20 TRANSFORMING ENERGY

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 joined by pressures from rising carbon prices, and will be larger than the impact of the emissions trading scheme for some years.

Australia is exceptionally well endowed with energy options, across the range of fossil fuel and low-emissions technologies.

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

The future for coal-based electricity generation, for coal exports 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.

As emissions fall in electricity, it will become an increasingly important source of energy to other stationary energy and transport.

If the world is to meet the challenge of climate change, there will need to be a transformation in Australia's stationary energy sector as it adjusts to mitigation policies. Over the next 40 years, we will see the emergence of something close to a zero-carbon energy sector in Australia and around the world—an energy transformation.

This will be part of a wider set of big changes for Australians. We have become accustomed to low and stable energy prices. These have underpinned aspects of our economic structure and lifestyles. The cheap energy is being challenged by rapidly rising capital costs, large increases for natural gas and black coal prices on world markets, and a big lift of gas prices in eastern Australia to international levels as export facilities are established. On top of all this—smaller in magnitude in the early years, but increasingly important towards and beyond 2020—will come carbon pricing within the emissions trading scheme.

There will be three broad phases to the transformation to a low-emissions energy sector:

- 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 be important 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 technologies.

The electricity sector is projected to play a central role in the way in which the Australian economy achieves an abatement commitment within a global agreement. The role emerges from the 35 per cent contribution that electricity makes to greenhouse gas emissions today. It is magnified by the capacity for other sectors, notably other stationary energy and transport, to achieve lower emissions by changing from high-emissions fossil fuels to lower-emissions electricity. The transformation described in this chapter draws on and expands upon the results of Garnaut–Treasury economic modelling to describe the role and structure of the energy sector in a low-emissions economy.

For this reason, electricity is the major focus of this chapter, although broader issues for energy, and directly affected sectors such as coal and aluminium, are also described.

20.1 The energy sector today

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

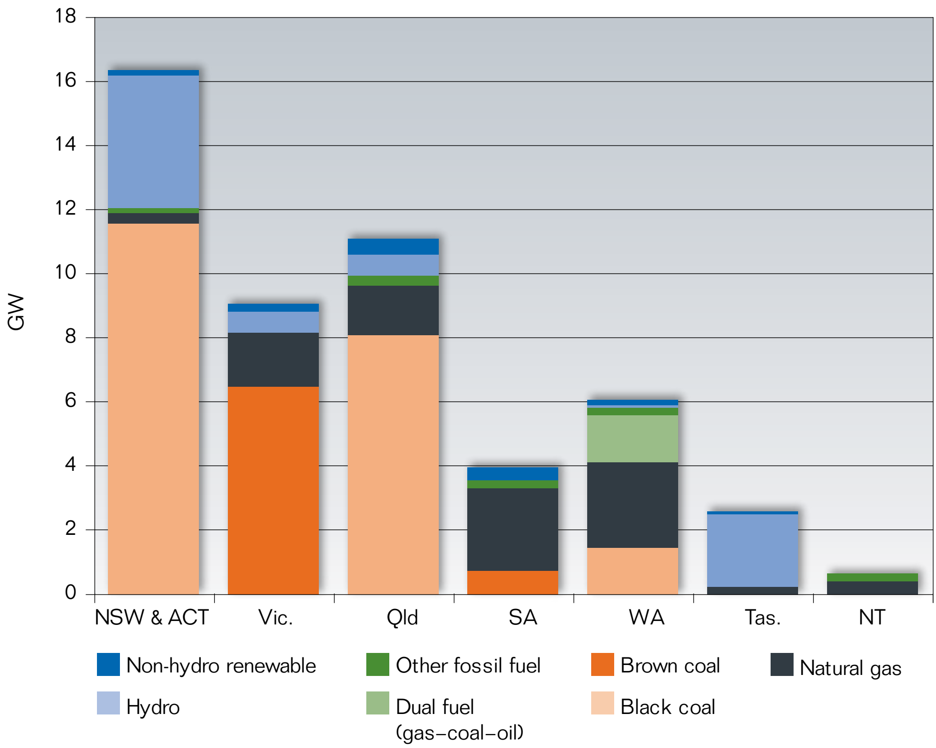
The energy sector, driven by the reforms of national competition policy and progressive privatisation, is now a physically and financially sophisticated and increasingly national sector, delivering security of supply, competitive prices and new investment. This evolution remains unfinished, with regulatory responsibility for monopoly subsectors still to make the full transition to national bodies. Government ownership remains dominant in several states, and price and service regulation remains in areas where competition should be capable of delivering greater consumer benefits.

The energy sector makes a larger contribution to greenhouse gas emissions in Australia than in other developed countries. An energy sector that addresses mitigation will therefore need to establish a balance between driving change towards a low-emissions future built 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

Growth in energy consumption has historically moved closely with GDP in Australia, with a tendency to be slightly lower since the early 1990s. The stationary energy sector is dominated by electricity generation and manufacturing processes. The size of the sector and its fuel mix vary across the country and reflect different regional economic structures and local fuel sources (see Figure 20.1).

Figure 20.1 Installed electricity generation capacity, 2005–06



Source: ESAA (2007).

The availability of large and accessible coal and gas resources has delivered electricity and gas prices that have been low in Australia relative to those in comparable countries. Australia and other developed countries have experienced substantial increases in domestic electricity prices in recent years (see Figure 20.2).

20.1.2 Recent developments

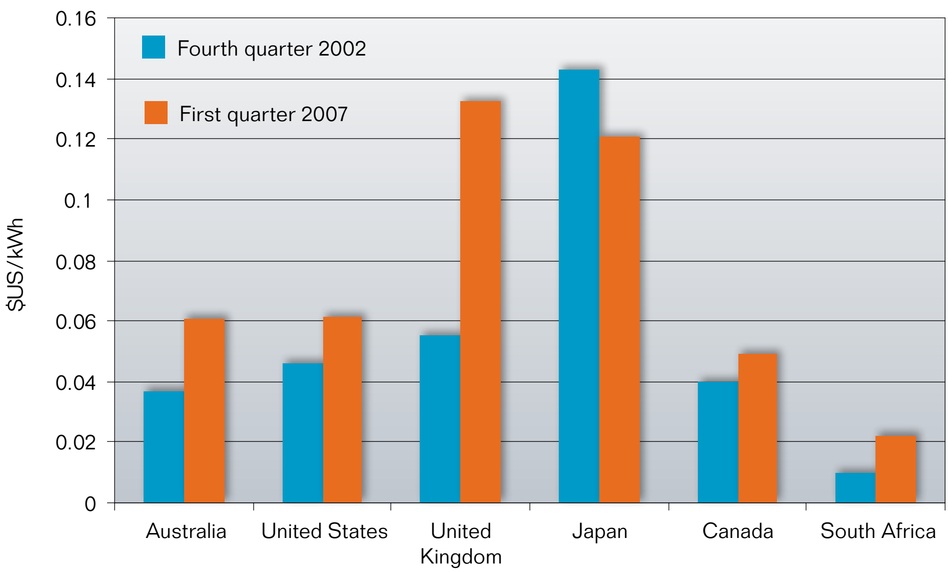
Since the early 1990s, there have been remarkable changes in Australia's energy sector. Privatisation and competition policy have led to a fundamental restructuring of the retail and generation sectors, with the integrated generator–retailer across both electricity and gas taking an increasingly dominant role.

The distribution and transmission pipeline sectors in gas are now entirely, and in 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.

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 base-load supply, transmission interconnection for flexibility and additional security, and gas-fired plant to meet the growing demand for peak and intermediate capacity have all been important in this period of rapid change. Almost 5000 MW or approximately 12 per cent of net additional generation capacity was added between 1999 and 2006, with further capacity either under construction or planned in response to the consistent growth in demand.

Figure 20.2 Comparison of industrial electricity prices



Note: Exchange rate movements were significant sources of changes in relativities between 2002 and 2007.

Sources: IEA (2003, 2008).

From the mid-1990s until around 2006, prices for both electricity and gas were 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
- the emergence of coal-seam gas as a major new supply source.

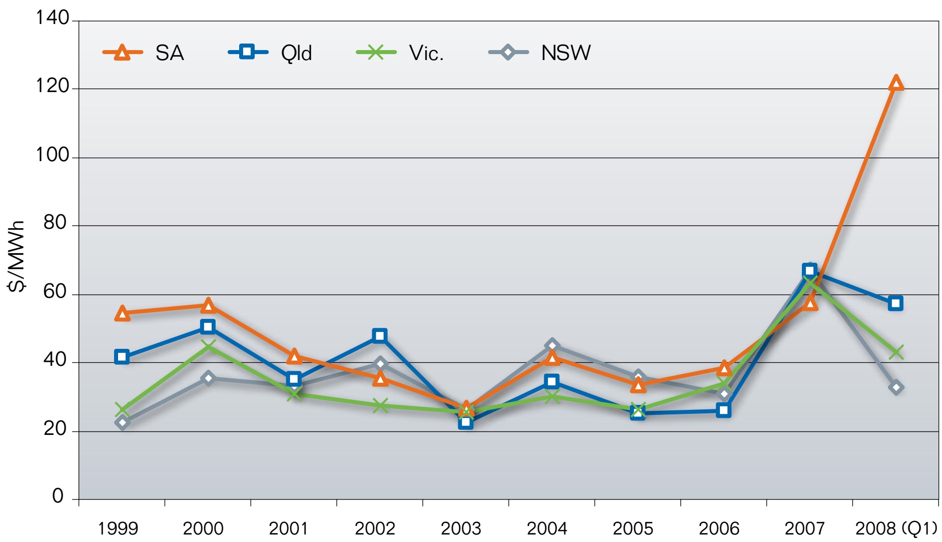
The electricity market has been characterised by strong growth, which has been met by new capacity, increased operability of existing plants and new inter-regional transmission lines.

Since 2006 there has been some upward tendency in prices (see Figure 20.3). Announced price increases have been large in 2008, and are likely to continue independently of any emissions trading scheme impacts.

The most significant remaining step towards establishing competitive markets 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 significant number of customers switching their retailer as full retail competition has been introduced.

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 make recommendations on the removal of remaining retail price controls.

Figure 20.3 Average electricity market prices, 1999–2008



Source: NEMMCO (2008).

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 and for electricity generation. There are mixed views across the industry as to whether established mechanisms are able to deliver the most efficient and timely investment in electricity transmission.

20.1.3 Energy and existing climate change policy

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

First, federal and state policies have been catalysts for investment in a specific set of lower-emissions technologies. The federal government's Mandatory Renewable Energy Target (MRET), the NSW Greenhouse Gas Abatement Scheme 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 GreenPower, an Australia-wide program whereby consumers use renewable energy sourced from the sun, wind, water and waste that is purchased by their energy company on their behalf. 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.

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 'town gas' made from coal to natural gas. The key to changes in sources of energy has always been the interaction between economic and environmental factors. With the challenge of climate change, the introduction of a price on greenhouse gas emissions will accelerate the change by increasing the cost of fossil fuels relative to alternatives.

The pace and direction of the energy transformation will be dictated by the dynamics of the supply and demand surrounding key fuel sources, and the global and domestic policy response to mitigation of climate change.

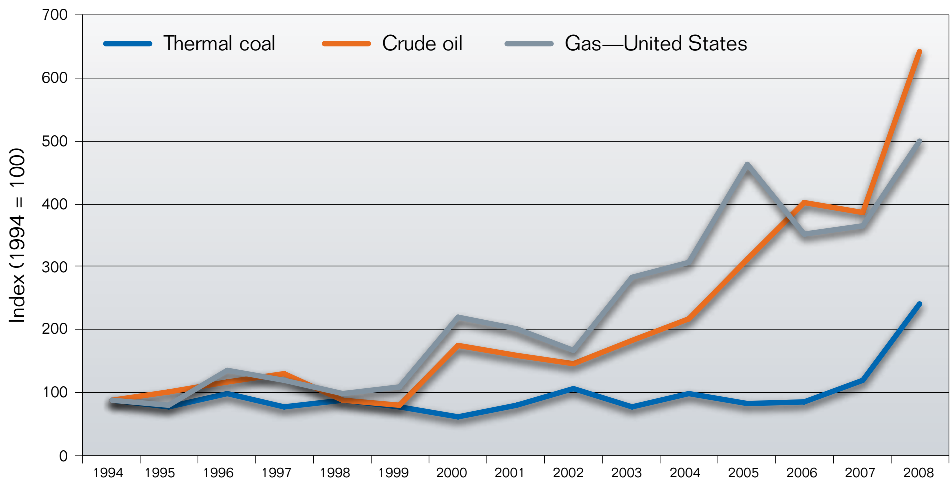
20.2.1 Global fuel dynamics

In the last few years, the domestic energy sector has been challenged by three developments:

- **Capital costs** have risen markedly with particular impact on capital-intensive industries. Industry advice to the Review indicates that there have been increases of up to 60 per cent in construction costs per installed kilowatt of power plants since 2004, across all technologies.

- A major uplift in **global coal prices**—180 per cent over the past three years and over 100 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** have not kept pace with even larger increases in oil prices. These movements in energy commodity prices are illustrated in Figure 20.4.

Figure 20.4 International energy commodity prices, indexed to 1994



Sources: ABARE (2008); State of Nebraska (2008); Government of Western Australia (2008).

In Australia, rising capital costs are starting to affect electricity prices. This has been compounded by 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 export infrastructure on the east coast have largely cushioned Australian prices from the other two factors.

This position is not sustainable: contracts will be renegotiated, new coal export infrastructure is being developed and several east coast liquefied natural gas export projects have been announced.

To put these price increases into perspective, a \$20 per tonne price on carbon dioxide emissions could add \$16–20 per MWh to the average wholesale electricity price. An increase of \$3 per gigajoule in the gas price, to somewhere closer to but still short of export parity would add more than \$20 per MWh to the price of gas-fired electricity, while an increase of \$100 per tonne to black coal prices would add approximately \$53 per MWh to the price of coal-fired electricity.

There is considerable scope for substitution across fuel types. In the discussion of the four broad fuel types in the Australian energy sector that follows, the outlook for oil—as traditional sources become increasingly constrained by resource availability and 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

Coal generally gets 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 way recognises the economic advantages of integrating coal production and power generation within a single business, especially for low-quality coal and when international prices are low. This model generally applies in Victoria and Queensland, including at the recently established plant at Kogan Creek.

The second is characterised by relatively long-term contracts. The most important example is in New South Wales, where the government separated mining rights from electricity generation when it corporatised the energy sector some years ago. In the past, this structure has provided some flexibility for competitive market forces to optimise outcomes and keep domestic prices low. However, firms operating under such supply contracts 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.

Third, in export markets annual contracts are common and prices reflect the dynamics of global supply and demand.

Coal demand is experiencing a period of unprecedented growth, driven by China and India. As contracts for the domestic supply of thermal coal expire, and if suppliers have the potential to access this export market, there is upward pressure on domestic prices. Such prices, if they hold up for an extended period, have the potential to encourage coal-drying technologies and enhance the economic outlook for Australia's brown coal industry.

In the absence of any expectation of a significant slowing of growth in Asian developing economies, prices in real terms are likely to remain well above the levels of the late 20th century for the foreseeable future, but to come down from current peaks as supply expands. There is not likely to be a supply constraint on coal resource availability for many decades, although the exploitation of deeper and more distant deposits is likely to keep prices at a high level.

Gas

Natural gas in Australia has two geographically separate main 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 large volumes of liquefied natural gas for export. Recently, a third market of smaller domestic significance has developed in northern Australia, centred on Darwin. For more than 20 years, 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.

As long-term contracts came to an end during the 1990s, new sources of supply emerged, as did an expansion in the gas transmission network to provide greater security of supply and competition between basins. The take-up of gas for power generation to meet increasing peak and intermediate demand and the introduction of the Queensland Gas Scheme have influenced these developments. Most importantly, the coal seam gas sector, an unintended consequence of the Queensland Gas Scheme in the first instance, now has a vigorous life of its own.

The increasing confidence in large coal seam gas reserves in Queensland has led to recent announcements about the development of liquefied natural gas export infrastructure in the east. Major global energy companies have been taking a stake in the sector, having identified the potential to supply a growing Asian demand for gas.

The recent strength of global demand and higher world prices have resulted in a lift in gas prices in Western Australia. Other domestic gas prices can be expected to rise towards export parity and remain at that level over the longer term. International prices for gas are likely to rise relative to other fossil fuels, as its advantages in lower emissions are increasingly recognised and valued.

The Garnaut–Treasury modelling assumes this rise will take place over a period of around 10 years. If recently announced liquefied natural gas developments were to accelerate that movement, then it would affect the relative cost of gas in Australia for all applications.

Nuclear

The global uranium industry has recently experienced a surge in demand. This is set to go further. China has committed to a program that is immense by any previous global standards, and India has high nuclear power ambitions. In China, nuclear will still account for no more than 6 per cent of total power in 2020. Some countries, including the United Kingdom, have decided that nuclear power stations should continue to play a role alongside other low-carbon electricity sources (HM Government 2008), and that should lead to investment in new capacity. This expanded demand for nuclear energy arises from a combination of influences, from climate change, energy security and relative costs. With more than one-third of currently estimated global resources of uranium, Australia is well placed to benefit from this growth.

Nuclear power stations will have been disproportionately affected by the recent increases in capital costs on account of their exceptional capital intensity, although the latest 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 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, the level of public acceptance of nuclear power is an important barrier. Any government committed to implementation of a nuclear power program would need to recognise public opposition as a constraint—a potential source of delays and increased costs. 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 in 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. Modelling by the Review of the effects of allowing nuclear power generation in Australia (Figure 20.12) supports this assessment. However, it would be wise to reconsider the constraints if:

- future nuclear costs come in at the low end of current estimates
- 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.

In these circumstances, there would be reason for the Australian Government to engage with community disquiet on the issue, and to seek a change of policy.

Renewable energy

In recent years, power generated from non-hydro renewable sources has increased as a result of MRET and, to a lesser extent, GreenPower demand. However, by 2007 it represented only around 3.3 per cent of capacity and 2.5 per cent of delivered electricity (ESAA 2008). This capacity has been dominated by wind, with contributions from solar hot water and biomass.

There is little likelihood of large expansion in storage-based hydroelectric generation in Australia, although there is scope for much better use of existing storage capacity in the current 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 hydroelectricity 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. The value comes initially from their zero-emissions status and low underlying operating costs. This is enhanced by their potential for counteracting the intermittent supply from wind and solar power. If market conditions can be effectively exploited, power from intermittent sources at times of low demand and price could 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, has 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 they be removed.

20.2.2 Things might have been different

In the absence of climate change, global and domestic forces would lead to major adjustments in the Australian energy sector in particular.

One key force for change is strongly increasing Asian and global demand for Australia's commodity exports, driving strongly rising terms of trade in the longer term, and a GDP that roughly triples by 2050 in the 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 increases in energy prices. Australia's energy supply continues to be dominated by coal, while globally, nuclear energy and gas play lesser but significant roles, dictated by fuel availability and the public acceptance of nuclear. 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.

Climate change adds a major dimension to the future of the energy sector, with direct implications from the impacts of climate change and even greater implications as mitigation responses are adopted. Unmitigated climate change is predicted to cause greater storm, wind and bushfire damage and increased levels of materials degradation. This will mean additional transmission and distribution losses across the gas and electricity networks.

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 of January 2007, when a bushfire caused disruption to the transmission system between New South Wales and Victoria.

The most significant impact that will require adaptation planning in the energy sector is that on urban water supply. 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 most fossil-fuel 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. One consequence of water shortages is additional electricity demand for recycling, desalinisation or longer-distance pumping.

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

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

20.2.3 The domestic emissions trading scheme

The implementation of an emissions trading scheme, as the central element in the policy recommendations of the Review, will unleash far-reaching change, as the market responds to the emissions constraint and delivers an assessment of consequent pricing expectations. In the electricity market, the short-term price implications will cause a direct adjustment in marginal cost structures and asset values. This market response is also expected to be associated with a more certain framework to underpin contracting behaviour across the sector. The long-term price expectations will provide long-needed clarity to frame major investment decisions for new energy infrastructure, including base-load 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 would have a powerful effect in accelerating innovation. The overall suite of domestic mitigation policy measures recommended by the Review provides the necessary and sufficient policy conditions for the transformation described below.

For much of the 21st century energy, including transport, is projected to provide the major source of reductions in emissions. The marginal cost of energy supply, interacting with the permit price, will determine the balance of domestic mitigation and international permit trading. The role of technology developments and associated assumptions on availability and costs forms a central theme in the Review's analysis of the energy sector in a low-emissions economy.

20.3 The transformation

In considering the way forward, three broad phases can be identified. These are neither prescriptive nor precise, but separate the ebb and flow of particular developments as they might unfold, especially future changes in technology.

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

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

Therefore, while major structural change always presents challenges, energy supply security is not likely to be one of them. Furthermore, Australia has a strong recent history of supporting its resources and engineering industries with appropriately skilled people. However, that skills base may be challenged as the transformation accelerates.

Within Australia and through the application of the emissions trading scheme, the size, structure, greenhouse gas emissions and, ultimately, the cost of the electricity sector will be determined by:

- the adoption of supply-side energy efficiency, retrofitting of CO_2 capture and other in-plant abatement opportunities
- rebalancing the use of current generation plant in favour of plant with lower emissions
- demand reduction through demand-side energy efficiency and price elasticity
- adoption of new and replacement plant with lower emissions, driven by post–permit price economics and leading to progressive retirement of existing higher-emissions plant.

Section 20.3 describes the phases of the energy transformation over the century, while section 20.4 provides an analysis of this transformation as informed by the Garnaut–Treasury modelling.

20.3.1 Phase 1—commitment and adjustment

The Review has recommended that the emissions trading scheme commence in 2010 at about $20 per tonne (2005 prices), and rise at 4 per cent per annum in real terms. This is roughly what the Garnaut–Treasury modelling indicates would be generated by a global agreement around stabilisation of greenhouse gas concentrations at 550 ppm CO_2-e. Tighter global trajectories than that implied by the 550 scenario would generate a higher price after 2013. Even with the initial fixed price of the Kyoto period, the primary and secondary markets would be expected to quickly establish a spot and forward price curve for emissions permits beyond 2012.

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

As this phase evolves, and the trajectory diverges from the business-as-usual path, the next set of responses is likely to involve some fuel switching. Constraints will include transmission interconnection for new (and possibly remote) capacity, and gas availability and cost, involving existing gas-fired open-cycle plants being operated more intensively. Competitive tensions will arise from the relative emissions intensities of existing coal-fired plants as the permit price is incorporated into short-run marginal costs. Increased price volatility is likely to be a feature of this period—around a tendency for prices to be 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 the effect of these factors on their competitors and east coast electricity prices, and therefore their capacity to recover lost volume in prices.

It is likely that some coal-fired generators with captive coal supply will stand to reap significant increases in profits 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 including partial fuel substitution. Beyond the commercial limits of in-plant emissions reduction, it is likely that it will be economical for some time for such generators to purchase domestic offset credits or international permits to maintain substantial production despite their high emissions intensity, in an environment in which high gas and black coal prices are underpinning higher electricity prices.

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.

Offsets, trade in permits, and hoarding and lending of permits would all provide the flexibility necessary to modify the high permit prices that could flow through to delivered energy prices as demand and supply factors, including any short-term demand surprises, adjust to the emissions constraint.

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. It has concluded that compensation for the cost of permits has no priority in circumstances in which there are stronger calls on permit revenue. Chapter 16 addresses in some detail the specific arguments raised in relation to emissions-intensive electricity generation. However, 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 current circumstances.

Opportunities for increased energy efficiency are envisaged to begin slowly, with the support of the programs described in chapters 18 and 19, and accelerate as the rising permit price provides an increasing incentive for their adoption. Research, development and innovation funding across the development cycle will drive substantial investment in a range of technologies with the potential to be competitive over time, as the emissions cap tightens and the price rises. This dynamic will be strongly influenced in the early years, while emissions permit prices may be relatively low, by the proposed expansion of MRET, even with the price limitations proposed in Chapter 14.

20.3.2 Phase 2—transition

The second phase of the transformation will see 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. Either way, this scenario plays out to Australia's advantage due to its diversity of fuels, its favourable sites for geosequestration and biosequestration, and its wide range of relatively low-cost renewable generation opportunities.

This phase is likely to be dominated by technology shifts as the investment in research, development and commercialisation delivers the commercial-scale models of new generation capacity across several technologies. New baseload fossil fuel generation plant is likely to incorporate coal drying and coal gasification technologies. It is expected that 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 will be 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 various factors—the rising permit price, the results of programs such as the large-scale solar energy program called Solar Cities, and funding for research, development and innovation in renewable technologies such as geothermal, solar thermal and solar photovoltaic—will be delivering favourable trends in the deployment of such technologies at a commercial scale.

A challenge for wind power could be that costs struggle to remain competitive due to site availability, wind quality and community restrictions. Energy storage technologies, including through effective use of the stored hydroelectric 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, meaning that these sources could act as baseload sources. The marrying of such technologies to demand that matches their availability will enable 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 in 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.

The combined impacts of rising energy prices, capital replacement cycles and complementary measures to deploy cost-effective energy efficiency changes will contribute to major changes in the energy technology portfolio in this phase, driven primarily by the increasingly stringent emissions trading scheme trajectory, with 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, both public and private, is also likely to be based largely on this zero-emissions electricity generation supply.

The success of near-zero emissions coal technologies would lead to the retention of coal as the main fossil fuel energy source, while Australia continues to gain as an exporter from the ongoing high global gas prices. Gas is likely to be most valuable to countries without local coal resources and for which near-zero emissions coal technologies are neither physically nor economically feasible.

The development of storage technologies and the reduction in solar costs—driven by larger-scale deployment and ongoing technological innovation—are 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 remain a significant energy source for some time. An alternative possibility could be the successful development of biosequestration technologies. Such a development could deliver a more favourable long-term future for coal in the energy sector, allowing it to compete 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 and to apply economically superior options flexibly as they emerge.

20.4 Modelling results for the energy sector

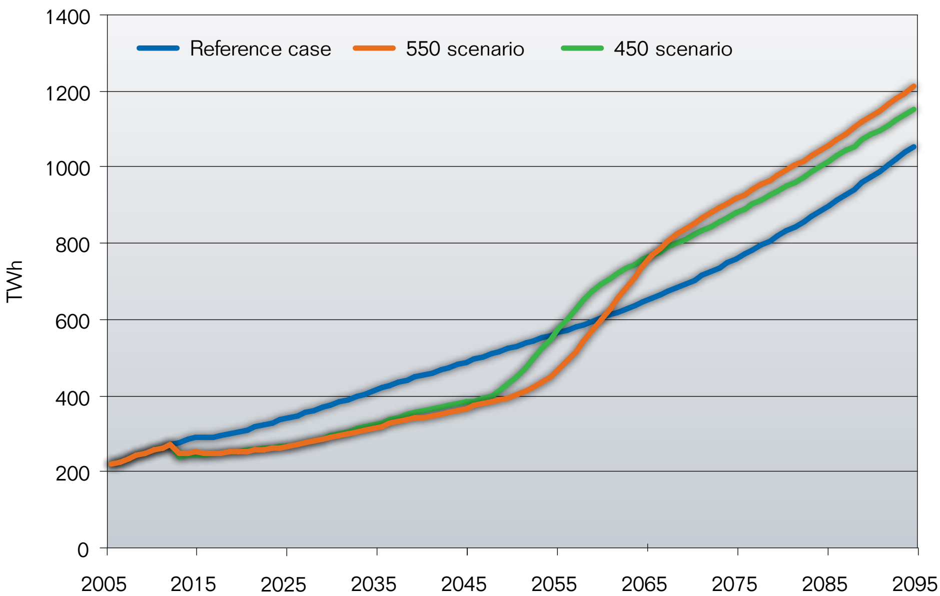
This section provides a quantification assessment of the transformed electricity sector based on the Garnaut–Treasury economic modelling, followed by a description of the main modelling sensitivities.

Results from three scenarios of Chapter 11 are discussed—a no-mitigation scenario (the reference case), and 550 and 450 ppm CO_2-e global stabilisation scenarios—drawing on three of the models used by the Review: the Australian general equilibrium model, MMRF; the global general equilibrium model, GTEM; and the bottom–up modelling of the Australian electricity sector, by McLennan Magasanik Associates using the Strategist model. As in Chapter 11, MMRF is implemented with the post-2050 emergence of a fixed-cost backstop technology, and GTEM is implemented with both standard and enhanced technology assumptions. Unless otherwise stated, the modelling results presented in this section and in section 20.5 are based on standard technology assumptions.

20.4.1 The central policy scenarios

The net result of the factors discussed above on electricity demand over the modelled period is shown in Figure 20.5. Initially this demand is determined within the electricity sector, but progressively it rises above the reference case as the sector becomes decarbonised and fuel substitution towards electricity occurs in other sectors. Transport is the major contributor to this development; its role is described more fully in Chapter 21.

Figure 20.5 Australia's electricity demand

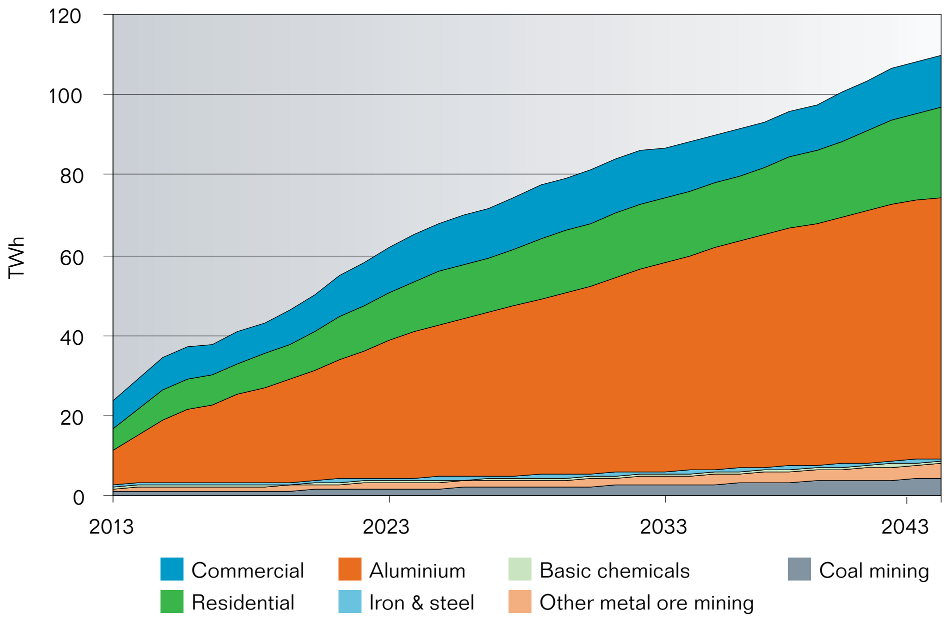


Note: These results were generated using MMRF and standard technology assumptions.

Within the constraints and assumptions of the modelling, the initial response to the carbon constraint is a reduction in electricity demand. The major contributors (aluminium, residential and commercial) are shown in Figure 20.6. While the real world could smooth out this initial price impact, the longer-term change is for a demand reduction, with residential demand falling 11 per cent below the reference case by 2020.

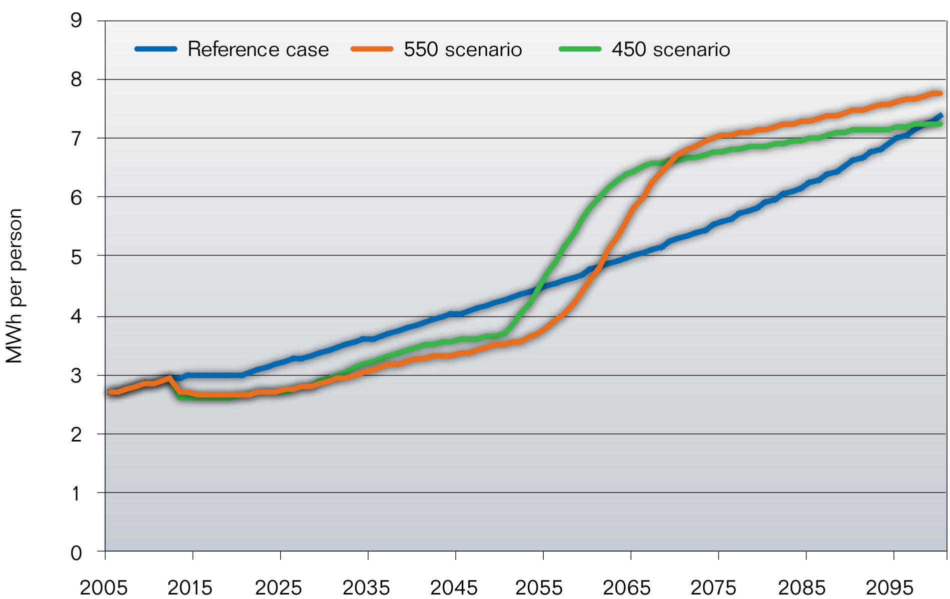
The implications of the above for the aluminium sector are clearly significant; these are explored more fully in section 20.5.4. After the initial price response, residential demand on a per capita basis grows steadily, as shown in Figure 20.7, until this growth is strongly augmented by the switching to electricity for private transport.

Figure 20.6 Electricity demand reduction in selected sectors, 550 scenario



Note: These results were generated using Strategist and standard technology assumptions.

Figure 20.7 Residential demand, 2005–2100

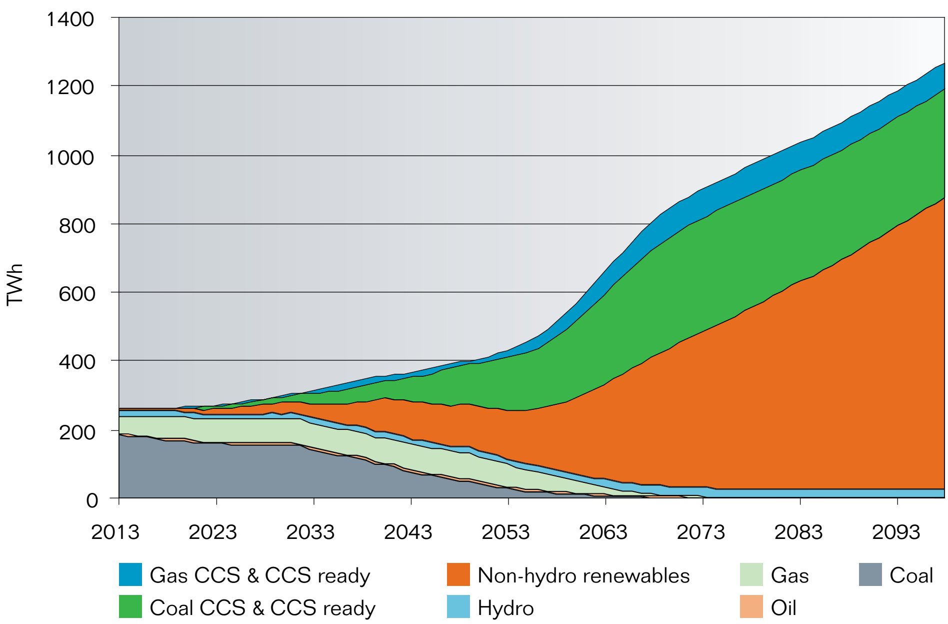


Note: These results were generated using Strategist and standard technology assumptions.

The structure and technology mix is illustrated in Figure 20.8. The transformation begins with an increase in the role of gas as a relatively low-cost and immediately available source of lower-emissions electricity. Progressively, the availability and relative cost of carbon capture and storage technology (either as geo- or biosequestration) sees it emerging to play a strong role by mid-century with additional growth in renewable supply sources. As the abatement target becomes more restrictive, the residual CO_2 emissions associated with carbon capture and storage would cause it to become increasingly less competitive and renewable sources dominate.

The relative contributions of fossil fuels and renewable sources are driven by the cost assumptions (as described in the technical report available at <www.garnautreview.org.au>) and technology-specific constraints (for example, for intermittent sources). The modelling excludes any additional policy instrument such as the expanded MRET, that acts to 'force in' specified technologies.[1] Accordingly, non-hydro renewables' share of the electricity mix remains below 10 per cent until the mid-2020s, but then rises strongly to reach 30 per cent by 2050.

Figure 20.8 Australia's electricity technology shares, 550 scenario



Note: These results were generated using MMRF and standard technology assumptions.

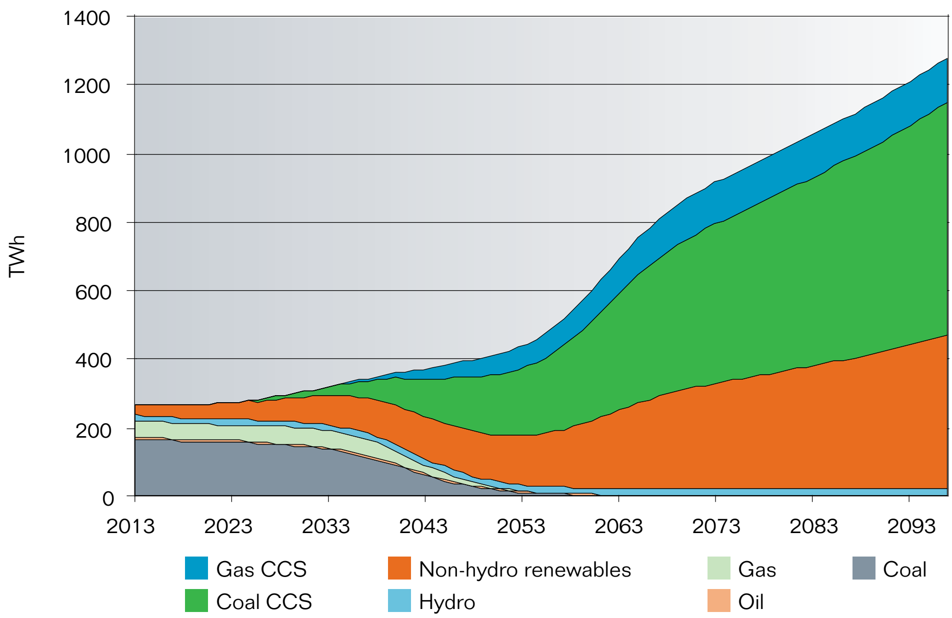
Over the longer term, the critical factor that is likely to determine the structure of the electricity supply sector and the future of fossil fuels, both in Australia and internationally, is achieving near-zero emissions carbon capture and storage. The implications are described in section 20.5.3 and are illustrated in Figure 20.9, which shows the much greater share taken by coal with carbon capture and storage when such a technological change is included.

The major difference between the Australian outlook in these figures and the global picture is that the modelling of the former has excluded nuclear generation. The effects of removing this constraint are described in section 20.4.2.

In the 450 standard technology scenario, the constraints described above would act much more tightly, such that the role of carbon capture and storage diminishes and non-hydro renewable energy dominates Australia's electricity supply, rising to 13 per cent by 2020 and towards 50 per cent by mid-century. This is illustrated in Figure 20.10.

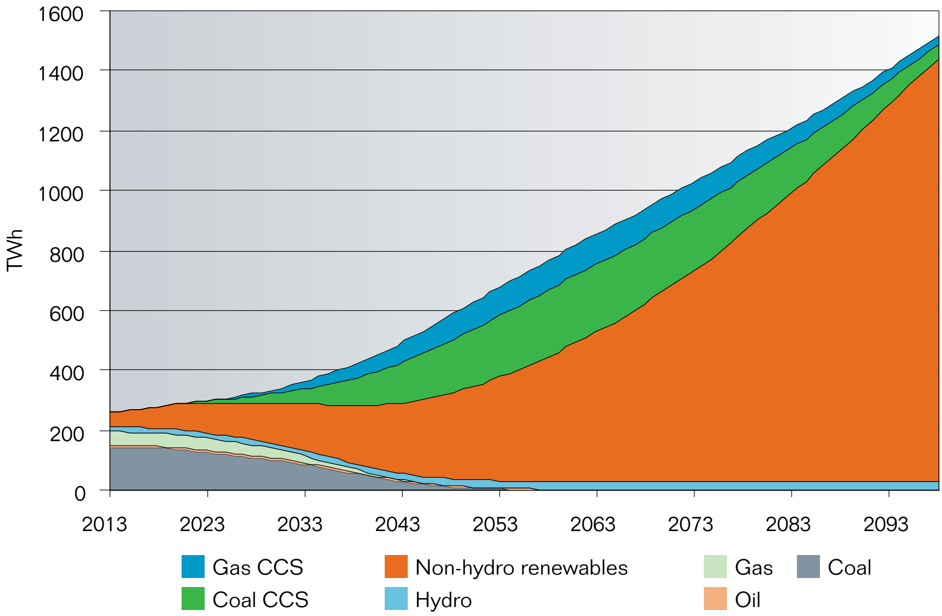
It is clear that whatever specific technology mix emerges, it is likely to deliver a progressive decarbonisation of electricity generation by mid-century to an extent ultimately determined by the cost of near-zero and zero emissions coal technologies. This is shown in Figure 20.11.

Figure 20.9 Australia's electricity generation technology shares, 550 scenario with zero-leakage carbon capture and storage



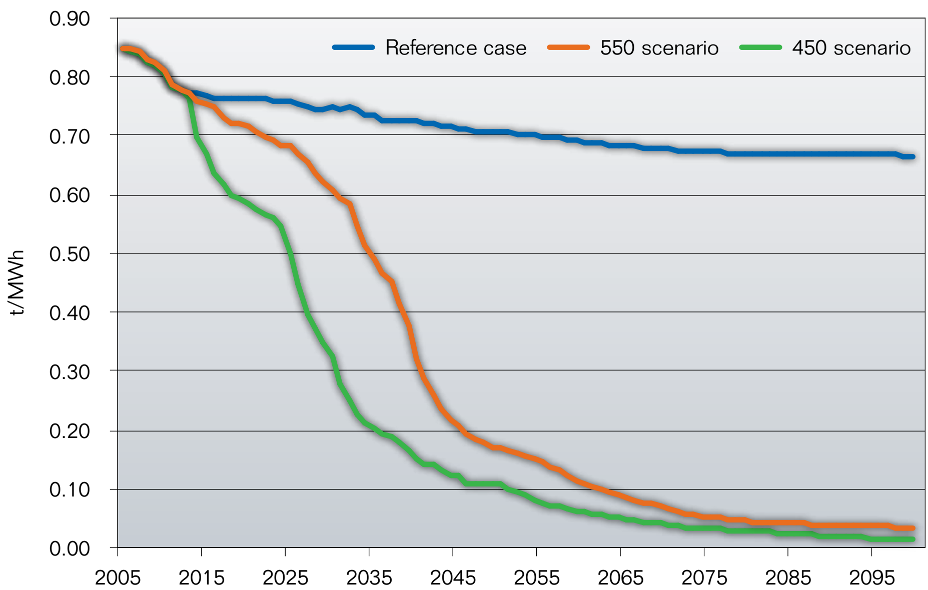
Note: These results were generated by applying the technology shares from GTEM under the zero-leakage CCS scenario to the electricity demand from MMRF under the 550 standard technology scenario. This illustrates the impact of zero-leakage CCS in MMRF.

Figure 20.10 Australia's electricity generation technology shares, 450 scenario



Note: These results were generated using GTEM and standard technology assumptions.

Figure 20.11 Electricity emissions intensity



Note: These results were generated using MMRF and standard technology assumptions.

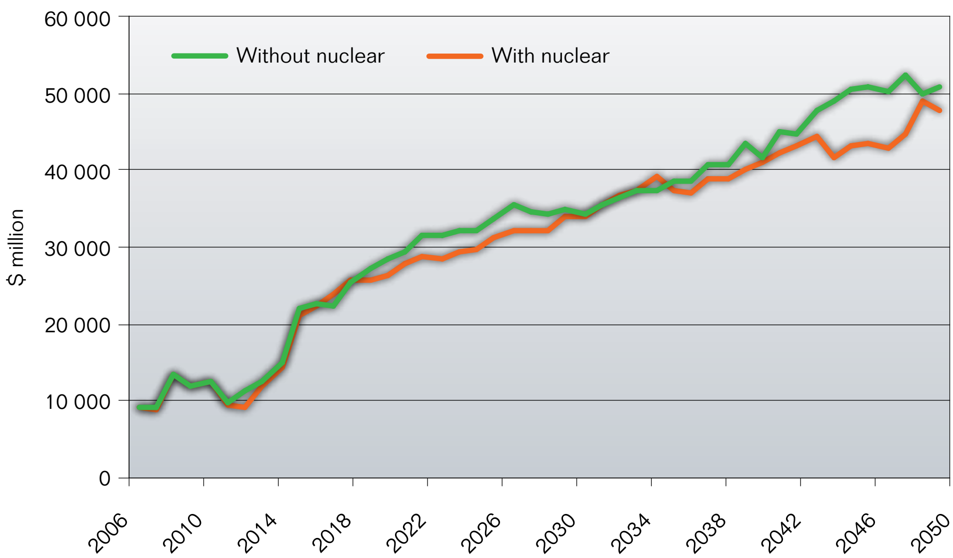
20.4.2 Modelling sensitivities

The structure of the energy sector and the future for specific technologies as projected in the modelling are critically dependent on the assumptions of future technology developments. While many of these could be subject to sensitivity analysis, the Review focused on three of these for assessment.

Nuclear energy

When the economic modelling includes a nuclear option for Australia, nuclear is adopted, supplying 27 per cent of total electricity demand by 2050 in the 550 scenario, and primarily replacing coal combined with carbon capture and storage. This outcome is particularly sensitive to relative technology cost assumptions. Within this framework, and as shown in Figure 20.12, the impact on electricity costs is modest. As discussed in section 20.2.1, other issues are likely to be more important for determining the future of nuclear energy in Australia's energy mix.

Figure 20.12 Total wholesale electricity costs, with and without nuclear, 550 scenario

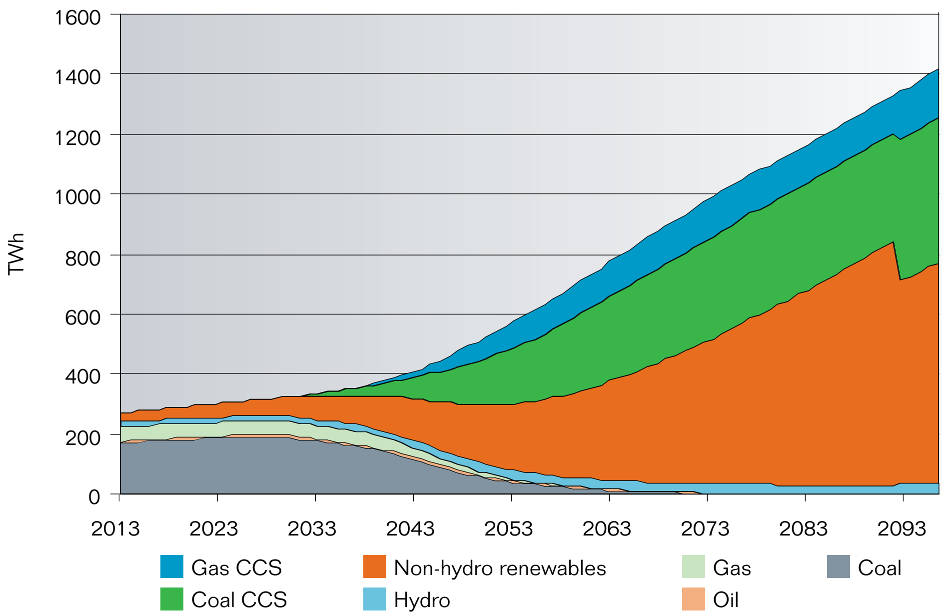


Note: These results were generated using Strategist and standard technology assumptions.

High rate of technology development: enhanced technology assumptions

The Garnaut–Treasury modelling ran an enhanced technology scenario using GTEM, for which the macroeconomic impacts are discussed in chapters 11 and 23. The lower permit price, relative to the standard technology scenario combined with high rates of carbon dioxide sequestration by carbon capture and storage, to shift the technology mix somewhat towards carbon capture and storage at the expense of non-hydro renewables. This is illustrated in Figure 20.13.

Figure 20.13 Technology mix under an enhanced technology scenario



Note: These results were generated using GTEM.

Near-zero emissions coal technologies

Global and Australian dependence on coal, with its high combustion emissions, for power generation means that the future of the energy sector is particularly sensitive to assumptions regarding the way in which this subsector is affected by an emissions constraint. This sensitivity is described in section 20.5.3.

20.5 Major economic impacts

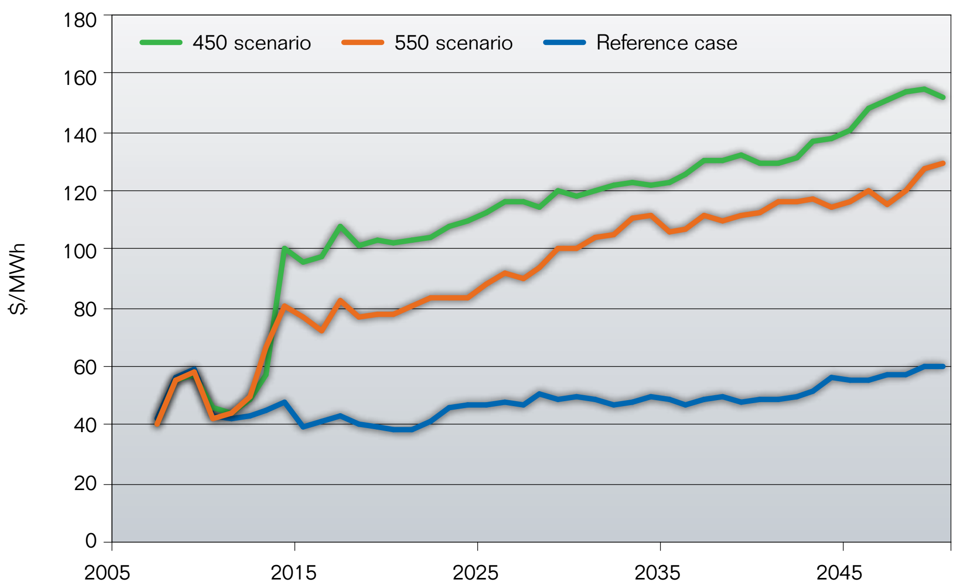
The transformation as described through economic modelling will have widespread impacts, both within and beyond the electricity sector.

20.5.1 Electricity costs

The transformation is projected to be accompanied by increases in the cost of electricity influenced by assumptions for future technology costs. The result is an increase in electricity wholesale costs, as shown in Figure 20.14, increasing steadily as existing and lower-cost/higher-emissions technologies are displaced and then reflecting future assumptions regarding the relative costs of the range of near-zero emissions technologies described in the technical appendix on the Review's website.

These wholesale electricity prices would then flow through to retail prices, with the proviso that there are no regulatory impediments. In the 550 scenario, Australian retail electricity prices in the first few years following the introduction of the emissions trading scheme are projected to be around 40 per cent higher in real terms than they would have been otherwise. The implications for households in regard to the affordability of essential services are considered in chapters 16 and 23.

Figure 20.14 Wholesale electricity prices, 2005–50



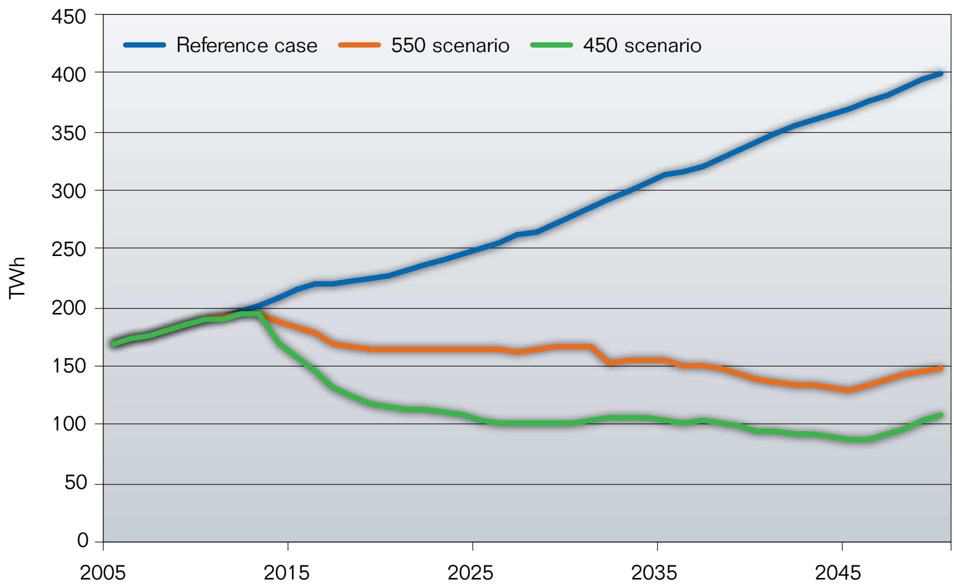
Note: These results were generated using Strategist and standard technology assumptions.

20.5.2 Existing electricity generation

The changes in demand and technology mix, described earlier in this chapter, carry with them significant implications for established generation with its concentration on black and brown coal. Most of the existing generators are projected to continue in profitable operation beyond 2020, although growth is either curtailed or supplied by gas and renewables as described earlier in this chapter. Figure 20.15 indicates the impact on electricity generation from coal.

The dynamics of price projections for black coal and gas have an influence on the permit price at which switching occurs. A result is that coal generators are still frequently marginal suppliers, thereby setting the wholesale price, more often than under the reference case. This leads to the impact on electricity prices described in the preceding section, with permit prices being passed through by generators.

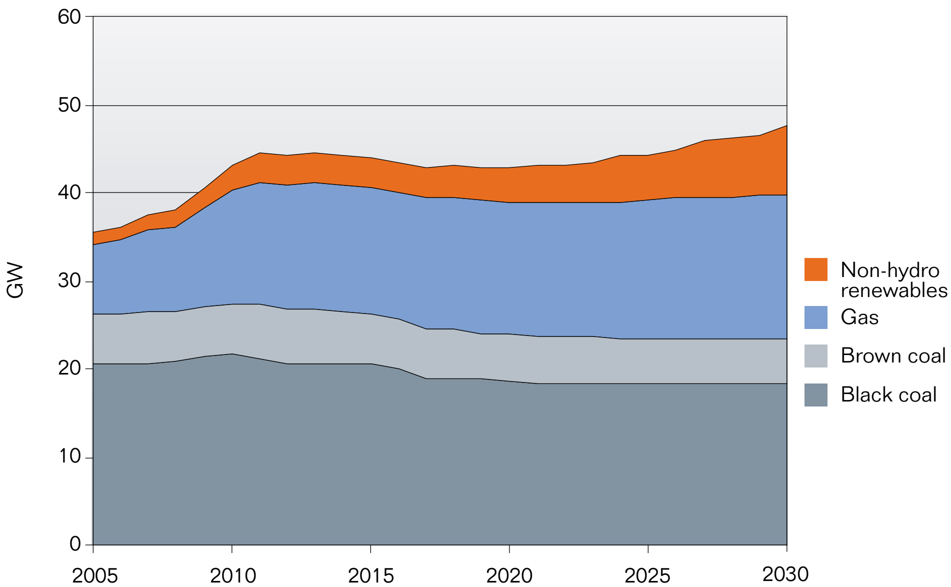
Figure 20.15 Electricity generated from coal



Note: These results were generated using Strategist and standard technology assumptions.

In the 550 scenario, there is an impact on existing coal generators as shown in Figure 20.16, although most of the current capacity remains profitable and in place beyond 2020. Even for brown coal, 93 per cent of today's capacity is projected to still be in place by 2020.

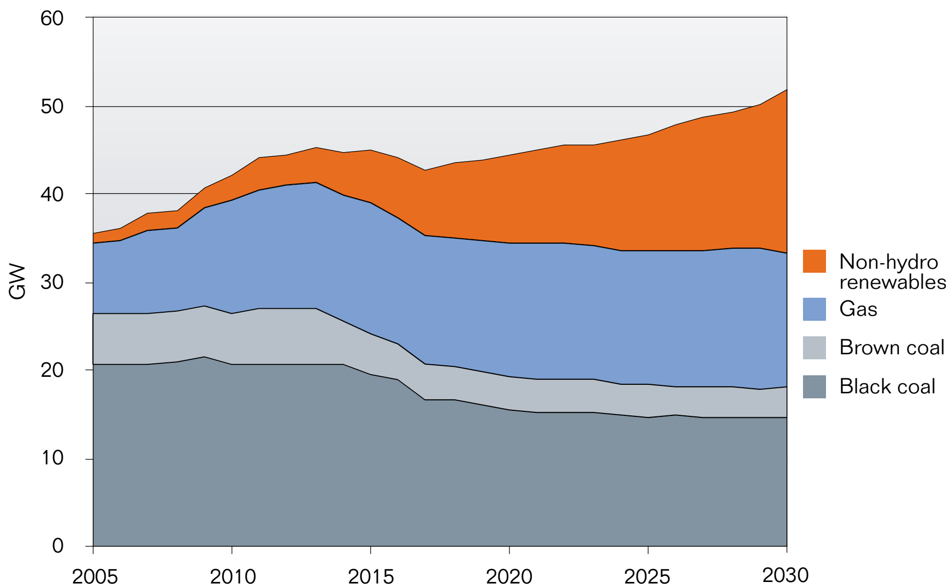
Figure 20.16 Generation capacity, 550 scenario



Note: These results were generated using Strategist and standard technology assumptions.

In the 450 scenario (Figure 20.17), the impacts are magnified—the installed brown and black coal capacities are 37 per cent and 26 per cent, respectively, below today's level by 2020.

Figure 20.17 Generation capacity, 450 scenario



Note: These results were generated using Strategist and standard technology assumptions.

In addition to the gains made by some coal generators in both scenarios, existing gas generators generally benefit substantially from the higher permit prices, as do renewable generators such as hydro and wind. The pump storage units associated with the existing hydro generators are projected to see some reduction in profitability through the higher price of their electricity purchases.

20.5.3 The future for coal

For Australia, reducing emissions from coal combustion is of national importance. Under any realistic scenario, Australia's response to climate change, both internationally and domestically, will be inextricably intertwined with the long-term future of the coal industry.

First, coal underpins Australia's domestic electricity supply sector. An early resolution of the future role of coal-fired generation will be important in shaping a smooth transition for Australia's energy sector into 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. 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. These contributions will be at risk sooner or later, unless low-emissions ways of using coal are applied successfully in our major Asian markets.

Third, the effective participation of China, Indonesia, India and other major developing countries in ambitious emissions reduction is essential for the success of the global mitigation effort. These counties could find such participation in an effective global agreement easier if zero-emissions technologies for using coal are available.

Last but not least, 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 continued health of the industry could obviate the need for assistance measures.

If the coal 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 mid-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 20.1).

Priority should be given to the resolution of 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 initiatives that would contribute to an efficient transition.

- Technology innovation in the sector will benefit from the early research funding described in Chapter 18, as will investment in demonstration and commercialisation from the suggested matched funding scheme.
- The Review explores the need for structural adjustment assistance under very specific circumstances in Chapter 16, and proposes an additional allocation of funds, of the order of $1–2 billion, to match industry investments in the adoption of proven technologies during the period of transition.
- In Chapter 11, the Review identifies the leadership role that Australia could play in coordinating a major global effort to develop and deploy carbon capture and storage technologies, and to transfer those technologies to developing countries.

Box 20.1 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 but must not be released into the atmosphere if coal is to achieve near-zero emissions status. This can be achieved by capturing the carbon dioxide and then either converting it to some environmentally benign end product or consigning it to permanent storage (sequestration).

Carbon capture technologies

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 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.

Box 20.1 The technologies of zero-emissions coal *(continued)*

Transport technologies

If the source point of the carbon dioxide is physically distant from the final destination, then some form of transport will be required. Carbon dioxide transport is relatively well developed as a technology. The issues associated with the provision of appropriate transport infrastructure are discussed in Chapter 19.

Sequestration technologies

There are two categories of sequestration. The first, geosequestration, involves storing 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 the CO2CRC project 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 from power stations or industrial process exhaust.

New technologies: what are the issues?

A focused approach will be needed to address the range of technical, regulatory, environmental and economic issues associated with each area of technology described in Box 20.1.

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

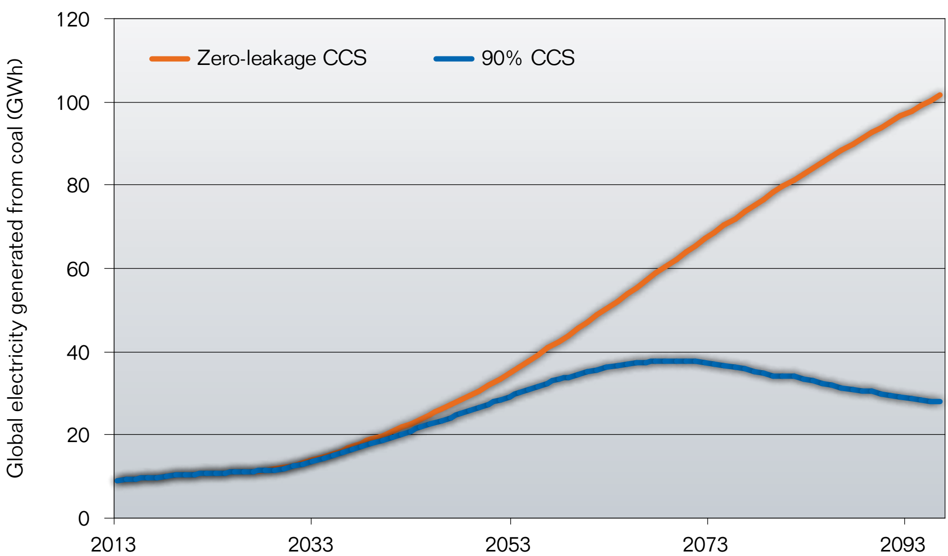
The challenge posed by the scale of the task is the most significant of these. It will ultimately involve the annual capture and sequestration of several hundred million tonnes of carbon dioxide in Australia alone. An operation on this scale will be a substantial new industry in itself, and will include export of services and possibly export of storage reserves to countries which lack low-cost geo-sequestration sites. The power requirements of the geo-sequestration process itself will add substantially to the demand for power generation. These developments will place a considerable strain on regulatory processes and human resources and be the source of considerable growth in associated activity, employment and incomes for the regions in which they are located.

If the challenges of low-emissions coal technologies can be successfully addressed, a profoundly 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 favour retrofitted (post-combustion capture) coal plants with captive coal supplies and low-emissions profiles and, ultimately, near-zero emissions plants that use integrated coal drying and gasification technology.

Under the 550 and 450 standard technology scenarios modelled by the Review, the demand for Australia's coal largely depends on the ability of coal generation to capture a share of an expanding electricity market in a rapidly growing world. The modelling assumes that carbon capture and storage technologies from 2020 onwards are able to capture 90 per cent of coal-fired electricity generators' emissions. While this assumption causes global demand for coal to remain relatively high, global mitigation causes the rate of growth to moderate, such that Australian coal exports fall by around 25 per cent by 2050 and 20 per cent by 2100, relative to the base case.

As the carbon price rises to high levels, zero-emissions electricity generation becomes increasingly competitive against coal generation, even where 90 per cent of carbon capture and storage is assumed. It is likely that the development of zero-emissions technologies would increase demand for coal-fired energy generation and hence maintain global demand for coal. Illustrative global modelling undertaken by the Review shows that the introduction of a zero-leakage carbon capture and storage technology could significantly increase the demand for coal-fired electricity generation and hence increase demand for Australian coal, relative to a scenario with only 90 per cent carbon capture and storage. Figure 20.18 shows the impact of zero-leakage carbon capture and storage relative to 90 per cent carbon capture and storage.

Figure 20.18 Carbon capture and storage scenarios



Note: These results were generated using MMRF and standard technology assumptions.

Australian coal production moves in line with the global demand for Australia's coal exports. A future scenario in which Australia stands aside from a strong global mitigation effort is more likely to damage than to assist the circumstances of the Australian coal industry.

20.5.4 The impact on aluminium

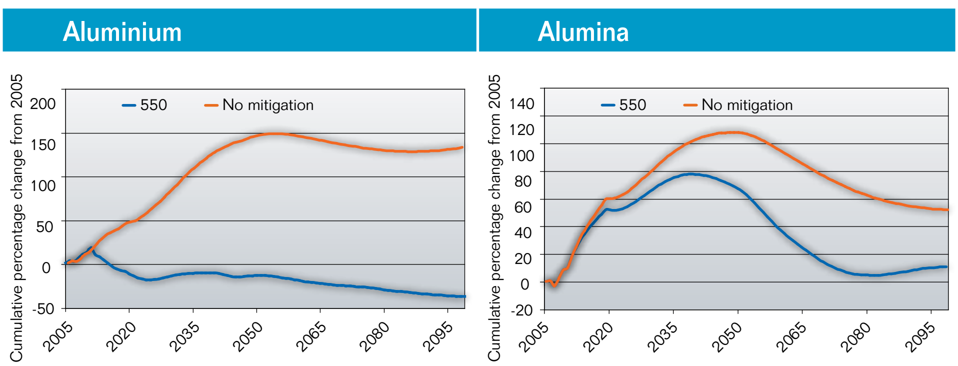
The aluminium industry comprises two distinct subsectors: alumina production and aluminium smelting. Each is modelled separately in MMRF.

Figure 20.19 shows the projected changes in activity for the two sectors under the no-mitigation and the 550 standard technology scenario. They show that both industries are projected to grow to mid-century in an unmitigated world. Beyond that, global productivity convergence within the modelling framework influences the results. One of the consequences is that the aluminium industries in developing countries gain competitiveness and gain market share relative to the Australian industry.

While both industries are energy intensive, they use energy from different sources. The process of refining bauxite to form alumina (alumina production) uses energy to generate heat, for example, mainly from coal and gas. Aluminium smelting, on the other hand, uses mainly electricity. Under an emissions trading scheme, the aluminium smelting industry loses its advantage in cheap electricity and hence is affected more than the alumina industry.

Figure 20.19 shows that the Australian coal-based aluminium industry is projected to decline in absolute terms for a while, as sources of low-emissions electricity, such as stranded hydro in Africa, the island of New Guinea and South America, and standard natural gas in a number of countries become increasingly competitive. The ultimate scale of this tendency will be determined by the ongoing availability of hydro sites. The alumina industries' growth is projected to be significantly moderated under an emissions reduction scheme.

Figure 20.19 Projections for aluminium and alumina industries

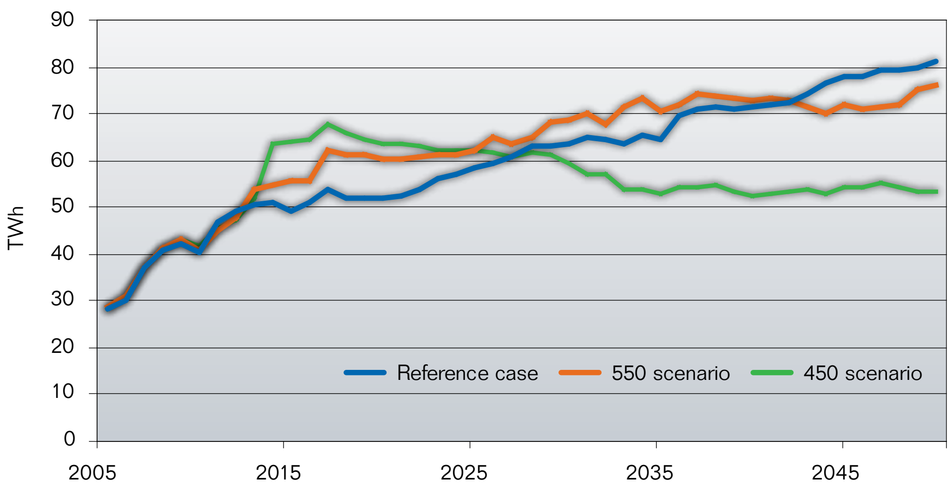


Note: These results were generated using MMRF and standard technology assumptions.

20.5.5 The role of gas

As described above, the introduction of an emissions trading scheme is projected to lead to an increasing role for gas in power generation, as shown in Figure 20.20, reaching 23 per cent and 27 per cent by 2020 in the 550 and 450 scenarios, respectively. In the process, gas is projected to meet 21 per cent of Queensland's demand, more than would be required under the existing Queensland Gas Scheme. Mitigation policies overseas also expand the opportunities for exports of natural gas at higher prices. Gas's role becomes constrained in later years as coal with carbon capture and storage and renewable sources become more competitive under the rising permit price, even when combining carbon capture and storage with gas is included. As with coal, this outcome can be strongly influenced by relative movements in future technology costs and global commodity prices.

Figure 20.20 Electricity from gas sources



Note: These results were generated using Strategist and standard technology assumptions.

Australia's competitive position in the global gas market will be driven by fuel-specific dynamics as described earlier in this chapter. As with coal, global gas demand in the 450 scenario is constrained later in the century by the increasing permit price and would also be favoured by the development of near-zero emissions carbon capture and storage technology.

20.5.6 The role of other stationary energy

Emissions from fuel combustion for energy, other than electricity or transport, include onsite energy production for the agriculture, mining, manufacturing, communications, services and residential sectors. Key sources of other stationary energy emissions in 2005 were the steel and alumina sectors, which use large amounts of coal; the gas and private heating sectors, through their use of gas; and the coal, agriculture and services sectors through their use of diesel.

Current levels of emissions from other stationary energy sources are of a similar magnitude to transport and, like the transport sector, there is a high potential for abatement through switching towards zero- or low-emissions fuels. In the manufacturing sector, for larger plants in industries such as cement, lime and plaster, iron and steel, and alumina refineries, there is also the potential for the application of capture and storage technologies.

Emissions reductions from other stationary energy contribute 12 per cent of the overall abatement task in both the 450 and 550 standard technology scenarios. The majority of abatement occurs after 2050, reflecting a switch to low-emissions energy sources and the adoption of carbon capture and storage technologies in parts of the manufacturing sector. The carbon capture and storage technologies are assumed to become commercially viable with a lag to their rate of adoption in the electricity generation sector. The switching towards low- or zero-emissions fuels occurs at the same rate as the electrification of the transport sector.

By the end of the century, emissions from other stationary energy account for 12 per cent and 18 per cent of overall emissions for the 550 and 450 scenarios respectively, and are increasing very gradually in the 450 scenario. This reflects an assumed natural limit to the degree to which the process of fuel switching can occur, which has been set at 90 per cent, reflecting, for example, the lack of availability of grid-generated electricity in remote areas. It also reflects the assumed limit to the capture of emissions from carbon capture and storage technologies.

As outlined above, emissions in the 'other stationary energy' category are sourced from a range of different activities. Stationary energy emissions represent some or all of the fuel combustion emissions from almost every sector considered, with the exception of electricity generation and a subset of the transport sectors. The potential for fuel switching will vary considerably within the combustion activities in any one sector—some of these combustion activities, such as residential heating, would be especially conducive to a switch to electricity, as there is already widespread use of electricity in these activities.

Such switching would amplify the increased demand for electricity and its central role as described earlier in this chapter. While reductions in emissions were included as described above, this was not accompanied, in the modelling detail, by price-based fuel switching.

20.6 Risks to the transformation

20.6.1 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 complex and costly and have struggled to make real progress. Their 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 there are other possibilities with shorter time frames. 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 much of the 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 across the range of technological change.

20.6.2 Second-guessing the market

There is a risk that Australia is not bold enough to rely on a market-based emissions trading scheme, supported by mechanisms to remove defined market failures, as proposed by the Review. This hesitancy could arise from the general Australian business and community distrust of market mechanisms. 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 by the Review. 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 costs for some products may drive demands for truncation of sectoral coverage.

20.6.3 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 associated with the introduction of the emissions trading scheme may introduce unexpected delays into energy market reform. 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.

20.6.4 Short-term instability

The energy market is likely to experience wholesale price volatility in the short term as the impact of pre-existing cost pressures, the emissions constraint and the full emissions reduction 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.

20.6.5 Insufficient people and 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 evolving as the economy in general, and the resources sector in particular, is suffering from an acute skills shortage in engineering, management, finance, and a range of trades. Maintaining strong investment in appropriate education and training will be an important element in the success of the transition to a low-emissions Australian energy sector.

Note

1 The reference case includes existing federal and state and territory policies on climate change mitigation. The modelling assumes that the measures will be phased out when the emissions trading scheme begins.

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