INTERNATIONAL ENERGY AGENCY

Energy Policies of IEA Countries

Australia 2001 Review

OECD

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-five* of the OECD's thirty Member countries. The basic aims of the IEA are:

- To maintain and improve systems for coping with oil supply disruptions;
- To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- To operate a permanent information system on the international oil market;
- To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- To assist in the integration of environmental and energy policies.

** IEA Member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission also takes part in the work of the IEA.*

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed:

- To achieve the highest sustainable economic growth and employment and a rising standard of living in Member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;
- To contribute to sound economic expansion in Member as well as non-member countries in the process of economic development; and
- To contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

The original Member countries of the OECD are Austria, Belgium, Canada, Denmark, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The following countries became Members subsequently through accession at the dates indicated hereafter: Japan (28th April 1964), Finland (28th January 1969), Australia (7th June 1971), New Zealand (29th May 1973), Mexico (18th May 1994), the Czech Republic (21st December 1995), Hungary (7th May 1996), Poland (22nd November 1996), the Republic of Korea (12th December 1996) and Slovakia (28th September 2000). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

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SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Australia is a major energy producer and exporter. At current depletion rates, the country has 820 years of brown coal, 290 years of hard coal, 270 years of uranium, 36 years of natural gas and 13 years of oil. About half of Australia's energy production is exported. Australia is the world's largest coal exporter and coal is Australia's largest export industry, accounting for 1 per cent of GDP and 10 per cent of total exports. Australia ranks third in liquefied natural gas (LNG) exports to Asia.

Over the last decade, a major programme of market reform in the energy industries and beyond culminated in the onset of the National Electricity Market (NEM) on 13 December 1998, and the entry into force of the Commonwealth Gas Pipelines Access Act and related state legislation in 1997/98.

Competition in the power industry has existed for a number of years; competitive trading began in 1994 in Victoria and in 1996 in New South Wales. In May 1997 the NEM extended competition to the interconnected states in the south-east, i.e. South Australia, Victoria, New South Wales, the Australian Capital Territory and Queensland. Each of the five NEM states has a separate transmission company. Full privatisation has occurred only in Victoria. In South Australia, the state-owned generation, transmission and distribution companies are managed by private companies under long-term leases; in the other NEM states they remain in government ownership.

Liberalisation of the Australian electricity supply industry has resulted in large increases in labour productivity; between 1990 and 1999, the number of employees was nearly halved despite growing electricity output. Capital productivity also increased, with a 10 per cent increase of plant availability. Average real electricity prices declined by some 14 per cent between 1991 and 1998. Over the last three years, large demand growth and limited new investment eliminated excess capacity and caused prices to rise again. Prices are now 10 per cent below 1991 values. Victoria experienced reliability problems in 2000, when an industrial dispute, generator outages and an extremely high summer demand peak coincided, with the situation exacerbated by Victorian government intervention.

The NEM is not yet strongly integrated; the amount of electricity traded is comparatively low and prices can differ across NEM regions, particularly when transmission constraints emerge. During periods of peak demand, the network can become congested and the NEM separates into its regions, potentially exacerbating reliability problems and market power of regional utilities. Solutions comprise more transmission interconnection, new generation and demand-side measures. In the IEA's view, transmission augmentation is essential for better integration. Several private, unregulated (entrepreneurial) interconnectors are under construction, but better signals for investment are needed.

The main challenge in the Australian power market is to complete the highly successful electricity reforms by reviewing transmission pricing with a view to strengthening interconnection, and by extending retail access to all consumers, using load profiling if necessary. A transmission price review was initiated in 2000. Full retail competition was initially foreseen by 2001 but will now be completed in 2003.

Liberalisation and integration of the Australian gas industry are key issues not only in their own right. They also improve the prospects for commercialisation of Australia's vast but remote gas resources and for a relatively environmentally benign increase in the role of gas in its energy market. Reform of the downstream natural gas industry is more recent than electricity reform. All states except Tasmania and the Northern Territory have submitted grid access regimes to the National Competition Council for approval, but by April 2001, only the regimes of South Australia, Western Australia and the Australian Capital Territory had been approved; the others are pending. Full retail competition is expected by 2002.

Among those customers already eligible, a sizeable number have switched suppliers, but it is too early to discern any clear effect on prices. To date, Western Australia is the only state with significant upstream reform. The National Competition Council estimated that this led to price reductions of 25-50 per cent.

There is significant progress in network integration. In the last ten years, the transmission pipeline system doubled in length. Although there is still little interconnection, two new pipelines have just been completed, and some ten pipeline projects are at various stages of development, including the first-ever pipeline connection with a foreign country, the 2,500 km pipeline between Brisbane and Papua New Guinea. Furthermore, six major LNG projects under discussion could double Australia's exports from its existing LNG terminal to 15 million tonnes by 2020. One of these projects came closer to realisation in 2001, when a supply contract for 4.8 million tonnes of LNG as of 2005 was signed with the United States. Gas market reform and development have proceeded somewhat more slowly than anticipated, but appear sound and should be continued.

Market reform is also continuing in the coal and oil industries. In the coal industry, the main objective is increased productivity and less sector-specific regulation. In the downstream oil industry, where in some locations market power can be an issue, generalised price controls have been abolished in favour of sporadic "hot-spot" investigations.

Under the Kyoto Protocol[1], Australia is committed to limit its greenhouse gas emissions in 2008-2012 to 108 per cent of their 1990 levels. Current forecasts predict that actual emissions could be as high as 123 per cent. An important

1. The evolving U.S. position on the Kyoto Protocol and climate change mitigation may change the context for developing energy-environment policy in IEA Member countries. The Australian government stated in May 2001 that its climate change mitigation policy as described in this report would not change in the light of these developments.

underlying factor is Australia's relatively energy-intensive economic structure, economic growth and the expectation of 30 per cent population growth between 1990 and 2010.

The Australian government's response measures comprise the Greenhouse Gas Abatement Programme (a competitive bidding programme that supports measures for greenhouse gas emissions abatement or sink enhancement), the Greenhouse Challenge programme (a voluntary energy efficiency programme aimed at industry), mandatory efficiency standards, energy labelling, and support programmes for energy efficiency.

The most important measure related to renewables is the new Mandatory Renewable Energy Target (MRET). It aims to raise the contribution of renewable electricity generation to 9,500 GWh by 2010. This corresponds to a 2 per cent increase in the share of renewable generation. Overall, national government spending for greenhouse gas abatement in 1999-2004 amounts to nearly A$ 1 billion.

The government made a public commitment in August 2000 to adopt only greenhouse policies that are cost-effective, minimise the burden on businesses and allow Australian industry to remain competitive. With its current range of greenhouse gas abatement programmes and through use of the Kyoto flexibility mechanisms, the Commonwealth government believes it can reduce emissions growth sufficiently to meet the Kyoto target. But it also expects greenhouse benefits from energy market reform over the long term. However, owing to the low cost of coal, electricity market reform has so far led to increased use of coal, especially Victorian brown coal, and increased carbon and air pollutant emissions. The reform of the gas market is expected to lower gas prices and lead to greater gas use in the power and other industries. It is too early to discern any significant effects in this sense.

RECOMMENDATIONS

The government should:

Energy Market and Energy Policy

- Maintain and build on its successful implementation of competitive energy markets, especially in the grid-based energy industries, while addressing remaining issues, such as reliability of supply.

- Maintain the basic regulatory structure, which appears to be sound, but undertake efforts to streamline regulatory processes and interaction between the individual organisations, especially at the state-Commonwealth interface.

- Provide innovative approaches to reducing greenhouse gas emissions. Seek to design mechanisms for internalisation of externalities in such a way that they do not penalise those industries most exposed to international competition that is not burdened by environmental regulations. Implement these mechanisms swiftly to gain experience.

- Give special attention to crafting solutions to the problem of declining crude oil production, petroleum products security of supply, and effectively functioning and reliable energy retail markets.

Energy Efficiency, Environment and Renewables

- Continue to use, and if possible expand, incentives within the regulatory reform process, such as the Mandatory Renewable Energy Target, to reduce adverse environmental consequences.

- Implement the Mandatory Renewable Energy Target rapidly, and review it periodically with a view to tightening it.

- Finalise as soon as possible the data collection on land-use and sinks in order to provide a reliable evaluation of the potential gap between the Kyoto commitment and the measures decided or set in motion under the National Greenhouse Strategy. If necessary, set up an action plan to address the gap, in co-ordination with all stakeholders.

- Define a coherent national energy efficiency strategy with clear and firm objectives, measures, implementation and evaluation. Foster market-oriented approaches to meeting energy and electricity efficiency targets by 2010.

- Rapidly develop programmes to increase automotive fuel efficiency and pursue the introduction of mandatory fuel efficiency standards.

- Participate in international efforts to reduce dramatically the cost of renewable energy equipment through market aggregation and large-scale manufacturing. Support IEA Implementing Agreements to meet this objective.

- Expand opportunities for manufacture of wind turbines, bagasse-fired high-pressure turbines, photovoltaics and biomass gasification units.

- Place greater emphasis on measures to reduce emissions from burning coal (e.g. clean coal technologies, power station efficiency standards).

- Consider whether policies favouring increased use of gas would provide least-cost solutions to meeting greenhouse gas targets.

- Consider measures to reflect the full environmental costs in the price of different fuels so that gas can compete on a fairer basis with coal.

- ☐ Continue to provide a favourable environment for renewables in niche markets, such as the "dispatchable wind power" in Tasmania.

Coal

- ☐ Complete the reform of the coal industry. In particular:
  - Continue its efforts to remove over-regulation;
  - Implement the recommendations of the Productivity Commission, especially those relating to work practices and industrial relations, where this has not already happened.

- ☐ Monitor the progress made in the states regarding third party access for coal freight services in the coming months and, if necessary, work with the state governments to ensure that effective, non-discriminatory and transparent access regimes are developed and implemented.

- ☐ Encourage state governments to set prices for port services in a transparent manner. Ensure that rates of return used for port pricing reflect those of a representative basket of Australian industries.

- ☐ Encourage the shift towards *ad valorem* royalties.

Oil

- ☐ Continue to implement the measures under its 1999 Offshore Petroleum Strategy, especially those relating to pre-competitive surveys and data and information dissemination.

- ☐ In parallel, continue to review and adapt its upstream regime, especially the fiscal regime and the licensing process. This should be done with a view to maintaining the international competitiveness of the Australian oil industry and in order to attract new investment, especially in exploration.

- ☐ In the downstream oil sector, implement those recommendations of the last in-depth review that are still valid, notably:
  - Implement all reforms proposed by the Australian Competition and Consumer Commission (ACCC) to eliminate remaining market power in oil product retailing;
  - In particular, re-submit the legislation repealing the Petroleum Retail Marketing Acts and replacing it by the Oilcode at the earliest convenient moment. Prepare this action by further negotiation with the industry, as well as by devising an alternative legislative solution;
  - Take a proactive role to ensure that deregulation of the downstream sector at Commonwealth level is supplemented at the state level.

- ☐ Maintain the current approach to the refining industry, and continue to inform the sector about future policies affecting it in a transparent manner and with ample notice.

Natural Gas

- ☐ Continue its policies to promote fully competitive gas retail markets, with special emphasis on the upstream business.

- ☐ Lend continued support to pipeline infrastructure investment, to enhance competition and provide benefits to consumers and traders alike.

- ☐ Create conditions to supply domestic gas demand from indigenous resources as well as through imports from neighbouring countries.

- ☐ Pursue its plans to create conditions for significantly increased LNG production to supply the growing demand in the Asian market and elsewhere.

Electricity

- ☐ Consider measures to promote investment in interconnectors taking into account the potentially large benefits of reinforced interconnections for reliability and competition.

- ☐ Invite the states to consider the added value that privatisation might bring about and, for as long as the industry remains in public ownership, set measures to promote competitive neutrality with a special emphasis on ensuring that publicly-owned companies operate and compete under the same terms and conditions as private companies.

- ☐ Ensure that small end-users share the benefits of reform. To this end, encourage the states to:
  - Introduce full retail contestability promptly;
  - Review tariffs for distribution and domestic end-users, and establish a clear benchmarking of these tariffs across Australian states;
  - Ensure that the right to choose supplier can be effectively exercised by small end-users.

- ☐ Review policies concerning investment in transmission and generation and market design, including greater demand-side participation, to ensure security of supply.

- ☐ Monitor reliability and, if needed, consider measures to promote investment in additional capacity.

- ☐ Identify options to streamline and simplify regulatory processes and to improve co-ordination among regulatory bodies.

- ☐ Encourage the states and the relevant institutions to finalise plans for the reform of transmission pricing and to implement them.

- ☐ Review trading arrangements in the wholesale electricity market, especially the need for a mandatory pool, in the light of international experience.

Technology Research and Development

- ☐ Implement the key recommendations of the Chief Scientist's report.
- ☐ Expand R&D collaboration with major centres of energy and power research, focusing on priority areas of modern power technology.
- ☐ Implement or participate in RD&D programmes on coal production, transportation, utilisation and carbon sequestration. Collaborate with major vendors to bring coal-gasification technology into the global market-place.
- ☐ Support public-private partnerships to integrate information technology into electricity and gas networks.
- ☐ Place greater emphasis on measures to reduce emissions from burning coal (e.g. clean coal technologies).

2

ORGANISATION OF THE REVIEW

An IEA review team visited Australia in December 2000 to review the country's energy policies. This report was drafted on the basis of information received during, prior to and after the visit, including the Australian government's official response to the IEA's 2000 policy questionnaire and the views expressed by various parties during the visit. The team greatly appreciated the openness and co-operation shown by everyone it met.

The members of the team were:

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The team held discussions with the following organisations:

- The Department of Industry, Science and Resources (ISR);
- The Australian Greenhouse Office (AGO);
- The Australian Competition and Consumer Commission (ACCC);
- The National Competition Council (NCC);
- The Australian Bureau of Agricultural and Resource Economics (ABARE);
- Commonwealth Scientific and Industrial Research Organisation (CSIRO);
- The Ministry of Energy and Utilities (New South Wales);
- The New South Wales Treasury;
- The Independent Pricing and Regulatory Tribunal (IPART) (New South Wales);
- The Office of the Regulator-General (ORG) (Victoria);
- The Sustainable Energy Development Authority (SEDA) (New South Wales);
- The Sustainable Energy Authority of Victoria (SEAV);
- The Australian Gas Association (AGA);
- The Australian Institute of Petroleum (AIP);
- The Australian Petroleum Production and Exploration Association (APPEA);
- The Australian Pipeline Industry Association (APIA);
- The Electricity Supply Association of Australia (ESAA);
- The National Electricity Market Management Company (NEMMCO);
- Renewable Energy Generators Australia Ltd (REGA).

3

ENERGY MARKET AND ENERGY POLICY

OVERVIEW

Australia is the only country that occupies an entire continent. It encompasses several climatic zones, ranging from desert climate in the vast central areas of the continent to marine climate in Tasmania and the lower eastern seaboard, humid subtropical climate farther north and savannah near the northern coast. Australia is the lowest, the flattest and, apart from Antarctica, the driest of the world's continents. Great variability in rainfall is characteristic of much of Australia, as are extreme climate events such as droughts, floods and tropical cyclones. With a land surface of just over 7.7 million square kilometres, Australia is the sixth largest country in the world, roughly comparable to the United States without Alaska. Vast distances separate urban centres within Australia, and even greater distances separate Australia from other countries.

Australia is a relatively young nation. Systematic European settlement began after 1800, and the Australian Federation was declared exactly one hundred years ago[2]. Australia's population in 1998 was 18.7 million, yielding a low average population density figure of 2 persons per square kilometre. In comparison, Canada also has 2 persons per km^2, the United States 29, Indonesia 105, China 130, India 291, and the Netherlands 376[3]. Population is increasing rapidly today and is projected to grow by 29.6 per cent to almost 24 million by 2020. This growth rate is higher than that of many other IEA countries.

The majority of Australia's population is concentrated in a relatively narrow strip along the southern and eastern seaboard, in Victoria and New South Wales, with another pocket in the Perth area in Western Australia. The cities of Sydney, Melbourne, Brisbane, Perth and Adelaide together account for 11.4 million inhabitants or over 60 per cent of the country's total population. There are vast areas in the centre of the continent where population density is extremely low. Unlike many other IEA countries, land-use patterns in Australia are still undergoing significant change.

Australia is a federal country. The country has a Commonwealth government, six self-governing states and two self-governing territories, and more than 700 local governments. Australia's constitutional arrangements are complex. The central Commonwealth government has limited constitutional powers in relation to many aspects of the energy economy. It is responsible for income and company taxation, interstate and foreign trade, foreign investment and compliance with international treaty obligations. State and territory governments have primary responsibility within their borders for energy production, transport, land-use, mineral rights and environmental assessments.

2. The Commonwealth of Australia was proclaimed on 1 January 1901.
3. Source: United Nations Statistics Division: *World Statistics Pocketbook*, *Statistical Yearbook* and *Demographic Yearbook 1999*.

ENERGY MARKET

Energy Production and Supply

Australia has vast reserves of low-cost energy. Reserves which could be recovered economically at current prices are coal, uranium, natural gas, crude oil and condensate, and naturally occurring liquefied petroleum gas (LPG). As an approximate, and conservative, measure of demonstrated economic resources, brown coal reserves cover 820 years at current rates of production, hard coal 290 years, uranium 270 years, natural gas 36 years, LPG 35 years, and oil 13 years. Further reserves, particularly of oil and gas, are being discovered.

About half of Australia's total energy production is exported (net exports, 1999). Australia is the world's largest exporter of hard coal, and hard coal is Australia's largest export industry. The country's exports have ranged between 35 and 40 per cent of world sea-borne trade since 1984. They accounted for over 10 per cent of Australia's total exports and more than 1 per cent of GDP in 1999. Coal exports are fairly evenly divided between steam coal and coking coal. Steam coal is exported mainly to markets in North Asia; coking coal mainly to Japan, Korea and Europe.

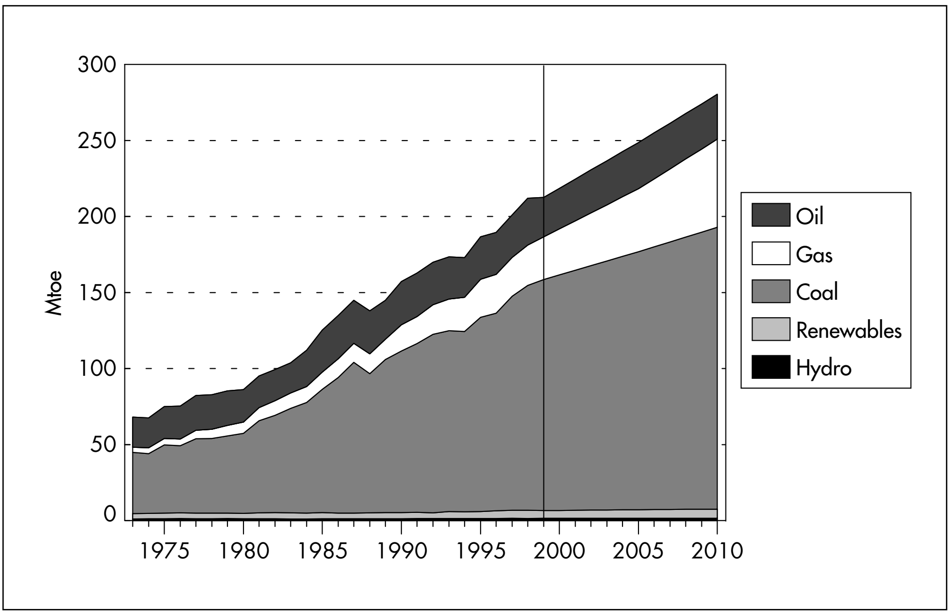
Australia accounts for nearly 30 per cent of the reasonably assured resources of uranium in the world and is the world's second largest producer of uranium after Canada. The country has no nuclear programme, and all uranium production is for export to Japan, the United States and European countries. Australian uranium mining and exports are subject to strict environmental controls and nuclear safeguards.

Following a change in government in 1996, the new government removed the previous government's policy, which restricted uranium mining to three mines: Ranger (Northern Territory), Olympic Dam (South Australia), and Nabarlek (Northern Territory). The latter was closed in 1988. Following the abolition of the "three mines" policy in 1996 and following increases in uranium prices the same year, uranium exploration activity picked up in 1997 and 1998, and exploration expenditure increased to more than A$ 19 million in 1998 (*Note:* in 2000, A$ 1 = US$ 0.578 = € 0.630). However, exploration expenditure declined to around $A 9.3 million in 1999. The new Beverley mine in South Australia commenced commercial production in late 2000.

Total cumulated uranium oxide (U_3O_8) production between the beginning of the industry in 1954 and 1998 was 77,692 tonnes. Uranium production has increased in recent years from 5,848 tonnes of U_30_8 in 1996 to 8,937 tonnes in 2000. The revenue from uranium exports in 2000 was A$ 426 million. This corresponded to less than 0.1 per cent of GDP. Hence, the uranium export industry is significantly smaller than the coal industry. All Australian production is exported, and Australia plays a key role in supplying uranium to other countries, enabling them to meet their objectives of diversity of energy supply mix and energy security.

Australia is also a net exporter of natural gas and is currently the third largest LNG exporter in Asia after Indonesia and Malaysia. Most of the exports are sold under long-term contracts to Japan. In the last few years, exports reached 7.9 million tonnes of LNG per year. Very significant increases of LNG exports under discussion could lead to a doubling of LNG exports in 2020. A new pipeline project is to link Australia to Papua New Guinea, allowing pipeline gas trade with another country for the first time. Figure 1 shows energy production over time. With 72 per cent of total production in 1999, coal dominated energy production.

Figure 1
Energy Production by Fuel, 1973 to 2010



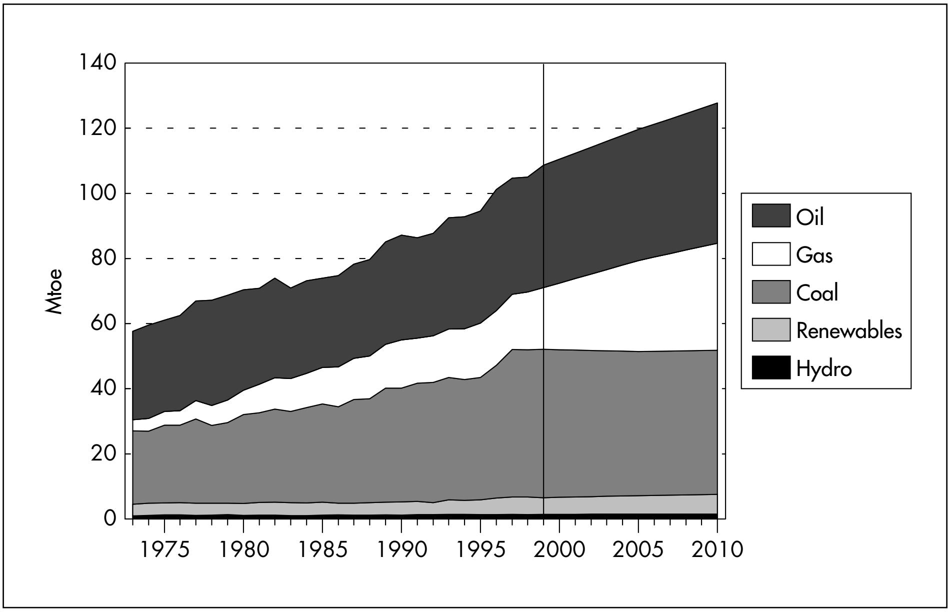
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

Figure 2 shows total primary energy supply (TPES). Coal dominates domestic energy supply with 47.4 million tonnes of oil equivalent (Mtoe) or nearly 44 per cent of TPES in 1999. This was followed by oil (35.6 Mtoe or 33 per cent of TPES) and gas (18.2 Mtoe or 16.9 per cent of TPES). Together, fossil fuels contributed almost 94 per cent to TPES. The remainder was from renewables, of which 4.9 per cent is combustible renewables, mainly bagasse (sugar cane waste) and wood, 1.3 per cent hydroelectricity, and 0.1 per cent solar, wind and other.

Energy Demand

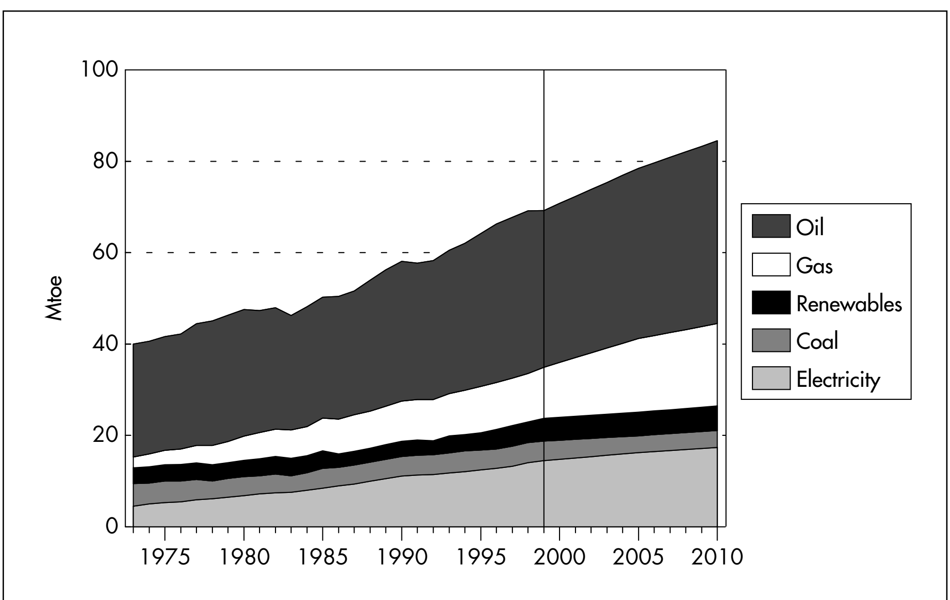
Figures 3 and 4 depict energy demand (total final consumption, TFC) by fuel and by sector. Electricity generation, industry and transport are the largest consumers of energy. Transport accounts for almost 40 per cent and is almost exclusively based on oil products. A range of fuels is used in the industrial sector, including hard coal in basic metal products, and oil and gas in basic chemicals. Just over 80 per cent of electricity generation is based on coal.

Figure 2
Total Primary Energy Supply, 1973 to 2010



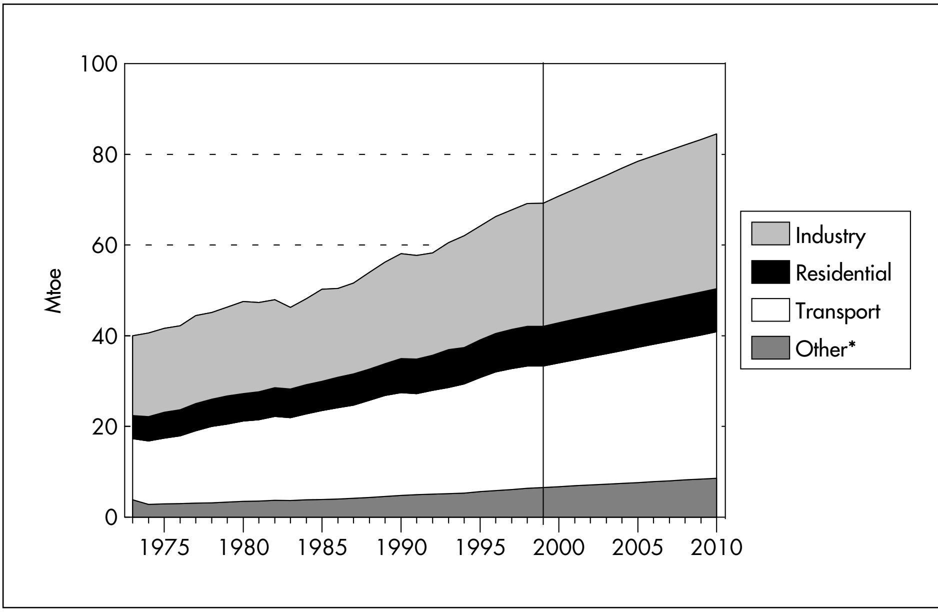
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

Figure 3
Total Final Consumption by Fuel, 1973 to 2010



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

Figure 4
Total Final Consumption by Sector, 1973 to 2010



* includes commercial, public service and agricultural sectors.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

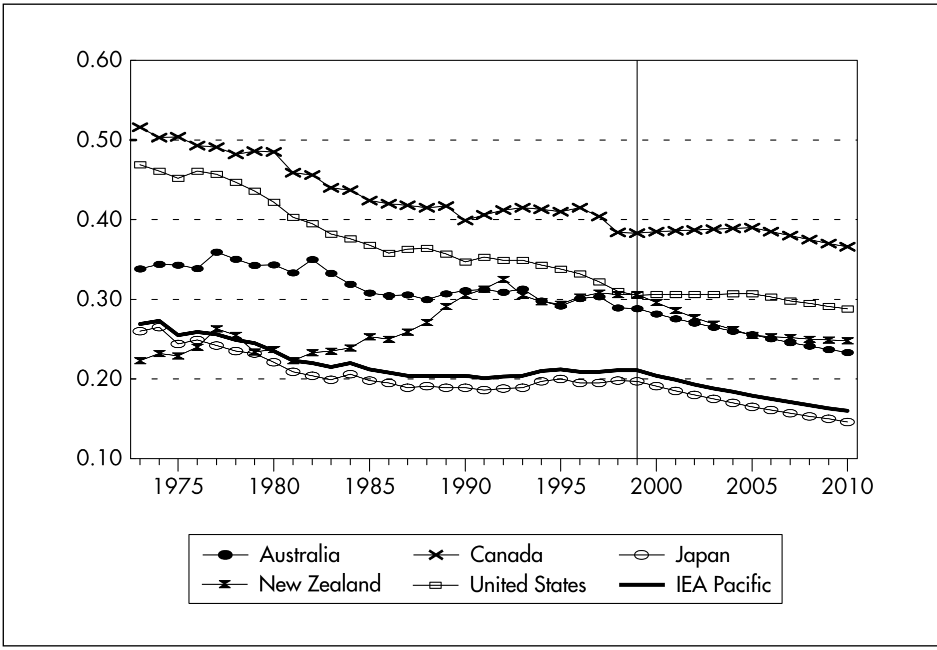
Australia's energy intensity per unit of GDP has been on a slow declining trend since 1982 (Figure 5). At 0.24 tonne of oil equivalent per thousand U.S. dollars[4] in 1999 (0.25 in 1998) it is mid-way between the IEA Pacific region (0.17 toe/thousand US$ in 1998) and IEA North America (0.31 toe/thousand US$ in 1998), and very close to the IEA overall average (0.24 toe/thousand US$ in 1998). Per capita energy intensity is increasing, up to 3.65 toe per person in 1999 from 3.40 in 1990, largely due to GDP growth.

Like all major industrialised economies, Australia has experienced a decline in the importance of its goods-producing sector relative to its service sector over the past decades. However, the impact of the shift towards the service sector has been partly offset by a shift towards energy-intensive production, owing to Australia's abundant, low-cost energy resources. The net effect of the structural change towards both energy-intensive and service industries has been a decline in the energy intensity of the Australian economy between 1973 and 1999 by about 6 per cent according to IEA data (12 per cent over roughly the same time span according to the Australian Bureau of Agricultural and Resource Economics, ABARE).

Geography, patterns of urban settlement and trade patterns result in Australia having large requirements for national and international passenger and freight transport.

4. At 1990 prices and exchange rates.

Figure 5
Energy Intensity in Australia and in Other Selected IEA Countries, 1973 to 2010
(Toe per thousand US$ at 1990 prices and purchasing power parities)



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000; *National Accounts of OECD Countries*, OECD Paris, 2000; and country submissions.

This is reflected in the country's pronounced growth in energy intensity per GDP in the transport sector.

The Australian economy has grown strongly over the last few years, reaching 3.8 per cent growth in 1998 and 4.4 per cent in 1999. Annual growth averaging over 3 per cent is expected until the end of the decade. A recent report[5] by the Australian Bureau of Agricultural and Resource Economics (ABARE) on energy market developments and projections estimates that, largely due to this GDP growth, Australia's total primary energy consumption grew by 3.6 per cent per annum between the financial years 1993/94 and 1997/98.

Increased electricity demand in the competitive National Electricity Market (NEM) was responsible for this growth to a significant degree. Primary energy use in the electricity sector averaged over 5 per cent per year in this time period, and in 1997/98, growth over the previous financial year even rose to 9 per cent, making electricity the largest consuming and fastest growing sector in that year. Increased

5. Bush, S.; Dickson, A.; Harman, J.; Anderson, J.: *Australian Energy – Market Developments and Projections to 2014/15*. ABARE Research Report 99.4, Canberra, 1999.

energy consumption for power generation was especially strong in Victoria and Queensland. In Queensland, energy use for power generation grew by 8.3 per cent over the whole period, and by more than 15 per cent in 1997/98. Since over 97 per cent of power generation in Queensland is coal-fired, this expansion led to increases in hard coal consumption. In Victoria, the 1997/98 growth rate was 12.6 per cent, and since Victorian power generation is dominated by brown coal, power demand growth has resulted in strong growth in brown coal consumption.

Moreover, Victoria, New South Wales, the Australian Capital Territory (ACT) and South Australia are interconnected in the south-east integrated electricity market and trade electricity among themselves. Since 1993/94, brown coal has strongly expanded its share in the fuel mix of this interconnected region and has become the primary fuel source for electricity generation, substituting for hydro, natural gas and hard coal. At the national level, this has meant that the long-term trend towards greater use of natural gas has stalled in favour of coal, especially brown coal. Since Victoria's brown coal plans have relatively low thermal efficiencies, this substitution has also had the effect of reducing the average thermal efficiency in the power market to the levels of the late 1980s.

In the same study, ABARE predicts that total Australian energy consumption will rise to about 145.4 Mtoe in 2014/15, which represents almost a halving of the growth rate experienced since 1973. The reasons for this are:

- Expected further improvements in energy efficiency, in response to price-induced behavioural changes by consumers, technological improvements and government policy. Transformation efficiency in the electricity sector is expected to increase because of greater use of natural gas and cogeneration. In the longer term, significant end-use efficiency improvements are expected in the road transport fleet, and in the residential and commercial sectors. The transport sector is expected to overtake the electricity sector as the main energy-consuming sector in 2014/15.

- Over the medium to long term, strong growth in natural gas consumption is expected in electricity generation, mining, manufacturing and in the commercial sector. The projected annual growth rate for natural gas use is almost 4.3 per cent up to 2014/15. This expectation is partly based on the numerous new pipeline projects that are currently under discussion. Strong support for natural gas demand also comes from the manufacturing sector, which is the main gas-consuming sector in Australia. Although the share of this sector in total energy consumption has fallen throughout the last two decades, ABARE expects this trend to diminish quickly with the sector sustaining its share of 40 per cent of total energy use in 2014/15. This translates into increased energy and gas consumption in absolute terms.

- Whereas coal has benefited most from electricity market reform in recent years, ABARE expects this effect to be transitory. As competition in the power market matures, putting more market participants under competitive pressure, and as competition in the gas industry is phased in, gas is expected to become much cheaper and to compete more favourably with electricity in end-uses.

- For the past 25 years, the mining sector has had the strongest growing energy demand, but demand growth is expected to be much slower in the future.

The ABARE study projects total energy production in Australia to be 18 951 PJ in 2014/15, over 55 per cent above 1997/98 levels. Energy exports are also expected to increase significantly. This represents an annual growth rate of 2.6 per cent. Natural gas production is expected to grow at almost 7 per cent per year on average, largely owing to increased exports of liquefied natural gas (LNG).

In contrast[6], IEA energy production figures show an estimated increase in energy production to 280.4 Mtoe in 2010, representing a 32 per cent increase over 1999 figures. TPES is expected to increase by 18 per cent to 127.7 Mtoe by 2010,TFC by 21 per cent and exports by 41 per cent.

The ABARE study takes into account government energy efficiency and greenhouse gas abatement programmes up to 1996, but not beyond. The Australian Greenhouse Office is currently preparing an update on emissions. In April 2001, the government estimated greenhouse gas emissions to be some 22-23 per cent higher in 2010 than in 1990.

ENERGY POLICY

Energy Policy Institutions

A large number of institutions are involved in energy policy-making. One of the reasons for this is the federal structure of the country. The Constitution gives the Commonwealth government limited powers in relation to many aspects of the energy economy. The Commonwealth's constitutional powers relevant to the energy sector comprise responsibility for free and fair interstate trade in goods and services, income taxation, foreign trade, foreign investment and compliance with international treaty obligations. The Commonwealth government has a clear mandate to further Australia's interests in international forums. It also sees its role as fostering reform in all states and territories by providing national leadership. This leadership role is exemplified by the competition reforms that were undertaken starting in 1992.

In October 1992, an agreement was reached among the Commonwealth, state and territory governments to study how to apply national competition policy more effectively. A committee of inquiry, chaired by Professor Fred Hilmer, was established to examine relevant issues and advise governments on how competition principles could be put into effect. In August 1993, the committee presented its report *National Competition Policy*, often referred to as the Hilmer report. The report

6. Because of different definitions of the energy content of energy resources, there is a sizeable discrepancy between IEA and ABARE figures. For example, the 18 951 PJ of energy production expected by ABARE in 2014/15 amount to 452.6 Mtoe, and the corresponding 1997/98 value is 292 Mtoe. In contrast, the IEA estimates energy production in 1998 at 213.8 Mtoe.

contained numerous recommendations and was to become the basis of the Australian government's ensuing liberalisation policies. One of the recommendations stated that access to certain "essential facilities", such as electricity transmission systems, on fair and reasonable terms was an important element of national competition policy.

In 1993/94, the Industry Commission (part of today's Productivity Commission) estimated the benefits from these competition policy reforms at A$ 5.8 billion (in 1993/94 dollars) per year, with an additional A$ 1.8 billion (net present value over 35 years) if further interstate interconnection of electricity and gas networks took place.

After the benefits of reform were quantified in the Hilmer report and its recommendations had been transformed into concrete policy and legislative proposals, the Commonwealth government encouraged states to embark on these reforms through competition policy payments, the so-called "Hilmer cheques": the redistribution to states of revenues from taxes collected by the Commonwealth government was made dependent on progress with competition policy reform, including energy but also other sectors.

The National Competition Policy (NCP) Implementation Agreement sets out conditions for three tranches of NCP payments to states and territories, including specific requirements in relation to the current process of natural gas reform. National Competition payments are an economic dividend paid by the Commonwealth to states and territories in return for their investment in reform. The National Competition Council's third assessment, scheduled for completion before July 2001, is to build on the work of the first and second tranche assessments, undertaken in June 1997 and June 1999 respectively, of governments' progress in implementing the NCP reforms.

Satisfactory progress in meeting the NCP obligations is a prerequisite for states and territories to receive full payment since dividends derive from improved economic activity resulting from the implementation of reforms. The National Competition Council's formal assessments of state and territory reform progress include recommendations to the Commonwealth Treasurer on the level of payments. Where governments do not invest in reforms in the public interest, reductions in payments may be recommended. The NCP payments are available over the period 1997/98 to 2005/06[7].

The government also sometimes uses progressive legislation in one state as a model for others to follow. A recent and relevant example is the current process of nation-wide gas market reform, as described in Chapter 7. The same process was used for liberalisation of the power industry.

The main responsibility for energy policy in the federal government lies with the Minister for Industry, Science and Resources and the Department of Industry, Science and Resources. In common with other IEA countries, energy and

7. For information on estimated annual competition payments, please refer to http://www.ncc.gov.au, National Competition Policy Payments.

environment issues also involve other Commonwealth departments, such as the Department of Foreign Affairs and Trade, the Treasury, Environment Australia, the Department of Transport and Regional Services and the Australian Greenhouse Office (see below).

State governments have responsibility within their borders for energy production, transport, land-use, infrastructure and urban planning. States and territories also have constitutional power over development of energy resources such as coal, oil, gas and hydro within their jurisdictions. Responsibility for energy issues in states and territories lies mainly with ministries for energy, natural resources, mines and energy, or fuel and energy.

Apart from federal and state ministries, numerous other organisations have a strong impact on the design and implementation of energy policy. The following is a non-exhaustive list of the most important institutions:

- **The Council of Australian Governments (CoAG)**, comprised of the highest elected official from each jurisdiction (namely premiers, chief ministers and the prime minister), meets annually to consider issues that affect all jurisdictions. Energy and resource management issues are often considered.

- **The Australia New Zealand Minerals and Energy Council (ANZMEC)**. This group meets annually at ministerial level and is supported by a number of sub-groups and working groups comprised of representatives from each jurisdiction who meet to consider specific issues and report back to senior officials and ministers meetings.

- **The Australian Competition and Consumer Commission (ACCC)** was formed in 1995 by the merger of the Trade Practices Commission and the Prices Surveillance Authority. It is an independent statutory authority responsible for competition matters in general, and administers the 1974 Trade Practices Act and the 1983 Prices Surveillance Act. The Trade Practices Act, together with state application legislation, prohibits anti-competitive conduct across virtually all businesses in Australia. Under the Trade Practices Act, the ACCC is also responsible for third party access to facilities of national significance. In this function, it is the national regulator (except for Western Australia) for gas transportation pipelines and for distribution pipelines in the Northern Territory, as well as the national electricity regulator with responsibility for transmission network pricing, national electricity pricing oversight and electricity market conduct.

- **The National Competition Council (NCC)** is a policy advisory body established by all Australian governments in 1995. It provides national oversight of National Competition Policy. The NCC does not set reform agendas or implement reforms itself; those are the responsibility of the various governments. Although funded by the Commonwealth, the council is a statutory body, independent of the executive government. Essentially the council has four main roles;
  - Assessment of governments' progress in implementing the competition reforms – and recommendations to the federal treasurer as to the level of competition payments to be made to the states.

- Advice on the design and coverage of access rules under the National Access Regime, which is the methodology for third party access to essential infrastructure.
- Community education and communication of both specific reform implementation matters and National Competition Policy generally.
- Specific projects as requested by a majority of Australian governments.

■ **The Australian Competition Tribunal** is a national appeals body that reviews certain decisions of the ACCC and NCC. There are exceptions to its responsibility; for example, in the Western Australian gas market, appeals are heard by the Western Australian Gas Review Board.

■ **The Productivity Commission (PC)** was established in April 1998 under the 1998 Productivity Commission Act. The three bodies which joined to form the new Commission – the Industry Commission, Bureau of Industry Economics and Economic Planning Advisory Commission – had been amalgamated on an administrative basis already in 1996. The Productivity Commission is an independent Commonwealth agency and the government's principal review and advisory body on microeconomic policy and regulation. The commission's work covers all sectors of the economy, under both Commonwealth and state responsibility. The commission provides advice and holds independent public inquiries on matters relating to industry and productivity. It investigates complaints about competitive neutrality through its Commonwealth Competitive Neutrality Complaints Office, and reviews and advises on regulation through its Office of Regulation Review.

■ **The Australian Greenhouse Office (AGO)** was formed in 1998 to implement and help develop the government's greenhouse programmes and policies, and to contribute to the development of Australia's position on international greenhouse negotiations. At the national level, the political responsibility for climate change policy lies with the Ministerial Council on Greenhouse.

In addition, numerous other bodies have responsibility for energy matters across the board at state level, or nationwide for individual energy industries. The first category comprises state regulators such as the Victorian Regulator-General, the New South Wales Independent Pricing and Review Tribunal (IPART), or the Queensland Competition Authority. Organisations such as the National Electricity Market Management Company (NEMMCO), which is the independent market and system operator in the National Electricity Market, fall into the second category, as does the Gas Policy Forum. The Gas Policy Forum consists of representatives of all jurisdictions as well as industry. It was established to develop further policy initiatives related to natural gas market reform.

Energy Policy Objectives

The key objectives for Australian energy policy are contained in an energy policy framework released by ANZMEC in 1999. This framework provides a basis for co-operation on energy policy to improve international competitiveness and economic and social outcomes for Australia, while also contributing to sustainability and environmental objectives. The ANZMEC governments believe that this requires development of an open and competitive, or, as it is often put, contestable[8], national energy market. This is to include:

- The provision of reliable energy services to all Australians, including those in regional Australia.

- Improving the efficiency with which energy services are made available.

- Reducing the local and global environmental impacts of energy production, supply and use, and achieving a less carbon-intensive economy.

- Fully realising the energy sector's export potential in terms of commodities, technology and services, in line with new capacity development.

Since the release in 1993 of the Hilmer report, Australia has been engaged in energy market reform. Although market reform is not part of Australia's greenhouse response policy, the government believes such market reform will in the long run contribute significantly to reducing the growth rate of emissions by improving the efficiency of energy supply. In electricity, for example, greater competition is expected to provide incentives for more efficient production, including cogeneration, and to reduce incentives for over-investment in supply capacity. Integrated regulatory frameworks for gas and electricity can support greater penetration of natural gas into electricity generation and energy end-use.

National competition policy reforms for the electricity market were adopted in 1995. They are designed to encourage competition in the trading activities of government-owned enterprises and, in particular, to achieve competitive neutrality between government-owned and private industries.

Recent reforms have resulted in increased efficiency and productivity through restructuring the industry with vertical separation of generation and retail activities from the natural monopoly elements of transmission and distribution. This has been achieved through corporatisation of utilities, the introduction of competition into generation and retail markets by providing access to the transmission and

8. A contestable market is a market without any legal or statutory barriers to entry by new market participants. The absence of statutory barriers implies that consumers are free to chose their suppliers. Although a competitive market is necessarily a contestable market, the economic technical term contestability only expresses the potential that actual competition might occur. However, according to the theory of contestable markets developed in the early 1980s by William Baumol and others, contestability has the same ability to rein in potential market power abuses as actual competition, except in very few cases of strong natural monopoly where competition cannot be maintained over time. See Baumol, W.J., Panzar, J.C. and Willig, R.D.: *Contestable Markets and the Theory of Industry Structure*, New York, 1982. In Australia, the notion of contestability is used to designate what in other countries is often called competition. The background to this is that in a fully open market, it is up to private entities themselves to decide whether or not it is worthwhile to enter a market.

distribution systems on a non-discriminatory basis, and the enhancement and extension of interconnections between states. The national electricity market is structured around a mandatory pool for trading wholesale electricity. Actions are currently being initiated to reduce any residual impediments to the market.

The net effect of these reforms has been an increase in the level of competition and depth[9] in the energy market. There is also growing convergence between the electricity and gas industries, with a number of gas and independent companies seeking electricity retail licences in the new market.

In the natural gas market, a national strategy to introduce competition has been adopted. The regime contains a nationally uniform mechanism for the regulation of third party access to natural gas pipelines throughout Australia. It is designed to provide certainty in the terms and conditions of access to the services of gas infrastructure facilities, while preserving the role of commercial negotiation.

Accessibility and use of natural gas in Australia have increased significantly in recent years as a result of liberalisation and privatisation in the natural gas market. Traditionally a monopoly structure, government ownership of the natural gas pipeline system has progressively diminished, such that with a few exceptions in remote areas, all the major gas companies in Australia's gas pipeline and retail sectors are privately owned. The net effect of this reform has been a reduction in the price of natural gas and an increase in the accessibility of natural gas. The consumption of gas is expected to grow at a higher rate than the growth of total energy consumption in Australia over the next two decades.

The government has also set in motion measures that are designed to limit greenhouse gas emissions and increase energy efficiency and the use of renewables. Measures already in force encompass energy labelling of products and the establishment of minimum energy performance standards for major energy-using equipment, especially household appliances.

These are being progressively extended to a wider range of industrial and commercial equipment. Energy standards for commercial and residential buildings are being developed co-operatively with the industries concerned to extend standard building practice beyond minimum energy performance requirements.

Another important initiative is the Mandatory Renewable Energy Target (MRET), which aims at raising the contribution of renewable energies to Australian electricity supply by 9,500 GWh or around 2 per cent, to approximately 12.7 per cent in 2010. Further details about greenhouse policies and measures are given in Chapter 4 on energy and the environment.

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9. A market is called deep if it has a large number of players.

Energy Taxation

The Commonwealth of Australia levies excise taxes on crude oil[10] and on oil products. The current rates of oil product excise duties are listed in Table 1. Until 7 August 1997, the states levied State Government Business Franchise Fees; after that date, the fees were abolished and are now part of the Commonwealth excise tax. Some states impose taxes on natural gas sales, and Victoria has a levy on large gas users. States that own electric or gas utilities generally require the payment of dividends.

Table 1
Excise Taxes on Oil Products in Australia, 2001

Commodity	*Excise duty in Australian $ per litre*
Motor spirit – leaded	0.40516
Motor spirit – unleaded	0.38143
AVGAS	0.02808
AVTUR	0.02845
Kerosenes	0.07557
Diesel, light fuel oils	0.38143
Heating and fuel oils	0.07557

Source: Department of Industry, Science and Resources.

Australia has taxes on most transport fuels. The most significant is an excise levied on petrol and diesel on a cents-per-litre basis. This excise tax was indexed to inflation. In response to consumer protests against high prices following the oil price increases of 1999 and 2000, the government announced on 1 March 2001 that excise tax rates would be reduced by 3.8 per cent and that inflation adjustment of the excise taxes would be abolished. Taxation is a shared responsibility between the Commonwealth government and the states. Taxes are levied on upstream production, imported petroleum products and consumption.

On 1 July 2000, Australia introduced a Goods and Services Tax (GST) of 10 per cent on most goods and services sold in the country. The tax is essentially a value-added tax and replaces the Wholesale Sales Tax. The reform also included a streamlining of the tax system. In return for the new tax, the government reduced income tax and excises on petrol and diesel, eliminated an export tax and increased pensions and allowances.

The ACCC conducted a review and found that in the quarter immediately following the introduction of the GST, fuel prices had increased less than expected, especially taking into account the current high oil prices and the exchange rate of the Australian dollar.

10. For this and other upstream taxes and royalties see Chapter 6.

Taxation is not explicitly used to internalise environmental costs, with the exception of differential excise rates on unleaded gasoline and the excise exemption for alternative fuels such as LPG. The stated reason for this is that practical issues render the concept of fully cost-reflective pricing difficult to apply, because it is difficult to measure accurately the environmental impacts and costs associated with energy supply and use. The government also sees a need for careful assessment of the impact of internalisation of externalities through taxation on Australia's international competitiveness. The government is studying other mechanisms such as emissions trading to deal with the issue of externalities. For example, the Australian Greenhouse Office is currently investigating the feasibility of introducing a domestic emissions trading scheme.

The government has a number of tax rebate schemes in place to support certain activities seen as environmentally benign or socially relevant. These include:

- The Diesel Fuel Rebate Scheme (DFRS). This scheme provides rebates for diesel and similar fuels[11] used for certain eligible activities. The rebate is applicable to certain off-road activities including mining, agriculture, forestry, fishing, rail and marine transport, electricity generation for residential premises and the operation of hospitals, nursing, age-care homes and other medical institutions.

- The Fuel Sales Grant Scheme. From 1 July 2000, the government introduced a fuel sales grant paid to all retailers of petrol and diesel in regional and remote areas where fuel prices are generally higher. A grant rate of 1 cent per litre is paid for sales of petrol and diesel to consumers in regional areas, with a 2 cent per litre grant provided for sales in remote areas. For isolated cases where fuel prices are beyond A$ 1.20 per litre in very remote areas, fuel retailers may apply to the Australian Tax Office for an additional grant.

- The Diesel and Alternative Fuel Grant Scheme (DAFGS). The on-road Diesel and Alternative Fuel Grant Scheme is available to transport vehicles of over 20 tonnes gross vehicle mass (GVM) and transport vehicles weighing between 4.5 and 20 tonnes GVM that undertake their operations in the service of regional areas. The DAFGS provides grants to encourage the use of compressed natural gas (CNG), liquefied petroleum gas (LPG), ethanol and other renewable fuels.

CRITIQUE

Australia's energy sector has made significant progress since the last IEA review. Australia is at the leading edge in the reform of energy markets, especially in electricity. Its natural gas and electricity markets are in the process of developing towards an integrated national market, and performance of the energy sector has

11. Similar fuels include heavy fuel oil, light fuel oil and all fuels that attract the same duty as diesel (except for gasoline, coal tar and coke-oven distillates).

been good insofar as energy exports were carried out without any disruption and the energy markets have supported Australia's dynamic economic growth.

Competition in the electricity and gas industries has been successfully implemented. Regulatory obstacles to the integration of state markets into a national market have been overcome, and infrastructure projects have been proposed that could soon also eliminate physical bottlenecks.

The Australian National Electricity Market (NEM) is among the more advanced in the world and has introduced a number of innovations that provide inspiration to reformers in other countries. The benefits of reform include consumer choice, lower prices and increased capital and labour productivity.

The institutional set-up has undergone a deep transformation aimed at enhancing the competitive neutrality and transparency of regulatory decisions. This is commendable. The ACCC and the analogous organisations in the states provide a workable foundation for energy regulation.

The implementation of reforms also offers some useful lessons. In Australia's federal structure, the Commonwealth government has relatively limited constitutional powers on energy policies and there is a constant need to reconcile Commonwealth and state energy policies. Despite these difficulties, the states have taken a co-ordinated approach to reform. The Commonwealth government has played a key role in providing incentives for the states to move forward with reforms.

The decision-making and regulatory processes still appear complex and cumbersome, as do the processes for changing the codes. This is because of the inherent complexity of the federal system, but streamlining the regulatory apparatus should be a high priority. This does not mean that any of the existing organisations need to be dismantled or merged with each other. For example, the current structure with various layers of regulation for the grid-based industries – the state regulators responsible for distribution, the ACCC for regulation, the Australian Competition Tribunal for appeals and the NCC for high-level policy advice and assurance that states meet Competition Principle Agreement requirements – appears basically sound.

What may need some additional attention, however, is the way these institutions' tasks are delineated, the way they interact with each other, and the speed with which new infrastructure projects can pass through the system and obtain all necessary approvals. In any case, the timetable for full retail contestability should be maintained in both electricity and gas.

Within this very positive framework, much remains to be done. Electric sector reform has yielded major benefits in terms of lower prices for consumers, but issues to be resolved include: strengthening market-based solutions that build on existing foundations to address the power shortages and reliability problems in Victoria; ensuring competitive neutrality throughout the national market; and addressing environmental impacts in a market where coal-fired power remains the cheapest supply source.

Recent increased production from Victorian brown coal plants and concurrent air pollution and greenhouse gas emissions highlight the fact that competition *per se* is not an environmental protection mechanism. Competition can greatly reduce resource squandering, but it cuts resource use back to efficient levels at marginal private cost (at best). It does not take into account externalities. The government views this as a transitory effect and expects gas market reform to lead to lower gas prices, opening the possibility for substitution of coal by gas. It remains to be seen to what degree and how quickly this effect materialises.

Market liberalisation primarily helps save generating capacity, and hence capital. By providing more accurate price signals, e.g. through real-time spot market pricing and/or peak load pricing, competitive markets improve customers' information about the utilisation and scarcity of generating capacity. Consumers may then be able to adjust the timing of their consumption decisions accordingly. They may decide to switch on their dishwasher during the night when power is cheap, rather than during the daytime load peak. If many users do this, the cumulative effect may well be that new power plant construction can be deferred. But unless electricity prices rise significantly on average – which would be the contrary of what market reform is expected to yield – consumers will use their dishwashers as often as before. As long as their equipment is not replaced by more energy-efficient equipment, savings in electricity generation, and hence in energy resources, remain a side-effect at best.

Experience in other liberalised markets is also beginning to show that reluctant monopoly power utilities are not the main barrier to the uptake of renewable energies. The higher cost of renewables is still the major deterrent. In this situation, dismantling statutory barriers and installing multiple wholesale traders do not change the situation much. If a significant number of consumers are willing and able to pay extra for power generation from renewables, "green pricing" may have a beneficial effect. However, in most countries, the number of such customers is not large enough to yield any significant effect. Specific environmental support policies are still necessary to bring about change.

In the specific Australian context, characterised by abundant and cheap supplies of fossil fuels, especially coal, reconciling greenhouse goals and market liberalisation appears to be a particularly challenging task. Although policies and programmes encourage energy efficiency, actual implementation of energy efficiency measures is no easier in a competitive market-place than it was in a more centralised market; in fact, it may well be more difficult.

Climate change is among the most challenging issues for Australia because the country is greenhouse gas emission-intensive. Owing to uncertainties on land-use and sink issues, it is not yet possible to evaluate the possible gap with the Kyoto commitment. A new set of measures may be needed. The Australian Greenhouse Office is currently examining the feasibility of introducing a national emissions trading system to assist in meeting Australia's commitments. The Australian government has indicated its willingness to review its measures when international policies have been clarified.

Market-based approaches to implementing energy efficiency on a significant scale are not yet in place, but progress is under way. The Mandatory Renewable Energy

Target is a certificates trading system that is designed to be fully compatible with the national electricity market. It will soon come into force. A national greenhouse emissions trading system is under discussion, and, importantly, thought has already been given to making both systems compatible.

The Mandatory Renewable Energy Target aims to raise the contribution of renewables to the Australian electricity supply by 9,500 GWh over the ten years to 2010, to a total of approximately 12.7 per cent of total electricity generation. The target and its implementation mechanism are a significant first step. The biannual revisions of the overall target should be used to examine in a continuous manner whether the target can be made more ambitious.

Oil developments warrant attention. Upstream, oil production is projected to decline significantly in the coming years. Downstream, a major restructuring of the refining industry is anticipated. In the retailing sector, reforms should be pursued to liberalise the market.

The government has taken the initiative to develop a comprehensive energy policy within the coming months. This provides the opportunity to balance national objectives of industrial competitiveness, low prices for consumers and environmental sustainability. Current approaches point in the right direction and should be built on, but might have to be pursued with greater speed and vigour.

RECOMMENDATIONS

The government should:

- ☐ Maintain and build on its successful implementation of competitive energy markets, especially in the grid-based energy industries, while addressing remaining issues, such as reliability of supply.

- ☐ Maintain the basic regulatory structure, which appears to be sound, but undertake efforts to streamline regulatory processes and interaction between the individual organisations, especially at the state-Commonwealth interface.

- ☐ Provide innovative approaches to reducing greenhouse gas emissions. Seek to design mechanisms for internalisation of externalities in such a way that they do not penalise those industries most exposed to international competition that is not burdened by environmental regulations. Implement these mechanisms swiftly to gain experience.

- ☐ Give special attention to crafting solutions to the problem of declining crude oil production, petroleum products security of supply, and effectively functioning and reliable energy retail markets.

4

ENERGY EFFICIENCY, ENVIRONMENT AND RENEWABLES

CLIMATE CHANGE

Australia signed the Convention on Climate Change in June 1992 and ratified it in December 1992. The country is a signatory to the 1997 Kyoto Protocol. Under the Kyoto Protocol, Australia is committed to limit its average annual greenhouse gas emissions in the period 2008-2012 to 108 per cent of the baseline year 1990. Australia's target recognises the potentially high trade impacts of meeting Kyoto targets owing to the country's energy-intensive exports and limited opportunities to switch to less greenhouse gas-intensive forms of energy.

According to a government estimate, greenhouse gas emissions in 1990 were 389.8 million tonnes of CO_2 equivalent (see Table 2). This figure does not constitute the official baseline for the Kyoto Protocol accounting requirements, as the elements to be included in the baseline are still under negotiation.

Estimates from the 1998 National Greenhouse Gas Inventory show that Australia's net greenhouse gas emissions for 1998, excluding emissions from land clearing, were 455.9 million tonnes of carbon dioxide equivalent (see Table 2). Thus, over the period 1990 to 1998 greenhouse gas emissions for all sectors excluding land clearing rose by 16.9 per cent, largely because of Australia's strong economic growth. Preliminary results for the year 1999 indicate that the rate of growth in emissions has slowed.

If best estimates of land clearing emissions were incorporated, Australia's total emissions would be brought to 519.9 Mt in 1998. This would correspond to a 5 per cent increase in total emissions including land clearing between 1990 and 1998. But estimates are highly uncertain. Therefore, no reliable figure can be given.

Australia has a relatively high share of non-CO_2 greenhouse gas emissions, mainly from agriculture, (reductions in) forestry and land clearing. CO_2 contributes 68.4 per cent to total greenhouse gas emissions, methane 25.2 per cent, nitrous oxide 6 per cent, and perfluorocarbons 0.3 per cent. Table 2 details the development of emissions by emitting source (or sink) between 1990 and 1998. Total energy sector emissions comprise stationary energy use, transport energy use and fugitive emissions from energy extraction, infrastructure and use, and amount to 79.6 per cent of total national emissions.

Figures 6 and 7 provide further detail. Figure 6 details the development of emissions by fuel and by sector over time. Figure 7 shows CO_2 emissions per unit of GDP. It is noteworthy that Australia's population increased by 9.7 per cent between 1990 and 1998. The projected population increase between 1990 and 2010 is 30 per cent.

Table 2

Estimated Greenhouse Gas Emissions by Source, 1990 and 1998

(Million tonnes of CO_2 equivalent)

Sources and sinks	*Emissions in 1990*	*Emissions in 1998**	*Emissions growth 1990-1998*	*Share of total emissions in 1998*	*Main greenhouse gas*
			Per cent		
Stationary energy	208.2	258.7 (259.8)	24.3	56.8	
of which:					
• Energy production:		*187.9*[c] *(188.8)*[c]			
– electricity generation		*168.6 (171.8)*	*30.6*	*37*	
– petroleum refining		*6.5 (6.3)*			CO_2
– solid fuels production		*12.8 (10.6)*			(82 per cent)
• Energy use:					
– manufacturing/ construction		*51.7 (52.0)*		*11.3*	
– residential/services/other	*14.2*	*16.7 (16.7)*	*17.6*	*3.7*	
Transport	61.4	72.6 (73.9)	18.1		
of which:					
• Road transport:	*54.8*	*64.8 (66.6)*	*18.2*		CO_2
– Cars		*40.9 (37.9)*		15.9	(94 per cent)
– Trucks, buses		*23.8*			
• Air	*2.6*	*4.4 (4.2)*	*71.5*		
Fugitive emissions	29.5	31.5 (30.8)	6.7	6.9	CH_4 (80 per cent)
Industrial processes	12	9.8 (9.7)	-18.4	2.2	CO_2 (94 per cent)
Agriculture	90.6	92.2 (93.9)	1.8	20.2	CH_4 (76 per cent)
Forestry & other	-27.2	-24.5 (-25.9)	11.5	-5.4	-
Land clearing	*103.5*	*64 (71.7)*	*n.a.*[b]	*12.3*	-
Waste	14.9	15.5 (16.0)	4.2	3.4	CH_4
Total	**389.8**[a]	**455.9**[a] **(458.2)**[a]	**16.9**	**100**	CO_2 (68.4 per cent)

* Figures in brackets refer to 1999. The methodology for estimates of emissions from land clearing changed in the meantime.

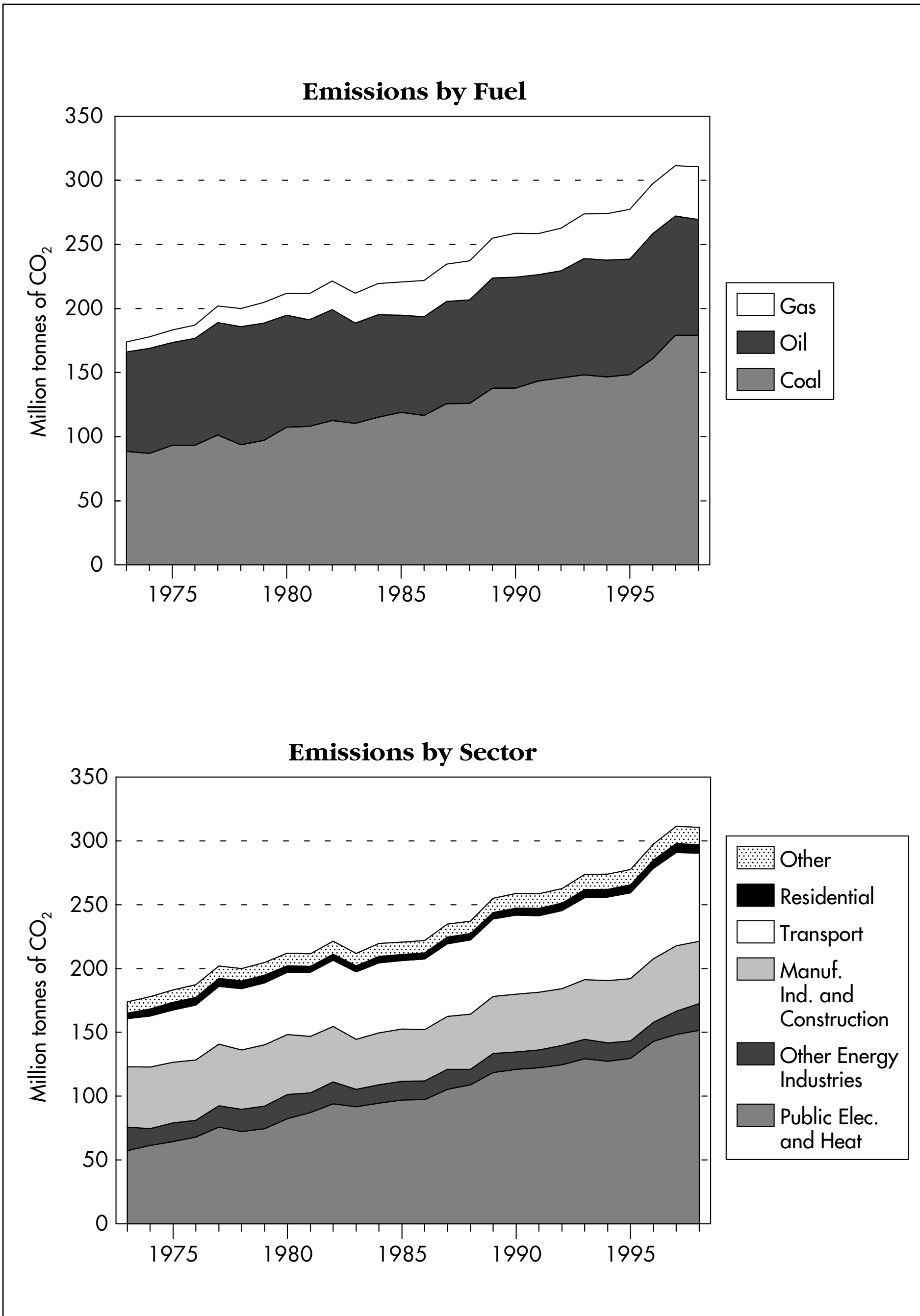
a. excluding land clearing emissions. If these were included (not in Kyoto Protocol accounting requirements), total emissions would amount to 493.3 million tonnes in 1990 and 519.9 million tonnes in 1998.

b. estimates are highly uncertain, especially over time.

c. italics only reported for information, but not included in the summation.

Source: Australian Greenhouse Office: *National Greenhouse Gas Inventory*, July 2000 and April 2001 issues.

Figure 6
Energy-Related CO_2 Emissions by Fuel and by Sector, 1973 to 1998

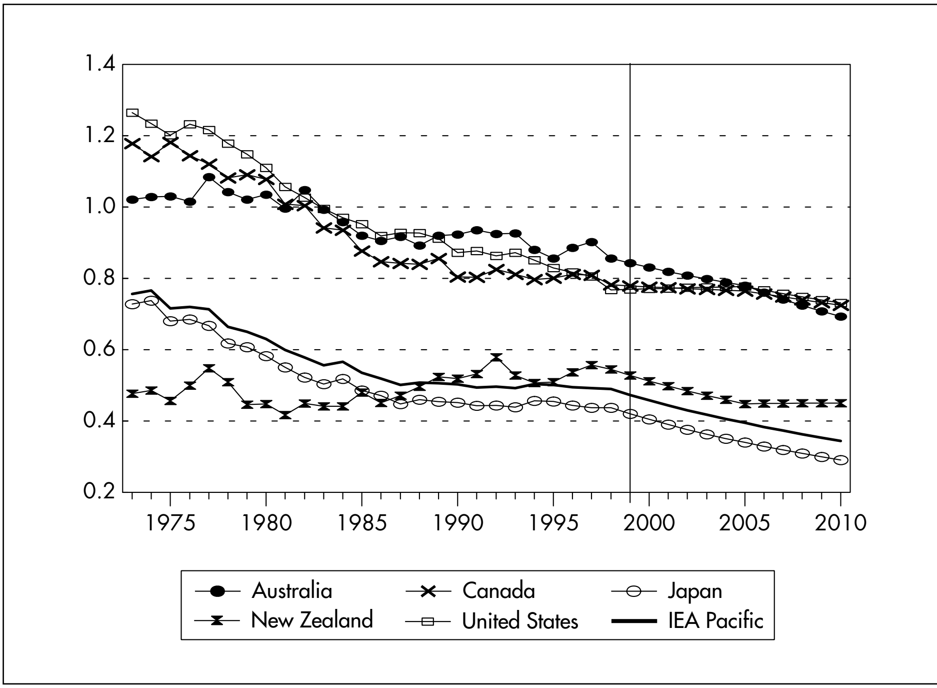


Source: *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2000.

Figure 7

Energy-Related CO_2 Emissions per GDP in Australia and in Other Selected IEA Countries, 1973 to 2010

(CO_2 emissions/GDP using 1990 prices and purchasing power parities)



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000; *National Accounts of OECD Countries*, OECD Paris, 2000; and country submissions.

Australia submitted its second national report to the Framework Convention on Climate Change (FCCC)[12] in November 1997. The next report is due in November 2001. The 1997 report contains emissions projections up to 2010, including the effects of policy measures to reduce emissions that were in place in mid-1997. According to this forecast, emissions from the energy sector, including transport but excluding fugitive fuel emissions, were expected to grow by 40 per cent (about 106 million tonnes of CO_2 equivalent) between 1990 and 2010, from 269.6 million tonnes to 375.4 million tonnes. This reflected assumptions of continuing growth in GDP, in minerals processing and in transport. Emissions from the energy sector were expected to grow in absolute and in relative terms, accounting for an increasing share of Australia's total greenhouse gas emissions.

Among the policy measures to reduce emissions that are included in the projections are microeconomic reform in the energy sector and the Greenhouse Challenge Programme (see below). In combination with other abatement measures, these

12. Commonwealth of Australia: *Climate Change. Australia's Second National Report under the United Nations Framework Convention on Climate Change*, Canberra, 1997.

were expected to reduce emissions growth from the energy sector in 2010 by 22 million tonnes compared with the levels they would otherwise have reached, i.e. from 128 million to 106 million tonnes.

Emissions from other sectors were expected to develop as follows. Agriculture accounted for about one-fifth of total national emissions in 1990. Emissions from this sector were projected to grow by 7 per cent (6 million tonnes) from 1990 to 2010. The forestry sub-sector provides a net sink. In 1997, the contribution of this sink for the year 1999 was estimated to amount to –5 per cent of total emissions, i.e. forestry was thought to have removed 23 million tonnes from gross total emissions in 1990. Plantation expansion and re-vegetation activities were projected to increase this sink by 8 million tonnes between 1990 and 2010. As can be seen from Table 2, the estimate for 1990 has been substantially revised since then.

Fugitive fuel emissions, waste emissions and non-energy emissions from industrial processes together accounted for about 10 per cent of total national emissions in 1990. They were expected to fall slightly, then increase again to exceed their 1990 levels by 11 per cent in 2010. According to data from the National Greenhouse Gas Inventory, land clearing – primarily for cropping and pastures – accounted for about one quarter of total national emissions in 1990, with this proportion declining to about one-sixth in 1995.

The uncertainties in estimating emissions in the land-use sub-sector, for both the inventory and projections, exceed those for any other sector. Historical land clearing data were mostly inferred through modelling, but analysis of satellite imagery provided some confirmation that figures used in the National Greenhouse Gas Inventory on recent land clearing rates were reasonably sound. There are uncertainties in estimating the emissions per unit of area of land cleared, especially for the carbon that is released over many years from soils. Because of the uncertainties in land clearing data, projections of future emissions from this sector were not presented in the second report to the FCCC.

All emissions developments taken together yielded the forecast for total emissions. Including all sources and sinks except emissions from land clearing, and allowing for the effects of policy measures up to mid-1997, Australia's total emissions were expected to increase by 28 per cent (110 million tonnes of CO_2 equivalent) between 1990 and 2010. In the absence of measures to reduce emissions of greenhouse gases, Australia's emissions would be approximately 552 million tonnes of CO_2 equivalent in 2010, an increase of 166 million tonnes or 43 per cent from 1990 levels.

New projections of Australia's emissions for 2010 are currently under preparation. Preliminary results yield estimates of around 22 to 23 per cent above 1990 levels (excluding emissions from land-use change). The new estimates are lower than the previous ones, in part because they reflect projected emissions savings from new abatement programmes, especially those announced in the prime minister's November 1997 statement "Safeguarding the Future" and the 1999 statement "Measures for a Better Environment".

RESPONSE POLICIES

Policies and Institutions

In recognition of the importance of reducing greenhouse gas emissions, the Commonwealth government's stated goal is to ensure that Australia carries its fair share of the burden in worldwide efforts to combat global climate change. In August 2000, the Minister for Industry, Science and Resources clarified the position of the Australian government in this respect. According to the minister's statement, the Australian government remained fully committed to Australia's international greenhouse obligations. However, the national interest was to maintain the competitiveness of Australian industry. In this context, the minister emphasised that many sectors of Australian industry face competition from industries located in developing countries which have no obligations to reduce emissions under the Kyoto Protocol and would not face Australia's costs. This applies in particular to the liquefied natural gas (LNG) industry (see Chapter 7). Against this background, the minister announced that the government was committed to the pursuit of cost-effective greenhouse gas abatement policies and measures in order to minimise the burden for business and the community so that Australian industry can remain competitive. The government would only have implemented a mandatory domestic emissions trading scheme if the Kyoto Protocol had been ratified by Australia, had entered into force, and if there had been an established international emissions trading regime.

An important element of the Australian government's policy response to climate change was formulated as of 1992 in the form of the National Greenhouse Response Strategy (NGRS). This document, which was endorsed by the Council of Australian Governments in December 1992, listed three potential policy areas related to climate change abatement in the energy sector: potential emissions reductions flowing from energy market reform and competition, internalisation of externalities in energy pricing, and specific action to promote energy efficiency and renewables. In Australia, greenhouse abatement is viewed as a positive consequence of pursuing competition policy objectives in energy markets.

The National Greenhouse Response Strategy was reviewed as of late 1996 and replaced by the National Greenhouse Strategy (NGS) in 1998. The release of the NGS was a policy initiative of the Commonwealth, state and territory governments, and builds on a co-operative effort of governments.

The NGS contains a series of policies and measures within an overall strategic framework designed to meet Australia's international climate change commitments. The strategy has eight modules targeting all sectors of activity that have a bearing on Australia's energy efficiency and greenhouse gas emissions. Among these are energy, transport, industry, waste, agriculture and vegetation, and households. The NGS provides a framework for action by all levels of government. Implementation plans are currently being finalised for this strategy, which focuses action on three areas:

- Improving awareness and understanding of greenhouse issues.

- Reducing greenhouse gas emissions and enhancing greenhouse sink capacity.

- Developing adaptation responses.

Reducing emissions of greenhouse gases, consistent with the Kyoto Protocol, has been identified by governments as the most important of the three areas for action. Included in the National Greenhouse Strategy are a range of pre-existing actions as well as new policy initiatives. In 1997, the Australian prime minister announced a major policy package entitled "Safeguarding the Future: Australia's Response to Climate Change". This package received funding of A$ 180 million. The most important individual measures in this package are described in the sections below on Energy Efficiency and on Renewable Energy Sources in this chapter. All measures under this package are now part of the National Greenhouse Strategy, as are other state and territory initiatives.

The effects of the Safeguarding the Future initiative are not included in the emissions projections prepared in 1997 for the second report to the FCCC, as this initiative was announced at the end of the year. It was estimated, however, that this package would reduce Australia's net emissions in 2010 by about 39 million tonnes.

In May 1999, the prime minister announced an additional package of policy measures under the title "Measures for a Better Environment". Within this framework, the government has allocated a further A$ 796 million to new greenhouse abatement measures in accordance with Australia's Kyoto commitments. This brings total government expenditure on climate change measures to almost A$ 1 billion between 2001 and 2004.

About half of the funding included in the Measures for a Better Environment package, i.e. some A$ 400 million, is to be spent under the Greenhouse Gas Abatement Programme (GGAP). This measure commenced in 2000 and runs until 2004. It aims to reduce Australia's net greenhouse gas emissions by supporting projects that are likely to result in substantial emissions reductions or substantial sink enhancement, particularly in the first commitment period under the Kyoto Protocol (2008-2012).

The guidelines for this programme were examined and approved by the Ministerial Council on Greenhouse. This council comprises the Minister for the Environment and Heritage, the Minister for Industry, Science and Resources, the Minister for Agriculture, Fisheries and Forestry, and since December 1999 the Minister for Finance and Administration.

Applicants from across the economy can seek funding for large-scale, cost-effective investment projects that result in sustained greenhouse gas abatement in a competitive bidding process. To qualify, projects must be new and lead to quantifiable abatement not expected to occur in the absence of GGAP funding. Winning bids must minimise both GGAP funds needed and net national cost per tonne of CO_2 equivalent abated in 2008-2012.

Priority is given to projects that deliver abatement exceeding 250,000 tonnes of carbon dioxide equivalent per year. One of the criteria for selection is that projects should provide complementary benefits such as rural and regional development opportunities, contributions to ecologically sustainable development, employment growth, use of new technologies and innovative processes and non-government investment. The first call for tenders under this programme was opened on 8 July 2000. The Australian Greenhouse Office received 107 applications for the first round of the programme by the closing date of 5 September 2000. The Ministerial Council on Greenhouse (MCOG) was expected to decide which proposals shall be offered funding in March 2001.

The remaining A$ 396 million under the Measures for a Better Environment are to be spent on other initiatives. These are to encourage increased use of alternative fuels and substantially boost the level of Commonwealth support for the development, commercialisation and use of renewable energy. Initiatives include renewable energy generation, alternative fuels use and household energy reduction.

In his 1997 Safeguarding the Future statement, the prime minister had announced the establishment of an organisation called the Australian Greenhouse Office (AGO) to help implement these greenhouse strategies. The Commonwealth government effectively established the Australian Greenhouse Office in April 1998 under the responsibility of the Ministerial Council on Greenhouse.

The office's legal status was changed in March 2000, when the AGO was made an executive agency of the government. Its is now administratively located with the Minister for the Environment and Heritage, but on climate change policy and programme matters, the AGO reports to the Ministerial Council on Greenhouse. The main tasks of the Australian Greenhouse Office include:

- To provide advice to the government as the lead Commonwealth agency on greenhouse issues.
- To support the work of the Ministerial Council on Greenhouse, the body responsible for determining greenhouse policy matters in Australia.
- To administer specific greenhouse programmes, including the ones announced and funded under the Safeguarding the Future and Measures for a Better Environment policy packages.
- To contribute to the development of Australia's position on international greenhouse negotiations.

The Australian Greenhouse Office is currently working towards the publication of a revised set of emissions projections using Kyoto Protocol accounting definitions. Although estimates of savings from measures undertaken by states and territories are not yet complete, preliminary work[13] indicates Commonwealth and nationally co-

13. See Commonwealth of Australia: *National Greenhouse Strategy 2000 Progress Report*, Canberra, 2000.

ordinated NGS measures will reduce 2010 "business as usual" emissions by 58 to 64 million tonnes, around 14–16 per cent of 1990 levels, excluding emissions from land clearing. Overall, therefore, emissions are currently expected to lie around 21–23 per cent above 1990 levels, excluding land clearing, in 2010. These projections do not yet take account of the new Commonwealth measures to combat emissions growth announced in the Measures for a Better Environment package in 1999. The government believes that when the impact of the 1999 package is taken into account, as well as the opportunities likely to be presented by international flexibility mechanisms currently under negotiation, Australia will be able to meet its Kyoto target.

Australia is intent upon making use of the flexibility measures under the Kyoto Protocol. It has taken steps to carry out international collaborative projects to reduce greenhouse gas emissions through Joint Implementation (JI, with other Annex I countries) or through the Clean Development Mechanism (CDM, with non-Annex I countries). The Australian government has set up a programme called International Greenhouse Partnerships (IGP), a co-operative effort by Australian industry and government to reduce greenhouse gas emissions through overseas projects. The IGP was established to facilitate Australia's participation in the flexibility mechanisms related to Joint Implementation and the Clean Development Mechanism under the Kyoto Protocol and has provided A$ 6 million over three years for this initiative. The programme is pursuing its objectives by undertaking a range of complementary activities, including establishing pilot projects (Activities Implemented Jointly, AIJ) with other countries to gain experience in the lead up to the establishment of the CDM and JI, and undertaking capacity-building activities for developing countries to increase their awareness of potential project opportunities and technical issues associated with CDM. To date, Australia has reached agreement with Chile, Indonesia, Malaysia, Vietnam, Mauritius, Peru, Fiji and the Solomon Islands to establish 14 greenhouse gas mitigation projects.

Emissions Trading

The government is considering the feasibility of a domestic emissions trading scheme. The Australian Greenhouse Office is currently examining the issue in a public consultation process. However, the government announced in August 2000 that it will only implement a domestic emissions trading scheme if the Kyoto Protocol is ratified by Australia and enters into force, and if there is an international emissions trading scheme and it is in the national interest.

Some of the questions pertaining to the participation of domestic entities in an international emissions trading system were explored in a simulation organised by the IEA in June-July 2000[14]. Among delegations of 16 other developed countries, the simulation included participants from government and private sector entities in Australia.

14. Baron R. (2000): *Emission Trading – A real time simulation*, IEA paper prepared for the Sixth Conference of the Parties to the UNFCCC. http:/www.iea.org/envissu/cop6/emistr.pdf

Energy Efficiency

In recent years, the Commonwealth government has undertaken a number of initiatives to encourage improvements in energy efficiency. These include:

- Voluntary agreements, such as:
  - The Greenhouse Challenge programme, which started in 1995. It is described in more detail below.
  - Generator efficiency guidelines for new fossil-fuelled power plants, introduced in July 2000. The programme is described in detail below.
  - The Energy Efficiency Best Practice Programme (EEBP). The Commonwealth government launched this programme in mid-1998. The programme is scheduled to run over a five-year period with government funding of A$ 10.3 million. It assists targeted industries to reduce their greenhouse gas emissions through improving energy efficiency, while also reducing costs and increasing productivity. Programme activities include training, energy surveys and data collection; good-practice guides and good-practice case studies.

- Mandatory minimum efficiency standards. Recent developments in this area include:
  - The introduction as of 1999 of minimum energy performance standards for refrigerators, freezers and electric water heaters; as well as the development of minimum energy performance standards for electric motors, lighting ballasts and air-conditioners for implementation in 2001 and 2002.
  - Preparatory work for the introduction of mandatory energy efficiency standards for buildings into the Building Code of Australia. In March 1999, the federal government and the building industry, represented by the Australian Building Energy Council (ABEC), agreed on a comprehensive strategy to make Australia more energy-efficient. ABEC, supported by the AGO, is developing a "Voluntary Code of Practice for Energy Efficient Building Design" for new buildings which will describe best practice and encourage designers to go beyond the minimum requirements.

The AGO estimated in 1999 that in the absence of any such measures, the energy consumption of residential buildings could grow by 40 per cent between 1990 and 2010, leading to a 17 per cent increase in greenhouse gas emissions. The energy use in non-residential buildings could even increase by 91 per cent, leading to a 94 per cent growth in CO_2 equivalent emissions, or 62.8 million tonnes of CO_2 equivalent from commercial buildings alone in 2010.

- Energy labelling. This includes:
  - Domestic appliances. April 2000 marked the beginning of a round of revision of energy labels for all major domestic appliances.
  - Passenger cars. A mandatory model-specific fuel consumption labelling scheme for new passenger cars is currently being implemented through an Australian Design Rule (ADR). Industry has agreed in principle to the introduction of targets for commercial vehicles. These targets will be introduced progressively; timing will be largely dependent upon the availability of suitable information.

National Average Fuel Consumption targets for new passenger motor vehicles in Australia are already in place.

- Residential buildings. In the residential sector, energy labelling is in the form of the National House Energy Rating Scheme (NatHERS), which operates in most States and Territories. Further work is to be conducted on NatHERS for free-running houses, assessments for small houses, and a building greenhouse rating scheme.

■ Support programmes, such as the Household Greenhouse Action programme. This programme finances projects promoting the efficient use of energy in the domestic sector. The programme focuses on lighting, heating and cooling, hot water and refrigeration.

■ Improving Energy Efficiency in Commonwealth Operations, introduced in 1997. The Australian government has made a commitment to lead by example and reduce the intensity of energy use in Commonwealth operations. Overall responsibility of the policy rests with the Department of Industry, Science and Resources (DISR). The cumulative reduction in total Commonwealth energy consumption since the first reporting period in 1997/98 was more than 10 per cent, and associated greenhouse gas emissions were reduced by more than 9 per cent.

The **Greenhouse Challenge programme** is a joint voluntary initiative between the Commonwealth government and industry in Australia to abate greenhouse gas emissions, but much of its activity focuses on energy-efficient technologies and processes. The Greenhouse Challenge programme was announced in 1995 and the Greenhouse Challenge Office (GCO) was established in late 1995 to implement the programme. The programme was part of an early, "no regrets" Commonwealth package of greenhouse measures, entitled Greenhouse 21C. In the framework of Greenhouse 21C, it was estimated that co-operative agreements could yield in the order of 15 million tonnes of greenhouse emissions reductions annually by 2000.

The Greenhouse Challenge programme was extended by the 1997 Safeguarding the Future statement. Included in the A$ 180 million package was an additional A$ 27.1 million over five years for the Greenhouse Challenge programme. Targets for participating organisations were set: 500 organisations by 2000, and 1,000 by 2005. The Safeguarding the Future initiative anticipated that Greenhouse Challenge would achieve emissions abatement of 22 million tonnes of CO_2 equivalent in the year 2000.

Following the creation of the Australian Greenhouse Office (AGO), the Greenhouse Challenge Office became part of the new AGO. The AGO drew together new and existing greenhouse programmes from Environment Australia, and the then Departments of Industry, Science and Tourism, and Primary Industries and Energy. These were consolidated in the 1998 National Greenhouse Strategy. The NGS features the Greenhouse Challenge in its Partnerships for Greenhouse Action module.

The Greenhouse Challenge programme is open to large industrial firms. Large and medium-sized industrial business members include BP, Australia Post, Westpac, AGL, Cairns Hilton, Monash University, Jones Lang Lasalle and Holeproof. Major industry groups such as the Australian Aluminium Council, the Minerals Council of Australia and the Housing Industry Association are also members. Smaller businesses can participate through another programme called Greenhouse Allies. Under the Greenhouse Allies programme, large Greenhouse Challenge members mentor smaller firms through a group process in order to help them reduce their emissions.

The Greenhouse Challenge programme consists of three phases: the commitment (a contract between the Commonwealth government and an industrial company), the co-operative agreement, and performance reporting. The co-operative agreement includes an inventory of emissions, an action plan with specific actions to minimise emissions, performance indicators to measure progress, and a forecast of expected abatement of emissions over a set time period. The programme also provides information to members, including technical advice on how to identify, monitor and mitigate emissions in each sector, a workbook to assist participants in developing their co-operative agreement, and workshops and seminars on technical issues and greenhouse actions.

The programme is subject to independent evaluation by external organisations. Such an evaluation was last carried out in 1999. The findings of the evaluation were as follows. As of 1 July 1999, 224 large and medium-sized organisations had signed agreements, and another 178 had indicated through a formal letter of intent their desire to join the programme. A further 153 small organisations were involved through partnership arrangements with large participating organisations. Public and private organisations, both large and small, from virtually every industrial sector have joined the Greenhouse Challenge.

The Greenhouse Challenge programme had extensive coverage of emissions in some areas, including 100 per cent coverage of aluminium and cement production, 98 per cent of oil and gas extraction and electricity generation and distribution, and 91 per cent of coal mining. In other areas, however, coverage was less comprehensive, often significantly so, and opportunities remained for greater coverage of large emitters not yet in the programme and a number of sectors with relatively low participation. In 2000, it was estimated that 45 per cent of Australia's industrial greenhouse gas emissions were covered by the Greenhouse Challenge programme.

The Greenhouse Challenge programme demonstrated significant greenhouse gas emissions abatement action in industry. The data available in 1999 indicated that in 2000 the actions being undertaken by industrial end-users would result in emissions reductions of 23.5 million tonnes of CO_2 equivalent per annum, or 16 per cent less than in the absence of those actions.

On the same basis, electricity generators and distributors expected savings to amount to 5 million tonnes of CO_2 equivalent per annum or 3 per cent less in emissions in 2000. Participants undertook a wide range of abatement actions, including investments in new technology and sinks, process and energy efficiency improvements, fuel switching, and the capture of fugitive emissions.

Based on these data, participants in industrial end-use sectors expect very limited emissions growth of 2.1 million tonnes of CO_2 equivalent or 1.6 per cent to have occurred over the period 1995 to 2000. A number of sectors, including oil and gas extraction, cement and coal mining even expect absolute declines.

Over the same period, as a result of growth in electricity demand associated with growth in GDP (21 per cent) and population (6 per cent), the electricity generation and distribution sector projects absolute emissions growth of 31.4 million tonnes of CO_2 equivalent or 22.8 per cent.

Australia Post is the country's largest retail network, with more than 4,000 outlets. Through its Greenhouse Challenge membership, Australia Post introduced a raft of energy efficiency measures. In the first year the organisation expected a 1.8 per cent reduction in its greenhouse emissions, and forecast a target of 3 per cent by 2005. But the results exceeded forecasts. Australia Post achieved a 14.9 per cent reduction in its first reporting year, saving about 50,000 tonnes of CO_2 equivalent and an estimated A$ 3 million a year. Still more significant carbon savings are expected by the dairy foods group Bonlac Foods. This company reduced its energy costs by about A$ 1.1 million in 1998/99 as a result of its state-of-the-art milk processing facility in Victoria. Combined with other initiatives under its Greenhouse Challenge action plan, Bonlac Foods is expected to reduce its total emissions by 16 per cent or 77,000 tonnes of CO_2 equivalent by 2002/03.

Voluntary Efficiency Guidelines for Power Generation, like the Greenhouse Challenge programme, had also been announced in the prime minister's 1997 Safeguarding the Future statement and subsequently incorporated into the National Greenhouse Strategy. The measure was developed in recognition of the fact that power generation is responsible for more than a third of national greenhouse emissions (excluding change of land-use). It is expected to reduce emissions by 4 million tonnes of CO_2 equivalent per year.

Based on the model developed by the Efficiency Standards Working Group (ESWG), the government introduced efficiency guidelines for power generators using fossil fuels on 1 July 2000. The standards apply to new power plants (approved after 30 June 2000) and existing power generators above a minimum threshold on a case-by-case basis. This includes grid-connected power stations, off-grid plant or autogenerators. The minimum threshold is 30 MW capacity, 50 GWh electrical output, and a capacity factor of 5 per cent or more in each of the last three years. The best practice efficiency guidelines for new plant are:

- Natural gas plant: 52 per cent thermal efficiency (measured using the Higher Heating Value, HHV) of sent-out electricity (η_{SO}).
- Hard coal plant: 42 per cent η_{SO} HHV.

- Brown coal plant: 31 per cent η_{SO} HHV.

These guidelines are based on international best practice adjusted for Australian conditions (such as different air temperatures). In the case of existing power plants, plant-specific guidelines apply, within a best practice performance band. It is proposed that the measure be implemented through legally-binding, 5-year agreements between the Commonwealth and power generators. The contract specifies the approach generators should take in identifying and undertaking agreed actions that improve plant efficiency and reduce greenhouse gas intensity. Generators first sign the agreement. Then they calculate the best practice performance band and current performance of the plant and submit this information, together with a menu of options, to the government for agreement, within six months of signing. The menu of options outlines potential improvements for the plant.

Generators then undertake feasibility studies on potential options and submit a proposed action plan within 21 months of signing the agreement. Once agreed with the government, this becomes the action plan for the plant incorporating greenhouse target for the plant. The greenhouse actions are to be implemented within the 5-year time frame of the agreement.

The generators must monitor their performance and report to the AGO on a regular basis. The standards are reviewed every five years. The measure is expected to save about 4 million tonnes of carbon dioxide equivalent a year during the first commitment period under the Kyoto Protocol.

Renewable Energy Sources

Renewable energy currently contributes 5 per cent of Australia's total primary energy supply. Combustible renewables contribute 5.3 per cent. These essentially comprise bagasse (sugar cane waste) used to generate electricity and steam, and wood used primarily for home heating. Renewable sources represent 10 per cent of Australia's electricity generation, with 8.2 per cent coming from hydro.

The most important initiative in the area of renewables is the Mandatory Renewable Energy Target (MRET), which was adopted by the Commonwealth government in 2000 as a legally-binding commitment. It seeks to increase the contribution of renewables to the Australian electricity supply mix by 9,500 GWh or around 2 per cent by 2010. Since Australian statistics estimate the current share of renewables at 10.7 per cent, this involves raising the share to 12.7 per cent. The overall target increase of 9,500 GWh will be reviewed every two years. Like many other climate policy initiatives, the MRET was part of the 1997 Safeguarding the Future statement. The design principles of the Mandatory Renewable Energy Target were developed to achieve the following objectives:

- To accelerate the uptake of renewable energy in grid-based applications, so as to stimulate renewables and provide base for the development of commercially competitive renewable energy.

- To contribute to the development of internationally competitive industries which could participate effectively in the global energy markets.

The legislation underpinning the measure comprises the Renewable Energy (Electricity) Act 2000 and the Renewable Energy (Electricity) (Charge) Act 2000. These acts were adopted in late 2000, and these legally-binding measures are in force as from 1 April 2001. They establish an entity for surveillance, the Renewable Energy Regulator (RER), who is responsible for implementing provisions of the legislation. He also has the power to register and accredit power stations and to register renewable energy certificates as valid. The RER also has the power to audit parties for compliance and impose non-tax-deductible penalties for non-compliance.

The MRET places a legal requirement on electricity wholesalers to purchase electricity generated from renewables. In order to improve planning certainty, the requirement is set at 9,500 GWh of annual generation from new renewables in 2010. The measure will be phased in by specifying a number of interim targets over the period 2001-2010. The final 9,500 GWh target will be maintained constant in the years 2011-2020. Actual trading was to start on 1 April 2001.

The measure applies nationally. All electricity wholesale electricity buyers and retailers on grids of over 100 MW installed capacity in all states and territories must contribute proportionately to the achievement of the measure. The requirement of purchasing renewables-based electricity will be allocated in proportion to the overall electricity purchases of wholesalers and retailers. The purchase obligation is based on a system of tradeable certificates to minimise the costs of delivering the target. As the Renewable Energy (Electricity) (Charge) Act 2000 sets the penalty for non-compliance at A$ 40/MWh, it provides a ceiling on the price of the tradeable certificates. Penalties are redeemable if the shortfall is made up over the three years following the year in which the shortfall was recorded.

The renewable energy certificates (RECs) are issued by the regulator to renewable generators, based on their accredited generating capacity (one for 1 MWh). New renewable generators obtain RECs for their entire output, whereas existing generators received RECs for all generation above a baseline. Renewable generators then sell the RECs to power purchasers at wholesale or retail level that enter into supply contracts with them. Instead of buying renewable power from the generators, power purchasers can also buy them from other purchasers. The purchasers' liability under the MRET for any year is met when they surrender the appropriate number of certificates to the regulator. Banking of certificates is allowed, i.e. they remain valid until they are surrendered to the RER, but borrowing is not. RECs may be traded among liable parties in the National Electricity Market (NEM) or third party traders, and in financial markets that are separate from the NEM. Each transaction must be registered with a central registry office.

There is a plan to develop a voluntary, industry-owned Green Electricity Market (GEM) that trades in "green electricity rights"; this trading will include RECs. Regarding the domestic greenhouse gas emissions trading scheme that is currently under discussion, it is expected that accredited renewable generators under the MRET will not require emissions permits.

The technologies or fuel types classified as eligible renewable energy sources under the MRET[15] (where they are used for electricity generation, or in the case of solar hot water, where they are displacing electricity) are listed below. Despite the broad range of eligible fuel types, it is expected that the majority of the target will be met by biomass, solar hot water systems, and wind generation.

The renewable certificate regulations implicitly allow pumped storage to be included, but requires that the energy generated be net of any fossil electricity inputs. Based on these rules, the Tasmanian electric utility Hydro Tasmania has a proposal to develop a mini hydroelectric pumped storage plant (PSH) of about 1 MW, to be filled using wind power, on an island off the Tasmanian coast, King Island. The small local community on King Island is currently supplied through diesel generation, since the island is not interconnected with Tasmania. This "dispatchable wind power" project will thus reduce carbon and air pollutant emissions to the extent that it can displace diesel generation on the island. At present, a halving of diesel generation is expected. Apart from the mini PSH, Hydro Tasmania's project comprises a number of components including a battery and inverter system, demand-side load management systems and an integrated renewable energy control system. The proposal received A$ 1 million in government support under a programme called the Remote Renewables Power Generation Programme (RRPGP).

The project is clearly a niche application for remote areas and is not likely to be extended to the rest of Tasmania in the near future. Tasmania's electricity system is nearly 100 per cent hydro and does not have any pumped storage at present. Tasmania also has an installed wind capacity of 130 MW and a large wind potential of up to 1,000 MW. However, Hydro Tasmania does not at present have any plans to build a large-scale PSH in Tasmania itself. Interconnection of Tasmania to Victoria on the Australian mainland via the Basslink sea cable is expected in 2003. Once interconnected through the Basslink cable, Hydro Tasmania expects to enhance Victoria's energy security because an extra 600 MW could be made available from its system to Victoria during peak hours from its system. In turn, Tasmania would import brown coal-generated power from Victoria during off-peak hours to save the water in the reservoirs for sale during peak hours.

The Victorian Department of Treasury and Finance predicted that the MRET would lead to electricity purchase cost increases of only 1.5 per cent nationally. This is equivalent to a rise of 0.16 cents per kWh in average Australian residential electricity tariffs and a rise of only 0.11 cents per kWh in the average business tariff.

15. Solar and solar water heating; wind and hydro; ocean, wave and tidal; geothermal; biomass, bioenergy, bio-liquids and biogas; renewable component of Remote Area Power Supply (RAPS) systems; co-firing renewables with fossil fuels; fuel cells using a renewable fuel; and other eligible renewable energy sources as approved by the regulator.

Apart from the MRET, there are numerous other policy initiatives relating to renewables in Australia. Of the A$ 180 million to be spent on climate change abatement in the framework of the prime minister's 1997 Safeguarding the Future statement, A$ 60 million was earmarked for renewable energy programmes. A further A$ 321 million, to be spent over four years as of 1 July 2000, was set aside for renewable energy programmes as part of the prime minister's 1999 Measures for a Better Environment initiative. This brings total funding for renewables over the period 1998-2003 to A$ 381 million. The funds are to be used in the framework of the following measures:

- The Renewable Energy Commercialisation Programme (RECP). The RECP is a five-year, A$ 56 million programme established to foster the renewable energy industry through grants. RECP grants, which are allocated through a competitive tendering system, are normally in the range of A$ 50,000 to A$ 1 million. The programme focuses on innovative renewable energy technologies that are close to full commercialisation. To date, three rounds have been completed, and a total of A$ 22.5 million has been committed.

- The Photovoltaic Rebate Programme (PVRP). The Commonwealth government has provided A$ 31 million over four years for this programme to encourage the long-term use of photovoltaic technology for electricity generation. Key objectives of the PVRP are to reduce greenhouse gas emissions, to assist in the development of the Australian photovoltaics industry, and to increase public awareness of renewable energy.

- The Remote Renewable Power Generation Programme (RRPGP). This programme was announced in mid-1999 as part of the Measures for a Better Environment initiative and aims to increase the uptake of renewable energy technology in remote areas of Australia. As of 1 July 2000, the Commonwealth government provided funding of up to A$ 66 million per annum for four years to the states and territories to subsidise cash rebates for remote renewable area power systems.

- The Renewable Energy Action Agenda (REAA). The REAA was developed by the Commonwealth government, in partnership with industry, to assist the long-term development of the renewable energy industry. The Action Agenda, launched in June 2000, sets a target for growth and identifies the strategies and actions necessary to achieve it. The vision of the industry is to achieve a sustainable and internationally competitive renewable energy industry with annual sales of A$ 4 billion by 2010. To reach this target, industry sales would need to grow at an annual compound growth rate of around 25 per cent.

In addition to the Commonwealth initiatives relating to renewables and energy efficiency described above, there are also numerous state initiatives and bodies. One example is the New South Wales Sustainable Energy Development Authority (SEDA), which continued to develop new markets for energy efficiency and renewable energy. The New South Wales sustainable energy industry recorded sales of A$ 1.2 billion with growth of 25 per cent in 1998. In 1999, SEDA projects resulted in the reduction of over 400,000 tonnes of carbon dioxide.

CRITIQUE

Australia is a relatively energy-intensive economy, and much of the energy resources used are fossil. The dependence on fossil fuels, particularly coal, makes the economy relatively greenhouse gas-intensive. Emissions from agriculture and land-use are also higher than in most other IEA countries.

The availability of inexpensive fossil fuels and other resources has a strong influence on the country's industry structure, with a relatively strong focus on primary production, and its position in the world economy, as both a low-cost energy industrial location and an exporter of energy products. Australia has gone through a long period of economic expansion as well as population expansion, which has brought the country prosperity. In the last ten years, it has sought to introduce market reform across the economy and has been successful in doing so. The population is also highly sensitive to environment issues.

Although greenhouse policy was never a driver for liberalisation, government responses to climate change include the idea that market reform itself can significantly benefit the environment. Market reform is not *per se* a form of environmental protection, although there are good examples of how it can be environmentally benign. It is well known that the "dash for gas" following electricity liberalisation in England and Wales has had the effect of reducing carbon emissions in the United Kingdom.

Market reform is carried out for a host of excellent reasons, but environmental benefits certainly do not flow from it automatically. Environmental benefits can develop under certain circumstances and over time. But the first, and often most important objective for microeconomic energy market reform is to reduce prices, which leads to greater energy consumption. Also, competition is very effective in reducing costs by shifting production to the least-cost supply option. These are the *primary* demand-side and supply-side effects of market reform – i.e. they are large and they materialise relatively quickly.

Provided that the welfare benefits eventually work their way through the economy and lead to significant net macroeconomic growth, there may well be a re-investment cycle during which old, resource-intensive equipment is replaced by new, less resource-intensive (and often more capital-intensive) technology. This effect has been observed in many OECD economies over the last three decades.

While in principle very beneficial, the outcome of this effect in terms of resource savings still depends on the relative prices of resources versus capital. This is a *secondary* effect. It is indirect, it takes a lot of time to build up, it may easily be thwarted by external causes reducing macroeconomic performance, and its size is highly uncertain.

Australia has the good fortune to possess abundant, high-quality coal resources near to demand centres – in other words, very cheap coal. It is lucky enough also to possess ample gas reserves, but these are more remote and more expensive to bring to consumers. Energy market reform can contribute to reducing greenhouse gas emissions through a significant *primary* effect only if competition in the gas industry could bring gas prices down to or below coal prices. That is what arguably happened in the UK. Whether this can happen in Australia is questionable.

First, competition and market integration are only now beginning in the gas market[16], and it will be some time before the full effects will be felt, and before gas prices might fall sufficiently to out-compete coal in power generation. Even if this happens, the need to construct new generating capacity or refuel existing capacity may further delay large-scale substitution of coal by gas in the power industry. In the interim, existing coal-fired power plants are dispatched more in the competitive power market, not less, causing increased carbon and air pollutant emissions. In the past six or seven years, competition in Australia's national electricity market has effectively favoured the least-cost fuel used in pulverised coal-fired power stations, especially Victorian brown coal, leading to adverse local and global environmental impacts. Very recent data indicate that in the last two years the growth of gas use in power generation has accelerated to 14.5 per cent per annum, albeit from a low base. It is not clear yet whether this is an early sign that gas liberalisation is beginning to encourage fuel switching to gas.

Second, it should not be forgotten that the coal industry is also striving for productivity increases and market reform, especially with respect to coal transport. Hence, the coal price target is a moving target.

The more recent response packages seem to reflect clearer recognition that it will take some effort to reconcile market reform and greenhouse gas abatement in the specific Australian context. Greater policy efforts are being made. It should be noted that care is being taken from the outset to make these efforts compatible with the competitive energy sector, and that generally a competitive bidding process is used. In this context, specific recognition is due for the Mandatory Renewable Energy Target, but also for other initiatives such as the large new Greenhouse Gas Abatement Programme.

Another general remark is that climate change policies and programmes are relatively generously funded, but there is reluctance to adopt policies that may impose costs on Australian business that would render otherwise competitive Australian industries uncompetitive. On 23 August 2000, the government announced a public commitment that future greenhouse gas abatement policies and measures would be cost-effective and minimise the burden for business and the community, so that Australian industry would remain competitive. This reflects the fact that many key Australian export industries, such as the aluminium and LNG industries, face strong competition from non-Annex I countries, particularly in the Asia-Pacific region. These countries will not face greenhouse gas emissions reduction obligations in the first Kyoto Protocol budget period.

Consequently, policies towards greenhouse gas abatement, energy efficiency and renewable energies have relied to a very large extent on voluntary action,

16. See also Chapters 5 (Coal), and 7 (Natural Gas) in this context.

information dissemination, energy labelling and advice and assistance to measures that are cost-effective under present conditions. It is commendable that many such actions are taken in Australia. In all OECD countries, companies and consumers are simultaneously losing money and squandering energy, often unbeknownst to them, owing in part to the cost of obtaining relevant and unbiased information on cheaper, more energy-efficient options. This "slack in the system" can add up to significant totals at societal level. Addressing it in order to reduce greenhouse gas emissions is a necessary, low-cost first step that governments are well advised to take.

However, even if the "slack" were to be entirely eliminated (which is improbable in the real world), this approach addresses only part of the problem, and only the minor part. Essentially, people forgo cost-effective possibilities to save energy and money for some reason. The reasons can be manifold, ranging from split incentives and information and transaction costs to divergences between individual and societal interest and time preference rates. By addressing these reasons, their consumption decisions can be brought in line with rational behaviour towards *existing prices* – but not with externalities added.

It is the very nature of environmental externalities that resource-saving behaviour does not create adequate money savings. And it is for this reason that cost-effective energy or emissions savings will fall short of what is needed as long as the externality is not fully internalised. In some instances, it may even be possible to save a bit more, if a sufficient part of the population is inclined to spend more than the market price for cleaner energy or less energy-intensive equipment, e.g. through "green pricing". However, the share of the population able and prepared to do this is very limited in most countries and therefore does not replace government action to internalise externalities.

Under the Kyoto Protocol, Australia is committed to limit its greenhouse gas emissions growth to 8 per cent between 1990 and 2008-2012, but the latest tentative estimate predicts that may be as high as 23 per cent (excluding changed patterns of land-use). This is a challenging gap and indicates a need to take action that goes beyond eliminating "slack". More recent policy initiatives are beginning to take this challenge into account, albeit in a timid manner. Nevertheless, the introduction of the Mandatory Renewable Energy Target and the current discussion of a domestic allowances trading system deserve commendation. Another positive measure was the establishment of a dedicated entity, the Australian Greenhouse Office, to prepare, co-ordinate and implement the country's greenhouse response policies. Exactly how large the task is, and how much of it has already been accomplished, will become clearer only after the new emissions projections are published by the AGO.

That said, the balance between promotion of energy efficiency and promotion of renewables appears to be somewhat lopsided in Australia. Energy efficiency appears to receive significantly less attention than renewables, despite the fact that energy efficiency measures tend to be more cost-effective. While there is a host of measures at federal and state level and analyses of the potential savings in terms of carbon and dollars, implementation lags behind other advanced countries. Though

Australia has a range of efficiency standards, these are not sufficiently rigorous or widespread, and the institutional arrangements for implementation and enforcement seem to be missing. Innovative market-oriented approaches will be required. A coherent national energy efficiency strategy with clear and firm objectives, measures, implementation and evaluation appears to be lacking.

A redeeming factor may be that the large new Greenhouse Gas Abatement Programme leaves it up to applicants to propose all sorts of projects, be they based on renewables, energy efficiency, afforestation or non-CO_2 greenhouse gas abatement. Since this is a programme where projects must be near market maturity to win support, the least-cost project should be the first to be selected, and the balance between energy efficiency and renewables should thus automatically approach the optimum.

As far as renewables are concerned, the Mandatory Renewable Energy Target (MRET) appears achievable. The target has been set at 9,500 GWh of generated electricity per year, to be achieved after a phase-in period of ten years. It is currently estimated that this will correspond to a 2 per cent increase in the share of renewables in electricity generation. This does not appear very ambitious at first sight.

However, the target is more challenging than it may appear. Assuming that a balanced mix of intermittent and base load options becomes viable under the scheme, the construction of 2,000 MW or more of new renewable generating facilities could be required. On the basis of current estimates of demand and capacity growth, the target could represent at least 20 per cent of all new growth in electricity consumption, and possibly up to 40 per cent, depending on economic growth and electricity consumption. This is clearly significant, and the target is commendable. Nevertheless, there are examples of equally or more ambitious targets in other countries. The target should therefore be reviewed after two years, as anticipated, and increased if a higher target appears feasible.

The MRET also seems to cause very little extra cost, with a very minor increase in average end-user electricity prices. It also seems to be fully compatible with the national electricity market. Therefore, the MRET appears very promising, offering multiple advantages to many players.

It is also welcome that the MRET includes "dispatchable wind power" by covering pumped storage, provided the latter is based exclusively on renewable generation. This opens the possibility of using a part of Tasmania's exceptional wind resource before the Basslink interconnector is built. It is a niche application for remote areas that should be interesting for other countries with similar wind and hydro resources.

Finally, as long as there is not sufficient clarity as to how large past greenhouse gas emissions were, and how large future emissions will be, it will be difficult for the government to implement an effective greenhouse abatement package. Therefore, the government should quickly finalise its new set of projections, and in particular, make an additional effort to estimate greenhouse gas emissions from land-use and sinks.

RECOMMENDATIONS

The government should:

- ☐ Continue to use, and if possible expand, incentives within the regulatory reform process, such as the Mandatory Renewable Energy Target, to reduce adverse environmental consequences.
- ☐ Implement the Mandatory Renewable Energy Target rapidly, and review it periodically with a view to tightening it.
- ☐ Finalise as soon as possible the data collection on land-use and sinks in order to provide a reliable evaluation of the potential gap between the Kyoto commitment and the measures decided or set in motion under the National Greenhouse Strategy. If necessary, set up an action plan to address the gap, in co-ordination with all stakeholders.
- ☐ Define a coherent national energy efficiency strategy with clear and firm objectives, measures, implementation and evaluation. Foster market-oriented approaches to meeting energy and electricity efficiency targets by 2010.
- ☐ Rapidly develop programmes to increase automotive fuel efficiency and pursue the introduction of mandatory fuel efficiency standards.
- ☐ Participate in international efforts to reduce dramatically the cost of renewable energy equipment through market aggregation and large-scale manufacturing. Support IEA Implementing Agreements to meet this objective.
- ☐ Expand opportunities for manufacture of wind turbines, bagasse-fired high-pressure turbines, photovoltaics and biomass gasification units.
- ☐ Place greater emphasis on measures to reduce emissions from burning coal (e.g. clean coal technologies, power station efficiency standards).
- ☐ Consider whether policies favouring increased use of gas would provide least-cost solutions to meeting greenhouse gas targets.
- ☐ Consider measures to reflect the full environmental costs in the price of different fuels so that gas can compete on a fairer basis with coal.
- ☐ Continue to provide a favourable environment for renewables in niche markets, such as the "dispatchable wind power" in Tasmania.

5

COAL

INDUSTRY OVERVIEW

Australia has a very substantial coal resource. There are ample reserves of hard coal – or black coal, as it is referred to in Australian terminology – of brown coal (or lignite), and of hard coal of superior quality needed for metallurgical processes, especially steel-making (coking coal).

The country is the world's sixth largest coal producer and, since 1984, the largest exporter of hard coal, responsible for between 35 and 40 per cent of world sea-borne trade. Exported quantities are about evenly divided between thermal coal and coking coal. Brown coal is not exported, but is used domestically, mainly for power generation in mine-mouth power plants.

Hard coal is Australia's largest export industry. In 1999 it accounted for over 10 per cent of Australia's exports (A$ 8.2 billion) and more than 1 per cent of GDP. 17 million tonnes or 72.7 per cent of total hard coal production was exported in 1999. Coal also holds a very important position in the domestic energy market. Hard coal and lignite together account for some 80 per cent of electricity generation.

Like many other industries in Australia, the coal industry has undergone reform in recent years. A key document in coal industry reform was the 1998 inquiry report by the Productivity Commission[17], to which the government responded in 1999. The recommendations of the Productivity Commission and the reform efforts are described in the section Recent Reforms below.

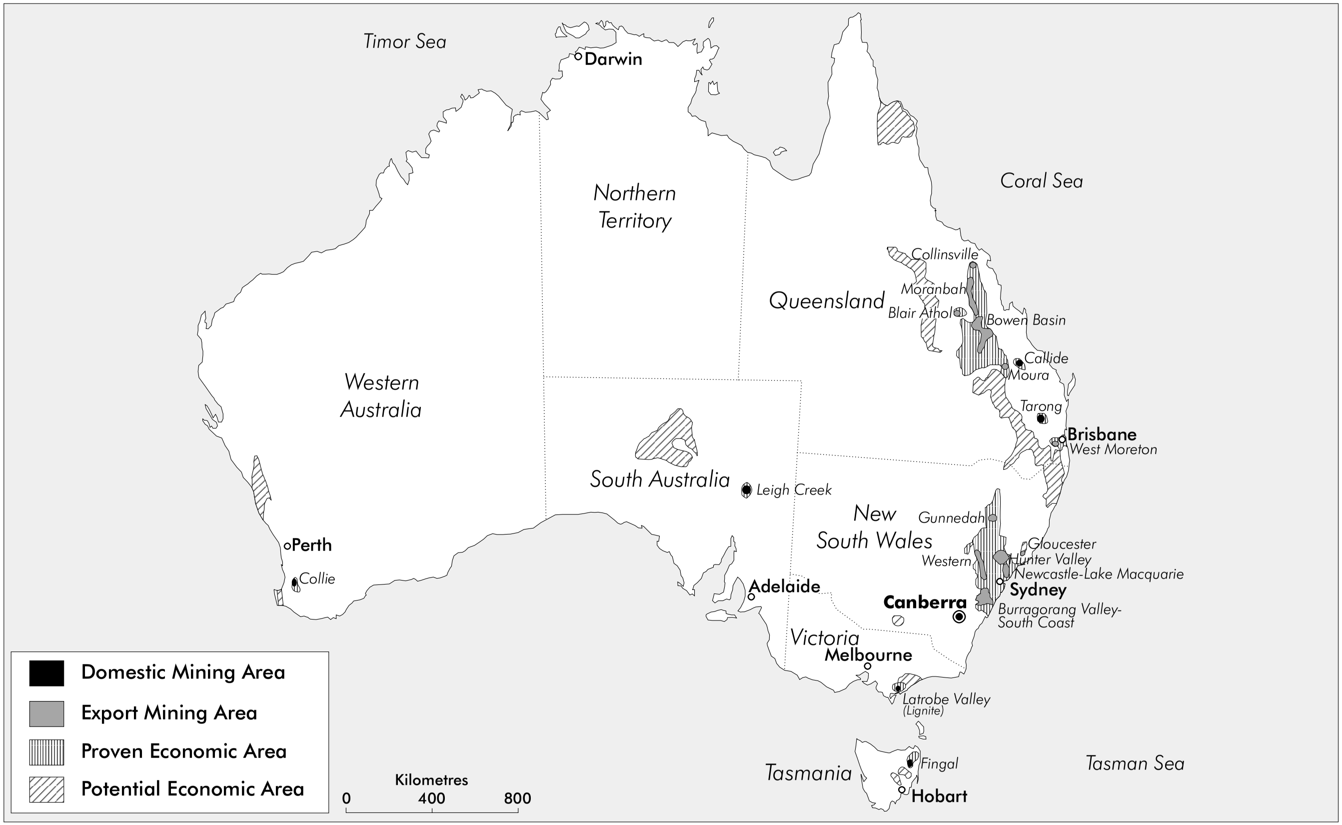
Coal Resources and Production

Australia has economically recoverable hard coal reserves of more than 50 billion tonnes, or more than 210 times current production[18]. Hard coal is found mainly on the east coast of the country, but there are also reserves elsewhere, as shown in Figure 8. The Bowen Basin in Queensland and the Sydney Basin in New South Wales are the main hard coal-producing regions, especially for export. Queensland and New South Wales have about 90 per cent of hard coal reserves and 95 per cent of production. Some production for the domestic market also occurs in South Australia and Western Australia. Reserves in the Victorian Latrobe Valley are brown coal. Brown coal accounts for approximately 20 per cent of production.

Australian mines produced 241 million tonnes of hard coal in 2000. Total coal production was 316 million tonnes. The Australian hard coal industry has the capacity to expand production substantially to meet possible future demand increases.

17. Productivity Commission: *The Australian Black Coal Industry*. Inquiry Report, AusInfo, Canberra, 1998.
18. At current prices.

Figure 8
Coal Reserves in Australia



Source: Department of Industry, Science and Resources.

Australian hard coal is generally of high quality with high calorific value, moderate ash content and low sulphur and heavy metal content. The higher the quality, the better are generally the coking qualities of the coal. Coking coal reserves are scarcer than coal resources generally, and receive a higher price. Australia has coal resources of sufficient variety to be able to meet the required quality specifications of most customers, e.g. through selective mining or blending.

Coal is produced in two different types of mines, surface (open cut or open cast) and underground mines. Coal more than 70 metres below the surface is mined with underground methods. Surface mining is the cheapest and most productive form of mining in that it allows extraction of up to 95 per cent of the resource. A large part of Australian coal resources is sufficiently close to the surface to allow open cut strip mining; currently over 70 per cent of hard coal is produced this way.

Coal mining in New South Wales dates back to 1799 and used to be dominated by underground mining (72 per cent in 1980, 46 per cent in 1997). In contrast, coal mining in Queensland was developed mainly for export from large open cut operations as of the 1960s (90 per cent open cut in 1980, 86 per cent in 1997). At the end of 1997, 118 hard coal mines were in operation in Australia: 58 underground and 60 open cut mines. They varied in size from some 70,000 tonnes to over 11 million tonnes of annual production (1998/99). Usually mines with production of less than 100,000 tonnes per annum are either mines just starting up or nearing the end of their commercial reserves. New South Wales had 69 mines, Queensland 42, and other states 7. In 2000, about 100 mines were still in operation.

Hard coal mining is carried out by a large number of companies. Nevertheless, a consolidation process that has been under way for more than a decade has left the industry relatively concentrated. Depressed coal prices had caused low overall industry profitability with many mines making losses. The industry responded by reducing their cost structures and improve productivity. This process involved closing down the least productive mines, which were predominantly underground mines, and reduction of employment. Over the last few years industry productivity has increased by around 20 per cent per annum. As a consequence, Australian mines can now operate profitably at lower prices.

There have also been major changes in industry ownership. Ownership of smaller mines is being consolidated. Companies that have a long-term commercial stake in coal are expanding their Australian holdings. In 2000, the four biggest producers – Broken Hill Proprietary Company Limited (BHP), Rio Tinto, Glencore and Peabody – were together responsible for more than 40 per cent of total saleable hard coal production. Australia's largest coal producer, BHP, alone accounts for 15 per cent of industry output. The consolidation process still continues. In 2000, Rio Tinto bought Peabody's assets; more recently, BHP merged with the coal company Billiton to create the world's largest coal exporter. However, there are still many small producers.

Most mining companies are privately owned. In the year 2000, only eight mines, located in New South Wales, remained fully government-owned. There is a significant degree of vertical integration; alongside specialist mining companies, several large steel producers, power generation companies and international trading houses have equity interests in coal mines.

In New South Wales, the state government established three state-owned power generators who compete in the state and national electricity markets. Among them is Pacific Power, a power utility that owns the eight mines still in full state ownership. However, coal purchases of New South Wales generators are carried out through competitive open tenders from both private and state-owned mines. No concession is given to the state-owned mines. In Queensland, coal supply to all power stations is based on competitive tenders from privately-owned mines. In Victoria, brown coal mines and mine-mouth power stations are vertically integrated and privately owned. Coal prices are internalised.

There is also a large amount of foreign ownership, and in fact most mines have some foreign equity. Several mines are fully owned by foreign investors. In 1997, the government estimated that about half of hard coal production capacity was in majority ownership by Australian interests, 22 per cent by Japanese interests, 12 per cent by European companies and 11 per cent by U.S. investors. As part of its overall economic strategy, the government welcomes overseas investment in the Australian coal industry. There are no limits on the level of foreign equity in Australian companies, but investment proposals above A$ 50 million are considered on their merits by the Foreign Investment Review Board.

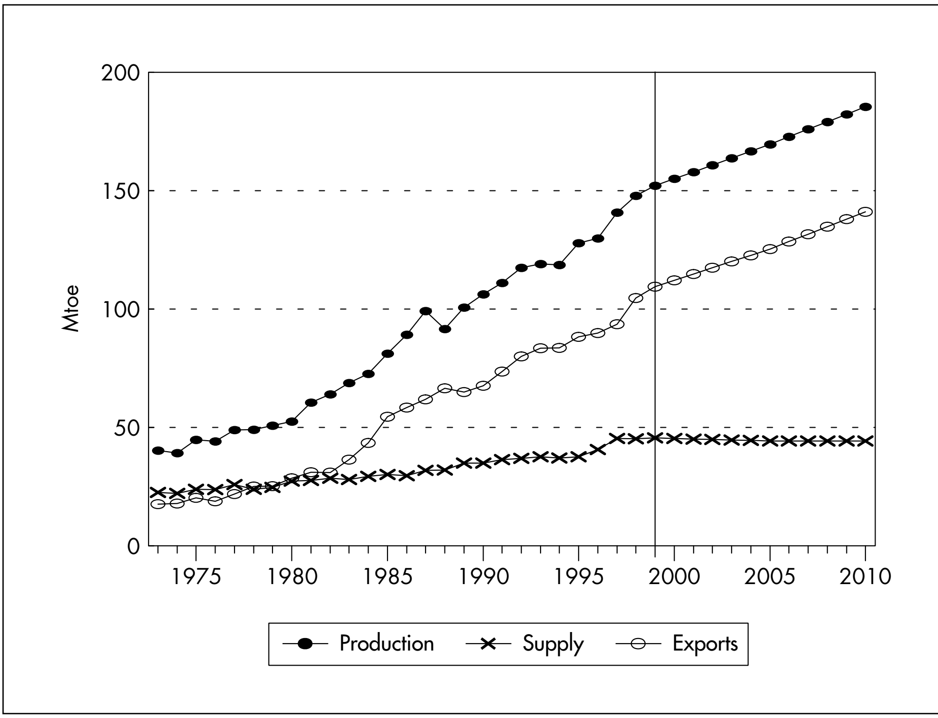
Coal Demand and Trade

Overall, domestic coal demand has remained on a trend of slow growth since 1973. As in most IEA countries, the main domestic consumers of hard coal are the steel, aluminium and cement industries and coal-fired power generators. The coal consumption of Australia's domestic steel industry has declined in relative and absolute terms; its share of hard coal consumption declined from 22 per cent in 1980 to 12 per cent in 1997. The closure of the Newcastle steelworks in 1999 contributed to continuing decline thereafter. The demand share of the metals refining industry and other industries declined slightly from 11 to 10 per cent in the same time period.

In contrast, coal consumption for power generation increased from 67 per cent in 1980 to 78 per cent in 1997. Electricity generation from coal has remained on a continuous and vigorous growth trend throughout the last 25 years, except for a brief period of stagnation after 1980. In 1990, coal-based generation amounted to more than 77 per cent of total gross power generation. Following this, the growth appeared to decelerate somewhat. But the implementation of the National Electricity Market in 1996 gave cheap coal-based generation, especially from Victorian brown coal, a renewed impetus and once more led to vigorous growth. In 1999, almost 81 per cent of generation was from coal.

As can be seen from Figure 9, coal production grew rapidly as of the late 1970s. This was largely owed to demand for Australian coal from abroad. As from 1959, Australia had exported coking coal and thermal coal to Japan; these exports were a major driving factor behind the development of coal mines in Queensland as of the 1960s. In the following decade, the oil price shocks and the industrialisation of East Asia led to the acceleration of export growth.

Figure 9
Coal Production, Supply and Exports, 1973-2010



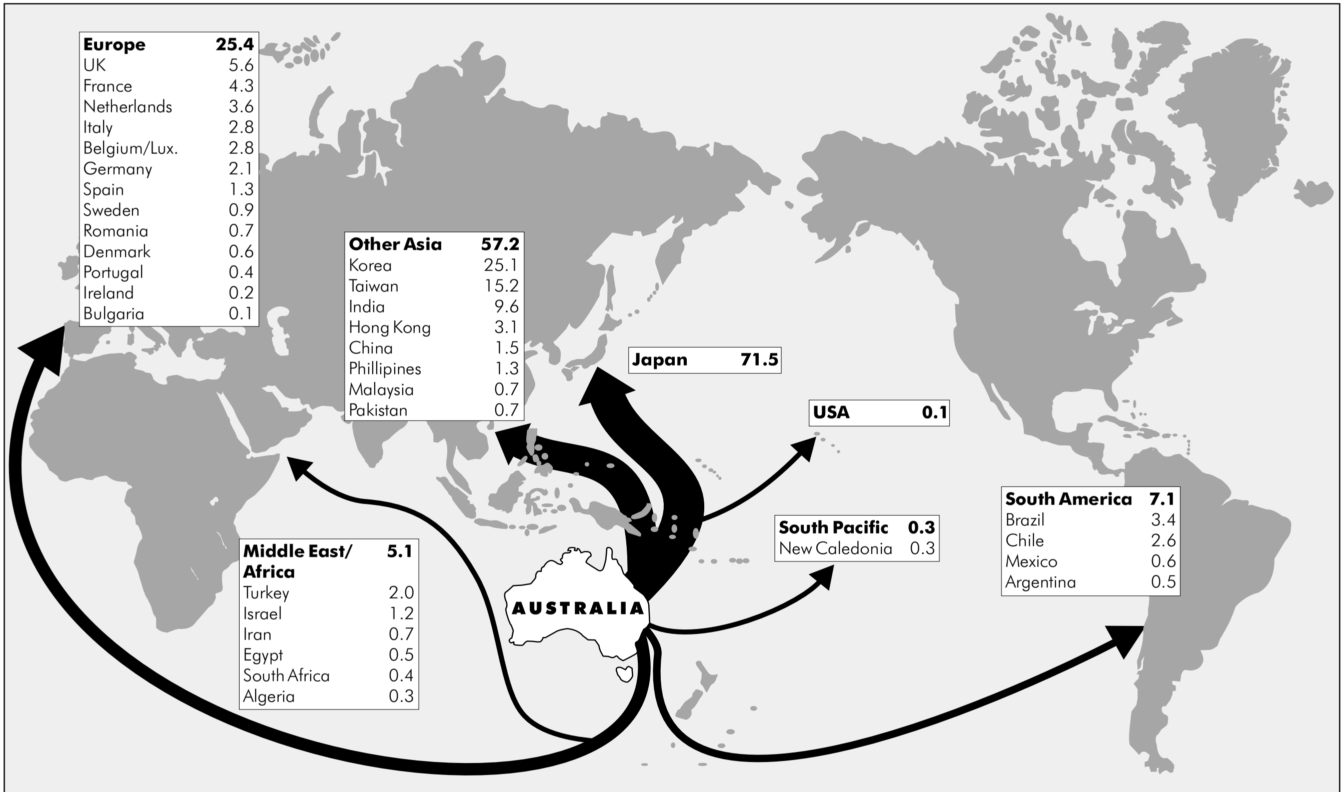
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

At present, Australia exports hard coal to over 30 countries around the world. The major markets are Japan, the world's largest coal importer, and other Asian economies. Japan alone took 43 per cent of Australia's hard coal exports in 1998. Together with the other Asian consuming countries Japan accounts for 77 per cent of exports. Significant amounts of coal are also exported to Europe, India, North Africa, the Middle East and South America. This is illustrated in Figure 10.

Transportation

Australia's existing coal mines and most of its reserves are situated close to the sea, allowing shipment by sea to the main consuming countries in Asia at reasonable distance and, in principle, comparatively low cost. Coal transport in Australia is handled by rail, road, conveyor and shipping systems.

Figure 10
Australia's Hard Coal Exports, 1998
(Million tonnes)



Source: Department of Industry, Science and Resources.

Most land transport occurs by rail, both for domestic coal use and, even more importantly, for coal export. Coal is carried by rail in New South Wales, Queensland, South Australia, Western Australia and Tasmania. In the two coal-exporting states Queensland and New South Wales, 75 per cent of coal production is transported by rail. Most of the remainder is transported by road and/or conveyor to power stations. Road transport is important for some mines, especially in New South Wales. There is also a limited amount of barge transport (in Queensland) and coastal shipping (in New South Wales).

Rail transport can be a significant factor in the price of Australian coal. The share of rail transport in the free on board coal delivered to Australian ports was estimated to be 15 per cent on average of FOB cost per tonne[19], but for certain mines it can be significantly higher, up to more than one-quarter of FOB cost per tonne. This alone indicates that reductions in coal freight rates can have a significant effect on coal prices. In addition, industry inquiries repeatedly found that Australian coal freight rates were significantly higher than in comparable operations abroad, due to governments' use of rail freights to collect implicit royalties and monopoly rents from the coal industry.

The cost of inland coal transport in Australia is relatively modest compared to other major coal producers such as Canada or the United States, partly because of the location of Australian coal deposits relatively close to the coast. In Canada, the cost of inland coal transport is estimated to range between US$ 9 and 13, in the United States between US$ 6.4 and 20.3, in Indonesia, one of Australia's main competitors in Asia, between US$ 2 and 7, and in Australia itself between US$ 4.1 and 6.9[20]. However, other cost components, including mine-mouth cost and loading, can be significantly lower for Australia's competitors in the international coal market than for Australian production.

Moreover, most of Indonesian transport cost is towards the lower end of the indicated range. Most importantly, coal is sold internationally at U.S. dollar prices, whereas inland transport and all other FOB costs are payable in Australian dollars. Since exchange rate fluctuations between the Australian dollar and the U.S. dollar can be very significant, reaching up to ± 15 per cent within relatively short time spans, there is a perception in the Australian government and coal industry that inland transport is a cost factor that must not be neglected.

Railway services were part of Australia's reform and restructuring of government-owned business enterprises, although reform proceeded on a somewhat slower schedule than that of other sectors, e.g. electricity or telecommunications. Nevertheless, by the mid-1990s, a certain amount of restructuring had occurred. Following the conclusion of the competition policy agreement between the Commonwealth and state governments in 1995, there were initiatives to open rail freight services to competition. However, under the national Competition Policy Reform Act, coal freight services were exempt from open access requirements until November 2000.

19. Productivity Commission: *The Australian Black Coal Industry*, Inquiry Report, AusInfo, Canberra, 1998.
20. International Energy Agency (IEA): *Coal Information 2000*. IEA/OECD Paris, 2000.

The main coal provinces New South Wales and Queensland have acted upon these reforms, but have taken different approaches. In New South Wales, the government-owned New South Wales State Rail Authority was separated into four businesses in 1996. These businesses cover rail infrastructure (Rail Access Corporation, RAC) track and rolling stock maintenance, provision of freight services (FreightCorp) and provision of passenger services. All businesses have meanwhile been corporatised; RAC and FreightCorp are to remain in state ownership.

The New South Wales government decided to open third party access for coal freight services before November 2000, albeit at coal access prices that were set at a uniform ceiling rate for all service providers. These prices were lowered during the transitional period, thus removing part of the implicit monopoly rent.

In Queensland, the government-owned rail services provider Queensland Rail (QR) was corporatised in 1995. QR has four business groups: coal and minerals, freight, city train and travel train. Initially, Queensland expected to delay open access for coal freight until after November 2000, but in 1998 decided to open the network as soon as an acceptable access regime could be developed. Also in 1998, a special Network Access Group was set up within QR, following a recommendation in a state government review.

The Australian Competition and Consumer Commission (ACCC) and the state competition organisations work towards creating a transparent access regime which will ensure competition. There is already competition across state boundaries. In Australian governments' view, ongoing reviews of pricing policies and the threat of competition have already lowered freight rates noticeably. Concurrent reform of price-setting, such as the abolition of royalty collection through rail freight rates, has contributed to this result. The Commonwealth government believes that following the end of the transition period for coal freight, third party access will exert further downward pressure on rates.

Australia's coal export industry is serviced by nine port coal loading terminals in six port locations. The country's coal loading facilities are among the largest in the world, with a combined annual loading capacity of 203 million tonnes, although they vary in size from the huge Newcastle facility (more than 65 million tonnes capacity) to the small Brisbane one (5 million tonnes). Ownership of the port facilities is mixed public and private.

Harbour services can amount to 6-8 per cent of total FOB cost and can therefore have a significant effect on prices. The Productivity Commission's inquiry yielded that the performance of Australian ports was more in line with world standards than the performance of the railway system, although room for improvement existed. A particular concern was possible excessive rates of return earned by some government port authorities.

Regulation and Government Interventions

All three levels of Australia's three-tired system of government – Commonwealth, state/territory, and local – intervene in the coal industry. Local governments have responsibility for planning matters, including buildings on mine sites, zoning and local environmental issues.

As hard coal is a state-owned resource in Australia, state or territory governments are responsible for management of coal reserves. State governments make the reserves available to companies for development and exploitation against payment of royalties. In New South Wales, royalties are levied on the amount of coal produced, currently at A$ 1.70 per tonne of coal. In addition, a super royalty of A$ 0.50 per tonne applies on all open cut mines. In Queensland, royalties are collected as a percentage of the sales value of production (*ad valorem* royalty). The current royalty rate for all mines in Queensland is 7 per cent.

State or territory mining acts and related regulations specify the procedures for coal exploration and exploitation. Other relevant issues such as safety, employment, environmental protection, royalties and transport within Australia are also generally defined in state or territory legislation. State governments levy taxes, as well as charges for rail transport and, in some cases, for coal loading.

The Commonwealth government has little direct responsibility for coal issues but certain areas of general economic policy such as international trade, the economy, commerce, industrial relations, the environment and land access/native title are pertinent to the coal industry. One notable exception to this was the Commonwealth government's export controls that had been in force since 1973 to ensure that coal exports were at world market price levels. Export price controls were removed in 1996. Export controls (relating primarily to environmental standards) remained in place until 1997.

Work practices and industrial relations is an area that has long been subject to industry-specific legislation and monitoring through special bodies at both state and Commonwealth level. In recent years, the federal government has become very active in fostering and overseeing reform in this area. This issue is described in more detail in the following section.

RECENT REFORMS

Beginning in the mid-1980s, the Australian hard coal industry felt increasing competitive pressures on its export markets as well as in the domestic market. These pressures were exacerbated after 1990, when Indonesia and China rapidly increased their exports to Australia's traditional export markets in Asia[21].

Changing technology in the steel industry and increasing competition in steel making and power generation further increased the pressures, and, taken together

21. Indonesia produces coal mainly for export, especially to Japan. China is the world's largest coal producer and a significant exporter, but exports are a relatively small share of its total production. There are excess supply and high stock levels at coal mines, partly because of inadequate rail transport infrastructure.

with the government's drive for structural reform, led to thorough analysis of productivity and possible cost reductions in the coal industry.

This work culminated in the inquiry into the Australian hard coal industry carried out by the Productivity Commission in 1997 and 1998. Based on its findings, the Productivity Commission issued a report containing numerous recommendations in 1998. The Commonwealth government published a response to these recommendations on 11 February 1999.

The findings of the Productivity Commission indicate that profitability was poor in the years prior to the inquiry, and well below the average for other mining activities in Australia. Productivity was low on average, lagging some 20 to 30 per cent behind comparable mines in the United States. There was significant variation in the results, though, with modern open cast mines in Queensland up to 20 per cent better than comparable foreign operations.

It was found that low productivity was in part caused by poor mine management, which in turn was attributed to restrictive work arrangements, resulting in inefficient utilisation of equipment and high labour cost. Mine labour cost was estimated to amount to 22 per cent of the FOB price of Australian hard coal on average in 1996, a very significant cost component. Industry-specific legislation and supervisory bodies at Commonwealth and state level were seen as major contributing factors to these problems. Other issues raised by the Productivity Commission encompassed price-setting and price control for coal rail freight and port facilities, and royalty arrangements.

The Commonwealth government has since promoted reform efforts in these areas, with a special focus on work practices and industrial relations arrangements. The reforms aim at raising productivity by encouraging a more direct relationship between employers and employees, with reduced third party intervention.

Early reforms included the abolition of the Coal Industry Tribunal in 1995. This federal body had been responsible for considering and settling industrial disputes in the coal industry since it was established in 1946. Its abolition was based upon the recognition that labour disputes in the coal industry did not necessitate an industry-specific body. Australia's general organisation responsible for industrial relations, the Industrial Relations Commission, now also covers coal industry disputes.

The Joint Coal Board, established by the Commonwealth and New South Wales governments in 1946, also had extensive powers over the coal industry in New South Wales, including the right to prevent mine closings and to limit mine production. The organisation was reformed in 1992, and its areas of responsibility were reduced to monitoring of health and safety in the work environment, provision of the Coal Mines Insurance – a special insurance scheme for coal miners – and training, education and information services. Queensland has a similar body, which was established around the same time. As specified below, the Productivity Commission has suggested further reform.

In parallel with these efforts to reform work practices, productivity improvements were sought through reduction in employment and closure of uneconomic mines (mainly underground) since the late 1980s. Employment in all of Australia fell from its peak level of 32,700 in December 1986 to 23,800 in December 1997 despite continuously growing output. Productivity rose from about 4,550 tonnes/employee on average[22] in 1986 to 9,170 tonnes/employee in 1997.

Since then, productivity growth has accelerated, a fact that is attributed to the recent industrial relations reforms. For instance, in the two years between June 1997 and June 1999, average labour productivity in New South Wales mines increased by 30 per cent. This is equivalent to the increase recorded in the previous six years. Similar improvements were achieved in Queensland. Industry-wide saleable output per employee rose by 22.7 per cent to 12,010 tonnes in the calendar year 1999 alone. This recent productivity growth is primarily the result of more efficient work practices rather than of capital investment or development of newer, more efficient mines. Productivity improvements were somewhat higher in the open cut mines than in underground collieries, with hourly output per employee almost doubling between 1990 and 1998 in open cast operations and 83 per cent improvement in underground mines. Despite these improvements, the Productivity Commission found significant potential for further improvement in its 1998 inquiry into the hard coal industry[23]. Based on these findings, it issued recommendations, the most important of which are:

- Governments should refrain from prescribing details of mine managers' responsibility or skills.

- The Coal Mining Qualifications Board (New South Wales) and the role in the coal industry of the Board of Examiners (Queensland) should be abolished.

- Restrictive practices, such as limitations on recruitment, part-time or temporary employment, should be abolished.

- The New South Wales and Queensland governments should facilitate the early establishment of comprehensive and effective rail access regimes.

- In New South Wales and Queensland, price-setting for rail and port services should be made more transparent. Freight customers should have a right of appeal to these bodies regarding the application of these principles.

- The Productivity Commission recommends that workplace parties, i.e. principally employers, be legally responsible for mine safety. It suggests that underground mining can be covered adequately by general health and safety and mining legislation. As there is still a high fatality rate in underground mining, it proposes that separate regulation should be maintained only for underground coal mines.

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22. This figure combines the higher productivity at open cut operations with the necessarily lower productivity at underground mines.
23. Productivity Commission, 1998.

- The Joint Coal Board should be abolished and its functions taken over by the New South Wales Department of Mineral Resources, WorkCover and private insurance providers where appropriate.

- The New South Wales government should adopt an *ad valorem* royalty system.

The Commonwealth government supports all of these recommendations. As far as royalties are concerned, the Commonwealth government believes that the *ad valorem* approach is more responsive to market conditions than a quantity-related (specific rate) royalty system, because the former is calculated on the value of production. Consequently, an *ad valorem* regime means that coal producers are not adversely affected during periods of market downturn. Such a downturn is being experienced currently. In this commercial environment, the current disparity between the Queensland and New South Wales regimes unfairly penalises New South Wales coal producers. For this reason, the Commonwealth intends to promote this recommendation with the New South Wales government.

CRITIQUE

Australia is the largest hard coal exporter in the world. It is also a stable and reliable exporter. Production and sale of coal from Australia's mines thus contribute significantly to security of supply, first of all in the nearby Asian market but also in the world market, and ultimately contributes to the strength of the global economy. Coal demand in Asia is expected to expand rapidly[24], and Australia is expected to remain the main supplier of the region[25]. Judging from the extent of the resource, Australia can continue playing this important role for a long time, provided potential obstacles can be overcome.

One of these obstacles is the need to remain competitive. This was recognised a decade or more ago, and significant progress has been made. The other difficulty lies in the environmental impact of coal, especially with regard to climate change. This issue is much harder to address. Nevertheless, or perhaps for this very reason, it deserves much attention. It will in all likelihood require a technological solution. The first issue is discussed in this chapter; for the second, the discussion in Chapter 4 on energy and the environment and Chapter 9 on technology research and development, is relevant.

In the early days of coal mining[26], production and exports expanded fairly rapidly, although under strong government influence and, during certain time periods, under monopoly rights. Virtually from the beginning, the industry was

24. Australian Bureau of Agricultural and Resource Economics (ABARE): *Australian Energy: Market Developments and Projection to 2014/15*, Research paper, Canberra, 1999.
25. International Energy Agency (IEA): *World Energy Outlook 2000*, OECD/IEA Paris, 2000.
26. Hard coal was first mined in 1799 in the Newcastle area in New South Wales. By 1898, every state had commercial coal mining operations.

characterised by a relatively high level of industrial dispute. Following a first peak in production and exports in the 1920s, the Great Depression and substitution by cheaper petroleum products led to loss of market share, especially abroad, and resulted in a domestic focus. This tendency was reversed only when rapid industrialisation in Japan led to swift growth of coal exports to Japan after 1959[27]. The oil price shocks of the 1970s gave an additional impetus to Australian coal exports, especially to Europe and Asia, as did industrialisation in East Asia. Consequently, Australian coal exports, especially of thermal coal, expanded particularly rapidly throughout the early 1980s.

Even so, the Australian coal industry was insulated from strong competition until about the mid-1980s. Until the mid-1970s, most of the output was destined for the domestic market, principally the electricity industry, not subject to competition at the time. Inter-fuel competition for supply to power stations from other domestic energy sources was limited as alternative resources remained to be discovered, especially in New South Wales.

Throughout the 1960s and 1970s, there were only few producers of coking coal in the region other than Australia. Japanese coal purchases occurred under long-term contracts for security of supply reasons. Also, coking coal prices negotiated with Australian and Canadian producers were used as a benchmark for thermal coal contracts, which were usually concluded later (until 1996). In these contracts, annual adjustments for thermal coal prices were identical with those for certain types of coking coal (until 1994). Moreover, Japanese importers paid a price premium on grounds of security of supply, and other Asian markets tended to follow the Japanese benchmark price.

In its 1998 report, the Productivity Commission concluded that this combination of a captive domestic market, an export market that placed great emphasis on security of supply, and a history of industrial dispute, resulted in a culture of "maintaining supply at all costs"[28], giving rise to the perception that coal required special legislation, regulation and institutions. This ultimately caused the relatively poor productivity described in the preceding section.

The situation began to change when oil prices dropped in 1986. Following this, competition on the coking coal market increased and new steel-making techniques developed that increased the substitutability between coking and thermal coals or even eliminated the use of coking coal. As of 1990, China and Indonesia emerged as major suppliers of thermal coal, expanding their market share in the Asian market from 5 per cent and 2 per cent, respectively, in 1985 to 18 per cent each in 1996.

27. A large amount of this was coking coal destined for steel-making. Although this report is concerned with energy issues exclusively, developments in the coking coal market are reported insofar as they affect the market for thermal coal. The two are linked, because certain thermal coals can be used as coking coals and vice versa.

28. Productivity Commission, 1998. The number of days lost to industrial dispute was much higher than generally in Australian industry in the period 1970 to 1997. Except in the two years 1983 and 1984, it was also significantly higher than in other mining industries in Australia.

Still more recently, and partly because of a quest for greater cost-efficiency and deregulation in the Japanese power industry, Japanese purchases shifted away from the benchmarking system and towards greater use of the spot market. Taken together, these factors began to exert significant pressure on coal prices in the late 1980s and created the current market with significantly lower, less transparent and more volatile coal prices. Today, coal purchases are dominated by the spot market, especially in Asia.

The reforms the Commonwealth government has promoted to accelerate adaptation to these developments in the coal industry have been successful and have already addressed a significant number of these issues. The progress made since the last IEA review is very encouraging, as illustrated by the impressive efficiency improvements recorded in the last years.

In particular, over-regulation of the coal industry was reduced through the abolition of export controls and the dismantling of industry-specific procedures, legislation and organisations. This is clearly a significant achievement. The task at hand now is to complete the reform process. The government should follow the recommendations of the Productivity Commission and work towards dismantling the remaining special arrangements and institutions except where they are clearly necessary and well-performing.

Although progress has been made, two transport-related areas also still need attention: third party access arrangements for coal rail services and price-setting for coal ports, in particular the expected rate of return. Owing to the high share of inland transportation in the price of coal, the perception of the government and industry that this issue must be tackled to maintain competitiveness is valid. Further progress on the former issue can be expected soon, given that the exemption for coal freight from third party access has just ended. The latter issue appears to be a standard regulatory issue. Here, the Commonwealth should work with state governments to adjust rates of return to economy-wide rates and increase transparency as quickly as possible.

Apart from being a major industry in the Australian economy, the hard coal industry also contributes significantly to the state revenues in New South Wales and Queensland through the royalties paid for the use of the resource. In the financial year 1996/97, this contribution was A$ 233.5 million in New South Wales, or 1.6 per cent of the state's own revenue, and A$ 402 million or 4.7 per cent in Queensland.

New South Wales and Queensland effectively sell different products – New South Wales sells mainly steam coal whereas Queensland sells mainly coking coal that commands a price premium of about US$ 10 per tonne. However, as the Productivity Commission notes, the disparity between royalty systems in the two major coal-producing states creates an economic burden for coal production in New South Wales. Compared to specific (quantity-related) royalties, *ad valorem* royalties are lowered automatically if the price of coal decreases and the economic viability of mines may become strained. New South Wales once decreased its royalties temporarily during a time of very low coal export prices. However, such action would in all likelihood come late, when some economic strain had already occurred. The government should promote a change towards an *ad valorem* royalty system with the New South Wales government, as it indeed intends to do.

RECOMMENDATIONS

The government should:

- ☐ Complete the reform of the coal industry. In particular:
  - Continue its efforts to remove over-regulation.
  - Implement the recommendations of the Productivity Commission, especially those relating to work practices and industrial relations, where this has not already happened.

- ☐ Monitor the progress made in the states regarding third party access for coal freight services in the coming months and, if necessary, work with the state governments to ensure that effective, non-discriminatory and transparent access regimes are developed and implemented.

- ☐ Encourage state governments to set prices for port services in a transparent manner. Ensure that rates of return used for port pricing reflect those of a representative basket of Australian industries.

- ☐ Encourage the shift towards *ad valorem* royalties.

6

OIL

INDUSTRY OVERVIEW

Upstream

Exploration and Production

Australia has significant hydrocarbons reserves. Table 3 details these reserves as of 31 December 1997. This table follows the traditional petroleum industry classification used by the Australian Geological Survey Organisation. Category 1 includes both proved and probable reserves. Category 2 comprises estimates of recoverable reserves which have not yet been declared economically viable. They may be either proved or awaiting further appraisal. According to this classification, 57 per cent of the oil reserves are declared commercial.

Table 3

Petroleum Reserves in Australia at End 1997

(Million barrels, except for natural gas)

	Oil	*Condensate*	*LPG*	*Natural gas billion cubic metres*
Category 1: commercial at current prices	1,001.8	704.3	791.1	803.4
Category 2: not commercial at current prices	770	1,053.7	1,174.3	1,975.3
Total	**1,771.8**	**1,758**	**1,965.4**	**2,778.7**

Source: Australian Geological Survey Organisation: *Oil and Gas Resources of Australia 1999*, Department of Industry, Science and Resources, Canberra, 1999.

A large part of these resources is concentrated in four offshore areas: the Gippsland basin off the Victorian coast and in the Bass Strait, and the Carnarvon, Browse and Bonaparte basins on the north-west shelf. The Carnarvon basin is particularly important as it contains a large part of commercial (category 1) reserves: 41 per cent of oil, 76 per cent of condensate, 64 per cent of naturally occurring LPG and 71 per cent of gas. In addition, it also contains significant portions of pre-commercial (category 2) reserves, i.e. 20 per cent of gas reserves and roughly one-third each of the others. The Gippsland basin contains slightly more than half of commercial oil reserves and sizeable amounts of condensate, LPG and gas. But being a mature production region, only modest pre-commercial amounts are expected, except perhaps for oil (23 per cent of category 2 reserves).

North-east of the Carnarvon area, in the Timor Sea, the Bonaparte basin is estimated to contain 41 per cent of pre-commercial oil reserves, and the Browse basin, 40 per cent of condensate, 63 per cent of LPG and 48 per cent of gas, all in category 2. In contrast, both basins have only negligible category 1 reserves. These offshore basins are depicted in Figure 11.

Some additional commercial petroleum reserves are located in the onshore Cooper/Eromanga basin straddling the border between Queensland and South Australia, which is one of Australia's most mature production areas.

However, this picture may be very incomplete. Australia has extensive areas of potentially petroleum-bearing sedimentary basins, including its continental shelf. This area of about 16 million square kilometres is under-explored: at the end of 1999, 7,620 exploration and development wells had been drilled in Australia, compared to about 3 million in the United States, where over 60,000 wells have been drilled in the Gulf of Mexico alone, an area smaller than the Carnarvon basin. Only 1,763 of the Australian wells are offshore. There is one wildcat hole per 20,000 square kilometres, a density that compares to the situation in the United States in the late 1860s.

Moreover, Australia's 200-mile exclusive economic zone (EEZ), as defined under the United Nations Convention on the Law of the Sea (UNCLOS), is significantly smaller than the country's continental shelf. The country intends to claim a further 3.3 million square kilometres of continental shelf beyond the current EEZ before 2004. The EEZ would then be 12 million square kilometres, more than twice as large as the Australian land area.

The Australian Geological Survey Organisation estimates that there is a 95 per cent probability that Australia has 1.3 billion barrels of undiscovered oil reserves, 400 million barrels each of undiscovered condensate and LPG, and more than 500 billion cubic metres of gas.

In 1997, a large number of oil and gas reserves were discovered in Australia. This prompted very high levels of exploration by private companies in 1998, despite the relatively low oil prices. Exploration expenditure increased by 30 per cent compared to 1997 to more than A$ 1 billion, and the area covered by seismic surveys was doubled. In 1999 and 2000, however, these numbers were back to, or even below, their longer-term average. In 1999, 22 per cent of the wells drilled were successful.

In a longer perspective, it is noteworthy that Australia also has very significant reserves of non-conventional oil. In Queensland alone, 30 billion barrels of shale oil *in situ* resources have been discovered. This is three times the oil reserves in Norway, currently the world's second largest oil exporter.

Based on past discoveries, there has been perception for many years that large parts of Australia are "gas-prone", i.e. that gas discoveries are much more likely than oil discoveries. The high cost of transporting gas to demand centres from remote areas limits the commercial attractiveness of gas discoveries. Recently, oil has been found in the "gas-prone" regions, but the discoveries were not large enough to reverse current market trends.

Figure 11

Offshore Petroleum Basins in Australia

Source: Department of Industry, Science and Resources: *Australian Offshore Petroleum Strategy*, Canberra, 1999.

In the financial year 1999/2000, 186.14 million barrels of crude oil, 49.44 million barrels of condensate and 27.47 million barrels of LPG were produced from Australian wells. Total oil and natural gas liquids (NGLs) production in calendar year 2000 was 34.84 Mtoe. At this rate, current commercial reserves would last for about eight years. As there has not been any major oil discovery in recent years, oil production is expected to decline in the near future. Currently, the Australian government expects that production of oil and NGLs will sink to 32.0 Mtoe in 2005 and 31 Mtoe in 2010. The IEA expects total oil production to decline slightly to 29.4 Mtoe in 2010 (see Annex A).

About 94 per cent of Australia's current crude oil production and 75 per cent of its gas production are from the offshore resources in the Bass Strait, the north-west shelf and the Timor Sea. With 48 per cent of total oil production, the Carnarvon basin was the largest producer, while Gippsland basin produced 41 per cent. The order was reversed for LPG, where Gippsland basin produced 45 per cent and Carnarvon basin 33 per cent.

Figure 12 shows Australia's petroleum-producing facilities. The figure contains a diamond-shaped area off the Darwin coast in the Timor Sea. This is the Timor Gap Zone of Co-operation (ZOCA) between Australia and East Timor, which is currently administered by the United Nations Transitional Administration in East Timor (UNTAET) and Australia. In this area, Australian petroleum production occurs on the basis of the Timor Gap Treaty, underpinned by a memorandum of understanding with UNTAET. Area A in the zone lies within the extended continental shelf area that Australia is to claim with UNCLOS. Currently, it contains one oil-producing facility. Operating companies are planning a large-scale liquids stripping project from a gas/condensate field (with re-injection of the natural gas). Companies are also planning large-scale natural gas development with a pipeline to the Australian mainland to supply gas for domestic use and for export. The Australian Commonwealth government is in the process of making arrangements with UNTEAT, East Timorese representatives and other organisations to adapt the Treaty to East Timorese independence, expected at the end of 2001.

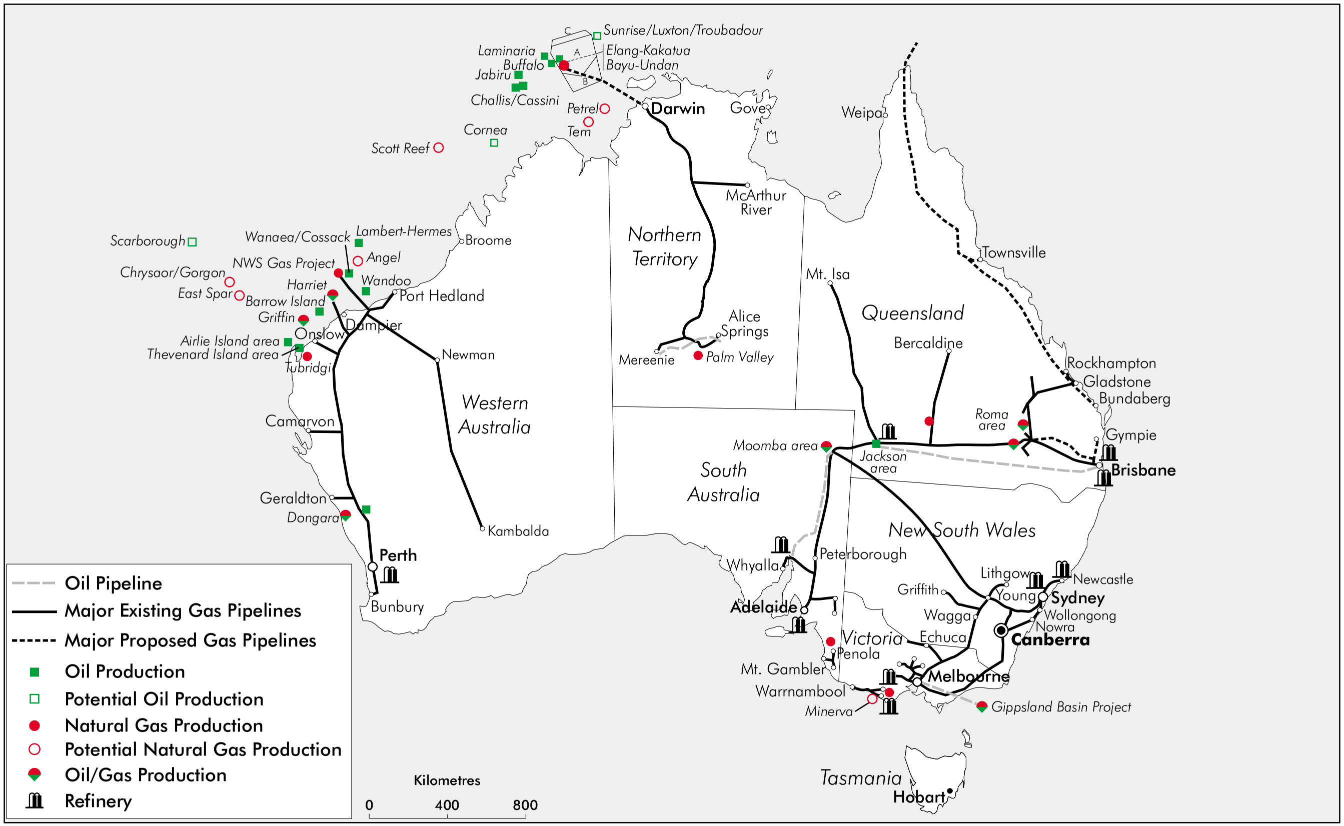
More than a hundred private-sector companies are active in exploration and production in Australia. These companies are of differing size and often of foreign ownership. The largest producers are Esso and BHP in the Gippsland basin, along with Woodside and other New South Wales-based joint venture partners in the Carnarvon basin.

At the Stuart shale oil deposit near Gladstone, the Australian resource owners have entered into a joint venture with the Canadian company Suncor to exploit the deposit's 3 billion barrels of shale oil reserves. Suncor is a world leader in non-conventional oil extraction and has developed shale oil technology that enables recovery of 92 per cent of the *in situ* oil in the deposit. In 1999, a stage 1 pilot plant was commissioned at Stuart with an extraction capacity of 4,500 barrels per day. The pilot is presently run in 5-day test cycles, with the aim of optimising performance and reducing odour problems.

If successful, the Stuart project could lead to an 85,000 barrels per day commercial operation by the end of the decade, after an intermediate 14,800 barrels per day

Figure 12

Petroleum Production, Transportation and Refining Infrastructure in Australia



Source: Department of Industry, Science and Resources.

facility (stage 2) further proves the project's viability. The Stuart consortium has invested A$ 250 million in the stage 1 pilot, and the Australian government has so far contributed some smaller R&D grants and some tax relief measures.

Transportation and Trade

As illustrated in Figure 12, Australia has only four onshore crude oil pipelines. These are Gippsland to Melbourne, the Cooper/Eromanga basin to Brisbane, the Cooper/Eromanga basin to Whyalla (Port Bonython) in South Australia and the pipeline supplying Warrnambool in Victoria. Crude oil produced in the Carnarvon basin, the Timor Sea and the Perth basin is transported to refineries by coastal shipping or exported overseas directly. There is only one oil product pipeline of 200 km length, linking Mereenie with Alice Springs (Northern Territory). Most transport of oil products is by road. Australian oil companies try to limit the need for transportation across the huge distances through swaps.

In 1999, 30 per cent of Australia's oil supply stemmed from net imports. In 1998, this figure had been less than half at 14 per cent. In contrast, the country was a net exporter of natural gas. Most oil found to date in Australia has been of a light grade; about 10 per cent of the country's imports are heavier oils for refining into lubricating oils, grease and bitumen. In turn, Australia exports higher value-added light oil and oil products. In the financial year 1999/2000, the value of crude oil and gas production was around A$ 10.3 billion, with exports valued at A$ 7.8 billion. For the calendar year 1999, the value of exports was A$ 6 billion, with a net return of A$ 248 million to the Australian economy after taking account of imports.

Government Intervention in the Upstream Oil Sector

Commercial petroleum exploration and development in Australia is in the hands of the private sector. The government nevertheless has an important, multi-faceted role:

- It owns the resource and levies royalties and taxes.
- It provides a regulatory framework for exploration, development, project approval processes, safety, environmental assessment and revenue provision.
- It is active in promoting petroleum exploration, by generating and disseminating basic geo-scientific information.
- It looks for ways to improve the industry's competitiveness, including removal of impediments.
- It acts upon the macroeconomic environment through its general economic policy, and upon the Australian oil industry's situation in the international oil market through its foreign, trade and customs policy.

Both the Commonwealth government and the state and territory governments have important roles affecting petroleum exploration and development.

- The state governments own the petroleum resource onshore and within three nautical miles offshore[29] (coastal waters). They allocate petroleum rights, administer petroleum operations, including operational health and safety, and collect the royalties on petroleum produced.

- The Commonwealth government has rights over offshore petroleum resources on the continental shelf beyond coastal waters under the Petroleum (Submerged Lands) Act (PSLA) of 1967.

Under the Submerged Lands Act, the Commonwealth government grants exploration permits that confer exclusive rights to undertake seismic surveys and drilling in a defined area, production licences following a commercial discovery, and retention leases where a discovery is not commercial but thought to become so in the future. Onshore and within coastal waters, state legislation applies. The states also have a two-stage system of exploration permit and production licence. The minimum area covered by the licence, the initial term of the permits and royalties can vary between states. State governments also grant pipeline licences for pipeline infrastructure or processing plants.

Table 4 provides an overview of the system of royalties and secondary taxes applied to the upstream oil industry in Australia. The Commonwealth Crude Oil Excise is collected under the Excise Act of 1901 and the Excise Tariff Act of 1921. The tax base is the sales value of oil produced in a certain region, determined by actual sales prices and production in that region. Due to differing oil qualities among regions, prices differ, and so do values. The tax rate also varies, depending on the time of discovery and development of the oil field in question. The first 30 million barrels of crude oil from an oil field are exempt from this tax. This tax led to very high government receipts of over A$ 4 billion in the mid-1980s, as a reaction to the high international oil prices (with a time lag) and the peak of production from the Bass Strait. Since 1990/91, revenues have been very low.

The Petroleum Resource Rent Tax (PRRT) is collected under the Petroleum Resource Rent Tax Assessment Act of 1987. Government revenues from this tax began increasing noticeably after 1990. In the financial year 1999/2000, revenues of A$ 1.13 billion were expected. This is much higher than from any other current Commonwealth petroleum taxation scheme. Since it is profits-based, the tax adjusts automatically to changes in prices and costs. Unlike the Commonwealth Crude Oil Excise, there is thus no need to adjust the tax in response to external economic factors.

Nevertheless, the oil industry criticised the tax as discriminating against long lead-time, low profit developments, especially those in deep water. In December 1998, the government conducted an investigation into the tax and found no substance to the deep water argument, noting that the tax take was lower than in most other deep water oil provinces except the UK. In particular, it was somewhat below the

29. From the baseline, which is in some places not identical with the shore line.

U.S. rate for similar water depth. But the government did announce a number of adjustments, the most important of which is a gas transfer price to remove taxation insecurity for LNG and other gas-to-liquids projects, such as future gas-to-methanol and gas-to-diesel developments (see Chapter 7).

The Commonwealth Petroleum Royalty is based on the PSLA and the Petroleum (Submerged Lands) (Royalty) Act, also of 1967. This Commonwealth royalty is shared with the state adjacent to the production wells (Western Australia) in exchange for ongoing administration of the royalty regime.

Table 4
Petroleum Taxation and Royalty Regime

	Offshore (Commonwealth)	
Tax/Royalty	**Area of Application**	**Rate**
Petroleum Resource Rent Tax	All areas except north-west shelf	Profits-based, 40 per cent of net revenues
Commonwealth Crude Oil Excise	North-west shelf	Percentage share of the value of oil sold
Commonwealth Petroleum Royalty	North-west shelf	Percentage share of value at wellhead, currently 10-12.5 per cent
	Onshore and coastal waters (states and territories)	
Tax/Royalty	**Area of Application**	**Rate**
Commonwealth Crude Oil Excise	All areas except Barrow Island	Percentage share of the value of oil sold
State/Territory Petroleum Royalty	All areas except Barrow Island	
Resource Rent Royalty	Barrow Island	Profits-based

Source: Department of Industry, Science and Resources.

Where a state introduces a Resource Rent Royalty (RRR), the Commonwealth Crude Oil Excise can be waived under the Petroleum Revenue Act of 1985, provided the revenues are shared with the Commonwealth. Currently, such an arrangement is applied only to the Barrow Island project, located some 1,300 km north of Perth, 56 kilometres off the West Australian coast between Port Headland and Onslow. This project is operated by WAPET. Here, both administration costs and RRR revenues are shared 75:25 between the Commonwealth and Western Australia.

Recognising the fact that Australia remains under-explored, and the benefits of stimulating exploration and development, the government set out its policies for the offshore petroleum industry in its Resources Policy Statement released in 1998.

The main objective of this policy is to ensure that the legislative framework provides an internationally competitive operating environment and a high degree of certainty for companies and other stakeholders. The Minister for Industry, Science and Resources launched the Australian Offshore Petroleum Strategy in April 1999. This strategy is to provide the framework for efficient exploration of Australia's continental shelf over the next five to ten years by translating this objective into concrete measures. These are:

- A new Offshore Exploration Acreage Release Programme. Australia releases new acreage for exploration every year around the month of May. Companies have between six and 12 months to prepare applications. In the framework of the Offshore Petroleum Strategy, the size of the areas on offer was readjusted to comply with industry demands for greater access to more mature exploration provinces. Any areas from relinquishment, surrender, or cancellation of permits are released again more rapidly, as are areas not taken up from earlier offers. Increasing emphasis is given to deep water areas and frontier regions. Releases from 2001 to 2005 are to include frontier areas such as the Lord Howe Rise, the Bremer basin and the South Tasman Rise. As of 2005, areas in the Kerguelen and Wallaby Plateaux will be offered.

- Improved access for explorers to low-cost geological and geophysical data. To achieve this, a national petroleum information strategy is to be established in order to improve uniformity and availability of data. The information explorers are required to make available to the government under the PSLA, as well as pre-competitive information provided by the states, are to be bundled, standardised and made available on the Internet and through the Asia-Pacific Economic Co-operation Organisation (APEC), and especially its network of minerals and energy databases. Government geo-scientific databases are available to explorers in a range of formats against a fee covering handling and administrative costs.

- An enhanced programme of regional geophysical work to be undertaken by the Australian Geological Survey Organisation (AGSO). Under this initiative, an increase in funding of A$ 33.3 million was made available for the Australian Geological Survey Organisation over four years, beginning with the 1997/98 budget. The monies are dedicated to the organisation's programme to identify prospective new oil zones in frontier areas of Australia's Marine Jurisdiction, especially in the southern continental margin of the Great Australian Bight. The results of these initiatives are intended to reduce geological uncertainties in the evaluation of petroleum prospectivity and attract commercial exploration in frontier areas.

- Progressive reform of the regulatory framework for petroleum exploration and development in offshore areas. The government keeps the regulatory framework for offshore petroleum exploration and development under scrutiny. Recent initiatives included streamlining of government administration of the offshore industry, a long-term review of the relevant legislation in consultation with industry – notably including review and amendment of the PSLA in 1998 –

review of the legislation against competition policy principles, and a planned subsequent rewrite of the legislation to improve readability and reduce compliance costs.

- Support for other policies that enhance Australia's competitiveness in attracting scarce investment. The areas addressed under this initiative include clear and efficient taxation policies – especially the review of the PRRT referred to above – ocean planning and management, promotion of the LNG industry[30], effective and clear environmental protection and native title provisions, investment incentives as well as support to foreign investors in dealing with the various layers of Australian government.

The Australian government seeks to encourage foreign investment in the oil industry. Foreign companies are not obliged to engage Australian interests in their petroleum exploration activities. Neither are foreign companies required to seek approval under foreign investment policy when they are granted a new petroleum exploration right by the Commonwealth, or state governments. Moreover, proposals to acquire a stake in an existing petroleum exploration right are exempt from examination under the Foreign Acquisitions and Take-overs Act of 1975 (FATA), although large new petroleum projects above A$ 10 million and acquisitions above A$ 5 million are examined for their compatibility with Australia's national interest.

Downstream

Refining and Retailing

Australia has eight major refineries. They are owned by four vertically integrated companies: BP, Shell, Caltex and Exxon/Mobil, each owning two refineries. Almost all of these refineries are located on the coast near demand centres. All states except Tasmania have a refinery.

In the financial year 1999/2000, the major refineries had a combined capacity of 847,500 barrels per day. Their combined output was 42,851 million litres or approximately 740,000 barrels per day. Consumption in the same time span was 45,054 million litres of petroleum products, of which 41 per cent was gasoline, 29 per cent automotive diesel, 11 per cent jet fuel and 4 per cent auto LPG, and the remainder fuel oil, lubricants, etc. This represented an average demand growth over the previous financial year of 3.4 per cent. Consumption of auto LPG grew most by far, with 19 per cent growth over the previous financial year.

Imports of oil products are increasing and accounted for about 10 per cent of total supply in 1999/2000. As can be seen from Figures 13 and 14, pre-tax gasoline and diesel prices are the lowest among all IEA Members, and have been the lowest for years.

30. The government designed an LNG Action Agenda in 1997 that is discussed in more detail in Chapter 7.

The downstream industry recorded a 2.6 per cent return on assets of A$ 10.7 billion. However, the refining segment recorded an A$ 61 million loss. The loss was more than compensated for by the profitability of marketing, leading to the passable overall result.

There are around 8,300 service stations in Australia. The four integrated refiners/ marketers own about 3,000 service stations themselves and have supply contracts with another thousand dealer-owned service stations. As the Petroleum Retail Marketing Sites Act of 1980 limits the number of service stations the refiners/ marketers can operate directly, presently set at around 5 per cent of total sites, these companies currently lease their service stations out to other operators.

The refiners/marketers also have links with distributors who supply about 3,900 distributor- or dealer-owned service stations mostly in rural areas. There are several independent chains, including Liberty, Gull and 7/11, with around 480 service stations in total and one chain of 85 outlets linked to the supermarket chain Woolworth.

Government Intervention in the Downstream Oil Sector

Government has a considerable involvement in the downstream oil industry. Among other things, it taxes oil products, monitors market developments and possible anti-competitive behaviour in the industry and sets fuel quality standards that have a strong effect on the refining operations.

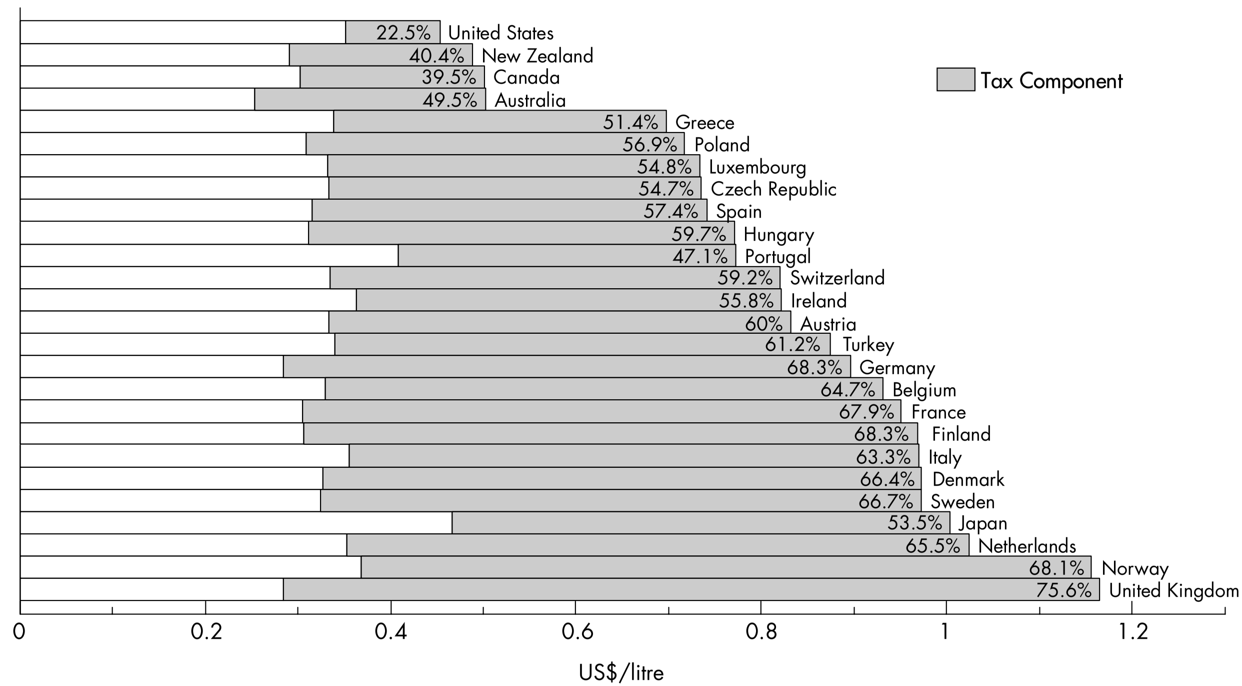
The refining sector is the target of a recent policy initiative, the Downstream Petroleum Products Action Agenda (DPPAA), developed and released in late 1999. This initiative attempts to address the low and declining profitability in the Australian refining industry, which is seen by the government and by the industry alike as a business in crisis.

The refining sector has been characterised by poor profitability for many years, and despite industry efforts to cut costs over the last five years, the situation has not changed for the better. The causes of the poor profitability of Australian refineries are seen to be weak economies of scale, compared to Australia's competitors in the region, and refinery equipment geared towards expensive "sweet" (low-sulphur) crude oil.

Whereas a modern refinery in an ASEAN country would typically have a capacity of 300,000 barrels per day, Australian refineries are much smaller at about 100,000 barrels per day. Refinery equipment has long been oriented towards the "sweet" crudes that are produced in Australia, following a Commonwealth government requirement throughout the 1970s and 1980s to use Australian crude oils before importing. This requirement was abandoned in 1987, but the legacy of this policy is still felt, especially since Australian oil demand began outstripping indigenous production. Some Australian refineries have been upgraded so that they can process much cheaper "sour" (high-sulphur) crudes imported from the Middle East, but some are still restricted to "sweet" crudes. In contrast, ASEAN refineries are equipped to process "sour" crudes.

Figure 13

OECD Gasoline Prices and Taxes, 4th Quarter 2000

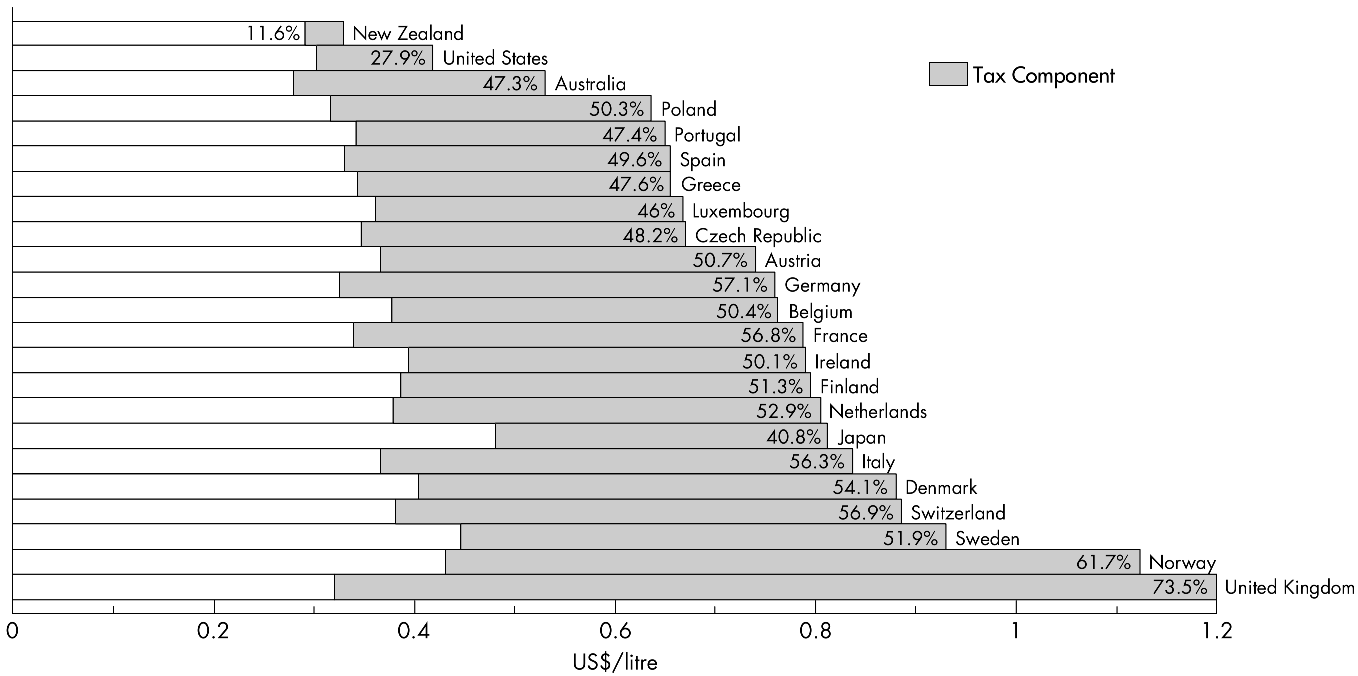


Note: Data for Mexico not available.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2001.

Figure 14

OECD Automotive Diesel Prices and Taxes, 4th Quarter 2000



Note: Data not available for Canada, Hungary, Mexico and Turkey.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2001.

Table 5 shows that the best average cost from an Australian refinery, despite the proximity to the market, is only US$ 0.20 per barrel below the incremental cost from a large refinery in Singapore. At this landed price, the Australian refinery just breaks even, i.e. only just covers its depreciation cost. The Australian best cost applies when the price differential between "sweet" and "sour" crudes is particularly small; at other times it will be more economic to import products. During such periods, Australian refineries rapidly accumulate losses. On the one hand, declining sales reduce revenues. On the other hand, declining sales and output increase average costs, as the high fixed costs have to be spread over a reduced volume of production.

The closure of one or two refineries is probably inevitable. But more fundamental change is necessary to improve the profitability of the remaining refineries, especially since the government intends to introduce more stringent fuel specifications in the coming years.

Table 5

Typical Cost for Australian and Singapore Refineries

(US$ per barrel)

	Australian refinery (east coast) 100,000 b/d Average cost	*Singapore refinery 300,000 b/d Average cost*	*Singapore refinery 300,000 b/d Marginal cost*
Crude cost	16.00-16.60	15.40	15.40
Freight to refinery	1.00-1.40	0.60	0.60
Refinery operation			
– fixed cost	0.90	0.40	
– variable cost	0.50	0.30	0.30
Other cost	0	0.40	0.40
Product price at refinery	18.40-19.40	17.10	16.70
Freight to market	0	1.90	1.90
Product cost	18.40-19.40	19.00	18.60

Source: Department of Industry, Science and Resources: *Downstream Petroleum Products Action Agenda*, Canberra, 1999.

Notably, the Euro 3 emissions standard is to be phased in by 2005 for new vehicles and by 2006 for all vehicles, reducing the allowable benzene content from 5 per cent to 1 per cent. This would entail additional investment of A$ 10 to 50 million at each refinery. Further changes under discussion, such as introduction of the 95 octane rating (RON), the Euro 4 standard and a ban on MTBE would cause additional costs.

Between 2003 and 2007, Euro 2, 3 and 4 are to be introduced in rapid succession for diesel. By 2006, the sulphur content of diesel will be reduced to 50 parts per million (ppm), with one intermediate step of 500 ppm in 2002. Today, the applicable standard is 5,000 ppm (0.5 per cent), and the average actual sulphur content is 1,300 ppm. This measure will require investment of A$ 100 to 200 million per refinery. Some oil companies have already signalled that they will not make this investment, which would mean the closure of the refineries concerned at end 2005 at the latest, and possibly as early as end 2002 if the intermediate step is not taken.

To address the current problems and their possible worsening in the future, the government set in motion a policy process entitled Downstream Petroleum Products Action Agenda in 1999. This initiative consists so far of closer consultation and co-operation between the government and the oil companies, and government support for industry restructuring and joint ventures put to the Australian Competition and Consumer Commission, provided they demonstrate economic benefits and are carried out in a transparent manner. In mid-2001, progress made in the refining industry will be reviewed. The background to these support measures is that market power in the oil industry has been an issue for several years.

Both the Commonwealth government and state governments have powers to intervene in the downstream oil business. Federal interventions are based on the Trade Practices Act of 1974, the Petroleum Retail Marketing Sites Act of 1980, and the Petroleum Retail Marketing Franchise Act of 1980. Under the Prices Surveillance Act, the Australian Competition and Consumer Commission (ACCC) had powers to intervene in the sector and set a wholesale price ceiling, the Maximum Endorsed Wholesale Price (MEWP), for gasoline and automotive diesel.

In 1996, the ACCC undertook an inquiry into the structure and the competitiveness of the downstream market. The commission's report, entitled "Inquiry into the Petroleum Products Declaration" included the following findings:

- The four oil majors were found to have substantial market power. Horizontal co-ordination, for instance through product exchanges between the majors, potentially allows monitoring of each other's activities.

- Government policy on coastal trade that does not allow international vessels to operate maintains high coastal freight prices and supports refinery exchanges.

- Gasoline prices are higher in rural areas than in cities. This reflects higher distribution costs in rural areas, but the differences were found to go beyond what was justifiable by these cost differentials.

- Despite the provisions in the Petroleum Retail Marketing Sites Act limiting the number of service stations that could be run directly through the integrated oil companies, these companies were found to be able to exert effective control on retailers through exclusive supply arrangements, price supports and oil company cards.

Based on the review of the ACCC, the Treasurer and the Minister for Industry, Science and Resources (then Minister for Industry, Science and Tourism) released a policy document entitled "Petroleum Marketing – the New Era". The document contained a number of initiatives to improve competition in the retail market and to protect consumers, including:

- The repeal of the Petroleum Retail Marketing Sites Act and the Petroleum Retail Marketing Franchise Act and the lifting of price surveillance by removing petroleum products from the scope of the Prices Surveillance Act.

- Implementation of an open access regime for port oil terminals, thereby allowing large users of petroleum products to purchase their goods from the terminal gate at wholesale prices.

- Introduction of an independent price monitoring system, established as a joint venture between the Australian Automobile Association and the major oil companies, to monitor prices at the retail level.

- Ongoing "hot-spot" monitoring of prices by the ACCC.

The document also contained measures to protect small businesses, replacing the provisions of the two Petroleum Retail Marketing Acts that were to be repealed. A new self-regulatory code of conduct for the oil industry, the Oilcode, was to be implemented through regulation under the Trade Practices Act, to govern the relationship between oil companies and their resellers.

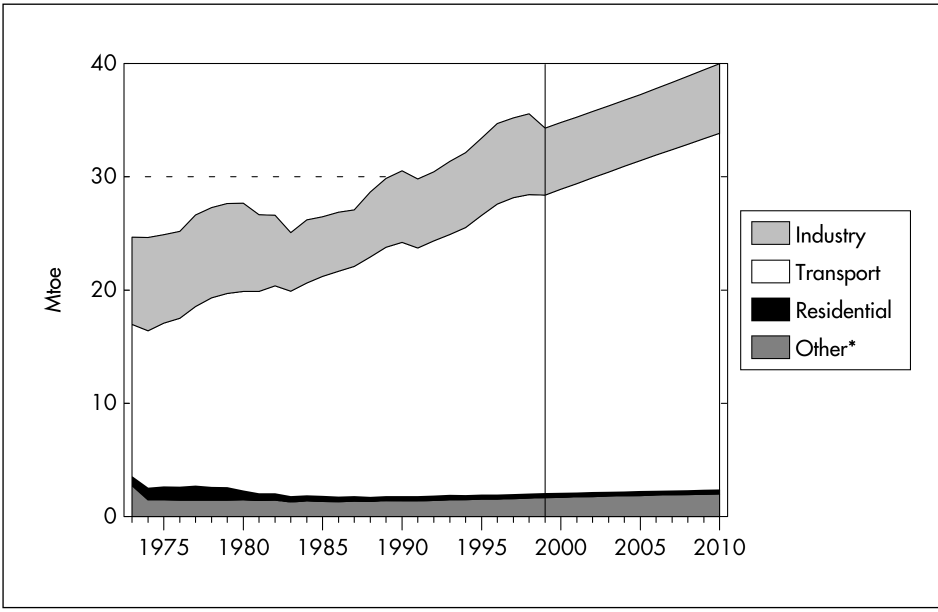
Considerable progress was made in finalising the measures announced in the package, including the negotiation of an agreed Oilcode. However, industry participants remained divided over the future of the Petroleum Retail Marketing Sites Act. The government, having made a commitment not to proceed without the agreement of all major participants, withdrew its reform package from the Senate on 23 September 1999, seeing no possibility to advance its reform project.

The Maximum Endorsed Wholesale Price was abolished on 1 August 1998. The government had concluded that the MEWP had an adverse effect on the retail petrol market. In metropolitan areas, the MEWP had acted as a target for prices at the end of a discount cycle, whereas in rural and regional markets it had acted as a minimum price. The Australian Competition and Consumer Commission retains the power to monitor retail prices and investigates local markets where high prices might suggest a lack of competitive behaviour at a local level ("hot-spot" monitoring).

However, ending government price surveillance has not meant that monitoring of petrol prices has ceased. It now forms part of the self-regulatory tasks of the industry under the Oilcode agreement. The oil industry has implemented a regime of retail price monitoring covering one hundred sites across Australia. Thus, consumers are provided with a measure of the retail price of petroleum, which enhances transparency in the market-place. This information is publicly available on the Internet[31] and is provided by an independent monitoring company, overseen by the automotive associations and the industry itself. This provides the transparency of price monitoring without the distorting effects of the previous Maximum Endorsed Wholesale Price system.

31. It can be consulted under: http://www.informedsources.com.au/petrol/default.htm

Figure 15
Final Consumption of Oil by Sector, 1973 to 2010



* includes commercial, public service and agricultural sectors.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

Emergency Preparedness

The Liquid Fuel Emergency Act of 1984 provides the principal authority to manage a severe fuel shortage at the national level and the authority for fulfilling Australia's obligations under the International Energy Program (IEP) Agreement. The Act is based on a co-operative approach between Commonwealth, state and territory governments and the oil industry.

In 1997/98 the Commonwealth government undertook a very comprehensive re-evaluation of emergency measures to determine their adequacy in light of the changing world oil market and the changing supply/demand situation in Australia. Among other issues, the study covered the appropriate level of emergency preparedness of government and the oil industry and the likely effectiveness of government options for dealing with an oil shortage. In particular, the re-evaluation resulted in the restructuring and streamlining of administrative arrangements for managing a national liquid fuels supply emergency with the establishment of a single committee comprising government and industry representatives to oversee and co-ordinate response measures.

The evaluation found that the most useful emergency measures available to Australia are market-driven demand restraint, voluntary and compulsory demand restraint and, to a lesser extent, stock draw. Surge production can contribute very little.

Commercial stocks are adequate to meet Australia's obligations under the IEP Agreement. The policy of the Commonwealth government in terms of a threshold for stock draw is flexible and, to a certain extent, at the discretion of the minister. Australia has no legal impediments to participation in a joint stock draw for an oil supply loss below the 7 per cent supply disruption threshold defined in the IEP Agreement. Since private industry is the holder of all stocks, any government-initiated stock draw would require industry co-operation. In addition to national response measures, the state/territory governments have enacted their own emergency response legislation and have prepared emergency response plans to be activated in the event of more localised supply disruptions.

Demand restraint is an important element in the Australian response programme and measures may be implemented either before or after activation of the IEP emergency measures. The main focus of government-induced demand restraint would be the road transport sector which accounts for around 60 per cent of Australia's total petroleum consumption.

In relation to increasing supply, the Petroleum (Submerged Lands) Act 1967 gives the Commonwealth government legal power to require production increases consistent with good oil-field practice.

CRITIQUE

As a first and general observation, the Australian oil industry operates in a fully deregulated and market-based environment. The government restricts its role to the classical, and essential, tasks of government in functioning markets, i.e. setting the broad legal framework, taking account of major externalities, levying taxes and royalties, and exerting anti-trust surveillance to maintain and promote competition.

There is no other direct economic regulation. Oil operations are generally privately-owned, and foreign investment, already amply present in the industry, is expressly encouraged. This general approach deserves commendation.

Within this positive framework, a number of issues deserve attention, in both the upstream and the downstream industry. As these issues are quite different, they are addressed separately in the following two sections.

Upstream

The main issue in the upstream industry is the fact that, to date, Australia remains under-explored. This is in spite of the fact that Australia is an attractive oil province. Its vast sedimentary basins appear to contain significant further petroleum resources, especially offshore. Its stable political climate, prosperous economy and skilled workforce add to the favourable picture.

Nevertheless, the total level of exploration up to the present appears to lag behind other oil provinces of comparable calibre. The lag is particularly large if compared to the United States. In drawing such comparisons, it must not be forgotten that Australia is a relatively young country – the Australian Federation was founded in 1901 – and that it is still thinly populated, despite the current rapid population growth. Distances within the country are vast, and the distances that separate it from most other countries are much greater still. This has important implications for the petroleum market.

Over the last two decades, private-sector exploration activity has increased. The number of onshore exploration wells shows a clear correlation with the oil price (with a time lag of several years), and peaked between 1984 and 1988. During the same period, domestic production covered, and even exceeded, domestic demand. Following this, Australia became a net oil importer again, although it has been between two-thirds and 90 per cent self-sufficient in the long-term average.

The number of offshore exploration wells has grown steadily over time, with no discernible correlation to the oil price. The area covered annually by new seismic surveys roughly doubled at the beginning of the 1990s, compared to the long-term average of the 15 preceding years. Following a number of significant oil finds in 1994, seismic surveying activity again showed very significant, almost exponential growth until 1998, after which it fell back to levels nearer the long-term average.

This indicates that there is significant interest among private companies in exploring for oil in Australia if and when interesting finds appear probable. In the recent past, a large part of the discoveries was gas. Natural gas is commercially less attractive than oil if it is located far from demand centres, because transportation of gas via pipeline or LNG is expensive. Much of Australian gas is located in remote areas, except in the Gippsland and Bass Strait area. Unsurprisingly, these are among Australia's best-explored and most mature petroleum areas.

Owing to the absence of a major recent oil discovery, forecasts anticipate a sharp decline in production of crude oil and condensate in the next ten years. If these forecasts are borne out in practice, this would certainly lead to declining degrees of self-sufficiency and might reduce security of supply in Australia. This might be a cause for concern. However, similar previous projections have not come true.

Whereas in recent years, oil finds have occurred in some provinces that had been classified as "gas-prone", the government clearly has a role to play in encouraging continued exploration for oil, as well as in promoting the use of gas. It does both (see also Chapter 7). In the framework of the 1999 Offshore Petroleum Strategy, a significant overhaul of government legislation, regulation and taxation/royalty policy targeted on the upstream sector was carried out in co-operation with the industry. In particular, efforts are being made to provide potential explorers with comprehensive data, including in frontier regions.

Although it would be preferable for Australia to find more oil and less gas, or gas located closer to demand centres, Australia's resources are a given that the government must accept. It appears that the government tries to make the best of the situation it finds, using initiatives such as the Offshore Petroleum Strategy. It is too recent to be able to judge the effectiveness of the Offshore Petroleum Strategy, but some results in terms of greater exploration rates and perhaps more finds should be forthcoming in the next years. The high oil price will contribute to this.

These results will show whether greater encouragement for exploration is needed. It is up to the government to decide how far such encouragement should go, but it can contribute significantly to Australia's international competitiveness in petroleum exploration by reviewing and adapting its upstream regime as the effects emerge, especially the fiscal regime and the licensing process.

That said, Australia also has significant reserves of non-conventional oil. With continued stamina from the commercial operators, and perhaps increased support from the Australian government, it is quite possible that within ten to 20 years, non-conventional oil could represent an important part of domestic energy supply and could contribute to the energy security of other IEA countries though export.

Downstream

The two main issues in the downstream oil sector are the poor profitability of the refining industry and market power in oil product marketing. Both issues are linked to some degree, as there is vertical integration in the oil industry. This means that profitable marketing activities have compensated for the poor results in refining. A number of developments indicate that this will not be possible in the future. The most important of these developments are recent action and further striving to address market power issues in oil marketing, and the imminent adoption of more stringent fuel efficiency standards.

Regarding market power, significant progress has been made in implementing the recommendations of the ACCC. Australia has instituted a policy of terminal gate pricing, with open access to all terminals of the majors and independent operators. The problem also seems to be lessening as some retail competition is emerging from new entrants. Increased competition and pressures for greater efficiency contribute to the trend in closure of smaller service stations, which may give rise to difficulty of access to petroleum products in remote areas.

The Maximum Endorsed Wholesale Price was abolished and replaced by a self-regulatory oil industry regime of retail price monitoring, carried out by an independent company. The ACCC retains the power to investigate, especially in local "hot-spot" markets where high prices suggest a lack of competitive behaviour.

However, despite the progress made, the cornerstone of the reform, replacement of the two Petroleum Retail Marketing Acts by the self-regulatory Oilcode, has so far failed, through resistance from part of the industry. Having made a commitment not to proceed without the agreement of all major participants, the government has withdrawn its reform package.

Having opted for a light-handed approach that relies to a large degree on self-regulation by the industry, the government is obliged to opt for consensus legislation to implement the ACCC's recommendations. This conjures up the danger that such consensus can only be found with difficulty and after long delays. The failure to reach agreement has shown that this danger is not merely theoretical. It is commendable that the government was able to introduce some of the recommended changes, thereby reducing the possibility of market power abuses. But the government should make another attempt to get the legislation passed as soon as possible. The consensus-based approach relies on the confidence among participants that the Commonwealth government is able to broker an agreement. In the absence of success, this confidence might not last forever. It might be useful to begin reflecting upon what must be done if it turns out to be impossible to phase in legislation this way. This reflection will have to include other, less consensus-based processes.

Regarding the refining sector, it is useful to note that the refining industry is under strain globally. Australia's refineries are not grossly uneconomic, but their competitiveness is very fragile. Any additional strain could tip them over the brink, and such strains, in the form of tighter fuel quality standards, seem to be firmly anchored in the government's future agenda.

In the light of this, the government's Downstream Petroleum Action Agenda is a useful measure. But the measures announced in the framework of this Action Agenda to date do not appear very vigorous. They seem to be based mainly on joint discussions and analysis with the industry. This is well in line with the Australian system of liberal democracy and free markets, which does not generally rely on strong coercion from government. Action Agendas are developed as partnerships between government and industry.

On the other hand, the government and industry have formulated the joint vision of establishing a strong, efficient and environmentally responsible domestic refining industry. This industry is to supply the majority of the country's oil product needs. Given current developments and those on the horizon, it is not clear how this transition is to be accomplished. In fact, the vision appears to have three goals that appear irreconcilable in the near future: competition and transparency; a strong, profitable industry; and high environmental standards.

At present, any progress on one of the issues appears to have an adverse effect on one or both of the others. The downstream industry has been characterised by market power. In trying to reduce this market power, the government will probably reduce the profitability of oil product marketing, a market segment that has so far served to compensate for the losses from refining. The anticipated tightening of the fuel quality specifications will certainly put profitability under strain and lead to refinery closures. The government obtained agreement from the industry to report separately on refining and marketing, which is already a step towards more transparency.

But in the longer run, more radical solutions are needed, either a thorough shake-out in the refining sector with the withdrawal of one or several players from the industry and/or take-overs in the business, or relocation of the bulk of refining activities abroad. In this case, Australia would rely more on product imports. This might have an adverse effect on security of supply.

The government is of the opinion that it is up to the industry to decide what the appropriate industry structure should be, provided that retail competition is ensured. This is an appropriate approach, and probably the only viable solution, but it might mean that the vision will become reality only after a long delay.

The IEA Emergency Response Review of Australia of 1998 commended the significant and comprehensive re-evaluation of emergency response measures in light of the changing world oil market and supply and demand situation in Australia. The re-evaluation led notably to the streamlining of the committee structure responsible for co-ordinating liquid fuels emergency response measures.

RECOMMENDATIONS

The government should:

- ☐ Continue to implement the measures under its 1999 Offshore Petroleum Strategy, especially those relating to pre-competitive surveys and data and information dissemination.

- ☐ In parallel, continue to review and adapt its upstream regime, especially the fiscal regime and the licensing process. This should be done with a view to maintaining the international competitiveness of the Australian oil industry and in order to attract new investment, especially in exploration.

- ☐ In the downstream oil sector, implement those recommendations of the last in-depth review that are still valid, notably:
  - Implement all reforms proposed by the ACCC to eliminate remaining market power in oil product retailing.
  - In particular, re-submit the legislation repealing the Petroleum Retail Marketing Acts and replacing it by the Oilcode at the earliest convenient moment. Prepare this action by further negotiation with the industry, as well as by devising an alternative legislative solution.
  - Take a proactive role to ensure that deregulation of the downstream sector at Commonwealth level is supplemented at the state level.

- ☐ Maintain the current approach to the refining industry, and continue to inform the sector about future policies affecting it in a transparent manner and with ample notice.

7

NATURAL GAS

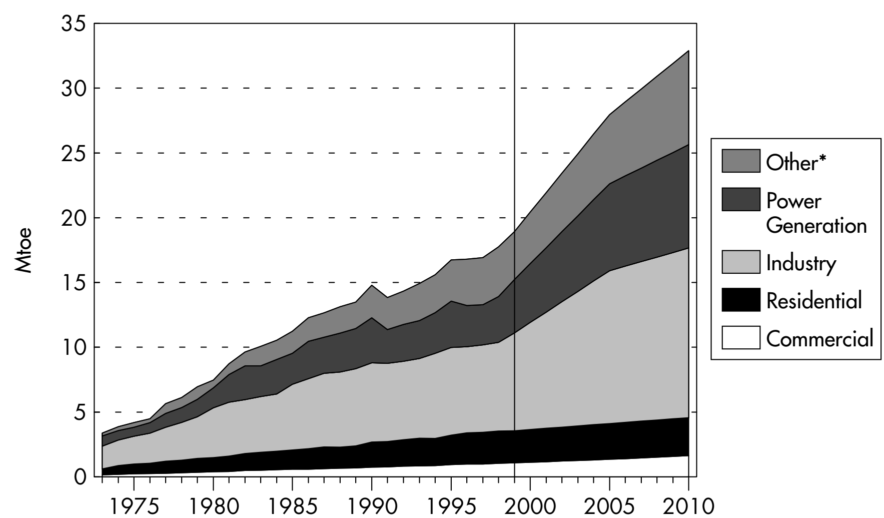
INDUSTRY OVERVIEW

Natural Gas Demand

The Australian natural gas industry began supplying customers in 1969, following the development of the Gippsland basin in the late 1960s by Esso/BHPP. Since then, gas demand growth has continued almost unbroken to reach 18.2 Mtoe or 16.9 per cent of TPES (10.8 Mtoe or 15.5 per cent of TFC) in 1999. Figure 16 illustrates that industry is the main consuming sector, followed by power generation. The other sectors show steady but slow growth trends. The figure also shows that significant demand growth is forecast for the current decade, with an acceleration compared to the long-term trend in the first half of the decade.

In line with this, a forecast prepared by the Australian Bureau of Agricultural and Resource Economics (ABARE)[32] for the time period to 2014/15 predicts that natural

Figure 16
Natural Gas Consumption, 1973 to 2010



* includes transformation, own use in the energy sector and non-energy use.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

32. Australian Bureau of Agricultural and Resource Economics (ABARE): *Australian Energy - Market Developments and Projections to 2014/15*, Research Report 99.4, Canberra, 1999.

gas consumption could more than double in absolute terms and that the share of natural gas in Australia's primary energy consumption could grow from its 1998 figure of 17.9 per cent (IEA: 16.9 per cent of TPES) to 28.9 per cent in this time frame. This means that gas would become the second largest primary energy input to the Australian energy economy after oil, overtaking coal.

The demand growth is expected essentially from the power generation and industrial sector. Natural gas had a share of 10.6 per cent of national gross power generation in 1999, a figure that is expected to grow to 17.1 per cent in 2005 and 20 per cent in 2010 (see Annex A, Energy Balances and Key Statistical Data). According to a study commissioned in 1999 by the Australian Gas Association (AGA) to complement the ABARE report[33], this growth is expected to continue to 23 per cent in 2014/15. The industrial sector, especially minerals processing, is thought to have the second largest demand growth potential.

To date, the Australian gas market has developed to a large degree as separate markets in individual states, with little interconnection and exchanges. Demand varies greatly across states, ranging from a 44 per cent share of total energy consumption in Western Australia to only 6 per cent in New South Wales. Currently, Western Australia is the largest consumer, owing to the absence of a large, cheap coal resource, and to the existence of a vast gas resource nearby. While there is coal mining, and also coal potential, the resource is nowhere near as large as the one in Australia's south-east, and the quality tends to be somewhat lower.

In terms of current gas use, Western Australia is followed closely by Victoria. The Australian Gas Association expects the strongest growth potential in Western Australia and Queensland. Western Australia's gas use could grow by more than 80 per cent between 1996/97 and 2014/15. In contrast, Queensland is a minor gas user now, but is expected to increase its gas use sevenfold in the observation period. The two states taken together could account for 60 per cent of the Australian market in 2014/15. New South Wales ranks third, both in current gas consumption and in growth prospects.

Interestingly, the AGA study predicts that gas could make large inroads into Queensland's power generation sector. Power generation in this state is dominated by coal, and gas has so far played only a minor role with 0.7 per cent of fuel use for thermal generation. The study anticipates that gas could reach a share of over 28 per cent in Queensland in 2014/15, provided market reform in the gas and power generation markets continues, and environmental standards continue to be tightened. Queensland has adopted a policy objective to produce 13 per cent of its electricity from gas by 2005.

It should be noted that this is only a description of the most significant trends and that the complexity of the Australian energy market should not be underestimated.

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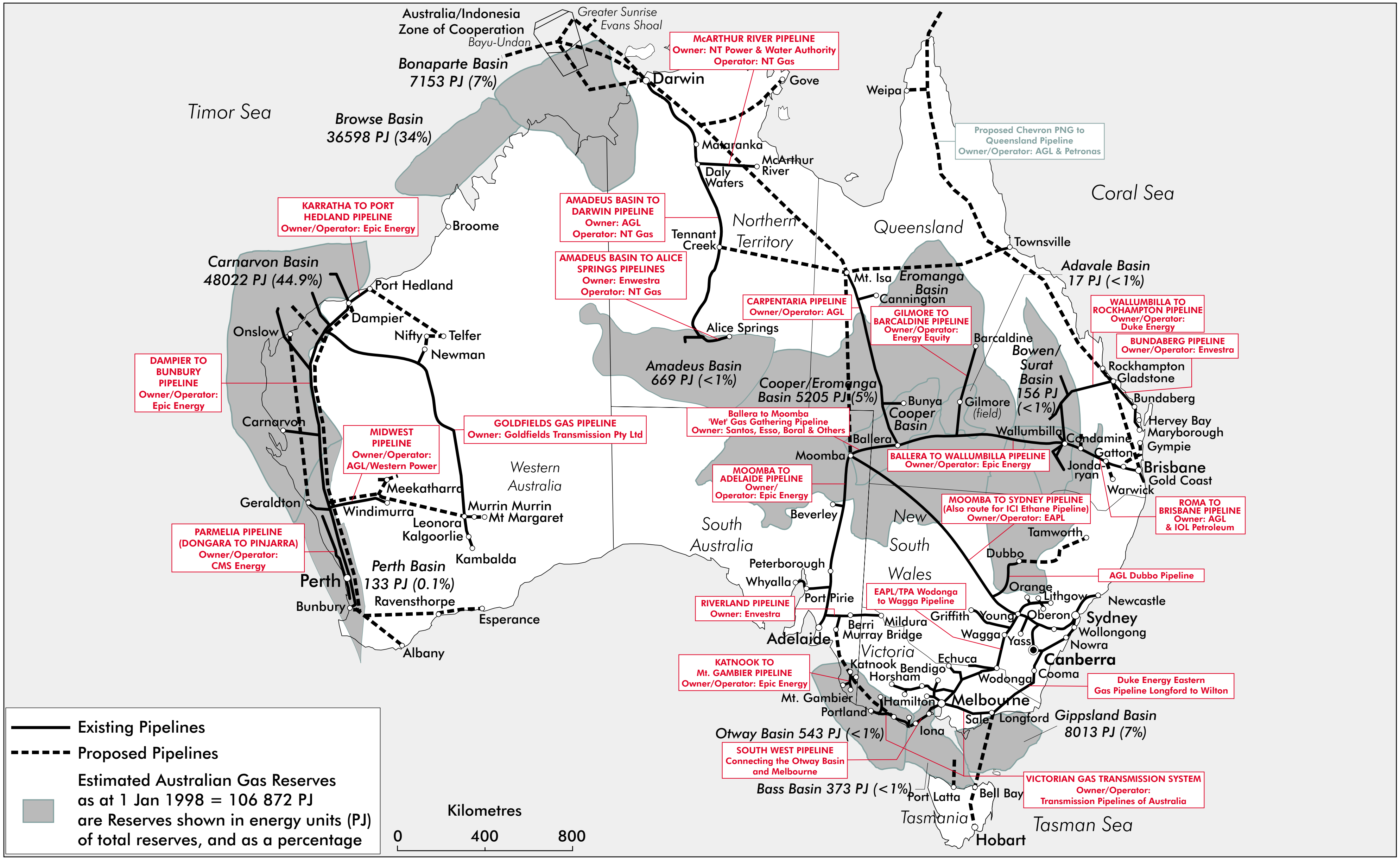
33. Australian Gas Association (AGA): *Natural Gas Consumption in Australia to 2015 – Prospects by State, Industry and Sector*, prepared for the Australian Gas Association by the National Institute of Economic and Industry Research (NIEIR), Canberra, 1999.

Figure 17
Natural Gas Reserves and Natural Gas Transportation Pipelines, 2000



Source: Department of Industry, Science and Resources.

In particular, there are large differences among states. For example, the highest share of gas use in power generation occurs in the Northern Territory, with almost 84 per cent in 1996/97 and a potential to reach more than 86 per cent in 2014/15. The absence of any significant coal resource is a major factor. However, in absolute terms, the state is the smallest gas user because of low population numbers. Tasmania has neither gas production nor supply.

Natural Gas Production

Gas exploration occurs as an integral part of hydrocarbons exploration, which is discussed in detail in Chapter 6. Figure 17 shows Australia's gas reserves and their geographical location, as well as the country's network of high-pressure transportation pipelines. Australia's recoverable natural gas reserves were estimated by the government to amount to 2,508.2 Mtoe at 31 December 1998 (2,835.3 bcm), or more than 91 times that year's production. This figure includes reserves that have not been declared commercially viable at current prices.

Natural gas production occurs in eight basins of differing size. There are about ten major gas producers active in Australia, including foreign companies such as Esso in the Gippsland basin, Apache Energy in the Carnarvon basin, and Phoenix Energy in the Perth area.

In terms of current production, the Carnarvon basin off the west coast of Western Australia is by far the biggest with 16.34 Mtoe or almost 60 per cent of total production in 1998/99. This is more than three times as large as the two next biggest production areas, the Cooper/Eromanga basin in Queensland/South Australia and the Gippsland basin off the Victorian coast. The reserve in the Carnarvon basin is very large, amounting to roughly 45 per cent of Australia's total reserve. Hence, it is estimated that these production levels can be maintained for 69 years (from end 1998).

Natural gas from the Carnarvon basin – the largest single deposit in the country – supplies most of the Western Australian market. Current production fields in this basin include the Goodwyn, North Rankin, Cossack, Wanea, Tubridgi, Harriet and Griffin fields. The remainder is from the much smaller Perth basin with its gas fields Beharra Springs, Dongarra and Woodada. The gas from Carnarvon is piped from Dampier to Perth and on to Bunbury, but also to Port Hedland, where it supplies a gas-fired power station and an iron processing plant, as well as to Kalgoorlie, equally for power generation and minerals processing.

The Goodwyn and North Rankin fields are operated by Woodside Energy as part of the North West Shelf Gas Project. This project has two components, one for domestic gas supply and one for gas export in the form of liquefied natural gas (LNG). LNG exports are discussed in the following section.

Victoria is primarily supplied from Gippsland basin (about 80 per cent of consumption), supplemented by the Otway basin, a smaller offshore basin that lies off the Victorian and South Australian coast. The small Bass basin, which lies between Gippsland and Otway, is not yet producing. All three basins are located close to demand centres.

New South Wales and the Australian Capital Territory do not have gas production of their own and "import" all their gas from Queensland, Victoria and South Australia.

Nearly all natural gas consumed in South Australia is supplied from the Cooper/Eromanga basin, that extends from south-western Queensland to the north-eastern part of South Australia. The city of Moomba serves as gathering point both for local production and for gas "imported" from Ballera in Queensland and piped to Adelaide. A small, segregated system supplies gas from the small offshore Otway basin to Katnook, Snuggery and Mt. Gambier.

Natural gas is produced in Queensland from the Cooper/Eromanga, Bowen/Surat and Adavale basins. In the Adavale basin, gas is produced from the Gilmore gas field. The main production point in Cooper/Eromanga is Ballera. The Bowen/Surat basin has four main production areas, including Roma, Silver Spring, and Denison Trough. The Bowen basin also produces coal seam methane at Moura and Fairview, which is fed into the gas pipeline linking Wallumbilla and Gladstone. Two further coal seam projects are under way at Peat and Scotia. Australia has the world's fourth largest coal seam gas resources, after Russia, Canada and China. Reserves are estimated at between 7,300 and 12,830 Mtoe. In 1999, production of coal seam methane was 220 thousand tonnes of oil equivalent.

In the Northern Territory, gas is produced from the Amadeus basin at Palm Valley and Mereenie, located about 150 and 250 kilometres respectively west of Alice Springs. Both fields supply Alice Springs, Darwin and a number of smaller centres, including a lead-silver-zinc mine at McArthur River.

Transportation and Trade

As can be seen in Figure 17, gas transportation, like gas production, has historically developed largely within state boundaries. Little interconnection exists at the moment: only the Moomba-Sydney pipeline, the Eastern Gas pipeline (EGP), the Wodonga to Wagga pipeline, the branch line to the Moomba-Adelaide pipeline connecting Berri and Mildura, and the Moomba-Bellera wet gas gathering pipeline cross state boundaries.

One reason for this is the huge distances involved, but low population density outside the south-eastern coastal region also plays a role. Both factors tend to constrain the economic viability of pipeline investment. That said, the current situation represents a major development from the situation a decade ago. Since then, the total length of Australia's transmission pipeline system doubled from 7,670 km to over 15,600 km today.

At present, there are ten major gas pipeline companies in the Australian transportation market, including foreign companies such as Duke Energy International (EGP from Victoria to New South Wales, Roma-Gladstone pipeline in Queensland) and Epic Energy (Ballera to Wallumbilla in Queensland, as well as Moomba to Adelaide and Peterborough to Whyalla in South Australia). In the Northern Territory, there is only one pipeline company, operating the Palm Valley/Alice Springs to Darwin pipeline.

At present, some major new pipeline projects are under discussion (see also Figure 17). These include:

- An A$ 3 billion gas development project including a pipeline component from Papua New Guinea to Brisbane (Queensland). This proposal by AGL/Petronas includes a 2,500 km onshore section worth A$ 1.5 billion.

- A 300 km Central Ranges pipeline from Dubbo to Tamworth, New South Wales, proposed by AGL, the state's dominant gas retailer.

- The A$ 200 million, 630 km Victoria to South Australia gas pipeline project. The pipeline is intended to supplement South Australia's energy supply and provide South Australia an alternative gas supply to the Cooper basin. On 3 March 2001, the South Australian government announced it had entered into a non-financial facilitation agreement with a consortium comprising Origin Energy, Australian National Power (ANP) and SAMAG (proponents of the new magnesium smelter near Port Pirie).

- An interconnection from the Scotia field to south-eastern Queensland (not included in Figure 17).

- The Tasmanian Gas Project, estimated at about A$ 400 million, linking Longford (Victoria) to Bell Bay station in Tasmania over a length of 350 km, with laterals to Port Latta, Launceston and Hobart (390 km). The proponent, Duke International Energy, announced on 8 November 2000 that it would construct the Tasmanian Natural Gas Pipeline, subject to the resolution of environmental and regulatory issues. The project is expected to be completed in the first half of 2002.

- A pipeline connecting Onslow to Geraldton in Western Australia.

- An extension linking Geraldton to Mt. Margaret (Western Australia).

- Duplication and upgrade of the Western Australian Dampier-Perth pipeline. System expansions and new pipelines included in this project by Epic Energy represent a combined value exceeding A$ 2 billion.

- The Timor Sea Gas Project in the Northern Territory, based on gas resources from the Bayu-Undan and Greater Sunrise fields. The initial onshore pipeline (indicative cost A$ 1.3 billion) would run from Darwin to Mt. Isa, and from Mt. Isa to Townsville, with a spur line to the Gove (Northern Territory) alumina refinery.

In addition, two pipelines under construction in the last few years have recently been completed:

- The A$ 450 million, 792 km Eastern Gas Pipeline (EGP), linking Longford (Victoria) to Horsley Park in the Sydney area in New South Wales was due to be completed in September 2000. It is owned and operated by Duke Energy International.

- The 353 km Midwest Pipeline linking Windimurra to Mt. Magnet was completed in August 1999. There are plans to extend this line eventually to Mt. Margaret, which would close the loop between the Dampier-Perth pipeline and the Newman-Kalgoorlie pipeline. The current stage, owned and operated by AGL/Western Power, supplies natural gas for direct use at the Windimurra Vanadium Project and generation of electricity by a 12 MW gas-fired power station at a new mine.

Australia is a net exporter of gas. The country exports 35 per cent of its gas production in the form of liquefied natural gas through the A$ 12 billion North West Shelf Gas Project located in the Carnarvon basin. The LNG phase of the project is owned by a consortium composed of Woodside Energy Ltd, Shell, BHP, BP-Amoco, Chevron and Mitsubishi/Mitsui of Japan. Japan is the world's largest importer of LNG, accounting for 58 per cent of the world's LNG imports in 1999. The exports to Japan are carried out under long-term contracts with eight Japanese utilities (five power generators and three gas distributors) for LNG supplies of 7.5 million tonnes (10.6 bcm regasified) per year.

The project's onshore gas treatment plant is located on the Burrup Peninsula, some 1,260 kilometres north of Perth near the towns of Karratha and Dampier. Since July 1989, some 1,100 cargoes of LNG have been delivered to overseas buyers. In 1999/2000, LNG production and exports rose to a peak of 7.9 million tonnes per annum, as the contract sales to Japan are complemented by spot market sales to other countries. These have included Spain, South Korea, Turkey and the United States. The exports were worth A$ 1.9 billion in 1999/2000, making Australia the fifth largest LNG exporter in the world and the third largest exporter in the Asia-Pacific region. The LNG project operates at maximum capacity now, and volumes cannot be expanded from the existing facilities.

The government estimates that the North West Shelf LNG Project has been very beneficial to Australia, leading to a GDP increase of 1.4 per cent at national level, which includes a 14 per cent increase in Western Australia, and an increase of total exports of 3.5 per cent. Other benefits included an additional 80,000 jobs and an increase in government revenues of A$ 206 million at state level and A$ 850 million at Commonwealth level.

Australia has considerable additional gas resources that could be used for further LNG developments. Six major new LNG projects are currently under discussion:

- Expansion of the existing North West Shelf Project through construction of two new LNG trains, which could increase production capacities to 15.5 million tonnes.

- The Bayu-Undan Project, located in area A of the Timor Gap Zone of Co-operation (ZOCA). In October 1999, it was decided to proceed with development of this gas field. Feasibility studies are currently under way concerning the marketing of the gas, including an onshore LNG facility in Darwin of US$ 1.4-1.5 billion.

- The Gorgon Project, some 100 km south-west of the North West Shelf Project, about 200 km offshore in water depths of 100-300 metres. An onshore LNG facility is under consideration.

- The Sunrise Project in the Bonaparte basin, 350 km north-west of Darwin. A facility of two or more trains, of 4 million tonnes annual capacity each and an investment cost of A$ 10 million is under consideration. A feasibility study is under way.

- The Scarborough Project, on a large gas field 300 km off Exmouth in Western Australia in water depth of 900 metres. The resource is under assessment, as is the possibility of building an onshore LNG plant.

- The Scott Reef/Brecknock Fields Project. These gas fields are very large but remote: 750 km north-east of the North West Shelf Project, 500 km south of Bayu-Undan, and 300 km from the Western Australian coast line. The participants in the North West Shelf Project, who also hold title to this field, are considering piping the gas either to an onshore LNG plant or to the North West Shelf Project.

Although these potential projects are the most advanced, there are other possibilities in the Timor Sea. However, those proposals will only materialise if suitable long-term contracts can be secured. In this case, the Australian government expects that offshore natural gas could potentially supply 25 million tonnes of LNG per annum[34].

Between 1990 and 1997, the global LNG market grew at 6.7 per cent per annum, with 75 per cent of the global market in the north-Asian markets of Japan, South Korea and Taiwan. Significant growth is expected in these markets throughout the next 20 years. The government and the gas industry also consider China and India as potential export destinations. However, Australian projects face strong competition from new and well-established LNG projects with excess capacity or easy expansion. Competition includes potential projects in Indonesia, Malaysia and in some countries in the Middle East.

For this reason, the Commonwealth, Western Australian and Northern Territory governments are co-operating closely with the LNG industry to realise Australia's

34. For this and the following, see e.g.: Commonwealth of Australia: *Liquefied Natural Gas Action Agenda 2000*, Canberra, 2000.

potential. The industry and governments have formulated a common vision for the industry to 2020. The vision aims to:

- Make Australia the preferred supplier for new LNG demand.

- Realise the LNG potential within the next 20 years, to make LNG one of Australia's main export industries.

- Expand its market share in the Asian market from the current 10 per cent to 30 per cent.

Australia's main advantages lie in its proximity to Asian markets, the good supply record of the North West Shelf Project, the country's political stability and low sovereign risk. The main obstacle to further significant LNG growth is high cost onshore (partly because of relatively high labour cost) as well as offshore (partly owing to the greater water depths).

To address these issues, the Commonwealth, Western Australian and Northern Territory governments and the petroleum industry formed the LNG Action Agenda Working Group in mid-1998. The working group issued a document entitled "LNG Action Agenda" in 2000. In this report, seven key issues relevant to the growth prospects and international competitiveness of the Australian LNG industry were identified:

- The need to provide certainty to industry in terms of the industry's role in meeting Australia's greenhouse gas emission targets.

- Customs and import tariffs impediments.

- The need for taxation arrangements, which are internationally competitive and reflect the financial risk taken by companies investing in LNG projects.

- Ensuring opportunities for Australian industry participation in supplying goods and services to LNG projects.

- Clarification and co-ordination of Commonwealth and state/Northern Territory roles in the project approvals process.

- Effective marketing and promotion activities to capture opportunities in growing Asian markets.

- Resolution of fiscal and regulatory uncertainties relating to the processing of gas in the Timor Gap Zone of Co-operation (ZOCA).

In particular, and as a key component of the LNG Action Agenda, the government pledged to promote only cost-effective greenhouse gas abatement strategies that minimise the burden on industry and that preserve the competitiveness of the LNG industry. The government made a commitment to avoid greenhouse policies and measures that distort investment between particular LNG projects and locations. And the government decided that it will only implement a domestic emissions trading scheme if the Kyoto Protocol is ratified by Australia and enters into force, and if there is an international emissions trading scheme.

The LNG Action Agenda contains numerous other actions, such as streamlining approvals processes, duty-free importation of essential capital equipment and components, co-ordinated promotion efforts and continuing consultation and negotiations with UNTAET regarding the Timor Gap (ZOCA).

It is worthwhile mentioning that during the 1998 review of the Petroleum Resource Rent Tax[35], a special Gas Transfer Pricing (GTP) system was devised for the LNG industry. The effect of this transfer price is to reduce uncertainty to LNG operators about their tax liability by removing the necessity of estimating a (non-existent) market price for gas that is never sold but that remains within the fully integrated gas-to-liquids operation.

In March 2001, the government announced that the Australian resources company Phillips has firm plans to export LNG from a major new LNG project to the United States. Subsidiaries of Phillips and El Paso signed a letter of intent (LOI) for the long-term purchase by El Paso of liquefied natural gas from a plant to be built by Phillips near Darwin. The project would deliver approximately 4.8 million tonnes of LNG per year to growing gas markets in southern California and Mexico's Baja California peninsula from 2005. Phillips and El Paso are also working jointly to develop LNG shipping and a new LNG receiving terminal on the west coast of North America that will receive, store and regasify the LNG. The Darwin LNG facility, which is to be built using Phillips' Optimized Cascade LNG Process, will be supplied with gas from the Greater Sunrise fields in the Timor Sea. These fields contain gas reserves of approximately 250 bcm. This project, along with Phillips' co-operative development agreements with Shell and Woodside, will enable the company to commercialise net hydrocarbon reserves of up to an additional 760 million barrels of oil equivalent from Bayu-Undan and the Greater Sunrise fields. This is in addition to 186 million barrels of net condensate reserves already under development at Bayu-Undan.

THE PATH OF REFORM

Reform Process at Commonwealth Level

As in the oil industry, the mandate for Commonwealth government intervention in the gas industry is largely restricted to gas exploration and production in offshore regions, interstate gas trade and general competition policy. State or territory governments are responsible for surveillance and regulation of the entire supply

35. See Chapter 6.

chain on their territory, from exploration, production, and transmission to distribution and supply. However, the Commonwealth government has concluded agreements with the state/territory governments to share administration of production from offshore areas adjacent to these states, and also to share royalties under certain arrangements (see Chapter 6).

Reform of the natural gas industry in Australia can be traced back to the Natural Gas Strategy adopted by the Commonwealth government in 1991. This document contained the key objectives for gas reform that are still relevant today, including competition through non-discriminatory open access to pipelines, intensified interstate trade through removal of regulatory barriers and infrastructure interconnection, and a light-handed approach to regulation.

A key step was taken to translate these objectives into concrete nationwide policy action when the Council of Australian Governments (CoAG) reached an agreement in February 1994 that committed all Australian governments to achieving "free and fair trade in natural gas" within and between their jurisdictions by 1 July 1996. The focus of this agreement was to remove barriers to competition, promote investment in pipelines, and establish a fully contestable gas market. This was to be achieved by:

- Dismantling restrictions on interstate trade.
- Removing policy and regulatory impediments to retail competition in the natural gas sector.
- Encouraging the development of a nationally integrated and competitive natural gas market by establishing a national regulatory framework for third party access to natural gas pipelines and facilitating the interconnection of pipeline systems.

Third party access rights are necessary to ensure contestability where there are monopoly pipeline facilities serving a market. This situation exists in most of Australia, as the pipeline network does not contain many parallel routes.

To achieve these objectives, the governments involved and the gas industry in June 1995 established a Gas Reform Task Force, which was to develop a national regulatory framework for grid access. After several rounds of consultation, the task force's successor organisation, the Gas Reform Implementation Group (GRIG), made up of representatives of the Commonwealth, all state and territory governments, the Australian Gas Association, the Australian Petroleum Production and Exploration Association, the Pipeline Industry Association and the Business Council of Australia as well as national regulatory bodies, especially the ACCC and the National Competition Council, submitted such a framework to the governments. This document, the Natural Gas Pipelines Access Inter-Governmental Agreement (IGA), was signed by the prime minister and the premiers and chief ministers of all states and territories on 7 November 1997.

The IGA constitutes a binding commitment by the governments to adopt legislation for open access. It also contains the legislative, administrative and transitional arrangements for implementing the national regulatory regime. The national access regime is made up of the access legislation and the National Third Party Access Code for Natural Gas Pipeline Systems (the Code). Legislation and the Code define the rights and obligations of pipeline operators and users that apply for third party access to natural gas transmission pipelines and distribution networks. They do not cover upstream facilities, as there is a separate process under way for upstream competition (see below). The Code includes the following features:

- Coverage provisions, i.e. a mechanism by which pipelines, including distribution systems, become subject to the Code.
- Reliance on an upfront access arrangement outlining services and reference tariffs that are applicable to a covered pipeline.
- Pricing principles.
- Ring fencing provisions. These provisions preclude direct activity by the service provider in related upstream and downstream gas markets.
- Information disclosure requirements.
- Guidelines to facilitate negotiation between the network operator (or network service provider) and the gas shipper.
- Binding arbitration where there is a dispute.
- Specific timelines for all processes.

The grid access rules under the Code are a variant of negotiated third party access. The operators of pipelines which are covered by the Code (offshore gathering pipelines or oil pipelines are excluded) must submit a proposed access arrangement including prices and access terms to the relevant regulator for approval. Nevertheless, the pipeline operator is free to conclude an access agreement with a private gas shipper that differs from the one submitted to the regulator. The approved access arrangement only becomes relevant if a dispute arises, in which case the regulator must apply the approved access arrangement in resolving the dispute.

Legislation to implement the Code incorporates an "application of laws" approach. This is an approach that has also been adopted in the reform process of the electricity market in Australia. Under this approach, one state or territory adopts comprehensive legislation, and the other states subsequently enact enabling legislation in their own jurisdiction. In the case of gas, it was agreed that South Australia should enact the "lead legislation". This occurred in the form of the Gas Pipelines Access (South Australia) Act 1997, which applies the national gas access regime in South Australia, where a contestable gas market began operating in July 1998.

To establish third party access in interstate trade, another separate piece of Commonwealth legislation was necessary. It was adopted in the form of the Gas Pipelines Access (Commonwealth) Act, which came into force on 30 July 1998. The

Commonwealth also made a number of amendments to various other pieces of legislation to apply the national access regime (the Code) to the Moomba-Sydney pipeline, as well as to offshore transmission pipelines. The 1974 Trade Practices Act also had to be amended to confer upon the national competition bodies the right to perform key regulatory functions referred to them by the states and territories under the National Gas Law. The national bodies now carrying out regulatory functions in the gas market comprise:

- The Australian Competition and Consumer Commission. The ACCC is the national regulator for gas transmission pipelines, except in Western Australia. It also regulates distribution pipelines in the Northern Territory. In Western Australia, OffGAR (Office of Gas Access Regulation) has regulatory responsibility for access arrangements covering both transmission and distribution pipelines.
- The National Competition Council (NCC). This body advises on whether a pipeline should be included in the access regime. It must also certify each jurisdiction's regime.
- The Australian Competition Tribunal. In all areas except Western Australia, the tribunal acts as the appeals body that reviews certain decisions of the ACCC and NCC. In Western Australia, appeals are heard by the Western Australian Gas Review Board.

All states and territories other than Western Australia have passed their own legislation to apply the gas pipelines access legislation, including the Code, as laws of their state or territory in line with the South Australian Act. Western Australia passed and proclaimed the Gas Pipelines Access (Western Australia) Act 1998, which has effects essentially identical to the 1997 South Australian Act.

All states except Tasmania and the Northern Territory have submitted access regimes to the National Competition Council for certification of their access regimes under the Trade Practices Act. South Australian, Western Australian and Australian Capital Territory access regimes obtained final certification from the Commonwealth Minister for Financial Services and Regulation on 8 December 1998, 31 May 2000 and 25 September 2000, respectively. The regimes adopted in New South Wales, Queensland and Victoria have been forwarded to the Commonwealth treasurer for decision.

Based on past experience with electricity market reform, both in Australia and abroad, special attention is given in Australia to the process of changing the legislation, regulations and rules upon which competition is built. The government's assessment is that the rules need to be flexible to allow correction of errors and to adjust to unexpected events and outcomes, but that the process must be sufficiently transparent and that no special interest must have the power to exert undue influence on these changes.

Also, there is a strong belief in the government that ultimately it is in the interest of the industry to establish and maintain fair rules of the game and that a light-handed approach to regulation, including a certain degree of self-regulation, will be beneficial to competition. For these reasons, it has put in place a body with broad industry participation whose explicit task it is to administer the Code and to facilitate changing the rules of competition.

This body, the National Gas Pipelines Advisory Committee (NGPAC) is a non-statutory, multi-jurisdictional body established under the Inter-Governmental Agreement (IGA) to administer the National Third Party Access Code for Natural Gas Pipeline Systems (the Code) applying to transmission and distribution pipelines. It is empowered to recommend changes to the Code to ministers, a legislation-amending role normally reserved to Parliament. NGPAC comprises an independent Chair and the Code Registrar along with representatives from Commonwealth, state and territory governments, the gas industry and national and state regulators. It meets on average four times per year. The Commonwealth has voting power equal to the other eight jurisdictions, but makes a one-third contribution to the NGPAC budget, with the other jurisdictions funding the remainder. Ministers agreed to a number of Code changes in late 1999 and mid-2000.

Further reform efforts have already begun. One very important piece of additional reform concerns the introduction of competition to the upstream gas sector. In this area, barriers to competition are thought to exist, especially in the form of joint gas marketing schemes by producers.

To introduce more competition into the upstream market, the government set up the Upstream Issues Working Group (UIWG), comprising members of the Australian and New Zealand Minerals and Energy Council (ANZMEC) and the Gas Reform Implementation Group (GRIG).

This group analysed upstream (production) issues that impact on growth, diversity and competition in downstream (especially retail) gas markets. These include acreage management, access to upstream processing facilities and joint marketing arrangements. Its conclusions were delivered in a report to ANZMEC and the prime minister (for CoAG) in December 1998. The main conclusions and recommendations of UIWG were:

- The offshore acreage management regime was working effectively, but there was a clear need to make the onshore regime similarly transparent.

- The relative immaturity of Australia's upstream petroleum market was making separate marketing by joint venture partners premature in some regions. However, ultimately the ACCC and state governments should require separate marketing as soon as feasible.

- Third party access to upstream facilities such as gas processing plants and gathering lines should preferably be determined through commercial negotiations. Parties should have access to a binding dispute resolution mechanism when commercial negotiations fail.

- A set of best practice principles for fair and reasonable access terms should be developed by the industry and be submitted to ministers for endorsement. The effectiveness of these principles was to be evaluated two years later.

Reforms arising from the Upstream Issues Working Group report are being implemented by governments and industry. A consultative body, the Gas Policy Forum (the Forum), has been established to achieve national consensus on outstanding gas reform issues. The upstream gas industry developed principles for third party access to spare capacity at upstream facilities. Energy ministers agreed in August 1999 to review the effectiveness of the principles in increasing upstream competition in mid-2001.

Management of acreage allocation is to a large extent addressed by governments in the context of reviews of their petroleum legislation. At their 1999 meeting, ANZMEC ministers also reviewed acreage management strategies. Following this, the work programme bidding system guidelines for offshore exploration permits were streamlined. Moreover, as noted in Chapter 6, the Commonwealth's petroleum legislation – especially the Petroleum (Submerged Lands) Act, PSLA – was reviewed against national competition policy principles. The findings of the competition review were submitted to ministers in August 2000. The review concluded that the PSLA and its mirror state and Northern Territory legislation are free of significant anti-competitive elements which would impose net costs on the community. To the extent that the legislation governing exploration and development of the offshore petroleum resources contains restrictions on competition (for example, in relation to safety, the environment, or resource management), these were considered appropriate by ANZMEC given the net benefits they provide to the community as a whole.

The UIWG's recommendations have also had specific legislative impact in some states. For example, processes for fair competitive bidding for new onshore acreage in Victoria were enshrined in the new onshore Petroleum Act 1998, which came into effect in December 1999.

Governments and industry are working to complete full retail contestability over the next two years. Table 6 shows the steps for retail market opening for all states and territories. The following two sections discuss gas market reforms in greater depth for Victoria and New South Wales.

Gas Market Reform in Victoria

Victoria implemented the national third party access legislation on 1 July 1999 through the Gas Pipelines Access (Victoria) Act 1998. Together with the Victorian Gas Industry Act of 1994, this act forms the legal basis of the competitive gas industry in the state.

The Victorian gas industry serves some 1.43 million Victorian customers; 98 per cent of the gas that enters the Victorian market is from the Longford processing plant owned and operated by the BHP/Esso consortium. This gas is extracted mainly in the Bass Strait (Gippsland and Bass) basin but is supplemented by gas from the Otway basin. Some gas is supplied from the Cooper basin via the Moomba-Sydney pipeline and the Wagga-Wodonga interconnector.

Table 6
Competition Timetable for Natural Gas

Date of eligibility	*Vic*	*NSW*	*Qld*	*WA*	*SA*	*ACT*
1996, 30 August		> 500 TJ				
1997, 1 January				> 500 TJ		
1997, 1 July		> 100 TJ				
1998, 1 January				> 250 TJ		
1998, 1 April					> 100 TJ	
1998, 1 July		> 10 TJ				> 10 TJ
1999, 1 July					> 10 TJ	
1999, 1 October	> 500 TJ	> 1 TJ			> 1 TJ	> 1 TJ
2000, 1 January				> 100 TJ		
2000, 1 March	> 100 TJ					
2000, 1 July					all I&C*	
2000, 1 September	> 10 TJ					
2000, 1 December			> 100 TJ			
2001, 1 July		all			all**	all
2001, 1 September	all		all			
2002, 1 January				> 1 TJ		
2002, 1 July				all		

* I&C = industrial and commercial customers.

** Subject to review of technical and economic constraints.

Source: The Australian Gas Association: *Gas Statistics Australia 2000*, Canberra, 2000.

The gas is then transported to the "city gate" of Melbourne and other major cities via the 1,600 km high-pressure grid owned and operated by GPU Gasnet International. GPU is a monopoly regulated by the ACCC. Regulation is based on the access agreement system as outlined in the preceding section, i.e. the regulator approves an access arrangement submitted by the infrastructure owner, but this regime is only relevant for dispute resolution. This method is used in Victoria for all regulated companies including distribution firms.

A company called VENCorp acts as the manager of the wholesale market. It operates the wholesale and transportation system on a daily basis and is also responsible for system planning and for directing expansion of the intrastate pipeline system. VENCorp is also regulated by the ACCC.

In 1997, the former Gas and Fuel Corporation was disaggregated into three gas distributors and their related gas retailers, and sold to private industry. At present, gas is distributed to end-users by three monopolies:

- Multinet, serving 600,000 customers in the eastern suburbs of Melbourne.
- Vic Gas Distribution, supplying over 400,000 customers on the outskirts of Melbourne and in rural areas.

- TXU Networks with more than 400,000 customers in the western suburbs of Melbourne and in Western Victoria. Large industrial customers are supplied directly from the Weststar high-pressure pipeline.

The vicinity of Mildura is supplied from the Cooper basin via the Moomba-Adelaide pipeline. All distributors are regulated by the Victorian regulator, the Office of the Regulator-General. The main retailer in Mildura is Origin Energy Victoria.

The distributors each have their own retail subsidiary, but there are also other, new retailers in Victoria. Gas retailing remains subject to a retail licence issued by the Regulator-General. The licence can be denied or revoked under certain circumstances, e.g. based on consumer protection considerations.

Table 7 provides details on the steps of retail market opening. The minimum customer load applies per take-off point and cannot be aggregated. During the transitional period, maximum tariffs apply for those customers that are not yet eligible for competition.

Table 7

Timetable for Retail Competition in Victoria

Date	*Customer load (TJ)*	*Number of customers (approx.)*	*Cumulative market share, per cent*	*Examples*
1 October 1999	> 500	35	24	Paper mill, brick manufacturer
1 March 2000	> 100	110	37	Hospitals, hotels
1 September 2000	> 10	600	45	Large commercial
To be determined	> 5	600	49	Small commercial
1 September 2001	all	1,400,000	100	Domestic

Source: Office of the Regulator-General, Victoria: *Annual Report 1999/2000*, Melbourne, 2000.

One of the results of gas industry reform in Victoria was that by June 2000, 43 per cent of the tranche 1 (> 500 TJ) customers and 14 per cent of the tranche 2 customers (> 100 TJ) had changed retailers. It is not yet known what the effect of competition on prices is.

Gas Reform in New South Wales

New South Wales was the first state to introduce third party access into the downstream gas market. In August 1996, the state introduced an interim access regime through the Gas Supply Act 1996. This regime was based on an early version of the national access code and was certified by the Commonwealth treasurer in 1997. As a result, the downstream regulator, the Independent Pricing and Regulatory Tribunal (IPART), examined the first interim access arrangement in July 1997. This arrangement concerned AGL, the state's dominant gas retailer. Following the adoption of the national third party access legislation, New South Wales adopted the Gas Pipelines Access (NSW) Act 1998, which replaces the 1996 regime.

The government's original timetable for retail competition foresaw that all customers should be eligible by 1 July 1999. Early in 1999, it became clear that the gas industry had not made sufficient progress in establishing the appropriate operational systems to handle the approximately 800,000 retail customers in the state, and the timetable was extended to 1 July 2000, as detailed in Table 8.

Table 8

Timetable for Retail Competition in New South Wales

Date	*Customer load (TJ)*	*Number of customers (approx.)*	*Cumulative market share, per cent*	*Examples*
1 August 1996	> 500	n.a.	44	Heavy manufacturing
1 July 1997	> 100	n.a.	61	Hospitals, hotels
1 July 1998	> 10	500	74	Large commercial
1 October 1999	> 1	2,600	81	Small commercial
1 July 2000	all	800,000	100	Domestic

Sources: New South Wales Ministry of Energy and Utilities, various publications.

New South Wales does not have any significant gas resources of its own, but it can source gas from the Cooper/Eromanga basin through the 1,351 km pipeline from Moomba to Sydney (in service since 1976), the Gippsland basin through the Eastern Gas Pipeline (completed in 2000) and to a lesser extent through the Wodonga (Victoria)-Wagga Wagga (New South Wales interconnector completed in 1998). New South Wales can also source gas from the Otway basin through the Wodonga-Wagga Wagga interconnector. Both the Moomba-Sydney and Wodonga-Wagga Wagga interconnector pipelines are owned by East Australian Pipeline Ltd. The Longford-Sydney pipeline is owned and operated by Duke Energy.

Gas is distributed through most of New South Wales by AGL Gas Networks. With 97 per cent of the market, AGL is by far New South Wales' largest gas utility. AGL purchases all its gas from the Cooper/Eromanga basin under long-term contracts. It supplies retail customers through its subsidiary AGL Retail, and commercial and industrial customers through AGL Energy Sales and Marketing and AGL Wholesale, respectively.

The state-owned utility Great Southern Energy (GSE) was established in 1996 through a merger of eight state-owned energy distribution utilities. It distributes and retails both gas and electricity in the south of New South Wales; its gas business is in the Wagga Wagga area.

Other retailers are moving into the state's gas market. The power utility Energy Australia, owned by the state of New South Wales and one of Australia's largest energy service companies, is extending its business into gas. The other large state-owned power utility, Integral Energy, operates a gas business on the southern coast of New South Wales. Envestra/Origin Energy, originally based in Victoria, supplies towns near the New South Wales-Victorian border.

Gas Supply in Other States and Territories

In South Australia, natural gas is retailed by Origin Energy Ltd (formerly Boral Energy Ltd) and Terra Gas Trader, and distributed by Envestra Ltd, while Origin Energy Asset Management maintains the distribution assets, which are owned by Envestra Ltd.

In October 2000, AGL's natural gas network and marketing business in the Australian Capital Territory (ACT) was merged with the ACT government-owned electricity network and marketing business, ACTEW, to form ActewAGL. The new multi-utility is the first in Australia to offer gas, electricity, water and sewerage services.

Gas is distributed to Western Australia's 406,000 domestic, commercial and industrial customers by the formerly state-owned corporation, AlintaGas, which began operation on 1 January 1995. In August 2000, the Western Australian government sold 45 per cent of its interest in AlintaGas to the U.S. energy group, Utilicorp United, and its Australian associate, United Energy. The remaining 55 per cent of AlintaGas was sold to other investors in October 2000. Operators in the Perth basin sell to major customers in competition with AlintaGas using the Dongara to Perth pipeline, which is owned by CMS Gas Transmission of Australia.

Origin Energy Ltd retails natural gas in Alice Springs, and Northern Territory Gas Distribution Pty Ltd (AGL) retails in Darwin. In March 1996 natural gas was reticulated in Darwin for the first time when Northern Territory Gas began distribution to customers in Darwin's Trade Development Zone.

Tasmania is the only state in Australia without access to natural gas. The main activity of the Gas Corporation of Tasmania Ltd (GCT, owned by Origin Energy) is the supply of bulk LPG to thousands of consumers throughout the state. Most gas sold is used in industrial/commercial applications while automotive and domestic uses take up the balance.

CRITIQUE

The Australian natural gas market has changed considerably in the last few years, and further change is anticipated in the future. The most important changes are the introduction of competition and the steps taken towards the gradual establishment of a national gas market. Another important issue is the government's initiative to promote LNG.

Taking these issues in turn, it must be said that Australia has a lot to gain from a more closely integrated and more competitive gas market. The country has abundant gas reserves and, because of the high cost of LNG operations and the strong competition in the international LNG market, it is advantageous to seek domestic uses for the gas. This would contribute to security of energy supply in Australia and, against the background of a largely coal-based market for stationary energy uses, have a significant impact on greenhouse gas emissions. Last but not least, it would increase inter-fuel competition, consumer choice, economic growth, investment, and employment.

If these benefits are to materialise, gas must be able to compete against coal, and gas prices must come down significantly. This can only be achieved through strong and effective competition throughout the entire supply chain. The reforms that have been put in place in the last five years go a very significant way towards this objective, without reaching it entirely. Australia's achievements are considerable:

- National legislation has been adopted that sets rules for interstate trade and competition and establishes the ACCC as the national regulator for the transportation pipeline grid. Western Australia has its own transmission regulator, but that does not affect competition on the national scale as Western Australia is unlikely to be connected to the remainder of the country in the near future.

- All states have implemented this legislation in their own jurisdiction as state law, even Tasmania, which does not yet have any gas infrastructure.

- One simple nationwide regulatory regime has been found that can be used for transmission and distribution alike, and that is applied by all regulators, ACCC and state regulators alike.

- This regime represents a light-handed approach to pipeline regulation through approved access arrangements that serve as a fallback for dispute resolution. This approach has a number of advantages, including freedom for trading partners to establish contractual arrangements that suit them and flexibility to change them without going through a lengthy regulatory approval process. Since the approved access arrangements are there to fall back on, dispute resolution should be greatly simplified. This should keep the burden on regulators manageable (and allow them to focus on monitoring of abuses), except perhaps during times when access arrangements need to be updated.

It should be noted that there are also drawbacks to this system. It does not provide one fixed, uniform national pricing system that might be published and thus be accessible to everybody. Hence, it may give rise to increased transaction costs. It is perhaps for this reason that some industry participants view it as heavy-handed.

However, the alternative, regulated third party access with price caps established by the regulator, are, if anything, even more heavy-handed. They may generate lower transaction costs, since all participants are well aware of the "rules of the game" after the first rounds of price-setting, but the regulatory cost remains very high. On the other hand, the Australian system, which resembles a negotiated third party access regime with a "regulated commitment" at its core, may have higher transaction cost in the beginning but probably lower regulatory cost.

It also resembles to a certain degree the arrangements under the U.S. Federal Energy Regulatory Commission's (FERC) Orders 888 and 889, which opened access to interstate trade on the power grid. Under these FERC Orders, utilities had to file access prices and arrangements that they then had to apply to themselves. This suggests that this type of arrangement may be more easily acceptable in a federal context than continuous price cap regulation. Its combination of simplicity and a great deal of freedom for trading partners and regulators alike in determining the details may well have been what made it acceptable to all Australian governments.

Perhaps also because of the federal structure of the country, the progress of contestability legislation has been slower than expected, including some delays among the early movers New South Wales and Western Australia. While this retards the onset of competition and benefits to consumers, such delays may be inevitable in federal systems. Ultimately it is more important to keep moving in the right direction than to meet pre-established schedules at all costs.

As far as the outcomes of reform are concerned, it is too early to say how much of the anticipated benefits have materialised. Price data for the eligible consumer groups do not yet exist. But there are early signs that companies are interested in using opportunities to compete, as illustrated by the developments in Victoria and New South Wales, especially with respect to alternative supply routes and new pipeline infrastructure.

The developments and proposed projects in the gas transmission business are encouraging insofar as they contribute to establishing a meshed pipeline network for the first time in Australia. At present, loops are being closed. The isolated northern areas, where much of the gas is, are in the process of being interconnected with demand centres. Through the Papua New Guinea-Brisbane pipeline, the first non-LNG route for gas trade with a foreign country is established.

Many gas fields have been discovered in the past ten years in the northern and western part of the continental shelf. These discoveries are relatively remote from major demand centres. The government's gas liberalisation programme opens the possibility for gas traders to access their competitors' pipelines and facilitates aligning a supply route from the gas fields to demand centres. Against this background, private investors are contemplating the construction of a major pipeline (the Timor Sea pipeline) to transport this gas to the consuming regions in south-eastern Australia.

All these projects are major milestones on the way to a fully integrated national gas market. They should further increase competitive pressure on prices and benefit consumers and traders alike. The government has contributed substantially to bringing the pipeline investment about by dismantling administrative obstacles to interstate gas trade.

Although it is still early, the conclusion is that introduction of contestability into the downstream sector has been successful. Whereas all these developments are very positive, more may have to be done. The full benefits of gas market competition will only materialise once the entire business, including the upstream sector, are fully competitive and downstream contestability can work its way back into the upstream, leading to reduced wholesale prices. To date, Western Australia is the only state with significant upstream reform. Here, wellhead gas prices have fallen by 25-50 per cent according to the National Competition Council[36].

The government understands the importance of this issue and set in motion the process to address it in 1998. This process should be pursued according to the timetable that the ministers have set for themselves. To some degree, the lack of producer diversity and its effects may be alleviated over time. For example, one of the major new pipeline projects will connect the Kutubu gas fields in Papua New Guinea's southern highlands with Townsville, Gladstone and Brisbane. With the completion of this pipeline, Australia will for the first time be an importer of natural gas. But to achieve greater efficiency and significantly lower prices across the board, government action remains important.

The third policy initiative that deserves mention is the LNG Action Agenda. Australia's north-west shelf seems to contain enough gas to provide good opportunities for increased production and export of LNG on top of these projects. The government recognises that LNG can be an interesting complementary outlet for gas. It has understood that, given the sharp international competition in the LNG market, it is in the national interest to reduce the administrative burden on investors and to provide an attractive investment climate, while at the same time maintaining essential regulation, generating government revenue from the resource, and guaranteeing protection of the marine environment. The LNG Action Agenda goes a long way towards achieving this.

The three policy strands discussed in this section – competition in the gas market, increasing interconnection and promotion of LNG exports – can be expected to bring substantial benefits to Australia in terms of extracting wealth from gas reserves, establishing an efficient gas supply system that minimises costs and ensures a high level of system security, and providing some diversity to the national energy market.

36. National Competition Council: *Annual Report 1999-2000*, Melbourne, 2000.

RECOMMENDATIONS

The government should:

- Continue its policies to promote fully competitive gas retail markets, with special emphasis on the upstream business.

- Lend continued support to pipeline infrastructure investment, to enhance competition and provide benefits to consumers and traders alike.

- Create conditions to supply domestic gas demand from indigenous resources as well as through imports from neighbouring countries.

- Pursue its plans to create conditions for significantly increased LNG production to supply the growing demand in the Asian market and elsewhere.

8

ELECTRICITY

The Australian electricity supply industry (ESI) has undergone radical transformation since the last IEA review in 1997. The National Electricity Market (NEM) was established in 1998 across the eastern and south-eastern states of Australia, providing the foundations for the development of competition in generation and retail supply activities and for the integration of the previously separated state markets. NEM has succeeded in creating strong competition, especially in some states, and has brought significant price reductions and other benefits to consumers.

Despite these significant achievements, reforms are still under way. Contestability is currently being extended to small electricity consumers. Improvements in transmission pricing and other regulatory arrangements are being considered in the context of an ongoing review of regulation. The corporatisation and privatisation of some assets is still at a planning stage and the physical infrastructure on which the market operates is also adapting to the new competitive conditions. Stronger interconnections between the states, which are essential for developing effective competition in the whole market, are gradually being expanded. A key challenge for the Australian ESI is to complete the reform process.

INDUSTRY OVERVIEW

Industry Structure

The ESI is vertically disaggregated into the activities of generation, transmission, distribution and supply in all NEM participating states and territories (New South Wales, Victoria, Queensland, ACT and South Australia). The ESI remains under state ownership in New South Wales, Queensland and Tasmania. In 1994, the Victorian ESI was privatised and in 2000, the South Australian ESI was put under private management through long-term leases even though it remains state-owned. Table 9 shows the degree of vertical and horizontal disaggregation in the NEM.

There are three independent systems in addition to the interconnected system that covers NEM. In Western Australia, the main electricity supplier is Western Power, a state-owned corporation composed of five “ring-fenced” units covering generation, transmission, distribution and sales, the Pilbara interconnected system and isolated regional systems. In addition, five private electricity supply authorities service townships in remote locations. In the Northern Territory, the ESI is characterised by a small and geographically dispersed load with minimal grid development. Electricity is supplied primarily by the Power and Water Authority, a state-owned corporation, but private ownership of generation and distribution facilities is permitted. In Tasmania, the ESI consisted until 1998 of a single vertically integrated

Table 9
Industry Structure Across the National Electricity Market

	Generation		*Trans-mission*	*Disribution (number of distributors)*		*Retail supply (number of licences)*
	State-owned	*Privately-owned*		*State-owned*	*Privately-owned*	
New South Wales	4	1	TransGrid*	6	–	25
Victoria	–	7	PowerNet**	–	5	23
Queensland	2	2	Powerlink*	2	–	20
South Australia***	3	1	Electra-Net***	1	–	13
ACT	–	–	TransGrid*	–	3	17

* State-owned.
** Privately-owned.
*** State-owned assets are privately managed under long-term leases.

company under state ownership. In 1998, this company was structurally separated into three businesses responsible for generation, transmission, and distribution and supply.

This process of corporatisation and privatisation of the Australian ESI has resulted in a large increase in labour productivity and a commensurate reduction in the number of ESI employees. From 1990 to 1999, output per ESI employee more than doubled, the number of customers per employee increased by 240 per cent, and the number of employees was reduced by a half, from 66,000 to 33,000.

Generation

Electricity Production and Fuel Mix

Propelled by strong economic growth, electricity generation increased by 10 per cent from 1997 to 1999, reaching nearly 186 TWh in 1999. About one-third of generation originated in NSW and the ACT, followed by Victoria and Queensland (see Table 10). Electricity is traded among NEM participants, including the Snowy Mountains Hydroelectric scheme (SMA), a large hydro facility jointly owned by the states of NSW and Victoria and the Commonwealth government. It is planned that SMA will be corporatised and its transmission assets sold to a separate entity.

Coal is the dominant fuel for electricity generation, reflecting the abundant supply and low price of coal in Australia. According to the Electricity Supply Association of Australia (ESAA), the share of coal in electricity generation increased from 75 per cent in 1973 to about 80 per cent in 1990 and 84 per cent in 1999 (See Figure 18). In 1999, the shares of hydro resources and natural gas were 9 per cent and 7 per cent, respectively, down from 10 per cent and 9 per cent in 1990.

Table 10
Electricity Generation and Trade, 1998/99

	NSW & ACT	*VIC*	*QLD*	*SA*	*WA*	*TAS*	*NT*	*SMA**
Total generation (GWh)	60,058	49,442	40,230	8,304	12,152	9,879	1,612	4,573
Net imports (GWh)	5,634	–4,558	–345	3,686	0	0	0	–4,573

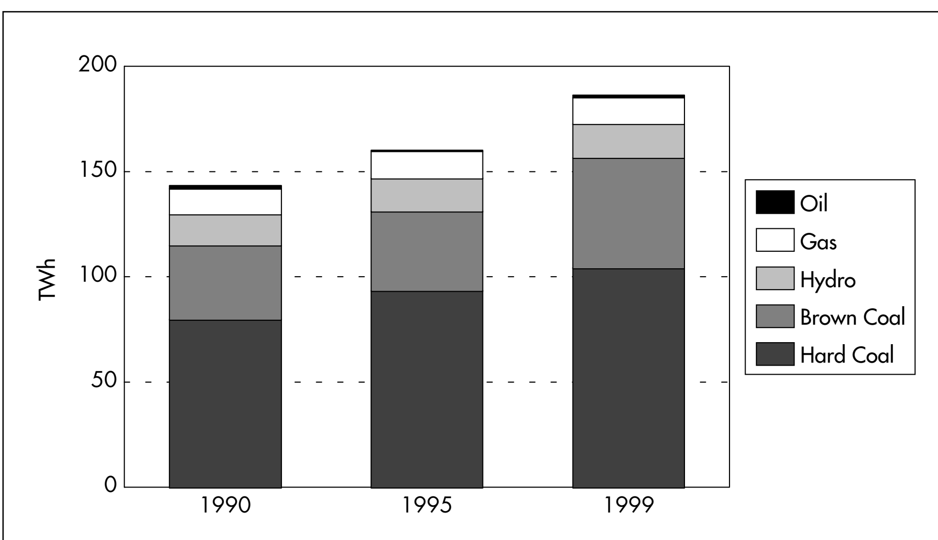
* Snowy Mountains Hydroelectric scheme.
Source: ESAA.

The fuel mix varies by state (See Figure 19). New South Wales, the largest state, Victoria and Queensland rely largely on coal. There is some gas-fired generation in Victoria, Queensland and, outside the NEM, in Western Australia and the Northern territory. Gas is the dominant fuel in South Australia. The Tasmanian system is based on hydro resources.

Reserves and Reliability

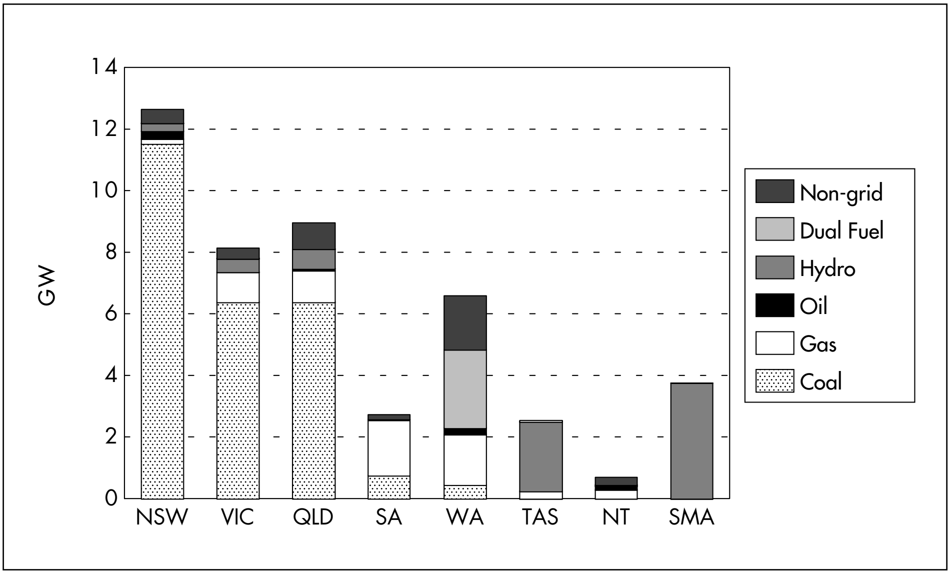
As of 1998/99, generating reserves remained strong across Australia (see Table 11). Reserve levels in most areas were similar to those observed in other OECD countries such as the UK (21 per cent in 1997), Germany (27 per cent in 1997) and

Figure 18
Shares and Volumes of Electricity Generation by Fuel
(Estimated)



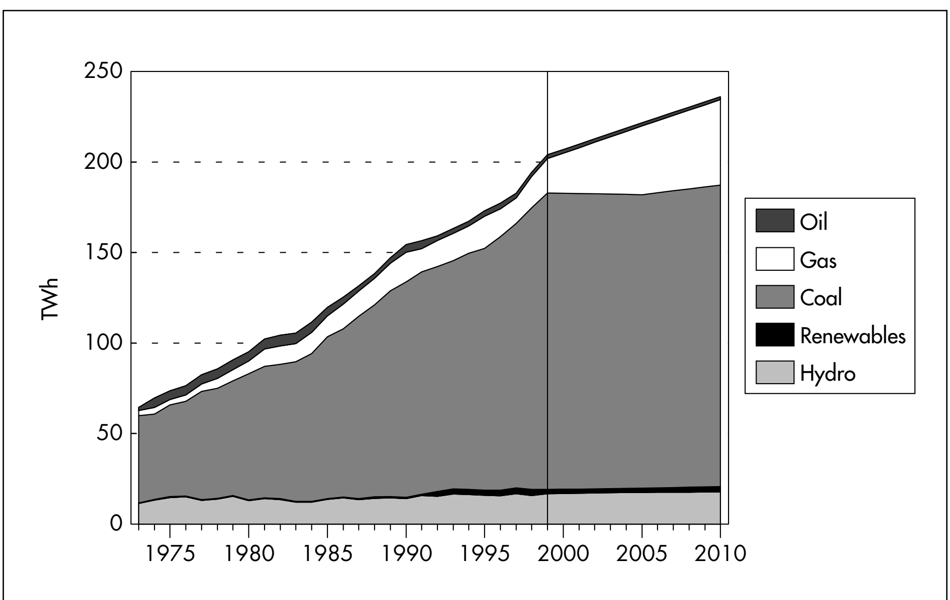
Source: Electricity Supply Association of Australia (ESAA).

Figure 19
Installed Capacity by State and by Fuel Type, 1999
(GW)



Source: ESAA.

Figure 20
Electricity Generation by Fuel, 1973 to 2010



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

Sweden (27 per cent in 1997). Large demand growth in recent years combined with less investment in new capacity – in Victoria, for instance, no new capacity was built since 1992 until 2000 – has eliminated the significant excess generating capacity that existed at the beginning of the 1990s. In addition, average plant availability increased by about 10 per cent from 1992 to 1999 to a level of 93 per cent, reducing the need for reserve generating capacity.

The supply and demand balance varies by state, ranging from the low reserves of South Australia, which relies on imports from the NEM, to the large reserves of the hydro-based Tasmanian ESI. New plant capacity is to be completed in South Australia in 2001.

Table 11

Generation Capacity and Reserves, 1998/99

	NSW & ACT	*VIC*	*QLD*	*SA*	*WA*	*TAS*	*NT*	*SMA*
System peak load (MW)	11,424	7,480	5,994	2,500	2,331	1,566	218	–
Installed capacity (MW)	12,641	8,135	8,957	2,726	5,043	2,534	686	3,756
Reserve margin*	23%	18%	23%	3%	38%	60%	22%	–

* Includes capacity of Snowy Mountains Hydroelectric for both NSW and VIC; excludes pumped storage.

Source: ESAA.

Following a series of outages that took place in Victoria in February 2000, there is a debate on the adequacy of investment in the NEM. The Victorian outages reflected a combination of unusual circumstances, including an industrial dispute which had taken around 20 per cent of generating capacity off line, two unplanned generator outages, and an extremely high peak demand caused by a heat wave across south-eastern Australia. The situation was exacerbated by Victorian government intervention to introduce a price cap and establish consumption restrictions, which prolonged the shortages and distorted market responses.

The Victorian government's interference in the February incident is illustrative of the negative impact that government intervention in the market can have. The intervention prolonged and exacerbated the crisis. The mandatory consumption restrictions introduced by the Victorian government over six days lowered demand in Victoria and had the perverse effect of electricity flowing from Victoria into New South Wales and South Australia while the restrictions were in place. If the market had been allowed to operate, a continual flow of electricity would have been supplied into Victoria from New South Wales, resulting in a more timely resolution of the crisis.

Several measures are being considered to strengthen security of supply in the Victorian market and NEM. There is general agreement on the need for a more effective demand-side response and ways to increase demand-side participation in the NEM are being considered. There are also proposals to raise the cap on wholesale electricity prices and to improve transmission pricing, which would result in stronger incentives to invest and better signals to investors on where investment is needed. The Victorian government is also considering the possibility of establishing an Essential Services Commission with responsibility, *inter alia*, to oversee and co-ordinate security of supply arrangements in the ESI. Transmission adequacy, which is also essential for a reliable supply of electricity, is discussed below.

Outlook

According to the Electricity Supply Association (ESAA)[37], electricity generation is expected to grow by about 37 per cent from 1999 until 2010 and generating capacity is expected to grow by about 25 per cent in the same period. Approximately one-half of the new capacity is expected to be gas-fired and another quarter is expected to rely on gas. Other sources, including non-hydro renewables, would triple, increasing their share of total capacity from under 1 per cent to 2.5 per cent (see Figure 21). This forecast does not reflect the mandatory goal set for renewables later in the year 2000, which requires a stronger growth of renewable generating capacity.

Networks

The transmission network reflects the geographical distribution of the Australian population, which is concentrated along the coast and in the south-east of the country, and the long distances between population areas, which have favoured the development of several weakly interconnected and independent areas (See Figure 22).

Interconnection capacity between the regions of the National Electricity Market (NEM), as shown in Figure 22, is small relative to a generating capacity of nearly 31,400 MW. In 1998/99, exchanges among NEM regions amounted to only 7 per cent of total energy generated (see Table 12). By way of comparison, international exchanges in the Nordic electricity market comprising Finland, Sweden and Norway amounted to about 14 per cent of energy generated in 1998. Queensland was isolated from the rest of NEM until the QNI interconnector started operation in February 2001.

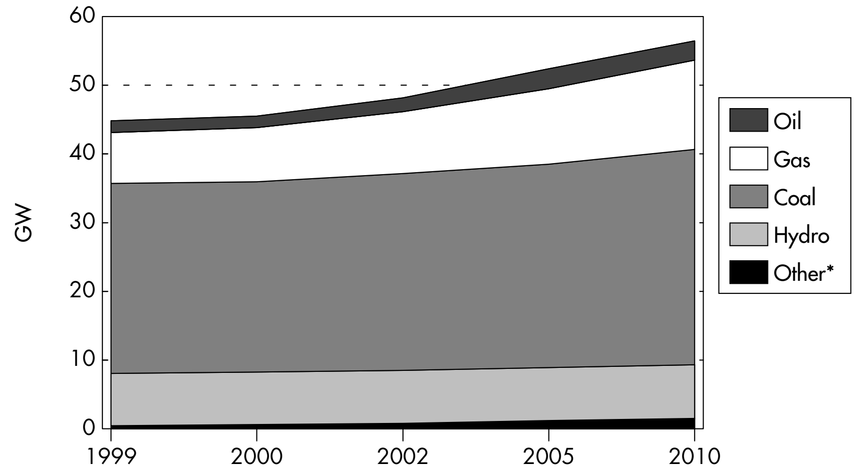
The construction of some additional interconnection capacity to connect South Australia and New South Wales is being considered and could be operational by 2002. Three other DC interconnectors are being considered (see Table 13): 480 MW between Tasmania and Victoria, 250 MW between Victoria and South Australia and an additional 65 MW between Victoria and South Australia.

37. Electricity Australia 2000.

Figure 21

Forecast of Installed Capacity, 1999 to 2010

(GW)



* includes independent power producers.

Source: ESAA.

Table 12

Trade Across Interconnectors, 1998/99

	GWh	*Per cent of total NEM generation*
Snowy – New South Wales	2,754	3
Victoria – South Australia	2,044	2
Victoria – Snowy	1,800	2

Source: NEMMCO.

Table 13

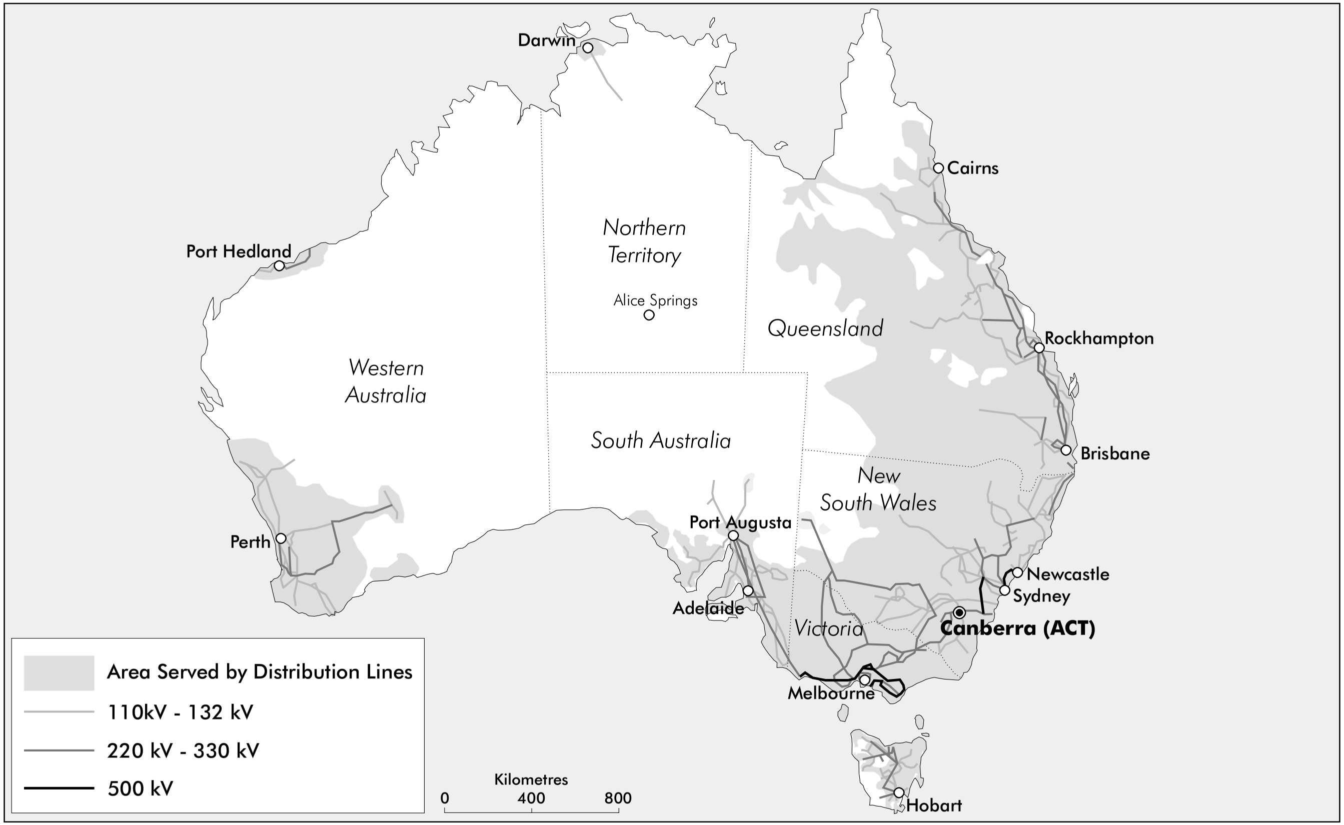
Proposed Interregional Links Between Australian States

	Interconnector
NSW – South Australia	SANI, 250 MW.
Victoria – South Australia	Murraylink, 250 MW, DC connection Southlink, 65 MW, DC connection
Victoria – Tasmania	Basslink, 480 MW, DC connection
Queensland – NSW	QNI, 500 MW by December 2000, increasing to 750 MW in 2001 and 1,000 MW in 2002

Sources: NEMMCO, ESAA and Department of Industry, Science and Resources.

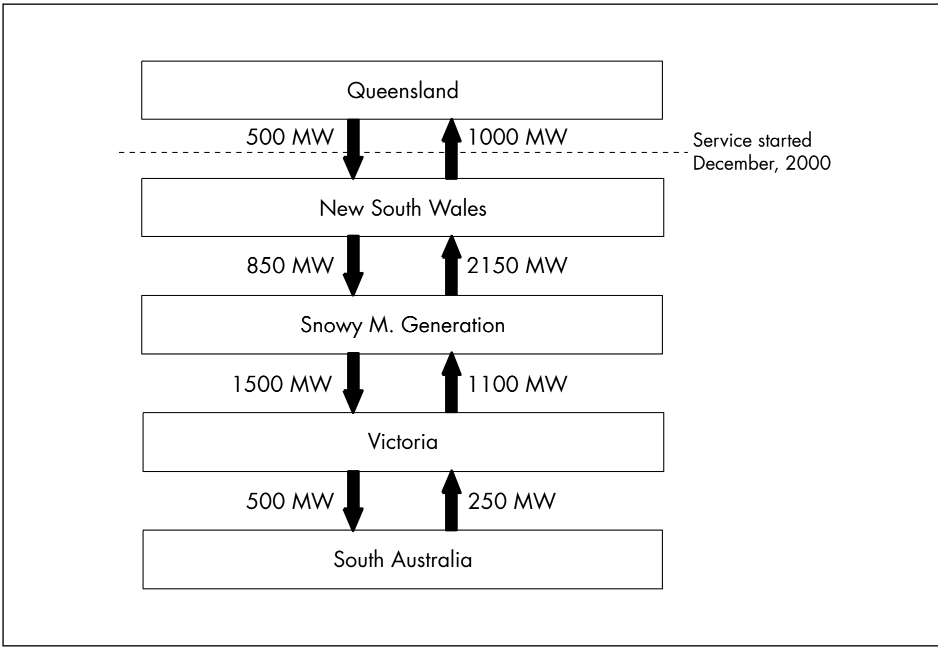
Figure 22

Electricity Transmission Grids in Australia, 2000



Source: Department of Industry, Science and Resources.

Figure 23
Interregional Links Between Australian National Electricity Market Regions, 2000



Source: Australian Competition and Consumer Commission.

Demand

The industrial sector weighs heavily in the Australian economy, accounting for almost one-half of electricity consumption, compared to an OECD average of 38 per cent in 1998. The residential sector accounts for another quarter of total electricity consumption. Electricity consumption per capita, at nearly 14,000 kWh in 1998, is also higher than the OECD average.

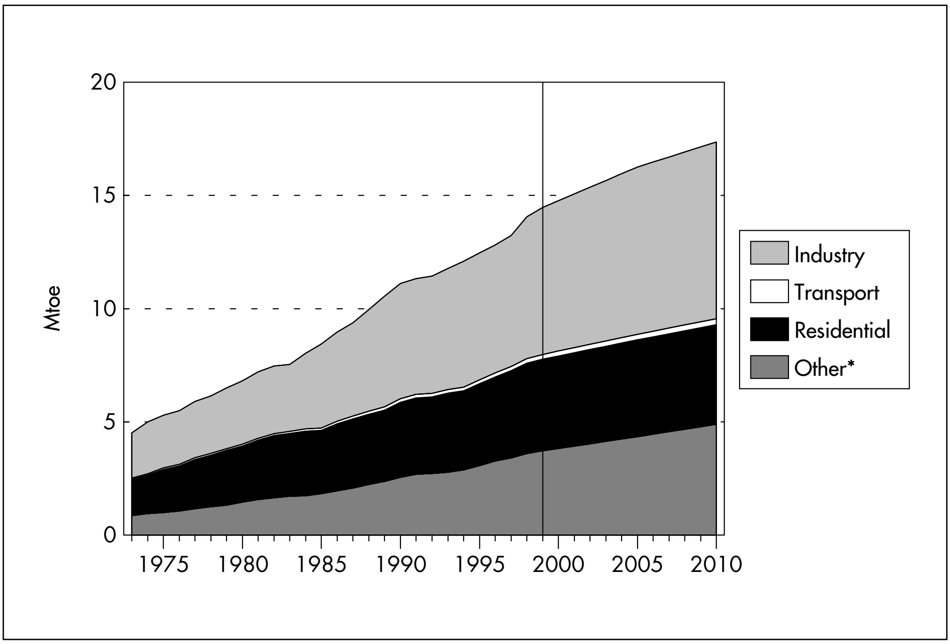
Electricity consumption grew at annual rates of 2-3 per cent over most of the 1990s until it peaked in 1998 at a 6 per cent annual growth rate. Demand growth remained strong at 4 per cent in 1999 and estimates indicate a similar growth rate for 2000.

Prices

End-user prices are low by international standards, reflecting the low cost of input fuels to electricity generation (see Figure 25). However, there are significant differences among the states reflecting different resource availability, demand configurations and government policies (see Figure 26). Prices are higher in the

Northern Territory and Western Australia, where electricity is produced predominantly from gas and diesel, which are more expensive than coal, and network costs are high owing to the low population density. Prices are lowest in Tasmania, where electricity is produced from hydro resources.

Figure 24
Electricity Consumption by Sector, 1973 to 2010



* includes commercial, public service and agricultural sectors.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000, and country submission.

THE PATH OF REFORM

Reform Process and Legislation

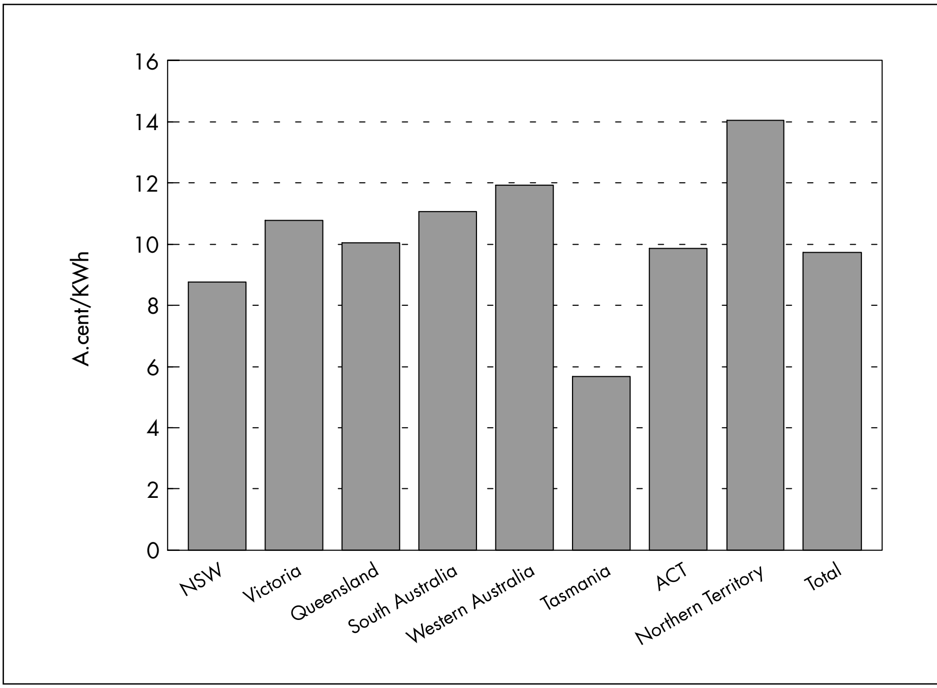
The development of the Australian National Electricity Market (NEM) was initiated in the early 1990s by the federal government and the state governments. At that time, the ESI was vertically integrated under state ownership, interstate trade was scarcely developed, there was a history of excess capacity, and labour productivity was generally perceived to be inadequate. The reform process involved the restructuring of the industry and the development of a new regulatory framework over a period of eight years. NEM commenced operation on 13 December 1998.

The following were milestones in the development of the National Electricity Market:

Figure 25
International Electricity Prices, January 2000
(In Australian cents per KWh)

Source: ESAA.

Figure 26
Average Retail Prices by State, 2000/2001
(Estimated prices in Australian cents per kWh)



Source: ESAA.

- Industry Commission Report, 1991.
- National Grid Management Council's NEM Paper Trial, 1993/94.
- Victorian Electricity Market, 1994.
- Competition Principles Agreement, 1995 (A$ 4.2 billion of Commonwealth funds were set aside for the period to 2005/06 to implement electricity reform).
- NSW Electricity Market, 1996.
- Agreement on National Electricity Code, 1996.
- Start of NEM, 1998.
- Queensland Electricity Market, 1998.

In 1991, a federal economic research agency, known as the Industry Commission, produced a report entitled *Energy Generation and Distribution*. The report recommended a major restructuring of the ESI leading to a corporatisation of the utilities, the unbundling of generation, transmission and distribution, and placing them in a competitive market-place with minimal political interference in operational aspects[38].

In response, the Council of Australian Governments (CoAG) created the National Grid Management Council (NGMC) to oversee the development of a national electricity market based on free choice for electricity buyers; free entry for generators and suppliers, non-discriminatory access to networks and free interstate trade.

NGMC developed these principles into a code of conduct, the National Electricity Code (NEC), that establishes the rules by which each NEM participant must abide. In 1996, NEC was adopted by the states of NSW, Victoria, South Australia, Queensland and the ACT and the two bodies responsible for the implementation of the Code were established. These are the National Electricity Code Administrator (NECA) and the National Electricity Market Management Company (NEMMCO), which acts both as system operator and power exchange.

The federal government played a key role in this process by providing financial incentives to the state governments for their continued active participation in ESI reform and other microeconomic reforms. The Commonwealth government decided to pay "competition payments" to the states and territories totalling A$ 4.2 billion up to 2005-2006. Payments are conditional, in part, on the satisfactory implementation of electricity supply and gas industry reforms.

Regulatory Bodies

Constitutionally, the regulation of the ESI is the responsibility of the states while the Commonwealth government has responsibility for interstate issues and national economic management. With the establishment of NEM, the institutional landscape has changed considerably. An independent national electricity regulator has been created – the Australian Competition and Consumer Commission (ACCC) – as well as a number of independent state regulators (see Table 14). The institutional set-up is summarised in Figure 27.

Most regulatory functions are performed by the independent regulatory agencies with the national agency specialising in the regulation of transmission and wholesale markets, and the state regulators specialising in distribution and retail. The Ministry of Industry, Science and Resources also conducts policy in other energy areas such as energy efficiency, R&D, environmental protection and international energy issues. State governments also have an important role in regulatory issues in the ESI, including establishing the mandates of the state regulatory agencies.

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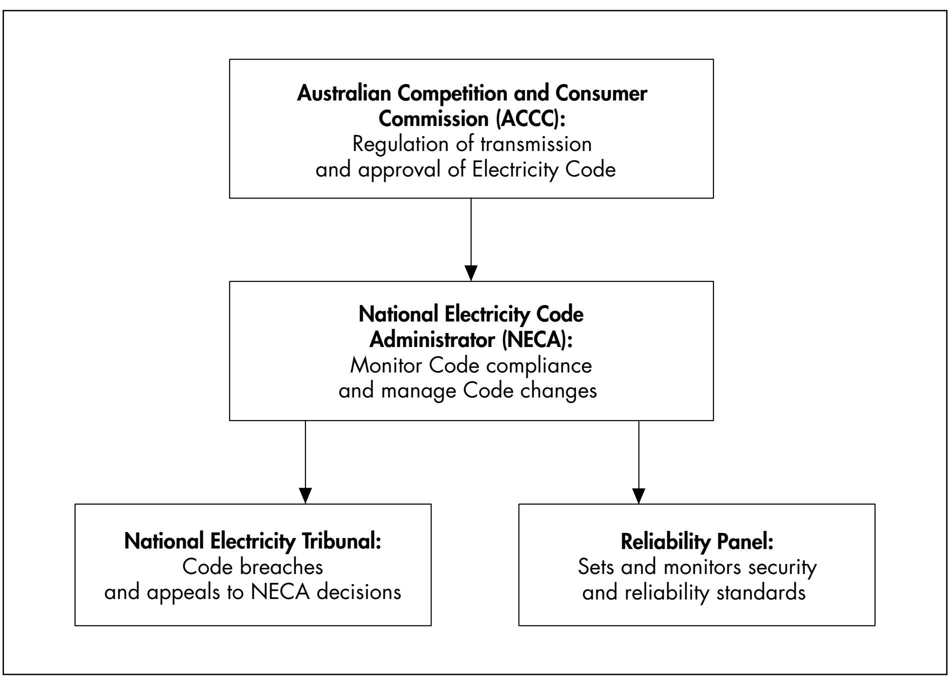
38. Asher A., *Creating a Common Market: discussion of national experiences*, paper presented at the IEA regulatory forum, The Hague, 8-9 February 1999.

Table 14
Regulatory Agencies in the States and Territories

	Regulatory agency
New South Wales	Independent Pricing and Regulatory Tribunal
Victoria	Office of the Regulator-General
Queensland	Queensland Competition Authority
South Australia	South Australian Independent Industry Regulator
Tasmania	Office of the Tasmanian Electricity Regulator
Western Australia	Office of Energy
Australian Capital Territory	Independent Pricing and Regulatory Commission

Various organisations deal with the operation of the market. The National Electricity Code Administrator (NECA) monitors compliance with rules of the National Electricity Market and raises Code breaches with the National Electricity Tribunal. NECA is overseen by the states. In addition, a reliability panel determines power system security and reliability standards, and monitors market reliability.

Figure 27
National Bodies Involved in the Regulation of the Electricity Market
(and their main functions)



Source: ACCC.

- **The Australian Competition and Consumer Commission (ACCC).** As indicated in Chapter 3, the ACCC was formed on 6 November 1995 by the merger of the Trade Practices Commission and the Prices Surveillance Authority. It is the body responsible for administering and enforcing the Trade Practices Act that applies to all sectors, including electricity. This law deals with anti-competitive and unfair market practices, including misuse of market power and anti-competitive mergers. The ACCC provides for the surveillance and monitoring of prices in certain industries and has general cross-sector responsibilities. It advises the government on rights of access to essential infrastructures and, where these rights have been established as in the ESI, acts as "arbitrator of last resort", determining access conditions and prices in case of disputes. Finally, the ACCC also has a significant role in promoting competition through regulatory reform in Australia. The specific regulatory responsibilities of the ACCC in the ESI are:
  - Regulation of the network: Developing accounting and reporting rules and benchmarks for electricity transmission and advising state regulators on similar rules for distribution companies, setting service standards for transmission network performance, determining the annual revenue requirement for each transmission company operating in the NEM, developing the details of regulatory policy, approval of interconnector proposals and capital expenditures, and approval of access arrangements to the network.
  - Organisation of the market: Evaluation and approval of changes to the "Code" that governs the operation of the market and development of new market arrangements such as the future structure of network charges, market design and retail competition.
  - Promotion and defence of competition: Investigation of market arrangements and behaviour that may contravene antitrust laws and evaluation of electricity industry mergers.

  In an international perspective, the ACCC is unique in that it is responsible for both regulation and competition and covers many industries. Typically, regulatory agencies in OECD countries are much more specialised – covering, for instance, energy industries only – and are not in charge of applying competition law.

- **State regulators.** The functions of the state regulators in the ESI concern mainly distribution and retail supply. The regulation of distribution includes setting price controls for distribution and approval of distribution tariffs and setting service standards for distribution and other related services, and monitoring compliance. The regulation of retailing includes approval of retail tariffs for "franchise" consumers – those without a choice of supplier, setting standards for retail services and monitoring compliance, and developing a scheme of retailer of last resort. The state regulators also have responsibilities for monitoring market conduct of retailers and distributors, developing information programmes to customers, introducing competition in other supply-related services, such as metering, and issuing licences for all electricity companies operating in the state.

This framework makes co-ordination between regulatory bodies at federal and state level indispensable. The institutional framework of the Australian ESI is often perceived as complex. There is potential for some overlap of functions between the ACCC and the state regulators, and between the ACCC and NECA. A number of steps have been taken to minimise uncertainty regarding jurisdiction and to avoid confusion. The ACCC has frequent information exchanges with state regulators through regular liaison meetings and the exchange of publications and other information. In addition, chairpersons of various Commonwealth and state economic regulators such as the Victorian Office of the Regulator-General are associate members of the ACCC. These measures are intended to bridge the "knowledge gap" that can arise between the separate bodies.

In an international perspective, this institutional approach is similar to that of other federal countries. In the United States, for instance, there is a federal regulator (FERC), a state regulator in each of the states, a reliability organisation (the National Electric Reliability Council), independent boards governing the independent system operators (e.g. in Calfornia and PJM, the Pennsylvania–New-Jersey–Maryland electricity market), and a separate competition authority. A similar but more decentralised framework exists in Canada. In NordPool, each of the participating countries has retained its own regulatory bodies and no regulatory body has jurisdiction over the whole of the market. There is an organisation of transmission system operators, Nordel, that deals with reliability and transmission co-ordination issues.

The Wholesale Market

Trading Arrangements

The National Electricity Market is a mandatory auction market in which generators of 30 MW or more and wholesale market customers compete. Generators submit bids consisting of simple price-quantity pairs specifying the amount of energy they are prepared to supply at a certain price. Up to ten such pairs can be submitted per day. Two additional "revenue bids" are also permitted, specifying a minimum payment if the generator is forced to run below a certain level. In principle, bids are firm and can only be altered under certain conditions. Generator bids are used to construct a merit order of generation. Customer bids are used to construct a demand schedule. Dispatch minimises the cost of meeting the actual electricity demand, taking into account transmission constraints for each of the five regions in which the market is divided. Generation is scheduled according to this merit order and regional prices are calculated *ex post* for each five-minute period from actual supply and demand. Generators are paid the spot price, which is calculated for each half-hour as the average of the six prices in that half-hour. There are no capacity payments or any other capacity mechanisms. There is a cap on spot prices currently set at A$ 5,000 per MWh.

A financial contracts market has developed in parallel to the NEM. Contracts for differences are traded bilaterally between the parties to each arrangement. In addition, the Sydney Futures Exchange is trading two electricity futures contracts.

The general organisation of NEM's wholesale market is similar to that of the old England and Wales electricity pool, which was also mandatory with a single institution playing the roles of power exchange and system operator. NEM differs from the old England and Wales pool in that prices are calculated *ex post*, bids are firm and there are no capacity payments.

This approach differs from the models adopted in most other electricity markets across the OECD, in which participation is voluntary and prices are calculated *ex ante* on the basis of scheduled supply and demand. Mandatory pool participation, which was required in the England and Wales pool and transitionally in the Californian market, has been linked to high price volatility and market manipulation issues[39]. Participation is now voluntary in both markets.

Performance

Wholesale prices differ widely across NEM regions, reflecting transmission constraints, differences in the fuel mix among the constrained regions and different competitive conditions. As in many other electricity spot markets, prices are volatile, ranging from zero to values at or near the maximum price allowed (see Table 15). As a result of intense competition among generators coupled with overcapacity, prices in New South Wales and Victoria were initially low, at levels well below the long-run marginal cost of generating electricity. Prices have gradually increased in the whole of NEM since then (See Figure 28).

Table 15

The National Electricity Market Trading Summary

(A$/MWh, Financial Year 1 July to 30 June)

Price	*New South Wales*		*Victoria*		*Queensland*[1]		*South Australia*[2]		*Snowy Mountains region*[2]	
	97/98	*98/99*	*97/98*	*98/99*	*97/98*	*98/99*	*97/98*	*98/99*	*97/98*	*98/99*
Maximum	333.08	3,037.97	4,814.05	3,653.28	888.00	5,000.00	-	4,438.66	-	320.43
Minimum	2.79	4.46	0.00	0.00	5.51	0.00	-	5.19	-	5.15
Average volume weighted	15.03	25.56	15.17	26.02	41.39	63.26	-	54.03	-	18.80

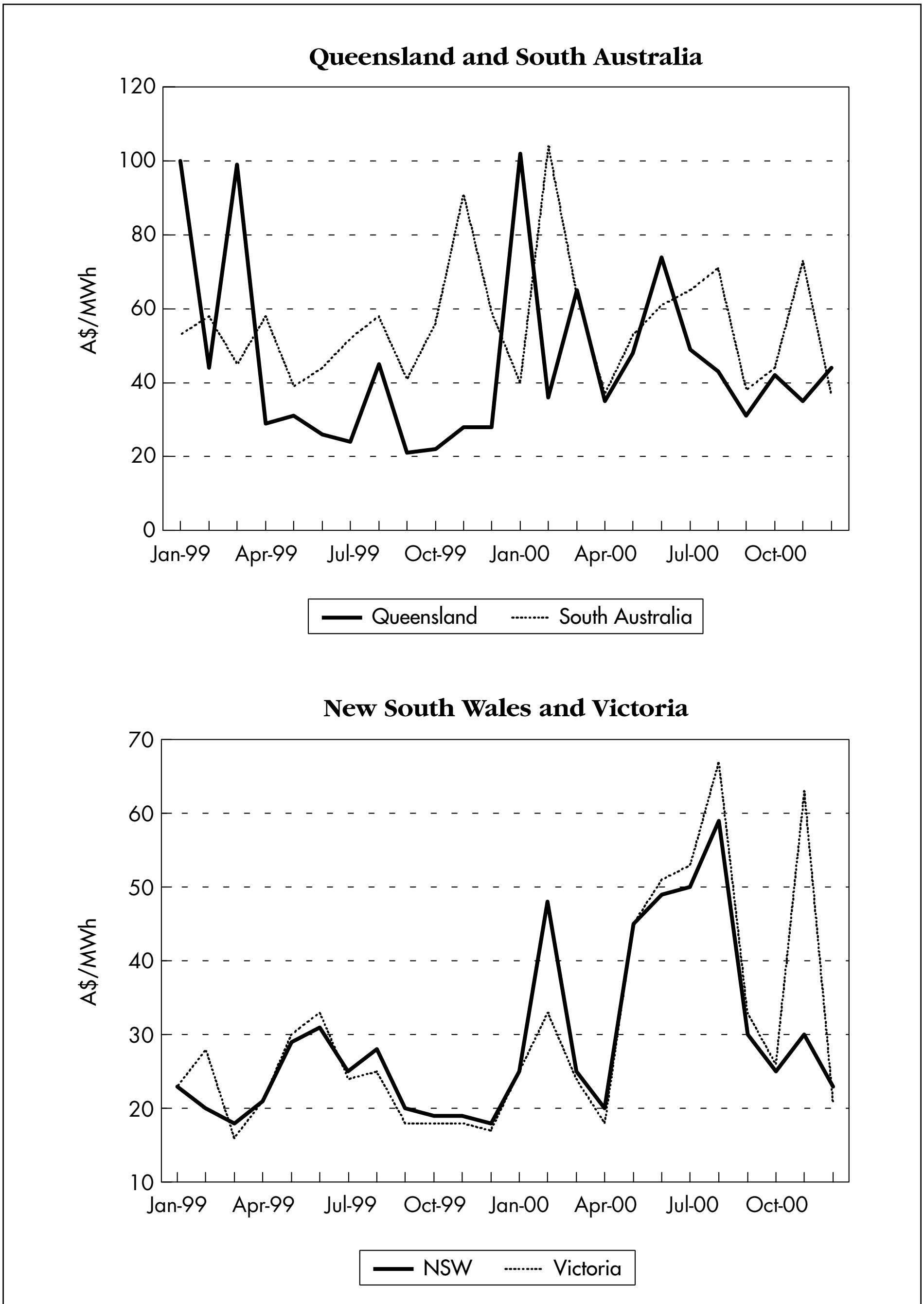
1. Figures for Queensland in 1997/98 are for the period between 22 March 1998 and 30 June 1998.
2. Figures for South Australia and Snowy Mountains region are from 13 December 1998 to 30 June 1999.
Source: ESAA.

Competitive Conditions

Market shares of generation companies are relatively low in the whole of NEM. The share of the two largest generators is below 40 per cent. By comparison, in 1998,

39. *Competition in Electricity Markets*, IEA/OECD Paris, 2001.

Figure 28
Average Monthly Wholesale Prices, 1999/2000
(A$/MWh)



Source: NEMMCO.

the share of the two largest generators was about 40 per cent in England and Wales and the Netherlands, and about 35 per cent in the Nordic electricity market.

However, NEM often comprises several separated markets and generator concentration in each of these markets is high at levels above 50 per cent (see Table 16). Furthermore, in New South Wales and Queensland, the states remain the sole owners of most generation capacity so that ownership concentration is very large. This suggests that, unless transmission constraints are reduced, market power could be an issue in the NEM, particularly during peak demand periods.

Table 16

Market Shares in Generation, 1999

(Per cent)

	Largest generator	*Two largest generators*
New South Wales	38	70
Victoria	31	54
Queensland	27	54
South Australia	31	62
Tasmania	100	–
ACT	n.a.	n.a.

n.a.: not available.

Source: ESAA

Regulation of Transmission

Transmission Pricing

Prices for most transmission assets are regulated, subject to a revenue cap, but it is also possible for new assets to be unregulated and earn market rates. An unregulated interconnector is entitled to retain the value of energy flowing from the interconnector less the value flowing into it in each spot trading interval.

The same price regulations will apply to all transmission assets in the NEM, including the links between the states. There are, however, transitional arrangements lasting until 2002, exempting certain assets from NEM's pricing regulations for a certain period. These exemptions were given at the time of privatisation to facilitate the sale of the assets.

The revenue of transmission companies is regulated on the basis of an adjusted replacement value of the assets, known as deprival value, and its weighted cost of capital. The maximum annual revenue allowed to transmission is subject to a "CPI-X" price cap, fixed for a period of at least five years, that reduces transmission charges over time in real terms.

Transmission charges are paid entirely by end-users through a two-part tariff including a variable component related to actual use of the network (per kW and/or kWh) and a fixed component. Transmission companies may also get some revenue from interregional congestion. When there are constraints between regions, prices are higher in the importing region. The surplus revenue in the importing region is used to pay for any deficits in the financial contracts that cover retail prices to franchise customers in each state and the remainder is used to reduce transmission charges for the customers. Intraregional congestion is not reflected in prices and thus it does not generate revenue.

The allocation of charges to different consumer groups varies across regions, particularly regarding the degree to which charges are averaged over all end-users, regardless of their location. Costs are entirely averaged in South Australia, while New South Wales and Queensland have adopted a 50/50 split for cost-reflective versus postage stamp charges. Victoria has adopted a locational pricing method, but, since it is combined with a price cap, locational signals are in the end substantially reduced.

These arrangements do not adequately reflect transmission costs. The averaging of charges across end-users creates distortions that subsidise, for instance, rural and remote end-users. In addition, remotely located generators do not face any charges for transporting electricity to the market, thus putting distributed generation units that do not use the transmission network at a disadvantage. More generally, because generators do not pay transmission charges, their siting decisions may be distorted.

Charges were entirely borne by end-users in most systems in the pre-competitive era as it did not make any difference, from the point of view of final prices, how the charges were split between users and generators. This is still the approach in many systems such as in New Zealand, Finland, Spain and some U.S. markets including California and PJM. However, as generation becomes competitive, there is increasing pressure towards a split of charges. Charges are split in England and Wales, Norway and Sweden, for instance, and this arrangement is being considered for cross-border trade in the European Union.

A review of transmission pricing arrangements was initiated in 2000 with the goal of addressing these problems. The review is considering the scope for nodal and zonal pricing including options for integrating energy and network services, and mechanisms to deal with price risks and signal needs for new investment. A key issue being discussed is to what extent a zonal pricing system could be a viable and less complex alternative to full nodal pricing.

International experience shows that a sophisticated pricing of transmission services is both feasible and effective in managing the grid but provides only limited guidance on the optimal trade-off between complexity and efficiency in transmission pricing. Full nodal pricing has been adopted in some markets in the U.S. (e.g., PJM) and in New Zealand, while simplified locational methods (i.e. zonal pricing) are in use in other U.S. markets such as California, and in NordPool.

Beyond these issues, the main difficulty in reforming the transmission pricing regime arises from concerns about the impact reform would have on end-user prices, especially given the existence of subsidies to rural and remote end-users.

Transmission Development

The development of transmission is essential for the effective integration of the five NEM regions within a common market. Historically, cross-border links were often limited to providing emergency supplies, but were not designed to accommodate commercial electricity transfers. New trade patterns have been developing since the establishment of NEM, including an increase in interstate trade that is often limited by the availability of transfer capacity.

Current ACCC policy regarding interstate links is that unregulated, or "entrepreneurial", interconnectors will be preferred to regulated interconnectors. An entrepreneurial interconnector is funded by risk capital and there is no guarantee that it will recover its costs. It is difficult to assess the potential of entrepreneurial interconnectors in developing the network as this is essentially a new approach, but some investment is already taking place. Construction of one unregulated 180 MW interconnector between Queensland and New South Wales (Directlink) was completed in 2000, and three others are planned.

Alternatively, approval of new regulated assets can be granted provided the investment passes a "net benefit test" [40]. This test, as currently applied, has proved very demanding and it is being reviewed. ACCC is considering the merits of moving to a more traditional cost-benefit analysis.

The Retail Market

Following a gradual opening of the market that started in 1994, all end-users within NEM are expected to have choice of supplier by the beginning of 2003. Full market opening was planned in Victoria, Queensland and ACT for the beginning of 2001 but implementation for the smallest group of consumers, including domestic consumers, has been delayed for at least another year. The final timetable remains uncertain. Outside NEM, there will be a partial opening of the market (see Table 17).

The introduction of retail choice for businesses has resulted in substantial price reductions. According to one survey conducted in 2000, about 33 per cent of business consumers have switched suppliers and about 70 per cent have actively sought alternative offers [41]. A recent study quoted in ESAA's biannual customer survey EnergyTrends looked at more than 820 Australian businesses, half of them free to choose now and the other half mainly becoming contestable in 2001. The study provided the following information:

40. The procedure is similar to a cost-benefit test, requiring that the investment has a positive net present value, but applies a higher cost of capital. The cost of capital applied in the public benefit test is the cost of capital faced by a market participant in building a new generation plant. By contrast, a cost-benefit test would apply a lower cost of capital, taking into account that the risk of investing in a regulated asset is lower because recovery of the investment is guaranteed, ultimately, by the consumers. This test is intended to keep a level playing field for generation.
41. ESAA, New Customer Survey for Electricity Retailers (www.esaa.com.au) 5 February 2001.

- 31 per cent of contestable electricity customers surveyed have found new suppliers since becoming free to choose.

- more than 67 per cent of contestable businesses have opted to stay with their former franchise electricity supplier.

- 79 per cent have changed retailer only once although 1.6 per cent of respondents say they switched supplier four times in four years.

- 40 per cent of large companies (in terms of electricity consumption) and 43 per cent of very large companies have changed retailers.

- a survey of non-contestable businesses shows that almost 70 per cent will seek quotes for supply contracts from other retailers when they become free to choose.

The development of detailed metering and profiling rules for small consumers is still under discussion across NEM participating states. The initial industry proposal is to require small customers to install an interval meter as a condition of changing retailer. However, several parties, including state governments and regulatory bodies, consider that this requirement would constitute a barrier to competition and that small consumers should have the option of retaining their existing basic meters and having their consumption settled using a load profiling system. This system assigns to each consumer a profile of consumption over time based on statistical inference and charges consumers accordingly. This approach is criticised on the basis that consumption in a given period is estimated instead of measured, thus providing no incentive to conserve energy or control energy use.

Load profiling is an option for small consumers in several IEA countries including the United Kingdom, the United States (California), Finland and Sweden. In Sweden, for instance, customers had a choice of supplier since 1996 but were required to install special meters in order to switch supplier and to give notice of their decision six months in advance. This resulted in weak competition for small consumers. Load profiling was introduced in 1999 together with other measures intended to stimulate competition for small consumers. The result was a rapid increase in the number of consumers who switched supplier.

All states in Australia maintain regulated tariffs at least for the smallest customers. There are no tariffs for the largest consumers and the threshold for this so-called "mandated contestability" is gradually being lowered.

Electricity prices decreased on average from 1991/92 until 1997/98 but increased in 1998/99 and are projected to increase in the following two years (See Figure 29). In real terms, this amounts to a reduction in electricity prices of nearly 10 per cent from 1991/92 until 2000/01.

Prices have evolved differently for residential and business consumers. Residential prices steadily but moderately increased from 1991/92 until 1999/00. An increase of about 11 per cent is expected in 2000/01 as a result of the introduction of a new Goods and Services Tax replacing the old system of wholesale taxes, and higher wholesale prices (Electricity Prices in Australia, 2000/2001, ESAA). In real terms, (after tax) residential prices are expected to be similar in 2000/01 to those in 1991/92 (see Figure 29). Business prices have decreased over the period in both nominal and real terms. Large price reductions for large industrial consumers, as much as 50 per cent, have been reported in Victoria and New South Wales since competition began in late 1998. As shown in Table 18, price trends vary by state.

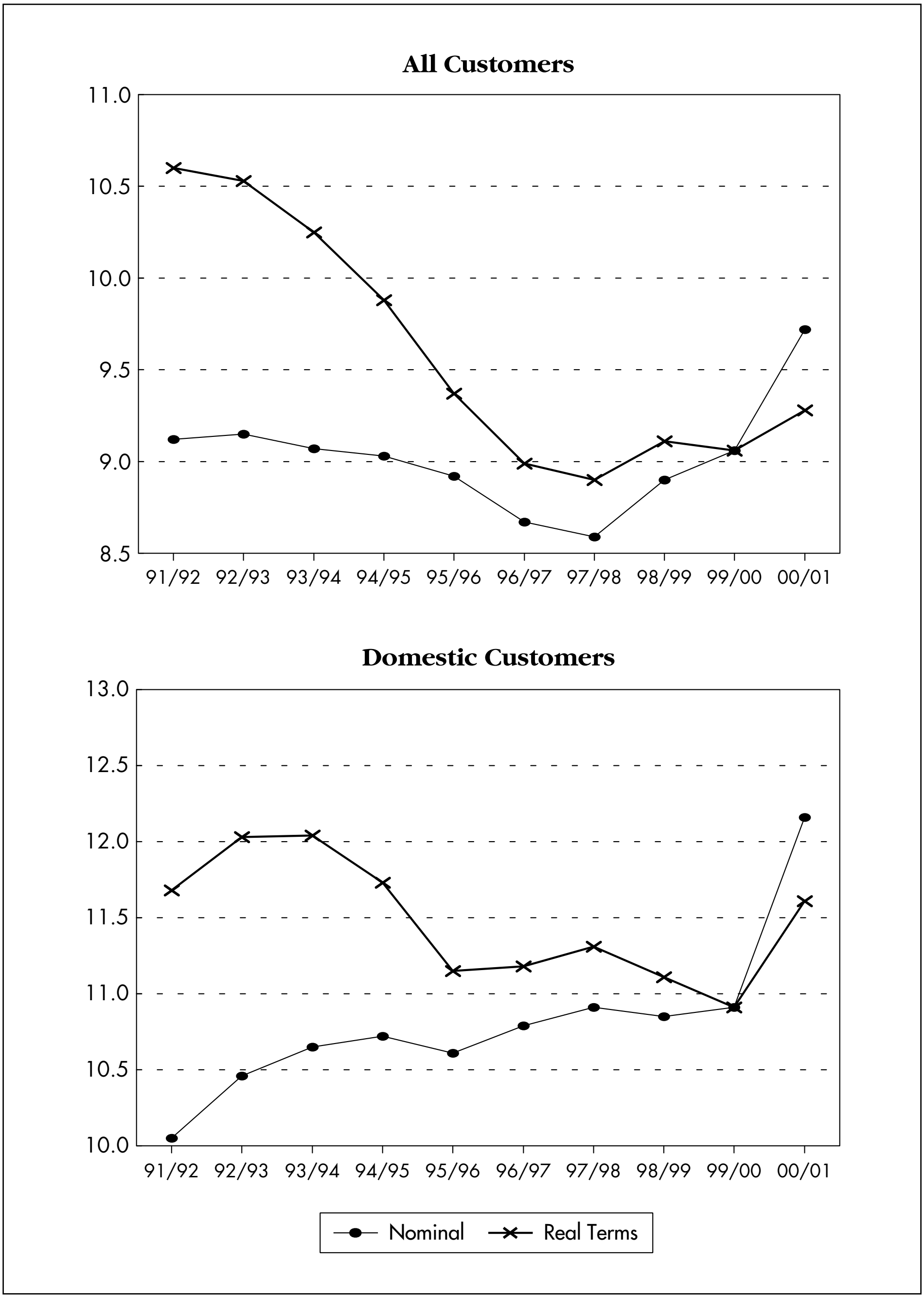
Table 17

Timetable for Market Opening

	Date for eligibility	*Site thresholds ≥*
New South Wales	1-Oct-96	40 GWh
	1-Apr-97	4 GWh
	1-Jul-97	750 MWh
	1-Jul-98	160 MWh
	1-Jan-2001	100 MWh
	1-Jul-2001	40 MWh
	1-Jan-2002	All sites
Victoria	30-Nov-94	5 MW
	1-Jul-95	1 MW
	1-Jul-96	750 MWh
	1-Jul-98	160 MWh
	1-Jan-2001	40 MWh
	1-Jan-2002	All sites
Queensland	29-Mar-98	40 GWh
	1-Jan-99	4 GWh
	1-Jan-2000	200 MWh
	1-Jan-2002 (or later)	All sites
Australian Capital	1-Oct-97	20 GWh
	1-Mar-98	4 GWh
	1-May-98	750 MWh
	1-Jul-98	160 MWh
	?	All sites
South Australia	20-Dec-98	4 GWh
	1-Jul-99	750 MWh
	01-Jan-2000	160 MWh
	01-Jan-2003	All sites
Western Australia	1-Jul-97	10 MW
	1-Jul-98	5 MW
	1-Jan-00	1 MW
Nothern Territory	20-Apr-00	4 GWh
	1-Oct-00	3 GWh
	1-Apr-01	2 GWh
	1-Apr-02	750 MWh

Source: ESAA.

Figure 29
Average Electricity Prices, 1991 to 2000
(In Australian cents per KWh)



1999/2000 and 2000/2001 are based on projections.
Source: ESAA.

Table 18
Real Price Changes by State
(Per cent)

	Residential		*Business*		*Total*	
	97/98	*98/99*	*97/98*	*98/99*	*97/98*	*98/99*
New South Wales	2.10	-4.80	-3.00	4.30	-1.40	2.60
Victoria	0.20	-2.50	-5.30	5.10	-2.70	4.60
Queensland	-0.70	-1.10	2.00	-3.50	0.40	0.50
South Australia	7.60	0.70	-3.80	2.20	0.80	1.10
Western Australia	-3.50	-0.90	1.70	-3.50	0.00	-2.40
Tasmania	1.70	9.40	0.60	-2.70	1.20	-0.50
ACT	-0.95	0.10	-16.05	-2.10	-10.28	-1.10
Northern Territory	0.00	4.60	-6.50	1.50	-5.00	2.40
Australian average	**1.10**	**–1.80**	**–6.50**	**2.50**	**–4.10**	**2.30**

Source: ESAA

Retail supply companies in New South Wales and South Australia have entered into so-called vesting contracts with generators to hedge the risk of a mismatch between the wholesale price of electricity, which fluctuates over time, and the regulated tariff charged to franchise consumers. Tariffs set under this system reflect the contracted price of energy instead of the spot price. Vesting contracts require authorisation by the ACCC.

CRITIQUE

Substantial progress has been made in the Australian electricity supply industry, which has undergone deep structural change. The industry has made the transition from vertically integrated monopolies to a competitive market-place characterised by several generation and distribution companies, independently regulated transmission companies, a competitive power pool and the gradual introduction of choice of supplier for end-users. In this process, labour and capital productivity have greatly increased, and prices for contestable end-users have significantly dropped.

The implementation of reforms offers some useful lessons. In Australia's federal structure, the Commonwealth government has limited constitutional powers regarding energy policies and there is a constant need to reconcile Commonwealth and state energy policies. Despite these difficulties, the states have taken a co-ordinated approach to reform. The Commonwealth government has played a key role in providing incentives for the states to move forward. The institutional set-up has evolved with the goal of enhancing the competitive neutrality and transparency of regulatory decisions. The establishment of the ACCC and the state regulatory bodies provides a workable foundation for energy regulation.

Despite the progress made to date, the reform process is still far from complete. Completing the reforms requires extending end-user choice of supplier to all end-users, strengthening competitive neutrality, particularly to ensure that state-owned businesses do not enjoy competitive advantages by virtue of their public ownership, and reinforcing transmission interconnections across the NEM in order to make it a truly integrated market. The box below summarises the assessment of the National Competition Council[42] on the progress of reforms in the ESI.

Assessment of the National Competition Council (NCC) on the Progress of Reforms

According to the NCC, the chief obstacles to full competition are delays in allowing customers choice of supplier and continuing derogations and transitional arrangements. In electricity, issues have also arisen concerning:

- The need for further interconnection within the NEM, notably between South Australia and New South Wales.
- The ongoing use of vesting contracts to manage financial risk.
- The lack of consistent response to supply imbalances, in some cases resulting in inflated electricity prices.
- The belief among some parties that government-owned businesses in the electricity sector may enjoy competitive advantages by virtue of their public ownership.

Source: NCC, Annual Report 1999-2000, pp.29-30.

There is evidence that the pace of reform has slowed and that the goal of fully competitive electricity markets, originally set for June 2001 by the National Competition Policy, will be delayed. The introduction of full retail contestability has been postponed in some states and there is uncertainty concerning the date when residential end-users will be allowed to choose supplier in these states. Expectations concerning the privatisation of the ESI have also changed. There is public sentiment against further privatisation and there are no plans for it in the states in which the ESI remains under public ownership.

Interconnections between the states need to be reinforced. The weak interconnections among the states have a negative impact on both reliability and competition. Existing transmission capacity is not enough to accommodate trade among NEM regions, as shown by the significant price differences between NEM

42. The National Competition Council is the body set up by the Commonwealth government to oversee the progress of the National Competition Policy (see also Chapter 3). In particular, the council makes recommendations to government concerning the payment to the states of the financial incentives which are conditional on the implementation of this policy.

regions. Even if the development of connections between certain zones is made uneconomical by the long distances involved, there is a clear need for stronger links between certain NEM regions as well as a commercial interest in developing these links.

The development of entrepreneurial interconnectors can help to alleviate transmission constraints without imposing additional risks on end-users. Completion of one entrepreneurial interconnector and plans for developing others confirm the feasibility and promise of this approach. However, as this is a new approach, its full potential is still unknown. Incentives to invest in entrepreneurial interconnectors may be weakened by regulatory uncertainty and by distortions in price signals. There is, for instance, a cap on the price of energy, which also caps the revenue of entrepreneurial interconnectors, and transmission charges are not generally cost-reflective, which may distort locational decisions of market players. There are currently two major reviews of transmission pricing – one on network pricing and one on locational pricing – that have the potential to significantly improve price signals and the effectiveness of investment in the NEM[43].

The option of building regulated interconnectors should be maintained, particularly during the transition until undistorted market prices emerge. Conditions for approval of regulated interconnectors are currently very demanding, resulting in few approvals and possibly discouraging proposals to build new lines or upgrade existing ones. Furthermore, regulatory reviews of proposed transmission investments should take into account the potentially significant benefits in terms of increased reliability and more intense competition between generators that may result from stronger interconnections. A more flexible application of the "consumer benefit test" on transmission investments, which is being considered by the ACCC, could help to improve the outlook for transmission development.

Ensuring competitive neutrality throughout the national market is also essential. Privatisation of electricity in Australia has had mixed results. The Victorian privatisation programme was completed in April 1999 and, in South Australia, electricity assets are under long-term leases. In other states, namely New South Wales, ACT and Tasmania, despite strong government support, all privatisation proposals failed to pass the state's legislative Council Assembly or were halted by new elections.

State ownership may distort competition because there is a potential conflict of interests between the roles of the states as regulators and as owners. It has been alleged, for instance, that in New South Wales private investors find it difficult to compete with state-owned companies because these companies have comparatively low debt levels[44]. In Queensland, the state has announced plans to require generators to increase the share of gas-fired generation up to 15 per cent.

43. The ACCC's Transmission and Distribution Pricing Review (www.accc.gov.au) and NECA's Review of the Scope for Integrating the Energy Market and Network Services (www.neca.com.au).
44. U.S. International Trade Commission (2000): "Electric Power Services: Recent Reforms in Selected Foreign Markets", Chapter 3, Australia, pp. 3-8.

State ownership may also weaken incentives for the development of transmission interconnectors, which would bring stronger competition among generators and reduce their revenue.

Privatisation would resolve these issues. However, if companies remain under public ownership, it is important that measures be taken to ensure a level playing field. Reinforcing competitive neutrality in the decentralised Australian framework requires co-ordinated action among the states. Thus, it is important that the benefits to the states of a more competitive and integrated ESI be clearly assessed and understood by all parties.

These benefits include increased efficiency and reliability of the electricity industry, enhanced competitiveness for the whole economy, and a larger potential for attracting investment. The Commonwealth government, through the National Competition Policy, may play a key role in promoting competitive neutrality.

Reliability issues must be monitored. The reliability problems experienced in Victoria in February 2000, while largely caused by a combination of unusual circumstances, suggest the need to review and reinforce reliability arrangements across NEM to prevent recurrence. In particular, the Victorian blackouts reflect the limited availability of interconnection capacity[45] and suggest the need to introduce a more effective demand response to deal with demand peaks. The evolution of peak demand *vis-à-vis* peak generating capacity also needs to be monitored.

A number of market-based solutions to reinforce reliability in a cost-effective way are being considered. NEM arrangements to identify options to increase demand-side participation in the market are under continuing review. Another measure under consideration is raising the cap on the wholesale price of energy so that no available generation units are discouraged from bidding at peak demand periods. Priority should be given to implementing these measures in the whole NEM.

The introduction of full retail contestability should not be delayed. Delaying the introduction of choice of supplier for small end-users limits the efficiency gains that will result from reform, makes it difficult for small end-users to reap the benefits of reforms and, ultimately, may have a negative impact on the public view of reforms. Large price reductions have been recorded for contestable end-users while captive end-users have not had the opportunity to seek lower prices.

45. Interconnectors are not necessarily the most efficient solution to reliability problems. In a competitive market with efficient pricing, scope must be provided for private investors to make a rational choice between network augmentation, new generation and demand-side management on a commercial basis. This requires that network prices send appropriate and effective signals for capacity expansion, and that the administrative processes, especially for network augmentation and new generation, function as smoothly as possible. Currently there are two major reviews of network pricing (Transmission and Distribution Pricing Review, see ACCC website at www.accc.gov.au) and locational pricing arrangements (Review of the Scope for Integrating the Energy Market and Network Services, see NECA website at www.neca.com.au), which could contribute to significantly improving pricing signals and the efficiency of investment in the NEM.

Priority should be given to a rapid introduction of full retail contestability in all NEM participant states. Full contestability has been already introduced in a number of countries including Finland, Germany, Norway, Sweden, the United Kingdom and parts of the United States. The international experience shows that the basic arrangements needed to introduce full retail contestability such as metering and billing codes, can be developed and implemented quickly and straightforwardly.

An additional issue is how to ensure that the right to choose supplier can be effectively exercised by small end-users. Experience in some IEA countries indicates that choice is severely limited when small end-users are obliged to install expensive meters in order to switch supplier. There are alternatives such as load profiling that should be considered. Load profiling has been criticised for not providing adequate incentives for demand management. However, most existing tariffs for residential end-users also apply load profiling. Thus, load profiling does not provide perfect signals, but it is no worse than the tariffs currently in use. It can provide a relatively cost-effective means of allowing customer choice and capturing some competition benefits in the form of more competitive average energy prices, lower retail costs and improved retail service.

Meanwhile tariffs will continue to play an important role. Tariff regulations will still be needed because the development of effective retail competition for small end-users will only occur gradually. Distribution and retail tariffs are set by the regulatory bodies of the states. There is large variation in tariff levels and tariff changes over time reflecting both differences in costs and differences in policy across the states. A review of tariffs for distribution and captive end-users, and a clear benchmarking of these tariffs across Australian states would help to assess the scope for improvements in tariff structures and levels. Continued monitoring of the price of energy set in the vesting contracts by the franchised retail suppliers is also important to ensure that tariffs are not inflated and to prevent cross-subsidisation of eligible consumers.

Regulatory processes could be streamlined. Regulation of the NEM is generally perceived by industry participants to be complex, particularly because of the existence of several regulatory bodies operating at the Commonwealth and state levels. Co-ordinating decisions and reaching agreement on system reforms are more difficult when many regulatory bodies are involved. Complying with the regulations set by various regulators imposes a cost on market participants. The skills and resources needed to manage regulation are dispersed across agencies.

A significant part of this regulatory complexity is difficult to avoid, particularly in a federal system. The institutional setting is also complex in other federal countries and there is a worldwide trend towards establishing regulatory agencies in the electricity sector. In the Australian case, some economy of resources has been attained by creating multi-sectoral agencies that pool the resources and skills needed to administer regulation and competition law.

The need for a co-ordinated, or "whole-of-government", approach to regulation is recognised by all parties involved. Strengthening co-ordination mechanisms among regulatory bodies, limiting their expansion and reviewing the possibilities for integration of agencies would help to reduce the complexity of regulation. As the market becomes more effectively integrated, greater integration of regulatory policies across the states will be needed. Issues such as reliability and grid expansion, for instance, will need to be increasingly addressed from a NEM-wide perspective.

Finalising and implementing plans to improve transmission pricing would clearly improve the performance of NEM. Action has been taken to review and improve other areas of regulation. Introducing a more cost-reflective pricing system would improve the performance of NEM. A more cost-reflective pricing of transmission would provide better locational signals to investors, eliminate barriers to the development of distributed (or "embedded") generation, improve dispatch decisions and eliminate cross-subsidies between consumer groups.

Reforming network pricing is difficult because of concerns about the impact that cost-reflective pricing would have on prices. Some market players, particularly generators connected to the transmission network and some end-users, would have to pay more for transmission services. However, these higher costs to some transmission users would be compensated by savings of equal size accruing to other users. In addition, there would be a net gain as a result of more efficient dispatch and investment decisions. Despite difficulties, a draft decision on transmission pricing was issued by the ACCC in December 2000 and a final decision is expected in 2001.

Competition in the wholesale market should be monitored. Despite the deep restructuring in the electricity supply industry to reduce market power, competitive behaviour in the NEM needs close monitoring. Market players still have significant market power and, therefore, the ability to raise prices. In particular, market power is an issue when interconnection capacity is limited owing to high demand or other circumstances.

The cap on wholesale energy prices provides a safeguard against anti-competitive generator behaviour. However, in order to improve price signals to investors and other market players, there are plans to increase the cap to a level of at least A$ 10,000/MWh, doubling its current value. While there is a sound rationale for increasing the cap, the protection against price increases that the cap provides is going to be significantly reduced and episodes of high prices may become more common than in the past.

A definitive solution to the issues raised by market power requires further improvement of the competitive structure through new entry and reinforced interconnections. However, structural changes take place slowly. As an interim solution, close monitoring of competitive behaviour and strict enforcement of competition law can help prevent the exercise of market power.

Organisation of the wholesale market should be reviewed in the light of international experience. The trading arrangements in the wholesale market, while providing a workable foundation for electricity trade, could be improved. There is general agreement on the need to increase demand-side participation in the NEM as a means to reduce price spikes and to improve market performance generally. This is a challenge for virtually all electricity markets across the world.

The case for mandatory participation in the pool should be reconsidered in the light of international experience. Virtually all electricity markets in OECD countries today operate on the basis of voluntary participation. Mandatory pools are deemed to be more volatile and more subject to manipulation by generators than voluntary pools. Implementing a voluntary pool is complex, however, under current circumstances because it would require addressing a number of additional issues, including the potential for "self-dealing" between the previously vertically integrated generation and distribution companies, and the scheduling mechanism, which would have to be modified to accommodate bilateral trade. Some problematic features in pool design that have tended to mar spot market performance elsewhere have been avoided in Australia. However, there seems to be a growing consensus that well-designed voluntary power pools perform at least as well as mandatory pools and offer greater freedom of choice.

RECOMMENDATIONS

The government should:

- ☐ Consider measures to promote investment in interconnectors taking into account the potentially large benefits of reinforced interconnections for reliability and competition.

- ☐ Invite the states to consider the added value that privatisation might bring about and, for as long as the industry remains in public ownership, set measures to promote competitive neutrality with a special emphasis on ensuring that publicly-owned companies operate and compete under the same terms and conditions as the private companies.

- ☐ Ensure that small end-users share the benefits of reform. To this end, encourage the states to:
  - Introduce full retail contestability promptly;
  - Review tariffs for distribution and domestic end-users, and establish a clear benchmarking of these tariffs across Australian states;
  - Ensure that the right to choose supplier can be effectively exercised by small end-users.

- ☐ Review policies concerning investment in transmission and generation and market design, including greater demand-side participation, to ensure security of supply.

- ☐ Monitor reliability and, if needed, consider measures to promote investment in additional capacity.
- ☐ Identify options to streamline and simplify regulatory processes and to improve co-ordination among regulatory bodies.
- ☐ Encourage the states and the relevant institutions to finalise plans for the reform of transmission pricing and to implement them.
- ☐ Review trading arrangements in the wholesale electricity market, especially the need for a mandatory pool, in the light of international experience.

9

TECHNOLOGY RESEARCH AND DEVELOPMENT

OVERVIEW

Objectives

Australia's overall policy objectives relating to energy research, development and demonstration are to improve basic research levels; increase the levels of research and development (R&D) carried out by business; and stimulate the overall levels of commercialisation of energy products and services.

These energy R&D policy objectives are derived from the government's overall energy, industrial and environmental policy objectives. A competitive Australian industry, through a strengthened system of science and innovation, should bring economic, social and environmental benefits. Energy R&D in Australia aims to maximise the national benefits of research and innovation, encourage businesses to utilise technology and knowledge created from R&D, increase investment in Australia and expand market access for Australian business in a sustainable fashion. The government sees an increasingly important role for science and technology in Australia's future.

Institutions

One of the most important features of the Australian government's research and development policy is that there is no institutional delineation of energy research versus general, industrial research. Energy research is carried out on a programme basis but is not administered by any specialised policy or funding bodies. The activities of the Energy Research and Development Corporation (EDRC) that had been established under the umbrella of the predecessor to the Department of Industry, Science and Resources in 1990 to provide direct government funding for energy R&D projects were discontinued in 1998. For this reason, energy R&D is shaped and influenced by general policy initiatives directed at industrial research.

The main political body responsible for advising the government on innovation policy is the Prime Minister's Science, Engineering and Innovation Council (PMSEIC). The PMSEIC was announced by the prime minister in December 1997. It replaces the Australian Science, Technology and Engineering Council (ASTEC) that had carried out similar functions and was ended by act of Parliament in June 1998. The council is the government's principal source of independent advice on issues in science, engineering and innovation and relevant aspects of education and training. It meets twice a year to discuss these major national issues and their contribution to the economic and social development of Australia. The council has resources to examine Australia's science and engineering capabilities and the effectiveness of their organisation and utilisation. It is supported by a secretariat located in the Department of Industry, Science and Resources.

The Commonwealth government held a National Innovation Summit in February 2000 to draw upon the contributions stakeholders can make. The summit aimed to collect stakeholders' recommendations and distil them into an action plan. An effort will be made in the energy sector to develop a more streamlined process for public funding, direct strategic investment, to increase the levels of energy innovation and to encourage entrepreneurial behaviour within business.

In addition, stakeholders have a number of special mechanisms to comment on, and play an active part in government policy: ministerial councils, industry associations, action agenda working groups. Stakeholders are also represented on a number of government funding boards such as the Industry Research and Development (IR&D) board and the boards of the Co-operative Research Centres (CRCs).

Funding Mechanisms

Both the Commonwealth government's major climate change policy packages, the 1997 "Safeguarding the Future" package and the 1999 "Measures for a Better Environment" programme, included subsidies, grants and other support measures for renewables, including vehicle conversion subsidies, grants for photovoltaic applications in households, green power investment, remote power generation and greenhouse gas abatement programmes. A number of these measures are in turn related to energy R&D, particularly to renewables R&D, and address both the supply and demand sides of energy use.

The Commonwealth government also has a number of programmes which provide direct or indirect funding for research, development, demonstration and commercialisation, including energy-related R&D. These encompass:

- **The R&D Tax Concession**. The R&D tax concession encourages Australian industry to undertake more R&D by allowing industries to deduct up to 175 per cent of qualifying expenditure incurred on R&D activities when filing their corporate tax return. The concession is the Commonwealth government's principal incentive to enhance and increase the amount of R&D in Australia. There were 3,200 registrations for the concession, amounting to about A$ 4.3 billion on R&D.

- **R&D Start**. This is a programme that provides for a number of different options for businesses to assist them in their R&D efforts. It contains five sub-programmes (Core Start, Start Plus, Start Premium, Start Graduate and Concessional Loans), under which support between 20 and 50 per cent of R&D project cost is made available.

In addition, there are numerous other programmes, including the Technology Diffusion Programme, or the Innovation Investment Fund. The most important R&D structures are:

- **The Commonwealth Scientific and Industrial Research Organisation (CSIRO)**. CSIRO had funding of about A$ 125 million for 1999/2000 for its minerals and energy programme, with coal and energy accounting for about 25 per cent of this budget. The main areas relating to energy are: coal exploration and mining, environmental impacts of mining, coal preparation and handling, clean utilisation technologies, fuel cells, gas utilisation, energy storage and renewables.

- **Co-operative Research Centres (CRCs)**. CRCs operate through formal long-term collaborative arrangements. There are currently five specific energy CRCs: mining technology and equipment, petroleum, clean power from lignite, hard coal utilisation, and renewable energy. Total programme funding for all five programmes was A$ 11 million in 1999/2000.

- **Australian Nuclear Science and Technology Organisation (ANSTO)**. ANSTO has five core scientific areas, including operation and development of nuclear facilities, providing quality advice on nuclear fuel cycles, treatment and management of radioactive substances, and development of a competitive and sustainable nuclear science and technology industry.

Apart from these domestic initiatives, Australia participates in international research co-operation. This includes co-operation in 17 IEA Implementing Agreements and in the Energy Working Group of the Asia-Pacific Economic Co-operation (APEC).

Areas of Energy Research

Energy Efficiency and Alternative Fuels

The work of the Energy Efficiency Team at the Australian Greenhouse Office includes R&D efforts, and many of Australia's energy efficiency and renewables programmes that are described in Chapter 4 have an R&D component. One example is the Energy Efficiency Best Practice Programme. The programme aims at stimulating "big-step" improvements in energy efficiency, which requires innovation. This part of the programme involves identifying a key energy-using process and gathering expertise from government, industry, research bodies and academia. This expertise enables participating companies to use existing R&D and innovation not currently utilised within the sector, and helps them to achieve major energy savings. This approach is currently being tried in the beverage, beverage packaging and aluminium sectors. The uptake of cost-effective technologies and practices across sectors is supported. Close co-operation exists with other agencies, particularly the Greenhouse Challenge programme of the Australian Greenhouse Office. Programme funding of around A$ 7 million is available over the three years from 2000/01 to 2002/03.

The AGO runs a number of programmes devoted to sustainable transport, including the Compressed Natural Gas Infrastructure programme, the Alternative Fuel Conversion programme and the Alternative Fuel grant scheme. The Alternative Fuel Conversion Programme (AFCP) has funds of A$ 150,000 that can be used to support road fuels and technologies not based on CNG and LPG. The programme now also includes funding of two ethanol-powered buses. The government supports the production of ethanol with A$ 3 million through the AGO.

Oil and Gas

One of CSIRO's major energy programmes seeks to provide R&D for the gas utilisation industry. Within this programme, CSIRO has researched gas conversion technologies, storage of natural gas, environmental impacts from cogeneration and methane reforming for thermochemical solar energy storage. Currently, CSIRO is focusing on catalytic systems directed at gas and liquid processes, with emphasis on cleaner chemical and energy production strategies.

The Australian Petroleum CRC had a budget of A$ 3 million in 1999/2000. The main areas of research include improved oil recovery, improved surface seismic imaging, and geological disposal (CO_2 sequestration).

Coal

A number of R&D Start grants were awarded in 1999/2000 to projects relating to coal. These encompassed coal gasification technology and mining exploration technology projects.

There are three Co-operative Research Centres responsible for coal: the CRC for Mining Technology and Equipment, the CRC for Clean Power from Lignite, and the CRC for Black Coal Utilisation. The programme funding for the CRC for Black Coal Utilisation was A$ 1.8 million in 1999/2000. The CRC for Mining Technology and Equipment delivers safety and productivity technologies to the Australian mining industry. The four research programmes are mining (drilling, cutting and loading rock), geological sensing, automation, and reliability and maintenance. The programme budget for 1999/2000 was A$ 2.6 million. The CRC for Clean Power from Lignite undertakes research to develop power generation technologies that are efficient and cost-competitive, to secure Australia's competitive advantage in low-cost energy and decrease greenhouse gas emissions from power generation. Programme funding for 1999/2000 was A$ 2 million.

The CSIRO has four research streams devoted to coal R&D: coal exploration and mining, environmental impacts of mining, coal preparation and handling, and clean utilisation technologies. The coal exploration and mining programme focuses on technology for effective design and efficient and safe operation of open cut and underground mines. The current research focuses on geological and geo-technical assessment of reserves, mine design and mining technologies, coal seam gas (prediction and extraction), mining equipment, coal mining safety technology and management, and coal fragmentation.

Australian hard coal producers contribute to a research programme that is conducted in a commercial organisation named Australian Coal Association Research Programme (ACARP). Coal producers are committed to providing 5 cents per tonne of coal produced to ACARP until June 2005. ACARP's objective is to research, develop and demonstrate technologies that lead to the safe, sustainable production and utilisation of coal. In 1999, ACARP committed A$ 9.8 million to selected projects relating to underground and open cut mining, coal preparation and utilisation, and greenhouse gas mitigation projects.

HRL Limited, another commercial company, produces clean coal technology for power generation. It developed a specific technology called Integrated Drying Gasifier Combined Cycle Technology (IDGCC). A 10 MW Coal Gasification Development Facility (CGDF) has been built at Morwell in Victoria to test and investigate laboratory developments on a larger scale, and to use the information to scale processes up to a full-size plant. The technology provides for 20-30 per cent increases in efficiency (with decreased CO_2 emissions), lower coal consumption per MWh of electricity generated, lower water use and less waste.

Renewable Energy

The Australian CRC for renewable energy focuses on four programmes: power generation, energy efficiency, energy storage and power conditioning. The budget for the centre was A$ 1.6 million in 1999/2000.

CSIRO has one programme relating to renewable energy called Energy Storage and Renewables. The aim of this programme is to develop sustainable technologies to decrease reliance on fossil fuels. The current research focuses on energy storage (e.g. solar-fossil fuel hybrid system), integrated thermochemical advanced generation technology (i.e. distributed energy supply with minimal CO_2 production), utilisation of biomass for energy production and wind energy.

A number of the programmes announced in the framework of the 1997 Safeguarding the Future package have an R&D component. This comprises the Renewable Energy Equity Fund (REEF), the Renewable Energy Commercialisation Programme (RECP), and the Renewable Energy Action Agenda (REAA), which are described in Chapter 4.

CRITIQUE

Energy-related R&D is carried out by a large number of organisations in Australia, much of it at federal level but also among states. There are organisations that do research across the board, such as the CSIRO, ranging from medical science and agriculture to energy, as well as others that specialise in one area or industry, e.g. coal. There is significant involvement of the private sector in government-sponsored or co-funded R&D. The sheer diversity of institutions and programmes raises questions as to how the government-influenced part of this research is co-ordinated.

The focal areas of Australian energy R&D appear to be well aligned with the country's overall economic and energy policy objectives. For example, since coal is one of Australia's major industries and contributes significantly to the country's comparative cost advantage in the international market, but also has significant environmental impacts, coal research should be a major focus of Australian RD&D. The discussion in the preceding section shows that coal is indeed a major focus, although there might be scope to strengthen the clean coal technology element.

The government does not have a special, centralised energy research organisation in place. Energy research thus competes against the demands of other research areas. The one energy-specific institution that had been established, the ERDC, was dismantled in 1998 after eight years of operation and not replaced by any similar organisation. Funding of energy R&D projects occurs very much on the basis of individual programmes.

However, the government has conducted a relatively large number of investigations into the administration of its R&D activities, and it seems that there are almost constant efforts to improve the allocation of funds and refine the decision-making criteria. Increasingly, the emphasis is towards building competitive elements into funding processes. Simultaneously, wide consultation is sought to bring research funding in line with the needs of future "clients", especially industry, as well as "suppliers", including the government but also private businesses. The recent National Innovation Summit and the process surrounding it provide a clear example of these highly positive trends.

In preparation for the summit, a report was prepared on the capability of Australia's science and research sector to further Australia's policy goals – economic competitiveness combined with environmental sustainability – and to accomplish the transition away from a resource-based and towards a knowledge-based economy. The following draws on the findings and recommendations of this report by the Chief Scientist[46].

The report finds that as a result of Australia's enormous endowments of minerals and agricultural land, and the traditional reliance on economic exploitation of these resources, the national system of innovation is fragile. It has few large innovative manufacturing firms and a high degree of dependence on R&D-intensive industry by overseas firms.

Australia's national innovation system continues to be characterised by a comparative paucity of private investment and its export profile is still heavily dependent on traditional commodities. International comparisons of market-to-book ratios demonstrate that Australian companies are increasing their intangible value very slowly, and from a low base, in comparison to other nations where governments have focused on new industry development.

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46. Commonwealth of Australia: *The Chance to Change*, Final Report by the Chief Scientist, Canberra, 2000.

According to the report, the government has primary responsibility for fostering the transition towards a knowledge-based economy. The government has taken a number of measures to address some of the shortcomings in the national innovation system. For example, a lack of venture capital and related financial and management skills had impeded the creation of new businesses. Measures such as the Innovation Investment Fund and recent changes in the capital gains tax are on the way to promoting a more vibrant and well-resourced venture capital industry in Australia.

However, much of Australia's relatively high ranking in international comparisons of public R&D spending is accounted for by high levels of public support for agriculture R&D. This sector, which accounts for only 3 per cent of GDP, attracts 18 per cent of public R&D expenditure, much more than in any other OECD country. This implies that Australian public sector R&D expenditure is lower in engineering, information technologies and physical and applied sciences than in most other developed countries. A compounding factor is that public sector R&D expenditure in Australia has fallen from 0.83 per cent of GDP in 1996/97 to a projected 0.74 per cent in 2000/01. Energy R&D spending has fallen at even steeper rates.

In a comparison with Canada and Finland, two countries that also have traditionally had a comparative advantage in energy-intensive primary production, the report finds that Australia is beginning to approach Canada's degree of knowledge-based exports, but that it is far from matching Finland's. Australia's high-tech exports as a share of merchandise exports grew from a low base by over 2 per cent between 1990 and 1995 to reach 6 per cent; this growth dipped in 1995/96. Canada's high-tech exports have fluctuated around 8 per cent of merchandise exports. Finland, on the other hand, experienced spectacular growth from 6 per cent in 1991 to about 15 per cent in 1996.

The report issues a number of recommendations, the two most important of which are that

- Any additional research funding should be closely linked to measurable performance indicators, and that

- A Science Capability Implementation Group be established as a working group of PMSEIC to implement those detailed recommendations of the report that are endorsed by the government.

The recommendations of this report appear very valid and relevant to energy policy in two different ways. First, since energy R&D is not institutionally separated from other R&D in Australia, the recommendations apply directly to energy R&D. Second, they contain key messages relevant to the future development of the Australian economy that have a bearing on future long-term greenhouse gas emissions, an area central to energy R&D and energy policy today. The recommendations should be endorsed and implemented by the government.

RECOMMENDATIONS

The government should:

- ☐ Implement the key recommendations of the Chief Scientist's report.
- ☐ Expand R&D collaboration with major centres of energy and power research, focusing on priority areas of modern power technology.
- ☐ Implement or participate in RD&D programmes on coal production, transportation, utilisation and carbon sequestration. Collaborate with major vendors to bring coal-gasification technology into the global market-place.
- ☐ Support public-private partnerships to integrate information technology into electricity and gas networks.
- ☐ Place greater emphasis on measures to reduce emissions from burning coal (e.g. clean coal technologies).

A

ANNEX

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	1998	1999	2005	2010	2020
TOTAL PRODUCTION		**68.0**	**157.7**	**213.8**	**212.2**	**248.6**	**280.4**	**..**
Coal[1]		40.3	106.3	149.3	153.3	169.6	185.4	..
Oil		19.8	29.0	31.1	25.1	30.4	29.4	..
Gas		3.4	17.1	26.6	27.1	41.4	58.0	..
Comb. Renewables & Wastes[2]		3.5	4.0	5.3	5.3	5.5	5.8	..
Nuclear		–	–	–	–	–	–	..
Hydro		1.0	1.2	1.4	1.4	1.5	1.5	..
Geothermal		–	..	..	..	–	–	..
Solar/Wind/Other[3]		–	0.1	0.1	0.1	0.1	0.2	..
TOTAL NET IMPORTS[4]		**–10.3**	**–65.7**	**–108.9**	**–108.3**	**–129.0**	**–152.6**	**..**
Coal[1]	Exports	17.6	67.7	104.7	109.5	125.4	141.1	..
	Imports	–	–	–	–	–	–	..
	Net Imports	–17.6	–67.7	–104.7	–109.5	–125.4	–141.1	..
Oil	Exports	3.4	9.3	18.4	17.2	22.2	24.4	..
	Imports	12.5	14.2	23.7	28.0	32.9	38.9	..
	Bunkers	1.8	0.6	0.7	0.8	0.9	0.9	..
	Net Imports	7.4	4.3	4.6	10.1	9.8	13.6	..
Gas	Exports	–	2.3	8.9	8.9	13.4	25.1	..
	Imports	–	–	–	–	–	–	..
	Net Imports	–	–2.3	–8.9	–8.9	–13.4	–25.1	..
Electricity	Exports	–	–	–	–	–	–	..
	Imports	–	–	–	–	–	–	..
	Net Imports	–	–	–	–	–	–	..
TOTAL STOCK CHANGES		**–0.1**	**–4.5**	**–0.5**	**4.0**	**–**	**–**	**..**
TOTAL SUPPLY (TPES)		**57.6**	**87.5**	**104.4**	**107.9**	**119.6**	**127.7**	**..**
Coal[1]		22.6	35.0	44.8	47.4	44.3	44.3	..
Oil		27.1	32.5	35.1	35.6	40.2	43.0	..
Gas		3.4	14.8	17.7	18.2	27.9	32.9	..
Comb. Renewables & Wastes[2]		3.5	4.0	5.3	5.3	5.5	5.8	..
Nuclear		–	–	–	–	–	–	..
Hydro		1.0	1.2	1.4	1.4	1.5	1.5	..
Geothermal		–	..	..	..	–	–	..
Solar/Wind/Other[3]		–	0.1	0.1	0.1	0.1	0.2	..
Electricity Trade[5]		–	–	–	–	–	–	..
Shares (%)								
Coal		*39.2*	*39.9*	*42.9*	*43.9*	*37.0*	*34.7*	..
Oil		*47.1*	*37.2*	*33.6*	*33.0*	*33.6*	*33.7*	..
Gas		*5.9*	*16.9*	*17.0*	*16.9*	*23.4*	*25.8*	..
Comb. Renewables & Wastes		*6.1*	*4.5*	*5.1*	*4.9*	*4.6*	*4.6*	..
Nuclear		–	–	–	–	–	–	..
Hydro		*1.7*	*1.4*	*1.3*	*1.3*	*1.3*	*1.2*	..
Geothermal		–	..	..	..	–	–	..
Solar/Wind/Other		–	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	..
Electricity Trade		–	–	–	–	–	–	..

0 is negligible, – is nil, .. is not available.

Please note: All data except GDP and population refer to the fiscal year July to June. All forecast data are based on the 1999 submission.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	1998	1999	2005	2010	2020
TFC	**40.0**	**58.1**	**69.0**	**69.9**	**78.4**	**84.5**	**..**
Coal [1]	4.9	4.3	4.3	4.2	3.7	3.7	..
Oil	24.7	30.5	35.6	36.0	37.2	40.0	..
Gas	2.4	8.8	10.7	10.8	16.1	18.1	..
Comb. Renewables & Wastes [2]	3.5	3.3	4.3	4.3	5.0	5.2	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.1	0.1	0.1	0.1	0.2	..
Electricity	4.5	11.1	14.0	14.5	16.3	17.4	..
Heat	–	–	–	–	–	–	..
Shares (%)							
Coal	*12.3*	*7.4*	*6.3*	*6.1*	*4.7*	*4.4*	..
Oil	*61.7*	*52.6*	*51.5*	*51.5*	*47.5*	*47.3*	..
Gas	*5.9*	*15.2*	*15.5*	*15.5*	*20.5*	*21.4*	..
Comb. Renewables & Wastes	*8.7*	*5.6*	*6.2*	*6.1*	*6.4*	*6.1*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	..
Electricity	*11.3*	*19.1*	*20.3*	*20.7*	*20.7*	*20.6*	..
Heat	–	–	–	–	–	–	..
TOTAL INDUSTRY [6]	**17.6**	**23.1**	**27.0**	**27.2**	**31.8**	**34.1**	**..**
Coal [1]	4.6	4.1	4.2	4.1	3.5	3.6	..
Oil	7.7	6.3	7.2	7.2	5.8	6.1	..
Gas	1.8	6.1	6.9	7.0	11.8	13.1	..
Comb. Renewables & Wastes [2]	1.5	1.5	2.4	2.4	3.3	3.5	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	2.0	5.1	6.3	6.5	7.4	7.8	..
Heat	–	–	–	–	–	–	..
Shares (%)							
Coal	*26.4*	*17.6*	*15.5*	*15.1*	*11.0*	*10.4*	..
Oil	*43.8*	*27.4*	*26.6*	*26.4*	*18.3*	*18.0*	..
Gas	*10.0*	*26.5*	*25.7*	*25.8*	*37.2*	*38.4*	..
Comb. Renewables & Wastes	*8.5*	*6.4*	*8.9*	*8.8*	*10.3*	*10.3*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*11.3*	*22.0*	*23.3*	*23.9*	*23.3*	*22.9*	..
Heat	–	–	–	–	–	–	..
TRANSPORT [7]	**13.5**	**22.7**	**27.0**	**27.4**	**29.8**	**32.3**	**..**
TOTAL OTHER SECTORS [8]	**8.9**	**12.3**	**15.1**	**15.3**	**16.9**	**18.1**	**..**
Coal [1]	0.3	0.1	0.1	0.0	0.1	0.1	..
Oil	3.5	1.8	2.0	2.0	2.2	2.3	..
Gas	0.6	2.7	3.6	3.6	4.1	4.6	..
Comb. Renewables & Wastes [2]	2.0	1.8	1.9	1.9	1.7	1.7	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.1	0.1	0.1	0.1	0.2	..
Electricity	2.5	5.9	7.6	7.8	8.6	9.3	..
Heat	–	–	–	–	–	–	..
Shares (%)							
Coal	*3.2*	*1.1*	*0.4*	*0.3*	*0.4*	*0.4*	..
Oil	*39.7*	*14.2*	*13.1*	*13.0*	*13.0*	*12.9*	..
Gas	*7.0*	*21.8*	*23.6*	*23.2*	*24.4*	*25.2*	..
Comb. Renewables & Wastes	*22.5*	*14.4*	*12.4*	*12.1*	*10.3*	*9.1*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*0.7*	*0.6*	*0.6*	*0.8*	*1.0*	..
Electricity	*27.7*	*47.7*	*50.0*	*50.8*	*51.0*	*51.3*	..
Heat	–	–	–	–	–	–	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	1998	1999	2005	2010	2020
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**16.0**	**35.1**	**45.1**	**47.3**	**48.1**	**49.9**	**..**
OUTPUT (Mtoe)	**5.5**	**13.3**	**16.8**	**17.5**	**19.1**	**20.3**	**..**
(TWh gross)	64.4	154.3	195.6	203.0	221.6	236.1	..
Output Shares (%)							
Coal	*74.9*	*77.1*	*79.5*	*78.1*	*73.1*	*70.5*	..
Oil	*2.6*	*2.7*	*1.4*	*1.3*	*0.8*	*0.7*	..
Gas	*4.3*	*10.6*	*8.9*	*10.6*	*17.1*	*20.0*	..
Comb. Renewables & Wastes	*0.5*	*0.4*	*2.1*	*1.8*	*1.0*	*1.3*	..
Nuclear	–	–	–	–	–	–	..
Hydro	*17.7*	*9.2*	*8.1*	*8.2*	*7.9*	*7.5*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	*0.0*	*0.0*	..	..	..
TOTAL LOSSES	**17.8**	**29.3**	**38.8**	**40.2**	**41.1**	**43.3**	**..**
of which:							
Electricity and Heat Generation[10]	10.5	21.7	28.2	29.8	29.5	29.6	..
Other Transformation	5.5	0.6	1.8	1.5	2.7	2.7	..
Own Use and Losses[11]	1.7	7.0	8.8	8.9	9.0	11.0	..
Statistical Differences	**–0.1**	**0.2**	**–3.5**	**–2.2**	**–**	**–**	**..**

INDICATORS

	1973	1990	1998	1999	2005	2010	2020
GDP (billion 1995 US$)	193.56	318.14	427.92	446.61	549.00	642.64	..
Population (millions)	13.51	17.09	18.73	18.97	20.36	21.49	..
TPES/GDP[12]	0.30	0.28	0.24	0.24	0.22	0.20	..
Energy Production/TPES	1.18	1.80	2.05	1.97	2.08	2.20	..
Per Capita TPES[13]	4.27	5.12	5.57	5.69	5.87	5.94	..
Oil Supply/GDP[12]	0.14	0.10	0.08	0.08	0.07	0.07	..
TFC/GDP[12]	0.21	0.18	0.16	0.16	0.14	0.13	..
Per Capita TFC[13]	2.96	3.40	3.69	3.68	3.85	3.93	..
Energy–related CO_2 Emissions (Mt CO_2)[14]	173.9	259.8	308.6	321.6	344.6	364.1	..
CO_2 Emissions from Bunkers (Mt CO_2)	7.3	6.3	9.3	9.7	9.9	10.1	..

GROWTH RATES (% per year)

	73–79	79–90	90–98	98–99	99–05	05–10	10–20
TPES	3.0	2.2	2.2	3.4	1.7	1.3	..
Coal	1.5	3.2	3.1	5.8	–1.1	0.0	..
Oil	2.9	0.1	1.0	1.3	2.1	1.4	..
Gas	12.7	7.1	2.3	2.8	7.4	3.3	..
Comb. Renewables & Wastes	0.1	1.0	3.8	–1.1	0.8	1.0	..
Nuclear	–	–	–	–	–	–	..
Hydro	5.1	–0.7	1.4	5.6	0.8	0.2	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	17.3	1.5	5.5	6.1	5.5	..
TFC	2.5	2.1	2.2	1.2	1.9	1.5	..
Electricity Consumption	6.3	5.0	3.0	3.3	1.9	1.3	..
Energy Production	3.9	5.7	3.9	–0.7	2.7	2.4	..
Net Oil Imports	4.2	–6.9	0.8	120.4	–0.5	6.8	..
GDP	2.7	3.1	3.8	4.4	3.5	3.2	..
Growth in the TPES/GDP Ratio	0.3	–0.8	–1.5	–0.9	–1.7	–1.8	..
Growth in the TFC/GDP Ratio	–0.2	–1.0	–1.5	–3.0	–1.5	–1.7	..

Please note: Rounding may cause totals to differ from the sum of the elements.

Footnotes to Energy Balances and Key Statistical Data

1. Includes lignite and peat, except for Finland, Ireland and Sweden. In these three cases, peat is shown separately.
2. Comprises solid biomass and animal products, gas/liquids from biomass, industrial waste and municipal waste. Data are often based on partial surveys and may not be comparable between countries.
3. Other includes tide, wave and ambient heat used in heat pumps.
4. Total net imports include combustible renewables and waste.
5. Total supply of electricity represents net trade. A negative number indicates that exports are greater than imports.
6. Includes non-energy use.
7. Includes less than 1% non-oil fuels.
8. Includes residential, commercial, public service and agricultural sectors.
9. Inputs to electricity generation include inputs to electricity, CHP and heat plants. Output refers only to electricity generation.
10. Losses arising in the production of electricity and heat at public utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of 33% for nuclear, 10% for geothermal and 100% for hydro.
11. Data on "losses" for forecast years often include large statistical differences covering differences between expected supply and demand and mostly do not reflect real expectations on transformation gains and losses.
12. Toe per thousand US dollars at 1990 prices and exchange rates.
13. Toe per person.
14. "Energy-related CO_2 emissions" specifically means CO_2 from the combustion of the fossil fuel components of TPES (i.e. coal and coal products, peat, crude oil and derived products and natural gas), while CO_2 emissions from the remaining components of TPES (i.e. electricity from hydro, other renewables and nuclear) are zero. Emissions from the combustion of biomass-derived fuels are not included, in accordance with the IPCC greenhouse gas inventory methodology. TPES, by definition, excludes international marine bunkers. INC-IX decided in February 1994 that emissions from international marine and aviation bunkers should not be included in national totals but should be reported separately, as far as possible. CO_2 emissions from bunkers are those quantities of fuels delivered for international *marine* bunkers and the emissions arising from their use. Data for deliveries of fuel to international *aviation* bunkers are not generally available to the IEA and, as a result, these emissions have not been deducted from the national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 1999 and applying this factor to forecast energy supply. Future coal emissions are based on product-specific supply projections and are calculated using the IPCC/OECD emission factors and methodology.

B

ANNEX

INTERNATIONAL ENERGY AGENCY "SHARED GOALS"

The Member countries* of the International Energy Agency (IEA) seek to create the conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and the well-being of their people and of the environment. In formulating energy policies, the establishment of free and open markets is a fundamental point of departure, though energy security and environmental protection need to be given particular emphasis by governments. IEA countries recognise the significance of increasing global interdependence in energy. They therefore seek to promote the effective operation of international energy markets and encourage dialogue with all participants.

In order to secure their objectives they therefore aim to create a policy framework consistent with the following goals:

1 **Diversity, efficiency and flexibility within the energy sector** are basic conditions for longer-term energy security: the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable. Non-fossil fuels, particularly nuclear and hydro power, make a substantial contribution to the energy supply diversity of IEA countries as a group.

2 Energy systems should have **the ability to respond promptly and flexibly to energy emergencies.** In some cases this requires collective mechanisms and action: IEA countries co-operate through the Agency in responding jointly to oil supply emergencies.

3 **The environmentally sustainable provision and use of energy** is central to the achievement of these shared goals. Decision-makers should seek to minimise the adverse environmental impacts of energy activities, just as environmental decisions should take account of the energy consequences. Government interventions should where practicable have regard to the Polluter Pays Principle.

4 **More environmentally acceptable energy sources** need to be encouraged and developed. Clean and efficient use of fossil fuels is essential. The development of economic non-fossil sources is also a priority. A number of

* Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

IEA Members wish to retain and improve the nuclear option for the future, at the highest available safety standards, because nuclear energy does not emit carbon dioxide. Renewable sources will also have an increasingly important contribution to make.

5 **Improved energy efficiency** can promote both environmental protection and energy security in a cost-effective manner. There are significant opportunities for greater energy efficiency at all stages of the energy cycle from production to consumption. Strong efforts by governments and all energy users are needed to realise these opportunities.

6 **Continued research, development and market deployment of new and improved energy technologies** make a critical contribution to achieving the objectives outlined above. Energy technology policies should complement broader energy policies. International co-operation in the development and dissemination of energy technologies, including industry participation and co-operation with non-member countries, should be encouraged.

7 **Undistorted energy prices** enable markets to work efficiently. Energy prices should not be held artificially below the costs of supply to promote social or industrial goals. To the extent necessary and practicable, the environmental costs of energy production and use should be reflected in prices.

8 **Free and open trade** and a secure framework for investment contribute to efficient energy markets and energy security. Distortions to energy trade and investment should be avoided.

9 **Co-operation among all energy market participants** helps to improve information and understanding, and encourage the development of efficient, environmentally acceptable and flexible energy systems and markets worldwide. These are needed to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives.

(The Shared Goals were adopted by IEA Ministers at their 4 June 1993 meeting in Paris.)

C

ANNEX

GLOSSARY AND LIST OF ABBREVIATIONS

In this report, abbreviations are substituted for a number of terms used within the International Energy Agency. While these terms generally have been written out on first mention and abbreviated subsequently, this glossary provides a quick and central reference for many of the abbreviations used.

AC	alternating current.
ASEAN	Association of South East Asian Nations.
BP	British Petroleum.
bcm	billion cubic metres.
b/d	barrels per day.
cal	calorie.
CCGT	combined-cycle gas turbine.
CERT	Committee on Energy Research and Technology of the IEA.
CFCs	chlorofluorocarbons.
CHP	combined production of heat and power; sometimes, when referring to industrial CHP, the term "co-generation" is used.
CNG	compressed natural gas.
CO	carbon monoxide.
CO_2	carbon dioxide.
cm	cubic metre.
DC	direct current.
DH	district heating.
DSO	distribution system operator.
EFTA	Europe Free Trade Association: Iceland, Norway, Switzerland and Liechtenstein.
EIA	environmental impact assessment.
ETSO	European Transmission System Operators Group.
EU	The European Union, whose members are Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom.
Euro	European currency (€).
FCCC	Framework Convention on Climate Change.

GDP	gross domestic product.
GNP	gross national product.
GEF	Global Environmental Facility.
GJ	gigajoule, or 1 joule $\times 10^9$.
GW	gigawatt, or 1 watt $\times 10^9$.
GWh	gigawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^9$.
IAEA	International Atomic Energy Agency.
IEA	International Energy Agency whose Members are Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Luxembourg, Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States.
IEP	International Energy Program, one of the founding documents of the IEA.
IGCC	integrated coal gasification combined cycle plant.
IPCC	International Panel on Climate Change.
ISO	independent system operator.
J	joule; a joule is the work done when the point of application of a force of one newton is displaced through a distance of one metre in the direction of the force (a newton is defined as the force needed to accelerate a kilogram by one metre per second). In electrical units, it is the energy dissipated by one watt in a second.
kV	kilo-volt, or one volt $\times 10^3$.
kWh	kilowatt-hour, or one kilowatt $\times$ one hour, or one watt $\times$ one hour $\times 10^3$.
LDC	local distribution companies.
LNG	liquefied natural gas.
LPG	liquefied petroleum gas; refers to propane, butane and their isomers, which are gases at atmospheric pressure and normal temperature.
mcm	million cubic metres.
Mt	million tonnes.
MTBE	methyl tertiary butyl ether, an additive that allows more complete and cleaner petrol combustion; but it can cause water pollution.
Mtoe	million tonnes of oil equivalent; see toe.
MW	megawatt of electricity, or 1 watt $\times 10^6$.
MWh	megawatt-hour = one megawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^6$.

NEA	the Nuclear Energy Agency of the OECD.
negTPA	negotiated third party access.
NO_x	nitrogen oxides.
OECD	Organisation for Economic Co-operation and Development.
PJ	petajoule, or 1 joule $\times 10^{15}$.
PJM	the Pennsylvania-New-Jersey-Maryland electricity supply market in the United States, a competitive market often cited for its efficient operation.
ppm	parts per million.
PPP	purchasing power parity: the rate of currency conversion that equalises the purchasing power of different currencies, i.e. estimates the differences in price levels between different countries.
regTPA	regulated third party access.
R&D	research and development, especially in energy technology; may include the demonstration and dissemination phases as well.
SB	Single Buyer.
SLT	Standing Group on Long-Term Co-operation of the IEA.
SO_2	sulphur dioxide.
TFC	total final consumption of energy; the difference between TPES and TFC consists of net energy losses in the production of electricity and synthetic gas, refinery use and other energy sector uses and losses.
toe	tonne of oil equivalent, defined as 10^7 kcal.
TOP	take-or-pay contract.
TPA	third party access.
TPES	total primary energy supply.
TSO	transmission system operator.
TW	terawatt, or 1 watt $\times 10^{12}$.
TWh	terawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^{12}$.
UGS	underground storage (of natural gas).
UN	the United Nations Organisation.
VAT	Value Added Tax.
VOCs	volatile organic compounds.
WANO	World Association of Nuclear Operators.

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