for newly built plant favouring retrofitting of existing plant for carbon dioxide capture.

Transport technologies

Carbon dioxide transport is relatively well developed as a technology. The issues associated with the provision of appropriate transport infrastructure will be discussed in the final report.

Sequestration technologies

As with capture, there are two categories of sequestration.

The first, geosequestration, involves storing the carbon dioxide permanently underground or below the seabed in depleted oil or gas reservoirs or in deep saline aquifers. Another possibility is sequestration in deep coal seams where the injection of carbon dioxide could enhance coal-seam gas recovery. The challenges in this area mostly involve geology and geophysics, including seismic mapping and developing a robust regulatory regime that may have to coexist with the extraction of gas or petroleum products.

There are several projects under way or proposed in Australia that will test various aspects of these technologies, including that being undertaken by the CO2CRC in the Otway Basin in Victoria.

A more intriguing, and potentially highly valuable, approach is biosequestration. There are, for example, proposals to produce biofuels from algae, the growth of which is enhanced by access to a constant stream of carbon dioxide.

Box 20.3 The technologies of zero-emissions coal

At its simplest, the challenge is to develop technologies that allow coal combustion with zero, or near-zero, carbon dioxide emissions while maintaining its relative competitive position as a fuel. Carbon dioxide is an unavoidable product of combustion. This means that the carbon dioxide must not be released into the atmosphere. This outcome can be achieved by capturing it somewhere during the process and then either converting it to some environmentally benign end product or consigning it to permanent storage (sequestration). If the source point of the carbon dioxide is physically distant from the final destination, then some form of transport will be required.

Most of the so-called clean coal technologies are well developed individually, although they are rarely, if ever, deployed comprehensively at the scale required by the current challenge. It is also likely that, at least in the short to medium term, some combination of technologies will be applied in a cost-effective way that makes major reductions in current emissions without getting close to zero.

There are broadly two groups of technologies related to carbon dioxide capture.

Members of the first seek to capture the carbon dioxide from an existing gas stream, such as the exhaust stack of a generation plant. These are of most relevance to existing plants and have the significant advantage of extending the life of such assets. The most significant challenge in this area is that such plants were not designed with carbon dioxide capture in mind and the exhaust gas stream is generally low in carbon dioxide, making the capture more expensive and energy intensive.

Members of the second deploy fundamentally different new approaches to create, at some point in the process, a concentrated stream of carbon dioxide that is more readily suitable for large-scale capture. The challenges here are those of technology commercialisation and cost in the early stages.

Clearly, those technologies that apply after coal has been gasified, or a carbon dioxide stream created, are equally applicable to carbon dioxide capture and sequestration from gas-fired power generation plants. With large gas reserves, including coal-seam gas, Australia also has a strong strategic interest in such applications. Process streams involving coal gasification can potentially be applied to the production of transport fuels as an alternative to electricity generation.

What are the issues?

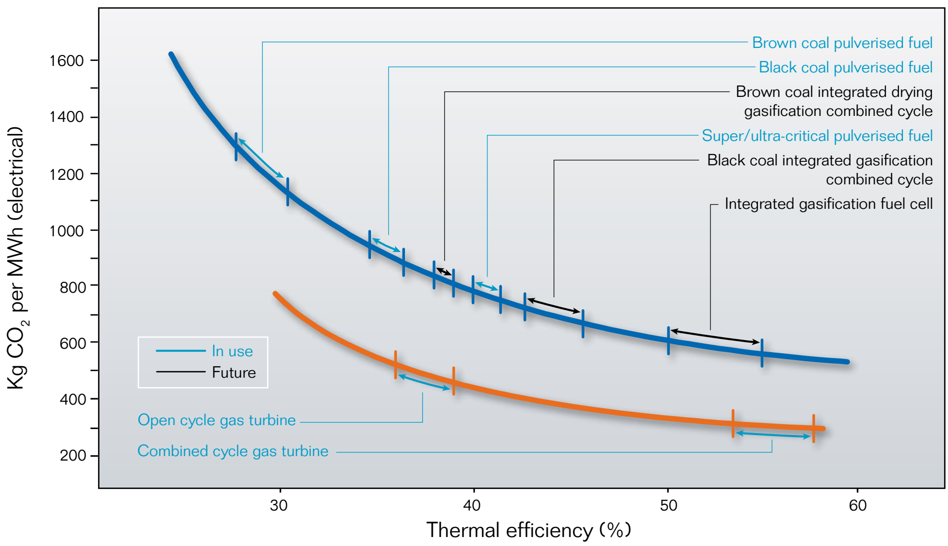
There is a range of technical, regulatory, environmental and economic issues associated with each set of technologies described above. To address these issues, a series of focused projects will need to be implemented, each addressing a relevant technological issue. In this context we note the Commonwealth Minister for Resources and Energy's positive response to the call by the alliance formed by the Australian Coal Association, the Construction, Forestry, Mining and Energy Union, the Climate Institute and WWF–Australia, for a national task force on carbon capture and storage.

Many of the individual technologies are technically proven. The issues of scale, integration and economics are likely to be the greatest challenges.

Finally, but most significantly, there is the challenge posed by the scale of the task. This will ultimately involve the annual capture and sequestration of several hundred million tonnes of carbon dioxide in Australia alone. In addition to the challenges already mentioned, such scale will place a considerable strain on regulatory processes and human resources.

If the considerable challenges these technologies pose can be successfully addressed, a very different medium- and longer-term future emerges. Those same forces of high capital costs, high world gas prices and relatively strong export coal prices will strongly favour retrofitted (post-combustion capture) coal plants with captive coal supplies and low-emissions profiles and ultimately, near-zero emissions plants involving integrated coal drying and gasification technology. At the same time, projects such as those envisaged by the Monash Energy Project will move to the stage where the technical and economic feasibility at commercial scale will be fully tested. Such technologies straddle both stationary and transport energy opportunities (see Figure 20.9).

Figure 20.9 Reduction in greenhouse gas emissions through increasing efficiency



Source: Wright (2007).

Energy efficiency opportunities are envisaged to begin slowly with the support of the programs described in Chapter 18, and accelerate as the rising permit price provides an increasing incentive for their adoption. The capital replacement cycles of homes and businesses and any application of mandatory appliance and building standards will also influence the rate at which this uptake is accelerated.

In the absence of other policy instruments, most renewable energy technologies have a cost disadvantage that may limit their roles in the energy supply or emissions mitigation story until emissions prices have risen above threshold levels. However, research, development and innovation funding across the development cycle will be driving substantial investment in a range of technologies with the potential to be competitive over time, as the emissions cap tightens and the price rises. As discussed in Chapter 14, this dynamic will be strongly influenced in the early years, while emissions permit prices are low, by the expanded MRET that is proposed by the government.

20.3.2 Phase 2—transition

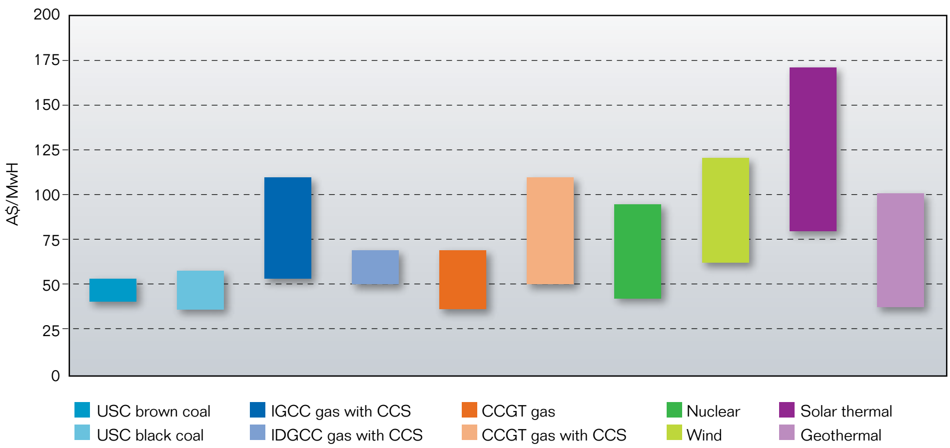
The second phase of the transformation will see the resolution of the tension between the pull of global gas prices and successful deployment of the first coal-fired power stations with carbon capture and storage, on the one hand, and an extension of the gas story as more stable gas prices combine with delays in achieving competitive near-zero emissions coal outcomes on the other. Either way, this scenario plays out to Australia's comparative advantage of a diversity of fuels, including coal and gas.

This phase is likely to be dominated by technology shifts as the investment in research, development and commercialisation from the first phase delivers the first and subsequent commercial-scale models of new generation capacity. New baseload fossil-fuel generation plant is likely to incorporate coal drying and coal gasification technologies. It is expected that all technically feasible retrofitting of oxy-firing and carbon dioxide capture will be added to existing coal and gas-fired plants, accompanied by carbon dioxide pipelines and commercial-scale geosequestration operations. For other coal-fired plant, where such changes are not economically feasible, this phase will see increasing cost pressure as the permit price rises. This phase is characterised by investment in technologies for which the electricity costs have been demonstrated at commercial scale through the investments in research, development and commercialisation of the first phase. Victoria's brown coal resource, unsuitable in its natural state for export, could be expected to have a strong future in this scenario.

At the same time, it is expected that this rising permit price, the results of programs such as Solar Cities and funding for research, development and innovation in renewable technologies such as geothermal, solar thermal and solar photovoltaic, will also be delivering favourable trends in deployment of such technologies at commercial scale. Wind power is expected to reach its maximum technical penetration in the market, while costs may struggle to remain competitive. Energy storage technologies, including through effective use of the stored hydro-electric potential in the Snowy Mountains and Tasmania, can be expected to be available on a commercial basis to support the intermittent nature of solar and wind. The marrying of such technologies to demand that matches its availability will reflect a more comprehensive approach to infrastructure planning. This phase may see the validation of the potential for technologies such as biochar and algal conversion of carbon dioxide as a form of recycling. Market developments around vehicle fuels and motor technologies will strongly influence whether such biomass material realises greater value as a liquid transport fuel or for stationary electricity generation.

Figure 20.10 indicates a range of cost forecasts for different technologies to illustrate that very different outcomes on the energy mix are possible as these forecasts are confirmed or rejected.

Figure 20.10 Electricity generation technology cost chart



Notes: USC = ultra-supercritical; IGCC = integrated gasification combined cycle; IDGCC = integrated drying gasification combined cycle; CSS = carbon capture and storage; CCGT = combined cycle gas turbine.

Source: Energy Futures Forum (2007), IEA (2008), Wright (2007) and industry submissions.

The impacts of rising energy prices, capital replacement cycles and complementary measures to deploy cost-effective energy efficiency changes will accumulate in this phase driven primarily by the increasingly stringent emissions trading scheme trajectory, taking some considerable pressure from the supply side.

20.3.3 Phase 3—emergence

In the third phase of the transformation, the energy sector will move close to a position of zero carbon emissions. The balance of supply and demand that will achieve this outcome will ultimately be determined by the economics of technology developments, which cannot be forecast with certainty. The transport sector will also be based largely on this zero-emissions electricity generation supply for both public and private transport.

The success of near-zero emissions coal technologies will mean that new fossil fuel plant will continue to be coal, while Australia continues to gain as an exporter from the ongoing high global gas prices. Gas is likely to be most valuable to countries for which near-zero emissions coal technologies are neither physically nor economically feasible.

The development of storage technologies, the reduction in solar costs driven by larger-scale deployment and ongoing technology innovation is expected to combine with geothermal energy to begin to replace fossil fuels as the long-term solution to our energy needs. Near-zero emissions coal technology will have carried out its primary role and will remain a significant energy source for some time. An alternative possibility could be for successful development of biosequestration technologies. Such a development could deliver a more favourable and long-term future for coal in the energy sector, competing with renewable energy technologies as resources and geography dictate.

As in the earlier phases, Australia will be in the fortunate position of being able to monitor the global competitive dynamics of coal, gas, nuclear and renewable technologies to its advantage.

20.4 Key economic impacts

The three phases of the energy transformation will be dependent on many variables, including the global fuel dynamics outlined in section 20.2.1.

These and many other parameters—some domestic and others international; some affecting supply, others demand—will all combine to influence the rate of change experienced in Australia.

The supplementary draft and final reports will examine these issues in further detail and will present this analysis in the context of the modelling undertaken by the Review.

20.5 Risks to the transformation

20.5.1 Inertia

In recent years, there has been much discussion regarding new, integrated coal gasification technologies, featured in such projects as ZEROGen in Australia and FUTUREGen in the United States. These projects are large in both complexity and cost and have struggled to make real progress. Further, this complexity is partly responsible for the generally held view that clean coal technologies will not be commercially viable until after 2020.

While such projects remain critical for the longer term, the work of the Review suggests that this time frame is unrealistically long. Having considered the economics of the technologies, the urgency of making major inroads into our emissions, and the other fuel cost pressures, the Review concludes that there is a strong case for accelerated work on the retrofitting of technologies applied in existing plants. This could facilitate the capture of carbon dioxide from such plants, even if it does not involve complete capture. In some areas, such developments could also be associated with carbon capture and storage from gas-fired plant, at least in the medium-term.

There is a compelling case for Australia to play a major role in accelerating the international research effort on carbon capture and storage (see Chapter 17 and Box 20.3)

20.5.2 Second-guessing the market

There is a risk that Australia is not bold enough to proceed on the basis that a market-based emissions trading scheme, supported by mechanisms to remove defined market failures, as proposed by the Review, offers the most effective and efficient solution. This hesitancy could arise from the Australian distrust of markets, deeply rooted in its business and community sectors. It may also arise from anxiety that the cap and trade system will not drive new technologies, even with the support for research, development and commercialisation of new technologies proposed in this draft report. There will be pressure from interests that stand to lose from high permit prices for caps on price that would compromise the emissions reduction objectives. Political resistance to the implications of carbon pricing on prices for some products may drive demands for truncation of sectoral coverage.

The Review is confident in its advice that Australia will meet its mitigation goals with least risk and lowest cost if it holds firmly to a comprehensive, market-oriented emissions trading system as its primary mitigation instrument.

20.5.3 Reform fatigue

The energy sector has been on a path of continual reform since the mid 1990s, and that journey is not yet complete. These reforms are consistent with the aims of the emissions trading scheme and, in cases such as removal of retail price regulation, may be important in facilitating it. However, there is a risk that the added complexity may introduce unexpected confusion or delays. It will therefore be important that an effective linkage is created between the energy market and emissions reduction reforms, through the agenda of the Ministerial Council on Energy of the Council of Australian Governments.

20.5.4 Short-term instability

It is likely that the energy market will experience wholesale price volatility in the short term as the impact of the pre-existing cost pressures, the emissions constraint and the full policy suite works its way through the economy. Price volatility can be an important and essential feature of an effective market. It is therefore important that governments and their regulators work closely with industry to monitor the causes and effects of any such price volatility, and allow the normal mechanisms of the market to operate. Adverse effects of price fluctuations on the living standards of low-income Australians should be managed through fiscal arrangements outside the markets for electricity or emissions permits.

20.5.5 Insufficient people and/or inadequate skills base

The depth and breadth of the transformation described in this chapter carry significant implications for human resource requirements. The transformation will be happening as the economy in general, and the resources sector in particular, are suffering from an acute skills shortage in engineering, management, finance, and a range of trades. Keeping a strong focus on appropriate education and training will be an important element in the success of the transition to a low-emissions Australian energy sector.

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20A Stationary energy compensation

As discussed in Chapter 15, it has been suggested to the Review that 'compensation' should be made to owners of energy-intensive businesses where the profitability and asset values could be significantly diminished by the introduction of the emissions trading scheme. That chapter set out several arguments that would put a relatively low priority on such claims. This appendix addresses this issue in more detail for the electricity generation sector, where the concern has been most acute.

Position	Review response
Equity There will be an immediate and significant reduction in asset value caused by the introduction of an emissions trading scheme. The asset owners should be compensated for this loss, which is disproportionate to that of the rest of the economy. The expected reduction in future profitability as it impacts the real loss of asset value should be offset.	The electricity pool market in the National Electricity Market is designed to efficiently reflect marginal costs and their changes in the spot wholesale market. In any market, all else being equal, a change in marginal costs that is not borne by competing energy sources will lead to a loss of asset value. The National Electricity Market is likely to crystallise any loss most directly and immediately. The relative position of electricity generators differs considerably. Taken with other forces on energy prices, this means that the absolute and relative position of a generator under 'business as usual' or with an emissions trading scheme in place, in the context of what they might have expected, is far from clear. The results of economic modelling will assist in the quantification of these impacts, but in their nature they cannot be defined with a high level of confidence in advance. The societal benefits of financial compensation by way of free allocation of permits or cash are problematic. Governments do not, as a matter of course, compensate asset owners when environmental or social externalities are internalised. As the Review stated in its Emissions Trading Scheme Discussion Paper: 'The claims of shareholders in this sector for special consideration on equity grounds should be assessed by government alongside the equity claims of others.'

Position	Review response
Sovereign risk Generators have had a right to emit carbon dioxide and this right is being taken away by a policy change. In these cases, the Australian Government does and should compensate the holders of the right.	This is not a sovereign risk issue, but a policy risk, exacerbated by the breadth of the policy intervention. Governments always retain the absolute right to vary policy, and industry is generally cognisant of the risk. There is no basis for or claim that a right to emit was issued. Government does not generally compensate for loss of asset value because of the internalisation of an environmental externality. Past cases where a taken right was removed without compensation include policy changes applying to asbestos and tobacco.
Transition continuity The introduction of the emissions trading scheme will be one of the most significant policy changes that the Australian economy has ever seen. The transition will require the full involvement of the existing generators. Also, the owners of the existing generation assets are most likely those that will be needed to invest in low- and zero-emissions technologies; indeed some have already shown a willingness to do so. That willingness will be compromised in the absence of compensation for loss of asset value that will wipe out equity value and a substantial proportion of debt.	Although there may be risks to prices through market behaviour, the absence of alternative electricity generation supply is expected to provide sufficient incentive for the existing generation plants to run to the extent required by the market. The needs of the retail market for supply and the incentives that the forward permit price will provide to invest in mitigation will tend to encourage ongoing operation. It is not clear how financial compensation would reduce residual risk of generator unavailability during the transition period, or affect their on-going business decisions . The owners of existing assets have been important participants in the energy market, and it is acknowledged that failure to secure compensation of the nature and extent sought may cause them to decide against future investment in that market. However, it is expected that a clearly communicated and credible policy response to climate change will provide significant investment opportunities and that these will be attractive to an adequate range of both new and existing investors.

Position	Review response
Investor confidence Major write-downs in assets will both drive up the cost of capital for new investment and delay timely future investment. This could create another source of threat to supply. There will at least be a diminution in investor confidence at a time when it may be most needed to support this artificially created market. If there is no compensation for a disproportionate loss due to a policy change, investors will add a significantly higher risk premium on the basis of possible future policy changes in the face of something as uncertain as climate change. Companies do make judgments on market and policy risk in physical markets, and even financial markets with a physical basis, but there may be an argument that the carbon market is not in this category.	The review acknowledges that providers of existing capital through equity or debt markets will view with considerable concern the magnitude of the asset loss that will crystallise from the introduction of a price on emissions. There is little information to indicate how such entities have been factoring an emissions price into their decisions on existing and new assets over the last decade or so, although it would be surprising if the issue had been ignored. The fact that the industry has been citing uncertainty on climate change policy as a deterrent to new investment would suggest that it has been recognised for some years. State and federal policies to address climate change have been on the agenda for some years. The federal government's 2004 statement 'Securing Australia's Energy Future' advised that 'investors should have regard to the government's policy objective of reducing Australia's greenhouse signature in the longer term'. While the materiality of the impact of this policy is likely to be significant, policy changes that adversely affect asset values without compensation are not unusual. In such circumstances, the credibility of the policy change and the clarity with which it is structured and communicated will be critical in providing appropriate certainty for future investors.
Price volatility Generators faced with such a large loss of asset value and with considerable market power, at least in the short term, will be compelled to exercise that power to recover as much as they can of the loss through higher wholesale electricity prices. This could be very much greater and more volatile than anything previously seen in the National Electricity Market.	It is likely that the changes associated with the introduction of the emissions trading scheme will lead to higher prices and possible that it will lead to more volatile prices. While such price signals will create a strong incentive for new lower-emissions plant and for in-plant changes to reduce emissions, the drivers for such price volatility will not be diminished through financial compensation. Economic logic and the experience of the EU scheme indicate that free permit allocation to generators does not mitigate price changes.

Position	Review response
Threat to reliability The cost impost on existing coal generators will threaten their operational viability. At one level, there will be more forced outages due to constrained operating and maintenance expenditure. At another level, there is a risk that an existing coal generator will be shut down in the face of imminent bankruptcy.	There would seem to be low risk of a precipitous loss of electricity supply. If there is no alternative, lower-emissions source of power, the existing generators will get the benefit of the higher price. The major challenge is to change plant to a different mode of operation, and this will most likely lead to higher operating costs. The energy and financial markets adjustments should provide protection against any threat to reliability of supply. However, the complexity of the impact of the emissions trading scheme price on the detailed positions of generation plants at the unit level, means that nothing can be taken for granted. A free allocation of permits will be of value to the owner, but will not affect the short-run marginal cost of the generator, who will value these permits at the market price. The merit order of generators in the National Electricity Market will be directly changed by the reality and size of the price that the market sets on carbon emissions and will continue to change as the price varies. Any interference with this dynamic would increase the costs of adjustment.
Reversal of previous assurances The previous government and the states-based national emissions trading taskforce had indicated that compensation for disproportionate loss would be made in the form of a one-off, once-and-for-all allocation of free permits.	While the reports of the National Emissions Trading Taskforce (2007) and the Task Group on Emissions Trading (2007) did make such recommendations, neither became a policy position of any state or federal government, and no evidence has been provided to the Review to suggest that subsequent decisions have been based on such recommendations.
Complexity is no excuse Potential complexities in designing a compensation methodology—for example, through free permit allocation—should not stand in the way of the arguments in favour of compensation.	The Review has concluded that auctioning is preferable to free allocation as an overall mechanism of permit release into the market. Complexity is only one argument against free allocation. As well as having lower implementation and transaction costs, auctioning of permits is supported by the design principles of credibility, simplicity and integration with other markets.