INTERNATIONAL ENERGY AGENCY

Energy Policies of IEA Countries

Special 30th anniversary Edition

2004 Review

OECD

INTERNATIONAL ENERGY AGENCY
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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-six* 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, the Republic of Korea, 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).

FOREWORD

Reviewing the energy policies of member countries is a central and important activity of the International Energy Agency. Every four years, the policies of individual member countries are reviewed in depth by their peers. In intervening years, brief standard reviews update the main energy policy developments. These regular reviews have contributed substantially over the years to policy-making at the national level and to sharing experience among IEA countries and worldwide. As well as country-specific reviews, a detailed overview of significant energy-related developments across IEA member countries that focuses on certain key themes is also essential for sound policy-making. The purpose of the annual compendium, *Energy Policies of the IEA Countries*, is to provide comprehensive information on these two fronts, namely, country-specific analysis and cross-country analysis on key themes.

The overview focuses on recent developments in the energy market and energy policies. It examines trends in energy markets, including an analysis of energy demand, energy supply, energy prices and energy-related CO_2 emissions. It also highlights key policy trends across member countries looking at energy security, energy market reform, climate change mitigation, energy efficiency, renewable energies and energy research and development. Notable developments in major non-member countries are also presented.

The 2004 edition, which commemorates the 30th anniversary of the IEA, contains two special sections. "The IEA 30 Years On" looks carefully at past trends in energy markets and policy developments in the three decades since the IEA's establishment in 1974 and underlines the new challenges in the next 30 years, taking into account the outcome of the *World Energy Outlook 2004*. The "In-depth Reviews in the Past Four Years – Cross-country Overview" identifies common challenges from the reviews carried out over the past four years, covering all 26 member countries, and serves as a touchstone for future in-depth reviews.

This book contains summaries of the in-depth reviews of Canada, Finland, France, the Netherlands, Portugal and Sweden conducted from October 2003 to June 2004. Shorter standard reviews are also covering seven other member countries: Austria, Denmark, Germany, Greece, Korea, the United Kingdom and the United States. Key statistical information is also included.

Claude Mandil
Executive Director

ACKNOWLEDGEMENTS

Much of the information in this report is drawn from in-depth reviews conducted by representatives of IEA member countries and members of the IEA Secretariat. The information contained in this publication is the best available as of September 2004 and is subject to change. The desk officer listed in each team was responsible for managing the review and was principal author of the report, which has also been published in a separate volume and appears in summary form here. The desk officers also wrote the shorter standard reviews included here.

Jun Arima supervised preparations for this book and wrote the sections of the In-depth Reviews in the Past Four Years (Chapter 3) and Market Trends (Chapter 4). Many members of the IEA staff contributed to this book. Major contributions came from Fatih Birol (The IEA 30 Years On), Antoine Halff, David Fyfe, Lawrence Eagles (oil), John Cameron (coal), Fridtjof Unander (energy indicators), Doug Cooke, Ulrik Strisbaek, Julia Reinaud (electricity), Sylvie Cornot-Gandolphe (gas), Alain Meier (efficiency), Peter Tulej (renewables), Mitsuhide Hoshino, Jacek Podkanski, Giorgio Simblotti (R&D), Jeffrey Logan (China), Dagmar Graczyk (India), Brett Jacobs (South-East Asia), Augusto Ruiz-Abensur (Latin America), Isabel Murray (Russia), Cristof Van Agt (Caspian and Central Asia), Emmanuel Bergasse (Central and South-Eastern Europe), Dunia Chalabi (Middle East and North Africa). Karen Treanton and Ana Belen Padilla prepared key statistics and indicators, Monica Petit prepared the figures and Marilyn Ferris provided administrative assistance for the project.

2003–2004 IN-DEPTH REVIEWS

Canada

Team leader: Bjarne Moe (Norway). *Team members:* Jane Anderson (Australia), Richard Lavergne (France), Sabine Semke (Germany), Peter Wilmer (NEA), Noé van Hulst (IEA), Ralf Dickel (IEA), Pierre Audinet (IEA).

Finland

Although the in-depth review for Finland was conducted in the 2002-2003 review cycle, the timing of its publication meant that the summary and conclusions could not appear in *Energy Policies of IEA Countries – 2003 Review*.

Team leader: Hugo Brouwer (the Netherlands). *Team members:* Christina Oettinger Biberg (Sweden), Takashi Wada (Japan), Timo Aaltonen (EC), Evelyne Bertel (NEA), Peter Fraser (IEA), Jun Arima (IEA), Jonathan Coony (IEA).

France

Team leader: Pieter Boot (the Netherlands). *Team members:* Duncan Millard (United Kingdom), Oliviero Bernardini (Italy), Walter Sandter (Germany), Timo Haapalehto (Finland), Timo Aaltonen (EC), Noé van Hulst (IEA), Martina Bosi (IEA), Jonathan Coony (IEA).

Luxembourg

Although the in-depth review for Luxembourg was conducted in the 2003-2004 review cycle, the timing of its publication meant that the summary of conclusions could not appear in *Energy Polices of IEA Countries – 2004 Review*.

Team leader: Marc Deprez (Belgium). *Team members:* Thomas Levander (Sweden), Helen Donoghue (EC), Jun Arima (IEA), Pierre Audinet (IEA).

Netherlands

Team leader: Pentti Puhakka (Finland). *Team members:* Naoko Fukutome (Japan), Göran Morén (Sweden), Cristobal Burgos-Alonso (EC), Tom Howes (IEA), Jun Arima (IEA), Lea Gynther (IEA).

Portugal

Team leader: Yasuo Tanabe (Japan). *Team members:* Philippe Guillard (France), Vera Pieterman (the Netherlands), Lars Valdresbråten (Norway), Manfred Decker (EC), Jun Arima (IEA), Peter Fraser (IEA), Lea Gynther (IEA).

Sweden

Team leader: José Carvalho Netto (Portugal). *Team members:* André Filion (Canada), Reinhard Fink (Germany), Luis Simo (Spain), Helen Donoghue (EC), Evelyne Bertel (NEA), Doug Cooke (IEA), William Blyth (IEA), Jun Arima (IEA), Jonathan Coony (IEA).

STANDARD REVIEWS

Austria: Jonathan Coony; *Denmark:* Pierre Audinet; *Germany:* Lea Gynther; *Greece:* Lea Gynther; *Korea:* Pierre Audinet; *United Kingdom:* Jonathan Coony; *United States:* Pierre Audinet.

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EXECUTIVE SUMMARY

THE IEA 30 YEARS ON

The International Energy Agency (IEA) was created in 1974 as a response to the threat posed by the first oil crisis and commemorated its 30th anniversary in 2004. While energy markets and the world have changed in many ways since then, energy security remains a fundamental goal of its member countries. However, security considerations have become more broadly defined. IEA's focus has been expanded from oil to other forms of energy, such as natural gas, of which consumption and imports are rapidly increasing, and to electricity, following several serious transmission failures in recent years. Furthermore, reliable access to energy supply needs to be compatible with other policy objectives, namely, the pursuit of greater economic efficiency in the energy sector and the mitigation of environmental consequences of energy production and use.

Recent energy market and geopolitical developments have pushed security of supply back to the top of the energy policy agenda. The events of 11 September 2001 and worsening political instability in the Arab Gulf and elsewhere have heightened the sense of vulnerability to disruptions to energy supplies. Energy installations such as nuclear power stations, gas terminals, gas pipelines, and oil installations have moved to a higher state of alert. Global cross-border energy trade has grown by almost three-quarters since 1973 and will continue to expand between now and 2030. Because of cost, geopolitical and technical factors, almost all the increase in energy production from now on will occur in non-OECD countries. As a result, the reliance of IEA members and non-IEA oil-importing developing countries on imported oil and gas will continue to grow. This will increase mutual economic interdependence, but will also intensify concerns about the world's vulnerability to a price and supply shock. These developments underline the need for IEA member countries and non-member oil- and gas-importing countries to take a more proactive role in dealing with the energy security risks in fossil fuel trade. Measures to deal with short-term supply emergencies or price shocks will need to be enhanced. Countries will also have to diversify their fuels as well as the geographic sources of imported fuels. Indigenous renewable energy sources will contribute to this end. Improving relations with energy suppliers will also be essential for IEA countries' security strategies. The importance of this dialogue was apparent in the effective response by producer countries to the threat of market disruption during the military action in Iraq in 2003. Better data collection and exchange for improving transparency in world markets will remain the key in this dialogue. Similarly, the importance of co-operation with other non-member countries in such fields as emergency preparedness, data exchange and energy policy reform will also grow as their shares in global energy demand and imports rise.

Long-term security of supply will depend on whether the investment needed to expand energy supply capacity will be forthcoming in a timely manner. The 2003 *World Energy Investment Outlook* estimates that more than $16 trillion of investment in maintaining and expanding energy supplies will be needed up to 2030. Mobilising all this investment will require the lowering of regulatory and market barriers, and the creation of an attractive investment climate, including stable and enforceable legal and regulatory systems, is a daunting task in many developing countries and the former Soviet Union. Stamping out corruption is also essential in many countries. Good governance is crucial to extend electricity supplies to the energy-poor and give them better access to other forms of modern energy.

The environmental implications for rising energy use will remain a key issue for IEA countries. Energy-related CO_2 will continue to grow steadily unless tough new policies are adopted to counter this trend. The adoption of new policies in OECD and non-OECD countries, together with faster deployment of more efficient and cleaner technologies, would yield big savings in energy and promote switching to less carbon-intensive fuels. Political will and public acceptability of the economic cost of such policies will determine how far IEA countries go down this path.

New technologies will undoubtedly be a major part of the solution. Governments and the private sector should share the responsibility for RD&D of new energy technologies. While this type of involvement has declined significantly in the past decade in IEA countries, given that the energy industry's overall research efforts are undermined in new market structures, governments need to reappraise the need for renewed public commitment to energy R&D. Sharing costs and gains through international collaboration via such instruments as IEA's Technology Implementing Agreement, is one way of getting better value for the money spent on R&D.

Addressing all of these policy challenges can be encompassed in how to strike the balance between the "3Es", namely, energy security, economic development and environmental protection, in a cost-effective manner. The IEA's mission is to support member countries' efforts to devise policies to this end. The IEA's operational mandate has expanded considerably over the past three decades. The concept of energy security has broadened from oil to natural gas and electricity. This trend will continue in accordance with the changes in political, technological and market framework and the emergence of new policy challenges.

IN-DEPTH REVIEWS IN THE PAST FOUR YEARS: CROSS-COUNTRY OVERVIEW

All the IEA member countries are tackling new energy policy challenges. One of the IEA's core activities is to carry out in-depth country reviews that support its member countries in their efforts to implement better policies. While the critiques and recommendations of these reviews focus on the reviewed countries' specific national circumstances, several common challenges can be extracted from the reviews carried out over the past four years, covering all 26 member countries. For the first time, the Secretariat has tried to identify such elements, which could serve as touchstones for future in-depth reviews. These common challenges include the following:

General Energy Policy

- Developing, monitoring and timely updating of energy supply-demand forecasts.
- Ensuring availability of timely, consistent and high-quality energy data.
- Ensuring close co-ordination among various ministries and central/local government.
- Ensuring good understanding by the general public of the national energy situation and future challenges.

Energy and the Environment

- Analysing cost-effectiveness of policies and measures in tackling climate change through quantifying the contribution of each policy and measure, re-evaluating the current priority of policy mix, streamlining policies and measures addressing the same objective where possible, internalising externalities in energy pricing and taxation and placing more emphasis on market-based instruments.
- Constant monitoring of progress in climate change mitigation policies and taking additional actions, if necessary.

Energy Efficiency

- Clarifying the role of voluntary agreements in relation to emissions trading.
- Stronger measures in transport and residential/commercial sectors.
- Careful designing of new instruments such as white certificates.
- Ensuring cost-effectiveness of policies to promote combined heat and power (CHP).

Renewable Energy

- Ensuring cost-effectiveness of policies to promote renewable energies.
- Streamlining licensing procedures of renewable energy projects.

Energy Market Reform

- Ensuring undistorted, cost-reflective prices for efficient market functioning and sound investments.

- Avoiding subsidising prices for social policy objectives.
- Maximising the benefits of electricity and gas market reform through a strong and independent energy regulator, effective unbundling, non-discriminatory access to facilities, monitoring (and if necessary controlling) market power, expanding market size through regional integration and enhancing demand-side response.

Energy Security

- Ensuring constant compliance with the obligations on oil stocks stipulated in the International Energy Program (IEP).
- Enhancing exploration of domestic oil and gas resources through fiscal and regulatory measures.
- Further diversification of supply sources of oil and gas.
- Defining clear objectives and responsibilities of different players for the security of electricity and gas supply.
- Fostering investment of gas and electricity facilities through creating a more stable regulatory framework, cost-reflective pricing, monitoring investment needs, sending the right signals to investors and streamlining licensing procedures for energy infrastructure.

Nuclear

- Clarifying how to retain the role of nuclear power in a liberalised market, including addressing such issues as improvement of availability and life extension of existing plants, improvement of public acceptance, nuclear safety and radioactive waste disposal.
- Conducting thorough quantitative examination in terms of economy, environment and security of supply when deciding to phase out nuclear.

Research and Development

- Appropriate funding for government R&D.
- Developing coherent energy R&D strategy in line with the national energy policy goals, with clear prioritisation.
- Monitoring performance of government-funded R&D.
- Strong collaboration among various institutions.
- Involving the private sector for technology deployment.
- Promoting multilateral and bilateral international co-operation.

MARKET TRENDS

Energy markets in 2003 and the first half of 2004 can be characterised by significantly higher energy prices. Average crude oil prices for 2003 rose sharply over 2002 levels. For example, the average West Texas Intermediate (WTI) price in 2003 was 19% higher than in 2002. High volatility was seen during the year in the wake of some significant supply disruptions and geopolitical issues around the world, coupled with the rapid improvement in world economic conditions. In 2003, prices for gasoline, diesel and space-heating oil followed price fluctuations of crude oil. As for natural gas, spot prices at Henry Hub peaked in March 2003 and remained high throughout the rest of 2003 and the beginning of 2004. For example, the average Henry Hub spot price in 2003 was 63% higher than in 2002. Steam coal prices, which were on a declining trend in the first half of 2003, started to climb rapidly in the second half of the year mainly owing to freight rates and the impact of exchange rate movement. While the annual import price of steam coal in 2003 was 1.4% above the 2002 level, in the fourth quarter of 2003 it was 16% higher than it had been in the fourth quarter 2002.

The price of oil still matters to the health of the world economy. According to the quantitative exercise carried out by the IEA in collaboration with the OECD and the International Monetary Fund (IMF), a sustained $10 per barrel increase in oil prices from $25 to $35 would result in 0.4 percentage point lower GDP growth in the OECD as a whole in the first and second years of higher prices. The adverse economic impact of higher oil prices on oil-importing developing countries is generally even more severe than for OECD countries. It is estimated that the loss of GDP averages 0.8 percentage point in Asia and 1.6 percentage points in very poor heavily indebted countries in the year following a $10 oil price increase. The loss of GDP in the sub-Saharan African countries would be more than 3 percentage points.

ENERGY SECURITY

During 2003, substantial supply disruptions involving a failure of transmission services struck North America and Europe (Sweden, Denmark, Italy, among others). While large blackouts have happened in the past, the supply disruptions in 2003 created considerable concern among policy-makers, practitioners and the general public about transmission network performance and its implications for the efficient and reliable operation of electricity markets. Growing public sensitivity reflects the increasing dependence of modern economies on reliable and efficient electricity supplies. Investigations were conducted into these events and the IEA launched a project to identify and analyse the key issues affecting the development and performance of transmission network services under competitive electricity markets. In the IEA workshop held in March 2004, common factors affecting the network performance were summarised as the 3Ts, namely, *Tools:* for system operators to monitor and assess a wide area and to evaluate actions, *Training:* to improve system operators' capacity to manage increasingly complex network environments in real time and *Trees:* effective vegetation management to minimise the risks of tree flash-over. 3Cs (co-operation, co-ordination and communication) were identified as a means to help reduce the potential for cascading failures in the future, particularly where regional markets span more than one system operator's area of responsibility. A fourth T (*Trade*) was identified as a key factor which has emerged as a result of electricity reform, and which may help widen the impact of transmission network events. Following the second workshop to be held in November 2004, a book on this issue will be published in 2005.

With the progress in the opening of gas and electricity markets, the tremendous increase of gas-fired power generation worldwide as a new driver of gas demand, the cost reductions in the liquefied natural gas chain allowing more flexible LNG trade and the growing gas import dependence on a limited number of non-OECD countries, the issue of security of gas supply is inspiring increasing attention among IEA countries. In 2004, the IEA conducted a comprehensive study, *Security of Gas Supply in Open Markets*, analysing the most recent developments in security of gas supply and reliability in all IEA regions in the context of open markets and in view of the new demand and supply trends. In contrast to the era of state-owned gas companies or private companies with exclusive concession rights, governments in open markets have to work out the right framework by defining the clear responsibilities of each market player, setting objectives for reliability of gas supply, in particular to ensure gas deliveries to household customers in the case of low-probability events, and fostering demand-side response. The increase in gas demand requires timely investment in all parts of the gas chain, from exploration and production to transporting the gas to the market as well as investment into the distribution and gas-consuming infrastructure. While governments should not play a role in the management of geological, technical and market risks, they should help to reduce sovereign and regulatory risks by creating a clear and stable framework for investment. A variety of instruments were developed to hedge the investment risks, such as long-term sales contracts, vertical integration along the gas chain and access to liquid markets and to financial instruments. Governments should leave the choice of instruments to the market players concerned.

Amidst the volatile energy market, the 9th International Energy Forum (IEF) was held in May 2004 in Amsterdam on the theme "Investing in Energy: Choices for the Future", to which IEA has significantly contributed through the *World Energy Investment Outlook*. Greater stability in the international oil market was recognised as the mutual interest of both consuming and producing states. The establishment of stable, transparent and adequate fiscal and legal frameworks was recognised as pivotal in attracting more foreign direct investment to ensure security of supply and access to reserves.

ENERGY MARKET REFORM

After the large reforms in many IEA countries in the late 1990s and the setback in the aftermath of the Californian crisis, the electricity market reform process now seems to have picked up again in many IEA member countries, albeit at a different pace. In Europe, the European Parliament passed an amended electricity market directive and a regulation on cross-border trade in June 2003. 2004 is a challenging year with the enlargement of the EU to 25 member states and the opening of the electricity market to all non-household customers. The European Commission (EC) also proposed a directive in December 2003 to safeguard security of electricity supply and infrastructure investment. In North America, the US Federal Energy Regulatory Commission (FERC) issued a new set of rules to standardise the interconnection of new generation facilities to transmission grids in July 2003. The Ontario government proposed an Electricity Restructuring Act in June 2004 following the reversal of the market reform in December 2002. In IEA Pacific, in December 2003 the Ministerial Council of Energy (MCE) in Australia agreed on a new electricity market reform package to improve regulatory efficiency by concentrating many regulatory responsibilities in one body instead of having different regulators in the states and territories. In Japan, the Electricity Utility Law was amended in June 2003, stipulating a retail market opening of 40% in 2004, rising to 63% in 2005. In Korea, the planned separation of distribution assets of the Korean Electricity Power Corporation (KEPCO) was brought to a halt in June 2004.

As for the gas sector, market competition has continued to spread in the three OECD regions at different speeds and stages. In the United States sharply higher prices for natural gas have dampened consumer interest in alternative supply options and the number of marketers actively serving consumers has dropped from 159 to 92 in the past two years. No state has changed its unbundling status in 2003. To improve the supply situation which is causing high gas prices, the US government has moved quickly to encourage the construction of LNG terminals by adopting supporting regulation and streamlining the authorisation process. Since the end of August 2003, all four existing LNG terminals have been operational and there are more than thirty proposals for new import facilities. In Europe, the new EU Gas Directive has become part of the Community law with the main provisions entering into force in July 2004. 2004 is a challenging year, with the enlargement of the EU to 25 member states and the opening of the gas market to all non-household customers. A Directive on Security of Gas Supply was adopted at the end of April 2004 and a common position has been agreed by the Council on the legislation on regulation of access to gas networks. In IEA Pacific, the Australian Productivity Commission of the natural gas access regime published a report in January 2004 proposing improvements to reduce regulatory costs. A change in the legislation is expected by the end of 2004. In Japan, the Gas Utility Law was amended in June 2003 to expand the mandatory third-party access (TPA) regulation to all gas supply pipelines. The government is also considering measures to create incentives for the development of gas networks such as allowing a higher rate of return for TPA for a certain period of time.

CLIMATE CHANGE

While uncertainty about the fate of the Kyoto Protocol has not been dispelled entirely, IEA member countries have taken various climate change mitigation measures such as fiscal measures, regulatory instruments, voluntary agreements, policy process and outreach, RD&D and tradable permits. Several countries, for example France and the United Kingdom, have also set ambitious long-term greenhouse gas emissions reduction targets towards 2050. 2003 was an important year at the regional and national levels for the development and implementation of climate change policies, most notably the European Union GHG Emissions Trading Scheme (EU-ETS). It is significant in terms of its coverage, innovation and potential implications. As of July 2004, fifteen countries had submitted their final National Allocation Plan (NAP) to the Commission and four countries (including regional governments) had published draft NAPs. The steps towards its implementation will be closely followed by governments around the globe. On 30 September 2004, the Cabinet of the government of Russia decided to approve the Protocol and submit it to the Parliament (State Duma) for ratification. The fate of the Kyoto Protocol now hinges upon its ratification by the State Duma, which remains to be seen. If it is ratified, 2004 could see greater political impetus for new and additional policies and measures to mitigate GHG emissions, as current emissions trends indicate that most IEA countries are not on track to meet their commitments. Whatever happens to the Kyoto Protocol, many governments may start considering objectives for the future, beyond 2012, in order to provide clear signals to those investing in long-term capital projects with GHG implications.

ENERGY EFFICIENCY

Most IEA member countries regard energy efficiency as one of the key policy tools to achieve GHG emissions reduction targets as well as energy security. Three specific events in 2003-2004 have also influenced energy efficiency policies, namely, continuing high oil prices, blackouts in large regions of North America and Europe, and the heat wave in Europe during the summer of 2003. Policies implemented in the IEA countries include adjusting energy prices, establishing financial instruments to encourage the use of efficient products and practices, mandating minimum efficiency levels, and voluntary measures. New market instruments such as energy efficiency certificates (white certificates) are also emerging. In 2004, the IEA started work on "saving electricity in a hurry" to analyse how electricity demand can be rapidly reduced to cope with the temporary shortfalls of electricity supply as a result of a drought, a heat wave, a breakdown in a power plant or a partial loss of transmission capacity.

RENEWABLE ENERGY

Many policy-makers in IEA member countries see renewables as contributing to protecting the environment and improving energy security. On the other hand, in most cases renewables are still not competitive and account for only a small portion of the IEA energy mix. Furthermore, RD&D funding for renewables in relative and absolute terms has further declined during the past ten years. In 2004, the IEA conducted a comprehensive survey *Renewable Energy - Market & Policy Trends in IEA Countries*. The survey takes a 30-year view of *a)* actual market growth and penetration of renewables to energy and electricity supply; *b)* changes in renewables RD&D priorities and composition in IEA countries; and *c)* the trends of policies and measures to support market deployment of renewables. Starting in the 1970s, governments set up RD&D to develop renewable energy sources. This was followed by a series of technology deployment schemes, including investment incentives, tax measures and incentive tariffs, particularly for "new" renewables. In the late 1990s, countries started to experiment with quota obligations with tradable certificates. Significant market growth has always resulted from a combination of policies rather than one single policy. Longevity and predictability of policy support and active support by the local governments are also essential for market success. An assessment of renewable energy policies needs to be based on their cost and effectiveness. There is also a need to examine how renewables mix with other energy alternatives, including energy efficiency, advanced nuclear, carbon sequestration and hydrogen. To this end, more concerted efforts would be necessary to record information on policy costs, market data and technology cost improvements. At the International Conference for Renewable Energies held in Bonn in June 2004, which adopted a political declaration, an international action programme and policy recommendations to increase the penetration of renewables, the IEA stressed increasing targeted RD&D, improving market deployment strategy and including externalities in policy considerations.

ENERGY R&D

In recent years, member countries' RD&D in the areas of end-use technologies, transmission technologies, renewables and alternative fuels (*e.g.* biofuels) for the short and medium term has remained at a low level. On the other hand, they are conducting RD&D in fields such as carbon capture and storage (CCS) (*e.g.*

implementation of pilot projects), hydrogen and fuel cells (*e.g.* significant investment in both the public and private sectors) and linking basic science and future energy technologies for the long term (2020 and beyond). In 2003-2004, the IEA has provided active support to such activities, including holding a joint workshop of IEA/CSLF (the Carbon Sequestration Leadership Forum) on the legal aspects of CCS, conducting comparative reviews of member countries' hydrogen policies under the IEA HCG (Hydrogen Co-ordination Group) and establishing AHGSET (AdHoc Group on Science and Energy Technologies).

ENERGY POLICIES IN NON-MEMBER COUNTRIES

There have been various developments in major non-OECD countries in terms of energy security and energy market reform. This book contains a short introduction to such developments in China, India, South-East Asia, Latin America, Russia, Central and South-Eastern Europe and Libya.

In ***China***, oil demand has grown explosively, and the country will be importing 40% of its crude oil needs by 2005. As a result, its interest in co-operating with Kazakhstan and in constructing a strategic petroleum reserve has intensified. China will begin stockpiling around 10 million tonnes by 2007 and over 20 million tonnes by 2010. Electricity demand has also grown rapidly, exceeding the newly added generating capacity. Because of this lack of generating capacity, over two-thirds of regions have experienced blackouts or shortages since 2003. The Energy Bureau has moved quickly to encourage the building of new plants, with nearly 40 GW in 2004 and even more in 2005. There is growing concern that China could experience overcapacity by 2007 or 2008, depending on several factors, including the pace of its economic growth. The natural gas sector continues to be the priority in rationalising the energy supply structure. The eastern half of the East-West Pipeline started operations in late 2003 and the western half will be opened around year-end 2004. Two LNG import terminals have been constructed, with plans for up to eight others in the near future. The coal sector has expanded its output enormously in the past few years, but shortages still result in lost economic output.

In ***India***, despite considerable progress in recent years, the pace of energy sector reforms varies between sub-sectors and the country still lacks a comprehensive national energy policy. Work towards a national energy policy started in 2004. The Electricity Act of 2003, which seeks to insulate the tariff-setting process from political intervention, to reorganise transmission as a separate activity and to permit private-sector participation, provides long-term legal certainty to potential investors. Regulatory responsibility for the power sector is being vested in the Central Electricity Regulatory Commission (CERC) and State Electricity Regulatory Commissions (SERCs). These legal and regulatory reforms in the power sector are of course positive, but their implementation will determine their effectiveness in achieving reform of the sector. The petroleum and gas sectors are the most dynamic sectors. The launching of the New Exploration Licensing Policy (NELP), the abolition of the administered pricing mechanism for petroleum products, and the opening of the retail and refining market to the private sector are typical examples of this. India also approved a plan for establishing Strategic Oil Stocks in early 2004. On the other hand, the coal sector has not seen any fundamental restructuring in over 30 years despite the need to raise investments to close the supply-demand gap. Given the new government's emphasis on employment creation, it is unlikely that major structural changes will occur.

Russian GDP has been growing by an average of 6.7% per year during the period 1999 to 2003, spurred on by high international oil prices and sound fiscal management. For Russia to continue this rate of economic growth – a goal set by the Russian President in mid-2003 – energy sector reforms are critical for Russia to match increasing domestic energy demand and export obligations. Increasing gas production from Russian oil companies and the emergence of independent gas producers argue for sector reform, and this will need to reflect the enormous investment challenges ahead. The pace of reform is much further advanced in the electricity sector where effective implementation of restructuring plans will be essential to meet increasing electricity and heat demand. The oil sector was liberalised over a decade ago, and – despite issues of transparency, rule of law and recent political actions – has managed since 1999 to steadily increase oil production from 6.1 million barrels per day to 8.5 mb/d in 2003. Experts continue to question how long Russian oil companies will be able to sustain growth rates based largely on "*low-hanging fruit*". In June 2004, the Russian government forecast a sharp slow-down in oil output growth, stressing the need for more emphasis on exploration and greenfield production and the need for regulatory and fiscal reform in terms of a more performance-based licensing regime and progressive taxation on resource production to enhance the investment environment. On 30 September 2004, the Cabinet of the government decided to approve the Kyoto Protocol and submit it to the State Duma for ratification. The fate of the Kyoto Protocol now hinges upon its ratification by the State Duma, which remains to be seen.

THE IEA 30 YEARS ON[1]

INTRODUCTION

As already stated in the Executive Summary, the International Energy Agency, which was created in 1974 as a response to the threat posed by the first oil crisis to the security of the industrialised countries' energy supplies, commemorates its 30th anniversary in 2004. During the last thirty years, much has been done to improve the collective energy security of member countries. However, the events of the past year have reminded them that many of the greatest challenges arise from political events in supplier countries. Energy markets never stand still and the IEA has had to move with the times. This chapter provides a review of how the Agency's mission has evolved over the past thirty years within the context of the shifting energy market and the ever-changing policy landscape, and outlines the main energy challenges facing IEA member countries today.

GLOBAL ENERGY MARKETS THIRTY YEARS ON

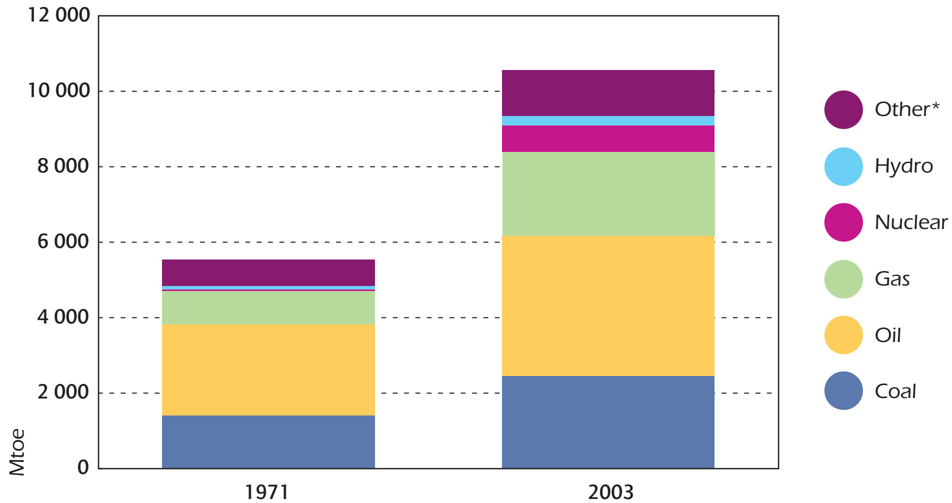
How has the global energy market changed in the last thirty years? In some respects, a lot, but in others, surprisingly little. The primary fuel mix has shifted from coal and oil towards natural gas, nuclear power and new renewable energy sources, while energy end-use has shifted to electricity. The overall size of the market has almost doubled, driven by a rapid expansion in energy use in the developing world, and in particular in Asia, as populations and economic activity have grown. Yet fossil fuels still provide the bulk of the world's primary energy needs, even as non-commercial biomass – used mainly in poor developing countries – still meets the energy needs of billions of people (Figure 1).

World energy demand has increased steadily by around 2.1% per year since 1971, interrupted only by the oil price shocks of 1973-74 and 1979-80. Oil remains the dominant fuel in both primary energy supply and the final energy mix, although its share has declined markedly. It has lost market shares in the power generation, industrial, residential and service sectors, and is now concentrated in the transport sector, where competitive alternatives to oil-based fuels have yet to emerge. Natural gas is overtaking coal as the second-largest primary fuel, driven mostly by power generation demand. Nuclear power has seen the biggest increase in market share in the last thirty years, thanks to a surge in the construction of reactors in the 1980s, mainly in IEA countries, although its growth has stalled in recent years.

1. This chapter is based on *The International Energy Agency Thirty Years On* presented to the IEA Governing Board in April 2004, and the *World Energy Outlook 2004*.

Figure 1

World Primary Energy Demand, 1971 and 2003



* includes geothermal, solar, wind, heat, etc.
Source: *World Energy Outlook 2004*, IEA/OECD Paris, 2004.

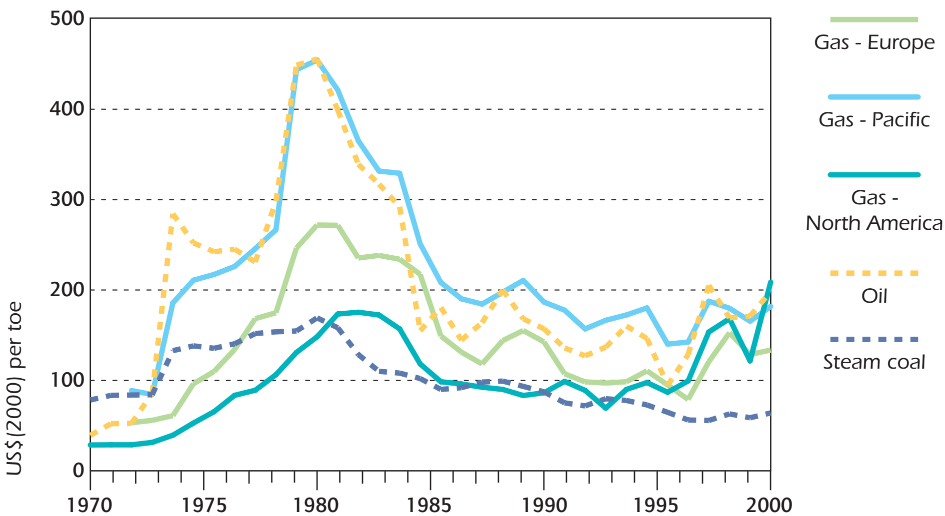
But economic growth has far outpaced energy demand: global primary energy use per unit of GDP fell by about a quarter since the early 1970s, mainly owing to a structural shift in the world economy towards less energy-intensive activities. However, the rate of decline has varied significantly among countries and regions. It fell steadily in the IEA, but increased until the early 1990s in developing countries. It surged in the former Soviet Union and Eastern and Central Europe – the transition economies – with the collapse of GDP in the early 1990s, but is falling back as their economies recover.

More than 60% of the increase in world primary energy demand over the past three decades has come from developing countries, especially in Asia. As a result, these countries' share of world primary demand has jumped from 22% to 36%. China has emerged as a major energy consumer and importer. The OECD's share has fallen from 62% to 53% over the same period, while the share of the former Soviet Union and other transition economies has also dropped sharply. Production of energy has also grown faster in non-OECD countries: these have provided around 60% of the increase in primary energy output since the early 1990s. This has led to an increase in the OECD's reliance on imports of energy, notably oil and increasingly gas.

The prices of all forms of energy have fluctuated enormously both in absolute terms and relative to each other over the past three decades. The first oil shock saw oil prices increase fourfold: the price of Arabian Light crude oil jumped from $1.85/barrel in 1972 to $11.58 in 1974 in money of the day. The price peaked at almost $40/barrel in 1981 in the wake of the Iranian Revolution. Oil prices plummeted in 1986 when Saudi Arabia abandoned its swing-producer policy and increased its oil production. They plunged again in 1997 and 1998 owing to OPEC over-production and the Asian financial crises. Prices fell to below $10/barrel in early 1999 – their lowest level since 1973. But they increased threefold in the following two years as a result of lower OPEC production, and have fluctuated in the range $25-50/barrel since then. In real terms, oil prices fell by more than three-quarters between 1982 and 1999, but they have doubled since then. (Figure 2). The prices of natural gas and, to a lesser extent, coal have more or less followed those of crude oil, but have generally fluctuated less.

Figure 2

Energy Fuel Prices, 1970 to 2003



Source: *World Energy Outlook 2004*, IEA/OECD Paris, 2004.

These market trends have been accompanied by profound changes in the structure and organisation of the energy industry, in the geopolitics of energy supply and in government energy policies. There have also been dramatic advances in the technologies used to produce, transport, deliver and consume energy, notably in the area of oil and gas extraction, in liquefied natural gas, in gas-turbine power generation, in the exploitation of renewable energy sources and in reducing toxic emissions from energy use. And the energy market has become more global, through increased cross-border capital flows as well as physical trade in energy products. The global trend towards open, pluralistic democracies and market economies is matched by the trend towards open, expanding, competitive markets for energy.

THE IEA'S MISSION IN A CHANGING ENERGY WORLD

The industrialised countries' decision to set up the International Energy Agency in 1974 was a direct response to the oil shock of the previous year – the first major global economic crisis since the Second World War. The Arab oil embargo and the surge in oil prices that resulted revealed those countries' heavy dependence on imported oil and their vulnerability to politically inspired disruptions in supply. The apparent organisational cohesiveness of the oil producers under the OPEC banner and their collective determination to exercise their new-found economic and political power through co-ordination of their oil pricing policies contrasted starkly with the oil-consuming countries' disarray and inability to cope effectively with the challenges the crisis presented to them. Pessimism about the long-term availability of fossil fuels, fed by dire predictions by the Club of Rome, contributed to the growing clamour for concerted action.

The initial role of the Agency was to help its member countries reduce their exposure to damage from any future oil supply shock. This was to be achieved by equipping them with a collective response mechanism for the short term, through the establishment of emergency oil stocks and demand restraint mechanisms; by improving the transparency of oil markets through data collection and monitoring; by co-operating on policies aimed at lowering their vulnerability in the longer term through increased efficiency, new sources of oil supply and diversification of energy supplies away from oil; and by collaborating on the development of new technologies aimed at enhancing energy security.

While energy markets and the world in which they operate have changed in many ways since 1974 and the Agency itself has grown from 16 to 26 member countries, energy security remains a fundamental goal of the IEA and a fundamental policy objective of all its member governments. Oil price shocks still hold the potential to inflict serious damage to the economies of oil-importing IEA countries and the global economy generally.[2] But security considerations have become more broadly defined. The Agency's initial focus was on oil. Today, the supply security of other forms of energy is attracting more attention, notably natural gas, the consumption and imports of which are rising rapidly in many member countries, and electricity, following several serious transmission failures in recent years. Although reliable access to

2. See *The Impact of Higher Oil Prices on the Global Economy*, 2004, prepared by the IEA Secretariat.

affordable energy remains at the core of energy security, attainment of this goal now involves embracing other policy objectives, notably the pursuit of greater economic efficiency in the energy sector, through liberalisation and the promotion of competition, and mitigating the nefarious environmental consequences of energy production and use.

All IEA countries have embarked on a course of liberalising their energy markets, with varying degrees of enthusiasm and gusto. The rationale is both economic and political: it is widely accepted that competitive markets lead to more economically efficient outcomes, lower costs and, all other things being equal, lower prices to consumers. And markets give consumers the freedom to choose their supplier – a fundamental characteristic of democratic societies. In promoting efficiency and increasing the diversity of supply, market reforms should, in principle, reinforce energy security, though this depends very much on the design of those reforms and the incentives for investors to provide the degree of security demanded by consumers.

Environmental considerations exert a strong influence on energy policy. The initial focus was on local pollution, including smog and acid rain. Attention is now focusing more on rising emissions of greenhouse gases, the bulk of which come from energy production and use, and on growing evidence of the link between those emissions and rising global temperatures and climate change. All IEA countries are committed to taking action to limit their emissions, with potentially profound implications for energy markets and, thus, energy security.

Energy supply that causes unacceptable environmental damage is not secure – or sustainable – energy. In recognition of this, the IEA has become increasingly engaged in broader global issues, which today come under the banner of "sustainable development". Energy, of course, is implicated deeply in all three pillars of sustainable development – the economy, social welfare and the environment. This shift in IEA thinking was already evident in the Agency's restatement in 1993 of its members' collective mission. These "Shared Goals" state the members' commitment to "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." At the World Summit on Sustainable Development in Johannesburg in 2002, IEA members restated the challenge as "a quest for ways to meet our needs for energy that sustain and strengthen our economies, while protecting our environment and improving the social conditions of the world's people".

ENERGY SECURITY IN A DANGEROUS WORLD

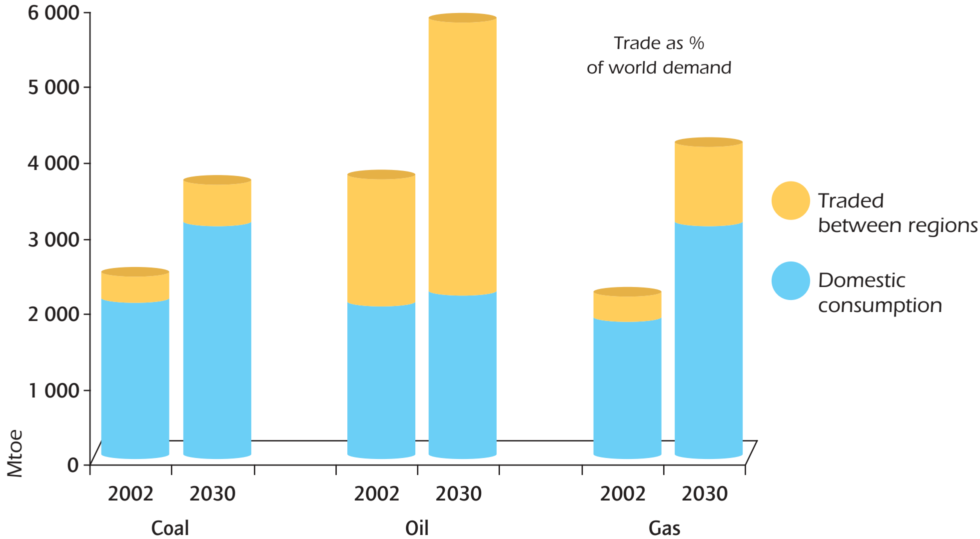
Recent energy market and geopolitical developments have pushed supply security back to the top of the energy policy agenda. The events of 11 September 2001 and worsening political instability in the Arab Gulf and elsewhere have heightened the sense of vulnerability to disruptions to energy supplies. Energy installations everywhere have had to move to a higher state of alert. The vulnerability of nuclear power stations, gas terminals, gas pipelines, oil installations and generating plants has been reappraised. Events in Afghanistan, Indonesia, Iraq, Israel and Palestine, Pakistan and India, and Venezuela all had, or have, the potential to disrupt world peace or, at least, world trade, especially trade in oil. The stability of the regimes of the Gulf oil-producing states is a continuing concern.

The terrorist threat has brought home to everyone the dangers of becoming overly reliant on imports of non-substitutable forms of energy from unstable regions. And several events – notably the Californian energy crisis in late 2000 and early 2001; the electricity blackout in the US Northeast and Canada in August 2003; recent power failures in several European countries; the disruption of liquefied natural gas supplies from the Arun plant in Indonesia in 2001 due to civil unrest; and incidents at Japanese nuclear reactors – have reminded the member countries that energy security extends to other forms of energy. Increasing competition and pressures on energy companies to reduce costs, reflected in falling spare capacity, smaller inventories, increased use of just-in-time delivery practices and less investment in fuel-switching facilities, are reducing supply flexibility and increasing the vulnerability of energy systems to deliberate or accidental supply disruptions. A particular concern is whether competitive markets can ensure that sufficient capacity is made available to meet peak demand for energy services. These developments highlight the need for governments to play a central role in ensuring reliable supplies and investment: governments must develop effective policies that protect against failures in energy supply that are not adequately handled by market and which could cause unacceptable damage to the economy, the environment or social conditions. However, governments should prefer market mechanisms such as emissions trading when designing their energy policies.

Growing energy trade, almost entirely in fossil fuels, will ensure that energy security remains at the heart of the IEA's mission and member countries' own policy goals. Global cross-border energy trade has grown by almost three-quarters since 1973. The most recent projections of the IEA's *World Energy Outlook 2004* show a further large expansion of inter-regional energy trade – both in absolute terms and as a share of production – to accommodate the mismatch between the location of demand and that of production between now and 2030 (Figure 3). Because of cost, geopolitical and technical factors, almost all the increase in energy production over that period will occur in non-OECD countries, compared to just 60% from 1971 to 2000. As a result, the reliance of the IEA and of most non-IEA oil-importing Asian countries on imports of oil and gas will continue to grow. Oil imports in China and India are set to grow particularly rapidly as domestic demand surges in line with rapid economic development. And their reliance on imports from the Middle East, in particular, is set to grow sharply: the Middle East, which has massive hydrocarbon resources, is expected to meet a significant portion of the growth in world oil and gas demand.

Figure 3

Share of Net Inter-regional Trade in World Fossil Fuel Supply



Note: Total international trade is even larger because of trade between countries within each WEO region and re-exports.
Source: *World Energy Outlook 2004*, IEA/OECD Paris, 2004.

This development will increase mutual economic interdependence, but will also intensify concerns about the world's vulnerability to a price shock induced by a supply disruption. Maintaining the security of international sea-lanes and pipelines will become more important as oil supply chains lengthen. Increasing dependence on imports of natural gas in Europe, North America and other regions will heighten those concerns. The disruption to Indonesian LNG supply in 2001 demonstrated the risks of relying on imports of gas from politically sensitive regions. On the other hand, the expected expansion of international LNG trade could alleviate some of the risks of long-distance supply chains if it leads to more diversified supplies. Increased short-term trading will also make LNG supplies more flexible.

These developments point to a need for the governments of IEA members and of non-member oil- and gas-importing countries to take a more proactive role in dealing with the energy security risks in fossil fuel trade. The IEA will remain the primary vehicle for countries to develop collective mechanisms for effective responses to supply disruptions and co-operate on long-term policies. Measures to deal with short-term supply emergencies or price shocks will surely need to be stepped up. The IEA's work in enhancing transparency in world energy markets through data collection and analysis will become even more vital. And governments will have to look anew at ways of diversifying their fuels, as well as the geographic sources of those fuels. Renewable energy technologies, mostly based on indigenous resources, will remain a focus of IEA efforts in this respect. An Alternative Policy Scenario in the *World Energy Outlook 2004* demonstrates the strong impact that new policies to curb energy demand growth and encourage switching away from fossil fuels, which countries around the world are currently considering, could have on import dependence as well as on carbon emissions.

Improving relations with energy suppliers will also continue to form a central plank of IEA countries' security strategies. Producers and consumers have come to understand that they share a common interest in smoothly functioning and stable international energy markets. Over the past decade or so, the oil producer-consumer dialogue, fostered by the IEA and bringing together member countries and OPEC countries, has been remarkably successful in establishing a more co-operative relationship between the two groups. This is allowing a better exchange of views and co-ordination of policies. The fruits of this dialogue were apparent in the effective response by OPEC countries to the threat of market disruption following the US-led military intervention in Iraq in 2003. Better data collection and exchange, aimed at improving transparency in world markets, will remain a pivotal element of this dialogue. But improved relations should also provide an avenue for constructive disagreement with producers. Supply restraint policies continue to exact a high economic cost on world economies and must be challenged accordingly.

Similarly, the importance of co-operating with other non-member countries will also grow as their share in global energy demand and their energy imports rise. Those trends will affect the energy security of IEA countries, as the resulting increase in dependence on imports from the Middle East will increase the threat of supply disruptions and international price instability – regardless of whether supplies to IEA countries are affected. Enhancing relations with non-member countries, including co-operating on emergency preparedness, data exchange and energy policy reform, will remain an important activity for the IEA.

INVESTMENT NEEDS AND THE IMPORTANCE OF GOOD GOVERNANCE

Long-term supply security will depend on whether the investment needed to expand energy supply capacity will be forthcoming in a timely manner. The *World Energy Investment Outlook*, a major study in the *World Energy Outlook* series released at the end of 2003, estimates that more than \$16 trillion of investment in maintaining and expanding energy supplies will be needed during the three decades to 2030. Almost \$10 trillion will be needed in the electricity sector alone. The bulk of the projected \$4 trillion of upstream oil and gas investment will be needed simply to maintain existing production capacity. Most investment will be needed in developing countries.

Mobilising all this investment will require the lowering of regulatory and market barriers and the creation of an attractive investment climate – a daunting task everywhere, and in particular in the developing world and the former Soviet Union. The developing countries' investment needs will only be met if there is a huge increase in capital inflows from industrialised countries. For that to happen, investment returns will have to improve and the investment environment will need to be more stable than is generally the case today.

Governments of IEA countries and non-members alike have an important role to play in creating and maintaining an enabling environment for investment. By minimising policy-induced risk and clarifying economic risk, reforms can reassure equity investors that energy companies will be able to generate a reasonable rate of return. Experience shows that capital will flow to sectors and countries that have established sound and predictable systems of corporate governance. A well-governed energy sector is characterised by stable and enforceable legal and regulatory systems, with companies operating under the best commercial practices by international standards. In practice, the issue is not so much whether the laws or regulations exist, but whether they are enforced in a fair and transparent manner. In many countries, priority must be given to stamping out corruption. Developing countries and transition economies can continue to learn from the experience of IEA countries in improving the regulatory and policy environment, through bilateral and multilateral exchanges of information and peer reviews of energy policies – such as the recent IEA review of China's natural gas policies.

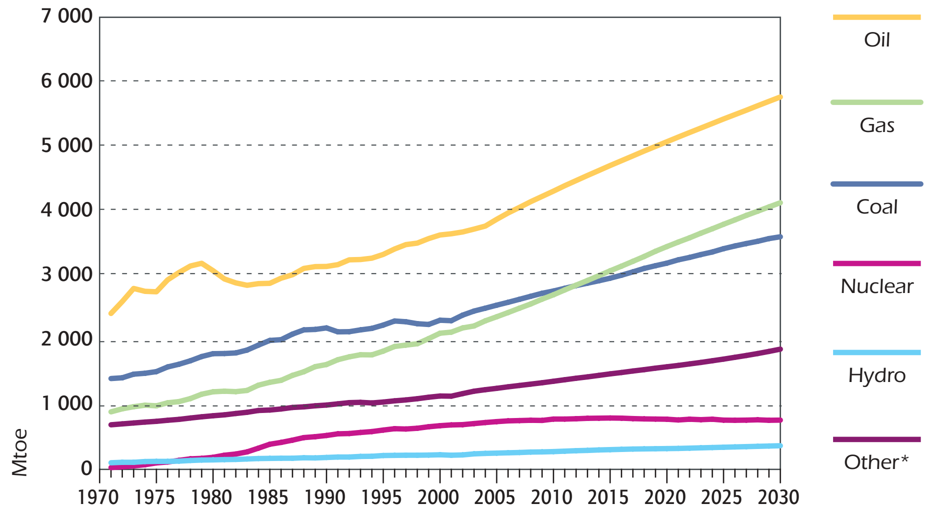
MEETING ENVIRONMENTAL CHALLENGES

The environmental implications of rising energy use will remain a key issue for IEA countries. According to the *World Energy Outlook 2004*, economic development and population growth drive the continuing expansion of the global energy market. Primary energy demand is projected to increase by 1.7% per year over the next three decades. The cumulative increase will be equal to two-thirds of current demand. Fossil fuels will remain the primary sources of energy and will meet more than 90% of the projected increase in demand (Figure 4). As a result, energy-related carbon dioxide emissions will continue to grow steadily, unless tough new policies are adopted to counter this trend.

In fact, worldwide carbon dioxide emissions are set to grow slightly faster than energy consumption because the shares of carbon-free nuclear and hydropower in the primary fuel mix are likely to fall. By 2010, energy-related CO_2 emissions will be 34% higher than in 1990 – the Kyoto base year. By 2030, they will be 70% above current levels (Figure 5). Two-thirds of the increase in emissions will come from developing countries. But it must be borne in mind that these projections assume no additional policies beyond those that have already been adopted. In the Alternative Policy Scenario, the

Figure 4

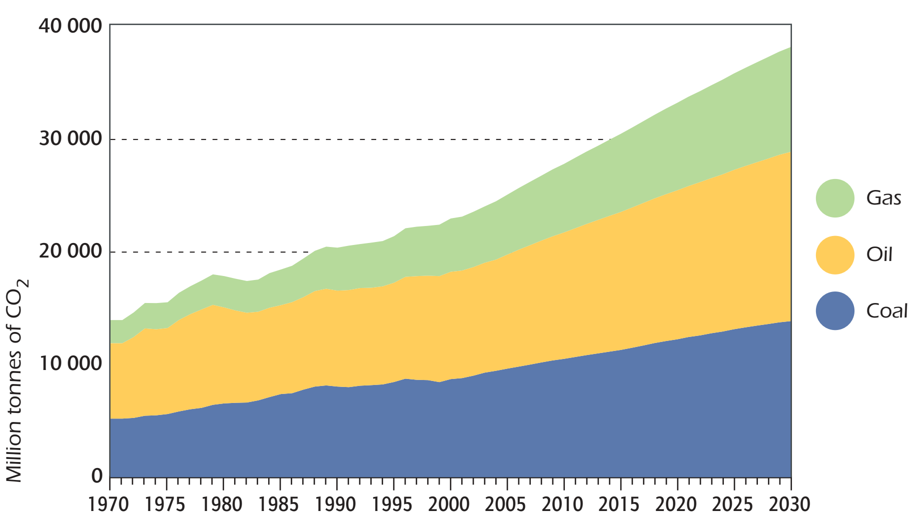
World Primary Energy Demand, 1970 to 2030



* includes geothermal, solar, wind, heat, etc.
Source: *World Energy Outlook 2004*, IEA/OECD Paris, 2004.

Figure 5

World Energy-related CO_2 Emissions, 1970 to 2030



Source: *World Energy Outlook 2004*, IEA/OECD Paris, 2004.

adoption of new policies in OECD countries, together with faster deployment of more efficient and cleaner technologies, would yield big savings in energy and promote a degree of switching to less carbon-intensive fuels. These developments would eventually stabilise CO_2 emissions in OECD countries, though only towards the end of the *Outlook* period. Political will and public acceptability of the economic cost of such policies will determine how far IEA countries go down this path.

The IEA provides a forum for its member countries to co-operate on the development of effective policies and measures to abate greenhouse gas emissions. It has been mandated by its member countries to provide analytical work on the energy dimension of climate change and the implications of the United Nations Framework Convention on Climate Change (UNFCCC) and its Kyoto Protocol on the energy sector. The IEA also undertakes work on options for the future evolution of the international climate change mitigation regime, participating actively in all meetings of the Conference of the Parties to the UNFCCC. The IEA's current work programme covers areas such as emissions trading, project-based instruments such as the clean development mechanism and joint implementation, and detailed analysis of policies and measures. And, together with the OECD Environment Directorate, it provides a secretariat for the Annex I Expert Group (AIXG) on the UNFCCC.

PUSHING NEW TECHNOLOGIES

New technologies will undoubtedly be a major part of the solution. Advances in carbon sequestration and storage, for example, hold out the prospect of much lower carbon emissions, even with the continuing use of fossil fuels. More efficient combustion technologies can reduce emissions per unit of useful energy. Governments can accelerate the development and deployment of new technologies by means of economic and regulatory instruments – including carbon taxes and emissions trading programmes. National and international trading of greenhouse gas emission credits can potentially lower considerably the overall cost of reducing emissions, although major practical issues will need to be adequately addressed before such a system can work properly.

Governments and private sectors should share responsibility for financing research, development and market deployment of new energy technologies. This type of involvement has declined significantly in the past decade in IEA countries. Recent changes in market structure, involving more private participation, and the growing share of developing countries in energy demand and production may undermine the energy industry's overall research efforts. IEA countries may therefore need to reappraise the need for a renewed public commitment to energy research and development.

One way of getting better value for the money spent on R&D is to share the costs and gains through international collaboration. The IEA, through its technology implementing agreements, will remain the primary clearing-house for collaborative technology projects. More than 40 implementing agreements have so far been put in place covering a range of technologies, including energy efficiency, renewables, clean coal use in power generation, carbon capture and storage, hydrogen and fusion. Non-member countries and private businesses are now being encouraged to participate in these agreements.

COMBATING ENERGY POVERTY

IEA countries will continue to take the lead in dealing with climate change. They have a similar responsibility to address the issue of energy poverty in developing countries. The analysis of the *World Energy Outlook 2004* shows that more than a quarter of the world's population has no access to electricity, and that two-fifths still rely mainly on traditional biomass for their basic energy needs. Although the number of people without power supplies will fall in the coming decades, a staggering 1.4 billion people will still be without electricity in 2030. And the number of people using wood, crop residues and animal waste as their main cooking and heating fuels will actually grow.

To extend electricity supplies to the energy-poor and give them better access to other forms of modern energy, stronger government policies and co-ordinated international action will be essential. Boosting global electricity investment by just 7% would be sufficient to bring a minimal level of supply to these marginalised people. But that would mean raising another $665 billion in regions that are already struggling to raise capital.

Pressure on the international community to take on more responsibility for financing the provision of basic electricity services to the very poor will surely grow. More generally, it seems inevitable that IEA countries' own energy security strategies and sustainable development goals will have to take into consideration the social and economic development priorities of the poorest regions of the world. For how long can the rich countries feel secure, even in a narrow sense, while such extremes of wealth and deprivation exist?

But better governance, more than direct aid, is what is really needed to tackle the problem of energy poverty. The authorities need to put into practice the fundamental principles of accountability, openness, transparency and predictability in all aspects of governing and regulating business and running the public sector. They need to enforce the rule of law effectively, adopt internationally accepted accounting standards and stamp out corruption. Such actions would help improve the attractiveness of the investment climate. The IEA is doing its bit in the energy sector to promote better governance by reviewing the energy policies of non-member countries, and offering non-binding advice and recommendations on how to improve those policies.

POLICIES FOR A SUSTAINABLE ENERGY FUTURE

The energy policies of all IEA countries encompass a set of policy objectives commonly referred to as the three "Es": energy security, economic development and environmental protection. These goals can be both complementary and contradictory. More secure energy would normally promote long-term economic development, but can involve higher costs. And higher energy consumption associated with economic growth can increase pollution. Devising policies that strike the right balance between the "3Es" and that embrace cost-effective approaches to achieving them are, and will remain, at the heart of the IEA's mission.

The *Outlook's* Reference Scenario projections depict an unsustainable energy future, in which global energy use rises inexorably while the energy needs of the world's poor remain unmet; in which environmentally harmful emissions continue to grow; and in which the oil- and gas-consuming regions become increasingly dependent on imports from a dwindling number of producers – notably in the Middle East. But that scenario assumes that governments maintain the policies that are currently in place. Fortunately, that is unlikely to be the case. IEA governments and the people they represent have shown a readiness to adjust personal and social conduct to give greater weight to environmental and energy security considerations. This has been evident in the changing preoccupations of energy policy-makers in IEA countries and some non-member countries. Further policy responses aimed at cutting import dependence, boosting the use of renewables and emerging energy technologies, and improving energy efficiency will surely be forthcoming. *World Energy Outlook 2004* presents an Alternative Scenario which analyses, for the first time, the global impact of environmental and energy security policies that countries around the world are already considering, as well as the effects of faster deployment of energy-efficient technologies. In this scenario, global energy demand and carbon dioxide emissions are significantly lower than in IEA's Reference Scenario.

The IEA's operational mandate has expanded considerably over the past three decades. That trend will most likely continue as the political, technological and market framework continues to change rapidly and new policy challenges emerge. These are likely to include:

- How to reform the legal, regulatory and policy framework to mobilise the necessary investment in IEA and non-member countries to secure energy supplies in the short and long term.
- How to meet climate change and sustainable development objectives while enhancing the security of energy supplies and economic and social development.
- How to respond to the further globalisation of the energy business and the increasing role of non-member countries.
- How to encourage the development and deployment of new technologies in a liberalised market.

WEO-2004: Key Findings

World Energy Outlook 2004 paints a sobering picture of how the global energy system is likely to evolve from now to 2030. If governments stick with the policies in force as of mid-2004, the world's energy needs will be almost 60% higher in 2030 than they are now. Fossil fuels will continue to dominate the global energy mix, meeting most of the increase in overall energy use. The shares of nuclear power and renewable energy sources will remain limited.

The Earth's energy resources are more than adequate to meet demand until 2030 and well beyond. Less certain is how much it will cost to extract them and deliver them to consumers. Fossil fuel resources are, of course, finite, but we are far from exhausting them. The world is not running out of oil just yet. Most estimates of proven oil reserves are high enough to meet the cumulative world demand we project over the next three decades. Our analysis suggests that global production of conventional oil will not peak before 2030 if the necessary investments are made. Proven reserves of gas and coal are even more plentiful that those of oil. There is considerable potential for discovering more of all these fuels in the future.

But serious concerns about energy security emerge from the projected market trends. The world's vulnerability to supply disruptions will increase as international trade expands. Climate-destabilising carbon dioxide emissions will continue to rise, calling into question the sustainability of the current energy system. Huge amounts of new energy infrastructure will need to be financed. And many of the world's poorest people will still be deprived of modern energy services. These challenges call for urgent and decisive action by governments around the world.

A central message of *WEO-2004* is that short-term risks to energy security will grow. Recent geopolitical developments and surging energy prices have brought that message dramatically home. Major oil and gas importers – including most OECD countries, China and India – will become ever more dependent on imports from distant, often politically unstable parts of the world. Flexibility of oil demand and supply will diminish. Oil use will become ever more concentrated in transport uses in the absence of readily available substitutes. Rising oil demand will have to be met by a small group of countries with large reserves, primarily Middle East members of OPEC and Russia. Booming trade will strengthen the mutual dependence among exporting and importing countries. But it will also exacerbate the risks that wells or pipelines could be closed or tankers blocked by piracy, terrorist attacks or accidents. Rapid worldwide growth in natural gas consumption and trade will foster similar concerns.

If current government policies do not change, energy-related emissions of carbon dioxide will grow marginally faster than energy use. CO_2 emissions will be more than 60% higher in 2030 than now. The average carbon content of energy, which fell markedly during the past three decades, will hardly change. Well over two-thirds of the projected increase in emissions will come from developing countries, which will remain big users of coal – the most carbon-intensive of fuels. Power stations, cars and trucks will give off most of the increased energy-related emissions.

These trends are, however, not unalterable. More vigorous government action could steer the world onto a markedly different energy path. *WEO-2004* presents an Alternative Scenario, which analyses, for the first time, the global impact of environmental and energy security policies that countries around the world are already considering, as well as the effects of faster deployment of energy-efficient technologies. In this scenario, global energy demand and carbon dioxide emissions are significantly lower than in our Reference Scenario.

IN-DEPTH REVIEWS IN THE PAST FOUR YEARS: CROSS-COUNTRY OVERVIEW

INTRODUCTION

IEA member countries are subject to in-depth reviews almost every four years. The review teams, composed of experts from member countries and the Secretariat staff, visit the countries under review and provide critiques and recommendations on various energy policy issues. The list of countries reviewed in the last four years is as follows.

- 2000/2001 review cycle : Australia, Belgium, the Czech Republic, New Zealand, Norway, Spain and Turkey.
- 2001/2002 review cycle : Austria, Denmark, Germany, Greece, Korea, the United Kingdom and the United States.
- 2002/2003 review cycle : Finland, Hungary, Italy, Ireland, Japan and Switzerland.
- 2003/2004 review cycle : Canada, France, Luxembourg, the Netherlands, Portugal and Sweden.

First of all, it should be stressed that considerable progress in pursuing the IEA *Shared Goals* has been made in all member countries since the previous review. The critiques of all the in-depth reviews start by commending such positive developments. These include formulation/revision of national energy plans and/or climate change action plans, further promotion of energy market reform (market opening, setting up regulatory institutions, etc.). The progress made by IEA countries is described in more detail in the subsequent chapters of this book. By their nature, the recommendations which are described and analysed in this chapter address what still has to be done for further improvement. The critiques and recommendations are negotiated with the reviewed countries and even though they may not necessarily agree with all of them, they ultimately accept them.

The critiques and recommendations are developed in a "tailor-made" manner according to the reviewed countries' specific national circumstances. Nevertheless, an analysis of the critiques and recommendations in the past four years reveals several common challenges.

With a view to providing a general sense of the key issues raised in recent in-depth reviews, the Secretariat has tried to identify the common challenges in the fields of general energy policy, energy and the environment, energy efficiency, renewables, energy market reform, security of supply, nuclear and R&D, drawing on recommendations to specific member countries from in-depth reviews completed in the last four years. It should be noted that energy policies are always evolving in member countries and therefore the recommendations cited in this chapter only reflect "snapshots" taken at the time the reviews were conducted. In fact, there have undoubtedly been further positive developments since these reviews.

While it is impossible to provide comprehensive country examples in such a limited space, the Secretariat has tried to draw examples from a diverse group of countries. This should not be interpreted as indicating that the countries that are highlighted have more serious problems than the others.

GENERAL ENERGY POLICY

In formulating their energy policies, all member countries are trying to achieve a balance among the 3Es – namely, energy security, economic development and environmental protection – in line with the IEA *Shared Goals*. Nevertheless, several areas were identified where there is clearly further room for improvement to ensure the effective and efficient implementation of energy policies. The following issues provide some examples.

MONITORING AND UPDATING OUTLOOK

Almost all member countries base their energy policy planning on specific energy supply-demand projections. Such projections are particularly crucial in addressing GHG emissions mitigation targets. Many countries are using such projections to calculate the potential gap between the business-as-usual scenario and the GHG emissions reduction target. However, the reality in the energy market may differ from such projections because of a more rapid than expected growth of energy demand or CO_2 emissions, or the acceleration or delay of energy projects. Development, monitoring and timely updating of energy supply-demand forecasts have therefore been recommended in many in-depth reviews, including ***New Zealand, Spain, Turkey, Germany, Greece, Ireland, Italy, Japan, Switzerland*** and ***Sweden***. For example, in ***Germany***, the IEA noted that the most recent outlook had been completed in 1999 and its assumptions concerning nuclear phase-out and new energy policy measures were not fully in line with actual policy decisions.

QUALITY OF ENERGY DATA

Availability of timely, consistent and high-quality energy data is a prerequisite for an effective energy policy formulation. However, this is becoming more challenging for many countries. In liberalised markets, participants require a certain amount of confidentiality concerning their operations if they are to gain and maintain a market advantage. This impacts negatively on the availability of energy data and has reduced the quality of energy quantitative information over recent years. Consequently, submission of energy statistics to international organisations has also been affected. This blurs the proper understanding of market dynamics and may affect the design and implementation of sound energy policies. The need to improve the timeliness and the quality of energy data has been pointed out in the reviews for ***Belgium, the Czech Republic, Spain, Greece, Italy, Japan*** and ***Canada***.

BALANCING ENERGY DIVERSIFICATION AND ENVIRONMENTAL PROTECTION

Addressing the 3Es simultaneously is a challenge for many countries. The role of coal in the energy mix is a typical example. Coal-fired power is often economically attractive and strengthens security of supply. Its strengths on these grounds have to be balanced against environmental objectives, particularly the objective of climate change mitigation.

For example, in the case of ***Ireland***, there was a clear conflict between two policy objectives, namely, energy security and environmental protection. Its National Climate Change Strategy proposed the closure of Moneypoint coal power plant in 2008 to achieve the Kyoto target. The disadvantage of this measure would be the increased cost of electricity and the loss of a secure energy source for the power sector. If this plant were to be shut down, up to 80% of Irish electricity could come from imported natural gas by 2010, which could cause energy security concerns. Similarly, in ***Italy***, the use of coal was expected to increase to avoid excessive dependence on imported gas. Again, this could cause a conflict with its GHG emissions target. The IEA recommended that these countries develop a long-term strategy for an energy supply mix striking the appropriate balance between energy diversification and climate change.

Germany provides a typical example of how major coal users/producers in the IEA are trying to balance these two objectives. Germany intends to continue using domestic coal and lignite as energy sources essential for ensuring energy security. Coal is also regarded as a cost-effective means of replacing nuclear capacity owing to the limitation of other alternatives. However, this will substantially increase emissions of greenhouse gases above the level achievable with continued use of nuclear power. Germany is therefore looking closely at other available technologies, including advanced combustion technologies, which could raise the thermal efficiency and reduce the greenhouse gas emissions from coal-fired power generation. Given the importance of coal in the German fuel mix and the likely expansion of coal-fired plant to replace existing nuclear capacity, the IEA recommended that higher priority be given to research and development of clean coal technologies, including carbon capture and storage.

CO-OPERATION AMONG RELEVANT MINISTRIES

Because of its multi-faceted nature, the energy sector is affected not only by energy policies, but also by a range of other policies: environment, building, transport, taxation, science and technology, etc. For example, in many countries energy demand is increasing rapidly in the residential/commercial sector and in the transport sector, which is causing concern in terms of both energy security and GHG emissions. Energy demand in these sectors is highly affected by the sectoral policies of relevant ministries (building code, public transport infrastructure development programmes, etc.). On the other hand, the priorities of national energy policies are not always appropriately incorporated in such sectoral policies or their sense of priority is not shared by other ministries. Closer co-ordination by the ministry in charge of energy policy with other relevant ministries is explicitly recommended in many in-depth reviews, including those for ***New Zealand, Spain, the United Kingdom, Italy*** and ***Portugal***.

CO-OPERATION BETWEEN THE CENTRAL AND LOCAL GOVERNMENTS

In some member countries, local governments have powerful control over energy policy formulation and implementation. For example, in ***Canada*** and ***Belgium***, provinces or regions have more jurisdiction over energy than the federal government. In ***Italy***, significant decision-making powers have been transferred to the local authorities under the amendment of the constitution. The challenge is to what extent local authorities and communities are fully informed of their national energy situation and challenges so that their decisions will reflect national as well as local interests. Given that the responsibilities of local governments are clearly defined in the constitution, the only viable approach is a process of closer dialogue and consultation to achieve a national consensus on the goals and means of energy policies. Such co-operation is particularly crucial in the field of climate change mitigation and the development of an energy-related infrastructure. Energy market reform is another area for such co-operation in countries where local governments have primary responsibilities in market reform. Strong co-operation between the central and local governments has also been emphasised in the reviews for ***Australia, Belgium, Spain, the United States, Austria*** and ***Switzerland***.

PUBLIC AWARENESS AND VISIBILITY OF NATIONAL ENERGY STRATEGY

A good understanding by the general public of the national energy situation and future challenges is a prerequisite for effective implementation of energy policies. This is obviously crucial for climate change mitigation where the general public is largely responsible for the rapid increase of GHG emissions in the residential and transport sectors. A more informed public would help to facilitate co-operation between the central and local governments in such areas as siting of the energy infrastructure because local governments' decisions are often affected by the residents in local communities. The NIMBY (not in my back yard) phenomenon is a typical area where enhancing public awareness is imperative. Energy policy issues are frequently very complex and/or technical and often difficult to communicate to the general public. While this is a challenge for all democratic societies, this is particularly crucial in such countries as ***Switzerland*** where important energy issues (*e.g.* nuclear phase-out, electricity market reform, energy taxation, etc.) are decided through referendum or public initiatives. Involving stakeholders in the energy policy formulation is another challenge to increase the awareness and visibility of national energy policies. For example, in the case of ***the Netherlands***, the IEA recommended that consumers should be more involved in designing liberalised energy markets in order to ensure maximum benefits for consumers from full market opening. The issue of enhancing public awareness and involving stakeholders was explicitly mentioned in the reviews for ***Belgium, Hungary, Italy, Switzerland, Sweden, the Netherlands*** and ***Portugal***.

ENERGY AND THE ENVIRONMENT

For those countries which have ratified the Kyoto Protocol, the achievement of Kyoto targets and the targets under the Burden Sharing for EU countries is a challenging task. As found in the IEA's Database for Policies and Measures, almost all member countries have introduced a national climate change strategy covering a wide range of policies and measures to address GHG emissions reduction.

COST-EFFECTIVENESS OF CLIMATE CHANGE MITIGATION STRATEGY

For those countries subject to legally binding obligations under the Kyoto Protocol, it is more critical to develop policies that are certain to meet national targets. On the other hand, as policies become more stringent, they also cost more and efforts to identify the cost-effectiveness of policy interventions are becoming increasingly imperative. However, assessing the cost-effectiveness of policies and measures does not yet form an integral part of the decision-making process in most member countries. Therefore, the issue of cost-effectiveness in climate change mitigation is emphasised in almost all in-depth reviews, including those for ***Belgium, the Czech Republic, New Zealand, Spain, Denmark, Germany, Austria, Ireland, Italy, Japan, Switzerland, Finland, the Netherlands, Sweden, Portugal*** and ***France***.

Quantifying the contribution of each policy and measure is a prerequisite for any cost-effective approach in climate change mitigation policy. In the case of ***New Zealand***, it was recommended to quantify the contributions to be made by each group of policies and measures (such as for energy efficiency, domestic emissions trading, a carbon charge, negotiated greenhouse agreements, international emissions trading, including credit from sinks and investment in renewable energy). The lack of quantification was also pointed out in the review for ***Portugal***.

Re-evaluating the current priority of climate change mitigation strategy based on quantification is another important challenge. It should also be borne in mind that, while economic analysis recommends a particular policy tool on the basis of economic costs, the political reality often calls for a greater spread and diversity of efforts across the different economic sectors. This issue was highlighted in several in-depth reviews. For example, in the case of ***Switzerland***, it was deemed necessary to re-evaluate whether the existing mix of policies and measures would be cost-effective for both its current and future GHG emissions goals. According to the assessment made by the government, significant gains were projected from energy efficiency while substantially smaller gains were projected from renewable energy. On the other hand, renewable energy programmes were funded at very high levels. A similar situation was observed in ***Australia***. While recognising that such high levels of funding for renewables were often driven by political support and could be considered as an investment for energy security and future climate change mitigation commitments, it was recommended that energy-related climate change mitigation policies be reviewed, with a view to balancing efforts on energy efficiency and renewables.

Another interesting issue is streamlining policies and measures addressing the same issue. For example, in the review for ***the United Kingdom***, it was pointed out that the government was superimposing numerous different layers of promotion measures for renewables, whereas the implementation of fewer, but more stringent measures might have led to the same results at less cost and friction. In the review for ***Sweden***, where there are a number of policies and measures to address climate change, it was recommended to streamline them to ensure that they are complementary to the trading scheme. Potential overlap between emissions trading and domestic measures and the possibility for streamlining was also pointed out in the review for ***Finland***.

INTERNALISING EXTERNALITIES IN ENERGY PRICING AND TAXATION

Internalising externalities in energy pricing and taxation is an important point of departure for a cost-effective approach, as often recommended in earlier in-depth reviews. From this viewpoint, in the case of ***the United States***, it was pointed out that its policy was focused on technology development and on a range of conservation measures, rather than fiscal measures such as energy pricing and taxes, and carbon dioxide cap-and-trade programmes being developed in other IEA countries. It is in fact very difficult to properly reflect externalities in energy pricing and taxation for technical, economical and political reasons. Even environmental taxation that is specifically introduced to address climate change is not necessarily fully incorporating externalities. For example, in ***the United Kingdom***, the team found that there was some room for improvement for the Climate Change Levy noting that it was not reflecting the carbon content of fuels and not covering the household sector. In the case of ***Germany***, it was also pointed out that the current eco-tax did not adequately reflect the CO_2 emissions of each fuel, as it exempted coal and lignite. Another example is the differentiated taxation for diesel and gasoline. In some countries, energy taxes on fuels are highly favourable to diesel while diesel engines emit more harmful pollutants such as particles and non-methane volatile organic compounds (NMVOCs). In-depth reviews have often recommended that countries review taxation schemes favouring diesel by paying due attention to the availability of new, cleaner diesel technologies and tightening the emissions standard, which would reduce diesel's externalities over time. At the same time, the IEA also pointed out that, if such revision is likely to result in more GHG emissions, other measures may need to be introduced to offset such an impact. This issue has been taken up in the reviews for such countries as ***Belgium, Spain, Switzerland, Portugal*** and ***France***.

THE ROLE OF MARKET-BASED INSTRUMENTS

As observed in the IEA database of policies and measures, fiscal measures, regulatory instruments and voluntary agreements are the major components of member countries' climate change mitigation strategies. The majority of fiscal measures have been set up to support the development of emerging low-carbon technologies rather than to impose a direct cost on fossil fuel sources like carbon tax.

On the other hand, the introduction of market-based mechanisms has been slow, despite their economic efficiency and cost-effectiveness, mainly because of member countries' inexperience in using such options to reduce GHG emissions and the complex framework needed to fully exploit the flexible nature of these instruments. This issue could also lead to a proper balance between domestic measures and international measures in GHG emissions reduction.

For example, in the case of ***Finland***, a clear preference for domestic measures rather than international measures was observed. The cost of domestic measures is more predictable than the as yet not fully developed international carbon markets. Over-reliance on emissions cuts derived from flexible mechanisms could be risky. Furthermore, establishing the capacity to cut emissions through domestic means could be very important beyond Kyoto's first commitmet period of 2008-2012 when additional cuts may be called for. Domestic measures would also enhance energy security. Nevertheless, the review team thought that flexible mechanisms could be useful and should be accepted as a likely tool for cutting emissions. Accordingly, it was recommended to closely review the package of measures and the supplementary role that flexible mechanisms could play. A similar reticence to use international measures was also observed in the reviews for ***Denmark, Germany*** and ***Austria***. However, the position of European countries with regard to the flexible mechanisms could have changed with the adoption of the EC Directive on Emissions Trading System.

MONITORING AND TAKING ACTION, IF NECESSARY

Effective monitoring of progress made under climate change strategy is also a prerequisite for its success. Such monitoring would entail both ensuring that suggested measures are implemented and reviewing their results once they have been put into practice. In the case of ***the United States***, given the influence of US emission on global greenhouse gas emission levels and climate, the IEA recommended quantifying the impact of current energy-environment policies on projected greenhouse gas emissions at the national and global levels and developing specific targets for the control of US greenhouse gas emissions. Updating the outlook of CO_2 emissions, as noted in the General Energy Policy section, is also essential in this respect. For example, in the case of ***Japan***, the government developed an impressive range of policies in 2002 to reduce CO_2 emissions from energy. However, some of the reduction measures were voluntary (*e.g.* building standards, energy management systems only at the testing stage), involving behavioural changes that cannot be taken for granted (such as measures to improve traffic conditions), or hinging on public acceptance (*e.g.* nuclear development programme). It was deemed difficult to predict how effective these measures would be. From this viewpoint, the government's intention to review policies by 2004 was commended. In ***the Netherlands***, its reserve package approach was commended as a prudent one because the country could immediately embark on the package if it found itself off track. The issue of monitoring has also been touched upon in the reviews for ***Spain, Austria, Finland*** and ***Portugal***.

ENERGY EFFICIENCY

Most IEA countries regard energy efficiency as one of the key policy areas to achieve GHG reduction targets as well as energy security. Member governments have introduced a range of tools to encourage energy conservation and efficiency, including adjusting energy prices, establishing financial instruments to encourage energy efficiency, mandating minimum efficiency levels, and voluntary programmes. As discussed above, the importance of closer co-operation among relevant ministries, cost-effectiveness, emphasis on market-based instruments and close monitoring have been stressed in past in-depth reviews.

CLARIFYING THE ROLE OF VOLUNTARY AGREEMENTS IN THE INDUSTRIAL SECTOR

Voluntary agreements have been widely set up with industrial sectors in member countries to improve energy efficiency and reduce GHG emissions. This policy tool has been favoured partly because of its flexibility and relatively light-handed approach compared with regulations. This is particularly important to industrial sectors exposed to international competition. Nevertheless, several issues have been identified in recent in-depth reviews.

One of them is the coverage of voluntary agreements. In the reviews for ***the United Kingdom*** and ***Switzerland***, expanding coverage of voluntary agreements to all energy-intensive industries was recommended. In the reviews for ***Japan*** and ***Italy***, the issue of "outsiders" from voluntary agreements was identified. This is crucial for a country like Italy where small and medium-sized enterprises account for a large share of energy consumption.

Clear and measurable targets are also crucial. In the case of ***Sweden***, while companies co-operating with the government on long-term agreements could enjoy exemptions from electricity tax, there were no firm targets for efficiency improvements in these agreements. Consideration of quantitative benchmarks was recommended.

Another important issue for EU countries is the clarification of the future role of voluntary agreements and the forthcoming framework of domestic emissions trading under the EU directives. For example, in ***the Netherlands***, the benchmarking covenants set targets on energy intensity allowing the growth of energy consumption in line with economic growth. On the other hand, the emissions trading scheme caps CO_2 emissions for large emitters. Therefore, in certain cases, large emitters could be obliged to buy credits even though they fulfil the intensity targets under the voluntary agreements. Accordingly, it was recommended to clarify how the benchmarking covenant could be incorporated within the emissions trading scheme.

STRONGER MEASURES IN THE TRANSPORT SECTOR

In almost all member countries energy demand in the transport sector is expanding more rapidly than in other sectors. While various policies and measures have been taken in member countries' climate change mitigation strategies, in most cases the ongoing trends suggest that the current measures would not be enough to meet the transport sector's energy efficiency goals. Energy efficiency in the transport sector as well as in the residential/commercial sector is more difficult to manage, given the number of players involved. Accordingly, enhanced energy efficiency policies in the transport sector have been recommended for almost all member countries. Specific measures recommended include stronger fuel efficiency standards (***United States, Japan***), reviewing vehicle taxation (***Norway, Finland, Italy, Netherlands, Portugal***), road pricing (***Netherlands, Luxembourg***), alternative transport fuels (***Spain***), car labelling (***Hungary, Spain***), accelerating the elimination of old vehicles (***Italy***), public transport (***Portugal, Ireland, Italy, Denmark, United Kingdom, Hungary***), and the integration of energy efficiency policy goals in the overall national transport plan (***United Kingdom***).

ENHANCING ENERGY EFFICIENCY IN THE RESIDENTIAL/COMMERCIAL SECTOR

In the residential/commercial sector, the in-depth reviews recognised that there is still a lot of room for improvement in energy efficiency in buildings. For example, in ***Belgium***, it was observed that the violation of building codes was rampant. The IEA recommended the establishment of systematic control activities and a system of penalties to reduce the number of building code violations. For then EU candidate countries such as ***Hungary*** and ***the Czech Republic***, strengthening building standards in line with EU standards was recommended. For ***Japan***, it was recommended to examine the possibility of introducing mandatory building measures such as efficiency standards for buildings. In many countries, energy efficiency in existing buildings is an important challenge from the viewpoint of their large stocks. With this in mind, stronger measures for existing buildings – such as stricter standards for renovated buildings – were recommended in such countries as ***the Netherlands*** and ***Luxembourg***. In the heating sector, the need for individual metering was pointed out in such countries as ***Switzerland, Finland*** and ***Sweden***. In federal countries, the authority for energy efficiency policy in the building sector often lies with local governments. Therefore, for example in ***the United States***, it was recommended that the federal government continue to work with state governments to strengthen building codes by providing leadership through standards and guidelines to improve energy efficiency in buildings.

The importance of international development of energy efficiency standards and regulations for appliances was also emphasised. In ***Italy***, for example, it was recommended that it actively participate at the EU level in setting efficiency performance requirements for energy labelling and energy performance standards.

DEFINING DETAILS OF NEW INSTRUMENTS

Some member countries are introducing new market-based instruments such as the white certificate, where gas and electricity distributors are obliged to achieve predefined energy efficiency targets and can achieve them either by saving energy themselves or purchasing energy efficiency certificates. In the reviews for ***France*** and ***Italy***, the IEA welcomed this proposal noting that the process of certificate trading would concentrate resources and efforts in those areas where they would be the most cost-effective. At the same time, the IEA emphasised that many administrative questions would need to be solved for the effective functioning of this new scheme. Such issues would include: how to verify the net effect of energy saving; who will monitor and verify the saving; how to minimise the administrative cost; and how to define the interaction between this scheme and similar schemes, including green certificates and emissions trading.

ENSURING COST-EFFECTIVENESS IN PROMOTING CHP

In some member countries, combined heat and power (CHP) is promoted through various supportive measures on the grounds that it could be effective in meeting the CO_2 reduction targets as well as enhancing energy efficiency. In general, in-depth reviews have taken the position that policy measures to promote efficient CHP should be designed carefully. Efficient CHP should be competitive in nature and needs little support: it would not be sensible to promote CHP installations with poor performance. For example, in such countries as ***Spain*** and ***Belgium***, the IEA pointed out the importance of an appropriate environment, including the adjustment of buy-back tariffs and provision of more certainty for the future as well as access to cheaper gas through gas market reform. It was also recommended to review subsidies with a view to phasing them out fully. In ***the Netherlands***, it was observed that subsidies increased CHP fivefold in the 1990s, causing significant overcapacity, limiting the output of existing economic baseload plants to accommodate new CHP plants and resulting in underutilised capacity and higher unit costs. In this context, it was welcomed that the government was going to revise the support scheme to take into account the actual emissions reduction resulting from each installation.

RENEWABLES

Many IEA countries have set ambitious targets for the introduction of renewables. Almost all IEA countries have taken various measures to support market deployment of renewable energy technologies ranging from investment incentives, tax measures, incentive tariffs, voluntary programmes, obligations, tradable certificates and regulatory and administrative rules. As identified in

Renewable Energy – Market & Policy Trends in IEA Countries, the evolution of energy policies for renewable energy shows a pattern over the past three decades, starting with RD&D, and moving to investment incentives and tax measures, to incentive tariffs, to obligations and, today, towards tradable certificates.

ASSESSING COST-EFFECTIVENESS

Cost-effectiveness of policies to promote renewable energies has been the major issue in the recent in-depth reviews. For example, in ***Austria***, it was recommended to explore the most cost-effective measures to achieve the country's targets for contributions from renewable sources. Similar recommendations were made to such countries as ***Belgium, the Czech Republic, Denmark, Korea, the United Kingdom*** and ***Switzerland***. Another issue related to this point, which was raised in several reviews, was the economic feasibility of promoting a certain type of renewable under country-specific natural circumstances. For example, in ***Germany***, given that the country would not be an ideal place for large-scale deployment of photovoltaics because of its climate and land-use constraints, it was observed that providing heavy support to photovoltaics through the feed-in mechanisms and R&D may incur disproportionate cost burdens for consumers and taxpayers. Accordingly, it was recommended to take the economically feasible potential of renewables into account when promoting their use. A similar recommendation was provided to ***Switzerland*** and ***the Netherlands***.

MONITORING EFFECTIVENESS OF CERTIFICATE SYSTEM

With a view to ensuring cost-effectiveness, a more market-based approach has been generally favoured in the recent in-depth reviews, including those for ***Belgium, Denmark, Greece, Hungary, Ireland, Finland*** and ***Canada***. For example, in ***Greece***, where renewables were promoted mainly by providing subsidies, setting attractive feed-in tariffs, priority dispatching and R&D, it was recommended to shift policies towards a more market-oriented approach. The tradable certificate system is often used to facilitate compliance with quota obligations to reduce the cost of compliance. While it is more compatible with a liberalised energy market, it is relatively new and its real effectiveness remains to be seen. The effectiveness of a quota system with tradable certificates strongly depends on the firmness of the target – including the level of obligation and the penalties for non-compliance. It is crucial to ensure that this new mechanism will lead to more investment opportunities for renewable energy projects. For example, in ***Sweden*** it was recommended to share information to implement the new renewables quota obligation effectively and efficiently as anticipated, and closely monitor the results.

INCORPORATING COST REDUCTION INCENTIVES IN FEED-IN TARIFF SYSTEMS

Almost all countries with significant markets for renewable energy have established guaranteed prices in the form of a fixed feed-in tariff. However, the use of a feed-in tariff is not without potential shortcomings. The prices to be paid are administratively determined, relying on the government rather than on market competition. The availability of guaranteed prices may not provide an incentive for technology innovation or for producers to reduce prices unless the prices paid decrease over time, in line with the expected learning curve of technology costs and the time period during which a producer receives a guaranteed price is limited. How to incorporate proper incentives for cost reduction is a key challenge for this scheme. In ***Portugal***, it was recommended to review the current feed-in tariff scheme to assess the benefits of incorporating incentives for cost reduction through gradually reducing the tariff levels and limiting the duration of the buy-back period, with a view to better assuring cost minimisation to consumers, while ensuring investor confidence. In ***Germany***, it was recommended to better incorporate the learning curves into the degression scheme of feed-in tariffs.

STREAMLINE LICENSING PROCEDURE

In several countries, it was observed that renewable energy projects encounter difficulties linked with slow proceedings in central/local authorities and, in some cases, local opposition. Excessive costs due to such difficulties could add to the developers' costs and thus render certain locations uneconomic. In ***Italy***, for example, it was recommended to streamline authorisation procedures for setting up renewable energy projects. Similar recommendations were also provided to ***Portugal*** and ***France***.

ENERGY MARKET REFORM

All IEA member countries have been proceeding with energy market reform (particularly electricity and gas market reform) in the last four years, although the extent of progress is mixed. Reflecting these developments, the recommendations have become more refined and detailed over the past four years. Because of the specificity of national and regional circumstances and the complexity of this reform, recommendations have been developed on a wide range of issues. The following provides some examples of issues often raised in the recent in-depth reviews.

COST-REFLECTIVE PRICES

Undistorted, cost-reflective energy prices – including electricity and gas tariffs and related services – are prerequisites for the efficient functioning of the energy market. They send the right signals to consumers and investors.

In fact, undistorted, cost-reflective pricing is a challenging task for many countries, and pricing practices such as cross-subsidisation among different customer groups and artificially low price-setting below cost for social policy objectives have been observed. This issue has been addressed in many reviews, including those for ***Australia, Belgium, the Czech Republic, New Zealand, Spain, Turkey, Greece, Korea, the United States, the United Kingdom, Austria, Hungary, Ireland, Japan, Switzerland, Finland, the Netherlands*** and ***France***. For example, in Belgium, the UK, Greece, Hungary, Ireland and France, social policy objectives such as fuel poverty were pursued through special energy pricing. Such policies could give rise to market distortions as well as discourage energy investment and energy efficiency efforts. In the light of the importance of "undistorted energy prices" in its *Shared Goals*, the IEA has recommended that social policy objectives could be better addressed by direct support to the needy.

ENHANCING EFFICIENCY IN THE OIL DOWNSTREAM SECTOR

The oil downstream sector has been largely liberalised in all member countries leading to industry restructuring and increased efficiency. In many in-depth reviews, recommendations have been developed to enhance further efficiency in the downstream sector.

For example, in the reviews of ***Belgium*** and ***Greece***, it was recommended that the remaining price ceiling mechanisms be eliminated, noting that such mechanisms would not only be obsolete in areas where many filling stations compete with one another, but could also lead to less energy efficiency.

In ***Japan***, despite a reduction in the number of filling stations, the team noted that a further reduction could be expected, based on experience in other countries. It also commended Japan for allowing self-service facilities to enter into the market, thus providing broader consumer choice that could exert downward pressure on prices in the distribution market.

PROMOTING THE RESTRUCTURING OF THE COAL SECTOR

A number of IEA countries give varying degrees of financial and other assistance to their indigenous coal producers. In most cases, the grounds for support are based on a pragmatic concern to maintain employment and regional economic activities. In general, the reviews have taken a position that markets work more efficiently when energy prices are not distorted and that the international coal market ensures supply security. The IEA has been asserting that social and regional policy objectives could be better addressed through other more efficient methods for distributing scarce financial resources to regions affected by the decline of the indigenous coal industry. From this viewpoint, in ***Germany***, it was recommended that coal subsidies continue to be reduced with the aim of eliminating them completely, and to set a clear deadline for their abolition. A similar recommendation was also made for ***Spain***. Subsidies for peat production and use in ***Ireland*** raised similar issues. Some countries such as ***Belgium*** and ***Japan*** were commended for their successful phase-out of coal subsidies.

CREATING A STABLE REGULATORY FRAMEWORK

Creating a stable regulatory framework is a prerequisite for effective electricity and gas market reform. This is also crucial for sending clear signals to potential investors. For EU member countries, uncertainties may have lessened because the time-frame of market opening for non-household customers and all customers has been clearly defined in the EU directive of 2003. Nevertheless, uncertainties will not disappear completely until a detailed national legislation for the electricity and gas market has been completed.

For example, in the review of ***Portugal***, the timing of full market opening and the creation of the Iberian electricity market was announced. However, many technical details, including the rules for small consumers to switch suppliers and the treatment of capacity payment, need to be worked out to make the market work effectively. It was therefore recommended to proceed quickly to introduce new legislation for the Iberian electricity market. As for the gas sector, while the IEA welcomed the decision by the Portuguese government to bring forward the introduction of gas market liberalisation from 2008 to 2004, it urged the government to establish the regulatory framework to meet this target without delay. Noting that further steps for liberalisation beyond the first market opening could cause regulatory uncertainty and discourage long-term investment planning and decisions, it was also recommended to set a fixed schedule for the different steps of gas market liberalisation. In the review for ***Italy***, while the EU directive for gas liberalisation had already been transposed into law, the government had not yet worked out regulations for some areas, including network, distribution, LNG terminals and storage. Accordingly, it was recommended that the remaining codes be issued as rapidly as possible.

The issue of uncertainties persists for non-EU countries without a common time-frame for market liberalisation, as in the EU. For example, this is the case for ***Switzerland*** where the first attempt to liberalise the electricity market was rejected by the public despite careful planning by the federal government and close consultation with the different interest groups. This is hampering new investments in distribution and transmission capacity as well as strategic orientation of utilities. From this viewpoint, it was recommended to continue efforts to introduce competition to clarify future orientations in market reform. In the case of ***Japan***, the government did not define steps towards further market opening after 2007 at the outset of the process but instead took the approach of evaluating the impact of each step before taking the next. While recognising that this cautious approach reflects Japan's concerns over energy security and environmental protection, the review pointed out that such regulatory uncertainty could make it difficult for the market players to adequately carry out long-term strategic planning and take investment decisions. ***Korea*** was recommended to set a clear time-frame for full liberalisation of its electricity market.

Uncertainties that discourage investment are not limited to those related to regulation. In ***Sweden***, for example, it was observed that the ongoing debate about energy in areas such as the future of nuclear power, changes in the energy taxation scheme and the ultimate means of tackling climate change had produced a degree of uncertainty which could undermine investment in new electricity capacity investments, despite a shrinking reserve margin and periods of high prices. It was recommended to create a more stable policy environment in which energy stakeholders can plan effectively.

STRONG AND INDEPENDENT ENERGY REGULATOR

With a view to promoting successful gas and electricity market reform, the role of an independent regulator with sufficient regulatory power, staff and budget has been emphasised in many in-depth reviews, such as for ***Belgium, the Czech Republic, Greece, Norway, Korea, Austria, Hungary, Italy, Japan, Finland, Switzerland, Sweden, the Netherlands, Portugal*** and ***France***.

For example, countries which did not have an independent regulator at the time of their review, such as ***Korea*** and ***Switzerland***, were recommended to establish one. The possibility of expanding the responsibilities of an independent regulator was also raised. For example, in ***Hungary***, pricing decisions for non-eligible consumers were primarily the government's responsibility, while the government owned capital in energy firms and had a potential interest in price levels. To prevent possible conflicts of interests, it was recommended that full responsibility for price controls be given to the regulator, not only in calculating prices but also in setting them. A similar recommendation was made for ***France***. In ***Finland***, it was recommended that the number of staff should be expanded and the mandate widened to include district heating. In ***Portugal***, the IEA expressed a concern that no additional staff had been authorised for the regulator while its responsibility had been expanded to gas market regulation. The shift from *ex post* to *ex ante* regulation in EU countries would further necessitate a strong regulator with adequate resources.

PROMOTING UNBUNDLING

In order for competition to develop in gas and electricity markets, effective unbundling of the electricity transmission and distribution network and the gas transport network is needed. While unbundling can take different forms, namely, divestiture, legal separation and accounting separation, the in-depth reviews have not taken a specific position on which form would be better. Rather than regarding unbundling as an objective in itself, they have developed recommendations on unbundling taking into account the effectiveness of market opening.

In the case of the electricity market reform in ***Germany***, for example, transmission system operators (TSOs) were not required to unbundle their operation beyond accounting separation but they voluntarily implemented legal separation. Noting that many IEA countries had chosen to establish independent TSOs and require legal unbundling (in some countries, even ownership unbundling), it was recommended to consider options for separating network operation from other activities of vertically integrated companies at different network levels. In the case of electricity market reform in ***Japan***, accounting separation was introduced in 1999 on a voluntary basis and the disclosure of the balance and "information firewall" was made obligatory by amending the law in 2003. The government also decided to establish "neutral transmission organisations" instead of one national independent TSO. While the IEA recommended that Japan implement account unbundling and information firewalls as a first step, it also recommended Japan not to preclude the option of a single independent TSO if fair and effective competition does not emerge. On the other hand, as for gas market reform, noting that Japan is import-dependent and does not have a well-developed gas network, a modest form of unbundling was thought preferable to secure the conditions for investment and diversification. From this viewpoint, the IEA recommended introducing account unbundling, as proposed by the government, as a starting point for fair and transparent market access while taking into account gas network development needs. In the case of gas market reform in ***Austria***, where there is a well-developed gas network and strong dominance of the incumbent, potential market entrants and large consumers complained about the difficulties of their access to pipelines despite a non-discriminatory third-party access (TPA) rule. Accordingly, it was recommended to consider, if necessary, requiring the legal unbundling of all pipeline owners or the divestiture of assets to achieve non-discriminatory TPA to the entire pipeline system.

In many countries, while independent TSOs were established to operate the transmission network, the ownership of the grid stayed with the incumbents. This could raise a concern about the independence of TSOs in terms of operation, maintenance and development of a transmission system. In the review for ***Greece***, for example, it was recommended to consider the feasibility of transferring ownership of the transmission network to the TSO, noting the experiences of other countries where an independent TSO owns the network. This issue was also raised in the reviews for ***Italy*** and ***Ireland***.

NON-DISCRIMINATORY ACCESS TO GAS AND ELECTRICITY FACILITIES

Clear, transparent and non-discriminatory third-party access to gas and electricity facilities on reasonable terms is essential to stimulate trade, competition and liquidity. In general, the in-depth reviews have been in favour of regulated TPA rather than negotiated TPA, and *ex ante* regulation rather than *ex post* regulation. However, this is not the case for the new gas investment which can be contested, such as LNG terminals, import pipelines and storage, so that such projects would not be deterred.

In the gas market reform in ***Belgium***, for example, the government changed the access rule from the negotiated TPA to the regulated TPA for transmission. The IEA welcomed this initiative on the grounds that regulated TPA would be more efficient and would provide equal opportunities to any potential new entrants to the market. In ***Germany***, the government had chosen negotiated TPA through an Association Agreement over regulated TPA both for gas and electricity. While the IEA recognised that negotiated TPA was a market-oriented approach by market players, it registered a caution that the process could be time-consuming and burdensome for small market players and that TPA tariffs were still high. Accordingly, an option was suggested that the government could be involved in the negotiation of the agreement so that the agreement would become legally binding, which would reduce the possibility of abusive behaviour. In ***Austria***, the system access charges for the electricity transmission network were much higher than the average in other European countries, which could imply cross-subsidisation. While system access charges had already begun to fall since liberalisation and the regulator intended to reduce them further, it was recommended to continue to lower the system access charges and consider more complete unbundling if such a reduction did not succeed. In the gas market reform in ***Japan***, the government proposed to establish regulated TPA to all gas pipelines while promoting negotiated TPA to LNG terminals. While questioning whether LNG terminal owners would have enough incentives to allow access to their terminals without TPA obligation, the IEA recommended Japan to follow the effectiveness of this arrangement and to consider TPA obligation if the measure was not adequate to ensure effective competition. On the other hand, the IEA recognised a positive impact on new investment in a pipeline through exempting the owner of the new pipeline from notification and publication of terms, rates and conditions for TPA.

MONITORING MARKET POWER

Market reform is a moving target and monitoring the outcome of market liberalisation is essential in order to maximise its benefit to consumers. Even though the energy market is fully opened, this does not automatically lead to effective competition. Strong market power of incumbents was identified as a potential obstacle for effective competition in some countries. This issue was raised in ***Australia, Belgium, the Czech Republic, Spain, Denmark, Greece, Korea, Austria, Hungary, Italy, Ireland, Japan, Portugal, Sweden*** and ***France***.

For example, in ***Korea***, while commending the lifting of many oil sector regulations, the IEA recognised a new concern that certain companies had considerable market influence and could control prices to their advantage. From this viewpoint, stronger monitoring was recommended to prevent unfair pricing by large companies. In ***Hungary***, where the downstream oil market had been fully liberalised, the IEA registered a concern about the market power of the incumbent oil company solely operating refineries in Hungary.

In ***Denmark***, it was recommended to prevent the state-owned incumbent gas company from becoming a monopoly supplier along the entire gas chain and to ensure close monitoring of its behaviour by the competition authority. In ***Italy***, the incumbent gas company remained in a dominant position because new entrants could not buy gas directly from Algeria or Russia, existing import pipelines were saturated and the obligation on imports from non-EU countries was too stringent. It was recommended to enforce a strict regulatory control to prevent abuse of a dominant market position.

In the case of ***Spain***, electricity generation was dominated by two large power utilities representing about 80% of total generation and distribution. While the legislation for market liberalisation had created a market environment allowing for new entrants, true competition was developing very slowly. The IEA welcomed the government's action to impose strict conditions on a proposed merger of these two companies and the resultant cancellation of the merger plan. Nevertheless, it was recommended to continuously address the concentrated nature of the electricity markets to further stimulate competition. In the case of ***Greece*** where the publicly-owned incumbent electricity company accounted for 97% of both total generation and capacity, the IEA recommended that consideration be given to creating competing generation companies from the incumbent's generation assets if no proof of competition emerges. In ***France***, the incumbent gas company operates 83% of the storage capacity and the incumbent electricity company generates more than 90% of electricity. It was recommended that this dominant position be monitored to ensure that the incumbent would not enjoy any undue advantages over new entrants. As for electricity, it was recommended that further investments in interconnections be facilitated in order to diminish the market share of the incumbent by expanding the relevant market for France.

EXPANDING THE MARKET SIZE AND REGIONAL INTEGRATION

Expanding the size of electricity markets through enhanced international or inter-regional connection is a useful option to achieve effective competition through providing a greater choice to consumers, reducing the share of strong incumbents and thus weakening excessive market power, as demonstrated in the Nordic Power Market. This is a strong motive for the creation of an Iberian electricity market. Further harmonisation of daily operation by TSOs and regulators among neighbouring countries makes the integration much more effective. Expansion would also provide benefits in terms of reserve-sharing, deferral of investment in new generating capacity and more efficient utilisation of the existing infrastructure. From this viewpoint, the in-depth reviews have been recommending this to many countries, including ***Australia***, ***the Czech Republic***, ***Spain***, ***Denmark***, ***Germany***, ***Hungary***, ***Ireland***, ***Italy***, ***Japan***, ***the Netherlands***, ***Canada***, ***Portugal*** and ***France***.

For example, in ***Ireland***, the presence of motivated and independent competitors has been negligible owing to the small size of its market. While Ireland cannot arbitrarily increase the size of its electricity market, it can effectively increase it by improving interconnections with other markets. Therefore, the IEA first recommended that Ireland should continue to develop an all-island electricity market by increasing the usable capacity of the North-South interconnector, and then to explore whether an East-West interconnector with ***the United Kingdom*** could be constructed. Expanding the regional interconnection is crucial when the national market is effectively separated into several areas. In ***Japan***, for example, a transmission grid had been developed on the basis of each supply region's self-sufficiency and interconnections between some regions were weak. At the time of the review, the emergence of new entrants was still minimal in each supply region and there was little revealed competition across the region. The IEA stressed that the interconnection issues would need to be resolved if Japan wished to develop national electricity markets with active competition. The recent need to increase imports to the Tokyo region after the closure of nuclear power plants has also demonstrated the benefits of strong interconnections for security of supply.

Creating larger gas markets also offers more possibilities for underutilised capacity/volumes to find their way to other regions, with higher gas value, thereby creating higher liquid volumes to be drawn on in case of shortage or extreme temperatures. In this context, it was recommended that ***Spain***, for example, encourage the construction of new gas interconnections with neighbouring countries and increase the capacity of existing ones in order to ensure security of supply and enhance competition.

DEVELOPING POWER EXCHANGES AND GAS HUBS

Many member countries have established electricity exchanges or competitive pools. While there are problems with some of these power exchanges, their existence provides a positive signal for the continued development of a successful reformed market. In general, voluntary pools or power exchanges have become increasingly dominant, and mandatory pools have been receding.

In ***the United Kingdom*** review, the IEA commended the introduction of the New Electricity Trading Arrangements as the decisive correction of the flaws in the early mandatory pool. It was regarded as a positive step towards a real market because it involved the demand side, provided market players with the choice of the market and market instruments, including direct bilateral contracts. In ***the Netherlands***, the volume in the power exchange was still rather modest and a larger-scale operation was deemed necessary to give the proper price signals. For this purpose, it was recommended that co-operation with neighbouring countries be enhanced in order to increase the volume of the market. Better information on the maintenance and outage of production capacity and greater liquidity in the balancing market were also regarded as necessary to reduce price spikes and increase the interest of market players to participate in the market. To ensure that there is sufficient volume in the market, ***Greece*** is exploring the establishment of the South-East European electricity pool with neighbouring countries.

On the gas side, many member countries are developing gas hubs at the interconnection of gas pipelines. These hubs are important in fostering competition and security as they make it possible to trade gas on the spot, and balance supply and demand more easily. As most of the hubs emerging in continental Europe are still in their infancy, the review teams generally recommended their further development to foster liquidity in the gas market and access to gas.

In the case of ***the Netherlands***, the team welcomed the establishment of Eurohub, a physical hub, and Title Transfer Facility (TTF), a virtual hub, as they could increase liquidity in the market by facilitating a spot market and creating new possibilities to access gas. However, noting that the volume traded through TTF was still rather limited and that it was too early to say how these hubs would work, it was recommended that they be monitored and that their development be further facilitated.

ENHANCING DEMAND-SIDE RESPONSE IN THE ELECTRICITY AND GAS SECTORS

Enhanced demand-side response can provide great benefit to the electricity market, including reducing price volatilities, reducing the market power of incumbents, reducing the need for peak capacities and reducing investment risks by providing more predictable prices to potential investors. Fostering demand-side response in the gas market also needs to be in line with the opening of the household sector to competition.

Because many member countries tend to focus on the supply side, the importance of demand-side response has often been emphasised in recent reviews.

For example, in ***Japan***, the promotion of pricing mechanisms, such as peak tariffs and real-time pricing, which reflect the high cost of generation peak, was recommended to change consumption behaviour and flatten the load curve during the summer peak. In ***Canada***, which had experienced very high price volatility in some jurisdictions, the lack of ability and incentives for demand to respond to price was regarded as a cause of low elasticity and, hence, price volatility. Demand-side measures are expected to moderate growth in electricity demand and contribute to greater price stability by increasing the elasticity of demand. Therefore, noting that this depends on provincial decisions, the IEA pointed out that there might be a role for the federal government to foster the formulation and implementation of demand-side response mechanisms across provinces.

SECURITY OF SUPPLY

The issue of energy security has been a constant concern to member countries because of the risk of imminent supply disruptions in the oil market due to political, military and social events in producing countries. At the same time, there is a growing recognition that energy policy-makers must address a much broader agenda than near-term supply risks. This includes long-term security of gas and electricity supplies under liberalised markets and growing dependence on oil and gas imports.

COMPLIANCE WITH THE IEP OBLIGATION

While most IEA member countries are compliant with the obligation to hold 90-day oil stocks stipulated in the International Energy Program (IEP), the in-depth reviews have been recommending that countries failing to fulfil the obligation rectify the situation. In the past four years, ***Greece***, ***Portugal*** and ***Luxembourg*** received such recommendations. In the case of Portugal, which had been frequently non-compliant since 1992, it was recommended that it establish the legal and organisational foundation to ensure that it will be compliant with the IEP obligation in the future.

ENHANCING EXPLORATION OF DOMESTIC OIL AND GAS RESOURCES

For those countries with domestic oil and gas resources, it has often been recommended that they make best use of such resources for the security of oil and gas supply. Increasing dependence of member countries on oil and gas imports from non-member countries is making it even more important. For example, in the case of ***the United Kingdom***, the IEA found that the tax system, including Royalty and Petroleum Revenue Tax (RPT), was not providing sufficient incentive to develop small fields. With this in mind, it was recommended that the taxation system be revised to ensure optimal exploitation of the North Sea resources. In the review for ***the Netherlands***, it was observed that new exploration activities were hampered by the lack of a stable regulatory and fiscal framework for investment and uncertainties caused by policy changes, market liberalisation and environmental requirements. It was recommended that the reintroduction of a tax incentive for offshore projects be considered and that the government intake on the profit from small fields be reviewed.

In some countries, oil and gas exploration in prospective areas is limited on environmental grounds. For example, in ***the United States***, the most promising oil prospects in onshore Alaska and offshore California have been administratively or legislatively declared off-limits to oil and gas exploration for many years. Even for those areas available for exploration and production activities, businesses must comply with a variety of federal and state regulations where the defined requirements can be very complex and deadlines during the process are not necessarily clear. Accordingly, it was recommended to remove undue obstacles to oil exploration both onshore and offshore, particularly on federal territory. This can be accomplished by government support for environmentally sound technologies for oil and gas exploration and production, thus boosting public confidence that such activities can be conducted in an environmentally responsible manner. Similarly, in ***Canada***, some promising areas in terms of oil and gas resources remain closed to production for environmental reasons. Taking into account the technology development in environment-friendly exploration, it was recommended to continue inquiring whether such areas could be opened. Similar recommendations on enabling an investment climate for upstream gas were developed for ***Hungary, Ireland*** and ***Italy***.

DIVERSIFYING OIL AND GAS SUPPLY SOURCES

For those countries endowed with almost no domestic oil resources, the importance of supply diversification has been emphasised. In the case of ***Japan***, the IEA noted with concern that dependence on the Middle East had been increasing since the mid-1980s and had reached 89%, a much higher level than at the time of the first oil crisis. In this context, Japan's efforts to develop oil supplies via a pipeline from Eastern Siberia were appreciated for their contribution to less dependence on the Middle East. It was recommended that supply security continue to be addressed by encouraging the procurement of fuels from diverse sources. However, as dependence on the Middle East cannot be reduced in the short term, it was also recommended that Japan enhance its relations with Middle East producer countries and promote a producer-consumer dialogue. Similar recommendations were made for ***Korea***.

Diversification of gas supply sources is essential for the security of gas supply. In particular, EU countries are largely dependent on pipeline gas imports from Algeria and Russia. While both countries have a long-standing record as reliable suppliers, some concerns still remain. In both countries, there is no clear gas upstream nor transport regulation. Gas production and exports are managed by companies which exercise sovereign rights of the state. Furthermore, the transit of Russian gas to the EU is highly concentrated in the Ukraine. Therefore, increased diversification of suppliers and supply routes is crucial for EU countries. With this in mind, the in-depth reviews have been encouraging in this area. For example, ***Finland*** is entirely dependent on Russian gas. While it has been examining alternative natural gas supply routes, none of the alternative pipeline projects has progressed to the planning stage. Acknowledging that such pipelines would be very costly and that Finland has had a historical success with supplies from Russia, the IEA recommended that it continue to examine additional international gas connections working with multi-country partnerships. In the case of ***Portugal***, while it had been dependent on a single supply source, Algeria, the new LNG terminal has significantly enhanced security of supply both by allowing diversification of supply sources and by providing enough supply capacity for several years. In the mid to long term, it is expected that supplies via pipeline and LNG will be half and half. The IEA commended this and recommended Portugal to maintain the policy of diversified supply sources and the balance between pipeline and LNG. ***Spain*** has also successfully diversified its supply sources with the introduction of LNG. To enhance supply diversification, Spain set an indicative limit of gas supplies from any single country and for each supplier at 60%, with the exception of gas supplied to facilities with guaranteed alternative supplies of other fuels. While the IEA regarded this as a valid policy objective, it recommended that care should be taken in implementing this measure to ensure that it would have no adverse impact on fair and effective competition by allowing new market entrants access to economical gas sources.

DEFINING CLEAR OBJECTIVES AND RESPONSIBILITIES OF DIFFERENT PLAYERS IN THE ELECTRICITY AND GAS MARKETS

Unlike the period of state-owned gas and electricity companies, or private companies with exclusive concession rights when governments managed the energy sectors, governments in open gas and electricity markets need to define the right framework for market players so that markets can deliver reliable gas and electricity supplies and make sure that market players follow the rules. Governments have the responsibility of creating a framework for security and for defining the responsibilities of each player. However, low profitability events may not be valued by the market. Therefore, governments need to set objectives for reliability of gas and electricity supply, including gas deliveries to household consumers during extreme low temperatures.

This viewpoint is reflected in the recommendations of recent reviews such as ***Italy*** and ***Ireland***. In ***Ireland***, the IEA suggested, as an example, a mandatory obligation that all suppliers must be able to continue supplying consumers in the event of any number of supply interruptions. At the same time, the government was encouraged to allow companies to choose the most appropriate means of meeting such standards among gas storage, additional/redundant pipelines, fuel switching capabilities or interruptible contracts with customers. In ***Italy***, mandatory strategic storage is imposed on shippers importing gas from non-EU countries to achieve security of supply. The IEA thought that this measure would add an extra cost and could act as one more entry barrier for competition. Accordingly, it was recommended that the costs and benefits of this measure be assessed and to consider whether the portfolio of flexible tools could be expanded to allow the same level of security of supply at a lower cost.

FOSTERING GAS AND ELECTRICITY INVESTMENT

With a growing share of natural gas in the energy mix and increasing concerns about blackouts, recent in-depth reviews have often addressed how to foster appropriate gas and electricity investment under liberalised markets. Some issues identified in Chapter 6 on market reform, including creating a stable regulatory framework and cost-reflective prices, are also relevant in this context. In addition, the following issues have often been raised in the reviews.

Monitoring investment needs

One of the important responsibilities of governments is the monitoring of investment needs. Governments need to monitor investment performance and make the results public. If the market fails to generate the necessary investment on its own, they should act, *i.e.* to provide additional market incentives. For example, in ***the United States***, where substantial investment, including new pipelines to bring gas from Canada, is necessary, the government has conducted various analyses of energy infrastructure and identified regional areas which were expected to require additional infrastructure. These analyses highlighted areas where investment was needed to ensure sufficient supply capacity. In addition, the market was well informed through projections of key market parameters such as growth in demand. Continuous review of the adequacy of investment in gas transmission, distribution and storage was recommended. In ***Italy***, the IEA suggested that the government should ensure the effective monitoring by the TSO of the reserve margin for electricity generation or the additional need for domestic or international transmission, bearing in mind sufficient lead times. It was noted that tight supplies could require more involvement of the energy regulator to provide technical support in designing the government's response to such a situation and to encourage new investments. In ***France***, as part of its responsibility to provide for energy security, the government has instituted the Long-Term Investment Programmes for Electricity Production. The IEA commended France for its focus on energy security on the grounds that short- medium- and long-term projections of supply adequacy are instrumental for energy policy-makers to assess security. At the same time, the IEA pointed out that care should be taken to ensure that such policies would result in minimal market distortion which could decrease the economic efficiency of the system as a whole. Monitoring the trend of generating capacities was also recommended in ***Australia, Spain, Greece, the United States, Sweden, the Netherlands*** and ***Portugal***.

Sending the right signals to investors

Based on this type of monitoring, governments need to ensure that markets can work properly and send the right signals to attract the necessary investment. In general, the in-depth reviews have been taking the position that the role of governments is to help decrease regulatory risks and thereby improve financial conditions by creating a clear and stable framework for investment. They have also taken the view that market incentives to invest are sufficient to ensure adequate investment as long as prices reflect real costs, while recognising the need for additional incentives if market incentives are not sufficient to cope with low probability events. They have also been generally cautious about direct intervention by governments while recognising the need for such policies, in such cases as the initial stage in emergent gas markets.

For example, in ***the Netherlands***, available contractual capacity at gas interconnections was very small, limiting import possibilities by new entrants as well as the possibility of responding to the inevitable increase of imports due to the depletion of domestic production. The IEA thought ***the United Kingdom*** connection and the North European Gas Pipeline from Russia would need to be studied. Recognising that it would be the role of industry to make the investment, the government was encouraged to put in place the right investment framework and incentives to invest. A temporary exemption for TPA obligation in new gas pipelines was suggested as one option. In ***Portugal***, investment subsidies for a natural gas infrastructure from the government and the EU, and the exemption of excise tax and VAT had contributed significantly to the rapid penetration of natural gas. The IEA considered that the Portuguese gas market was moving towards a mature stage, particularly on the high-pressure side, where there would be no need for government intervention. Taking into account the possible risk of overinvestment, it was recommended to limit subsidies to distribution and phase them out. In ***Greece***, where natural gas is exempt from excise tax until 2010, the IEA also saw the need of reviewing such policies when the market matured.

In the electricity market, past reviews often raised the issue of how to send the right signals to the market to ensure adequate peak capacity and efficient development of transmission networks. As for peak capacity, in ***Portugal*** for example, it was recommended that a cautious approach to capacity payment be taken on the grounds that this had not been proven to be an effective or efficient policy to secure adequate supply. In ***Sweden***, where TSO administered a capacity mechanism involving contracting a certain amount of peak capacity, the IEA pointed out that the system could potentially crowd out an efficient private response to peak demand, add to the cost of providing peak power and make it difficult for authorities to effectively evaluate the potential for a market-based response. Accordingly, it was recommended that the peaking power contracted by TSO be monitored to ensure that it would not undermine the development of efficient, market-based demand response or peak generation investment.

As for transmission networks, the IEA emphasised that efficient development of transmission networks could only proceed where prices and returns on investment create appropriate incentives to invest efficiently. It was also recognised that it is challenging to strike a proper balance between reducing network tariffs (and prices for end-users) and ensuring stable and adequate returns to attract investment. In the case of ***Norway***, the transmission companies were subject to an income cap for grid operation. While the IEA recognised some room for fine-tuning of the system, it generally regarded the cap system as a useful incentive mechanism to reduce costs. In ***Turkey***, the importance of a clear, transparent and non-discriminatory transmission tariff was emphasised as a driver for the establishment of appropriate transmission capacity as well as generating capacity to meet future demand. In ***New Zealand***, the cap on fixed charges and the requirement to keep rural line charges in accord with urban line charges were regarded as potential impediments to the free market and to the clear signals for investment in the network.

Streamlining licensing procedures for energy infrastructure

In many countries, electricity and gas infrastructure projects, such as generation and transmission capacities, are encountering very long lead times for development approval. The existence of several regulatory bodies operating at central and local governments is one contributing factor. Furthermore, a licensing procedure by local authorities tends to be very slow because of local opposition and the NIMBY phenomenon. For example, ***Italy*** proposed a legislation taking over the authorisation process for new power plants if local authorities are unable to complete the procedure within a certain period. While the IEA welcomed this as a positive step, it also recommended further streamlining of the authorisation procedure for building an electricity infrastructure. In ***Canada***, setting up a long pipeline from frontier areas to the markets requires numerous authorisations as these projects overlap jurisdictions, which can further deter investors. The National Energy Board is making efforts to co-ordinate with other regulatory agencies to eliminate duplication. Such efforts were commended, and it was recommended that the concept of a one-stop shop for regulatory approvals be promoted. A similar recommendation was also developed for ***the United States***.

NUCLEAR

There is a marked difference among member countries regarding their position on nuclear power. Some countries wish to retain and improve the nuclear option for the future because nuclear energy contributes to energy diversification and climate change mitigation. On the other hand, there are some countries ruling out or attempting to phase out nuclear options because of perceived safety concerns. The critiques and recommendations also reflect this diversity.

CLARIFYING THE ROLE OF NUCLEAR IN THE ENERGY MIX

For countries which are determined to keep their nuclear option and intend to construct new nuclear power plants, the IEA has been generally endorsing such a direction, noting the contribution of nuclear to energy security and GHG emissions mitigation. On the other hand, in a competitive and deregulated market, the risk of longer construction lead times and higher capital costs will all act to discourage investments in nuclear power. In the review of ***the United States***, the IEA emphasised that the government needs to develop acceptable policies to overcome these disadvantages without intervening unreasonably in the market in favour of one fuel, noting that these issues were relevant in several countries and were not specific to the United States. In ***Japan***, which had an ambitious plan to increase nuclear power generation by 30% by 2010, it was recommended that the role of nuclear power in a liberalised market be clarified, along with the demarcation of responsibilities between the public and private sectors in high radioactive waste disposal, MOX fuel fabrication and long-term nuclear liabilities. In ***France***, while endorsing the government's policy to maintain the nuclear option, the IEA recommended that the demonstration unit of the new European Pressurised Reactor should be built in open market conditions whereby companies invest in the plant solely as a profitable venture in a liberalised market.

On the other hand, at the time of the reviews, several countries had already decided to phase out nuclear or had been undergoing national debates regarding the phase-out. In ***Switzerland***, two public initiatives on a nuclear phase-out were waiting for the public vote. Noting that Switzerland was obtaining almost all of its power from carbon-free sources, namely, hydro and nuclear, the IEA considered that the phasing-out of nuclear could have a significant impact on Switzerland in terms of energy security, GHG emissions reduction and economic efficiency. Accordingly, it was recommended that Switzerland keep its nuclear option open. Because the public vote has a decisive impact on the direction of Swiss energy policy, the IEA also recommended conducting an analysis to identify and evaluate the potential impacts of the phasing-out of nuclear and share the results with the public prior to the vote. In ***Belgium***, the government had committed itself to phase out nuclear power when the current operation units reach the age of 40 years. This was a significant challenge because more than half of Belgium's electricity was produced by nuclear power plants. Along the lines of the recommendation by the commission established to investigate policies for future electricity generation, the IEA also recommended that the government keep its nuclear option open until a reliable quantitative analysis is conducted comparing the various technological options available to replace it. In ***Germany***, as the negotiated agreement for the nuclear phase-out had been worked out between the government and the utilities, it was recommended that the consequences of the phase-out be monitored, including its implications for the economy, the environment and security of supply. A similar recommendation was made to ***Sweden***, where negotiations with the industry for a nuclear phase-out were under way.

The Netherlands reversed its earlier decision to phase out nuclear power plant and decided to use it up to the end of its lifetime. The IEA commended its decision as a prudent approach to ensure security of supply and climate change mitigation and recommended to maintain a stable and predictable policy framework for nuclear power.

IMPROVING AVAILABILITY AND LIFE EXTENSION OF EXISTING PLANTS

Improving the availability and life extension of existing plants is instrumental in making the best use of nuclear power plants. In ***Japan***, the availability of power plant was lower than the world's best levels. The IEA observed that boiling water reactors (BWR) could have the potential to increase availability by 10%, and such an improvement in 20 plants would be equivalent to constructing and operating two completely new plants. Accordingly, it was recommended to increase the load factor of existing units by shortening the statutory and other outage periods and reducing their frequency. In ***France***, the IEA considered that significant economical and emissions-saving opportunities could be achieved by life extension from the current 40 years assumption.

ENSURING PUBLIC ACCEPTANCE

One of the biggest challenges for the countries which intend to keep their nuclear option open is how to improve the level of public acceptance to nuclear. In ***Japan***, nuclear power operations have been marred by safety-related incidents in recent years. In particular, the recent data falsification by one utility has seriously undermined public confidence in nuclear power. The IEA recommended that the government make the utmost efforts to restore public confidence, in particular by addressing political sensitivities in local governments where nuclear facilities are located. In ***the United States***, while industry surveys suggested that public opinion would not be an impediment for the future development of the industry, the government was advised to make an independent assessment of public attitudes and to respond objectively to any findings suggesting that the public is concerned about the use of nuclear power. A similar recommendation was made for ***Korea***.

ENSURING NUCLEAR SAFETY

Ensuring the highest standard of nuclear safety is the prerequisite for keeping the nuclear option open. While all member countries with nuclear energy are addressing this issue very seriously, the question of nuclear safety has been reiterated as a reminder in past in-depth reviews. The efficiency and independence of nuclear safety organisations has also been touched upon in several reviews. For example, in ***Japan*** where the resources for nuclear safety were increased by 190% and a second nuclear safety regulatory organisation was established following the data falsification problem, it was recommended that an effective working interface be ensured between the Nuclear and Industry Safety Agency and the newly established Japan Nuclear Energy Safety Organisation.

ADDRESSING RADIOACTIVE WASTE

Appropriate nuclear waste management is essential to keep the nuclear option viable. In ***Hungary***, the IEA found the storage of spent fuel and low- and intermediate-level nuclear wastes well organised.

However, the ultimate disposal of these wastes was not yet finalised and the programme to develop a final disposal facility for the highest radioactive wastes was still in a very early phase. It was recommended that decisions on the nuclear waste disposal framework should be taken as soon as possible. In ***Switzerland***, a disposal option had not yet been defined since the rejection of an underground repository project for low- and intermediate-level waste in local voting in Nidwalden. Despite this setback, the IEA recommended that actions to develop safe radioactive waste repositories continue to be taken. In ***the United States***, the decision on the Yucca Mountain repository project for high-level radioactive wastes had not been made at the time of the review. Bearing in mind that the decision would have considerable impact worldwide on future investment in nuclear power, it was recommended that a firm decision be taken as early as possible. In ***Finland***, the IEA observed that the government and industry had taken timely measures towards the management and disposal of all types of radioactive wastes. The high-level waste repository near Olkiluoto should be commissioned by 2020 while a number of laboratory tests remain to be completed before the construction and operation licences are issued. The review recommended the active continuation of regulatory support for the implementation of the high-level waste repository.

RESEARCH AND DEVELOPMENT

Energy technologies can make a substantial contribution to mid- to long-term solutions of energy policy challenges, namely, energy security, environmental protection and economic growth. In the recent in-depth reviews, the following issues have often been raised.

ENSURING FUNDING FOR ENERGY R&D

Despite the critical role to be played by energy technologies, the current level of energy R&D, in both the public and private sectors, is a cause for concern. After a significant increase from the mid-1970s to early 1980s, government energy R&D budgets in member countries have declined, although there was a slight increase after 1997. For example, in ***Canada***, public R&D suffered from budget cuts from $271.6 million in 1991 to $168.5 million in 1999. The IEA commended the fact that this trend had been reversed since then, which would facilitate continuous programme conditions for developing technologies with mid- or long-term perspectives. It was recommended that budget cuts like those in the late 1990s be avoided and that the upward nominal trend be maintained. In ***Italy***, the level of the budget for energy R&D expressed in terms of GDP percentage has been stable in the past three years, after the sharp decrease from the late 1980s to the early 1990s. While commending this, given the relatively low level of Italy's overall investment in R&D and the growing challenges of energy security and environmental protection, the IEA recommended that the government maintain this trend and try to increase its R&D expenditure. The importance of appropriate funding has been touched upon in the reviews for ***Turkey, Germany, the United States, Austria, Sweden, the Netherlands*** and ***Portugal***.

CONSISTENCY WITH NATIONAL ENERGY POLICY GOALS AND CLEAR PRIORITISATION

Under the stringent budgetary conditions for government energy R&D programmes in many countries, a coherent energy R&D strategy, in line with the national energy policy goals and with proper prioritisation, is crucial. This issue has been touched upon in many in-depth reviews, including those for ***Belgium*, *the Czech Republic*, *New Zealand*, *Spain*, *Turkey*, *Norway*, *Denmark*, *Germany*, *the United Kingdom*, *Austria*, *Hungary*, *Ireland*, *Italy*, *Japan*, *Switzerland*, *Canada*, *Portugal*** and ***France***. For example, in ***Portugal***, the Ministry of Economy responsible for energy policy did not have an energy R&D strategy or programme to achieve its energy policy goals. While energy was a core area of R&D activities of the National Institute for Engineering and Industrial Technology (INETI) under the auspices of the Ministry of Economy, the Ministry of Science and Higher Education responsible for national R&D policy did not regard energy R&D as its priority. Because of these factors, public funding for energy R&D in Portugal was the lowest in relation to GDP. Noting the significant energy and environment policy challenges for Portugal, the IEA recommended that the government develop a coherent energy R&D strategy. In ***New Zealand***, the IEA considered that the present structure of energy R&D could impede its full potential contribution to achieving the government's objectives for the energy sector. Energy-related R&D activities were spread across a number of programmes and undertaken in a number of the Crown Institutes and elsewhere, while there was no organisation dedicated to energy R&D. Accordingly, the team recommended that the government review the structure of government R&D in light of government priorities for the energy sector, suggesting the possibility of a reallocation of funds. In Austria, it was noted that the energy R&D policy had a mixed record in terms of focusing resources on technologies well suited to Austria's specific energy requirements. On the one hand, the country channelled the majority of spending to biomass, a strategy consistent with both Austria's current significant use of biomass and its substantial natural endowments of this fuel. On the other hand, the country spent 30% of its renewables budget on solar energy despite the fact that solar energy provided Austria with only 0.17% of its TPES. While recognising that Austria might want to support solar technologies as part of industrial or trade policies, the IEA recommended that the government review its priorities in order to maximise the cost-effectiveness of limited government R&D expenditures. In ***Germany***, photovoltaics received 18% of its entire energy R&D budget despite limited expectation about photovoltaics' competitiveness in Germany, while clean coal technologies received only 7% of the federal non-nuclear R&D budget in spite of the prospect of continuous use of coal as a cost-effective means of replacing nuclear power.

ASSESSING THE PERFORMANCE OF R&D PROJECTS

In addition to proper prioritisation, effective monitoring and assessment of the performance of government-funded energy R&D are also crucial to maximise the cost-effectiveness of the R&D programme. In ***Canada***, the energy R&D programme had been restructured since the 1999 review to improve its efficiency, increase its focus on long-term activities and adapt to the need for climate change mitigation. As a result, several R&D programmes had been consolidated and new evaluation methods were introduced. The government annually reviews one-fourth of the programme objectives to complete a full cycle in four years, involving related departments as well as stakeholders from industry and science. The IEA commended this movement and encouraged further efforts. In ***Finland***, while commending the impressive 300% increase in Finnish energy technology exports, the IEA pointed out that it was unclear to what extent the government R&D programmes had contributed to energy policy objectives. With this in mind, it was recommended that an indicator or a set of indicators be developed to assess the effectiveness of government-funded R&D efforts. The issue of monitoring and assessment has also been emphasised in the reviews for ***Belgium***, ***New Zealand, Spain, Korea, Austria, Portugal*** and ***France***.

BETTER COLLABORATION

When energy-related R&D activities are carried out by a number of organisations, appropriate collaboration among them is one of the prerequisites for the effectiveness of such activities. The increasing linkage between energy and other research areas also necessitates effective collaboration among different research organisations. For example, in ***France***, the review team encountered difficulties in obtaining consistent and reliable information on government activities. Among such problems were inconsistent reports on the amount of money being spent, lack of clarity on what administrative and political processes were used to set priorities, how such priorities were linked to energy policy, and how cost-effectiveness of the expenditures was assessed. It was considered such problems could, at least, be partly alleviated through improved co-ordination among the relevant government bodies. For example, three government agencies were engaged in technologies related to nuclear, energy efficiency and renewables and their division of responsibilities was not necessarily clear, which could result in inefficient use of financial resources. In ***the Netherlands***, while the ministry in charge of energy policy was responsible for all R&D, R&D for energy conservation became the responsibility of several ministries as a result of reorganisation. Hence, this created a strong need to co-ordinate energy efficiency R&D between the ministries, as well as to co-ordinate energy efficiency R&D with environmental, GHG-oriented R&D. In addition, within GHG R&D management, there was a sectoral breakdown and ongoing allocation of responsibilities to the different ministries. Given this situation, the IEA recommended that the government ensure clear multi-sectoral communication regarding R&D programmes and policy priorities among all ministries. In ***Spain***, a new ministry in charge of science and technology was established in 2000 and the responsibility for energy R&D was transferred to it from the ministry responsible for energy policy. Again, this created a situation where an additional co-ordination mechanism would be necessary to ensure that R&D activities would be consistent with national energy policy objectives. Accordingly, close co-ordination between these two ministries and research organisations was recommended. The issue of better co-ordination was also raised in the reviews for ***Australia, New Zealand, Norway, Denmark, Italy*** and ***Portugal***.

PUBLIC-PRIVATE PARTNERSHIP

It is increasingly important to involve the private sector in R&D activities to facilitate the process of technology deployment. In ***the United Kingdom***, for example, the government was supporting collaboration between universities and companies on long-term solutions, especially in the oil and gas industry, taking into account recommendations by a joint industry/government body. For countries where the public R&D budgets are limited, co-operation with private-sector partners could be an effective means. In ***Ireland***, the scheme of "Share Cost", which engages the private and public sectors through sharing the risks associated with short- to mid-term RD&D investment, was regarded as a useful approach. On the other hand, it is also a challenging task to clarify the respective roles of the government and industry to facilitate the efficient deployment of new technologies. Furthermore, with market liberalisation where private-sector R&D becomes more focused on short-term and applied research, governments also need to redefine their roles and improve their policy measures to stimulate private initiatives more effectively. In ***Japan***, the IEA commended government co-operation with industry to encourage industrial R&D activities. At the same time, it cautioned that the government should not finance any R&D that industry would have conducted without receiving government support, such as energy efficiency measures to achieve voluntary commitments. The importance of public-private partnership has been emphasised in the reviews for ***Australia, New Zealand, Turkey, Greece, Korea*** and ***Portugal***.

INTERNATIONAL CO-OPERATION

International co-operation, on both a multilateral and a bilateral basis, is an instrumental means to maximise the benefit of energy R&D. This is particularly the case for small countries with limited budgets for government R&D. With this in mind, enhanced international co-operation was recommended in many in-depth reviews including those for ***the Czech Republic, Spain, Turkey, Greece, Korea, Hungary, Ireland, Italy, the Netherlands*** and ***Luxembourg***. Countries which had not participated in the IEA Implementing Agreement have been encouraged to consider participation.

KEY MESSAGES

In the face of the growing complexity of energy policy issues, it is becoming ever more challenging to grasp the energy situation in member countries within a limited time-frame and provide them with a useful critique and recommendations that are well tailored to their specific domestic circumstances. Nevertheless, some key common messages can be drawn from the above exercise, which could serve as touchstones for future in-depth reviews.

GENERAL ENERGY POLICY

- Developing, monitoring and timely updating of energy supply-demand forecasts or projections is a starting point for effective energy policy-making.
- Availability of timely, consistent and high-quality energy data should be ensured.
- Safeguarding energy diversification could make the achievement of environmental objectives even more difficult.
- In cases where responsibilities are dispersed among various ministries and central/local government, stronger co-ordination efforts by the ministry in charge of energy policy are imperative in order to meet policy objectives.
- Better understanding by the general public of the national energy situation and future challenges is a prerequisite for effective implementation of energy policies.

ENERGY AND THE ENVIRONMENT

- More emphasis should be placed on the cost-effectiveness of policies and measures in tackling climate change, by, for example:
  - Quantifying the contribution of each policy and measure.
  - Re-evaluating the current priority of policy mix.
  - Where possible, streamlining policies and measures addressing the same objective.
  - Internalising externalities in energy pricing and taxation.
  - Placing more emphasis on market-based instruments.
- The progress of climate change mitigation policies should be constantly monitored and additional actions should be taken, if necessary.

ENERGY EFFICIENCY

- The role of voluntary agreements, including their coverage, clear and measurable targets and their relation with emissions trading schemes, should be clarified.

- Stronger measures need to be taken in the transport and residential/commercial sectors where energy demand is increasing rapidly.
- New instruments such as white certificates should be carefully designed and monitored.
- CHP promotion policies should be cost-effective.

RENEWABLE ENERGY

- The cost-effectiveness of policies to promote renewable energies should be ensured. As for quota systems with tradable certificates, careful design and monitoring would be necessary to ensure that this would lead to more investment opportunities. The key challenge for feed-in tariff is how to incorporate proper incentives for cost reduction.
- Licensing procedures should be streamlined to maximise the potential of renewable energy development.

ENERGY MARKET REFORM

- Undistorted, cost-reflective prices are the prerequisites for the efficient functioning of energy markets, as well as sending the right signals to consumers and investors. Low price-setting (at levels below cost for social policy objectives) should be avoided.
- Further efficiency in the downstream oil sector and the coal sector should be promoted, and any remaining coal production subsidies should be phased out.
- In the gas and electricity sector, a strong and independent energy regulator, strong and effective unbundling, non-discriminatory access to facilities, monitoring (and, if necessary, controlling) market power, expanding market size through regional integration, and enhancing demand-side response are the important elements for successful market reform.

ENERGY SECURITY

- Constant compliance with IEP obligation on oil stocks should be ensured.
- Exploration of domestic oil and gas resources should be enhanced through fiscal and regulatory measures.
- Supply sources of oil and gas should be further diversified.

- Clear objectives and responsibilities of different players for the security of electricity and gas supply should be defined.
- Governments should play a role in fostering investment in gas and electricity facilities through such measures as:
  - Creating a more stable regulatory framework.
  - Cost-reflective pricing.
  - Monitoring investment needs.
  - Sending right signals to investors.
  - Streamlining licensing procedures for energy infrastructure.

NUCLEAR

- Countries wishing to retain their nuclear option should clarify how they intend to retain the role of nuclear power in a liberalised market. Improving the availability and life extension of existing plants, improving public acceptance, ensuring nuclear safety and resolving the radioactive waste issue all need to be addressed if nuclear is to remain an option.
- Any decision to phase out nuclear should be based on clear plans about how nuclear power will be replaced, supported by a quantitative examination of its implication on the economy, environment and security of supply.

RESEARCH AND DEVELOPMENT

- Appropriate funding for government R&D should be ensured.
- Coherent energy R&D strategy in line with national energy policy goals and clear prioritisation should be developed.
- The performance of government-funded R&D should be carefully monitored and assessed.
- Strong collaboration is essential when energy-related R&D activities are dispersed among various institutions.
- The private sector should be involved in R&D activities to facilitate the process of technology deployment.
- Multilateral and bilateral international co-operation should be further promoted. The IEA Implementing Agreement provides a useful instrument.

ENERGY DEMAND: OECD

In 2003, the total primary energy supply (TPES) of OECD countries increased to 5 391 million tonnes of oil equivalent (Mtoe), up by 0.8% from the previous year. TPES increased by 0.3% in OECD Europe, 1.7% in OECD North America and 0.7% in OECD Pacific. Within each region, the situation differed from one country to another. In OECD North America, there was a 0.7% decrease in TPES in Canada while it stayed at the same level in the United States, whereas in Mexico there was an increase of 5.6%. In OECD Europe, with the exception of Germany, Ireland, Norway, Portugal, Sweden and Switzerland, all countries recorded positive growth. In OECD Pacific, while Australia and Korea continued to show positive growth of 2.8% and 2.6% respectively, TPES in Japan continued to decrease by 0.5%.

In 2003, oil remained the largest source of energy, *i.e.* 41% of TPES in OECD countries, followed by natural gas (22%), coal (21%), nuclear (11%), non-hydro renewables (4%) and hydro (2%). The share of oil, gas and coal out of TPES differs among regions. In OECD North America, it was 41%, 23% and 21%. In OECD Europe, the share of each fuel was 38%, 23% and 18%. In OECD Pacific, on the other hand, it was 47%, 14% and 23%, and unlike in the other two regions, the share of coal was higher than that of gas.

In OECD North America, the share of natural gas slightly decreased from 2002 to 2003 as a result of high natural gas prices, while that of oil increased during the same period. In OECD Europe, where natural gas prices were stable, the situation was the opposite. In OECD Pacific, the share of nuclear decreased with the outage of nuclear power plants in Japan.

In 2003, OECD North America accounted for 50% of TPES of OECD countries, followed by OECD Europe (34%) and OECD Pacific (16%).

In the longer period between 1990 and 2003, the TPES of OECD countries grew by 19%. This growth has been strongest in OECD Pacific (34%), followed by North America (20%) and Europe (12%). The share of natural gas has increased from 19% to 22% while those of oil and coal have decreased from 50% and 23% to 41% and 21% respectively. This trend was led by OECD Europe, where the share of gas has increased from 16% to 23% at the expense of coal, down from 27% to 18%.

Table 1

Total Primary Energy Supply in OECD Regions

(Mtoe)

	1990	2001	2002	2003[1]
TPES TOTAL				
Total OECD	4 527	5 296	5 346	5 391
North America	2 261	2 654	2 698	2 706
Europe	1 626	1 805	1 797	1 828
Pacific	640	837	851	857
OIL				
Total OECD	1 903	2 174	2 166	2 202
North America	931	1 085	1 080	1 111
Europe	631	696	688	688
Pacific	341	392	399	403
GAS				
Total OECD	841	1 136	1 171	1 175
North America	517	622	651	631
Europe	258	404	407	425
Pacific	66	111	113	118
COAL				
Total OECD	1 062	1 087	1 096	1 111
North America	486	573	579	580
Europe	436	325	321	330
Pacific	139	189	196	201
NUCLEAR				
Total OECD	450	593	593	581
North America	180	229	232	227
Europe	204	251	253	255
Pacific	66	113	108	99
HYDRO				
Total OECD	101	104	106	105
North America	51	47	52	51
Europe	38	46	43	40
Pacific	11	11	11	13
OTHER*				
Total OECD	171	202	213	217
North America	97	99	104	105
Europe	59	82	85	89
Pacific	16	22	24	23

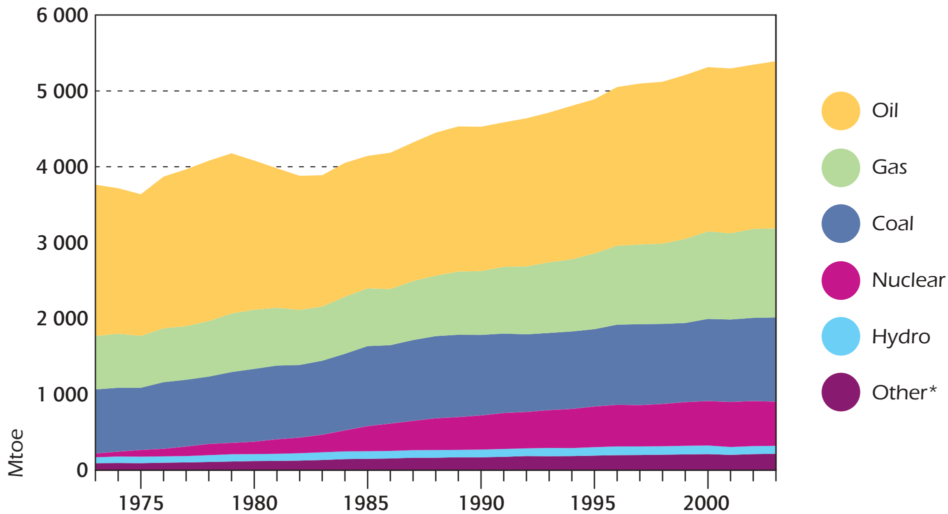
1. Preliminary data.

* includes combustible renewables, heat, geothermal, solar and wind.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Figure 6

Total Primary Energy Supply in OECD Countries, 1973 to 2003



* includes geothermal, solar, wind, heat, combustible renewables and wastes.
Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

OIL

Growth in OECD oil consumption gathered momentum in 2003-2004, following five years of relatively modest increases. Annual OECD demand growth had slowed to an average 250 thousand barrels per day after the Asian financial crisis of 1998 to 2001-2002, when it sank to a low of 30 kb/d for two consecutive years. In 2003, just as analysts had begun to speculate that fast growth in oil demand was a thing of the past, the start of global economic recovery coincided with a 1.7 million barrels per day jump in global consumption, to 78.9 mb/d. The OECD accounted for 710 kb/d of that increase, bringing total OECD demand to 48.68 mb/d. At the time of writing, global demand for 2004 was expected to soar by 2.5 mb/d, including 610 kb/d from OECD countries. Another 440 kb/d OECD demand increase was expected for 2005, compared to a global consumption gain of 1.8 mb/d.

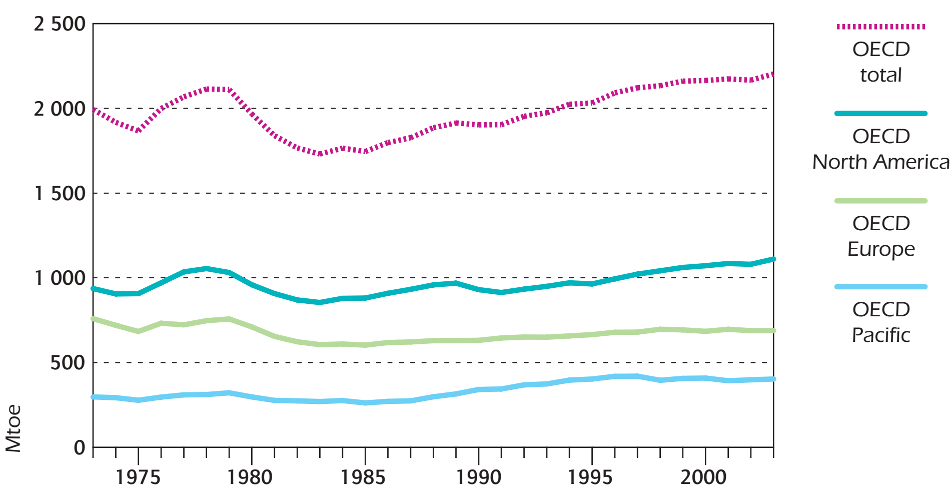
Several factors account for this rebound in OECD and global oil demand growth. In 2003, the boost from nascent economic recovery was compounded by one-off factors, such as severe winter weather across the entire OECD region, a spike in natural gas prices, and gas deliverability issues that spurred large-scale fuel-switching from natural gas to oil in the United States, and a serious disruption of nuclear power generation in Japan. Although those factors partly abated in late 2003-2004, they were replaced with a sharp acceleration in the pace of global, synchronous economic expansion.

North American demand grew faster in both volumetric and percentage terms than in the rest of the OECD economies, reflecting both the scope of United States fuel-switching into oil and the impact of severe winter weather in 2003, as well as the strength of the United States economic recovery, sustained by tax cuts and low interest rates, in the second half of 2003 and first half of 2004. In 2003, utility demand led consumption growth, which particularly benefited distillate and residual fuel oil demand for power generation and industrial use. Jet fuel demand, on the other hand, contracted in the wake of the 11 September 2001 terrorist attacks and around the time of the military offensive in Iraq, while LPG demand also declined as strong natural gas prices meant more liquids were left in the gas stream. In late 2003-2004, in contrast, transportation fuel demand – including for diesel, gasoline and jet fuel – took the lead, reflecting stronger economic conditions and a recovery in air travel, while LPG demand also showed signs of recovery.

Demand in the Asia-Pacific region bounced back into growth of 140 kb/d in 2003 after several years of contraction. The main driver was an extended shortfall in nuclear power generating capacity, caused by a controversy over nuclear reactor safety rules and practice, which led Japanese utilities to ramp up rates at oil-fired power plants and reactivate mothballed oil units, boosting consumption of residual fuel oil and heavy, sweet crude for direct burn. In late 2003-2004, that temporary boost started abating, as idled nuclear plants were progressively returned to service, while cooler-than-usual summer temperatures, followed by a relatively mild winter 2003-2004, minimised electricity requirements. Despite the strong Japanese recovery, Asian demand was expected to contract in 2004, owing to the reversal of the one-off factors that boosted demand in 2003, and to hold fast in 2005.

Figure 7

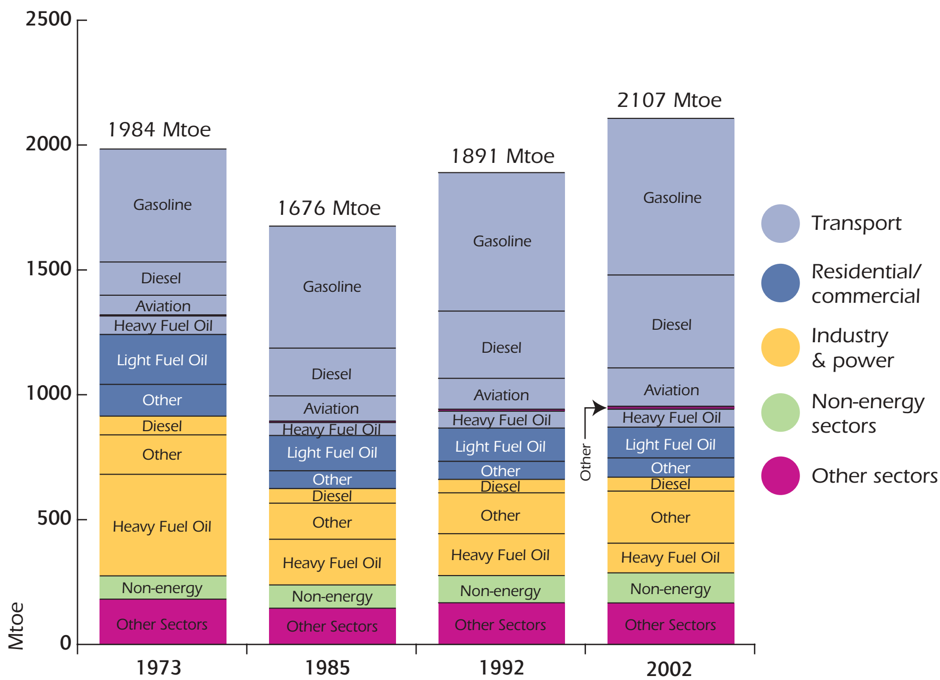
Oil Demand in OECD Countries by Region, 1973 to 2003



Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Figure 8

Consumption of Oil Products by Sector in IEA Countries, 1973 to 2002



Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Demand was comparatively weaker in OECD Europe in 2003, reflecting more sluggish economic performance, a mild winter, fuel-switching away from oil in favour of natural gas in many European economies, and efficiency gains associated with the conversion of the automobile fleet from gasoline to diesel. However, European demand growth was expected to gather momentum in 2004 and 2005, led in part by strong growth in the less mature, faster-growing economies of Eastern Europe, where consumption benefits doubly from rapidly rising household demand and from a transfer on manufacturing from higher labour-cost markets in the West.

GAS

In 2003, natural gas demand in OECD countries was 1 175 Mtoe, up by 0.3% from 2002. In OECD North America, gas consumption decreased by 3.1%. This can be attributed to the 3.8% drop in gas demand in the United States.

Demand from the US industrial and power sectors dropped significantly as a result of high gas prices. The growth in gas use in the residential and commercial sectors did not offset the drop in other sectors.

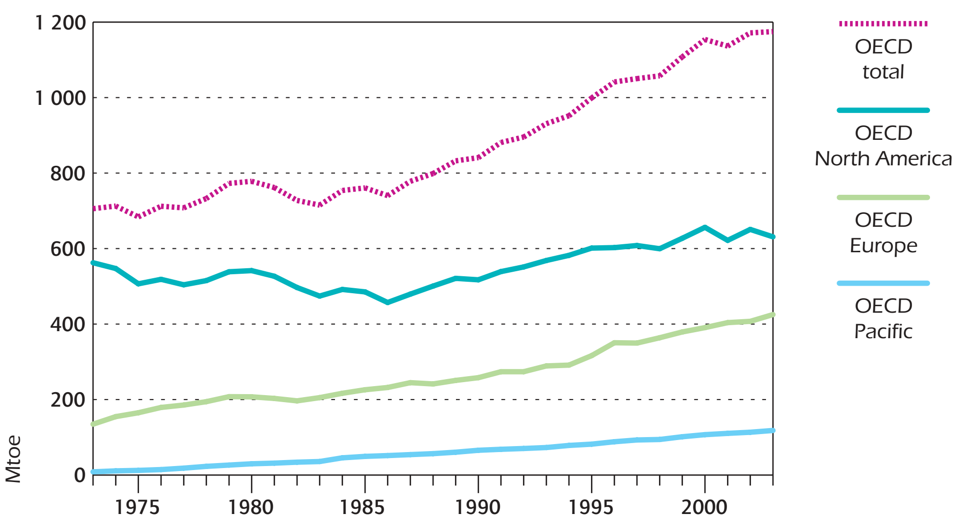
OECD Europe had an increase of 4.4%. A number of common features could be highlighted for the growth in gas sales throughout Europe. Severe temperatures in the first quarter of year 2003 gave a new impetus to demand from the residential sector. Cold temperatures were later followed by an unusually hot summer. Natural gas competitiveness against other energies, in particular coal in power generation, enabled it to maintain its position in industrial uses, despite the modest growth of the economy.

OECD Pacific gas demand showed a growth of 4.3%. In particular, gas demand in Japan significantly increased by 6.6% owing to economic recovery and additional LNG needs from the electricity sector to cope with nuclear plants outage.

In 2003, OECD North America accounted for 54% of total OECD gas demand, followed by Europe (36%) and Pacific (10%). Between 1990 and 2003, the demand growth was strongest in OECD Pacific (79%), followed by Europe (65%) and North America (22%).

Figure 9

Natural Gas Demand in OECD Countries by Region, 1973 to 2003



Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

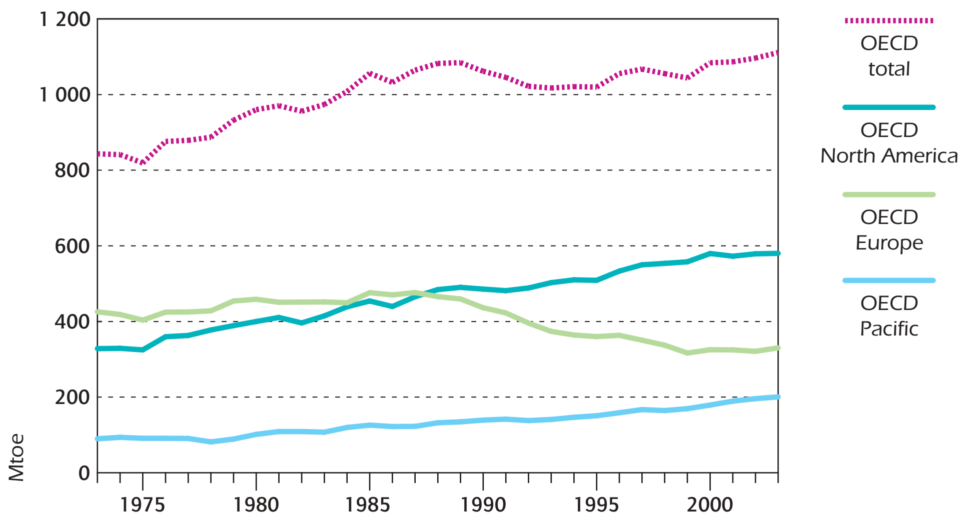
COAL

In 2003, coal demand in OECD countries was 1 111 Mtoe, up by 1.4% from 2002. Coal demand increased in OECD North America, OECD Europe and OECD Pacific by 0.2%, 2.8% and 2.6% respectively. Coal demand in OECD Europe in 2003 increased by 2.8% from 2002. Except for a few years, it had been continuously decreasing since the mid-1980s as a result of pressure from the European Union to reduce subsidies for domestic coal production and for consumers, increased environmental awareness and growing natural gas penetration. In OECD Pacific, Japanese consumption increased by 2.9% owing to rising demand in the power sector to cope with the outage of nuclear power plants.

In 2003, OECD North America accounted for 52% of total OECD coal demand followed by Europe (30%) and Pacific (18%). The demand growth was strongest in OECD Pacific (45%), followed by North America (19%) while OECD Europe recorded negative growth of 25%.

Figure 10

Coal Demand in OECD Countries by Region, 1973 to 2003



Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

ENERGY CONSUMPTION BY SECTOR: OECD

Total final consumption (TFC) in OECD countries was 3 688 Mtoe in 2002, 0.6% up from 2001. Its reversal after the decline in 2001 can mainly be attributed to growth in OECD North America. TFC in OECD North America recovered by 1.3% after the decrease of 1.9% in 2001 stemming from the economic slow-down, the energy crisis in California and the terrorist attacks of 11 September. OECD Pacific also recorded a 2.5% increase, led by strong growth in Australia and Korea. On the other hand, TFC in OECD Europe decreased by 0.9% reflecting economic slow-down.

Petroleum products accounted for the largest share in TFC in 2002, with 53%, followed by gas (20%), electricity (20%) and coal (3%). While this fuel share was almost unchanged from 2001, there has been certain change since 1990 when the shares for oil, gas, electricity and coal were 52%, 19%, 18% and 7% respectively.

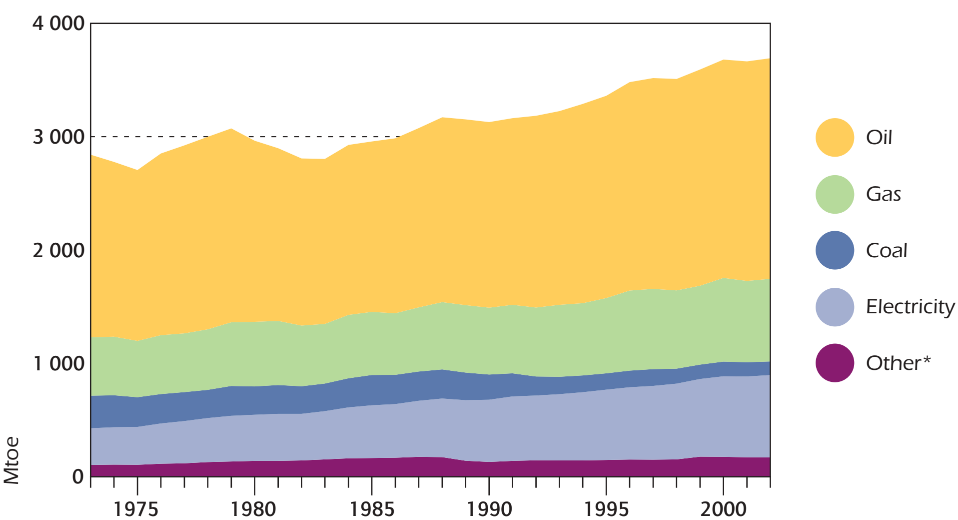
Electricity consumption in OECD countries was 722 Mtoe, up 1.1% from 2001. OECD North America, OECD Europe and OECD Pacific registered increases of 1.7%, 0.4% and 4.9% respectively. In OECD North America, electricity consumption recovered from the drop in 2001 caused by the electricity crisis in California. North America accounted for 49% of total OECD electricity consumption, followed by Europe (33%) and Pacific (18%).

In 2002, OECD North America accounted for 50% of the total OECD consumption, followed by Europe (34%) and Pacific (16%).

In the longer term, TFC increased by 18% over its 1990 level. The growth was strongest in OECD Pacific (37%), followed by North America (18%) and Europe (11%).

Figure 11

Total Final Consumption in OECD Countries by Source, 1973 to 2002



* includes geothermal, solar, wind, combustible renewables and wastes.
Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table 2

Total Final Consumption in OECD Regions

(Mtoe)

	1990	*2000*	*2001*	*2002*
TFC TOTAL				
Total OECD	3 128	3 681	3 665	3 688
North America	1 556	1 853	1 817	1 837
Europe	1 148	1 261	1 280	1 269
Pacific	424	568	568	582
INDUSTRY				
Total OECD	1 101	1 264	1 226	1 235
North America	501	592	563	569
Europe	421	433	427	425
Pacific	179	239	237	241
RESIDENTIAL/COMMERCIAL				
Total OECD	1 038	1 197	1 216	1 210
North America	478	560	553	553
Europe	432	466	491	478
Pacific	128	171	171	179
TRANSPORT				
Total OECD	990	1 221	1 223	1 242
North America	578	701	700	715
Europe	294	362	363	366
Pacific	118	158	160	161

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table 3

Electricity Consumption

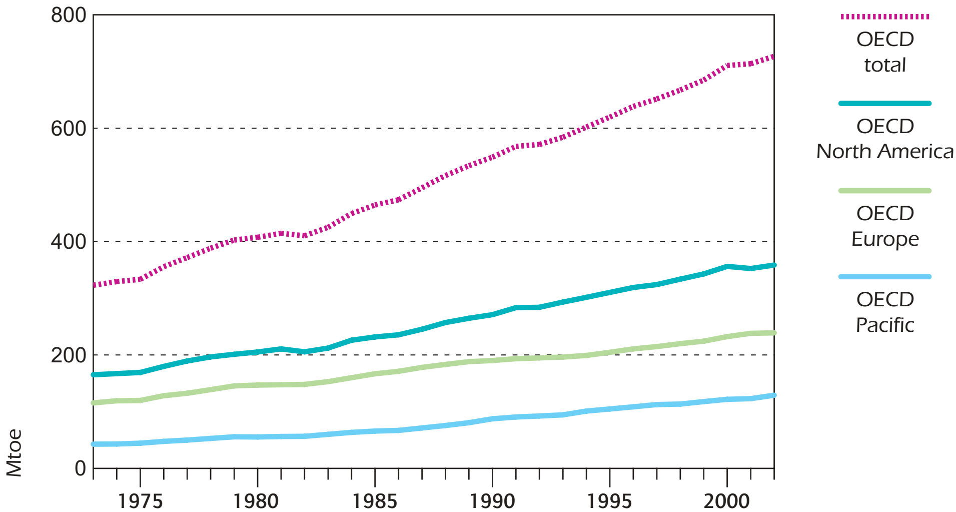
(Mtoe)

	1990	*2000*	*2001*	*2002*
Total OECD	549	711	714	722
North America	271	356	353	354
Europe	190	232	238	239
Pacific	87	122	123	129

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Figure 12

Electricity Demand (Final Consumption) in OECD Countries by Region, 1973 to 2002



Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

INDUSTRY SECTOR

In 2002, OECD energy consumption in the industry sector was 1 235 Mtoe, up 0.7% from 2001. While it decreased in all three OECD regions in 2001, OECD Pacific and OECD North America showed increases of 1.7% and 1.0% respectively in 2002. Energy consumption in the industry sector continued to decrease in OECD Europe (–0.5%).

From 2001 to 2002, gas consumption increased by 2.5%, led by OECD North America's 3.8% growth. On the other hand, coal consumption dropped by 3.2%, again led by the 11% decrease in OECD North America, reflecting the rising price of coal. Electricity consumption increased by 1.1% as a total, while it remained almost stable in OECD North America and OECD Europe, and increased in OECD Pacific by 4.9%.

In 2002, the industry sector accounted for 41% of TFC in OECD Pacific, 33% in OECD Europe and 31% in OECD North America.

In 2002, petroleum products accounted for 38% of industrial energy consumption, followed by natural gas (25%), electricity (22%) and coal (8.2%). However, the structure of energy use differed between regions. In OECD North America, the share of petroleum products was the largest (36%), followed by gas (31%), electricity (20%) and coal (5.4%). OECD Europe has a similar structure with petroleum products (36%), gas (26%), electricity (24%) and coal (8.5%). On the other hand, in OECD Pacific, the share of petroleum products was much higher (49%), followed by electricity (24%), coal (14%) and gas (9.7%).

In 2002, OECD North America accounted for 46% of industry TFC of OECD countries, followed by Europe (35%) and Pacific (20%).

In the longer period between 1990 and 2002, consumption growth was stronger in OECD Pacific (35%) and OECD North America (13%) compared with OECD Europe (0.9%).

RESIDENTIAL/COMMERCIAL SECTOR

In 2002, energy consumption in the residential/commercial sector in OECD countries was 1 210 Mtoe, down by 0.1% from 2001. However, the development from 2001 to 2002 differed significantly between regions. In OECD Europe, energy consumption in this sector decreased by 2.6%, while it remained stable in OECD North America and increased by 4.7% in OECD Pacific.

In 2002, the residential/commercial sector accounted for 38% of TFC in OECD Europe, 31% in OECD Pacific and 31% in OECD North America.

The structure of fuel use in 2002 also varied considerably between regions. In OECD Pacific, the share of petroleum products was the largest (43%), followed by electricity (39%) and gas (15%). On the other hand, electricity accounted for the largest share in OECD North America (44%), followed by gas (39%) and petroleum products (14%). In OECD Europe, gas held the largest share (35%), followed by electricity (29%) and petroleum products (24%).

In 2002, OECD North America accounted for 46% of total OECD consumption in the residential/commercial sector, followed by Europe (39%) and Pacific (15%).

From 1990 to 2002, consumption growth was much stronger in OECD Pacific (40%) than in OECD North America (18%) and OECD Europe (11%).

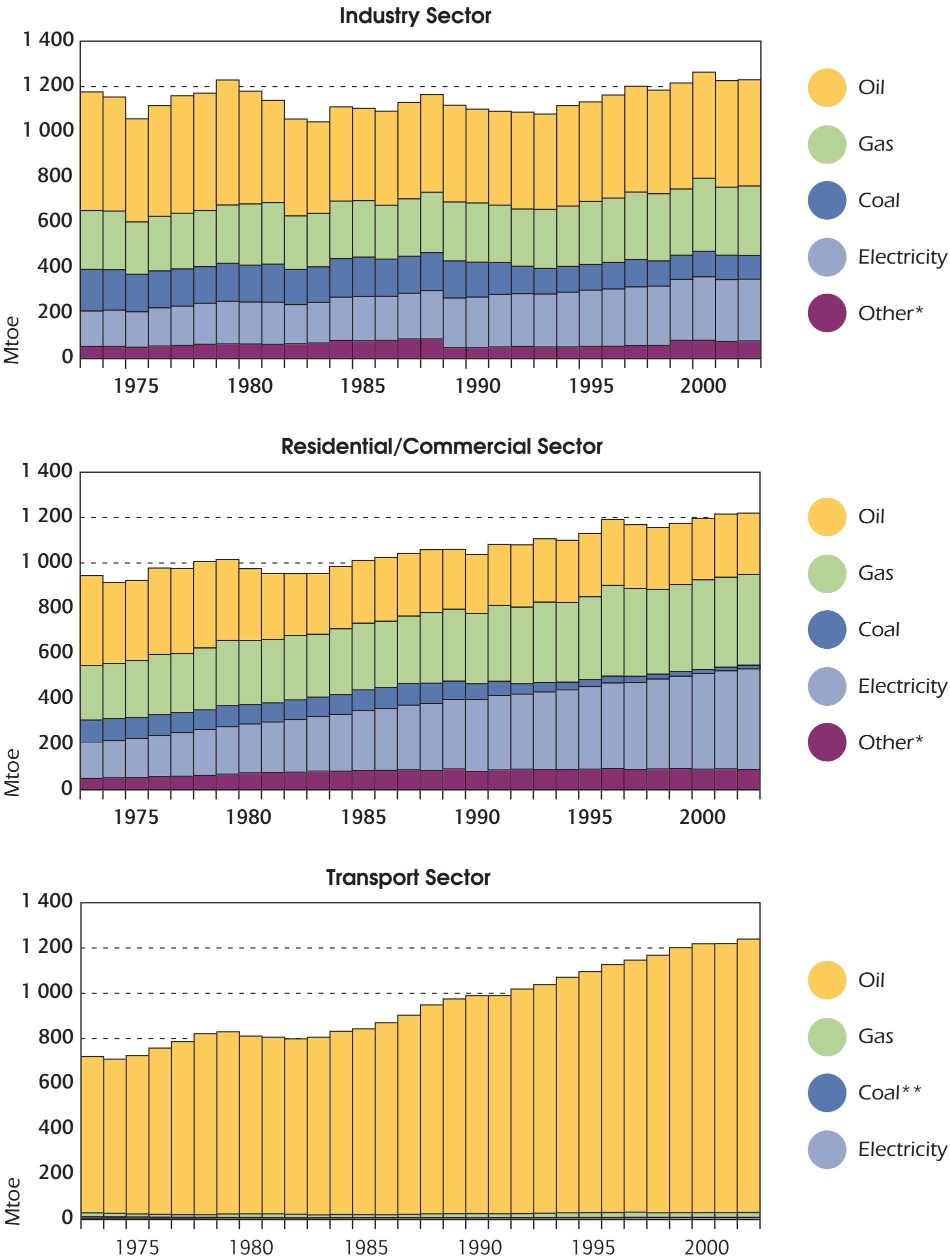
TRANSPORT SECTOR

Following the flattening between 2000 and 2001, TFC in the transport sector in OECD countries in 2002 was 1 242 Mtoe, up 1.5% from 2001.

OECD North America accounted for 58% of the OECD's total transport demand, followed by OECD Europe (29%) and OECD Pacific (13%). While the

Figure 13

Final Consumption by Sector and by Source in OECD Countries, 1973 to 2002



* includes geothermal, solar, wind, combustible renewables and wastes.

** negligible

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

transport demand in OECD North America slightly decreased from 2000 to 2001, which was the first decrease since 1991 and was due to the plummeting demand for jet fuel after 11 September, it increased again by 2.1% in 2002.

The share of oil has remained 97% and the shares of gas and electricity were 1.8% and 0.8% respectively. Penetration of natural gas was strongest in OECD North America at 2.9%, while it was very weak in other regions at 0.2-0.3%. On the other hand, electricity had shares of 1.8% and 1.3% in OECD Europe and OECD Pacific respectively, while it only had a 0.1% share in OECD North America.

In 2002, OECD North America accounted for 58% of total OECD consumption in the residential/commercial sector, followed by Europe (29%) and Pacific (13%).

In the longer term between 1990 and 2002, the growth of consumption was strongest in OECD Pacific (36%), followed by OECD Europe (24%) and OECD North America (24%).

WORLD ENERGY PRODUCTION

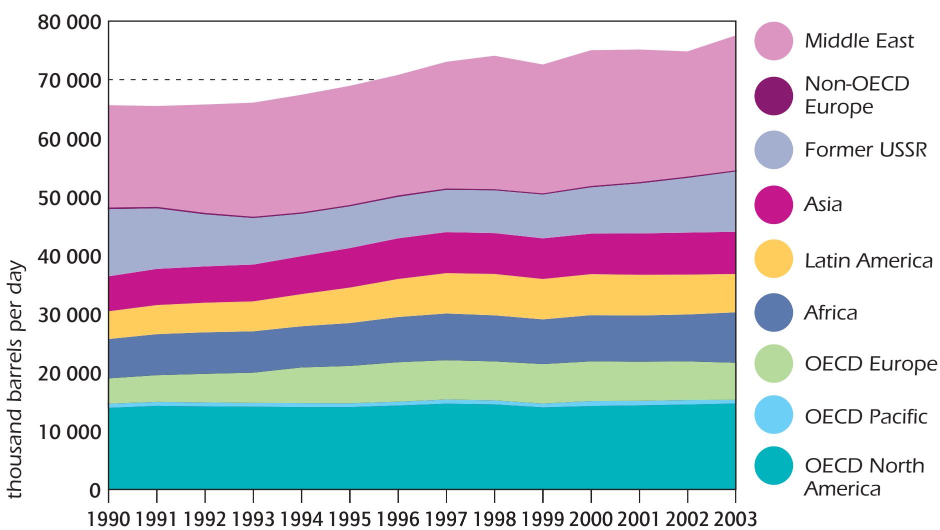
OIL

World oil production averaged 79.4 mb/d in 2003, an increase of 2.8 mb/d or 3.6% higher than in 2002. Despite supply disruptions in Venezuela, Nigeria and Iraq in the first half of the year, rising output by other OPEC members, plus markedly higher production in the former Soviet Union (FSU), underpinned the rise in total supply. Having curtailed supply in 2002, several OPEC producers increased production once again in the light of supply disruptions among a number of their fellow OPEC members. Saudi Arabia in particular boosted supply year-on-year by 1.1 mb/d, Iran by 385 kb/d, Kuwait and the United Arab Emirates (UAE) by 300 kb/d each and Algeria by 260 kb/d. In contrast, the war in Iraq severely curtailed production and exports, the former falling from 2.5 mb/d immediately before the hostilities to a low of 160 kb/d in April 2003, before progressively recovering to 2.0 mb/d by year end. For 2003 as a whole, Iraqi supply was off by 685 kb/d and that for Venezuela, adversely affected by a strike by oil workers begun at end 2002, by 280 kb/d. Both countries have since struggled to regain former production levels and remained prone to disruption (Iraq) or gradual field decline (Venezuela) in the first half of 2004. Indonesia also saw a second consecutive year of production decline in 2003 as new field developments could not make up for the prevailing decline at mature fields, a process that has continued into 2004. The other OPEC member suffering supply disruption in 2003, Nigeria, actually boosted production by 185 kb/d year-on-year as new offshore fields developed by foreign joint venture partners counteracted onshore production shut-in due to ethnic unrest in the Niger Delta. Several producers in Nigeria still face constraints on their onshore production in 2004.

Supply disruptions were not confined to OPEC producers in 2003, however, with non-OPEC supply also affected. Nonetheless, total non-OPEC output increased by 860 kb/d (1.8%) in 2003, to reach 48.9 mb/d. FSU supply growth accelerated in 2003 to reach 940 kb/d, up 10% from 2002. Russia accounted for 825 kb/d of the increment as producers boosted output and exports from established producing areas in order to take advantage of higher crude oil prices. Russia remained the driver of non-OPEC supply growth in 2004, although issues surrounding the political, fiscal and export capacity framework obscure the outlook for future production. Among other non-OPEC suppliers, the 2003 performance was mixed, with output declining by a collective 80 kb/d. Malaysia, Thailand and China boosted supplies by 100 kb/d combined. Canada and Mexico pushed production up by 340 kb/d, based on oil sands development and increased off-take from the Cantarell field. However, supply growth from Africa and Latin America was moderate compared to their 2002 performance. Furthermore, supply disruptions in OECD Europe (North Sea) and OECD Pacific (offshore Australia) resulted in reduced supplies from these areas of a collective 375 kb/d. Non-OPEC Middle East production also dropped by 110 kb/d (5%). United States supply fell by 180 kb/d (2%) as high natural gas prices sharply cut into NGL supply in 2003.

Figure 14

World Oil Production, 1990 to 2003



Source: Oil Market Report, IEA.

GAS

World production of gas grew to 2 719 billion cubic metres (bcm), up 3.7% over 2002. Russia and the United States continue to be the largest producing countries in the world, accounting for more than 40% of global gas production.

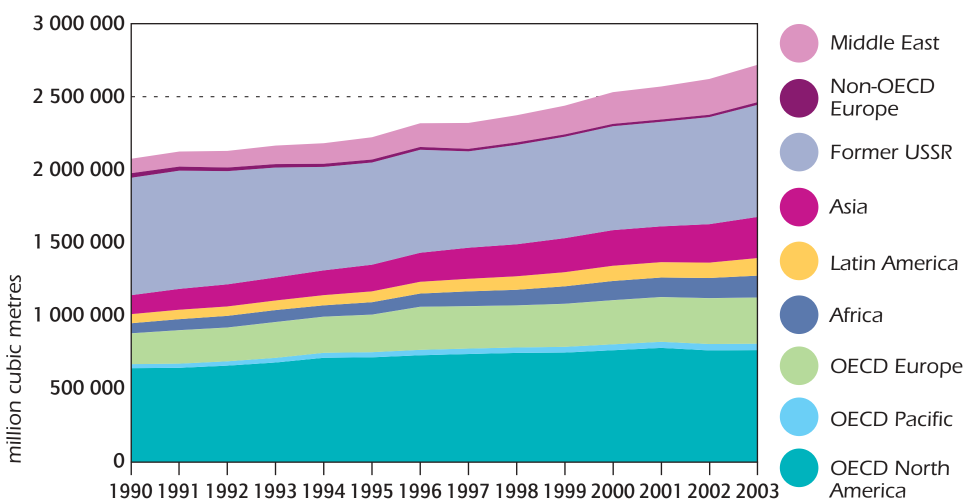
In 2003, the United States upstream was very dynamic and drilling showed strong activities. Natural gas production in the United States rose by 0.5% to 542 bcm in a context of record high prices at the well-head of about US$ 5/million cubic feet on average during the year, even skyrocketing to US$ 6.69/mcf in March. On the other hand, production in Canada was down by 2.9%.

In 2003, the growth of gas production in OECD Europe slowed down to 0.8%. Norway played the major role in European gas production by increasing its production by 11%. On the other hand, gas production in Germany, Denmark, Italy, the Netherlands and the United Kingdom decreased.

Gas production in the FSU grew by 4.7% to 768 bcm in 2003. For the second consecutive year, production in Russia recorded solid growth by 4.3% to 608 bcm. Most of the growth in production came from the Zapolyamoye field in Western

Figure 15

World Natural Gas Production, 1990 to 2003*



* 2003 data are provisional for the OECD and are estimates for the non-OECD countries.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004; and *Energy Statistics of Non-OECD Countries*, IEA/OECD Paris, 2004.

Siberia as Gazprom boosted capacity at the gas processing plant. Turkmen gas production also soared by 11% to 59 bcm.

Gas production in Asia grew by 4.7%. In particular, China, Indonesia, Malaysia, Thailand, India and Pakistan saw gas production increase. In response to growing LNG exports and domestic demand, gas production in the Middle East also increased by 4.5%.

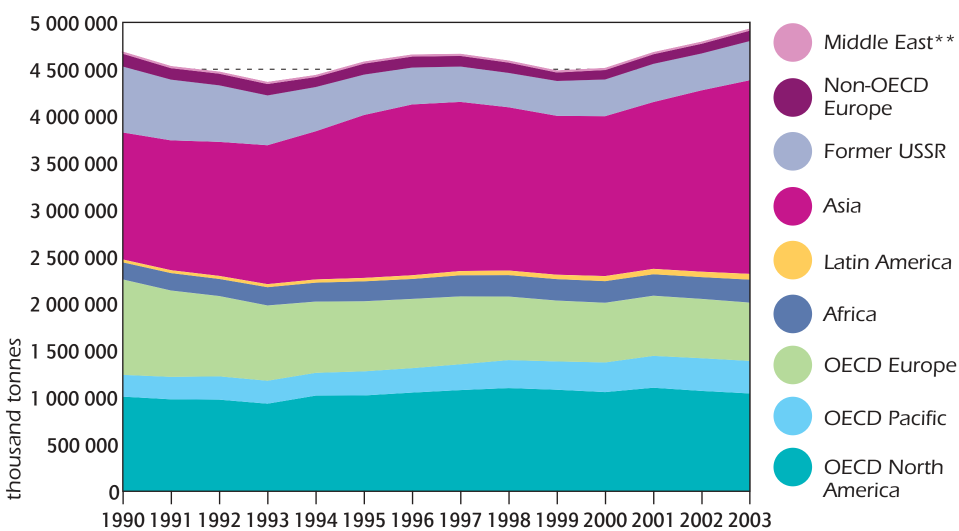
In 2003, OECD North America accounted for 28% of world natural gas production, followed by the FSU (28%), OECD Europe (12%), Asia (10%) and the Middle East (9.4%).

COAL

In 2003, world coal production was 4 924 million tonnes (Mt), up 2.9% from 2002. Chinese coal production surged by 7.5%, following its successive increased in 2001 and 2002. Production in the FSU also recorded an increased of 6.9%, reversing its decrease in 2002. On the other hand, coal production in OECD North America, OECD Europe and OECD Pacific decreased by 2.4%, 1.8% and 0.7% respectively.

Figure 16

World Coal Production, 1990 to 2003*



* 2003 data are provisional for the OECD and are estimates for the non-OECD countries.

** negligible.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004; and *Energy Statistics of Non-OECD Countries*, IEA/OECD Paris, 2004.

ELECTRICITY: OECD

In 2003, electricity generation in OECD countries was 9 822 TWh, up by 0.7% from 2002. Coal-fired generation rose by 2.8% while gas generation, which had been showing rapid growth, rose by just 1.0%. Nuclear power decreased by 2.0%, mainly owing to the nuclear power generation outage in Japan. In Japan, nuclear power generation dropped by 29% as a consequence of continuous outage due to data falsification problems. Hydropower generation decreased by 1.1% because of dry weather conditions. While electricity generated from other renewables grew by 3.3%, their share remains marginal at 2.7 %.

Table 4

Electricity Generation by Source, 1993 and 2003[1]

(TWh)

	France				*Germany*				*Italy*			
	1993		*2003*		*1993*		*2003*		*1993*		*2003*	
	Output	*Share %*	*Output*	*Share %*	*Output*	*Share %*	*Output*	*Share %*	*Output*	*Share %*	*Output*	*Share %*
Coal	25	5	30	5	300	57	308	52	20	9	44	15
Oil	6	1	5	1	10	2	5	1	114	52	74	26
Gas	3	1	24	4	35	7	58	10	40	18	119	42
Nuclear	368	78	441	78	153	29	165	28	0	0	0	0
Hydro	65	14	59	11	18	3	21	4	41	19	37	13
Comb. renewables	2	0	4	1	7	1	33	6	4	2	12	4
Total	**470**	**100**	**563**	**100**	**522**	**100**	**591**	**100**	**220**	**100**	**285**	**100**

	Japan				*United Kingdom*				*United States*			
	1993		*2003*		*1993*		*2003*		*1993*		*2003*	
	Output	*Share %*	*Output*	*Share %*	*Output*	*Share %*	*Output*	*Share %*	*Output*	*Share %*	*Output*	*Share %*
Coal	148	17	295	27	171	53	140	36	1 811	53	2 080	52
Oil	212	24	147	14	21	7	6	2	127	4	124	3
Gas	172	19	248	23	34	11	145	37	441	13	661	17
Nuclear	249	28	250	23	89	28	89	23	647	19	787	20
Hydro	96	11	105	10	4	1	5	1	283	8	243	6
Comb. renewables	19	2	29	3	2	0	8	2	82	2	90	2
Total	**897**	**100**	**1 074**	**100**	**322**	**100**	**392**	**100**	**3 392**	**100**	**3 985**	**100**

1. Preliminary data.

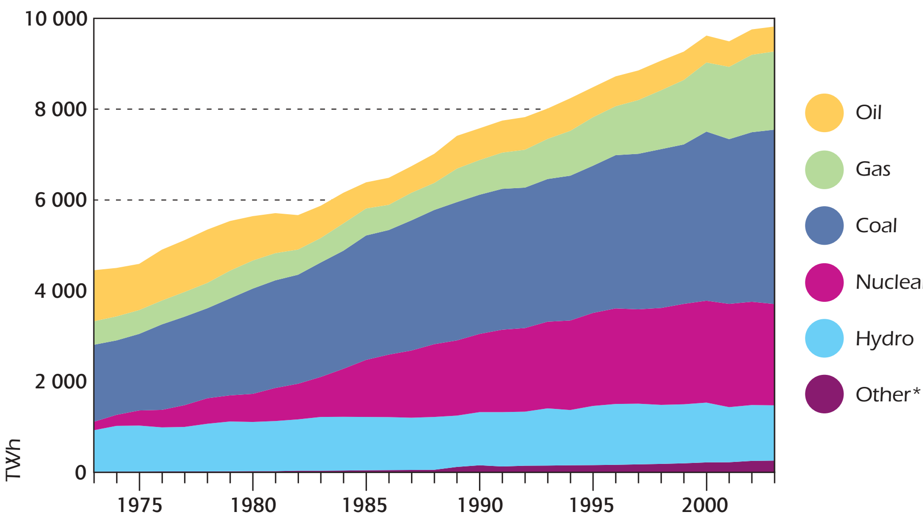
Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Shares in electricity generation in OECD countries were as follows: coal 39%, nuclear 23%, gas 18%, hydro 12%, oil 6%, other renewables 3%.

In the last decade, the share of gas in OECD electricity generation sharply increased. This trend is apparent in OECD Europe, particularly in the United Kingdom and Italy where the share of gas increased from 11% to 37% and from 18% to 42% respectively. In Japan and Italy, the generation from coal power plants has almost doubled in the last decade. Dependence on coal in the United States and Germany is still much higher than the OECD average.

Figure 17

OECD Electricity Supply by Source, 1973 to 2003



* includes geothermal, solar, wind, combustible renewables and wastes.
Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

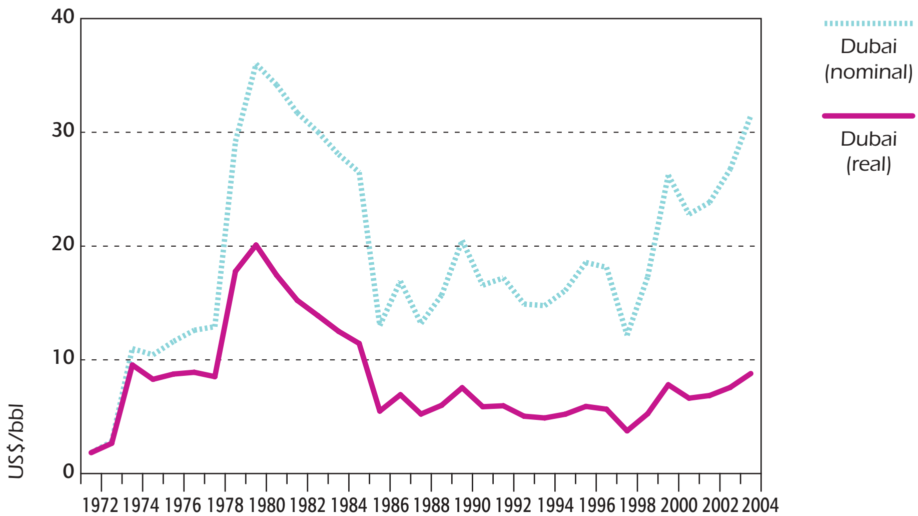
ENERGY PRICES

CRUDE OIL

Average crude oil prices for 2003 rose sharply over 2002 levels. High volatility was seen during the year following some significant supply disruptions and geopolitical issues around the world, coupled with a rapid improvement in world economic conditions. Average prices for the three main marker crudes were $28.83 for Dated Brent (up $3.81 from $25.02 in 2002), $31.06 for West Texas Intermediate (WTI) (up $4.90 from $26.16 in 2002) and $26.76 for Dubai (up $2.91 from $23.85 in 2002).

Figure 18

Crude Oil Prices, 1972 to 2004*



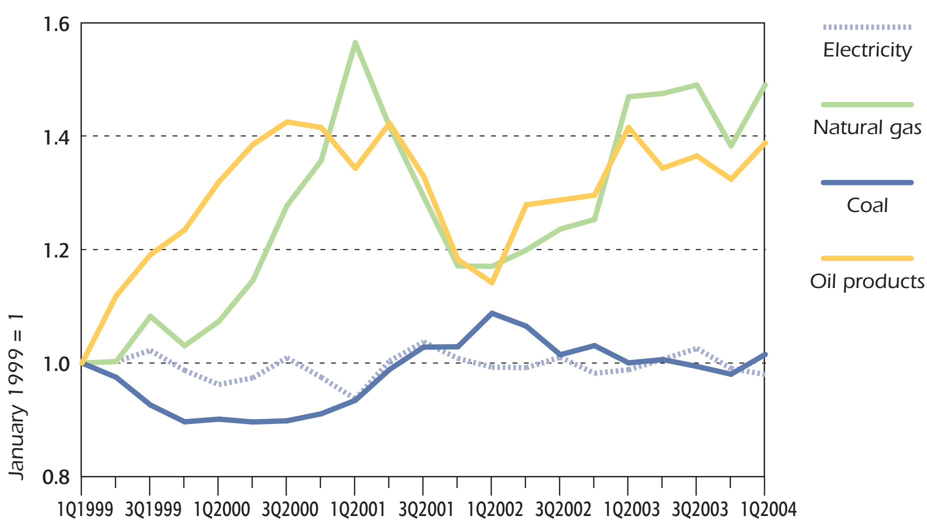
Note: Crude oil prices are annual averages of Arabian Light (1972 to 1984) and Dubai first month (1985 to 2004). Real oil price is based on 1972 dollars. Real price for 2004 data point is estimated by year to date average price divided by the 2004 US GDP deflator.

* 2004 = estimates.

Source: IEA.

Figure 19

Indexed Fuel Prices, First Quarter 1999 to First Quarter 2004



Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

WTI hit the peak for the year in March 2003 at $37.08 following a sharp drawdown in global crude stocks caused by the Venezuelan oil workers strike and concern about military action in Iraq. An increase in crude supplies from OPEC countries, an end to the Venezuelan industrial action and a relatively swift war in Iraq helped to moderate prices in the second quarter of the year.

Prices swiftly resumed their uptrend as demand increased in line with the global economic recovery. Oil demand growth rose globally as concomitant economic growth was seen across the world. China emerged as a major consuming nation of all commodities and a surge in its internal demand for crude and petroleum products was a major driving force for the recovery in oil prices. Continued supply disruptions in Iraq and geopolitical issues in the Middle East, Nigeria and Venezuela were further underpinning features in the crude oil market throughout 2003.

The upward trend in prices seen in the second half of 2003 continued through 2004 in line with the world economic expansion, with benchmark WTI Cushing hitting a peak of $48.75 in mid-August. World oil demand in the first half of 2004, although exaggerated by the depressive effects of SARS (severe acute respiratory syndrome) and the Iraqi war, was provisionally estimated at 81.65 mb/d, up nearly 3 mb/d from the first half of 2003.

As a result of stronger economic growth, the United States and European transportation fuel markets were tightened by a combination of robust demand and heavy refinery maintenance. This produced the most attractive refinery margins for over a decade, supporting the higher crude price trend, particularly for high light-end product yielding light/sweet benchmarks WTI and Dated Brent. Increased production by OPEC reduced their available spare capacity, heightening nervousness about possible supply disruptions in Iraq and the impact of other geopolitical issues.

Impact of High Oil Prices on the Global Economy

Oil prices still matter to the health of the world economy. Higher oil prices since 1999 – partly the result of OPEC supply management policies – contributed to the global economic downturn in 2000-2001 and are dampening the current cyclical upturn: world GDP growth could have been at least half a percentage point higher in the last two or three years had prices remained at mid-2001 levels. Fears of OPEC supply cuts, political tensions in

Venezuela and tight stocks have driven up international crude oil and product prices even further in recent months. By March 2004, crude prices were well over $10 per barrel higher than three years before. Current market conditions are more unstable than normal, in part because of geopolitical uncertainties and because tight product markets – notably for gasoline in the United States – are reinforcing upward pressures on crude prices. Higher prices are contributing to stubbornly high levels of unemployment and exacerbating budget deficit problems in many OECD and other oil-importing countries.

The vulnerability of oil-importing countries to higher oil prices varies markedly depending on the degree to which they are net importers and the oil intensity of their economies. According to the results of a quantitative exercise carried out by the IEA in collaboration with the OECD Economics Department and with the assistance of the International Monetary Fund Research Department, a sustained $10 per barrel increase in oil prices from $25 to $35 would result in 0.4 of a percentage point lower GDP growth for the OECD as a whole in the first and second years of higher prices. Inflation would rise by half a percentage point and unemployment would also increase. The OECD imported more than half its oil needs in 2003 at a cost of over $260 billion – 20% more than in 2001. Euro-zone countries, which are highly dependent on oil imports, would suffer most in the short term, their GDP dropping by 0.5 of a percentage point and inflation rising by 0.5 of a percentage point in 2004. The United States would suffer the least, with GDP falling by 0.3 of a percentage point, largely because indigenous production meets a bigger share of its oil needs. Japan's GDP would fall by 0.4 of a percentage point, with its relatively low oil intensity compensating to some extent for its almost total dependence on imported oil. In all OECD regions, these losses start to diminish in the following three years as global trade in non-oil goods and services recovers. This analysis assumes constant exchange rates.

The adverse economic impact of higher oil prices on oil-importing developing countries is generally even more severe than for OECD countries. This is because their economies are more dependent on imported oil and are more energy-intensive, and because energy is used less efficiently. On average, oil-importing developing countries use more than twice as much oil to produce a unit of economic output as do OECD countries. Developing countries are also less able to weather the financial turmoil wrought by higher oil-import costs. India spent $15 billion, equivalent to 3% of its GDP, on oil imports in 2003. This is 16% higher than its 2001 oil-import bill. It is estimated that the loss of GDP averages 0.8 of a percentage point in Asia and 1.6 percentage points in very poor heavily indebted countries in the year following a $10 oil price increase. The loss of GDP in the sub-Saharan African countries would be more than 3 percentage points.

World GDP would be at least half of 1 percentage point lower – equivalent to $255 billion – in the year following a $10 oil price increase. This is because the economic stimulus provided by higher oil export earnings in OPEC and other exporting countries would be more than outweighed by the depressive effect of higher prices on economic activity in the importing countries. The transfer of income from oil importers to oil exporters in the year following the price increase would alone amount to roughly $150 billion. A loss of business and consumer confidence, inappropriate policy responses and higher gas prices would amplify these economic effects in the medium term. For as long as oil prices remain high and unstable, the economic prosperity of oil-importing countries – especially the poorest developing countries – will remain at risk.

The impact of higher oil prices on economic growth in OPEC countries would depend on a variety of factors, particularly how the windfall revenues are spent. In the long term, however, OPEC oil revenues and GDP are likely to be lower, as higher prices would not compensate fully for lower production. In the IEA's recent *World Energy Investment Outlook*, cumulative OPEC revenues are $400 billion lower over the period 2001-2030 under a Restricted Middle East Investment Scenario, in which policies to limit the growth in production in that region lead on average to 20% higher prices, compared to the Reference Scenario.

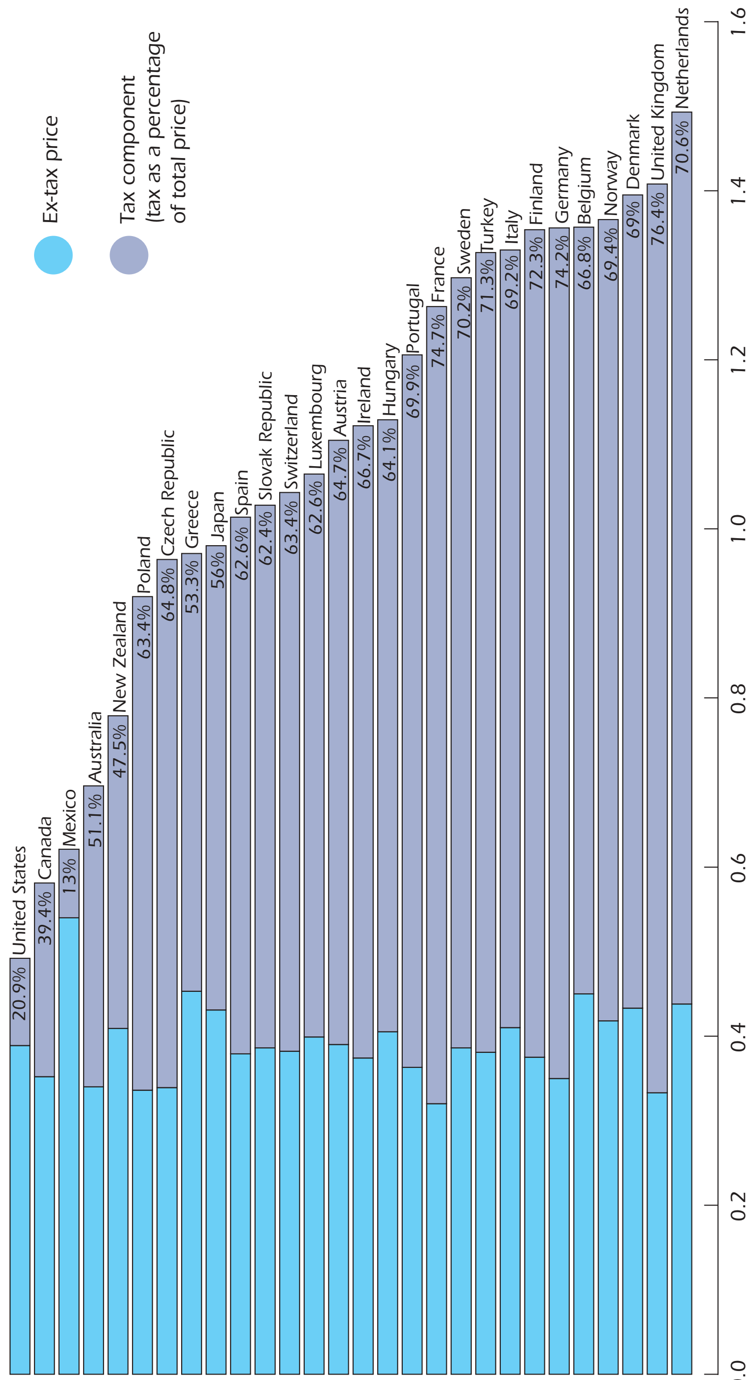
GASOLINE

2003 gasoline prices broadly followed crude oil price movements, particularly in Europe and Asia. The United States, however, experienced a surge in prices during August due to domestic issues, which were compounded by the low product stocks that resulted from the tight crude oil market in the first half of the year. The United States refining industry tends to run close to capacity during the summer months, and a series of disruptions to key refining units were compounded by a major blackout in August that hit several refineries in the United States East Coast, Midwest and Canada. Although the problems were short-lived, gasoline prices rose by over $12/barrel over end-July levels to a peak of $52.45/barrel.

Transportation fuel demand has a strong link with GDP growth which, coupled with a trend towards less-economical sports utility vehicle ownership in the United States, contributed to robust gasoline demand in 2003, particularly in the second half of the year. The Asian market was also tightened by increased domestic gasoline demand which constrained exports in the fourth quarter of the year.

Figure 20

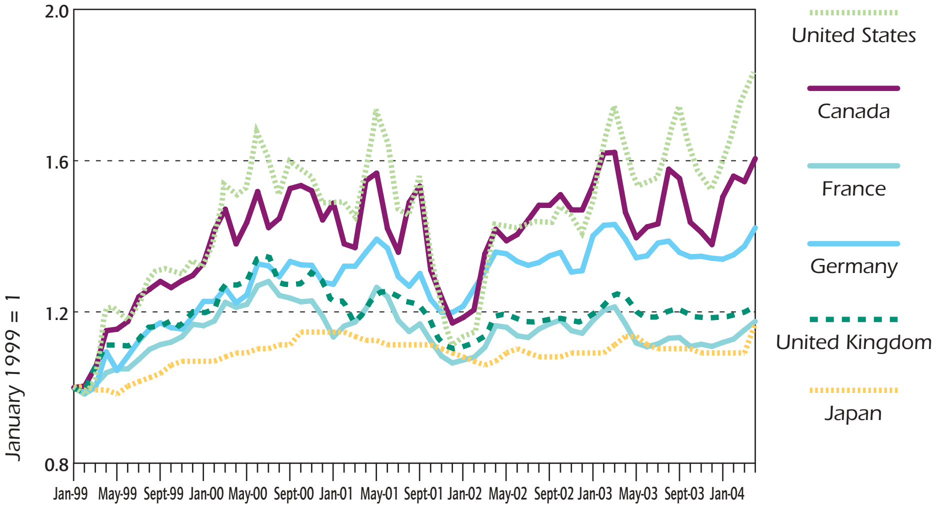
OECD Unleaded Gasoline Prices and Taxes, First Quarter 2004



Note: Data not available for Korea.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 21
Gasoline Price Trends in Selected IEA Countries, January 1999 to April 2004



Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

DIESEL

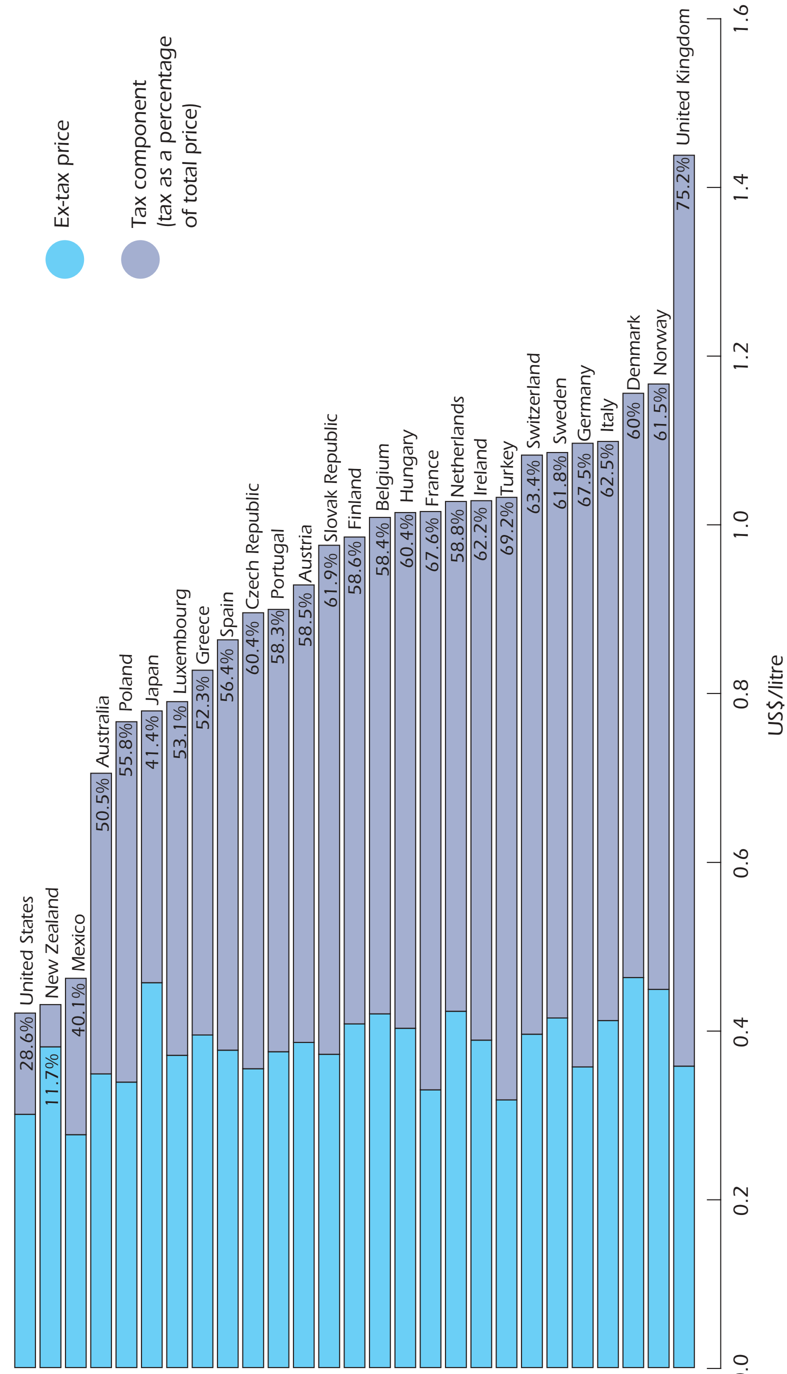
Diesel prices rose sharply in 2003, following the general trend in crude prices. However, a cold winter in the United States and strong military demand into the Middle East ahead of the war in Iraq tightened the distillate market in the first quarter of 2003. Diesel is part of the middle distillate portion of refined products that includes jet/kerosene and heating oil. Consequently, increased demand for one or more of these products can often cause a reduction in the supply of other distillate products.

The cold United States winter in the second half of 2003 attracted European distillate stocks to the United States during February which, combined with strong military demand for diesel and jet aviation fuel in the Middle East, drew down European stocks and resulted in a spike in regional diesel prices in early March. Chinese demand for distillate products also increased sharply in 2003, particularly in the second half of the year.

SPACE HEATING OIL

The price trend in space heating oil and diesel in 2003 was broadly similar to the path followed by the diesel market, with the supply of the two products being very closely linked. Cold temperatures in the United States in the first quarter of 2003 bolstered demand, but this was followed by a sharp fall in

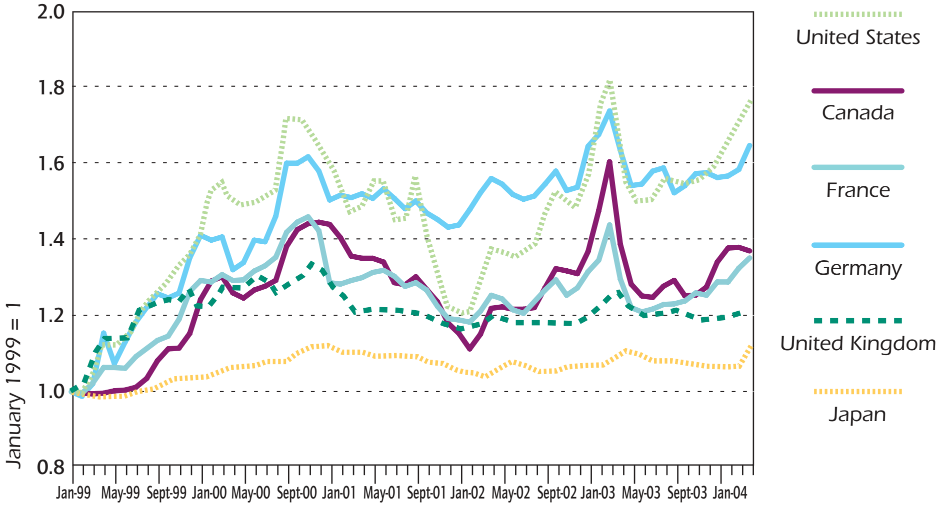
Figure 22 **OECD Automotive Diesel Prices and Taxes, First Quarter 2004**



Note: Data not available for Canada and Korea.
Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 23

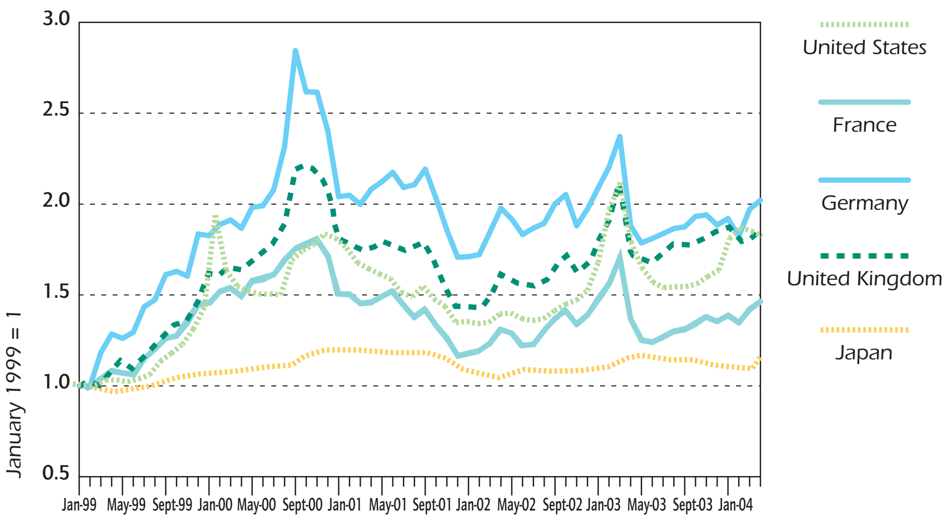
Diesel Price Trends in Selected IEA Countries, January 1999 to April 2004



Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 24

Space Heating Oil Price Trends in Selected IEA Countries, January 1999 to April 2004



Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

prices around the onset of the Iraqi war. This encouraged some early post-winter restocking by consumers which, coupled with a rebuilding of primary inventories, helped to reduce price volatility in the second half of 2003.

A surge in demand in China for diesel-powered electricity generators and for heating purposes turned China from a net gasoil exporter to a net importer in the fourth quarter of 2003, underpinning prices.

NATURAL GAS

Spot prices at Henry Hub, the most active spot market centre in the United States, peaked in March 2003 at more than US$ 9/million British thermal units (MBtu) and remained high throughout 2003 and the beginning of 2004. They averaged US$ 5.47/MBtu in 2003, up 63% from their 2002 average of US$ 3.35/MBtu. The Energy Information Administration[1] projects that natural gas prices will continue at high levels through the rest of 2004. Spot prices averaged about US$ 5.35 MBtu in the first quarter of 2004 and were above US$ 6.00 during the spring and early summer, as strong demand for natural gas coupled with high petroleum prices have led to higher gas prices despite nearly normal storage inventory levels. Natural gas prices weakened during the summer as cooling demand levels and peak power demand stayed below normal. Storage stocks at the end of May 2004 were less than 1% below the 5-year average (1999-2003) and 23% higher than the previous year at the same time. Overall in 2004, spot prices will likely average about US$ 5.85/MBtu, which is 7% higher than the 2003 average.

Import prices in Europe increased too in 2003, but not as sharply as in the United States. EU import prices by pipeline averaged about US$ 3.92/MBtu, compared with an average US$ 3.17/MBtu in 2002, an increase of 24%. This rise reflects, with an approximately six-month time lag, the movement of gasoil and low-sulphur fuel oil (LSFO) prices, to which the price of imported gas is indexed in European contracts.

Table 5

Quarterly Natural Gas Price Indices

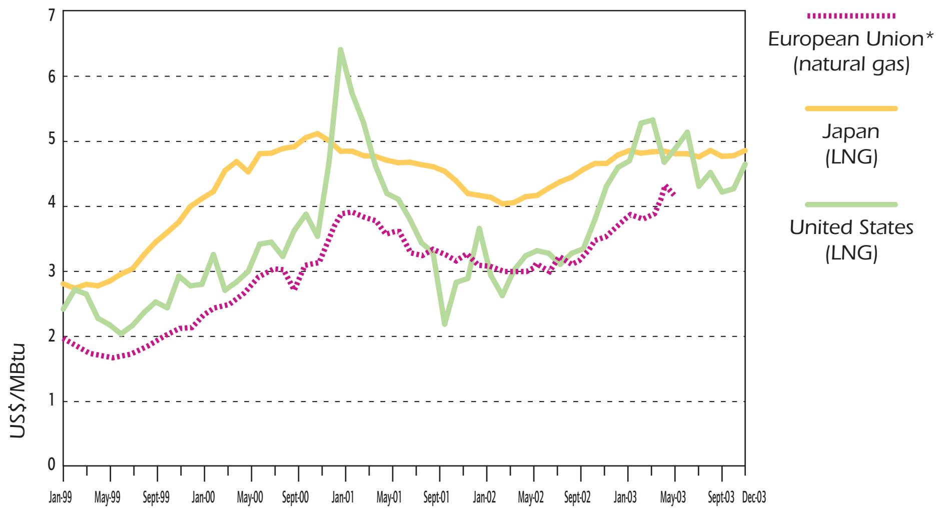
	OECD	*North America*	*Europe*	*Pacific*
1Q2003	151.0	182.3	115.4	107.8
1Q2004	151.7	184.5	114.2	108.5

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

1. EIA Short-term Energy Outlook, http://tonto.eia.doe.gov/oog/info/ngw/steosummary.htm

Figure 25

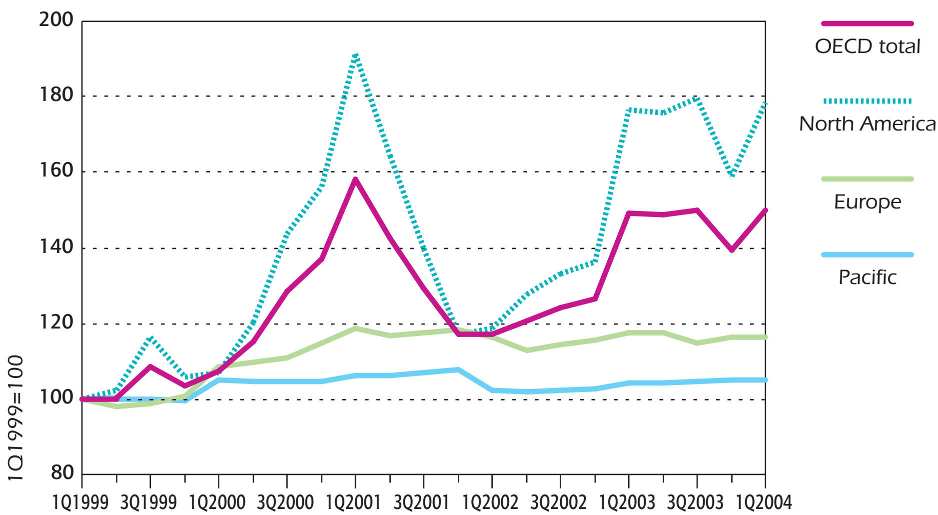
Gas and LNG Import Prices in the European Union, Japan and the United States, January 1999 to December 2003



* average import prices. Calculated average prices may not be comparable from one month to the other owing to differing components.
Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 26

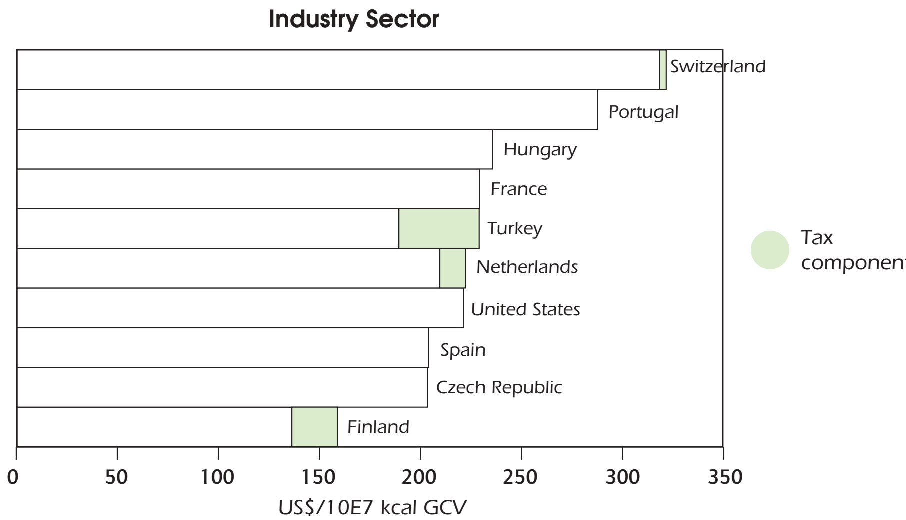
End-use Gas Prices by OECD Region, First Quarter 1999 to First Quarter 2004



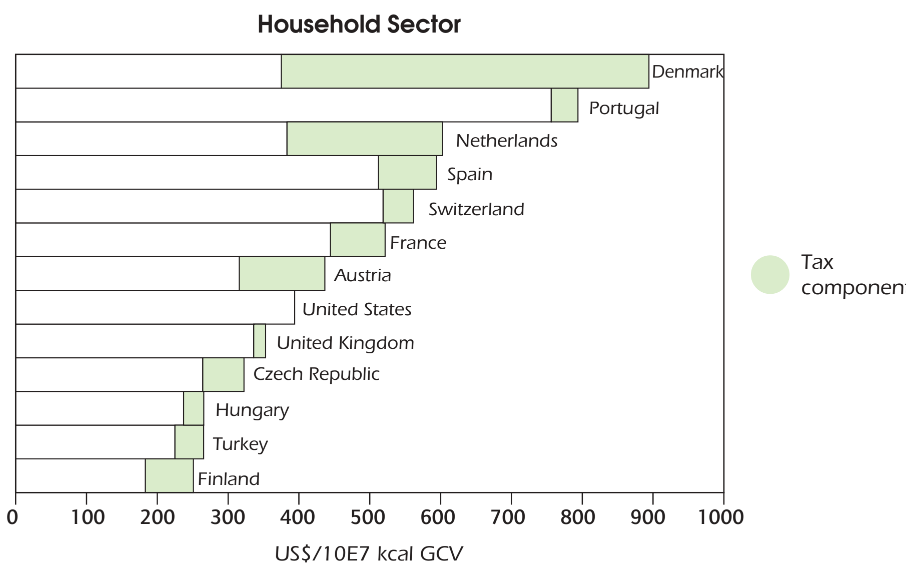
Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 27

Gas Prices in IEA Countries, 2003



Note: Tax information not available for the United States. Data not available for Australia, Austria, Belgium, Canada, Denmark, Germany, Greece, Ireland, Italy, Japan, Korea, Luxembourg, New Zealand, Norway, Sweden and the United Kingdom.



Note: Tax information not available for the United States. Data not available for Australia, Belgium, Canada, Germany, Greece, Ireland, Italy, Japan, Korea, Luxembourg, New Zealand, Norway and Sweden.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

In Japan and Korea, import LNG prices increased in 2003 compared with 2002. In Japan, cif LNG import prices amounted to US$ 4.82/MBtu on average, up 12% compared with 4.32 in 2002. This reflects the additional needs from the electricity sector to cope with nuclear power outages. Prices are based on the Japanese crude cocktail (JCC) and reflect the evolution of JCC with a time lag shorter than the European one. In Korea, import LNG prices increased to about US$ 5.04/MBtu in 2003, up 16% compared with US$ 4.36 in 2002.

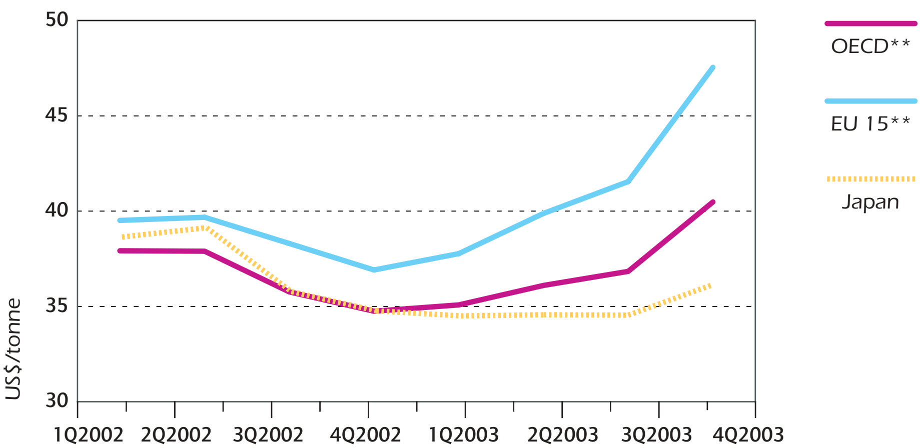
Following the increase throughout 2002 and sharp rise in 1Q 2003, end-use prices for natural gas in OECD North America stayed high throughout the year 2003. Average prices in 2003 were 34% higher than those of 2002. On the other hand, end-use gas prices in OECD Europe were almost stable during the same period, reflecting long-term contracts. End-use gas prices in OECD Pacific were also stable.

COAL

Steam coal prices were on a declining trend in the first half of 2003, but started to climb rapidly in the second half of the year principally because of freight rates and the impact of exchange rate movements. The spot market delivered price of steam coal imported into Europe rose from about US$ 33 per tonne in May 2003, to about US$ 49 per tonne in October 2003, and to about US$ 65 per

Figure 28

Steam Coal Import Costs*, First Quarter 2002 to Fourth Quarter 2003
(average unit value, CIF)



Note: Excludes the Czech Republic, Hungary, Iceland, Korea, Mexico, New Zealand, Norway, Poland, the Slovak Republic, Switzerland and Turkey.

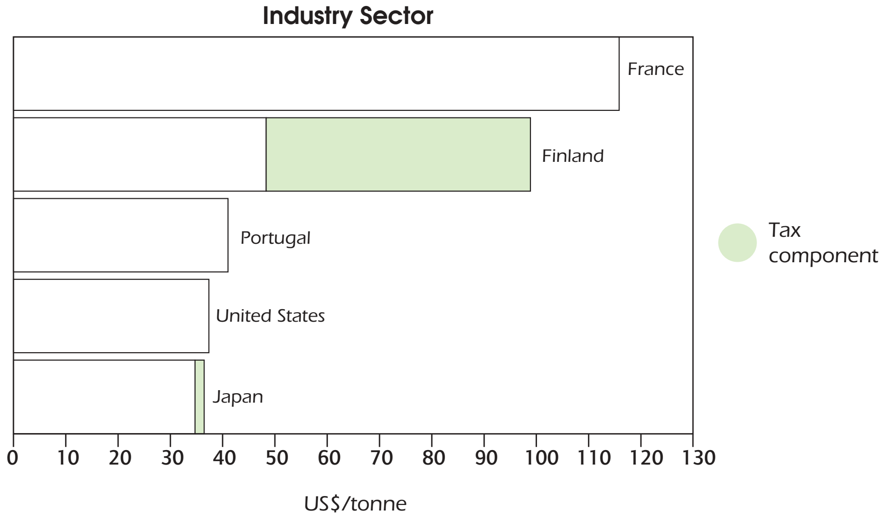
* excluding intra-EU trade.

** weighted average of individual countries using import volumes as weights.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 29

Steam Coal Prices in IEA Countries, 2003



Note: Data not available for Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Germany, Greece, Hungary, Ireland, Italy, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

tonne in December 2003. The delivered price to Japan rose from about US$ 36 per tonne in October 2003 to about US$ 48 per tonne in December 2003. While the annual import price of steam coal in 2003 was just 1.4% above the 2002 level, in 4Q 2003 the import price was 16% higher than 4Q 2002.

Coking coal prices are also rising. Recovery in steel output and the shortage of high-quality coking coal are the underlying causes of higher prices in this market. Competing domestic demand growth in China has reduced coking coal available for export. This has added tension to the market because coking coal reserves are less widely distributed throughout the world and China is an important supplier to Japan and Korea.

Freight rates are determined independently of the coal market because the dominant bulk cargoes are grains and iron ore, which compete directly with coal for space. Coal freight doubled in the Atlantic market from about US$ 12 per tonne in October 2003 to about US$ 25 per tonne in January 2004. Shipping demand has been high to meet growth in bulk commodity trade, particularly of iron ore to China.

The immediate influence of freight rates will eventually subside. Reports of new investment in bulk carriers began emerging in March 2004 and a cyclical downturn in rates is inevitable as capacity becomes available. Competition with other fuels encourages the belief that coal prices could nevertheless remain high. Higher oil prices, and perhaps more importantly uncertainty about the trend in oil prices, must have an overall influence on energy prices generally. Higher gas prices could raise the ceiling on coal prices.

ELECTRICITY

Average electricity prices in the OECD regions have been on a declining trend throughout the past decade, but were stable during the last three years. From 1Q to 3Q of 2003, higher fuel prices (oil and gas) have created an upward pressure in OECD countries. In OECD North America and OECD Pacific, the price trends tend to peak in 3Q, reflecting peak summer demand.

Table 6

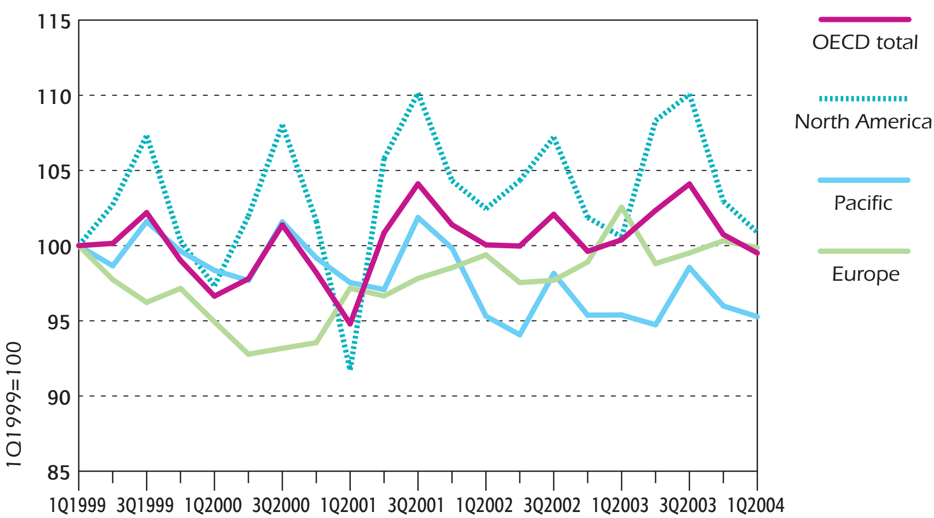
Quarterly Electricity Price Indices

	OECD	*North America*	*Europe*	*Pacific*
1Q2003	92.4	89.3	96.5	91.9
1Q2004	91.6	89.6	94.0	91.8

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 30

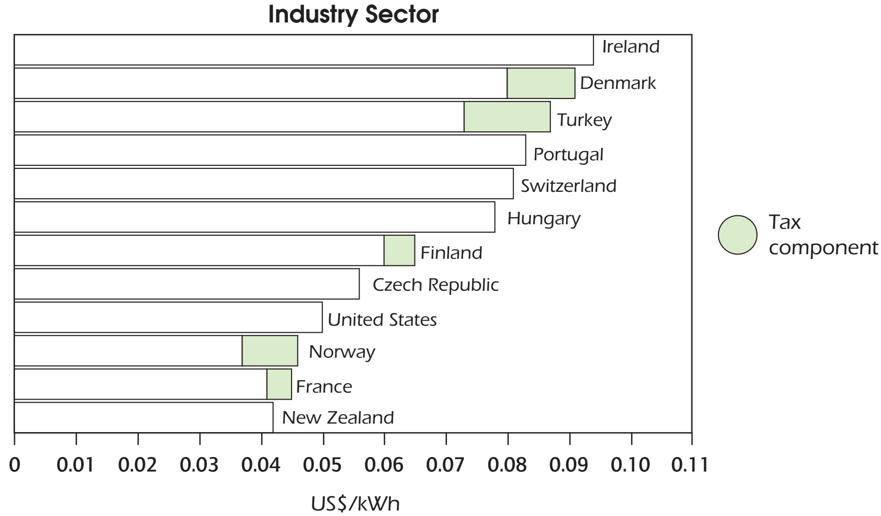
End-use Electricity Prices by Region, First Quarter 1999 to First Quarter 2004



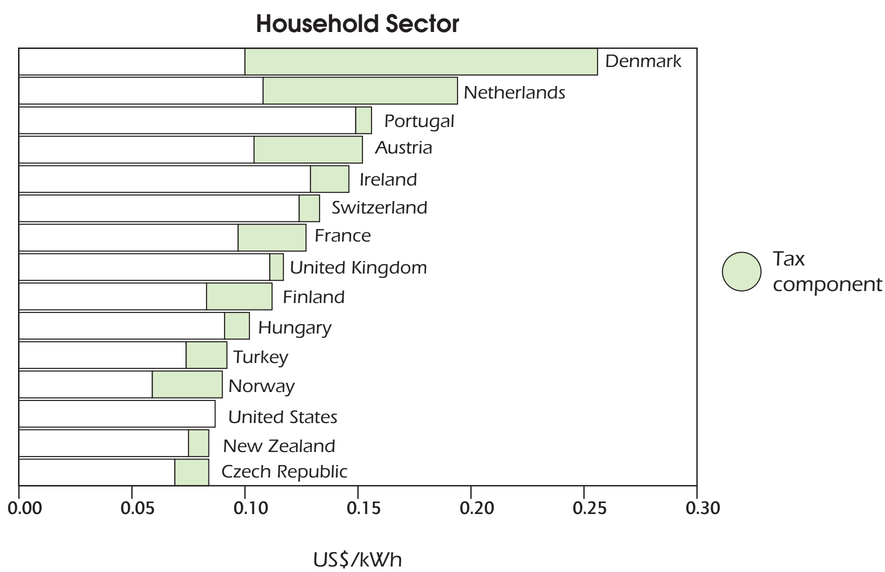
Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Figure 31

Electricity Prices in IEA Countries, 2003



Note: Price excluding tax for the United States. Data not available for Australia, Austria, Belgium, Canada, Germany, Greece, Italy, Japan, Korea, Luxembourg, the Netherlands, Spain, Sweden and the United Kingdom.



Note: Price excluding tax for the United States. Data not available for Australia, Belgium, Canada, Germany, Greece, Italy, Japan, Korea, Luxembourg, Spain and Sweden.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

ENERGY INTENSITY AND CO_2 EMISSIONS

ENERGY INTENSITY

In IEA member countries, energy intensity in 2003 expressed as total primary energy supply (TPES) divided by gross domestic product (GDP) in purchasing power parities (PPPs) stayed at the same level as the 2002 figure. From a long-term perspective, it fell by 36% from the 1973 figure.

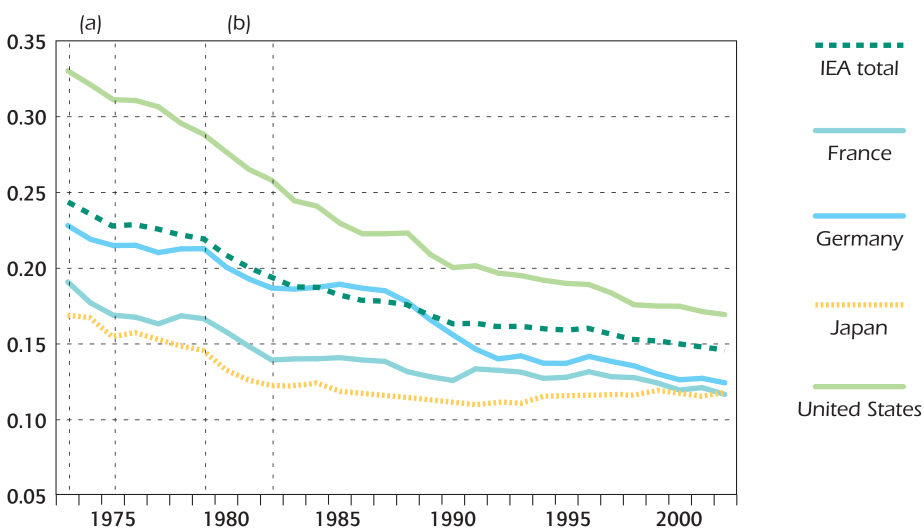
While such overall improvement of energy intensity can be observed, the rate of decline varies between countries. Energy intensity in the United States has decreased by 44% from 1973 to 2003, while in Germany, Japan and France it has dropped by 41%, 25% and 21% respectively during the same period. Many factors influence the development of energy per GDP, including improvements in energy efficiency and changes in the level of energy services that consumers and businesses demand relative to GDP.

Despite the significant decline, United States energy intensity in 2003 was still 33% higher than the IEA average. Some of the other IEA countries not shown in Figure 32 diverge even further from the average. Why are the differences in intensity across countries so significant? Part of the difference

Figure 32

Energy Intensity in Selected IEA Countries, 1973 to 2002

(toe per thousand US$ at 1995 prices and purchasing power parities)



(a) corresponds to the first oil shock (end 1973) and macro-economic recession induced by this shock.

(b) corresponds to the second twin oil shock (early 1979 and end 1980) and the macro-economic recession induced by this double shock.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004; and *National Accounts of OECD Countries*, OECD Paris, 2004.

reflects variations in energy efficiency but it would be very misleading to rank energy efficiency performance according to a country's energy per GDP measure since that ratio is affected by many non-energy factors such as climate, geography, travel distance, home size and manufacturing structure.

Similarly, it is misleading to judge a country's improvement in energy efficiency over time only on the basis of the energy consumption per GDP ratio. Understanding energy efficiency developments requires a closer look at how energy service demand and energy intensities disaggregated by end-use and sector have evolved. The recent IEA publication *Oil Crises and Climate Challenges: 30 Years of Energy Use in IEA Countries* provides a detailed analysis of how various factors, including energy efficiency, have affected energy demand and CO_2 emissions in IEA countries since 1973. The box below highlights some of the finding from this study.

Figure 33 illustrates the wide spread in some of the factors that can help to explain why countries use different levels of energy per unit of GDP.[2] The spread is shown for both 1973 and 1998. Note that the spread in GDP per capita basically did not change while the spread in TFC per capita decreased from 1973 to 1998. This helps to understand why the variations in TFC/GDP in 1998 are lower than in 1973 (see also Figure 32).

The proportion of energy-intensive raw materials manufacturing in GDP is significant for energy use levels in an economy: the production of some products like steel and aluminium requires 10 to 20 times the energy per value-added than less energy-intensive products such as electronics. Compared to generating GDP in the services sector, the difference is even higher, often more than a factor of 30. The spread in the raw material share of GDP has increased since 1973. It varied by a factor of 2.5 among the countries in 1998, indicating that differences in industry structure are still a crucial factor behind differences in energy per GDP levels.

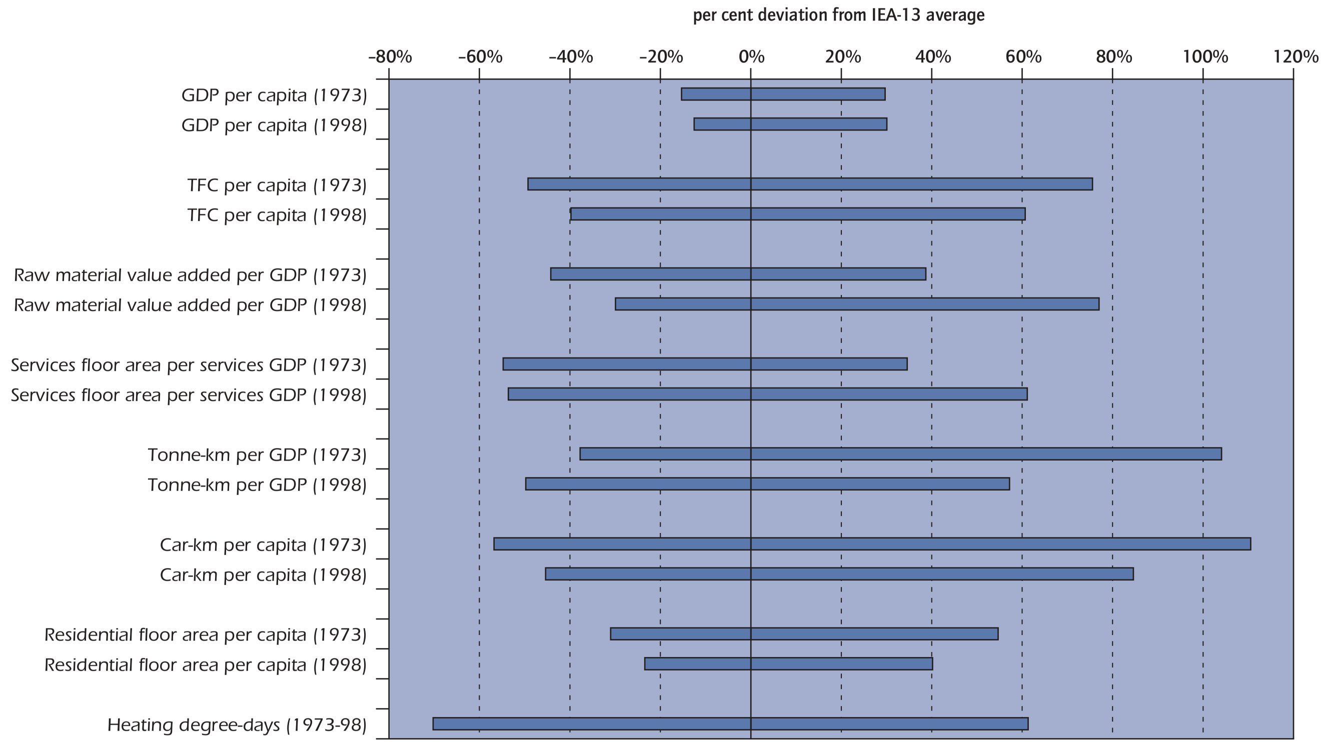
The range in another key factor, the building area per unit of GDP in the services sector, has also increased since 1973. The larger the area-per-dollar-generated, the more demand for energy for heating, cooling and lighting and the higher contribution to the energy per GDP ratio. In 1998, this varied by a factor of 3.5 among the thirteen IEA countries included in Figure 33.

Clearly in freight transportation, the more goods moved around at a given level of GDP, the higher the freight energy use in an economy. Tonne-km per GDP in 1998 varied by more than a factor of 3 among the IEA-13 countries, to a large extent because of differences in country size. Geography also explains to some degree the differences in automobile use per capita, which in 1998 ranged from more than 13 000 km/year in the United States to 3 900 km/year in Japan.

2. The findings presented in this box are taken from the IEA publication *Oil Crises and Climate Challenges: 30 Years of Energy Use in IEA Countries*, IEA/OECD 2004.

Figure 33

Minimum and Maximum versus IEA-13* Average Values for Key Factors Affecting Energy Use



* IEA-13 denotes Australia, Canada, Denmark, Finland, France, Germany, Italy, Japan, the Netherlands, Norway, Sweden, the United Kingdom and the United States.

Source: *Oil Crises and Climate Challenges: 30 Years of Energy Use in IEA Countries*, IEA/OECD Paris, 2004.

Household area per capita also impacts a country's energy use. The variation in this ratio fell from 1973 to 1998, but there was still a difference of almost a factor of 2 between the highest value (United States) and lowest (Japan). Climate is a key determinant for energy use in buildings. IEA countries cover a wide range of winter climates with 30-year average heating degree days (base 18°C) varying from 900 in Australia and 1 800 in Japan to more than 4 500 in Canada and Finland.

As shown in Figure 32 there are also significant variations between countries in how much energy per unit of GDP has fallen over time. Not all of these variations are due to different rates of energy efficiency improvements; some of them stem from differences in how the demand for energy services has evolved relative to GDP. How much the demand for energy services has grown depends on the development of factors such as those depicted in Figure 33. To better isolate the impact of energy efficiency, changes in energy use per GDP can be decomposed into the impact of two main factors: changes in the ratio of energy service demand to GDP and changes in sub-sectoral energy intensities (such as energy used to heat a square metre of floor space or to ship a tonne of freight per kilometre). Changes in the latter factor are closely related to changes in energy efficiency and thus of key policy interest.

The result of this decomposition for a group of eleven IEA countries is shown in Figure 34.[3] The intensity effect for the whole economy is calculated as the sum of changes in energy intensities for some 30 end-uses, weighted at 1990 energy use shares.

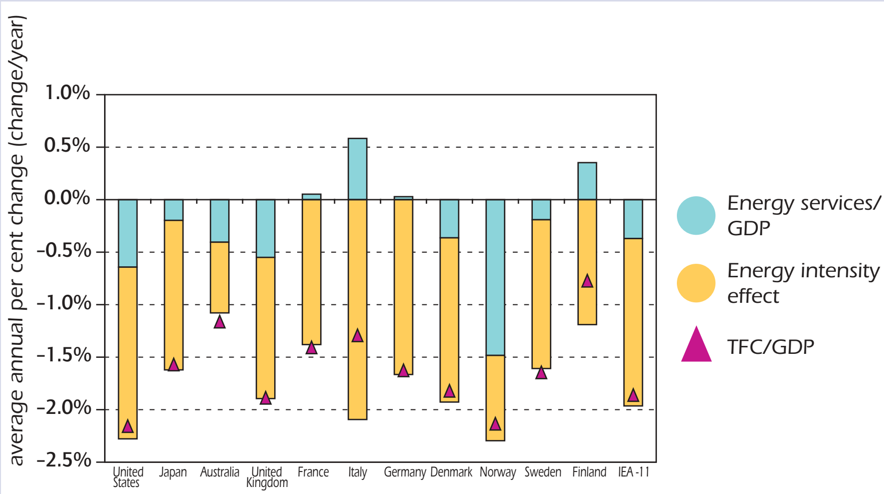
Energy per unit of GDP fell by between 1% and 2% per year on average since 1973, except in the United States where it fell more and in Finland where it fell less. In almost all countries, lower growth in energy services than in GDP, *i.e.* demand for energy services relative to GDP fell, helped reduce the energy per GDP ratio. In most countries the main reason why energy service demand grew at a slower rate than GDP is changes in industry structure towards less energy-intensive products. This lowers the energy required to produce one unit of manufacturing value added. In many countries, another important factor is that the increase in heated building area lagged economic growth and thus reduced the need for space heating relative to GDP. The countries with the strongest reduction in energy per GDP (the United States, the United Kingdom, Denmark and Norway) are also the countries where energy services declined relative to GDP. In the United States and to some extent in Denmark, this was because energy service levels in the early 1970s were already relatively high. In Norway and the United Kingdom, a rapid expansion in offshore oil and gas production led to strong GDP growth without increasing the demand for land-based energy services at the same rate.[4]

3. IEA-11 is IEA-13 less Canada and the Netherlands. The methodology used for the IEA study requires time series going back to 1973 with detailed energy and activity data. IEA-11 represents the countries for which these data were available. Together, IEA-11 account for more than 80% of IEA total energy demand and thus the results shown for this group well represent the overall IEA development.

4. Energy use in oil and gas production is accounted for in the energy sector and is thus not part of TFC.

Figure 34

Changes in TFC/GDP Decomposed into Changes in Energy Service/GDP and Intensity Effect*, IEA-11, 1973 to 1998

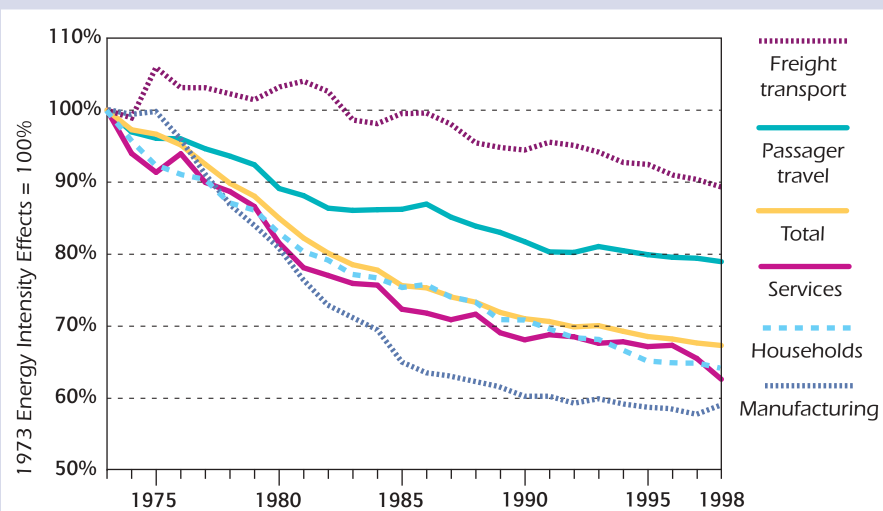


* In the index decomposition approach used here, the sum of the annual percentage changes in energy services per GDP and energy intensities does not always add up to the changes in TFC/GDP owing to a residual interaction term. This explains why the triangles representing TFC/GDP do not exactly match the sum of the two other components for some countries.

Source: *Oil Crises and Climate Challenges: 30 Years of Energy Use in IEA Countries*, IEA/OECD Paris, 2004.

Figure 35

Sector Intensities and Total Economy Effect, IEA-11



Source: *Oil Crises and Climate Challenges: 30 Years of Energy Use in IEA Countries*, IEA/OECD Paris, 2004.

In the countries where demand for energy services grew less than GDP, energy per GDP declined faster than what was attributable to the effect of falling sub-sectoral intensities. This means that using energy per GDP as a measure for energy efficiency developments would overestimate the improvements. On the other hand, in Italy and Finland, where growth in energy services outpaced economic growth, the effect of declining intensities is stronger than what the energy per GDP ratio would imply. In these two countries, the main reason is that the production of energy-intensive raw materials grew faster than GDP. In the case of Italy, this was augmented by a strong growth in passenger travel, increasing the demand for transport fuels relative to GDP.

For a majority of countries, declining end-use intensities have been responsible for most of the drop in the energy/GDP ratio during the 1973 to 1998 period. But notably, almost everywhere the rate of decline has slowed since the mid to late 1980s. The line labelled "Total" in Figure 35 illustrates the effect the decline in these intensities (the economy-wide intensity effect) had on IEA-11 energy use (also depicted in Figure 34). This intensity effect declined by as much as 2.0% per year on average between 1973 and 1990. After 1990, the decline rate was down to only 0.7% per year, averaged over the 1990 to 1998 period. Investigating data for countries where more recent data are available confirms the tendency of slowing energy saving rates across most sectors.

This trend of slowing rates of energy savings is most prominent in the manufacturing sector: the manufacturing intensity effect (corrected for structural changes) for IEA-11 fell by 41% over the 1973 to 1998 period, but it had already declined by 36% by 1986 (Figure 35). This corresponds to an average annual rate of decline of 3.5% between 1973 and 1986 and only 0.6% per year for the next twelve years.[5]

The services and household sectors trailed manufacturing in terms of total intensity reductions. The decline rates in these two sectors have followed each other closely throughout most of the period, with slightly stronger reductions than the average for the whole economy. Passenger and freight transport have pulled up the average economy-wide intensity effect. Energy use for freight transport is dominated by trucks, and although individual trucks have become more efficient, the energy intensity decline per tonne-km is modest owing to a trend towards trucks carrying lighter goods. Similarly, the intensity effect for passenger transport is heavily influenced by the limited reduction in fuel use per car-km that took place over this period. Major improvements were made to engines and other car components, but these were largely offset by heavier and more powerful cars.

5. This intensity measure is adjusted for changes in manufacturing structure, *e.g.* shift in the mix of output. Generally the output mix in IEA shifted moderately towards less energy-intensive products. Together, the energy intensity effect and the effect of structural changes reduced aggregate IEA-11 energy use per manufacturing value-added by 50% between 1973 and 1998.

CO_2 EMISSIONS

During 2002, energy-related CO_2 emissions in IEA countries grew by 0.7% compared to 2001, reaching more than 11.8 billion tonnes, up 15% compared to 1990 levels. In 2002, IEA North America represented 52% of total IEA energy-related CO_2 emissions; IEA Europe 31%; and IEA Pacific 17% (see Table 7). This increase is greater than the 2000-2001 increase in energy-related CO_2 emissions (0.5%). However, the escalation was not homogeneous among regions. The 2001-2002 increase in IEA Pacific and IEA North America was 2.4% and 0.9% respectively, while there was a decrease of 0.72% in IEA Europe. Since 1990, aggregate emissions for IEA Pacific have risen by 26%, in IEA North America by 18%, and in IEA Europe by only 3% over the same period. In all regions, the two main reasons for increased energy-related CO_2 emissions are the rising demand in road-based transport and an increase in power generation.

Although overall emissions increased in 2002 compared to 2001, some sectors experienced a decrease – with marked differences between IEA regions. While reductions in CO_2 emissions in IEA Pacific and IEA North America came mainly from the industry sector (–1.2% and –3.8% respectively compared to 2001), in IEA Europe they came from other energy industries and the agricultural sector (–4%).

CO_2 emissions related to industry represented on average 15% of total energy-related emissions of IEA countries (*i.e.* 1 705 Mt CO_2). Since 1990, the share of these emissions has decreased by over 7%. Nevertheless, in countries such as Japan, industry emissions have grown by approximately 5% since 1990.

Over the last decade, CO_2 energy-related emissions from the transport sector increased continuously. Its share in total emissions remained stable at 27%. In 2002, the share of energy-related emissions from the transport sector represented 28% of IEA energy-related CO_2 emissions (*i.e.* 3 275 Mt CO_2), compared to 2 636 Mt CO_2 in 1990. There were stark contrasts between IEA countries.

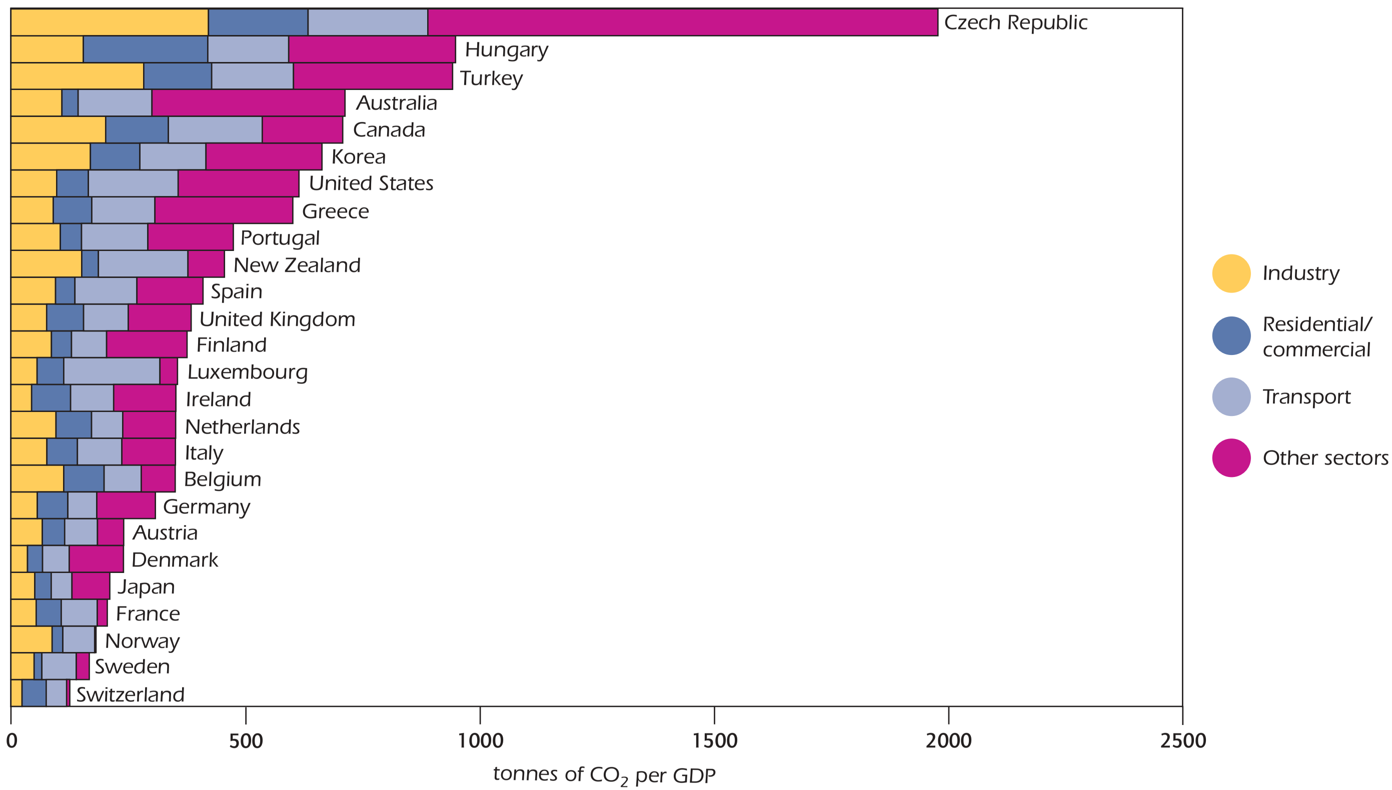
Energy production has remained by far the largest component, 39% in total energy-related CO_2 emissions in most IEA countries, reaching 4 539 Mt CO_2 in 2002. Its relative importance varied between IEA countries, ranging from 58% for Australia to less than 5% for Norway where hydroelectricity plays a dominant role in the production of electricity and heat. The carbon content per kWh from electricity and heat generation in IEA countries has remained stable over the past decade despite an increase in total emissions from energy production of 26% since 1990. IEA North America is the main contributor to CO_2 emissions from energy production in the IEA total.

The residential and commercial sector accounts for 8% of the total IEA energy-related CO_2 emissions. Emissions from this sector have increased by 2.5% over the last decade, totalling 0.98 Mt CO_2 in 2002. However, the per capita emissions from this sector have remained constant.

Figure 36

CO_2 Emissions per GDP by Sector in IEA Countries, 2002

(CO_2 emissions/GDP using 1995 prices and exchange rates)



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004; and *National Accounts of OECD Countries*, OECD Paris, 2004.

It is clear from these observed emission trends that if reductions are to be achieved in the sectors mentioned above, additional policies and measures will be needed (see Chapter 7 for details on the policies and measures which have been implemented in 2003).

Table 7

Energy-related CO_2 Emissions in IEA Countries

(excluding international marine and aviation bunkers) (million tonnes of CO_2)

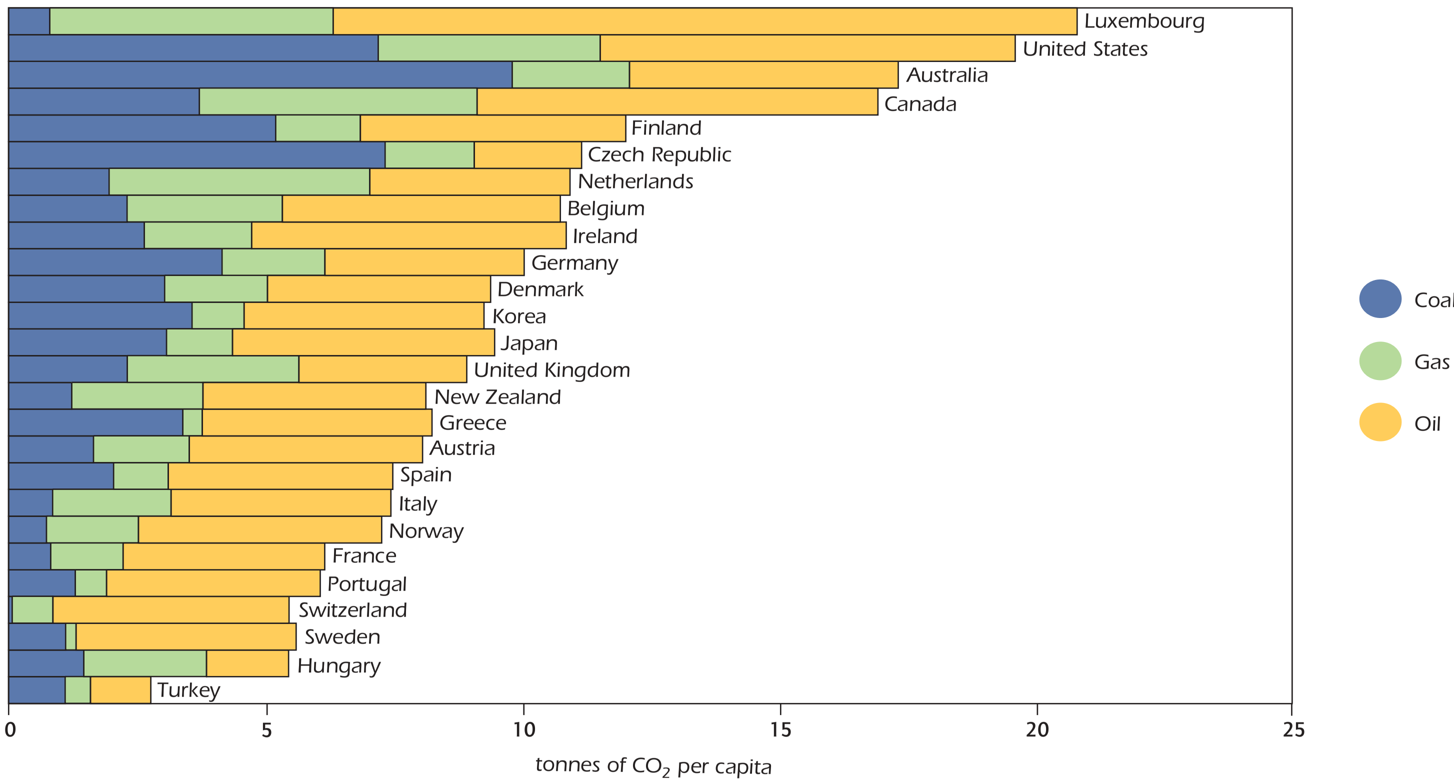
	1990	*2002*	*% change 1990-2002*	*2010*	*% change 1990-2010*
Canada	430	532	23.63	575	33.74
United States	4 843	5 652	16.71	6 776	39.92
North America	**5 273**	**6 184**	**17.28**	**7 352**	**39.41**
Australia	260	343	32.02	398	53.39
Japan	1 015	1 207	18.89	1 146	12.90
Korea	226	452	99.65	..	..
New Zealand	22	34	52.47	33	48.92
Pacific	**1 523**	**2 035**	**33.61**	**..**	**..**
Austria	57	66	15.41	66	14.57
Belgium	107	113	5.30	..	..
Czech Republic	154	115	- 25.24	104	- 32.65
Denmark	51	51	1.23	64	26.75
Finland	55	64	15.50	61	10.22
France	353	377	6.92	415	17.64
Germany	966	838	- 13.34	..	..
Greece	71	90	28.17	118	67.43
Hungary	71	55	- 21.38	58	- 17.68
Ireland	30	42	40.33	45	47.17
Italy	400	433	8.29	476	19.03
Luxembourg	10	9	- 11.28	8	- 22.94
Netherlands	157	178	13.20	166	5.79
Norway	29	33	15.27	..	..
Portugal	40	63	59.00	67	67.94
Spain	207	303	46.92	340	64.67
Sweden	51	50	- 1.63	48	- 6.12
Switzerland	42	43	3.20	44	5.49
Turkey	129	193	49.88	405	214.76
United Kingdom	560	529	- 5.54	539	- 3.87
IEA Europe	**3 538**	**3 646**	**3.06**	**..**	**..**
IEA Total	**10 335**	**11 866**	**14.82**	**..**	**..**

Note: Energy-related CO_2 emissions have been estimated using the IPCC Tier I Sectoral Approach. In accordance with the IPCC methodology; emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2002 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.

Sources: *CO_2 Emissions from Fuel Combustion*, IEA Paris, 2004; and country submissions.

Figure 37

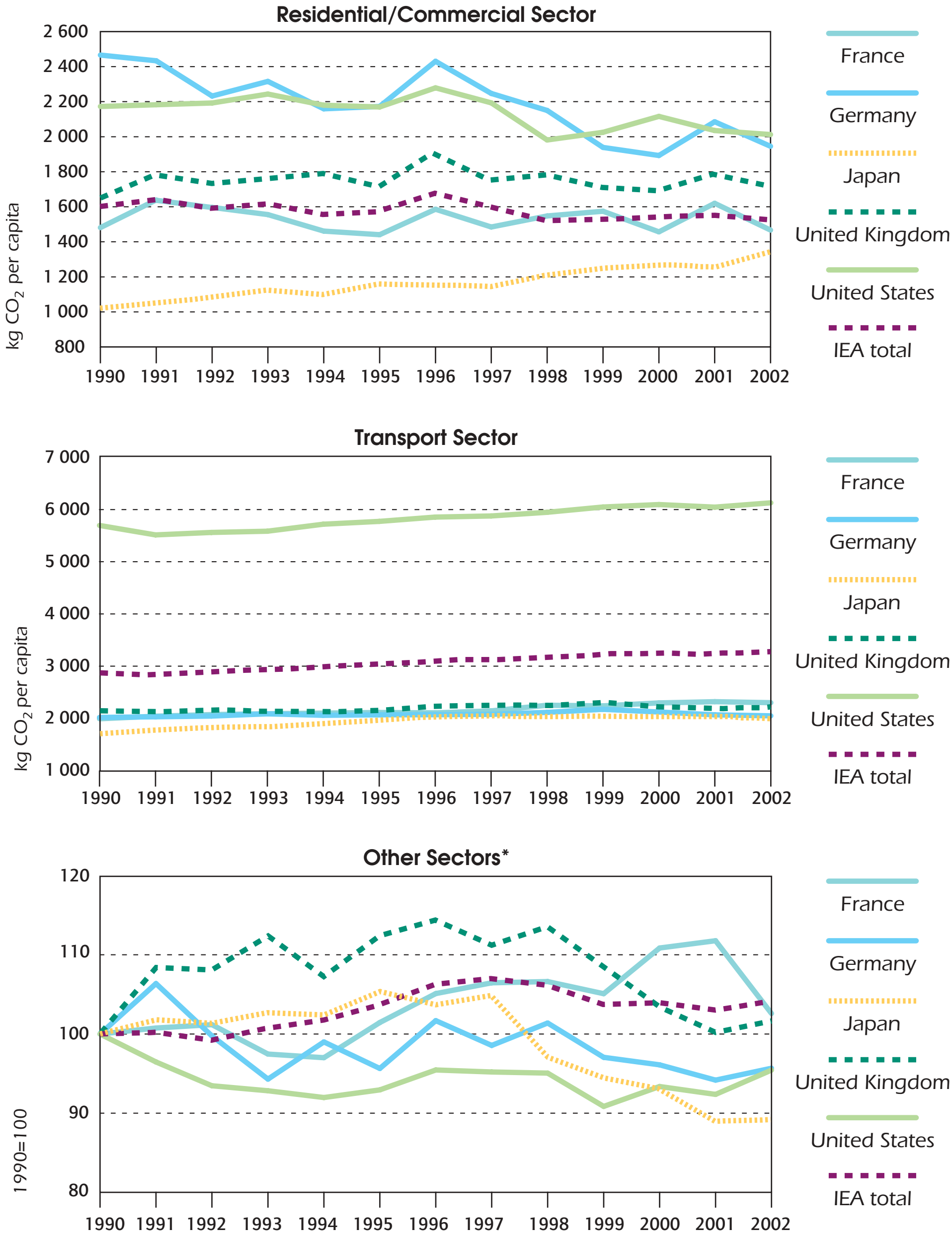
CO_2 Emissions per Capita by Fuel in IEA Countries, 2002



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004; and *National Accounts of OECD Countries*, OECD Paris, 2004.

Figure 38

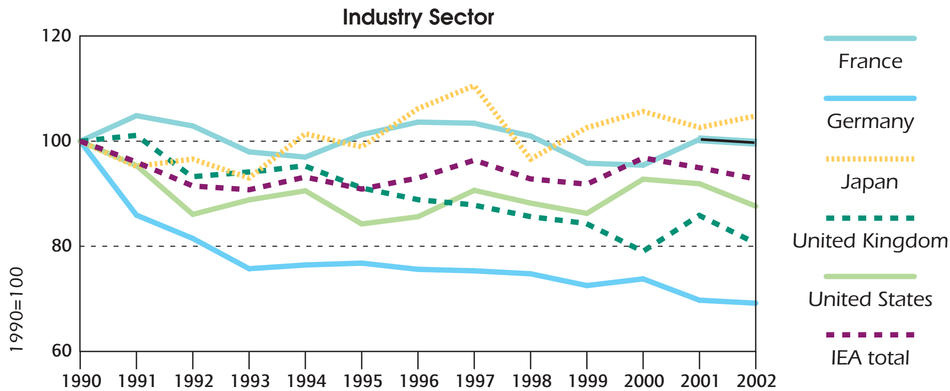
Energy-related CO_2 Emissions by Sector in Selected IEA Countries, 1990 to 2002



* includes other energy industries, agricultural sector, other non-specified sectors; and non-energy use in other sectors.

Figure 38 *(continued)*

Energy-related CO_2 Emissions by Sector in Selected IEA Countries, 1990 to 2002



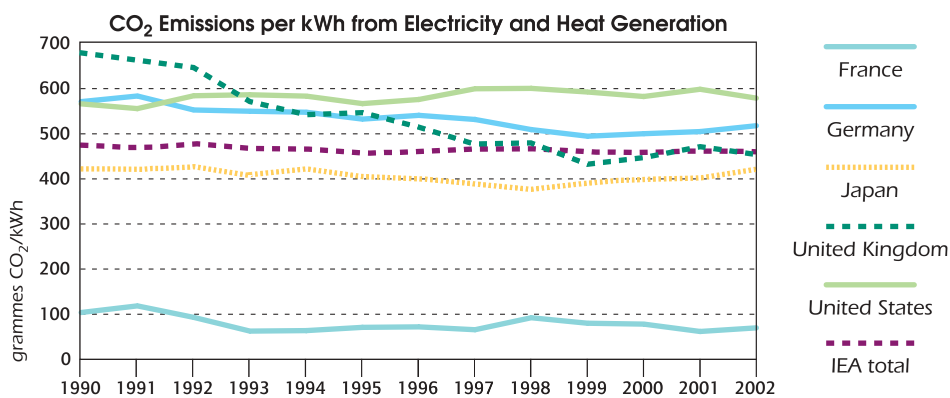
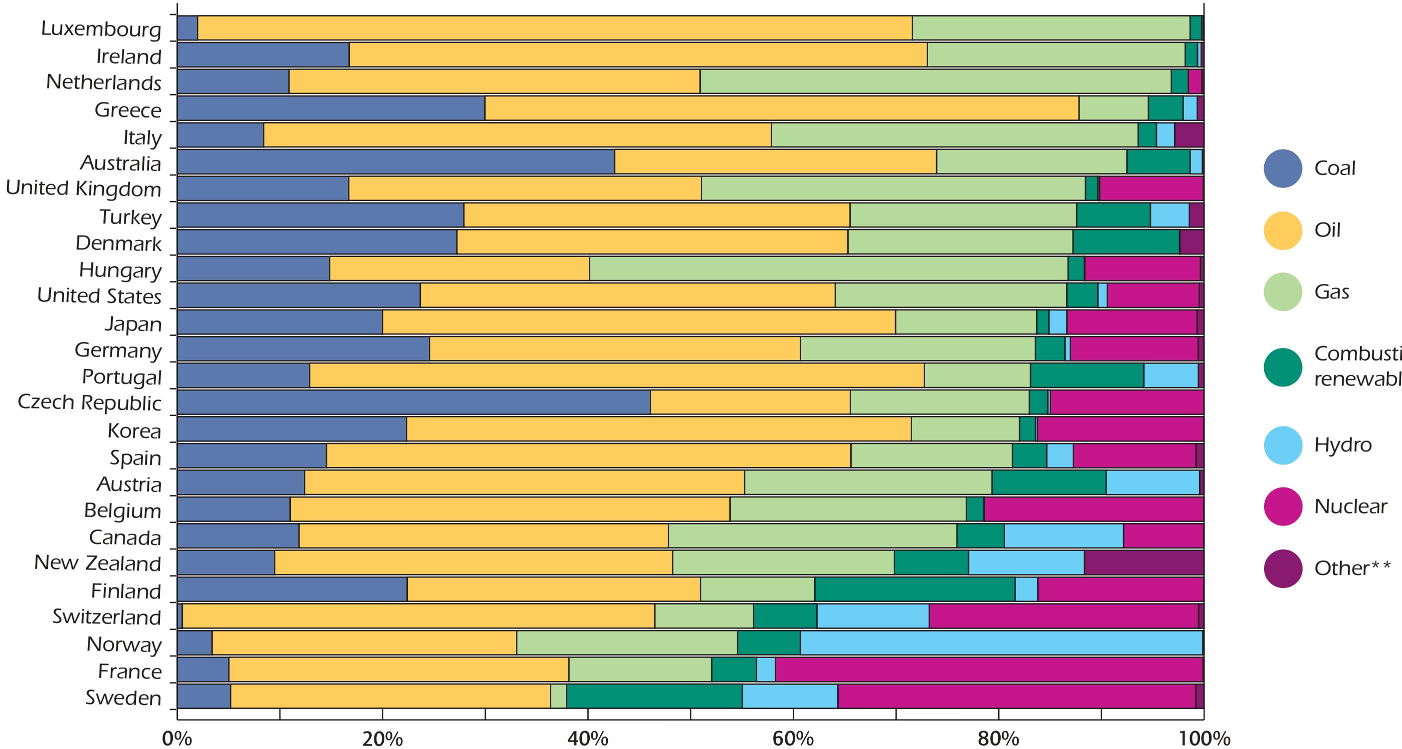


Figure 39

Total Primary Energy Supply in IEA Countries, 2003*



* preliminary data.

** includes geothermal, solar, wind, and ambient heat production.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

From 2003 to 2004, energy security continued to be of prime importance to energy policy-makers. Although the period of hostilities in Iraq in early 2003 raised concerns about energy security, the IEA's readiness to act in co-ordination with oil-producing countries, in particular with OPEC members, minimised the risk of supply disruption and price spikes and limited their duration. However, in 2003 there was growing recognition that energy policy-makers must address not only short-term oil supply risks but also broader energy security issues. This includes the reliability of electricity transmission in the wake of the serious electricity supply disruptions in North America and Europe, long-term security of gas supply in liberalised markets, and producer-consumer dialogue in the context of growing dependence on oil and gas imports and volatile market conditions.

RELIABILITY OF TRANSMISSION NETWORKS

2003 BLACKOUTS IN NORTH AMERICA AND EUROPE

Substantial supply disruptions involving a failure of transmission services struck North America and Europe during 2003. The most significant disruptions included:

- **North-eastern United States and Ontario, Canada:** The largest supply disruption in North American history struck at around 4.10 p.m. (Eastern Daylight Time) on 14 August 2003, affecting eight US states and the Canadian province of Ontario. Between 60 000 MW and 65 000 MW of electricity load was lost over a 9 300 square mile (24 000 sq km) area. Around 50 million people were disconnected initially. While most services were restored in the United States within two days, in some areas it took up to four days to restore services, while much of Ontario operated under power restrictions for over a week until services were fully restored.

- **Sweden-Denmark:** The Nordic transmission system experienced its worst disruption in 20 years at around 12.35 p.m. on 23 September 2003. Southern Sweden lost around 4 700 MW of supply, while Denmark lost around 1 850 MW of supply. Around 4 million people were disconnected, including disruption of services to Copenhagen. Transmission services in southern Sweden were restored within an hour, with complete services restored within a few hours.

- **Italy:** The worst supply disruption in over 50 years struck Italy at around 3.30 a.m. on 28 September 2003. Around 19 600 MW of electricity load was lost over a 277 000 square kilometre area. Nearly 56 million people were disconnected, with services restored within 24 hours.

Supply disruptions of this magnitude clearly demonstrate the fundamental importance of reliable networks to the efficient and secure operation of electricity markets and highlight the vulnerability of electricity markets to network failures.

While large blackouts have happened in the past, these and other supply disruptions in Europe and North America during 2003 created considerable concern among policy-makers, practitioners and the general public about transmission network performance and its implications for the efficient and reliable operation of electricity markets. Growing public sensitivity to supply disruptions reflects the increasing dependence of modern economies on reliable and efficient electricity supplies, and adds to the pressure on governments to effectively address these issues.

The timing of the disruption also raised questions as to whether electricity market reforms in the affected countries had been responsible. Electricity market reform has brought unbundling and independent, decentralised decision-making. As a result, decisions relating to network use and investments affecting network operation and performance that were once made in a centrally co-ordinated way within vertically integrated utilities are now made by a number of independent market participants. Decentralised decision-making has also led to much higher and more volatile use of the transmission networks, reflecting growing inter-regional trade and a larger number of participants. These fundamental changes to the nature and pattern of transmission usage have created new challenges for maintaining reliable transmission services and maximising transmission network performance.

INVESTIGATIONS ON BLACKOUTS

Investigations launched into these events include:

- The US-Canada Power System Outage Task Force (Final Report released in April 2004).
- Elkraft (Danish system operator) and Svenska Kraftnat (Swedish system operator) investigations into the event of 23 September 2003 in Denmark and Sweden (Elkraft's Final Report released in November 2003).
- The Swiss Federal Office of Energy investigation into the event of 28 September 2003 in Italy (Final Report released on 25 November 2003).
- The joint investigation by the Italian regulator (*Autorità per l'Energia Elettrica e il Gas*) and the French regulator (*Commission de régulation de l'énergie*) into the event of 28 September 2003 in Italy (Final Report released in April 2004).
- Union for the Co-ordination of Transmission of Electricity Investigation of the Italian Blackout (Final Report released in April 2004).

Although the individual circumstances surrounding these disruptions were unique, none of these investigations have indicated that electricity market reform was the root cause of any of these events. Findings have generally been limited to the specific circumstances of these events, with none proposing definitive solutions to prevent future blackouts.

North America

In the case of the 14 August 2003 blackout in north-eastern US and south-western Canada, the final report of the US-Canada Power System Outage Task Force[6] found that the outage was globally caused by deficiencies in corporate policies, lack of adherence to industry policies and inadequate management of reactive power and voltage. More specifically, the report identified the following four groups of causes for the blackout:

- FirstEnergy and ECAR[7] failed to assess and understand the inadequacies of FirstEnergy's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FirstEnergy did not operate its system with the appropriate voltage criteria.
- There was an overall inadequate awareness of the situation occurring at FirstEnergy as the company did not recognise or understand the deteriorating condition of its system.
- FirstEnergy failed to manage adequately tree growth in its transmission rights-of-way (common cause of the outage of the three 345 kV transmission lines and the 138 kV line).
- A failure of the interconnected grid's reliability organisations to provide effective real-time diagnostic support.

In respect of these groups of causes, the report finds a total of seven specific violations of North American Electric Reliability Council (NERC) reliability policies, guidelines and standards. It also explains how certain NERC standards and processes were inadequate as they did not give sufficiently clear directions to industry members concerning some of the preventive measures needed to maintain reliability.

Denmark and Sweden

As regards the 23 September 2003 blackout in eastern Denmark and southern Sweden, the final report on the course of events released by Elkraft System[8] indicated that the disruption was caused by a number of mechanical

6. http://reports.energy.gov
7. East Central Area Reliability Co-ordination Agreement (the reliability co-ordinator in the region including FirstEnergy)
8. http://eng.elkraftsystem.dk/Elkraft/UK/Publications.nsf/0/21DDBE484146452EC1256DD60042FE03/$File/Final_report_uk-web.pdf!OpenElement

faults in the South Sweden power system whose sum-up exceeded the designed system capacity to remain in operational conditions. The report identified the following sequence of principal faults:

- There was an initial problem with a valve of the feed-water circuit in unit 3 of the Oskarshamn nuclear power station in the south of Sweden, which led to the trip of the unit and the loss of 1 200 MW on the system.
- A second event, pointed out as the main cause of the power failure, was a double busbar fault in the south Swedish transmission grid, resulting from the mechanical failure of an isolator, which caused four 400 kV transmission lines to trip.
- As a consequence of the 400 kV lines trip, units 3 and 4 of the Swedish Ringhals nuclear power station lost their connection to the system, causing a further loss of 1 800 MW and the system voltage drop, then consequent collapse.

The report concluded that given the present design of the power system and the current criteria for system operation and protection of grid and plants, it was impossible to prevent power failure once a short circuit had occurred at the two busbars.

Italy

The 28 September 2003 blackout in Italy has raised the particularly delicate issue of determining the responsibilities between the Italian TSO, GRTN[9], and the Swiss TSO's co-ordinator, ETRANS. In this respect, we will resume the main findings of the three final reports on the event made by the Swiss Federal Office of Energy (SFOE), the joint investigation of the Italian regulator AEEG (*Autorità per l'Energia Elettrica e il Gas*) with the French regulator CRE (*Commission de régulation de l'énergie*), and the Union for the Co-ordination of Transmission of Electricity, UCTE.

The final report on the Italian blackout released by the SFOE[10] indicated that the main causes of the September 2003 outage are unresolved conflicts between the trading interests of the countries and companies involved, and the technical requirements of the existing transnational electricity system. Present-day standards and legal instruments are lagging well behind economic realities. Italy's electricity imports have risen sharply over the past few years, mainly because of the pronounced difference in wholesale prices between Italy and those countries that usually produce surpluses. Italy's imports are mainly transmitted via the high-voltage networks of France and Switzerland. The report indicated that in Italy there is also a need for reserve capacity to secure a balance between production and consumption by switching power plants on and off as necessary.

9. *Gestore della Rete di Trasmissione Nazionale.*
10. http://www.swiss-energy.ch/imperia/md/content/energiemrkteetrgertechniken/elektrizitt/strompanne03/3.pdf

The final report of the joint investigation by the Italian regulator and the French regulator into the 28 September 2003 blackout in Italy[11] identified the following four main findings in relation to the event:

- Before and during the night of 27-28 September, the Swiss transmission grids lacked sufficient prevention and preparation measures to an extent that endangered the security of grid operation and supply across other power systems in Europe.
- The integrated Swiss electricity companies did not comply with the UCTE rules during the night of 28 September.
- UCTE rules shall be made more detailed. Compliance with them shall be made legally binding. Independent assessment and control shall be enforced.
- During the night of 27-28 September, the operators of the Swiss transmission grids took inappropriate measures. These operational mistakes led to the loss of the Sils-Soazza 380 kV line, following the loss of the Mettlen-Lavorgo 380 kV line (Lukmanier line), and thus to a N–2 event (absence or failure of two network elements), for which the interconnected grids were not prepared.

Moreover, the report made the following recommendations:

- Co-ordination among TSOs shall be reinforced for operational planning and real time operation of the interconnected grids.
- A legal and regulatory framework coherent with EU legislation is necessary in Switzerland to ensure the security of grid operation and supply in Europe.

AEEG and CRE's independent investigation therefore demonstrated that it is crucial for the European Union's security of electricity supply that a legislative and regulatory framework be implemented in Switzerland, in line with European Union legislation.

The final report of the Investigation Committee of the Union for the Co-ordination of Transmission of Electricity, UCTE, on the September 2003 Italian blackout[12] took a relatively stricter technical approach to its analysis of the event. It outlined the following points:

- The blackout was triggered by causes in Switzerland, the first of which consisted of the unsuccessful re-closing of the Lukmanier (Mettlen-Lavorgo) line because of a phase angle difference that was too high. This was followed by a lack of any sense of urgency regarding the San Bernardino (Sils–Soazza) line overload, and meant that countermeasures taken in Italy were inadequate.

11. http://www.autorita.energia.it/docs/04/061-04all.pdf
12. http://www.ucte.org/pdf/News/20040427_UCTE_IC_Final_report.pdf

- The blackout was not caused by some extraordinary, low-probability event such as a severe storm, a cyber-attack, simultaneous lightning strikes on several lines, etc.
- After the first contingency, although the relevant countermeasures for returning the system to a secure state were available from a purely technical point of view, human, technical and organisational factors prevented this from happening.
- Although the restoration process of the Italian system was performed successfully, its duration might have been reduced had more units separated from the grid successfully or if they had black-start capability.

COMMON CAUSES

All these investigations suggest some common causes including:

- The inherent vulnerability of alternative current transmission networks to multiple breaches of operational reliability contingencies where they occur within the period normally allowed for the system to recover from a single breach.
- Poor communication and co-ordination of real-time system operation where markets span more than one system operator's responsibility.
- Inadequate transmission capacity, and maintenance of diagnostic equipment and network infrastructure (especially management of vegetation).
- Inadequate training and loss of experience among system operators.
- A more dynamic and challenging network operating environment, reflecting the erosion of excess capacity under economic regulation, and greater volatility of flows and increased inter-regional trade resulting from electricity market reform.
- Continuation of pre-reform operating procedures which were not designed to accommodate the new demands placed on the network as a result of electricity market reform.
- Inability to enforce voluntary reliability standards.

IEA PROJECT ON TRANSMISSION NETWORK RELIABILITY AND PERFORMANCE

The IEA Secretariat has launched a project to:

- Identify and analyse the key issues affecting the development and performance of transmission networks to service competitive electricity markets.

- Promote understanding of these issues among policy-makers and regulators.
- Facilitate debate and exchange of views between stakeholders about these issues and how best to address them.

The project includes two workshops in 2004. The first workshop held on 29-30 March focused on transmission network reliability in competitive electricity markets. Once the second workshop has been held in November 2004, a book will be published in 2005. The key themes from the first workshop are as follows:

Critical importance of transmission network reliability for electricity markets

Electricity reform has led to an increase in regional trade and the development of more integrated regional electricity markets incorporating many independent decentralised decision-makers. In this environment, an event affecting a relatively distant part of an integrated transmission network has the potential to interrupt the delivery of electricity throughout an interconnected network and severely disrupt the operation of electricity markets. Case studies presented on supply disruptions in North America and Europe during the summer of 2003 graphically illustrated the potential impact of these disruptions on competitive electricity markets. A key question is how to accommodate the interface between transmission network reliability and electricity markets.

Lessons from the 2003 blackout case studies

Common causes were summarised as the 3Ts:

- Tools: For system operators to monitor and assess a wide area and to evaluate actions.
- Training: To improve system operators' capacity to manage increasingly complex network environments in real time.
- Trees: Effective vegetation management to minimise the risk of tree flashover.

3Cs (co-operation, co-ordination and communication) were proposed as a means to help reduce the potential for cascading failures in the future, particularly where regional markets span more than one system operator's area of responsibility. In this regard, perhaps the Australian National Electricity Market (NEM) has arrived at a solution that may provide a useful model for others.

A fourth T (Trade) was identified as a key environmental factor which has changed as a result of electricity reform, and which may help widen the impact of transmission network events.

Although system restoration following a blackout is an important technical issue, it does not appear to be a first-order issue for policy-makers given the relative ease and speed with which systems were restored in each of the case studies. The success of restoration efforts raises questions about the cost-effectiveness of potential options to improve transmission network reliability through means that would require a substantial capital investment, such as increasing deterministic reliability standards from, say, N–1 to N–2[13]. A key question in this context is the extent to which users' willingness to pay for transmission network reliability can be captured in a private property right.

Defining common rules and institutions – a first-order market design issue

Common rules and institutions are important. But what should be the features of these common rules? This is a first-order problem of market design. Markets operate within the framework and rules created by governments. Care needs to be exercised. Experience to date shows that market participants will respond quickly and efficiently to the incentives created by market rules, sometimes with unintended consequences.

Reliability rules - adequacy and compliance

Presentations on the North American and European case studies highlighted the importance of complying with reliability rules, while presentations during the workshop session on reliability noted efforts to improve compliance. However, in most cases the existing rules were developed during the era preceding market liberalisation, raising the issue of whether the rules are adequate and appropriate for the new era of electricity market reform.

It may be possible to employ more sophisticated analytical approaches to determining reliability standards, such as probabilistic risk assessment or refined system analysis. However, these alone may not be sufficient. Deterministic and probabilistic approaches are complementary. N–1 is a relative standard, which provides a tool for flexibly determining transmission network reliability standards.

New technology can strengthen system operation

New technologies provide an opportunity to improve system reliability and operation in real time, especially visualisation tools of the kind being developed by Pennsylvania-New Jersey-Maryland (PJM) Interconnection.

13. N-1 refers to the network being able to maintain a secure/reliable operating state in the absence (failure) of a single network element. N-2 refers to maintaining a secure/reliable operating state in the absence (failure) of two network elements (*e.g.* going-down of two transmission lines within a single control area).

However, such technologies may also create new risk exposures associated with the potential failure of electronic management/diagnostic equipment. Technology provides a means of assisting system operators, but it is unlikely to replace them.

Workshop materials, including the full Chairman's summary, agenda, all presentations and the IEA Scoping Paper have been posted on the IEA website. (http://www.iea.org/Textbase/work/workshopdetail.asp?id=166)

SECURITY OF GAS SUPPLY[14]

With the progress being made in the opening to competition of gas and electricity markets, the tremendous increase of gas-fired power generation worldwide as a new driver of gas demand, the cost reductions in the LNG chain allowing more flexible LNG trade and the growing import dependence on a limited number of non-OECD countries, the issue of security of gas supply is the subject of increasing attention in IEA countries. In 2004, the IEA conducted a comprehensive study, *Security of Gas Supply in Open Markets – LNG and Power at a Turning Point*, analysing the most recent developments in security of supply and reliability in all IEA regions in the context of open markets and in view of the new demand and supply trends. The following are key issues identified in the study.

OPEN GAS MARKETS AND CHALLENGES OF SECURITY OF SUPPLY

Open markets allow customer choice. Eligible customers can choose their suppliers and eventually their own level of reliability of supply, but they are responsible for their choice. Open markets will not always result in lower prices for customers, but they will result in an efficient allocation of resources, capacity and investment. Compared to markets for commodities, the design of gas markets requires special consideration as gas delivery is capacity-bound and because part of gas demand is price-inelastic, especially the household sector, which is even temperature-dependent. Therefore, prices may be volatile when capacity limits are close, and there is a risk that supply will not meet demand in low-probability events like extreme temperatures.

Governments in open gas markets play a different, but important role to ensure secure and reliable gas deliveries from the production/import point to the final customer. Instead of managing the sector, they have to set objectives to minimise the geopolitical implications of increasing import dependence

14. Drawn on *Security of Gas Supply in Open Markets: LNG and Power at a Turning Point*, IEA (2004), http://www.iea.org/dbtw-wpd/bookshop/add.aspx?id=178.

and impacts on the environment, as well as ensuring that markets work to deliver reliable gas supplies. At the time of state-owned gas companies, or private companies with exclusive concession rights, governments played an important role in the management of the sector but delegated responsibility for security of supply to these entities and made all customers pay for it. These companies were responsible for security of gas supply across the whole gas market. In open markets, governments still play an important, but different role: they have to define the right framework for market players so that markets can deliver reliable gas supplies and they have to make sure that market players follow the rules. Governments have the responsibility of creating a framework for security and for defining the responsibilities of each player. However, low-probability events (like supply interruptions and extreme temperatures) may not necessarily be valued by the market itself. Governments should therefore set objectives for reliability of gas supply, especially to ensure gas deliveries to household customers during spells of extremely low temperatures. They should also foster demand-side response as one of the important policies to ensure security of supply. The opening of the gas (and electricity) market results in the development of hubs and market centres which prove a useful instrument to optimise the use of the capacity of the gas system and to bring gas to its highest value use.

Governments may be concerned about market outcomes – like volatile prices and high prices – eventually leading some industries to relocate to regions with lower gas/electricity prices. Governments may interpret unsatisfactory market outcomes as a need to rethink the framework and eventually discuss and implement its modification. However, they would be well advised not to interfere in the operation of the market. While some of the arguments to ensure security of gas supply are similar to those for oil, the arguments for establishing stocks and a co-ordinated stock draw do not apply to gas. Strategic gas storage is much more expensive than oil storage and requires additional substantial investment into a spare transport infrastructure. Other instruments like interruptible contracts or fuel-switching may be less expensive instruments than strategic gas storage, if storage is possible at all. As the market is not yet global and disruptions only have a local impact, a global response is not possible. It is therefore best to leave the design of the response mechanism to individual countries and their market players.

CHANGES IN THE GLOBAL GAS SUPPLY AND DEMAND BALANCE

From 1971 to 2000 worldwide gas consumption more than doubled from 895 Mtoe (of which about a quarter, 207 Mtoe, for power generation) to 2 085 Mtoe (of which slightly more than a third, 725 Mtoe, for power generation). The *World Energy Outlook 2002* projects another doubling to 4 203 Mtoe (of which close to half, 2 032 Mtoe, of total gas consumption) by the year 2030. So gas consumption for power generation almost triples every 30 years.

For OECD countries, the trends in gas consumption look similar: From 1971 to 2000, gas consumption almost doubled from 653 to 1 143 Mtoe and is projected to almost double again to 2 012 Mtoe by the year 2030. The share of gas for power consumption was 117 Mtoe in 1971, or about one-sixth of total gas consumption, increasing to 328 Mtoe in 2000, or a bit more than a quarter of total gas consumption, and is projected to reach 958 Mtoe in 2030 – almost half of gas consumption in OECD countries. So in OECD countries the trend towards increased use of gas in power generation is even more pronounced, owing to increasing saturation in the residential and commercial and industrial sectors.

The import dependence of OECD countries is projected to increase from a total of 274 bcm/year or a share of about 20% of total gas consumption in 2000, to a total of 1 091 bcm/year, or more than 40% of gas consumption. The major part of the increase in gas imports is explained by the projected increase in gas used in power plants.

Gas has developed into the fuel of choice for the residential and commercial sector, but also for process and small applications in the industry sector, wherever gas can be economically supplied. While gas can be replaced for each individual customer, mainly by oil products which define price limits for individual customers, many IEA countries have no large-scale alternative to gas on a country-wide scale. The use of gas is not only linked to a long-lasting investment decision on the customers' side, but also to substantial investment in the gas infrastructure, which would become obsolete in case of a substantial shortage of gas.

With the domestic gas reserves of IEA countries on the decline, imports are going to cover an increasing part of gas demand in most IEA countries. This raises the issue of import levels from a limited number of non-OECD countries such as Russia, Iran and Qatar versus the ability of the market to handle a gas shortfall. It also raises the issue of the implications of uneven reform in countries along the gas chain.

The increase in gas use for power (and the dominance of gas as a fuel for new power generation since the beginning of the 1990s in many IEA countries) is driven by the high technical and economic efficiency of new gas turbines and combined-cycle gas turbines (CCGTs), as well as by the environmental advantages of gas compared to other fossil fuels. This situation results in a projection of a substantial increase in gas for power generation in OECD countries, which, on balance, will have to be imported from non-OECD countries. The result will be a strong increase in import dependence in most OECD countries/regions and a strong increase in cross-border trade of gas by pipeline and as LNG.

Volume and diversification reasons will require gas to be developed for export, mainly as LNG, from an increasing number of resource-owning countries. The LNG industry has now entered an era of unprecedented growth. Large new markets are emerging, cost reductions along the LNG chain allow new projects which were uneconomic 20 years ago, and increased inter-regional trading adds flexibility and security to the global gas system.

EMERGENCE OF LARGER REGIONAL MARKETS

Larger regional markets are emerging with the opening of gas markets (in addition to the already strongly interlinked North-American market), *e.g.* in the European Union. With more flexible LNG trade, more trade develops between LNG-buying countries like Japan and Korea, and also in the Atlantic basin between parts of the EU and the United States. The creation of larger markets offers more possibilities for underutilised capacity/volumes to find their way to other regions, with higher gas value, thereby creating higher liquid volumes on which to draw in case of shortage or extreme temperature. Creating a larger (regional) market-place may require extra investment into interconnection infrastructures, which so far have been built on the basis of national markets. This may require governments to define common standards (*e.g.* technical norms, gas quality, LNG specification and safety norms for LNG tankers), to foster inter-operability and to arrange for the right framework to remove obstacles to cross-border (OECD) investment and trade.

INCREASED LINKS BETWEEN OPEN GAS AND POWER MARKETS

Increased links between open gas and power markets offer the chance for more efficient use of both systems. However, the reliability of each system must also be ensured in view of the interlinks between them. The increased use of gas in power generation combined with the parallel opening of both sectors creates operational and market links between the two sectors. However, it must be observed that while the link is creating larger flexibility for the use of gas and for the production of electricity, both systems are capacity-bound. This may require setting reliability objectives which take into account the interactions between both systems. The projected high dependence of power generation on imported gas might create a domino effect on the power sector in cases of gas supply shortages, if not addressed.

NEED FOR BALANCE OF INTERESTS BETWEEN GAS IMPORTING AND EXPORTING COUNTRIES

The willingness of non-IEA gas-rich countries to develop their gas resources for export is key to the further development of gas markets in IEA countries. This will require a stable balance of interests between gas-importing and gas-exporting countries. The import volumes of all OECD regions are increasing substantially, and even the United Kingdom and the United States are becoming substantial net importers of gas. About 10% of world proved gas reserves are in OECD countries, whereas outside the OECD gas reserves are highly concentrated: more than 50% are in three countries: almost 30% are in Russia, 15% in Iran, 9% in

Qatar. While investment decisions for exploration and production, transportation and other gas infrastructure, as well as on the use of gas, are best left to private investors, decisions about the depletion of natural resources are in most countries vested in the government of the resource-owning country. To optimise the use of their resources, they have to decide on the development path for their reserves, on domestic and export use, as well as on maximising the remuneration for the export of a finite resource. While maximising the rent income for a finite resource is a sensible objective for an exporting country, IEA gas-importing countries will try to limit such rent transfers by promoting diversification of supply sources and routes and by promoting the use of other fuels.

While IEA countries are interested in reliable gas supplies at competitive prices, governments of resource-owning countries will look for secured access for their gas to IEA gas markets and for a reliable income from selling their resources. Long-term contracts have been a most useful instrument to create a stable balance between gas exporters and gas importers. With more open markets, new, additional instruments develop, such as selling into a liquid market, as well as more flexible LNG deals, but long-term contracts will remain an important instrument, although with some features changed. While having a bankable gas market or a creditworthy gas buyer is a major precondition for viable investment into gas production and into gas export infrastructure, a clear framework for foreign investors and a neutral conflict resolution mechanism would help to mobilise financing for new export capacity at favourable conditions. A suitable means to address how to create a fair and stable balance between gas-producing and gas-consuming countries is the Producer-Consumer Dialogue.

ROLE OF GOVERNMENTS

Governments have to ensure that investment in all parts of the gas chain can be mobilised in a timely way in competition with other capital use. The increase in gas demand requires the alignment of timely investment in all parts of the gas chain, from exploration and production to transporting the gas to the market, as well as investment into the distribution and gas-consuming infrastructure, especially gas-fired power plants. While governments cannot and should not play a role in managing geological, technical and market risks, they should help to reduce sovereign and regulatory risks and thereby improve financing conditions by creating clear and stable frameworks for investment, especially in cross-border infrastructure. They should also help with the adoption of clear and streamlined siting rules, while minimising regulatory risk by creating a stable and predictable regulatory framework which would allow investors free commercial disposal of their property and, where regulated, a rate of return competitive with other investment opportunities.

Both the industry from all parts of the gas chain and the resource-owning countries have an interest in being able to hedge their decisions dedicating investment or gas resources on a long-term basis. A variety of instruments linked to the development and maturity of reforms in each gas market/region was developed to hedge the risks stemming from the long-term nature of the gas business:

- Long-term sales contracts associated with long-term transportation contracts.
- Vertical integration along the gas chain.
- Access to liquid markets (by investing into LNG regasification terminals and import pipelines) and to financial instruments derived from liquid gas markets.

Governments of IEA countries should leave the choice of instruments to the market players concerned; they should not favour or disfavour any of these instruments, as long as they do not negatively affect competition.

MAJOR DIFFERENCES BETWEEN THE THREE IEA REGIONS

In spite of generic and global developments, the status of market opening and the challenges of security of gas supply are specific for each IEA region and in some cases even for single countries.

IEA North America

Open gas markets introduced in the 1980s were able to mobilise private investment in time for expansion of the infrastructure and the development of reserves. These markets led to the development of liquid hubs and gas exchanges and to a more efficient use of the gas infrastructure. So far, gas supply and demand have been balanced by markets. Upstream, the role of governments was restricted to rule-setting and in the case of Canada, also encompassed rent-taking – however, with some restrictions on exploration and production (E&P) in US federal/state-owned land, offshore and in Arctic areas. The decline in production due to the depletion of North American gas reserves, combined with the massive increase in gas use in CCGTs with only limited fuel-switching capacity, resulted recently in rising gas prices so that some industrial gas users considered moving to other regions. This situation signalled the need to increase LNG imports substantially to satisfy the projected use of gas in power generation. After the requirements were dropped for third-party access (TPA) in LNG terminals, many new projects emerged. While the chances of obtaining diversified LNG supplies are good, the expected large share of LNG supplymay raise the question of whether interruptions of LNG supplies can be compensated by the market.

IEA Europe

There is a marked difference between the UK gas market and the continental gas market. While the UK was a front runner in opening the gas market, the opening in the continental part of the EU happened more recently with the two EU Gas Directives and their implementation in EU member states.

The opening of the gas market in the UK resulted in the establishment of the National Balancing Point (NBP), a liquid (notional) market-place where gas is traded on a daily basis. It assisted the massive use of gas for power generation in the 1990s and, in parallel, a remarkable increase in gas production from the UK continental shelf (UKCS). However, lacking large new finds in frontier areas and with the UKCS becoming a mature gas province, within a short time span the UK will change from being a net gas-exporter to a massive net importer. Long-term contracts are still predominant in the UK, though now they are increasingly linked with the price at the NBP and in some cases also use the NBP as the delivery point. The UK is well on the way to attracting the additional supplies and the necessary investment to adapt its infrastructure, although with some specific challenges caused by the differing quality of the gas to be imported. Another challenge to be addressed is the link between gas and power, as a large increase in imported gas will go to gas-fired power plants.

In continental Europe, several of the challenges for reliable gas supplies set before the gas sector by the new Gas Directive still lie ahead, such as finding the right allocation between the responsibility for reliable gas supplies and the effects of unbundling; finding the right incentives for the enlargement of the transport, import and storage infrastructure by allowing for a rate of return which is competitive in a global context. Creating more regulatory stability by giving the industry the time to adapt to and to fulfil the requirements stemming from the directives currently in force is now of paramount importance.

In view of the increasing import dependence from only a few gas-exporting countries, long-term contracts will remain an important instrument to ensure gas supplies. In the continental gas market, some hubs are developing, although they still do not have a deep liquidity. However, beyond the challenge of creating open gas markets in each EU member state, the challenge remains to create a single gas market for the EU, which requires rules, standards and technical regulations that are as uniform as possible. The infrastructure, which was built on a national basis driven by large import projects, must be adapted to allow for more EU-wide gas trade and liquidity. As in North America, the projected strong increase of gas in power generation which will, on balance, be based on imported gas, raises challenges of increased gas import shares from non-IEA countries and their impact on the gas and power sector. The pace of supplier and transit gas sector reform has important implications for the quality and reliability of security of gas supply to European end-use customers.

The EU is to a large extent dependent on pipeline gas imports from Algeria and Russia, which are projected to increase substantially. Although both countries have a long-standing record as reliable suppliers to the EU, there is some concern about the long-term future of gas imports from Algeria and Russia as neither of these countries has yet a clear gas upstream or transport regulation. In addition, gas production and export are managed by companies which, in addition to their commercial role, exercise sovereign rights of the State in the gas sector. While Russia has often announced its intention to reform its gas sector, little has been done so far. A failure to implement much-needed market reform, including TPA to the gas network and raising prices to economic levels, could impede the financing of new upstream and transportation projects needed to replace the maturing Western Siberian gas fields. Another concern is that the transit of Russian gas to the EU is highly concentrated in Ukraine, a country which is struggling to find an appropriate regulatory framework for its gas sector. Increased diversification of suppliers and supply routes, and provision of market flexibility (backup supply and/or demand management), will remain crucial issues for the EU.

IEA Pacific

The gas industries of the OECD countries in the Pacific region differ very much from each other: Japan and South Korea are almost entirely dependent on LNG supplies, Australia is becoming a large LNG exporter and New Zealand is so far self-sufficient. While Japan and South Korea were the driving force of the growth in the LNG trade, market reforms in both countries have led to more uncertainty about future gas demand growth. This has led the LNG-importing companies to seek more volumes and pricing flexibility in their LNG contracts. Increased competition among LNG suppliers, as well as cost reductions in the LNG chain, allow producers to accept more flexible LNG terms. Security of supply in the region has always been ensured through diversification of supplies and infrastructure. The recently increased flexibility of LNG trade allowed importing companies to swap LNG cargoes, *e.g.* to exchange cargoes to meet peak gas demand. It allowed Japanese and Korean buyers to successfully manage the seven-month shut-down of the Indonesian liquefaction plant at Arun in 2001.

PRODUCER-CONSUMER DIALOGUE

The Producer-Consumer Dialogue has evolved significantly since its inception in 1991 with the objective of achieving understanding and exchange of information between producing and consuming nations. Since then, it has endeavoured to bridge the gap between producing and consuming states, ensure market stability and security of supply. The Dialogue has successively highlighted the importance of maintaining good working relations with key oil- and gas-producing states, particularly during periods of political and economic uncertainty which have emerged throughout the world over the past decade.

The 9th International Energy Forum (IEF), the latest in the series of the biennial Ministerial meetings, took place on 22-24 May 2004 in Amsterdam, the Netherlands, and was co-hosted by Norway and Iran. The theme "Investing in Energy: Choices for the Future" emphasised current concerns about the need for greater investment across the energy spectrum. The hosts furthermore introduced the newly appointed Secretary-General to the permanent Secretariat of the International Energy Forum (IEFS), which was established in Riyadh in late 2003 upon the proposal made by H.R.H Crown Prince Abdullah bin Abdul Aziz bin Saud at the 7th IEF. Ministers at the 9th forum stressed their support for the IEFS, which will ensure continuous dialogue among producers and consumers.

Energy ministers from 63 energy-producing and consuming countries and 11 international organisations participated in the event and focused on the world energy situation, oil and gas in particular, and the investments needed to meet the world's growing energy demand in a healthy market environment. Greater stability in international oil markets was recognised as being in the interest of both consuming and producing states, rendering improved co-operation all the more important as it continues to be beneficial to the security of supply for consumers, the security of demand for producers, the stability of markets and sustainable economic growth in general. Security of supply and access to reserves were identified as being of particular relevance, given the estimated investment requirements estimated to amount to US$ 6 trillion over the next 30 years in new capacity and replacement of existing capacity. However, the establishment of stable and transparent, adequate fiscal and legal frameworks was recognised as being pivotal in order to attract sufficient foreign direct investment.

The 9th IEF furthermore highlighted the relevance of the Joint Oil Data Initiative (JODI) which aims to harmonise world oil data in a timely manner and achieve transparency. The IEF emphasised its commitment to the JODI exercise with the IEF Secretariat gradually establishing itself as the co-ordinator of the JODI World Database as well as of other activities linked to the development and promotion of the Initiative.

ENERGY MARKET REFORM

ELECTRICITY

After the extensive reforms introduced in many IEA countries in the late 1990s and the setback in the aftermath of the Californian crisis, the reform process now seems to be picking up again in many IEA member countries, albeit at a varied pace. 2002-2003 saw several legislative developments on the path to reform. The past year has mainly been a year of implementation of previously decided reform initiatives. Examples of successful electricity sector reforms now seem to be sufficiently established to serve as inspiration in a slow evolutionary process.

IEA EUROPE

EU policy reform on energy infrastructure and security of supply

Following the publication in 2000 of the Green Paper "Towards a European strategy for the security of energy supply", in December 2003 the European Commission proposed a directive concerning measures to safeguard security of electricity supply and infrastructure investment. By underlining the importance of a competitive internal electricity market as a key element in the strategy for the security of energy supply, the directive addresses security of supply through the further developments needed for a fully competitive internal electricity market. The following main topics are addressed:

- Investments in transmission lines to ease bottlenecks between regions and markets are necessary to strengthen cross-border competition.
- Investment in production or demand management resources is needed to maintain the balance between demand and supply, also during peak load. Special measures may be used if necessary, but issues like free-riding by regions with less reserve capacity, a level playing field for competitors under different reserve requirements, and possible distortions across borders must be taken into due consideration.
- There is a need for a stable regulatory framework for investments both in transmission and production capacity and in demand management resources.
- Planning and international co-ordination that allow for efficient development and operation of reserves and infrastructure are called for.

Developments towards an internal electricity market

In June 2003, an amended electricity market directive and a regulation on cross-border trade were passed by the European Parliament. The regulation and the most important parts of the directive were to be implemented no later than 1 July 2004, including market opening for all non-household consumers, legal unbundling of Transmission System Operators and the appointment of a national regulator. On 1 May 2004, the internal electricity market was extended with the joining of the ten new EU member countries.

The association of European Transmission System Operators (ETSO) has implemented an amended compensation mechanism for Cross-Border Trade (CBT) for 2004 in line with the EU regulation. The CBT mechanism has been put in place to allow compensation for grid costs due to transit flows, while at the same time avoiding entry tariffs at country borders that would distort international competition. However, significant issues covered in the regulation, such as compensation for investment and congestion management, are not addressed by the CBT mechanism for 2004.

As for the 1 July deadline, the EU Commission declared that very few EU countries have fully implemented the directive, according to its internal benchmarking reports.

Important country developments

In France, it has been decided to change the status of the utility *Electricité de France* from a public enterprise to a corporation, which will put it on an equal footing with new-entrant competitors. At the same time, the legal possibility of opening up to 30% of the company's capital to non-governmental groups has been introduced.

In Italy, the electricity exchange *Gestore del Mercato Elettrico* opened for spot trade on 1 April 2004.

On the Iberian peninsula, the Spanish and Portuguese governments signed an agreement on 19 January 2004 to form a common Iberian electricity market, MIBEL. While the agreement was supposed to be provisionally implemented on 22 April 2004, it was postponed to an undefined date later in 2004.

Sweden continues to implement a plan to execute the shut-down of its nuclear power plants. A government negotiator was appointed to discuss the conditions of a gradual phase-out with the industry and other stakeholders. The negotiator was scheduled to provide a plan acceptable to all by May 2004, but the release of the plan has been delayed owing to ongoing differences between the stakeholders. As of July 2004, no firm date had yet been established for finalising and releasing the nuclear shut-down plan.

Table 8

Electricity Market Reform Progress in IEA-EU Countries – March 2004

	Declared market opening (% of total)	*Large[1] eligible customers switch (% during 2002)*	*Small eligible customers switch (% during 2002)*	*Regulator*	*Unbundling transmission*	*Unbundling distribution*
Austria	100	15	5	Ex ante	Legal	Accounting
Belgium	80	5		Ex ante	Legal	Legal
Czech Republic[2]	30	8		Ex ante	Legal	Legal
Denmark	100	45		Ex ante	Legal	Accounting
Finland	100	[3]	10	Ex post	Ownership	Accounting
France	37	15		Ex ante	Management	Accounting
Germany	100	20	5	Planned	Legal	Accounting
Greece	34	Nil		Ex ante	Legal/Mgmt	Accounting
Hungary[4]	30	>50		Not known	Accounting	Accounting
Ireland	56	20	2	Ex ante	Legal/Mgmt	Management
Italy	66	15		Ex ante	Own/Legal	Legal
Luxembourg	57	10		Ex ante	Accounting	Accounting
Netherlands	63	20		Ex ante	Ownership	Legal
Portugal	45	10		Ex ante	Ownership	Management
Spain	100	20		Ex ante	Ownership	Legal
Sweden	100	[5]	10[6]	Ex post	Ownership	Legal
United Kingdom	100	15	12	Ex ante	Ownership	Legal

1. In general the split between large and small customers is at the threshold of more or less than 1 GWh/year.
2. The Czech Republic became a EU member in May 2004.
3. Most large users in Finland tender every year for a new supplier.
4. Hungary became a EU member in May 2004.
5. Most large users in Sweden tender every year for a new supplier.
6. Cumulative 40% since 1998.

Source: EU Commission, Third Benchmarking Report.

IEA NORTH AMERICA

Recommendations by 14 August 2003 Blackout Task Force

In the aftermath of the 14 August blackout in the eastern part of North America, the governments of the United States and Canada formed a joint task force to review the incident and make recommendations for initiatives to handle similar incidents better in the future. As described before, some of the main conclusions were that the blackout was avoidable and was not caused by the effects of liberalised markets. The report of the task force states that reliability and economic efficiency can be compatible but that sustained, focused efforts will be required to strengthen and maintain the institutions and rules needed to protect both goals. The task force presents 46 concrete recommendations and several of them have broad consequences for continued electricity market reform.

Of particular importance to the development prospects for electricity sector reform are the recommendations concerning the institutional framework. These include mandatory and enforceable reliability standards, funding mechanisms for investments in reliability, strengthening of the institutional framework for reliability management and conditioning the approval of Regional Transmission Organisations or Independent System Operators to the fulfilment of certain minimum functional requirements.

Furthermore, the task force recommends commissioning an independent study on the relationships between industry restructuring, competition and reliability.

The United States: formation of regional transmission organisations

According to the US Federal Energy Regulatory Commission (FERC) the formation of Regional Transmission Organisations (RTOs) and Independent System Operators (ISOs) is an important element in the vision for a reformed efficient electricity sector [White Paper (April 2003), Standard Market Design (July 2002) and regulation on Regional Transmission Organisations (December 1999)]. To be recognised as a RTO or ISO, certain minimum criteria must be met, including the publication of good market rules. The evolvement of the formation of RTOs and the growth of existing RTOs have progressed slowly during the past year. A few new grid areas have been included in established RTO control areas and more are planned. There are still numerous states where there is no apparent intention to establish RTOs and to open electricity markets.

The PJM Interconnection, which operates a large wholesale electricity market, has been joined by new member companies and now includes 35 million consumers. In December 2003, the PJM Interconnection and the Midwest ISO executed and filed a joint operation agreement with the FERC. The agreement is the foundation for a co-operation in serving wholesale electricity customers in both their control areas.

In July 2003, the FERC issued a new set of rules to standardise the interconnection of new generation facilities to transmission grids. The rule requires public utilities that offer transmission services also to offer a non-discriminatory, standardised interconnection service. This means that they have to file open access transmission tariffs containing standard generator interconnection procedures and a standard agreement for an interconnection service to generating facilities. Two sets of rules were issued, one for generators larger than 20 MW and the other for small generators of less than 20 MW.

The main purpose of the rules is to ensure non-discriminatory interconnection and access to transmission grids to make the entry of merchant generators as easy and open as possible for the sake of competition in the wholesale market.

The main points in the new rules are:

- The rule clarifies who pays for interconnection costs when the transmission provider is not independent.
- The rule sets out standard interconnection procedures that the transmission provider and an interconnection customer must follow throughout the interconnection process.
- The rule applies to Independent Transmission Providers such as Regional Transmission Operators (RTOs) and Independent System Operator (ISOs) as well as non-independent Transmission Providers. Independent Transmission Providers would be allowed more flexibility in proposing alternative interconnection policies for both pricing and non-pricing matters.

Canada: Electricity Restructuring Act in Ontario

The government of Ontario proposed an Electricity Restructuring Act in June 2004. The restructuring act comes after the reversal of the electricity market reform in December 2002. The key elements in the proposed act include:

- The creation of 2 500 MW of new generation or demand-side capacity through an open tender. The new generation must be fuelled by other sources than coal and oil and should be commissioned no later than 1 June 2009 but preferably before 2008.
- The formation of the Ontario Power Authority (OPA). Among other things the OPA will assess the adequacy and reliability of electricity resources. It will prepare integrated system plans for generation, transmission and energy conservation.

- The Ontario Energy Board will approve an annual rate plan for low-volume electricity consumers.
- Electricity rates to medium-sized and large businesses will reflect a combination of regulated, contract and competitive market prices.

The declared goal of the government is to close existing coal-fired generating capacity (approximately 7 500 MW or 25% of total capacity) which will be compensated by energy conservation and new production capacity that is not fuelled by coal or oil. The medium-term goals are that 5% of Ontario's generating capacity should come from renewable energy sources by 2007, 10% by 2010, and that by 2007 electricity demand should be reduced by 5% through conservation.

IEA PACIFIC

Australia: Electricity market reform

The Ministerial Council of Energy (MCE) agreed on a new reform package in December 2003 as a response to the Council of Australian Governments Energy Market Review of December 2002. In many aspects the MCE followed the recommendations in the review. The main focus of the reform was to improve regulatory efficiency by concentrating many of the regulatory responsibilities in one body instead of the regulators in the states and territories. The call for improved regulatory efficiency was mainly driven by the need for new investments. The key elements of the electricity market reform are:

- Finalisation of an intergovernmental agreement and enactment of co-operative legislation.
- Establishment of the Australian Energy Regulator and the Australian Energy Market Commission to resume responsibility from 1 July 2004.
- Implementation of electricity transmission reforms, including the compilation of an Annual National Transmission Statement to forecast possible interconnection and supply problems.
- Establishment of an agreed national framework for distribution and retailing.
- Enhancing user participation in energy markets.

New Zealand: New Electricity Commission resumes control

Following the government announcement in May 2003 of the formation of a new Electricity Commission, the commission assumed responsibility for the operation of the New Zealand Electricity market in March 2004.

In May 2003, it was also announced that reserve power will be contracted to provide for a balance between supply and demand in a 1-in-60-year drought. In May 2004, the government-financed electricity plant Whariniki, a 150 MW open-cycle gas turbine, went into operation to serve as reserve power. The Electricity Commission has announced that no additional reserve power will be needed in 2005, even in the event of a 1-in-60-year drought.

The first nationwide audit of infrastructure was released in May 2004. The report is intended to be updated regularly every three years. Two main concerns were identified in the electricity sector:

- Electricity security of supply, both short-term, arising because of the failure of the market to provide for security margins, and long-term, created by uncertainty around fuel availability and regulatory issues.
- Lack of investment in electricity transmission due to uncertainties about who should pay for investment and under what pricing methodology, coupled with land access issues.

Japan: Amendment of Electricity Utility Industry Law

The Electricity Utility Industry Law was amended in June 2003 stipulating a plan for further liberalisation until three years after entering into effect of the law. The retail market will be liberalised in steps corresponding to 40% of total consumption in 2004 and 63% in 2005. Full market opening will be reviewed in 2007. General power utilities will be obliged to ensure fairness and transparency of the transmission and distribution by accounting separation, information firewalls and prohibition of discriminatory treatment. A Neutral System Organisation (NSO) will be established to manage transmission and distribution issues, supervised by the Ministry of Economy, Trade and Industry (METI). The current transaction-based transmission tariffs will be replaced by a postage stamp system. A voluntary national electricity exchange was established in 2003 and will start its operation in 2005.

Korea: Process to separate distribution brought to a halt

The Korean electricity sector reform was planned to consist of four phases. The first phase was the establishment of a legislative framework in 2000. The second phase included the separation and eventual privatisation of generation assets from the Korean Electricity Power Corporation (KEPCO) from 2001. The third phase of the restructuring plan was to be initiated in 2004. It included plans to separate the distribution assets from KEPCO into separate distribution companies that were to be privatised over time.

In June 2004, the Korean government announced that the plan to separate KEPCO's distribution assets has been brought to a halt. This was after advice from a tripartite committee consisting of representatives from the government, labour unions and management.

GAS

Market competition continues to spread in the three OECD regions, at different speeds and stages. The North American wholesale gas market is already fully competitive, and efforts now focus on the retail level. In Europe, 2004 has been a challenging year with the enlargement of the EU to 25 member states and the opening of the gas market to all non-household customers. In IEA Pacific, reforms of the gas markets are progressing, with an emphasis on promoting further gas pipeline investments.

IEA NORTH AMERICA

The North American gas industry has undergone profound structural changes over the last three decades, largely as a result of regulatory reforms aimed at promoting competition and improving efficiency. In the United States, this process began with the phased partial lifting of controls on well-head prices in 1978 (full decontrol occurred after the Wellhead Decontrol Act of 1989), followed by optional open access to the interstate pipeline and storage system in 1985 (FERC Order 436), then mandatory open access to transportation and storage, and unbundling of activities in 1992 (FERC 636). In Canada, gas sales were unbundled at the end of 1985. The governments of Canada and the three gas-producing provinces of British Columbia, Alberta and Saskatchewan signed an Agreement on Natural Gas Prices and Markets in October 1985 which allowed gas buyers, for the first time, to directly contract for supplies with producers, marketers and other agents at freely negotiated prices.

The North American wholesale market for gas is highly competitive. Thousands of producers, independent marketers, pipeline affiliates, local distribution companies (LDCs) and end-users compete to buy and in some cases sell gas at the well-head and at market centres, or "hubs", located across the region.

Restructuring at the retail level

In recent years, the US retail market has opened more to competition as various states have initiated retail unbundling programmes to allow residential natural gas users to select their gas suppliers. The nature of these "customer choice" programmes varies widely from state to state. Table 9 provides an overview of the status of the natural gas industry restructuring in each state, focusing on the residential customer class.

Table 9

Status of US Natural Gas Industry Restructuring at the Retail Level, by State, as of December 2003

Natural gas industry restructuring status	*States*
Statewide unbundling – 100% eligibility	DC, NJ, NM, NY, PA, WV
Statewide unbundling – implementation phase	CA, CO, GA, MD, MA, MI, OH, VA
Pilot programmes/partial unbundling	FL, IL, IN, KY, MT, NE, SD, WY
No unbundling – considering action	IA, KS, ME, MN, NV, NH, OK, SC, TX, VT
No unbundling	AK, AL, AR, AZ, CT, HI, ID, LA, MS, MO, NC, ND,OR, RI, TN, UT, WA
Pilot programme discontinued	DE, WI

Source: EIA website, http://www.eia.doe.gov/oil_gas/natural_gas/restructure/restructure.html

Enrolment in existing "customer choice" programmes increased by less than 1% (36 118) in 2003, although the number of eligible customers increased by nearly 4%, or 1.2 million. Almost all the increase in participation is attributable to gains in Ohio, which is second only to Georgia in the size of its residential choice market. No state has changed its unbundling status between 2002 and 2003, although state regulatory agencies are continuing to refine and evaluate existing programmes.

In total, more than 30 million of the approximately 60 million residential customers in the United States have access to choice programmes and more than 4 million are participating (13% of eligible). Overall, however, sharply higher prices for natural gas in 2003 and increased price variability seem to have dampened consumer interest in alternative supply options and reduced the number of suppliers interested in serving the residential market. Since December 2001, the number of marketers authorised to serve residential customers has dropped from 165 to 121 and the number of marketers actively serving customers had dropped from 159 to 92 as of December 2003.

US gas prices

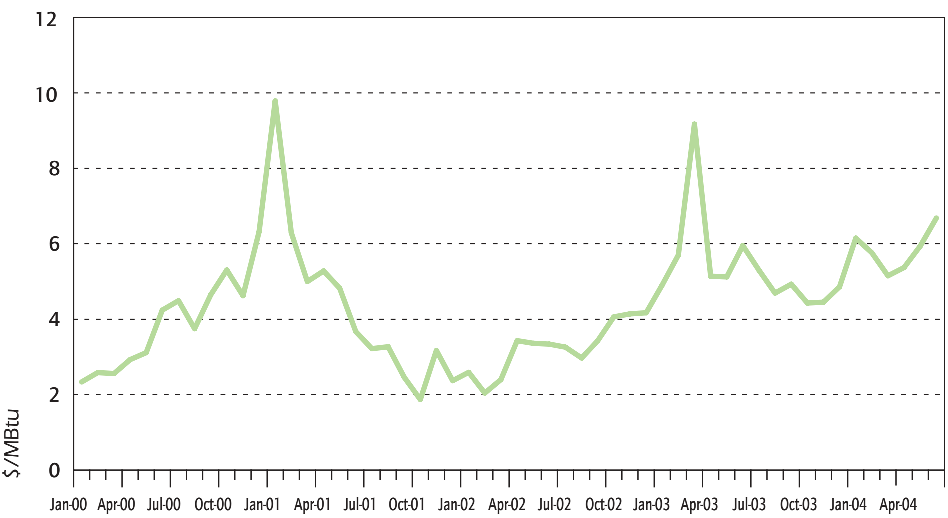
As mentioned in Chapter 4, spot prices at Henry Hub, the most active spot market centre in the US, peaked in March 2003 at more than $9/MBtu and remained high throughout 2003 and the beginning of 2004. They averaged $5.47/MBtu in 2003. The Energy Information Administration[15] projects that

15. IEA Short-term Energy Outlook, http://tonto.eia.doe.gov/oog/info/ngw/steosummary.htm

natural gas prices will continue at high levels through the rest of 2004. Spot prices averaged about $5.35/MBtu in the first quarter 2004 and were above $6.00 during the spring and early summer, as strong demand for natural gas coupled with high petroleum prices has led to higher gas prices despite nearly normal storage inventory levels. Natural gas prices weakened during the summer as cooling demand levels and peak power demand stayed below normal. The average spot price for natural gas at Henry Hub was about $5.40/MBtu in August. Storage stocks at the end of May were less than 1% below the 5-year average (1999-2003) and 23% higher than the same time last year. The lower prices and relatively weak summer demand spurred high rates of storage injection during the summer, resulting in an estimated end-August level that is more than 7% above the 5-year average. Overall in 2004, spot prices are likely to average about $5.85/MBtu, which is about 7% higher than the 2003 average.

Figure 40

United States Spot Prices – Henry Hub



Source: Energy Intelligence.

The current high prices are an indicator of the tight supply and demand balance in the US. They result from disappointing geological experience over the last few years plus restrictions on exploration areas, combined with a shift to new uses of gas that increased consumption. The result is a mismatch between supply and demand, and prices are performing their essential function: signalling market needs and changing conditions to both producers and consumers.

To improve the supply situation, the US government has moved quickly to encourage the construction of LNG terminals by adopting supporting regulation and streamlining the authorisation process. Major changes to the regulation of offshore and onshore terminals were adopted in 2002 to facilitate the construction of LNG facilities. The Amendment of the Deepwater Port Act in November 2002 places offshore terminals under Coast Guard jurisdiction and both streamlines the permitting process and relaxes regulatory requirements. The Maritime Security Act of 2002 also exempts owners of offshore LNG facilities from open-access provisions, thereby granting owners the right to reserve for themselves all of the import and storage capacity at their facilities (proprietory access).

Onshore, LNG receiving terminals are subject to FERC regulation. In December 2002, the FERC terminated open-access requirements for new onshore LNG terminals, placing them on an equal footing with offshore terminals regulated under the provisions of the Maritime Security Act of 2002. The FERC ruling, which granted preliminary approval to the proposed Dynegy/Sempra LNG terminal in Hackberry, Louisiana, is referred to as the Hackberry Decision. It authorised Hackberry LNG (now Cameron LNG) to provide services to its affiliates under rates and terms mutually agreed upon (*i.e.* market-based), rather than under regulated cost-of-service rates, and exempted the company from having to provide open-access service. This new policy allows owners of LNG terminals the exclusive use of the entire capacity of an LNG terminal, thus suppressing the uncertainty faced by LNG terminal developers.

In February 2004, the FERC, the US Coast Guard and the Department of Transportation announced an interagency agreement to provide for the comprehensive and co-ordinated review of land and marine safety and security issues at US LNG import terminals.

Higher US prices in recent years and months, together with the new proactive legislation and regulation, stimulated plans for reopening and expanding existing terminals and building new ones. Since the end of August 2003, all four existing terminals have been operational. In addition, there are more than thirty proposals for new import facilities.

IEA PACIFIC

Downstream gas markets in OECD Pacific are in a state of transition, as governments introduce competition into the sector.[16]

16. This section is drawn on *Security of Gas Supply in Open Markets: LNG and Power at a Turning Point*, IEA (2004).

In **Japan**, the main legislation governing the gas sector, the Gas Utility Law, was amended in June 2003 to expand the mandatory third-party access regulation to all gas supply pipelines. Previously, it was mandatory for only the four major companies (Tokyo Gas, Osaka Gas, Toho Gas, Saibu Gas). The government also promotes negotiated TPA to LNG receiving terminals. In the area of retail liberalisation, the government is trying to balance maintaining gas supply security with enhancing the competitiveness of the gas utilities. It intends to gradually expand the scope of retail liberalisation to consumers with an annual demand of at least 500 000 cubic metres in 2004 (representing an estimated 44% of total sales), then to consumers with an annual demand of at least 100 000 cubic metres in 2007, or about 50% of the gas market. To ensure fair and transparent third-party access to pipelines, the government proposes accounting separation and information firewalls between transportation activities and other activities of gas companies, and prohibition of discriminatory treatment against particular pipeline users.

METI is also considering measures to create incentives for the development of gas networks. The proposed measures include granting an exception for notification and publication of terms, rates and conditions for TPA or allowing higher rates of return for TPA for a certain period of time. These measures and the ongoing market reforms create the possibility for new projects to venture outside their traditional markets or team up with other energy companies. Two recent examples include the Minami-Fuji Pipeline and the Osaka Gas-Chubu Electric pipeline network. Both are private initiatives to build natural gas pipelines to connect LNG terminals together.

In **Korea**, the electricity and gas sectors are in the early stages of a long process of restructuring, deregulation and privatisation. In 1999, the South Korean government announced its intention to privatise the state-owned gas monopoly Kogas. Following an initial public offering of 33% of Kogas equity in December 1999, privatisation plans were stalled because of labour union opposition and questions about the structure of the companies that would replace Kogas after privatisation. Although the legislation necessary to restart the process has not yet been passed by the South Korean legislature, certain deregulation policies may go ahead. The government intends to open access to LNG receiving terminals and the transmission network, but the related legislation has yet to be passed. The government requested Kogas to let Posco-SK, the private operator of the fourth terminal now under construction, use the trunkline and Kogas agreed. Eventually, generation companies may import directly, whereas direct imports by city gas companies are likely to come later.

In **Australia**, the government has decided that Australia's gas and electricity markets are to be regulated by a single statutory body starting from July 2004. The Australian Energy Regulator (AER) will replace state-based regulators, thus eliminating unnecessary barriers for investors. The AER will come under the umbrella of the Australian Competition and Consumer Commission (ACCC) but will operate as a separate entity. It will progressively take responsibility for electricity and gas wholesale, network and retail regulation: gas transmission is to come under the AER in 2005, with distribution and retail responsibility following in 2006. AER will also have to compile an Annual National Transmission Statement to forecast possible interconnection and supply problems. Another body, the Australian Energy Market Commission (AEMC), is being established to develop markets.

Further reforms of the gas access regime are expected, following the review by the Productivity Commission of the national gas access regime. The commission's draft report, published in January 2004, indicated that the current regime, subject to a cost-based regulation structure, has significant costs in terms of information gathering, decision-making delays, appeals, and merit reviews. More importantly, the report found that the regulatory risk associated with it is very large, and certainly has an adverse effect on some forms of investment – either deterring or distorting investment. The existence of regulations at state level was seen as a barrier by investors for new interstate pipelines. In particular, investors have identified core areas where they believe the regime could be significantly improved to avoid the risk of regulatory failure: improving access pricing, regulatory guidance and accountability; creating incentives for investment in new and existing infrastructure; and ensuring the appropriate scope, governance and administration of the regime.

The Productivity Commission has proposed improvements that would "reduce regulatory costs, while preserving the benefits from facilitating competition through third-party access to pipelines". A change in the legislation is expected by the end of 2004.

In **New Zealand**, the expected depletion of the Maui gas field, which produces 80% of the country's gas supply, signals the need for significant changes in gas supply arrangements in the New Zealand market. Production from an increasing number of smaller gas fields will require more sophisticated market arrangements. The government has prepared a policy package designed to increase efficiency and reliability in gas production and transportation, and improve fairness for gas customers. The policy package invites the gas industry to set up a governing entity representing all stakeholders, to develop arrangements relating to production, wholesale markets, transmission and distribution networks, and retail markets. These industry arrangements should be in place by December 2004. Implementation will help promote efficient and secure energy markets for New Zealand. Open access to the Maui pipeline is also being considered, so that non-Maui gas can be transported on the Maui pipeline.

IEA EUROPE

The new Gas Directive has now become part of the Community law with the main provisions entering into force in July 2004. This event, combined with the enlargement of the EU to 25 Member States, means that the gas markets have entered a new stage of development. A Directive on Security of Gas Supply was also adopted at the end of April 2004 and a common position was agreed by the Council on legislation for the regulation of access to gas networks.

Amendment to the Gas Directive

On 26 June 2003, the European Parliament and Council approved Directive 2003/55/EC amending the earlier directive adopted in 1998. The aim of the new directive is to accelerate market opening, create a more consistent regulatory framework for EU member States, and increase the level of integration among individual markets. The timetable for market opening follows a two-stage approach, with deadlines on 1 July 2004 for non-household users and 1 July 2007 for household users. This process will take account of a report assessing the impact of liberalisation to be presented by the Commission in 2006.

The provisions in the Directive 2003/55/EC on the organisation of access to the system have been divided into two sections, one on third-party access (Article 18), which mandates regulated third-party access for transportation and one on new infrastructure (Article 22), which allows a regulatory authority to exempt major new infrastructure from Article 18 under certain conditions. In addition, there are various new obligations for system operators, such as providing system users with the information needed for efficient access to the system.

The directive requires legal unbundling of transmission and distribution activities from the rest of the activities of the gas companies, compared with account unbundling previously. The directive also provides for access to storage which might be either negotiated or regulated. It also establishes provisions for public service obligations, regulatory tasks, and requests monitoring of security of supply.

Although the amendments introduced major changes, several EU member States already apply the provisions included in the directive. Comparing with last year, Table 10 shows some changes in the degree of market opening and in unbundling provisions.

Table 10

Gas Market Reform Progress in IEA-EU Countries – March 2003

	Declared market opening	*Large eligible industrial users switch (% 2002)*	*Unbundling transmission*	*Network access*
Austria	100%	6%	Legal	Regulated
Belgium	83%	Unknown[1]	Legal	Regulated
Czech Republic[2]	0%	–	Accounting	Hybrid
Denmark	100%	17%	Ownership	Regulated
Finland	Exemption	–	–	–
France	37%	20%	Accounting	Regulated
Germany	100%	5%	Management	Negotiated
Greece	Exemption	–	–	–
Hungary[3]	0%	–	Legal	Regulated
Ireland	85-88%	100%[4]	Management	Regulated
Italy	100%	10%	Legal	Regulated
Luxembourg	72%	0%	Management	Regulated
Netherlands	60%	15%	Management	Hybrid
Portugal	Exemption	–	–	–
Spain	100%	38%	Legal	Regulated
Sweden	51%	0%	Accounting	Regulated
United Kingdom	100%	16%	Ownership	Regulated

1. 1.6% of total gas consumption in 2002 (CREG annual report).
2. The Czech Republic became an EU member in May 2004.
3. Hungary became an EU member in May 2004.
4. All large users (mostly power stations), self ship.

Source: European Commission, Third Benchmarking Report.

Directive on Security of Gas Supply

In addition to the new Gas Directive, the Council adopted a new Directive on Gas Supply on 26 April 2004, based on a revised version of the proposed Directive (COM(2002)488). The directive mandates member States to ensure an adequate level for the security of gas supply and to protect supplies to household customers. It sets a common framework for member States to define general, transparent and non-discriminatory security of supply policies compatible with the requirements of a competitive internal European market for gas; clarify the roles and responsibilities of the different market actors; and implement specific non-discriminatory procedures to safeguard security of gas supply.

The Commission has monitoring powers based on Article 100. The directive also establishes a Gas Co-ordination Group comprising stakeholders from member States, industry and consumers. The group will facilitate the co-ordination of supply security measures. Member States must transpose the directive into national law by May 2006.

Third benchmarking

The European Commission published a third review of competition in the European gas and electricity market in March 2004. The main points of the report are:

- There is an agreed timetable for gas market opening which member States must comply with.

- There has been an improvement in tariff structures with the removal or modification of a number of crude distance-related tariff regimes. Greater consistency for transactions between different TSO areas is, however, still needed.

- Some improvements have been made in transparency regarding the availability of infrastructure capacity with most TSOs now publishing this information. However, publication of available capacity at most relevant entry-exit points still needs to be accomplished. Moreover, a harmonised methodology to calculate and compare the available capacities still needs to be established.

- Capacity reservation procedures have become more flexible and responsive to clients for third-party access, and balancing regimes have improved in a number of cases. However, booking procedures, congestion management and balancing mechanisms have not yet been harmonised among different TSO areas, thus causing obstacles to new entrants in obtaining capacity and in managing transportation of the same flow through different countries. Contractual congestion also still exists in the absence of appropriate "use it or lose it" mechanisms.

- Non-discriminatory and transparent TPA to storage still has to be implemented in many member States.

Overall, the Commission notes that although there has been steady progress in market opening, competition in the gas sector still lags behind the electricity sector. In particular, the Commission notes that the degree of concentration at national level remains a problem and this underlines the need to establish a more effective single market for gas in the extended EU as soon as possible. With this objective in mind, the Commission has proposed to introduce a regulation relating to cross-border exchanges of gas.

Regulation regarding access to the gas transmission network

The Council reached political agreement on the common position concerning the proposal for a regulation on conditions for access to gas transmission networks, which is intended to complete the internal energy market package. The proposal, built on the voluntary Guidelines for Good Practices[17] (GGPs) of the European Gas Regulatory Forum (Madrid Forum), sets detailed rules for a number of aspects relevant for third-party access to member States' gas transmission networks. The agreement suggests, in particular, the entry into force of the regulation on 1 July 2006, whereas the guidelines providing the minimum degree of harmonisation required to achieve the aim of this regulation may not be amended before 1 January 2007.

Those guidelines shall specify details of third-party access services, details of the principles underlying capacity-allocation mechanisms, including “use it or lose it” and secondary trading mechanisms; and on the application of congestion-management procedures, tariff structures, as well as details on the definition of the technical information necessary for network users to gain effective access to the system and on transparency requirements.

In order to help it address these issues in a coherent manner across the EU, the Commission has created an advisory group called the European Energy Regulators Groups for Electricity and Gas (ERGEG).

The development of gas hubs and trading in continental Europe

Under the impetus of TPA to the grid and evolving competition, spot trading in continental Europe is developing although it is still in its infancy. New gas hubs are emerging in several locations, mostly in north-west Europe, to provide physical balancing and trading services with the likely evolution of new commodity spot markets. Trading is developing at Zeebrugge (Belgium), Emden, Bunde (Germany/Netherlands) and TTF (Title Transfer Facility) (a wholesale gas exchange in the Netherlands).

Unlike the situation in the UK or the US, there is no gas exchange in continental Europe as yet. Over-the-counter transactions are the only way to trade. This means that so far no official price exists, although prices at Zeebrugge and Bunde are reported by specialised press agencies (Heren, Platt’s, Argus). Trading is still limited at these hubs and they do not offer a solid pricing reference. After the Enron collapse and the withdrawal of US companies from European trading, liquidity had suffered a blow, but markets finally started to recover in 2003, after the entrance of banks and the growth of trading subsidiaries of producers and utilities.

17. The second version of the “Guidelines for Good Practices” was adopted by the Madrid Forum in September 2003.

While uncertainty about the fate of the Kyoto Protocol[18] has not been dispelled entirely, IEA member countries are taking various climate change mitigation measures. Some member countries have adopted ambitious long-term targets up to 2050. The UK and France have set targets to reduce their GHG emissions by 60% and 75% respectively by 2050. 2003 was an important year at a regional and national level for the development and implementation of climate policies, notably the European Union GHG Emissions Trading Scheme (EU-ETS). The scheme is significant in terms of its coverage, innovation and potential implication, and the steps towards its implementation are being closely followed by the world.

On 30 September 2004, the Cabinet of the Russian government decided to approve the Protocol and submit it to the State Duma for ratification. The fate of the Kyoto Protocol now hinges upon its ratification by the State Duma, which remains to be seen. If it is ratified, there could be greater political impetus for new and additional policies and measures to mitigate GHG emissions, as current emission trends indicate that most IEA countries are not on track to meet their GHG commitments. Governments may be interested in developing additional market-based mechanisms to ensure that cost-effective emissions reductions are available to make compliance with emissions commitments possible. They may also be interested in deepening and developing other policies and measures, particularly in sectors not covered by any domestic emissions trading scheme. Policies to stimulate greater development and use of renewable energy are also foreseeable in many countries.

Whatever happens to the Kyoto Protocol, many governments may start considering objectives for the longer term (*e.g.* after 2012) in order to provide clear signals to those investing in long-term capital projects with GHG implications.

CLIMATE CHANGE POLICIES OF IEA COUNTRIES

Member countries have continued to develop energy-related national climate change policies over the past year. While many of these have been taken explicitly to meet Kyoto objectives, others are the result of domestic efforts that are independent of Kyoto. In an effort started in 1999, the IEA systematically collates and classifies information on policies and measures

18. Many countries have ratified the Kyoto Protocol, but its entry into force is now dependent on its ratification by the Russian Federation.

taken or planned to reduce greenhouse gas emissions from the energy sector[19], offering a continuous follow-up of the climate change mitigation policy-making process. IEA member governments review and certify the listed policies and measures on a yearly basis. Regarding the policy mix, in terms of numbers of policies to be implemented in IEA countries in 2003, fiscal measures were dominant.

FISCAL MEASURES

Fiscal measures are an important component of the policy mix developed by IEA member countries to reduce greenhouse gas emissions, representing over 20% of the policies and measures implemented in 2003. However, few new tax measures directly related to energy use or carbon emissions were initiated. In Japan, the Ministry of Economy, Trade and Industry (METI) implemented the revision of the energy tax on fossil fuels. This revision is set to equalise the tax burden and take account of the amount of carbon dioxide emitted in the use of energy. Finland also increased its energy taxes in 2003, partly on the basis of CO_2 content, with the objective of reducing energy consumption and associated CO_2 emissions. Portugal is considering the introduction of a carbon tax. In Europe, the Council of Ministers adopted a directive restructuring the Community framework for the taxation of energy products and electricity. The directive widens the scope of the EU's minimum rate system for energy products, which was previously limited to mineral oils, to all energy products, including coal, natural gas and electricity.

As in previous years, the vast majority of fiscal measures taken or planned have been developed to provide incentives for the deployment of energy efficiency improvements, renewable energy sources, and emerging low-carbon technologies. These measures usually take the form of subsidies, tax credits or feed-in tariffs. For example, in the United States, the fiscal year 2004 budget proposed tax incentives totalling $4.2 billion through FY 2008 to spur the use of clean, renewable energy and energy-efficient technologies.

In the field of energy efficiency improvements, in the United States, California provided a financial incentive to customers who install renewable and non-renewable self-generation units. In the building sector, grants were provided in several countries (*e.g.* Canada) to home-owners once they complete energy efficiency improvements. In the transport sector, energy efficiency improvements and fuel-switching were also supported through government incentives and subsidies. Japan adopted preferential taxation on fuel-efficient and low-emission vehicles, and in France funds were awarded in order to accelerate the promotion of those vehicles.

19. The "Dealing with Climate Change" policies and measures database is accessible on http://www.iea.org/envissu/index.htm

In the field of renewable energy technologies, subsidies in several IEA countries were allocated in the building, energy production and transport sectors. In the building sector, grants were essentially focused on promoting renewable energy systems for space and water heating. For energy production, feed-in tariffs were introduced for all renewable energy sources in Ireland, Belgium and the Netherlands. Feed-in tariffs set a predetermined buy-back rate for all or an amount of electricity produced. Tax credits or exemptions were allocated to the industries in the manufacturing sector that invest in energy-efficient equipment or environment-friendly sources. The Spanish government enacted a modified tax code which includes a 10% deduction for companies investing in renewable energy sources.

In the transport sector, some countries (*e.g.* Australia, Italy and Canada) developed grants for lower carbon-emitting technologies. These measures aim to contribute to the expansion of fuel ethanol production and use, and to reduce transport-related GHG emissions. Grants were initiated in the United Kingdom to build new bioenergy infrastructure. They also intend to lower the upfront cost of less-emitting vehicles (fuelled with natural gas, ethanol or biodiesel), to encourage manufacturers to increase their production and to induce owners of vehicles to invest in retrofit options. The German government has proposed a draft law to introduce tax incentives for owners of vehicles which, after being fitted with a filter, meet Euro III and Euro IV[20] emission standards.

REGULATORY INSTRUMENTS

Regulatory instruments include a new set of laws or the introduction of mandates and standards. They are another important policy tool to reduce greenhouse gas emissions and have been increasingly used by IEA member countries over the past couple of years.

Regulatory policies or reforms form a very important category of regulatory instruments. An EU directive promoting combined heat and power generation (CHP) entered into force in March 2003. Member States must transpose the directive into national law by 21 February 2006. The aim of the rules is to promote CHP to produce energy at higher efficiency, so reducing emissions, especially of greenhouse gases, as well as saving primary energy. By 21 February 2006, the European Commission is to establish harmonised

20. Before passenger cars can be type-approved for sale in the European Union, they must meet certain standards for exhaust emissions. The Euro III limits, specified in Directive 98/69, were introduced from 1 January 2000 and became fully effective, for the majority of vehicles, on 1 January 2001. The Euro IV limits, also specified in Directive 98/69, will be introduced from 1 January 2005 and become fully effective from 1 January 2007, although vehicle manufacturers may seek to meet these limits in advance.

efficiency reference values which member States will be required to use to guarantee the origin of their co-generated power and heat.

In November 2002, the government of Canada released the Climate Change Plan for Canada, which proposes that targets for emissions reductions – totalling 55 Mt – be established for large final emitters (LFEs) through covenants with a regulatory or financial backstop. To provide LFEs with flexibility in achieving their targets, the plan proposes access to emissions trading, domestic offsets, and international permits.

Mandates and standards are also often used to promote energy efficiency or renewable sources of energy. Mandates reduce flexibility in the choice of options to achieve emissions reductions, but offer a high level of certainty on reductions being achieved. Several IEA countries have set mandates to ensure that a minimum proportion of biofuels and other renewable fuels is placed on their markets. In Sweden, since March 2003 power consumers are obliged to buy certificates from renewable sources to cover a set proportion of their use. In Europe, a directive on the promotion of the use of biofuels and other renewable fuels for transport was adopted in May 2003. The directive aims at promoting their use to replace diesel or petrol for transport. Member States should ensure that a minimum proportion of biofuels and other renewable fuels is placed on their markets and shall set national indicative targets. A reference value for these targets is 2% of all petrol and diesel use for transport purposes.

Another approach for retail goods is to require the mandatory labelling of the energy performance of goods. In the transport sector, following the expansion of a vehicle fuel consumption label scheme in Australia, new regulations require that information on the fuel consumption and CO_2 emissions of vehicles be made available to potential buyers at car sales points. The labelling framework provides for determinations that set fuel quality information standards for specified supplies of specified fuels to be made, and in the first instance will be used to set parameters for the labelling, at the point of sale, of ethanol blends.

For manufacturing and retail goods such as electric appliances, the Top Runner Programme was renewed in 2003 in Japan. Under this programme, the energy performances of the most efficient products supplied domestically are used to set up the next efficiency standards. Minimum energy efficiency standards must be met in order to be able to sell the good on the domestic market. The European Commission is also proposing a directive on the eco-design of energy-using products such as electrical and electronic devices or heating equipment. The proposal does not introduce directly binding requirements for specific products, but does define conditions and criteria for setting requirements regarding environmentally relevant product characteristics (*e.g.* energy consumption).

VOLUNTARY AGREEMENTS

Voluntary agreements are commonly introduced as a co-operative and less rigid way of reducing greenhouse gas emissions than regulatory measures. Such approaches offer an opportunity to address environmental problems in a flexible manner at a low cost, based on consensus-building between the different stakeholders. In 2003, the same number of voluntary agreement (VA) policies as in 2002 was implemented. These policies often contain a target and a time schedule to achieve it. In the environmental policy mix of IEA countries, voluntary measures are most often used in combination with one or more other instruments as part of "policy mixes". A VA can be implemented along with fiscal measures in order to encourage the reaching of the VAs' targets. Providing tax exemptions, for example, to the sectors in question in return for "voluntary" abatement commitments can encourage the undertaking of the VA while reducing the loss of international competitiveness. VAs can also be implemented with outreach measures such as publicity campaigns that encourage abatement measures. Such agreements in 2003 were most frequently set up between governments and the transport or industry sector.

In the transport sector, the Environmental Protection Agency (EPA) in the United States established SmartWay Transport Partnership, a voluntary partnership with the freight industry. This voluntary agreement establishes market-based incentives for fuel efficiency improvements and greenhouse gas emissions reductions in freight operations (ship, rail and truck). Likewise, the Federal Chamber of Automotive Industries (FCAI), an industry organisation representing the automotive industry in Australia, adopted a code declaring the membership's commitment to improving environmental outcomes through the progressive reduction in carbon dioxide emissions and fuel consumption of new passenger cars and other light vehicles it supplies to the Australian market. The code includes a target reduction in national average fuel consumption (NAF) for new petrol-fuelled passenger cars of 6.8 litres per 100 kilometres by 2010, and appropriate target reductions in greenhouse gas emissions for other new light vehicles by 2010.

In the industry sector, New Zealand signed a Negotiated Greenhouse Gas Agreement with firms. They receive a full or partial exemption from the emissions charge in exchange for moving towards world's best practice in emissions management. In France, the government has created a "High Energetic Performance" label which is attributed on a voluntary basis to buildings which exceed the mandatory thermal efficiency requirements. In the United States, the Department of Energy in 2003 launched Climate Voluntary Innovative Sector Initiative: Opportunity Now (VISION) programme, a public-private partnership that works with an industry trade association representing 12 energy-intensive economic sectors to reduce emissions. The Environmental Protection Agency's Climate Leaders programme is a similar programme that works with individual companies.

POLICY PROCESSES AND OUTREACH

Policy processes represent the most broadly used category of policy instruments with fiscal measures. A clear distinction can be made within policy processes between "planning" policies (consultation, strategic planning, and institutional development) and "outreach" policies (information dissemination, and advisory efforts).

Planning policies are the backbone of greenhouse gas mitigation programmes. In the past few years, all IEA member countries have developed national, regional or sectoral climate change strategies, highlighting the fact that climate change is now higher on the political agenda of all IEA countries. Many of them are taking into account the imminent start of the Kyoto Protocol's first commitment period (2008-2012). These strategic plans set out a co-ordinated set of actions to be implemented in order to reduce greenhouse gas emissions. On a national level, these include the UK Energy White Paper published in February 2003. It sets four new goals for its energy policy: *i*) to put the UK on a path to cut carbon dioxide emissions by some 60% by about 2050, with real progress by 2020; *ii*) to maintain the reliability of energy supplies; *iii*) to promote competitive energy markets in the UK and beyond, helping to raise the rate of sustainable economic growth and improve its productivity; and *iv*) to ensure that every home is adequately and affordably heated. The Netherlands also released a three-year Biomass Action Plan, developed in co-operation with market parties. The plan tackles various restrictions and problems that currently arise when starting up biomass projects, in the fields of financing, licensing, public relations, the availability of fuel and biomass technology.

Planning policies also often involve the creation of specific institutions for the implementation of climate change measures. This was the case in 2003 in Belgium. The National Climate Commission, formally installed on 5 December 2003, has a key role in assessing and monitoring the national climate policy and the institutional setting-up of the flexible instruments. This commission is composed of representatives of the federal and regional governments.

Planning policies also entail aid in implementation. In Finland, funds were made available in 2003 to aid investments in selected renewable energy projects as a means to partially offset the initial capital cost of these systems. Similarly, the government of Canada announced the investment of $160 million from the 2003 budget for the Opportunities Envelope. This initiative will provide additional flexibility to the provinces and territories as they continue to develop solutions that meet their specific needs and circumstances, and support national climate change goals at the same time. The Opportunities Envelope will also allow the government of Canada to contribute to cost-effective emissions reduction initiatives brought forward by its provincial and territorial partners.

Outreach policies aim to inform and advise people or organisations on how to reduce their greenhouse gas emissions efficiently. These programmes are still an important component of climate change mitigation strategies. In Canada, the Marketing of Efficient Vehicles initiative provides a market pull for more efficient vehicles and also supports the consumer education campaign. The latter initiative targeted campaigns to reduce fuel use through improved vehicle maintenance and modified driving practices. Likewise, in the United States in May 2004 the Department of Energy (DoE) and the Alliance to Save Energy launched a new year-long public education and awareness campaign called "Powerful $avings". The campaign will provide consumers with the information and tools necessary to make smart energy choices a part of their daily lives. The new partnership with the Alliance to Save Energy continues Energy Secretary Spencer Abraham's "Smart Energy" campaign, which was launched in summer 2003. The partnership between the DOE and the Alliance will focus on increasing public awareness on the importance of energy efficiency and smart energy practices both at home and on the road through an extensive media outreach campaign. It will include broadly disseminated news releases via video, audio, and print.

RESEARCH, DEVELOPMENT & DEMONSTRATION (RD&D)

Funding for energy research and technology development has mainly focused on the development of cleaner technologies, notably with respect to hydrogen-based technologies. In 2003, several countries (Canada, Japan and the United States) and regions (European Union) stressed their will to accelerate the development and commercialisation of fuel cells and other technologies which would form the basis of the emerging hydrogen economy. Investments are aimed at supporting public and private sector partnerships to develop and demonstrate hydrogen technologies and the required infrastructure. In such a case, government intervention plays an essential role in financing RD&D investment. The European Commission, for example, has facilitated the establishment of a European Hydrogen and Fuel Cell Technology Platform aimed at accelerating the development and deployment of these key technologies in Europe. In the United States, the Hydrogen Fuel Initiative was created in 2003 to work with the private sector in accelerating the country's transition both to the technology of hydrogen fuel cells and to a fuelling infrastructure. Another RD&D policy related to hydrogen was also implemented in the United States. The International Partnership for the Hydrogen Economy intends to serve as a mechanism to organise and implement effective, efficient, and focused international research, development, demonstration and commercial utilisation activities related to hydrogen and fuel cell technologies.

In 2003, new RD&D schemes were also introduced to support biofuelled and renewable energy systems and technologies. Italy intensified its search for alternative sources of energy – looking to solar and biomass to boost its growth in renewables. The United States participated in a research project to harness the promise of fusion energy, the same form of energy that powers the sun. Participants include the European Union, Russia, Korea, Japan and China. Three major international co-operation initiatives were established to develop hydrogen and fuel cells: the IEA Hydrogen Co-ordination Group; the International Partnership on Hydrogen Economy and the European Hydrogen and Fuel Cell Technology Platform. The United States, like Norway, also established new research schemes in the fields of capture and storage technologies. In the United States, the Carbon Sequestration Leadership Forum (CSLF) was launched. It is an international climate change initiative focusing on the development of cost-effective technologies for the separation and capture of carbon dioxide, its transport, and its long-term safe storage. The goal of the CSLF is to make these technologies broadly available internationally and to identify and address wider issues relating to carbon capture and storage. In the United States, the development of climate change technologies is co-ordinated through the Climate Change Technology Program, which has ten participating agencies.

TRADABLE PERMITS

Various trading instruments have been developed to address greenhouse gas emissions in industry in IEA countries, including greenhouse gas tradable permits, renewable energy certificates or green electricity trading and energy efficiency trading. Emissions trading consists of tradable permits and project-based programmes, including clean development mechanisms (CDM) and joint implementation (JI) under the Kyoto Protocol.

Emissions trading is a result-oriented instrument rather than an instrument which imposes a particular type of technology. It sets rigid limitations on how much individual installations can emit, but provides flexibility in how to achieve this. The rationale behind emissions trading is to ensure that emissions reductions take place where the cost of the reduction is lowest, thus lowering the overall costs of combating climate change. In contrast to regulations that impose emissions limit values on particular facilities, emissions trading gives companies the flexibility to meet emissions reduction targets according to their own strategy.

The European Union GHG Emissions Trading Scheme (EU-ETS) was the most significant policy development at the regional level in 2003. On 22 July 2003, the European Commission voted in favour of a directive establishing an EU emissions trading scheme in 2005. It is significant in terms of its coverage (including more than 10 000 installations in Europe's energy and energy-intensive sectors), its innovation (through the use of a market-based instrument to address a global environmental challenge), and its potential implications (as it could have profound impacts on the production and use of energy). The steps towards its implementation are indeed being followed closely by governments and stakeholders around the globe (see the following section for additional details).

Table 11 highlights other countries which are also thinking about implementing emissions trading schemes as a means to mitigate climate change.

The Climate Change Plan for Canada, released end 2002, established a three-pronged approach to address emissions from large industrial emitters and to reduce their emissions by 55 Mt-CO_2 from the 2010 business-as-usual projections, including access to a domestic emissions trading system. Large final emitters will have the option of negotiating a covenant with the government or accepting emissions reduction targets set out in the regulations.

- Firms will receive permits free of charge.
- The volume of permits is, on average, equal to 85% of forecast 2010 emissions, which will achieve the goal to reduce these firms' emissions by 55 Mt.
- Allocation based on emissions intensity targets, meaning that the exact number of permits a company receives will depend on its level of production.
- Permits will be distributed at the end of the year, after companies report to government (*ex post* distribution).
- Partial *ex ante* being considered to facilitate trading.
- Covenants to address: competitiveness, early action, or larger future reductions.
- Price assurance mechanism – $15 per tonne price cap.
- Penalties will be implemented.

Emissions trading systems have also been implemented or are being designed at the state or more local levels in countries such as Australia and the United States. In the United States, these systems include states such as Massachusetts, Oregon, New York State, New Hampshire, Illinois, North

Table 11

Emissions Trading Schemes under Discussion in non-EU IEA Countries

Country	*Coverage*	*Initial permit allocation*	*Interface with other instruments*
Canada	All GHG from large industrial emitters, including thermal electricity, oil and gas, mining, pulp and paper, chemicals, iron and steel, smelting and refining, cement, lime, and glass. Start-up pre-2008 possible.	Free allocation determined through sector-specific covenants with regulatory or financial backstop.	Possible integration of previous voluntary domestic credit-based systems. Development of an offsets system, involving initially forestry and agriculture, and possibly landfill gas, is under way. Links to other trading schemes envisaged.
Japan	To be determined. Trial trading with participants from chemical, oil refinery, car manufacturing, semiconductor, and food industry.	To be determined.	To be determined.
Korea	Registry to be established by 2004 targeting GHG emissions from the manufacturing industry. There are plans to adopt a CO_2 emissions trading system at a later stage.	To be determined.	To be determined.
Norway	All GHGs and all sectors, covering over 80% of emissions.	To be determined, partial auctioning, partial grandfathering.	In parallel with carbon tax from 2005, eventually to replace it after 2008.
Switzerland	Large emitters, companies and energy-intensive producers can exempt themselves from the CO_2 law by adopting absolute CO_2 limits, with possibility to trade. Pilot phase 2005-2007.	Based on negotiated agreements. Free allocation.	Tax on fossil fuels will be imposed from 2004 if agreements prove insufficient. Interested in links to EU emissions trading scheme.

Source: OECD/IEA.

Carolina, Michigan, California, New Jersey and Wisconsin. Generally, such schemes are designed to provide information and experience to companies and governmental agencies by practical experience of trading carbon dioxide-equivalent emissions.

If Canada, through its Large Final Emitters Group, and other countries also move towards the implementation of a domestic emissions trading scheme, an important policy focus in 2004 and 2005 could very well entail the development of appropriate linking between the schemes to benefit from a broader emissions trading market through greater compliance options, increased market liquidity and lower overall compliance costs.

Emissions trading can also include the credits from project-based programmes such as joint implementation (JI) and clean development mechanism (CDM). The Netherlands and the European Bank for Reconstruction and Development set up a Carbon Fund to promote the reduction of greenhouse gas emissions in Central and Eastern Europe. The Bank will use €32 million of Dutch funds to acquire carbon credits for the account of the Netherlands under JI projects. The Austrian JI/CDM programme also aims to make a contribution to achieving the Austrian reduction commitment under the Kyoto Protocol through the application of the project-related flexible mechanisms.

There are a number of other trading schemes in addition to greenhouse gas emissions trading. These include renewable energy certificate trading schemes and the emerging energy efficiency trading schemes. The idea of a tradable renewable energy certificate (TREC) approach is to use market forces to determine the necessary additional payments to investors in renewable energy plants. In Sweden, a law instituting an electricity certificate system came into force on 1 May 2003. Under the scheme, generators using solar, wind, biomass, geothermal, wave or small (<1.5MW) hydro are awarded one certificate for each MWh produced, and all consumers are obliged to buy these certificates to cover a set proportion of their use. This requirement starts at 7.4% of electricity supplied in 2003, rising to 16.9% in 2010. For consumers who fail to buy enough certificates there is a penalty of 150% of the annual average price for certificates with a sealing at SKr 175/MWh (€19.3/MWh) in 2003 and SKr 240/MWh (€26.5/MWh) in 2004. Norway also plans to introduce its own green certificate scheme within two years and set up a joint market with Sweden for trading green certificates. The aim is to encourage the development of a binding international system into which the bilateral scheme would be assimilated. Likewise, an EU directive on electricity labelling agreed in July 2003 also requires that all member states introduce similar systems allowing transfers of certificates to enable international digital transfer of guarantees under the European Energy Certificate System that is to replace current green certificate systems.

EUROPEAN EMISSIONS TRADING SCHEME

In October 2003, the European Parliament and the Council of the European Union adopted Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community (referred to as the EU Emissions Trading Scheme – EU-ETS).

The first phase of the EU-ETS will be over three years, 2005-2007, while the second phase will cover a 5-year period (2008-2012), matching the Kyoto Protocol's first commitment period. The directive specifies that each subsequent phase will also be over 5-year periods.[21] Compliance with the EU-ETS is required on an annual basis within these periods, but the allocation of allowances will be decided separately for the two periods. For the second period, transfers of EU allowances between installations in different member states will need to be matched by a corresponding adjustment of assigned amount units (AAUs)[22] under the Kyoto Protocol.

The coverage of the EU-ETS reflects quite closely the coverage of an earlier (1996) Directive on Integrated Pollution Prevention and Control. It is a "downstream" trading system, in the sense that it covers the point of emission of greenhouse gases. However, starting in 2008, the EU Trading Directive does allow member states to include other installations and GHGs, provided these have been approved by the Commission. The directive's provisions on key features (*e.g.* allocation mode, coverage, banking, treatment of new entrants, etc.) of the EU-ETS are summarised in Table 12.

The next step towards the implementation of the EU-ETS is for each member state to develop a National Allocation Plan (NAP) stating the total quantity of allowances that it intends to allocate for the period and how it proposes to allocate them. NAPs are to be based on objective and transparent criteria, including those listed in the directive. Public comments also need to be taken into account.

IMPLEMENTATION PROCESS

Tasks for the Commission

The European Commission has had, and continues to have, an important role in preparing for the implementation of the EU directive. These tasks include, *inter alia*: adopting monitoring and reporting guidelines; adopting regulations and building an electronic registry system; and adopting allocation guidelines.

21. The Kyoto Protocol does not specify when a second commitment period would start, nor how long it would last. The only reference to a second commitment period can be found in Article 3.9 which stipulates that Parties to the Protocol "...shall initiate the consideration of [commitments for subsequent periods] at least seven years before the end of the first commitment period."

22. AAUs are the currency for international emissions trading under the Kyoto Protocol. Each party with commitments under the Kyoto Protocol is allocated AAUs corresponding to its total allowed emissions.

Table 12

Key Features of the EU Emissions Trading Scheme

Features	*Description/requirements*
Type of target	Absolute target, *e.g.* X tCO_2-equivalent. One allowance in the EU-ETS gives the owner the right to emit one tonne of CO_2-equivalent during a specific period.
Allocation mode	During 2005-2007, mostly free allocation by member states following common criteria. Up to 5 % auctioning allowed during 2005-2007. Up to 10% auctioning allowed for 2008-2012.
Sectors included	CO_2 emissions from large combustion installations (>20 MWth rated input) from all sectors, plus emissions from oil refineries, coke ovens, and the iron and steel, cement, lime, glass, ceramics, and pulp & paper sectors (coverage of these sectors is subject to certain size criteria).
Coverage	Initially CO_2 only. After 2008, other gases may be included, provided adequate monitoring and reporting systems are available and provided there is no damage to environmental integrity or distortion to competition.
Banking	Banking allowances from one period to the next at the discretion of each member state.
New entrants	Member states shall take into account the need to provide access to allowances for new entrants; how and how much is to be decided by each member state.
Links with Kyoto units	The Council of Ministers and the European Parliament agreed (April 2004) on a text for the EU "Linking Directive" that will allow entities covered by the EU-ETS to use emission units from the Kyoto Protocol's project-based mechanisms (*i.e.* Joint Implementation and the Clean Development Mechanism) towards meeting their emissions targets. The use of the mechanisms is to be "supplemental" to domestic action, in accordance with the relevant provisions of the Kyoto Protocol and the Marrakech Accords. The EU directive does not include a recognition of assigned amount units (*i.e.* governments' overall emissions allocation under the Kyoto Protocol).
Links with other countries' schemes	The directive includes the possibility of linking with third parties with Kyoto commitments and that have ratified the Kyoto Protocol, based on agreements that provide for the mutual recognition of allowances between the EU-ETS and other domestic GHG trading schemes.
Penalties	A non-compliance penalty tax of €40 per tonne of excess CO_2 emissions in the first compliance period and of €100 in the second period, plus restoration of the GHG emitted without having surrendered allowances.

Sources: OECD/IEA; EU Directive 2003/87EC.

Commission-developed guidance for NAPs

In a communication on 7 January 2004 the Commission presented the eleven criteria listed in Annex III of the directive that member states should use to draw up their plans. Some of the criteria presented in the document are of a mandatory nature whereas others are optional. Some apply to the total level of allowances allocated; others only have an effect for sectors or individual installations.

One of the obligatory criteria is the consistency between the national allocation scheme and the member states' commitment under the Kyoto Protocol. Member states will have some freedom to decide on a "path" of reductions leading to compliance with their Kyoto targets. Another mandatory criterion prescribes that the allocation plans shall include provisions for informing and involving the public.

Member states are also compelled to achieve several tasks. These include the transposition of the directive into national law, the installation permitting process, the assignment of the competent authority(ies), the preparation of the NAPs, and the building of an allowance registry.

The communication, which the Commission calls a "guidance document", also includes provisions in case of a *force majeure*. Under certain circumstances (*e.g.* natural disasters, war, terrorist acts, sabotage, etc.), member states can ask the Commission to issue additional allowances for certain installations.

Responsibilities of individual member states

Allocation methodology

Each participating country in the EU-ETS must produce a National Allocation Plan (NAP). The plan shows the overall amount of allowances to be allocated for the EU-ETS in that country for any given phase of the scheme, and how those allowances will be allocated to all installations participating in the EU-ETS in that country. The directive (Article 10) provides guidance on the method of allocation, whereby at least 95% of allowances for the first period (2005-2007) shall be allocated free of charge and at least 90% for the second period (2008-2012).

The deadline for EU-15 member states for submitting their NAP for the first phase of the scheme (1 January 2005-31 December 2007) to the European Commission was 31 March 2004. The 10 newest members of the EU had a later deadline of 1 May 2004. Each plan ought to state the number of allowances that will be allocated to each installation covered by the scheme for that phase. There are also a number of criteria and other factors where member states have discretion, such as the treatment of new entrants (*i.e.* installations that both appear and come on stream during the trading period), or compensating for early action and clean technologies, or taking account of impacts on competitiveness. However, member states must follow the directive's provisions.

Annex III of the directive on the EU-ETS specifies that member states will allocate the total quantity of allowances to the installations under the scheme. However, the directive specifies that "the total quantity of allowances to be allocated shall not be more than is likely to be needed (...) Prior to 2008, the quantity shall be consistent with a path towards achieving each member state's target under the Kyoto Protocol".

Once all participating countries have submitted their NAPs to the Commission, the Commission will assess them all for compatibility with the NAP criteria in Annex III to the directive. These criteria include consistency with national climate change programmes, consistency with other Community legislative and policy instruments, and competitive issues between sectors and between countries.

Treatment of new entrants

In drawing up their National Allocation Plans, governments have three choices in their treatment of new installations entering the scheme under the Emissions Trading Directive: "They can auction up to 5% of their national total allocation; they can set aside a reserve to allocate them for free; or they can leave new entrants to buy the allowances they need from the market". State aid rules would be applied to at least the absence of 5% auctioning and banking from 2007 to 2008. The only guidance from the EC until now on the topic is that "normal state aid rules will apply".

Other elements in the NAPs are left to the member states to decide. These include:

- Treatment of plant closure.
- Updating of allocation in the second period to account for emissions reductions made in the first period.
- Rules on banking of surplus allowances between the first and the second period.
- Nature of the allowance and tax treatment.
- Detailed definitions of coverage.
- The extent to which governments plan to buy carbon credits from overseas to help them meet their targets.
- The treatment of combined heat and power generation.

Revision by the Commission

Once the National Allocation Plans are submitted, the Commission must assess them within three months of their notification to ensure that they follow the spirit of the directive – most importantly, to move member states towards the environmental goal of reducing emissions in line with their Kyoto targets. The Commission may reject a plan in whole or in part if it is incompatible with the directive's provisions on allocation criteria or method of allocation. The member states' amendments then need to be accepted by the Commission. Other key considerations include whether the plans breach state aid rules, by providing companies with over-generous allocations, for example, or discriminate between companies and sectors.

The Commission has outlined on what grounds it would assess state aid to companies if governments:

- Forgo revenue by not auctioning the 5% of CO_2 allowances they are entitled to under the directive.
- "Over-allocate" to businesses, thereby providing them with an asset without requiring any effort in return.
- Be more generous to one sector than another (whether covered by the EU-ETS, or outside it).
- Take pressure off industry by buying a substantial number of allowances in the open market, and therefore requiring domestic industry to make fewer reductions.

The Commission's first "verdicts" on the member states' NAPs by the original 31 March deadline must be given by 30 June 2004.

NATIONAL ALLOCATION PLANS

Tables 13 and 14 summarise some of the key elements related to the National Allocation Plans available on the European Commission website as of July 2004. Table 13 includes member states that have submitted a final NAP to the Commission: Austria, Denmark, Finland, Germany, Ireland, Luxembourg, the Netherlands, Portugal, Sweden, the United Kingdom, Lithuania, the Slovak Republic, Slovenia, Estonia, and Latvia. Table 14 includes member states that have published draft NAPs: Belgium (Flanders), Belgium (Wallonia), Italy, France and the Czech Republic. Member states that have not yet published their final NAP, nor a draft as of July 2004, are not included in this table. They are Greece, Hungary, Poland, Cyprus, Spain and Malta.

Table 13

Information Regarding Member States' NAPs Submitted to the Commission

Country	*Number of allowances in first period*	*Relation to the baseline*	*Energy sector*	*Treatment of new entrants*	*Number of installations*
Austria	98.2 $MtCO_2$ allocated[1]; 0.9 $MtCO_2$ of these are set aside as a free reserve for new entrants.	-7.5% from BAU. For industry: - 0.6 Mt less annually relative to BAU.	-1.05 $MtCO_2$ annually compared to BAU.	1.2% of total amount as free reserve. First-come-first-served basis, with 75% earmarked for industry and 25% for energy.	205
Denmark	33.5 $MtCO_2$/y free; 1.7 $MtCO_2$/y auctioned (5%).	85% of BAU estimates.	Electricity and heat sector will get 65.1 $MtCO_2$ for 2005-07, annual reduction of 1.3 $MtCO_2$ from the sector's current cap under Danish legislation.	0.9 $MtCO_2$/y.	362
Finland	136.5 $MtCO_2$. No auctioning envisaged.	-3% compared to BAU.		2.5 $MtCO_2$ (or 2% of total quantity).	500
Germany	499 $MtCO_2$ /y.	-0.39%/y (*i.e.* -2Mt/y)			2631
Ireland	22.5 $MtCO_2$ for 2005-07. 0.75% of allowances auctioned. The sector allocation covers 93.5% of projected emissions in the power generation sector and 98.2% in all other sectors.	-2% compared to BAU.	14.5 $MtCO_2$ for power generation.	1.5% of allowances for new entrants free of charge[2].	143

Table 13 *(continued)*

Information Regarding Member States' NAPs Submitted to the Commission

Country	*Number of allowances in first period*	*Relation to the baseline*	*Energy sector*	*Treatment of new entrants*	*Number of installations*
Luxembourg	3.5 $MtCO_2$/y.	-5% compared to BAU for included installations.		1.2 $MtCO_2$ for the first phase.	19
Netherlands	95.3 $MtCO_2$/y[3].	n.a.	Electricity production: 39.1 $MtCO_2$/y. Electricity production joint-venture: 5.7 $MtCO_2$/y.	4 $MtCO_2$/y free.	333
Portugal	116.6 Mt CO_2 or 38.9 $MtCO_2$/y.	n.a.	27.31 $MtCO_2$ allocated.	5.6 $MtCO_2$ or 1.87 $MtCO_2$/y. New plants allocated based on best available technology or most efficient installation in operation[3].	239
Sweden	22.9 $MtCO_2$/y[4].	n.a.		1 $MtCO_2$/y.	499
United Kingdom	736 $MtCO_2$. 238.2 $MtCO_2$/y.	-16.3% by 2010.	132.2 $MtCO_2$/y allocated to power stations.	7.7% saved for new entrants[5, 6].	1078[7]
Lithuania	14.70 $MtCO_2$ in 2005. 14.15 $MtCO_2$ in 2006. 13.66 $MtCO_2$ in 2007.	n.a.	8 200 tCO_2 in 2005. 7 650 tCO_2 in 2006. 7 154 tCO_2 in 2007.	5% of total freely allocated for new entrants.	90
Slovak Republic	35.6 $MtCO_2$/y for 2005-2007.	n.a.		1.5% set aside as free reserve for new entrants.	300

Table 13 *(continued)*

Information Regarding Member States' NAPs Submitted to the Commission

Country	*Number of allowances in first period*	*Relation to the baseline*	*Energy sector*	*Treatment of new entrants*	*Number of installations*
Slovenia	26.3 $MtCO_2$ allocated freely; no auctioning.	n.a.	6.5 $MtCO_2$ allocated to the power generation sector in 2005, 6.1 Mt in 2006 and 5.8 Mt in 2007. A forecast emission approach will be used for allocation at installation level.	200 000 tCO_2 or 0.76% of total allowances shall be freely distributed to new entrants [8].	98
Estonia	64.779 $MtCO_2$ over the 2005-2007 period.	n.a.		New entrants' free reserve of 1.94 $MtCO_2$.	43
Latvia	13.77 $MtCO_2$.	n.a.		2.2 $MtCO_2$ free reserve is included for new entrants.	90

BAU: business-as-usual.

1. Industries need to meet half of their CO_2 obligation during 2005-2007 and the other half between 2008-2012.
2. Allowances from closed companies will be auctioned.
3. Installations emitting less than 25 000 tCO_2/y are opted out.
4. National goal to reduce emissions by 4%.
5. CHP have the priority allocation for new entrants.
6. Allowances already issued retained up to year after closure.
7. Companies with Climate Change Agreements or participating in UK-ETS offered opt-out from first phase.
8. Allowances from closed installations will be transferred to the free reserve.

Note: Some NAPs were only available in the member states' official language, so all relevant information could not be included.

Source: National Allocation Plans available on the EU Commission website, CAN Europe, RIIA, Environmental Finance, COGEN, PointCarbon.

Table 14

Information Regarding Draft NAPs Submitted to the Commission

Country	*Number of allowances in first period*	*Energy sector*	*Treatment of new entrants*	*Number of installations*
Belgium[1] Flanders*				160 – 170
Belgium Wallonia*	28.1 $MtCO_2$ allocated per annum over the first phase, or 84.3 $MtCO_2$ in total including special reserves.	The electricity sector will be allocated an average of 7.281 $MtCO_2$ per year or 21.843 $MtCO_2$ over 2005-2007.	The new entrants' reserve is 0.5 $MtCO_2$ per annum (around 2% of current emissions of the installations covered).	100 - 110
Italy	837.4 $MtCO_2$.	Allowed to produce 228.4 $MtCO_2$ in 2005.	New entrants' reserve based on sectoral level. Power generation sector is allocated 57 Mt for non-cogeneration power installations and 8.5 Mt for co-generation. Reserve for other sectors under the scheme ranges from 0.4 Mt to 0.9 Mt..	2 000
France	126,3 $MtCO_2$/y. Overall, reduction must be 2.3 $MtCO_2$ per year, or global reduction of 1.8% compared to BAU. Industry receives 56.83 $MtCO_2$/y.	65.88 $MtCO_2$ per year.	Free reserve of 3.5 $MtCO_2$/y.	
Czech Republic	93.5 $MtCO_2$ will be allocated annually.	The energy sector will be allocated 61.1 $MtCO_2$ a year – a reduction of its emissions by 2% from 1999-2001.	0.92 Mt of free reserve. 4.58 $MtCO_2$ reserve for Early Action bonus and a 1.37 $MtCO_2$ reserve for CHP.	n.c.

* These are draft regional level plans. In Belgium, each region draws its own plan, according to the intra-Belgium agreement on the contribution of the overall Belgium Kyoto target of -7.5%: the Walloon region is to reduce its emissions by 7.5%; the Flanders region by 5.2%, and the Brussels region by 3.475%. A draft plan for Belgium as a whole is expected in June 2004.

1. For industry, allocation will be combined with a voluntary benchmarking system. Industry included in EU-ETS likely to be exempted from energy and CO_2 taxes.

Source: National Allocation Plans available on the EU Commission website, COGEN, PointCarbon.

INITIAL INSIGHTS

The information on all the NAPs for the 2005-2007 period of the EU-ETS is not yet available: most EU-15 member states were late in releasing their NAPs by the 31 March deadline and most of the ten newest EU member states were late in meeting their 1 May deadline. Moreover, some NAPs are still only available in the member states' official language and have yet to be translated into English. It is also important to keep in mind that NAPs will only be "final" once they have been approved by the EU Commission. It is thus still too early to analyse their full implications, in particular for the energy sector, although it is clear that they will have some impact. Some observations can nonetheless be made at this point which can lead to initial insights from the first steps towards the implementation of the EU's ground-breaking GHG trading scheme.

The market for CO_2 emissions is reacting to news on the relative stringency of NAPs, with prices responding to the publication of allocations. EU allowances with the vintage year of 2005 and 2006 are currently (*i.e.* 11 June 2004) trading at around 10 euros.

ENERGY EFFICIENCY

GENERAL TRENDS IN EFFICIENCY POLICIES

The energy market consists of suppliers and consumers and, for every unit of energy supplied to the market, a unit is consumed. In spite of this equality, the overwhelming majority of energy policies are directed towards influencing the supply side of the market. This asymmetry is not surprising because the energy supply market generally consists of large, easily identifiable elements. In contrast, the consumption side is extremely diffuse – lighting, space heating, refrigeration and consumer electronics to name just a few applications in the residential sector – and specific policies need to be developed to address them. The ability to monitor progress or failure in improving efficiency is similarly difficult to establish and track because the results are often obscured by changes in consumer behaviour, quality of life, industrial structure, macroeconomic situation and so forth.

Nevertheless, most IEA member countries regard energy efficiency as one of the key policy tools to achieve GHG reduction targets as well as energy security. In particular, many countries have recognised that, if current consumption trends continue, they will not meet their Kyoto obligations.

Three specific events in 2003-2004 have also influenced energy efficiency policies:

- Continuing high oil prices.
- Blackouts in large regions of North America (Northeast USA and Ontario) and Europe (Italy).
- The heat wave in Europe during the summer 2003.

This has caused a re-examination of conservation programmes to find additional opportunities for savings. The UK's White Paper issued in early 2003 assumes that energy efficiency can achieve about half of the total GHG reduction target up to 2020. In 2003-2004, several European countries have also established similar goals, again relying on improved efficiency of energy use to provide much of the savings. For example, in France, one of the three major elements of the *Livre Blanc* (White Paper) on energy released in November 2003 was an increased push for greater energy efficiency. It called for accelerating the improvement of energy intensity so that final energy consumption will be stabilised by the year 2015.

Governments have a range of tools available to encourage energy conservation and efficiency, including adjusting energy prices, establishing financial instruments to encourage the use of efficient products and practices, mandating minimum efficiency levels, creating voluntary programmes, and energy rationing. In 2003-2004, IEA member countries employed all of these tools (except rationing) to promote energy efficiency. Some of the highlights are described below. It should be borne in mind that it is increasingly difficult to identify policies specifically directed at improving efficiency because much of the new legislation and programmes have the combined goal of raising efficiency, decreasing emissions and achieving other environmental goals (such as cooling the urban heat island or reducing smog).

MINIMUM ENERGY PERFORMANCE REGULATIONS

The energy use of domestic appliances and equipment represents a significant end use of energy in all IEA member countries and large efficiency improvements are technically feasible and highly cost-effective. This regulatory approach has been used successfully for appliances, office equipment, motor vehicles and buildings. Existing regulations have already been responsible for huge electricity and fuel savings; however, independent analyses have shown that a large untapped potential remains and that further regulations are economically justified in most cases. In most IEA economies minimum efficiency regulations only apply to a proportion of the energy-using equipment types that they could potentially address. Standards must be regularly updated if they are to remain effective.

Japan now has one of the more comprehensive sets of minimum efficiency standards (called the “Top Runner Programme” for the procedure used to set the minimum level of efficiency) and has begun updating levels for several appliances. In 2002, the Top Runner Programme was expanded to eighteen products with the addition of several products such as gas appliances and transformers. Other countries, notably Korea, Australia, the United States and Canada, have mandatory standards covering many of the same products. However, they have not yet developed mandatory standards for most equipment used in the commercial building sector. Japan is the only country to include requirements for vehicles.

Europe has developed a number of voluntary initiatives but lags in mandatory efficiency programmes for appliances and other energy-using equipment. Present EU regulations only cover refrigerators, boilers, and ballasts and have not been updated since they were issued. In response to this, a new piece of framework legislation known as the “Ecodesign Directive for Energy-Using Products”, which gives the European Commission the authority to introduce mandatory minimum energy performance standards for most types of energy-using equipment sold within the EU, is close to being adopted. The draft directive empowers the Commission to set efficiency requirements at the level that will provide consumers with the least life-cycle cost-efficiency level.

The technical basis for determining efficiency levels applied in equipment standards varies considerably between IEA countries. Japan sets the threshold at the level of the most efficient equipment on the national market at the time the policy measure is developed. The United States, Canada and the EU use analyses of the relationship between life-cycle costs and product efficiency levels, although they also take into account a variety of market and industrial factors. Australia and New Zealand have a policy to adopt the most demanding existing standard in place among their major trading partners as their own standard level for each equipment type.

Building codes have been developing apace in many IEA member states, although a number of issues remain to be resolved. In 2002, the EU approved the Energy Performance of Buildings Directive, which requires each country to develop minimum efficiency standards for new buildings; energy performance rating schemes; mandatory equipment energy performance inspections; and energy performance certification to reduce energy use in new and existing buildings. This directive is now being implemented by the individual EU member states. In Germany, for example, the new Energy Conservation Ordinance in 2002 integrated the thermal insulation and the heat insulation ordinances taking integrated methodology as required by the EU directive. To complement this effort, a new set of analytical standards are being developed, which for the first time are likely to result in a common basis for calculating building energy performance across Europe. Australia has recently improved its building energy performance codes so that thermal mass issues are better taken into account to minimise cooling loads. Most US states have now implemented ASHRAE 90.1 and 90.2 requirements into their mandatory building codes. Japan continues to lag in energy performance codes for the building sector.

The responsibility for many aspects of energy efficiency affecting tradable goods has been ceded by individual European countries to central control by Brussels. Nevertheless, some countries have started programmes to address unique problems or aspects still under local control. In 2004, Denmark, for example, established a programme to phase out traditional double-glazed windows in favour of more sophisticated technologies. New speed limits on motorways and stricter enforcement of traffic laws in Germany, France and Italy have dramatically cut accident rates and probably resulted in fuel savings.

The United States has not introduced any new major energy efficiency regulations during the past year. However, individual states have been active, especially where the federal government has not taken action. The states are acting either because of unique local circumstances or because of the absence of initiatives at the federal level. California is preparing vehicle emissions limits that act just like minimum efficiency requirements. Several states in the Northeast have announced that they will adopt the same requirements. The states' authority in this area is not yet resolved, so the eventual result is uncertain. California has also proposed to enact a host of efficiency regulations for special aspects of buildings and products not covered by federal laws, including external power supplies, set-top boxes, and equipment used in commercial buildings. Several states in the Northeast have also approved (or are seriously considering) regulations on various products.

VOLUNTARY PROGRAMMES TO IMPROVE EFFICIENCY

Voluntary programmes continue to play an important role in overall government efficiency policies in nearly all sectors. Voluntary programmes take many forms, from an agreement with an individual company regarding a single energy-intensive factory to broad agreements covering dozens of groups and millions of products. Such agreements can either complement mandatory programmes or operate where regulatory mechanisms are unsuitable. Most voluntary programmes are initiated and administered by national governments although states, cities, and utilities can also be responsible. Firms are encouraged to participate by financial incentives (such as through the UK's Carbon Trust) or by public recognition, technical assistance with developing competitiveness, efficiency improvement strategies, and other means of support.

For EU countries, the relation between the voluntary agreements and the forthcoming EU-ETS needs to be clarified. Voluntary agreements often set targets on energy intensity allowing the growth of energy consumption in line with economic growth. On the other hand, the EU-ETS caps CO_2 emissions for large emitters. Therefore, in certain cases, large emitters could be obliged to buy credits even though they fulfil the intensity targets under the voluntary agreements. In the Netherlands, to maximise the incentive to fulfil the achievement of Benchmarking Covenants, the initial allocation is made on the basis of the performance of the covenants.

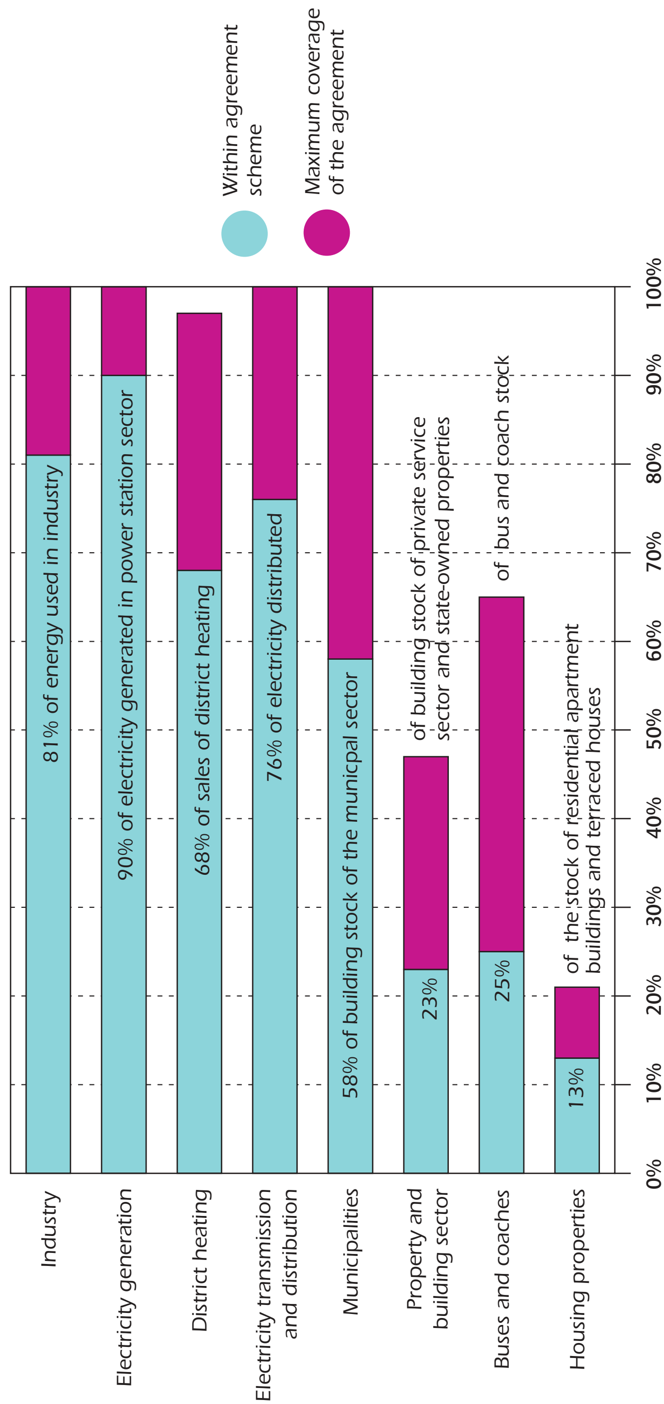
With respect to cars, European manufacturers have agreed to cut specific emissions (which translates into fuel efficiency) of new vehicles from 185 gCO_2/km in 1995 to 140 g/km in 2008. Further negotiations in 2004 may result in an even more ambitious target of 120 g/km by 2008.

In the United States, the Environmental Protection Agency established the Smart Way Transport Partnership with the freight industry providing market-based incentives for fuel efficiency improvement and GHG reductions in freight operations (ship, rail and truck).

In Australia, the Federal Chamber of Automobile Industries (FCAI) adopted a code declaring the membership's commitment, including a target reduction in

Figure 41

Coverage of Voluntary Efficiency Programmes in Finland



Source: *Motiva Oy*, December 2003.

national average fuel consumption for new petrol-fuelled passenger cars of 6.8 litres per 100 kilometres by 2010.

Finland has one of the most active networks of voluntary efficiency programmes (see Figure 41). The enterprises and communities participating in the energy conservation agreements currently in force account for more than 55% of Finland's energy use in 2003.

The increasing amount of electricity consumed by electronic equipment has prompted a variety of government actions. Standby power – the energy consumed by appliances while they are switched off – continues to get significant attention, especially in Korea, Australia, Denmark and Japan. Korea and Australia have policies to reduce standby in all equipment to 1 watt. Japanese industry implemented voluntary measures to reduce standby power to 1 watt by FY 2003 and the government takes into account the level of standby power in setting Top Runner standards. Government purchasing specifications in the United States require standby levels below 1 watt for most equipment. Now the attention is broadening to include the energy use of other low power modes (or "lopomos") in electronic equipment.

International initiatives are a unique aspect of voluntary efficiency programmes. These are most effective for products that are internationally traded (most often electronic goods). In 2004, Energy Star programmes revised and tightened many of its specifications for office equipment. Originally the specifications targeted reducing energy use while in the "sleep" mode. The specifications affected a relatively small percentage of total energy use in many devices. Now the specifications are being revised to improve efficiency in all modes of operation. Energy savings are expected to be significantly greater. A global initiative to improve the efficiency of external power supplies was also launched in 2003. This initiative involved the Chinese government, the US Environmental Protection Agency, the California Energy Commission, the European Commission and the Australian Greenhouse Office. These groups are co-ordinating test procedures, voluntary performance levels and mandatory regulations. Finally, the IEA sponsored an effort to increase the efficiency of set-top boxes. Set-top boxes (that is, the boxes connecting televisions to cable, satellite or terrestrial services) are an especially critical item because a billion low-efficiency units could appear on the market by 2010. The energy impact of set-top boxes amounts to over 30 GW if no actions are taken. This initiative resulted in an international effort by several governments, including Australia, China and the United States, to pursue co-ordinated efficiency levels for simple converter boxes.

FISCAL POLICIES

A range of both direct and indirect financial mechanisms encourage energy efficiency. Direct mechanisms include rebates and subsidies for efficient equipment. Financial policies directed towards achieving other goals may also have energy impacts. For example, London's congestion charge on motor vehicles entering the City has probably reduced energy consumption by private vehicles. Tokyo recently approved special zoning allowances for buildings that incorporated "green" roofs and other measures to mitigate urban heat islands. These measures may also reduce cooling energy needs.

In 2002, the United Kingdom revised its tax codes to encourage greater efficiency in the fleet of company cars because these represent about half of all new car sales (Sweden has had a similar policy for several years). Recent evaluations suggest that this policy has been successful in both improving vehicle efficiency and reducing distances driven. France hopes to improve vehicle efficiency by imposing a tax based on large vehicles and a subsidy towards the purchase of efficient vehicles. The cost of a new "sport utility vehicle" (SUV) will rise next year by as much as €3 500, while buyers of very efficient cars will receive a rebate of as much as €700. In 2004, Belgium approved a similar scheme except that there are no penalties for cars with high levels of emissions.

Few significant new financial policies to encourage energy efficiency have been enacted in the past year (although many schemes are already in place and continue operation). Canada established a subsidy of up to $1 000 to home-owners who make qualified energy efficiency improvements to their homes. Belgium also approved a subsidy scheme for energy-saving improvements in residences. The United States is considering a subsidy to home-owners similar to the Canadian plan. Some new demand-side management (DSM) incentives appeared (while others ended) in various regions of the United States. The UK has introduced its Enhanced Capital Allowances scheme for a range of energy-efficient equipment which allows businesses to write off the whole of the capital cost of their investment in qualifying technologies against their taxable profits of the period during which they make the investment. Qualifying equipment includes: energy-saving plant and machinery, low carbon dioxide emission cars and natural gas and hydrogen refuelling infrastructure, and water conservation plant and machinery. By contrast, the Netherlands has recently ended its long-standing rebate scheme for a variety of class-A labelled domestic appliances because the national appliance market is already largely transformed. Elsewhere no special trends were apparent.

MARKET INSTRUMENTS

Many countries are seriously considering new financial measures to encourage energy efficiency investments. France, the UK and Italy, for example, will probably implement a "white certificates" scheme to create a market in conserved energy. The idea behind this system is to target the diffuse energy consumption of the many different actors who could make energy savings. Under such a system, major energy suppliers (electricity, gas, fuel oil or motor fuels) would be obliged to realise an amount of energy savings equal to a certain percentage of the energy they supplied. These savings could be achieved in one of three ways: *i)* directly realising savings in their own operations, *ii)* helping their clients realise savings, or *iii)* buying energy efficiency certificates (white certificates) from related groups that have realised savings. By doing so, the saving could be realised where they are least costly within the economy. To maximise the benefit of this system, a number of administrative questions need to be addressed, such as how savings will be measured, who will issue certificates and administer the system, and what will be the relationship between this system and emissions trading systems.

The main developments in emissions trading have been in the European Union where, as of the time of writing, the Commission had approved the national plans (NAPs) of five EU member states for the EU greenhouse gas emissions trading scheme and had offered conditional approval to three more. The scheme as a whole is due to be launched in January 2005 and, if successful, is likely to provide an important stimulus to energy efficiency measures in the industrial sector.

Within the European Union as a whole, the Commission is continuing to promote the draft Energy Services Directive that aims to encourage the development of an energy services market in which services involving the use of energy are sold, rather than the energy itself. The current draft of the directive sets indicative targets for member states to achieve 1% annual savings in energy efficiency compared with a business-as-usual estimate. If implemented, each member state would have the freedom to decide how to distribute this target among energy distribution sectors, although the Commission envisages covering all distribution sectors, from electricity and gas to district heating and transport fuel. Existing energy supply companies would be obligated to actively promote energy services and audits to their customers. The targets are intended to be designed in a manner that will take into account any action carried out by energy producers to comply with obligations they may have under the new EU emissions trading scheme.

SPECIAL SITUATIONS – SAVING ELECTRICITY IN A HURRY

In 2004, the IEA started work on "Saving electricity in a hurry". Temporary shortfalls of electricity supply can occur as a result of a drought, a heat wave, a breakdown in a power plant or partial loss of transmission capacity. The traditional response has been to cut power to customers while trying to restore supplies, but blackouts may be economically and politically unacceptable if the shortage is expected to continue for more than a few hours. An alternative approach is to launch an aggressive programme to quickly conserve electricity, relying on a combination of measures to improve energy efficiency and change consumer behaviour. Several regions, including Brazil, California, New Zealand and Norway have recently implemented such programmes. It is possible to quickly reduce electricity demand by 3% to 20%, sometimes with programmes started in only a few months. Moreover, the reductions in demand can be accomplished without major economic disruption or hardship. These results (and the policies that achieved the savings) are important because temporary shortfalls in electricity supply are likely to occur more often. Market liberalisation has led to reduced reserves and safety margins throughout the whole electricity supply chain. This, in turn, makes the electricity supply system more vulnerable to unusual weather events or other disruptions.

RENEWABLE ENERGY

Renewables are considered by many policy-makers to contribute to protecting the environment and improving energy security. On an average cost basis, some renewables in the best locations are competitive with conventional energy sources; however, in most cases, renewables are still not competitive and account for only a small portion of the IEA energy mix. In 2001, the share of renewable energy in total primary energy supply was 5.5%, down from 6% in 1992.

Contrary to popular belief, the annual growth rate of renewables in energy supply in IEA countries overall slowed to 1.2% from 1990 to 2001 compared with 2.8% during the period 1970-1999. Out of total renewable energy supply, combustible renewables and waste accounted for the largest share of renewable energy supply with 55%, a major change from the past, followed by hydro with 35%. Wind, solar and ocean energy sources still provide only 2% of total renewable energy supply in IEA countries. The role of renewable energy in electricity supply has declined dramatically over the past 30 years from 24% in 1970 to 15% in 2001. The composition of the renewable share of electricity production was hydropower at 86%, combustible renewables and waste at 9%, and solar, wind and ocean energy at 3%.

These developments are governed by three factors. First, more mature renewables, such as hydro and geothermal, did not increase and even declined in the 1990s in many IEA countries. Second, combustible renewables have consistently grown by 3% per annum since 1970. Third, the rapid growth of "new" renewables, such as wind and solar, was unable to compensate for the stagnation of more mature technologies.

RD&D funding for renewables in relative and absolute terms has further declined during the past ten years. It accounted for only 7.7% of IEA RD&D budget expenditures from 1987 to 2002. More than 70% of these expenditures are undertaken by only three countries, the United States, Japan and Germany. More than 50% is spent on solar technologies, followed by biomass (18%) and wind (8%). The decreasing share of public spending for renewables RD&D appears to be inconsistent with the political announcements, objectives and aspirations of many IEA countries to increase the share of renewables in TPES and electricity supply.

In 2004, the IEA conducted a comprehensive survey, *Renewable Energy - Market & Policy Trends in IEA Countries*. The review takes a 30-year view of *a)* actual market growth and penetration of renewables to energy and electricity supply; *b)* changes in renewables RD&D priorities and composition in IEA countries; and *c)* the trends of policies and measures to support market deployment of renewables.

The review of polices and measures indicates that countries need to differentiate much more clearly than in the past between the objectives, implementation and evaluation of: *a)* RD&D policies for renewables; *b)* market deployment policies that warrant public support to encourage both industry and consumers to adopt renewables; and *c)* market-based energy policies that provide a level playing field for renewables.

POLICY TYPES

Research and innovation policies support technology innovation through basic and applied research up to the demonstration phase. Governments have traditionally played a decisive role in both framing and funding RD&D policies at the national level and in international collaborations. Governments have also been a catalyst in using research and innovation policies to ensure adequate private-sector involvement in research, development and demonstration.

Market deployment policy instruments can be categorised into four quadrants, based on the direction of their support. Policies can be directed towards consumers (demand side) or producers (supply side). They can also be directed towards capacity (*i.e.* the facility and/or its capital costs) or generation (*i.e.* the product and/or the associated price to the customer). In some cases, the same policy can appear in more than one quadrant.

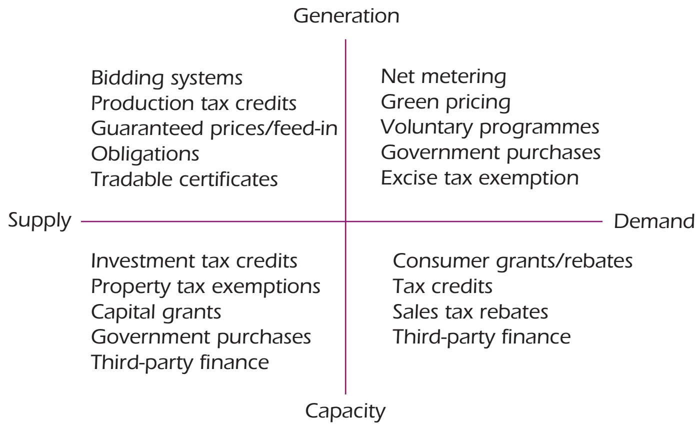
In addition to the policy instruments in Figure 42, there are administrative or regulatory procedures that are not financial in nature, but nevertheless contribute to the market deployment of renewables. Additionally, there are public awareness programmes that support market deployment. The following sections describe the major types of policies that have been implemented in IEA countries.

POLICIES ADDRESSING SUPPLY AND CAPACITY

Investment incentives are used to reduce the capital cost of deploying renewable energy technologies. ***Capital grants*** and ***third-party finance*** arrangements can also reduce investor risk and are generally funded out of national and/or state budgets and thus compete with other public funding needs. As such, incentives are often subject to legislative review and changes, including recision. Incentives must be of adequate size and must be predictable and consistent over time to be effective.

Figure 42

Market Deployment Policy Instruments



Source: *Renewable Energy: Market & Policy Trends in IEA countries*, IEA/OECD Paris, 2004.

Tax measures are used to encourage production or to discourage consumption. On the production side, ***investment tax credits*** and ***property tax exemptions*** reduce tax payments for project owners.

Government purchases of systems at above-market rates are a type of investment incentive to industry. In a number of cases, governments have purchased large, on-site renewable energy systems such as solar thermal hot water systems or photovoltaic systems for schools or other public buildings.

POLICIES ADDRESSING SUPPLY AND GENERATION

Incentive tariffs: ***guaranteed price systems, feed-in tariffs*** and ***preferential rates*** are all terms for tariffs at above-market rates. Generally, the government sets a premium price to be paid for power generated from renewable energy sources. The price is usually differentiated by technology, and is paid by either consumers or taxpayers through the utility.

Bidding systems are based on competition for contracts to build projects with the lowest generating costs. The principal mechanism is a guaranteed price, with the rate set by competition for the lowest bid based on a function of the power pool wholesale price plus a technology-specific premium that is paid by electricity consumers. Renewable energy technologies are separated into different technology categories, and competitive bidding rounds are organised separately for each category.

Tax measures ***production tax credits*** are offered to renewable energy producers at a kilowatt-hour rate, which often serves to reduce their tax burden.

Obligations: most obligations are based on the final product (kWh of electricity or litres of liquid fuel), although some are based on capacity. Renewable energy ***portfolio standards***, also known as ***quota systems***, place an obligation on suppliers to provide a set quantity or percentage of their supply from renewable energy sources. Generally, quota systems do not distinguish between different renewable energy sources, *i.e.* a quota level is established and the market determines which resources are chosen. These systems encourage the development of renewables at lowest cost. Renewable energy certificates (discussed below) may be used to facilitate compliance with quota systems and can also reduce the cost of compliance.

Targets are a form of obligation. Target systems determine different levels of obligation for each renewable energy technology, sometimes with a penalty for non-compliance.

Tradable certificates: ***renewable energy certificates*** (RECs) provide a mechanism to track and register renewable electricity production. Certificates can be used to document compliance with quota systems or can be sold to end-use customers in a voluntary green power market. The creation of a certificate allows the renewable energy attribute to be sold or traded separately from the physical electricity product. The establishment of a RECs system does not by itself constitute a supply requirement, but rather certificates provide greater market flexibility in achieving the goals of other policy instruments.

RECs systems can be consistent with energy labelling. This type of system may be advanced by the European Commission's directive on guarantee of origin of electricity produced by renewable energy sources which requires member states to establish appropriate mechanisms "to enable producers of electricity from renewable energy sources to demonstrate that the electricity they sell is produced from renewable energy sources."

POLICIES ADDRESSING DEMAND AND GENERATION

Voluntary programmes are implemented through government "requests" to energy suppliers to buy electricity generated from renewables.

Green pricing is an optional utility service that gives customers an opportunity to support an increased level of utility company investment in renewable energy technologies. Participating customers generally pay an additional amount on their electricity bill to cover the incremental cost of the renewable energy.

Net metering arrangements allow customers to "bank" at the utility any excess electricity generated from qualifying systems for later use. The customer pays only for the electricity used "net" of the electricity generated over the entire billing cycle.

Tax measures: tax policy can be used to capture the externalities associated with energy production and consumption, such as environmental degradation and energy import dependence.

POLICIES ADDRESSING DEMAND AND CAPACITY

Investment incentives can also be used to reduce the capital cost of renewable energy technologies to end-users. With ***consumer grants*** and ***third-party finance***, the government assumes the risk by, for example, providing low-interest loans, or buying down the capital cost of renewable systems.

Tax measures: for customer-owned systems, a ***tax credit*** or ***system rebate*** allows the owner to recover a portion of the upfront capital costs more quickly after the investment is made. Provisions are sometimes made for ***sales tax rebates.***

REGULATORY AND ADMINISTRATIVE RULES

Market regulations are often introduced at the same time as market deployment policies, which helps to ensure successful deployment of renewable energy technologies.

PUBLIC AWARENESS PROGRAMMES

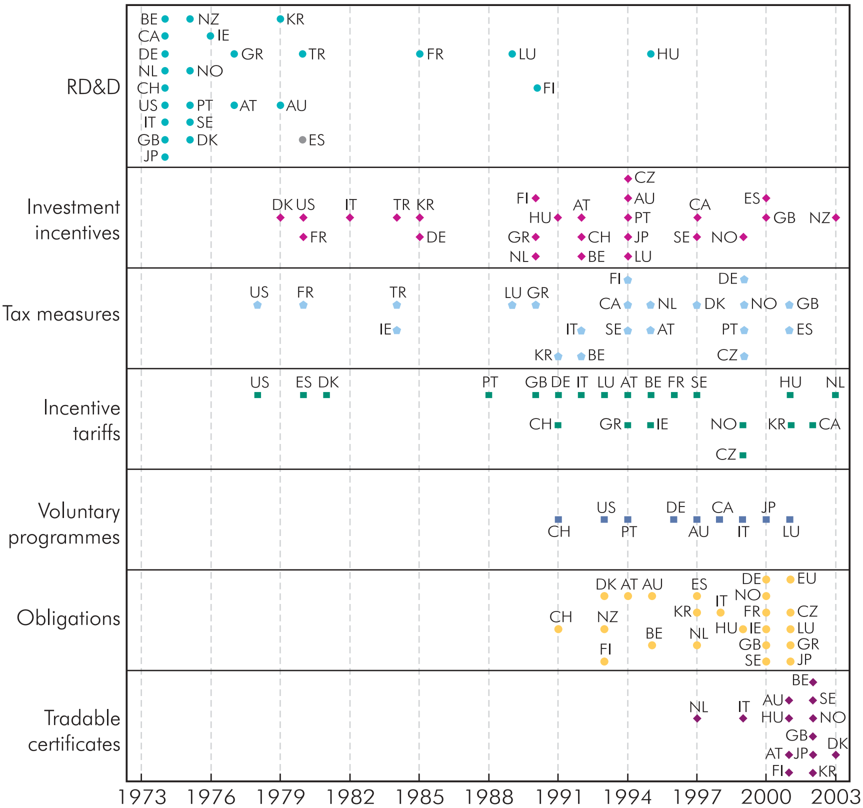
Public awareness programmes are used to encourage broad-based support for renewable energy.

TRENDS IN IEA RENEWABLE ENERGY POLICIES

Figure 43 provides an indication of the evolution of policies and measures in IEA countries over the past three decades. On the vertical axis, renewable energy policies and measures include RD&D polices and various market deployment policies that are categorised as investment incentives, tax measures, incentive tariffs, voluntary programmes, obligations and tradable certificates. The year that each country first introduced a specific renewable energy policy is indicated by country initials.

Figure 43

The Introduction of Renewable Energy Policies by Country



AT=Austria - AU=Australia - BE=Belgium - CA=Canada - CH=Switzerland
CZ=Czech Republic - DE=Germany - DK=Denmark - ES=Spain - FI=Finland
FR=France - GB=United Kingdom - GR=Greece - HU=Hungary - IE=Ireland
IT=Italy - JP=Japan - KR=Korea, Republic of - LU=Luxembourg - NL=Netherlands
NO=Norway - NZ=New Zealand - PT=Portugal - SE=Sweden - TR=Turkey
US=United States

Source: *Renewable Energy: Market & Policy Trends in IEA Countries*, IEA/OECD Paris, 2004.

KEY OBSERVATIONS IN POLICY EVOLUTION

Starting in the 1970s and sometimes even before, governments have set up RD&D programmes to develop renewable energy sources as an "alternative" to fossil fuels. This was followed by a series of technology deployment schemes, including investment incentives, tax measures and incentive tariffs, particularly for "new" renewables. In the late 1990s, countries started to experiment with tradable certificate systems. While a clear evolution of overall policies and measures in IEA countries is evident from Figure 43, it does not necessarily denote a single trend. Each country has chosen policies and measures that best match their resource endowments, economic structure and objectives for market deployment.

Significant market growth has always resulted from combinations of policies, rather than single policies. As an early example, in Japan, photovoltaic (PV) technology was supported by extensive RD&D investments to increase the competitiveness of the technology, by demonstration projects which increase public awareness and acceptance, through financial incentives to reduce the purchase price of PV systems, and by requiring utilities through net metering to accept excess power generated by PV systems at the retail price of electricity. In Spain, wind technology is supported by feed-in tariffs, low-interest loans, capital grants, and local support for manufacturing turbines. In no case is there evidence of strong market growth with only one policy in place. Those countries that have experienced strong growth in "new" renewables, such as wind and solar, including Germany, Spain, the United States and Denmark, have done so through a combination of financial incentives and guaranteed prices, underpinned by strong RD&D.

Longevity and predictability of policy support is important to overall market success. In most cases, feed-in tariffs for renewable energy sources typically have an eight- to twenty-year time-frame, *e.g.* Italy and Germany. The challenge is how to incorporate strong incentives for cost-reduction and competition while ensuring longevity and predictability of policy support. The long-term support offered to biomass district heating plants in Austria provides another example. Conversely, the "stop and go" nature of incentives, such as the production tax credits in the United States, has undermined private-sector investment.

National policies are also strengthened when local, state or provincial governments have the authority to act independently of the national government. For example, in Spain, the bulk of wind power growth is occurring in those areas where regional governments have actively supported development through administrative changes and financial support, and in some cases, by becoming a development partner. In the United States, although the federal government has set up a renewable energy deployment programme, thirteen states have established their own renewable portfolio standards, and many more states offer their own set of financial incentives. These have met with varying degrees of success.

Market liberalisation offers new challenges for renewable energy technologies still in the technology deployment stage. On the one hand, if energy prices fall, the price targets that renewables must meet become more challenging. On the other hand, policies and systems such as quotas and renewable energy certificates can be compatible with more competitive market structures. In fact, many current policies are being implemented within the backdrop of a transition to market liberalisation, *e.g.* Ireland, Sweden and the United Kingdom.

Individual policy mechanisms are evolving as countries gain more experience. In Germany, for example, early feed-in tariffs were set as a function of the avoided cost of electricity, and then modified to a level deemed necessary by the government to encourage industrial development. Later iterations included better measures for incorporating and driving cost reductions. At the same time, policies in some cases have been evolving from one type to another. In Denmark, for example, the feed-in tariff scheme is in a transitional phase as it was superseded by a certificate trading system that has not yet come into effect. When Japan established its portfolio standard in 2002, however, it retained the funding for RD&D and other incentives for market deployment. When a renewable portfolio standard does not specify a preferred renewable energy technology, competition is expected to be enhanced among technologies.

It is too soon to fully assess the impacts of many renewable energy policies, as most have been established since 2000. This is particularly true for most obligation systems, as well as the tradable certificate systems. Nevertheless, experience with investment incentives, tax measures and incentive tariffs suggests that all these policies can be made effective. It is the design of the support mechanism rather than the type of policy that determines their success. Over time, the array of policy choices has become broader and the market learning experience richer. Strong market growth of "new" renewables in the late 1990s indicates that the support schemes in place may have been effective. On the other hand, it can be stated also that without government support "new" renewables would show little or no increase in market growth rates.

An assessment of renewable energy policies needs to be based on their costs and effectiveness. It should also examine how renewables mix with other energy alternatives, including energy efficiency, advanced nuclear, carbon sequestration and hydrogen. However, direct and indirect costs associated with renewable energy policies have not yet been fully compiled, and will involve more concerted efforts to record information on policy costs, market data and technology cost improvements.

INTERNATIONAL CONFERENCE FOR RENEWABLE ENERGIES, JUNE 2004, BONN

In response to the call of the Johannesburg Summit, Germany hosted the International Conference for Renewable Energies from 1 to 4 June 2004 in Bonn to find a way towards an expansion of renewable energies worldwide. It also kept up the momentum generated by the coalition of like-minded countries for the promotion of renewable energies (known as the Johannesburg Renewable Energy Coalition, JREC). A total of 3 600 participants met in Bonn, among them official governmental delegations including energy, environmental and development ministers, representatives of the United Nations and other international and non-governmental organisations, civil society and the private sector. The conference adopted the following outcomes:

- A **Political Declaration** containing shared political goals for an increased role of renewable energies and reflecting a joint vision of a sustainable energy future, which provides better and more equitable access to energy as well as increased energy efficiency.
- An **International Action Programme**, including actions and commitments by governments, international organisations and stakeholders. Responding to the "Call for actions and commitments" that was issued before the conference, participants contributed to the action programme with voluntary commitments to goals, targets and actions within their own spheres of responsibility.
- **Policy Recommendations for Renewable Energies** which can be of benefit to governments, international organisations and stakeholders as they develop new approaches and political strategies and address the roles and responsibilities of key actors.

At the June 2004 International Conference in Bonn, the IEA presented its work on renewable energy, including its latest publication *Renewable Energy – Market & Policy Trends in IEA Countries*, and proposed three major items for consideration by policy-makers.

INCREASE TARGETED RD&D

If national objectives for diverse and environmentally sustainable energy use are to be achieved, additional funding for renewables will be necessary to lower the costs and make available to the market-place a variety of technological options. However, RD&D funding for renewable energy technologies has steadily declined since 1980. Some technologies are still far from being competitive. Industrial applications for PV, for example, have long been cost-effective, and limited niches in high solar resource areas are close to economic. These niche markets should be encouraged with further market deployment support. But to enter the mainstream energy supply, PV costs must come down substantially. More RD&D funding will be needed to achieve the breakthroughs that can lead to large-scale markets. Other renewable energy technologies, *e.g.* concentrating solar power, ocean energy, and advanced geothermal, have fallen out of the RD&D pipeline, having lost much of their RD&D funding some years ago. It is time to increase RD&D investments to these technologies to enable them to enter the market, although not necessarily by increasing overall funding levels.

IMPROVE THE STRATEGY FOR MARKET DEPLOYMENT

There is a need to improve the efficiency and effectiveness of market deployment policies. Decision-makers may need to be more selective about when and how funds are allocated. For example, would it be more efficient to pay for the needed concentrating solar power pilot projects through incentive tariffs or through RD&D?

There is also a need to expand the number of countries that are shouldering the burden of deployment policies. In 2001, 86% of the wind market in IEA countries was in only four countries, while 85% of the PV market was in only three, producing an unstable investment climate for the industry. Deployment efforts/policies have recently been established in a number of IEA countries, and while encouraging, this has not yet led to much market growth.

International co-operation is key to both learning about policy successes and about developing markets. For example, more work is needed to evaluate how policy adjustments over time can be used to stimulate technology cost reductions as the market grows. And solar thermal hot water systems would benefit from aggregated procurement programmes at a multinational level.

Building global markets will require the co-operation of and partnership with developing countries. With financial support, where renewable resources are adequate and prices are cost-based, developing countries can quickly and economically pick up the more mature renewable energy technologies (like small hydropower, sustainable biomass combustion, and geothermal). Developing countries can also effectively and economically integrate emerging technologies, such as wind and solar, where resource conditions are very good and support is given to help set up attractive market conditions. This can benefit all countries. With IEA countries driving technology costs down, developing countries may benefit from some economic advantages to becoming part of a global industry. Renewables may also play a major role in solving the challenge of energy access.

INCLUDE EXTERNALITIES IN POLICY CONSIDERATIONS

As governments continue to incorporate measures to ensure that the external costs of energy production and use are appropriately reflected in national policies, renewables will achieve their economically efficient place in energy systems. Renewable energy is not the objective *per se*, but is one of the technologies that will be important in reducing global warming and improving the security of supply.

ANNOUNCEMENT OF THE RENEWABLE ENERGY TECHNOLOGY DEPLOYMENT IMPLEMENTING AGREEMENT

At the Bonn Conference on 4 June 2004, the ministers and other high-level officials representing the governments of Denmark, France, Germany, Ireland, Italy and Norway announced at a press conference that they are working towards the creation of a new Implementing Agreement, in the framework of the IEA, on renewable energy technology deployment. The working title of the Agreement is Renewable Energy Technology Deployment Implementing Agreement (RETD).

The governments confirmed that this new Implementing Agreement is intended to strengthen international co-operation in the area of global renewable energy technology diffusion and will be open to all IEA and non-IEA countries as well as to qualified private-sector organisations.

TECHNOLOGY AND RESEARCH AND DEVELOPMENT POLICY

RECENT TRENDS IN MEMBER COUNTRIES' ENERGY R&D POLICIES[23]

Concerns about energy security and climate stabilisation have fuelled the discussion about the relative importance and focus of energy RD&D in member countries at a time of budget constraints. Member countries pursued two distinctive trends: first, the continuation of a low level of RD&D in end-use technologies, renewables, energy storage and transmission technologies, alternative fuels including biofuels that promise market introduction and impact on energy demand and CO_2 reduction in the short and medium term; and second, a renewed and widely publicised effort in scientific research and RD&D for long-term energy technologies, *i.e.* technologies that are likely to have an impact over a 25 to 50-year horizon. These initiatives range from CO_2 capture and storage (CCS), hydrogen and fuel cells, nuclear fission technology including waste management, fusion including the ITER project, and connecting basic sciences with energy technology research.

This chapter provides an overview of member countries' recent activities in three of the long-term RD&D areas that are likely to shape energy supply in the years 2020 and beyond: CCS; hydrogen and fuel cells; and basic science and energy technologies.

CO_2 CAPTURE AND STORAGE (CCS)

Capture and storage of CO_2 from fossil fuel combustion could play an important role in stabilising CO_2 concentration in the atmosphere. National and international R&D programmes on CCS are being pursued by Australia, Canada, Germany, Japan, Norway, the United Kingdom, the United States and other countries, as well as by the European Union. IEA activities include the IEA Greenhouse Gas R&D Programme, the IEA Working Party on Fossil Fuels (WPFF), the IEA Secretariat and the IEA Coal Industry Advisory Board.

The IEA Greenhouse Gas R&D Programme was established in 1991. The programme is a leading international collaboration on technologies for

23. See also Chapter 9.

reducing greenhouse gas emissions from the use of fossil fuels. It conducts in-depth investigations into technology options, identifies targets for RD&D and provides objective information to different stakeholders, including the research community, policy-makers and the general public. Support for the programme is provided by 16 member countries, the European Commission and nine major industrial sponsors.[24] The Greenhouse Gas R&D Programme is involved in many important international projects. These include, among others: Saline Aquifer CO_2 Storage (SACS) project based in the Sleipner Oil Field; International Weyburn Carbon Dioxide Monitoring Project, GESTCO (the European Potential for Geological Storage of CO_2 from Fossil Fuel Combustion); CO_2NET (the European Technology Networking Programme for CO_2 Sequestration into Geological Formations); and RUCADI (recovery and utilisation of CO_2).

The Zero Emission Technologies (ZETs) Strategy was initiated by the *IEA Working Party on Fossil Fuels (WPFF)* in 2001. Recent activities of the WPFF include the organisation of the Asia-Pacific ZETs Conference in Brisbane, Australia, the organisation of the joint IEA/CSLF Workshop on Legal Aspects of Storing CO_2 held in Paris and the publication of information materials for the general public.[25]

MAJOR NATIONAL AND INTERNATIONAL ACTIVITIES[26]

Australia

The Commonwealth Scientific and Industrial Research Organisation (CSIRO) is active in ZETs for power generation purposes, CO_2 capture and storage technologies, and the GEODISC project (geological disposal of CO_2).

Canada

Many CO_2 and ZETs-related activities are under way, including: assessment of sedimentary basins for CO_2 storage; sequestration in oil and gas reservoirs; storage in deep coal seams; enhanced capture technologies; oxy-fuel combustion concepts; performance evaluation of closed gas turbine cycles with oxy-fuel combustion; the Weyburn CO_2 monitoring and storage project; and acid gas reinjection.

24. Members of the Greenhouse Gas R&D Programme include Australia, Canada, the Commission of European Communities, Denmark, Finland, France, India, Japan, Korea, the Netherlands, New Zealand, Norway, Sweden, Switzerland, the United Kingdom, the United States, Venezuela, and several sponsors: ALSTOM Power Technology, BP, Chevron Texaco, EniTecnologie SpA, EPRI-Electric Power Research Institute, ExxonMobil, RWE AG, Shell International, and TotalFinaELf (www.ieagreen.org.uk)

25. Presentations from these events and also publications issued by the WPFF can be downloaded from the IEA website www.iea.org.

26. Most of the information included here comes from the IEA WPFF publication on ZETs "Organisations and Major Programmes" (www.iea.org/dbtw-wpd/textbase/papers/2003/Org_Fossil_Fuels.pdf). For a broad list of national and international CCS projects, go to www.co$_2$sequestration.info.

Germany

During 2003, the German government, in close co-ordination with industry and the research institutions, has developed a nationwide COORETEC strategy, its Research and Development Concepts for Zero-Emissions Fossil-Fuel Power Plants Activities. The concept was introduced to the general public at a conference in May 2004 in Berlin. Besides the CCS pilot project it also involves increased efficiency in fossil-fuel electricity generation through advanced technologies such as natural gas combined cycle (NGCC), integrated gasification combined cycle (IGCC,) pressurised pulverised combustion (PPC), pressurised fluidised-bed combustion (PFBC) and externally-fired combined cycle (EFCC).

Japan

Japan has the longest-running carbon capture and sequestration R&D programme. The Research Institute of Innovative Technology for the Earth (RITE) is focusing on the development of innovative CO_2 control measures. A range of projects are under way, examining biological CO_2 fixation, CO_2 capture and ocean storage techniques.

Norway

In 1997, the Norwegian National Climate Technology Programme (KLIMATEK) was launched to promote GHG-related RD&D technologies. The programme's portfolio comprises some 50 individual projects involving the offshore petroleum industry, process gas industry, gas-fired power generation with CO_2 capture, and CO_2 storage. The programme is heavily involved in many international collaborative ventures.

United Kingdom

The UK Department of Trade and Industry maintains several programmes aimed at the development of technologies and processes for enhancing environmental performance, while still using fossil fuels. Imperial College is active in several projects assessing reservoir characteristics with reference to coal-bed methane recovery and CO_2 sequestration. The UK is also very active in the IEA Greenhouse Gas R&D Programme.

United States

The US is undertaking a broad range of carbon sequestration activities through government agencies, universities and the private sector. The US Department of Energy (DoE) Office of Fossil Energy and the National Energy Technology Laboratory administer DoE's Carbon Sequestration Program comprising around 60 individual projects.

European Commission (EC)

The EC's programme "Preserving the Ecosystem – Research Actions for Energy" supports zero emission technologies (ZETs) for fossil fuels through a series of collaborative projects, including SACS and SACS2; GESTCO; CO_2 STORE (investigating new potential locations for CO_2 reservoirs); CO_2NET2; AZEP (advanced zero emission power plants); GRACE (reducing CO_2 capture and separation costs) and RECOPOL (CO_2 storage in coal seams).

In 2003, the US initiated a ministerial meeting for the Carbon Sequestration Leadership Forum (CSLF).[27] The CSLF is a framework for international co-operation in research and development for the separation, capture, transportation and storage of carbon dioxide. The CSLF will seek to realise the potential of carbon capture and storage over the coming decades, making it commercially competitive and environmentally safe.

The activities of the CSLF will be conducted by a Policy Group which governs the overall framework and policies of the CSLF, and a Technical Group which reviews the progress of collaborative projects and makes recommendations to the Policy Group on any needed actions. Collaborative projects may be undertaken by the CSLF as authorised by the Policy Group on the recommendation of the Technical Group. This specifically includes projects involving the following:

- Information exchange and networking.
- Planning and road-mapping.
- Facilitation of collaboration.
- Research and development.
- Demonstrations.
- Public perception and outreach.
- Economic and market studies.
- Institutional, regulatory, and legal constraints and issues.
- Support to policy formulation.
- Other issues as authorised by the Policy Group.

The United States announced plans for the construction of a prototype plant fired by fossil fuels, FutureGen, to generate electricity (up to 275 MW_e) and produce hydrogen. The plant will produce virtually no harmful emissions, including greenhouse gases, and will serve as a test bed for a range of the latest pollution control and CO_2 capture technologies. Common pollutants such as sulphur and nitrogen oxides will be recovered and converted into useful by-products; captured CO_2 will be stored in a suitable underground

27. Members of the CSLF are Australia, Brazil, Canada, China, Colombia, European Commission, Germany, India, Italy, Japan, Mexico, Norway, Russian Federation, South Africa, the United Kingdom and the United States (www.cslforum.org).

geological formation. Current plans call for the plant to be designed and built over five years. Funding will be provided on a fifty-fifty basis by the US federal government and the private sector.

The IEA/CSLF Joint Workshop on Legal Aspects of Storing Carbon Dioxide was held in Paris in July 2004. Participants included energy and environmental policy-makers, energy industry professionals and environmental NGOs. The discussions identified the following priority issues:

- Member countries need to work closely with industry on more enhanced oil recovery (EOR) and CCS demonstration projects.
- There is a need to streamline national regulations for onshore CCS and also for EOR activities.
- Member countries need to take a more proactive stance to reconcile international conventions dealing with preservation of marine environments (London Convention, OSPAR) and international conventions dealing with climate change.
- There is a need to establish a level playing field for CCS as climate mitigation technology.

As R&D for CCS proceeds and the various national and international initiatives prepare and implement technology road-maps for CCS, priority attention needs to be given to three non-technology bottlenecks:

- The lack of public awareness and acceptance of CCS.
- The costly, time-consuming regulatory framework for onshore CCS and the legal uncertainty surrounding offshore CCS in geologic formations.
- The fact that existing environmental policy mechanisms such as emissions trading or CDM do not yet include provisions for CCS.

More demonstration projects and evaluation of ongoing projects are an urgent first step to gain experience, provide the baseline information to build public awareness and, ultimately, public acceptance. These activities are on a critical path. In parallel, member countries should proceed immediately with establishing the enabling regulatory and legal environment, and include CCS in the policy framework that allows all low or zero emission technologies to compete in the market-place.

HYDROGEN AND FUEL CELLS

In 2003 policy-makers in OECD member countries placed strong emphasis on hydrogen and fuel cells as the key technologies to contribute to energy security, economic growth and environmental protection in the context of more robust, future energy scenarios. Significant investments are backing up this hydrogen and fuel cell strategy in both the public and private sectors. The United States is investing US$ 5 billion over 5 years. The European Commission is investing up to €2 billion in the 6th Framework Programme, including renewable energy technologies and hydrogen and fuel cell R&D. Japan is also investing about ¥32 billion a year, and many other IEA member countries (*e.g.* Canada, Germany, France, Korea, Italy, etc.) have already made, or are considering, significant investment in hydrogen and fuel cell R&D. According to preliminary evaluations, global public R&D spending is currently about US$ 1 billion a year, and private-sector investment is even larger. The overall strategy includes many dimensions such as technology R&D policies, infrastructure investment, international harmonisation of codes and standards, and deployment policies and measures.

Close international co-operation among national governments and with the industry will be the key to developing this technology option in an efficient and co-ordinated way. Three major international co-operation initiatives have recently been established: the IEA Hydrogen Co-ordination Group (IEA-HCG in April 2003); the International Partnership on Hydrogen Economy (IPHE, in November 2003); and the European Technology Platform on Hydrogen and Fuel Cells (in January 2004). Whilst the European Technology Platform is a cluster of EU public/private initiatives building on the R&D projects of the 6th Framework Programme of the European Commission, and the IPHE is a sort of global, political interface with the RD&D world and the private sector, the IEA HCG was established by the IEA Executive Director with the primary objective of enhancing co-operation in the R&D and policy programmes of IEA member countries. The HCG builds on 20-year policy analysis and R&D work carried out by the IEA Secretariat and relevant IEA Implementing Agreements (IAs). In addition to the activities on hydrogen and fuel cells, the technology for CO_2 capture and storage also has a key role as it might pave the way to the transition from the current fossil-based energy system to a hydrogen-based system. Ongoing HCG activities include:

- Comparative review of national programmes in IEA member countries (to be published in autumn 2004).
- Review of IEA activities to identify priorities and gaps in the IEA R&D programme and recommend possible additional co-operation activities.
- Advise policy-makers on hydrogen and fuel cell development, and deployment strategies.
- Policy analysis to help guide the IEA work.

Provisional outcomes of these activities are summarised below.

COMPARATIVE REVIEW OF NATIONAL PROGRAMMES

According to the survey conducted by the HCG, virtually all of the IEA countries indicate that research into hydrogen and fuel cells is of key importance either as a purposely designed and funded programme, or as an element of a broader energy and/or environmental strategy. Japan, the United States and Iceland (a non-member country) provide exceptional examples of fully integrated, highly funded HFC programmes. Germany gives strong support to RD&D of fuel cells and hydrogen technologies within the German Federal Programme for "Energy Research and Energy Technologies" as well as the "Programme on Investment into the Future".

In Japan, the New Hydrogen Project (NHP) extends the work initiated during the seminal, 10-year, ¥18.6 billion WE-NET programme, which initially focused R&D on core technologies necessary for establishing a hydrogen infrastructure (*e.g.* electrolysis, liquefaction, storage) and then later on the utilisation of hydrogen and construction of fuelling stations. The NHP not only ties together a number of METI's ongoing and new programmes, but it integrates the development of fuel-cell, hydrogen production, and hydrogen transportation and storage technologies, concurrently with the implementation of demonstration programmes, construction of refuelling infrastructure, establishment of codes and standards, and a general push to enlarge the consumer market for fuel cells and fuel-cell vehicles. Specific commercialisation targets include 50 000 fuel-cell vehicles on the road by 2010, 5 million in 2020, and 15 million in 2030, and a similar development is targeted in the field of stationary fuel cells for (distributed) power generation.

The US conducts the vast majority of its R&D on hydrogen and fuel cells under the "Hydrogen, Fuel Cells and Infrastructure Technologies Program," which funds research, development, and validation activities linked to public-private partnerships. The programme is led by the US Department of Energy (DoE) and integrates the activities of a number of US government agencies, including the Department of Defence, the Department of Transportation and the Environmental Protection Agency. The government's current role is to concentrate funding on high-risk, applied research in the early phases of development to the point where the private sector can make informed decisions on whether or not, and how best to commercialise these technologies. With a fiscal year 2004 budget of US$ 144 million, the programme seeks to implement recommendations in the President's National Energy Policy, the DoE Strategic Plan, and the National Hydrogen Energy Vision and Roadmap.

Similarly, Canada's HFC R&D work contains various programme elements focusing on the development of clean, efficient technologies for the production of hydrogen using renewable or sustainable energy sources. The hydrogen R&D programme has been managed by Natural Resources Canada since 1985 and is largely based on cost-shared R&D partnerships with the private sector – focusing primarily on automotive fuel-cell technologies, stationary power applications concentrating on solid oxide fuel cells (SOFC) and portable power using direct methanol fuel cells. Overall, the Canadian programme is oriented towards the development of technologies with short-to-medium term commercial potential. The R&D programme focuses on hydrogen production and storage; fuel-cell commercialisation; and the development of co-ordinated hydrogen and fuel cell standards that will be required for hydrogen to be a safe and cost-effective energy carrier. Two of the most successful technologies have been the Ballard PEM fuel cell and the Stuart Energy alkaline water electrolyser. Overall, these efforts have recently been strengthened by Canada's $1 billion "Climate Change Plan for Canada", which allocates C$ 130 million to developing a hydrogen economy in Canada.

Australia's national hydrogen study, undertaken in 2003, investigated the`longer-term potential of hydrogen and fuel cells in relation to transport, portable appliances and distributed generation, particularly in remote areas. Since the completion of the study, the Australian government has released an energy White Paper in which it acknowledged the long-term importance of hydrogen as an energy carrier, and the need for Australia to be involved in the development and adoption of appropriate international codes and standards. In relation to the provision of funding for hydrogen initiatives, R&D under way in Australia is largely associated with broader government programmes and other policy initiatives. These support, for example, Australia's participation in bodies such as the International Partnership for the Hydrogen Economy (IPHE) as well as the country's participation in established forums such as the International Energy Agency (IEA) and the Asia Pacific Economic Co-operation (APEC). At the national level, research and development into hydrogen is occurring in a number of universities as well as through Energy Transformed, a significant, wide-ranging and long-term initiative of the Commonwealth Scientific and Industrial Research Organisation (CSIRO), Australia's principal public-sector research institution. Through CSIRO, a comprehensive review of Australian hydrogen and fuel cell technology projects is being compiled, and this is expected to be completed before the end of 2004. Australia is an example where hydrogen and fuel-cell R&D is consistent with the government's objective of reducing the greenhouse gas intensity of energy supply and use. Hydrogen and fuel-cell work is an element of Australia's COAL21 programme which includes research into hydrogen production by coal gasification (and employing carbon sequestration) as part of the national clean coal strategy.

Most of the other HFC programmes are not integrated. For example, Austria, despite having no overarching HFC programme, has some 40 Austrian organisations involved in 50 ongoing hydrogen and/or fuel-cell projects. The

Danish fuel-cell strategy is oriented towards smaller SOFC and polymer electrolyte fuel cell (PEFC) stationary power systems and a total of 35 projects with a total budget of €22.63 million were approved in the period 1998-2002. Although Greece has no specific HFC programme, it conducts a plethora of R&D activities, undertaken by Greek research institutions in the context of EC co-funded projects. The Netherlands reports that "all aspects of hydrogen technology are being investigated, and R&D on hydrogen production is but one part." So while the Netherlands has no significant hydrogen research programmes, in 2003 it did initiate the "Sustainable Hydrogen" project, intended to stimulate hydrogen-related activities at universities. Within the German federal programme for "Energy Research and Energy Technologies", the Ministry of Economics and Labour (BMWA) supports RD&D of fuel cells and hydrogen technologies. Intensive measures on hydrogen technologies started in Germany in 1988 and were concentrated on the development of specific technologies like hydrogen production using electrolysis, hydrogen storage and on larger projects to demonstrate the complete supply chain of a solar hydrogen energy economy. This work was concluded in 1995-1999 with the result that in principle the main components of a hydrogen energy system were developed and functioning. Since 1995, RD&D was concentrated on fuel cells with an annual BMWA budget of €8-10 million per year. In the "Programme on Investment into the Future", launched in 2001, more than 40 additional projects, *i.e.* the construction of several 250 kW molten carbonate fuel cell (MCFC) plants or the demonstration of a hydrogen infrastructure under the EU CUTE project, are being funded by BMWA. Noteworthy are the annual €15 million support of basic research in the Helmholtz research centres by the Ministry of Research and Education and the programmes of the Länder, for example Bavaria's "Hydrogen Initiative" or the North-Rhine Westphalia "Hydrogen and Fuel Cell R&D Programme", both being funded at a rate of €7 to 10 million per year. Norway's research focuses on producing hydrogen from its abundant natural gas resources or by electrolysis, utilising electricity from its hydro-electric generation facilities. Regardless of the approach taken on HFC research and development, a vast amount of information was reported in response to the IEA's HCG survey questionnaire.

PRIORITY AND GAPS IN THE IEA TECHNOLOGY COLLABORATION

The Hydrogen Co-ordination Group is currently assessing priorities and gaps in the IEA R&D programme to identify areas in need of further effort and co-operation. Current R&D and policy activities cover many, if not all major R&D topics. Whilst R&D "gaps" are rare, the more detailed the breakdown of R&D areas, the more areas appear in need of further R&D work and call for increased efforts to achieve H_2/FC deployment relatively soon.

Beneath the bold target of a "hydrogen economy" lies a very complex array of technologies and logistics. The Hydrogen Co-ordination Group (HCG) has drawn attention to the economic, environmental and security implications of the entire hydrogen chain, including production from primary energy sources (fossil, nuclear, renewable energy), distribution, storage, end-uses, and infrastructure requirements. The hydrogen chain should ideally remain CO_2-neutral from production to the end-uses. And equally important to the emissions target is the need to bring down the costs of each stage of the process so that hydrogen can become an affordable energy carrier. All these issues are being investigated in the national R&D programmes of IEA countries or through participation in relevant IEA Implementing Agreements (IAs). Three of them in particular, *i.e.* Hydrogen, Advanced Fuel Cells, and the Greenhouse Gas R&D Programmes, are central to HCG activity. Other IAs (Clean Coal Centre, Advanced Motor Fuels, Hybrid and Electric Vehicles, Bioenergy, and Hydropower) provide contributions on specific topics.

The Hydrogen Implementing Agreement (HIA) has been operating for 25 years. Member countries are Canada, Denmark, the EC, France Japan, Italy, Iceland, Lithuania, the Netherlands, Norway, Spain, Sweden, Switzerland, the UK and the US, and contacts are under way for the participation of Australia, Austria, Finland, Germany, Hungary, Korea, New Zealand and Singapore. Current work focuses on photo-electrolytic and photo-biological hydrogen production, hydrogen from carbon-containing materials, solid and liquid storage materials, system integration and demonstration projects. The agreement is also active in networking, communication, and outreach activities. Achievements include a photo-electrochemical water-splitting process with 16% efficiency, a hydrogen production process from algae, metal hydride storage materials with 5% (weight) at 150˚C, a database on metal hydride storage materials (www.hydpark/ca.sandia.gov), about 22 international demo projects and engineering modelling to analyse energy hydrogen systems, and the design of a pre-combustion natural gas decarbonisation plant. The Hydrogen Agreement also collaborates with several industrial partners. Its priorities for future work are:

- Continued work on photo-electrolytic and photo-biological production.
- Production from wind and solar thermal energy via electrolysis and high-temperature water splitting.
- Production from fossil fuels (coal and natural gas) with CO_2 sequestration.
- Production from nuclear energy.
- High-temperature electrolysis.
- Solid storage, and bulk storage.
- Hydrogen supply purity in relation to demand requirements.

- Hydrogen trading issues.
- Codes and standards and safety issues.
- Taining, education and dissemination aspects.

The Advanced Fuel Cells (AFC) Implementing Agreement works on a full range of key issues concerning the development of various fuel-cell technologies, their fuels (hydrogen, natural gas, etc.), and their stationary, portable and mobile applications. Current work addresses measures to reduce costs and improve performance, and investigate commercialisation and deployment issues through demonstration projects. Participating countries are Australia, Belgium, Canada, Finland, France, Germany, Italy, Japan, Korea, the Netherlands, Norway, Sweden, Switzerland, the UK and the US. The AFC IA collaborates with the Clean Coal Centre and the Hydrogen Agreements. The AFC's work has identified barriers to commercialisation of various fuel-cell technologies. Key issues are the need for improved, low-cost stack materials and catalysts, higher power densities, longer lifetimes (beyond 40 000 hours), packaging, fuel storage, and responsive, light-weight on-board reformers. Non-technical barriers relate to the need for standards and regulations, application/user requirements and training of technicians and field experts.

As already mentioned, for more than ten years the Greenhouse Gas R&D Programme (GHG) has provided an international source of information and assessment of technologies to reduce GHG emissions with a focus on CO_2 sequestration technology. GHG achievements include a comprehensive assessment of performance and costs of the CO_2 sequestration technologies, *i.e.* potential for emissions reduction from coal and gas; CO_2 capture, transmission (by pipeline and tanker) and storage costs; impact on plant efficiency and electricity costs; and overall costs of CO_2 avoidance. Also, costs of H_2 production from natural gas and coal with CO_2 sequestration; implications of introducing H_2 in existing natural gas pipelines and effects on performance of the end-use appliance. Priority activities in hydrogen are: production from fossil fuels with CO_2 sequestration, transmission and distribution; mix hydrogen/natural gas supply by pipeline networks.

According to the survey conducted by the Hydrogen Co-ordination Group (HCG), there are no large gaps in current R&D programmes but increased efforts are required to:

- Reduce costs of producing and storing CO_2-free H_2.
- Reduce costs and improve life-time of fuel cells.
- Improve on-board hydrogen storage for fuel-cell vehicles.

Production R&D should focus on fossil fuels with CO_2 sequestration for the transition phase, and on other sources for the longer term (nuclear, renewable energies with high-temperature electrolysis, photo-electrolytic and photo-biological production). Costs of fuel cells and on-board hydrogen storage are the most critical aspects for using hydrogen in transport. R&D should focus on low-cost fuel-cell materials and catalysts with longer lifetimes, solid storage materials and – as an alternative – responsive, light-weight, on-board reformers. The HCG also identified broader recommendations to overcome non-technical barriers such as:

- Analyse the potential and implications of the H_2 economy in future energy scenarios; quantify investment for infrastructure.
- Analyse early niche markets and understand user requirements.
- Harmonise international codes and standards.
- Greater interaction with the private sector.
- Public education, training of technicians and realistic information to policy-makers.

LINKAGE BETWEEN BASIC SCIENCE AND ENERGY TECHNOLOGIES

To meet world energy challenges, we will need advanced clean energy technologies. These are not likely to be achieved with incremental technology development. In other words, breakthrough is required. Linkage between basic science and energy technology plays a critical role here.

The IEA Conference on Linking Basic Science and the Development of New Energy Technologies held in Paris in April 2003 addressed this topic. The Ad Hoc Group on Science and Energy Technologies (AHGSET) was established in March 2004 to reflect a commitment by the IEA to continue this important work and to extend the initial progress over the foreseeable future.

AHGSET is under the Committee of Energy Research and Technology (CERT). Mr Barry Gale, CERT Vice-Chair and the US CERT delegate, is the Chairman. Australia, Canada, France, Germany, Korea (as an observer), Japan, Italy (as an observer), the Netherlands (as an observer), the United States, and the European Commission, have agreed to participate in AHGSET.

The significance of AHGSET includes *i*) focus on energy technologies; *ii*) focus on issues of importance to IEA member countries; *iii*) utilisation of IEA Technology Networks such as CERT, Working Parties (End Use WP, Renewable Energy WP, Fossil Fuel WP, Fusion Power Co-ordinating Committee, Hydrogen Co-ordinating Group), Sub and Ad Hoc Groups (Expert Group on R&D Priority Setting and Evaluation, Advisory Group on Oil and Gas Technologies), some

40 Implementing Agreements which are at the core of the IEA's International Energy Technology Co-operation Programme and which cover fossil fuels, renewables, energy end-use (*i.e.* transportation, industry, buildings), fusion power, information centres, system analysis and technology transfer; *iv*) close co-operation with other international organisations, such as the Global Science Forum (GSF), and the OECD.

AHGSET's mission is to support the development of new energy technologies, strengthening the connections between basic science and applied new energy programmes. One of the key elements of its activities is to hold workshops to bring key stakeholders together. These key stakeholders include scientists, energy technologists and public policy officials. The key stakeholders of IEA non-member countries will also be invited. The strategy of these workshops is to facilitate two-way exchanges. In other words, the aim of the workshops is to explore what energy technologists need from basic scientists (demand pull), whilst at the same time exploring what basic scientists believe they can offer to energy technologists (science mining).

ENERGY POLICIES IN NON-MEMBER COUNTRIES

CHINA

Explosive economic growth driven by surging fixed asset investment has intensified the strains on the Chinese energy sector in 2003 and early 2004. While official GDP growth has been measured at close to 10% over this period, industrial activity seems to point to even higher growth. Chinese policy-makers have taken steps to slow down investment, especially in overheated sectors like real estate, steel and cement. Preliminary data in June 2004 show encouraging signs that these measures are beginning to work, but it is far too early to declare a successful "soft landing", especially as many of the undisciplined investments could end up as non-performing loans in the coming years.

ELECTRICITY SECTOR

Needed reforms in China's electric power sector have largely taken a back seat to measures to address current electricity shortages. Electric power demand has grown by over 15% annually in the last two years and far exceeded the amount of newly added generating capacity. The lack of generating capacity has been intensified by shortages of (inexpensive) coal, rail capacity and rainfall in hydro-reliant areas. Over two-thirds of Chinese administrative regions have experienced blackouts or shortages since 2003. Shortages peaked in the summer of 2004, with cities like Shanghai, Nanjing, Beijing and Guangzhou implementing emergency measures to control peak load. Given these recent shortages, government officials are again paying great attention to demand-side issues when discussing overall energy policy.

The Energy Bureau in China's National Development Reform Commission, which was created in March 2003, has moved quickly to encourage the building of new plants, with nearly 40 gigawatts of capacity to come on line in 2004, and even more in 2005. There is growing concern, however, that China will overshoot the target and again experience overcapacity in power generation by 2007 or 2008 if either or both of the following situations occur: *i)* the economy slows suddenly, or *ii)* too many plants are built that have not been approved by the government. The difficulty of balancing power demand and supply in a country where new capacity additions in 2003 and 2004 match the total installed capacity of a country like the UK, cannot be overstated. But the introduction of reforms to influence investor and consumer behaviour would clearly help bring the two into better balance. A revision to the Electricity Law is scheduled to be published in late 2004 or 2005, but analysts are concerned that, by itself, it will be too general to bring about the changes needed.

OIL SECTOR

Chinese petroleum demand has also grown explosively, with an alarming percentage now imported from abroad. In 2003, Chinese crude oil imports jumped by 31% to reach 91 million tonnes, with roughly similar growth anticipated for 2004. China will probably have to import 40% of its crude oil needs by 2005. To address the growing insecurity of supply, China has intensified efforts to take oil equity stakes in overseas oil production assets and to import oil via pipeline. China has demonstrated growing interest in co-operating with Kazakhstan over a 20 million tonne per year cross-border crude pipeline, even though the economics are questionable. Progress on this pipeline may accelerate if Russia builds a line from Irkutsk to Nakhodka on its Pacific coast rather than to Daqing as the two countries had previously anticipated.

China has also continued to build its strategic petroleum reserve capacity, although little official information on progress or strategy has been released. Four sites are reportedly under construction, with the first to be completed in 2005. Two of the depots are located in Zhejiang province, with the other two in Liaoning and Shandong. Chinese policy-makers claim that global oil prices have recently been too high for them to actually begin storing oil at the facilities. After prices decline, they will begin stockpiling around 10 million tonnes in phase I by 2007 and over 20 million tonnes in phase II by 2010. The IEA Secretariat has held two workshops with the Chinese oil policy-makers on how to build and operate strategic reserves, and plans to continue collaboration on operational aspects in 2004 and 2005.

GAS SECTOR

China's natural gas sector continues to attract considerable attention and is at the heart of the country's priority to rationalise its energy supply structure. In 2003, China produced 35 bcm of natural gas, ranking approximately 18th in the world. It accounted for about 2.5% of the country's total energy consumption, compared to the world average of 24%. Government planners envision gas demand rising to 200 bcm by 2020 (equivalent to about 10% of the projected total energy share), with roughly one-third imported from abroad and two-thirds produced domestically.

Actions that support the government's new attention to gas include:

- Construction of a 3 900 km-long East-West pipeline that will eventually deliver 12 bcm of gas from Xinjiang to Shanghai; the eastern half of the pipeline began operations in late 2003, and opening of the western half has been advanced to year-end 2004.
- Construction of two LNG import terminals (Guangdong and Fujian), with plans for up to eight others in the near future. LNG has attracted huge attention recently as domestic coal prices have soared and the clean fuel now looks much more competitive.
- Detailed discussions and a feasibility study to import approximately 20 bcm of natural gas from Russia's Kovytka field to north-east China beginning in 2008.
- Acceleration of other smaller domestic and offshore pipelines to bring gas to urban areas.

The IEA Secretariat was following up on its 2002 study on Chinese gas issues by participating in a high-level policy seminar on 10 July 2004 in Beijing.

COAL SECTOR

China's coal sector has expanded output enormously in the past few years, but shortages still result in lost economic output. Coal production is up approximately by 16% so far in 2004 after exhibiting similar growth in 2003 to approximately 1 600 million tonnes. Statistics that track coal-related emissions of sulphur oxides, particulates and carbon dioxide are also up sharply for the first time since the mid-1990s.

China is also likely to give greater attention to renewable energy supply in the coming years. A new law on renewable energy is to be issued in 2005 with the aim of promoting investment in small hydro, wind power and photovoltaics. These sources of "new energy" could play a significant role in meeting development needs in remote areas, but their overall impact in developed, urban areas of China has been hindered by high cost, technical difficulty, and distorted markets. There is growing talk in China of introducing more significant energy taxes, which could provide greater incentives for clean energy and demand-side energy management.

INDIA

India has made considerable progress with energy sector reforms and restructuring in recent years. However, the pace of reforms varies considerably between energy sub-sectors, and the country still lacks a comprehensive national energy policy that could identify the challenges, outline a vision for the future and propose a coherent policy. Work towards a national energy policy started in early 2004. The new government which took office in May 2004 following national elections confirmed that the development of an integrated national energy policy remains a major priority. An integrated national energy policy is seen as a key ingredient for achieving energy security, which is given paramount importance in the new government's policy declaration.

ELECTRICITY SECTOR

Substantial progress has been made with power sector reform in India in the last few years. The Electricity Act 2003 is an enabling legal framework capable of adapting to the changing situation in the sector and providing long-term legal certainty to potential investors. It replaces and consolidates all existing provisions for the power sector. The act reflects several of the recommendations contained in the IEA Secretariat's 2002 publication *Electricity in India*, in particular those related to independent sector regulation, the need for a national tariff policy, the reduction of subsidies and cross-subsidies, the vertical unbundling of State Electricity Boards (SEBs), the commercialisation and corporatisation of sector entities and the need to pursue rural electrification outside the main grid through decentralised supply systems. The act seeks to effectively insulate the tariff-setting process from political considerations and limits the roles of the central and state governments to providing overall policy guidance. Accordingly, regulatory responsibility for the sector is being vested in the Central Electricity Regulatory Commission (CERC) and the State Electricity Regulatory Commissions (SERCs) whose establishment has been made mandatory. As of end 2003, 20 states had established SERCs and tariff orders have been issued in 18 states. The act also allows for the introduction of a multi-year tariff framework. In April 2004, CERC announced a five-year tariff order stipulating a flat 14% return on equity for all central public-sector undertakings and mega private projects. These legal and regulatory reforms in the power sector are of course positive, but their implementation will determine their effectiveness in achieving reform of the sector.

The Indian private sector has reacted positively to the new business opportunities arising from the provisions made in the act. The act recognises transmission as a separate activity and permits private-sector participation. At the end of December 2003, the first transmission licence under the act was awarded to a joint venture between the state-owned Powergrid Company and the privately-owned Tata Power, with the latter being the majority shareholder, making it India's first interstate transmission project in the private sector. CERC operationalised open access in interstate transmission with effect from

6 May 2004. The act also opened the sector for power trading and the first licence was issued to Power Trading Company in July 2003; seven more licences have been issued since then. The terms and conditions of interstate trading were notified by CERC in February 2004.

OIL AND GAS SECTORS

Oil and gas have emerged as the most dynamic energy sectors in India. The sectors have seen major policy developments in the last few years that have substantially altered investment conditions in the sectors, even if deregulation and the creation of a comprehensive legislative framework are far from complete. The launching of the New Exploration Licensing Policy (NELP), the abolition of the administered pricing mechanism for oil products, and the opening of the retail and refining markets to the private sector have all resulted in strong interest by Indian oil companies to invest.

Major international oil and gas companies showed only limited interest in the NELP. The government reacted to this in January 2004 with a decision to remove the ceiling on foreign direct investment limits on virtually all activities in the petroleum sector and to allow up to 100% equity by foreign investors. In a further step towards sector deregulation, the government allowed foreign investors to participate in the initial public offering (IPO) of 10% of its equity share in the Oil and Natural Gas Corporation (ONGC) and the Gas Authority of India Limited (GAIL), two of the country's largest companies. The IPOs went ahead in March 2004, were quickly oversubscribed and brought almost US$ 2.5 billion in revenue to the government.

The construction and operation of petrol retail outlets has long been limited to public-sector companies. In late 2003, the country only had 20 000 petrol outlets. In 2003, the ministry revised its policy and issued over 11 000 licences to the private sector to establish retail outlets. All major private-sector companies have applied for licences and the first 1 500 private petrol outlets are expected to become operational by the end of 2004.

India officially entered the LNG economy on 30 January 2004 with the arrival of the first tanker at its Dahej terminal on the western coast which has a capacity of 2.5 million tonnes per annum. However, India is facing major challenges on its way to becoming a sophisticated gas economy, including the lack of sufficient transmission infrastructure and of a coherent legal and regulatory framework. Construction of a "National Gas Grid" is one of the major priorities and GAIL has recently unveiled plans for the construction of over 7 000 km of pipelines at a cost of about US$ 4.5 billion by 2008.

Issuance of a draft LNG policy paper announced for 2003 has been postponed and the draft *Petroleum Regulatory Board Bill* is still pending owing to ongoing discussions about the proposal to extend the scope of the bill to cover the gas sector too. In September 2003, the government issued a draft policy for the development of a gas pipeline network that foresees the construction of the future gas transportation network on a common carrier principle with requirements for third-party access under public ownership and management. GAIL was nominated as monopoly builder and operator of cross-country gas pipelines. The draft policy triggered substantial debate among industry players, and the private sector in particular raised questions about a conflict of interest resulting from the different roles of GAIL as producer, transporter and retailer of gas. Discussion of the draft policy is ongoing. Critics have also pointed out that the current approach to sector regulation is unlikely to attract the urgently needed foreign investment into the sector and that the lack of a consolidated legal and regulatory framework might weaken its growth potential. However, it is now expected that instead of pushing ahead with the pending multiple legal bills, the new government will consolidate them within the integrated national energy policy it is committed to issue.

ENERGY SECURITY

As a response to India's increasing import dependence on crude oil, the Indian Cabinet approved a plan for the establishment of strategic oil stocks in early 2004. Construction of storage facilities is expected to commence towards the end of 2004, as announced by the new government. Stocks are part of India's four-pronged approach to oil security consisting of: *i)* increased domestic exploration and production efforts under the NELP; *ii)* import source diversification through overseas investments by public Indian oil and gas majors; *iii)* fuel diversification, *e.g.* compressed natural gas (CNG) and *iv)* strategic oil stocks. The government expects its strategic oil storage to provide an emergency response mechanism against short-term supply disruptions. The government had consulted with the IEA since 2000 in preparing its proposal, which resulted in an acceleration of India's decision-making process. The Indian government requested the IEA Secretariat to organise a Joint Workshop on Indian Emergency Oil Stocks, which took place in New Delhi in January 2004. The Joint Joint Workshop received much interest from the local and international media who highlighted the role of IEA in the government's decision-making process. Beyond this co-operation for the workshop, a joint press release issued on the second day outlined future areas of co-operation, including the regular exchange of information and the establishment of a hotline for information-sharing during emergencies.

COAL SECTOR

Coal will remain the dominant commercial fuel in India. However, despite its huge reserves, India faced a demand-supply gap of about 40 million tonnes in 2002-2003, which is set to widen to about 95 million tonnes by 2010.

The coal sector is in desperate need of structural reform to raise the investment required to close the demand-supply gap. Moreover, the coal sector is the only key energy sub-sector that has not seen any fundamental restructuring of its legal and organisational structure in over 30 years.

The Indian government has recognised that the coal industry stands at a crossroads. While it is poised for substantial growth, it requires huge infusions of both capital and technology to really take off. There is a growing awareness that this cannot be accomplished without public-private partnership. However, currently there is no comprehensive sector reform and investment mobilisation strategy in place. A draft legislative bill, the "Coal Mines (Nationalisation) Amendment Bill" that would allow private-sector participation in commercial mining beyond captive usage has been pending in Parliament since 2000. The Ministry of Coal is also considering introducing a "Coal and Lignite (Regulation and Development) Bill". This new bill would be more comprehensive than the pending legislation and would introduce competitive bidding in allocation of mining blocks, create an independent authority to oversee competitive bidding with the aim of creating a level playing field between the public and private sectors, and broaden the eligibility of the Build-Own-Operate Project for coal washeries. Under the proposed captive mining policy, private Indian companies operating power projects as well as coal or lignite mines for captive consumption in such projects may be allowed foreign equity up to 100%, provided that the coal or lignite produced by them is meant entirely for captive consumption in power generation. Private Indian companies engaged in exploration or mining of coal and lignite for captive consumption, for production of iron and steel and production of cement may be allowed foreign equity up to 74%.

Both bills were drafted in response to the fact that the policy permitting captive mining for domestic power, iron, steel and cement-sector companies, introduced in 1993, received only a lukewarm response. Only five projects have materialised since then, because of the restrictions on selling coal in excess of captive needs in the free market. However, there appears to be little political support within the new government to move more decisively towards fundamental sector restructuring. Given the new government's emphasis on protection of employees and employment creation and the fact that it depends on support from the leftist block, it is unlikely that major structural changes in the coal sector will be instituted.

SOUTH-EAST ASIA

Recovering from the Asian financial crisis of 1997-1998, demand for energy, particularly petroleum, is growing rapidly in the countries of the Association of South-East Asian Nations (ASEAN). To address region-wide energy issues, the ASEAN Senior Officials Meeting on Energy (SOME) and the ASEAN

Ministers of Energy Meeting (AMEM) are held annually to review the progress of policy and programmes in place and to provide direction for future regional policy and programmes.

ENERGY SECURITY

As Malaysia and Indonesia move from net oil exporter status to net importers, ASEAN as a region is now a net importer of oil. Combined with rapidly expanding transport sectors and global socio-political uncertainty, ASEAN countries are very conscious of oil and energy security issues. While longer-term security issues are being addressed through energy source and mix diversification policies, oil disruption crises are also being addressed. The 1986 ASEAN Petroleum Security Agreement (APSA) remains under review and its operationalising instrument, the "Co-ordinated Emergency Response Mechanism" (CERM), is close to agreement at the industry level.

Recognising the need for an interim measure to address a supply crisis, ASEAN Energy Ministers agreed to work towards a regional co-ordination and consultation procedure. A "Standard Operating Procedure" (SOP) has been agreed at the ASEAN industry level and will be reviewed by a special meeting of the SOME in 2004. Ministers also agreed to open a dialogue with Middle East oil-producing countries to promote stability in the global market and secure markets in ASEAN.

The IEA and its ASEAN partner, the ASEAN Council on Petroleum (ASCOPE), continue to collaborate on the region-wide 2003-2004 "ASEAN Oil Security and Emergency Preparedness" Project. This project includes policy and technical workshops, site visits, information exchange and key ASEAN participation in an IEA Emergency Response Exercise. The project is providing increased awareness of global and national energy security issues, along with very practical mechanisms to address such issues.

TRANS-ASEAN ENERGY NETWORK

To address issues of longer-term security, energy mix and source diversification, sectoral efficiency and environment sustainability, ASEAN policy-makers continue towards establishing the Trans-ASEAN Energy Network, made up of the ASEAN Power Grid (APG) and the Trans-ASEAN Gas Pipeline (TAGP).

The newly formed Heads of ASEAN Power Utilities and Authorities (HAPUA) Council, responsible for APG planning and co-ordination, recently established eight electricity sector working groups and a permanent HAPUA Secretariat with a three-year term rotation.

Five power interconnection projects are planned within 2005-2009. Recognising the need for cross-border harmonisation to facilitate interconnections based on commercial trade, HAPUA is preparing a study on the challenges, opportunities and options for electricity trading in ASEAN as well as an ASEAN Co-operation Agreement on a common policy for regional power interconnection and trade.

Gas interconnections between national markets and cross-border fields are being developed when commercially expedient, and the ASEAN Council on Petroleum (ASCOPE) maintains its policy, planning and co-ordination support. The ASEAN Memorandum of Understanding (MOU) on the TAGP recently entered into force and it sets out the co-operation framework for greater public-private partnership in the development of the TAGP. ASCOPE recently completed models for a TAGP Gas Sale and Purchase Agreement and a Gas Transport Agreement. A proposal for the creation of the Joint Venture Company (JVC), including a business plan for opportunities in the ASEAN gas industry, is being finalised.

The recently formed ASEAN Gas Consultative Council (AGCC) is an industry and government policy and analysis council. It is undertaking studies into taxation/tariff matters, financing, transit rights and access, security of supply and emergency supply, and health and environment.

ELECTRICITY AND GAS SECTOR REFORMS AND PRIVATE-SECTOR INVESTMENT

ASEAN governments and industry recognise the need for private-sector investment in the ASEAN electricity and gas networks, and ASEAN Energy Ministers called on the private sector to actively participate on a commercial basis. To support this investment, ministers agreed to work to create a stable, predictable and competitive business environment.

ASEAN countries' electricity and gas reforms and regulations are seeking to provide stable and predictable national frameworks for energy project investment and cross-border interconnections. The IEA and its ASEAN partner, the Philippines Department of Energy (PDOE), are collaborating on an ASEAN-wide 2003-2004 "Role of Regulators and Regulatory Frameworks in ASEAN electricity and gas sector reform: a comparative examination of national and regional models" project. This project includes a study tour of European electricity and gas regulators and industry, a meeting to develop an "ASEAN Forum for Energy Regulators", information exchange, and a conference on "National Regulatory Models and Regional Regulatory Frameworks in the Electricity and Gas Sector". The project is providing increased awareness of global and national energy regulatory issues and models for national and regional regulators.

ASEAN PLAN OF ACTION FOR ENERGY CO-OPERATION (APAEC) 2004–2009

Recognising the effectiveness of the first ASEAN Plan of Action for Energy Co-operation (APAEC) 1999-2004 in providing a clear structure for ASEAN-wide co-operation, an APAEC for 2004-2009 was recently agreed. This can be viewed in detail at: http://www.aseansec.org/pdf/APAEC0409.pdf

Under the APAEC, specialised bodies such as the ASEAN Centre for Energy (ACE), the ASEAN Council on Petroleum (ASCOPE), the Heads of ASEAN Power Utilities and Authorities (HAPUA) Council, the ASEAN Forum on Coal (AFOC), the Energy Efficiency and Conservation Sub-Sector Network (EE&C-SSN), the Renewable Energy Sub-Sector Network (RE-SSN), and the newly established Regional Energy Policy and Planning Sub-Sector Network (REPP-SSN) are involved in the formulation and implementation of ASEAN energy co-operative activities.

The new APAEC reflects key regional energy issues in the context of anticipating sustainable development and global policy scenarios. Specific action plans address the recent Ministerial directions, including:

- Strengthen co-ordination/participation to narrow the development gap among ASEAN countries.
- Encourage a conducive environment for greater private-sector participation, including securing foreign direct investment.
- Enhance human resources and capacity-building skills.
- Develop the energy mix and supply source by utilising regional resources, including frontier exploration and development and research on oil, natural gas, coal, hydropower, geothermal, EE & C and renewable energy.
- Develop transparent legal, regulatory and technical frameworks in various energy projects, in particular the cross-border interconnection projects.

INTERNATIONAL COLLABORATION

Recognising the positive impact of dialogue and exchange with non-ASEAN countries and international agencies on ASEAN policy and programmes, ASEAN Ministries and agencies have established ongoing relations and collaborative programmes with ASEAN "dialogue partners".

VIENTIANE INTEGRATION AGENDA 2004-2010: ASEAN ENERGY CO-OPERATION INPUTS

The ASEAN Energy Co-operation Inputs to the draft Vientiane Integration Agenda (VIA) 2004-2010 establishes energy co-operation activity milestones until 2010. These milestones draw on the APAEC and aim at enhancing the integration of the Trans-ASEAN Energy Network, promoting energy security, enhancing market reforms and liberalisation, and preserving environmental sustainability.

The milestones are:

- Operationalisation of the ASEAN Memorandum of Understanding (MOU) on the Trans-ASEAN Gas Pipeline (TAGP) project with a fully functional ASEAN Gas Consultative Council and ASCOPE Gas Centre.
- Significant implementation of the ASEAN Power Grid (APG) project with an established policy framework and modalities for interconnection and trade.
- Enhanced energy infrastructure facilities in ASEAN with the commissioning of three gas pipelines under the TAGP and five power interconnections under the APG.
- Comprehensive institutional arrangements for enhanced security and stability of energy supply.
- Enhanced sustainable energy development through expanding markets for renewable energy technologies and energy-efficient products.
- Increased renewable energy in the ASEAN power generation mix to at least 10%.

LATIN AMERICA[28]

Over the past 15 years, energy policy reforms in key Latin American countries have achieved mixed success, often influenced directly by domestic political, social and economic instability. Enormous challenges remain in developing appropriate policies and regulations to ensure secure, clean and affordable energy access in Brazil, Mexico, Venezuela, Argentina and Bolivia. Most importantly, stable investment environments must be created to ensure adequate expansion of the energy sectors, and demand-side policy measures are needed to promote efficient energy use.

BRAZIL

Brazil is the largest economy in Latin America, and ranks 10th among global power energy consumers. It is the fourth-biggest power energy user among IEA non-member countries after China, India and Russia. It depends on

28. All non-quoted statistic data and information has been prepared and produced by the IEA.

hydropower to generate 83% of its electricity supply, and has instituted strong measures to promote renewable energy use.

Brazil has the third-largest proven oil reserves in Latin America after Venezuela and Mexico,[29] and its oil production has risen steadily in the past few years driven by the goal of achieving self-sufficiency by 2006 and net-exporter status by 2010. PETROBRAS is expanding investment domestically and overseas, and is the only company in Brazil to achieve commercially viable discoveries in recent years.

Liberal reform measures taken by the Cardoso administration in the late 1990s and early years of the new century included, *inter alia*, privatisation, unbundling and the establishment of independent regulators. These measures met with severe challenges due to macroeconomic instability, implementation delays and a prolonged drought leading to an electricity crisis; which, as a result, required the implementation of further new measures.

In March 2004, Brazil's new Lula administration approved the New Electricity Model which aims to strengthen supply security, increase competition, and rationalise regulation in order to attract greater investment. The implementation of the New Electricity Model has already begun with the issuance, at the end of July and first half of August 2004, of three law decrees that regulate it. Likewise, the government has initiated a New Natural Gas Model, expected to be approved by the Parliament by the end of 2004, although there is no official deadline for the completion of the Natural Gas Law's reform. The new natural gas policy would aim to clarify federal and state jurisdiction, and improve pipeline planning, financing and operation.

Despite controversy, the reform of regulatory agencies is also under way. The responsibility for awarding concessions in the electricity, oil and natural gas, water, telecoms, and transport sectors would be taken away from the regulators and given to relevant ministries instead.

MEXICO

Mexico has the second-largest proven oil reserves in Latin America after Venezuela,[30] it is the world's fifth-largest oil producer and the largest in Latin America. In addition, it is the fifth-largest oil exporter in the world and the second-largest oil exporter in Latin America behind Venezuela. While Mexico is one of the world's major natural gas producers and the second-largest in Latin America behind Argentina, it still imports around 16% of its total demand from the United States at relatively high prices. Mexico faces

29. World Energy Council, *Survey of Energy Resources*, 20th Edition (Elsevier Ltd.: London, England), 2004, pp. 43-45.
30. Ibidem, pp. 43-45.

significant challenges in meeting the investment needs of an expanding energy sector.

Mexico's Ministry of Energy forecasts a growth in power energy demand of 5.6% annually through 2012,[31] requiring a huge investment that the State cannot meet alone. In this respect, the Fox administration has worked hard to enact reforms that will allow more private and foreign investment in the energy sector, but legislative opposition and constitutional constraints have limited progress. Without demand-side policies and significant new investment to develop new energy sources and construct the associated infrastructure, Mexico could soon face a severe energy shortage.

At present, private participation in the oil and natural gas sectors is only allowed through service contracts where resources ownership remains under PEMEX and fixed amounts are paid for work performed. In the power sector, where there are two state-owned electricity companies, limited private investment (independent power producers, self-suppliers, co-generation) has been allowed since 1992.

LNG imports are expected to grow rapidly in Mexico over the coming decade. A significant share of this gas could be re-exported to the United States, whose own imports could be limited by public opposition to construction of regasification terminals. Permits have been granted to private investors for the construction of a terminal in the Port of Altamira and two in the Ensenada region of Northern Baja California. Opposition to the latter has also raised doubts about Mexico's ability to overcome NIMBY (not in my back yard) issues.

VENEZUELA

Venezuela has the world's sixth-largest proven oil reserves.[32] It is the world's eighth-largest oil producer and the second-largest in Latin America behind Mexico. In addition, Venezuela is the fourth-largest oil exporter in the world and the largest in Latin America. It is also an OPEC member and a major supplier to the United States. However, secure exports have been threatened by political instability and strikes in the oil industry. Despite Venezuela's hydrocarbon potential, investment needed to keep oil flowing has been discouraged.

Venezuela has the largest proven natural gas reserves in Latin America and the eighth-largest in the world.[33] Over 90% of this natural gas is associated with oil production, however, and a large share is reinjected to enhance oil

31. Energy Information Administration, *Country Analysis Brief: Mexico*, EIA website (2004), <http://www.eia.doe.gov > (5 Jul. 2004).
32. World Energy Council. See note 29, pp. 43-45.
33. World Energy Council. See note 29, pp. 129-130.

production. The government is taking steps to expand natural gas consumption by *i)* developing non-associated natural gas reserves; *ii)* expanding pipeline infrastructure; *iii)* constructing LNG export facilities, and *iv)* building more natural gas-fired power and petrochemical plants. Foreign investment is allowed along the entire chain of Venezuela's natural gas sector.

Private companies operate and own roughly 86% of Venezuela's installed generating capacity.[34] Before President Chavez came into power almost six years ago, Venezuela's electricity sector privatisation was under way. Laws towards deregulation of the electricity market were enacted in 1999 and 2000, requiring the unbundling of integrated electricity companies' activities. Nevertheless, the completion of this privatisation process has been postponed indefinitely owing to Venezuela's economic and political instability. It is expected that distribution and transmission will remain as regulated segments, while generation and marketing will be deregulated and opened to competition.

Observers note that the current political climate has slowed down economic development, and hence the needed investment in the energy sector. Opposition parties pushed for a constitutional referendum, which was held on 15 August 2004, to decide if President Chavez would stay in power. President Chavez obtained around 58% of the vote and won the referendum. He will stay in power and complete his term through December 2006.

ARGENTINA

Argentina has the third-largest proven natural gas reserves in Latin America behind Venezuela and Bolivia,[35] and it is the largest natural gas producer in Latin America. Argentina had a leading role in energy reforms in the region, although, at present, it is experiencing an energy crisis. Natural gas and electricity shortages were caused by a lack of investment in the natural gas sector because of low prices, and a drought that resulted in lost hydroelectric output. In addition, the country's economic and financial crisis that began in 2001 critically affected the energy sector. Thus, recession, devaluation of the peso, and massive foreign debts hampered the ability of energy companies to invest in exploration and development. Power cuts and energy rationing have occurred in 2004 for the first time in a decade.

Argentina has been forced to restrict natural gas exports to Chile and Uruguay as a result of the shortages, although the crisis is now easing. Argentina is currently importing natural gas from Bolivia, and has auctioned the right

34. EIA, *Country Analysis Brief: Venezuela*, EIA website (2004), <http://www.eia.doe.gov > (6 Jul. 2004).
35. World Energy Council. See note 29, pp. 129-130.

to import power from Brazil, which began in June 2004. Additionally, the governments of Argentina and Venezuela have signed an agreement to exchange agricultural goods from the former for oil from the latter.

In the midst of the energy crisis, President Kirchner announced a new energy plan in May 2004. The plan calls for the implementation of a US$ 3.85 billion investment programme to expand the country's natural gas and electricity infrastructure by 2009. It also includes the creation of a new state-owned energy company and measures regarding energy imports from Bolivia, Brazil and Venezuela which had been taken previously. Measures to raise energy efficiency and conserve energy are also encouraged. The bill that creates the new state-owned energy company was approved by the Senate in mid-August 2004. The impact of the recent measures will take some time to assess.

Argentina has the fifth-largest proven oil reserves in Latin America,[36] and is the fourth-largest oil producer behind Mexico, Venezuela and Brazil; it is the third net oil exporter of the region after Venezuela and Mexico. The oil sector in Argentina is completely privatised. The decrease in production and investment in the oil sector in 2002 is also linked to the collapse of the Argentinian economy in 2001. However, a mixture of economic recovery, government incentives and high oil prices encouraged a few oil companies to reinvest in the country's oil sector in 2003.

BOLIVIA

Bolivia's proven natural gas reserves are the second-largest in Latin America after Venezuela,[37] although it is the first in terms of non-associated gas. It has the potential to become South America's natural gas hub, and could be a major exporter of LNG to the United States and Mexico, although not without greater political stability. At present, Bolivia exports natural gas to Brazil and Argentina, and also has plans to export natural gas to Paraguay and to increase existing exports to Brazil and Argentina in the future. However, the plan to increase natural gas exports to Brazil could be negatively affected by large new natural gas reserve discoveries in this country, which were confirmed in 2003.

In September 2003, major protests erupted in opposition to the government's plan to export gas to the United States and Mexico through Chile. A general perception that economic liberalisation had not helped reduce poverty contributed to the public revolt. The protests forced President Sanchez de Lozada from power in October 2003.

36. World Energy Council, *op. cit.* note 29, pp. 43-45.
37. World Energy Council, *op. cit.* note 29, pp. 129-130.

The new administration called for a referendum on the country's hydrocarbon policy, including the revivification of the formerly state-owned company Yacimientos Petroliferos Fiscales Bolivianos (YPFB). The referendum, which took place on 18 July 2004, supported the proposals, although some time will be needed before the outcome of the new measures comprised in Bolivia's energy policy can be assessed. At present, it is very likely that Bolivia will export its natural gas through a port in Peru, as a letter of intent on this matter was signed by the leaders of both countries days after the referendum. Under this document, Peru would create a *special economic zone* in order to facilitate Bolivian natural gas exports. A final agreement is expected after the approval of the New Hydrocarbons Bill by the second week of October 2004. This bill would go further than the referendum proposals owing to pressure from the opposition. Thus, it would renationalise upstream companies Andina and Chaco and transport company Transredes, increase royalties and taxes on hydrocarbon production to 50 %, and create a new oil regulator. As a result, the State would own all hydrocarbons at the well-head, and exploration, production, transport and trading would only be carried out by state companies or fixed-length concessions. The private sector is opposed to this bill, and considers that it puts future investment in Bolivia's hydrocarbon sector at risk, and, hence, its development.

Most of the oil production in Bolivia is for domestic consumption. However, during 1992-2002 it imported diesel to cover its demand for the product. Thus, in order to decrease this diesel dependence, Bolivia is considering the construction of two natural gas-to-liquids plants to produce diesel from gas.

The electricity sector in Bolivia is 53% hydro-dependent and 45% thermo-dependent; the remainder is sourced by combustible renewables and waste. The unbundling and privatisation of Bolivia's electricity sector began in 1994.

RUSSIA

In President Vladimir Putin's State of the Nation Address in 2003 and again in 2004, he stressed the political goal to double the nation's GDP over the next decade. In this context, energy sector reforms are increasingly essential for Russia to match increasing domestic energy demand and export obligations during a period of strong GDP growth without significant new improvements in energy efficiency. GDP has been growing by an average of 6.7% per year during the period 1999 to 2003, much faster and more sustained than most observers believed possible after the 1998 financial crisis. Total investment requirements in the energy sector to 2020 are estimated by the Russian government between \$660 billion and \$770 billion[38] compared to the IEA's *World Energy Investment Outlook*

38. Russian Energy Strategy investment estimates include \$70 billion for the heat sector and between \$50 to \$70 billion directed to energy efficiency.

2003 estimates of \$660 billion. Whether Russia continues to play a significant role in the future as a key oil and gas exporter depends on the political will to continue the implementation of difficult reforms over the next decade in order to attract the needed investment – domestic and foreign – to sustain and increase current production for domestic needs (including electricity generation) as well as export capacity.

ENERGY MARKET REFORM

The challenge of creating a more competitive gas sector will have to take as its point of departure the existing structure of Gazprom, the state gas monopoly. Increasing gas production from Russian oil companies and the emergence of independent gas producers argue for sector reform, and this reform will need to reflect the enormous investment challenges ahead. A legacy of the Soviet system is the pricing structure where households (and other customers such as district heating plants and services) hardly pay cost-recovery prices. Changes here will have to be carefully implemented to mitigate the social implications of higher prices. Another problem inherent to the extreme distances from supplies to markets is the existence of large price differentials between the Russian borders with Central Asian suppliers and the countries of the EU-25 where market-based pricing predominates. Finally, the reordering and reform of Soviet trading relationships and practices with former Warsaw Pact partners, which include problems of non-payment, barter, vestigial preferential relations and other non-market practices, make market reform all the more difficult and retard the development of an effective Eurasian gas market.

The Ministry of Economic Development and Trade (MEDT) has been drafting various concepts for restructuring the gas sector over the past few years. As expected, Gazprom has been quite open in its aversion to these concepts which envision the eventual break-up of Gazprom, emphasising the threat these plans pose to security of gas supply and to the whole economic and social framework of the country. Given the company's central importance to the economy, President Putin has been careful with Gazprom, holding off reformers while at the same time pushing Gazprom to become more transparent and open. The most recent reform plans of the MEDT call for the separation of Gazprom's gas transportation business and Central Dispatching Unit into 100%-owned subsidiaries, gradual liberalisation of domestic gas prices by 2008-2010 and the basis for gas-on-gas competition within Russia. The Russian government has promised to review the concept of gas sector reform over summer/autumn 2004. The abrupt about-face, in mid-March 2004, of Gazprom's CEO Alexei Miller could reflect a growing consensus between the MEDT and Gazprom. Miller stated that by the beginning of 2005, Gazprom would financially unbundle its accounts according to activities – production, transportation, gas processing, storage and distribution. Financial unbundling will allow for transparency in transportation tariff-setting – key for third-party access – and will also clarify areas where efficiency and cost-cutting can be enhanced. As experience in IEA countries has shown, financial unbundling is a positive first step in liberalising the sector. Successful implementation and further development of the government's restructuring plans are critical if Russia is to sustain its economic growth while continuing to meet domestic and export obligations. In this respect, the long-term contracts and alliances Russia has formed with Central Asian countries allow Gazprom to delay its own restructuring by controlling domestic non-Gazprom production while at the same time effectively removing Central Asian gas as a potential competitor on the export market. This is an increasing concern from a longer-term security of supply perspective.

Until recently, government regulation of domestic gas prices, which are thought to be below full-cost, is a critical uncertainty for the financial health of the gas industry and its capacity to finance capital spending. Domestic prices also affect prospects for Russian gas demand and, therefore, incentives for energy efficiency, heightened competitiveness and the amount of gas that will be available for export. The outlook to raise domestic gas prices to cost-reflective levels (including investment costs, *i.e.* rate of return on investment) over the next five years[39] is an essential factor in the reform of the gas sector and the Russian economy as a whole. This commitment has been institutionalised within the EU-Russia agreement signed on 21 May 2004, where the EU gave its support for Russia's accession to the World Trade Organization (WTO). An increase in gas prices will not only encourage production by Gazprom, oil companies and independent gas producers but will also discourage consumption and favour efficiency.

In the past, the pace of reform has depended to a large degree on future international oil prices. When oil prices remained high, there was little motivation to make difficult reform decisions. Market liberalisation was slow. Little changes were made to the fiscal, legal and/or regulatory regimes and foreign investment was not considered especially necessary. In this environment, Gazprom, for example, can more easily retain its monopoly power given that healthy export revenues limit the need to raise domestic gas prices. This in turn provides little incentive for energy efficiency. If this were to continue, Russia could run the risk of facing an energy security risk as energy production would be hard pressed to match growing consumption. This situation changes dramatically if oil prices drop over the medium term. Russia would then consider it more urgent to reform its fiscal regime, to increase

39. The latest outlook proposed by the Ministry of Economic Development and Trade (MEDT) provides for a 20% growth in natural gas tariffs in 2005, along with a 10% increase in electricity prices and 9% increase in rail rates. The MEDT proposal tapers off after 2005, providing for an increase of 11% in 2006 and 8% in 2007, just slightly higher than their outlook for inflation. In terms of prices, this translates into an average industrial wholesale price of $US 36/trillion cubic metres in 2006 (with VAT).

domestic gas prices (to match the lost export revenues from lower gas export prices), to follow through with plans to restructure the natural gas sector, to stimulate energy efficiency and to attract foreign investment. Enhanced co-operation with the IEA and the OECD at a time when Russia is implementing various key energy sector reforms could encourage Russia to take difficult decisions and not make the same mistakes as IEA countries have made in the past.

OIL SECTOR

Since 1999 Russia has steadily increased oil production from 6.1 mb/d to 8.5 mb/d in 2003. Most of this growth has been from enhancing production at existing fields. Experts continue to question how long Russian oil companies will be able to sustain growth rates based on “low-hanging fruit”. In June 2004, the Ministry of Economic Development and Trade forecast a sharp slow-down in Russia’s oil output growth over 2003-2007, saying that the year-on-year increase could grind to an almost complete halt at 9.5 mb/d in 2007. The problems identified by the MEDT reinforce the concerns IEA has raised over the last few years in terms of the need for more emphasis on exploration and production (as opposed to enhancing existing production) and the need for regulatory and fiscal reform in terms of a more performance-based licensing regime and progressive taxation on resource production to enhance the investment environment. In a high oil price environment, the shortcomings of the Russian fiscal structure are not evident. Until recently, the united stance by international majors that investments in Russia can be undertaken only with Production Sharing Agreement (PSA) terms reinforced the view that the Russian fiscal and legal regime was not attractive and stable enough to warrant long-term investments. The equity investment by BP in 2003 to form a new Russian oil company – TNK-BP – followed by Shell stating its willingness to work without a PSA, should bring new impetus to reform the generic fiscal regime along with Russia’s legal and regulatory regime. In the short to medium term, export capacity constraints are the key problems hampering expansion of Russian oil production. President Putin, in his State of the Nation Address in May 2004, stressed the need for quicker government decision-making on export pipelines and the need to expand export capacity infrastructure. Investments here face the added problem of Transneft’s monopoly power and the lack of transparency in the transportation system, tariff-setting methodology and quality banks.

July 2004 saw an escalation in the battle for control of Russia's largest producer, Yukos. In mid-2004 the company accounted for almost one-fifth of Russia's 9.35 mb/d oil production and held 1.0 mb/d of total Russian refining capacity of 5.5 mb/d. It accounted for 20% of Russian crude exports. Yukos not only faces a $3.4 billion back-tax demand for 2000 and reportedly similar arrears for 2001, but its 2002 fiscal affairs are also under scrutiny. There is much speculation over the fundamental reason – beyond the issue of tax evasion or minimisation schemes – for the government's targeted focus on Yukos and its former CEO, Mr. Khordokovsky. The September 2004 announcement by the Russian government that it supported the concept of merging the state-owned oil company, Rosneft, into Gazprom lends credence to the view that the Russian government is interested in clawing back interest and control in the oil sector. As it stands, the government's share of Russia's production is 7%. This would increase to almost 20% were Yukos or its assets somehow folded back in.

The Yukos situation is troubling in and of itself, but particularly in the context of an oil market whose spare capacity is already stretched. However, sustained disruption to production and exports is in the interest of neither the Russian government nor Yukos. The company could be forced into bankruptcy in the near future, but even then, maintaining operations and revenue flow under administration is likely to be a priority. A more regime-friendly Yukos look-alike may emerge at the end of the day. Foreign companies may defer further forays into the Russian upstream until the dust settles, although both Shell and BP have recently reiterated their confidence in Russia as a partner and place to do business. All in all, despite adding to speculative fears and concerns about short-term market tightness, the Yukos affair seems unlikely to undermine Russia's role as the key driver of non-OPEC supply growth in the short term.

NATURAL GAS SECTOR

An estimated one-third of the world's natural gas reserves remain in Russia's super-giant fields and in smaller fields adjacent to the super-giants. At a high-level Gazprom meeting in Sochi in April 2004, Gazprom's development strategy was discussed. Gazprom officials stressed that to maintain its position as a key gas supplier, it will need to focus increasingly on reserve replacement and exploration. For Gazprom to be able to achieve the targets set in its more ambitious outlook, and increase production levels to 590 bcm/year by 2020 and to 630 bcm/year by 2030, it will need to increase annual reserve replacement on the order of 700 bcm/year to 2015 and 750-800 bcm/year for the period 2016-2030. This is 36% more than 2002 reserve replacement levels, the first year in almost a decade when reserve replacement was anywhere near production in the same year.

Although Gazprom management points to a reversal in trends in terms of efficiency of exploration and development drilling, reserve replacement and a more bullish outlook for production, the three jewels in its current production portfolio – the Medvezhe, Urengoye (Cenoman) and Yamburg (Cenoman) fields with more than 75%, 65% and 54%[40] respectively, of their reserves depleted – are experiencing significant production declines. The latest Gazprom outlook projects reserves at Urengoye and Yamburg to be significantly

40. Russian Energy Strategy, approved by the Russian government in August 2003.

exhausted by 2020 and that by 2030 the recoverable reserves of Medvezhe and Yubilenoye as well as other important fields will be completely exhausted. Fields at Medvezhe, Yamburg and Urengoye, which produced 80% of Gazprom's production in 2001, had dropped to account for only 70% in 2003. The depletion of these three giants has produced a decline in Russia's average daily gas well flow rates of almost 30%, from 400 trillion cubic metres/day in 1990 to 287 tcm/d in 2003.

Production from these three fields is expected to decline at a rate of 7 to 8% over the next five years. The Zapolyarnoye field alone, starting up in 2001 and reaching full production in 2008, will not be able to continue to sustain Gazprom's production levels in the face of the decline at its three major producers. Zapolyarnoye is expected to compensate depletion at other main producing fields for only another five years. In order to compensate for the decline in production at existing fields, Gazprom estimates it will need to start up new gas fields with a total production in the order of 350 bcm/year over the next 20 years.

Clearly Gazprom is facing a steep rise in production costs if it is to develop new fields in deeper strata and/or in the Arctic and other difficult to develop regions. Zapolyarnoye is considered the last relatively cheap gas in Russia. Much of Gazprom's production is currently from Cenomanian reserves with production costs estimated at about $10/tcm. The Russian Energy Strategy presents estimates for development of the Yamal fields in the order of $30/tcm and this does not include investments needed for the related new transportation infrastructure this project will demand. The economics of Gazprom's yet untapped fields are nowhere near as attractive as those of the handful of giant fields already being tapped or those lying beyond Russia's borders in Central Asia – especially if one factors in the geopolitical premium. Were it not for the reserves in Turkmenistan, and to a lesser extent in Uzbekistan and Kazakhstan, there would surely be a more receptive ear from both Gazprom and the Russian government to the growing lobby of Russian independent gas producers and oil companies for more transparent and reliable access to Gazprom pipelines. But because there is gas in Central Asian republics, we are witnessing Russia's rush to conclude agreement after agreement for economic and energy co-operation with them, forming what Russia has called the "gas alliance".[41] Clearly, this relieves pressure on Gazprom to invest in difficult areas to ensure supplies for the domestic and export market. More importantly, this also dampens any momentum for reforming and restructuring the gas sector and providing transparent and stable terms for third-party access for oil companies and independent gas producers. This clearly raises security of gas supply concerns for the future.

41. On 10 April 2003, Gazprom signed a long-term agreement with Turkmenistan for gas purchases of 5-6 bcm in 2004 increasing to 70-80 bcm/year by 2009 out to 2028. Prices are set at $44/tcm until 2006 at which time they will be renegotiated.

ELECTRICITY SECTOR

Russia is the fourth-largest generator of electricity in the world, behind the United States, China and Japan. In 2003 it generated 916 TWh, an 11% increase over the level in 1998, the year which marked the economic turnaround of Russia since the break-up of the Soviet Union in 1991. Thermal generation accounted for about 65% of total production in 2003, with the balance provided by hydro (20%) and nuclear (15%).

Electricity market reform was introduced in Russia through the Government Resolution "On Restructuring the Electric Power Industry of the RF" (No. 526 of 11 July 2001), which set out a three-staged restructuring plan for the sector. The main thrust of reform was set in motion in April 2003 through the adoption of the laws "on Electricity" (FZ No. 35) and "on the Functioning of the Electricity Sector over the Transition Period" (FZ No. 36) and a succession of related laws, amendments to existing laws and regulations. The main objectives of reform were to promote efficient electricity generation, increase price transparency and improve the attractiveness of Russian generation and supply sectors to strategic investors. The legislation envisages a break-up of vertically integrated structures into competitive generation and supply sectors and regulated transmission and distribution.

Effective implementation of the electricity industry restructuring plan is essential for the sector to meet increasing electricity and heat demand. The six laws passed by the Duma and signed by the President in April 2003 are in line with the approach of many OECD countries in unbundling the electricity sector. It is expected to facilitate trade among regions and to form a sound basis on which competition and an open electricity market can build. Effective implementation of these laws over a vague time-frame set to 2009 will depend to a large extent on the strength and independence of federal and regional regulatory bodies to ensure a competitive "level playing field" for competition in all natural resource sectors and the electricity and heat industries. Regulatory bodies will need to ensure fair third-party access to the grid, transparent tariff-setting based on full costs, as well as clear licensing rules for new players in the markets. The large share of gas-fired electricity generation also raises the importance of Russia realising its commitment to increasing gas prices to cost-reflective levels, especially during this period of gas-fired capacity.

ENERGY EFFICIENCY AND THE ENVIRONMENT

With the current outlook for stronger economic growth, more effective implementation and funding for environmental protection will become possible. This is critical if the country is to limit the environmental damage inherent in meeting increased energy demand. As party to the Annex I group within the framework of the UNFCCC, Russia has committed itself to implement policies to limit GHG emissions and to enhance sinks and reservoirs. If it were to ratify the Kyoto Protocol, the Protocol would come into force and Russia would be committed to stabilising emissions of six greenhouse gases at 1990 levels by 2008-2012. In July 2003, during the UNFCCC Review of Russia's Third National Communication,[42] the Russian government was considering the ratification of the Kyoto Protocol and the possible implications of climate change policy on President Putin's goal to double Russia's GDP within a decade. There is a concern that ratification would limit Russia's ability to meet the ambitious economic target. In the framework of May 2004 EU-Russia meetings on accession to the WTO, President Putin promised to accelerate examination of the issue of Russian ratification. On 30 September 2004, the Cabinet of the government decided to approve the Protocol and submit it to the Parliament (State Duma) for ratification. It reflects the recognition that the Protocol could provide added investments through its mechanisms to aid Russia in its goal to enhance energy efficiency, reduce energy intensity and ensure its energy security during this period of expected rapid economic growth. The fate of the Kyoto Protocol now hinges upon its ratification by the State Duma, which remains to be seen.

CASPIAN AND CENTRAL ASIA

Central Asia and the Caspian Sea region is rapidly becoming an important new oil-producing province. Situated at the crossroads of major oil producers Russia and the Middle East, the region looks to European and Asian markets that are eager to diversify supply. Even though Caspian and Central Asian oil and gas export volumes are only marginal compared to the dominant export potential of neighbouring oil and gas producers, unrestricted exports to world markets is of critical importance to:

- Spur economic development and regional co-operation.
- Diversify supply to import-dependent markets.
- Rationalise production transport and consumption by stimulating competition and market disciplines.
- Offset decline rates in mature production provinces.
- Increase efficiency of capital and technology.

For these reasons, the once landlocked republics of the former Soviet Union, now independent states of Central Asia and the Caspian Sea, are gradually becoming key players on the international oil and gas scene.

42. See http://unfccc.int/resource/docs/idr/rus03.pdf

The independent states of the Caspian Sea and Central Asia offer new strategic opportunities. During the first decade of their independence, Kazakhstan and Azerbaijan have made successful policy choices which have enabled international oil and gas companies to invest in their vast upstream resources. Today, these successful investment promotion and market reform policies offer a model for other Central Asian and Caspian states to follow.

The strategic oil potential is beneficial for the Caspian region and importing countries alike. Caspian and Central Asian states have successfully capitalised on the upstream hydrocarbon potential and their new-found sovereignty, achieving rapid economic growth. Equally, it has provided both IEA member countries and international oil and gas companies with an opportunity to diversify supply sources and ensure stable flows of oil and gas to world markets, offsetting import dependence on mature oil and gas provinces and adding resources to their reserve base. The stability of these strategic contracts will be a determinant factor that will shape the conditions for next generation investment.

Establishing transparent and fair terms for access and transit as well as new cross-border infrastructure facilities to transport oil and gas to international market outlets on competitive terms remains an important factor in mobilising next generation investment. It will also provide the rationale for ongoing economic integration both among countries of the Caspian Sea and Central Asia as well as with key adjacent states. Transport options to international markets remain the key driver for assessing the value of upstream assets in Central Asia.

Much progress has been made. The construction of the Baku-Tbilisi Ceyhan oil pipeline that may ultimately carry Central Asian oil and of the Baku Tbilisi Erzerum gas pipeline stimulates more competitive terms for westbound transport of oil and gas via dominant transport routes. Plans to access Eastern demand markets through a Trans-Kazakhstan oil pipeline that links Northwest Kazakhstan to China or through a Trans-Afghan gas pipeline that links the vast gas reserves of Turkmenistan with demand markets of Pakistan and India may further instil market disciplines and economic integration along eastbound transport and trade options. Ultimately, this will serve the economic prosperity and political stability of Caspian and Central Asian states and underpins sustainable oil and gas export to world markets.

Ten years down the road, rapid developments in Kazakhstan alone have seen a threefold increase in oil production. As a consequence of this success, perceptions of the balance of risks and rewards between new foreign investors and host governments of Caspian and Central Asia are shifting. Macroeconomic considerations appear to influence conditions proposed for second-generation investment and may come to prevail over the fairly straightforward investment promotion policies that characterised the success of the first-generation investment. Kazakhstan, which boasts a positive investment grade rating various investor services, is testing its international market value by adjusting the balance of benefits for new potential investors, notably in the framework of the State Programme for the Development of the Kazakhstan Sector of the Caspian Sea. In this sense, it is in competition with newly emerging independent production provinces in north-west Africa and Latin America. In a volatile international oil and gas market, potential investors will be studying these newly proposed terms carefully when making their investment decisions.

Kazakhstan is enforcing market regulation with more rigour to avoid alleged abuse of its dominant market power, allowing for more transparent and accommodating access to transport infrastructure, including rail and port facilities. It protects national interests, through, for instance, tightening of transfer pricing, local content requirements and environmental rules. Other Caspian and Central Asian states have slow-tracked market and democratic reforms. As a consequence, disparities among Caspian and Central Asian states may adversely affect investment decisions by international oil and gas companies that assess the region in its entirety.

Finally, there is an increasing awareness among the vast majority of the region's government and corporate officials that new policies need to maintain a macroeconomic balance between the pace of growth in the oil and gas sector and that of other economic sectors. This would alleviate boom and bust cycles and other adverse economic effects of specialisation on petroleum sector development such as "Dutch Disease".

International oil and gas companies as well as home and host governments are subject to ever more stringent public and private accountability standards. Scrutiny by electorates, shareholders and the media, along with the engagement of interest groups from civil society that is driven by unprecedented access to information networks, means that good public and corporate governance disciplines, ranging from transparent revenue management to environmental standards will by themselves determine share value and host-country attractiveness to investors. As a consequence of market liberalisation, economic integration, democratisation and globalisation processes, good public and corporate governance disciplines will be more universally applied. In turn, productive Trans-Caspian and Central Asian co-operation will become of increasing importance. The Central Asian Economic Co-operation Organisation and the Shanghai Co-operation Organisation are important complements to policies directed at accession to the World Trade Organization to help integrate Caspian and Central Asian states into the global economy. While Armenia, Kyrgyzstan and Georgia have completed their accession to the WTO and Kazakhstan, Russia, Azerbaijan, Uzbekistan and Tajikistan are in their accession phase, Turkmenistan has yet to apply for membership.

CENTRAL AND SOUTH-EASTERN EUROPE

Membership in the European Union (EU) and preparation for membership largely influence the energy scene in the region.

On 1 May 2004, ten countries[43] became effective members of the EU, with the following implications on their energy scene:

- Effective implementation of transposed directives and participation in the EU legislative and executive process.
- Progressive integration of their markets into the EU internal energy market (all trade restrictions were lifted).
- Possible co-funding of investment, including for energy efficiency and renewables projects by the EU structural regional funds.
- Enforcement of competition rules, including for mergers and acquisitions.
- Direct EU monitoring of nuclear safety and planned decommissioning of least safe nuclear plants (Ignalina in Lithuania by 2009, Bohumice 1 and 2 in the Slovak Republic by 2006/2008).

With the enlargement, the EU-25 incorporates a greater energy transit dimension, as the new members transit 25% of its natural gas and about 10% of its crude oil supplies.

The new member states depend largely on Russian oil and gas supplies but have diversified energy import sources and routes, as well as the fuel mix, and have reduced their energy intensity. However, non-IEA countries' oil security systems (storage and emergency plans) do not yet comply with EU and IEA standards.[44]

The potential for energy efficiency remains high, and offers multiple economic, environmental and social benefits at low cost. Voluntary energy efficiency governmental policies with adequate resources are required to stimulate awareness, initiatives and investment in co-ordination with EU energy efficiency and climate change policies, regulation and programmes.

Regulatory reforms aim to align with the EU directives, in particular for the internal electricity and gas markets which need cost-reflective pricing of transmission and final products, and transparency. The opening of the electricity markets to competition has been initiated but has remained constrained by the dominance of vertically integrated companies (in some cases privatised), long-term contracts, baseload overcapacity and persistent price distortions.

43. The Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Slovakia, Slovenia, Malta and Cyprus.
44. Links to EPPD and EU DG TREN web pages.

In Poland, the restructuring of state-owned energy companies has focused on the legal unbundling of electricity and natural gas transmission companies and regional consolidation of electricity distribution companies. The privatisation process is expected to continue in the oil sector (Lotos Group-owned Gdansk refinery), power and heat generation, and the gas holding (POGC Group).

The government has continued its efforts to develop a plan to phase out long-term electricity contracts (60% of sales), which largely prevent an effective market opening.

Gazprom's decision to suspend gas delivery and transit to Belarus and by extension to Poland on 19-20 February 2004 prompted the Polish government to increase Norwegian import volumes from the current level of 0.5 bcm/year to 1-2 bcm/year by 2006 and to increase gas storage capacities.

In 2004, the Slovak government continued its ambitious energy reform plan. Efforts have focused on price reforms, unbundling of electricity transmission and distribution as a preparation for market opening. Most of the state-owned companies have been either fully privatised (oil refiner Slovnaft to MOL) or partially (gas monopoly SPP to Gaz de France-Ruhrgas consortium,[45] three electricity distributors to Western utilities, oil pipeline company Transpetrol to Yukos). The privatisation of SE, the power generation company, is continuing, though the issue of stranded costs and nuclear assets remains. The threshold of 49% for privatisation has been increased to 67%.

To establish its major role for gas transit, Slovakia is also developing its electricity and oil transit. Oil projects using the Transpetrol-operated Druzbha pipeline include the DruzhbAdria pipeline (Russian exports to Croatian Sea terminal), Bratislava-Swchewat OMV refinery and the Odessa-Brody/Czech Republic. However, the persistent turmoil surrounding Yukos, a 49% shareholder of Transpetrol, and the uncertainties around the commercial use of Odessa-Brody have raised questions on the implementation and timing of these projects.

The four Visegrad countries[46] have developed a regional co-operation organisation[47] and envisage further electricity and gas market openings to develop a regional market, including through a regional power exchange in the context of the EU-25. Nevertheless, the recent appearance and rapid extension of off-shore electricity and gas trading companies in the region and beyond have raised issues of transparency and fair competition.

In south-east Europe, Bulgaria, Romania and, since June 2004, Croatia, are currently EU candidate countries.

45. Gazprom extended its option to join the consortium by the end of 2005.
46. Czech Republic, Hungary, Poland and Slovakia.
47. Visegrad Energy Group: www.visegrad.org and TSO Regional Association CENTREL: www.centrel.org

The Bulgarian government has continued its ambitious energy reforms that are guided by the 2002 energy strategy. Projects include continuous price adjustment, new efficiency strategy and legislation, restructuring and modernisation of energy companies. Privatisation of the three regional electricity distributors attracted large interest from international investors[48] despite a depressed international investment environment.

Similarly, Croatia bases its reforms on the 2002 energy strategy and has focused on regulatory reforms and restructuring of the vertically integrated electricity and gas companies. The sale of 25% of INA, the national oil company, was awarded to MOL.

Romania, the second-largest country in the region, has consolidated the restructuring and unbundling of its electricity and gas companies as well as establishing the conditions for market opening prior to the privatisation of electricity and gas regional distributors. OMV acquired Petrom, the major domestic oil refinery. The government chose Ruhrgas and Gaz de France to purchase the two natural gas distribution companies, Distrigaz Nord and Distrigaz Sud, respectively.

Western Balkan countries have still to catch up with other countries in the region in designing coherent energy strategies, reliable energy data systems and solid institutional structures to implement thorough and sustained reforms. These national efforts, together with the support of donors within the Regional Energy Market/Athens process, should contribute to attaining the market conditions required to effectively and transparently open the electricity markets at domestic and then at the regional levels.

Progress has been made on the possible development of gas diversification for Europe from the important gas reserves in the Caspian and the Gulf. The commercially supported projects of the Turkey-Greece-Italy interconnector and Nabucco (Turkey-Austria) have progressed well and should increase medium-term additional supply security, market efficiency and transparency in South-East, Central and Western European gas markets.

MIDDLE EAST AND NORTH AFRICA

LIBYA

Libya's current proven oil reserves of 36 billion barrels make it the holder of Africa's largest petroleum resource base. With 14 oil fields holding reserves of up to 1 billion barrels each, and only around 25% of the country covered by oil companies, Libya is considered to be largely unexplored. Despite the fact

48. Potential winners include Austrian EVN, German EoN, Italian ENEL and Czech CEZ.

that oil exploration in Libya began in 1955, the underdevelopment of the resource base is generally attributed to the combination of United Nations and United States sanctions and inflexible fiscal terms for international oil companies.

The lifting of UN sanctions in September 2003, the phased lifting of US economic sanctions, completed in September 2004 following Libyan steps to eliminate weapons of mass destruction, and planned changes to Libya's 1955 hydrocarbon legislation to allow the introduction of advanced technology and foreign capital could, however, be conducive to increasing the country's oil output which averaged 1.48 mb/d in 2003. Stringent fiscal terms imposed on international oil companies in 1970 led to a significant decrease of Libya's oil field investment and oil production, sliding from 3.3 mb/d in 1970 to 1.5 mb/d five years later. Although oil production rose to 2.1 mb/d in 1979, production averaged a mere 1.2 mb/d throughout the 1980s, rising to 1.4 mb/d in the 1990s. Libya's current objective of increasing oil production capacity from just under 1.5 mb/d to 2 mb/d by 2010 is estimated to require $30 billion in foreign investment. On 16 August 2004 Libya's National Oil Company (NOC) announced "EPSA IV", a new round of bidding for the award of exploration and production sharing agreements under revised terms. Fifteen areas are on offer: one in Cyrenaica, two in the Ghadames basin, three each in the Murzuq and Sirte basins, and six offshore. The announced schedule contemplates the submission and opening of sealed bids on 10 January 2005, and the signing of agreements during the second half of January. In an effort to shore up production levels, Libya plans to attract the majors, independent oil companies as well as oil field service companies that can help improve the recovery of its oil from wells that are already producing. In view of the country's dependence on oil revenues, accounting for over 95% of its hard currency earnings, the shift towards encouraging further foreign firm access to the oil sector, thus spurring production and the transfer of technology, is not surprising. Considering the lack of spare capacity among member countries of OPEC, access to Libyan resources, even if slow and gradual, could be a significant development. Libya may follow the example of its neighbour and fellow OPEC member Algeria, which has gradually positioned itself as an important player in the energy scene by opening its sector to international investment and diversifying into natural gas exports both in piped and LNG form. Political stability and good governance remain, however, prerequisites for such a major development.

PART 2

THE COUNTRY REPORTS

IN-DEPTH REVIEWS: SUMMARIES

This chapter contains summaries of the findings and full list of recommendations of the 2003/2004 in-depth reviews for the following countries. The summary of **Luxembourg is not included here as the report will only be reviewed in the October 2004 SLT meeting.** The findings and recommendations reflect the situation when the report was drafted and finalised. The full reviews have been published separately.

CANADA

Team visit: November 2003; approval at the Standing Group on Long-Term Co-operation (SLT): March 2004.

FINLAND

Team visit: March 2003; approval at the Standing Group on Long-Term Co-operation (SLT): October 2003.

FRANCE

Team visit: January 2004; approval at the SLT: June 2004.

LUXEMBOURG

Team visit: April 2004; to be approved at the SLT: October 2004.

NETHERLANDS

Team visit: November 2003; approval at the SLT: March 2004.

PORTUGAL

Team visit: January 2004; approval at the SLT: June 2004.

SWEDEN

Team visit: October 2003; approval at the SLT: February 2004.

CANADA

Endowed with large reserves of conventional and non-conventional oil and gas, coal, uranium and hydro, Canada is among the world largest producers of most types of energy and one of the IEA's largest energy exporters, principally to its neighbour, the United States. Marked differences among provinces and territories in terms of climate conditions and primary energy endowments, combined with a fast growing population and a strong and dynamic market economy, have impacts on energy demand and supply and raise a number of challenges for energy policy formulation and implementation.

Canada's constitution limits responsibilities of the federal government with regard to energy to international matters and inter-provincial issues and the management of uranium resources. The federal government is responsible for promoting the overall economic development of Canada. It is also responsible for preserving national interests such as environmental protection or the reduction of provincial economic disparities. Provinces have more jurisdictions over energy than the sub-national governments of other federal countries in the IEA. The only viable approach in addressing the most important energy policy challenges seems to be a process of intensive dialogue and consultation to achieve a national consensus on the goals and means of energy policies, but this process takes time. Such a process should cover areas such as climate change mitigation, streamlining regulatory regimes for new investment of energy production and transport, expansion of inter-provincial electricity interconnections, and research and development (R&D).

The federal government is to be commended for its efforts and achievements in formulating the National Climate Change Plan for Canada in November 2002. However, living up to Canada's commitment to the Kyoto Protocol, moving to a less emission-intensive economy and at the same time ensuring continued growth is the biggest single economic and political challenge for Canadian energy policy in the coming years. Curbing greenhouse gas (GHG) emissions is challenging because of the rapid expansion of energy production and exports. Since some provinces are clearly more emission-intensive than others, their support for the ratification of the Kyoto Protocol in December 2002 was not unanimous. Co-operation between the federal and provincial stakeholders is essential if Canada is to move forward with climate change policy implementation. While Canada has a large range of policies and measures to address climate change, the federal government's approach is largely based on fiscal and regulatory measures. Reflecting the concerns of the industrial sector competing with US industry not bound by the Kyoto Protocol, the carbon price to Large Final Emitters under the covenant and trading scheme is capped. This could weaken the incentives for companies to invest in GHG emissions mitigation measures. Linking the emissions trading system with another region is being explored with a view to reducing carbon cost.

While Canada is highly energy-intensive owing to various structural factors, it has made significant improvements in increasing both the visibility of its energy efficiency policies and the systematic efforts to seek efficiency improvements in all sectors. Canada holds an excellent record in measuring, reporting and monitoring energy efficiency. Most importantly, measures are in place to constrain the growth of Canada's energy intensity. Nevertheless, Canada has at present the capacity to set more ambitious and sectoral energy efficiency goals and the ability to achieve them. Market-based measures, including fiscal incentives to increase more fuel-efficient vehicles could be explored in this direction. Close consultation between the federal and provincial governments is essential.

Although the old oil fields display a rather high decline rate, higher levels of exploration and production drilling of bitumen and synthetic crude oil from oil sands and east coast offshore have managed to keep production levels growing. To tap the potential of domestic resources further, exploration of areas under moratorium could be evaluated, taking relevant measures to maintain an adequate protection of the environment. There seems to be sufficient pipeline capacity to carry the current oil production to the refineries and the markets, but there may be concerns in the near future unless sufficient capacity is added. The production of unconventional oil from oil sands, which is growing rapidly, offers significant potential with a good economic margin. However, the huge forecast expansion in oil sands output will have local environmental impacts and contribute significantly to growth in Canada's greenhouse gas emissions because of the high energy input (from gas) to produce synthetic crude. Development of technologies to reduce emissions and the need for local natural resources such as gas and water is essential.

The Canadian gas sector is driven by competition upstream and is tightly integrated with the US market, with large volumes of Canadian gas exported to the US and Canadian gas prices determined in the larger North American market. The drilling level is high and the resulting increase in production, while disappointing, is sufficient to maintain supplies for domestic consumption and significant levels of exports over the long run, but not sufficient to allow for long-run export growth. Large and yet unexploited resources exist, but additional efforts are required in the future to stimulate production. Beyond possible external gas supply in the form of liquefied natural gas (LNG), possibilities to open the areas under moratorium should be considered. Resources of coal-bed methane (a form of non-conventional natural gas) have begun to be explored. The tax regime applied to coal-bed methane exploitation could be reviewed to facilitate its development.

Well-developed infrastructures within Canada and between Canada and the US create an integrated North American market for natural gas. Competition is well advanced. The regulatory environment in Canada has been stable, thereby creating trust by investors. However, within the regulated pipeline sector, different rates of return and risk between Canada and the US affect competition for investment between the two countries. In addition, setting up long pipelines requires numerous authorisations as these projects overlap jurisdictions. These factors could deter investors. Where jurisdictions overlap, the National Energy Board is working with provincial and territorial regulatory agencies to ensure that environmental assessment and regulatory issues are dealt with in a co-ordinated manner. Close co-operation with other regulatory agencies, wherever possible, and streamlining regulatory processes by using a single location for all administrative approvals should be pursued.

Although hydro remains the largest potential for renewable energy in Canada, large hydroelectricity projects (beyond 10 MW) are increasingly difficult to set up because of local environmental opposition. Given Canada's large potential, hydroelectricity should receive more attention. Recent years have witnessed a development of new and emerging renewable energy from wind or biomass. The main measures taken to support and guide the development of renewable energy in Canada are subsidies under various programmes. However, care should be taken to build in incentives for cost reduction in these subsidy programmes to ensure better cost-effectiveness than a flat subsidy scheme. Government efforts to maximise economic efficiency of the support scheme and to consider the advantage of market mechanisms are commendable. An *ad hoc* Federal-Provincial-Territorial Renewable Energy Working Group is now considering new measures to promote renewable energy, including the introduction of a renewable portfolio standard. It is also noteworthy that several provincial governments are also assessing the potential benefits of introducing portfolio standards.

Electricity in Canada is under provincial jurisdiction, except inter-provincial trade and international trade with the US. Nevertheless, with a view to improving overall competitiveness of the Canadian electricity industry and hence the Canadian economy, the federal government has to play an important role in several key policy issues. One of them is a growing interconnection between Canada and the US electricity markets. The grid failure of August 2003 demonstrates the need for more co-ordination and joint actions between the federal governments, provinces and their counterparts in the US with a view to ensuring reliability of electricity supply. Another issue is the development of Canadian domestic electricity markets through increased interprovincial transmission networks. When limited to provinces' boundaries, the supply-demand balance assessment cannot lead to cost-effective investment decisions. The federal authorities have to play their role to avoid this difficulty. While an east-west high-voltage link has yet to be proven economic, a larger integration of regional power systems is worth investigating. Further development of inter-provincial and international electricity trade could ensure effective competition. Close co-operation between the federal and provincial governments is the prerequisite.

The provinces have been taking the lead role in electricity market reform. They generally consider reform of the electricity sector to be necessary and are addressing the issues. However, reform progress differs among provinces according to their specific circumstances, such as the potential for competition, potential stranded assets and interconnections with other jurisdictions. Alberta and Ontario have competitive wholesale electricity markets and have introduced some amount of retail competition. Québec, Manitoba and British Columbia introduced wholesale competition while other provinces and territories continue to be supplied by one utility.

Electricity market liberalisation has sometimes been accompanied by increased price volatility. Measures taken in Ontario and Alberta to cope with electricity price hikes provide useful insights, in particular in terms of price volatility, investment and government intervention. To reduce the impact of a price hike on consumers after the market opening in 2002, the Ontario government capped retail prices for about half of the market at a price well below the cost of power and the entry cost of new plant. This has resulted in higher government subsidies and reluctance of investors to move into the Ontario market. The Alberta government, on the other hand, established a price cap at a relatively high level to preserve the signal for new investments to cope with price volatility. Investment in new generating capacity, which had been keeping pace with growth in peak load, is continuing. Such experiences could be shared in the federal and provincial co-operation process, and a consensus on effective mechanisms to mitigate the price volatility for households could be explored. While depending on provincial decisions, the federal government could also play a role in improvement of demand-side response with a view to reducing the extreme price volatility.

Canada's nuclear power programme is at a critical point in its history. While newer plants are performing satisfactorily, some of the old plants are experiencing significant problems in refurbishment. For example, the refurbishment of Pickering A Unit 4 resulted in significant cost and schedule overruns. An official review has identified many problems related to project management. Canada should not forgo potentially attractive nuclear generation and the federal government should explore barriers to the attainment of maximum economic generation from the existing shut down plants and help overcome the obstacles, consistent with safety considerations. At the same time, noting that Canada has a wide range of energy sources at its disposal for the generation of electricity, it seems appropriate for the federal government to evaluate the costs and benefits of deploying new nuclear plants in the future, in particular with regard to the environment and the benefit of further diversification of power generation in Canada.

The federal and provincial governments are making commendable efforts to pursue energy R&D. Since 1999, the federal government R&D budget has been increasing, which is in line with the policy goals to make Canada a strong knowledge economy. The announcement by the federal government on multi-year R&D programmes to cope with GHG emissions is also a positive development. Under the complexity of the funding structure, the federal government is establishing a comprehensive priority-setting process involving key stakeholders. Appropriate transparency in the decision-making process has been sought, supported by information exchange on activities and results achieved. Such efforts should be further enhanced.

RECOMMENDATIONS

The government of Canada should:

General Energy Policy

- *Take a more active role in initiating co-operation between federal, provincial and territorial governments with a view to formulating national consensus on the goals and implementation of energy policies, where mutually beneficial,* e.g. *through the Council of Energy Ministers and bilateral and regional meetings of ministers and high officials. Where applicable, the utilisation of the fiscal and regulatory instruments within federal jurisdiction could be explored to this end.*
- *Continue to ensure that the fiscal and regulatory environment is sufficiently competitive on an international basis to bring forward the necessary investment in the energy sector.*
- *Review energy data-reporting mechanisms to enable timely and comprehensive supply of data to policy-makers, analysts and international organisations.*

Energy and the Environment

- *Increase co-operation with provinces and territories to implement the National Climate Change Plan, and in particular to develop the range of market incentives based on climate change policies. Promote the integration of energy and greenhouse policy objectives across federal and provincial governments.*
- *Undertake emissions projections and analyses for existing climate change measures as a matter of priority to allow adequate time for the identification of necessary further policies and measures.*

- *Investigate the possibility of strengthening and broadening the price signal for GHG emissions to ensure that new energy investment decisions reflect environmental considerations.*

- *Investigate further the potential of low emissions technology, and in particular CO_2 capture and storage, and the possibility of providing appropriate economic signals to encourage their development.*

Energy Efficiency

- *Continue to assess the potential for energy efficiency improvements in all Canadian energy producing and consuming sectors.*

- *Consider developing a new set of sectoral efficiency goals associated with the introduction of market-based incentives to increase the uptake of efficient practices and enable structural change across sectors.*

- *Investigate and implement stronger measures to accelerate the shift towards more efficient motor vehicles.*

- *Enhance the consultation process between the levels of the federal government and provinces and territories in order to develop a comprehensive strategy for energy efficiency.*

Oil

- *Evaluate the possibility of opening areas now closed for exploration and production, taking relevant measures to maintain an adequate protection of the environment (*e.g. *offshore British Columbia).*

- *Continue to facilitate the increase of oil sands production through fostering research and development on processing technology and environmental issues such as water treatment and CO_2 emissions reduction.*

- *Actively pursue the process to reduce the inconsistencies in regulations between the Atlantic provinces for offshore activity.*

Natural Gas

- *Consider reviewing the tax regime to ensure the level playing field between conventional and unconventional gas to facilitate the exploitation of coal-bed methane.*

- *Continue reviewing the possibility of opening areas now closed for exploration and production, taking relevant measures to maintain an adequate protection of the environment (*e.g. *British Columbia).*

- *Investigate whether it is possible to streamline the pipeline approval process so that all the stakeholders are taken into consideration in a more efficient way. Promote the concept of a one-stop shop for regulatory approvals.*

- *Explore, in co-operation with the provincial regulatory authorities, the possibility of offering household customers an option to automatically be hedged against price volatility.*

Renewable Energy Sources

- *Investigate further advancement of hydroelectricity.*

- *Consider new market-oriented incentives to promote renewable energy.*

- *Continue to facilitate production and use of renewable energy and concentrate its development and deployment on niche markets and high-value applications (*e.g. *energy supply to remote areas).*

Electricity and Nuclear

Electricity

- *Work together with the provinces to ensure reliability of electricity supply, addressing the implications of increased physical and trade links with the US and the effects of ongoing market reform on grid design, operation and information flow between North American system operators and between other market participants.*

- *Analyse, in collaboration with the provinces, the costs/benefits of increased electricity links between different Canadian provinces with regard to improving reliability of electricity supply and creating larger electricity markets. Analyse what instruments would best promote such benefits.*

- *Set up a process of consultation with the provincial administrations and regulators, and the electricity supply industry to promote a consensus on the further advancement of electricity market reform compatible with US and Canadian electricity market developments. Co-ordinate with other policy objectives, such as environmental and industrial objectives, in order to ensure timely investment in new generating capacity.*

- *Foster the simplification of regulatory processes required for the authorisation of new power capacity and power lines.*

- *Address ways to improve demand-side response by all market participants. Analyse the effects of market opening on household consumers and find ways to protect households from electricity price volatility for those who do not wish to participate in the market.*

Nuclear

- *Explore barriers for the attainment of maximum economic generation from existing nuclear plants, including the return of plants currently shut down, consistent with safety considerations. To this end, consider promoting more competition in the Canada Deuterium Uranium reactor (CANDU) plant operation and refurbishment.*
- *Evaluate the costs and benefits of adding new nuclear capacity with particular regard to the environment and diversification of power generation.*
- *Maintain under critical review the potential for the deployment of the Advanced CANDU Reactor (ACR).*
- *Maintain the option to deploy nuclear power plants in the future, irrespective of the success of the Atomic Energy of Canada Ltd. (AECL) in marketing ACR.*
- *Continue plans and intentions to identify and pursue the optimum means for the long-term management of irradiated CANDU fuel in Canada.*
- *Increase third-party liability of nuclear operators to reflect the kind of liabilities already established in other developed Western countries.*

Energy Research and Development

- *If possible, avoid the kind of budget cuts in energy R&D that occurred in the late 1990s and maintain recent upward nominal trend.*
- *Increase further the profile of government R&D support by stronger prioritisation and concentration on a comprehensive view on key technologies.*

FINLAND

Finnish energy policy is characterised by three commendable traits. One, Finland employs a holistic approach to energy. Its energy policy strives to simultaneously pursue the three E's – Energy security, Economic development and Environmental sustainability. This approach is apparent in the effective communication on energy policy issues between the various ministries and energy programmes which pursue numerous policy goals in tandem and act in concert rather than in conflict with one another.

Two, Finnish energy policy successfully employs international trade to lower energy costs and enhance energy security. Finland's lack of substantial domestic energy resources requires significant imports. Efforts to import fuels and electricity from a variety of countries provide Finland with a diverse energy supply, which lowers costs and enhances energy security. As part of the Nordic Power Market (Nordpool), Finland has successfully integrated its electricity market with those of the Scandinavian countries.

Three, Finland applies a light-handed approach to energy regulation. Its electricity sector is one of the least regulated in the world, with companies free to build power plants as they wish and all customers free to choose their supplier. Most of the regulation is done *ex post*, meaning that companies that own and operate assets still considered to fall under regulatory review, such as electricity networks and district heating suppliers, have significant leeway to set their own tariff structures. While this approach has been successful overall for Finland, this in-depth review identifies a few selected areas where regulatory authority could be expanded.

The most important energy development since the last in-depth review four years ago is the development of a new nuclear power plant, scheduled to come on line in 2009. While Finland already has two such facilities – providing 30% of the country's power generation with four reactors – the new plant would be the first nuclear facility built in a liberalised electricity sector. In May 2002, the Parliament ratified the government's earlier decision-in-principle in favour of the plant. While this decision implied neither state guarantees for the plant nor a specific endorsement of the project, it did allow the development of the project to proceed.

This new nuclear facility could help Finland meet its need for new generating capacity without producing new greenhouse gases (GHG). However, nuclear facilities worldwide have in the past faced cost overruns and delays, so the government is encouraged to closely monitor the progress of the plant and be prepared to provide alternatives for both electricity capacity and GHG mitigation should delays or other obstacles arise.

Under the Kyoto Protocol, Finland has agreed to keep its GHG emissions at 1990 levels during the 2008-2012 target period. Initial assessments indicate that emissions were 9% above 1990 levels in 2002. This anomalously high figure could be the consequence of low availability of hydroelectricity during the year. Nevertheless, measures will have to be implemented to address this issue given that business-as-usual projections by the government indicate further increases in GHG, reaching 15% above 1990 levels during the first target window.

In June 2001, the Parliament passed the National Climate Strategy (NCS) to curb GHG emissions. The NCS focuses on domestic measures as the best way to reduce Finland's GHG emissions, and includes an impressive array of programmes in all emission-producing sectors. While domestic emissions cutting measures do present a number of advantages, Finland should also rigorously explore the use of international mechanisms, especially emissions trading. This is particularly true given the high variability of Finland's emissions owing to climatic reasons, such as hydro availability and heating needs in the winter. If emissions are higher than predicted during the Kyoto window, it will be too late to employ domestic measures, which take years to implement. Consequently, international mechanisms will be essential and their optimal utilisation should be implemented in a timely manner. Large emissions cuts are expected to come from the proposed nuclear plant coming on line in 2009. However, if the plant is delayed, Finland will need to rapidly cut substantial emissions, and international mechanisms are well suited for this purpose. International mechanisms may also provide Finland with a lower-cost alternative to cutting emissions than the exclusive use of domestic measures.

Energy security is particularly important for Finland. On the supply side, the country lacks substantial domestic fossil fuels and its geographical position limits the amount of energy interconnections it can feasibly construct. While imported fuels do not necessarily imply greater risk than domestic fuels, high import levels do require monitoring. On the demand side, the country's cold climate and the significance of its energy-intensive industry make the reliable supply of energy particularly important.

Finland has responded well to its energy security challenges. It has emergency stocks of imported fuels corresponding to five months' average consumption (or import) based on the Security of Supply Act, which is far beyond the IEA stock obligation in terms of volume and coverage. Finland has a diverse mix of primary energy supplies, with five different fuels contributing at least 10% to the country's total primary energy supply (TPES). Finland relies on market mechanisms to ensure that sufficient electricity capacity is available. The electricity market will be tested in the coming years as new capacity will be required. The government should monitor this situation and respond if the market is incapable of adding the needed plant. The extensive use of fuel-switching for natural gas also enhances energy security. While all natural gas is imported from just one source (Russia), extensive fuel-switching capabilities and the compulsory oil stocks to replace natural gas in the event of disruption help to mitigate this exposure.

Renewable resources give Finland substantial emission-free domestic energy sources. Biomass and hydroelectricity account for 20% and 3% respectively of the country's TPES. The government is using a number of support programmes with the objective to increase the use of renewable energy by 30% by 2010. While this can benefit Finland, the support schemes could be rendered more effective, and perhaps less costly, through a more market-based approach. This is particularly the case for the investment subsidies the government spends to encourage specific types of renewable energy.

RECOMMENDATIONS

The government of Finland should:

Energy Market and Energy Policy

- *Continue the country's holistic approach to energy policy, including the strategy of pursuing numerous goals in tandem and with successful co-ordination between relevant ministries.*
- *Continue to expand the international approach to reaching energy policy goals, particularly regarding interconnections and the most cost-effective means of meeting climate change obligations.*
- *Enhance the energy regulator's role through expansion of staff and budget, especially for electricity transmission and distribution and for district heating, in order to further improve the efficiencies of these sectors.*
- *Continue to augment the country's energy security of supply through emergency preparedness, market mechanisms in the electricity sector, fuel diversity and fuel-switching capabilities.*

Energy and the Environment

- *Proceed with the implementation of the energy efficiency and renewable energy elements of the NCS in order to effect the needed changes by the time of the first Kyoto commitment window.*

- *Continue to undertake energy supply-demand and CO_2 emissions projections, evaluate the progress of the NCS and update it as required to achieve the Kyoto target in the most cost-effective manner.*

- *Closely follow the development of the fifth nuclear power reactor and consider alternative emissions reduction plans in the event that the planned nuclear facility does not come on line in the expected time frame.*

- *Review the package of measures on the supplementary role that emissions trading can play, particularly regarding potential overlaps with domestic measures.*

- *Determine a framework for allocation of emissions allowances in the relevant sectors as soon as possible.*

- *Assess the advantages, particularly in terms of cost-effectiveness, of the application of joint implementation and clean development mechanisms.*

Energy Efficiency

- *Study the issue of cross-subsidies between district heating and electricity operations, and evaluate possibilities to improve transparency and competition in the district heating sector, starting with large heating networks. Consider the possibility of extending Energy Market Authority jurisdiction over the district heating sector.*

- *Expand the analysis of the energy efficiency aspects of heating choices in new residences.*

- *Examine the legal, economic and technical possibilities for developing heat metering in individual apartments that are currently billed according to static indicators on consumption, often with a flat fee.*

- *Review the use of voluntary agreements for industry in light of the European Union directive on emissions trading. Consider more stringent energy conservation targets in the agreements.*

- *Consider introducing more sophisticated economic signals that would favour a more fuel-efficient private car fleet, for example through an annual circulation tax or taxes on acquisition.*

- *Continue to encourage combined heat and power (CHP) production and new investment, especially for plants fuelled with renewable energy.*

Renewable Energy

- *Evaluate the existing support scheme for renewables with the aim of developing a market-based system that will achieve emissions reductions at a minimal cost and give incentives to reduce production costs from renewables.*

- *Take measures to simplify and accelerate licensing and appeal procedures of wind and small hydropower plants.*

- *Explore measures to increase the economic supply of biomass.*

Fossil Fuels and Peat

- *Continue to value peat for its energy security advantages, while taking into account its costs and environmental implications.*

- *Continue the policy of non-interference in the oil markets, combined with effective anti-trust oversight.*

- *Explore the use of different methodologies to establish natural gas tariffs.*

- *Examine opportunities to expand the unregulated secondary gas market as a means of gaining more experience with competition in the sector and promoting, where possible, greater efficiency in gas use by customers.*

- *Continue to examine additional international gas connections, working with multi-country partnerships to find and develop economically feasible options that can increase security of supply and possibilities for competition.*

Electricity

- *Make greater efforts to harmonise rules in the Nordic electricity market, particularly common approaches to enhancing security of supply and market oversight.*

- *In order to ensure more efficient development of transmission infrastructure, adopt a common Nordic approach to mechanisms for financing transmission investment.*

- *Make greater use of* ex ante *regulation, particularly to encourage more efficient pricing of transmission and the disposition of transmission congestion rents.*

- *Proceed with the legal separation of distribution from retailing. Evaluate the minimum size of companies to be separated.*

- *Examine further measures to increase customer choice, including supplier of last resort policies.*

Nuclear Power

- *Ensure that the licensing process for the new plant is completed without unnecessary delay within the current regulatory framework.*

- *Pursue active regulatory support for the implementation of the high-level waste repository.*

Energy Research and Development

- *Develop an indicator or set of indicators that manages to better assess the effectiveness of government-funded energy research and development (R&D) efforts.*
- *Monitor and support the industry R&D effort to ensure that the existing and future nuclear power plants continue to improve their technical and safety performances and that radioactive waste is managed and disposed of safely.*

FRANCE

French energy policy over the past decades has been characterised by a centralised, nation-based approach with strong government involvement. This philosophy has been largely successful: French consumers of all classes enjoy some of the cheapest energy prices in the OECD, security of supply for all energy sources is sound and the country has one of the lowest levels of greenhouse gas emissions (GHG) per unit of GDP in the world. Nonetheless, the context in which French energy policy historically operated has changed dramatically in recent years, driven by two main forces: the introduction of competition into the electricity and natural gas sectors, and the growing internationalisation of the energy sector in Europe as it moves towards a single market. The present objective for French energy policy-makers is to adapt to and benefit from these changes. The two sector-specific areas currently receiving considerable attention are the liberalisation of the electricity sector and the efforts to reduce GHG emissions.

Regarding electricity, France has taken a number of important steps to establish a sound legal and regulatory framework for a liberalised market. It has created a largely independent transmission system operator (TSO), introduced non-discriminatory third-party access to the network for all eligible players, and developed a regulator with adequate resources, experienced personnel and significant independence although the government has the final authority in tariff-setting based on the advice from the regulator. A promising French electricity exchange, Powernext, has opened. France has now transposed the European Union directive on the internal market, giving it a current market opening of 37% (by volume) to be expanded to all commercial customers in July 2004 and all customers regardless of size in July 2007. The incumbent vertically integrated, state-owned Electricité de France (EDF) will be transformed from an *établissement public industriel et commercial* (EPIC) into a *société anonyme* (SA) in 2004, pending a Parliament vote. This would put it on a more equal footing with new entrants.

These are all commendable steps in line with a successful liberalised market. By addressing some of the still remaining issues, the country will be able to more fully enjoy the benefits of competition. Two significant remaining issues are the continued market power of EDF and the government's potential role in influencing the timing of capacity additions. EDF currently generates over 90% of the electricity for the French market, which could act as an impediment to true competition. Among the various options available for addressing this issue, the most promising solution would be to develop stronger interconnections with neighbouring countries and thus expand the market, effectively reducing EDF market share in the process.

The second issue to be addressed is the government's potential involvement in influencing the magnitude and timing of additions to the generating portfolio. As part of its responsibility to provide for energy security, the government has instituted the Long-term Investment Programme for Electricity Production. The government is to be commended for its focus on energy security, especially during the transitional phase towards competition. The short-, medium- and long-term projections of supply adequacy are instrumental for policy-makers to assess security. Under the Long-Term Investment Programme, the government establishes ranges of capacity for different technologies that it would like to see built by certain dates. If investors attempt to build more than the allotted amount of a given technology, the government has the option of denying the permits for the plants. If insufficient capacity is built, the government has the option of launching tender offers and guaranteeing acceptable rates of return for the winning bidder. While renewable energy and combined heat and power (CHP) policy will influence the generating mix, care should be taken that government policies beyond that result in minimal market distortion which could decrease the economic efficiency of the system as a whole. The government is advised to continue with its security of supply measures while monitoring and minimising any such market distortions.

Under the EU burden-sharing agreement, France is obliged to keep its GHG emissions at 1990 levels by the Kyoto Protocol's 2008-2012 commitment period. While France's total GHG emissions in 2001 were roughly equal to 1990 levels, energy-related carbon dioxide (CO_2) emissions rose by 9.1% between 1990 and 2001 and are expected to rise further to 2010 and especially in the longer term (*e.g.* to 2030). This is primarily due to continuing emission increases in the transport and residential sectors, as well as to assumed greater penetration of natural gas in France's electricity generation mix. Reversing the course of GHG emissions is one of the greatest challenges for the French energy policy, especially given the limited scope of emissions reduction potential in the power sector resulting from the current large share of GHG-free power generation (mainly nuclear). The measures in the first climate change mitigation strategy in 2000 are not sufficient to meet the target. Another Climate Plan which was supposed to come out in 2003 has not been released as of mid-May. In addition, France (along with a number of other EU countries) is late in releasing its National Allocation Plan for the coming EU emission trading system scheduled to start in 2005. The government needs to make this issue a greater priority by deciding upon and releasing these documents as soon as possible. The new Climate Plan should provide clear signals for market players and be backed with thorough cost-benefit analysis.

The government has already announced several highly ambitious goals that would reduce emissions. Among these are the desire to maintain final energy consumption at 2003 levels by 2015, building up to 10 000 MW of wind power by 2010 and reducing CO_2 emissions by 75% by 2050. The government is to be commended for the long-term scope and vision these objectives represent. At the same time, the difficulties and expenses of reaching these goals pose huge challenges and need to be better explored. More cost-benefit studies examining the positive and negative aspects of these goals for the energy sector and the overall economy are needed with their results disseminated widely to the public.

The primary new measure to be introduced to help reach the energy consumption stabilisation goal by 2015 is the energy efficiency white certificate system. Under this system, consumers or suppliers that use energy more efficiently will receive certificates equal to their level of savings. Certain energy suppliers will be obliged to obtain a pre-determined number of certificates, thus creating a market that values them and encourages energy-efficient behaviour among all energy users. The government is to be commended for launching this innovative system and is encouraged to proceed with its implementation. A number of administrative questions remain to be answered, such as how savings will be measured and who will issue certificates and administer the system. It will be important to keep administrative costs low, so as to not outweigh the system's benefits. France is encouraged to pursue this promising programme, seeking to simplify and standardise procedures wherever possible. More emphasis should be placed on the transport sector where energy use per GDP, as well as CO_2 emissions, are continuously rising.

France has the most renewable energy production of any EU country, helping it lower emissions and augment energy security; 98% of French renewable energy comes from hydropower and biomass, sources developed for their cost advantages rather than as a result of government support. Policy-driven support for non-hydro renewables has thus far not resulted in substantial renewable capacity, at least in relation to other countries. This may change in the future as the government has announced a number of ambitious goals to expand the use of renewables. Installations below 12 MW can receive above-market feed-in tariffs and those above 12 MW can bid for long-term electricity sales contracts. The government is encouraged to look at the experience of other countries that used the bidding system to support renewables (*e.g.* Ireland and the UK) where the proffered contracts often failed to lead to sufficient installed capacity. Plant siting is key to the future of renewables in France, particularly for wind plants. The government must respect the desires of local communities but effectively weigh them against the national benefits that renewable energy technologies can bring.

The government is taking commendable steps to liberalise the natural gas sector. Currently, all customers with an annual consumption above 283 000 million British thermal units (MBtu) – around 600 customers representing 37% of the market by volume – are eligible to choose their supplier. In July 2004, all commercial customers will be eligible to change suppliers and all customers regardless of size will be free to do so in July 2007. A sound regulatory framework has been put in place, including rules for third-party access and a gas regulator. The primary concern at this point is providing new entrants non-discriminatory access to the network, at the entry points into France and internally in the southern part of the country. The government should continue to promote development of the gas infrastructure to eliminate physical bottlenecks. Legal unbundling of network transport operator should be implemented as mandated by the EU directive. In addition, the dominant position of the incumbent, Gaz de France (GDF), in gas storage facilities should be closely monitored.

France has the second-largest integrated system of nuclear power plants in the world, with 58 production units accounting (in 2001) for 41% of total primary energy supply and 77% of electricity generation. Nuclear power has served France well and while a decision on long-term storage for the radioactive waste has not yet been taken, the government is expected to rule on this issue in 2006. France has developed a substantial technological resource in the abilities of companies and individuals to build, operate and maintain nuclear facilities. It is prudent to ensure this capability is preserved in order to maintain the nuclear option.

This nuclear capability can be maintained in a number of ways. For example, the leading French nuclear company, AREVA, has recently sold a 1.6 GW, €3 billion plant with European pressurised water reactor technology in Finland to come on line in 2009. In addition, according to IEA data, the French government has spent an average of €455 million per year from 1992 to 2001 on research and development (R&D) in nuclear fission technology. The government has recently proposed a "demonstration" unit for the European pressurised water reactor (EPR) technology to be completed around 2012. Maintaining the nuclear option by sustaining the country's technological resources is sound policy. Regarding the "demonstration unit", the government should ensure that any such plant would be built under market conditions whereby companies invest in the plant solely as a profitable venture in a liberalised market.

France has a tradition of contributing substantially to energy R&D and in 2001, spent more than any other European country in this area. However, funding has dropped in recent years, with 2001 expenditures nearly 30% below 1999 levels, and it is hoped that this decrease does not represent a long-term downward trend. France is encouraged to develop a clear energy R&D policy with priorities and allocations integrated into the overall energy policy goals. For example, despite the ambitious efficiency targets for renewable energy and energy efficiency, a relatively small portion of government R&D funding went to these areas in 2001.

RECOMMENDATIONS

The government of France should:

Energy Market and Energy Policy

- *Explore the benefits of adopting a more regional approach to energy security within the context of the evolving European policy framework. While maintaining the option for the government of influencing fuel mix (*e.g. *renewable energy), take into account the increasingly open European market where players make their own fuel choices, and thus any given energy mix cannot be guaranteed by government.*
- *Continue to monitor the supply-demand balance and investment trends of the energy supply sectors. Ensure that the manner of implementing the system of tendering for power plants will not send perverse incentives to market players.*
- *Further improve the design of market reform by completing full legal unbundling at both the transmission and distribution levels (in electricity and gas) and further strengthen the powers of the regulator by allowing it to fix the regulated tariffs.*
- *Move as quickly as possible to change the legal status of EDF and GDF to ordinary companies and, after this step has been taken, consider allowing "opening up" of their capital which is important to strengthen domestic competition in both the electricity and gas markets.*
- *Increase transparency in the energy field, especially by defining the different roles (and their limits) played by the government: as shareholder, law maker, regulator and financier of public research.*
- *Undertake additional economic studies on the feasibility of far-reaching climate change and efficiency targets and examine the cost-effectiveness of measures to reach them.*

Energy and the Environment

- *Finalise and publish, as soon as possible, the government's plan to meet the GHG stabilisation target, including the contribution sought by different actors of the economy, to send clear signals for investments by market players.*
- *Seek to maximise cost-effectiveness and flexibility in the development of the government's strategy to meet GHG objectives. Carefully assess and regularly monitor the costs and impacts of the climate change policies and measures. Share the results with the stakeholders.*

- *Undertake additional economic studies on the cost-effectiveness of climate change mitigation policies and measures, particularly with respect to meeting France's GHG target for 2050. Disseminate the results as widely as possible, with a focus on benefits of such a strategy and the possible implications for the energy and energy-intensive sectors.*

- *Carefully monitor the emissions market and develop its strategy with respect to purchases in order to take advantage of periods of low emission prices to avoid the potential risk of needing to buy during a price spike.*

- *Expedite discussions on the national allocation plan for installations covered by Phase I (2005-2007) of the European Union Emission Trading Scheme (EU-ETS), with the objective of ensuring that a timely, appropriate and clear signal is sent to the market, while also looking forward to Phase II (2008-2012) of the EU-ETS. Work with other EU countries to ensure a level playing field in the EU-ETS.*

Energy Efficiency

- *Continue to make efficiency activities in the transport sector a priority.*

- *Evaluate the feasibility and economic costs of stabilising energy consumption at 2003 levels by 2015.*

- *Develop the administrative framework of the "white certificates" programme, including standardised and clear methods for the issuance of energy efficiency certificates and a follow-up function to monitor the results.*

Renewable Energy

- *Assess the most effective policies for achieving renewable energy goals, evaluating and disseminating information on the costs and benefits involved in meeting such ambitious targets. Draw upon experiences of other countries.*

- *Ensure that the tender offer system results in substantial timely installed renewable capacity; while allowing significant time for the system to work and to give investors confidence, do not exclude the possibility of other market-based options if results are not satisfactory.*

- *Co-ordinate between the relevant authorities to ensure that the siting of wind plants and associated transmission lines can proceed without undue delay to achieve national objectives while still taking into account local concerns.*

- *Resolve the pending debate on water rights and hydroelectric plants to determine how much, if any, hydroelectric capacity will be lost and make plans accordingly.*

- *Adopt a unified approach to the renewable energy programme (both electricity and thermal) and those other programmes that could confer similar advantages, notably energy efficiency.*

Fossil Fuels

- *Promote the development of cost-effective gas transport infrastructure, to better accommodate competition in the gas sector through appropriate tariff structures.*
- *Maintain regulatory oversight of GDF's and Total's dominant gas storage position until sufficient alternative capacity becomes available.*
- *Implement the EU directive to expedite legal unbundling of a network transport operator with strong regulatory oversight to ensure equal access to the gas market for all market players.*
- *Send a clear signal on future excise tax differential for diesel and gasoline to allow industry and consumers to take appropriate investment decisions.*

Electricity

- *Monitor potential obstacles to the development of competition, including fair access to all networks and existence of market power; consider all options to remove such barriers.*
- *Ensure that government policies have minimal market distortions by using market forces as much as possible to determine the choice of power sources in line with traditional cost-benefit analysis and within the framework of policies for renewable energy, CHP, etc., thus boosting market confidence and opportunities for new entrants.*
- *Continue to integrate the idea of* service public *into the liberalised market, taking steps to avoid its becoming a barrier to entry.*
- *Facilitate further cost-effective investments in interconnections and thus continue to develop an EU-wide electricity market,* e.g. *by addressing local siting concerns wherever possible.*
- *Consider the use of existing and future demand-response mechanisms as a way to mitigate the effects of peak demand periods.*

Nuclear Power

- *Favour maintaining nuclear power as an option by authorising the building of a demonstration unit in an open market situation.*

- *Explore all possibilities of lifetime extension, power uprates and improved availability to increase the production capacity taking into account the climate policy and safety standards.*

- *Continue developing high-level radioactive waste management solutions, respecting the time schedule defined in 1991 and ensure that the entire waste management and decommissioning system is fully funded by the waste producers.*

- *Continue efforts in international co-operation in developing new nuclear power systems as part of diversification of energy sources and long-term actions to limit GHG emissions.*

Energy Research and Development

- *Clarify the allocation method (how, how much, in which fields and to which institutions) for public spending on energy R&D.*

- *Define a clear energy R&D policy that supports government long-term energy objectives, particularly in the fields of transport, energy efficiency and renewable energy.*

- *Assess the effectiveness of R&D programmes in a broader concept of energy policy, for example in comparison with the effectiveness of public budget allocated to market introduction of renewable energy.*

- *Monitor R&D expenditure in the industrial sector.*

NETHERLANDS

Since the last IEA in-depth review in 2000, the Netherlands has made progress in most energy policy areas. Liberalisation of electricity and gas markets has advanced. The country has ratified the Kyoto Protocol and is pursuing active climate policies. Research and development (R&D) policy has been rationalised and the initiative towards a sustainable energy system has been launched. The Netherlands has shown great pragmatism in the attention it has accorded to cost-effectiveness while pursuing its energy policy targets, namely energy security, environmental protection and economic efficiency. Despite this progress, the Netherlands still faces challenges in all areas of energy policy as discussed hereunder.

Energy security is attracting increasing attention in the Netherlands. Whilst the most recent Energy Report 2002 concludes that no urgent problems are foreseen, the Netherlands recognises the need to stay alert, improve monitoring and create the necessary instruments to deal with future problems.

The Dutch government has made great efforts to meet its Kyoto target of a 6% reduction in **greenhouse gas (GHG) emissions** between 1990 and the first commitment period (2008-2012). While the government's analysis shows that the country is well on track to meet the target, with GHG emissions having almost stabilised, it is still a challenge. For example, curbing the rapid growth of energy demand in the transport sector will require strong policies and measures.

Cost-effectiveness of GHG emissions reductions has received a lot of attention. Extensive use of Kyoto flexible mechanisms, reduction of non-carbon dioxide emissions, streamlining subsidies for renewables and combined heat and power (CHP), and keeping the Borssele nuclear power plant open are such examples. However, there may be further room for improving cost-effectiveness, which should be looked for and pursued.

The decision to fill up to half of its GHG emissions gap through joint implementation (JI) and clean development mechanism (CDM) projects is ambitious. Given that there are few international examples, the Netherlands is in a forerunner position in creating and testing the methodologies. Finalising the preparations for the European Union carbon dioxide (CO_2) trading scheme, scheduled to start at the beginning of 2005, is a challenge for the Netherlands as it is for all other EU member States.

The introduction of the reserve package to support the basic package of domestic climate change mitigation measures is a prudent and effective approach, because the Netherlands can immediately embark on the reserve package if it finds itself off track. A reserve package is no longer required for sectors that take part in the EU emissions trading; however for the other sectors it is important to develop new measures into the reserve package as most of the existing ones have already been used. This will be carried out within the so-called *Optiondocument*, which is expected in summer 2004.

The Netherlands has had an ambitious **energy efficiency** policy, which includes the use of benchmarking covenants and active monitoring and evaluation of policies to reduce policy "free riders". However, the targeted 1.3% annual improvement in energy efficiency will become more challenging if the momentum of energy efficiency policies is weakened by budget cuts. Moreover, it is important to ensure good co-ordination of policies within the government.

The principal energy efficiency measure in the industrial sectors is the Benchmarking Covenant which is a voluntary long-term agreement. Historically, voluntary long-term agreements have performed well in the Netherlands but the covenant needs to be adapted to the forthcoming CO_2 emissions trading. This reflects the increasing impact of EU legislation on energy efficiency policies at the national level. The current measures are inadequate to meet the energy efficiency goals in the transport sector, which appear to be overly optimistic. As more and stronger measures are necessary, road pricing would definitely merit more attention as would modification of vehicle taxation to take into account energy efficiency. In the residential and commercial sectors, efforts could be strengthened by, for example, stricter norms for the renovation of buildings. While streamlining the subsidies for energy efficiency in the residential sector to avoid "free riders", care should be taken not to abolish the investment subsidies, which improve energy efficiency in a cost-effective way and would not be implemented without subsidies.

Gasoline prices in the Netherlands are among the highest within IEA member countries. The reason appears to be inadequate competition in the retail market, which is dominated by few players. Auctioning of filling stations and other measures may help but the government should continue monitoring the market and take further measures as necessary, especially in encouraging new entrants.

Recognising the great contribution of the large domestic **natural gas** resources to security of supply both in the Netherlands and abroad and state revenues, the government has protected the resources by controlling the depletion of the Groningen field via a national production cap, by maintaining the small fields policy and promoting imports. However, the gradual depletion of the Groningen field, declining small fields production and market liberalisation necessitate an upstream gas policy review. For example, the alternative mechanisms for capping the Groningen production need to be carefully evaluated and the small fields policy should be adapted to the liberalised markets. Stable and cost-effective fiscal incentives and streamlined regulatory procedures related to environment and spatial planning would encourage investment.

One of the major challenges is reorganising the gas market structure (*Gasgebouw*) to the present circumstances and EU legislation. This should occur in a manner that creates a compatible and open market, encourages competition and meets energy security objectives. The first step is to establish an independent transmission system operator (TSO), which will happen with implementation of the second EU Gas Directive. Although the second step, the split of Gasunie Trade and Supply into two competing companies, is a highly complex one, it could help to increase competition.

Access to import infrastructures, flexibility, short-term balancing and quality conversion facilities are essential for the effective functioning of the market. At present, available contractual capacity at interconnections is very small calling for better capacity management and new capacities. The EuroHub and Title Transfer Facility (TTF) are still at an early stage; however, they could help to increase liquidity in the market by facilitating a spot market and creating new possibilities to access gas. At present, Gasunie Trade and Supply, and Nederlandse Aardolie Maatschappij (NAM) have a dominant position in providing short-term balancing services. The Office for Energy Regulation (DTe) has taken an initiative to establish third-party access (TPA) regulation to gas storage but the effectiveness of the rules remains to be demonstrated because there are very few practical access cases. Investments in new storage capacity should be encouraged and TTF could be further developed to include access to flexibility services. Furthermore, the Netherlands has opted for an hourly balancing regime, which is more stringent than the daily balancing option of most other countries. There are two gas markets in the Netherlands, high and low calorific gas markets, making conversion facilities absolutely essential for the consumers of low calorific gas to change suppliers. Access to conversion services should, therefore, be carefully monitored. In this context, it is helpful that one of the planned tasks for the new TSO will be to provide conversion services.

Competition has developed relatively well in the Dutch gas market, with two-thirds of the market being liberalised. It is commendable that the government has recognised the benefits of market liberalisation even though state revenues from gas may be negatively affected in the short term. However, the functioning of the market will be further enhanced through better transparency via market restructuring and solving the existing switching, measurement data and billing problems. The special requirements of small consumers need to be addressed in the full market opening that is scheduled for 1 July 2004. Given their requirement for a very high reliability, effective and fairly priced access to flexibility services needs to be ensured. Adequate information will have to be provided for the small consumers and attention given to minimising the costs of switching.

Full liberalisation of the green electricity market and the ecotax exemption substantially increased demand for electricity generated from **renewable energy sources** but not for domestic generation. Instead, renewable electricity imports increased greatly, leading to congestion in the transmission system. The feed-in tariff system included in the new supply-oriented approach, Environmental Quality of Electricity Production (MEP), is likely to boost domestic renewable electricity generation, but its cost needs to be monitored. As with all incentive regimes, the incentives for cost reductions should be maximised. Moreover, whilst government support for renewables is a sound policy because the externalities of renewables and other competing fuels are not fully captured by the market, all such measures should be regularly assessed to ensure they are as cost-effective as possible.

The overall design of the Dutch **electricity market** is good with adequate unbundling, the necessary bodies for regulation, transmission and market operation in place and network use based on regulated TPA. Consequently, competition has developed relatively well in two-thirds of the market, which has been opened for competition. The Dutch government should be commended for its approach to market liberalisation.

However, the government still faces some challenges, including increasing interconnection capacity and its fair and transparent allocation, enhancement of network reliability and expanded operation of power exchange. Administrative problems with switching of supplier and billing need to be solved without delay. This is a prerequisite for effective full market opening on the planned date of 1 July 2004. Consumers need to be informed about the reasons for market opening, ways to access the market, possible risks and how to avoid them, and the cost of switching needs to be minimised.

Reinforcement of interconnection capacity is essential both for security of supply and more effective competition. This is an international problem that requires solutions at the international level. Therefore, it is very important that the Dutch government and TenneT (the electricity transmission system operator) continue to work closely with other European TSOs. It would also help to address these issues at governmental level in Memoranda of Understanding between the Netherlands and its neighbouring countries to create a single market among them, comparable to the Nordic and Iberian markets. The auctioning mechanism of interconnection may need to be reviewed. Price-setting mechanisms for networks and interconnections should take into account the costs generated by increasing interruptible sources, notably wind power.

Security of electricity supply has received due attention. Nevertheless, it is a challenge to encourage adequate investment in generating capacity, particularly peak load capacity. Although there is abundant capacity at present, in the longer term, excess capacity will be absorbed and the decision by Belgium and Germany – at present important import sources – to phase out nuclear power can increase the need for domestic generating capacity. Allowing markets to signal the need for new investment means that prices will go high on occasion but better transparency could reduce such price peaks as would better information on the maintenance and outages of production capacity. The Dutch government considered different capacity mechanisms and better demand response. Capacity mechanisms are believed by the government to have negative effects such as being expensive. Consequently, the government concluded that optimising the wholesale market and improving demand response was a better approach, which can reduce the need for investment in peak load capacity.

The Dutch **energy R&D** framework has undergone several changes over the last three years, but overall, it has produced a coherent long-term R&D strategy addressing energy policy goals, with a clear regard for cost-effective policy and evaluation procedures. Despite a tightening government budget, the energy R&D budget has been relatively stable over the last ten years. The government initiative towards a sustainable energy system (energy transition management), which has a broad policy context, incorporating R&D discussions, is a good example of clear and systematic treatment of energy policy and priority setting.

RECOMMENDATIONS

The government of the Netherlands should:

General Energy Policy

- *Ensure a stable policy approach to encourage investments in the energy sector.*
- *Streamline the licensing procedures.*
- *Enhance local authorities' and the general public's understanding of national energy policy challenges and objectives.*
- *Further clarify the relations between the regulator and the Ministry of Economic Affairs. Ensure that the regulator has adequate powers and means to effectively carry out its tasks.*
- *Increase involvement of consumers in designing liberalised energy markets and introduce greater consumer protection, including ensuring smooth transition to full market opening.*
- *Strengthen the transition management process through clarifying targets for the transition projects, developing milestones and benchmarks to monitor their progress.*

- *Deepen collaboration with neighbouring countries in order to increase the effectiveness of energy policy. This includes continuing the efforts to create a real single energy market with the neighbouring countries via Memoranda of Understanding, and eventually the EU market.*

Energy and the Environment

- *Continue the approach in which both national and international policies are implemented and monitor these in order to be able to prioritise according to cost-effectiveness.*

- *Make greater use of economic instruments, including tax differentials based on external cost.*

- *Ensure that other climate policies and measures are streamlined with respect to the emissions trading scheme. In particular, clarify the relationship between the benchmarking covenants and the emissions trading.*

- *Continue the projects for flexible mechanisms to give a concrete example of how they can be used as a tool to supplement domestic measures.*

- *Consider promoting natural gas and other alternative transport fuels to contribute to achieving EU biofuel and national GHG targets.*

Energy Efficiency

- *Enhance the role of energy efficiency in the energy policy, including securing adequate budget but continuing to pay attention to cost-effectiveness.*

- *Take stronger measures in the transport sector, including road pricing, modification of vehicle taxation, extension of eco-driving and the promotion of on-board technologies.*

- *Introduce further measures in the existing buildings such as stricter building standards for renovated buildings.*

Fossil Fuels

- *Continue to monitor the development of competition in oil retailing and take additional measures as necessary.*

- *Promote a stable regulatory and fiscal framework for domestic gas production by:*
  - *Revising the tax and fiscal incentives, including the reintroduction of "depreciation at will" or other incentives.*
  - *Reviewing and streamlining regulatory procedures related to environment and spatial planning, including searching for an environmentally sustainable solution for using the gas deposits in environmentally sensitive areas.*

- *Review the cap mechanism on national gas production with a view to securing production from the small fields.*

- *Adapt the small fields policy to be compatible with an open and competitive market as long as it makes a positive contribution to energy security. Make this a continuous process.*

- *Restructure the* Gasgebouw *as soon as possible, including promptly establishing a legally independent TSO.*

- *Monitor and facilitate the development of EuroHub and Title Transfer Facility.*

- *Create a framework that encourages investment in infrastructures, including interconnectors, gas storage and quality conversion facilities, which is compatible with market mechanisms.*

- *Set a clear plan to tackle gas market bottlenecks in order to facilitate new market entry and to avoid excessive market power. This should address access to flexibility (including storage) services, quality conversion, inadequate import capacity and the balancing regime but without endangering investments.*

Renewables

- *Monitor closely the costs of the Environmental Quality of Electricity Production (MEP) scheme and incorporate strong incentives for cost reduction and competition, recognising that global learning will be the principal driver of cost reduction.*

- *Monitor closely the long-term economic impacts and the impact on international biomass markets of expanding domestic biomass production and importing biomass.*

- *Place caution on promoting technologies not necessarily suited to the climate conditions in the Netherlands, such as photovoltaic energy.*

- *Assess progress towards a competitive renewable energy sector with a view to ensuring a stable investment environment until targets are met. Phase out the subsidies in the longer term when the different positive and negative externalities of renewables and other energy forms have been internalised.*

- *Investigate the requirements for the reliability and stability of the future electricity network, given the indicative goal of connecting large amounts of wind power to the grid.*

- *Study the possibilities to increase the use of renewables in heat production.*

Electricity, Heat and Nuclear Power

- *Evaluate the different market mechanisms for ensuring security of supply and adequate peak load capacity. Pay attention to the possibilities of improving demand response as an alternative to capacity increases. Avoid the introduction of maximum levels for consumer prices.*
- *Improve the monitoring of the generating capacity and publish the data to increase transparency. Publish maintenance outages of production capacity.*
- *Continue to increase interconnection capacity and improve its operation in co-operation with neighbouring countries, for example through Memoranda of Understanding.*
- *Facilitate the further development and broadening of the power exchange. Enhance co-operation with other power exchanges in Europe.*
- *Ensure that full market opening will be implemented effectively and without further delays.*
- *Ensure a stable and predictable policy framework for nuclear power.*

Research and Development

- *Stabilise the R&D programme framework and avoid disruptions to long-term R&D planning.*
- *Ensure that there is clear multisectoral communication regarding R&D programmes and policy priorities across ministries.*
- *Extend to all relevant stakeholders the current approach for discussing the development of specific R&D programmes.*
- *Ensure that all government departments consider creating new international research networks, or using those of the IEA, to bring in international partners from both the public and private sectors to support the work on the new R&D priorities.*

Since the last IEA in-depth review in 2000, there have been many positive developments in Portugal's energy sector. The Portuguese government decided in 2003 to restructure the energy sector. It set guidelines for energy policy associated with a demanding implementation plan. Natural gas is successfully penetrating the energy mix. Important political decisions have been taken to develop the Iberian electricity market. It has also been decided to fully liberalise the electricity market from July 2004. Oil prices have been totally liberalised. The regulator (ERSE) is functioning well with high independence and strong authority. A national action strategy to tackle climate change has been proposed and renewables are given high priority. Portugal is making efforts to tackle the many challenges in the years to come.

SECURITY OF SUPPLY

The share of oil in Portugal's TPES was 62% in 2002 and has been decreasing over the last decade, but it is clearly higher than the IEA average of 41% (2001). Consequently, oil supply is very important for Portugal's security of supply. However, Portugal has frequently been non-compliant with its IEA obligation of holding oil stocks equivalent to 90 days of net imports since late 1992. This situation has been continuously addressed by the IEA and its members, as energy security in today's energy environment depends on solidarity. Positive decisions have been taken by the government but they still need to be fully implemented.

The government of Portugal should be commended for its efforts in the introduction of natural gas into the energy mix. Natural gas will reduce Portugal's high dependence on imported oil and will continue to diversify energy supply. While Portugal had been dependent on a single supply source (Algeria), the new liquefied natural gas (LNG) terminal has significantly enhanced security of supply both by allowing diversification of supply sources and by providing enough supply capacity for several years. Also the new underground storage facility enhances security of supply.

ENERGY AND THE ENVIRONMENT

The EU Burden-Sharing Agreement under the Kyoto Protocol commits Portugal to limit its increase of greenhouse gas (GHG) emissions to 27% between 1990 and the first commitment period of 2008-2012. Since 1990 to 2001, GHG emissions grew by 36.4%, in line with GDP growth, but already 9.4 percentage points over the target. Even with the policies and measures in place, emissions are expected to stay above the final target. Therefore, meeting it will be a challenging task. Prompt introduction of new, strong policies and measures is required.

Furthermore, the baseline estimates should be reviewed when necessary to reflect the rapid growth in energy demand, in particular in the transport sector.

The introduction of the Climate Change National Programme (PNAC) will be particularly important and should include effective policies and measures with a clear implementation plan, time schedules as well as adequate funds for implementation. Careful monitoring of the trends and the effectiveness of policies, followed by a prompt policy response, is important. More attention needs to be paid to the cost-effectiveness of the policies and measures. Introduction of the EU Emissions Trading Scheme (EU-ETS) will be an important device to curb GHG emissions from the large emitters. Because the reference scenario shows that domestic measures are not enough to meet the target, the use of the Kyoto flexible mechanisms will be necessary. This is a sensible policy as the use of these mechanisms is likely to reduce the cost of achieving the target.

END-USE EFFICIENCY

It is a matter of concern that since 1990, energy demand in Portugal has grown faster than GDP, thus increasing energy intensity. However, energy intensity remains below the IEA average, but the growing trend is in contrast with the trend in most other IEA member countries. While this is partly attributable to the improving living standards, there is potential in Portugal to improve energy efficiency. Better energy efficiency would also contribute positively towards energy security. Though significant new action has been taken recently to strengthen the policies, a more solid energy efficiency strategy is necessary. This should include measurable targets and thorough monitoring. The policies and measures to be included should be chosen on the basis of their cost-effectiveness.

The introduction of the EU-ETS could give a good incentive to large emitters to further improve their energy efficiency, but a new type of arrangement would be necessary for emitters not covered by the EU-ETS. Policies to de-link transport demand growth from economic growth need to be thoroughly explored and the process should be supported by effective co-ordination among different ministries.

RENEWABLES

Portugal has a demanding indicative target to increase the share of renewables in electricity generation to 39% by 2010, and specific targets for several technologies. For this purpose, the government has relied on a feed-in tariff scheme which has the same impact as subsidies. Additional efforts are needed so that the required extra capacity will be built in time. The government should also seek to improve the current system so that the final consumers could benefit from the cost reduction through gradually reducing the feed-in tariff and limiting the duration of the buy-back period while ensuring investor confidence.

GAS MARKET REFORM

The new challenge in the gas sector is market liberalisation and the announced intention to create an Iberian gas market. The incumbent supplier, GALP Energia, dominates the gas market from upstream to retail. It is commendable that the government has announced its intention to bring forward the beginning of the gas sector liberalisation from 2008 to 1 July 2004, even though the country has a derogation from the EU directive. Following this move, it is important to implement as soon as possible a regulatory framework which is clear, gives sufficient powers to the regulator and provides incentives for an efficient market. The third-party access tariff for networks needs to be set and should provide for fair, non-discriminatory and transparent access. One prerequisite for implementing these principles is effective unbundling of the supply and network operations.

ELECTRICITY MARKET REFORM

The electricity market in Portugal has developed significantly since the last in-depth review, but remains dominated by Electricidade de Portugal (EDP). However, there are several initiatives to induce electricity market competition in Portugal and at the Iberian level. Increasing physical interconnections with Spain would improve competition and security of supply. The development of the natural gas network has increased the feasibility of independent entry into power generation in Portugal. Particularly, the political initiative to create a common Iberian electricity market is an important step in creating a competitive market but progress is behind schedule. The creation of the Iberian market requires adequate legislation in both countries to make them compatible but it is yet to be detailed and published. Furthermore, close monitoring of the prices and bidding behaviour of the major players in the Iberian market, particularly in terms of wholesale prices in Portugal, will be necessary.

The need to unwind the long-term power purchase agreements (CAEs) between Rede Eléctrica Nacional (REN) and main suppliers creates an important opportunity to enhance competition in the Portuguese market. One possible way would be auctioning the contractual obligations by REN to new suppliers, which would make more electricity available to new entrants. This would have the impact of reducing EDP’s market share until a better interconnection can be achieved. However, the issue of concentrated generation in the Iberian electricity market can only really be dealt with at the Iberian level.

On 1 July 2004, Portugal plans to open the electricity market to all consumers in the country, as already exists in Spain. However, it is still uncertain that meaningful competition will develop quickly. Legislation and regulations will be needed to clarify the rules for small consumers to switch suppliers. While it is proposed to eliminate the regulated tariff option for all consumers, this process should take place at the Iberian level, starting with the largest consumers and allowing for the existence of suppliers of last resort.

A policy of capacity payments, which places obligations on retailers to acquire more than sufficient capacity to supply consumers, has not been proven to be an effective or efficient policy to secure adequate supply. More efficient instruments should be considered. Enhancing the demand response of consumers to the market price of electricity would reduce the need to invest in new generating capacity while increasing the efficiency of the market and reducing price volatility.

RESEARCH AND DEVELOPMENT

Given that Portugal is facing significant energy and environment policy challenges, the government needs to explore all possible means to respond to these challenges, including formulating an effective energy R&D policy. To implement such a policy, a coherent energy R&D strategy with adequate financing, as well as better co-operation between the different ministries and the research laboratories under them, are necessary. To increase the cost-effectiveness of energy R&D and to make better use of the results, it is necessary to improve monitoring and assessment mechanisms.

RECOMMENDATIONS

The government of Portugal should:

General Energy Policy

- *Continue efforts to diversify the energy mix and closely monitor progress to improve security of supply and enhance climate change mitigation and environmental protection.*
- *Enhance co-ordination of energy policy measures between the different ministries and appropriate organisations to take better account of energy in other policies and to increase efficiency.*
- *Involve all stakeholders, including consumers, in developing energy policies and disseminate information to them.*
- *Continue the close co-operation with the government of Spain to develop consistent policies for the Iberian energy markets. This includes electricity tariff schemes, the access and availability of natural gas, the allocation of CO_2 emission permits, and the policies regarding renewables and security of supply.*

- *Scrutinise the impacts of EDP's acquisition of GALP's gas supply and retailing activities on competition in the electricity and natural gas markets.*

- *Make sure that ERSE is given the necessary means to conduct its duties, also in the gas sector.*

Energy and the Environment

- *Finalise the Climate Change National Programme (PNAC) and adopt a time schedule for the policies and measures with reasonable and achievable goals at each step. Periodically review on the basis of recent GHG projections and the progress of various policies and measures.*

- *Further examine the cost-effectiveness of climate change policies and measures.*

- *Clarify the role which Kyoto flexible mechanisms should have in meeting the emissions targets and accelerate the preparation for their utilisation.*

- *Increase the use of fiscal instruments to internalise the externalities related to climate change and air pollution.*

Energy Efficiency

- *Establish an integrated national energy efficiency strategy as soon as possible. This should incorporate, at the national and sectoral levels, targets and strong cost-effective measures, including full implementation of the measures in the EU framework.*

- *Evaluate the cost-effectiveness and achieved energy savings of the energy efficiency projects.*

- *Enhance efforts to address the sectors not covered by the EU emissions trading scheme by, for example, the CO_2 tax and reimbursement in the case of taking appropriate measures such as more effective voluntary agreements and measures in the building sector.*

- *Curb energy demand growth in the transport sector by:*

    - *Decoupling transport activity growth from economic growth, considering a wide range of policies such as better urban planning, promoting teleworking, road pricing and modernisation of the economy away from transport-intensive activities.*

    - *Fostering more energy-efficient modes such as railways.*

    - *Encouraging car buyers to choose fuel-efficient cars and to retire old and inefficient cars by economic and regulatory measures, in particular vehicle taxation.*

Fossil Fuels

- *Continue to evaluate the competition situation in the oil market.*

- *On the basis of the newly established emergency legislation and the new Stockholding Agency (EGREP), make all necessary efforts, together with the oil industry, so that Portugal will be constantly compliant with the IEA emergency stockholding obligation in the future.*

- *Maintain the policy for diversified supply sources of natural gas and the balance between pipeline gas and LNG.*

- *Phase out subsidies and tax benefits for natural gas.*

- *Finalise the regulatory framework for the partial market liberalisation in July 2004. Set the schedule for the next steps of liberalisation.*

- *Make sure that third-party access to the facilities, including the pipelines, the LNG terminal and gas storage, is on a fair, non-discriminatory and transparent basis.*

- *Closely co-operate with Spain to introduce an Iberian gas market, preferably in pace with domestic market opening, and present a realistic time schedule for the market players.*

Renewables

- *Review the current feed-in tariff scheme in order to assure cost minimisation to consumers while ensuring investor confidence. Assess the benefits of incorporating incentives for cost reduction through gradually reducing the tariff level and the duration of the buy-back period. Also review the interaction of the feed-in tariffs and subsidies to determine when and which incentives can best be reduced.*

- *Assess progress towards a competitive renewable energy sector with a view to ensuring a stable investment environment until targets are met. Phase out the subsidies in the longer term when the different positive and negative externalities of renewables and other energy forms have been internalised.*

- *Continue efforts to streamline licensing procedures, including the environmental impact assessment, for renewable energy projects.*

- *Investigate the requirements of reliability and stability of the future electricity network, given the indicative goal of connecting large amounts of wind power to the grid.*

Electricity and Co-generation

- *Finalise the new legislation to carry out the objective of creating an Iberian market and to open the market to all consumers.*
- *Ensure the development of adequate interconnection capacity and its fair allocation.*
- *Consider at the Iberian level a mechanism to increase competition in generation through the use of "virtual power plant auctions" to make the energy available to suppliers other than major Iberian players.*
- *Monitor price developments in the Iberian electricity market, and be prepared and able to act promptly should concerns about manipulation of electricity prices arise.*
- *Develop a timetable for the phase-out of regulated power supply tariffs at the Iberian level and consistent with the 2003 EU Electricity Directive.*
- *Monitor generation investment developments in the Iberian electricity market. Consider removing the capacity payment or, as a temporary measure, replacing it with a more efficient instrument.*
- *Encourage the development of demand response mechanisms to enhance the security of supply and decrease the volatility of electricity prices.*
- *Re-evaluate the feasibility of the co-generation target to ensure that it is based on useful heat demand. Improve the environmental performance of some co-generation projects by encouraging the use of natural gas instead of oil.*

Research and Development

- *Develop a coherent energy R&D strategy with adequate financing to support energy policy objectives.*
- *Better monitor and assess the R&D projects.*
- *Improve the co-ordination between the different ministries involved in energy and related R&D.*
- *Improve the collection of data on governmental R&D funding.*

SWEDEN

Swedish energy policy employs a mix of government involvement and lightly-regulated market forces to achieve its objectives. On the one hand, Sweden has high and complicated energy taxation, the largest electricity company is 100% owned by the State and the government intends to shape the supply mix through a possible phase-out of nuclear power and the encouragement of renewable energy technologies. On the other hand, as part of the Nordic Power Market (Nord Pool), Sweden is one of the true pioneers in liberalised electricity sectors and generally employs a very light-handed approach to regulating energy companies. In general, this mix of government influence and free market forces has been judiciously applied and consequently, Sweden has a successful history of providing its citizens with low-cost, reliable, secure and environment-friendly energy.

Swedish energy policy is currently facing many important issues, which will test whether its success will continue. The issue currently receiving the most attention is the proposed phase-out of nuclear power. Concerns about nuclear safety were expressed politically as long ago as 1976 in the general election and in 1980 the people voted in a public referendum for a delayed phase-out of nuclear power plants. In the 1990s and early in this decade, a number of government decisions called for the closure of nuclear power plants and in 1999 one reactor was shut (Barsebäck 1). To date no further nuclear power capacity has been closed since conditions for plant closure have not been met. A government negotiator is now discussing with the industry and other stakeholders the conditions of a gradual phase-out, which will take place during the first half of 2004. The national energy policy implications of phasing out nuclear power, which currently provides 46% of electricity generation and 35% of TPES, are significant. The review team encourages any such plan for government-mandated plant closures to take into account the costs associated with replacing nuclear power and the implications for Sweden's energy security, greenhouse gas (GHG) emissions and economic growth. Such information should be widely disseminated to the general public. Concrete plans for replacing the phased out capacity should be developed and deployed as soon as decisions on this issue are final.

Sweden uses energy taxation as an important tool for promoting certain energy sources while discouraging others. In connection with the 1990/1991 tax reforms, Sweden began its green tax shift whereby taxes on energy were raised while other taxes, such as payroll taxes, were decreased by an equivalent amount. This process continues with the carbon tax on fuels being increased by 18% to SKr 910[1] per tonne of CO_2 on 1 January 2004. Biomass

1. In 2003, 1 Swedish krona (SKr) = US$ 0.123.

is one beneficiary of the green tax shift. From 1990 to 2002, Swedish biomass use increased by nearly 50%, rising from 12% to 16% of the country's TPES. While effective in this sense, continued increases in energy taxation may yield increasingly diminishing returns. If the tax already makes a less-emitting fuel more attractive than a more-emitting fuel, added taxation will not serve to change supply-side behaviour any further, although resulting higher energy prices would probably curb demand. By way of comparison, the current SKr 910 per tonne of CO_2 is equivalent to approximately €100 per tonne, well above the expected prices for allowances under the European Union (EU) emissions trading scheme.

Simultaneously, energy tax exemptions given to industry mitigate the effectiveness of the taxes in changing overall national energy behaviour. While the exemptions are understandable on international competitiveness grounds, Swedish industry still faces energy-related taxes on a par with industrial companies in other EU countries. Nevertheless, the exemptions do leave industrial emissions largely uncovered by one of Sweden's main climate change mitigation policy tools. The EU emissions trading scheme can play a key role in tackling industrial emissions although the effectiveness of this programme will depend on the price of carbon allowances and the initial allocations to industry. As the emissions trading scheme is put in place and, assuming it becomes effective at curbing emissions, other purely domestic policies may be streamlined to ensure their compatibility with the trading scheme.

The lingering uncertainty surrounding the possible nuclear power phase-out and continued energy tax increases can undermine investor confidence and thus deter investment in both energy supply infrastructure and energy consumption infrastructure such as factories. The government is encouraged to provide as much certainty as possible to the market, particularly regarding the nuclear question, so that companies can make plans and proceed with investments.

Sweden is to be commended both for the pioneering and far-sighted spirit in which it liberalised its electricity market and for its continued efforts to improve the system as it evolves and as more experience is gained. Many countries beginning the liberalisation process look to Sweden as a successful model to be emulated. However, Sweden faces several challenges, including a tightening supply-demand balance throughout the Nordic market; growing concentration of ownership, particularly among generators; and the emergence of significant constraints on the Nordic transmission network, particularly on interconnections. These factors could erode the sustainability and effectiveness of the Nordic electricity markets. Svenska Kraftnät, the transmission system operator (TSO), now administers a transitional capacity mechanism contracting 2 000 MW of peak capacity until 2008 to ensure sufficient capacity is available during times of potential capacity shortage. Noting that this could potentially crowd out an efficient private response to peak demand, clearly identified trigger conditions for intervention are essential. As increasingly international electricity trading takes place both inside and outside Nord Pool, the above-mentioned challenges for Sweden will need to be addressed internationally in co-ordination with other countries both at political and regulatory levels. In particular, there is no clear responsibility among stakeholders for translating the planning process of Nordel, the Nordic TSO co-operative body, into timely and efficient investment. Effective regulatory arrangements to improve price signals for new interconnector investments should be explored. It is worth noting that Sweden can best address these and other issues in an international context through enhanced co-operation with governments and regulators from other countries.

Sweden has ambitious targets for increasing electricity generation from renewable energy technologies. It intends to raise annual generation from renewable plants by 10 TWh from 2002 to 2010. The primary means of meeting this goal is the newly introduced electricity certificate scheme in which electricity suppliers are obliged to acquire electricity certificates from renewable plants equal to a certain percentage of the electricity they supply. This percentage level began at 7.3% in 2003 – approximately equivalent to Sweden's existing level of renewable generation at that time – and will rise in steps to 16.9% by 2010. This scheme has a strong market component that will promote generation from the lowest-cost renewable energy technology and also foster competition and thus increase production efficiencies. However, the costs of such a system must be monitored closely as the ambitious targets may lead to excessive prices for the certificates, which will ultimately lead to very high bills for consumers. If certificate prices reach "politically unacceptable" levels, the target level should be reconsidered and alternative means of achieving the same emissions reductions should be explored.

Sweden's high energy intensity as measured by national TPES per unit of GDP is primarily the result of its cold climate and energy-intensive industries rather than the inherent inefficiency of energy producers or consumers. Nevertheless, further improvements in energy efficiency offer a very attractive way to meet national goals, especially in light of the proposed nuclear phase-out and the potential high costs of meeting the renewables target. Such goals may be more easily achieved through introducing quantitative efficiency improvement targets that could involve national energy efficiency improvement or efficiency improvements for companies that sign long-term agreements with the government. A programme for energy efficiency for energy-intensive businesses is under preparation within the Swedish government. Sweden's goal of keeping transport sector emissions at 1990 levels by 2010 is very ambitious judging from the recent trends. The government will have to undertake more aggressive energy efficiency activity in this sector to meet this target.

District heating is used extensively in Sweden and contributes to the country's energy efficiency. While largely regarded as successful, the sector could benefit from greater regulation in those regions where it enjoys a *de facto* monopoly. This would encourage greater operational efficiency of the systems and decreasing prices for consumers.

While natural gas currently provides only 1.5% of Sweden's TPES, it is seen as a fuel whose use could expand substantially in the medium to long term. In areas where the gas pipeline already extends, natural gas has captured between 20% to 25% of the relevant market. Natural gas could expand Sweden's fuel diversity, lower GHG emissions if displacing other fossil fuels and provide economic advantages if it proves to be the lowest-cost option. Gas use would become a particularly attractive option if nuclear plants are phased out. The government has taken a commendably hands-off approach to natural gas, allowing the suppliers and consumers to decide their level of involvement. However, the government could make dealing with gas easier for all parties by simplifying the regulatory structure governing transport. In addition, resolution of uncertainties over nuclear power and future energy taxation would, as mentioned above, allow investors to make the investments to expand gas use if they so desired.

Swedish government expenditures on energy R&D rose by 100% from 1996 to 2002, and represented the highest spending levels as a percentage of national GDP of all but four IEA countries. The government-appointed Commission on Energy Research, Development and Demonstration (ERDD) released its conclusions in 2003. The commission rightly commends the Swedish government for its activity in this sector but adds, nevertheless, a number of suggestions for improvement, two of which may be particularly helpful. The first is to define energy areas where Sweden requires only a minimum level of competence and areas in which it can excel. Priorities and funding should be allocated accordingly. The second recommendation is to improve the system's ability to bring more products through to commercialisation. While this need not be done through a reallocation of government resources, which are still best spent on more basic research with industry concentrating on commercial aspects, the commission proposes a number of changes to help the commercialisation yield that are worth serious consideration.

RECOMMENDATIONS

The government of Sweden should:

Energy Market and Energy Policy

- *Continue to develop a long-term vision of a sustainable energy future, based on sound modelling of the economic costs of various options.*

- *Place greater overall emphasis and attention on energy efficiency and demand-side response as a way of meeting the country's environmental and security of supply targets.*

- *Strive to create a more stable policy environment in which energy stakeholders can plan effectively by resolving the future of nuclear power (including clear ideas on alternative supply sources and consequences for GHG emission commitments) and by providing a more stable and simplified energy tax regime.*

- *Undertake more quantitative assessments of the costs and benefits of various energy policy options, including the decision on nuclear power, and disseminate this information as widely as possible to energy actors and the general public.*

- *Continue to monitor progress towards established goals and evaluate effectiveness of policy measures.*

- *Consider increasing the scope, transparency and independence of the energy regulator.*

Energy and the Environment

- *Increase the level of analysis and quantification of policies to better assess the cost-effectiveness of different measures and show how both individual policy measures and the climate strategy as a whole are consistent with achieving national objectives.*

- *Improve the environmental effectiveness of the energy and CO_2 taxation regime by addressing the tax structure (including exemptions and reductions) rather than focusing on the top rate of tax.*

- *Address the need for emissions reductions from industry, either through changes in tax structure or effective use of emissions trading.*

- *Streamline, when appropriate, climate mitigation policies, including CO_2 taxes, to ensure they are complementary to the trading scheme, and ensure expenditure on climate policies is justified on the basis of cost-effectiveness of the expected CO_2 savings.*

- *Identify ways to manage Sweden's substantial forestry assets in a way that best meets environmental goals, recognising their major potential both as sinks for GHG and as a renewable fuel source.*

Energy Efficiency

- *Make use of additional measures to encourage more efficient and rational energy use in the transport sector.*

- *Negotiate quantitative targets for companies participating in the long-term agreements, keeping in mind the forthcoming EU emissions trading scheme.*
- *Consider the benefits of extending regulation over the district heating sector.*
- *Examine the possibilities for developing heat metering in individual apartments.*

Renewable Energy

- *Share information and experiences with other countries introducing electricity certificate systems to support renewables.*
- *Monitor the cost-effectiveness of the electricity certificate system in achieving environmental and security of supply goals in comparison with measures to improve the efficiency in electricity consumption.*
- *Explore ways to move towards competitive renewable motor fuels.*
- *Assess progress towards a sustainably competitive renewable energy sector.*

Fossil Fuels

- *Establish a stable, appropriate tax regime for fossil fuels.*
- *Consider establishing a single gas transmission system operator.*
- *Consider the effects of current ownership of major gas utilities on the efficient functioning of a liberalised gas market.*
- *Establish a clear and stable policy framework to facilitate access to the system network and to allow for the development of network infrastructures by interested parties.*

Electricity

- *Explore opportunities for greater harmonisation within the Nordic market in relation to economic regulation, system operation and competition surveillance in the electricity sector, possibly in the context of the electricity group of the Nordic Council of Ministers and through Nordel.*
- *Monitor the evolution of production capacities in case of nuclear phase-out.*
- *Review closely all arrangements and responsibilities in relation to system operation and network planning to ensure that efficient and transparent development of the transmission network can proceed without undue delay. In this context, take steps to improve price signals for new investment and for expediting investment to strengthen interconnections where clear economic cases exist.*

- *Monitor the peaking power contracting by Svenska Kraftnät to ensure it does not undermine the development of efficient, market-based demand response or peak generation investment. Consider clearly identifying the trigger conditions for intervention and strengthening the link between the trigger conditions and movements in physical reliability balances.*
- *Examine options for further structural reform to strengthen competition and reduce the potential for undue exercise of market power, including options to manage concentration of ownership among generators and retailers. Examine whether strengthening the separation of transmission and distribution networks from generation and retail businesses is warranted.*

Nuclear Power

- *Pursue the negotiations with the industry to reach an agreement on phasing out nuclear power with a credible and commonly agreed implementing plan.*
- *Ensure that the nuclear power plants in service continue to be operated safely.*
- *Pursue the implementation of a final repository for high-level radioactive waste.*

Energy Research and Development

- *Renew the RD&D programme funding at a comparable level.*
- *Implement the recommendations of the Commission on Energy Research, Development and Demonstration (ERDD), including increasing the proportion of projects that will lead to the commercialisation of new energy efficiency and renewable energy technologies.*

PART 2.2

STANDARD REVIEWS

This part contains the 2003/2004 standard reviews for the following seven countries, updating the situation since these countries underwent the in-depth reviews of the 2001/2002 review cycle. The report reflects the situation when they were drafted from July to September 2004.

AUSTRIA

GENERAL ENERGY POLICY

According to the latest Energy Report 2003 that was adopted by the Austrian government on 4 May 2004, Austria's energy policy is committed to the following four objectives:

Security of Supply: Austrian energy policy seeks security of supply for both the provision of primary fuels to the country as a whole and the delivery of end-use fuels to final consumers. The two primary fossil fuels in the market, natural gas and oil, derive a measure of energy security from *i)* storage capabilities within the country, and *ii)* extensive international pipeline capacities. Policy governing security for energy end-use by the consumer relates primarily to electricity, where the regulator for that field is responsible for monitoring adequacy of supply in both the short and the long term.

Cost-effectiveness: The Austrian government uses cost-effectiveness in assessing all policy decisions. This can be seen in the liberalisation of the natural gas and electricity sectors, where the introduction of competition and supplier choice is intended to improve efficiency in the energy supply industry and subsequently lower costs to final consumers. Government R&D and energy efficiency initiatives are also intended to reduce energy costs to Austrian consumers by developing more efficient equipment and technology.

Environmental Compatibility: Austria has traditionally placed great emphasis on the environmental impacts of energy production and use. In March 2002, Austria ratified the Kyoto Protocol, which obliges the country to reduce greenhouse gas emissions by 13% below 1990 levels by the first commitment period 2008-2012. The country has developed a *Klimastrategie* which includes a blueprint of actions that can be taken to meet this goal. In addition, the electricity liberalisation law includes ambitious targets for the inclusion of renewable energies in the electricity mix. Lastly, Austria's ban on the production of nuclear power is based on environmental concerns. Both the Austrian government and the Austrian people are opposed to nuclear power. While the country has never had an operating nuclear facility, such plants in neighbouring countries and regions cause debate within Austria.[1]

Social Compatibility: The Austrians have long worked within the "Social Partnership", a forum where business, labour and agriculture can discuss

1. The utilisation of nuclear fission for energy supply is prohibited in Austria by a federal law that entered into force on 15 December 1978 as a result of a referendum. Austria does not regard nuclear energy as a viable strategy option to combat climate change.

national policy. This provides a voice for labour and other members of civil society to express their views and influence the direction of energy policy, thus ensuring that decisions are acceptable to all segments of society.

Austria is a federal state with a central national government and state governments in each of the country's nine *Bundesländer*, or *Länder*. The Federal Constitution allocates responsibilities either exclusively to the federal level, or to both the federal and the state levels. In so far as a matter is not expressly assigned by the Constitution to the federation for legislation or also execution, it remains within the states' autonomous sphere of competence. Federal level responsibilities cover issues that require co-ordination between Länder, such as energy security, while the Länder responsibilities involve issues endemic to each state, such as building code efficiency regulations where diverse local conditions require different types of approaches.

ENERGY SUPPLY AND DEMAND

In 2002, Austria's total primary energy supply (TPES) was 30.4 Mtoe, a 1.4% decline from 2001. This decline was seen mostly in the natural gas and coal sectors and reflects a general decline in economic growth rates compared to the previous years. The five-year average TPES growth rate for Austria is 1.2%, the same as the average growth rate from 1973. For European IEA countries as a whole, the annual average growth of TPES from 1973 to 2001 was 0.9%. In 2002, 43.5% of the country's primary energy came from oil, 21.7% from natural gas, 11.9% from coal, 11.3% from hydro and 11.1% from biomass. Over the last thirty years, both oil and coal have decreased their percentage share of national TPES, replaced by hydropower, biomass and, to a lesser extent, natural gas.

In 2002, Austrian total final consumption was 25.3 Mtoe. This was a 2.5% drop from 2001, mostly occurring in the industrial sector. For the five years leading to 2002, Austrian TFC grew at an annual average rate of 1.5%. This matches the long-term growth in TFC of 1.5% from 1973 to 2002. By way of comparison, TFC for all IEA European countries grew at a rate of 0.8% annually from 1973 to 2002. Transport accounted for 29% of Austria's 2002 TFC, followed by the residential sector (28%) and industry (26%).

ENERGY AND THE ENVIRONMENT

Under the EU Burden Sharing Agreement among EU countries, Austria is committed to reducing its GHG emissions by 13% below 1990 levels by the time of the first commitment period, 2008-2012. The Austrian Parliament ratified this agreement in March 2002 and the EU as a whole in May 2002, making the country's commitment to GHG emission targets legally binding.

In 2002, total GHG emissions from fuel combustion were 84.6 Mt CO_2-equivalent, which was 6.6 Mt CO_2-equivalent, or 8.5% above 1990 levels; 82% of GHG emissions are CO_2 emissions, which are themselves 15.4% above 1990 levels. In order to meet its Kyoto commitment, Austria would therefore need to reduce total GHG emissions by nearly 20% from 2002 levels, one of the most challenging targets in the EU.[2] Regarding CO_2 emissions related to the combustion of fossil fuels, in 2002, oil and oil products accounted for 55.3% of GHG emissions, natural gas accounted for 22.7%, coal 20.2% and other fuels 1.8%. These percentage shares for fuels have not changed substantially in either the short or the longer term. Regarding emissions by sector, transport is the fastest growing segment. In 2002, it accounted for 28.9% of Austrian CO_2 emissions from fuel combustion, up from 21.7% of the total in 1990. Over that span, they have grown at an average annual rate of 3.7%.

In order to curb emissions, the Austrian government has instituted the Strategie Österreichs zur Erreichung des Kyoto-Zieles – Klimastrategie 2000–2008/2012. This plan is being implemented by the Federal Ministry for Agriculture and Forestry, Environment and Water Management. It includes a variety of measures across sectors and industries. It targets both the demand side and the supply side. The combined effect of all the measures is intended to curb emissions by approximately 13.85 Mt of CO_2-equivalent. Energy policy measures from the Energy Report 2003 are broken down by general categories and specific policy tools, and generally correspond to the measures laid down in the Climate Strategy 2008/2012 of 2002.

As a member state of the EU, Austria will participate in the emissions trading scheme. Austria was one of only five countries to submit their National Allocation Plan (NAP) to the EC by the deadline of 31 March 2004. According to the NAP, about 200 installations will participate in the emissions trading regime starting on 1 January 2005. Yearly certificates for 33.1 million tonnes of CO_2 will be distributed free of charge, of which 300 000 tonnes will represent the reserve for new entrant installations.

On 7 July 2004, the European Commission completed its initial review of Austria's NAP. It requested that Austria delete a clause allowing it to transfer allowances from plants that close down during 2005-2007, the first trading period of the EU emissions trading scheme, by 30 September 2004. The EC said this was an *ex post* adjustment and could distort the market.

RENEWABLE ENERGY

Renewable energy plays a crucial part in Austrian energy supply. This comes primarily from hydropower and biomass. In 2002, hydropower accounted for 11.3% of TPES and 66.1% of electricity generation, while biomass accounted

2. This reduction could take place domestically or through the use of Kyoto mechanisms.

for 11.1% of TPES. Other renewable fuels making a contribution were solar energy (0.2% of TPES), geothermal (0.1%) and wind energy (0.1%).

Supporting the generation of electricity by means of renewable sources of energy is a key objective for Austrian energy policy, documented in the European Union's Directive 2001/77/EU to which Austria must adhere and domestically in the Green Electricity Act, which the Austrian Parliament passed in July 2002. The Austrian government regards renewable energy as a significant contribution to protecting against climate change and reducing dependence on imports as well as promoting the opportunity to use domestic fuels for electricity production. In accordance with the Green Electricity Act, by 2008 at least 9% of electricity is to be generated in small-scale hydroelectric plants (<10 MW) and 4% in other government-subsidised renewable plants (mainly wind power and biomass).

Because "green" power is usually more expensive than that generated from other energy sources, the government has introduced a support mechanism to allow it to reach its targets. The Green Electricity Act provides for a support scheme based on minimum feed-in tariffs for "other green power" and small hydro, and for support tariffs for electricity generated by combined heat and power (CHP) plants beginning 1 January 2003.

Under this support system, the control area managers have a take-or-pay obligation in their role as "green" power balancing group representatives. They must allocate "green" power to the electricity traders in proportion to the latter's annual sales volume. The feed-in tariffs are fixed by the Minister of Economic Affairs and Labour in consultation with the Minister of Justice and the Minister of Agriculture and Forestry, Environment and Water Management, as well as the provinces. The Green Electricity Act stipulates that the feed-in tariffs must be based on the generation costs of the most efficient plants of a given technology. It also caps the maximum cost burden.

The cost of the support scheme borne by electricity traders and final consumers is as follows:

- The electricity traders must take a *pro rata* share of the subsidised "green" power at an average price of 4.5 euro cents/kWh (higher than the sales price realised by them).
- The end-users must pay a surcharge on the network tariff averaging 0.12 cent/kWh for power from "other green plants", 0.005 cent/kWh for small hydropower and 0.15 cent/kWh for CHP power.

The feed-in tariffs were originally fixed on a regional basis where a specific feed-in tariff for each *Land* had been foreseen, but this was subsequently changed so that national tariffs would apply equally in all the *Länder*. The overall cost of supporting "green" power on a federal basis is lower than that of provincial arrangements because it enables generating capacity to be deployed where it is cost-effective. Most of the feed-in tariffs are valid for a period of thirteen years from the commissioning of the plants and, according to the Green Electricity Act, must be valid for a minimum of at least ten years. This order applies to all new plants licensed up to the end of 2004 and which begin operation by June 2006.

Concerns about the cost of the feed-in system have prompted government officials to discuss the need for caps on the total amounts spent to support-renewable energy. A draft bill is being formulated that would cap the length of time for receiving feed-in tariffs to ten years. It would also lower the tariffs by 5% annually. The government has noted that the surcharges for green electricity would increase from €247 million to €282 million. According to the government, the feed-in tariff represents an expensive means of cutting greenhouse emissions: approximately €100 per tonne for wind power, €200 per tonne for biomass and €900 per tonne for photovoltaic power, compared to an estimated €7 to €13 per tonne using the EU emissions trading scheme.

ENERGY EFFICIENCY

The reduction of energy demand through better utilisation of energy and by improvements in energy use is one of the two main strategies of the Austrian energy policy. Energy efficiency contributes to the following government policy objectives: *i)* security of supply, *ii)* environmental protection, *iii)* economic efficiency, and *iv)* social acceptance of the energy supply system. Austria has numerous support measures to encourage energy-efficient investments and operations throughout society and industry. Government support is given in the form of loans, grants, investment subsidies, annuity subsidies and project cost subsidies.

In 2002, Austrian energy intensity (measured as toe of TPES per thousand 1995 US$ PPP) was 0.1438. This compares favourably to the OECD European average of 0.1764 and even more favourably to the average for the IEA as a whole, 0.2105. Since 1973, Austrian energy intensity has decreased by 29% compared to a decrease of 34% for the IEA as a whole.

FOSSIL FUELS

Oil is the dominant primary fuel in Austria. In 2002, it accounted for 43.5% of TPES, more than twice as much as the next fuel, natural gas (21.7%). Oil use as a percentage of TPES has remained remarkably constant over the years, ranging from between 40% and 45% since 1984. In general, increased oil use for transport is replacing decreased industrial oil use. OMV is the largest oil company in Austria. Following a series of partial privatisations it is now owned (indirectly through a holding company) 35% by the Austrian federal government.

In 2002, domestic oil production accounted for 8% of TPES. The Austrian retail market for petroleum products is considered competitive, with prices in the mid-range compared to neighbouring countries and the European countries in general.

Natural gas has been a steady source of primary fuel for Austria. Since 1990, it has accounted for between 17% and 24% of TPES. In 2002, it accounted for 21.7% of TPES with domestic fields producing 24.2% of supply and the remainder coming from imports. Austria has long imported gas from the Soviet Union and now Russia. While nearly 100% of physical supply currently comes from Russia, contractual agreements for supply from other countries (primarily Germany and Norway) have been increasing as a means of augmenting energy security. Austria also acts as a major transit country for natural gas with about three times the volume of gas passing through the country than is consumed domestically. All of the transit gas originates in Russia, with nearly 75% going to Italy and the remainder going in smaller amounts to Hungary, Germany and Slovenia.

In recent years, Austria has undertaken a process of liberalisation in the natural gas market. The basis for this transformation was the relevant EU internal market directives. The market was fully opened to competition in October 2002 when all natural gas customers were free to choose their supplier. This was well in advance of EU deadlines for full opening. At the same time, all customers and suppliers were given the right to non-discriminatory access to the gas network at regulated tariffs and terms.

Driven largely by the push for market reform, the Austrian gas industry has seen substantial consolidation in recent years. This began with co-operation agreements between five regional utilities in 2001 and 2002 that created substantial horizontal integration within the industry. This co-operative entity was termed EnergieAllianz and included the provincial utilities of EVN, Wiener Stadtwerke, BEWAG/Begas, Energie AG and the municipal utility Linz AG. Regional utilities purchased the great majority of their gas from the large oil and gas company OMV. In 2002, the gas supply activities for customers above 500 000 cubic metres (cm) per year of EnergieAllianz were split out and these spin-off assets and operation merged together with Oberösterreichische Ferngas with the gas activities of OMV to form EconGas, formally registered in June 2002. EconGas is embedded in the vertically- and horizontally-integrated company structure of its owner, serving over 75% of the Austrian gas market. The majority of remaining customers are served by the regional utilities that did not join EnergieAllianz. The only major foreign competitor in Austria is Ruhrgas Austria, a subsidiary of Ruhrgas Germany. Ruhrgas Austria formed a joint venture ("Terragas") with Salzburg AG to serve large-scale consumers as a means of expanding its market share. New market players regarding supply are Rohölaufsuchungs AG (RAG), MyElectric and Unsere Wasserkraft. Residential customers currently have the choice between four suppliers.

Gas prices are strongly linked to the oil indexation used in the long-term contracts, although they are less volatile than the oil markets because the price movements are lagged by up to three to six months. For industrial customers, changes in natural gas prices since the onset of liberalisation have been driven more by oil price variations than a change in the dynamics of supply resulting from market reform, although competition has assured that decreases in the wholesale price of gas are being passed through to the final customers. Nevertheless, Austrian retail prices for industry are currently in the middle – compared to other European countries on both an *ex tax* and a tax basis.

Most of the benefit of the price reductions touched off by liberalisation has gone to industrial and commercial customers rather than to the residential sector. In addition, the increase of the tax on gas in 2004, from 4.36 euro cents per cm to 6.60 euro cents per cm will largely eliminate any price decreases from competition for residential customers. Prices vary widely across Austria from one *Land* to the next, particularly for the network charges component of the final bill. For example, a standard residential customer in Salzburg pays approximately 70% more for network services than a comparable customer in Vorarlberg. The energy prices (*i.e.* just the gas itself) tend to be inversely proportional to the network charges when looking at different utilities. The regulator, E-Control, suggests that this may be a sign of potentially anti-competitive cross-subsidisation. While residential *ex tax* prices for gas are in the middle range compared to neighbouring countries, prices with taxes are among the highest in Europe.

The regulator, E-Control, has repeatedly tried to lower the regulated rates for network charges. The most recent such network rate adjustment occurred in May 2004 when the regulator announced reductions in network tariffs for seven of the nine provinces. Cuts range from 2.46% in Vorarlberg to 8.21% in Vienna, with cuts of 4.32% in Burgenland, 4.72% in Carinthia, 6.81% in Lower Austria, 6.29% in Salzburg, 5.17% in Styria, and no change in Tyrol or Upper Austria. The regulator claims that this will save consumers up to €25 million annually. Network charges currently make up about 35% of customers' bills.

One means of encouraging competition, and particularly the introduction of new entrants to the market, has been the auction of gas by EconGas. The first such auction was held in 2003 and the second was completed in July 2004 when 10 packets of 10 million cm each were sold off. There were twelve companies bidding for the gas from Austria, France, Italy and Switzerland, which represented an increase in interest compared to the first auction.

ELECTRICITY

Domestic production of electricity is dominated by hydropower. In 2002, hydropower accounted for 66.1% of total generation, followed by natural gas (15.5%), coal (12.3%), biomass (3.1%), oil (2.6%), and solar, wind and other renewables (0.3% combined). While these figures have stayed relatively constant over the last ten years, the government expects coal use to decline by 2010 and more so by 2020, largely driven by climate change concerns. Natural gas is the most likely candidate to replace coal.

As with the natural gas market, the electricity market has also undergone reform. As of October 2001, all electricity consumers have been free to choose their suppliers well in advance of the EU deadline. All consumers and suppliers have non-discriminatory access to transmission and distribution networks. Prior to market reform, Verbund operated as the sole utility with a national focus, owning much of the nation's generation and high-voltage transmission lines, while utilities in each of the nine *Länder* owned and operated distribution networks and handled supply to customers. Cross-holdings among the provincial utilities, and between them and Verbund, are a hallmark of the Austrian power sector. For example, provincial utilities Wienstrom and EVN have interests in Verbund while Verbund held a portion of EVN until selling it to another provincial utility, Estag, at the end of 2002. By law, either the federal or the provincial governments must have a majority ownership stake in all electricity utilities.

Driven largely by this liberalisation process, the electricity industry has undergone a period of consolidation among the major domestic players. A marketing alliance termed EnergieAllianz was formed among five of the major provincial utilities, which in turn partnered with Verbund to form EnergieAustria. The planned creation of EnergieAustria was submitted to the European Commission cartel office for approval which launched a detailed investigation. The Commission approved the merger on 11 June 2003 with a number of conditions. Most of these conditions involved divestiture of Verbund assets, including those of its holdings in MyElectric and Unsere Wasserkraft, effectively removing itself from the downstream retail market. One of the last such divestitures was Verbund's sale of the APC/Austrian Power Vertriebs wholesale organisation to the Slovenian Istrabenz group. Nevertheless, ongoing negotiations between Verbund and EnergieAllianz may delay full and timely implementation of EnergieAustria. Other industry moves resulting from liberalisation include two smaller independent new entrants competing in the niche market of "green" power. Oekostrom AG and Alpen Energia AG are focusing on the sale of electricity from renewable energy plants such as wind and small hydro. Thus far, the new entrants have captured minimal market share. As of year-end 2003, German utility EnBW was the only foreign company to supply final customers in Austria, although a number of others own minority shares in some of the provincial utilities.

The Graz-based Energy Exchange Austria (EXAA) was launched on 21 March 2002. It handles hourly and block contracts on the Austrian spot market. From January to July 2003, an average of 3 360 MWh of power was traded, equivalent to 2.3% of Austria's total offtake of electricity. As a means of increasing volume and defending market share against other European electricity exchanges, EXAA is launching additional products. For example, in October 2003, EXAA introduced spreads to the market which gives traders and other participants more options in buying and selling electricity and related financial products.

Austria, Germany and Switzerland effectively form a single Central European pricing area and there is a very strong correlation between each country's wholesale prices. These prices are in turn connected to the markets of other European countries such as Italy and France. As of March 2003, forward wholesale prices for 2004 through 2006 had firmed considerably, after having dropped substantially in previous years. None of the obvious fundamentals generally affecting electricity prices have changed in a way that would normally precipitate such a change and the regulator has speculated that the rise may be partly due to the influence of market concentration among the major players.

On the retail level, industrial customers have seen substantial drops in the price of their electricity. These price decreases resulted from stiff competition for industrial customers and in many cases negotiated retail prices were below those of wholesale prices as suppliers were willing to take losses in order to gain market shares. Industrial retail prices have since been steadily rising but despite this trend, electricity prices for Austrian industry remain in the mid-range for European countries.

Retail consumers have seen much fewer price reductions than their industrial and commercial counterparts. *Ex tax* prices have certainly declined but this has been offset by increases in taxes. As with natural gas, energy prices vary widely across Austria in each different *Land*, largely owing to variations in the network charges in each province. Where prices have declined in 2002, they have principally done so as a result of cuts in these network charges imposed by the regulator. Austria has some of the highest network tariffs in the EU, approximately 50% above the average in 2002. The regulator is planning on bringing down tariffs further with the aim of reaching a level comparable to European standards within the coming years. Overall, Austrian residential electricity prices are in the middle range of European utilities.

RESEARCH AND DEVELOPMENT

In 2002, government spending on energy R&D equalled €29.2 million. Of this amount, €7.9 million was spent on conservation, €411 thousand on fossil fuels, €9.7 million on renewable energy systems, €3.3 million on nuclear fusion, €169 thousand on nuclear fission and €3.8 million on power and storage technologies.

In 2003, the sub-programme "Energy Systems of Tomorrow" was established within the Austrian Programme on Technologies for Sustainable Development. The goal of this energy programme is to develop technologies and concepts – based on the use of renewable energy sources in an energy-efficient and flexible way – which will allow Austria to meet its energy needs over the long term. The programme seeks to create new opportunities for the economy with innovation encouraged on the following three levels:

- *Structural innovations:* Changes in structure and systems, system behaviour, basic conditions.
- *Social innovations:* Changes in user behaviour dependent on knowledge, attitudes and lifestyle.
- *Technological innovations:* Developments in the entire spectrum from primary energy sources to energy services.

An important quality criterion applicable to all projects to be financed is their potential to make significant contributions to an intelligent overall system solution. The programme supports the integration of Austrian players into international activities such as the EU research programme and the activities of the International Energy Agency. In the course of the calls for proposals, decisive key questions will be progressively identified and addressed, and projects and topics will be further developed with respect to implementation.

The first call for proposals, with two deadlines in autumn 2003 and spring 2004, included the following subject areas:

- Questions related to energy systems, integration of renewable energy sources.
- Innovative production and service systems.
- Specific technology development needs with particular emphasis on system integration.
- Strategic accompanying projects and co-operative international efforts.

A total funding of approximately €3.4 million was directly committed and an additional €0.9 million was kept in reserve.

GENERAL POLICY DEVELOPMENTS

A new Danish government took office in November 2001. This has led to several developments in energy policy. The first change came when responsibilities for energy policy were moved from the former Ministry of Environment and Energy (now Ministry of the Environment) to the Ministry of Economic and Business Affairs.

As a general policy direction, the government envisions an efficient energy market supported by a framework that ensures a high degree of consumer and environment protection, efficient use of energy, moderate developments in energy prices, and a high security of energy supply in both the short term and the long term. The government considers that management of environmental concerns and security of supply can be achieved most efficiently through the energy market.

Following a proposal on the liberalisation of the energy markets submitted by the government in September 2002, an energy policy agreement was signed on 9 May 2003 between the different Danish political forces, promoting the development of efficient electricity companies and ensuring that consumer assets in electricity companies are used in a way that is beneficial to consumers. The agreement also means that there is equal competition between energy companies for the use of electricity and gas transmission grids. The agreement covers all of the following issues:

- Improved possibilities for selling municipality-owned utilities.
- Prevention of price increases as a consequence of sales of monopoly companies.
- Ownership unbundling of system operators and transmission companies (the agreement led to the creation of a state-owned transmission system operator in the gas sector – Gastra).
- Recycling of tied-up capital to electricity consumers.
- Enabling system operators to tender for additional capacity to improve security of supply.
- Providing incentives to grid companies to maintain reliable and stable electricity supply.
- R&D in renewables is improved by DKr 47m annually.
- Modifying support schemes for CHP and renewables to make them more compatible with the open electricity market.

The conditions for long-term development of North Sea activities were also clarified in 2003. By the end of 2003, the Danish Parliament adopted the proposal and the accompanying legislation implementing the agreement of 29 September 2003 between the Minister for Economic and Business Affairs and the company A.P. Møller-Mærsk. This has provided a stable and long-term basis for exploiting the resources in the North Sea, while also affording the State a substantially larger share of profits generated from the activities (see section "Oil and Natural Gas" for details).

On 29 March 2004, three important agreements were signed. The first two were completed between the government and a broad majority of the Danish Parliament (Folketinget): the first agreement concerns securing a reliable energy infrastructure for the future; the second agreement establishes the framework for expanding the number of wind farms and for a better-functioning electricity market. A third agreement was signed between the Ministry of Economic and Business Affairs and Elfor (the Danish Association of Electricity Distribution Companies) determining financial conditions in the electricity supply companies and establishing an independent and state-owned transmission company in the electricity sector.

ENERGY SUPPLY AND DEMAND

In 2003, Denmark TPES amounted to 20.5 Mtoe, growing from 17.6 Mtoe in 1990. Oil accounted for around 42% of the supply, while coal and gas contributed a little less than a quarter, and renewables more than 10%. Denmark remains a net energy exporter, with net oil exports accounting for more than 10 Mtoe (in 2002), gas for more than 3 Mtoe and a certain amount of electricity.

Denmark's final consumption (TFC) was above 15 Mtoe in 2002, or 9% more than the 1990 level. The commercial and residential sectors remain the largest final consumers with 47% of the TFC in 2002. Transport and industry account for 32% and 21% of TFC respectively.

ENERGY AND THE ENVIRONMENT

Energy-related CO_2 emissions reached 51.2 Mt in 2002, up 1.2% from their 1990 level. The energy sector emits most CO_2, and increased exports of electricity to Norway and Sweden will significantly increase emissions in Denmark.

As a consequence of the Kyoto Protocol and the subsequent EU Burden Sharing Agreement, Denmark is committed to reducing average annual emissions of greenhouse gases by 21% in 2008-2012 compared to the 1990 basis year. It is estimated that the excess emissions of greenhouse gas will be 20-25 million tonnes of CO_2-equivalent per year in 2008-2012. This corresponds to between 25% and 30% of Danish greenhouse gas emissions. The costs to Danish society of this excess could be reduced to between DKr 1 and 2 billion per year in 2008-2012 as a result of the government's climate strategy proposed in February 2003.

The Danish government attempts to maintain a high level of efforts to mitigate energy-related emissions through cost-effective measures. This strategy very much involves the energy area, and supplements existing activities. CO_2 quotas at EU level will be the most important instrument in meeting Denmark's climate commitments. The European CO_2 quota system that was agreed upon during the Danish EU Presidency (from 1 July to 31 December 2002) covers energy production and parts of energy-intensive industry. Companies will be allocated a number of quotas in relation to a quota-allocation key. Denmark's allocation plan was among the first national plans to be approved by the European Commission in July 2004.

Today, Danish companies are in a strong position with large exports of environment-friendly energy technologies such as wind turbines and various energy-saving technologies. Companies are already oriented towards the new projected emissions market and enterprises subject to quotas are expected to gradually show more interest and demand for more efficient technologies.

The government considers important that the other environmental aspects in energy production are incorporated when broader cohesive solutions are assessed. For example, noise nuisance and landscape impacts from energy plants should be minimised as much as possible. It is also considered important that energy production from biomass and biogas are combined with considerations in other environmental problems associated with agricultural policy. The government will make it possible to continue expanding biogas use, which, within certain limitations, will be economically advantageous. New biogas installations established before the end of 2007 will benefit from a fixed tariff of DKr 0.6 per kWh over the first ten years, and DKr 0.4 per kWh over the next ten years, within an overall ceiling of 8 petajoules (PJ).

Denmark has made efforts to minimise air pollution from energy production. Measures for removing sulphur dioxide and nitrogen oxides from exhaust gases, replacing coal and oil with gas, and district heating in urban areas have all helped improve ambient air quality in towns, and further measures are on the way. The EU National Emissions Ceilings Directive (NEC), implemented into Danish law in January 2003, contains ceilings for emissions of sulphur dioxide and nitrogen oxides in 2010. Furthermore, the EU Large Combustion Plant Directive (LCP) was implemented in Danish law in 2003.

ENERGY DEMAND AND END-USE EFFICIENCY

Energy production per TPES has grown significantly since 1990, from 0.55 toe to 1.46 toe (in 2002), while the energy intensity of the Danish economy measured as TPES per unit of GDP decreased from 0.11 toe in 1990 to 0.09 toe in 2002.

The gradual decrease of energy intensity is due to improved efficiency in energy consumption at the end-user, and more efficient energy supply, partly as a result of greater use of combined heat and power (CHP).

Efforts by the Danish government to improve energy efficiency emphasise consumer considerations, competition between technologies and solutions, cost-effectiveness, and long-term benefits for society.

More flexible energy consumption, in particular, can lead to improvements in security of supply. It is therefore important that as many energy consumers as possible are able to react to market prices. More flexible electricity consumption can reduce costly peak loads. This is not the case in Denmark today. Demand for electricity is inflexible. Therefore, the Danish government will ensure that the trials in progress in this area are followed up. Such trials are part of grid companies' efforts to assess the flexibility of demand in industry and households.

Just like other energy policies, initiatives for cost-effective energy consumption should be regarded in an international framework. The Danish government is intending to work actively for the development of common tools within the EU to promote energy conservation. The aim is to ensure greater influence with producers and provide greater savings at lower cost, but also to make sure that measures do not affect the competitiveness of Danish companies.

In September 2004 the government announced the preparation of an action plan on energy saving and efficiency. The Energy Authority will publish a report in December 2004 to appraise the demand response of electricity consumers as a way to prepare further possible energy efficiency and conservation measures in a market context, exploiting the flexibility of demand in relation to prices.

RENEWABLE AND NON-CONVENTIONAL FUELS

Exploitation of renewable energy sources such as wind and biomass is taking an increasingly prominent position in Danish energy supply. Capacity development with renewable energy installations continued in 2003.

Renewables are pursuing growth in the total supply. Their share was above 13% in 2003, against close to 7% in 1990. The bulk of it is made of energy from combustible renewables and wastes, but the fastest growing share originates from wind, which, along with solar and other renewables, accounted for 2% of TPES in 2003.

As part of the agreement on the electricity reform in 1999, an objective was laid down that renewable energy-based electricity production in Denmark should represent at least 20% of domestic electricity consumption by the end of 2003. Under what is considered as normal wind conditions, renewable energy capacity installed at the end of 2003 would have contributed about 23% of the national electricity consumption for 2003. The objective has thus been realised.

The renewable energy proportion of national electricity consumption is expected to rise to about 29% in the years to come, primarily as a result of the two new offshore wind farms decided in the latest energy policy agreements.

As a result of the biomass agreement of 2000 and the fixed tariff introduced at that time, there has been an expansion of biomass-based power production. The overall objective of the biomass action plan has been achieved, but in such a way that the amounts of straw are smaller, while amounts of woodchip have been greater than anticipated. Discussions are in progress between the energy sector and the agricultural sector supplying straw on possibilities to use further amounts of straw. The target to build several central power stations has now been more or less achieved. The number of small independent biomass installations, especially wood pellet boilers, is also increasing, and this expansion is expected to continue. The Danish government intends to ensure the quality and environmental properties of the smaller installations through support to testing smaller bio-fuel boilers.

OIL AND NATURAL GAS

Although oil production is projected to decrease in the coming decades, the 2003 figure is still higher than the previous year, with 18.7 Mtoe produced. In 2003, at 7.2 Mtoe, gas production was a little less than in 2002. However, production from the North Sea oil and gas fields is the main reason why Denmark has been self-sufficient in energy since 1997. Technological development has made it possible to exploit a steadily increasing percentage of the oil discovered in Danish territory. A sixth Licensing Round is to be held at the end of 2004 for the purpose of awarding new oil and gas exploration and production licences.

The agreement of 29 September 2003 between the Ministry for Economic and Business Affairs and A.P. Møller-Mærsk sets the framework for the long-term organisation of oil exploration in the North Sea until 2042. The agreement seeks to ensure an optimum exploitation of domestic oil resources, and to secure considerably higher revenue for the State.

From 2004 to 2042, the State's share of profits on these activities is estimated at 61%, subject to certain assumptions with regard to production volumes and oil prices. This represents a substantial improvement over the average 47% share received by the State in the past, and the 40% received in recent years. It appears from the statement to the Danish Parliament on the North Sea of October 2003 that additional revenue of more than DKr 2 billion (€270 million) is anticipated for the period until 2012.

ELECTRICITY

Gross electricity production reached 46 TWh in 2003, growing regularly (from 26 TWh in 1990). More than half of it remains produced from coal, 22% is produced using gas and 12% from renewables (essentially wind). Expressed in terms of domestic consumption only, the share of wind is higher, around 16%, in 2003. Denmark exports significant quantities of electricity, especially to Norway.

On 23 September 2003, a substantial power cut hit Sealand and southern Sweden. Conscious of the challenges this poses for the economy, the government is attempting to establish a stable framework for electricity supply, in co-operation with other Nordic countries.

After liberalising electricity supply in 2000, changes took place in the framework of the electricity sector. Electricity transport and distribution are monopoly tasks, subject to state regulation, while electricity production and trade are subject to competition under normal market conditions.

The political task is to establish a framework for the monopoly tasks that will secure equal access to the grid for all producers, under equal and non-discriminatory conditions. This ensures not only competition for production, but also that consumers are able to choose freely between different producers. This involves creating a stable framework for new investment so that market forces can secure efficient cohesion between consumption and supply.

The system operators play a central role in maintaining an efficient market and in sustaining security of supply.

To ensure segregation of ownership between system operation and overall transmission from production and trade so that the conditions for access to the electricity grid are laid down independently of commercial interests, the government made the State responsible for system operation and overall transmission. To accomplish this, following the agreement with Elfor, the State intends to take over Eltra, Elkraft System, and Elkraft Transmission from the grid companies.

The March 2004 agreement involves the new joint system operation and transmission company "EnergiNet Danmark" remaining in public ownership. EnergiNet Danmark is being set up by statute as a state-owned enterprise that will ensure efficient operation and expansion of the overall infrastructure. EnergiNet Danmark can include a normal return for grid companies in its tariffs for future investment, including possible purchases of regional transmission grids. The remaining surpluses will be transferred back to consumers.

A first right and duty of purchase for the State will be implemented for the regional transmission grids in connection with direct or indirect transfers. Thus, section 38 of the Electricity Supply Act, stating that electricity production and electricity trading companies may not own more than 15% of a grid company, is repealed. In order to bring capital relationships in the electricity sector into order, the definition of capital as free equity capital and tied-up equity capital in the electricity legislation will be amended so that they no longer differentiate between free and tied-up capital.

There is political consensus that the price of electricity cannot be allowed to rise as a result of these changes in the definition of capital and the establishment of EnergiNet Danmark. This will be ensured through new price regulation. There will therefore be no increase in revenue caps due to the modified concept of capital. Thus, the interests of the consumers are still being taken into consideration. An additional part of the agreement is simpler regulation regarding supply obligation and consumer representation, which harmonises with a well-functioning market.

In recent energy policy agreements, it has been decided to prepare a national action plan for the future infrastructure up to 2010. The goals are to secure a greater degree of security of supply, to establish well-functioning competitive markets, and to accommodate renewable energy.

Before 1 March 2005, the Minister for Economic and Business Affairs will present an action plan for the future infrastructure.

The action plan will also describe the future energy supply, the interplay and integration of different energy technologies, as well as the perspectives for future energy supply up to 2025, including use of new energy technologies.

Experience of open electricity markets shows that a well-functioning electricity market and a comprehensive transmission grid that can ensure free movement of energy both domestically and across national borders are equally necessary if production capacity is to be fully exploited. If the transmission grid is to meet this requirement, the action plan will also highlight possible needs to enhance international and domestic grid interconnections.

About a quarter of the total electricity production comes from decentralised combined heat and power plants. Through better regulation and better use of the decentralised plants, the government wants to ensure a better electricity market for all, including the smaller electricity producers. Therefore, the government will implement a number of changes as agreed in the recent energy policy agreements. The aim is for the new regulations to enter into force on 1 January 2005.

Subsidies to existing decentralised CHP plants will be reorganised to secure the plants the same total level of subsidies as under the current three-period tariffs. Subsidies will be regulated in relation to changes in the price of electricity. The government considers that heating prices must not increase as a result of the reorganisation. The aim is to better optimise the supply of power from CHP with demand for electricity and avoid situations where CHP plants produce electricity in excess of what the market can absorb.

Subsidies will be set for individual plants so that total subsidies reflect the size of the subsidy granted to the plant under the three-period tariff. The subsidy period is 20 years from the date the plant is connected to the grid, and no less than 15 years from 1 January 2004. A 2-year transitional scheme will be established for plants of less than 10 MW and a special flexible scheme for small plants of less than 5 MW.

RESEARCH, DEVELOPMENT AND DEMONSTRATION

The government considers it important that energy research contributes to developing useful and environment-friendly new technologies, that will be competitive when needed, *e.g.* in order to replace Denmark's domestic oil and gas production. Research, development and demonstration of new technologies therefore need to be strengthened.

From 2004, an extra amount of DKr 47 million is allocated to research, development and demonstration activities in order to promote exploitation of new energy-efficient technologies. The extra efforts involve a permanent annual increase of DKr 15 million, from 10 to 25 million per year in the financial framework for grid company research and development activities, and an increase of DKr 25 million in allocations to the energy research programme, which will be provided annually over a 5-year period starting from 2004.

Furthermore, DKr 7 million will be earmarked annually for type approval and quality assurance of renewable energy technologies. A legislative amendment will seek to raise financing of state initiatives through taxes expected to be received under the existing CO_2 Quota Act when CO_2 quotas are exceeded.

Financing through CO_2 taxes will be an additional supplement to existing funds, *e.g.* the DKr 110 million allocated to research into renewable energy under the Danish Research Councils for 2003- 2005. Demonstration activities based on strong research environments within renewable energy, new energy technologies, and energy-efficient technologies, must be given extra focus.

To strengthen and facilitate public and private partnerships for R&D, the government is currently working on formalising a co-operation model that will ensure the best synergy between the Renewable Energy Fund of the Danish Research Council, the Energy Research Programme under the Danish Energy Authority, and the electricity companies' Public Service Obligation (PSO) funds.

GENERAL ENERGY POLICY

In 2002, the Ministry of Economics and Technology merged with some parts of the Ministry of Labour and Social Affairs to become the Ministry of Economics and Labour, with responsibility for federal energy policy. The Ministry for the Environment, Nature Conservation and Nuclear Safety was given responsibility for market introduction and project-oriented research on renewable energy sources as well as leading responsibility for the Renewable Energies Act and its further development.

In accordance with the requirements of European legislation and of the government's Monitoring Report, from August 2003 Germany implemented a regulatory authority for the electricity and gas sector in the succeeding months. From July 2004, the draft of a new Energy Industry Act (*Energiewirtschaftsgesetz* – EnWG) assigns the tasks of the electricity and gas regulator to the former Regulatory Authority of Telecommunications and Post (RegTP). The organisational structures and the distribution of responsibilities between the regulator and the anti-trust agencies are included in the same legal framework.

The EU Directive on Minimum Energy Taxes (2003/96/EC) did not have much impact on German energy taxation because taxes were generally already much higher than the minimum levels required by the directive. The "eco-tax" regime was revised by a new act in January 2003. The revision increased tax revenues by about €1.4 billion per year. The changes include the following:

- The standard rate of the petroleum tax on natural gas used for heating was raised from €3.476 to €5.5 per MWh. The increase counts as an additional eco-tax.
- The discounts on tax rates given for electricity, fuel oil, and fuel gas for manufacturing companies, agriculture and forestry were reduced from 80% to 40% of the standard eco-tax rates.
- The former link between eco-tax rebates and pension payments for energy-intensive manufacturing industry has been removed and the rebates now only depend on energy consumption.

The Ministry of Economics and Labour orders regular energy forecasts from independent scientific institutions. The most recent forecast "The Longer-term Development of Energy Markets in Light of Competition and Environmental Factors" dates from 1999. A new forecast called "The Trend on the Energy Markets up to the Year 2030 – Energy Sector Reference Outlook" will be prepared by the Institute of Energy Economics (EWI) and the PROGNOS AG by the end of 2004.

ENERGY SUPPLY AND DEMAND

Germany depends on imports for a large part of its supply. In 2003, it imported 61% of the energy it consumed. In 2003, total primary energy supply (TPES) was 345 Mtoe. TPES has decreased by 3.2% since 1990, partly because of the reduction of energy demand in the eastern part of the country (New Laender) that resulted from economic restructuring. The share of oil in TPES was 36%, followed by coal (25%), natural gas (23%), nuclear (12%) and renewables (3%).

In 2002, total final energy consumption (TFC) of energy was 241 Mtoe, 2.5% under the 1990 level. The residential, services and other sectors (when combined) represent the largest energy-consuming sector (41%), followed by industry (32%) and transport (27%). Consumption has increased by 9% between 1990 and 2002 in transport, declined by 13% in industry and levelled off in the other combined sectors.

ENERGY AND THE ENVIRONMENT

Germany is pursuing two climate change mitigation targets. Its national target, adopted in 1995, is to reduce CO_2 emissions by 25% in the 1990-2005 period. Germany's target within the EU Burden Sharing Agreement under the Kyoto Protocol is to reduce its GHG emissions by 21% (compared to the 1990-1995 levels depending on the GHG) for the first commitment period of 2008-2012. Germany sees the need to further develop the obligations contained in the Kyoto Protocol beyond 2008-2012. In the view of the German government, further ambitious emissions reduction obligations are necessary by all industrialised countries and effective first obligations should be taken by developing countries, to reach a fair balance in the distribution of climate protection efforts between countries. In this context, Germany proposes for the EU as a whole to commit itself to reduce GHGs until 2020 by 30% as compared to the base years 1990-1995, and under this precondition is willing to pursue a 40% reduction target itself.

Germany is on track to meet its climate protection targets under the Kyoto Protocol; in 2002, its total GHG emissions were 18.9% under the base year levels. Meeting the target requires a further reduction of emissions by 25.8 Mt of CO_2-equivalent. The 2002 CO_2 emission levels were about 10 percentage points above the national target for 2005. In the longer term, measures will be needed to offset the estimated 120 Mt of CO_2 emissions caused by the phase-out of nuclear power.

Germany's National Allocation Plan for the EU Emissions Trading Scheme was approved by the European Commission in July 2004. The plan covers about 2 400 existing installations which will be allocated 1 485 Mt of emission rights for 2005-2007.

The federal government recognises both the importance of paying attention to the cost-effectiveness of its policies and the difficulty of doing so. To be able to take better account of cost-effectiveness, it has asked PROGNOS AG to conduct a study entitled "Analysis of the Effectiveness of CO_2 Reduction Measures in the Energy Sector and Their Further Development up to 2015". In this context, the government is interested in encouraging investments in new very efficient power stations and in energy-efficient manufacturing methods because they will also bring other benefits such as job creation and contributing to climate protection on a global scale.

ENERGY EFFICIENCY

The organisation of the Deutsche Energie-Agentur GmbH (DENA), founded in 2000, was finalised at the end of 2002. It now has a staff of over 60 employees and had a turnover of over €5.6 million in the first half of 2004. DENA is involved in promoting energy conservation and renewable energies both at national and international levels.

Major elements of the EU Directive on the Energy Performance of Buildings (2002/91/EC) have already been introduced in Germany, as the Ordinance on Energy Conservation requiring energy demand for new buildings to be lowered by 25-30% and introducing energy certificates for new buildings took effect in February 2002. In December 2002, the Energy Consumption Labelling Ordinance was amended, thus transposing European Directives 2002/31/EC (Energy Labelling of Household Air-Conditioners) and 2002/40/EC (Energy Labelling of Household Electric Ovens) into national law. In February 2004, a further amendment was made to implement EU Directive 2003/66/EC. The Passenger Car Energy Consumption Labelling Ordinance was published in June 2004. It transposes EU Directive 1999/94/EC.

The Ordinance on Maximum Energy Consumption was revised in December 2002 to transpose into national law EU Directives 1996/57/EC (Energy Efficiency Requirements of Household Electric Refrigerators, Freezers, and Combinations thereof) and 2000/55/EC (Energy Efficiency Requirements for Ballasts for Fluorescent Lighting).

In May 2003 an additional €160 million of eco-tax revenues were given to the Kreditanstalt für Wiederaufbau (KfW) for the "Climate Protection Programme for Existing Buildings"; the original budget for the 2001-2005 period was €1.02 billion. This modernisation programme for buildings aims to improve energy efficiency and reduce CO_2 emissions by, for example, substituting other heating forms by renewable energies. If the so-called low-energy standard is reached through energy modernisation, 20% of the loan can be remitted as a special bonus. KfW's "Programme for Modernisation of Living Space" provides low-interest loans for investment in the modernisation and repair of existing housing, including energy conservation measures, and for the improvement of the housing environment. The maximum amount of loans accorded by this programme is €8 billion for the 2003-2004 period. Until the end of May 2004, €2.9 billion of loans had been granted for 80 000 dwellings, especially for energy efficiency measures and the improvement of economic value.

The "Energy Efficiency Contracting in Federally Owned Real Estate" project was initiated in the framework of the government's National Sustainability Strategy of April 2002. The project is designed to contribute to the aims of reducing CO_2 emissions in federal buildings by 25% by 2005 and by 30% by 2010, as compared to the 1990 levels, through energy conservation.

OIL

Oil demand has remained quite steady over the period 1990 to 2002, reaching 125 Mtoe in 2003. Oil's share in TPES increased from 35.5% in 1990 to 38.7% in 2000 and fell back slightly to 36.2% in 2003. Final oil consumption was 120.5 Mtoe, only 2.4% above the 1990 level, but oil's share in TFC rose from 47.6% in 1990 to 50% in 2002.

The long-term forecast for the petroleum industry projects a decline in specific energy consumption, a decline in mileage per passenger car, further substitution of gasoline by diesel and increasing use of alternative fuels. The petroleum industry estimates that oil consumption will decline by 14% between 2002 and 2020. The outlooks for diesel and gasoline are different. Diesel consumption is expected to expand by 5.5% by 2005 and thereafter decline by 6.4% by 2020 as compared to the 2002 level, whereas gasoline consumption is expected to fall by 7.7% by 2005 and drop to 40% below the 2002 level by 2020.

Nearly all of the crude oil used is imported; in 2002 domestic oil production covered 4.2% of oil supplies. In 2003, crude oil imports were 109 Mt. Principal suppliers were the former USSR (39%), Norway (21%), the United Kingdom (11%), the Middle East (10%) and Libya (8%). Germany's oil reserves were estimated at 60.3 Mt at the end of 2002. In 2003, oil product imports were 37 Mtoe and came principally from the Netherlands (54%), with the rest coming from many other countries.

The petroleum market continues, even after the recent major corporate mergers, to be characterised by a large number of market players and effective competition. The number of filling stations continues to fall slightly, from 16 324 at the beginning of 2001 to 16 068 in 2002. In 2002, the largest filling station operator was BP/Aral with 3 385 stations, followed by Shell/DEA with 2 977 stations.

The prices of gasoline and diesel fuel have been largely determined by taxes on petroleum products. At the end of 2002, tax accounted for 73.5% of the price of gasoline and 65% of the price of diesel fuel. The pre-tax prices in Germany have been among the lowest in the EU.

Since the beginning of 2003, nearly all gasoline and diesel sold in Germany has corresponded to the sulphur limit established by the EU for 2005 (partially) and 2009.

The oil emergency stocks held by the stockholding agency (*Erdölbevorratungsverband*, EBV) exceed the minimum requirements established by international commitments. As of 1 April 2004, the level was 116 days of net imports.

NATURAL GAS

Germany is the second-largest European gas market after the United Kingdom. In 2003, total gas demand reached 79 Mtoe, representing 23% of TPES. Natural gas use for electricity generation and heat production accounts for about 20% of total gas demand. In 2002, final gas consumption was 56 Mtoe, of which 63% was used in the residential and services sectors and 37% in the industry sector.

The Energy Industry Act was amended in May 2003 to transpose the 2003 EU Gas Directive, including items such as network definition, rules for interoperability, network access and accounting. In addition, the revised act strengthened anti-trust supervision by making decisions on TPA violations effective immediately after they have been given.

In legal terms, the German gas market has been fully liberalised since 1998. However, the Monitoring Report concluded that competition in the gas sector has not developed as well as in the electricity sector. While there are some signs of competition, there is not yet nationwide competition covering all consumer groups. The report concludes that the main reason for lack of competition is the so-called "contract-path model", which may lead to "pancaking"[3] of TPA tariffs and is not flexible enough for competitive actions. The federal government is now considering replacing it by another model in which the country would be split into several entry-exit zones.

COAL

The decline of German hard coal production over the past four decades continued in 2003. In 2003, production was 25.7 Mt, 0.4 Mt (1.6%) less than

3. "Pancaking" means that two or more access charges are collected in electricity transactions making use of two or more transmission systems.

in 2002. The number of employees in hard coal production declined from 50 082 at the end of 2002 to 46 671 at the end of 2003.

The reduction of hard coal mining is continuing as mergers are reducing the number of mines. One of these was the fusion of Friedrich Heinrich/Rheinland and Niederberg at the beginning of 2002. There are now ten mines in operation, with seven in the Ruhr district, two in Saarland and one in Ibbenbüren, under the roof of RAG.

In September 2003, the Supervisory Boards of RAG and DSK adopted further steps. They are focusing mainly on merging Warndt/Luisenthal with Ensdorf into "Bergwerk Saar" on 1 January 2004, the closure of Warndt/Luisenthal production at the beginning of 2006 and Lohberg/Osterfeld on 31 March 2006.

The coal agreement of 1997 sets the rules for financing Germany's hard coal mining up to 2005. According to RAG's plans, coal production will be 26 Mt and 36 000 workers will still be employed by the hard coal industry in 2005. In July 2003, the state of North Rhine-Westphalia, the IG BCE union and RAG agreed on the key elements of a follow-up agreement for the period of 2006 to 2012. According to the agreement, hard coal production will decline to 16 Mt in 2012. The associated workforce cuts are to be undertaken in a socially acceptable manner.

In November 2003, the government made a decision on financial support to hard-coal mining in 2006-2012. As in the past, aid will be reduced. The assistance provided by federal and state governments will decline from €2.7 billion in 2005 to €1.83 billion in 2012, and the maximum level of support for the period has been set at €15.87 billion. In addition, RAG's own contribution will be €1.13 billion.

In 2002, lignite production reached a volume of 181.8 Mt. This was an increase of 3.7% over the 2001 level. Some 92% of the lignite produced was used for electricity generation in 2002. The remaining output was sold as briquettes, pulverised fuel, and fluidised-bed coal on the heating market.

The government has reached an agreement with Vattenfall Europe AG for a 50 TWh/year sales guarantee for East German lignite for electricity production until 2011. The sales guarantee made it possible to introduce the First Act to Amend the Act for the Reorganisation of Statutes in the Energy Sector on 20 May 2003 to abolish the so-called "lignite protection clause". With this step, electricity production in eastern Germany is fully integrated in the liberalised electricity market.

RENEWABLES

In 2003, the use of renewables and waste amounted to 9.9 Mtoe and their share of TPES was 2.9%. Electricity generation from renewables totalled

52 TWh in 2002 (9.2% of total generation) with contributions coming from hydropower (44%), wind/solar (31%) and combustible renewables and waste (25%). In terms of installed capacity, wind energy in Germany continued to hold a leading position worldwide in 2002.

By 2010, the federal government aims to increase the share of renewable energies in power generation and primary energy consumption to the level of at least 12.5% and by 2020 of at least 20%. To promote this policy, the Renewable Energies Act was reviewed in 2004.

Renewables are promoted principally by the feed-in tariffs introduced by the 2000 Renewable Energies Act, the 100 000 Roof Solar Energy Programme and the Market Incentive Programme. The introduction of the feed-in tariffs in particular has rapidly increased the use of renewables for power generation over the past few years.

The act was reviewed in August 2004 and contains special regulations concerning time duration of feed-in tariffs for the various technologies employed as well as regulations concerning the reduction of renewable energy costs for electricity-intensive industries. The volume of support for heat generation based on renewable energies remains stable.

An international renewable energy conference was held in Germany in June 2004 to promote the worldwide use of renewable energies. The federal government also intends to strengthen the existing Export Initiative on Renewable Energies which promotes the export of technologies for the use of renewable energy systems. The aim is to make German technology known abroad and provide contacts for German companies with potential customers in countries which have the potential to use this kind of energy-producing system.

NUCLEAR

In 2002, the 19 German nuclear power plants in operation produced 165 TWh and covered 29% of total electricity supplies. The average operating time of the nuclear power stations was 86% in 2002.

The 2001 agreement between the government and the power companies on the phase-out of nuclear power was transposed to legislation by amending the Atomic Energy Act, effective as of April 2002. The first unit closed was in Stade in November 2003. The Obrigheim unit is scheduled for closure at the end of 2005. The companies will be responsible for closing down the nuclear power plants, and, with this in mind, appropriate sums have already been set aside and must be available when needed.

Uranium is no longer mined in Germany and uranium ore, uranium-hexafluoride, and enrichment services are purchased on the world market by

German utilities. The Urenco Group, a company operating worldwide in the field of enrichment services, owns an uranium enrichment facility in Gronau. ANF, a subsidiary of Framatome ANP, is a major manufacturer and supplier of fuel elements for the reactors in Germany.

The transport of depleted fuel rods for reprocessing in France and in the United Kingdom will end on 1 July 2005 and, thereafter, nuclear waste can only be disposed directly at final storage. To comply with this governmental decision, the power companies are setting up intermediate storage sites at or near the nuclear power plants.

The Federal Office for Radiation Protection is responsible for the construction and operation of federal facilities for the final storage of nuclear waste. The salt deposits in Gorleben are considered as a possible final storage site. However, the examination of this site has been interrupted for the period of 3 to10 years to resolve concept and safety issues. The project to store low- and medium-level radioactive waste in the former iron-ore mine shaft in Konrad has been suspended owing to legal considerations.

ELECTRICITY

Electricity consumption in Germany was 499 TWh in 2002, 9.7% over the 1990 level. With 51.4% share, coal remains the most important energy for electricity generation, followed by nuclear power (29.1%), natural gas (9.5%), hydro (4.1%), wind and solar (2.8%) and combustible renewables and wastes (2.3%).

The German electricity market is fully liberalised. The Monitoring Report notes that electricity prices declined after market liberalisation but since 2001 they have been rising because of higher wholesale prices and taxation. While the report considers that the Associations Agreements – supported by the competition authorities' supervision of abuse of dominant positions – have facilitated competition, significant improvements are needed to the TPA rules. First, the TPA tariffs should accurately reflect cost (the so-called principle of "efficiently incurred costs", *Kosten der elektrizitätswirtschaftlich rationellen Betriebsführung*) which will be ensured by better transparency and benchmarking of costs. Second, competition should be developed in the supply of frequency and voltage control power (*Regelenergie*), also principally by improving the procurement methods. Third, the possibilities of residential consumers to switch suppliers must be improved by better implementation of the already agreed procedures.

The 2002 act on combined heat and power generation (CHP) created the framework for the development of CHP. The modernisation of CHP plants, which has already started, will require considerable investments. The act requires an interim report to be submitted at the end of 2004 on the expected CO_2 reductions in 2005-2010 arising from the use of CHP, on the economics of CHP generation and on the necessary investments. The impact of the act will have to be monitored closely against the background of price trends on the electricity market. The German act is largely compatible with the EU CHP directive.

RESEARCH AND DEVELOPMENT

The federal government's energy R&D objectives are defined in its "Fourth Energy Research Programme" of 1996 and they continue to apply. However, a new programme is expected during the present legislative period. The primary objective is to ensure that energy supply is secure, affordable and environment-friendly, and that it produces less greenhouse gas emissions. The secondary objective is to develop high technology that will help to create professional jobs and enhance the competitiveness of German industry.

In 2002, the government's energy R&D budget was €265 million, as compared to €293 million in 2001. The estimated total budgets for 2003 and 2004 are approximately the same as in 2002. In 2002, 33% of the budget was allocated to nuclear fusion, 29% to renewables, 13% to power and storage technology, 11% to nuclear fission, 6% to energy conservation, 5% to fossil fuels and 3% to other areas.

Responsibilities in energy R&D continue to be distributed among various ministries. The overall responsibility for the energy research programme lies within the jurisdiction of the Ministry of Economics and Labour. Furthermore, the ministry is responsible for project-oriented research on new energy conversion technologies, technologies for the rational use of energy, and nuclear safety and waste disposal. The Ministry for the Environment, Nature Conservation and Nuclear Safety is responsible for project-oriented research on renewables, except for biomass, which lies within the jurisdiction of the Ministry of Consumer Protection, Food, and Agriculture. Research on nuclear fusion is assisted through the Ministry of Education and Research as well as the institutionally financed R&D activities of the Helmholtz centres. In addition, there are assistance programmes operated by the individual states and some municipalities. The funding from the states, including contributions to the Helmholtz-Gemeinschaft, was about €60 million in 2002.

There is a lot of activity in the area of technology transfer through international co-operation – most recently in the field of renewables. Additionally, bilateral projects have been implemented with Indonesia, China and Brazil. In all cases, the focus has been on the on-site demonstration of new technologies and operations with specific emphasis on the inclusion of foreign partners.

Germany participates in numerous implementing agreements under the IEA and is also working together with international partners as part of the EU's research programmes.

GENERAL ENERGY POLICY

Since the Energy Policy in-depth review of Greece in 2002, there have been no major changes in the overall general policy for security of supply, taxation or other areas, except the institutional setting.

The institutional setting has progressed as the Regulatory Authority for Energy (RAE), which was established in July 2000 to cover the electricity, gas and oil markets, has been fully set up. In addition, the Hellenic Transmission System Operator (HTSO), established in 2000, has now been fully staffed.

ENERGY SUPPLY AND DEMAND

Greece depends on imports for a large part of its supply. In 2003, it imported 66% of the energy it consumed. In 2003, total primary energy supply (TPES) was 29.9 Mtoe, representing a rapid growth of 35% over the 1990 figure. The share of oil in TPES was 57%, followed by coal (30%), natural gas (6.7%), renewables (5.4%) and electricity trade (0.6%). TPES is projected to grow by 36% between 2003 and 2010. The share of natural gas is expected to increase as it will be replacing some coal and oil use while the share of renewables is estimated to increase slightly.

Between 1990 and 2002, total final energy consumption (TFC) grew by 32%, with 11% increase in the industry sector, 28% in the transport sector and 59% in the residential, services and agricultural sectors. The government expects TFC to increase by 44% by 2010. Growth will be strongest in the transport sector (50%), but significant demand increase is also expected in industry (41%) and other sectors (41%).

ENERGY AND THE ENVIRONMENT

Greece ratified the Kyoto Protocol in May 2002. The government agreed to limit the net increase in greenhouse gas (GHG) emissions to 25% above the 1990 levels by 2008-2012 under the European Union (EU) Burden Sharing Agreement to the Kyoto Protocol. However, energy-related CO_2 emissions, which constitute the major share of total emissions, were already 28.2% higher in 2002 than in 1990.

The "National Programme for Reducing Greenhouse Gas Emissions 2000-2010" was adopted in March 2003 to ensure compliance with Greece's Kyoto target. The programme includes a set of emissions reduction measures which have been chosen on the basis of their cost-effectiveness. The areas of activity included in the programme are further penetration of natural gas in all sectors, promotion of renewables, energy conservation in all sectors (*e.g.* promotion of energy-efficient appliances, equipment in the residential and service sectors) and better transport and waste management.

The use of the Joint Implementation or Clean Development Mechanism was not included in the National Programme for Reducing Greenhouse Gas Emissions. However, Greece is reconsidering the issue owing to the introduction of the EU Emissions Trading Scheme (EU-ETS) and the "linking directive". As of July 2004, Greece had not yet submitted its National Allocation Plan for the EU-ETS. The transposition of EU-ETS into national legislation had been assigned to an Inter-ministerial committee and was still in progress.

Urban air pollution is a serious problem in Greece. Air pollution is principally caused by emissions from transport, but also by emissions from heating and industry. Five studies have been completed and five are under way to prepare reduction plans for atmospheric pollution in the ten largest cities. The project is co-financed by the Third Community Support Framework.

ENERGY EFFICIENCY

TPES per capita has increased from 2.15 toe in 1990 to 2.73 toe in 2003. Although it has increased, it is still lower than the average for IEA Europe which was 3.54 toe in 2003. The Greek government expects TPES per capita to reach 3.69 toe in 2010. Energy intensity (TPES per unit of GDP) in Greece has been rising to a level where it has exceeded the average for IEA Europe. While in 2003 the energy intensity in Greece was 0.19 toe per US$ 1 000 at 1995 prices and exchange rates, it was 0.16 in IEA Europe.

At present there is no clearly structured policy, comprehensive programme or targets for energy efficiency. However, some new steps have been taken during recent years. The EU Directives regarding energy labelling of household air conditioning equipment (2002/31/EC) and electric household ovens (2002/40/EC) were transposed in national legislation in 2003 and the Directive regarding energy labelling of household electric refrigerators, freezers and their combinations (2003/66/EC) in 2004. Furthermore, the laws to enforce Directive 2002/91/EC addressing the energy performance of buildings are under preparation and are expected to be finalised by early 2006.

Energy efficiency projects are subsidised under the framework of Greek Development laws and the Operational Programme for Competitiveness (OPC).[4]

4. The programme, which operates from 2000 to 2006, has been launched to co-ordinate the financing coming from the EU Community Support Framework for the modernisation of the Greek economy.

OIL

Total oil supply increased from 12.8 Mtoe in 1990 to 17.2 Mtoe in 2003. Its share in TPES has remained rather steady around 60% since the mid-1980s. In 2002, 46% of oil was consumed in the transport sector, 14% in the power sector, 12% in industry and 24% in the other sectors. The government expects total oil demand to grow significantly, by 32% between 2002 and 2010, with an increase in oil consumption expected in all of the end-use sectors.

Almost all of the oil in Greece is imported. Indigenous production from the Prinos oil field has dropped to 0.9% of total refinery intake. In 2002, 19.1 million metric tonnes of crude oil were imported, about half from the former Soviet Union and another half from the Middle East. Greece is a net exporter of oil products and these exports have been increasing rapidly. In 2002, 3.8 million tonnes of oil products were exported. Greece also imports oil products and these imports were 4.2 million tonnes in 2002. Product imports came from diverse sources, the largest being the former Soviet Union, followed by Italy, non-OECD Europe, Venezuela and the United States.

The Greek average gasoline price was the lowest, whilst the average diesel price was the second-lowest in OECD Europe in the third quarter of 2003. These low prices are mainly due to lower taxes.

The main player in the Greek oil market, Hellenic Petroleum S.A., operates in all market segments, including three refineries. Its market share is 79% in refining and 23% in retailing. It acquired the privately-owned Petrola refinery in September 2003. The merger left only one privately-owned refinery to the market, the export-oriented Motor Oil Hellas, but reduced the state ownership in Hellenic Petroleum. Its new shareholding structure is: State 35.5%, Paneuropean & Industrial Holdings S.A. (Petrola) 24.7%, Hellenic Finance 8.21% and free floating shares 31.6%.

Greece has frequently failed to meet its IEA International Energy Program stockholding obligations of 90 days of net imports plus 10% for unavailable stocks. As of 1 April, the emergency reserves were 83 days. The new oil market law (3054/2002) and a complementary Ministerial Decision 9480/2003 allow all companies to import oil products directly, provided that they meet their stockholding obligation.

NATURAL GAS

The Greek natural gas market is young and under development. Gas consumption began to increase with the first imports of natural gas from Russia in 1996. A LNG terminal started operation in Revithousa near Athens in November 1999 receiving gas from Algeria but Greece is looking to diversify its gas import sources. Gas demand reached 2 Mtoe in 2003 and accounted for

6.7% of TPES. The government estimates gas demand to climb to about 7 Mtoe (17% of TPES) by 2010 driven mainly by gas use in power generation.

The 295-km, 36" Turkey-Greece interconnector (ITG) from Karacabey to Komotini will be commissioned by the end of 2006. The interconnector will make it possible to import gas to Greece from Azerbaijan and Iran and later from Turkmenistan, Iraq, and other countries via the Turkish pipeline system. In December 2003, a 15-year contract was signed between the Greek Public Gas Corporation (DEPA) and BOTAS (Turkey) for the supply of 750 mcm of Azeri gas per annum. A feasibility study for an interconnector between Greece and Italy was launched in March 2004 and is expected to be finalised by the end of 2004.

DEPA constructs, owns and operates the transmission system and the LNG terminal. DEPA is owned directly by the State, except for a blocking 35% owned by Hellenic Petroleum, itself partly state-owned. In 2003, the government opened 35% of DEPA's shares for privatisation and negotiations with the Spanish Gas Natural are at an advanced stage.

Only DEPA is authorised to form new distribution companies. At present, there are three local distribution companies: Attiki (Athens), Thessalonika and Thessalia. The companies had been opened partly for private investments. Consequently, Italgas (Italy) acquired 49% of the distribution companies in Thessalonika and Thessalia and a consortium by Cinergy (US) and Royal Dutch/Shell acquired 49% of the one in Attiki. New distribution companies, one in Sterea and Evia, and one or two in Macedonia and Thrace, are planned to be established through partial private investments. Law 2992 of 2002 allows DEPA to establish new distribution companies without the participation of the local authorities which are, however, entitled to receive 10% of the stream dividends paid by the distribution companies to DEPA.

Greece is an emerging gas market and, therefore, it has a derogation from the EU Gas Directive until November 2006, with a possible further extension past that date if one dominant external supplier continues to exist. However, despite the derogation, the first step of market liberalisation has been taken as Law 3175/2003 opens the Greek gas market, as of 1 July 2005, for power producers and co-generation operators with consumption above 25 mcm per year. This means that 63% of the market will be liberalised. Account unbundling of the different operations of all vertically integrated natural gas companies was required by Law 2837/2000 and consequently DEPA unbundled its accounts in 2001. DEPA submitted to the Ministry of Development a proposal for the first third-party access (TPA) tariffs for the transmission system in October 2003. The new EU Gas Directive (55/2003) granted 30-year derogation from TPA to the three existing distribution companies. Any new distribution company may derogate from TPA for 10 to 20 years subject to EC approval.

COAL

Solid fuel (almost exclusively lignite) demand was 8.9 Mtoe in 2003, 10% above the 1990 level. Further growth of 7% is forecast for the period of 2003 to 2010; 92% of all coal is used for power generation, mainly by the Public Power Corporation (PPC). Lignite is Greece's most important domestic energy source, with a production volume of 8.6 Mtoe in 2002. Domestic production is expected to continue approximately at the current level. Domestic production has been partly opened to private companies but the PPC is still the largest producer.

RENEWABLES

In 2002, energy from renewable sources (including waste) amounted to 1.43 Mtoe. This represents a slight increase from 1990, when energy from renewables totalled 1.1 Mtoe. The contribution of renewables to TPES was 4.9% in 2002. Combustible renewables and waste make the largest contribution, almost two-thirds, to Greece's renewable energy supply.

In 2002, electricity production from renewables was 3.7 TWh, representing 6.8% of total gross generation. Greece therefore needs to rapidly increase its renewable electricity generation to meet its indicative target in the context of the EU Renewables Directive 2001/77/EC, whereby Greece aims at generating 20.1% of its electricity from renewables, including large-scale hydro, by 2010. Wind power capacity has increased from 27 MW in 1995 to 397 MW in 2003; 256 MW of wind power plants are under construction out of a total of 642 MW that have been granted an installation licence. By July 2004, 3 790 MW of wind power plants had received a generation licence. The installed thermal solar heater is 3 100 000 m^2.

Renewable energies are promoted by preferential feed-in tariffs introduced by Law 2244/94 and consolidated in 1999 by Law 2773, which was enacted primarily for the liberalisation of the electricity market, and by grants given by the Operational Programme for Competitivity (OPC). The feed-in tariffs paid by the Hellenic Transmission System Operator (HTSO) are 70% of the low-voltage end-use tariff, except for co-generators using renewable energy who receive 90% of the end-use tariff. In 2004, the average feed-in tariff is €0.067178/kWh in the interconnected system and €0.07955/kWh on the non-interconnected islands. The OPC provides grants to private investments in renewable energy technologies and in co-generation plants of less than 50 MW, with grant levels differing according to technology.

The licensing procedures for renewables have been complex. Law 2941/2001 simplified the process but a number of licences and permits were still required before renewable power generation facilities could be installed. The problem was addressed again by a joint Ministerial Decision 1726/2003 which set time limits for issuing the various environmental permits. These depend on the type of renewable energy involved and geographical location.

Law 3175, adopted in 2003, established rules for the rational use of geothermal energy and asserted the exclusive rights for the exploitation of geothermal energy with the State: the State can, however, assign this role to private investors. The recoverable potential of the two fully explored high-enthalpy fields for power generation purposes amounts to 170 MW_e whereas the probable potential of the whole country exceeds 500 MW_e.

ELECTRICITY

In 2002, electricity consumption was 46.6 TWh, compared to 28.5 TWh in 1990. This corresponds to an average growth rate of 4.2% per year. The government estimates that electricity demand will reach 67.3 TWh by 2010, corresponding to an annual growth rate of 4.7%. In 2002, lignite-fired stations accounted for 64% of total gross electricity production followed by oil (16%), natural gas (13%), hydropower (5.2%), solar/wind (1.2%) and combustible renewables and wastes (0.4%).

To supply the rapidly increasing demand new power plant capacity is needed. Two large new power plants have been commissioned by PPC during the last few years, a 330 MW lignite-fired unit in Florina in 2003 and a 485 MW combined-cycle gas turbine plant in Komotini in 2002. New power plants will be mainly gas-fired but renewable energy generation is also expected to contribute. In July 2004, there was a major blackout in the Athens area, implying that either new capacity or better system management might be necessary.

Taking into account the maximum import capacity (500 MW from Italy and 600 MW from the northern neighbouring countries) the capacity margin of the Greek system is 17%. However, the third EU benchmarking report estimates the capacity margin at –0.3% if imports are excluded and on the assumption that thermal power plants have a smaller net output capacity during summer.

PPC is the main electricity generation company throughout the country. PPC is also the exclusive owner of the electricity transmission system, the interconnections and any future system expansions. However, system operation has been entrusted to the independent transmission system operation company, HTSO. Furthermore, PPC is the exclusive owner and operator of the distribution network as well as of the grid and power plants in the non-interconnected islands. Government ownership of PPC has been gradually reduced to 51.2% since 2000, and 29.3% of the shares are now held by institutional investors, 15.7% by the general public and 3.8% by the Personnel Insurance Organisation. Although 34% of the electricity market has been opened for competition, PPC retains its 97% share of electricity generation as the projects of new entrants are proceeding slowly because of financing difficulties. Several supply and installation licences have been granted for sizeable private projects, including the 12 generation licences which have been given to projects with a total capacity of 4 153 MW. However, only one plant of 400 MW is expected to be commissioned at the earliest in 2005.

Greece both exports to and imports electricity from Albania, the former Yugoslav Republic of Macedonia (Fyrom) and Bulgaria via the northern interconnectors. The total net interconnection capacity with these three countries is 600 MW in each direction. This represents about 6.3% of generating capacity. In 2002, a 500 MW sub-sea interconnection was commissioned between Italy and Greece. Greece is seeking for possibilities to upgrade its links with Bulgaria and with West Europe via Croatia and Bosnia. In addition, Greece and Turkey hope to reach agreement by 2006 on linking their power grids.

Greece's Electricity Market Law (2773/1999) was amended by Law 3175/2003 "Exploitation of Geothermal Potential, District Heating and Other Provisions" to speed up the electricity market liberalisation and to comply with the EU Electricity Directive of 2003. The market was opened for all non-household consumers within the interconnected system on 1 July 2004, representing 60.1% of the market. The law enables the HTSO to sign supply contracts to cover the system balance and to provide auxiliary services. For the first application, the maximum limit for capacity generation contracts has been set at 900 MW, with a supplementary option of another 400 MW of which PPC is eligible to bid for only 200 MW. The new law also provides for PPC to renew and substitute 1 600 MW of the capacity in its existing plants. The law also introduces a power exchange, to be operated by the HTSO, but implementation is still under way. In addition, it introduces shortened and simplified procedures for the reinforcement and extension of power transmission lines.

In May 2004, the EC sent a reasoned opinion to Greece about its failure to respect European legislation concerning common rules for the internal electricity market, specifically the provisions on the unbundling of accounts of electricity undertakings. According to the European Commission, PPC's practice of including the lignite extraction cost into the electricity generation cost may distort competition. Consequently, PPC published its unbundled accounts regarding lignite extraction undertakings in August 2004.

In October 2002, the EC authorised three areas of stranded cost payments to PPC, one connected with the cost of inefficient thermal power stations (maximum €929 million), one with projects related with water resource management (maximum €324 million) and one with contracts to Aluminium of Greece (maximum €178 million).

RESEARCH AND DEVELOPMENT

In 2002 the public energy research and development (R&D) budget for energy was €8.8 million, which is somewhat higher than the €7 million budget in 2001 and €5.7 million in 2000. In 2002, 36.9% of the R&D budget was used on renewable energy, 28.5% on power and storage technologies, 16.5% on energy conservation, 12.3% on nuclear and 6.8% on fossil fuels. The Centre for Renewable Energy Sources (CRES) is one of the major recipients of government R&D financing (mainly project-based). Other recipients are universities and research centres that are working on linking basic science to energy technology, such as hydrogen and fuel cells. Private funding, however, is also rapidly gaining ground in energy R&D in areas such as biodiesel, fuel cells, and photovoltaic and other solar technologies.

GENERAL ENERGY POLICY

On 28 March 2002, Korea became the 26th member of the IEA.

The Korean economy continues to display signs of maturity, with economic growth rates that are slower today than in the years that preceded the Asian economic crisis of 1997-1998. Economic growth was a strong 6.3% in 2002, but decreased to 3.1% in 2003, a relatively high level compared to other IEA countries. Being totally dependent upon primary energy imports, Korea has a strong influence on the world energy markets as the third-largest crude oil importer, and the second-largest importer of liquefied natural gas (LNG) in 2002.

Following the publication of the "Vision and Development Strategies for Korea's Energy Policy toward 2010", Korea released "The Second National Energy Plan" in December 2002. Pursuant to Article 4 of the Rational Energy Utilization Act, every five years the Minister of Commerce, Industry and Energy is obligated to formulate a 10-year National Energy Plan.

Accordingly, the objectives of the 2002 National Energy Plan are as follows:

- To promote a stable supply of energy.
- To promote energy conservation to enable a rational use of energy and stabilise energy demand.
- To minimise energy-related environmental damage and to promote the development of energy-related technologies.
- To formulate directions and strategies for mid- and long-term national energy policies as well as the basic guidelines for all other energy plans by sector, source and region.

The 2002 National Energy Plan projects total energy demand to increase by an annual average of 3.1% from 2001 to 2010 and by an annual average of 2.4% from 2001 to 2020 to reach 312 Mtoe in 2020. Per capita energy demand, which stood at 4.1 toe in 2000, is projected to increase to 5.3 toe and 6.2 toe in 2010 and 2020, respectively. The assumption behind these forecasts is that, in addition to the existing energy policies, planned policies, such as the First Plan for Electricity Supply and Demand, the Sixth Long-term Plan for Natural Gas Supply and Demand (2002), are also carried out. However, the government plan to increase the share of new and renewable energy was not reflected in the forecast.

ENERGY SUPPLY AND DEMAND

In 2003, Korea's TPES reached 209 Mtoe, up 2.6% from 2002 and 125% above the 1990 level. The growth of TPES since 1990 amounts to a high 7% growth per annum. The share of oil in TPES was 49%, followed by coal (22%), nuclear (16%) and natural gas (10%).

By 2002, total final energy consumption had more than doubled since 1990, reaching 138 Mtoe, an annual growth rate of 7.5% that exceeded the economic growth rate during the same period. Likewise, per capita primary energy consumption grew from 2.2 toe in 1990 to 4.3 toe in 2002. By 2002, per capita consumption of both petroleum and natural gas had only recovered to pre-1998 levels.

Less than half of final energy is consumed by the industry. Energy consumption in the transport sector is gradually expanding along with the steady increase in the number of cars. Its share is relatively stable, at 24% of TFC. As for the residential and commercial sectors, energy consumption in these sectors is expected to expand gradually as income levels continue to rise, living space expands, home appliances get bigger, and service industries grow rapidly. Together they contribute 30% of TFC.

ENERGY AND THE ENVIRONMENT

Energy CO_2 emissions increased from 226 Mt in 1990 to 451 Mt in 2002. Total GHG emissions, of which energy-related emissions are the largest component, increased at an annual average of 5.1% from 1990 to 2002. The growing trend of greenhouse gas emissions will continue if considerable efforts to reduce emissions are not made.

As the implementation period of the first action plan to address the climate change (1999-2001) in Korea came to an end, the government rearranged the national programmes and established the second action plan (2002-2004) in March 2002. The plan promotes R&D on GHG reduction technologies, including new and renewable energy, and medium- and large-scale technologies; it expands GHG reduction programmes in all sectors (industry, transport, residential, waste management and agriculture), in particular through establishing an integrated management system for energy conservation; it facilitates the use of Kyoto mechanisms such as the Clean Development Mechanism and Emissions Trading by implementing a range of supporting programmes and by the development of a GHG registry system (by 2005). The plan foresees the adoption of a CO_2 emissions trading system at a later stage, with an emissions reduction target.

In 2003, the government revised the Rational Energy Utilization Act, which had been enacted in 1979 and revised in 2002, with the aim of promoting both the efficient use of energy and the reduction of greenhouse gases. In this context, the government made it mandatory for any public energy planning effort to include actions for GHG reduction. This applies to the National Energy Plan, the Basic Plan for Rational Energy Utilization and the Regional Energy Plan. The revised act also broadened the scope of greenhouse gases, so that the six greenhouse gases prescribed in the Kyoto Protocol (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6) are included.

New legislation and policies to mitigate air pollution were enforced. The Special Act on Seoul Metropolitan Air Quality Improvement was, enacted in December 2003, and will enter into force on 1 January 2005. The act includes the implementation of total pollution load management in industries, gradual emissions reduction through the widespread introduction of low-emission vehicles, attachment of pollution-reducing devices to cars, and other concrete measures to reduce air pollution. By legislating this special act, the government aims at markedly improving the air quality of the Seoul metropolitan area to the level of other advanced OECD countries within ten years

Recognising the seriousness of the air pollution situation in Korea, the government has implemented a "CNG Bus Supply Plan" in 2000 in order to lower the level of air pollutants in large cities. By the end of 2000, 58 CNG buses were plying the roads, and this number rocketed to 3 803 by the end of 2003, thanks to a variety of public measures such as economic incentives for CNG bus purchase, support funds for fuel, and an increase in the number of the refuelling stations.

ENERGY EFFICIENCY

Overall energy intensity now seems to have stabilised at 0.3 (toe per $1 000 of GDP in 1995 US$), after having increased in the 1990s from 0.27 at an annual average of 1.4%, essentially through investments in energy-intensive industries.

Aware of the high energy intensity and external dependence of the Korean economy, the government is trying to curb energy consumption through various measures. In the short run, with the high oil prices observed in recent years, the government implemented immediate measures to curb the growth of oil demand, especially in the transport sector. In the medium and longer run, the government is attempting to rationalise energy prices by eliminating subsidies and increasing taxes on several energies (see below section on oil). The government also has energy efficiency measures being implemented by the Korea Energy Management Corporation (KEMCO; founded in 1980) promoting energy service companies (ESCOs) and voluntary agreements.

OIL

Though still large, oil's contribution to TPES and TFC is slowly decreasing. Oil represented a little above half of TPES in 2003 (110 Mtoe), compared to 54% in 1990 (50 Mtoe), and 63% of TFC in 2002 (87 Mtoe), compared to 68% in 1990 (44 Mtoe).

With no domestic oil reserves, Korea imports all of its crude oil. This represented around 2.3 million barrels a day in 2003, as oil imports recovered to their pre-Asian financial crisis level of 1997. Korea is one of the main exporters of refined products in Asia. Thus, Korea's economy is highly vulnerable to oil price fluctuations and hikes.

This dependence on oil imports has led the government to implement a policy of securing and diversifying the country's oil supply and developing a short- and a long-term approach to oil security.

For short-term security purposes, Korea has developed a strategic petroleum reserve, managed by the state-owned Korea National Oil Corporation (KNOC). Strategic stocks reached their highest level in 2004, with 113 days, equivalent to the previous year's oil imports in January of that year (108 in June 2004). Korea has regularly increased its strategic reserve over recent years, in line with the IEA requirements.

For longer-term supply, KNOC is pursuing equity stakes in oil and gas exploration around the world. KNOC has 17 overseas exploration and production projects in 11 countries. This includes seven producing fields in Yemen, Argentina, Peru, the North Sea, Indonesia, Libya and Vietnam, and three fields under development in Yemen, Venezuela, and Vietnam. KNOC is also exploring domestic blocks offshore from Korea. The government expects KNOC to provide 10% of the country's oil needs by 2010.

Partly to promote energy conservation and rationalise oil products prices, the government is reforming the relative price system of petroleum products by modifying their respective taxes. This is being implemented in six stages, from July 2001 to July 2006, with the goal of adjusting the relative price of petroleum products to the level of non-oil producing countries of the OECD. In particular, the government wants to reduce the price differential between gasoline, diesel and LPG for cars. The government intends to double the relative LPG price to bring it to half the gasoline price. The government will also increase the price of diesel by 40% relative to gasoline. Finally, the government has applied a similar policy to reduce the differential between the price of kerosene used for cooking and the prices of LPG and natural gas.

COAL

Coal's contribution to TPES continues to decrease. It represented 22% of TPES in 2003 (46 Mtoe), against 28% in 1990 (26 Mtoe). Domestic production of anthracite coal is Korea's only domestic fossil energy source, but its production is decreasing. It represented an equivalent of 1.4 Mtoe in 2003 against 7.6 Mtoe in 1990.

Coal and fuel oil have traditionally been the two staple fuels for domestic heating, but are now being surpassed by lighter alternatives such as LPG and kerosene. Coal still provides 40% of Korea's electricity production, but most of this is imported bituminous coal. Whilst the expansion of LNG facilities and nuclear power will limit the growth of coal use, it is likely to remain a significant fuel source and a counterbalance to Korea's over-reliance on oil.

Bituminous coal supplies come essentially from Australia, China, and the US. The state-owned electricity company KEPCO has invested in several Australian coal mines. China has become a significant supplier of coal to Korea since 2000 as its coal export volumes have increased, displacing some of the volume from Australia.

NATURAL GAS

Natural gas is the fastest growing energy of the TPES. It grew from less than 3% in 1990 to 11% in 2003, with 22 Mtoe.

The Basic Plan for Restructuring the Gas Industry was completed in November 1999 and the government tried to implement the plan as scheduled. However, the plan was strongly opposed, especially by trade unions refusing the possible privatisation of KOGAS and the unbundling of imports and sales activities from the operation of terminals and transmission facilities. Opponents have been contesting the real benefits of the plan for both KOGAS and end-users. Thus, gas market reform has hardly progressed since 2000. With regard to introducing competition into KOGAS's import/wholesale sectors, the final decision on whether to split the sectors from KOGAS or to open the field to new entrants will be made following sufficient discussion among the interested parties. In March 2003, the government announced that the terminals and transmission facilities of KOGAS would maintain their present status under a state-owned corporation given the strong public interest nature of the sector.

The uncertainty over the future structure of gas industry has some implications on the security of gas supply. It has led to delays in KOGAS concluding agreements with new LNG suppliers while additional volumes of LNG beyond current contracts will be necessary by 2004. In the short term, the increased demand is likely to be satisfied through purchases on the spot market.

Large-scale end-users in Korea are currently considering direct imports of LNG. POSCO (Pohang Iron and Steel Corporation) and SK Corporation have already obtained approval to do so from the government. In 2004, they concluded LNG import contracts with Indonesia, and they are now constructing a receiving terminal in Gwang-yang. Local gas distribution companies and district heating companies are also interested in importing LNG directly.

The government is now considering the new method for implementing gas industry reform through deregulation, which allows new players to enter the LNG import/sales business. The new method has merit in terms of easier implementation of the reform by expanding the scope of direct imports without modifying the existing legal framework and thus avoiding opposition. The government requested KOGAS to let POSCO-SK use the trunk line and KOGAS agreed.

In addition to LNG imports, Korea began producing a small amount of domestic natural gas in November 2003. KNOC's $320 million Donghae-1 development project is building a natural gas deposit offshore from Ulchin in south-eastern Korea estimated to contain about 7 bcm of reserves. Donghae-1 is a relatively minor development, however, and will satisfy only an equivalent of 2% of Korea's current natural gas demand.

Meanwhile, Korea is also exploring the possibility of a natural gas pipeline from the Kovykta natural gas deposit in the Irkutsk region of Eastern Siberia.

RENEWABLES AND NON-CONVENTIONAL FUELS

Renewables represented 1.8% of TPES in 2003, a small figure compared to the IEA average of around 6%. The bulk of renewables is combustible renewables and wastes, with 3.2 Mtoe in 2003. Hydro represented 0.4 Mtoe for the same year. This share has been growing regularly over the past few years.

For many years, the emphasis on the development of renewable energy resources in Korea has been limited. However, the country's dependence on external oil and gas and a political willingness to fight climate change are triggering more policies to develop renewables.

The government also formulated the Second Master Plan for Developing and Disseminating New and Renewable Energy Technologies in December 2003, and selected three major areas which have viable market potential: hydrogen fuel cells, photovoltaic and wind power. Accordingly, the government determined a goal to boost the share of renewables to 5% of TPES in 2011 and decided to concentrate support for technology development and deployment in these areas through RD&D, third-party finance, investment tax credits and obligations.

The government considers that there has been insufficient investment in the development of new and renewable energy technologies and a lack of support for disseminating such technologies. In 2002, the government revised the 1987 Alternative Energy Act (Act on the Promotion, the Development, Use and Dissemination of New and Renewable Energy). According to this revision, Korea established a centre for new and renewable energy development and dissemination in February 2003, and introduced a certification system for new and renewable energy facilities.

The government wants to modify the structure of renewables' overall contribution to TPES with a smaller share of combustible waste energy (57% of total renewables in 2011 against 94% in 2002), a larger share of small hydro (12% in 2011 against 0.1% in 2002), wind (10% in 2011 against 0.1% in 2002), and biomass (8% by 2011 against 4% in 2002).

ELECTRICITY AND NUCLEAR

ELECTRICITY

Along with the rest of the economy, electricity production and demand have been growing steadily. Production reached 345 TWh in 2002, against 281 TWh in 2001. In 2003, coal remained the leading fuel, with around 40% of the generation, followed by nuclear (38%) and gas (13%). Gas is the fastest growing fuel with 46 TWh in 2003 against 9 TWh in 1990.[5]

Following the January 1999 Basic Plan for Restructuring the Electricity Industry, the generating assets of the state-owned Korea Electric Power Corp. (KEPCO) were separated into six competing entities in 2001, paving the way for partial privatisation. According to the plan, five of these entities are supposed to be sold, while the last one, which owns nuclear and hydro assets, will remain state property. KEPCO had been planning to sell a 34 to 51% stake in the first of these units in 2003 – Korean South-East Electric Power (KOSEPCO) – but the process was repeatedly delayed partly because of fierce union opposition, but also because of financial uncertainties facing key potential buyers, reducing the prospect of these sales' revenues.

The distribution/retail sector was expected to be separated from KEPCO and divided into several companies by April 2003. However, during the course of the restructuring process, it was postponed by more than a year. Finally, in June 2004, the government decided to halt the split of the distribution business from KEPCO following a recommendation by the Korea Tripartite Commission, and the plan for introducing wholesale competition based on demand-side bidding has been suspended.

To reduce the electricity price differential between industrial and residential/commercial consumers, the government is now implementing a three-stage electricity tariff reform policy from 2003 to 2006. Measures to achieve this goal were taken by the government in January 2003 and March 2004. The government has a plan to adopt an incentive regulation such as RPI-X in order to enhance competitiveness of the electricity supply industry.

Following the restructuring plan mentioned above, large consumers have the option of participating in wholesale competition since 2003. Consumers

5. Electricity production using gas began in Korea in 1986.

above 50 MW contract capacity are eligible to buy power from either Korea Power Exchange. For customers living in certain areas, electricity can be provided by a third party (local franchised electricity provider) other than KEPCO.

NUCLEAR

As the government expects demand for electricity to grow at a rate above 4% per annum in the coming years, future plans envisage the development of more nuclear power plants to fulfil a large part of this additional demand. A dozen nuclear plants are planned before 2015.

With regard to radioactive waste management, the government announced a plan to secure a radioactive waste disposal site in May 2003, which has been a pending national issue for a long time. The local government which volunteered to make such facilities available was supposed to be provided with financial support for regional development. Starting from June 2003, the government initiated promotional visits to four candidate areas to explain the potential benefits to local inhabitants and to identify a suitable disposal site. After this visit, Buan – in the middle south-west of Korea – was considered to be the best place for the repository. However, because of strong resistance from local residents and NGOs, in February 2004 the government announced that it would start to receive bids for a new site in which the radioactive waste repository will be built. With this announcement, not only Buan but other provinces can also bid for the site. This announcement focused on guaranteeing the participation of citizens and securing the safety of the repository.

RESEARCH AND DEVELOPMENT

The fund for government energy R&D comes from the Electric Power Industry Basis Fund and the Energy Project Special Account. The amount of R&D funded through the Electric Power Industry Basis Fund increased from 72.5 billion won in 2002 (€50 million), to 98.4 billion won in 2003 (€70 million), and this should be used for the R&D on stabilising the electricity supply, strengthening market competitiveness, environment-friendly electricity supply technology and innovative electric power technology.

Also, the government supports the development and dissemination of new and renewable energy technologies with money from the Energy Project Special Account, arising from a surcharge on the price of imported oil, kerosene, natural gas and LPG sales. In 2002, the Energy Project Special Account generated 25.9 billion won (€18 million) for R&D (5.4 billion won for fuel cells, 4.7 billion for photovoltaic and 3.3 billion for wind power). In 2003, the total amount of R&D increased to 33 billion won (€23 million), fuel cells to 7.5 billion won, photovoltaic to 5.1 billion, waste to 4.1 billion and wind power to 3.7 billion).

UNITED KINGDOM

GENERAL ENERGY POLICY

On 24 February 2003, the UK government published a policy paper, the White Paper "*Our energy future – Creating a low carbon economy*". The Energy White Paper highlighted three major challenges: *i)* climate change, *ii)* the decline of the UK's indigenous energy supplies and *iii)* the need to update much of the UK's energy infrastructure. To meet these and other energy challenges the government established four main goals:

i) To put the UK on a path to cut CO_2 emissions by 60% by around 2050, with real progress by 2020.

ii) To maintain the reliability of energy supplies.

iii) To promote competitive energy markets in the UK and elsewhere.

iv) To ensure that every home is adequately and affordably heated.

The White Paper is based on the following key principles:

- Energy investments are generally long-term and suppliers and consumers need the government to set clear goals and a strategy that supports them in making long-term investments.
- The cheapest, cleanest and safest way of meeting policy objectives is to use less energy. Energy efficiency should improve far more in the next 20 years than in the last 20.
- A well-designed, transparent and open energy market is the best way of achieving efficient outcomes.
- The UK will need to continue to use emissions trading as well as other measures to reduce carbon.
- The nationwide and local electricity grids, metering systems and regulatory arrangements will need restructuring over the next 20 years to support the emergence of far more renewable energy and small-scale, distributed electricity generation.
- The future energy system will require greater involvement from English regions and from local communities, complemented by a planning system that is more conducive to investment in infrastructure and new electricity generation.
- Diversity of energy supply is the best way to protect against supply interruptions, sudden price rises, terrorism or other threats to supply. International relations will be increasingly important to achieve the UK's overall energy aims.

- The government will maximise the use of market-based and/or voluntary mechanisms, promoting regulations only where they are necessary and well designed.

More specifically, the government will increase support for renewable energy by £60 million. This is in addition to the extra funding announced in the 2002 Spending Review, which allocated an additional £38 million for energy policy objectives in 2005-2006. The government aspires to double renewables' share of electricity generation by 2020 from the 2010 target of 10.4%. The government will simplify and streamline the planning process for renewable energy developments. The government will extend the Energy Efficiency Commitment beyond 2005 for domestic suppliers and consider whether there is scope to extend it beyond the domestic sector. The government aims to bring forward the date of the next major revision of the Building Regulations for new buildings and existing stock to 2005. The government will set an example by improving energy efficiency in public buildings and procurement. The UK will work with its EU partners to improve energy efficiency standards.

Regarding taxation, the rate of the climate change levy (a tax on the business use of energy to encourage greater efficiency and to reduce emissions of carbon dioxide) has remained frozen since 2001. Energy-intensive sectors can obtain an 80% discount from the climate change levy by entering into climate change agreements to improve energy efficiency and meet emissions targets. In the 2004 budget, the government announced that, subject to EU state aid approval, it would extend the eligibility criteria for climate change agreements to business in sectors that pass an energy intensity threshold and can in some cases demonstrate the existence of international competition issues. The government also announced that it will introduce the equivalent climate change levy discount for those installations in climate change agreements that would like to enter the EU Emissions Trading Scheme instead, once that scheme is up and running. Electricity from combined heat and power plants and coal-mine methane sold via licensed electricity suppliers was made exempt from climate change levy on account of their positive environmental benefits. Lastly, the budget of 2003 includes a duty incentive of 20 pence per litre for bioethanol to be introduced from 1 January 2005.

ENERGY SUPPLY AND DEMAND

In 2003, the UK's estimated total primary energy supply (TPES) was 229.5 Mtoe, a 1.3% increase from 2002. From 1999 to 2003 TPES declined by an average annual rate of 0.1%, and from 1973 to 2003 the average annual UK TPES growth rate was 0.2%. For European IEA countries as a whole, the annual average growth of TPES from 1973 to 2003 was 0.9%. In 2003, 37.45% of the UK's primary energy was estimated to come from natural gas, 34.3% came from oil, 16.7% from coal, 10.1% from hydro and 1.4% came from renewable energy, primarily biomass. Over the last thirty years, both oil and coal have lost substantial shares of TPES, replaced largely by natural gas and, to a lesser extent, by nuclear power.

In 2002, UK total final consumption (TFC) was 158.3 Mtoe, a decrease of 2.1% from the 2001 figure. For the five years leading up to 2002, UK TFC grew at an annual average rate of just 0.2%, and since 1973 it grew at a rate of 0.3%. By way of comparison, TFC for all IEA European countries grew at a rate of 0.8% annually from 1973 to 2002. Transport accounted for 33% of the UK's 2002 TFC, followed by the residential sector (27.8%) and industry (24.7%).

ENERGY AND THE ENVIRONMENT

Under the EU Burden Sharing Agreement under the Kyoto Protocol, by 2008-2012 the UK must reduce its GHG emissions by 12.5% compared with 1990 levels. The country has already seen a reduction in CO_2 emissions resulting from the "dash for gas" in power generation in the late 1990s. This involved the large-scale construction of gas-fired power plants replacing coal due to industry restructuring, technological advancements and domestic gas finds. In 2002, total CO_2 emissions from fuel combustion were 5.5% below 1990 levels.[6] Natural gas accounted for 37.4% of these emissions, followed by oil (36.6%) and coal (25.9%). In the baseline year of 1990, coal accounted for 42.9% of CO_2 emissions and gas just 18.9%. Regarding emissions by sector, electricity and heat generation accounts for the greatest share (29.9%) followed by transport (24.8%). However, over time emissions from electricity and heat production and from industry are decreasing as those from transport increase.

In March 2002 the government launched the UK Emissions Trading Scheme. This was the first ever large-scale programme in which participants could trade the right to emit greenhouse gases. Thirty-one organisations ("Direct Participants" in the scheme) have voluntarily adopted targets to reduce their emissions against 1998-2000 levels by 11.88 million tonnes of CO_2-eq (carbon dioxide equivalent) over the life of the scheme (2002-2006). In the first year, the Direct Participants achieved emissions reductions of 4.64 million tonnes of CO_2-eq against their baselines and in the second year they achieved emissions reductions of nearly 5.2 million tonnes of CO_2-eq against their baselines.

The EU Emissions Trading Scheme will begin in 2005 with its first trading period running until 2007. This will create an overlap of at least two years with the UK scheme. A report by the UK Comptroller and Auditor General,

6. These and all statistics (unless otherwise noted) come from IEA databases. UK government data show CO_2 emissions approximately 2 percentage points below IEA data.

published in April 2004,[7] acknowledges the complexities of integrating the two systems, especially given the important differences in their respective rules. The report also notes the "learning benefits" that the UK scheme has engendered and how this will benefit the UK participants in the EU-ETS. The UK government has submitted an application on behalf of the Direct Participants in the UK scheme to opt out of the EU scheme for the first two years, although it is currently not clear how many will do so, *versus* how many will make the transition to the new Europe-wide programme.

As part of the EU-ETS, the UK government was required to submit a National Allocation Plan (NAP) detailing how many and in what manner the emission allowances would be distributed among installations covered by the scheme. The UK government submitted its NAP to the European Commission on 30 April. On the basis of the available projections, the UK NAP predicted that this would cut CO_2 emissions by 15.2% compared with 1990 levels by 2010. On 7 July 2004, the Commission commented on the already submitted NAPs (including the UK's). Five plans – from Denmark, Ireland, the Netherlands, Slovenia and Sweden-were accepted unconditionally. The Commission generally lauded the UK NAP, saying it provided a "sound basis for further discussion", but it wanted the UK government to provide more information on how new entrants would be treated and details of allocations for installations in Gibraltar. The deadline for the UK to respond to these changes was 30 September 2004.

The Carbon Trust is one of the major government initiatives to curb emissions. The Carbon Trust is a non-profit organisation intended to accelerate the take-up of cost-effective, low-carbon technologies and other measures by business and the public sector. The aim of the Carbon Trust is to help the UK move towards a sustainable, low-carbon economy whilst maintaining business competitiveness. In the short term, the organisation will concentrate on helping businesses save energy and money. In the longer term, it will develop the UK's capacity to meet the problems of climate change, considering not only commercial and technological factors but also wider socio-economic factors that hinder the move towards a low-carbon economy.

Carbon Trust funding in 2002-2003 was around £50 million, drawn from Climate Change Levy receipts and from the government's Energy Efficiency Best Practice Programme (EEBPP), which is the UK's main energy efficiency information, advice and research programme. The Carbon Trust delivers independent information and impartial advice on energy efficiency and carbon management to the business and public sector through its Action Energy and Carbon Management programmes. It also invests in the development of low-carbon technologies in the UK from the research stage through pre-commercial and commercial applications. On 6 August 2002, the Carbon Trust took over responsibility for managing and promoting the government's Enhanced Capital Allowance (ECA) scheme for energy-saving technologies.

7. "The UK Emissions Trading Scheme, A New Way to Combat Climate Change".

ENERGY EFFICIENCY

From 1 April 2002 to 31 March 2005, the *Energy Efficiency Commitment* (EEC) to be enforced by Ofgem places an obligation on electricity and gas suppliers to help their domestic customers, particularly those on low incomes, to make improvements in energy efficiency to save energy and cut their fuel bills. The government estimated that the average annual financial benefit for low-income consumers would rise to around £14 a year by 2005 and for all consumers to around £11 a year by 2006. The proposed overall target for the EEC is energy savings of around 64 TWh, with 50% of the energy savings coming from customers receiving benefits or tax credit. The EEC is expected to cut greenhouse gas emissions by around 0.4 million tonnes of carbon a year by 2005.

In addition to these programmes, a number of already established schemes continue to operate. These encompass the *Energy Efficiency Best Practice Programme* (EEBBP), the UK's main energy efficiency information, advice and research programme aimed at commercial and industrial (including business transport) services, the public sector and all types of housing. The Carbon Trust took over responsibility for the non-domestic part of the EEBPP on 30 June 2002 and relaunched it as Action Energy. The Energy Saving Trust took over responsibility for the domestic part of the EEBBP in March 2003.

The government has several programmes for energy conservation in public buildings. In February 2003, the government announced new energy conservation targets for government buildings which, among other goals, will aim to cut carbon emissions by 29% between 1990 and 2011. The government has recently adopted effective minimum standards as part of its approach to sustainable procurement which, if more widely adopted, would help achieve volume take-up of efficient technologies. The UK Climate Change Programme gave a commitment to benchmark schools to improve their energy management over a five-year period. It is expected this will lead to 10% energy savings, equivalent to a reduction of 0.16 million tonnes of carbon over the next nine years. For the bodies of the National Health Service, the government has set a mandatory target to reduce energy consumption by 15% (equivalent to 0.15 million tonnes of carbon) of 2000 levels by 2010. For local authorities, the Home Energy Conservation Act (HECA) 1995 requires local authorities with housing responsibilities to submit an energy conservation report identifying practicable and cost-effective energy conservation measures. In the first six years to March 2002, local authorities reported an overall energy efficiency improvement in the residential sector of just over 10%. The 2003 Energy White Paper includes plans to review the energy efficiency guidance issued to local authorities.

Regarding transport, the government launched its Powering Future Vehicles Strategy in July 2002. The objectives of the strategy are: *i)* to promote the development, introduction and uptake of clean, low-carbon vehicles and fuels and *ii)* to ensure the full involvement of the UK automotive industry in these technologies. A number of measures are in place to achieve these objectives, including fiscal and grant incentives for consumer and business take-up of cleaner vehicles and fuels, and research, development and demonstration funding for new technologies, including the Ultra Low Carbon Car Challenge to develop ultra-efficient family vehicles, capable of mass production, and the Low Carbon Bus Programme to prove the in-service viability of efficient bus technologies. It also sets targets that by 2012, 10% of new cars sold in the UK will be low-carbon vehicles, defined as 100 or less grams of CO_2 per km at the tailpipe (compared with the current new car average of 178 g) and 600 new buses joining the fleet yearly (around 20%) will also be low-carbon.

RENEWABLES AND NON-CONVENTIONAL FUELS

In 2002, renewable energy provided 1.3% of the UK's TPES. Biomass was the largest contributor (1.0% of TPES) followed by hydropower (0.2%), wind (0.05%), solar thermal (0.01%) and trace amounts of geothermal and photovoltaic energy. The UK has one of the lowest percentage shares of renewables' contributions in the IEA.

The Renewables Obligation (RO) is the primary means that the UK government is using to increase renewable energy production. Introduced in April 2002, the RO requires all licensed electricity suppliers in England and Wales to supply a specified and growing proportion of their electricity sales from a choice of eligible renewable sources. Individual suppliers are responsible for demonstrating their compliance to the energy regulator Ofgem, through a system of Renewables Obligation Certificates (ROCs). In order to provide a stable and long-term market for renewable energy, the obligation will remain in place until 2027.

On 1 December 2003, the government announced specific targets for the RO beyond 2010. The previous target was to have 10.4% of electricity generation come from renewables in 2010. In 2003, the percentage of electricity coming from renewable resources was 3.1%, up slightly from 3.0% in 2002. This target level will increase by 1% yearly to 2015 when a minimum level of 15.4% of electricity generation will come from renewables. Other recent changes include the treatment of co-firing with biomass. Up to 31 March 2009, any biomass can be co-fired with no minimum percentage of energy crops. From April 2009 to March 2010, 25% of co-fired biomass must be energy crops and from April 2010 to March 2011, 50% will be required. From April 2011 to March 2016, 75% is required and after that, co-firing will cease to be eligible for ROCs.

FOSSIL FUELS

In 2003, coal provided an estimated 16.7% of national TPES. Total coal production in 2002 was 29.9 million tonnes, with 16.3 million tonnes from deep mines and 13.1 million tonnes from opencast sites. Provisional figures for

2003 show that total production has decreased to 28.2 million tonnes, with 15.6 million tonnes from deep mines and 12.1 million tonnes from opencast sites. In April 2002, there were 12 major deep mines in production and 8 smaller mines. There were 46 opencast sites in production and one site developing. In July 2002. UK Coal Plc announced that it was to phase out production at the Selby Complex, with complete closure due by summer 2004. The last deep mine in Scotland, Longannet Colliery, owned by Scottish Coal Ltd, closed in April 2002 owing to flooding.

A new state aid scheme, Coal Investment Aid, was introduced in 2003, with a total budget of £60 million available over three years to help eligible producers. Successful applicants will receive up to 30% funding for projects which maintain access to coal reserves and safeguard or create employment. Under the first application period, offers worth £40 million have been accepted.

In 2003, oil was estimated to account for 78.8 Mtoe of UK TPES, or 34.3% of the total. Domestic production was 110.7 Mtoe, with net exports of 29.18 Mtoe. The UK government expects to be a net importer of oil by around 2010 as reserves in the North Sea are depleted. In 2003, natural gas was estimated to account for 85.8 Mtoe of UK TPES, or 37.4% of the total, making it the country's most important primary fuel. Domestic production was 92.5 Mtoe with net exports of 6.7 Mtoe. The UK government expects to be a net importer of gas by around 2006 as reserves in the North Sea are depleted.

Government policy in upstream production is designed to maximise production from domestic reserves as long as possible. To achieve this end, the licensing system was reformed with the introduction of two new licences: *i)* the "promote" licence, at a tenth of the cost of a traditional licence, to attract new smaller investors, and *ii)* the "frontier" licence, to ensure the maximum opportunity for appraisal of prospects west of Shetland. The "Promote UK" campaign is promoting the UK Continental Shelf to new potential investors, particularly those from North America. The Brown Fields Initiative is ensuring that operators pursue all economic options available to maximise overall production from existing fields.

There have also been a number of tax changes. To remove a barrier to investment in older fields, the government abolished royalties from 1 January 2003. On 1 January 2004, the Petroleum Revenue Tax on all new third-party tariff business relating to the use of pipelines and other infrastructure was also eliminated. To encourage exploration, the government is introducing a new Exploration Expenditure Supplement to reduce barriers to entry for new companies that do not receive the full benefit of current 100% exploration and appraisal capital allowances.

The UK has a mature, competitive gas market. Recent developments have been incremental rather than fundamental. National Grid Transco's (NGT) new investment incentive regime is now in place. It comprises price signals generated by new long-term entry capacity auctions for the right to flow gas into the National Transmission System. The first annual long-term entry capacity auctions took place in January 2003. Transco is not required to build all of the incremental capacity bid for in the auctions, but it does have investment incentives under its new price control (for the period 2002-2007). Transco has already allowed £400m investment at St Fergus under its 2002-2007 price control.

As with the oil market, the major government policy initiatives for natural gas involve creating the proper framework for maximum exploitation of remaining domestic reserves. Some of these initiatives are:

- *RTPA exemptions:* Exemptions for certain new gas import infrastructure projects from the requirement to offer regulated third-party access.
- *Gas quality/specification:* Arising from the country's growing import dependence, the government is currently assessing policy options for handling future gas supplies that do not comply with the UK's gas quality specifications.
- *Information flows:* The Department of Trade and Industry has been working with offshore gas producers, Transco and Ofgem to improve information flows to Transco to improve security of supply and to assist efficient operation of the market.

As the UK becomes progressively reliant upon gas imports, a potential issue arises from the incompatibility of the "gas quality" specifications (composition) of the new supply sources with the regulatory requirements of the UK's Gas Safety (Management) Regulations. The UK government therefore launched a 3-phase "Gas Quality" exercise in June 2003 to assess the implications. Phase 1, an independent consultancy study, concluded that the quality of many potential future gas imports is likely to fall outside the limits set down in the GS(M)R. The Minister for Energy consequently launched Phase 2 of the exercise, a consideration of possible policy responses, in January 2004. A series of parallel research exercises during 2004 will seek to address specific technical aspects of the available options, and will inform decisions on future policy recommendations.

On the international side, in June 2003 the government concluded a memorandum of co-operation with the Russian government on Gazprom's proposed North European Gas Pipeline, aimed at working together in identifying and seeking to mitigate non-commercial risks. Also in 2003, the government agreed with the Norwegian government the principles to be incorporated in a new Framework Treaty for future cross-border oil and gas co-operation.

A number of gas import projects are now under active development. They include: expanded/new interconnector capacity with continental Europe; a new pipeline from Norway; and three new LNG import terminals. These terminals would handle gas from such sources as Norway, the Netherlands, Russia, Algeria, Qatar, other LNG exporters, or other sources of piped gas or LNG into continental Europe, thus giving the UK a more diverse infrastructure and a more diverse sourcing of gas.

A number of gas storage projects are also under development, targeting the opportunity provided by the progressive loss of the seasonal swing capacity that has traditionally been provided by the southern North Sea fields (now in decline).

The government has continued to work with the downstream oil industry on developing its contingency measures in the event of disruption. In November 2003, the revised contingency measures (the Downstream Oil Emergency Response Plan) was reviewed favourably by the IEA as part of the emergency response review of the UK.

ELECTRICITY AND NUCLEAR POWER

In 2002, electricity accounted for 18.1% of UK TFC, roughly the same average as the IEA European countries as a whole. Final consumption of electricity in the UK has grown at an average annual rate of 1.2% from 1973 to 2001, well below the approximately 2.6% annual average rate for the IEA European countries as a whole. On the basis of estimates for 2003, natural gas-fired plants generated 37% of the country's electricity, followed by coal (35.7%), nuclear (22.7%), biomass (1.6%), oil (1.5%), hydro (1.2%) and solar and wind technologies (0.3% combined). Over the long term, the generation shares of coal and oil have fallen substantially and were largely replaced with natural gas and nuclear power.

As with natural gas, the electricity market is both mature and competitive. The February 2003 Energy White Paper affirmed that the government would not intervene in the electricity market "except in exceptional circumstances, such as to avert, as a last resort, a potentially serious risk to safety". The White Paper also rejected calls for a capacity margin instrument, saying that the case for such an instrument had not been made and noting that the market already provides strong financial incentives for suppliers to contract for sufficient power. The market functioned well over winter 2003/04, with rising wholesale prices leading to mothballed generating plant being returned to service, following earlier concerns that generating capacity would not be sufficient. Plans to extend, and where necessary modify, the England and Wales trading arrangements to include Scotland and bring about a single wholesale electricity market in Great Britain ("British Electricity Trading and Transmission Arrangements") are being taken forward under the 2003 Energy Bill. A single Great Britain market is due to start operating in April 2005.

On 28 August 2004, London experienced a major power outage. 400 000 commuters were stranded for several hours before electricity service was fully restored. UK regulator Ofgem concluded that the outage resulted from the incorrect installation of equipment that was designed to protect the system from power surges. They conclude that "It is clear from our investigation that these power cuts were isolated incidents on the National Grid. Customers should not see them as signs that the network is suffering from lack of investment. The national grid network in this country is 99.9999% reliable." The UK has seen no other major outages since that time.

The 2003 Energy White Paper stressed the need to develop the existing transmission network to exploit the UK's onshore and offshore wind resources and noted that discussions were already taking place between Ofgem and the transmission operators on plans to upgrade the network across the whole country. The present transmission price control on the National Grid Company is due to run until 31 March 2006. In May 2004, Ofgem set out initial proposals for extending the price control for one year to align it with price control review dates for other transmission asset owners in both electricity and gas.

The White Paper also pointed out the need for changes in the way that electricity distribution networks are regulated in order to accommodate higher levels of distributed generation such as renewables and combined heat and power. Ofgem's proposals for new price controls on distribution network operators, due to take effect from April 2005, were set out in June 2004 and cover charges for network use, investment, incentives for quality of service provision, and measures to respond to growth in renewables generation.

In the late summer 2002, privately-owned nuclear operator British Energy (BE) disclosed substantial financial difficulties. The company cited four factors causing problems:

i) *Lower electricity prices:* Mostly as a result of the New Electricity Trading Arrangements (NETA) rules enacted in March 2001, wholesale electricity prices have fallen by 25% since the introduction of the new rules.

ii) *Climate change levy:* This new tax, implemented from April 2000, costs BE £80 to £100 million annually.

iii) *Waste reprocessing costs:* BE claims that the £300 million annual price it pays to the government-run British Nuclear Fuels ("BNFL") for waste reprocessing is too high.

iv) *Business rates:* Business rates are 50% higher for nuclear facilities than they are for gas and coal-fired power stations.

On 9 September 2002, the company received a loan from the UK government of £410 million enabling the company to continue operations. On 26 September, this loan was increased to £650 million to "provide working capital for the business and collateral". The loan was originally due to expire on 29 November 2002 but through a series of extensions and different restructuring plans, the government has continued to support British Energy. No plants have been shut down or had their capacity reduced owing to these financial problems. The current £5 billion government-backed rescue plan for British Energy is now being probed by the European Commission on the grounds that it may amount to illegal state aid. Under the plan, the government will take financial responsibility for the company's decommissioning liabilities.

In July 2002, the UK government published a White Paper entitled "The Nuclear Legacy: A strategy for action" in which it set outs its policy to create a strategic body to take forward the decommissioning and clean-up of civil public-sector nuclear sites. The government followed up this initiative by drawing up draft enabling clauses for inclusion in the Energy Bill. The Energy Bill is now going through the parliamentary process. If successful, the legislation will enable the setting-up of the Nuclear Decommissioning Authority (NDA). The NDA would take responsibility for the assets and liabilities on the sites currently operated by the United Kingdom Atomic Energy Authority (UKAEA) and British Nuclear Fuels Limited (BNFL). The NDA would be responsible for setting the strategy – and funding – for decommissioning and clean-up on the 21 UKAEA and BNFL sites, which include nuclear reactor sites, former research reactor sites and nuclear chemical sites. The NDA would receive its funds from the Department of Trade and Industry. The UK's civil public-sector nuclear liabilities are currently estimated at around £50 billion. The NDA is scheduled to become operative on 1 April 2005.

The "CHP Strategy to 2010" was published on 26 April 2004 in support of the government's target of at least 10 GW of Good Quality CHP capacity by 2010. The strategy sets out a framework to support the growth of CHP capacity, bringing together the measures in the 2002 draft CHP Strategy and those in the 2003 Energy White Paper. The government's aim through the strategy is to provide a framework in which business can plan long-term investment in CHP plants with greater certainty. Current modelling indicates that the government's target will be missed by around 1.5 GW. Barriers to uptake of CHP have been addressed through a range of fiscal incentives, regulatory framework, grant support, promotion of innovation, and government leadership and partnership.

Many of the measures in the strategy have already been introduced, *e.g.* Climate Change Levy exemption on all Good Quality CHP electricity outputs and, more recently, adopting a 15% target for government departments to use CHP-generated electricity. Others are being worked on, including reviewing existing guidance on power station consents to ensure full consideration of the CHP option which has been redrafted.

RESEARCH, DEVELOPMENT AND DEMONSTRATION

The government is looking closely at energy research needs across the board in the light of the 2003 Energy White Paper. In December 2003, the government published its "Innovation Report", which looked at the contribution that innovation can make to the UK economy. One aspect of this was the Technology Strategy, which will identify technology priorities and stimulate an industry-based technology programme. The Technology Programme, with some €225 million available over three years, will support collaborative R&D in priority areas, including renewable energy and sustainable technologies.

In the nuclear field, the government has a number of programmes to support research in nuclear fission as a means of keeping the nuclear option open. New initiatives include:

- New opportunities for fission research that have been announced as part of the Research Council's "Towards a Sustainable Energy Economy" initiative. Up to £5 million being made available over four years.
- Research opportunities through the European Union's Framework Programme for Research and Development (FP6 Euratom) and OECD co-ordinated research programmes.
- UK participation in the development of the Generation IV International Forum international research programme.

UNITED STATES

GENERAL ENERGY POLICY

Energy policy in the United States is determined both at the level of individual states and at the federal level. Consequently, energy market and policy development yields a highly dynamic and complex picture, of which only the main features can be rendered in this review.

Growing reliance on imported oil was a major consideration in the development of the government's National Energy Policy (NEP) issued in May 2001. The National Energy Policy places a priority on increased domestic production and energy efficiency, and conservation improvements through technological development. In particular, the NEP aims at reducing external oil dependence to less than half of US needs by 2011. The NEP also sought to introduce US$ 34 billion in tax cuts and other incentives to boost oil, gas and coal production, and other energy initiatives. This was granted preliminarily with the passage of the Securing America's Future (SAFE) Bill through the House in early August 2001, a bill focusing largely on facilitating domestic energy production. A second part of the Energy Policy, known as the Energy Policy Act, was passed in the Senate in April 2002. This bill focuses on improving co-ordination and integration of energy policy at the federal level, stimulating domestic oil and gas production, increasing energy efficiency and integrating energy and climate change mitigation policies. The Senate and House passed two different versions of the corporate tax legislation that includes a 10-year, approximately $18 billion package of tax incentives. The two bills are in the process of being reconciled in Conference Committee.

SUPPLY AND DEMAND

The US is the world's largest energy consumer, with more than 25% of global consumption of oil, natural gas, coal and nuclear energy. In 2003, it imported close to 30% of its energy needs, and 60% of its oil. It has the world's largest reserve for coal.

TPES grew at an annual rate of 1.4% since 1990, to reach 2 291 Mtoe in 2003. The share of oil in TPES was 40%, followed by coal (23%), natural gas (23%), nuclear (9%) and renewables (4%).

In 2002, TFC was 1 557 Mtoe, 1.2% up from 2001 and growing at a 2.5% annual rate since 1990. Transport represents the largest energy-consuming sector (40%) followed by the residential/commercial sector (31%) and industry (30%).

CLIMATE CHANGE

The US is a signatory to the U.N. Framework Convention on Climate Change (UNFCCC). Although the US signed the Kyoto Protocol to the UNFCCC in November 1998, it has not ratified it.[8] Nonetheless, the US government is committed to achieving the goals of the UNFCCC.

The US energy sector released 5 652 Mt CO_2 in 2002. Approximately 85% of greenhouse gas emissions from anthropogenic sources come from energy production and use. Between 1990 and 2002, carbon emissions increased by 17%. By 2015, they are expected to rise to 40% over 1990 levels. US carbon emissions are about equally split between the transport (32%), industry (29%), and commercial/residential (38%) sectors.

In February 2002, the government set a national goal to reduce greenhouse gas emissions intensity by 18% in 2012. To this end, the Administration has worked to engage industry sectors in voluntary partnerships – such as the Climate VISION (Voluntary Innovative Sector Initiative) Program in 2003 and SmartWay Transport Partnership in 2004 – to decrease growth in greenhouse gas emissions, develop improved standards for measuring and registering emissions reductions, promote energy efficiency and conservation, and create incentives for emissions reductions.

Internationally, the United States has formed 14 bilateral partnerships with key industrial and developing countries — representing more than 70% of global greenhouse gas emissions — on advanced energy technologies, climate monitoring and modelling, climate research, observation systems, and other activities – in co-ordination with the Climate Change Science Program.

The Climate Change Science Program's (CCSP) strategic plan, released in July 2003, is an effort of the government to advance knowledge of climate variability, the potential response of the climate system to growing greenhouse gas concentrations, the implications of these potential changes, and management options for natural environments. The plan also supports better observation systems that will be a crucial element in improving the understanding of climate change.

The Climate Change Technology Program (CCTP) co-ordinates and prioritises the government's nearly $3 billion annual investment in climate-related technology research, development, demonstration and deployment. The CCTP's strategic vision focuses on reducing emissions from energy use and infrastructure and from energy supply, capturing and sequestering CO_2, reducing emissions of other greenhouse gases, measuring and monitoring emissions, and bolstering the contributions of basic science.

8. The Kyoto Protocol calls for the US to reduce its emissions by 7% below 1990 levels by 2008-2012.

The Administration's fiscal year 2004 climate change spending request totalled more than $4.3 billion, which includes R&D funding on all technologies achieving low or zero emission levels (such as hydrogen, bioenergy, carbon sequestration, nuclear fission and fusion, etc.).

In February 2002, the government launched the Clear Skies Initiative, which is expected to cut power plants' emissions of sulphur dioxide, nitrogen oxide and mercury, through the implementation of a cap and trade system. The objectives of the Clear Skies Initiative are to:

- Cut sulphur dioxide (SO_2) emissions by 73%, from current emissions of 11 Mt to a cap of 4.5 Mt in 2010, and 3 Mt in 2018.
- Cut emissions of nitrogen oxides (NO_x) by 67%, from current emissions of 5 Mt to a cap of 2.1 Mt in 2008, and to 1.7 Mt in 2018.
- Cut mercury emissions by 69% – the first-ever national cap on mercury emissions. Emissions will be cut from current emissions of 48 tonnes to a cap of 26 t in 2010, and 15 t in 2018.
- Set emission caps to account for different air quality needs in the East and the West.

ENERGY EFFICIENCY

Energy intensity of the US economy expressed in TPES per unit of GDP ($1 000 at 1995 price) was equivalent to 0.24 toe in 2003.

The government has developed specific sub-goals in these areas with a time horizon to 2010. With respect to energy efficiency, the government strives to:

- Reduce energy consumption per gross square foot in federal facilities by 30% in 2005 and 35% in 2010, compared to 1985.
- Through hybrid and electric propulsion R&D, reduce the cost of a high-power 25 kW battery for use in light vehicles from $3 000 in 1998 to $500 by 2010.
- Between 1991 and 2010, contribute to a 20-25% decrease in energy intensity (Btu per unit of industrial output as compared to 1991) by the energy-intensive industries participating in US Department of Energy's (DoE) Industries of the Future programme (a potential energy savings of 3.6 to 4.5 quadrillion Btu); by 2020, contribute to a 30 to 35% decrease in energy intensity from 1991 (a potential saving of 6.3 to 7.4 quadrillion Btu).
- Improve the energy efficiency of the approximately 1.3 million new residential homes built each year and the 100 million existing homes, through research, development, demonstrations, and technology transfer

strategies aimed at energy uses such as space heating and cooling, ventilation, water heating, lighting, and home appliances.

- Achieve $3 billion in annual export sales of energy efficiency technologies, creating about 100 000 jobs in the country.

Support to research and development projects is considered as particularly important, but other mechanisms are also in use (energy efficiency legislation and standards, attempts to overcome institutional barriers to energy efficiency, *e.g.* through financial assistance and promoting energy savings performance contracting).

OIL

In 2003, oil amounted to 40% of the TPES, or 925 Mtoe, growing from 770 Mtoe in 1990. Net imports represented close to 60% of the total. Final oil consumption was 833 Mtoe in 2002, 19% above 1990 level. Transport consumed almost three-quarters of this amount, industry accounted for 20%, and 7% were used in other sectors.

The US remains the world's third-largest oil producer with 359 Mtoe in 2002, down from 433 Mtoe in 1990, as well as the world's single biggest consumer of oil.

Demand for imports is likely to carry on growing as oilfields in the lower 48 states reach maturity. This fact has led the government to formulate incentives to boost domestic production, improving exploration and drilling technology. The government also streamlined the process by which permits are granted for important energy projects, such as pipelines and refineries; and accelerated the leasing of non-restricted federal lands where environmentally appropriate. The NEP also called for the development of the Arctic National Wildlife Refuge (ANWR); however, it was voted down by the Senate in 2003.

The NEP endorsed adding oil to the Strategic Petroleum Reserve (SPR) using the Royalty-in-Kind (RIK) programme. On 13 November 2001, the government ordered the SPR to be filled to its maximum capacity, approximately 700 million barrels, by continuing to use the RIK programme carried out jointly between the DoE and the Department of the Interior. The RIK programme applies to oil owed to the US government by producers who operate leases on the federally-owned Outer Continental Shelf. These producers are required to provide from 12.5% to 16.7% of the oil they produce to the US government. Between November 2001 and August 2004, approximately 119 million barrels of oil have been added to the reserve, rising from 545 million to 664 million. Deliveries continue at the rate of 100 000 to 200 000 barrels per day. The reserve is expected to be filled to capacity in 2005.

NATURAL GAS

Deliveries of gas to end-use customers in 2003, according to preliminary US data, amounted to an equivalent of 523 Mtoe, compared to 436 Mtoe in 1990. Gas represented close to a quarter of the TPES in 2003. Domestic production was equivalent to 87% of the total gas supply.

In 2003, production and net imports decreased by less than 2.7 billion cubic metres (bcm) as demand for natural gas slowed down. Working gas inventories increased by about 5.4 bcm in 2003. Total natural gas consumption in 2003, according to preliminary 2003 data, decreased to 622 bcm after an increase of 21.6 bcm, or just over 3%, in 2002. Although below the record high of 661 bcm in 2000, total consumption in 2002 was still the second-highest level ever. A primary factor contributing to this increase is a larger stock of gas-fired generating capacity. Gas consumption grew by 24% between 1998 and 2002 in the electric power sector as a result of the large build-up during the past couple of years of gas-fired generation plants, which have been viewed by industry as environmentally and economically advantageous to other fuels for electric generation. However, gas consumption in this sector declined in 2003, to a level that was 7% greater than in 1998. In 2002, approximately 51 000 megawatts fuelled by natural gas came on line. This was approximately 82% of the electric generating capacity that came on line during the year.

As consumption evolves in each of the sectors, the trend differences may have important implications for natural gas markets. At present, electric power use of gas is the third-largest consuming sector. It moved ahead of residential consumption in 1998 through 2002, but fell back to third in 2003. Industrial use of natural gas during the same period has declined from 41% of end-use consumption to less than 35%, according to preliminary 2003 data. The residential, commercial, and electric power-consuming sectors exhibit seasonal variation in their consumption. Consequently, the share of the market driven by seasonal factors is growing, which may add to seasonal fluctuations in aggregate demand.

Net imports to the United States in 2003 decreased for the second year in a row, to 94 bcm, or nearly 6% below the level for 2002, according to preliminary 2003 data. Net imports were about 3% lower in 2002 than in 2001. This had been the first decline since 1986.

LNG imports have grown significantly over the last couple of years from the levels of the 1990s, although they still accounted for only about 1% of total supply in 2002. LNG imports during 2002 totalled 6.5 bcm. The largest supplier of LNG to the US in recent years has been the Atlantic LNG facility, located at Point Fortin in Trinidad and Tobago, which supplied 66% of LNG imports in 2002. It supplied about 75% in 2003, according to preliminary 2003 data.

2003 was a crucial year for the US gas industry as prices hit record levels in February and March with spot prices at Henry Hub peaking at an average of \$18.85 per MBtu on 25 February 2003 and remaining relatively high throughout all of 2003 and the beginning of 2004. Spot gas prices at Henry Hub averaged \$5.47/MBtu in 2003. This is an indication of the tight supply/demand situation, putting pressure on the need for additional external sources of gas to meet demand in the US in the future. The US still possesses over 5 200 bcm of proven natural gas reserves, but production levels now tend to apparently peak around 500 bcm per year. Incentives are being offered to encourage more gas exploration, while plans for the construction of new LNG terminals progress to enable increased imports. The National Energy Policy proposes the construction of over 38 000 miles of new natural gas transmission pipelines. To find ways to manage short-term natural gas shortage, the government organised a gas summit in June 2004.

Although higher prices for natural gas and price volatility have dampened the interest for retail competition, restructuring of the gas markets is progressing at the state level. As of December 2003, five states had 100% eligibility for consumers to choose their suppliers, eight states were unbundling commodities and services and implementing more retail competition, and eight states were in the process of developing pilot programmes for unbundling and introducing competition.

COAL

The United States produces and consumes over one billion short tons of coal per year, second only to China. It is the US's most abundant fuel source and, at present consumption trends, will last about 250 years. Over 99% of US coal production is consumed domestically, with electricity generation accounting for about 90% of coal consumption. Virtually all projections show coal continuing to supply around half of the nation's electricity for at least the next 20 years.

After peaking in 1982, coal prices have generally declined on a per-Btu basis. This trend is projected to continue through 2020, reflecting an expanding shift into lower-cost western coal production and substantial increases in productivity. While coal is expected to remain the dominant fuel in meeting US electricity demand through 2020, energy policy goals must be carefully integrated with environmental policy goals. The Clean Air Act Amendments of 1990 and related state regulations require electricity generators to reduce emissions of sulphur dioxide and nitrogen oxide.

Among other initiatives, the DoE is implementing the government's \$2 billion, 10-year initiative to develop and improve the generation of coal-based electric power and pollution control technologies that will be environmentally superior to the technologies used in today's power plants. The pollution-free power plant, FutureGen, as announced by President Bush in February 2003, is expected to be a $1 billion, coal-fuelled prototype plant intended to prove the technical and economic concept of the world's first zero-emission fossil fuel plant co-producing electricity and hydrogen. And, under the Clear Skies Initiative, the DoE is developing new pollution control technologies that can meet tighter standards without resulting in major cost increases for ratepayers.

ELECTRICITY

Electricity production reached 3 984 TWh in 2003, a 24% increase over the 1990 production level of 3 203 TWh. While coal remains the nation's major fuel with 52% of total generation, natural gas is growing in importance and represents 17% of gross electricity generation; 20% comes from nuclear, 8% from hydro and 3% from oil. Most forecasts envisage that the largest number of power plants to be built in the next 20 years will consume natural gas. Natural gas is also likely to be a primary fuel for distributed power generators – mini-power plants that would be sited close to where the electricity is needed.

There is a general perception at state level that slowing down reforms is unlikely to eliminate opportunities. All states are continuing to use policies that protect consumers. Some states have chosen to reinforce efforts to develop a competitive market. A few have opted to return to previous regulatory frameworks and others have taken actions somewhere between these two ends of the continuum.

By February 2003, twenty-four states and the District of Columbia had either enacted enabling legislation or issued a regulatory order to implement retail access. The local distribution company continued to provide transmission and distribution (delivery of energy) services. Retail access allowed customers to choose their own supplier, but each state's retail access schedule varied according to the legislative mandates or regulatory orders. Twenty-seven states were not actively pursuing restructuring,[9] and a delay in the restructuring process or in the implementation of retail access was observed in six states (Arkansas, Montana, Nevada, New Mexico, Oklahoma and California).

The federal government has been largely focusing its activities on three fronts:

- Facilitating the development of new generating capacity.
- Reinforcing reliability of supply.
- Developing technology to keep coal in US electricity production.

9. Alabama, Alaska, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, West Virginia, Wisconsin, and Wyoming.

Environmental law is being softened to promote new development. The so-called New Source Review (NSR) section of the 1970 Federal Clean Air Act has been amended by the Administration. The NSR subjected existing power plants that wanted to make revisions or additions to capacity to even stricter environmental standards than those applied to new ones. However, this has been amended so that companies are now able to replace as much as 20% of a facility before they must also include pollution-control measures as part of the repairs.

To increase reliability, the Administration is exploring the possibility of a national grid. While California was suffering rolling blackouts in 2000/2001, Texas was producing an electricity surplus, but the US does not have a national grid and transportation between states is very difficult. Similarly, the Administration also wants to buy more electricity from Mexico and Canada, but plans to upgrade the transmission system will have to be implemented to make this happen. A proposal in the NEP will grant the Federal Energy Regulatory Commission (FERC) more powers to seize private land in order to facilitate the laying of new electricity. The FERC has proposed the formation of regional transmission organisations (RTOs) and was hoping to get such measures passed in the Energy Bill. However, the major 2003 US blackout has given ammunition to opponents of the plans, including southern states, which fear that their fully-functioning transmission networks will be adversely affected by the plans. It now appears that the RTO proposals will be delayed until 2006 if the Energy Bill is approved, although there may be scope for some regions, such as the North-East US, to introduce the schemes early.

In July 2003, the FERC issued a new set of rules to standardise the interconnection of new generation facilities to transmission grids. The main purpose of the rules is to ensure non-discriminatory interconnection and access to transmission grids and hence to ensure competition in the wholesale market.

Following the August 2003 blackout that affected the North-East and Canada, the government created a Joint US-Canada Task Force on the Energy Outage that released its final conclusions in May 2004. Recommendations include: implementing mandatory and enforceable electricity reliability standards in both the US and Canada, with penalties for non-compliance, backed by appropriate government oversight. For this, the report recommended that the institutional framework of the North American Electricity Reliability Council (NERC) be strengthened.

RENEWABLES

Renewable energy represented 4.4% of the TPES in 2003, including 3.0% for combustible renewables and wastes, 0.9% for hydro, 0.4% for geothermal and 0.1% for solar, wind and others. This is equivalent to 99 Mtoe in 2002, against 91 Mtoe in 2001. The growth came essentially from combustible renewables and wastes, whereas hydro and geothermal capacity and production either stagnated or regressed since 1990.

Much of the policy support for renewables comes from state policies. Sixteen states currently have Renewable Portfolio Standards (RPSs), which require electricity providers to have a minimum amount of renewables in their generation mix. Public Benefit Funds (also known as System Benefits Charges) are a type of tax on electricity consumption, whose revenue is used to support various energy-related public goals, including expanding the use of renewables. In addition, a number of electricity providers, either voluntarily or as mandated by their states, offer green products – as green power or green tags.

Following the NEP, the proposed "Energy Law" contains provisions that would extend and modify the existing tax credit for electricity produced from some of the renewable energy sources. Current tax law allowed a 1.5 cent/kWh tax credit for electricity produced from wind, "closed loop" biomass (organic material from a plant that is used exclusively for the purpose of producing electricity), and poultry waste, until 31 December 2003. Under the proposed energy law, the tax credit for wind and biomass would be extended for three years. Other tax provisions are included for residential solar energy systems, for purchases of certain hybrid or fuel-cell vehicles; for energy produced from landfill gas; for certain combined heat and power systems; and for ethanol and renewable source methanol.

There are $10 billion worth of tax incentives in the NEP for energy conservation measures and the promotion of renewable energy technologies. In particular, about $4.5 billion could be spent on encouraging the development and greater utilisation of alternative fuels, and on household energy conservation – there is some $1 billion for developing methane gas from landfills electricity generation and tax credits of up to $2 billion for households that install solar panels on their property.

NUCLEAR

The 103 US nuclear units supplied about 20% of the electricity produced in the United States in 2003 – second only to coal as a fuel source.

The government is committed to nuclear energy, conducting research and development programmes to ensure nuclear energy's future viability. The Nuclear Power 2010 Program is a joint government-industry cost-shared programme to identify potential sites for new nuclear power plants, develop nearer-term advanced nuclear plant technologies, and demonstrate untested regulatory practices that will lead to decisions by power companies to deploy new nuclear power plants within the next ten to fifteen years. The Generation IV Nuclear Energy Systems Initiative is conducting research and development in co-operation with other countries to establish the viability of longer-term advanced reactor concepts that offer significant improvements in economics, sustainability, safety and reliability, and proliferation resistance and physical protection. The Nuclear Hydrogen Initiative programme goal is to demonstrate the economic, commercial-scale production of hydrogen using nuclear energy. The Advanced Fuel Cycle Initiative is developing proliferation-resistant spent nuclear fuel treatment and transmutation technologies to enable a transition from the current once-through nuclear fuel cycle to a future sustainable, closed nuclear fuel cycle. The advancement of these programmes is supported by the research and development conducted by the Nuclear Energy Research Initiative and International Nuclear Energy Research Initiative programmes. The Nuclear Energy Plant Optimization programme is aimed at conducting research and development to support the continued effective operation of the existing fleet of operating reactors.

The current National Energy Policy (NEP), released in May 2001, addresses recommendations, among which that the government should support the expansion of nuclear energy in the United States. Specific components of the policy include encouraging the Nuclear Regulatory Commission (NRC) in the review of future applications to license advanced technology nuclear reactors, and in the re-licensing and uprating of existing nuclear plants. The NEP also supports the use of the best science to provide a deep geologic repository for nuclear waste; the renewal of the Price-Anderson Act; decommissioning funding improvements; and advance nuclear reactor and fuel-cycle technologies development.

In 2002, DoE reached a significant milestone in its high-level radioactive waste management programme when the President and Congress approved the Yucca Mountain site for development as a geologic repository. DoE is working to submit a Licence Application to the NRC by December 2004. In July 2004, the draft licence application was completed and is undergoing DoE acceptance review. Allowing about three years for NRC review, DoE would then seek authorisation to construct a repository by 2007, which would enable it to meet its key objective of having an operational repository by 2010. The DoE Office of Civilian Radioactive Waste Management (OCRWM) issued the National Transportation Strategic Plan in November 2003. The plan addresses policies; interactions with states, local and tribal governments; identifies necessary activities and describes the approach to ensuring a collaborative process is used to develop an operational transportation system by 2010. On the basis of the Yucca Mountain Final Environmental Impact Statement, in April 2004 DoE selected a rail corridor in Nevada to support the shipment of radioactive materials to the proposed repository.

The DoE OCRWM began a Science and Technology Program in 2003 as part of its commitment to further enhance understanding of long-term repository performance, reduce life-cycle costs, and improve operational efficiencies.

Projects already under way seek *i)* advances in welding, *ii)* advances in understanding corrosion, *iii)* other advances in materials (*e.g.* waste package coatings, and low-pH cements), and *iv)* enhanced credit for the natural system's barriers and for the performance of the waste form.

RESEARCH AND DEVELOPMENT

The DoE is the largest federal government supporter of fundamental research in basic energy sciences, biological and environmental sciences, physical sciences, computational sciences, and materials and chemical sciences. With the requested 2004 budget of close to $7 billion in R&D, the DoE maintains a comprehensive portfolio of R&D activities to support its missions, including energy resources, environmental quality, national security and science.

Global climate change is considered as a major long-term energy and environmental challenge, and hence represents a significant component of DoE 's R&D efforts to develop technologies that reduce emissions and help develop low-emission energy supply technologies (such as the FutureGen project mentioned above, among others). Federal government investments in R&D for climate change technology are now approaching $2.3 billion, essentially as activities undertaken through the CCTP mentioned above.

In February 2003, the government launched the Carbon Sequestration Leadership Forum (CSLF), an initiative aiming at promoting the international diffusion of related technologies.

DoE is conducting research, in partnership with the fuel-cell industry, to develop technology for the stationary power generation – for example, for power units that can serve as distributed electricity generation units. DoE has established research goals for stationary fuel-cell systems that include increasing the electrical efficiency of 50-250 kW stationary fuel-cell systems operating on natural gas or propane from 29% in 2002 to 40% by 2010. Extensive hydrogen production research is also under way that will enable hydrogen for fuel cells to be generated from not only natural gas, but also from biomass and other renewables, and from coal (with sequestration).

The government launched the FreedomCAR Partnership (2002) and Hydrogen Fuel Initiative (2003). Together, the extensive multi-year research efforts of the Hydrogen Fuel Initiative and the FreedomCAR Partnership are expected to facilitate a decision by industry to commercialise hydrogen-powered fuel-cell vehicles in the year 2015. In 2003, the International Partnership for Hydrogen Economy was established as an interface with international RD&D and the private sector on many aspects of developments related to hydrogen as a fuel (production, transport, use).

The federal government is leading a national effort to modernise and expand America's electricity delivery system to ensure a more reliable and robust electricity supply, as well as economic and national security, and reduce the likelihood and impact of blackouts. There are six major R&D programs: *i)* High Temperature Superconductivity, *ii)* Transmission Reliability, *iii)* Electric Distribution Transformation, *iv)* Energy Storage, *v)* Gridworks, a programme that supports R&D of advanced conductors and deployment of low-cost reliable sensors that monitor current flow and voltage throughout the grid, and *vi)* Gridwise, a programme that supports R&D on intelligent grid operations, distributed energy devices, and enhanced customer service.

In the field of renewable energy, the federal government attempts to achieve the following goals, through R&D efforts:

- *Biomass* – Platforms R&D – *a)* Reducing the cost of cleaned and reformed biomass-derived synthesis gas produced, from a mature gasification plant, from $9.8/MBTU in 2003 to $7.6/MBTU in 2010; and *b)* reducing the cost of a mixed, dilute sugar stream suitable for fermentation to ethanol, in a mature biochemical plant, from 15 cents/lb in 2003 to 10 cents/lb by 2010. Feedstock Infrastructure: reduce biomass harvesting and storage costs so that the delivered cost will be reduced from $53 per dry ton in 2003 to $38 per dry ton by 2005.
- *Solar* – Reducing the 30-year user cost from photovoltaic (PV) electric energy to 16-21 cents/kWh in 2006 from 19-24 cents/kWh in 2003; and reducing the cost of solar water heating in non-freezing climates to 4 cents per kWh in 2006 from 8 cents/kWh in 2003. The long-term cost goal (2020) for PV systems is 6 cents/kWh.
- *Wind* – Reducing the cost of energy from large, on-shore wind systems in lower wind classes (Class 4) to 3 cents/kWh in 2012 (from 5.5 cents/kWh in 2002), and 5 cents/kWh for offshore (shallow water) systems (from 7.5 cents/kWh in 2005); and develop a class of small wind turbine systems designed for residential and small business applications by 2007 for Class 3 wind resources that achieve costs in the range of 10-15 cents/kWh.
- *Geothermal* – Reducing the levelised cost of power generated from conventional geothermal sources from 5-8 cents/kWh in 2000 to 3-5 cents/kWh in 2010.
- *Hydropower* – Develop new technology that will enable 10% growth from 2005 in hydropower generation at existing plants with enhanced environmental performance, compared to an expected loss of 6% at federal and non-federal hydropower plants.
- *Hydrogen* produced from renewables (see above the references to DoE's FreedomCAR Partnership and Hydrogen Fuel Initiative).

The federal government is investing in R&D activities to develop new nuclear energy generation technologies to meet energy and climate goals; develop advanced, proliferation-resistant nuclear fuel technologies that maximise energy from nuclear fuel; and maintain and enhance the US nuclear infrastructure. One R&D programme is the Nuclear Hydrogen Initiative, focused on the development of advanced technologies that can be used in tandem with next-generation nuclear energy plants to generate economic, commercial quantities of hydrogen to support a sustainable, clean energy future. Another programme, the Generation IV Nuclear Energy Systems Initiative, establishes a basis for expansive co-operation with international partners to develop next-generation reactor and fuel-cycle systems. A third programme, the Advanced Fuel Cycle Initiative, seeks to develop advanced, proliferation-resistant nuclear fuel technologies that maximise the energy produced from nuclear fuels while minimising wastes.

The federal government invests in scientific research capacity and supports a broad array of research subjects in a number of areas: fundamental research in energy, matter, and the basic forces of nature; health and environmental consequences of energy production and development; fundamental science that supports the foundations for new energy technologies and environmental mitigation; a science base for fusion as a potential future energy source; and advanced computational and networking tools critical to research. Such research programmes include: the High Energy Physics programme; the Basic Energy Sciences; or the Biological and Environmental Research programme.

PART 2.3

ENERGY BALANCES AND KEY STATISTICAL DATA OF IEA COUNTRIES

AUSTRALIA

AUSTRIA

BELGIUM

CANADA

CZECH REPUBLIC

DENMARK

FINLAND

FRANCE

GERMANY

GREECE

HUNGARY

IRELAND

ITALY

JAPAN

KOREA

LUXEMBOURG

NETHERLANDS

NEW ZEALAND

NORWAY

PORTUGAL

SPAIN

SWEDEN

SWITZERLAND

TURKEY

UNITED KINGDOM

UNITED STATES

AUSTRALIA

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**68.0**	**157.7**	**249.1**	**255.2**	**314.6**	**362.9**	**..**
Coal[1]		40.3	106.3	178.3	184.0	207.8	229.9	..
Oil		19.8	29.0	35.0	33.2	32.0	34.2	..
Gas		3.4	17.1	29.1	29.5	64.3	87.3	..
Comb. Renewables & Wastes[2]		3.5	4.0	5.1	7.0	8.5	9.4	..
Nuclear		–	–	–	–	–	–	..
Hydro		1.0	1.2	1.4	1.4	1.6	1.7	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other[3]		–	0.1	0.1	0.1	0.3	0.4	..
TOTAL NET IMPORTS[4]		**-10.3**	**-65.7**	**-135.0**	**-139.3**	**-168.5**	**-184.5**	**..**
Coal[1]	Exports	17.6	67.7	125.3	131.3	156.9	170.1	..
	Imports	–	–	–	–	–	–	..
	Net Imports	-17.6	-67.7	-125.3	-131.3	-156.9	-170.1	..
Oil	Exports	3.4	9.3	27.4	25.0	21.2	20.7	..
	Imports	12.5	14.2	27.3	26.6	39.2	48.6	..
	Bunkers	1.8	0.6	0.8	0.8	1.0	1.2	..
	Net Imports	7.4	4.3	-0.8	0.9	17.0	26.8	..
Gas	Exports	–	2.3	8.8	8.9	28.6	41.2	..
	Imports	–	–	–	–	–	–	..
	Net Imports	–	-2.3	-8.8	-8.9	-28.6	-41.2	..
Electricity	Exports	–	–	–	–	–	–	..
	Imports	–	–	–	–	–	–	..
	Net Imports	–	–	–	–	–	–	..
TOTAL STOCK CHANGES		**-0.1**	**-4.5**	**-5.7**	**-3.1**	**–**	**–**	**..**
TOTAL SUPPLY (TPES)		**57.6**	**87.5**	**108.3**	**112.7**	**146.1**	**178.5**	**..**
Coal[1]		22.6	35.0	48.2	48.9	50.9	59.9	..
Oil		27.1	32.5	33.2	34.7	49.0	60.9	..
Gas		3.4	14.8	20.3	20.6	35.8	46.1	..
Comb. Renewables & Wastes[2]		3.5	4.0	5.1	7.0	8.5	9.4	..
Nuclear		–	–	–	–	–	–	..
Hydro		1.0	1.2	1.4	1.4	1.6	1.7	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other[3]		–	0.1	0.1	0.1	0.3	0.4	..
Electricity Trade[5]		–	–	–	–	–	–	..
Shares (%)								
Coal		*39.2*	*39.9*	*44.5*	*43.4*	*34.8*	*33.6*	..
Oil		*47.1*	*37.2*	*30.7*	*30.8*	*33.6*	*34.1*	..
Gas		*5.9*	*16.9*	*18.7*	*18.3*	*24.5*	*25.9*	..
Comb. Renewables & Wastes		*6.1*	*4.5*	*4.7*	*6.2*	*5.8*	*5.3*	..
Nuclear		–	–	–	–	–	–	..
Hydro		*1.7*	*1.4*	*1.3*	*1.2*	*1.1*	*0.9*	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other		–	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	..
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.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**40.0**	**58.1**	**72.9**	**70.8**	**91.4**	**113.7**	**..**
Coal[1]	4.9	4.3	3.8	2.8	2.5	2.7	..
Oil	24.7	30.5	37.1	36.2	45.6	56.9	..
Gas	2.4	8.8	12.1	11.0	18.4	23.8	..
Comb. Renewables & Wastes[2]	3.5	3.3	4.3	4.4	4.8	5.5	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.1	0.1	0.1	0.1	0.2	..
Electricity	4.5	11.1	15.5	16.3	19.9	24.6	..
Heat	–	–	–	–	–	–	..
Shares (%)							
Coal	*12.3*	*7.4*	*5.2*	*3.9*	*2.7*	*2.4*	..
Oil	*61.7*	*52.6*	*50.9*	*51.1*	*49.9*	*50.0*	..
Gas	*5.9*	*15.2*	*16.6*	*15.6*	*20.2*	*20.9*	..
Comb. Renewables & Wastes	*8.7*	*5.6*	*5.9*	*6.2*	*5.3*	*4.8*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	..
Electricity	*11.3*	*19.1*	*21.3*	*23.1*	*21.8*	*21.7*	..
Heat	–	–	–	–	–	–	..
TOTAL INDUSTRY[6]	**17.6**	**23.1**	**28.7**	**25.5**	**36.5**	**44.2**	**..**
Coal[1]	4.6	4.1	3.6	2.6	2.3	2.6	..
Oil	7.7	6.3	7.5	5.9	9.2	10.8	..
Gas	1.8	6.1	8.0	7.1	12.5	16.2	..
Comb. Renewables & Wastes[2]	1.5	1.5	2.4	2.5	2.8	3.2	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	2.0	5.1	7.3	7.4	9.7	11.3	..
Heat	–	–	–	–	–	–	..
Shares (%)							
Coal	*26.4*	*17.6*	*12.6*	*10.3*	*6.4*	*5.8*	..
Oil	*43.8*	*27.4*	*26.0*	*23.1*	*25.2*	*24.5*	..
Gas	*10.0*	*26.5*	*27.9*	*27.7*	*34.4*	*36.7*	..
Comb. Renewables & Wastes	*8.5*	*6.4*	*8.3*	*9.6*	*7.5*	*7.3*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*11.3*	*22.0*	*25.3*	*29.2*	*26.5*	*25.7*	..
Heat	–	–	–	–	–	–	..
TRANSPORT[7]	**13.5**	**22.7**	**28.3**	**28.2**	**36.7**	**46.6**	**..**
TOTAL OTHER SECTORS[8]	**8.9**	**12.3**	**15.9**	**17.0**	**18.2**	**22.9**	**..**
Coal[1]	0.3	0.1	0.1	0.1	0.0	0.0	..
Oil	3.5	1.8	2.0	2.6	0.8	0.8	..
Gas	0.6	2.7	3.7	3.6	5.2	6.6	..
Comb. Renewables & Wastes[2]	2.0	1.8	1.9	1.9	2.1	2.3	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.1	0.1	0.1	0.1	0.2	..
Electricity	2.5	5.9	8.0	8.7	10.1	13.0	..
Heat	–	–	–	–	–	–	..
Shares (%)							
Coal	*3.2*	*1.1*	*0.4*	*0.4*	–	–	..
Oil	*39.7*	*14.2*	*12.8*	*15.4*	*4.2*	*3.5*	..
Gas	*7.0*	*21.8*	*23.5*	*21.2*	*28.4*	*29.0*	..
Comb. Renewables & Wastes	*22.5*	*14.4*	*12.0*	*11.2*	*11.3*	*9.8*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*0.7*	*0.7*	*0.6*	*0.7*	*0.8*	..
Electricity	*27.7*	*47.7*	*50.6*	*51.1*	*55.2*	*56.9*	..
Heat	–	–	–	–	–	–	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**16.0**	**35.1**	**50.1**	**55.7**	**61.2**	**72.6**	**..**
OUTPUT (Mtoe)	**5.5**	**13.3**	**18.6**	**19.1**	**23.0**	**28.4**	**..**
(TWh gross)	64.4	154.3	216.8	222.0	267.0	330.1	..
Output Shares (%)							
Coal	*74.9*	*77.1*	*78.3*	*78.3*	*68.4*	*67.6*	..
Oil	*2.6*	*2.7*	*1.3*	*1.7*	*1.1*	*0.9*	..
Gas	*4.3*	*10.6*	*12.1*	*11.6*	*20.5*	*22.5*	..
Comb. Renewables & Wastes	*0.5*	*0.4*	*0.6*	*1.1*	*2.2*	*2.1*	..
Nuclear	–	–	–	–	–	–	..
Hydro	*17.7*	*9.2*	*7.6*	*7.1*	*6.9*	*5.9*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	*0.1*	*0.2*	*0.9*	*0.9*	..
TOTAL LOSSES	**17.8**	**29.3**	**41.5**	**45.7**	**54.7**	**64.7**	**..**
of which:							
Electricity and Heat Generation[10]	10.5	21.7	31.4	36.6	38.3	44.2	..
Other Transformation	5.5	0.6	0.7	1.1	4.7	5.3	..
Own Use and Losses[11]	1.7	7.0	9.3	8.0	11.7	15.2	..
Statistical Differences	**-0.1**	**0.2**	**-6.1**	**-3.7**	**–**	**–**	**..**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	197.13	317.76	468.04	480.85	631.96	891.44	..
Population (millions)	13.61	17.18	19.51	19.75	21.33	23.19	..
TPES/GDP[12]	0.29	0.28	0.23	0.23	0.23	0.20	..
Energy Production/TPES	1.18	1.80	2.30	2.26	2.15	2.03	..
Per Capita TPES[13]	4.23	5.10	5.55	5.71	6.85	7.69	..
Oil Supply/GDP[12]	0.14	0.10	0.07	0.07	0.08	0.07	..
TFC/GDP[12]	0.20	0.18	0.16	0.15	0.14	0.13	..
Per Capita TFC[13]	2.94	3.38	3.74	3.58	4.28	4.90	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	157.9	259.7	341.9	342.9	398.4	489.3	..
CO_2 Emissions from Bunkers (Mt CO_2)	7.3	6.3	10.4	8.7	9.4	10.1	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	3.0	2.2	2.0	4.0	3.3	2.0	..
Coal	1.5	3.2	3.0	1.4	0.5	1.6	..
Oil	2.9	0.1	0.2	4.5	4.4	2.2	..
Gas	12.7	7.1	2.9	1.6	7.1	2.6	..
Comb. Renewables & Wastes	0.1	1.0	2.3	37.3	2.5	1.0	..
Nuclear	–	–	–	–	–	–	..
Hydro	5.1	-0.7	1.4	-3.5	1.9	0.6	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	17.3	3.9	11.4	12.1	2.3	..
TFC	2.5	2.1	2.1	-3.0	3.2	2.2	..
Electricity Consumption	6.3	5.0	3.1	5.3	2.5	2.1	..
Energy Production	3.9	5.7	4.2	2.5	2.7	1.4	..
Net Oil Imports	4.2	-6.9	–	–	44.7	4.6	..
GDP	2.5	3.0	3.6	2.7	3.5	3.5	..
Growth in the TPES/GDP Ratio	0.5	-0.8	-1.6	1.3	-0.2	-1.4	..
Growth in the TFC/GDP Ratio	-0.0	-0.9	-1.4	-5.5	-0.2	-1.2	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**7.9**	**8.1**	**9.7**	**9.9**	**10.4**	**11.6**	**..**
Coal[1]		1.0	0.6	0.3	0.3	0.0	0.0	..
Oil		2.7	1.2	1.0	1.1	1.0	1.1	..
Gas		2.0	1.1	1.5	1.6	1.8	2.1	..
Comb. Renewables & Wastes[2]		0.7	2.4	3.3	3.4	3.8	4.2	..
Nuclear		–	–	–	–	–	–	..
Hydro		1.6	2.7	3.5	3.4	3.5	3.7	..
Geothermal		–	0.0	0.0	0.0	0.0	0.0	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	0.3	0.4	..
TOTAL NET IMPORTS[4]		**14.0**	**17.4**	**20.0**	**20.6**	**22.0**	**23.9**	**..**
Coal[1]	Exports	0.1	0.0	0.0	0.0	0.0	0.0	..
	Imports	3.1	3.2	3.3	3.3	3.0	2.1	..
	Net Imports	3.0	3.2	3.3	3.3	3.0	2.1	..
Oil	Exports	0.1	0.6	1.7	1.5	1.6	1.8	..
	Imports	9.9	10.4	13.4	14.1	13.4	15.1	..
	Bunkers	–	–	–	–	–	–	..
	Net Imports	9.7	9.8	11.7	12.6	11.8	13.2	..
Gas	Exports	–	–	0.3	0.7	0.0	0.0	..
	Imports	1.3	4.4	5.4	5.4	7.1	8.4	..
	Net Imports	1.3	4.4	5.0	4.7	7.1	8.4	..
Electricity	Exports	0.4	0.6	1.2	1.3	1.3	1.3	..
	Imports	0.3	0.6	1.2	1.3	1.4	1.5	..
	Net Imports	-0.1	-0.0	0.0	0.1	0.1	0.1	..
TOTAL STOCK CHANGES		**-0.3**	**-0.3**	**1.2**	**-0.1**	**-0.2**	**-0.6**	**..**
TOTAL SUPPLY (TPES)		**21.7**	**25.3**	**30.9**	**30.4**	**32.3**	**34.9**	**..**
Coal[1]		3.9	4.1	3.9	3.6	3.0	2.1	..
Oil		12.3	10.8	13.2	13.2	12.5	14.1	..
Gas		3.3	5.2	6.9	6.6	9.0	10.3	..
Comb. Renewables & Wastes[2]		0.7	2.4	3.3	3.4	3.8	4.2	..
Nuclear		–	–	–	–	–	–	..
Hydro		1.6	2.7	3.5	3.4	3.5	3.7	..
Geothermal		–	0.0	0.0	0.0	0.0	0.0	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	0.3	0.4	..
Electricity Trade[5]		-0.1	-0.0	0.0	0.1	0.1	0.1	..
Shares (%)								
Coal		*17.9*	*16.2*	*12.6*	*11.9*	*9.2*	*6.0*	..
Oil		*56.7*	*42.9*	*42.7*	*43.5*	*38.9*	*40.3*	..
Gas		*15.3*	*20.5*	*22.4*	*21.7*	*28.0*	*29.5*	..
Comb. Renewables & Wastes		*3.3*	*9.7*	*10.6*	*11.1*	*11.8*	*12.1*	..
Nuclear		–	–	–	–	–	–	..
Hydro		*7.5*	*10.7*	*11.2*	*11.3*	*10.8*	*10.6*	..
Geothermal		–	–	*0.1*	*0.1*	*0.1*	*0.1*	..
Solar/Wind/Other		–	*0.1*	*0.3*	*0.3*	*0.8*	*1.1*	..
Electricity Trade		*-0.6*	*-0.2*	*0.1*	*0.2*	*0.4*	*0.4*	..

0 is negligible, – is nil, .. is not available.
All forecasts are based on the 2002 submission.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**16.8**	**20.3**	**25.9**	**25.3**	**26.9**	**29.0**	**..**
Coal[1]	2.0	1.5	1.3	0.9	0.9	0.7	..
Oil	10.2	9.3	11.8	12.3	11.2	12.1	..
Gas	1.8	3.1	4.3	3.6	5.6	5.8	..
Comb. Renewables & Wastes[2]	0.7	2.1	2.6	2.5	2.6	2.8	..
Geothermal	–	0.0	0.0	0.0	0.0	0.0	..
Solar/Wind/Other	–	0.0	0.1	0.1	0.1	0.1	..
Electricity	2.2	3.7	4.7	4.7	5.2	5.9	..
Heat	–	0.6	1.2	1.2	1.2	1.5	..
Shares (%)							
Coal	*11.8*	*7.5*	*4.9*	*3.7*	*3.4*	*2.5*	..
Oil	*60.4*	*45.6*	*45.6*	*48.5*	*41.7*	*41.8*	..
Gas	*10.7*	*15.1*	*16.5*	*14.2*	*21.0*	*20.1*	..
Comb. Renewables & Wastes	*4.1*	*10.6*	*9.9*	*9.8*	*9.8*	*9.6*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*0.1*	*0.3*	*0.3*	*0.5*	*0.5*	..
Electricity	*12.9*	*18.1*	*18.2*	*18.8*	*19.2*	*20.4*	..
Heat	–	*3.0*	*4.7*	*4.7*	*4.5*	*5.1*	..
TOTAL INDUSTRY[6]	**6.5**	**7.2**	**8.7**	**7.9**	**8.7**	**8.9**	**..**
Coal[1]	0.7	0.8	1.0	0.7	0.7	0.6	..
Oil	3.3	2.2	2.8	2.9	2.0	2.3	..
Gas	1.3	2.0	2.1	1.6	3.0	2.8	..
Comb. Renewables & Wastes[2]	0.0	0.6	0.8	0.8	0.8	0.8	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	1.0	1.5	1.8	1.8	2.1	2.3	..
Heat	–	0.1	0.2	0.2	–	0.0	..
Shares (%)							
Coal	*11.5*	*10.7*	*11.5*	*8.9*	*8.4*	*7.0*	..
Oil	*51.7*	*30.7*	*32.5*	*36.6*	*23.0*	*25.5*	..
Gas	*20.2*	*27.5*	*24.4*	*20.7*	*34.9*	*32.0*	..
Comb. Renewables & Wastes	*0.5*	*8.5*	*9.0*	*9.5*	*9.2*	*9.6*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*16.1*	*21.5*	*20.8*	*22.3*	*24.5*	*25.8*	..
Heat	–	*1.1*	*1.8*	*2.0*	–	–	..
TRANSPORT[7]	**4.0**	**4.7**	**6.7**	**7.2**	**7.3**	**8.1**	**..**
TOTAL OTHER SECTORS[8]	**6.3**	**8.4**	**10.5**	**10.1**	**10.9**	**12.0**	**..**
Coal[1]	1.1	0.8	0.3	0.2	0.2	0.1	..
Oil	3.1	2.7	2.8	2.6	2.6	2.5	..
Gas	0.5	1.0	1.9	1.8	2.4	2.7	..
Comb. Renewables & Wastes[2]	0.7	1.5	1.8	1.7	1.8	1.9	..
Geothermal	–	0.0	0.0	0.0	0.0	0.0	..
Solar/Wind/Other	–	0.0	0.1	0.1	0.1	0.1	..
Electricity	1.0	1.9	2.6	2.7	2.6	3.2	..
Heat	–	0.5	1.0	1.0	1.2	1.5	..
Shares (%)							
Coal	*17.9*	*9.0*	*2.6*	*2.2*	*1.7*	*0.9*	..
Oil	*48.6*	*31.7*	*26.7*	*25.8*	*23.5*	*20.7*	..
Gas	*7.6*	*11.8*	*18.4*	*17.7*	*21.7*	*22.6*	..
Comb. Renewables & Wastes	*10.3*	*18.3*	*17.0*	*16.9*	*16.6*	*16.0*	..
Geothermal	–	–	–	*0.1*	*0.1*	–	..
Solar/Wind/Other	–	*0.2*	*0.6*	*0.7*	*1.1*	*1.1*	..
Electricity	*15.6*	*22.6*	*24.8*	*26.4*	*24.2*	*26.4*	..
Heat	–	*6.4*	*10.0*	*10.3*	*11.1*	*12.2*	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**4.9**	**7.1**	**8.4**	**9.0**	**9.3**	**10.7**	**..**
OUTPUT (Mtoe)	**2.7**	**4.2**	**5.2**	**5.2**	**5.7**	**6.6**	**..**
(TWh gross)	30.9	49.3	60.8	60.4	66.7	76.5	..
Output Shares (%)							
Coal	*10.3*	*14.2*	*13.1*	*12.3*	*8.0*	*3.7*	..
Oil	*14.1*	*3.8*	*3.7*	*2.6*	*5.2*	*8.7*	..
Gas	*14.3*	*15.7*	*13.5*	*15.5*	*18.4*	*22.4*	..
Comb. Renewables & Wastes	*0.7*	*2.4*	*3.3*	*3.1*	*4.7*	*5.0*	..
Nuclear	–	–	–	–	–	–	..
Hydro	*60.6*	*63.9*	*66.1*	*66.1*	*61.0*	*56.5*	..
Geothermal	–	–	–	*0.0*	–	–	..
Solar/Wind/Other	–	–	*0.3*	*0.3*	*2.5*	*3.6*	..
TOTAL LOSSES	**4.7**	**5.0**	**4.7**	**5.0**	**5.4**	**6.0**	**..**
of which:							
Electricity and Heat Generation[10]	2.2	2.2	1.9	2.6	2.2	2.5	..
Other Transformation	1.3	1.0	1.0	0.9	0.8	0.7	..
Own Use and Losses[11]	1.2	1.8	1.8	1.6	2.4	2.8	..
Statistical Differences	**0.1**	**0.0**	**0.3**	**0.1**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	137.92	212.47	270.89	274.58	321.72	392.17	..
Population (millions)	7.59	7.73	8.03	8.05	8.20	8.28	..
TPES/GDP[12]	0.16	0.12	0.11	0.11	0.10	0.09	..
Energy Production/TPES	0.37	0.32	0.31	0.33	0.32	0.33	..
Per Capita TPES[13]	2.85	3.27	3.84	3.78	3.94	4.22	..
Oil Supply/GDP[12]	0.09	0.05	0.05	0.05	0.04	0.04	..
TFC/GDP[12]	0.12	0.10	0.10	0.09	0.08	0.07	..
Per Capita TFC[13]	2.22	2.63	3.23	3.14	3.28	3.50	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	54.3	57.3	67.3	66.1	65.7	69.9	..
CO_2 Emissions from Bunkers (Mt CO_2)	0.3	0.9	1.7	1.5	1.5	1.5	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	1.7	0.5	1.8	-1.4	0.7	0.8	..
Coal	-1.1	1.1	-0.4	-7.4	-2.4	-3.4	..
Oil	0.8	-1.6	1.8	0.4	-0.7	1.2	..
Gas	4.6	1.7	2.7	-4.6	4.0	1.3	..
Comb. Renewables & Wastes	6.3	8.1	2.7	3.0	1.6	1.0	..
Nuclear	–	–	–	–	–	–	..
Hydro	6.7	1.2	2.2	-0.6	0.2	0.6	..
Geothermal	–	–	33.0	26.1	1.2	–	..
Solar/Wind/Other	–	–	16.7	6.1	15.0	3.5	..
TFC	2.2	0.5	2.3	-2.5	0.8	0.7	..
Electricity Consumption	3.9	2.7	2.3	0.6	1.0	1.4	..
Energy Production	0.2	0.1	1.7	2.6	0.6	1.1	..
Net Oil Imports	2.7	-1.4	1.6	7.4	-0.8	1.2	..
GDP	3.0	2.4	2.2	1.4	2.0	2.0	..
Growth in the TPES/GDP Ratio	-1.2	-1.8	-0.4	-2.7	-1.2	-1.2	..
Growth in the TFC/GDP Ratio	-0.8	-1.8	0.0	-3.9	-1.2	-1.2	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**6.5**	**13.1**	**13.1**	**13.3**	**..**	**..**	**..**
Coal[1]		6.4	1.2	0.1	0.1	..	..	..
Oil		–	–	–	–	..	..	..
Gas		0.0	0.0	–	–	..	..	..
Comb. Renewables & Wastes[2]		0.0	0.7	0.8	0.8	..	..	..
Nuclear		0.0	11.1	12.1	12.3	..	..	..
Hydro		0.0	0.0	0.0	0.0	..	..	..
Geothermal		–	0.0	0.0	0.0	..	..	..
Solar/Wind/Other[3]		–	0.0	0.0	0.0	..	..	..
TOTAL NET IMPORTS[4]		**39.8**	**35.5**	**46.8**	**42.8**	**..**	**..**	**..**
Coal[1]	Exports	0.8	1.1	1.4	1.5	..	..	..
	Imports	5.3	10.3	9.7	7.2	..	..	..
	Net Imports	4.6	9.2	8.3	5.7	..	..	..
Oil	Exports	15.1	19.2	22.2	23.3	..	..	..
	Imports	46.4	41.7	52.0	52.7	..	..	..
	Bunkers	3.1	4.1	5.3	6.9	..	..	..
	Net Imports	28.2	18.4	24.5	22.6	..	..	..
Gas	Exports	–	–	–	–	..	..	..
	Imports	7.1	8.2	13.1	13.6	..	..	..
	Net Imports	7.1	8.2	13.1	13.6	..	..	..
Electricity	Exports	0.2	0.7	0.6	0.8	..	..	..
	Imports	0.1	0.4	1.4	1.4	..	..	..
	Net Imports	-0.1	-0.3	0.8	0.7	..	..	..
TOTAL STOCK CHANGES		**-0.0**	**0.1**	**-0.9**	**0.9**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**46.3**	**48.7**	**59.0**	**56.9**	**..**	**..**	**..**
Coal[1]		11.2	10.2	7.7	6.7	..	..	..
Oil		28.0	18.7	24.3	22.9	..	..	..
Gas		7.1	8.2	13.2	13.4	..	..	..
Comb. Renewables & Wastes[2]		0.0	0.7	0.9	0.9	..	..	..
Nuclear		0.0	11.1	12.1	12.3	..	..	..
Hydro		0.0	0.0	0.0	0.0	..	..	..
Geothermal		–	0.0	0.0	0.0	..	..	..
Solar/Wind/Other[3]		–	0.0	0.0	0.0	..	..	..
Electricity Trade[5]		-0.1	-0.3	0.8	0.7	..	..	..
Shares (%)								
Coal		*24.1*	*21.0*	*13.1*	*11.7*	..	..	..
Oil		*60.5*	*38.5*	*41.1*	*40.2*	..	..	..
Gas		*15.4*	*16.8*	*22.3*	*23.5*	..	..	..
Comb. Renewables & Wastes		–	*1.4*	*1.6*	*1.6*	..	..	..
Nuclear		–	*22.9*	*20.5*	*21.7*	..	..	..
Hydro		–	–	*0.1*	*0.1*	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other		–	–	–	–	..	..	..
Electricity Trade		*-0.1*	*-0.7*	*1.3*	*1.1*	..	..	..

0 is negligible, – is nil, .. is not available.
Please note: Forecasts are not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**34.6**	**33.0**	**43.1**	**41.0**	**..**	**..**	**..**
Coal[1]	5.7	3.4	2.9	1.8	..	..	..
Oil	21.0	17.3	22.4	21.2	..	..	..
Gas	4.6	6.8	10.2	10.4	..	..	..
Comb. Renewables & Wastes[2]	–	0.3	0.4	0.4	..	..	..
Geothermal	–	0.0	0.0	0.0	..	..	..
Solar/Wind/Other	–	0.0	0.0	0.0	..	..	..
Electricity	2.9	5.0	6.7	6.7	..	..	..
Heat	0.3	0.2	0.5	0.5	..	..	..
Shares (%)							
Coal	*16.5*	*10.2*	*6.7*	*4.4*	..	..	..
Oil	*60.7*	*52.4*	*51.9*	*51.8*	..	..	..
Gas	*13.3*	*20.6*	*23.8*	*25.3*	..	..	..
Comb. Renewables & Wastes	–	*1.0*	*0.8*	*0.9*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*8.5*	*15.1*	*15.6*	*16.5*	..	..	..
Heat	*0.9*	*0.7*	*1.1*	*1.2*	..	..	..
TOTAL INDUSTRY[6]	**16.8**	**13.5**	**19.0**	**17.5**	**..**	**..**	**..**
Coal[1]	3.5	2.9	2.7	1.6	..	..	..
Oil	7.9	4.3	7.3	6.7	..	..	..
Gas	3.2	3.3	5.0	5.3	..	..	..
Comb. Renewables & Wastes[2]	–	0.1	0.2	0.2	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	1.9	2.6	3.4	3.3	..	..	..
Heat	0.3	0.2	0.4	0.4	..	..	..
Shares (%)							
Coal	*21.1*	*21.5*	*14.1*	*8.9*	..	..	..
Oil	*46.8*	*32.1*	*38.7*	*38.0*	..	..	..
Gas	*18.7*	*24.5*	*26.3*	*30.4*	..	..	..
Comb. Renewables & Wastes	–	*1.0*	*1.0*	*1.2*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*11.5*	*19.5*	*17.8*	*19.1*	..	..	..
Heat	*1.9*	*1.4*	*2.2*	*2.4*	..	..	..
TRANSPORT[7]	**5.0**	**7.9**	**9.7**	**9.8**	**..**	**..**	**..**
TOTAL OTHER SECTORS[8]	**12.7**	**11.7**	**14.4**	**13.6**	**..**	**..**	**..**
Coal[1]	2.2	0.5	0.2	0.2	..	..	..
Oil	8.1	5.2	5.4	4.9	..	..	..
Gas	1.5	3.5	5.3	5.1	..	..	..
Comb. Renewables & Wastes[2]	–	0.2	0.2	0.2	..	..	..
Geothermal	–	0.0	0.0	0.0	..	..	..
Solar/Wind/Other	–	0.0	0.0	0.0	..	..	..
Electricity	0.9	2.3	3.2	3.3	..	..	..
Heat	–	0.0	0.1	0.1	..	..	..
Shares (%)							
Coal	*17.0*	*4.1*	*1.7*	*1.7*	..	..	..
Oil	*64.2*	*44.7*	*37.6*	*35.6*	..	..	..
Gas	*11.4*	*30.1*	*36.6*	*37.1*	..	..	..
Comb. Renewables & Wastes	–	*1.6*	*1.2*	*1.1*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*7.4*	*19.3*	*22.4*	*24.0*	..	..	..
Heat	–	*0.3*	*0.4*	*0.5*	..	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**10.0**	**17.7**	**18.7**	**19.1**	..	..	..
OUTPUT (Mtoe)	**3.5**	**6.0**	**6.8**	**7.0**	..	..	..
(TWh gross)	40.6	70.3	78.6	80.9	..	..	..
Output Shares (%)							
Coal	*21.7*	*28.2*	*16.2*	*15.6*	..	..	..
Oil	*53.7*	*1.9*	*2.1*	*1.2*	..	..	..
Gas	*23.7*	*7.7*	*20.1*	*22.1*	..	..	..
Comb. Renewables & Wastes	*0.3*	*1.0*	*2.0*	*2.1*	..	..	..
Nuclear	*0.2*	*60.8*	*59.0*	*58.5*	..	..	..
Hydro	*0.4*	*0.4*	*0.6*	*0.4*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	*0.0*	*0.0*	*0.1*	..	..	..
TOTAL LOSSES	**11.8**	**16.1**	**15.6**	**16.1**	..	..	..
of which:							
Electricity and Heat Generation[10]	6.2	11.4	11.4	11.5	..	..	..
Other Transformation	4.2	2.1	1.5	1.6	..	..	..
Own Use and Losses[11]	1.4	2.7	2.7	2.9	..	..	..
Statistical Differences	**-0.1**	**-0.5**	**0.3**	**-0.1**	..	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	174.32	255.67	318.61	320.84	..	..	..
Population (millions)	9.73	9.97	10.28	10.33	..	..	..
TPES/GDP[12]	0.27	0.19	0.19	0.18	..	..	..
Energy Production/TPES	0.14	0.27	0.22	0.23	..	..	..
Per Capita TPES[13]	4.76	4.88	5.74	5.51	..	..	..
Oil Supply/GDP[12]	0.16	0.07	0.08	0.07	..	..	..
TFC/GDP[12]	0.20	0.13	0.14	0.13	..	..	..
Per Capita TFC[13]	3.55	3.32	4.19	3.97	..	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	133.6	106.9	119.6	112.6	..	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	11.3	16.0	20.2	25.7	..	..	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	0.7	0.1	1.8	-3.6	..	..	..
Coal	-1.0	-0.3	-2.5	-13.6	..	..	..
Oil	-1.5	-2.8	2.4	-5.6	..	..	..
Gas	4.5	-1.2	4.4	1.5	..	..	..
Comb. Renewables & Wastes	41.7	22.8	2.7	-3.0	..	..	..
Nuclear	130.2	12.8	0.7	2.2	..	..	..
Hydro	4.9	1.3	4.7	-18.4	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	15.8	40.0	..	..	..
TFC	0.3	-0.6	2.4	-4.9	..	..	..
Electricity Consumption	4.2	2.6	2.7	0.4	..	..	..
Energy Production	2.4	5.2	0.0	1.3	..	..	..
Net Oil Imports	-0.8	-3.4	2.7	-7.9	..	..	..
GDP	2.4	2.2	2.0	0.7	..	..	..
Growth in the TPES/GDP Ratio	-1.6	-2.1	-0.3	-4.3	..	..	..
Growth in the TFC/GDP Ratio	-2.0	-2.7	0.4	-5.5	..	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

CANADA

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**198.0**	**273.7**	**379.2**	**385.4**	**528.3**	**554.5**	**..**
Coal[1]		11.7	37.9	37.6	34.8	39.9	38.7	..
Oil		96.3	94.1	130.2	135.9	217.3	206.8	..
Gas		61.4	88.6	152.3	153.5	197.0	232.8	..
Comb. Renewables & Wastes[2]		7.8	8.1	10.5	11.3	17.0	19.0	..
Nuclear		4.1	19.4	20.0	19.7	23.4	22.1	..
Hydro		16.7	25.5	28.6	30.1	33.3	34.6	..
Geothermal		–	–	–	–	0.4	0.4	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	0.1	0.1	..
TOTAL NET IMPORTS[4]		**-36.6**	**-60.6**	**-133.0**	**-140.6**	**-221.5**	**-204.3**	**..**
Coal[1]	Exports	7.6	21.4	20.9	18.5	20.3	23.1	..
	Imports	10.5	9.5	15.7	14.9	8.7	6.5	..
	Net Imports	2.8	-11.9	-5.2	-3.6	-11.6	-16.6	..
Oil	Exports	63.1	49.7	96.0	102.5	174.4	158.5	..
	Imports	48.8	34.5	56.7	53.5	54.2	60.0	..
	Bunkers	1.1	0.9	1.1	1.1	0.7	0.8	..
	Net Imports	-15.4	-16.1	-40.4	-50.1	-121.0	-99.4	..
Gas	Exports	23.1	33.0	88.5	88.2	88.0	88.0	..
	Imports	0.3	0.5	3.2	3.0	1.0	1.0	..
	Net Imports	-22.8	-32.5	-85.3	-85.2	-86.9	-86.9	..
Electricity	Exports	1.4	1.6	3.4	3.1	5.4	4.7	..
	Imports	0.2	1.5	1.4	1.4	3.4	3.3	..
	Net Imports	-1.2	-0.0	-2.0	-1.7	-2.0	-1.4	..
TOTAL STOCK CHANGES		**-1.6**	**-4.0**	**1.9**	**5.2**	**–**	**–**	**..**
TOTAL SUPPLY (TPES)		**159.8**	**209.1**	**248.2**	**250.0**	**306.8**	**350.2**	**..**
Coal[1]		15.3	24.3	30.7	29.4	28.3	22.1	..
Oil		79.9	77.1	88.4	85.9	96.4	107.4	..
Gas		37.3	54.7	71.9	75.3	110.1	145.9	..
Comb. Renewables & Wastes[2]		7.8	8.1	10.5	11.3	17.0	19.0	..
Nuclear		4.1	19.4	20.0	19.7	23.4	22.1	..
Hydro		16.7	25.5	28.6	30.1	33.3	34.6	..
Geothermal		–	–	–	–	0.4	0.4	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	0.1	0.1	..
Electricity Trade[5]		-1.2	-0.0	-2.0	-1.7	-2.0	-1.4	..
Shares (%)								
Coal		*9.5*	*11.6*	*12.4*	*11.8*	*9.2*	*6.3*	..
Oil		*50.0*	*36.9*	*35.6*	*34.4*	*31.4*	*30.7*	..
Gas		*23.3*	*26.2*	*29.0*	*30.1*	*35.9*	*41.7*	..
Comb. Renewables & Wastes		*4.9*	*3.9*	*4.2*	*4.5*	*5.5*	*5.4*	..
Nuclear		*2.5*	*9.3*	*8.1*	*7.9*	*7.6*	*6.3*	..
Hydro		*10.5*	*12.2*	*11.5*	*12.0*	*10.8*	*9.9*	..
Geothermal		–	–	–	–	*0.1*	*0.1*	..
Solar/Wind/Other		–	–	–	–	–	–	..
Electricity Trade		*-0.8*	–	*-0.8*	*-0.7*	*-0.7*	*-0.4*	..

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**132.1**	**160.8**	**184.4**	**190.5**	**221.5**	**251.0**	**..**
Coal[1]	5.2	3.1	3.2	3.1	4.7	5.4	..
Oil	76.5	70.6	81.5	82.5	86.8	98.2	..
Gas	23.7	43.3	48.8	52.6	63.4	72.1	..
Comb. Renewables & Wastes[2]	7.6	7.3	8.7	9.4	15.6	17.5	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	18.9	36.0	41.3	42.1	50.3	57.0	..
Heat	0.1	0.6	0.9	0.8	0.7	0.9	..
Shares (%)							
Coal	*4.0*	*1.9*	*1.8*	*1.6*	*2.1*	*2.1*	..
Oil	*57.9*	*43.9*	*44.2*	*43.3*	*39.2*	*39.1*	..
Gas	*18.0*	*26.9*	*26.5*	*27.6*	*28.6*	*28.7*	..
Comb. Renewables & Wastes	*5.8*	*4.5*	*4.7*	*5.0*	*7.0*	*7.0*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*14.3*	*22.4*	*22.4*	*22.1*	*22.7*	*22.7*	..
Heat	*0.1*	*0.4*	*0.5*	*0.4*	*0.3*	*0.3*	..
TOTAL INDUSTRY[6]	**52.8**	**62.7**	**70.5**	**73.1**	**97.5**	**111.1**	**..**
Coal[1]	4.7	3.0	3.2	3.0	4.6	5.3	..
Oil	21.4	18.7	21.7	21.8	24.9	27.6	..
Gas	11.9	20.2	20.5	22.3	31.2	36.2	..
Comb. Renewables & Wastes[2]	5.7	5.7	6.8	7.6	13.6	15.3	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	9.1	14.4	17.4	17.5	22.4	25.8	..
Heat	0.1	0.6	0.8	0.8	0.7	0.9	..
Shares (%)							
Coal	*8.9*	*4.8*	*4.5*	*4.1*	*4.8*	*4.8*	..
Oil	*40.4*	*29.8*	*30.7*	*29.8*	*25.5*	*24.9*	..
Gas	*22.5*	*32.3*	*29.1*	*30.5*	*32.0*	*32.6*	..
Comb. Renewables & Wastes	*10.8*	*9.0*	*9.7*	*10.4*	*14.0*	*13.8*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*17.2*	*23.1*	*24.7*	*24.0*	*23.0*	*23.2*	..
Heat	*0.2*	*1.0*	*1.2*	*1.1*	*0.8*	*0.8*	..
TRANSPORT[7]	**34.2**	**44.2**	**52.7**	**53.5**	**64.3**	**75.1**	**..**
TOTAL OTHER SECTORS[8]	**45.1**	**54.0**	**61.2**	**64.0**	**59.7**	**64.8**	**..**
Coal[1]	0.4	0.1	0.0	0.0	0.1	0.1	..
Oil	21.3	10.9	11.9	12.2	6.5	6.9	..
Gas	11.9	20.2	23.9	25.7	24.5	25.7	..
Comb. Renewables & Wastes[2]	1.9	1.6	1.8	1.8	2.0	2.2	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	9.5	21.2	23.5	24.2	26.7	30.0	..
Heat	–	0.0	0.0	0.0	–	–	..
Shares (%)							
Coal	*0.9*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	..
Oil	*47.4*	*20.2*	*19.4*	*19.0*	*10.8*	*10.7*	..
Gas	*26.3*	*37.4*	*39.1*	*40.2*	*41.0*	*39.6*	..
Comb. Renewables & Wastes	*4.2*	*3.0*	*3.0*	*2.9*	*3.3*	*3.3*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*21.2*	*39.3*	*38.5*	*37.9*	*44.7*	*46.2*	..
Heat	–	–	–	–	–	–	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**36.1**	**71.2**	**88.3**	**87.9**	**95.0**	**100.3**	**..**
OUTPUT (Mtoe)	**23.2**	**41.4**	**50.7**	**51.7**	**60.9**	**68.9**	**..**
(TWh gross)	270.1	481.9	589.6	601.4	708.2	800.6	..
Output Shares (%)							
Coal	*12.9*	*17.1*	*20.0*	*19.5*	*14.1*	*10.3*	..
Oil	*3.4*	*3.4*	*2.9*	*2.4*	*0.7*	*0.5*	..
Gas	*6.0*	*2.0*	*6.2*	*5.8*	*15.7*	*26.2*	..
Comb. Renewables & Wastes	–	*0.8*	*1.3*	*1.4*	*2.0*	*2.0*	..
Nuclear	*5.6*	*15.1*	*13.0*	*12.6*	*12.7*	*10.6*	..
Hydro	*72.1*	*61.6*	*56.5*	*58.2*	*54.6*	*50.2*	..
Geothermal	–	–	–	–	*0.1*	*0.1*	..
Solar/Wind/Other	–	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	..
TOTAL LOSSES	**31.2**	**49.2**	**62.0**	**61.2**	**85.3**	**99.2**	**..**
of which:							
Electricity and Heat Generation[10]	12.8	29.1	36.8	35.3	33.3	30.6	..
Other Transformation	1.9	-1.3	-3.4	-5.3	13.7	13.9	..
Own Use and Losses[11]	16.5	21.4	28.6	31.2	38.3	54.7	..
Statistical Differences	**-3.5**	**-0.9**	**1.8**	**-1.7**	**–**	**–**	**..**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	322.34	534.39	727.30	751.04	897.37	1116.62	..
Population (millions)	22.49	27.70	31.11	31.41	33.20	35.30	..
TPES/GDP[12]	0.50	0.39	0.34	0.33	0.34	0.31	..
Energy Production/TPES	1.24	1.31	1.53	1.54	1.72	1.58	..
Per Capita TPES[13]	7.11	7.55	7.98	7.96	9.24	9.92	..
Oil Supply/GDP[12]	0.25	0.14	0.12	0.11	0.11	0.10	..
TFC/GDP[12]	0.41	0.30	0.25	0.25	0.25	0.22	..
Per Capita TFC[13]	5.87	5.80	5.93	6.07	6.67	7.11	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	376.3	430.2	521.2	531.9	575.4	663.1	..
CO_2 Emissions from Bunkers (Mt CO_2)	5.2	5.6	6.6	6.4	5.1	5.3	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	3.0	0.8	1.6	0.8	2.6	1.3	..
Coal	4.4	1.9	2.2	-4.2	-0.5	-2.4	..
Oil	2.4	-1.6	1.3	-2.9	1.4	1.1	..
Gas	2.7	2.1	2.5	4.7	4.9	2.9	..
Comb. Renewables & Wastes	-1.6	1.2	2.3	8.2	5.2	1.2	..
Nuclear	15.7	6.4	0.3	-1.5	2.2	-0.6	..
Hydro	3.8	1.8	1.1	5.2	1.2	0.4	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	35.8	10.3	-0.8	–	..
TFC	2.6	0.4	1.3	3.3	1.9	1.3	..
Electricity Consumption	4.7	3.4	1.3	1.9	2.2	1.3	..
Energy Production	1.0	2.4	3.0	1.6	4.0	0.5	..
Net Oil Imports	–	–	8.7	24.1	11.6	-1.9	..
GDP	3.6	2.7	2.8	3.3	2.2	2.2	..
Growth in the TPES/GDP Ratio	-0.6	-1.8	-1.2	-2.4	0.3	-0.9	..
Growth in the TFC/GDP Ratio	-1.0	-2.2	-1.5	0.1	-0.3	-0.9	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**38.51**	**38.49**	**30.49**	**30.67**	**25.66**	**21.47**	**19.38**
Coal[1]		38.01	34.71	25.29	24.21	17.00	12.00	9.60
Oil		0.04	0.18	0.36	0.41	0.40	0.40	0.40
Gas		0.36	0.20	0.12	0.12	0.10	0.30	0.30
Comb. Renewables & Wastes[2]		-	–	0.69	0.84	1.30	1.90	2.20
Nuclear		–	3.28	3.84	4.88	6.70	6.70	6.70
Hydro		0.09	0.12	0.18	0.21	0.16	0.17	0.17
Geothermal		–	–	–	–	–	–	–
Solar/Wind/Other[3]		–	–	–	–	0.00	0.01	0.01
TOTAL NET IMPORTS[4]		**6.99**	**7.63**	**10.67**	**11.07**	**16.40**	**22.50**	**24.20**
Coal[1]	Exports	2.56	7.26	5.56	4.96	4.10	1.10	0.90
	Imports	0.15	1.57	1.11	1.13	1.20	1.40	1.60
	Net Imports	-2.41	-5.69	-4.45	-3.83	-2.90	0.30	0.70
Oil	Exports	0.04	6.56	1.31	1.42	1.60	1.60	1.70
	Imports	8.91	15.16	9.51	9.42	10.20	10.60	11.00
	Bunkers	–	–	–	–	–	–	–
	Net Imports	8.87	8.60	8.20	7.99	8.60	9.00	9.30
Gas	Exports	0.01	–	–	0.00	–	–	–
	Imports	0.73	4.78	7.73	7.92	11.00	13.00	14.00
	Net Imports	0.72	4.78	7.73	7.92	11.00	13.00	14.00
Electricity	Exports	0.44	0.76	1.63	1.80	0.70	0.40	0.60
	Imports	0.25	0.70	0.81	0.82	0.40	0.60	0.80
	Net Imports	-0.19	-0.06	-0.82	-0.98	-0.30	0.20	0.20
TOTAL STOCK CHANGES		**-0.08**	**1.25**	**0.24**	**-0.02**	**–**	**–**	**–**
TOTAL SUPPLY (TPES)		**45.42**	**47.38**	**41.40**	**41.73**	**42.06**	**43.97**	**43.58**
Coal[1]		35.59	29.84	21.09	20.51	14.10	12.30	10.30
Oil		8.91	8.94	8.39	8.53	9.00	9.40	9.70
Gas		1.01	5.26	8.03	7.76	11.10	13.30	14.30
Comb. Renewables & Wastes[2]		–	–	0.69	0.82	1.30	1.90	2.20
Nuclear		–	3.28	3.84	4.88	6.70	6.70	6.70
Hydro		0.09	0.12	0.18	0.21	0.16	0.17	0.17
Geothermal		–	–	–	–	–	–	–
Solar/Wind/Other[3]		–	–	–	–	0.00	0.01	0.01
Electricity Trade[5]		-0.19	-0.06	-0.82	-0.98	-0.30	0.20	0.20
Shares (%)								
Coal		*78.4*	*63.0*	*50.9*	*49.1*	*33.5*	*28.0*	*23.6*
Oil		*19.6*	*18.9*	*20.3*	*20.4*	*21.4*	*21.4*	*22.3*
Gas		*2.2*	*11.1*	*19.4*	*18.6*	*26.4*	*30.2*	*32.8*
Comb. Renewables & Wastes		–	–	*1.7*	*2.0*	*3.1*	*4.3*	*5.0*
Nuclear		–	*6.9*	*9.3*	*11.7*	*15.9*	*15.2*	*15.4*
Hydro		*0.2*	*0.3*	*0.4*	*0.5*	*0.4*	*0.4*	*0.4*
Geothermal		–	–	–	–	–	–	–
Solar/Wind/Other		–	–	–	–	–	–	–
Electricity Trade		*-0.4*	*-0.1*	*-2.0*	*-2.3*	*-0.7*	*0.5*	*0.5*

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**33.07**	**35.30**	**25.65**	**24.87**	**28.55**	**30.40**	**31.01**
Coal[1]	20.66	17.43	3.81	3.46	2.70	2.30	1.60
Oil	8.06	8.09	7.95	7.80	8.30	8.40	8.70
Gas	1.81	4.19	6.45	6.19	8.70	9.70	10.70
Comb. Renewables & Wastes[2]	–	–	0.28	0.41	0.70	1.00	1.20
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	0.00	0.00	0.01
Electricity	2.54	4.14	4.38	4.37	4.85	5.65	5.50
Heat	–	1.45	2.79	2.64	3.30	3.35	3.30
Shares (%)							
Coal	*62.5*	*49.4*	*14.8*	*13.9*	*9.5*	*7.6*	*5.2*
Oil	*24.4*	*22.9*	*31.0*	*31.4*	*29.1*	*27.6*	*28.1*
Gas	*5.5*	*11.9*	*25.1*	*24.9*	*30.5*	*31.9*	*34.5*
Comb. Renewables & Wastes	–	–	*1.1*	*1.7*	*2.5*	*3.3*	*3.9*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*7.7*	*11.7*	*17.1*	*17.6*	*17.0*	*18.6*	*17.7*
Heat	–	*4.1*	*10.9*	*10.6*	*11.6*	*11.0*	*10.6*
TOTAL INDUSTRY[6]	**19.42**	**18.63**	**10.92**	**10.61**	**12.50**	**13.10**	**13.00**
Coal[1]	12.06	10.06	2.81	2.65	1.80	1.60	1.10
Oil	5.30	4.23	2.80	2.54	3.40	3.30	3.40
Gas	0.46	2.02	2.61	2.58	4.20	4.70	5.10
Comb. Renewables & Wastes[2]	–	–	0.19	0.32	0.10	0.30	0.30
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	1.61	2.32	1.72	1.77	1.70	1.85	1.80
Heat	–	–	0.79	0.75	1.30	1.35	1.30
Shares (%)							
Coal	*62.1*	*54.0*	*25.7*	*25.0*	*14.4*	*12.2*	*8.5*
Oil	*27.3*	*22.7*	*25.7*	*24.0*	*27.2*	*25.2*	*26.2*
Gas	*2.4*	*10.9*	*23.9*	*24.3*	*33.6*	*35.9*	*39.2*
Comb. Renewables & Wastes	–	–	*1.7*	*3.0*	*0.8*	*2.3*	*2.3*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*8.3*	*12.4*	*15.7*	*16.7*	*13.6*	*14.1*	*13.8*
Heat	–	–	*7.2*	*7.1*	*10.4*	*10.3*	*10.0*
TRANSPORT[7]	**2.46**	**2.86**	**5.14**	**5.31**	**5.10**	**5.40**	**5.60**
TOTAL OTHER SECTORS[8]	**11.18**	**13.81**	**9.59**	**8.96**	**10.95**	**11.90**	**12.41**
Coal[1]	8.47	7.37	1.00	0.81	0.90	0.70	0.50
Oil	0.60	1.27	0.24	0.19	0.60	0.70	0.70
Gas	1.35	2.17	3.81	3.58	4.30	4.60	5.20
Comb. Renewables & Wastes[2]	–	–	0.07	0.08	0.60	0.70	0.90
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	0.00	0.00	0.01
Electricity	0.76	1.56	2.48	2.42	2.55	3.20	3.10
Heat	–	1.45	2.00	1.89	2.00	2.00	2.00
Shares (%)							
Coal	*75.7*	*53.3*	*10.4*	*9.1*	*8.2*	*5.9*	*4.0*
Oil	*5.4*	*9.2*	*2.5*	*2.1*	*5.5*	*5.9*	*5.6*
Gas	*12.1*	*15.7*	*39.7*	*39.9*	*39.3*	*38.6*	*41.9*
Comb. Renewables & Wastes	–	–	*0.7*	*0.8*	*5.5*	*5.9*	*7.3*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*6.8*	*11.3*	*25.8*	*27.0*	*23.3*	*26.9*	*25.0*
Heat	–	*10.5*	*20.9*	*21.1*	*18.3*	*16.8*	*16.1*

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**9.70**	**16.54**	**21.15**	**21.80**	**21.06**	**21.57**	**20.47**
OUTPUT (Mtoe)	**3.54**	**5.38**	**6.38**	**6.54**	**6.05**	**6.35**	**6.30**
(TWh gross)	41.17	62.56	74.23	76.00	70.35	73.85	73.26
Output Shares (%)							
Coal	*85.1*	*71.8*	*71.7*	*66.8*	*47.7*	*40.6*	*39.4*
Oil	*11.3*	*4.8*	*0.5*	*0.5*	*2.0*	*2.6*	*2.7*
Gas	*0.9*	*1.0*	*4.2*	*3.9*	*10.0*	*17.1*	*17.3*
Comb. Renewables & Wastes	–	–	*1.0*	*0.9*	*1.2*	*2.3*	*2.9*
Nuclear	–	*20.1*	*19.9*	*24.7*	*36.5*	*34.8*	*35.1*
Hydro	*2.6*	*2.3*	*2.8*	*3.3*	*2.6*	*2.6*	*2.6*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	*0.0*	*0.0*	*0.0*	*0.0*
TOTAL LOSSES	**13.62**	**13.52**	**15.21**	**15.80**	**13.51**	**13.57**	**12.57**
of which:							
Electricity and Heat Generation[10]	6.16	9.34	11.20	11.87	11.23	11.37	10.37
Other Transformation	5.90	1.71	1.21	1.08	0.40	0.20	0.10
Own Use and Losses[11]	1.57	2.48	2.80	2.85	1.88	2.00	2.10
Statistical Differences	**-1.27**	**-1.45**	**0.53**	**1.06**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	40.52	54.61	56.99	58.11	85.85	139.84	227.79
Population (millions)	9.92	10.36	10.22	10.21	10.10	10.10	10.10
TPES/GDP[12]	1.12	0.87	0.73	0.72	0.49	0.31	0.19
Energy Production/TPES	0.85	0.81	0.74	0.74	0.61	0.49	0.44
Per Capita TPES[13]	4.58	4.57	4.05	4.09	4.16	4.35	4.31
Oil Supply/GDP[12]	0.22	0.16	0.15	0.15	0.10	0.07	0.04
TFC/GDP[12]	0.82	0.65	0.45	0.43	0.33	0.22	0.14
Per Capita TFC[13]	3.33	3.41	2.51	2.44	2.83	3.01	3.07
Energy-related CO_2 Emissions (Mt CO_2)[14]	153.0	153.8	118.6	115.0	103.6	103.3	98.8
CO_2 Emissions from Bunkers (Mt CO_2)	0.7	0.7	0.5	0.5	0.5	0.5	0.5

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	1.2	-0.2	-1.2	0.8	0.1	0.4	-0.1
Coal	-0.3	-1.4	-3.1	-2.8	-4.6	-1.4	-1.8
Oil	4.2	-2.2	-0.6	1.6	0.7	0.4	0.3
Gas	14.3	8.0	3.9	-3.4	4.6	1.8	0.7
Comb. Renewables & Wastes	–	–	–	18.4	6.0	3.9	1.5
Nuclear	–	–	1.5	27.0	4.0	–	–
Hydro	13.3	-4.1	3.3	20.9	-3.6	0.3	–
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	5.2	7.2
TFC	2.8	-0.9	-2.9	-3.1	1.7	0.6	0.2
Electricity Consumption	3.4	2.6	0.5	-0.1	1.3	1.5	-0.3
Energy Production	2.0	-1.1	-2.1	0.6	-2.2	-1.8	-1.0
Net Oil Imports	3.9	-2.4	-0.4	-2.5	0.9	0.5	0.3
GDP	2.5	1.4	0.4	2.0	5.0	5.0	5.0
Growth in the TPES/GDP Ratio	-1.3	-1.6	-1.6	-1.1	-4.7	-4.3	-4.8
Growth in the TFC/GDP Ratio	0.3	-2.2	-3.2	-4.9	-3.1	-4.2	-4.6

Please note: Rounding may cause totals to differ from the sum of the elements.

DENMARK

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2017	2030
TOTAL PRODUCTION		**0.43**	**9.74**	**27.23**	**28.75**	**26.53**	**8.83**	**..**
Coal[1]		–	–	–	–	–	–	..
Oil		0.07	5.77	17.34	18.63	13.96	4.42	..
Gas		–	2.77	7.59	7.60	9.40	1.44	..
Comb. Renewables & Wastes[2]		0.35	1.14	1.83	2.01	2.44	2.24	..
Nuclear		–	–	–	–	–	–	..
Hydro		0.00	0.00	0.00	0.00	0.00	0.00	..
Geothermal		–	0.00	0.00	0.00	0.01	0.01	..
Solar/Wind/Other[3]		–	0.06	0.46	0.51	0.72	0.72	..
TOTAL NET IMPORTS[4]		**19.85**	**7.68**	**-7.23**	**-9.75**	**-2.96**	**14.88**	**..**
Coal1	Exports	0.04	0.03	0.10	0.10	–	–	..
	Imports	1.91	6.25	4.16	3.80	5.47	4.32	..
	Net Imports	1.87	6.22	4.06	3.70	5.47	4.32	..
Oil	Exports	2.89	5.48	16.27	17.98	2.77	–	..
	Imports	21.58	8.22	9.13	8.54	–	6.84	..
	Bunkers	0.69	0.96	1.13	0.94	1.13	1.13	..
	Net Imports	18.00	1.78	-8.27	-10.37	-3.90	5.71	..
Gas	Exports	–	0.93	3.05	3.07	3.36	–	..
	Imports	–	–	–	0.09	–	6.15	..
	Net Imports	–	-0.93	-3.05	-2.98	-3.36	6.15	..
Electricity	Exports	0.11	0.42	0.76	0.95	1.17	1.30	..
	Imports	0.09	1.03	0.71	0.77	–	–	..
	Net Imports	-0.02	0.61	-0.05	-0.18	-1.17	-1.30	..
TOTAL STOCK CHANGES		**-0.44**	**0.17**	**0.02**	**0.75**	**–**	**–**	**..**
TOTAL SUPPLY (TPES)		**19.83**	**17.58**	**20.01**	**19.75**	**23.57**	**23.71**	**..**
Coal[1]		1.93	6.09	4.22	4.18	5.47	4.32	..
Oil		17.57	7.87	8.84	8.53	10.05	10.13	..
Gas		–	1.82	4.63	4.63	6.04	7.58	..
Comb. Renewables & Wastes[2]		0.35	1.14	1.91	2.08	2.44	2.24	..
Nuclear		–	–	–	–	–	–	..
Hydro		0.00	0.00	0.00	0.00	0.00	0.00	..
Geothermal		–	0.00	0.00	0.00	0.01	0.01	..
Solar/Wind/Other[3]		–	0.06	0.47	0.51	0.72	0.72	..
Electricity Trade[5]		-0.02	0.61	-0.05	-0.18	-1.17	-1.30	..
Shares (%)								
Coal		*9.7*	*34.6*	*21.1*	*21.1*	*23.2*	*18.2*	..
Oil		*88.6*	*44.7*	*44.2*	*43.2*	*42.6*	*42.7*	..
Gas		–	*10.3*	*23.1*	*23.4*	*25.6*	*32.0*	..
Comb. Renewables & Wastes		*1.8*	*6.5*	*9.5*	*10.5*	*10.4*	*9.5*	..
Nuclear		–	–	–	–	–	–	..
Hydro		–	–	–	–	–	–	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other		–	*0.3*	*2.3*	*2.6*	*3.1*	*3.0*	..
Electricity Trade		*-0.1*	*3.4*	*-0.2*	*-0.9*	*-5.0*	*-5.5*	..

0 is negligible, – is nil, .. is not available.

Please note: TPES for a given year strongly depends on the amount of net import of electricity, which may vary substantially from year to year. For forecast years. electricity exports may be lower when the CO_2 quota system is taken into account. All forecasts are based on the 2002 submission.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2017	2030
TFC	**16.26**	**13.88**	**15.44**	**15.15**	**17.11**	**18.14**	**..**
Coal[1]	0.34	0.40	0.26	0.22	0.31	0.35	..
Oil	14.26	7.56	7.45	7.32	8.22	8.69	..
Gas	0.12	1.16	1.78	1.66	2.00	2.12	..
Comb. Renewables & Wastes[2]	0.16	0.56	0.71	0.75	0.66	0.68	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.00	0.01	0.01	0.01	0.01	..
Electricity	1.39	2.44	2.80	2.78	3.13	3.44	..
Heat	–	1.76	2.44	2.40	2.78	2.85	..
Shares (%)							
Coal	*2.1*	*2.9*	*1.7*	*1.5*	*1.8*	*1.9*	..
Oil	*87.7*	*54.5*	*48.2*	*48.3*	*48.1*	*47.9*	..
Gas	*0.7*	*8.3*	*11.5*	*11.0*	*11.7*	*11.7*	..
Comb. Renewables & Wastes	*1.0*	*4.1*	*4.6*	*5.0*	*3.9*	*3.7*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	*0.1*	*0.1*	–	–	..
Electricity	*8.5*	*17.6*	*18.1*	*18.4*	*18.3*	*19.0*	..
Heat	–	*12.7*	*15.8*	*15.8*	*16.2*	*15.7*	..
TOTAL INDUSTRY[6]	**4.10**	**3.00**	**3.30**	**3.22**	**3.79**	**4.19**	**..**
Coal[1]	0.21	0.32	0.23	0.20	0.28	0.32	..
Oil	3.41	1.23	1.06	1.05	1.19	1.30	..
Gas	0.02	0.54	0.82	0.76	0.99	1.09	..
Comb. Renewables & Wastes[2]	0.06	0.11	0.17	0.20	0.13	0.14	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	0.40	0.73	0.86	0.84	0.99	1.12	..
Heat	–	0.07	0.17	0.17	0.22	0.23	..
Shares (%)							
Coal	*5.2*	*10.7*	*7.0*	*6.2*	*7.3*	*7.5*	..
Oil	*83.3*	*40.9*	*32.0*	*32.6*	*31.4*	*31.1*	..
Gas	*0.4*	*17.9*	*24.8*	*23.6*	*26.2*	*25.9*	..
Comb. Renewables & Wastes	*1.4*	*3.8*	*5.0*	*6.2*	*3.4*	*3.4*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*9.7*	*24.2*	*26.2*	*26.1*	*26.1*	*26.6*	..
Heat	–	*2.5*	*5.1*	*5.2*	*5.7*	*5.5*	..
TRANSPORT[7]	**3.52**	**4.11**	**4.88**	**4.83**	**5.60**	**6.01**	**..**
TOTAL OTHER SECTORS[8]	**8.65**	**6.77**	**7.26**	**7.10**	**7.72**	**7.94**	**..**
Coal[1]	0.13	0.08	0.03	0.02	0.04	0.04	..
Oil	7.34	2.24	1.54	1.47	1.45	1.40	..
Gas	0.10	0.62	0.96	0.90	1.01	1.03	..
Comb. Renewables & Wastes[2]	0.10	0.45	0.55	0.55	0.53	0.54	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.00	0.01	0.01	0.01	0.01	..
Electricity	0.98	1.70	1.91	1.91	2.12	2.30	..
Heat	–	1.68	2.27	2.23	2.56	2.62	..
Shares (%)							
Coal	*1.4*	*1.2*	*0.4*	*0.3*	*0.5*	*0.5*	..
Oil	*84.9*	*33.1*	*21.2*	*20.8*	*18.8*	*17.6*	..
Gas	*1.2*	*9.2*	*13.2*	*12.7*	*13.1*	*13.0*	..
Comb. Renewables & Wastes	*1.2*	*6.7*	*7.5*	*7.8*	*6.9*	*6.8*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	*0.1*	*0.1*	*0.1*	*0.1*	..
Electricity	*11.3*	*25.1*	*26.3*	*26.9*	*27.5*	*29.0*	..
Heat	–	*24.9*	*31.3*	*31.4*	*33.2*	*33.0*	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2017	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**4.60**	**7.08**	**8.91**	**9.10**	**12.07**	**11.90**	..
OUTPUT (Mtoe)	**1.64**	**2.23**	**3.24**	**3.38**	**4.53**	**5.00**	..
(TWh gross)	19.12	25.98	37.71	39.25	52.71	58.12	..
Output Shares (%)							
Coal	*35.8*	*90.3*	*47.3*	*46.5*	*43.7*	*34.7*	..
Oil	*64.1*	*3.7*	*11.1*	*10.2*	*9.6*	*6.9*	..
Gas	–	*2.7*	*24.6*	*24.4*	*23.5*	*38.2*	..
Comb. Renewables & Wastes	–	*0.8*	*5.6*	*6.4*	*9.5*	*7.9*	..
Nuclear	–	–	–	–	–	–	..
Hydro	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*2.3*	*11.5*	*12.5*	*13.6*	*12.3*	..
TOTAL LOSSES	**3.66**	**3.65**	**4.55**	**4.62**	**6.47**	**5.58**	..
of which:							
Electricity and Heat Generation[10]	2.96	2.64	2.62	2.72	4.03	3.30	..
Other Transformation	0.44	-0.40	-0.01	-0.07	–	–	..
Own Use and Losses[11]	0.26	1.41	1.93	1.97	2.44	2.27	..
Statistical Differences	**-0.08**	**0.06**	**0.03**	**-0.02**	**–**	**–**	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	128.44	163.49	208.83	213.14	246.48	275.44	..
Population (millions)	5.02	5.14	5.36	5.38	5.45	5.50	..
TPES/GDP[12]	0.15	0.11	0.10	0.09	0.10	0.09	..
Energy Production/TPES	0.02	0.55	1.36	1.46	1.13	0.37	..
Per Capita TPES[13]	3.95	3.42	3.74	3.67	4.32	4.31	..
Oil Supply/GDP[12]	0.14	0.05	0.04	0.04	0.04	0.04	..
TFC/GDP[12]	0.13	0.08	0.07	0.07	0.07	0.07	..
Per Capita TFC[13]	3.24	2.70	2.88	2.82	3.14	3.30	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	56.6	50.6	51.6	51.2	64.1	63.2	..
CO_2 Emissions from Bunkers (Mt CO_2)	4.5	4.8	6.0	5.0	5.7	6.0	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	1.2	-1.7	1.2	-1.3	2.2	0.1	..
Coal	14.4	3.1	-3.3	-1.0	3.4	-3.3	..
Oil	-1.4	-6.3	1.1	-3.5	2.1	0.1	..
Gas	–	–	8.9	-0.1	3.4	3.3	..
Comb. Renewables & Wastes	6.9	7.3	4.8	9.2	2.0	-1.2	..
Nuclear	–	–	–	–	–	–	..
Hydro	–	–	–	50.0	-4.9	–	..
Geothermal	–	–	3.8	33.3	13.5	-1.4	..
Solar/Wind/Other	–	44.0	21.3	9.5	4.6	–	..
TFC	0.7	-1.8	1.0	-1.9	1.5	0.8	..
Electricity Consumption	4.9	2.5	1.3	-0.6	1.5	1.4	..
Energy Production	14.7	23.3	9.8	5.6	-1.0	-14.5	..
Net Oil Imports	-2.6	-17.8	–	25.4	-11.5	–	..
GDP	1.5	1.4	2.3	2.1	1.8	1.6	..
Growth in the TPES/GDP Ratio	-0.3	-3.1	-1.0	-3.3	0.4	-1.5	..
Growth in the TFC/GDP Ratio	-0.9	-3.1	-1.2	-3.9	-0.3	-0.7	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**4.9**	**12.1**	**15.4**	**16.1**	**18.2**	**19.6**	**..**
Coal[1]		–	–	–	–	-0.0	–	..
Peat		0.1	1.8	1.6	2.2	1.9	2.0	..
Oil		–	–	0.1	0.1	–	–	..
Gas		–	–	–	–	–	–	..
Comb. Renewables & Wastes[2]		3.9	4.3	6.6	7.1	7.6	8.1	..
Nuclear		–	5.0	5.9	5.8	7.6	8.4	..
Hydro		0.9	0.9	1.1	0.9	1.1	1.1	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other[3]		–	–	0.0	0.0	0.0	0.0	..
TOTAL NET IMPORTS[4]		**16.6**	**17.7**	**18.6**	**18.5**	**19.1**	**20.3**	**..**
Coal1	Exports	0.0	0.0	–	–	–	–	..
	Imports	2.4	4.4	4.2	4.0	4.4	5.2	..
	Net Imports	2.4	4.4	4.2	4.0	4.4	5.2	..
Peat	Exports	–	–	0.0	0.0	–	–	..
	Imports	–	–	–	–	–	–	..
	Net Imports	–	–	-0.0	-0.0	–	–	..
Oil	Exports	0.2	1.7	5.0	5.5	..	..	..
	Imports	14.0	12.5	15.4	16.0	8.5	8.4	..
	Bunkers	0.1	0.6	0.6	0.6	–	–	..
	Net Imports	13.8	10.2	9.8	9.8	8.5	8.4	..
Gas	Exports	–	–	–	–	–	–	..
	Imports	–	2.2	3.7	3.7	5.4	6.1	..
	Net Imports	–	2.2	3.7	3.7	5.4	6.1	..
Electricity	Exports	0.0	0.0	0.2	0.1	0.2	0.2	..
	Imports	0.4	0.9	1.0	1.2	0.9	0.8	..
	Net Imports	0.4	0.9	0.9	1.0	0.7	0.6	..
TOTAL STOCK CHANGES		**-0.1**	**-0.6**	**-0.1**	**1.1**	**–**	**–**	**..**
TOTAL SUPPLY (TPES)		**21.3**	**29.2**	**33.9**	**35.6**	**37.3**	**40.0**	**..**
Coal[1]		2.5	4.1	4.2	4.5	4.4	5.2	..
Peat		0.0	1.2	2.0	2.1	1.9	2.0	..
Oil		13.6	10.3	9.4	10.5	8.5	8.4	..
Gas		–	2.2	3.7	3.7	5.4	6.1	..
Comb. Renewables & Wastes[2]		3.9	4.6	6.6	7.1	7.6	8.1	..
Nuclear		–	5.0	5.9	5.8	7.6	8.4	..
Hydro		0.9	0.9	1.1	0.9	1.1	1.1	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other[3]		–	–	0.0	0.0	0.0	0.0	..
Electricity Trade[5]		0.4	0.9	0.9	1.0	0.7	0.6	..
Shares (%)								
Coal		*11.8*	*14.1*	*12.3*	*12.5*	*11.9*	*13.0*	..
Peat		*0.2*	*4.2*	*5.8*	*5.9*	*5.0*	*5.1*	..
Oil		*63.6*	*35.1*	*27.8*	*29.5*	*22.7*	*21.1*	..
Gas		–	*7.5*	*10.9*	*10.3*	*14.6*	*15.2*	..
Comb. Renewables & Wastes		*18.5*	*15.6*	*19.6*	*19.9*	*20.3*	*20.2*	..
Nuclear		–	*17.2*	*17.5*	*16.3*	*20.5*	*21.0*	..
Hydro		*4.2*	*3.2*	*3.4*	*2.6*	*2.9*	*2.8*	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other		–	–	–	–	*0.1*	*0.1*	..
Electricity Trade		*1.7*	*3.1*	*2.5*	*2.9*	*2.0*	*1.5*	..

0 is negligible. – is nil. .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**19.4**	**22.7**	**25.3**	**26.2**	**28.9**	**30.3**	**..**
Coal[1]	1.0	1.2	0.8	0.8	1.0	1.0	..
Peat	0.0	0.4	0.4	0.4	0.4	0.4	..
Oil	11.5	9.7	8.5	8.9	8.3	8.2	..
Gas	0.0	1.0	1.1	1.0	2.5	2.5	..
Comb. Renewables & Wastes[2]	3.9	3.5	4.8	5.0	5.7	5.9	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	2.3	5.1	6.6	6.9	8.0	9.0	..
Heat	0.6	1.9	3.0	3.2	2.9	3.2	..
Shares (%)							
Coal	*5.3*	*5.1*	*3.3*	*3.1*	*3.6*	*3.4*	..
Peat	*0.1*	*1.8*	*1.5*	*1.4*	*1.4*	*1.4*	..
Oil	*59.2*	*42.5*	*33.6*	*34.1*	*28.6*	*27.0*	..
Gas	*0.1*	*4.3*	*4.2*	*3.9*	*8.7*	*8.4*	..
Comb. Renewables & Wastes	*20.3*	*15.5*	*19.1*	*19.0*	*19.8*	*19.6*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*11.9*	*22.3*	*26.3*	*26.2*	*27.8*	*29.6*	..
Heat	*3.1*	*8.4*	*12.0*	*12.3*	*10.0*	*10.6*	..
TOTAL INDUSTRY[6]	**7.6**	**10.5**	**12.0**	**12.5**	**14.3**	**15.2**	**..**
Coal[1]	0.9	1.2	0.8	0.8	1.0	1.0	..
Peat	0.0	0.4	0.3	0.3	0.4	0.4	..
Oil	5.0	2.6	1.7	2.1	0.9	0.9	..
Gas	0.0	0.9	1.0	0.9	2.4	2.5	..
Comb. Renewables & Wastes[2]	–	2.5	3.7	3.8	4.7	4.9	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	1.6	2.8	3.6	3.8	4.5	5.1	..
Heat	0.1	0.2	0.8	0.9	0.3	0.3	..
Shares (%)							
Coal	*12.1*	*11.0*	*6.9*	*6.4*	*7.3*	*6.7*	..
Peat	*0.2*	*3.6*	*2.9*	*2.7*	*2.7*	*2.8*	..
Oil	*66.2*	*24.7*	*14.5*	*16.5*	*6.3*	*6.1*	..
Gas	*0.1*	*9.0*	*8.1*	*7.5*	*17.0*	*16.2*	..
Comb. Renewables & Wastes	–	*23.4*	*30.7*	*30.2*	*32.9*	*32.6*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*20.4*	*26.6*	*30.5*	*29.9*	*31.8*	*33.4*	..
Heat	*1.0*	*1.7*	*6.5*	*6.9*	*2.1*	*2.2*	..
TRANSPORT[7]	**2.6**	**4.4**	**4.6**	**4.7**	**5.1**	**5.1**	**..**
TOTAL OTHER SECTORS[8]	**9.3**	**7.9**	**8.7**	**8.9**	**9.5**	**10.1**	**..**
Coal[1]	0.1	0.0	0.0	0.0	0.0	0.0	..
Peat	0.0	0.0	0.0	0.0	0.0	0.0	..
Oil	3.9	2.7	2.2	2.3	2.3	2.3	..
Gas	0.0	0.0	0.1	0.1	0.1	0.1	..
Comb. Renewables & Wastes[2]	3.9	1.1	1.2	1.2	1.0	1.0	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	0.8	2.2	3.0	3.0	3.4	3.8	..
Heat	0.5	1.7	2.3	2.3	2.6	2.9	..
Shares (%)							
Coal	*1.1*	*0.1*	–	–	–	–	..
Peat	*0.1*	*0.2*	*0.3*	*0.3*	*0.1*	*0.1*	..
Oil	*42.3*	*35.0*	*25.7*	*25.3*	*24.7*	*22.7*	..
Gas	–	*0.5*	*0.8*	*0.8*	*0.7*	*0.6*	..
Comb. Renewables & Wastes	*42.6*	*13.6*	*13.4*	*13.2*	*10.7*	*9.8*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*8.2*	*28.5*	*34.0*	*34.1*	*36.3*	*38.1*	..
Heat	*5.7*	*22.1*	*26.0*	*26.3*	*27.4*	*28.6*	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**3.5**	**11.9**	**16.1**	**16.6**	**18.2**	**20.8**	**..**
OUTPUT (Mtoe)	**2.2**	**4.7**	**6.4**	**6.4**	**7.6**	**8.7**	**..**
(TWh gross)	26.1	54.4	74.5	74.9	88.2	100.9	..
Output Shares (%)							
Coal	*18.7*	*18.5*	*15.2*	*17.7*	*17.0*	*19.7*	..
Peat	*9.4*	*14.6*	*8.3*	*8.6*	*5.9*	*5.5*	..
Oil	*31.6*	*3.1*	*0.9*	*0.8*	*1.0*	*1.0*	..
Gas	–	*8.6*	*15.5*	*15.1*	*13.9*	*14.7*	..
Comb. Renewables & Wastes	–	–	*11.7*	*13.5*	*14.1*	*14.0*	..
Nuclear	–	*35.3*	*30.6*	*29.8*	*33.2*	*31.9*	..
Hydro	*40.3*	*20.0*	*17.7*	*14.4*	*14.5*	*12.7*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	*0.1*	*0.1*	*0.4*	*0.5*	..
TOTAL LOSSES	**2.0**	**7.1**	**9.1**	**9.2**	**8.5**	**9.7**	**..**
of which:							
Electricity and Heat Generation[10]	0.6	5.1	6.5	6.7	7.4	8.5	..
Other Transformation	0.5	0.6	1.0	0.9	0.5	0.5	..
Own Use and Losses[11]	0.9	1.4	1.7	1.6	0.6	0.6	..
Statistical Differences	**-0.1**	**-0.7**	**-0.5**	**0.3**	**–**	**–**	**..**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	82.60	135.66	165.33	168.96	203.58	251.44	..
Population (millions)	4.67	4.99	5.19	5.20	5.32	5.32	..
TPES/GDP[12]	0.26	0.22	0.20	0.21	0.18	0.16	..
Energy Production/TPES	0.23	0.41	0.45	0.45	0.49	0.49	..
Per Capita TPES[13]	4.57	5.85	6.53	6.85	7.02	7.52	..
Oil Supply/GDP[12]	0.16	0.08	0.06	0.06	0.04	0.03	..
TFC/GDP[12]	0.24	0.17	0.15	0.15	0.14	0.12	..
Per Capita TFC[13]	4.16	4.56	4.87	5.03	5.43	5.70	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	48.4	55.0	60.5	63.5	60.6	65.6	..
CO_2 Emissions from Bunkers (Mt CO_2)	0.5	2.8	2.9	3.1	1.1	1.1	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	2.3	1.6	1.4	5.2	0.6	0.7	..
Coal	7.4	0.6	0.2	6.7	-0.1	1.6	..
Peat	48.1	10.6	4.5	7.1	-1.5	0.8	..
Oil	-0.5	-2.3	-0.8	11.4	-2.6	-0.1	..
Gas	–	9.4	4.9	-0.6	5.0	1.1	..
Comb. Renewables & Wastes	-2.4	2.7	3.5	6.7	0.9	0.6	..
Nuclear	–	10.0	1.6	-2.1	3.5	0.9	..
Hydro	0.6	-0.0	1.8	-18.4	2.2	–	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	20.7	5.2	..
TFC	0.4	1.2	1.0	3.5	1.2	0.5	..
Electricity Consumption	4.7	4.7	2.5	3.1	2.0	1.1	..
Energy Production	4.7	5.9	2.2	4.5	1.6	0.8	..
Net Oil Imports	1.1	-3.3	-0.4	-0.2	-1.8	-0.1	..
GDP	2.5	3.2	1.8	2.2	2.4	2.1	..
Growth in the TPES/GDP Ratio	-0.2	-1.6	-0.4	2.9	-1.7	-1.4	..
Growth in the TFC/GDP Ratio	-2.0	-2.0	-0.8	1.2	-1.1	-1.6	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**44.2**	**111.9**	**132.9**	**134.7**	**142.0**	**146.0**	**138.7**
Coal[1]		18.0	8.2	1.6	1.3	0.5	0.4	–
Oil		2.1	3.5	1.6	1.5	–	–	–
Gas		6.3	2.5	1.5	1.4	–	–	–
Comb. Renewables & Wastes[2]		9.8	11.0	11.8	11.2	14.7	18.5	22.5
Nuclear		3.8	81.9	109.7	113.8	120.3	117.8	106.6
Hydro		4.1	4.6	6.4	5.2	5.9	5.9	5.9
Geothermal		0.0	0.1	0.1	0.1	..	..	..
Solar/Wind/Other[3]		0.0	0.1	0.1	0.1	0.6	3.3	3.7
TOTAL NET IMPORTS[4]		**142.8**	**117.1**	**132.0**	**133.2**	**156.8**	**173.9**	**198.9**
Coal[1]	Exports	1.3	0.6	0.5	0.3	–	–	–
	Imports	10.8	13.7	11.6	12.7	9.8	11.2	21.4
	Net Imports	9.5	13.0	11.2	12.4	9.8	11.2	21.4
Oil	Exports	13.7	14.8	20.1	19.5	13.3	14.6	16.1
	Imports	145.1	100.9	114.6	112.9	120.3	124.3	126.6
	Bunkers	5.3	2.5	2.7	2.6	3.0	3.0	3.0
	Net Imports	126.0	83.6	91.8	90.8	104.0	106.7	107.5
Gas	Exports	0.1	0.3	0.8	0.8	–	–	–
	Imports	7.6	24.7	35.7	37.5	47.3	59.0	70.0
	Net Imports	7.6	24.4	34.9	36.7	47.3	59.0	70.0
Electricity	Exports	0.6	4.5	6.3	6.9	4.3	3.0	–
	Imports	0.4	0.6	0.4	0.3	–	–	–
	Net Imports	-0.2	-3.9	-5.9	-6.6	-4.3	-3.0	–
TOTAL STOCK CHANGES		**-2.4**	**-1.7**	**1.4**	**-2.0**	**–**	**–**	**–**
TOTAL SUPPLY (TPES)		**184.7**	**227.3**	**266.4**	**265.9**	**298.8**	**319.9**	**337.6**
Coal[1]		29.2	20.2	12.7	13.3	10.3	11.6	21.4
Oil		124.3	87.3	93.9	91.3	104.0	106.7	107.5
Gas		13.6	26.0	37.5	37.5	47.3	59.0	70.0
Comb. Renewables & Wastes[2]		9.8	11.0	11.9	11.2	14.7	18.5	22.5
Nuclear		3.8	81.9	109.7	113.8	120.3	117.8	106.6
Hydro		4.1	4.6	6.4	5.2	5.9	5.9	5.9
Geothermal		0.0	0.1	0.1	0.1	..	..	..
Solar/Wind/Other[3]		0.0	0.1	0.1	0.1	0.6	3.3	3.7
Electricity Trade[5]		-0.2	-3.9	-5.9	-6.6	-4.3	-3.0	–
Shares (%)								
Coal		*15.8*	*8.9*	*4.8*	*5.0*	*3.4*	*3.6*	*6.3*
Oil		*67.3*	*38.4*	*35.2*	*34.3*	*34.8*	*33.4*	*31.8*
Gas		*7.3*	*11.5*	*14.1*	*14.1*	*15.8*	*18.4*	*20.7*
Comb. Renewables & Wastes		*5.3*	*4.9*	*4.4*	*4.2*	*4.9*	*5.8*	*6.7*
Nuclear		*2.1*	*36.0*	*41.2*	*42.8*	*40.3*	*36.8*	*31.6*
Hydro		*2.2*	*2.0*	*2.4*	*2.0*	*2.0*	*1.9*	*1.8*
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other		–	–	–	–	*0.2*	*1.0*	*1.1*
Electricity Trade		*-0.1*	*-1.7*	*-2.2*	*-2.5*	*-1.4*	*-0.9*	–

0 is negligible, – is nil, .. is not available.

Please note: Forecast data for Solar/Wind/Other include Geothermal.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**145.6**	**147.1**	**174.0**	**169.6**	**196.1**	**213.3**	**228.2**
Coal[1]	13.1	7.5	4.0	4.0	7.2	6.9	7.2
Oil	99.4	79.5	91.1	88.3	95.1	97.3	97.8
Gas	11.2	23.9	34.4	33.8	40.9	46.7	51.1
Comb. Renewables & Wastes[2]	8.9	9.6	9.8	9.1	13.9	16.1	19.6
Geothermal	0.0	0.1	0.1	0.1	..	..	..
Solar/Wind/Other	–	0.0	0.0	0.0	–	–	–
Electricity	12.8	26.0	34.0	33.8	39.0	46.3	52.5
Heat	0.3	0.5	0.5	0.6	..	..	..
Shares (%)							
Coal	*9.0*	*5.1*	*2.3*	*2.3*	*3.7*	*3.2*	*3.2*
Oil	*68.3*	*54.0*	*52.4*	*52.1*	*48.5*	*45.6*	*42.8*
Gas	*7.7*	*16.3*	*19.8*	*19.9*	*20.9*	*21.9*	*22.4*
Comb. Renewables & Wastes	*6.1*	*6.5*	*5.6*	*5.4*	*7.1*	*7.6*	*8.6*
Geothermal	–	*0.1*	*0.1*	*0.1*	..	..	..
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*8.8*	*17.6*	*19.5*	*19.9*	*19.9*	*21.7*	*23.0*
Heat	*0.2*	*0.3*	*0.3*	*0.3*	..	..	..
TOTAL INDUSTRY[6]	**56.6**	**46.2**	**51.0**	**50.8**	**62.2**	**67.3**	**71.8**
Coal[1]	7.2	5.9	3.3	3.4	5.6	5.1	5.0
Oil	35.3	18.0	20.5	19.1	22.2	22.1	22.6
Gas	5.8	11.1	14.1	15.4	16.3	18.5	20.0
Comb. Renewables & Wastes[2]	1.2	1.4	1.4	1.4	4.8	6.0	6.5
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	7.2	9.9	11.6	11.5	13.3	15.6	17.7
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*12.7*	*12.7*	*6.5*	*6.7*	*9.0*	*7.6*	*7.0*
Oil	*62.3*	*38.8*	*40.3*	*37.6*	*35.7*	*32.9*	*31.5*
Gas	*10.2*	*24.0*	*27.8*	*30.3*	*26.2*	*27.5*	*27.9*
Comb. Renewables & Wastes	*2.1*	*3.1*	*2.7*	*2.8*	*7.7*	*8.9*	*9.1*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*12.8*	*21.3*	*22.7*	*22.6*	*21.4*	*23.2*	*24.7*
Heat	–	–	–	–	–	–	–
TRANSPORT[7]	**27.1**	**42.8**	**52.9**	**52.9**	**56.4**	**62.2**	**68.3**
TOTAL OTHER SECTORS[8]	**61.9**	**58.1**	**70.2**	**66.0**	**77.5**	**83.9**	**88.1**
Coal[1]	5.8	1.7	0.6	0.5	1.6	1.8	2.2
Oil	37.6	19.5	19.0	17.7	18.1	15.4	10.4
Gas	5.4	12.8	20.2	18.4	24.6	28.2	31.1
Comb. Renewables & Wastes[2]	7.7	8.2	8.2	7.4	8.5	9.0	11.1
Geothermal	0.0	0.1	0.1	0.1	..	..	..
Solar/Wind/Other	–	0.0	0.0	0.0	–	–	–
Electricity	5.0	15.3	21.4	21.3	24.7	29.5	33.3
Heat	0.3	0.5	0.5	0.6	..	..	..
Shares (%)							
Coal	*9.4*	*2.9*	*0.9*	*0.8*	*2.1*	*2.1*	*2.5*
Oil	*60.8*	*33.5*	*27.1*	*26.7*	*23.4*	*18.4*	*11.8*
Gas	*8.7*	*22.1*	*28.8*	*27.8*	*31.7*	*33.6*	*35.3*
Comb. Renewables & Wastes	*12.5*	*14.1*	*11.6*	*11.2*	*11.0*	*10.7*	*12.6*
Geothermal	–	*0.2*	*0.2*	*0.2*	..	..	..
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*8.1*	*26.4*	*30.5*	*32.3*	*31.9*	*35.2*	*37.8*
Heat	*0.4*	*0.8*	*0.8*	*0.9*	..	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**36.8**	**98.5**	**127.3**	**131.8**	**138.3**	**147.9**	**153.2**
OUTPUT (Mtoe)	**15.7**	**35.8**	**47.0**	**47.7**	**51.0**	**57.0**	**60.9**
(TWh gross)	182.5	416.7	546.4	554.8	593.0	663.2	708.3
Output Shares (%)							
Coal	*19.4*	*8.5*	*4.0*	*4.5*	*1.9*	*2.8*	*8.7*
Oil	*40.2*	*2.1*	*1.0*	*0.8*	*0.9*	*0.3*	*0.2*
Gas	*5.5*	*0.7*	*3.6*	*4.2*	*6.0*	*11.3*	*16.2*
Comb. Renewables & Wastes	*0.4*	*0.4*	*0.6*	*0.6*	*0.5*	*1.2*	*1.4*
Nuclear	*8.1*	*75.4*	*77.1*	*78.7*	*77.8*	*68.1*	*57.8*
Hydro	*26.1*	*12.8*	*13.7*	*10.9*	*11.6*	*10.4*	*9.8*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	*0.3*	*0.1*	*0.1*	*0.1*	*1.2*	*5.8*	*6.1*
TOTAL LOSSES	**38.2**	**75.6**	**93.3**	**96.9**	**102.7**	**106.5**	**109.4**
of which:							
Electricity and Heat Generation[10]	20.8	62.2	79.8	83.5	87.3	90.9	92.3
Other Transformation	5.4	1.6	-0.1	0.5	0.3	0.4	0.4
Own Use and Losses[11]	12.0	11.8	13.7	12.9	15.1	15.2	16.7
Statistical Differences	**0.9**	**4.5**	**-1.0**	**-0.7**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	961.43	1473.22	1809.68	1831.52	2196.93	2757.86	3462.02
Population (millions)	53.30	58.17	60.91	61.23	61.70	63.50	65.35e
TPES/GDP[12]	0.19	0.15	0.15	0.15	0.14	0.12	0.10
Energy Production/TPES	0.24	0.49	0.50	0.51	0.48	0.46	0.41
Per Capita TPES[13]	3.46	3.91	4.37	4.34	4.84	5.04	5.17
Oil Supply/GDP[12]	0.13	0.06	0.05	0.05	0.05	0.04	0.03
TFC/GDP[12]	0.15	0.10	0.10	0.09	0.09	0.08	0.07
Per Capita TFC[13]	2.73	2.53	2.86	2.77	3.18	3.36	3.49
Energy-related CO_2 Emissions (Mt CO_2)[14]	489.0	352.7	384.3	377.1	414.9	454.8	520.3
CO_2 Emissions from Bunkers (Mt CO_2)	22.7	17.7	22.7	23.0	24.2	24.2	24.2

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	0.8	1.5	1.5	-0.2	1.5	0.7	0.5
Coal	1.7	-4.2	-4.2	5.3	-3.2	1.2	6.3
Oil	-1.4	-2.4	0.7	-2.8	1.6	0.3	0.1
Gas	7.4	2.0	3.4	-0.2	3.0	2.2	1.7
Comb. Renewables & Wastes	-0.5	1.4	0.6	-5.7	3.5	2.3	2.0
Nuclear	18.1	20.6	2.7	3.7	0.7	-0.2	-1.0
Hydro	5.7	-2.0	3.1	-18.8	1.6	0.0	–
Geothermal	46.8	24.4	1.4	–	–	–	–
Solar/Wind/Other	-1.8	4.5	0.9	14.3	27.5	18.3	1.2
TFC	0.5	-0.2	1.5	-2.5	1.8	0.8	0.7
Electricity Consumption	5.4	3.7	2.5	-0.6	1.8	1.7	1.3
Energy Production	1.3	8.0	1.6	1.3	0.7	0.3	-0.5
Net Oil Imports	-1.4	-2.9	0.8	-1.1	1.7	0.3	0.1
GDP	2.8	2.4	1.9	1.2	2.3	2.3	2.3e
Growth in the TPES/GDP Ratio	-1.9	-0.9	-0.4	-1.4	-0.8	-1.6	-1.7
Growth in the TFC/GDP Ratio	-2.2	-2.5	-0.3	-3.7	-0.5	-1.4	-1.6

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**171.7**	**186.2**	**134.6**	**134.8**	**..**	**..**	**..**
Coal[1]		141.4	121.8	58.2	58.8	..	..	..
Oil		6.8	4.7	4.0	4.2	..	..	..
Gas		16.4	13.5	15.9	16.0	..	..	..
Comb. Renewables & Wastes[2]		2.5	4.8	8.8	9.2	..	..	..
Nuclear		3.2	39.8	44.6	43.0	..	..	..
Hydro		1.3	1.5	2.0	2.0	..	..	..
Geothermal		–	0.0	0.1	0.1	..	..	..
Solar/Wind/Other[3]		–	0.0	1.0	1.5	..	..	..
TOTAL NET IMPORTS[4]		**167.3**	**165.4**	**214.9**	**208.3**	**..**	**..**	**..**
Coal[1]	Exports	18.3	8.2	0.5	0.5	..	..	..
	Imports	15.2	11.5	26.3	25.9	..	..	..
	Net Imports	–3.1	3.3	25.8	25.3	..	..	..
Oil	Exports	9.9	10.2	19.8	20.2	..	..	..
	Imports	171.1	132.9	152.8	144.7	..	..	..
	Bunkers	4.1	2.5	2.2	2.4	..	..	..
	Net Imports	157.1	120.2	130.7	122.1	..	..	..
Gas	Exports	0.1	0.9	5.2	5.8	..	..	..
	Imports	12.4	42.7	63.4	65.8	..	..	..
	Net Imports	12.3	41.7	58.2	60.1	..	..	..
Electricity	Exports	0.7	2.6	3.6	3.3	..	..	..
	Imports	1.7	2.7	3.9	4.2	..	..	..
	Net Imports	1.0	0.1	0.3	0.9	..	..	..
TOTAL STOCK CHANGES		**–1.1**	**4.7**	**3.8**	**3.3**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**337.9**	**356.2**	**353.4**	**346.4**	**..**	**..**	**..**
Coal[1]		139.4	128.5	86.5	85.3	..	..	..
Oil		161.9	126.5	134.5	128.8	..	..	..
Gas		28.7	55.0	75.6	75.5	..	..	..
Comb. Renewables & Wastes[2]		2.5	4.8	8.8	9.2	..	..	..
Nuclear		3.2	39.8	44.6	43.0	..	..	..
Hydro		1.3	1.5	2.0	2.0	..	..	..
Geothermal		–	0.0	0.1	0.1	..	..	..
Solar/Wind/Other[3]		–	0.0	1.0	1.5	..	..	..
Electricity Trade[5]		1.0	0.1	0.3	0.9	..	..	..
Shares (%)								
Coal		*41.2*	*36.1*	*24.5*	*24.6*	..	..	..
Oil		*47.9*	*35.5*	*38.1*	*37.2*	..	..	..
Gas		*8.5*	*15.4*	*21.4*	*21.8*	..	..	..
Comb. Renewables & Wastes		*0.7*	*1.3*	*2.5*	*2.6*	..	..	..
Nuclear		*0.9*	*11.2*	*12.6*	*12.4*	..	..	..
Hydro		*0.4*	*0.4*	*0.6*	*0.6*	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other		–	–	*0.3*	*0.4*	..	..	..
Electricity Trade		*0.3*	–	*0.1*	*0.2*	..	..	..

0 is negligible, – is nil, .. is not available.

Please note: All data include the new Laender of Germany. Forecasts are not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**246.6**	**247.3**	**246.4**	**241.0**	**..**	**..**	**..**
Coal[1]	53.1	37.3	9.7	9.2	..	..	..
Oil	138.2	117.7	125.1	120.5	..	..	..
Gas	21.1	41.0	56.0	56.0	..	..	..
Comb. Renewables & Wastes[2]	1.7	3.0	5.0	5.3	..	..	..
Geothermal	–	0.0	0.1	0.1	..	..	..
Solar/Wind/Other	–	0.0	0.1	0.2	..	..	..
Electricity	26.9	39.1	43.5	42.9	..	..	..
Heat	5.5	9.1	6.9	6.8	..	..	..
Shares (%)							
Coal	*21.5*	*15.1*	*3.9*	*3.8*	..	..	..
Oil	*56.0*	*47.6*	*50.8*	*50.0*	..	..	..
Gas	*8.6*	*16.6*	*22.7*	*23.2*	..	..	..
Comb. Renewables & Wastes	*0.7*	*1.2*	*2.0*	*2.2*	..	..	..
Geothermal	–	–	*0.1*	*0.1*	..	..	..
Solar/Wind/Other	–	–	*0.1*	*0.1*	..	..	..
Electricity	*10.9*	*15.8*	*17.6*	*17.8*	..	..	..
Heat	*2.2*	*3.7*	*2.8*	*2.8*	..	..	..
TOTAL INDUSTRY[6]	**105.9**	**89.5**	**78.7**	**77.9**	**..**	**..**	**..**
Coal[1]	28.7	20.7	8.4	8.0	..	..	..
Oil	46.9	27.3	27.7	27.4	..	..	..
Gas	13.3	19.7	20.8	20.8	..	..	..
Comb. Renewables & Wastes[2]	0.0	0.8	0.6	0.8	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	15.3	18.6	20.3	20.1	..	..	..
Heat	1.6	2.4	0.9	0.9	..	..	..
Shares (%)							
Coal	*27.1*	*23.1*	*10.6*	*10.2*	..	..	..
Oil	*44.3*	*30.5*	*35.2*	*35.2*	..	..	..
Gas	*12.6*	*22.0*	*26.4*	*26.7*	..	..	..
Comb. Renewables & Wastes	–	*0.9*	*0.8*	*1.0*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*14.5*	*20.8*	*25.8*	*25.8*	..	..	..
Heat	*1.5*	*2.7*	*1.2*	*1.2*	..	..	..
TRANSPORT[7]	**39.7**	**60.0**	**66.0**	**65.5**	**..**	**..**	**..**
TOTAL OTHER SECTORS[8]	**101.0**	**97.8**	**101.7**	**97.6**	**..**	**..**	**..**
Coal[1]	22.7	16.6	1.3	1.3	..	..	..
Oil	54.2	31.6	33.0	29.3	..	..	..
Gas	7.8	21.3	35.3	35.3	..	..	..
Comb. Renewables & Wastes[2]	1.7	2.2	4.1	4.1	..	..	..
Geothermal	–	0.0	0.1	0.1	..	..	..
Solar/Wind/Other	–	0.0	0.1	0.2	..	..	..
Electricity	10.7	19.3	21.7	21.4	..	..	..
Heat	3.9	6.7	6.0	5.9	..	..	..
Shares (%)							
Coal	*22.5*	*16.9*	*1.3*	*1.3*	..	..	..
Oil	*53.6*	*32.3*	*32.5*	*30.0*	..	..	..
Gas	*7.7*	*21.8*	*34.7*	*36.1*	..	..	..
Comb. Renewables & Wastes	*1.7*	*2.2*	*4.0*	*4.2*	..	..	..
Geothermal	–	–	*0.1*	*0.1*	..	..	..
Solar/Wind/Other	–	–	*0.1*	*0.2*	..	..	..
Electricity	*10.6*	*19.8*	*21.3*	*21.9*	..	..	..
Heat	*3.9*	*6.9*	*5.9*	*6.1*	..	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**98.6**	**141.2**	**137.3**	**136.4**	..	..	..
OUTPUT (Mtoe)	**32.2**	**47.1**	**50.0**	**48.8**	..	..	..
(TWh gross)	374.4	547.7	581.8	566.9	..	..	..
Output Shares (%)							
Coal	*69.0*	*58.8*	*51.8*	*51.4*	..	..	..
Oil	*12.0*	*1.9*	*0.8*	*0.8*	..	..	..
Gas	*10.9*	*7.4*	*10.0*	*9.5*	..	..	..
Comb. Renewables & Wastes	*0.8*	*0.9*	*2.1*	*2.3*	..	..	..
Nuclear	*3.2*	*27.8*	*29.4*	*29.1*	..	..	..
Hydro	*4.1*	*3.2*	*3.9*	*4.1*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	*0.0*	*1.8*	*2.8*	..	..	..
TOTAL LOSSES	**90.7**	**112.0**	**102.6**	**102.5**	..	..	..
of which:							
Electricity and Heat Generation[10]	60.0	83.4	79.6	80.1	..	..	..
Other Transformation	7.0	8.0	5.9	5.5	..	..	..
Own Use and Losses[11]	23.7	20.5	17.1	16.9	..	..	..
Statistical Differences	**0.5**	**-3.0**	**4.4**	**2.8**	..	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	1514.68	2221.56	2710.62	2715.40	..	..	..
Population (millions)	78.96	79.36	82.34	82.48	..	..	..
TPES/GDP[12]	0.22	0.16	0.13	0.13	..	..	..
Energy Production/TPES	0.51	0.52	0.38	0.39	..	..	..
Per Capita TPES[13]	4.28	4.49	4.29	4.20	..	..	..
Oil Supply/GDP[12]	0.11	0.06	0.05	0.05	..	..	..
TFC/GDP[12]	0.16	0.11	0.09	0.09	..	..	..
Per Capita TFC[13]	3.12	3.12	2.99	2.92	..	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	1058.7	966.4	850.1	837.5	..	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	21.8	22.1	28.2	28.5	..	..	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	1.5	-0.3	-0.1	-2.0	..	..	..
Coal	-0.2	-0.6	-3.5	-1.3	..	..	..
Oil	-0.1	-2.2	0.6	-4.2	..	..	..
Gas	10.2	0.6	2.9	-0.0	..	..	..
Comb. Renewables & Wastes	6.2	2.7	5.6	4.4	..	..	..
Nuclear	27.5	10.3	1.0	-3.8	..	..	..
Hydro	3.2	-0.5	2.4	1.7	..	..	..
Geothermal	–	–	29.9	3.2	..	..	..
Solar/Wind/Other	–	–	45.5	47.6	..	..	..
TFC	1.2	-0.6	-0.0	-2.2	..	..	..
Electricity Consumption	3.8	1.4	1.0	-1.3	..	..	..
Energy Production	1.0	0.2	-2.9	0.1	..	..	..
Net Oil Imports	0.2	-2.5	0.8	-6.6	..	..	..
GDP	2.4	2.2	1.8	0.2	..	..	..
Growth in the TPES/GDP Ratio	-0.9	-2.5	-1.9	-2.2	..	..	..
Growth in the TFC/GDP Ratio	-1.1	-2.8	-1.8	-2.3	..	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**2.33**	**9.20**	**9.97**	**10.23**	**11.14**	**..**	**..**
Coal[1]		1.69	7.12	8.39	8.58	8.82	..	..
Oil		–	0.84	0.18	0.17	0.30	..	..
Gas		–	0.14	0.04	0.04	0.04	..	..
Comb. Renewables & Wastes[2]		0.45	0.89	1.01	1.03	1.14	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.19	0.15	0.18	0.24	0.33	..	..
Geothermal		–	0.00	0.00	0.00	0.11	..	..
Solar/Wind/Other[3]		–	0.06	0.17	0.16	0.40	..	..
TOTAL NET IMPORTS[4]		**11.12**	**12.74**	**18.60**	**19.86**	**29.40**	**..**	**..**
Coal[1]	Exports	0.02	–	0.03	0.02	–	..	..
	Imports	0.47	0.92	0.89	0.65	0.76	..	..
	Net Imports	0.45	0.92	0.86	0.63	0.76	..	..
Oil	Exports	4.95	7.56	3.98	4.28	6.00	..	..
	Imports	16.51	21.87	23.32	24.64	31.22	..	..
	Bunkers	0.89	2.55	3.49	3.13	3.60	..	..
	Net Imports	10.67	11.76	15.85	17.23	21.62	..	..
Gas	Exports	–	–	–	–	–	..	..
	Imports	–	–	1.67	1.75	7.02	..	..
	Net Imports	–	–	1.67	1.75	7.02	..	..
Electricity	Exports	0.00	0.05	0.09	0.15	–	..	..
	Imports	0.01	0.11	0.31	0.40	–	..	..
	Net Imports	0.00	0.06	0.22	0.25	–	..	..
TOTAL STOCK CHANGES		**-1.10**	**0.24**	**0.14**	**-1.07**	**–**	**..**	**..**
TOTAL SUPPLY (TPES)		**12.36**	**22.18**	**28.70**	**29.03**	**40.54**	**..**	**..**
Coal[1]		2.10	8.07	9.31	8.97	9.58	..	..
Oil		9.61	12.81	16.14	16.57	21.92	..	..
Gas		–	0.14	1.68	1.80	7.06	..	..
Comb. Renewables & Wastes[2]		0.45	0.89	1.01	1.03	1.14	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.19	0.15	0.18	0.24	0.33	..	..
Geothermal		–	0.00	0.00	0.00	0.11	..	..
Solar/Wind/Other[3]		–	0.06	0.17	0.16	0.40	..	..
Electricity Trade[5]		0.00	0.06	0.22	0.25	–	..	..
Shares (%)								
Coal		*17.0*	*36.4*	*32.4*	*30.9*	*23.6*	..	..
Oil		*77.7*	*57.8*	*56.2*	*57.1*	*54.1*	..	..
Gas		–	*0.6*	*5.9*	*6.2*	*17.4*	..	..
Comb. Renewables & Wastes		*3.6*	*4.0*	*3.5*	*3.6*	*2.8*	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		*1.5*	*0.7*	*0.6*	*0.8*	*0.8*	..	..
Geothermal		–	–	–	–	*0.3*	..	..
Solar/Wind/Other		–	*0.3*	*0.6*	*0.5*	*1.0*	..	..
Electricity Trade		–	*0.3*	*0.7*	*0.9*	–	..	..

0 is negligible, – is nil, .. is not available.

Please note: All forecasts are based on the 2001 submission.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**9.21**	**15.47**	**20.09**	**20.49**	**29.53**	**..**	**..**
Coal[1]	0.52	1.20	0.89	0.70	0.76	..	..
Oil	7.15	10.75	13.92	14.29	19.87	..	..
Gas	0.00	0.11	0.38	0.42	1.88	..	..
Comb. Renewables & Wastes[2]	0.45	0.89	0.94	0.95	1.08	..	..
Geothermal	–	0.00	0.00	0.00	–	..	..
Solar/Wind/Other	–	0.06	0.10	0.10	0.14	..	..
Electricity	1.09	2.45	3.83	4.01	5.79	..	..
Heat	–	–	0.03	0.03	0.03	..	..
Shares (%)							
Coal	*5.6*	*7.8*	*4.4*	*3.4*	*2.6*	..	..
Oil	*77.6*	*69.5*	*69.3*	*69.7*	*67.3*	..	..
Gas	–	*0.7*	*1.9*	*2.0*	*6.4*	..	..
Comb. Renewables & Wastes	*4.9*	*5.8*	*4.7*	*4.6*	*3.7*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	*0.4*	*0.5*	*0.5*	*0.5*	..	..
Electricity	*11.9*	*15.8*	*19.1*	*19.5*	*19.6*	..	..
Heat	–	–	*0.1*	*0.1*	*0.1*	..	..
TOTAL INDUSTRY[6]	**3.49**	**4.70**	**5.23**	**5.21**	**7.32**	**..**	**..**
Coal[1]	0.46	1.18	0.87	0.69	0.72	..	..
Oil	2.39	2.18	2.58	2.67	3.54	..	..
Gas	–	0.10	0.35	0.38	0.99	..	..
Comb. Renewables & Wastes[2]	–	0.19	0.24	0.25	0.25	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.63	1.04	1.18	1.22	1.82	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*13.1*	*25.0*	*16.6*	*13.3*	*9.8*	..	..
Oil	*68.7*	*46.5*	*49.4*	*51.3*	*48.4*	..	..
Gas	–	*2.2*	*6.8*	*7.3*	*13.5*	..	..
Comb. Renewables & Wastes	–	*4.1*	*4.5*	*4.7*	*3.4*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*18.2*	*22.2*	*22.7*	*23.3*	*24.8*	..	..
Heat	–	–	–	–	–	..	..
TRANSPORT[7]	**2.70**	**5.95**	**7.53**	**7.63**	**11.44**	**..**	**..**
TOTAL OTHER SECTORS[8]	**3.03**	**4.82**	**7.33**	**7.66**	**10.78**	**..**	**..**
Coal[1]	0.04	0.03	0.02	0.01	0.04	..	..
Oil	2.08	2.63	3.83	4.02	4.98	..	..
Gas	0.00	0.01	0.02	0.03	0.86	..	..
Comb. Renewables & Wastes[2]	0.45	0.70	0.70	0.70	0.83	..	..
Geothermal	–	0.00	0.00	0.00	–	..	..
Solar/Wind/Other	–	0.06	0.10	0.10	0.14	..	..
Electricity	0.46	1.40	2.63	2.77	3.91	..	..
Heat	–	–	0.03	0.03	0.03	..	..
Shares (%)							
Coal	*1.4*	*0.5*	*0.3*	*0.1*	*0.3*	..	..
Oil	*68.6*	*54.5*	*52.2*	*52.5*	*46.2*	..	..
Gas	*0.1*	*0.1*	*0.2*	*0.4*	*8.0*	..	..
Comb. Renewables & Wastes	*14.9*	*14.6*	*9.6*	*9.2*	*7.7*	..	..
Geothermal	–	*0.1*	–	–	–	..	..
Solar/Wind/Other	–	*1.2*	*1.4*	*1.3*	*1.3*	..	..
Electricity	*15.0*	*29.0*	*35.8*	*36.2*	*36.3*	..	..
Heat	–	–	*0.4*	*0.4*	*0.3*	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**3.34**	**8.90**	**12.00**	**12.07**	**16.77**	..	..
OUTPUT (Mtoe)	**1.27**	**2.99**	**4.56**	**4.64**	**6.72**	..	..
(TWh gross)	14.82	34.78	53.08	53.95	78.12	..	..
Output Shares (%)							
Coal	*35.5*	*72.4*	*66.8*	*64.1*	*43.7*	..	..
Oil	*49.5*	*22.3*	*16.0*	*16.0*	*12.6*	..	..
Gas	–	*0.3*	*11.6*	*13.1*	*34.4*	..	..
Comb. Renewables & Wastes	–	–	*0.3*	*0.4*	*0.3*	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	*15.0*	*5.1*	*4.0*	*5.2*	*4.9*	..	..
Geothermal	–	–	–	–	*0.2*	..	..
Solar/Wind/Other	–	*0.0*	*1.4*	*1.2*	*4.0*	..	..
TOTAL LOSSES	**3.14**	**7.00**	**8.77**	**8.69**	**11.00**	..	..
of which:							
Electricity and Heat Generation[10]	2.07	5.91	7.41	7.41	10.00	..	..
Other Transformation	0.44	-0.23	-0.64	-0.67	–	..	..
Own Use and Losses[11]	0.64	1.31	2.00	1.95	1.00	..	..
Statistical Differences	**0.00**	**-0.28**	**-0.15**	**-0.16**	**–**	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	84.54	110.50	144.88	150.33	205.74	..	..
Population (millions)	9.08	10.34	10.94	10.95	11.00	..	..
TPES/GDP[12]	0.15	0.20	0.20	0.19	0.20	..	..
Energy Production/TPES	0.19	0.41	0.35	0.35	0.27	..	..
Per Capita TPES[13]	1.36	2.15	2.62	2.65	3.69	..	..
Oil Supply/GDP[12]	0.11	0.12	0.11	0.11	0.11	..	..
TFC/GDP[12]	0.11	0.14	0.14	0.14	0.14	..	..
Per Capita TFC[13]	1.01	1.50	1.84	1.87	2.68	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	34.4	70.6	90.2	90.5	118.2	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	4.5	10.5	13.4	12.2	13.7	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	4.4	3.0	2.4	1.1	4.3	..	..
Coal	8.7	8.0	1.3	-3.6	0.8	..	..
Oil	3.5	0.7	2.1	2.7	3.6	..	..
Gas	–	–	25.5	7.0	18.6	..	..
Comb. Renewables & Wastes	–	6.4	1.1	2.4	1.2	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	8.2	-6.2	1.5	33.9	3.9	..	..
Geothermal	–	–	-3.6	-50.0	79.5	..	..
Solar/Wind/Other	–	–	10.1	-4.2	12.4	..	..
TFC	4.0	2.6	2.4	2.0	4.7	..	..
Electricity Consumption	7.0	3.7	4.1	4.6	4.7	..	..
Energy Production	8.3	8.5	0.7	2.7	1.1	..	..
Net Oil Imports	2.5	-0.4	2.8	8.7	2.9	..	..
GDP	3.3	0.7	2.5	3.8	4.0	..	..
Growth in the TPES/GDP Ratio	1.1	2.3	-0.1	-2.5	0.3	..	..
Growth in the TFC/GDP Ratio	0.7	1.9	-0.1	-1.7	0.6	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**12.70**	**14.33**	**11.07**	**10.83**	**9.74**	**8.95**	**8.56**
Coal[1]		6.05	4.14	2.83	2.68	2.20	2.00	1.80
Oil		2.02	2.27	1.57	1.63	1.00	0.80	0.70
Gas		4.03	3.81	2.48	2.36	2.00	1.60	1.50
Comb. Renewables & Wastes[2]		0.59	0.42	0.40	0.41	0.84	0.84	0.84
Nuclear		–	3.58	3.70	3.65	3.60	3.60	3.60
Hydro		0.01	0.02	0.02	0.02	0.02	0.02	0.02
Geothermal		–	0.09	0.09	0.09	0.08	0.10	0.10
Solar/Wind/Other[3]		–	–	0.00	0.00	0.00	0.01	0.01
TOTAL NET IMPORTS[4]		**8.66**	**14.17**	**13.78**	**14.69**	**17.11**	**18.77**	**19.37**
Coal[1]	Exports	0.11	–	0.10	0.04	–	–	–
	Imports	1.74	1.63	1.09	0.95	1.33	1.35	1.27
	Net Imports	1.63	1.63	1.00	0.90	1.33	1.35	1.27
Oil	Exports	0.92	1.52	2.31	2.58	1.50	1.50	1.50
	Imports	7.39	7.96	7.05	7.29	7.65	8.15	8.45
	Bunkers	–	–	–	–	–	–	–
	Net Imports	6.48	6.44	4.73	4.72	6.15	6.65	6.95
Gas	Exports	0.01	0.02	0.00	–	–	–	–
	Imports	0.17	5.19	7.78	8.70	9.48	10.46	10.95
	Net Imports	0.15	5.17	7.78	8.70	9.48	10.46	10.95
Electricity	Exports	0.09	0.19	0.62	0.72	0.16	0.16	0.15
	Imports	0.49	1.14	0.90	1.08	0.31	0.47	0.35
	Net Imports	0.40	0.96	0.27	0.37	0.16	0.31	0.20
TOTAL STOCK CHANGES		**-0.02**	**0.06**	**0.73**	**-0.07**	**–**	**–**	**–**
TOTAL SUPPLY (TPES)		**21.33**	**28.55**	**25.58**	**25.45**	**26.85**	**27.73**	**27.93**
Coal[1]		7.91	6.12	3.78	3.62	3.53	3.35	3.07
Oil		8.21	8.51	6.62	6.49	7.15	7.45	7.65
Gas		4.17	8.91	10.71	10.80	11.48	12.06	12.45
Comb. Renewables & Wastes[2]		0.64	0.38	0.40	0.41	0.84	0.84	0.84
Nuclear		–	3.58	3.70	3.65	3.60	3.60	3.60
Hydro		0.01	0.02	0.02	0.02	0.02	0.02	0.02
Geothermal		–	0.09	0.09	0.09	0.08	0.10	0.10
Solar/Wind/Other[3]		–	–	0.00	0.00	0.00	0.01	0.01
Electricity Trade[5]		0.40	0.96	0.27	0.37	0.16	0.31	0.20
Shares (%)								
Coal		*37.1*	*21.4*	*14.8*	*14.2*	*13.1*	*12.1*	*11.0*
Oil		*38.5*	*29.8*	*25.9*	*25.5*	*26.6*	*26.9*	*27.4*
Gas		*19.6*	*31.2*	*41.9*	*42.4*	*42.7*	*43.5*	*44.6*
Comb. Renewables & Wastes		*3.0*	*1.3*	*1.6*	*1.6*	*3.1*	*3.0*	*3.0*
Nuclear		–	*12.5*	*14.4*	*14.3*	*13.4*	*13.0*	*12.9*
Hydro		–	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Geothermal		–	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*
Solar/Wind/Other		–	–	–	–	–	–	–
Electricity Trade		*1.9*	*3.4*	*1.1*	*1.4*	*0.6*	*1.1*	*0.7*

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**17.14**	**21.02**	**17.88**	**17.89**	**19.67**	**19.77**	**19.69**
Coal[1]	4.17	2.68	0.65	0.68	0.82	0.74	0.66
Oil	6.71	7.41	5.33	5.57	5.90	6.20	6.40
Gas	3.08	6.20	7.34	7.19	7.73	8.11	8.30
Comb. Renewables & Wastes[2]	0.62	0.34	0.33	0.36	0.89	0.89	0.89
Geothermal	–	0.09	0.09	0.09	–	–	–
Solar/Wind/Other	–	–	0.00	0.00	–	–	–
Electricity	1.51	2.72	2.63	2.71	2.78	2.20	1.80
Heat	1.06	1.59	1.52	1.30	1.55	1.64	1.64
Shares (%)							
Coal	*24.3*	*12.7*	*3.6*	*3.8*	*4.2*	*3.7*	*3.4*
Oil	*39.1*	*35.2*	*29.8*	*31.1*	*30.0*	*31.4*	*32.5*
Gas	*17.9*	*29.5*	*41.0*	*40.2*	*39.3*	*41.0*	*42.2*
Comb. Renewables & Wastes	*3.6*	*1.6*	*1.9*	*2.0*	*4.5*	*4.5*	*4.5*
Geothermal	–	*0.4*	*0.5*	*0.5*	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*8.8*	*12.9*	*14.7*	*15.1*	*14.2*	*11.1*	*9.1*
Heat	*6.2*	*7.6*	*8.5*	*7.2*	*7.9*	*8.3*	*8.3*
TOTAL INDUSTRY[6]	**7.90**	**8.08**	**4.90**	**4.89**	**5.54**	**5.62**	**5.51**
Coal[1]	1.87	0.80	0.42	0.41	0.53	0.48	0.43
Oil	2.34	2.11	1.30	1.36	1.68	1.77	1.81
Gas	2.29	3.76	1.89	1.78	2.01	2.11	2.11
Comb. Renewables & Wastes[2]	0.02	0.00	0.01	0.01	0.11	0.11	0.11
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	0.92	1.18	0.81	0.88	0.82	0.74	0.63
Heat	0.46	0.23	0.48	0.45	0.40	0.43	0.43
Shares (%)							
Coal	*23.6*	*9.9*	*8.5*	*8.5*	*9.5*	*8.5*	*7.8*
Oil	*29.6*	*26.1*	*26.5*	*27.7*	*30.4*	*31.5*	*32.8*
Gas	*29.0*	*46.5*	*38.6*	*36.4*	*36.2*	*37.4*	*38.3*
Comb. Renewables & Wastes	*0.2*	–	*0.2*	*0.2*	*1.9*	*1.9*	*1.9*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*11.7*	*14.6*	*16.5*	*18.0*	*14.8*	*13.1*	*11.4*
Heat	*5.9*	*2.8*	*9.7*	*9.2*	*7.2*	*7.6*	*7.7*
TRANSPORT[7]	**2.37**	**3.15**	**3.48**	**3.66**	**3.55**	**3.71**	**3.84**
TOTAL OTHER SECTORS[8]	**6.88**	**9.79**	**9.50**	**9.33**	**10.57**	**10.44**	**10.33**
Coal[1]	1.93	1.88	0.23	0.26	0.29	0.26	0.23
Oil	2.45	2.25	0.66	0.65	0.75	0.79	0.80
Gas	0.78	2.44	5.45	5.41	5.72	6.01	6.19
Comb. Renewables & Wastes[2]	0.60	0.34	0.32	0.34	0.78	0.78	0.78
Geothermal	–	0.09	0.09	0.09	–	–	–
Solar/Wind/Other	–	–	0.00	0.00	–	–	–
Electricity	0.52	1.43	1.73	1.74	1.88	1.40	1.11
Heat	0.60	1.36	1.04	0.85	1.15	1.21	1.21
Shares (%)							
Coal	*28.1*	*19.2*	*2.4*	*2.8*	*2.7*	*2.5*	*2.3*
Oil	*35.7*	*22.9*	*6.9*	*6.9*	*7.1*	*7.5*	*7.8*
Gas	*11.4*	*25.0*	*57.3*	*58.0*	*54.1*	*57.5*	*59.9*
Comb. Renewables & Wastes	*8.7*	*3.4*	*3.4*	*3.7*	*7.4*	*7.5*	*7.6*
Geothermal	–	*0.9*	*0.9*	*0.9*	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*7.5*	*14.6*	*18.2*	*18.6*	*17.8*	*13.4*	*10.8*
Heat	*8.7*	*13.9*	*11.0*	*9.1*	*10.9*	*11.6*	*11.7*

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**6.37**	**10.23**	**10.43**	**10.08**	**10.95**	**11.06**	**11.07**
OUTPUT (Mtoe)	**1.52**	**2.45**	**3.13**	**3.11**	**3.28**	**3.36**	**3.47**
(TWh gross)	17.64	28.44	36.41	36.16	38.11	39.06	40.38
Output Shares (%)							
Coal	*66.0*	*30.5*	*24.5*	*25.1*	*21.5*	*18.4*	*17.8*
Oil	*17.2*	*4.8*	*11.5*	*5.9*	*9.2*	*8.7*	*8.4*
Gas	*16.2*	*15.7*	*24.3*	*29.7*	*30.2*	*34.6*	*36.7*
Comb. Renewables & Wastes	–	*0.1*	*0.3*	*0.2*	*0.5*	*0.5*	*0.5*
Nuclear	–	*48.3*	*38.8*	*38.6*	*38.0*	*37.1*	*35.9*
Hydro	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	*0.0*	*0.0*	*0.1*	*0.2*	*0.2*
TOTAL LOSSES	**4.87**	**7.99**	**7.61**	**7.31**	**7.19**	**7.95**	**8.24**
of which:							
Electricity and Heat Generation[10]	3.67	6.03	5.60	5.50	5.80	5.78	5.61
Other Transformation	0.21	-0.05	0.16	0.07	-0.20	-0.20	-0.20
Own Use and Losses[11]	0.99	2.02	1.85	1.74	1.58	2.37	2.83
Statistical Differences	**-0.68**	**-0.45**	**0.09**	**0.25**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	35.10	50.35	56.49	58.44	81.22	126.13	201.57
Population (millions)	10.43	10.37	10.19	10.16	10.06	9.86	9.54
TPES/GDP[12]	0.61	0.57	0.45	0.44	0.33	0.22	0.14
Energy Production/TPES	0.60	0.50	0.43	0.43	0.36	0.32	0.31
Per Capita TPES[13]	2.05	2.75	2.51	2.51	2.67	2.81	2.93
Oil Supply/GDP[12]	0.23	0.17	0.12	0.11	0.09	0.06	0.04
TFC/GDP[12]	0.49	0.42	0.32	0.31	0.24	0.16	0.10
Per Capita TFC[13]	1.64	2.03	1.76	1.76	1.95	2.01	2.06
Energy-related CO_2 Emissions (Mt CO_2)[14]	68.5	70.5	56.2	55.5	58.1	59.4	59.7
CO_2 Emissions from Bunkers (Mt CO_2)	0.2	0.5	0.7	0.6	0.6	0.6	0.6

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	4.9	0.1	-1.0	-0.5	0.7	0.3	0.1
Coal	1.2	-3.0	-4.3	-4.2	-0.3	-0.5	-0.8
Oil	5.6	-2.6	-2.3	-1.9	1.2	0.4	0.3
Gas	10.0	1.7	1.7	0.9	0.8	0.5	0.3
Comb. Renewables & Wastes	-2.6	-3.3	0.5	3.0	9.3	–	–
Nuclear	–	–	0.3	-1.2	-0.2	–	–
Hydro	6.3	1.3	0.6	6.3	-0.8	–	–
Geothermal	–	–	–	–	-0.3	1.3	–
Solar/Wind/Other	–	–	–	–	–	11.6	2.9
TFC	4.5	-0.5	-1.5	0.0	1.2	0.1	-0.0
Electricity Consumption	6.0	2.2	-0.3	3.1	0.3	-2.3	-2.0
Energy Production	2.4	-0.2	-2.3	-2.1	-1.3	-0.8	-0.5
Net Oil Imports	7.1	-3.8	-2.8	-0.3	3.4	0.8	0.4
GDP	4.3	1.0	1.1	3.5	4.2	4.5	4.8
Growth in the TPES/GDP Ratio	0.6	-0.9	-2.0	-3.8	-3.4	-4.0	-4.5
Growth in the TFC/GDP Ratio	0.2	-1.5	-2.5	-3.3	-2.9	-4.3	-4.6

Please note: Rounding may cause totals to differ from the sum of the elements.

IRELAND

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**1.120**	**3.467**	**1.729**	**1.499**	**2.967**	**..**	**..**
Coal[1]		0.045	0.016	–	–	–	..	..
Peat		1.020	1.411	0.810	0.534	0.940	..	..
Oil		–	–	–	–	–	..	..
Gas		–	1.872	0.658	0.677	1.549	..	..
Comb. Renewables & Wastes[2]		–	0.108	0.180	0.176	0.205	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.055	0.060	0.051	0.078	0.070	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other[3]		–	–	0.029	0.034	0.203	..	..
TOTAL NET IMPORTS[4]		**5.901**	**7.357**	**13.607**	**13.664**	**13.795**	**..**	**..**
Coal[1]	Exports	0.073	0.023	0.014	0.018	0.009	..	..
	Imports	0.578	2.290	1.874	1.811	0.967	..	..
	Net Imports	0.505	2.267	1.860	1.793	0.958	..	..
Peat	Exports	–	–	–	–	0.010	..	..
	Imports	–	–	–	–	–	..	..
	Net Imports	–	–	–	–	-0.010	..	..
Oil	Exports	0.472	0.680	1.288	1.470	1.347	..	..
	Imports	5.956	5.788	10.296	10.447	9.859	..	..
	Bunkers	0.092	0.018	0.164	0.150	0.084	..	..
	Net Imports	5.392	5.090	8.844	8.827	8.428	..	..
Gas	Exports	–	–	–	–	–	..	..
	Imports	–	–	2.924	3.000	4.354	..	..
	Net Imports	–	–	2.924	3.000	4.354	..	..
Electricity	Exports	0.002	–	0.025	0.005	0.025	..	..
	Imports	0.006	–	0.003	0.049	0.090	..	..
	Net Imports	0.004	–	-0.022	0.044	0.065	..	..
TOTAL STOCK CHANGES		**0.168**	**-0.250**	**-0.197**	**0.140**	**–**	**..**	**..**
TOTAL SUPPLY (TPES)		**7.189**	**10.575**	**15.139**	**15.303**	**16.762**	**..**	**..**
Coal[1]		0.565	2.375	1.830	1.745	0.958	..	..
Peat		1.020	1.288	0.797	0.820	0.930	..	..
Oil		5.545	4.871	8.691	8.729	8.428	..	..
Gas		–	1.872	3.583	3.678	5.903	..	..
Comb. Renewables & Wastes[2]		–	0.108	0.180	0.176	0.205	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.055	0.060	0.051	0.078	0.070	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other[3]		–	–	0.029	0.034	0.203	..	..
Electricity Trade[5]		0.004	–	-0.021	0.043	0.065	..	..
Shares (%)			*..*	*..*				
Coal		*7.9*	*22.5*	*12.1*	*11.4*	*5.7*	..	..
Peat		*14.2*	*12.2*	*5.3*	*5.4*	*5.5*	..	..
Oil		*77.1*	*46.1*	*57.4*	*57.0*	*50.3*	..	..
Gas		–	*17.7*	*23.7*	*24.0*	*35.2*	..	..
Comb. Renewables & Wastes		–	*1.0*	*1.2*	*1.2*	*1.2*	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		*0.8*	*0.6*	*0.3*	*0.5*	*0.4*	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other		–	–	*0.2*	*0.2*	*1.2*	..	..
Electricity Trade		*0.1*	–	*-0.1*	*0.3*	*0.4*	..	..

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**5.416**	**7.840**	**11.744**	**11.830**	**13.033**	**..**	**..**
Coal[1]	0.520	1.138	0.408	0.419	0.226	..	..
Peat	0.408	0.427	0.106	0.106	0.135	..	..
Oil	3.856	4.149	7.589	7.723	8.232	..	..
Gas	0.103	0.998	1.685	1.548	2.009	..	..
Comb. Renewables & Wastes[2]	–	0.108	0.156	0.156	0.151	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.529	1.021	1.800	1.878	2.280	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*9.6*	*14.5*	*3.5*	*3.5*	*1.7*	..	..
Peat	*7.5*	*5.4*	*0.9*	*0.9*	*1.0*	..	..
Oil	*71.2*	*52.9*	*64.6*	*65.3*	*63.2*	..	..
Gas	*1.9*	*12.7*	*14.3*	*13.1*	*15.4*	..	..
Comb. Renewables & Wastes	–	*1.4*	*1.3*	*1.3*	*1.2*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*9.8*	*13.0*	*15.3*	*15.9*	*17.5*	..	..
Heat	–	–	–	–	–	..	..
TOTAL INDUSTRY[6]	**1.920**	**2.387**	**2.905**	**2.831**	**2.407**	**..**	**..**
Coal[1]	0.044	0.272	0.048	0.038	0.062	..	..
Peat	–	–	–	–	–	..	..
Oil	1.662	0.879	1.185	1.199	0.896	..	..
Gas	0.025	0.787	0.892	0.783	0.527	..	..
Comb. Renewables & Wastes[2]	–	0.063	0.113	0.113	0.109	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.189	0.386	0.667	0.697	0.813	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*2.3*	*11.4*	*1.7*	*1.3*	*2.6*	..	..
Peat	–	–	–	–	–	..	..
Oil	*86.6*	*36.8*	*40.8*	*42.4*	*37.2*	..	..
Gas	*1.3*	*33.0*	*30.7*	*27.7*	*21.9*	..	..
Comb. Renewables & Wastes	–	*2.6*	*3.9*	*4.0*	*4.5*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*9.8*	*16.2*	*23.0*	*24.6*	*33.8*	..	..
Heat	–	–	–	–	–	..	..
TRANSPORT[7]	**1.406**	**2.031**	**4.377**	**4.491**	**5.134**	**..**	**..**
TOTAL OTHER SECTORS[8]	**2.090**	**3.422**	**4.462**	**4.509**	**5.492**	**..**	**..**
Coal[1]	0.476	0.866	0.361	0.380	0.164	..	..
Peat	0.408	0.427	0.106	0.106	0.135	..	..
Oil	0.788	1.240	2.028	2.036	2.204	..	..
Gas	0.078	0.211	0.794	0.765	1.482	..	..
Comb. Renewables & Wastes[2]	–	0.045	0.043	0.043	0.042	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.340	0.634	1.130	1.178	1.465	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*22.8*	*25.3*	*8.1*	*8.4*	*3.0*	..	..
Peat	*19.5*	*12.5*	*2.4*	*2.4*	*2.5*	..	..
Oil	*37.7*	*36.2*	*45.5*	*45.2*	*40.1*	..	..
Gas	*3.7*	*6.2*	*17.8*	*17.0*	*27.0*	..	..
Comb. Renewables & Wastes	–	*1.3*	*1.0*	*1.0*	*0.8*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*16.3*	*18.5*	*25.3*	*26.1*	*26.7*	..	..
Heat	–	–	–	–	–	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**1.766**	**3.132**	**5.262**	**5.167**	**5.768**	..	..
OUTPUT (Mtoe)	**0.632**	**1.224**	**2.118**	**2.136**	**2.583**	..	..
(TWh gross)	7.348	14.229	24.632	24.843	30.034	..	..
Output Shares (%)							
Coal	*1.0*	*41.6*	*28.7*	*27.4*	*15.3*	..	..
Peat	*23.9*	*15.8*	*8.9*	*8.4*	*6.9*	..	..
Oil	*66.3*	*10.0*	*21.1*	*15.0*	*1.4*	..	..
Gas	–	*27.7*	*37.1*	*43.6*	*65.3*	..	..
Comb. Renewables & Wastes	–	–	*0.4*	*0.3*	*0.6*	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	*8.8*	*4.9*	*2.4*	*3.7*	*2.7*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	*1.4*	*1.6*	*7.9*	..	..
TOTAL LOSSES	**1.649**	**2.259**	**3.686**	**3.584**	**3.729**	..	..
of which:							
Electricity and Heat Generation[10]	1.134	1.908	3.144	3.031	3.185	..	..
Other Transformation	0.329	0.041	0.063	0.056	–	..	..
Own Use and Losses[11]	0.186	0.310	0.479	0.497	0.544	..	..
Statistical Differences	**0.124**	**0.476**	**-0.291**	**-0.111**	**–**	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	26.92	52.88	112.78	120.58	182.55	..	..
Population (millions)	3.07	3.51	3.85	3.91	4.29	..	..
TPES/GDP[12]	0.27	0.20	0.13	0.13	0.09	..	..
Energy Production/TPES	0.16	0.33	0.11	0.10	0.18	..	..
Per Capita TPES[13]	2.34	3.02	3.93	3.91	3.91	..	..
Oil Supply/GDP[12]	0.21	0.09	0.08	0.07	0.05	..	..
TFC/GDP[12]	0.20	0.15	0.10	0.10	0.07	..	..
Per Capita TFC[13]	1.76	2.24	3.05	3.03	3.04	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	21.0	30.3	43.1	42.5	44.5	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	1.1	1.1	2.7	2.8	2.5	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	3.6	1.6	3.3	1.1	1.1	..	..
Coal	6.9	9.9	-2.3	-4.6	-7.2	..	..
Peat	2.1	1.0	-4.3	2.9	1.6	..	..
Oil	2.3	-2.4	5.4	0.4	-0.4	..	..
Gas	–	13.6	6.1	2.7	6.1	..	..
Comb. Renewables & Wastes	–	–	4.8	-2.2	1.9	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	4.3	-1.5	-1.5	52.9	-1.3	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	17.2	25.0	..	..
TFC	4.3	1.0	3.7	0.7	1.2	..	..
Electricity Consumption	5.8	2.9	5.3	4.3	2.5	..	..
Energy Production	4.6	8.1	-6.1	-13.3	8.9	..	..
Net Oil Imports	2.9	-2.0	5.2	-0.2	-0.6	..	..
GDP	4.9	3.6	7.1	6.9	5.3	..	..
Growth in the TPES/GDP Ratio	-1.3	-1.9	-3.6	-5.5	-4.0	..	..
Growth in the TFC/GDP Ratio	-0.6	-2.4	-3.2	-5.8	-3.9	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**20.5**	**25.5**	**26.0**	**26.6**	**29.7**	**30.0**	**30.0**
Coal[1]		0.3	0.3	0.1	0.1	0.3	–	–
Oil		1.1	4.7	4.2	5.5	5.7	4.0	3.0
Gas		12.6	14.0	12.5	12.0	8.0	6.0	5.0
Comb. Renewables & Wastes[2]		0.2	0.8	1.9	1.9	6.5	8.0	9.0
Nuclear		0.8	–	–	–	–	–	–
Hydro		3.2	2.7	4.0	3.4	4.5	5.0	5.0
Geothermal		2.1	3.0	3.2	3.5	4.2	4.5	4.5
Solar/Wind/Other[3]		–	0.0	0.2	0.2	0.5	2.5	3.5
TOTAL NET IMPORTS[4]		**109.3**	**128.9**	**144.1**	**149.1**	**168.6**	**178.0**	**184.0**
Coal[1]	Exports	0.4	0.1	0.1	0.1	–	–	–
	Imports	8.2	13.9	13.6	13.2	18.0	20.0	21.0
	Net Imports	7.7	13.7	13.5	13.1	18.0	20.0	21.0
Oil	Exports	29.4	20.1	23.0	22.1	20.0	18.0	15.0
	Imports	136.4	109.5	106.9	107.7	100.0	93.0	91.0
	Bunkers	7.1	2.7	2.8	3.0	3.0	2.0	2.0
	Net Imports	99.9	86.7	81.1	82.6	77.0	73.0	74.0
Gas	Exports	–	0.0	0.1	0.0	–	–	–
	Imports	1.6	25.3	44.8	48.5	67.6	79.0	83.0
	Net Imports	1.6	25.3	44.8	48.5	67.6	79.0	83.0
Electricity	Exports	0.2	0.1	0.0	0.1	–	–	–
	Imports	0.3	3.1	4.2	4.4	6.0	6.0	6.0
	Net Imports	0.1	3.0	4.2	4.4	6.0	6.0	6.0
TOTAL STOCK CHANGES		**-0.9**	**-1.8**	**2.4**	**-3.0**	**–**	**–**	**–**
TOTAL SUPPLY (TPES)		**128.9**	**152.6**	**172.6**	**172.7**	**198.3**	**208.0**	**214.0**
Coal[1]		8.1	14.6	13.4	13.7	18.3	20.0	21.0
Oil		100.1	89.3	87.1	87.4	82.7	77.0	77.0
Gas		14.2	39.0	58.1	57.7	75.6	85.0	88.0
Comb. Renewables & Wastes[2]		0.2	0.9	2.4	2.5	6.5	8.0	9.0
Nuclear		0.8	–	–	–	–	–	–
Hydro		3.2	2.7	4.0	3.4	4.5	5.0	5.0
Geothermal		2.1	3.0	3.2	3.5	4.2	4.5	4.5
Solar/Wind/Other[3]		–	0.0	0.2	0.2	0.5	2.5	3.5
Electricity Trade[5]		0.1	3.0	4.2	4.4	6.0	6.0	6.0
Shares (%)								
Coal		*6.3*	*9.6*	*7.7*	*7.9*	*9.2*	*9.6*	*9.8*
Oil		*77.6*	*58.5*	*50.5*	*50.6*	*41.7*	*37.0*	*36.0*
Gas		*11.0*	*25.6*	*33.7*	*33.4*	*38.1*	*40.9*	*41.1*
Comb. Renewables & Wastes		*0.2*	*0.6*	*1.4*	*1.5*	*3.3*	*3.8*	*4.2*
Nuclear		*0.6*	–	–	–	–	–	–
Hydro		*2.5*	*1.8*	*2.3*	*2.0*	*2.3*	*2.4*	*2.3*
Geothermal		*1.7*	*1.9*	*1.8*	*2.0*	*2.1*	*2.2*	*2.1*
Solar/Wind/Other		–	–	*0.1*	*0.1*	*0.3*	*1.2*	*1.6*
Electricity Trade		*0.1*	*2.0*	*2.4*	*2.5*	*3.0*	*2.9*	*2.8*

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**98.7**	**117.6**	**134.2**	**133.5**	**154.9**	**166.9**	**173.8**
Coal[1]	3.3	3.4	2.5	2.0	3.5	3.4	2.5
Oil	72.1	64.2	66.1	66.6	70.0	69.0	71.0
Gas	12.8	30.6	39.7	38.7	47.5	54.0	55.0
Comb. Renewables & Wastes[2]	–	0.9	1.8	1.7	3.0	3.0	3.5
Geothermal	–	0.2	0.2	0.2	–	–	–
Solar/Wind/Other	–	0.0	0.0	0.0	0.1	1.0	1.5
Electricity	10.6	18.5	23.9	24.3	30.8	36.5	40.3
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*3.3*	*2.9*	*1.8*	*1.5*	*2.3*	*2.0*	*1.4*
Oil	*73.0*	*54.5*	*49.2*	*49.8*	*45.2*	*41.3*	*40.9*
Gas	*12.9*	*26.0*	*29.6*	*29.0*	*30.7*	*32.4*	*31.6*
Comb. Renewables & Wastes	–	*0.7*	*1.3*	*1.3*	*1.9*	*1.8*	*2.0*
Geothermal	–	*0.2*	*0.2*	*0.2*	–	–	–
Solar/Wind/Other	–	–	–	–	*0.1*	*0.6*	*0.9*
Electricity	*10.7*	*15.7*	*17.8*	*18.2*	*19.9*	*21.9*	*23.2*
Heat	–	–	–	–	–	–	–
TOTAL INDUSTRY[6]	**47.6**	**44.6**	**46.0**	**46.0**	**56.2**	**54.9**	**56.5**
Coal[1]	2.6	3.3	2.4	2.0	3.5	3.4	2.5
Oil	29.7	16.9	13.4	13.9	16.0	12.0	13.5
Gas	8.7	14.6	17.6	17.5	22.0	23.0	23.0
Comb. Renewables & Wastes[2]	–	0.2	0.3	0.3	0.5	0.5	0.5
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	6.6	9.5	12.3	12.3	14.2	16.0	17.0
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*5.6*	*7.3*	*5.2*	*4.4*	*6.2*	*6.2*	*4.4*
Oil	*62.3*	*37.9*	*29.1*	*30.2*	*28.5*	*21.9*	*23.9*
Gas	*18.2*	*32.9*	*38.3*	*38.0*	*39.1*	*41.9*	*40.7*
Comb. Renewables & Wastes	–	*0.5*	*0.7*	*0.6*	*0.9*	*0.9*	*0.9*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*13.9*	*21.4*	*26.8*	*26.8*	*25.3*	*29.1*	*30.1*
Heat	–	–	–	–	–	–	–
TRANSPORT[7]	**20.5**	**35.3**	**42.9**	**43.5**	**47.0**	**55.5**	**59.3**
TOTAL OTHER SECTORS[8]	**30.6**	**37.8**	**45.2**	**44.1**	**51.7**	**56.5**	**58.0**
Coal[1]	0.5	0.1	0.1	0.0	–	–	–
Oil	22.5	12.8	10.9	10.3	9.0	6.0	5.0
Gas	4.0	15.7	21.7	20.9	25.0	30.0	30.5
Comb. Renewables & Wastes[2]	–	0.6	1.5	1.4	2.0	2.0	2.0
Geothermal	–	0.2	0.2	0.2	–	–	–
Solar/Wind/Other	–	0.0	0.0	0.0	0.1	1.0	1.5
Electricity	3.6	8.3	10.8	11.2	15.6	17.5	19.0
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*1.5*	*0.3*	*0.2*	–	–	–	–
Oil	*73.5*	*33.8*	*24.1*	*23.4*	*17.4*	*10.6*	*8.6*
Gas	*13.1*	*41.6*	*48.0*	*47.4*	*48.4*	*53.1*	*52.6*
Comb. Renewables & Wastes	–	*1.7*	*3.3*	*3.1*	*3.9*	*3.5*	*3.4*
Geothermal	–	*0.5*	*0.5*	*0.5*	–	–	–
Solar/Wind/Other	–	–	–	–	*0.2*	*1.8*	*2.6*
Electricity	*11.8*	*22.1*	*24.0*	*25.5*	*30.2*	*31.0*	*32.8*
Heat	–	–	–	–	–	–	–

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**28.0**	**43.1**	**50.5**	**52.9**	**59.5**	**64.6**	**68.5**
OUTPUT (Mtoe)	**12.4**	**18.3**	**23.4**	**23.9**	**28.7**	**32.6**	**36.0**
(TWh gross)	143.9	213.1	271.9	277.5	334.1	379.2	418.2
Output Shares (%)							
Coal	*3.6*	*16.8*	*13.5*	*14.6*	*17.1*	*18.5*	*20.3*
Oil	*62.4*	*48.2*	*27.6*	*31.6*	*9.9*	*5.3*	*3.8*
Gas	*3.1*	*18.6*	*38.3*	*35.8*	*50.6*	*50.1*	*50.2*
Comb. Renewables & Wastes	*0.9*	*0.0*	*1.0*	*1.3*	*3.6*	*4.5*	*4.6*
Nuclear	*2.2*	–	–	–	–	–	–
Hydro	*26.1*	*14.8*	*17.2*	*14.2*	*15.7*	*15.3*	*13.9*
Geothermal	*1.7*	*1.5*	*1.7*	*1.7*	*1.8*	*1.7*	*1.6*
Solar/Wind/Other	–	*0.0*	*0.7*	*0.8*	*1.4*	*4.6*	*5.6*
TOTAL LOSSES	**29.9**	**35.0**	**37.5**	**39.5**	**43.4**	**41.1**	**40.2**
of which:							
Electricity and Heat Generation[10]	15.6	24.8	27.1	29.1	30.7	32.0	32.5
Other Transformation	6.0	1.0	1.0	0.5	–	–	–
Own Use and Losses[11]	8.3	9.2	9.4	9.9	12.6	9.1	7.7
Statistical Differences	**0.3**	**-0.0**	**0.9**	**-0.3**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	647.03	1030.05	1229.74	1234.31	1446.20	1762.90	2148.97
Population (millions)	54.75	56.72	57.93	58.03	58.50	58.00	57.00
TPES/GDP[12]	0.20	0.15	0.14	0.14	0.14	0.12	0.10
Energy Production/TPES	0.16	0.17	0.15	0.15	0.15	0.14	0.14
Per Capita TPES[13]	2.35	2.69	2.98	2.98	3.39	3.59	3.75
Oil Supply/GDP[12]	0.15	0.09	0.07	0.07	0.06	0.04	0.04
TFC/GDP[12]	0.15	0.11	0.11	0.11	0.11	0.09	0.08
Per Capita TFC[13]	1.80	2.07	2.32	2.30	2.65	2.88	3.05
Energy-related CO_2 Emissions (Mt CO_2)[14]	334.4	400.1	426.1	433.2	476.2	489.0	499.6
CO_2 Emissions from Bunkers (Mt CO_2)	26.3	15.0	19.3	19.2	19.2	16.1	16.1

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	1.5	0.7	1.1	0.1	1.7	0.5	0.3
Coal	4.3	3.1	-0.8	2.7	3.6	0.9	0.5
Oil	-0.0	-1.0	-0.2	0.3	-0.7	-0.7	–
Gas	8.1	5.1	3.7	-0.7	3.4	1.2	0.3
Comb. Renewables & Wastes	23.4	0.8	9.1	2.8	12.6	2.1	1.2
Nuclear	-2.9	–	–	–	–	–	–
Hydro	3.4	-3.3	3.6	-15.6	3.6	1.1	–
Geothermal	0.1	3.0	0.6	8.6	2.4	0.7	–
Solar/Wind/Other	–	–	38.8	8.2	12.2	17.5	3.4
TFC	1.3	0.9	1.2	-0.5	1.9	0.7	0.4
Electricity Consumption	4.0	3.0	2.4	1.8	3.0	1.7	1.0
Energy Production	0.2	1.9	0.2	2.2	1.4	0.1	–
Net Oil Imports	-0.4	-1.1	-0.6	1.8	-0.9	-0.5	0.1
GDP	3.5	2.4	1.6	0.4	2.0	2.0	2.0
Growth in the TPES/GDP Ratio	-1.9	-1.6	-0.5	-0.3	-0.3	-1.5	-1.7
Growth in the TFC/GDP Ratio	-2.1	-1.5	-0.4	-0.9	-0.1	-1.2	-1.6

Please note: Rounding may cause totals to differ from the sum of the elements.

JAPAN

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**29.4**	**76.1**	**105.9**	**98.1**	**..**	**..**	**..**
Coal[1]		17.9	4.5	1.7	–	–	..	..
Oil		0.7	0.6	0.7	0.7	..	..	..
Gas		2.3	1.9	2.2	2.4	..	..	..
Comb. Renewables & Wastes[2]		–	6.0	6.8	7.2	29.4	..	..
Nuclear		2.5	52.7	83.4	76.9	109.1	..	..
Hydro		5.7	7.7	7.2	7.1	8.2	..	..
Geothermal		0.2	1.6	3.2	3.1	3.6	..	..
Solar/Wind/Other[3]		–	1.2	0.8	0.8	2.3	..	..
TOTAL NET IMPORTS[4]		**300.7**	**371.8**	**411.0**	**420.6**	**..**	**..**	**..**
Coal[1]	Exports	0.4	1.1	1.2	1.7	..	..	..
	Imports	41.3	72.9	99.5	104.3	..	..	..
	Net Imports	40.9	71.7	98.3	102.6	..	..	..
Oil	Exports	2.9	3.6	4.8	3.7	..	..	..
	Imports	276.7	266.3	258.0	261.8	..	..	..
	Bunkers	16.8	5.1	4.3	4.5	..	..	..
	Net Imports	257.0	257.7	248.9	253.6	..	..	..
Gas	Exports	–	–	–	–	–	..	..
	Imports	2.8	42.4	63.7	64.4	..	..	..
	Net Imports	2.8	42.4	63.7	64.4	..	..	..
Electricity	Exports	–	–	–	–	–	..	..
	Imports	–	–	–	–	–	..	..
	Net Imports	–	–	–	–	–	..	..
TOTAL STOCK CHANGES		**-6.6**	**-2.1**	**0.1**	**-1.8**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**323.5**	**445.9**	**517.0**	**516.9**	**554.6**	**..**	**..**
Coal[1]		57.9	77.8	96.7	100.0	98.8	..	..
Oil		252.1	254.8	252.7	255.5	234.9	..	..
Gas		5.1	44.3	66.3	66.4	68.2	..	..
Comb. Renewables & Wastes[2]		–	6.0	6.8	7.2	29.4	..	..
Nuclear		2.5	52.7	83.4	76.9	109.1	..	..
Hydro		5.7	7.7	7.2	7.1	8.2	..	..
Geothermal		0.2	1.6	3.2	3.1	3.6	..	..
Solar/Wind/Other[3]		–	1.2	0.8	0.8	2.3	..	..
Electricity Trade[5]		–	–	–	–	–	..	..
Shares (%)								
Coal		*17.9*	*17.4*	*18.7*	*19.3*	*17.8*	..	..
Oil		*77.9*	*57.1*	*48.9*	*49.4*	*42.4*	..	..
Gas		*1.6*	*9.9*	*12.8*	*12.8*	*12.3*	..	..
Comb. Renewables & Wastes		–	*1.3*	*1.3*	*1.4*	*5.3*	..	..
Nuclear		*0.8*	*11.8*	*16.1*	*14.9*	*19.7*	..	..
Hydro		*1.8*	*1.7*	*1.4*	*1.4*	*1.5*	..	..
Geothermal		*0.1*	*0.4*	*0.6*	*0.6*	*0.7*	..	..
Solar/Wind/Other		–	*0.3*	*0.1*	*0.1*	*0.4*	..	..
Electricity Trade		–	–	–	–	–	..	..

0 is negligible, – is nil, .. is not available.

Please note: Only partial information is available for 2010.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**234.4**	**292.1**	**350.9**	**358.7**	**394.5**	**..**	**..**
Coal[1]	20.2	21.3	20.2	21.4	64.4	..	..
Oil	171.5	186.1	221.2	224.7	223.5	..	..
Gas	7.0	14.8	22.7	24.1	13.3	..	..
Comb. Renewables & Wastes[2]	–	2.6	2.3	2.4	4.7	..	..
Geothermal	–	0.1	0.2	0.2	0.5	..	..
Solar/Wind/Other	–	1.2	0.7	0.7	–	..	..
Electricity	35.7	65.9	83.0	84.6	88.0	..	..
Heat	0.0	0.2	0.5	0.5	..	..	..
Shares (%)							
Coal	*8.6*	*7.3*	*5.8*	*6.0*	*16.3*	..	..
Oil	*73.2*	*63.7*	*63.0*	*62.6*	*56.7*	..	..
Gas	*3.0*	*5.1*	*6.5*	*6.7*	*3.4*	..	..
Comb. Renewables & Wastes	–	*0.9*	*0.7*	*0.7*	*1.2*	..	..
Geothermal	–	–	*0.1*	*0.1*	*0.1*	..	..
Solar/Wind/Other	–	*0.4*	*0.2*	*0.2*	–	..	..
Electricity	*15.2*	*22.5*	*23.7*	*23.6*	*22.3*	..	..
Heat	–	*0.1*	*0.2*	*0.2*	..	..	..
TOTAL INDUSTRY[6]	**140.2**	**126.2**	**141.6**	**145.4**	**..**	**..**	**..**
Coal[1]	18.2	21.2	20.2	21.4	..	..	..
Oil	94.9	64.8	73.8	74.7	..	..	..
Gas	2.1	4.8	9.2	10.4	..	..	..
Comb. Renewables & Wastes[2]	–	2.5	2.3	2.3	..	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	25.1	32.9	36.1	36.6	..	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*13.0*	*16.8*	*14.3*	*14.7*	..	..	..
Oil	*67.7*	*51.4*	*52.1*	*51.4*	..	..	..
Gas	*1.5*	*3.8*	*6.5*	*7.1*	..	..	..
Comb. Renewables & Wastes	–	*2.0*	*1.6*	*1.6*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*17.9*	*26.1*	*25.5*	*25.2*	..	..	..
Heat	–	–	–	–	..	..	..
TRANSPORT[7]	**42.6**	**76.6**	**95.3**	**94.4**	**..**	**..**	**..**
TOTAL OTHER SECTORS[8]	**51.6**	**89.3**	**114.0**	**118.8**	**..**	**..**	**..**
Coal[1]	1.8	0.1	–	–	–	..	..
Oil	35.3	46.1	53.6	57.1	..	..	..
Gas	5.0	10.1	13.4	13.7	..	..	..
Comb. Renewables & Wastes[2]	–	0.1	0.0	0.0	..	..	..
Geothermal	–	0.1	0.2	0.2	..	..	..
Solar/Wind/Other	–	1.2	0.7	0.7	–	..	..
Electricity	9.5	31.5	45.3	46.4	..	..	..
Heat	0.0	0.2	0.5	0.5	..	..	..
Shares (%)							
Coal	*3.4*	*0.1*	–	–	–	..	..
Oil	*68.5*	*51.6*	*47.1*	*48.1*	..	..	..
Gas	*9.6*	*11.3*	*11.8*	*11.5*	..	..	..
Comb. Renewables & Wastes	–	*0.1*	–	–	..	..	..
Geothermal	–	*0.1*	*0.2*	*0.2*	..	..	..
Solar/Wind/Other	–	*1.3*	*0.7*	*0.6*	–	..	..
Electricity	*18.4*	*35.3*	*39.8*	*39.1*	..	..	..
Heat	*0.1*	*0.2*	*0.5*	*0.5*	..	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**90.6**	**173.4**	**222.2**	**224.4**	**248.1**	..	..
OUTPUT (Mtoe)	**40.0**	**73.2**	**91.7**	**93.5**	**96.9**	..	..
(TWh gross)	465.4	850.7	1066.2	1087.7	1126.9	..	..
Output Shares (%)							
Coal	*8.0*	*14.6*	*25.4*	*26.8*	*14.2*	..	..
Oil	*73.2*	*29.9*	*11.5*	*13.4*	*4.7*	..	..
Gas	*2.3*	*19.1*	*22.6*	*22.5*	*22.6*	..	..
Comb. Renewables & Wastes	–	*1.9*	*2.2*	*2.3*	*10.2*	..	..
Nuclear	*2.1*	*23.8*	*30.0*	*27.1*	*37.1*	..	..
Hydro	*14.3*	*10.5*	*7.9*	*7.6*	*8.4*	..	..
Geothermal	*0.1*	*0.2*	*0.3*	*0.3*	*0.3*	..	..
Solar/Wind/Other	–	*0.0*	*0.0*	*0.0*	*2.4*	..	..
TOTAL LOSSES	**94.4**	**148.7**	**172.2**	**171.7**	**151.2**	..	..
of which:							
Electricity and Heat Generation[10]	50.5	100.1	130.0	130.4	151.2	..	..
Other Transformation	24.9	28.0	22.0	20.8	..	..	..
Own Use and Losses[11]	19.0	20.6	20.1	20.5	..	..	..
Statistical Differences	**-5.3**	**5.1**	**-6.0**	**-13.5**	**–**	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	2613.32	4924.77	5707.03	5715.29	..	..	..
Population (millions)	108.66	123.54	127.29	127.44	..	..	..
TPES/GDP[12]	0.12	0.09	0.09	0.09	..	..	..
Energy Production/TPES	0.09	0.17	0.20	0.19	..	..	..
Per Capita TPES[13]	2.98	3.61	4.06	4.06	..	..	..
Oil Supply/GDP[12]	0.10	0.05	0.04	0.04	..	..	..
TFC/GDP[12]	0.09	0.06	0.06	0.06	..	..	..
Per Capita TFC[13]	2.16	2.36	2.76	2.81	..	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	891.2	1015.2	1164.6	1206.9	1146.1	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	58.6	29.6	32.7	35.9	..	..	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	1.5	2.1	1.4	-0.0	0.9	..	..
Coal	-2.0	3.9	2.0	3.4	-0.1	..	..
Oil	0.4	-0.1	-0.1	1.1	-1.0	..	..
Gas	24.2	8.2	3.7	0.1	0.3	..	..
Comb. Renewables & Wastes	–	–	1.2	4.5	19.3	..	..
Nuclear	39.1	10.1	4.3	-7.7	4.5	..	..
Hydro	3.2	0.9	-0.5	-2.1	1.8	..	..
Geothermal	22.3	6.7	6.6	-1.4	1.9	..	..
Solar/Wind/Other	–	51.6	-3.7	0.8	14.6	..	..
TFC	1.0	1.5	1.7	2.2	1.2	..	..
Electricity Consumption	3.9	3.5	2.1	1.9	0.5	..	..
Energy Production	4.9	6.2	3.0	-7.3	..	..	..
Net Oil Imports	0.5	-0.2	-0.3	1.9	..	..	..
GDP	3.5	4.0	1.3	0.1	..	..	..
Growth in the TPES/GDP Ratio	-1.9	-1.8	0.0	-0.2	..	..	..
Growth in the TFC/GDP Ratio	-2.4	-2.4	0.3	2.1	..	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**6.76**	**21.91**	**34.20**	**36.21**	**..**	**..**	**..**
Coal[1]		6.65	7.58	1.65	1.42	..	..	..
Oil		–	–	0.57	0.53	..	..	..
Gas		–	–	–	–	..	..	..
Comb. Renewables & Wastes[2]		–	–	2.36	2.91	..	..	..
Nuclear		–	13.78	29.22	31.04	..	..	..
Hydro		0.11	0.55	0.36	0.28	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other[3]		–	0.00	0.04	0.04	..	..	..
TOTAL NET IMPORTS[4]		**13.03**	**68.51**	**158.51**	**165.98**	**..**	**..**	**..**
Coal[1]	Exports	0.12	–	–	–	..	..	..
	Imports	0.45	15.73	39.15	44.33	..	..	..
	Net Imports	0.34	15.73	39.15	44.33	..	..	..
Oil	Exports	1.04	3.73	40.14	32.17	..	..	..
	Imports	14.28	55.41	146.53	138.64	..	..	..
	Bunkers	0.56	1.58	5.94	5.66	..	..	..
	Net Imports	12.69	50.10	100.46	100.81	..	..	..
Gas	Exports	–	–	–	–	..	..	..
	Imports	–	2.68	18.91	20.85	..	..	..
	Net Imports	–	2.68	18.91	20.85	..	..	..
Electricity	Exports	–	–	–	–	..	..	..
	Imports	–	–	–	–	..	..	..
	Net Imports	–	–	–	–	..	..	..
TOTAL STOCK CHANGES		**1.86**	**2.24**	**1.20**	**1.31**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**21.64**	**92.65**	**193.92**	**203.50**	**..**	**..**	**..**
Coal[1]		8.13	25.56	43.00	46.04	..	..	..
Oil		13.40	50.04	100.21	102.00	..	..	..
Gas		–	2.72	18.74	21.20	..	..	..
Comb. Renewables & Wastes[2]		–	–	2.36	2.91	..	..	..
Nuclear		–	13.78	29.22	31.04	..	..	..
Hydro		0.11	0.55	0.36	0.28	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other[3]		–	0.00	0.04	0.04	..	..	..
Electricity Trade[5]		–	–	–	–	..	..	..
Shares (%)								
Coal		*37.6*	*27.6*	*22.2*	*22.6*	..	..	..
Oil		*61.9*	*54.0*	*51.7*	*50.1*	..	..	..
Gas		–	*2.9*	*9.7*	*10.4*	..	..	..
Comb. Renewables & Wastes		–	–	*1.2*	*1.4*	..	..	..
Nuclear		–	*14.9*	*15.1*	*15.3*	..	..	..
Hydro		*0.5*	*0.6*	*0.2*	*0.1*	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other		–	–	–	–	..	..	..
Electricity Trade		–	–	–	–	..	..	..

0 is negligible, – is nil, .. is not available.

Please note: Forecasts are not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**17.40**	**63.99**	**129.96**	**137.97**	**..**	**..**	**..**
Coal[1]	6.49	11.37	7.23	8.62	..	..	..
Oil	9.81	43.82	85.25	86.80	..	..	..
Gas	–	0.67	11.52	13.05	..	..	..
Comb. Renewables & Wastes[2]	–	–	0.11	0.11	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	0.00	0.04	0.04	..	..	..
Electricity	1.10	8.12	21.53	25.28	..	..	..
Heat	–	–	4.28	4.08	..	..	..
Shares (%)							
Coal	*37.3*	*17.8*	*5.6*	*6.2*	..	..	..
Oil	*56.4*	*68.5*	*65.6*	*62.9*	..	..	..
Gas	–	*1.1*	*8.9*	*9.5*	..	..	..
Comb. Renewables & Wastes	–	–	*0.1*	*0.1*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*6.3*	*12.7*	*16.6*	*18.3*	..	..	..
Heat	–	–	*3.3*	*3.0*	..	..	..
TOTAL INDUSTRY[6]	**7.37**	**25.17**	**60.58**	**64.26**	**..**	**..**	**..**
Coal[1]	0.39	2.71	6.65	8.06	..	..	..
Oil	6.22	17.42	37.63	37.84	..	..	..
Gas	–	0.07	3.12	3.41	..	..	..
Comb. Renewables & Wastes[2]	–	–	–	–	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	0.76	4.97	11.37	12.99	..	..	..
Heat	–	–	1.81	1.97	..	..	..
Shares (%)							
Coal	*5.3*	*10.8*	*11.0*	*12.5*	..	..	..
Oil	*84.4*	*69.2*	*62.1*	*58.9*	..	..	..
Gas	–	*0.3*	*5.2*	*5.3*	..	..	..
Comb. Renewables & Wastes	–	–	–	–	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*10.3*	*19.7*	*18.8*	*20.2*	..	..	..
Heat	–	–	*3.0*	*3.1*	..	..	..
TRANSPORT[7]	**2.60**	**14.93**	**31.08**	**33.19**	**..**	**..**	**..**
TOTAL OTHER SECTORS[8]	**7.43**	**23.89**	**38.30**	**40.52**	**..**	**..**	**..**
Coal[1]	6.08	8.67	0.58	0.56	..	..	..
Oil	1.02	11.56	16.74	16.05	..	..	..
Gas	–	0.60	8.39	9.57	..	..	..
Comb. Renewables & Wastes[2]	–	–	0.11	0.11	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	0.00	0.04	0.04	..	..	..
Electricity	0.33	3.06	9.97	12.08	..	..	..
Heat	–	–	2.47	2.12	..	..	..
Shares (%)							
Coal	*81.9*	*36.3*	*1.5*	*1.4*	..	..	..
Oil	*13.7*	*48.4*	*43.7*	*39.6*	..	..	..
Gas	–	*2.5*	*21.9*	*23.6*	..	..	..
Comb. Renewables & Wastes	–	–	*0.3*	*0.3*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	*0.1*	*0.1*	..	..	..
Electricity	*4.5*	*12.8*	*26.0*	*29.8*	..	..	..
Heat	–	–	*6.4*	*5.2*	..	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**3.30**	**26.60**	**71.28**	**75.97**	..	..	..
OUTPUT (Mtoe)	**1.27**	**9.06**	**24.20**	**28.11**	..	..	..
(TWh gross)	14.83	105.37	281.44	326.91	..	..	..
Output Shares (%)							
Coal	*9.0*	*16.8*	*39.2*	*39.9*	..	..	..
Oil	*82.3*	*17.9*	*8.5*	*9.6*	..	..	..
Gas	–	*9.1*	*10.8*	*12.8*	..	..	..
Comb. Renewables & Wastes	–	–	*0.1*	*0.2*	..	..	..
Nuclear	–	*50.2*	*39.8*	*36.4*	..	..	..
Hydro	*8.7*	*6.0*	*1.5*	*1.0*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	*0.0*	*0.0*	..	..	..
TOTAL LOSSES	**4.10**	**28.58**	**62.46**	**62.66**	..	..	..
of which:							
Electricity and Heat Generation[10]	2.03	17.53	41.58	42.61	..	..	..
Other Transformation	1.06	6.64	8.55	9.42	..	..	..
Own Use and Losses[11]	1.01	4.41	12.34	10.63	..	..	..
Statistical Differences	**0.14**	**0.09**	**1.49**	**2.87**	..	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	93.22	341.55	639.70	680.29	..	..	..
Population (millions)	34.10	42.87	47.34	47.64	..	..	..
TPES/GDP[12]	0.23	0.27	0.30	0.30	..	..	..
Energy Production/TPES	0.31	0.24	0.18	0.18	..	..	..
Per Capita TPES[13]	0.63	2.16	4.10	4.27	..	..	..
Oil Supply/GDP[12]	0.14	0.15	0.16	0.15	..	..	..
TFC/GDP[12]	0.19	0.19	0.20	0.20	..	..	..
Per Capita TFC[13]	0.51	1.49	2.75	2.90	..	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	65.8	226.2	441.7	451.6	..	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	2.1	5.9	20.9	20.8	..	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	10.8	7.9	6.9	4.9	..	..	..
Coal	6.9	7.0	4.8	7.1	..	..	..
Oil	12.3	5.8	6.5	1.8	..	..	..
Gas	–	–	19.2	13.2	..	..	..
Comb. Renewables & Wastes	–	–	–	23.3	..	..	..
Nuclear	–	29.2	7.1	6.2	..	..	..
Hydro	10.5	9.6	-3.8	-22.1	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	26.3	-5.1	..	..	..
TFC	9.8	7.0	6.7	6.2	..	..	..
Electricity Consumption	15.9	10.6	9.3	17.4	..	..	..
Energy Production	4.9	8.4	4.1	5.9	..	..	..
Net Oil Imports	13.3	5.8	6.5	0.3	..	..	..
GDP	8.5	7.6	5.9	6.3	..	..	..
Growth in the TPES/GDP Ratio	2.1	0.3	1.0	-1.3	..	..	..
Growth in the TFC/GDP Ratio	1.2	-0.6	0.7	-0.2	..	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**0.00**	**0.03**	**0.06**	**0.06**	**0.05**	**..**	**..**
Coal[1]		–	–	–	–	–	..	..
Oil		–	–	–	–	–	..	..
Gas		–	–	–	–	–	..	..
Comb. Renewables & Wastes[2]		–	0.03	0.05	0.04	0.04	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.00	0.01	0.01	0.01	0.01	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other[3]		–	–	0.00	0.00	0.00	..	..
TOTAL NET IMPORTS[4]		**4.51**	**3.55**	**3.75**	**4.00**	**3.67**	**..**	**..**
Coal[1]	Exports	–	–	–	–	–	..	..
	Imports	2.44	1.13	0.11	0.09	0.10	..	..
	Net Imports	2.44	1.13	0.11	0.09	0.10	..	..
Oil	Exports	0.01	0.01	0.03	0.02	–	..	..
	Imports	1.69	1.67	2.49	2.58	1.80	..	..
	Bunkers	–	–	–	–	–	..	..
	Net Imports	1.67	1.65	2.46	2.56	1.80	..	..
Gas	Exports	–	–	–	–	–	..	..
	Imports	0.22	0.43	0.69	1.05	1.47	..	..
	Net Imports	0.22	0.43	0.69	1.05	1.47	..	..
Electricity	Exports	0.07	0.06	0.06	0.25	0.18	..	..
	Imports	0.24	0.40	0.55	0.55	0.48	..	..
	Net Imports	0.18	0.34	0.49	0.30	0.30	..	..
TOTAL STOCK CHANGES		**-0.01**	**-0.01**	**0.03**	**-0.02**	**–**	**..**	**..**
TOTAL SUPPLY (TPES)		**4.51**	**3.57**	**3.83**	**4.04**	**3.72**	**..**	**..**
Coal[1]		2.44	1.13	0.11	0.09	0.10	..	..
Oil		1.67	1.64	2.48	2.54	1.80	..	..
Gas		0.22	0.43	0.69	1.05	1.47	..	..
Comb. Renewables & Wastes[2]		–	0.03	0.05	0.04	0.04	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.00	0.01	0.01	0.01	0.01	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other[3]		–	–	0.00	0.00	0.00	..	..
Electricity Trade[5]		0.18	0.34	0.49	0.30	0.30	..	..
Shares (%)								
Coal		*54.1*	*31.7*	*2.9*	*2.3*	*2.7*	..	..
Oil		*37.1*	*46.0*	*64.8*	*62.9*	*48.4*	..	..
Gas		*4.9*	*12.0*	*18.1*	*26.1*	*39.5*	..	..
Comb. Renewables & Wastes		–	*0.7*	*1.2*	*1.1*	*1.1*	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		*0.1*	*0.2*	*0.3*	*0.2*	*0.2*	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other		–	–	*0.1*	–	*0.1*	..	..
Electricity Trade		*3.9*	*9.5*	*12.7*	*7.3*	*8.0*	..	..

0 is negligible, – is nil, .. is not available.

Please note: All forecast data are based on the 1999 submission.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**2.94**	**2.96**	**3.76**	**3.81**	**3.24**	**..**	**..**
Blast Furnace Gas	0.74	0.20	–	–	–	..	..
Other Coal[1]	0.24	0.35	0.11	0.09	0.10	..	..
Oil	1.54	1.64	2.48	2.54	1.80	..	..
Gas	0.18	0.42	0.64	0.63	0.72	..	..
Comb. Renewables & Wastes[2]	–	–	0.02	0.02	0.01	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.26	0.36	0.48	0.49	0.55	..	..
Heat	–	–	0.03	0.04	0.06	..	..
Shares (%)							
Blast Furnace Gas	*25.1*	*6.8*	–	–	–	..	..
Other Coal	*8.1*	*11.7*	*2.9*	*2.4*	*3.1*	..	..
Oil	*52.1*	*55.3*	*65.9*	*66.8*	*55.6*	..	..
Gas	*6.0*	*14.2*	*16.9*	*16.6*	*22.2*	..	..
Comb. Renewables & Wastes	–	–	*0.4*	*0.4*	*0.4*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*8.7*	*12.0*	*12.9*	*12.8*	*16.9*	..	..
Heat	–	–	*0.9*	*0.9*	*1.8*	..	..
TOTAL INDUSTRY[6]	**2.09**	**1.34**	**0.94**	**0.90**	**1.04**	**..**	**..**
Blast Furnace Gas	0.74	0.20	–	–	–	..	..
Other Coal[1]	0.20	0.34	0.11	0.09	0.10	..	..
Oil	0.81	0.30	0.08	0.06	0.09	..	..
Gas	0.14	0.28	0.41	0.41	0.45	..	..
Comb. Renewables & Wastes[2]	–	–	–	–	–	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.20	0.23	0.32	0.32	0.37	..	..
Heat	–	–	0.02	0.02	0.04	..	..
Shares (%)							
Blast Furnace Gas	*35.4*	*15.1*	–	–	–	..	..
Other Coal	*9.7*	*25.3*	*11.7*	*10.3*	*9.2*	..	..
Oil	*38.6*	*22.0*	*8.7*	*6.8*	*8.7*	..	..
Gas	*6.6*	*20.8*	*43.4*	*45.2*	*42.8*	..	..
Comb. Renewables & Wastes	–	–	–	–	–	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*9.7*	*16.8*	*34.0*	*35.5*	*35.1*	..	..
Heat	–	–	*2.2*	*2.2*	*4.2*	..	..
TRANSPORT[7]	**0.29**	**1.03**	**2.03**	**2.18**	**1.41**	**..**	**..**
TOTAL OTHER SECTORS[8]	**0.56**	**0.59**	**0.80**	**0.73**	**0.79**	**..**	**..**
Coal[1]	0.03	0.01	0.00	0.00	0.00	..	..
Oil	0.44	0.31	0.38	0.31	0.31	..	..
Gas	0.04	0.14	0.23	0.23	0.27	..	..
Comb. Renewables & Wastes[2]	–	–	0.02	0.02	0.01	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.05	0.13	0.16	0.16	0.17	..	..
Heat	–	–	0.01	0.02	0.02	..	..
Shares (%)							
Coal	*6.1*	*1.0*	*0.1*	*0.1*	*0.5*	..	..
Oil	*78.4*	*53.6*	*47.3*	*42.3*	*39.3*	..	..
Gas	*6.8*	*24.1*	*29.1*	*31.1*	*34.6*	..	..
Comb. Renewables & Wastes	–	–	*2.0*	*2.0*	*1.8*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*8.8*	*21.3*	*19.9*	*22.0*	*21.9*	..	..
Heat	–	–	*1.6*	*2.2*	*1.9*	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**0.44**	**0.20**	**0.10**	**0.46**	**0.58**	**..**	**..**
OUTPUT (Mtoe)	**0.12**	**0.05**	**0.04**	**0.24**	**0.30**	**..**	**..**
(TWh gross)	1.39	0.62	0.50	2.79	3.48	..	..
Output Shares (%)							
Blast Furnace Gas	*58.8*	*76.4*	–	–	–	..	..
Other Coal	–	–	–	–	–	..	..
Oil	*27.6*	*1.4*	–	–	–	..	..
Gas	*10.2*	*5.4*	*56.0*	*92.8*	*94.8*	..	..
Comb. Renewables & Wastes	–	*5.4*	*11.8*	*2.2*	*1.4*	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	*3.4*	*11.2*	*26.7*	*4.0*	*2.6*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	*5.4*	*0.9*	*1.1*	..	..
TOTAL LOSSES	**1.54**	**0.61**	**0.07**	**0.23**	**0.48**	**..**	**..**
of which:							
Electricity and Heat Generation[10]	0.32	0.14	0.02	0.18	0.23	..	..
Other Transformation	1.08	0.41	–	–	–	..	..
Own Use and Losses[11]	0.14	0.06	0.04	0.05	0.25	..	..
Statistical Differences	**0.02**	**0.00**	**0.00**	**0.00**	**–**	**..**	**..**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1990 US$)	8.44	14.90	25.77	26.10	31.31	..	..
Population (millions)	0.35	0.38	0.44	0.45	0.49	..	..
TPES/GDP[12]	0.53	0.24	0.15	0.15	0.12	..	..
Energy Production/TPES	0.00	0.01	0.02	0.01	0.01	..	..
Per Capita TPES[13]	12.83	9.35	8.67	9.06	7.65	..	..
Oil Supply/GDP[12]	0.20	0.11	0.10	0.10	0.06	..	..
TFC/GDP[12]	0.35	0.20	0.15	0.15	0.10	..	..
Per Capita TFC[13]	8.39	7.74	8.52	8.53	6.66	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	16.5	10.5	8.4	9.3	8.1	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	0.2	0.4	1.1	1.2	1.2	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	-2.5	-0.8	0.6	5.4	-1.0	..	..
Coal	-4.6	-4.3	-19.1	-15.5	0.9	..	..
Oil	-4.0	2.1	3.8	2.4	-4.2	..	..
Gas	13.6	-0.8	4.5	51.7	4.2	..	..
Comb. Renewables & Wastes	–	3.0	5.7	-4.3	-0.6	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	12.2	-2.6	5.7	-9.1	-2.8	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	9.1	..	..
TFC	-0.1	0.1	2.2	1.1	-2.0	..	..
Electricity Consumption	2.7	1.6	2.9	0.8	1.4	..	..
Energy Production	36.6	1.6	6.2	-6.7	-0.5	..	..
Net Oil Imports	-3.5	1.8	3.7	4.3	-4.3	..	..
GDP	1.3	4.6	5.1	1.3	2.3	..	..
Growth in the TPES/GDP Ratio	-3.7	-5.1	-4.2	4.1	-3.3	..	..
Growth in the TFC/GDP Ratio	-1.3	-4.3	-2.8	-0.2	-4.2	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**56.8**	**60.3**	**60.4**	**59.9**	**59.2**	**64.8**	**..**
Coal[1]		1.1	–	–	–	–	–	..
Oil		1.6	4.1	2.3	3.2	0.8	0.8	..
Gas		53.7	54.6	55.7	54.3	54.6	60.9	..
Comb. Renewables & Wastes[2]		–	0.7	1.2	1.4	2.5	2.5	..
Nuclear		0.3	0.9	1.0	1.0	1.0	–	..
Hydro		–	0.0	0.0	0.0	0.0	0.0	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	0.3	0.6	..
TOTAL NET IMPORTS[4]		**6.0**	**6.4**	**16.9**	**17.1**	**21.9**	**24.6**	**..**
Coal[1]	Exports	1.4	2.2	10.6	5.7	7.4	7.4	..
	Imports	2.9	11.6	19.0	13.8	15.5	16.7	..
	Net Imports	1.5	9.4	8.4	8.1	8.1	9.3	..
Oil	Exports	42.4	60.2	68.3	68.5	43.9	43.9	..
	Imports	83.8	91.1	110.1	109.0	91.9	95.3	..
	Bunkers	11.6	10.9	14.6	14.5	17.9	20.2	..
	Net Imports	29.8	19.9	27.2	26.0	30.1	31.3	..
Gas	Exports	25.3	25.8	35.5	37.6	33.9	33.9	..
	Imports	–	2.0	15.3	19.2	16.0	16.1	..
	Net Imports	-25.3	-23.8	-20.2	-18.4	-17.9	-17.8	..
Electricity	Exports	0.1	0.0	0.4	0.4	–	–	..
	Imports	0.0	0.8	1.8	1.8	1.6	1.8	..
	Net Imports	-0.1	0.8	1.5	1.4	1.6	1.8	..
TOTAL STOCK CHANGES		**-0.3**	**-0.2**	**-0.1**	**0.9**	**–**	**–**	**..**
TOTAL SUPPLY (TPES)		**62.4**	**66.5**	**77.3**	**77.9**	**81.1**	**89.4**	**..**
Coal[1]		2.9	8.9	8.3	8.4	8.1	9.3	..
Oil		30.9	24.3	29.5	29.8	30.9	32.0	..
Gas		28.5	30.8	35.5	35.8	36.6	43.1	..
Comb. Renewables & Wastes[2]		–	0.7	1.2	1.4	2.5	2.5	..
Nuclear		0.3	0.9	1.0	1.0	1.0	–	..
Hydro		–	0.0	0.0	0.0	0.0	0.0	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	0.3	0.6	..
Electricity Trade[5]		-0.1	0.8	1.5	1.4	1.6	1.8	..
Shares (%)								
Coal		*4.6*	*13.4*	*10.8*	*10.8*	*10.0*	*10.4*	..
Oil		*49.5*	*36.6*	*38.2*	*38.2*	*38.1*	*35.8*	..
Gas		*45.6*	*46.3*	*46.0*	*46.0*	*45.1*	*48.2*	..
Comb. Renewables & Wastes		–	*1.1*	*1.6*	*1.7*	*3.1*	*2.8*	..
Nuclear		*0.5*	*1.4*	*1.3*	*1.3*	*1.3*	–	..
Hydro		–	–	–	–	–	–	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other		–	–	*0.1*	*0.1*	*0.4*	*0.7*	..
Electricity Trade		*-0.2*	*1.2*	*1.9*	*1.8*	*2.0*	*2.0*	..

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**48.8**	**51.2**	**60.3**	**60.0**	**66.0**	**70.6**	**..**
Coal[1]	1.1	1.2	0.7	0.7	0.9	1.0	..
Oil	24.7	19.9	25.0	25.2	26.4	27.4	..
Gas	19.3	23.0	23.3	22.8	27.3	28.6	..
Comb. Renewables & Wastes[2]	–	0.3	0.2	0.2	0.4	0.4	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.0	0.0	0.0	0.0	0.1	..
Electricity	3.8	6.3	8.6	8.6	10.0	12.1	..
Heat	–	0.4	2.5	2.5	1.0	1.1	..
Shares (%)							
Coal	*2.2*	*2.4*	*1.1*	*1.1*	*1.4*	*1.4*	..
Oil	*50.5*	*38.9*	*41.5*	*42.0*	*40.0*	*38.8*	..
Gas	*39.5*	*44.9*	*38.7*	*38.1*	*41.3*	*40.6*	..
Comb. Renewables & Wastes	–	*0.6*	*0.4*	*0.4*	*0.6*	*0.5*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	*0.1*	..
Electricity	*7.8*	*12.4*	*14.2*	*14.3*	*15.1*	*17.1*	..
Heat	–	*0.9*	*4.2*	*4.1*	*1.6*	*1.5*	..
TOTAL INDUSTRY[6]	**21.2**	**21.1**	**22.9**	**22.8**	**27.2**	**30.2**	**..**
Coal[1]	0.8	1.2	0.6	0.6	0.9	0.9	..
Oil	10.4	8.2	9.7	9.6	10.4	10.9	..
Gas	8.1	8.8	7.6	7.7	11.7	13.4	..
Comb. Renewables & Wastes[2]	–	0.1	0.1	0.1	0.0	0.0	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	0.0	0.0	..
Electricity	2.0	2.9	3.5	3.5	3.8	4.5	..
Heat	–	–	1.4	1.3	0.4	0.4	..
Shares (%)							
Coal	*3.6*	*5.6*	*2.7*	*2.8*	*3.2*	*3.1*	..
Oil	*48.8*	*39.0*	*42.3*	*42.0*	*38.3*	*36.2*	..
Gas	*38.4*	*41.6*	*33.1*	*33.6*	*43.0*	*44.3*	..
Comb. Renewables & Wastes	–	*0.2*	*0.3*	*0.3*	–	–	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*9.2*	*13.5*	*15.3*	*15.5*	*13.9*	*15.0*	..
Heat	–	–	*6.3*	*5.7*	*1.6*	*1.4*	..
TRANSPORT[7]	**7.5**	**10.6**	**14.6**	**14.9**	**14.9**	**15.5**	**..**
TOTAL OTHER SECTORS[8]	**20.2**	**19.5**	**22.9**	**22.3**	**23.9**	**24.9**	**..**
Coal[1]	0.3	0.1	0.0	0.0	0.0	0.0	..
Oil	6.9	1.2	0.9	0.8	1.2	1.2	..
Gas	11.1	14.2	15.8	15.2	15.6	15.3	..
Comb. Renewables & Wastes[2]	–	0.2	0.2	0.2	0.4	0.4	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	0.0	0.0	0.0	0.0	0.1	..
Electricity	1.8	3.4	4.9	4.9	6.0	7.4	..
Heat	–	0.4	1.1	1.2	0.6	0.6	..
Shares (%)							
Coal	*1.6*	*0.3*	*0.1*	*0.1*	*0.2*	*0.1*	..
Oil	*34.2*	*6.2*	*3.9*	*3.8*	*5.0*	*4.7*	..
Gas	*55.3*	*72.9*	*68.9*	*68.1*	*65.2*	*61.3*	..
Comb. Renewables & Wastes	–	*1.3*	*0.7*	*0.7*	*1.7*	*1.5*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	*0.1*	*0.1*	*0.2*	..
Electricity	*8.8*	*17.2*	*21.5*	*22.0*	*25.2*	*29.6*	..
Heat	–	*2.3*	*4.8*	*5.2*	*2.6*	*2.5*	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**12.0**	**15.3**	**20.1**	**20.4**	**17.6**	**22.5**	**..**
OUTPUT (Mtoe)	**4.5**	**6.2**	**8.1**	**8.3**	**9.0**	**11.1**	**..**
(TWh gross)	52.6	71.9	93.7	96.0	105.2	129.0	..
Output Shares (%)							
Coal	*6.0*	*38.3*	*28.5*	*28.0*	*24.4*	*24.5*	..
Oil	*12.3*	*4.3*	*3.3*	*2.9*	*4.2*	*3.8*	..
Gas	*79.5*	*50.9*	*58.9*	*59.4*	*57.4*	*60.5*	..
Comb. Renewables & Wastes	–	*1.4*	*3.7*	*4.3*	*6.7*	*5.9*	..
Nuclear	*2.1*	*4.9*	*4.2*	*4.1*	*3.8*	–	..
Hydro	–	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*0.1*	*1.2*	*1.2*	*3.4*	*5.1*	..
TOTAL LOSSES	**14.3**	**15.5**	**17.3**	**17.9**	**15.1**	**18.8**	**..**
of which:							
Electricity and Heat Generation[10]	7.5	8.6	9.1	9.3	6.8	9.6	..
Other Transformation	1.6	0.9	1.7	1.7	6.2	6.4	..
Own Use and Losses[11]	5.2	6.0	6.5	6.9	2.1	2.8	..
Statistical Differences	**-0.7**	**-0.2**	**-0.4**	**-0.0**	**–**	**–**	**..**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	252.99	374.14	504.37	505.60	616.02	788.56	..
Population (millions)	13.44	14.95	16.04	16.15	16.09	17.00	..
TPES/GDP[12]	0.25	0.18	0.15	0.15	0.13	0.11	..
Energy Production/TPES	0.91	0.91	0.78	0.77	0.73	0.72	..
Per Capita TPES[13]	4.65	4.45	4.82	4.83	5.04	5.26	..
Oil Supply/GDP[12]	0.12	0.07	0.06	0.06	0.05	0.04	..
TFC/GDP[12]	0.19	0.14	0.12	0.12	0.11	0.09	..
Per Capita TFC[13]	3.64	3.42	3.76	3.72	4.10	4.15	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	153.8	157.1	177.7	177.9	166.2	187.9	..
CO_2 Emissions from Bunkers (Mt CO_2)	39.3	39.0	56.1	56.3	67.2	74.4	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	1.7	-0.3	1.4	0.8	0.5	1.0	..
Coal	2.4	9.4	-0.6	0.6	-0.4	1.4	..
Oil	0.4	-2.4	1.8	0.9	0.5	0.4	..
Gas	2.4	-0.6	1.3	0.8	0.3	1.6	..
Comb. Renewables & Wastes	–	10.3	5.1	9.4	7.8	0.2	..
Nuclear	21.0	0.0	1.2	-1.5	0.2	–	..
Hydro	–	–	2.0	10.0	7.8	0.5	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	29.4	8.8	14.9	6.1	..
TFC	2.0	-0.7	1.5	-0.6	1.2	0.7	..
Electricity Consumption	4.4	2.3	2.8	0.3	1.9	1.9	..
Energy Production	4.4	-1.8	0.0	-0.8	-0.2	0.9	..
Net Oil Imports	1.0	-4.1	2.9	-4.5	1.9	0.4	..
GDP	2.6	2.2	2.8	0.2	2.5	2.5	..
Growth in the TPES/GDP Ratio	-0.9	-2.5	-1.3	0.6	-1.9	-1.5	..
Growth in the TFC/GDP Ratio	-0.6	-2.8	-1.2	-0.8	-1.3	-1.8	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**4.05**	**12.15**	**14.61**	**14.88**	**15.18**	**17.61**	**20.80**
Coal[1]		1.29	1.39	2.37	2.72	3.06	3.26	4.57
Oil		0.18	1.96	1.82	1.67	1.16	1.35	1.10
Gas		0.28	3.90	5.32	5.06	3.28	3.81	3.10
Comb. Renewables & Wastes[2]		–	0.68	1.19	1.24	1.15	1.31	1.41
Nuclear		–	–	–	–	–	–	–
Hydro		1.23	2.01	1.85	2.10	2.21	2.32	2.39
Geothermal		1.07	2.21	1.99	2.02	4.18	5.37	7.98
Solar/Wind/Other[3]		–	0.01	0.07	0.07	0.14	0.19	0.24
TOTAL NET IMPORTS[4]		**4.27**	**1.79**	**3.06**	**3.39**	**4.61**	**5.01**	**6.34**
Coal[1]	Exports	0.02	0.23	1.31	1.41	1.80	2.00	2.00
	Imports	–	0.01	–	0.06	–	–	–
	Net Imports	-0.02	-0.22	-1.31	-1.35	-1.80	-2.00	-2.00
Oil	Exports	–	1.47	1.40	1.34	0.92	1.06	0.87
	Imports	4.60	3.80	6.01	6.40	7.71	8.51	9.76
	Bunkers	0.31	0.32	0.24	0.33	0.39	0.43	0.56
	Net Imports	4.29	2.01	4.36	4.74	6.41	7.01	8.34
Gas	Exports	–	–	–	–	–	–	–
	Imports	–	–	–	–	–	–	–
	Net Imports	–	–	–	–	–	–	–
Electricity	Exports	–	–	–	–	–	–	–
	Imports	–	–	–	–	–	–	–
	Net Imports	–	–	–	–	–	–	–
TOTAL STOCK CHANGES		**-0.05**	**-0.03**	**0.43**	**-0.25**	**–**	**–**	**–**
TOTAL SUPPLY (TPES)		**8.27**	**13.91**	**18.09**	**18.01**	**19.79**	**22.62**	**27.14**
Coal[1]		1.26	1.13	1.28	1.24	1.26	1.26	2.57
Oil		4.42	3.98	6.40	6.29	7.57	8.36	9.44
Gas		0.28	3.90	5.32	5.06	3.28	3.81	3.10
Comb. Renewables & Wastes[2]		–	0.68	1.19	1.24	1.15	1.31	1.41
Nuclear		–	–	–	–	–	–	–
Hydro		1.23	2.01	1.85	2.10	2.21	2.32	2.39
Geothermal		1.07	2.21	1.99	2.02	4.18	5.37	7.98
Solar/Wind/Other[3]		–	0.01	0.07	0.07	0.14	0.19	0.24
Electricity Trade[5]		–	–	–	–	–	–	–
Shares (%)								
Coal		*15.3*	*8.1*	*7.1*	*6.9*	*6.4*	*5.6*	*9.5*
Oil		*53.5*	*28.6*	*35.4*	*34.9*	*38.3*	*37.0*	*34.8*
Gas		*3.4*	*28.0*	*29.4*	*28.1*	*16.6*	*16.8*	*11.4*
Comb. Renewables & Wastes		–	*4.9*	*6.6*	*6.9*	*5.8*	*5.8*	*5.2*
Nuclear		–	–	–	–	–	–	–
Hydro		*14.9*	*14.4*	*10.2*	*11.7*	*11.2*	*10.3*	*8.8*
Geothermal		*12.9*	*15.9*	*11.0*	*11.2*	*21.1*	*23.8*	*29.4*
Solar/Wind/Other		–	*0.1*	*0.4*	*0.4*	*0.7*	*0.8*	*0.9*
Electricity Trade		–	–	–	–	–	–	–

0 is negligible, – is nil, .. is not available.

Please note: Forecast data, except GDP and population, refer to the fiscal year.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**6.05**	**9.98**	**13.79**	**14.66**	**14.27**	**15.99**	**17.83**
Coal[1]	0.87	1.01	0.93	0.90	0.90	0.96	1.07
Oil	3.67	4.43	5.82	6.36	7.01	7.80	8.87
Gas	0.14	1.30	2.81	3.00	1.80	2.06	2.32
Comb. Renewables & Wastes[2]	–	0.58	1.08	1.10	0.95	1.09	1.17
Geothermal	–	0.27	0.31	0.32	0.31	0.31	0.31
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	1.37	2.39	2.84	2.99	3.31	3.76	4.08
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*14.4*	*10.1*	*6.7*	*6.1*	*6.3*	*6.0*	*6.0*
Oil	*60.6*	*44.4*	*42.2*	*43.4*	*49.1*	*48.8*	*49.8*
Gas	*2.4*	*13.0*	*20.4*	*20.4*	*12.6*	*12.9*	*13.0*
Comb. Renewables & Wastes	–	*5.8*	*7.8*	*7.5*	*6.7*	*6.8*	*6.6*
Geothermal	–	*2.7*	*2.3*	*2.2*	*2.2*	*1.9*	*1.7*
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*22.6*	*23.9*	*20.6*	*20.4*	*23.2*	*23.5*	*22.9*
Heat	–	–	–	–	–	–	–
TOTAL INDUSTRY[6]	**2.18**	**4.15**	**5.97**	**6.25**	**5.31**	**5.93**	**6.49**
Coal[1]	0.69	0.86	0.78	0.76	0.90	0.96	1.07
Oil	0.96	0.59	0.52	0.55	0.44	0.45	0.49
Gas	0.05	1.06	2.37	2.54	1.52	1.75	1.97
Comb. Renewables & Wastes[2]	–	0.46	0.92	0.94	0.75	0.85	0.92
Geothermal	–	0.22	0.25	0.26	0.25	0.25	0.25
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	0.48	0.96	1.13	1.20	1.46	1.66	1.80
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*31.5*	*20.7*	*13.1*	*12.1*	*16.9*	*16.3*	*16.5*
Oil	*43.9*	*14.1*	*8.6*	*8.9*	*8.3*	*7.6*	*7.5*
Gas	*2.4*	*25.5*	*39.7*	*40.7*	*28.6*	*29.5*	*30.3*
Comb. Renewables & Wastes	–	*11.2*	*15.4*	*15.1*	*14.0*	*14.4*	*14.1*
Geothermal	–	*5.3*	*4.2*	*4.1*	*4.7*	*4.2*	*3.9*
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*22.2*	*23.2*	*19.0*	*19.2*	*27.5*	*28.0*	*27.7*
Heat	–	–	–	–	–	–	–
TRANSPORT[7]	**2.15**	**3.54**	**5.02**	**5.49**	**6.27**	**7.06**	**8.10**
TOTAL OTHER SECTORS[8]	**1.72**	**2.30**	**2.80**	**2.92**	**2.69**	**3.00**	**3.24**
Coal[1]	0.19	0.15	0.14	0.14	0.00	–	–
Oil	0.57	0.37	0.32	0.35	0.35	0.35	0.35
Gas	0.09	0.18	0.44	0.45	0.27	0.31	0.35
Comb. Renewables & Wastes[2]	–	0.12	0.16	0.16	0.21	0.24	0.26
Geothermal	–	0.05	0.06	0.06	0.06	0.06	0.06
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	0.88	1.42	1.67	1.76	1.80	2.04	2.22
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*10.7*	*6.6*	*5.1*	*4.8*	*0.1*	–	–
Oil	*32.8*	*16.0*	*11.3*	*12.1*	*13.0*	*11.7*	*10.8*
Gas	*5.3*	*7.8*	*15.8*	*15.4*	*10.1*	*10.4*	*10.8*
Comb. Renewables & Wastes	–	*5.2*	*5.7*	*5.5*	*7.7*	*8.0*	*7.9*
Geothermal	–	*2.3*	*2.2*	*2.1*	*2.2*	*2.0*	*1.9*
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*51.2*	*62.0*	*59.8*	*60.1*	*66.9*	*68.0*	*68.5*
Heat	–	–	–	–	–	–	–

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**3.16**	**5.27**	**6.31**	**6.11**	**7.81**	**9.28**	**11.97**
OUTPUT (Mtoe)	**1.59**	**2.78**	**3.39**	**3.47**	**3.52**	**4.00**	**4.34**
(TWh gross)	18.53	32.27	39.43	40.30	40.93	46.47	50.41
Output Shares (%)							
Coal	*8.5*	*1.5*	*3.8*	*4.0*	*3.7*	*2.6*	*11.9*
Oil	*6.1*	*0.0*	–	–	*0.0*	*0.0*	*0.0*
Gas	*1.4*	*17.6*	*31.6*	*25.1*	*18.1*	*21.5*	*9.7*
Comb. Renewables & Wastes	–	*1.3*	*1.0*	*1.1*	*1.4*	*1.4*	*1.4*
Nuclear	–	–	–	–	–	–	–
Hydro	*77.3*	*72.3*	*54.4*	*60.7*	*62.8*	*58.1*	*55.1*
Geothermal	*6.7*	*6.9*	*7.2*	*7.1*	*10.1*	*11.6*	*16.2*
Solar/Wind/Other	–	*0.4*	*2.1*	*1.9*	*3.9*	*4.7*	*5.6*
TOTAL LOSSES	**2.35**	**3.99**	**4.02**	**3.57**	**5.51**	**6.64**	**9.31**
of which:							
Electricity and Heat Generation[10]	1.57	2.49	2.92	2.64	4.30	5.28	7.63
Other Transformation	0.36	0.60	-0.05	-0.16	0.36	0.36	0.36
Own Use and Losses[11]	0.43	0.90	1.15	1.09	0.86	1.00	1.32
Statistical Differences	**-0.13**	**-0.06**	**0.28**	**-0.22**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	42.85	52.23	71.52	74.63	92.87	118.88	152.17
Population (millions)	2.97	3.41	3.91	3.98	4.50	5.00	5.50
TPES/GDP[12]	0.19	0.27	0.25	0.24	0.21	0.19	0.18
Energy Production/TPES	0.49	0.87	0.81	0.83	0.77	0.78	0.77
Per Capita TPES[13]	2.78	4.08	4.63	4.53	4.40	4.52	4.93
Oil Supply/GDP[12]	0.10	0.08	0.09	0.08	0.08	0.07	0.06
TFC/GDP[12]	0.14	0.19	0.19	0.20	0.15	0.13	0.12
Per Capita TFC[13]	2.04	2.93	3.52	3.69	3.17	3.20	3.24
Energy-related CO_2 Emissions (Mt CO_2)[14]	17.0	22.3	33.3	34.0	33.2	36.7	43.4
CO_2 Emissions from Bunkers (Mt CO_2)	1.6	2.4	2.7	2.9	3.1	3.2	3.7

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	1.5	4.0	2.4	-0.4	1.2	1.3	1.8
Coal	-4.5	1.5	1.1	-2.6	0.2	-0.1	7.4
Oil	-0.9	-0.5	4.4	-1.7	2.3	1.0	1.2
Gas	20.3	14.7	2.9	-4.9	-5.3	1.5	-2.0
Comb. Renewables & Wastes	–	3.1	5.3	3.4	-0.9	1.4	0.7
Nuclear	–	–	–	–	–	–	–
Hydro	4.6	2.0	-0.8	14.0	0.6	0.5	0.3
Geothermal	-2.2	8.1	-1.0	1.3	9.5	2.5	4.0
Solar/Wind/Other	–	12.5	18.5	-5.6	9.5	3.2	2.5
TFC	2.1	3.5	3.0	6.3	-0.3	1.1	1.1
Electricity Consumption	3.0	3.5	1.6	5.4	1.3	1.3	0.8
Energy Production	4.6	7.8	1.7	1.8	0.3	1.5	1.7
Net Oil Imports	-2.5	-5.4	7.3	8.6	3.8	0.9	1.7
GDP	0.0	1.8	2.9	4.3	2.8	2.5	2.5
Growth in the TPES/GDP Ratio	1.5	2.2	-0.5	-4.6	-1.5	-1.1	-0.6
Growth in the TFC/GDP Ratio	2.0	1.7	0.1	1.9	-3.0	-1.3	-1.4

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**8.08**	**120.30**	**226.43**	**232.22**	**..**	**..**	**..**
Coal[1]		0.29	0.20	1.20	1.43	..	..	..
Oil		1.52	84.51	164.66	159.08	..	..	..
Gas		–	24.14	48.88	59.15	..	..	..
Comb. Renewables & Wastes[2]		–	1.03	1.51	1.44	..	..	..
Nuclear		–	–	–	–	..	..	..
Hydro		6.27	10.42	10.17	11.12	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other[3]		–	0.00	0.01	0.01	..	..	..
TOTAL NET IMPORTS[4]		**6.15**	**-96.94**	**-202.06**	**-205.74**	**..**	**..**	**..**
Coal[1]	Exports	0.09	0.17	1.01	1.38	..	..	..
	Imports	0.67	0.84	0.88	0.69	..	..	..
	Net Imports	0.58	0.67	-0.13	-0.69	..	..	..
Oil	Exports	3.58	78.10	162.45	155.05	..	..	..
	Imports	10.23	4.47	4.47	4.49	..	..	..
	Bunkers	0.64	0.45	0.81	0.67	..	..	..
	Net Imports	6.01	-74.08	-158.80	-151.23	..	..	..
Gas	Exports	–	22.17	43.45	53.01	..	..	..
	Imports	–	–	–	–	..	..	..
	Net Imports	–	-22.17	-43.45	-53.01	..	..	..
Electricity	Exports	0.45	1.40	0.62	1.29	..	..	..
	Imports	0.01	0.03	0.92	0.46	..	..	..
	Net Imports	-0.45	-1.37	0.31	-0.84	..	..	..
TOTAL STOCK CHANGES		**0.41**	**-1.87**	**2.08**	**0.04**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**14.63**	**21.49**	**26.45**	**26.52**	**..**	**..**	**..**
Coal[1]		0.91	0.86	0.94	0.81	..	..	..
Oil		7.90	8.57	8.07	7.82	..	..	..
Gas		–	1.98	5.42	6.14	..	..	..
Comb. Renewables & Wastes[2]		–	1.03	1.52	1.46	..	..	..
Nuclear		–	–	–	–	..	..	..
Hydro		6.27	10.42	10.17	11.12	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other[3]		–	0.00	0.01	0.01	..	..	..
Electricity Trade[5]		-0.45	-1.37	0.31	-0.84	..	..	..
Shares (%)								
Coal		*6.2*	*4.0*	*3.6*	*3.1*	..	..	..
Oil		*54.0*	*39.9*	*30.5*	*29.5*	..	..	..
Gas		–	*9.2*	*20.5*	*23.2*	..	..	..
Comb. Renewables & Wastes		–	*4.8*	*5.8*	*5.5*	..	..	..
Nuclear		–	–	–	–	..	..	..
Hydro		*42.8*	*48.5*	*38.5*	*41.9*	..	..	..
Geothermal		–	–	–	–	..	..	..
Solar/Wind/Other		–	–	–	–	..	..	..
Electricity Trade		*-3.1*	*-6.4*	*1.2*	*-3.1*	..	..	..

0 is negligible, – is nil, .. is not available.
Please note: Forecasts are not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**13.73**	**18.04**	**21.18**	**20.61**	..	..	..
Coal[1]	0.81	0.79	0.87	0.73	..	..	..
Oil	7.68	7.96	8.51	8.64	..	..	..
Gas	0.01	–	0.67	0.51	..	..	..
Comb. Renewables & Wastes[2]	–	0.90	1.33	1.25	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	5.23	8.33	9.65	9.31	..	..	..
Heat	–	0.07	0.16	0.17	..	..	..
Shares (%)							
Coal	*5.9*	*4.4*	*4.1*	*3.6*	..	..	..
Oil	*55.9*	*44.1*	*40.2*	*41.9*	..	..	..
Gas	*0.1*	–	*3.1*	*2.4*	..	..	..
Comb. Renewables & Wastes	–	*5.0*	*6.3*	*6.1*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*38.1*	*46.1*	*45.6*	*45.2*	..	..	..
Heat	–	*0.4*	*0.8*	*0.8*	..	..	..
TOTAL INDUSTRY[6]	**6.96**	**7.91**	**9.26**	**8.64**	..	..	..
Coal[1]	0.76	0.78	0.87	0.73	..	..	..
Oil	3.01	2.79	2.77	2.73	..	..	..
Gas	0.00	–	0.66	0.50	..	..	..
Comb. Renewables & Wastes[2]	–	0.38	0.71	0.63	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	3.20	3.94	4.24	4.03	..	..	..
Heat	–	0.02	0.02	0.02	..	..	..
Shares (%)							
Coal	*10.9*	*9.9*	*9.4*	*8.5*	..	..	..
Oil	*43.2*	*35.3*	*29.9*	*31.6*	..	..	..
Gas	–	–	*7.1*	*5.7*	..	..	..
Comb. Renewables & Wastes	–	*4.8*	*7.6*	*7.3*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*45.9*	*49.8*	*45.8*	*46.6*	..	..	..
Heat	–	*0.2*	*0.2*	*0.3*	..	..	..
TRANSPORT[7]	**2.62**	**4.22**	**4.69**	**4.71**	..	..	..
TOTAL OTHER SECTORS[8]	**4.15**	**5.92**	**7.23**	**7.26**	..	..	..
Coal[1]	0.06	0.01	0.00	0.00	..	..	..
Oil	2.10	1.02	1.22	1.36	..	..	..
Gas	0.01	–	0.01	0.01	..	..	..
Comb. Renewables & Wastes[2]	–	0.52	0.62	0.62	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	1.98	4.31	5.24	5.13	..	..	..
Heat	–	0.06	0.14	0.15	..	..	..
Shares (%)							
Coal	*1.3*	*0.2*	–	–	..	..	..
Oil	*50.6*	*17.2*	*16.9*	*18.7*	..	..	..
Gas	*0.2*	–	*0.1*	*0.1*	..	..	..
Comb. Renewables & Wastes	–	*8.7*	*8.5*	*8.6*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	..	..	..
Electricity	*47.8*	*72.9*	*72.5*	*70.6*	..	..	..
Heat	–	*1.0*	*2.0*	*2.1*	..	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**6.31**	**10.59**	**10.48**	**11.43**	..	..	..
OUTPUT (Mtoe)	**6.28**	**10.46**	**10.25**	**11.19**	..	..	..
(TWh gross)	73.03	121.61	119.16	130.13	..	..	..
Output Shares (%)							
Coal	*0.0*	*0.2*	*0.2*	*0.2*	..	..	..
Oil	*0.2*	*0.0*	*0.0*	*0.0*	..	..	..
Gas	–	–	*0.2*	*0.2*	..	..	..
Comb. Renewables & Wastes	–	*0.2*	*0.3*	*0.3*	..	..	..
Nuclear	–	–	–	–	..	..	..
Hydro	*99.8*	*99.6*	*99.3*	*99.3*	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	*0.0*	*0.0*	..	..	..
TOTAL LOSSES	**0.86**	**3.65**	**4.53**	**4.28**	..	..	..
of which:							
Electricity and Heat Generation[10]	0.03	0.04	0.08	0.06	..	..	..
Other Transformation	0.09	-0.05	-0.14	-0.48	..	..	..
Own Use and Losses[11]	0.73	3.66	4.59	4.69	..	..	..
Statistical Differences	**0.05**	**-0.20**	**0.75**	**1.63**	..	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	67.45	122.52	180.00	181.71	..	..	..
Population (millions)	3.96	4.24	4.51	4.54	..	..	..
TPES/GDP[12]	0.22	0.18	0.15	0.15	..	..	..
Energy Production/TPES	0.55	5.60	8.56	8.76	..	..	..
Per Capita TPES[13]	3.70	5.07	5.86	5.84	..	..	..
Oil Supply/GDP[12]	0.12	0.07	0.04	0.04	..	..	..
TFC/GDP[12]	0.20	0.15	0.12	0.11	..	..	..
Per Capita TFC[13]	3.47	4.25	4.69	4.54	..	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	24.2	28.7	33.7	33.1	..	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	2.8	2.7	3.7	3.3	..	..	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	4.0	1.4	1.9	0.3	..	..	..
Coal	1.4	-1.3	0.8	-13.8	..	..	..
Oil	2.2	-0.4	-0.5	-3.1	..	..	..
Gas	–	9.8	9.6	13.2	..	..	..
Comb. Renewables & Wastes	–	5.6	3.6	-4.5	..	..	..
Nuclear	–	–	–	–	..	..	..
Hydro	3.3	2.9	-0.2	9.2	..	..	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	50.0	..	..	..
TFC	3.5	0.6	1.5	-2.7	..	..	..
Electricity Consumption	3.6	2.3	1.3	-3.5	..	..	..
Energy Production	33.7	9.1	5.9	2.6	..	..	..
Net Oil Imports	–	20.4	7.2	-4.8	..	..	..
GDP	4.9	2.8	3.6	1.0	..	..	..
Growth in the TPES/GDP Ratio	-0.9	-1.4	-1.6	-0.7	..	..	..
Growth in the TFC/GDP Ratio	-1.4	-2.2	-2.0	-3.6	..	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**1.40**	**3.39**	**4.10**	**3.64**	**5.64**	..	..
Coal[1]		0.13	0.12	–	–	–	..	..
Oil		–	–	–	–	–	..	..
Gas		–	–	–	–	–	..	..
Comb. Renewables & Wastes[2]		0.64	2.48	2.76	2.84	3.79	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.63	0.79	1.21	0.67	1.11	..	..
Geothermal		–	0.00	0.09	0.08	0.07	..	..
Solar/Wind/Other[3]		–	0.01	0.04	0.05	0.67	..	..
TOTAL NET IMPORTS[4]		**5.69**	**14.82**	**21.56**	**22.17**	**24.34**	..	..
Coal[1]	Exports	0.01	0.01	–	–	–	..	..
	Imports	0.28	3.00	2.97	3.47	3.07	..	..
	Net Imports	0.27	2.99	2.97	3.47	3.07	..	..
Oil	Exports	0.23	2.50	1.40	1.40	..	..	..
	Imports	6.44	14.93	18.19	17.69	17.51	..	..
	Bunkers	0.80	0.61	0.48	0.48	1.36	..	..
	Net Imports	5.42	11.82	16.32	15.81	16.15	..	..
Gas	Exports	–	–	–	–	–	..	..
	Imports	–	–	2.25	2.73	5.12	..	..
	Net Imports	–	–	2.25	2.73	5.12	..	..
Electricity	Exports	0.01	0.15	0.30	0.30	–	..	..
	Imports	0.01	0.15	0.32	0.46	–	..	..
	Net Imports	-0.00	0.00	0.02	0.16	–	..	..
TOTAL STOCK CHANGES		**0.14**	**-0.47**	**-0.22**	**0.58**	–	..	..
TOTAL SUPPLY (TPES)		**7.23**	**17.75**	**25.43**	**26.39**	**29.98**	..	..
Coal[1]		0.51	2.76	3.19	3.48	3.07	..	..
Oil		5.45	11.71	15.87	16.38	16.15	..	..
Gas		–	–	2.25	2.73	5.12	..	..
Comb. Renewables & Wastes[2]		0.64	2.48	2.76	2.84	3.79	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		0.63	0.79	1.21	0.67	1.11	..	..
Geothermal		–	0.00	0.09	0.08	0.07	..	..
Solar/Wind/Other[3]		–	0.01	0.04	0.05	0.67	..	..
Electricity Trade[5]		-0.00	0.00	0.02	0.16	–	..	..
Shares (%)								
Coal		*7.0*	*15.5*	*12.6*	*13.2*	*10.2*	..	..
Oil		*75.4*	*66.0*	*62.4*	*62.1*	*53.9*	..	..
Gas		–	–	*8.9*	*10.3*	*17.1*	..	..
Comb. Renewables & Wastes		*8.8*	*14.0*	*10.8*	*10.7*	*12.6*	..	..
Nuclear		–	–	–	–	–	..	..
Hydro		*8.7*	*4.4*	*4.7*	*2.5*	*3.7*	..	..
Geothermal		–	–	*0.4*	*0.3*	*0.2*	..	..
Solar/Wind/Other		–	*0.1*	*0.2*	*0.2*	*2.2*	..	..
Electricity Trade		–	–	*0.1*	*0.6*	–	..	..

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**6.11**	**14.00**	**20.34**	**20.78**	**23.81**	**..**	**..**
Coal[1]	0.19	0.59	0.19	0.18	0.17	..	..
Oil	4.59	8.97	13.08	13.17	14.33	..	..
Gas	0.05	0.05	1.04	1.18	1.72	..	..
Comb. Renewables & Wastes[2]	0.58	2.33	2.41	2.46	2.55	..	..
Geothermal	–	–	0.00	0.00	–	..	..
Solar/Wind/Other	–	0.01	0.02	0.02	0.06	..	..
Electricity	0.70	2.03	3.44	3.57	4.54	..	..
Heat	–	0.03	0.16	0.20	0.44	..	..
Shares (%)							
Coal	*3.1*	*4.2*	*0.9*	*0.9*	*0.7*	..	..
Oil	*75.1*	*64.0*	*64.3*	*63.4*	*60.2*	..	..
Gas	*0.8*	*0.4*	*5.1*	*5.7*	*7.2*	..	..
Comb. Renewables & Wastes	*9.5*	*16.6*	*11.8*	*11.9*	*10.7*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	*0.1*	*0.1*	*0.1*	*0.3*	..	..
Electricity	*11.5*	*14.5*	*16.9*	*17.2*	*19.1*	..	..
Heat	–	*0.2*	*0.8*	*1.0*	*1.9*	..	..
TOTAL INDUSTRY[6]	**2.71**	**6.81**	**8.37**	**8.46**	**9.39**	**..**	**..**
Coal[1]	0.14	0.59	0.19	0.18	0.17	..	..
Oil	1.81	3.96	4.56	4.45	4.26	..	..
Gas	0.00	–	0.83	0.92	1.20	..	..
Comb. Renewables & Wastes[2]	0.32	1.18	1.26	1.31	1.40	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	0.44	1.05	1.39	1.42	1.93	..	..
Heat	–	0.03	0.15	0.19	0.42	..	..
Shares (%)							
Coal	*5.1*	*8.7*	*2.3*	*2.1*	*1.8*	..	..
Oil	*66.9*	*58.2*	*54.4*	*52.6*	*45.4*	..	..
Gas	*0.1*	–	*9.9*	*10.8*	*12.8*	..	..
Comb. Renewables & Wastes	*11.8*	*17.3*	*15.0*	*15.5*	*14.9*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*16.2*	*15.4*	*16.6*	*16.7*	*20.6*	..	..
Heat	–	*0.4*	*1.8*	*2.2*	*4.5*	..	..
TRANSPORT[7]	**1.95**	**3.82**	**6.70**	**6.90**	**8.27**	**..**	**..**
TOTAL OTHER SECTORS[8]	**1.46**	**3.37**	**5.26**	**5.42**	**6.16**	**..**	**..**
Coal[1]	0.04	0.00	–	–	–	..	..
Oil	0.87	1.21	1.86	1.86	1.85	..	..
Gas	0.05	0.05	0.21	0.26	0.52	..	..
Comb. Renewables & Wastes[2]	0.26	1.15	1.15	1.15	1.15	..	..
Geothermal	–	–	0.00	0.00	–	..	..
Solar/Wind/Other	–	0.01	0.02	0.02	0.06	..	..
Electricity	0.25	0.95	2.01	2.12	2.56	..	..
Heat	–	–	0.01	0.01	0.02	..	..
Shares (%)							
Coal	*2.4*	–	–	–	–	..	..
Oil	*59.7*	*35.9*	*35.3*	*34.4*	*30.1*	..	..
Gas	*3.2*	*1.5*	*4.0*	*4.8*	*8.4*	..	..
Comb. Renewables & Wastes	*17.9*	*34.1*	*21.9*	*21.2*	*18.7*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	*0.3*	*0.4*	*0.4*	*1.0*	..	..
Electricity	*16.8*	*28.1*	*38.3*	*39.0*	*41.6*	..	..
Heat	–	–	*0.2*	*0.2*	*0.3*	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**1.33**	**5.10**	**7.87**	**8.42**	**10.49**	..	..
OUTPUT (Mtoe)	**0.84**	**2.44**	**3.97**	**3.93**	**5.18**	..	..
(TWh gross)	9.79	28.36	46.17	45.65	60.20	..	..
Output Shares (%)							
Coal	*3.9*	*32.1*	*29.5*	*33.3*	*21.8*	..	..
Oil	*19.2*	*33.1*	*20.2*	*25.0*	*7.9*	..	..
Gas	–	–	*15.6*	*19.8*	*33.8*	..	..
Comb. Renewables & Wastes	*2.0*	*2.4*	*3.5*	*3.8*	*3.0*	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	*74.8*	*32.3*	*30.4*	*17.1*	*21.5*	..	..
Geothermal	–	*0.0*	*0.2*	*0.2*	*0.1*	..	..
Solar/Wind/Other	–	*0.0*	*0.6*	*0.8*	*11.8*	..	..
TOTAL LOSSES	**1.23**	**3.21**	**5.05**	**5.48**	**6.17**	..	..
of which:							
Electricity and Heat Generation[10]	0.49	2.63	3.74	4.29	4.69	..	..
Other Transformation	0.23	-0.38	-0.02	-0.08	–	..	..
Own Use and Losses[11]	0.51	0.96	1.34	1.26	1.48	..	..
Statistical Differences	**-0.11**	**0.53**	**0.04**	**0.14**	**–**	..	...

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	57.68	98.55	132.07	132.64	169.34	..	..
Population (millions)	8.64	9.90	10.30	10.37	10.50	..	..
TPES/GDP[10]	0.13	0.18	0.19	0.20	0.18	..	..
Energy Production/TPES	0.19	0.19	0.16	0.14	0.19	..	..
Per Capita TPES[13]	0.84	1.79	2.47	2.54	2.85	..	..
Oil Supply/GDP[12]	0.09	0.12	0.12	0.12	0.10	..	..
TFC/GDP[12]	0.11	0.14	0.15	0.16	0.14	..	..
Per Capita TFC[13]	0.71	1.41	1.97	2.00	2.27	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	16.4	39.6	59.1	63.0	66.5	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	3.5	3.5	3.3	3.4	6.1	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	5.5	5.4	3.3	3.8	1.6	..	..
Coal	-2.4	18.2	1.3	8.9	-1.5	..	..
Oil	6.1	3.8	2.8	3.2	-0.2	..	..
Gas	–	–	–	21.1	8.2	..	..
Comb. Renewables & Wastes	3.2	11.2	1.0	2.9	3.7	..	..
Nuclear	–	–	–	–	–	..	..
Hydro	7.3	-1.8	4.0	-44.4	6.5	..	..
Geothermal	–	–	36.4	-7.7	-2.4	..	..
Solar/Wind/Other	–	–	12.7	24.4	38.0	..	..
TFC	4.7	5.2	3.4	2.2	1.7	..	..
Electricity Consumption	8.5	5.3	4.9	3.8	3.1	..	..
Energy Production	4.4	5.9	1.7	-11.1	5.6	..	..
Net Oil Imports	8.1	2.9	3.0	-3.1	0.3	..	..
GDP	2.9	3.4	2.7	0.4	3.1	..	..
Growth in the TPES/GDP Ratio	2.5	2.0	0.6	3.3	-1.4	..	..
Growth in the TFC/GDP Ratio	1.8	1.7	0.7	1.7	-1.3	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**11.3**	**34.7**	**33.5**	**31.7**	**..**	**..**	**..**
Coal[1]		6.5	11.9	7.8	7.5	..	..	..
Oil		0.7	1.2	0.3	0.3	..	..	..
Gas		0.0	1.3	0.5	0.5	..	..	..
Comb. Renewables & Wastes[2]		0.0	4.1	4.1	4.3	..	..	..
Nuclear		1.7	14.1	16.6	16.4	..	..	..
Hydro		2.5	2.2	3.5	2.0	..	..	..
Geothermal		–	–	0.0	0.0	..	..	..
Solar/Wind/Other[3]		–	0.0	0.6	0.8	..	..	..
TOTAL NET IMPORTS[4]		**42.5**	**56.6**	**93.9**	**101.9**	**..**	**..**	**..**
Coal[1]	Exports	0.0	0.0	0.4	0.5	..	..	..
	Imports	2.2	7.1	11.6	14.8	..	..	..
	Net Imports	2.2	7.1	11.2	14.4	..	..	..
Oil	Exports	4.3	12.3	6.4	6.2	..	..	..
	Imports	45.3	61.8	79.7	81.2	..	..	..
	Bunkers	1.4	3.7	6.7	6.8	..	..	..
	Net Imports	39.6	45.9	66.6	68.1	..	..	..
Gas	Exports	–	–	–	–	..	..	..
	Imports	0.9	3.7	15.8	18.9	..	..	..
	Net Imports	0.9	3.7	15.8	18.9	..	..	..
Electricity	Exports	0.2	0.3	0.6	0.6	..	..	..
	Imports	0.0	0.3	0.9	1.1	..	..	..
	Net Imports	-0.2	-0.0	0.3	0.5	..	..	..
TOTAL STOCK CHANGES		**-1.5**	**-0.1**	**0.5**	**-2.1**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**52.4**	**91.2**	**127.8**	**131.6**	**170.2**	**..**	**..**
Coal[1]		9.0	19.4	19.1	21.6	15.2	..	..
Oil		38.4	46.5	67.1	67.3	81.6	..	..
Gas		0.9	5.0	16.4	18.7	37.0	..	..
Comb. Renewables & Wastes[2]		0.0	4.1	4.1	4.3	13.5	..	..
Nuclear		1.7	14.1	16.6	16.4	16.6	..	..
Hydro		2.5	2.2	3.5	2.0	3.2	..	..
Geothermal		–	–	0.0	0.0	0.0	..	..
Solar/Wind/Other[3]		–	0.0	0.6	0.8	2.8	..	..
Electricity Trade[5]		-0.2	-0.0	0.3	0.5	0.4	..	..
Shares (%)								
Coal		*17.2*	*21.3*	*15.0*	*16.4*	*8.9*	..	..
Oil		*73.3*	*50.9*	*52.5*	*51.1*	*47.9*	..	..
Gas		*1.8*	*5.4*	*12.8*	*14.2*	*21.7*	..	..
Comb. Renewables & Wastes		–	*4.5*	*3.2*	*3.3*	*7.9*	..	..
Nuclear		*3.3*	*15.5*	*13.0*	*12.5*	*9.7*	..	..
Hydro		*4.7*	*2.4*	*2.8*	*1.5*	*1.9*	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other		–	–	*0.5*	*0.6*	*1.6*	..	..
Electricity Trade		*-0.3*	–	*0.2*	*0.3*	*0.2*	..	..

0 is negligible, – is nil, .. is not available.

Please note: The forecast data for 2010 have been estimated by the IEA Secretariat based on the official 2011 Spanish forecasts, assuming a linear growth between 2002 and 2011.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**39.9**	**62.5**	**93.3**	**94.7**	**127.6**	**..**	**..**
Coal[1]	4.0	3.2	1.5	1.5	2.2	..	..
Oil	30.1	39.9	57.6	57.7	73.8	..	..
Gas	0.7	4.6	13.5	14.2	22.8	..	..
Comb. Renewables & Wastes[2]	–	3.9	3.4	3.5	4.9	..	..
Geothermal	–	–	0.0	0.0	0.0	..	..
Solar/Wind/Other	–	–	0.0	0.0	0.3	..	..
Electricity	5.1	10.8	17.3	17.8	23.6	..	..
Heat	–	0.0	–	–	–	..	..
Shares (%)							
Coal	*9.9*	*5.2*	*1.6*	*1.6*	*1.8*	..	..
Oil	*75.6*	*63.9*	*61.7*	*60.9*	*57.8*	..	..
Gas	*1.8*	*7.4*	*14.5*	*15.0*	*17.9*	..	..
Comb. Renewables & Wastes	–	*6.3*	*3.7*	*3.7*	*3.8*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	*0.3*	..	..
Electricity	*12.7*	*17.3*	*18.5*	*18.8*	*18.5*	..	..
Heat	–	–	–	–	–	..	..
TOTAL INDUSTRY[6]	**20.7**	**25.3**	**36.2**	**36.5**	**46.5**	**..**	**..**
Coal[1]	3.6	2.9	1.4	1.4	2.2	..	..
Oil	13.4	11.3	15.2	14.9	16.0	..	..
Gas	0.4	3.8	10.5	10.8	17.1	..	..
Comb. Renewables & Wastes[2]	–	1.8	1.3	1.3	2.3	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	3.3	5.4	7.8	8.0	8.9	..	..
Heat	–	–	–	–	–	..	..
Shares (%)							
Coal	*17.5*	*11.6*	*3.9*	*3.9*	*4.6*	..	..
Oil	*64.7*	*44.6*	*42.1*	*40.9*	*34.4*	..	..
Gas	*2.0*	*14.9*	*28.9*	*29.6*	*36.9*	..	..
Comb. Renewables & Wastes	–	*7.3*	*3.6*	*3.7*	*5.0*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*15.8*	*21.5*	*21.5*	*21.9*	*19.1*	..	..
Heat	–	–	–	–	–	..	..
TRANSPORT[7]	**11.9**	**22.8**	**35.1**	**35.7**	**48.9**	**..**	**..**
TOTAL OTHER SECTORS[8]	**7.2**	**14.4**	**22.1**	**22.6**	**32.2**	**..**	**..**
Coal[1]	0.3	0.3	0.1	0.1	0.1	..	..
Oil	4.9	6.1	7.8	7.7	10.7	..	..
Gas	0.3	0.8	3.0	3.4	5.7	..	..
Comb. Renewables & Wastes[2]	–	2.1	2.1	2.1	2.1	..	..
Geothermal	–	–	0.0	0.0	0.0	..	..
Solar/Wind/Other	–	–	0.0	0.0	0.3	..	..
Electricity	1.7	5.1	9.1	9.4	13.4	..	..
Heat	–	0.0	–	–	–	..	..
Shares (%)							
Coal	*4.3*	*2.1*	*0.2*	*0.3*	*0.3*	..	..
Oil	*68.2*	*42.4*	*35.1*	*33.9*	*33.1*	..	..
Gas	*4.1*	*5.8*	*13.8*	*15.0*	*17.6*	..	..
Comb. Renewables & Wastes	–	*14.4*	*9.3*	*9.1*	*6.4*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	*0.2*	*0.2*	*1.0*	..	..
Electricity	*23.4*	*35.2*	*41.3*	*41.5*	*41.6*	..	..
Heat	–	–	–	–	–	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**12.6**	**33.0**	**45.9**	**49.1**	**61.3**	..	..
OUTPUT (Mtoe)	**6.5**	**13.0**	**20.1**	**20.9**	**27.4**	..	..
(TWh gross)	75.7	151.2	233.2	242.7	318.2	..	..
Output Shares (%)							
Coal	*18.9*	*40.1*	*30.8*	*34.0*	*16.6*	..	..
Oil	*33.2*	*5.7*	*10.6*	*11.8*	*4.8*	..	..
Gas	*1.0*	*1.0*	*10.0*	*13.3*	*31.4*	..	..
Comb. Renewables & Wastes	*0.1*	*0.4*	*0.8*	*1.9*	*7.2*	..	..
Nuclear	*8.7*	*35.9*	*27.3*	*26.0*	*20.0*	..	..
Hydro	*38.2*	*16.8*	*17.6*	*9.5*	*11.6*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	*0.0*	*2.9*	*3.6*	*8.5*	..	..
TOTAL LOSSES	**12.5**	**28.4**	**34.5**	**37.2**	**42.7**	..	..
of which:							
Electricity and Heat Generation[10]	6.1	20.0	25.8	28.3	33.9	..	..
Other Transformation	2.7	2.3	1.1	1.2	..	..	..
Own Use and Losses[11]	3.7	6.1	7.6	7.7	8.7	..	..
Statistical Differences	**0.0**	**0.3**	**0.0**	**-0.3**	**–**	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	346.85	542.10	725.58	740.40	925.36	..	..
Population (millions)	34.81	38.85	40.27	40.55	42.38	..	..
TPES/GDP[12]	0.15	0.17	0.18	0.18	0.18	..	..
Energy Production/TPES	0.22	0.38	0.26	0.24	..	..	..
Per Capita TPES[13]	1.50	2.35	3.17	3.24	4.02	..	..
Oil Supply/GDP[12]	0.11	0.09	0.09	0.09	0.09	..	..
TFC/GDP[12]	0.11	0.12	0.13	0.13	0.14	..	..
Per Capita TFC[13]	1.15	1.61	2.32	2.34	3.01	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	141.6	206.5	287.3	303.4	340.1	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	7.0	15.0	29.9	30.0	8.2	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	4.1	2.9	3.1	2.9	3.3	..	..
Coal	3.0	5.5	-0.1	12.7	-4.3	..	..
Oil	4.1	-0.5	3.4	0.3	2.4	..	..
Gas	6.7	12.3	11.5	14.3	8.9	..	..
Comb. Renewables & Wastes	24.8	49.4	0.2	3.9	15.4	..	..
Nuclear	0.4	20.9	1.5	-1.1	0.1	..	..
Hydro	8.2	-5.3	4.4	-43.8	6.0	..	..
Geothermal	–	–	–	–	-8.3	..	..
Solar/Wind/Other	–	–	68.4	27.8	17.0	..	..
TFC	4.1	1.9	3.7	1.5	3.8	..	..
Electricity Consumption	6.4	3.6	4.3	2.8	3.6	..	..
Energy Production	5.5	7.5	-0.3	-5.2	–	..	..
Net Oil Imports	3.2	-0.4	3.4	2.3	–	..	..
GDP	2.3	2.9	2.7	2.0	2.8	..	..
Growth in the TPES/GDP Ratio	1.8	0.0	0.4	0.9	0.4	..	..
Growth in the TFC/GDP Ratio	1.8	-0.9	1.0	-0.5	0.9	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**9.3**	**29.8**	**34.3**	**32.4**	**33.7**	**..**	**..**
Coal[1]		0.0	0.0	–	–	–	..	..
Peat		–	0.2	0.3	0.3	0.3	..	..
Oil		–	0.0	–	–	–	..	..
Gas		–	–	–	–	–	..	..
Comb. Renewables & Wastes[2]		3.5	5.5	8.0	8.3	9.5	..	..
Nuclear		0.6	17.8	18.8	17.6	17.2	..	..
Hydro		5.1	6.2	6.8	5.7	6.0	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other[3]		–	0.0	0.4	0.4	0.8	..	..
TOTAL NET IMPORTS[4]		**29.6**	**16.7**	**16.7**	**17.6**	**19.9**	**..**	**..**
Coal[1]	Exports	0.0	0.0	0.0	0.0	–	..	..
	Imports	1.7	2.6	2.4	2.3	2.4	..	..
	Net Imports	1.7	2.6	2.4	2.3	2.4	..	..
Peat	Exports	–	–	–	–	–	..	..
	Imports	–	–	–	–	–	..	..
	Net Imports	–	–	–	–	–	..	..
Oil	Exports	1.4	8.7	10.2	9.5	–	..	..
	Imports	30.4	23.1	25.7	24.8	18.3	..	..
	Bunkers	1.1	0.7	1.4	1.2	1.9	..	..
	Net Imports	27.8	13.8	14.2	14.1	16.4	..	..
Gas	Exports	–	–	–	–	–	..	..
	Imports	–	0.5	0.8	0.8	0.8	..	..
	Net Imports	–	0.5	0.8	0.8	0.8	..	..
Electricity	Exports	0.4	1.3	1.6	1.3	–	..	..
	Imports	0.5	1.1	1.0	1.7	0.4	..	..
	Net Imports	0.1	-0.2	-0.6	0.5	0.4	..	..
TOTAL STOCK CHANGES		**0.5**	**0.2**	**0.2**	**1.0**	**–**	**..**	**..**
TOTAL SUPPLY (TPES)		**39.3**	**46.7**	**51.2**	**51.0**	**53.7**	**..**	**..**
Coal[1]		1.6	2.7	2.5	2.5	2.4	..	..
Peat		–	0.2	0.3	0.3	0.3	..	..
Oil		28.4	13.8	14.3	14.9	16.4	..	..
Gas		–	0.5	0.8	0.8	0.8	..	..
Comb. Renewables & Wastes[2]		3.5	5.5	8.0	8.3	9.5	..	..
Nuclear		0.6	17.8	18.8	17.6	17.2	..	..
Hydro		5.1	6.2	6.8	5.7	6.0	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other[3]		–	0.0	0.4	0.4	0.8	..	..
Electricity Trade[5]		0.1	-0.2	-0.6	0.5	0.4	..	..
Shares (%)								
Coal		*4.1*	*5.8*	*4.9*	*4.9*	*4.4*	..	..
Peat		–	*0.5*	*0.5*	*0.7*	*0.5*	..	..
Oil		*72.2*	*29.6*	*27.9*	*29.2*	*30.6*	..	..
Gas		–	*1.1*	*1.5*	*1.5*	*1.4*	..	..
Comb. Renewables & Wastes		*9.0*	*11.8*	*15.7*	*16.3*	*17.8*	..	..
Nuclear		*1.4*	*38.1*	*36.7*	*34.5*	*32.1*	..	..
Hydro		*13.1*	*13.4*	*13.3*	*11.2*	*11.1*	..	..
Geothermal		–	–	–	–	–	..	..
Solar/Wind/Other		–	–	*0.8*	*0.9*	*1.4*	..	..
Electricity Trade		*0.2*	*-0.3*	*-1.2*	*0.9*	*0.7*	..	..

0 is negligible, – is nil, .. is not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**35.3**	**32.1**	**34.7**	**35.0**	**37.3**	**..**	**..**
Coal[1]	0.9	1.0	0.7	0.9	0.7	..	..
Peat	–	0.0	0.0	0.0	–	..	..
Oil	24.8	14.0	13.4	13.4	14.5	..	..
Gas	0.1	0.4	0.5	0.5	0.5	..	..
Comb. Renewables & Wastes[2]	3.5	4.6	4.7	4.9	6.2	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	0.0	0.0	0.0	–	..	..
Electricity	6.0	10.4	11.4	11.3	11.7	..	..
Heat	–	1.7	4.0	4.0	3.8	..	..
Shares (%)							
Coal	*2.6*	*3.3*	*2.2*	*2.7*	*1.9*	..	..
Peat	–	–	–	–	–	..	..
Oil	*70.4*	*43.7*	*38.5*	*38.1*	*38.8*	..	..
Gas	*0.3*	*1.1*	*1.4*	*1.4*	*1.3*	..	..
Comb. Renewables & Wastes	*9.8*	*14.4*	*13.5*	*14.0*	*16.5*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	*0.1*	–	..	..
Electricity	*16.9*	*32.2*	*32.9*	*32.3*	*31.3*	..	..
Heat	–	*5.3*	*11.5*	*11.4*	*10.1*	..	..
TOTAL INDUSTRY[6]	**15.5**	**13.3**	**13.9**	**14.5**	**15.9**	**..**	**..**
Coal[1]	0.9	1.0	0.7	0.9	0.7	..	..
Peat	–	0.0	0.0	0.0	–	..	..
Oil	8.3	3.5	3.4	3.9	4.1	..	..
Gas	0.0	0.3	0.3	0.3	0.3	..	..
Comb. Renewables & Wastes[2]	2.9	3.7	4.1	4.0	5.2	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	3.4	4.6	4.9	4.9	5.1	..	..
Heat	–	0.2	0.4	0.4	0.4	..	..
Shares (%)							
Coal	*5.7*	*7.6*	*5.4*	*6.6*	*4.5*	..	..
Peat	–	–	*0.1*	–	–	..	..
Oil	*53.4*	*26.5*	*24.6*	*26.8*	*26.0*	..	..
Gas	*0.1*	*1.9*	*2.4*	*2.4*	*2.0*	..	..
Comb. Renewables & Wastes	*18.9*	*27.7*	*29.4*	*27.8*	*32.7*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	–	–	..	..
Electricity	*21.9*	*35.0*	*35.4*	*33.7*	*32.1*	..	..
Heat	–	*1.3*	*2.8*	*2.8*	*2.7*	..	..
TRANSPORT[7]	**5.5**	**7.4**	**8.2**	**8.2**	**8.3**	**..**	**..**
TOTAL OTHER SECTORS[8]	**14.3**	**11.5**	**12.6**	**12.3**	**13.1**	**..**	**..**
Coal[1]	0.0	0.0	–	–	–	..	..
Peat	–	–	–	–	–	..	..
Oil	11.2	3.3	2.0	1.5	2.3	..	..
Gas	0.1	0.1	0.2	0.2	0.2	..	..
Comb. Renewables & Wastes[2]	0.5	1.0	0.6	0.9	1.0	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	0.0	0.0	0.0	–	..	..
Electricity	2.4	5.5	6.3	6.2	6.3	..	..
Heat	–	1.5	3.6	3.6	3.3	..	..
Shares (%)							
Coal	*0.3*	*0.4*	–	–	–	..	..
Peat	–	–	–	–	–	..	..
Oil	*78.7*	*28.9*	*15.7*	*12.3*	*17.6*	..	..
Gas	*0.7*	*1.0*	*1.3*	*1.3*	*1.4*	..	..
Comb. Renewables & Wastes	*3.6*	*8.4*	*4.7*	*7.1*	*7.4*	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	–	*0.2*	–	..	..
Electricity	*16.6*	*47.9*	*49.7*	*50.1*	*48.2*	..	..
Heat	–	*13.4*	*28.6*	*29.0*	*25.5*	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**8.2**	**26.7**	**30.6**	**28.7**	**28.6**	..	..
OUTPUT (Mtoe)	**6.7**	**12.6**	**13.9**	**12.6**	**13.0**	..	..
(TWh gross)	78.1	146.0	161.6	146.0	151.3	..	..
Output Shares (%)							
Coal	0.6	1.2	1.9	2.6	1.8	..	..
Peat	–	0.0	0.0	0.1	0.1	..	..
Oil	19.4	0.8	1.6	2.0	2.1	..	..
Gas	–	0.3	0.2	0.4	0.4	..	..
Comb. Renewables & Wastes	0.5	1.3	2.5	2.8	3.7	..	..
Nuclear	2.7	46.7	44.6	46.3	43.7	..	..
Hydro	76.7	49.7	48.9	45.6	45.7	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	*0.0*	*0.3*	*0.4*	*2.6*	..	..
TOTAL LOSSES	**3.4**	**15.2**	**16.3**	**16.3**	**16.3**	..	..
of which:							
Electricity and Heat Generation[10]	1.5	12.3	13.3	12.6	12.0	..	..
Other Transformation	1.0	0.2	0.4	1.3	2.1	..	..
Own Use and Losses[11]	1.0	2.8	2.6	2.5	2.2	..	..
Statistical Differences	**0.6**	**-0.7**	**0.2**	**-0.3**	**–**	..	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	170.32	239.25	293.87	299.51	351.84	..	..
Population (millions)	8.14	8.56	8.90	8.93	9.18	..	..
TPES/GDP[12]	0.23	0.20	0.17	0.17	0.15	..	..
Energy Production/TPES	0.24	0.64	0.67	0.63	0.63	..	..
Per Capita TPES[13]	4.83	5.45	5.75	5.72	5.84	..	..
Oil Supply/GDP[12]	0.17	0.06	0.05	0.05	0.05	..	..
TFC/GDP[12]	0.21	0.13	0.12	0.12	0.11	..	..
Per Capita TFC[13]	4.34	3.76	3.90	3.92	4.07	..	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	84.9	51.2	48.5	50.1	47.8	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	3.9	3.0	6.6	5.6	7.8	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	1.5	0.8	0.8	-0.3	0.6	..	..
Coal	1.6	3.9	-0.8	0.6	-0.7	..	..
Peat	–	–	1.4	25.7	-3.5	..	..
Oil	-1.3	-5.7	0.3	4.3	1.2	..	..
Gas	–	–	3.6	1.7	-0.1	..	..
Comb. Renewables & Wastes	1.8	3.1	3.5	3.5	1.8	..	..
Nuclear	46.7	11.3	0.5	-6.3	-0.3	..	..
Hydro	0.3	1.6	0.8	-15.9	0.5	..	..
Geothermal	–	–	–	–	–	..	..
Solar/Wind/Other	–	–	25.1	51.1	21.4	..	..
TFC	0.4	-1.1	0.7	0.9	0.8	..	..
Electricity Consumption	3.5	3.2	0.9	-0.8	0.4	..	..
Energy Production	8.0	6.6	1.3	-5.5	0.5	..	..
Net Oil Imports	-0.2	-6.1	0.3	-0.3	1.9	..	..
GDP	1.8	2.1	1.9	1.9	2.0	..	..
Growth in the TPES/GDP Ratio	-0.3	-1.4	-1.0	-2.2	-1.4	..	..
Growth in the TFC/GDP Ratio	-1.3	-3.2	-1.2	-1.0	-1.2	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

SWITZERLAND

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**4.28**	**9.83**	**12.37**	**11.94**	**11.21**	**10.50**	**9.01**
Coal[1]		–	–	–	–	–	–	–
Oil		–	–	–	–	–	–	–
Gas		–	0.00	–	–	–	–	–
Comb. Renewables & Wastes[2]		0.24	1.02	1.67	1.66	2.03	2.10	2.03
Nuclear		1.64	6.18	7.01	7.12	6.29	5.52	4.10
Hydro		2.40	2.56	3.55	3.03	2.88	2.88	2.88
Geothermal		–	0.06	0.11	0.11	–	–	–
Solar/Wind/Other[3]		–	0.01	0.03	0.02	0.00	0.01	0.01
TOTAL NET IMPORTS[4]		**15.23**	**15.16**	**15.47**	**15.24**	**15.87**	**16.20**	**16.47**
Coal[1]	Exports	0.02	0.01	–	–	–	–	–
	Imports	0.24	0.35	0.13	0.11	0.10	0.10	0.10
	Net Imports	0.22	0.34	0.13	0.11	0.10	0.10	0.10
Oil	Exports	0.23	0.16	0.56	0.62	–	–	–
	Imports	15.38	13.54	14.27	13.65	13.04	12.94	12.63
	Bunkers	–	0.02	0.01	0.01	–	–	–
	Net Imports	15.16	13.36	13.71	13.03	13.04	12.94	12.63
Gas	Exports	–	–	–	–	–	–	–
	Imports	0.15	1.63	2.53	2.49	2.85	2.99	3.13
	Net Imports	0.15	1.63	2.53	2.49	2.85	2.99	3.13
Electricity	Exports	0.90	1.97	2.97	2.78	0.12	..	..
	Imports	0.60	1.79	2.07	2.39	..	0.17	0.61
	Net Imports	–0.30	–0.18	–0.90	–0.39	–0.12	0.17	0.61
TOTAL STOCK CHANGES		**0.22**	**0.12**	**0.18**	**–0.04**	**–**	**–**	**–**
TOTAL SUPPLY (TPES)		**19.72**	**25.11**	**28.02**	**27.14**	**27.08**	**26.70**	**25.48**
Coal[1]		0.33	0.36	0.15	0.14	0.10	0.10	0.10
Oil		15.26	13.46	13.87	12.96	13.04	12.94	12.63
Gas		0.15	1.63	2.53	2.49	2.85	2.99	3.13
Comb. Renewables & Wastes[2]		0.24	1.03	1.67	1.67	2.03	2.10	2.03
Nuclear		1.64	6.18	7.01	7.12	6.29	5.52	4.10
Hydro		2.40	2.56	3.55	3.03	2.88	2.88	2.88
Geothermal		–	0.06	0.11	0.11	–	–	–
Solar/Wind/Other[3]		–	0.01	0.03	0.02	0.00	0.01	0.01
Electricity Trade[5]		-0.30	–0.18	-0.90	–0.39	–0.12	0.17	0.61
Shares (%)								
Coal		*1.7*	*1.4*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*
Oil		*77.4*	*53.6*	*49.5*	*47.8*	*48.2*	*48.5*	*49.6*
Gas		*0.8*	*6.5*	*9.0*	*9.2*	*10.5*	*11.2*	*12.3*
Comb. Renewables & Wastes		*1.2*	*4.1*	*6.0*	*6.1*	*7.5*	*7.9*	*8.0*
Nuclear		*8.3*	*24.6*	*25.0*	*26.2*	*23.2*	*20.7*	*16.1*
Hydro		*12.2*	*10.2*	*12.7*	*11.2*	*10.6*	*10.8*	*11.3*
Geothermal		*–*	*0.2*	*0.4*	*0.4*	*–*	*–*	*–*
Solar/Wind/Other		*–*	*–*	*0.1*	*0.1*	*–*	*–*	*–*
Electricity Trade		*-1.5*	*-0.7*	*-3.2*	*-1.4*	*-0.5*	*0.6*	*2.4*

0 is negligible, – is nil, .. is not available.

Please note: All forecast data are based on the 2002 submission.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**17.57**	**19.66**	**21.59**	**21.04**	**21.76**	**21.89**	**21.69**
Coal[1]	0.29	0.35	0.15	0.14	0.10	0.10	0.10
Oil	14.30	12.85	13.22	12.75	12.65	12.56	12.26
Gas	0.24	1.52	2.32	2.28	2.68	2.77	2.85
Comb. Renewables & Wastes[2]	0.24	0.60	0.78	0.77	1.31	1.38	1.39
Geothermal	–	0.06	0.11	0.11	–	–	–
Solar/Wind/Other	–	0.01	0.03	0.02	–	–	–
Electricity	2.50	4.04	4.65	4.63	4.76	4.83	4.83
Heat	–	0.25	0.34	0.35	0.27	0.26	0.26
Shares (%)							
Coal	*1.6*	*1.8*	*0.7*	*0.6*	*0.5*	*0.4*	*0.5*
Oil	*81.4*	*65.3*	*61.2*	*60.6*	*58.1*	*57.4*	*56.5*
Gas	*1.3*	*7.7*	*10.7*	*10.8*	*12.3*	*12.6*	*13.1*
Comb. Renewables & Wastes	*1.4*	*3.0*	*3.6*	*3.7*	*6.0*	*6.3*	*6.4*
Geothermal	–	*0.3*	*0.5*	*0.5*	–	–	–
Solar/Wind/Other	–	–	*0.1*	*0.1*	–	–	–
Electricity	*14.2*	*20.5*	*21.5*	*22.0*	*21.9*	*22.1*	*22.3*
Heat	–	*1.3*	*1.6*	*1.7*	*1.2*	*1.2*	*1.2*
TOTAL INDUSTRY[6]	**4.78**	**3.93**	**4.90**	**4.73**	**4.85**	**4.89**	**5.03**
Coal[1]	0.08	0.33	0.14	0.13	0.10	0.10	0.10
Oil	3.70	1.31	1.80	1.69	1.42	1.38	1.39
Gas	0.05	0.59	0.78	0.75	1.14	1.14	1.19
Comb. Renewables & Wastes[2]	–	0.16	0.45	0.44	0.49	0.51	0.50
Geothermal	–	–	0.01	0.01	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	0.95	1.48	1.59	1.56	1.63	1.69	1.77
Heat	–	0.05	0.14	0.15	0.08	0.07	0.07
Shares (%)							
Coal	*1.6*	*8.4*	*2.9*	*2.7*	*2.0*	*2.0*	*2.0*
Oil	*77.4*	*33.4*	*36.7*	*35.8*	*29.3*	*28.3*	*27.7*
Gas	*1.1*	*15.1*	*15.9*	*15.9*	*23.4*	*23.3*	*23.7*
Comb. Renewables & Wastes	–	*4.1*	*9.1*	*9.3*	*10.2*	*10.5*	*9.9*
Geothermal	–	–	*0.2*	*0.2*	–	–	–
Solar/Wind/Other	–	–	–	–	–	–	–
Electricity	*19.9*	*37.7*	*32.4*	*32.9*	*33.5*	*34.5*	*35.3*
Heat	–	*1.2*	*2.8*	*3.3*	*1.6*	*1.4*	*1.4*
TRANSPORT[7]	**4.29**	**6.29**	**6.90**	**6.71**	**7.10**	**7.43**	**7.47**
TOTAL OTHER SECTORS[8]	**8.49**	**9.44**	**9.80**	**9.60**	**9.81**	**9.58**	**9.20**
Coal[1]	0.21	0.02	0.01	0.01	0.00	0.00	0.00
Oil	6.48	5.47	4.76	4.58	4.43	4.06	3.72
Gas	0.19	0.92	1.54	1.53	1.54	1.63	1.66
Comb. Renewables & Wastes[2]	0.24	0.44	0.34	0.33	0.82	0.87	0.89
Geothermal	–	0.06	0.10	0.10	–	–	–
Solar/Wind/Other	–	0.01	0.02	0.02	–	–	–
Electricity	1.37	2.34	2.83	2.83	2.83	2.83	2.74
Heat	–	0.20	0.20	0.19	0.19	0.19	0.19
Shares (%)							
Coal	*2.5*	*0.2*	*0.1*	*0.1*	–	–	–
Oil	*76.3*	*57.9*	*48.6*	*47.7*	*45.2*	*42.4*	*40.4*
Gas	*2.2*	*9.8*	*15.7*	*15.9*	*15.7*	*17.0*	*18.0*
Comb. Renewables & Wastes	*2.8*	*4.6*	*3.4*	*3.5*	*8.4*	*9.1*	*9.7*
Geothermal	–	*0.6*	*1.0*	*1.1*	–	–	–
Solar/Wind/Other	–	*0.1*	*0.2*	*0.2*	–	–	–
Electricity	*16.1*	*24.7*	*28.9*	*29.5*	*28.8*	*29.5*	*29.8*
Heat	–	*2.1*	*2.1*	*2.0*	*1.9*	*2.0*	*2.1*

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**4.48**	**9.39**	**11.66**	**11.24**	**10.07**	**9.35**	**7.91**
OUTPUT (Mtoe)	**3.17**	**4.70**	**6.07**	**5.58**	**5.22**	**5.00**	**4.56**
(TWh gross)	36.82	54.62	70.55	64.94	60.73	58.18	53.03
Output Shares (%)							
Coal	*–*	*0.1*	*–*	*–*	*–*	*–*	*–*
Oil	*7.1*	*0.5*	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*
Gas	*–*	*0.6*	*1.2*	*1.4*	*1.7*	*2.2*	*2.7*
Comb. Renewables & Wastes	*–*	*1.0*	*2.1*	*2.3*	*3.2*	*3.6*	*4.2*
Nuclear	*17.1*	*43.3*	*38.0*	*41.9*	*39.8*	*36.4*	*29.6*
Hydro	*75.8*	*54.6*	*58.6*	*54.2*	*55.2*	*57.6*	*63.2*
Geothermal	*–*	*–*	*–*	*–*	*–*	*–*	*–*
Solar/Wind/Other	*–*	*0.0*	*0.0*	*0.0*	*0.1*	*0.1*	*0.1*
TOTAL LOSSES	**2.17**	**5.09**	**6.04**	**6.14**	**5.31**	**4.81**	**3.80**
of which:							
Electricity and Heat Generation[10]	1.32	4.42	5.23	5.28	4.55	4.06	3.05
Other Transformation	0.14	0.01	-0.02	-0.03	0.00	–	–
Own Use and Losses[11]	0.72	0.66	0.83	0.89	0.76	0.75	0.74
Statistical Differences	**-0.02**	**0.36**	**0.39**	**-0.04**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	246.18	308.43	339.22	340.00	404.66	460.45	523.93
Population (millions)	6.44	6.71	7.23	7.29	7.50	7.40	7.40
TPES/GDP[12]	0.08	0.08	0.08	0.08	0.07	0.06	0.05
Energy Production/TPES	0.22	0.39	0.44	0.44	0.41	0.39	0.35
Per Capita TPES[13]	3.06	3.74	3.87	3.72	3.61	3.61	3.44
Oil Supply/GDP[12]	0.06	0.04	0.04	0.04	0.03	0.03	0.02
TFC/GDP[12]	0.07	0.06	0.06	0.06	0.05	0.05	0.04
Per Capita TFC[13]	2.73	2.93	2.99	2.89	2.90	2.96	2.93
Energy-related CO_2 Emissions (Mt CO_2)[14]	43.6	41.5	43.9	42.8	43.8	43.8	43.3
CO_2 Emissions from Bunkers (Mt CO_2)	2.1	3.2	4.6	4.1	4.1	4.1	4.1

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	0.2	2.1	1.0	-3.1	-0.0	-0.1	-0.5
Coal	-6.3	4.5	-7.7	-8.1	-4.0	–	0.3
Oil	-2.2	0.1	0.3	-6.5	0.1	-0.1	-0.2
Gas	31.0	7.2	4.1	-1.9	1.7	0.5	0.5
Comb. Renewables & Wastes	11.2	7.7	4.5	-0.4	2.5	0.3	-0.3
Nuclear	11.0	6.5	1.2	1.5	-1.5	-1.3	-2.9
Hydro	2.1	-0.5	3.0	-14.8	-0.6	–	–
Geothermal	–	–	5.2	1.9	–	–	–
Solar/Wind/Other	–	–	11.3	-11.5	-22.5	5.2	1.8
TFC	-0.6	1.4	0.9	-2.6	0.4	0.1	-0.1
Electricity Consumption	2.6	3.0	1.3	-0.5	0.3	0.2	0.0
Energy Production	6.5	4.2	2.1	-3.4	-0.8	-0.6	-1.5
Net Oil Imports	-1.6	-0.3	0.2	-4.9	0.0	-0.1	-0.2
GDP	-0.4	2.3	0.9	0.2	2.2	1.3	1.3
Growth in the TPES/GDP Ratio	0.6	-0.2	0.1	-3.4	-2.2	-1.4	-1.7
Growth in the TFC/GDP Ratio	-0.3	-0.9	-0.0	-2.8	-1.7	-1.2	-1.4

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**15.52**	**25.86**	**25.06**	**24.43**	**39.22**	**58.20**	**71.68**
Coal[1]		5.21	12.41	12.88	11.64	26.15	32.36	35.13
Oil		3.59	3.61	2.49	2.39	1.13	0.49	0.17
Gas		–	0.18	0.26	0.31	0.17	0.14	0.10
Comb. Renewables & Wastes[2]		6.45	7.21	6.32	6.05	4.42	3.93	3.75
Nuclear		–	–	–	–	–	7.30	14.60
Hydro		0.22	1.99	2.07	2.90	5.34	10.00	10.00
Geothermal		0.05	0.43	0.76	0.82	0.97	1.71	3.64
Solar/Wind/Other[3]		–	0.03	0.29	0.32	1.05	2.27	4.28
TOTAL NET IMPORTS[4]		**8.74**	**27.98**	**46.00**	**50.73**	**113.00**	**220.98**	**391.56**
Coal[1]	Exports	–	–	–	–	–	–	–
	Imports	0.01	4.21	5.89	8.27	13.55	75.21	163.21
	Net Imports	0.01	4.21	5.89	8.27	13.55	75.21	163.21
Oil	Exports	0.86	1.90	2.58	3.13	–	–	–
	Imports	9.68	23.18	29.35	31.52	50.04	71.41	102.20
	Bunkers	0.09	0.12	0.24	0.53	–	–	–
	Net Imports	8.73	21.16	26.53	27.86	50.04	71.41	102.20
Gas	Exports	–	–	–	–	–	–	–
	Imports	–	2.68	13.21	14.34	49.41	74.36	126.15
	Net Imports	–	2.68	13.21	14.34	49.41	74.36	126.15
Electricity	Exports	–	0.08	0.04	0.04	–	–	–
	Imports	–	0.02	0.39	0.31	–	–	–
	Net Imports	–	–0.06	0.36	0.27	–	–	–
TOTAL STOCK CHANGES		**0.11**	**–0.83**	**0.53**	**0.26**	**–**	**–**	**–**
TOTAL SUPPLY (TPES)		**24.37**	**53.01**	**71.59**	**75.42**	**152.22**	**279.18**	**463.24**
Coal[1]		5.15	16.94	19.56	19.79	39.70	107.57	198.34
Oil		12.50	23.61	28.88	30.53	51.17	71.89	102.38
Gas		–	2.86	13.37	14.73	49.58	74.51	126.25
Comb. Renewables & Wastes[2]		6.45	7.21	6.32	6.05	4.42	3.93	3.75
Nuclear		–	–	–	–	–	7.30	14.60
Hydro		0.22	1.99	2.07	2.90	5.34	10.00	10.00
Geothermal		0.05	0.43	0.76	0.82	0.97	1.71	3.64
Solar/Wind/Other[3]		–	0.03	0.29	0.32	1.05	2.27	4.28
Electricity Trade[5]		–	–0.06	0.36	0.27	–	–	–
Shares (%)								
Coal		*21.1*	*32.0*	*27.3*	*26.2*	*26.1*	*38.5*	*42.8*
Oil		*51.3*	*44.5*	*40.3*	*40.5*	*33.6*	*25.8*	*22.1*
Gas		–	*5.4*	*18.7*	*19.5*	*32.6*	*26.7*	*27.3*
Comb. Renewables & Wastes		*26.5*	*13.6*	*8.8*	*8.0*	*2.9*	*1.4*	*0.8*
Nuclear		–	–	–	–	–	*2.6*	*3.2*
Hydro		*0.9*	*3.8*	*2.9*	*3.8*	*3.5*	*3.6*	*2.2*
Geothermal		*0.2*	*0.8*	*1.1*	*1.1*	*0.6*	*0.6*	*0.8*
Solar/Wind/Other		–	*0.1*	*0.4*	*0.4*	*0.7*	*0.8*	*0.9*
Electricity Trade		–	*-0.1*	*0.5*	*0.4*	–	–	–

0 is negligible, – is nil, .. is not available.

All forecast data are based on the 2002 submission.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**20.04**	**40.55**	**51.29**	**56.52**	**111.84**	**197.52**	**322.00**
Coal[1]	2.94	7.57	6.46	8.61	15.56	55.68	112.31
Oil	9.70	20.80	25.01	26.94	44.17	63.07	90.64
Gas	0.04	0.72	4.45	5.22	25.25	29.71	33.76
Comb. Renewables & Wastes[2]	6.45	7.21	6.21	5.97	4.42	3.93	3.75
Geothermal	0.05	0.36	0.69	0.73	0.89	1.64	3.56
Solar/Wind/Other	–	0.03	0.29	0.32	0.60	1.12	1.93
Electricity	0.85	3.87	8.20	8.73	20.95	42.39	76.04
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*14.7*	*18.7*	*12.6*	*15.2*	*13.9*	*28.2*	*34.9*
Oil	*48.4*	*51.3*	*48.8*	*47.7*	*39.5*	*31.9*	*28.2*
Gas	*0.2*	*1.8*	*8.7*	*9.2*	*22.6*	*15.0*	*10.5*
Comb. Renewables & Wastes	*32.2*	*17.8*	*12.1*	*10.6*	*3.9*	*2.0*	*1.2*
Geothermal	*0.2*	*0.9*	*1.3*	*1.3*	*0.8*	*0.8*	*1.1*
Solar/Wind/Other	–	*0.1*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*
Electricity	*4.3*	*9.5*	*16.0*	*15.5*	*18.7*	*21.5*	*23.6*
Heat	–	–	–	–	–	–	–
TOTAL INDUSTRY[6]	**4.30**	**13.71**	**18.36**	**21.88**	**51.26**	**108.99**	**202.38**
Coal[1]	1.14	4.52	5.44	7.31	11.88	46.04	101.82
Oil	2.60	6.16	7.46	8.25	12.33	19.77	31.63
Gas	0.00	0.67	1.47	2.01	15.41	18.04	20.67
Comb. Renewables & Wastes[2]	–	–	–	–	–	–	–
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	0.01	0.12	0.12	0.27	0.51	0.96
Electricity	0.55	2.35	3.87	4.20	11.37	24.64	47.30
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*26.5*	*33.0*	*29.6*	*33.4*	*23.2*	*42.2*	*50.3*
Oil	*60.5*	*44.9*	*40.7*	*37.7*	*24.1*	*18.1*	*15.6*
Gas	*0.1*	*4.9*	*8.0*	*9.2*	*30.1*	*16.5*	*10.2*
Comb. Renewables & Wastes	–	–	–	–	–	–	–
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	*0.1*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*
Electricity	*12.9*	*17.2*	*21.1*	*19.2*	*22.2*	*22.6*	*23.4*
Heat	–	–	–	–	–	–	–
TRANSPORT[7]	**4.49**	**9.58**	**11.99**	**12.93**	**23.71**	**33.94**	**48.48**
TOTAL OTHER SECTORS[8]	**11.26**	**17.26**	**20.95**	**21.71**	**36.88**	**54.60**	**71.14**
Coal[1]	1.28	3.03	1.02	1.30	3.68	9.64	10.49
Oil	3.15	5.11	5.65	5.89	8.31	9.73	11.29
Gas	0.04	0.05	2.94	3.16	9.83	11.66	13.07
Comb. Renewables & Wastes[2]	6.45	7.21	6.21	5.97	4.42	3.93	3.75
Geothermal	0.05	0.36	0.69	0.73	0.89	1.64	3.56
Solar/Wind/Other	–	0.02	0.17	0.20	0.34	0.61	0.98
Electricity	0.29	1.49	4.27	4.46	9.41	17.40	28.01
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*11.4*	*17.6*	*4.9*	*6.0*	*10.0*	*17.7*	*14.7*
Oil	*28.0*	*29.6*	*27.0*	*27.1*	*22.5*	*17.8*	*15.9*
Gas	*0.3*	*0.3*	*14.0*	*14.5*	*26.7*	*21.4*	*18.4*
Comb. Renewables & Wastes	*57.3*	*41.7*	*29.6*	*27.5*	*12.0*	*7.2*	*5.3*
Geothermal	*0.4*	*2.1*	*3.3*	*3.4*	*2.4*	*3.0*	*5.0*
Solar/Wind/Other	–	*0.1*	*0.8*	*0.9*	*0.9*	*1.1*	*1.4*
Electricity	*2.6*	*8.6*	*20.4*	*20.6*	*25.5*	*31.9*	*39.4*
Heat	–	–	–	–	–	–	–

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**2.77**	**11.08**	**24.66**	**24.09**	**56.01**	**116.54**	**206.29**
OUTPUT (Mtoe)	**1.07**	**4.95**	**10.55**	**11.13**	**24.65**	**48.72**	**85.17**
(TWh gross)	12.43	57.54	122.73	129.40	286.59	566.51	990.32
Output Shares (%)							
Coal	*26.1*	*35.1*	*31.3*	*24.8*	*33.3*	*37.2*	*35.3*
Oil	*51.4*	*6.9*	*8.5*	*8.3*	*0.0*	–	*0.0*
Gas	–	*17.7*	*40.4*	*40.6*	*43.1*	*35.0*	*44.5*
Comb. Renewables & Wastes	*1.6*	–	*0.1*	*0.1*	–	–	–
Nuclear	–	–	–	–	–	*4.9*	*5.7*
Hydro	*20.9*	*40.2*	*19.6*	*26.0*	*21.7*	*20.5*	*11.7*
Geothermal	–	*0.1*	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*
Solar/Wind/Other	–	–	*0.1*	*0.0*	*1.8*	*2.4*	*2.8*
TOTAL LOSSES	**4.03**	**11.58**	**19.90**	**18.74**	**40.38**	**81.65**	**141.24**
of which:							
Electricity and Heat Generation[10]	1.70	6.13	14.11	12.96	31.36	67.82	121.12
Other Transformation	1.32	2.89	1.06	1.00	2.51	3.79	5.87
Own Use and Losses[11]	1.00	2.56	4.73	4.78	6.51	10.05	14.25
Statistical Differences	**0.30**	**0.88**	**0.40**	**0.16**	**–**	**–**	**–**

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	68.40	144.57	190.07	204.87	354.64	684.70	1180.71
Population (millions)	38.45	56.20	68.61	69.67	74.12	81.92	88.87
TPES/GDP[12]	0.36	0.37	0.38	0.37	0.43	0.41	0.39
Energy Production/TPES	0.64	0.49	0.35	0.32	0.26	0.21	0.15
Per Capita TPES[13]	0.63	0.94	1.04	1.08	2.05	3.41	5.21
Oil Supply/GDP[12]	0.18	0.16	0.15	0.15	0.14	0.11	0.09
TFC/GDP[12]	0.29	0.28	0.27	0.28	0.32	0.29	0.27
Per Capita TFC[13]	0.52	0.72	0.75	0.81	1.51	2.41	3.62
Energy-related CO_2 Emissions (Mt CO_2)[14]	52.8	128.8	185.2	193.1	405.4	782.8	1333.8
CO_2 Emissions from Bunkers (Mt CO_2)	0.4	0.9	2.3	4.3	2.7	2.7	2.7

GROWTH RATES (% per year)

	73–79	79–90	90–01	01–02	02–10	10–20	20–30
TPES	3.7	5.2	2.8	5.3	9.2	6.3	5.2
Coal	4.1	9.0	1.3	1.2	9.1	10.5	6.3
Oil	3.1	4.2	1.8	5.7	6.7	3.5	3.6
Gas	–	–	15.1	10.2	16.4	4.2	5.4
Comb. Renewables & Wastes	3.1	-0.7	-1.2	-4.2	-3.9	-1.2	-0.5
Nuclear	–	–	–	–	–	–	7.2
Hydro	25.7	7.6	0.3	40.3	7.9	6.5	–
Geothermal	3.8	19.7	5.3	7.3	2.1	5.9	7.8
Solar/Wind/Other	–	–	23.8	10.3	15.9	8.0	6.6
TFC	4.1	4.3	2.2	10.2	8.9	5.9	5.0
Electricity Consumption	11.3	8.2	7.1	6.5	11.6	7.3	6.0
Energy Production	1.9	3.7	-0.3	-2.5	6.1	4.0	2.1
Net Oil Imports	5.1	5.5	2.1	5.0	7.6	3.6	3.7
GDP	4.5	4.5	2.5	7.8	7.1	6.8	5.6
Growth in the TPES/GDP Ratio	-0.8	0.7	0.2	-2.3	1.9	-0.5	-0.4
Growth in the TFC/GDP Ratio	-0.4	-0.2	-0.4	2.2	1.7	-0.9	-0.6

Please note: Rounding may cause totals to differ from the sum of the elements.

UNITED KINGDOM

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**108.5**	**208.0**	**262.0**	**257.8**	**..**	**..**	**..**
Coal[1]		75.9	53.6	19.0	17.8	2.6	–	..
Oil		0.5	95.2	121.7	121.0	..	..	..
Gas		24.4	40.9	95.2	93.2	..	..	..
Comb. Renewables & Wastes[2]		–	0.6	2.2	2.3	10.4	10.5	..
Nuclear		7.3	17.1	23.4	22.9	18.9	7.7	..
Hydro		0.3	0.4	0.3	0.4	0.4	0.4	..
Geothermal		–	0.0	0.0	0.0	–	–	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	..	..	..
TOTAL NET IMPORTS[4]		**110.4**	**2.1**	**-24.6**	**-32.6**	**..**	**..**	**..**
Coal[1]	Exports	2.0	1.8	0.7	0.6	–	–	..
	Imports	1.1	10.3	22.4	18.1	18.8	15.6	..
	Net Imports	-0.9	8.5	21.8	17.4	18.8	15.6	..
Oil	Exports	20.9	76.5	109.7	113.5	..	..	..
	Imports	136.9	65.4	73.1	72.2	..	..	..
	Bunkers	5.4	2.5	2.2	2.4	..	..	..
	Net Imports	110.6	-13.6	-38.9	-43.8	..	..	..
Gas	Exports	–	–	10.7	11.7	..	..	..
	Imports	0.7	6.2	2.4	4.7	..	..	..
	Net Imports	0.7	6.2	-8.3	-7.0	..	..	..
Electricity	Exports	0.0	0.0	0.0	0.1	–	–	..
	Imports	0.0	1.0	0.9	0.8	0.4	0.3	..
	Net Imports	0.0	1.0	0.9	0.7	0.4	0.3	..
TOTAL STOCK CHANGES		**1.8**	**2.1**	**-3.0**	**1.3**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**220.7**	**212.2**	**234.4**	**226.5**	**244.1**	**251.5**	**..**
Coal[1]		76.4	63.1	39.1	35.7	21.3	15.6	..
Oil		111.6	82.6	81.6	78.6	92.6	103.0	..
Gas		25.1	47.2	86.8	85.7	100.1	114.1	..
Comb. Renewables & Wastes[2]		–	0.6	2.2	2.3	10.4	10.5	..
Nuclear		7.3	17.1	23.4	22.9	18.9	7.7	..
Hydro		0.3	0.4	0.3	0.4	0.4	0.4	..
Geothermal		–	0.0	0.0	0.0	–	–	..
Solar/Wind/Other[3]		–	0.0	0.1	0.1	..	..	..
Electricity Trade[5]		0.0	1.0	0.9	0.7	0.4	0.3	..
Shares (%)								
Coal		*34.6*	*29.7*	*16.7*	*15.7*	*8.7*	*6.2*	..
Oil		*50.5*	*38.9*	*34.8*	*34.7*	*37.9*	*40.9*	..
Gas		*11.4*	*22.2*	*37.0*	*37.8*	*41.0*	*45.3*	..
Comb. Renewables & Wastes		–	*0.3*	*0.9*	*1.0*	*4.3*	*4.2*	..
Nuclear		*3.3*	*8.1*	*10.0*	*10.1*	*7.8*	*3.1*	..
Hydro		*0.2*	*0.2*	*0.1*	*0.2*	*0.2*	*0.2*	..
Geothermal		–	–	–	–	–	–	..
Solar/Wind/Other		–	–	–	*0.1*	..	..	..
Electricity Trade		–	*0.5*	*0.4*	*0.3*	*0.2*	*0.1*	..

0 is negligible, – is nil, .. is not available.

Please note: Forecast data are based on the 2000 submission. Forecasts for production. imports, exports of coal are IEA Secretariat estimates.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**147.1**	**145.4**	**161.7**	**158.3**	**180.0**	**195.6**	**..**
Coal[1]	26.5	10.8	4.4	3.5	3.6	3.3	..
Oil	77.0	68.8	72.6	72.8	84.9	95.2	..
Gas	23.6	41.8	53.1	51.0	57.9	61.3	..
Comb. Renewables & Wastes[2]	–	0.4	0.6	0.6	0.7	0.8	..
Geothermal	–	0.0	0.0	0.0	–	–	..
Solar/Wind/Other	–	0.0	0.0	0.0	–	–	..
Electricity	20.0	23.6	28.6	28.6	32.9	35.1	..
Heat	–	–	2.3	1.9	..	..	..
Shares (%)							
Coal	*18.0*	*7.4*	*2.7*	*2.2*	*2.0*	*1.7*	..
Oil	*52.3*	*47.3*	*44.9*	*46.0*	*47.2*	*48.7*	..
Gas	*16.1*	*28.7*	*32.8*	*32.2*	*32.2*	*31.3*	..
Comb. Renewables & Wastes	–	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*13.6*	*16.2*	*17.7*	*18.1*	*18.3*	*17.9*	..
Heat	–	–	*1.4*	*1.2*	..	..	..
TOTAL INDUSTRY[6]	**65.0**	**42.8**	**43.8**	**43.1**	**48.1**	**50.0**	**..**
Coal[1]	13.3	6.4	2.6	2.0	2.9	2.9	..
Oil	33.7	15.7	15.3	16.1	17.0	17.1	..
Gas	10.1	12.0	15.0	14.0	17.0	17.8	..
Comb. Renewables & Wastes[2]	–	0.1	0.2	0.2	0.6	0.6	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	7.8	8.7	9.6	9.6	10.6	11.6	..
Heat	–	–	1.0	1.1	..	..	..
Shares (%)							
Coal	*20.5*	*14.9*	*6.0*	*4.7*	*6.0*	*5.7*	..
Oil	*51.8*	*36.8*	*35.0*	*37.4*	*35.3*	*34.2*	..
Gas	*15.6*	*27.9*	*34.2*	*32.5*	*35.3*	*35.6*	..
Comb. Renewables & Wastes	–	*0.2*	*0.5*	*0.5*	*1.2*	*1.2*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*12.1*	*20.2*	*21.9*	*22.3*	*22.0*	*23.2*	..
Heat	–	–	*2.3*	*2.6*	..	..	..
TRANSPORT[7]	**31.0**	**46.5**	**52.3**	**52.2**	**62.8**	**73.0**	**..**
TOTAL OTHER SECTORS[8]	**51.2**	**56.1**	**65.6**	**63.0**	**69.1**	**72.7**	**..**
Coal[1]	13.1	4.4	1.8	1.5	0.7	0.4	..
Oil	12.6	7.0	5.8	5.2	5.8	5.9	..
Gas	13.5	29.8	38.1	37.0	40.9	43.5	..
Comb. Renewables & Wastes[2]	–	0.3	0.4	0.4	0.1	0.2	..
Geothermal	–	0.0	0.0	0.0	–	–	..
Solar/Wind/Other	–	0.0	0.0	0.0	–	–	..
Electricity	12.0	14.5	18.3	18.3	21.6	22.7	..
Heat	–	–	1.3	0.8	..	..	..
Shares (%)							
Coal	*25.5*	*7.8*	*2.7*	*2.3*	*1.0*	*0.6*	..
Oil	*24.7*	*12.5*	*8.8*	*8.2*	*8.4*	*8.1*	..
Gas	*26.4*	*53.2*	*58.0*	*58.6*	*59.2*	*59.9*	..
Comb. Renewables & Wastes	–	*0.6*	*0.6*	*0.6*	*0.2*	*0.2*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*23.4*	*25.8*	*27.9*	*29.0*	*31.3*	*31.2*	..
Heat	–	–	*2.0*	*1.2*	..	..	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**72.5**	**74.4**	**85.0**	**82.8**	**79.4**	**74.9**	..
OUTPUT (Mtoe)	**24.2**	**27.3**	**32.9**	**33.1**	**36.2**	**38.2**	..
(TWh gross)	281.4	317.8	382.3	384.5	420.9	443.7	..
Output Shares (%)							
Coal	*62.1*	*65.0*	*34.8*	*32.8*	*15.8*	*9.4*	..
Oil	*25.6*	*10.9*	*1.9*	*1.8*	*0.4*	*0.3*	..
Gas	*1.0*	*1.6*	*37.1*	*39.6*	*56.0*	*73.6*	..
Comb. Renewables & Wastes	–	*0.2*	*1.3*	*1.4*	*9.3*	*8.9*	..
Nuclear	*10.0*	*20.7*	*23.5*	*22.9*	*17.3*	*6.7*	..
Hydro	*1.4*	*1.6*	*1.1*	*1.2*	*1.2*	*1.1*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	*0.0*	*0.3*	*0.3*	–	–	..
TOTAL LOSSES	**72.7**	**67.5**	**72.0**	**69.5**	**64.1**	**55.9**	..
of which:							
Electricity and Heat Generation[10]	48.3	47.1	49.8	47.9	43.2	36.7	..
Other Transformation	7.1	4.1	3.7	2.4	2.6	2.5	..
Own Use and Losses[11]	17.3	16.3	18.5	19.2	18.3	16.7	..
Statistical Differences	**0.9**	**-0.7**	**0.8**	**-1.3**	**–**	**–**	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	751.15	1045.06	1352.58	1375.93	1644.01	2053.70	..
Population (millions)	56.22	57.57	58.84	59.21	61.00	61.65	..
TPES/GDP[12]	0.29	0.20	0.17	0.16	0.15	0.12	..
Energy Production/TPES	0.49	0.98	1.12	1.14	..	..	..
Per Capita TPES[13]	3.93	3.69	3.98	3.83	4.00	4.08	..
Oil Supply/GDP[12]	0.15	0.08	0.06	0.06	0.06	0.05	..
TFC/GDP[12]	0.20	0.14	0.12	0.12	0.11	0.10	..
Per Capita TFC[13]	2.62	2.53	2.75	2.67	2.95	3.17	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	640.0	560.3	541.7	529.3	538.7	577.8	..
CO_2 Emissions from Bunkers (Mt CO_2)	25.4	20.9	31.7	29.1	21.5	21.5	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	-0.1	-0.3	0.9	-3.4	0.9	0.3	..
Coal	-0.5	-1.5	-4.3	-8.7	-6.2	-3.1	..
Oil	-2.6	-1.3	-0.1	-3.6	2.1	1.1	..
Gas	8.3	1.4	5.7	-1.3	2.0	1.3	..
Comb. Renewables & Wastes	–	–	12.0	6.0	20.7	0.0	..
Nuclear	5.4	5.0	2.9	-2.0	-2.4	-8.6	..
Hydro	1.6	1.9	-2.2	18.1	0.6	–	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	21.9	28.9	–	–	..
TFC	0.1	-0.2	1.0	-2.1	1.6	0.8	..
Electricity Consumption	0.9	1.0	1.8	-0.1	1.8	0.6	..
Energy Production	10.1	0.7	2.1	-1.6	–	–	..
Net Oil Imports	-27.1	–	10.0	12.5	–	–	..
GDP	1.5	2.2	2.4	1.7	2.2	2.3	..
Growth in the TPES/GDP Ratio	-1.6	-2.5	-1.4	-5.0	-1.3	-1.9	..
Growth in the TFC/GDP Ratio	-1.4	-2.3	-1.4	-3.7	-0.6	-1.4	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY

		1973	1990	2001	2002	2010	2020	2030
TOTAL PRODUCTION		**1 455**	**1 650**	**1 694**	**1 667**	**1 915**	**2 064**	**..**
Coal[1]		333	539	575	555	636	703	..
Oil		534	433	362	359	389	347	..
Gas		503	419	459	444	533	618	..
Comb. Renewables & Wastes[2]		37	62	65	69	86	101	..
Nuclear		23	159	207	210	219	226	..
Hydro		23	23	16	20	27	27	..
Geothermal		2	14	8	8	21	37	..
Solar/Wind/Other[3]		–	0	2	2	4	6	..
TOTAL NET IMPORTS[4]		**289**	**315**	**626**	**607**	**834**	**1 098**	**..**
Coal[1]	Exports	31	67	29	24	23	17	..
	Imports	1	2	13	12	21	26	..
	Net Imports	-30	-65	-16	-12	-1	9	..
Oil	Exports	11	39	47	48	54	54	..
	Imports	316	413	623	606	763	992	..
	Bunkers	9	29	20	23	18	18	..
	Net Imports	296	346	556	535	691	920	..
Gas	Exports	2	2	9	12	23	23	..
	Imports	24	35	92	93	165	191	..
	Net Imports	22	33	84	81	142	167	..
Electricity	Exports	0	2	1	1	1	1	..
	Imports	1	2	3	3	4	2	..
	Net Imports	1	0	2	2	3	2	..
TOTAL STOCK CHANGES		**-8**	**-38**	**-66**	**17**	**–**	**–**	**..**
TOTAL SUPPLY (TPES)		**1 736**	**1 928**	**2 254**	**2 290**	**2 749**	**3 162**	**..**
Coal[1]		311	458	535	542	635	712	..
Oil		824	770	904	900	1 079	1 267	..
Gas		515	439	515	537	675	785	..
Comb. Renewables & Wastes[2]		37	62	65	69	86	101	..
Nuclear		23	159	207	210	219	226	..
Hydro		23	23	16	20	27	27	..
Geothermal		2	14	8	8	21	37	..
Solar/Wind/Other[3]		–	0	2	2	4	6	..
Electricity Trade[5]		1	0	2	2	3	2	..
Shares (%)								
Coal		*17.9*	*23.8*	*23.7*	*23.7*	*23.1*	*22.5*	..
Oil		*47.5*	*40.0*	*40.1*	*39.3*	*39.3*	*40.1*	..
Gas		*29.6*	*22.8*	*22.9*	*23.5*	*24.5*	*24.8*	..
Comb. Renewables & Wastes		*2.2*	*3.2*	*2.9*	*3.0*	*3.1*	*3.2*	..
Nuclear		*1.3*	*8.3*	*9.2*	*9.2*	*8.0*	*7.1*	..
Hydro		*1.3*	*1.2*	*0.7*	*0.9*	*1.0*	*0.8*	..
Geothermal		*0.1*	*0.7*	*0.3*	*0.4*	*0.8*	*1.2*	..
Solar/Wind/Other		–	–	*0.1*	*0.1*	*0.1*	*0.2*	..
Electricity Trade		*0.1*	–	*0.1*	*0.1*	*0.1*	*0.1*	..

0 is negligible, – is nil, .. is not available.

Please note: Care should be taken when evaluating consumption by sector since inputs of fuel to autoproducers are included in final consumption for some years and not for others.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2001	2002	2010	2020	2030
TFC	**1 323**	**1 307**	**1 539**	**1 557**	**1 842**	**2 126**	**..**
Coal[1]	74	54	32	28	33	33	..
Oil	701	698	825	833	990	1 161	..
Gas	367	303	335	345	404	443	..
Comb. Renewables & Wastes[2]	37	23	43	41	53	63	..
Geothermal	–	0	1	1	0	0	..
Solar/Wind/Other	–	–	1	1	1	2	..
Electricity	143	226	297	302	345	411	..
Heat	–	2	5	6	16	13	..
Shares (%)							
Coal	*5.6*	*4.2*	*2.1*	*1.8*	*1.8*	*1.6*	..
Oil	*53.0*	*53.4*	*53.6*	*53.5*	*53.7*	*54.6*	..
Gas	*27.8*	*23.2*	*21.8*	*22.1*	*21.9*	*20.9*	..
Comb. Renewables & Wastes	*2.8*	*1.7*	*2.8*	*2.6*	*2.9*	*3.0*	..
Geothermal	–	–	–	–	–	–	..
Solar/Wind/Other	–	–	*0.1*	*0.1*	*0.1*	*0.1*	..
Electricity	*10.8*	*17.3*	*19.3*	*19.4*	*18.7*	*19.3*	..
Heat	–	*0.2*	*0.3*	*0.4*	*0.9*	*0.6*	..
TOTAL INDUSTRY[6]	**483**	**401**	**461**	**460**	**511**	**576**	**..**
Coal[1]	60	45	29	26	30	31	..
Oil	161	149	168	168	174	196	..
Gas	177	124	139	143	167	186	..
Comb. Renewables & Wastes[2]	29	9	30	30	34	43	..
Geothermal	–	–	0	0	..	..	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	56	75	90	88	93	110	..
Heat	–	–	4	5	13	10	..
Shares (%)							
Coal	*12.5*	*11.2*	*6.4*	*5.7*	*5.9*	*5.3*	..
Oil	*33.4*	*37.1*	*36.5*	*36.6*	*34.1*	*34.1*	..
Gas	*36.7*	*30.9*	*30.1*	*31.1*	*32.7*	*32.2*	..
Comb. Renewables & Wastes	*5.9*	*2.3*	*6.5*	*6.5*	*6.7*	*7.5*	..
Geothermal	–	–	–	–	..	..	..
Solar/Wind/Other	–	–	–	–	–	–	..
Electricity	*11.5*	*18.6*	*19.6*	*19.1*	*18.2*	*19.1*	..
Heat	–	–	*0.9*	*1.0*	*2.5*	*1.8*	..
TRANSPORT[7]	**420**	**502**	**610**	**623**	**781**	**936**	**..**
TOTAL OTHER SECTORS[8]	**420**	**404**	**468**	**475**	**550**	**615**	**..**
Coal[1]	14	10	2	2	2	2	..
Oil	137	63	65	61	63	63	..
Gas	173	164	181	186	218	234	..
Comb. Renewables & Wastes[2]	9	14	10	9	12	12	..
Geothermal	–	0	0	0	0	0	..
Solar/Wind/Other	–	–	1	1	1	2	..
Electricity	87	152	206	214	250	298	..
Heat	–	2	1	1	3	3	..
Shares (%)							
Coal	*3.2*	*2.4*	*0.5*	*0.5*	*0.5*	*0.4*	..
Oil	*32.6*	*15.6*	*13.9*	*12.8*	*11.5*	*10.3*	..
Gas	*41.2*	*40.6*	*38.7*	*39.1*	*39.7*	*38.1*	..
Comb. Renewables & Wastes	*2.1*	*3.4*	*2.2*	*1.9*	*2.1*	*1.9*	..
Geothermal	–	*0.1*	*0.1*	*0.1*	–	–	..
Solar/Wind/Other	–	–	*0.3*	*0.3*	*0.2*	*0.3*	..
Electricity	*20.8*	*37.5*	*44.1*	*45.0*	*45.5*	*48.5*	..
Heat	–	*0.5*	*0.2*	*0.2*	*0.6*	*0.4*	..

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2001	2002	2010	2020	2030
ELECTRICITY GENERATION[9]							
INPUT (Mtoe)	**430**	**745**	**909**	**926**	**1 134**	**1 312**	..
OUTPUT (Mtoe)	**169**	**275**	**330**	**343**	**413**	**489**	..
(TWh gross)	1 966	3 203	3 839	3 993	4 808	5 685	..
Output Shares (%)							
Coal	*46.2*	*53.1*	*51.6*	*51.3*	*50.2*	*49.2*	..
Oil	*17.1*	*4.1*	*3.4*	*2.5*	*2.0*	*2.3*	..
Gas	*18.6*	*11.9*	*17.2*	*17.8*	*20.6*	*24.2*	..
Comb. Renewables & Wastes	*0.0*	*2.7*	*1.7*	*1.8*	*2.1*	*2.1*	..
Nuclear	*4.5*	*19.1*	*20.6*	*20.1*	*17.5*	*15.2*	..
Hydro	*13.5*	*8.5*	*4.9*	*5.8*	*6.5*	*5.5*	..
Geothermal	*0.1*	*0.5*	*0.4*	*0.4*	*0.5*	*0.7*	..
Solar/Wind/Other	–	*0.1*	*0.2*	*0.3*	*0.5*	*0.8*	..
TOTAL LOSSES	**421**	**631**	**708**	**715**	**907**	**1 036**	..
of which:							
Electricity and Heat Generation[10]	261	467	571	574	698	805	..
Other Transformation	-1	15	1	-4	40	40	..
Own Use and Losses[11]	160	149	135	145	169	191	..
Statistical Differences	**-7**	**-10**	**7**	**18**	**–**	**–**	..

INDICATORS

	1973	1990	2001	2002	2010	2020	2030
GDP (billion 1995 US$)	4 005.10	6 520.50	8 977.80	9 196.40	11 875.55	15 770.50	..
Population (millions)	211.94	249.98	284.82	287.46	309.28	334.61	..
TPES/GDP[12]	0.43	0.30	0.25	0.25	0.23	0.20	..
Energy Production/TPES	0.84	0.86	0.75	0.73	0.70	0.65	..
Per Capita TPES[13]	8.19	7.71	7.91	7.97	8.89	9.45	..
Oil Supply/GDP[12]	0.21	0.12	0.10	0.10	0.09	0.08	..
TFC/GDP[12]	0.33	0.20	0.17	0.17	0.16	0.13	..
Per Capita TFC[13]	6.24	5.23	5.40	5.42	5.96	6.35	..
Energy-related CO_2 Emissions (Mt CO_2)[14]	4703.9	4843.0	5613.8	5652.3	6776.2	7837.1	..
CO_2 Emissions from Bunkers (Mt CO_2)	45.2	129.8	113.5	123.9	108.1	109.0	..

GROWTH RATES (% per year)

	73-79	79-90	90-01	01-02	02-10	10-20	20-30
TPES	1.3	0.2	1.4	1.6	2.3	1.4	..
Coal	2.8	2.0	1.4	1.4	2.0	1.2	..
Oil	1.2	-1.2	1.5	-0.4	2.3	1.6	..
Gas	-1.3	-0.7	1.5	4.2	2.9	1.5	..
Comb. Renewables & Wastes	5.9	1.5	0.4	5.4	2.9	1.5	..
Nuclear	20.3	7.7	2.4	1.5	0.6	0.3	..
Hydro	1.1	-0.3	-3.3	24.1	3.7	0.0	..
Geothermal	9.0	13.4	-5.2	5.4	12.5	5.6	..
Solar/Wind/Other	–	–	18.2	13.2	5.9	4.5	..
TFC	0.7	-0.5	1.5	1.2	2.1	1.4	..
Electricity Consumption	3.1	2.5	2.5	1.7	1.7	1.8	..
Energy Production	0.8	0.7	0.2	-1.6	1.8	0.8	..
Net Oil Imports	5.1	-1.3	4.4	-3.7	3.2	2.9	..
GDP	3.0	2.9	2.9	2.4	3.2	2.9	..
Growth in the TPES/GDP Ratio	-1.6	-2.6	-1.5	-0.8	-0.9	-1.4	..
Growth in the TFC/GDP Ratio	-2.2	-3.3	-1.4	-1.2	-1.1	-1.4	..

Please note: Rounding may cause totals to differ from the sum of the elements.

ANNEX A

ENERGY BALANCES AND KEY STATISTICAL DATA TABLES

Table A1

GDP Growth Rates for IEA Countries[1]

(annual average percentage change)

	1973-1979	1998	1999	2000	2001	2002	2003
Canada	3.6	4.1	5.7	5.3	1.9	3.3	1.8
United States	3.0	4.3	4.1	3.8	0.3	2.4	2.9
North America	**3.0**	**4.3**	**4.3**	**3.9**	**0.4**	**2.5**	**2.8**
Australia	2.5	5.3	4.0	1.8	3.9	2.7	2.4
Japan	3.5	-1.1	0.1	2.8	0.4	0.1	2.7
Korea	8.5	-6.7	10.9	9.3	3.1	6.3	2.7
New Zealand	0.0	0.4	5.0	2.7	3.5	4.3	2.8
Pacific	**3.5**	**-1.2**	**1.2**	**3.3**	**0.9**	**0.9**	**2.7**
Austria	3.0	3.9	2.7	3.4	0.8	1.4	0.7
Belgium	2.4	2.0	3.2	3.8	0.6	0.7	1.1
Czech Republic	2.5	-1.0	0.5	3.3	3.1	2.0	2.9
Denmark	1.5	2.5	2.6	2.9	1.4	2.1	0.4
Finland	2.5	5.0	3.4	5.1	1.2	2.2	1.8
France	2.8	3.4	3.2	3.8	2.1	1.2	0.1
Germany	2.4	2.0	2.0	2.9	0.8	0.2	-0.1
Greece	3.3	3.4	3.4	4.4	4.0	3.8	4.8
Hungary	4.3	4.9	4.2	5.2	3.8	3.5	3.0
Ireland	4.9	8.6	11.3	10.1	6.2	6.9	1.8
Italy	3.5	1.8	1.7	3.1	1.8	0.4	0.3
Luxembourg	1.3	6.9	7.8	9.1	1.2	1.3	1.1
Netherlands	2.6	4.3	4.0	3.5	1.2	0.2	-0.5
Norway	4.9	2.6	2.1	2.8	1.9	1.0	0.3
Portugal	2.9	4.6	3.8	3.7	1.6	0.4	-0.8
Spain	2.3	4.3	4.2	4.2	2.8	2.0	2.4
Sweden	1.8	3.6	4.6	4.3	0.9	1.9	1.8
Switzerland	-0.4	2.4	1.5	3.2	0.9	0.2	-0.5
Turkey	4.5	3.1	-4.7	7.4	-7.5	7.8	5.8
United Kingdom	1.5	3.1	2.8	3.8	2.1	1.7	2.2
IEA Europe	**2.5**	**2.9**	**2.6**	**3.6**	**1.5**	**1.2**	**0.8**
IEA Total	**2.9**	**2.3**	**2.9**	**3.6**	**0.9**	**1.6**	**2.0**

1. Data are in 1995 dollars at 1995 prices.

Sources: *National Accounts, Volume 1*, OECD Paris, 2004, and *Main Economic Indicators*, OECD Paris, 2004.

Table A2

TPES/GDP Ratios for IEA Countries[1]

	1973	1979	2001	2002	2003[2]	Average Annual Growth Rates (%) 1991-1996	1997-2002
Canada	0.50	0.48	0.34	0.33	0.32	0.10	-3.1
United States	0.43	0.39	0.25	0.25	0.24	-1.2	-1.8
North America	**0.44**	**0.40**	**0.26**	**0.26**	**0.25**	**-1.1**	**-1.9**
Australia	0.29	0.30	0.23	0.23	0.24	-0.8	-1.5
Japan	0.12	0.11	0.09	0.09	0.09	1.1	-0.5
Korea	0.23	0.26	0.30	0.30	0.30	3.1	-1.4
New Zealand	0.19	0.21	0.25	0.24	0.24	-0.5	-2.6
Pacific	**0.14**	**0.13**	**0.12**	**0.12**	**0.12**	**1.9**	**-0.2**
Austria	0.16	0.15	0.11	0.11	0.12	-0.6	-1.2
Belgium	0.27	0.24	0.19	0.18	0.18	0.4	-2.2
Czech Republic	1.12	1.04	0.73	0.72	0.73	-2.6	-1.9
Denmark	0.15	0.15	0.10	0.09	0.10	0.5	-3.5
Finland	0.26	0.26	0.20	0.21	0.22	0.5	-1.8
France	0.19	0.17	0.15	0.15	0.15	0.1	-1.2
Germany	0.22	0.21	0.13	0.13	0.13	-0.9	-1.8
Greece	0.15	0.16	0.20	0.19	0.19	0.5	-0.8
Hungary	0.61	0.63	0.45	0.44	0.43	-1.4	-4.2
Ireland	0.27	0.25	0.13	0.13	0.12	-3.3	-4.1
Italy	0.20	0.18	0.14	0.14	0.15	-0.8	-0.5
Luxembourg	0.53	0.43	0.15	0.15	0.16	-4.8	-1.6
Netherlands	0.25	0.23	0.15	0.15	0.16	-0.8	-1.5
Norway	0.22	0.21	0.15	0.15	0.13	-3.1	-0.6
Portugal	0.13	0.15	0.19	0.20	0.20	1.2	1.2
Spain	0.15	0.17	0.18	0.18	0.18	-0.1	0.5
Sweden	0.23	0.23	0.17	0.17	0.16	-0.0	-2.5
Switzerland	0.08	0.08	0.08	0.08	0.08	0.2	-1.0
Turkey	0.36	0.34	0.38	0.37	0.37	0.6	0.2
United Kingdom	0.29	0.27	0.17	0.16	0.16	-1.2	-2.7
IEA Europe	**0.22**	**0.21**	**0.16**	**0.15**	**0.16**	**-0.5**	**-1.4**
IEA Total	**0.28**	**0.25**	**0.18**	**0.18**	**0.18**	**-0.2**	**-1.2**

1. Measured in toe per $1 000 of GDP at 1995 prices and exchange rates; changes in energy intensity reflect the combined effects of efficiency improvements, structural changes, fuel substitution and exchange rates.
2. Preliminary data.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004, *National Accounts, Volume 1*, OECD Paris, 2003, and *Main Economic Indicators*, OECD Paris, 2004.

Table A3

TPES per Inhabitant for IEA Countries

(toe per capita)

	1973	1979	2001	2002	2003[1]	Average Annual Growth Rates (%) 1991-1996	Average Annual Growth Rates (%) 1997-2002
Canada	7.11	7.88	7.98	7.96	7.85	1.4	-0.1
United States	8.19	8.36	7.91	7.97	7.90	0.70	0.1
North America	**8.09**	**8.31**	**7.92**	**7.97**	**7.89**	**0.77**	**0.1**
Australia	4.23	4.70	5.55	5.71	5.81	1.91	0.8
Japan	2.98	3.06	4.06	4.06	4.03	2.3	-0.3
Korea	0.63	1.07	4.10	4.27	4.35	9.1	2.2
New Zealand	2.78	2.88	4.63	4.53	4.48	2.15	-0.4
Pacific	**2.58**	**2.76**	**4.23**	**4.28**	**4.30**	**3.41**	**0.4**
Austria	2.85	3.17	3.84	3.78	3.94	0.8	0.9
Belgium	4.76	4.93	5.74	5.51	5.67	1.6	-0.4
Czech Republic	4.58	4.73	4.05	4.09	4.29	-0.3	-0.2
Denmark	3.95	4.16	3.74	3.67	3.80	2.3	-1.6
Finland	4.57	5.12	6.53	6.85	7.12	1.2	1.3
France	3.46	3.54	4.37	4.34	4.41	0.7	1.0
Germany	4.28	4.73	4.29	4.20	4.21	-0.2	-0.4
Greece	1.36	1.65	2.62	2.65	2.73	1.1	2.7
Hungary	2.05	2.65	2.51	2.51	2.57	-0.9	0.2
Ireland	2.34	2.63	3.93	3.91	3.70	1.8	2.8
Italy	2.35	2.51	2.98	2.98	3.11	0.2	1.0
Luxembourg	12.83	10.69	8.67	9.06	9.40	-3.4	2.3
Netherlands	4.65	4.91	4.82	4.83	4.96	0.7	0.4
Norway	3.70	4.54	5.86	5.84	5.22	0.4	0.9
Portugal	0.84	1.03	2.47	2.54	2.47	2.4	3.5
Spain	1.50	1.80	3.17	3.24	3.32	1.2	3.5
Sweden	4.83	5.17	5.75	5.72	5.59	0.7	0.3
Switzerland	3.06	3.15	3.87	3.72	3.70	-0.5	0.1
Turkey	0.63	0.70	1.04	1.08	1.14	3.2	-0.6
United Kingdom	3.93	3.91	3.98	3.83	3.86	0.9	-0.1
IEA Europe	**3.10**	**3.27**	**3.52**	**3.49**	**3.54**	**0.51**	**0.4**
IEA Total	**4.44**	**4.64**	**5.06**	**5.07**	**5.09**	**1.22**	**0.3**

1. Preliminary data.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004, *National Accounts, Volume 1*, OECD Paris, 2003, and *Main Economic Indicators*, OECD Paris, 2004.

Table A4

TFC/GDP Ratios for IEA Countries[1]

	1973	1979	2000	2001	2002	Average Annual Growth Rates (%) 1991-1996	1997-2002
Canada	0.41	0.39	0.27	0.25	0.25	0.3	-3.3
United States	0.33	0.29	0.17	0.17	0.17	-1.3	-1.6
North America	**0.34**	**0.30**	**0.18**	**0.18**	**0.18**	**-1.1**	**-1.7**
Australia	0.20	0.20	0.16	0.16	0.15	-1.1	-2.6
Japan	0.09	0.08	0.06	0.06	0.06	1.2	0.2
Korea	0.19	0.20	0.20	0.20	0.20	2.7	-1.7
New Zealand	0.14	0.16	0.20	0.19	0.20	-0.1	-0.0
Pacific	**0.10**	**0.09**	**0.08**	**0.08**	**0.08**	**2.0**	**0.13**
Austria	0.12	0.12	0.09	0.10	0.09	-0.0	-1.0
Belgium	0.20	0.18	0.13	0.14	0.13	1.3	-1.8
Czech Republic	0.82	0.83	0.45	0.45	0.43	-4.5	-2.8
Denmark	0.13	0.12	0.07	0.07	0.07	-0.6	-2.7
Finland	0.24	0.21	0.15	0.15	0.15	-0.6	-1.4
France	0.15	0.13	0.09	0.10	0.09	-0.3	-1.9
Germany	0.16	0.15	0.09	0.09	0.09	-0.7	-2.1
Greece	0.11	0.11	0.14	0.14	0.14	1.1	-1.2
Hungary	0.49	0.49	0.32	0.32	0.31	-2.4	-3.2
Ireland	0.20	0.19	0.11	0.10	0.10	-3.7	-3.4
Italy	0.15	0.13	0.11	0.11	0.11	-0.5	-0.5
Luxembourg	0.35	0.32	0.14	0.15	0.15	-3.1	-1.7
Netherlands	0.19	0.19	0.12	0.12	0.12	-1.1	-1.4
Norway	0.20	0.19	0.12	0.12	0.11	-2.2	-0.9
Portugal	0.11	0.12	0.16	0.15	0.16	1.6	0.8
Spain	0.11	0.13	0.13	0.13	0.13	0.6	0.8
Sweden	0.21	0.19	0.12	0.12	0.12	1.3	-3.3
Switzerland	0.07	0.07	0.06	0.06	0.06	0.1	-0.9
Turkey	0.29	0.29	0.28	0.27	0.28	0.3	-0.1
United Kingdom	0.20	0.18	0.12	0.12	0.12	-1.2	-2.4
IEA Europe	**0.17**	**0.16**	**0.11**	**0.11**	**0.11**	**-0.4**	**-1.5**
IEA Total	**0.21**	**0.19**	**0.13**	**0.13**	**0.13**	**-0.2**	**-1.1**

1. Measured in toe per $1 000 of GDP at 1995 prices and exchange rates.

Sources: *Energy Balances of OECD Countries*. IEA/OECD Paris, 2004, *National Accounts*, *Volume 1*. OECD Paris, 2003, and *Main Economic Indicators*, OECD Paris, 2004.

Table A5

Total Energy Demand in IEA Countries

(Mtoe and %)

	1973						1979					
	TPES	Shares of TPES					TPES	Shares of TPES				
	Mtoe	Coal %	Oil %	Natural Gas %	Nuclear %	Other[1] %	Mtoe	Coal %	Oil %	Natural Gas %	Nuclear %	Other[1] %
Canada	159.8	9.5	50.0	23.3	2.5	14.6	190.8	10.4	48.2	22.9	5.1	13.4
United States	1 736.4	17.9	47.5	9.6	1.3	3.7	1 881.2	19.5	47.0	25.4	3.7	4.4
North America	**1 896.3**	**17.2**	**47.7**	**29.1**	**1.4**	**4.6**	**2 072.0**	**18.7**	**47.1**	**25.1**	**3.9**	**5.2**
Australia	57.6	39.2	47.1	5.9	-	7.8	68.7	36.0	46.8	10.1	-	7.1
Japan	323.5	17.9	77.9	1.6	0.8	1.8	354.6	14.4	73.0	5.2	5.2	2.2
Korea	21.6	37.6	61.9	-	-	0.5	40.0	30.2	67.2	-	2.1	0.5
New Zealand	8.3	15.3	53.5	3.4	-	27.8	9.0	10.6	46.4	9.5	-	33.5
Pacific	**411.1**	**21.9**	**72.3**	**2.1**	**0.6**	**3.1**	**472.3**	**18.8**	**68.2**	**5.6**	**4.1**	**3.4**
Austria	21.7	17.9	56.7	15.3	-	10.1	23.9	15.2	53.9	18.1	-	12.9
Belgium	46.3	24.1	60.5	15.4	0.0	-0.1	48.4	21.7	52.9	19.2	6.1	-0.0
Czech Republic	45.4	78.4	19.6	2.2	-	-0.2	48.7	71.9	23.5	4.6	-	0.0
Denmark	19.8	9.7	88.6	-	-	1.7	21.3	20.3	75.9	-	-	3.7
Finland	21.3	12.0	63.6	-	-	24.4	24.4	17.4	54.0	3.3	7.2	18.0
France	184.7	15.8	67.3	7.3	2.1	7.4	193.9	16.7	59.0	10.7	5.4	8.1
Germany	337.9	41.2	47.9	8.5	0.9	1.4	369.6	37.4	43.6	13.9	3.7	1.4
Greece	12.4	17.0	77.7	-	-	5.2	16.0	21.6	73.6	-	-	4.8
Hungary	21.3	37.1	38.5	19.6	-	4.9	28.4	30.0	40.2	26.0	-	3.8
Ireland	7.2	22.0	77.1	-	-	0.8	8.9	22.5	71.5	5.2	-	0.8
Italy	128.9	6.3	77.6	11.0	0.6	4.4	141.1	7.4	70.8	16.1	0.5	5.3
Luxembourg	4.5	54.1	37.1	4.9	-	4.0	3.9	47.4	33.8	12.1	-	6.6
Netherlands	62.4	4.6	49.5	45.6	0.5	-0.2	68.9	4.8	45.9	47.6	1.3	0.4
Norway	14.6	6.2	54.0	-	-	39.8	18.5	5.4	48.7	3.8	-	42.1
Portugal	7.2	7.0	75.4	-	-	17.5	10.0	4.4	78.3	-	-	17.3
Spain	52.4	17.2	73.3	1.8	3.3	4.4	66.8	16.1	73.3	2.1	2.6	5.9
Sweden	39.3	4.1	72.2	-	1.4	22.3	42.9	4.2	61.3	-	12.8	21.7
Switzerland	19.7	1.7	77.4	0.8	8.3	11.9	20.0	1.1	66.9	3.8	15.4	12.8
Turkey	24.4	21.1	51.3	-	-	27.6	30.3	21.6	49.5	-	-	28.9
United Kingdom	220.7	34.6	50.5	11.4	3.3	0.2	220.0	33.7	43.2	18.4	4.5	0.2
IEA Europe	**1 292.2**	**26.5**	**57.4**	**9.8**	**1.5**	**4.7**	**1 405.9**	**25.1**	**52.1**	**13.9**	**3.6**	**5.2**
IEA Total	**3 599.6**	**21.1**	**54.0**	**19.1**	**1.4**	**4.5**	**3 950.2**	**21.0**	**51.4**	**18.8**	**3.8**	**5.0**

1. Includes hydro, geothermal, combustible renewables, wastes, solar, wind, tide, wave, ambient heat used in heat pumps, and electricity and heat trade.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A5 *(continued)*

Total Energy Demand in IEA Countries

(Mtoe and %)

	2002						2003[1]						2002-2003
	TPES	Shares of TPES					TPES	Shares of TPES					Change in TPES
	Mtoe	Coal %	Oil %	Natural Gas %	Nuclear %	Other[2] %	Mtoe	Coal %	Oil %	Natural Gas %	Nuclear %	Other[2] %	%
Canada	250.0	11.8	34.4	30.1	7.9	15.9	248.3	11.9	36.1	28.2	7.8	16.1	-0.7
United States	2 290.4	23.7	39.3	23.5	9.2	4.4	2 291.2	23.7	40.4	22.6	8.9	4.4	0.0
North America	**2 540.4**	**22.5**	**38.8**	**24.1**	**9.0**	**5.6**	**2 539.5**	**22.5**	**40.0**	**23.1**	**8.8**	**5.6**	**-0.0**
Australia	112.7	43.4	30.8	18.3	-	7.5	115.8	42.6	31.4	18.5	-	7.5	2.8
Japan	516.9	19.3	49.4	12.8	14.9	3.5	514.5	20.0	50.0	13.8	12.7	3.6	-0.5
Korea	203.5	22.6	50.1	10.4	15.3	1.6	208.7	22.3	49.2	10.5	16.2	1.8	2.6
New Zealand	18.0	6.9	34.9	28.1	-	30.1	18.1	9.5	38.8	21.6	-	30.1	0.5
Pacific	**851.2**	**23.0**	**46.8**	**13.3**	**12.7**	**4.1**	**857.1**	**23.4**	**47.0**	**13.8**	**11.6**	**4.2**	**0.7**
Austria	30.4	11.9	43.5	21.7	-	23.0	31.8	12.2	42.2	23.7	-	21.8	4.5
Belgium	56.9	11.7	40.2	23.5	21.7	2.8	58.3	10.9	42.5	22.8	21.2	2.7	2.5
Czech Republic	41.7	49.1	20.4	18.6	11.7	0.1	43.7	47.6	20.1	18.0	15.4	-1.1	4.7
Denmark	19.7	21.1	43.2	23.4	-	12.3	20.5	28.2	39.5	22.7	-	9.6	3.7
Finland	35.6	18.5	29.5	10.3	16.3	25.4	37.1	22.2	28.2	11.0	16.0	22.6	4.2
France	265.9	5.0	34.3	14.1	42.8	3.8	270.3	5.2	33.8	14.2	42.5	4.3	1.6
Germany	346.4	24.6	37.2	21.8	12.4	4.0	345.1	24.6	36.2	22.9	12.5	3.7	-0.4
Greece	29.0	30.9	57.1	6.2	-	5.8	29.9	29.8	57.5	6.7	-	6.0	3.0
Hungary	25.4	14.2	25.5	42.4	14.3	3.5	26.1	14.5	24.7	45.5	11.0	4.2	2.5
Ireland	15.3	16.8	57.0	24.0	-	2.2	14.6	16.7	55.9	24.9	-	2.5	-4.3
Italy	172.7	7.9	50.6	33.4	-	8.1	180.7	8.2	48.3	34.8	-	8.7	4.6
Luxembourg	4.0	2.3	62.9	26.1	-	8.7	4.2	1.8	64.7	25.1	-	8.4	4.9
Netherlands	77.9	10.8	38.2	46.0	1.3	3.7	80.1	10.7	39.3	45.0	1.3	3.6	2.8
Norway	26.5	3.1	29.5	23.2	-	44.3	23.8	3.3	28.8	20.9	-	47.0	-10.1
Portugal	26.4	13.2	62.1	10.3	-	14.4	25.7	12.8	59.3	10.3	-	17.7	-2.6
Spain	131.6	16.4	51.1	14.2	12.5	5.7	135.2	14.5	51.1	15.7	11.9	6.8	2.8
Sweden	51.0	5.6	29.2	1.5	34.5	29.2	50.0	5.1	30.4	1.6	34.1	28.8	-1.9
Switzerland	27.1	0.5	47.8	9.2	26.2	16.3	27.0	0.5	46.5	9.7	26.5	16.8	-0.4
Turkey	75.4	26.2	40.5	19.5	-	13.7	80.3	27.9	37.6	22.1	-	12.4	6.5
United Kingdom	226.5	15.7	34.7	37.8	10.1	1.6	229.5	16.7	34.3	37.4	10.1	1.5	1.3
IEA Europe	**1 685.7**	**15.5**	**39.4**	**23.2**	**14.7**	**7.1**	**1 714.1**	**15.7**	**38.7**	**23.8**	**14.6**	**7.1**	**1.7**
IEA Total	**5 077.3**	**20.3**	**40.3**	**22.0**	**11.5**	**5.8**	**5 110.7**	**20.4**	**40.7**	**21.8**	**11.2**	**5.9**	**0.7**

1. Preliminary data.
2. Includes hydro, geothermal, combustible renewables, wastes, solar, wind, tide, wave, ambient heat used in heat pumps, and electricity and heat trade.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A5 *(continued)*

Total Energy Demand in IEA Countries

(Mtoe and %)

	2010						2020						2010-2020
	TPES	Shares of TPES					TPES	Shares of TPES					Change in TPES
	Mtoe	Coal %	Oil %	Natural Gas %	Nuclear %	Other[1] %	Mtoe	Coal %	Oil %	Natural Gas %	Nuclear %	Other[1] %	%
Canada	306.8 e	9.2	31.4	35.9	7.6	15.9	350.2 e	6.3	30.7	41.7	6.3	15.1	14.2
United States	2 749.2	23.1	39.3	24.5	8.0	5.1	3 162.1	22.5	40.1	24.8	7.1	5.4	15.0
North America	**3 055.9**	**21.7**	**38.5**	**25.7**	**7.9**	**6.2**	**3 512.3**	**20.9**	**39.1**	**26.5**	**7.0**	**6.4**	**14.9**
Australia	146.1	34.8	33.6	24.5	–	7.1	178.5	33.6	34.1	25.9	–	6.4	22.1
Japan	554.6	17.8	42.4	12.3	19.7	7.8	..	..	..	..	..	..	..
Korea	..	..	..	..	..	..	..	..	..	..	..	..	..
New Zealand	19.8	6.4	38.3	16.6	–	38.8	22.6	5.6	37.0	16.8	–	40.7	14.3
Pacific	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**
Austria	32.3	9.2	38.9	28.0	–	24.0	34.9	6.0	40.3	29.5	–	24.3	8.2
Belgium	..	..	..	..	..	..	..	..	..	..	..	..	..
Czech Republic	42.1	33.5	21.4	26.4	15.9	2.8	44.0	28.0	21.4	30.2	15.2	5.2	4.5
Denmark	23.6	23.2	42.6	25.6	–	8.5	..	..	..	..	..	..	..
Finland	37.3	16.9	22.7	14.6	20.5	25.3	40.0	18.1	21.1	15.2	21.0	24.6	7.1
France	298.8	3.4	34.8	15.8	40.3	5.7	319.9	3.6	33.4	18.4	36.8	7.7	7.0
Germany	..	..	..	..	..	..	..	..	..	..	..	..	..
Greece	40.5	23.6	54.1	17.4	–	4.9	..	..	..	..	..	..	..
Hungary	26.9	13.1	26.6	42.7	13.4	4.1	27.7	12.1	26.9	43.5	13.0	4.6	3.3
Ireland	16.8	11.3	50.3	35.2	–	3.2	..	..	..	..	..	..	..
Italy	198.3	9.2	41.7	38.1	–	10.9	208.0	9.6	37.0	40.9	–	12.5	4.9
Luxembourg	3.7	2.7	48.4	39.5	–	9.5	..	..	..	..	..	..	..
Netherlands	81.1	10.0	38.1	45.1	1.3	5.5	89.4	10.4	35.8	48.2	–	5.6	10.2
Norway	..	..	..	..	..	..	..	..	..	..	..	..	..
Portugal	30.0	10.2	53.9	17.1	–	18.8	..	..	..	..	..	..	..
Spain	170.2 e	8.9	47.9	21.7	9.7	11.6	..	..	..	..	..	..	..
Sweden	53.7	4.9	30.6	1.4	32.1	31.0	..	..	..	..	..	..	..
Switzerland	27.1	0.4	48.2	10.5	23.2	17.7	26.7	0.4	48.5	11.2	20.7	19.3	-1.4
Turkey	152.2	26.1	33.6	32.6	–	7.7	279.2	38.5	25.8	26.7	2.6	6.4	83.4
United Kingdom	244.1	8.7	37.9	41.0	7.8	4.6	251.5	6.2	40.9	45.3	3.1	4.4	3.0
IEA Europe	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**
IEA Total	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**

1. Includes hydro, geothermal, combustible renewables, wastes, solar, wind, tide. wave, ambient heat used in heat pumps and electricity trade.

Note: The IEA Secretariat has estimated data for certain countries. Please see Energy Balances and Key Statistical Data for details.

Source: Country submissions.

Table A6

Development of IEA Energy Self-sufficiency by Product

(Mtoe and %)

	1973			1979			2001			2002			2003[1]		
	TPES	Production	%	TPES	Production	%	TPES	Production	%	TPES	Production	%	TPES	Production	%
North America															
Coal	326.3	345.1	105.7	386.8	443.6	114.7	565.4	612.2	108.3	571.5	589.9	103.2	571.8	569.7	99.6
Oil	903.9	630.2	69.7	975.6	581.7	59.6	992.4	492.7	49.6	986.0	494.7	50.2	1015.5	499.6	49.2
Natural Gas	551.8	564.0	102.2	520.6	521.8	100.2	587.2	611.5	104.1	612.4	597.2	97.5	586.8	595.1	101.4
Total	**1 896.3**	**1 653.5**	**87.2**	**2 072.0**	**1 736.1**	**83.8**	**2 502.1**	**2 073.5**	**82.9**	**2 540.4**	**2 052.1**	**80.8**	**2 539.5**	**2 030.0**	**79.9**
Pacific															
Coal	89.8	66.1	73.6	89.0	70.3	79.0	189.2	184.0	97.3	196.2	188.2	95.9	200.6	188.5	94.0
Oil	297.1	20.7	7.0	321.9	23.7	7.4	392.5	38.1	9.7	398.5	36.0	9.0	403.0	33.3	8.3
Natural Gas	8.7	6.0	68.1	26.4	9.9	37.6	110.6	36.6	33.1	113.2	37.0	32.7	118.1	37.1	31.4
Total	**411.1**	**108.2**	**26.3**	**472.3**	**138.9**	**29.4**	**837.4**	**403.8**	**48.2**	**851.2**	**404.4**	**47.5**	**857.1**	**394.2**	**46.0**
IEA Europe															
Coal	342.7	303.2	88.5	352.8	296.6	84.1	264.5	140.3	53.0	261.9	137.4	52.5	269.7	134.2	49.7
Oil	742.0	22.8	3.1	732.8	118.0	16.1	672.7	321.9	47.8	663.8	319.2	48.1	663.1	304.0	45.8
Natural Gas	127.0	119.9	94.4	195.9	167.2	85.3	387.4	242.8	62.7	391.2	249.2	63.7	408.4	251.1	61.5
Total	**1 292.2**	**525.9**	**40.7**	**1 405.9**	**705.3**	**50.2**	**1 692.9**	**1 070.4**	**63.2**	**1 685.7**	**1 071.4**	**63.6**	**1 714.1**	**1 059.2**	**61.8**
IEA Total															
Coal	758.9	714.4	94.1	828.6	810.6	97.8	1 019.1	936.5	91.9	1 029.5	915.5	88.9	1 042.2	892.4	85.6
Oil	1 943.0	673.7	34.7	2 030.4	723.4	35.6	2 057.6	852.6	41.4	2 048.3	849.9	41.5	2 081.6	836.9	40.2
Natural Gas	687.5	689.8	100.3	743.0	698.9	94.1	1 085.3	890.9	82.1	1 116.9	883.3	79.1	1 113.3	883.3	79.3
Total	**3 599.6**	**2 287.6**	**63.6**	**3 950.2**	**2 580.3**	**65.3**	**5 032.4**	**3 547.6**	**70.5**	**5 077.3**	**3 527.9**	**69.5**	**5 110.7**	**3 483.4**	**68.2**

1. Preliminary data.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A7

Indigenous Production/Primary Energy Supply in IEA Countries, 2002

	Total Energy[1]	Coal[1]	Oil[1]	Gas[1]	Electricity[2]
Canada	1.541	1.183	1.582	2.040	1.034
United States	0.728	1.024	0.399	0.826	0.995
North America	**0.808**	**1.032**	**0.502**	**0.975**	**1.000**
Australia	2.264	3.764	0.956	1.431	1.000
Japan	0.190	–	0.003	0.036	1.000
Korea	0.178	0.031	0.005	–	1.000
New Zealand	0.826	2.190	0.266	1.000	1.000
Pacific	**0.475**	**0.959**	**0.090**	**0.327**	**1.000**
Austria	0.326	0.092	0.080	0.242	0.989
Belgium	0.233	0.014	–	–	0.914
Czech Republic	0.735	1.180	0.048	0.015	1.176
Denmark	1.456	–	2.185	1.643	1.056
Finland	0.452	0.333	0.006	–	0.863
France	0.506	0.094	0.017	0.039	1.161
Germany	0.389	0.689	0.033	0.212	0.983
Greece	0.353	0.957	0.011	0.023	0.949
Hungary	0.426	0.741	0.251	0.218	0.895
Ireland	0.098	0.208	–	0.184	0.980
Italy	0.154	0.008	0.063	0.208	0.846
Luxembourg	0.014	–	–	–	0.448
Netherlands	0.769	–	0.106	1.514	0.854
Norway	8.758	1.758	20.348	9.633	1.081
Portugal	0.138	–	–	–	0.960
Spain	0.241	0.345	0.005	0.025	0.979
Sweden	0.635	0.120	–	–	0.964
Switzerland	0.440	–	–	–	1.075
Turkey	0.324	0.588	0.078	0.021	0.976
United Kingdom	1.138	0.499	1.538	1.088	0.979
IEA Europe	**0.636**	**0.525**	**0.481**	**0.637**	**0.991**
IEA Total	**0.695**	**0.889**	**0.415**	**0.791**	**0.997**

1. Calculated as production divided by primary energy supply.
2. Calculated as the ratio between domestic generation and total apparent consumption, or TFC plus own-use in the energy sector and distribution losses. Includes CHP units.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A8

Recent Energy and Oil Supply Trends for IEA Countries

(Mtoe and %)

	TPES					Oil Supply					Net Oil Imports[1]				
	2001	2002	% Chg.	2003[2]	% Chg.	2001	2002	% Chg.	2003[2]	% Chg.	2001	2002	% Chg.	2003[2]	% Chg.
Canada	248.2	250.0	0.8	248.3	-0.7	88.4	85.9	-2.9	89.5	4.2	-39.3	-49.0	24.5	-50.4	3.0
United States	2 253.9	2 290.4	1.6	2 291.2	0.0	904.0	900.1	-0.4	925.9	2.9	575.2	558.2	-3.0	595.2	6.6
North America	**2 502.1**	**2 540.4**	**1.5**	**2 539.5**	**-0.0**	**992.4**	**986.0**	**-0.6**	**1 015.5**	**3.0**	**535.9**	**509.2**	**-5.0**	**544.8**	**7.0**
Australia	108.3	112.7	4.0	115.8	2.8	33.2	34.7	4.5	36.3	4.7	-0.1	1.6	-2202.6	6.3	284.8
Japan	517.0	516.9	0.0	514.5	-0.5	252.7	255.5	1.1	257.1	0.6	253.2	258.1	1.9	260.7	1.0
Korea	193.9	203.5	4.9	208.7	2.6	100.2	102.0	1.8	102.6	0.6	106.4	106.5	0.1	110.1	3.4
New Zealand	18.1	18.0	-0.4	18.1	0.5	6.4	6.3	-1.7	7.0	11.6	4.6	5.1	9.9	5.8	13.6
Pacific	**837.4**	**851.2**	**1.6**	**857.1**	**0.7**	**392.5**	**398.5**	**1.5**	**403.0**	**1.1**	**364.2**	**371.3**	**2.0**	**382.9**	**3.1**
Austria	30.9	30.4	-1.4	31.8	4.5	13.2	13.2	0.4	13.4	1.5	11.7	12.6	7.4	12.7	0.8
Belgium	59.0	56.9	-3.6	58.3	2.5	24.3	22.9	-5.6	24.8	8.2	29.8	29.4	-1.2	31.9	8.5
Czech Republic	41.4	41.7	0.8	43.7	4.7	8.4	8.5	1.6	8.8	2.9	8.2	8.0	-2.5	8.4	5.4
Denmark	20.0	19.7	-1.3	20.5	3.7	8.8	8.5	-3.5	8.1	-5.2	-7.1	-9.4	32.1	-9.7	2.5
Finland	33.9	35.6	5.2	37.1	4.2	9.4	10.5	11.4	10.5	-0.2	10.4	10.4	0.4	11.4	8.9
France	266.4	265.9	-0.2	270.3	1.6	93.9	91.3	-2.8	91.4	0.1	94.5 e	93.4 e	-1.1	94.4	1.0
Germany	353.4	346.4	-2.0	345.1	-0.4	134.5	128.8	-4.2	125.0	-3.0	132.9	124.5	-6.4	124.6	0.1
Greece	28.7	29.0	1.1	29.9	3.0	16.1	16.6	2.7	17.2	3.8	19.3	20.4	5.3	19.7	-3.4
Hungary	25.6	25.4	-0.5	26.1	2.5	6.6	6.5	-1.9	6.5	-0.6	4.7	4.7	-0.3	4.8	2.5
Ireland	15.1	15.3	1.1	14.6	-4.3	8.7	8.7	0.4	8.2	-6.2	9.0	9.0	-0.3	8.5	-5.8
Italy	172.6	172.7	0.1	180.7	4.6	87.1	87.4	0.3	87.2	-0.2	83.9	85.6	2.0	84.4	-1.4
Luxembourg	3.8	4.0	5.4	4.2	4.9	2.5	2.5	2.4	2.7	7.8	2.5	2.6	4.3	2.7	7.3
Netherlands	77.3	77.9	0.8	80.1	2.8	29.5	29.8	0.9	31.5	5.7	41.8	40.5	-3.2	41.3	2.0
Norway	26.4	26.5	0.3	23.8	-10.1	8.1	7.8	-3.1	6.9	-12.2	-158.0	-150.6 e	-4.7	-145.0	-3.7
Portugal	25.4	26.4	3.8	25.7	-2.6	15.9	16.4	3.2	15.2	-7.0	16.8	16.3	-3.0	16.4	0.5
Spain	127.8	131.6	2.9	135.2	2.8	67.1	67.3	0.3	69.0	2.6	73.3	75.0	2.3	75.7	1.0
Sweden	51.2	51.0	-0.3	50.0	-1.9	14.3	14.9	4.3	15.2	2.3	15.5 e	15.3 e	-1.4	17.8	16.3
Switzerland	28.0	27.1	-3.1	27.0	-0.4	13.9	13.0	-6.5	12.6	-3.1	13.7	13.0	-5.0	12.5	-4.2
Turkey	71.6	75.4	5.3	80.3	6.5	28.9	30.5	5.7	30.2	-1.1	26.8	28.4	6.1	28.7	1.1
United Kingdom	234.4	226.5	-3.4	229.5	1.3	81.6	78.6	-3.6	78.8	0.2	-36.7	-41.3	12.7	-29.2	-29.4
IEA Europe	**1 692.9**	**1 685.7**	**-0.4**	**1 714.1**	**1.7**	**672.7**	**663.8**	**-1.3**	**663.1**	**-0.1**	**393.1**	**387.7**	**-1.4**	**412.0**	**6.3**
IEA Total	**5 032.4**	**5 077.3**	**0.9**	**5 110.7**	**0.7**	**2 057.6**	**2 048.3**	**-0.4**	**2 081.6**	**1.6**	**1 293.2**	**1 268.2**	**-1.9**	**1 339.6**	**5.6**

1. Imports minus exports.
2. Preliminary data.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A9

Share of Oil Use by Sector in IEA Countries

(%)

	TFC				Industry[1]				Residential/Commercial[2]				Transport			
	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002
Canada	57.9	53.3	44.2	43.3	40.4	37.3	30.7	29.8	47.4	35.4	19.4	19.0	98.8	95.2	91.1	90.7
United States	53.0	54.6	53.6	53.5	33.4	41.4	36.5	36.6	32.6	25.0	13.9	12.8	95.9	96.9	97.2	97.1
North America	**53.4**	**54.5**	**52.6**	**52.4**	**34.1**	**40.9**	**35.7**	**35.6**	**34.0**	**26.1**	**14.5**	**13.5**	**96.1**	**96.7**	**96.7**	**96.6**
Australia	61.7	59.7	50.9	51.1	43.8	40.6	26.0	23.1	39.7	26.7	12.8	15.4	99.4	99.6	97.7	98.0
Japan	73.2	70.3	63.0	62.6	67.7	62.2	52.1	51.4	68.5	63.6	47.1	48.1	96.9	97.6	98.3	98.3
Korea	56.4	62.0	65.6	62.9	84.4	77.7	62.1	58.9	13.7	25.1	43.7	39.6	99.1	99.4	99.4	99.1
New Zealand	60.6	55.1	42.2	43.4	43.9	35.0	8.6	8.9	32.8	22.8	11.3	12.1	99.9	99.9	99.3	99.3
Pacific	**70.4**	**67.8**	**61.6**	**60.8**	**65.6**	**60.5**	**50.4**	**49.3**	**58.1**	**53.2**	**42.5**	**42.5**	**97.6**	**98.2**	**98.5**	**98.5**
Austria	60.4	54.9	45.6	48.5	51.7	40.1	32.5	36.6	48.6	44.7	26.7	25.8	92.9	94.8	92.2	93.5
Belgium	60.7	56.9	51.9	51.8	46.8	38.6	38.7	38.0	64.2	58.3	37.6	35.6	98.4	98.6	98.7	98.7
Czech Republic	24.4	24.8	31.0	31.4	27.3	26.0	25.7	24.0	5.4	8.8	2.5	2.1	88.0	88.6	95.4	95.5
Denmark	87.7	80.2	48.2	48.3	83.3	70.5	32.0	32.6	84.9	76.2	21.2	20.8	99.7	99.7	99.4	99.3
Finland	59.2	54.8	33.6	34.1	66.2	54.3	14.5	16.5	42.3	41.1	25.7	25.3	99.3	99.5	98.5	98.5
France	68.3	64.0	52.4	52.1	62.3	58.6	40.3	37.6	60.8	50.7	27.1	26.7	97.7	98.1	97.6	97.5
Germany	56.0	53.2	50.8	50.0	44.3	39.5	35.2	35.2	53.6	47.8	32.5	30.0	93.5	97.1	97.5	97.3
Greece	77.6	77.4	69.3	69.7	68.7	69.4	49.4	51.3	68.6	61.6	52.2	52.5	99.2	99.7	99.7	99.6
Hungary	39.1	42.2	29.8	31.1	29.6	32.7	26.5	27.7	35.7	36.5	6.9	6.9	81.2	90.6	97.2	97.4
Ireland	71.2	64.3	64.6	65.3	86.6	73.8	40.8	42.4	37.7	30.5	45.5	45.2	100.0	100.0	100.0	100.0
Italy	73.0	65.1	49.2	49.8	62.3	52.1	29.1	30.2	73.5	58.5	24.1	23.4	97.1	97.3	97.4	97.4
Luxembourg	52.1	43.8	65.9	66.8	38.6	19.9	8.7	6.8	78.4	67.8	47.3	42.3	99.0	99.2	99.6	99.6
Netherlands	50.5	42.6	41.5	42.0	48.8	46.7	42.3	42.0	34.2	16.8	3.9	3.8	99.0	99.0	99.1	99.1
Norway	55.9	52.6	40.2	41.9	43.2	43.3	29.9	31.6	50.6	37.3	16.9	18.7	98.3	98.3	96.5	96.6
Portugal	75.1	73.7	64.3	63.4	66.9	66.9	54.4	52.6	59.7	52.9	35.3	34.4	98.0	99.0	99.5	99.4
Spain	75.6	78.6	61.7	60.9	64.7	70.0	42.1	40.9	68.2	64.4	35.1	33.9	98.8	99.1	98.7	98.5
Sweden	70.4	62.8	38.4	38.0	53.4	48.1	24.6	26.8	78.7	62.6	15.6	12.2	96.8	96.9	96.9	96.9
Switzerland	81.4	75.3	61.2	60.6	77.4	64.0	36.7	35.8	76.3	70.7	48.6	47.7	95.9	95.8	96.6	96.4
Turkey	48.4	49.4	48.8	47.7	60.5	56.6	40.7	37.7	28.0	23.7	27.0	27.1	88.1	96.3	99.2	99.1
United Kingdom	52.3	48.5	44.9	46.0	51.8	45.6	35.0	37.4	24.7	21.6	8.8	8.2	99.1	99.1	98.5	98.6
IEA Europe	**60.2**	**56.4**	**49.5**	**49.6**	**52.5**	**47.5**	**35.6**	**35.6**	**51.4**	**43.6**	**24.5**	**23.6**	**96.5**	**97.8**	**97.9**	**97.9**
IEA Total	**57.7**	**56.7**	**53.0**	**52.8**	**45.7**	**46.2**	**38.7**	**38.4**	**43.0**	**35.9**	**22.6**	**21.8**	**96.3**	**97.2**	**97.3**	**97.2**

1. Includes non-energy use.
2. Includes public and agricultural use.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A10

Historical and Projected Oil Production in IEA Countries

(Mtoe)

	1973	1979	2002	2003[1]	2010	2020	2030
Canada	96.3	86.6	135.9	142.0	217.3	206.8	..
United States	533.8	495.1	358.8	357.6	388.5	346.6	..
North America	**630.2**	**581.7**	**494.7**	**499.6**	**605.9**	**553.4**	**..**
Australia	19.8	22.7	33.2	30.8	32.0	34.2	..
Japan	0.7	0.5	0.7	0.7	..	..	..
Korea	–	–	0.5	0.5	..	..	..
New Zealand	0.2	0.4	1.7	1.3	1.2	1.4	1.1
Pacific	**20.7**	**23.7**	**36.0**	**33.3**	**..**	**..**	**..**
Austria	2.7	1.8	1.1	1.0	1.0	1.1	..
Belgium	–	–	–	–	..	..	..
Czech Republic	0.0	0.3	0.4	0.5	0.4	0.4	0.4
Denmark	0.1	0.4	18.6	18.7	14.0	..	..
Finland	–	–	0.1	0.1	–	–	..
France	2.1	2.0	1.5	1.4	–	–	–
Germany	6.8	4.9	4.2	4.4	..	..	..
Greece	–	–	0.2	0.1	0.3	..	..
Hungary	2.0	2.4	1.6	1.8	1.0	0.8	0.7
Ireland	–	–	–	–	–	..	..
Italy	1.1	1.8	5.5	5.9	5.7	4.0	3.0
Luxembourg	–	–	–	–	–	..	..
Netherlands	1.6	1.6	3.2	3.2	0.8	0.8	..
Norway	1.5	18.6	159.1	153.5	..	..	..
Portugal	–	–	–	–	–	..	..
Spain	0.7	1.4	0.3	0.3	..	..	..
Sweden	–	0.0	–	–	–	..	..
Switzerland	–	–	–	–	–	–	–
Turkey	3.6	2.9	2.4	2.3	1.1	0.5	0.2
United Kingdom	0.5	79.9	121.0	110.7	..	..	..
IEA Europe	**22.8**	**118.0**	**319.2**	**304.0**	**..**	**..**	**..**
IEA Total	**673.7**	**723.4**	**849.9**	**836.9**	**..**	**..**	**..**

1. Preliminary data.

Note: The IEA Secretariat has estimated forecast data for certain countries. Please see Energy Balances and Key Statistical Data for details.

Sources: *Energy Balances of OECD Countries*, Paris IEA/OECD, 2004, for 1973, 1979 and 2002; and country submissions for 2010. 2020 and 2030.

Table A11

Historical and Projected Net Oil Imports of IEA Countries[1]

(Mtoe)

	1979	2001	2002	2003[2]	2010	2020	2030
Canada	7.8	–39.3	–49.0	–50.4	–120.2	–98.6	..
United States	423.7	575.2	558.2	595.2	708.8	938.8	..
North America	**431.5**	**535.9**	**509.2**	**544.8**	**588.6**	**840.2**	**..**
Australia	10.8	–0.1	1.6	6.3	18.0	28.0	..
Japan	277.0	253.2	258.1	260.7	..	..	..
Korea	27.0	106.4	106.5	110.1	..	..	..
New Zealand	4.2	4.6	5.1	5.8	6.8	7.4	8.9
Pacific	**318.9**	**364.2**	**371.3**	**382.9**	**..**	**..**	**..**
Austria	11.4	11.7	12.6	12.7	11.8	13.2	..
Belgium	29.4	29.8	29.4	31.9	..	..	..
Czech Republic	11.2	8.2	8.0	8.4	8.6	9.0	9.3
Denmark	15.8	–7.1	–9.4	–9.7	–2.8	..	..
Finland	15.3	10.4	10.4	11.4	8.5	8.4	..
France	120.7	94.5	93.4 e	94.4 e	107.0	109.7	110.5
Germany	162.7	132.9	124.5	124.6	..	..	..
Greece	13.3	19.3	20.4	19.7	25.2	..	..
Hungary	9.8	4.7	4.7	4.8	6.2	6.7	7.0
Ireland	6.4	9.0	9.0	8.5	8.5	..	..
Italy	102.6	83.9	85.6	84.4	80.0	75.0	76.0
Luxembourg	1.4	2.5	2.6	2.7	1.8	..	..
Netherlands	41.4	41.8	40.5	41.3	48.1	51.5	..
Norway	–9.3	–158.0	–150.6 e	–145.0	..	..	..
Portugal	9.2	16.8	16.3	16.4	17.5	..	..
Spain	49.6	73.3	75.0	75.7	..	..	..
Sweden	28.4	15.5 e	15.3 e	17.8	18.3	..	..
Switzerland	13.8	13.7	13.0	12.5	13.0	12.9	12.6
Turkey	11.8	26.8	28.4	28.7	50.0	71.4	102.2
United Kingdom	19.2	–36.7	–41.3	–29.2	..	..	..
IEA Europe	**664.2**	**393.1**	**387.7**	**412.0**	**..**	**..**	**..**
IEA Total	**1 414.6**	**1 293.2**	**1 268.2**	**1 339.6**	**..**	**..**	**..**

1. Includes requirements for marine bunkers.
2. Preliminary data.
Note: The IEA Secretariat has estimated data for certain countries. Please see Energy Balances and Key Statistical Data for details.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004, for 1979, 2001 and 2002 and country submissions for 2010, 2020 and 2030.

Table A12

Total IEA Electricity Generation by Fuel

(TWh and %)

	1973		1979		2002		2003[1]	
	Output TWh	Share %	Output TWh	Share %	Output TWh	Share %	Output TWh	Share %
Coal	1 606.5	*37.2*	2 019.6	*37.8*	3 567.0	*38.1*	3 660.9	*38.9*
Oil	1 105.7	*25.6*	1 052.3	*19.7*	475.8	*5.1*	474.8	*5.0*
Natural Gas	512.9	*11.9*	598.5	*11.2*	1 633.1	*17.5*	1 635.6	*17.4*
Comb. Renewables & Wastes	6.9	*0.2*	11.7	*0.2*	166.8	*1.8*	166.6	*1.8*
Nuclear	188.3	*4.4*	573.4	*10.7*	2 248.0	*24.0*	2 202.1	*23.4*
Hydro	891.2	*20.6*	1 073.7	*20.1*	1 191.0	*12.7*	1 185.3	*12.6*
Geothermal	6.4	*0.1*	8.6	*0.2*	26.1	*0.3*	24.7	*0.3*
Solar/Wind	0.6	*0.0*	0.5	*0.0*	50.9	*0.5*	60.2	*0.6*
Total	**4 318.4**	***100.0***	**5 338.4**	***100.0***	**9 358.8**	***100.0***	**9 410.2**	***100.0***

1. Preliminary data.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A13

Electricity Generation in IEA Countries, 2002

	Energy Inputs[1] (Mtoe)	Electricity Output in TWh	Shares of Fuel in Electricity Generation (%)					
			Coal	Oil	Gas	Nuclear	Hydro	Other[2]
Canada	87.9 e	601.4	19.5	2.4	5.8	12.6	58.2	1.5
United States	926.1 e	3 992.7	51.3	2.5	17.8	20.1	5.8	2.4
North America	**1 013.9**	**4 594.1**	**47.1**	**2.5**	**16.3**	**19.2**	**12.7**	**2.3**
Australia	55.7 e	222.0	78.3	1.7	11.6	–	7.1	1.3
Japan	224.4	1 087.7	26.8	13.4	22.5	27.1	7.6	2.7
Korea	76.0 e	326.9	39.9	9.6	12.8	36.4	1.0	0.2
New Zealand	6.1	40.3	4.0	–	25.1	–	60.7	10.2
Pacific	**362.2**	**1 677.0**	**35.6**	**10.8**	**19.2**	**24.7**	**7.5**	**2.2**
Austria	9.0	60.4	12.3	2.6	15.5	–	66.1	3.5
Belgium	19.1 e	80.9	15.6	1.2	22.1	58.5	0.4	2.1
Czech Republic	21.8	76.0	66.8	0.5	3.9	24.7	3.3	0.9
Denmark	9.1	39.2	46.5	10.2	24.4	–	0.1	18.8
Finland	16.6 e	74.9	26.3	0.8	15.1	29.8	14.4	13.6
France	131.8 e	554.8	4.5	0.8	4.2	78.7	10.9	0.8
Germany	136.4 e	566.9	51.4	0.8	9.5	29.1	4.1	5.1
Greece	12.1 e	53.9	64.1	16.0	13.1	–	5.2	1.6
Hungary	10.1	36.2	25.1	5.9	29.7	38.6	0.5	0
Ireland	5.2 e	24.8	35.8	15.0	43.6	–	3.7	1.9
Italy	52.9	277.5	14.6	31.6	35.8	–	14.2	3.7
Luxembourg	0.5	2.8	..	..	92.8	–	4.0	3.1
Netherlands	20.4 e	96.0	28.0	2.9	59.4	4.1	0.1	5.5
Norway	11.4	130.1	0.2	0.0	0.2	–	99.3	0.3
Portugal	8.4	45.7	33.3	25.0	19.8	–	17.1	4.8
Spain	49.1 e	242.7	34.0	11.8	13.3	26.0	9.5	5.5
Sweden	28.7	146.0	2.6	2.0	0.4	46.3	45.6	3.2
Switzerland	11.2 e	64.9	–	0.1	1.4	41.9	54.2	2.4
Turkey	24.1 e	129.4	24.8	8.3	40.6	–	26.0	0.3
United Kingdom	82.8 e	384.5	32.8	1.8	39.6	22.9	1.2	1.7
IEA Europe	**660.8**	**3 087.8**	**26.1**	**5.9**	**18.3**	**30.9**	**15.6**	**3.3**
IEA Total	**2 036.8**	**9 358.8**	**38.1**	**5.1**	**17.5**	**24.0**	**12.7**	**2.6**

1. Includes CHP units.
2. Includes combustible renewables, wastes, geothermal, solar, wind, tide and wave.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004.

Table A14

Electricity Intensity of IEA Countries[1]

	1973	1979	2000	2001	2002	Average Annual Growth Rates (%) 1991-1996	1997-2002
Canada	0.79	0.83	0.80	0.78	0.77	-0.7	-2.4
United States	0.49	0.50	0.45	0.43	0.44	-0.8	-1.3
North America	**0.52**	**0.52**	**0.48**	**0.46**	**0.46**	**-0.8**	**-1.4**
Australia	0.33	0.40	0.46	0.46	0.46	-1.4	0.41
Japan	0.18	0.18	0.19	0.19	0.19	1.05	0.68
Korea	0.16	0.23	0.42	0.44	0.48	5.03	3.45
New Zealand	0.43	0.51	0.57	0.55	0.54	-1.7	-1.6
Pacific	**0.19**	**0.20**	**0.23**	**0.23**	**0.24**	**1.58**	**1.62**
Austria	0.21	0.22	0.22	0.23	0.22	-0.4	-0.2
Belgium	0.23	0.25	0.28	0.28	0.28	1.25	-0.3
Czech Republic	0.96	1.05	1.14	1.14	1.11	-0.4	-1.0
Denmark	0.15	0.18	0.18	0.18	0.17	-0.2	-2.2
Finland	0.37	0.42	0.50	0.51	0.51	1.05	-0.9
France	0.19	0.22	0.26	0.26	0.26	0.91	-0.8
Germany	0.25	0.27	0.21	0.22	0.21	-0.8	-0.4
Greece	0.18	0.22	0.38	0.38	0.38	2.63	0.68
Hungary	0.64	0.68	0.71	0.70	0.69	-0.4	-2.7
Ireland	0.27	0.30	0.22	0.22	0.21	-1.1	-3.1
Italy	0.22	0.23	0.26	0.26	0.27	0.55	1.06
Luxembourg	0.41	0.42	0.24	0.24	0.24	-0.9	-2.9
Netherlands	0.20	0.22	0.22	0.22	0.22	0.53	-0.1
Norway	1.01	0.94	0.68	0.68	0.66	-3.0	-1.1
Portugal	0.17	0.23	0.34	0.35	0.36	1.99	2.24
Spain	0.21	0.26	0.32	0.33	0.34	1.01	2.30
Sweden	0.46	0.51	0.50	0.51	0.49	-1.6	-2.2
Switzerland	0.14	0.16	0.18	0.18	0.18	0.35	0.31
Turkey	0.18	0.26	0.62	0.67	0.65	4.76	3.62
United Kingdom	0.37	0.36	0.29	0.29	0.29	-0.8	-1.2
IEA Europe	**0.26**	**0.28**	**0.28**	**0.29**	**0.28**	**0.15**	**-0.2**
IEA Total	**0.33**	**0.34**	**0.34**	**0.33**	**0.34**	**0.11**	**-0.3**

1. Calculated as production plus net imports divided by GDP and measured in kWh per dollar of GDP at 1995 prices and exchange rates; includes CHP units.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2004, *National Accounts, Volume 1*, OECD Paris, 2003, and *Main Economic Indicators*, OECD Paris, 2004.

Table A15

Electricity Generation in IEA Countries, 2002

(GW net)

	Total Capacity						
	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
Canada	..	..	..	10.62	69.21	0.18	..
United States[1]	340.47	46.27	372.08	104.93	96.34	19.49	979.59
North America	**..**	**..**	**..**	**115.55**	**165.55**	**19.67**	**..**
Australia	27.66	1.98	10.39	..	7.63	0.97	48.62
Japan[2, 3]	33.77	45.67	62.88	45.91	46.40	0.80	265.99
Korea	17.03 e	8.57 e	13.27 e	15.72	3.88	0.49 e	58.95
New Zealand	0.34	–	2.19	–	5.25	0.65	8.41
Pacific	**78.79**	**56.22**	**88.72**	**61.62**	**63.15**	**2.90**	**381.98**
Austria	2.17	0.27	3.42	–	11.70	0.46	18.03
Belgium	1.65	0.34	6.10	5.76	1.42	0.29	15.55
Czech Republic	10.38	0.06	0.76	2.76	2.14	0.21	16.31
Denmark	4.96	2.04	2.89	–	0.01	3.40	13.30
Finland	4.72	1.38	2.63	2.67	2.96	2.21	16.57
France	10.26 e	11.99 e	4.53 e	63.27	25.38	0.89 e	116.32
Germany	..	..	..	23.40	9.50	12.26	126.26
Greece	4.52	2.09	1.59	–	3.08	0.31	11.58
Hungary	1.83	0.54	4.20	1.87	0.05	0.03	8.51
Ireland[2]	1.20	0.82	2.72	–	0.53	0.15	5.43
Italy	6.80	22.60	24.26	–	20.51	2.32	76.49
Luxembourg	–	–	0.43	–	1.14	0.03	1.60
Netherlands	–	..	..	0.45	0.04	0.76	20.89
Norway	0.04	0.03	0.04	–	27.68	0.19	27.97
Portugal	1.95	2.76	1.66	–	4.59	0.29	11.24
Spain	11.58	7.83	9.58	7.58	18.07	5.76	60.40
Sweden	0.99	3.63	0.39	9.45	16.57	2.19	33.22
Switzerland	–	0.13 e	0.33 e	3.20 e	14.91 e	0.38 e	18.94
Turkey	6.98	2.88	9.68	–	12.24	0.07	31.85
United Kingdom	27.41	6.25	25.06	12.49	4.37	1.49	77.05
IEA Europe	**..**	**..**	**..**	**132.90**	**176.88**	**33.66**	**..**
IEA Total	**..**	**..**	**..**	**310.07**	**405.58**	**56.23**	**..**

1. Capacity is net summer capacity.
2. Only gross capacity data are available.
3. Does not include autoproducer capacity.

Source: Country submissions.

Table A16

Percentage Change in Real Energy Prices for End-users in IEA Countries, 2002-2003

	Total Energy		Oil Products		Electricity		Gas		Coal	
	Industry	Residential/ Commercial	Industry	Residential/ Commercial	Industry	Residential/ Commercial	Industry	Residential/ Commercial	Industry	Residential/ Commercial
Canada	38.5	14.2	10.1	3.4	..	..	..	..	..	..
United States	21.2	13.0	19.4	14.5	-0.4	0.1	39.7	17.8	-1.9	..
Australia	..	2.6	..	1.5	..	..	..	..	..	..
Japan	-0.7	1.5	7.8	2.3	..	..	..	..	-7.6	..
Korea	2.8	-1.5	12.8	-1.4	0.4	-2.2	..	..	2.8	..
New Zealand	8.3	1.9	-7.4	0.3	5.3	4.9	11.8	5.8	..	..
Austria	-2.0	-2.8	-1.2	-0.6	..	-3.5	..	-5.2	..	1.1
Belgium	-0.9	-0.3	4.0	2.3	..	..	..	..	..	-0.7
Czech Republic	-0.0	-0.6	-3.0	0.8	-1.6	-4.5	1.0	0.8	..	..
Denmark	7.1	0.9	4.9	..	9.4	0.4	..	1.5	..	..
Finland	14.6	4.3	5.5	1.0	29.2	9.2	5.5	3.0	-2.9	..
France	3.5	-1.0	2.8	-1.7	1.6	-1.0	10.8	0.1	-11.8	..
Germany	0.3	1.2	2.7	3.3	..	..	..	..	..	..
Greece	1.5	-2.1	3.2	-2.9	-1.5	0.5	..	..	..	..
Hungary	8.4	2.6	9.3	-0.2	11.8	6.6	7.2	2.7	..	-1.7
Ireland	12.8	2.5	11.7	-1.5	13.5	10.2	14.8	7.9	..	..
Italy	0.5	-1.4	2.4	-1.6	..	..	..	..	-14.3	..
Luxembourg	3.3	-1.4	3.3	-1.4	..	..	..	..	..	..
Netherlands	8.5	4.6	0.4	-0.9	..	2.0	12.1	7.6	..	..
Norway	26.7	32.2	5.7	2.1	32.2	59.0	..	..	..	..
Portugal	2.7	4.7	4.0	6.5	0.7	-0.6	..	..	-1.4	..
Spain	0.8	-2.8	2.0	-2.6	..	..	1.4	-3.2	..	..
Sweden	1.0	-1.5	0.5	-1.1	..	..	..	..	..	..
Switzerland	2.7	-0.2	6.4	0.8	-4.7	-2.4	-0.9	-2.3	..	..
Turkey	-16.7	-12.0	-9.0	-2.5	-27.4	-27.0	-15.9	-17.3	-15.8	-10.6
United Kingdom	2.5	-0.2	8.9	0.9	-4.9	-1.8	2.7	-1.0	-1.0	-0.8

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Table A17

Tax as a Percentage of Oil Product Prices in IEA Countries

	High Sulphur Fuel Oil Industry				Heating Oil Residential				Diesel Commercial Transport				Premium Unleaded Gasoline (95 RON)[1] Transport			
	2000	2001	2002	2003	2000	2001	2002	2003	2000	2001	2002	2003	2000	2001	2002	2003
Canada	..	..	..	..	10.2	10.2	10.2	10.2	32.7	32.4	34.5	32.1	41.2	42.3	42.4	40.3
United States	..	..	..	..	..	..	6.5	5.5	29.7	31.8	33.9	29.9	22.5	23.1	24.8	21.7
Australia	..	..	..	..	..	..	..	..	..	..	..	..	51.2	52.8	53.6	51.7
Japan	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	53.8	52.4	53.3	51.6	54.1	53.6	56.4	55.4
Korea	9.1	9.6	10.7	11.6	24.4	26.9	32.8	34.1	38.4	41.5	48.7	49.8	68.3	67.2	67.7	66.5
New Zealand	..	..	..	..	..	..	..	..	0.6	0.6	0.6	0.7	42.5	43.0	47.4	47.9
Austria	..	..	..	..	33.6	35.0	36.6	36.2	44.7	46.5	48.3	47.9	60.6	62.6	64.1	63.9
Belgium	9.5	10.7	10.9	..	21.2	21.5	22.0	21.6	44.4	46.1	50.8	47.0	65.8	67.7	69.2	67.2
Czech Republic	..	..	..	..	27.3	29.4	31.6	30.9	40.2	41.3	45.8	45.4	55.8	57.7	62.1	61.7
Denmark	..	..	..	..	55.8	56.3	57.4	56.4	45.3	48.7	50.6	50.7	66.3	68.4	69.7	69.5
Finland	..	..	..	..	33.6	34.9	36.5	36.1	43.6	45.3	47.3	48.2	67.3	68.4	70.0	71.7
France	9.6	10.8	10.0	10.0	30.6	26.5	29.8	30.9	54.5	56.1	59.4	59.1	69.8	71.6	73.7	74.3
Germany	..	..	..	..	28.8	30.2	31.3	31.2	54.7	57.7	60.8	61.5	69.3	71.7	73.4	73.7
Greece	..	..	..	8.9	41.2	46.5	40.7	40.8	43.3	45.4	46.5	45.4	52.8	54.5	55.5	55.3
Hungary	..	..	..	..	..	..	..	..	46.6	48.1	51.3	50.5	60.0	61.3	64.1	64.5
Ireland	5.5	6.1	5.2	5.1	21.4	21.7	22.1	22.3	46.4	36.5	47.5	49.8	58.9	55.8	64.2	63.8
Italy	26.6	28.9	27.2	..	60.6	61.4	65.0	64.1	51.5	53.2	56.5	55.1	64.8	66.4	68.4	67.8
Luxembourg	..	..	..	..	12.2	12.4	12.4	12.3	42.2	44.3	46.1	45.6	55.7	57.5	58.8	58.5
Netherlands	..	..	..	..	40.7	46.3	50.5	49.7	49.0	49.6	51.8	51.5	66.4	68.8	70.9	71.0
Norway	..	..	..	..	32.9	36.7	37.7	35.8	54.2	48.2	49.6	49.2	68.7	67.6	70.0	68.9
Portugal	11.4	11.5	11.6	..	..	..	..	..	48.3	47.5	53.4	53.1	49.4	46.2	68.9	68.1
Spain	6.6	7.5	7.4	7.1	32.3	34.0	36.7	35.7	45.0	45.2	49.5	49.2	59.2	59.9	62.4	62.3
Sweden	..	..	..	..	53.2	56.9	60.6	62.4	43.3	44.0	46.5	49.0	67.0	67.6	69.6	70.1
Switzerland	..	..	..	..	9.6	9.5	9.3	9.1	63.2	65.9	69.2	66.9	60.3	62.1	64.3	63.3
Turkey	21.7	27.7	34.4	36.3	62.0	56.8	63.1	64.8	58.6	54.0	64.3	65.5	61.8	62.8	70.1	71.2
United Kingdom	21.7	22.4	20.5	..	19.2	21.1	24.4	26.0	69.9	69.9	71.3	69.5	75.5	76.1	77.4	75.6

1. Regular unleaded gasoline for Australia, Canada and Japan 2000 to 2003.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2004.

Table A18

Energy Balances and Key Statistical Data for IEA and Regions

		IEA Total				IEA North America				IEA Pacific				IEA Europe			
		1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002
SUPPLY																	Unit: Mtoe
TOTAL PRODUCTION		**2 287.6**	**2 580.3**	**3 547.6**	**3 527.9**	**1 653.5**	**1 736.1**	**2 073.5**	**2 052.1**	**108.2**	**138.9**	**403.8**	**404.4**	**525.9**	**705.3**	**1 070.4**	**1 071.4**
Coal[1]		714.4	810.6	936.5	915.5	345.1	443.6	612.2	589.9	66.1	70.3	184.0	188.2	303.2	296.6	140.3	137.4
Oil		673.7	723.4	852.6	849.9	630.2	581.7	492.7	494.7	20.7	23.7	38.1	36.0	22.8	118.0	321.9	319.2
Gas		689.8	698.9	890.9	883.3	564.0	521.8	611.5	597.2	6.0	9.9	36.6	37.0	119.9	167.2	242.8	249.2
Comb. Renewables & Wastes[2]		78.3	97.6	156.6	164.8	45.3	59.9	75.8	80.2	3.5	4.0	15.5	18.3	29.4	33.7	65.3	66.3
Nuclear		49.2	150.0	585.9	585.9	27.3	80.3	226.5	229.3	2.5	19.2	112.6	107.9	19.3	50.6	246.8	248.6
Hydro		76.6	92.3	100.8	102.4	39.6	45.3	44.8	50.2	8.1	10.1	10.9	10.8	29.0	37.0	45.1	41.4
Geothermal		5.6	7.5	17.5	18.3	2.1	3.5	7.8	8.3	1.3	1.7	5.2	5.1	2.2	2.2	4.5	4.9
Solar/Wind/Other[3]		0.0	0.1	6.7	7.9	-	-	2.1	2.3	-	0.0	1.0	1.0	0.0	0.0	3.7	4.5
TOTAL NET IMPORTS[4]		**1 331.5**	**1 425.2**	**1 544.0**	**1 529.2**	**252.6**	**374.4**	**492.8**	**466.0**	**307.7**	**338.7**	**437.5**	**450.7**	**771.2**	**712.2**	**613.6**	**612.5**
Coal[1]	Exports	84.1	113.4	198.4	192.6	38.7	51.5	49.5	42.5	18.2	26.7	127.8	134.4	27.2	35.2	21.0	15.7
	Imports	114.4	144.7	310.7	312.2	11.2	15.5	28.8	27.3	41.8	44.4	138.7	148.7	61.4	84.9	143.3	136.2
	Net Imports	30.3	31.3	112.3	119.5	-27.5	-36.1	-20.8	-15.2	23.6	17.7	10.8	14.3	34.2	49.7	122.3	120.5
Oil	Exports	233.1	251.9	695.8	690.6	74.1	40.4	143.4	150.6	7.3	4.2	73.7	62.2	151.6	207.3	478.7	477.8
	Imports	1 596.3	1 666.4	1 989.0	1 958.7	365.3	471.9	679.3	659.8	308.1	323.1	437.8	433.4	923.0	871.4	871.8	865.5
	Bunkers	72.1	74.0	76.7	81.9	10.4	26.0	20.6	24.3	19.4	14.5	11.3	11.3	42.3	33.6	44.9	46.4
	Net Imports	1 291.1	1 340.5	1 216.4	1 186.2	280.8	405.5	515.3	485.0	281.3	304.4	352.9	360.0	729.0	630.6	348.3	341.3
Gas	Exports	50.3	82.5	205.0	221.5	24.9	24.0	97.1	100.0	-	-	8.8	8.9	25.5	58.5	99.1	112.6
	Imports	60.0	135.3	417.4	441.5	24.2	29.0	95.5	96.1	2.8	16.7	82.6	85.3	33.0	89.6	239.3	260.2
	Net Imports	9.7	52.8	212.4	220.1	-0.7	5.0	-1.6	-3.9	2.8	16.7	73.8	76.4	7.5	31.1	140.1	147.6
Electricity	Exports	6.7	10.3	26.3	27.4	1.6	2.9	4.8	4.4	-	-	-	-	5.0	7.4	21.6	23.0
	Imports	7.1	10.9	28.4	29.9	1.6	2.9	4.7	4.5	-	-	-	-	5.4	8.1	23.7	25.4
	Net Imports	0.4	0.6	2.1	2.6	0.0	-0.0	-0.1	0.2	-	-	-	-	0.4	0.7	2.2	2.4
TOTAL STOCK CHANGES		**-19.5**	**-55.4**	**-59.2**	**20.2**	**-9.8**	**-38.5**	**-64.3**	**22.4**	**-4.8**	**-5.3**	**-3.9**	**-3.9**	**-4.8**	**-11.6**	**9.0**	**1.7**
TOTAL SUPPLY (TPES)		**3 599.6**	**3 950.2**	**5 032.4**	**5 077.3**	**1 896.3**	**2 072.0**	**2 502.1**	**2 540.4**	**411.1**	**472.3**	**837.4**	**851.2**	**1 292.2**	**1 405.9**	**1 692.9**	**1 685.7**
Coal[1]		758.9	828.6	1 019.1	1 029.5	326.3	386.8	565.4	571.5	89.8	89.0	189.2	196.2	342.7	352.8	264.5	261.9
Oil		1 943.0	2 030.4	2 057.6	2 048.3	903.9	975.6	992.4	986.0	297.1	321.9	392.5	398.5	742.0	732.8	672.7	663.8
Gas		687.5	743.0	1 085.3	1 116.9	551.8	520.6	587.2	612.4	8.7	26.4	110.6	113.2	127.0	195.9	387.4	391.2
Comb. Renewables & Wastes[2]		78.4	97.7	157.3	165.6	45.3	59.9	75.8	80.2	3.5	4.0	15.5	18.3	29.5	33.8	66.0	67.1
Nuclear		49.2	150.0	585.9	585.9	27.3	80.3	226.5	229.3	2.5	19.2	112.6	107.9	19.3	50.6	246.8	248.6
Hydro		76.6	92.3	100.8	102.4	39.6	45.3	44.8	50.2	8.1	10.1	10.9	10.8	29.0	37.0	45.1	41.4
Geothermal		5.6	7.5	17.5	18.3	2.1	3.5	7.8	8.3	1.3	1.7	5.2	5.1	2.2	2.2	4.5	4.9
Solar/Wind/Other[3]		0.0	0.1	6.7	7.9	-	-	2.1	2.3	-	0.0	1.0	1.0	0.0	0.0	3.7	4.5
Electricity Trade[5]		0.4	0.7	2.1	2.6	0.0	-0.0	-0.1	0.2	-	-	-	-	0.4	0.7	2.2	2.4

Table A18 *(continued)*

Energy Balances and Key Statistical Data for IEA and Regions

	IEA Total				IEA North America				IEA Pacific				IEA Europe			
	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002
SUPPLY																Unit: Mtoe
Fuel Shares (%)																
Coal	*21.1*	*21.0*	*20.3*	*20.3*	*17.2*	*18.7*	*22.6*	*22.5*	*21.9*	*18.8*	*22.6*	*23.0*	*26.5*	*25.1*	*15.6*	*15.5*
Oil	*54.0*	*51.4*	*40.9*	*40.3*	*47.7*	*47.1*	*39.7*	*38.8*	*72.3*	*68.2*	*46.9*	*46.8*	*57.4*	*52.1*	*39.7*	*39.4*
Gas	*19.1*	*18.8*	*21.6*	*22.0*	*29.1*	*25.1*	*23.5*	*24.1*	*2.1*	*5.6*	*13.2*	*13.3*	*9.8*	*13.9*	*22.9*	*23.2*
Comb. Renewables & Wastes	*2.2*	*2.5*	*3.1*	*3.3*	*2.4*	*2.9*	*3.0*	*3.2*	*0.9*	*0.9*	*1.8*	*2.1*	*2.3*	*2.4*	*3.9*	*4.0*
Nuclear	*1.4*	*3.8*	*11.6*	*11.5*	*1.4*	*3.9*	*9.1*	*9.0*	*0.6*	*4.1*	*13.4*	*12.7*	*1.5*	*3.6*	*14.6*	*14.7*
Hydro	*2.1*	*2.3*	*2.0*	*2.0*	*2.1*	*2.2*	*1.8*	*2.0*	*2.0*	*2.1*	*1.3*	*1.3*	*2.2*	*2.6*	*2.7*	*2.5*
Geothermal	*0.2*	*0.2*	*0.3*	*0.4*	*0.1*	*0.2*	*0.3*	*0.3*	*0.3*	*0.4*	*0.6*	*0.6*	*0.2*	*0.2*	*0.3*	*0.3*
Solar/Wind/Other	-	-	*0.1*	*0.2*	-	-	*0.1*	*0.1*	-	-	*0.1*	*0.1*	-	-	*0.2*	*0.3*
Electricity Trade	-	-	-	*0.1*	-	-	-	-	-	-	-	-	-	-	0.1	0.1
DEMAND																Unit: Mtoe
FINAL CONSUMPTION BY SECTOR																
TFC	**2 727.2**	**2 919.1**	**3 498.8**	**3 527.8**	**1 455.0**	**1 533.1**	**1 723.3**	**1 747.9**	**297.8**	**332.2**	**567.5**	**582.1**	**974.4**	**1 053.9**	**1 207.9**	**1 197.8**
Coal[1]	253.9	227.7	109.9	106.2	79.0	72.0	35.1	31.5	32.5	33.1	32.1	33.7	142.5	122.6	42.6	41.0
Oil	1 574.0	1 654.6	1 854.4	1 863.3	777.5	835.7	906.9	915.7	209.6	225.1	349.4	354.0	586.8	593.9	598.1	593.6
Gas	501.4	539.8	695.8	707.5	391.0	368.0	383.8	397.5	9.5	14.3	49.1	51.2	100.8	157.5	262.9	258.8
Comb. Renewables & Wastes[2]	75.8	93.1	105.5	104.7	45.0	59.6	51.2	50.5	3.5	3.8	7.8	7.9	27.3	29.7	46.5	46.3
Geothermal	0.0	0.1	2.5	2.6	-	-	0.6	0.6	-	-	0.5	0.5	0.0	0.1	1.4	1.4
Solar/Wind/Other	-	0.0	3.0	3.0	-	-	1.4	1.3	-	0.0	0.9	0.9	-	0.0	0.7	0.8
Electricity	314.2	389.3	688.6	701.5	162.3	196.8	338.5	344.2	42.7	55.7	122.9	129.2	109.2	136.9	227.2	228.1
Heat	7.9	14.4	39.1	38.9	0.1	1.0	5.8	6.6	0.0	0.1	4.8	4.6	7.7	13.3	28.5	27.7
Fuel Shares (%)																
Coal	*9.3*	*7.8*	*3.1*	*3.0*	*5.4*	*4.7*	*2.0*	*1.8*	*10.9*	*10.0*	*5.7*	*5.8*	*14.6*	*11.6*	*3.5*	*3.4*
Oil	*57.7*	*56.7*	*53.0*	*52.8*	*53.4*	*54.5*	*52.6*	*52.4*	*70.4*	*67.8*	*61.6*	*60.8*	*60.2*	*56.4*	*49.5*	*49.6*
Gas	*18.4*	*18.5*	*19.9*	*20.1*	*26.9*	*24.0*	*22.3*	*22.7*	*3.2*	*4.3*	*8.7*	*8.8*	*10.4*	*14.9*	*21.8*	*21.6*
Comb. Renewables & Wastes	*2.8*	*3.2*	*3.0*	*3.0*	*3.1*	*3.9*	*3.0*	*2.9*	*1.2*	*1.2*	*1.4*	*1.4*	*2.8*	*2.8*	*3.9*	*3.9*
Geothermal	-	-	*0.1*	*0.1*	-	-	-	-	-	-	*0.1*	*0.1*	-	-	*0.1*	*0.1*
Solar/Wind/Other	-	-	*0.1*	*0.1*	-	-	*0.1*	*0.1*	-	-	*0.2*	*0.2*	-	-	*0.1*	*0.1*
Electricity	*11.5*	*13.3*	*19.7*	*19.9*	*11.2*	*12.8*	*19.6*	*19.7*	*14.3*	*16.8*	*21.7*	*22.2*	*11.2*	*13.0*	*18.8*	*19.0*
Heat	*0.3*	*0.5*	*1.1*	*1.1*	-	*0.1*	*0.3*	*0.4*	-	-	*0.8*	*0.8*	*0.8*	*1.3*	*2.4*	*2.3*

Table A18 *(continued)*

Energy Balances and Key Statistical Data for IEA and Regions

	IEA Total				IEA North America				IEA Pacific				IEA Europe			
	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002
DEMAND																Unit: Mtoe
TOTAL INDUSTRY[6]	**1 124.0**	**1 157.9**	**1 169.4**	**1 174.8**	**535.4**	**561.3**	**531.4**	**532.7**	**167.4**	**168.0**	**236.8**	**241.4**	**421.2**	**428.6**	**401.1**	**400.7**
Coal[1]	168.8	152.3	99.3	96.1	64.8	57.5	32.6	29.0	23.9	24.0	31.2	32.9	80.1	70.7	35.5	34.2
Oil	513.1	535.1	452.0	451.2	182.4	229.7	189.9	189.8	109.8	101.6	119.4	119.0	221.0	203.7	142.7	142.5
Gas	246.9	238.9	286.7	293.9	189.2	156.4	159.3	165.4	3.9	6.0	22.8	23.4	53.9	76.5	104.7	105.2
Comb. Renewables & Wastes[2]	40.3	47.1	58.3	59.5	34.3	39.5	36.9	37.6	1.5	2.1	5.6	5.7	4.6	5.5	15.8	16.1
Geothermal	-	-	0.4	0.4	-	-	0.1	0.1	-	-	0.3	0.3	-	-	0.0	0.0
Solar/Wind/Other	-	-	0.1	0.1	-	-	-	-	-	-	-	-	-	-	0.1	0.1
Electricity	152.2	180.2	259.1	259.3	64.6	77.2	107.7	105.4	28.3	34.2	55.8	58.2	59.3	68.9	95.5	95.7
Heat	2.5	4.4	13.5	14.3	0.1	1.0	4.8	5.4	-	-	1.8	2.0	2.5	3.4	6.9	6.9
Fuel Shares (%)																
Coal	*15.0*	*13.2*	*8.5*	*8.2*	*12.1*	*10.3*	*6.1*	*5.4*	*14.3*	*14.3*	*13.2*	*13.6*	*19.0*	*16.5*	*8.8*	*8.5*
Oil	*45.7*	*46.2*	*38.7*	*38.4*	*34.1*	*40.9*	*35.7*	*35.6*	*65.6*	*60.5*	*50.4*	*49.3*	*52.5*	*47.5*	*35.6*	*35.6*
Gas	*22.0*	*20.6*	*24.5*	*25.0*	*35.3*	*27.9*	*30.0*	*31.0*	*2.3*	*3.6*	*9.6*	*9.7*	*12.8*	*17.8*	*26.1*	*26.2*
Comb. Renewables & Wastes	*3.6*	*4.1*	*5.0*	*5.1*	*6.4*	*7.0*	*6.9*	*7.1*	*0.9*	*1.3*	*2.3*	*2.4*	*1.1*	*1.3*	*3.9*	*4.0*
Geothermal	-	-	-	-	-	-	-	-	-	-	*0.1*	*0.1*	-	-	-	-
Solar/Wind/Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electricity	*13.5*	*15.6*	*22.2*	*22.1*	*12.1*	*13.7*	*20.3*	*19.8*	*16.9*	*20.3*	*23.6*	*24.1*	*14.1*	*16.1*	*23.8*	*23.9*
Heat	*0.2*	*0.4*	*1.2*	*1.2*	-	*0.2*	*0.9*	*1.0*	-	-	*0.8*	*0.8*	*0.6*	*0.8*	*1.7*	*1.7*
TRANSPORT[7]	**696.4**	**796.0**	**1 172.7**	**1 191.4**	**454.6**	**498.7**	**662.2**	**676.1**	**60.9**	**80.3**	**159.7**	**161.4**	**180.9**	**217.0**	**350.8**	**354.0**
TOTAL OTHER SECTORS[8]	**906.8**	**965.1**	**1 156.7**	**1 161.5**	**464.9**	**473.1**	**529.7**	**539.2**	**69.6**	**83.9**	**171.0**	**179.3**	**372.3**	**408.2**	**456.0**	**443.0**
Coal[1]	81.5	74.5	10.4	10.0	14.0	14.5	2.5	2.5	8.3	9.1	0.8	0.8	59.2	50.9	7.1	6.8
Oil	390.0	346.2	261.4	253.7	158.1	123.6	76.8	72.9	40.5	44.6	72.7	76.2	191.4	178.0	111.9	104.6
Gas	237.5	284.7	388.7	392.0	185.0	195.7	205.3	211.6	5.7	8.3	26.0	27.4	46.8	80.7	157.4	153.0
Comb. Renewables & Wastes[2]	35.4	46.0	44.7	42.6	10.8	20.1	12.3	11.0	2.0	1.7	2.2	2.2	22.7	24.2	30.2	29.4
Geothermal	0.0	0.1	2.1	2.2	-	-	0.4	0.5	-	-	0.3	0.3	0.0	0.1	1.4	1.4
Solar/Wind/Other	-	0.0	2.9	2.9	-	-	1.4	1.3	-	0.0	0.9	0.9	-	0.0	0.6	0.7
Electricity	157.1	203.7	420.7	433.5	97.0	119.2	230.0	238.1	13.2	20.1	65.0	69.0	46.8	64.5	125.7	126.4
Heat	5.3	10.0	25.7	24.7	-	0.0	1.0	1.2	0.0	0.1	3.0	2.7	5.3	9.9	21.7	20.8

Table A18 *(continued)*

Energy Balances and Key Statistical Data for IEA and Regions

	IEA Total				IEA North America				IEA Pacific				IEA Europe			
	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002
DEMAND																Unit: Mtoe
Fuel Shares (%)																
Coal	*9.0*	*7.7*	*0.9*	*0.9*	*3.0*	*3.1*	*0.5*	*0.5*	*11.9*	*10.8*	*0.5*	*0.4*	*15.9*	*12.5*	*1.6*	*1.5*
Oil	*43.0*	*35.9*	*22.6*	*21.8*	*34.0*	*26.1*	*14.5*	*13.5*	*58.1*	*53.2*	*42.5*	*42.5*	*51.4*	*43.6*	*24.5*	*23.6*
Gas	*26.2*	*29.5*	*33.6*	*33.7*	*39.8*	*41.4*	*38.8*	*39.2*	*8.1*	*9.9*	*15.2*	*15.3*	*12.6*	*19.8*	*34.5*	*34.5*
Comb. Renewables & Wastes	*3.9*	*4.8*	*3.9*	*3.7*	*2.3*	*4.3*	*2.3*	*2.0*	*2.9*	*2.0*	*1.3*	*1.2*	*6.1*	*5.9*	*6.6*	*6.6*
Geothermal	-	-	*0.2*	*0.2*	-	-	*0.1*	*0.1*	-	-	*0.2*	*0.2*	-	-	*0.3*	*0.3*
Solar/Wind/Other	-	-	*0.2*	*0.3*	-	-	*0.3*	*0.2*	-	-	*0.5*	*0.5*	-	-	*0.1*	*0.2*
Electricity	*17.3*	*21.1*	*36.4*	*37.3*	*20.9*	*25.2*	*43.4*	*44.2*	*18.9*	*24.0*	*38.0*	*38.5*	*12.6*	*15.8*	*27.6*	*28.5*
Heat	*0.6*	*1.0*	*2.2*	*2.1*	-	-	*0.2*	*0.2*	-	*0.1*	*1.8*	*1.5*	*1.4*	*2.4*	*4.8*	*4.7*
ENERGY TRANSFORMATION AND LOSSES																
ELECTRICITY GENERATION[9]																
INPUT (Mtoe)	**907.5**	**1 136.0**	**1 999.4**	**2 036.8**	**466.3**	**577.3**	**997.1**	**1 013.9**	**113.1**	**152.5**	**349.8**	**362.2**	**328.1**	**406.2**	**652.5**	**660.8**
OUTPUT (Mtoe)	**371.4**	**459.1**	**782.8**	**804.9**	**192.3**	**233.8**	**380.8**	**395.1**	**48.4**	**63.1**	**137.9**	**144.2**	**130.7**	**162.2**	**264.0**	**265.5**
(TWh gross)	4 318.4	5 338.4	9 102.1	9 358.8	2 235.6	2 718.8	4 428.3	4 594.1	563.2	733.7	1 603.9	1 677.0	1 519.7	1 885.9	3 070.0	3 087.8
Output Shares (%)																
Coal	*37.2*	*37.8*	*38.0*	*38.1*	*42.1*	*43.3*	*47.4*	*47.1*	*15.7*	*15.7*	*34.5*	*35.6*	*37.9*	*38.5*	*26.4*	*26.1*
Oil	*25.6*	*19.7*	*5.1*	*5.1*	*15.4*	*12.5*	*3.3*	*2.5*	*63.2*	*46.9*	*9.3*	*10.8*	*26.6*	*19.5*	*5.5*	*5.9*
Gas	*11.9*	*11.2*	*16.9*	*17.5*	*17.0*	*13.4*	*15.7*	*16.3*	*2.4*	*11.0*	*19.3*	*19.2*	*7.8*	*8.2*	*17.4*	*18.3*
Comb. Renewables & Wastes	*0.2*	*0.2*	*1.7*	*1.8*	*0.0*	*0.1*	*1.6*	*1.7*	*0.1*	*0.1*	*1.6*	*1.7*	*0.4*	*0.5*	*1.7*	*1.9*
Nuclear	*4.4*	*10.7*	*24.7*	*24.0*	*4.7*	*11.2*	*19.6*	*19.2*	*1.7*	*10.0*	*26.9*	*24.7*	*4.9*	*10.3*	*30.8*	*30.9*
Hydro	*20.6*	*20.1*	*12.9*	*12.7*	*20.6*	*19.4*	*11.8*	*12.7*	*16.7*	*16.0*	*7.9*	*7.5*	*22.2*	*22.8*	*17.1*	*15.6*
Geothermal	*0.1*	*0.2*	*0.3*	*0.3*	*0.1*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.2*	*0.1*	*0.2*	*0.2*
Solar/Wind/Other	*0.0*	*0.0*	*0.4*	*0.5*	-	-	*0.2*	*0.3*	-	*0.0*	*0.1*	*0.1*	*0.0*	*0.0*	*0.9*	*1.2*
TOTAL LOSSES (Mtoe)	**888.0**	**1 030.6**	**1 528.0**	**1 544.8**	**452.2**	**533.3**	**769.6**	**776.2**	**118.7**	**142.1**	**280.2**	**283.6**	**317.1**	**355.2**	**478.2**	**484.9**
of which:																
Electricity and Heat Generation[10]	527.1	661.1	1 171.5	1 186.7	274.0	342.5	608.1	609.6	64.6	89.2	206.0	212.3	188.6	229.5	357.4	364.9
Other Transformation	80.3	95.9	47.8	39.0	1.3	33.4	-2.2	-9.3	31.9	24.9	31.2	31.2	47.1	37.6	18.8	17.2
Own Use and Losses[11]	280.5	273.7	308.8	319.0	176.9	157.4	163.7	176.0	22.2	28.1	43.0	40.2	81.5	88.2	102.1	102.8
Statistical Differences	**-15.5**	**0.4**	**5.6**	**4.7**	**-10.9**	**5.6**	**9.1**	**16.3**	**-5.4**	**-1.9**	**-10.3**	**-14.6**	**0.8**	**-3.3**	**6.8**	**3.0**

Table A18 *(continued)*

Energy Balances and Key Statistical Data for IEA and Regions

	IEA Total				IEA North America				IEA Pacific				IEA Europe			
	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002	1973	1979	2001	2002
INDICATORS																
GDP (billion 1995 US$)	13 077	15 525	27 420	27 851	4 327	5 182	9 705	9 947	2 947	3 631	6 886	6 951	5 803	6 712	10 828	10 953
Population (millions)	811	851	994	1 001	234	249	316	319	159	171	198	199	417	430	480	483
TPES/GDP[12]	0.28	0.25	0.18	0.18	0.44	0.40	0.26	0.26	0.14	0.13	0.12	0.12	0.22	0.21	0.16	0.15
Energy Production/TPES	0.64	0.65	0.70	0.69	0.87	0.84	0.83	0.81	0.26	0.29	0.48	0.48	0.41	0.50	0.63	0.64
Per Capita TPES[13]	4.44	4.64	5.06	5.07	8.09	8.31	7.92	7.97	2.58	2.76	4.23	4.28	3.10	3.27	3.52	3.49
Oil Supply/GDP[12]	0.15	0.13	0.08	0.07	0.21	0.19	0.10	0.10	0.10	0.09	0.06	0.06	0.13	0.11	0.06	0.06
TFC/GDP[12]	0.21	0.19	0.13	0.13	0.34	0.30	0.18	0.18	0.10	0.09	0.08	0.08	0.17	0.16	0.11	0.11
Per Capita TFC[13]	3.36	3.43	3.52	3.53	6.21	6.15	5.45	5.48	1.87	1.94	2.87	2.93	2.34	2.45	2.51	2.48
Energy-related CO_2 Emissions (Mt CO_2)[14]	9 837.9	10 369.1	11 769.5	11 865.9	5 080.2	5 298.8	6 135.0	6 184.2	1 131.9	1 249.3	1 981.5	2 035.3	3 625.8	3 821.0	3 653.0	3 646.4
CO_2 Emissions from Bunkers (Mt CO_2)	298.3	313.0	444.1	457.9	50.4	105.2	120.0	130.3	69.6	53.3	66.7	68.3	178.3	154.5	257.4	259.4
GROWTH RATES (% per year)																
	73-79	79-02	92-02	01-02	73-79	79-02	92-02	01-02	73-79	79-02	92-02	01-02	73-79	79-02	92-02	01-02
TPES	**1.6**	**1.1**	**1.5**	**0.9**	**1.5**	**0.9**	**1.5**	**1.5**	**2.3**	**2.6**	**2.3**	**1.6**	**1.4**	**0.8**	**1.1**	**-0.4**
Coal	1.5	0.9	0.9	1.0	2.9	1.7	1.7	1.1	-0.2	3.5	3.6	3.7	0.5	-1.3	-1.8	-1.0
Oil	0.7	0.0	1.0	-0.4	1.3	0.0	1.6	-0.6	1.3	0.9	0.8	1.5	-0.2	-0.4	0.5	-1.3
Gas	1.3	1.8	2.7	2.9	-1.0	0.7	1.5	4.3	20.3	6.5	4.9	2.3	7.5	3.1	4.1	1.0
Comb. Renewables & Wastes	3.7	2.3	1.3	5.3	4.8	1.3	-0.2	5.8	2.3	6.8	5.4	18.1	2.3	3.0	2.5	1.6
Nuclear	20.4	6.1	2.1	-0.0	19.7	4.7	1.8	1.2	40.1	7.8	4.0	-4.1	17.4	7.2	1.7	0.7
Hydro	3.2	0.5	0.3	1.6	2.3	0.4	0.2	12.0	3.8	0.3	0.3	-0.2	4.1	0.5	0.4	-8.3
Geothermal	4.9	4.0	-2.3	4.2	9.0	3.8	-5.8	5.4	4.7	4.9	2.6	-0.4	0.3	3.5	2.1	7.4
Solar/Wind/Other	7.2	22.3	14.3	17.8	-	-	21.9	13.1	-	16.7	-1.5	1.4	-1.4	21.8	24.6	25.7
TFC	**1.1**	**0.8**	**1.6**	**0.8**	**0.9**	**0.6**	**1.7**	**1.4**	**1.8**	**2.5**	**2.5**	**2.6**	**1.3**	**0.6**	**1.0**	**-0.8**
Electricity Consumption	3.6	2.6	2.4	1.9	3.3	2.5	2.3	1.7	4.5	3.7	3.4	5.1	3.8	2.2	2.1	0.4
Energy Production	2.0	1.4	1.1	-0.6	0.8	0.7	0.6	-1.0	4.3	4.8	3.6	0.2	5.0	1.8	1.2	0.1
Net Oil Imports	0.6	-0.5	1.2	-2.5	6.3	0.8	4.4	-5.9	1.3	0.7	0.6	2.0	-2.4	-2.6	-1.5	-2.0
GDP	2.9	2.6	2.4	1.6	3.0	2.9	3.3	2.5	3.5	2.9	1.6	0.9	2.5	2.2	2.1	1.2
Growth in the TPES/GDP Ratio	-1.3	-1.4	-0.9	-0.7	-1.5	-1.9	-1.7	-0.9	-1.2	-0.3	0.7	0.7	-1.0	-1.3	-1.0	-1.6
Growth in the TFC/GDP Ratio	-1.7	-1.7	-0.8	-0.7	-2.1	-2.2	-1.5	-1.0	-1.7	-0.4	0.9	1.6	-1.1	-1.6	-1.0	-2.0

Table A18 (Footnotes)

1. Includes lignite and peat, except for Finland, Ireland and Sweden. In these three cases, peat is shown separately.
2. Comprises solid biomass, liquid biomass, biogas, 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 wastes.
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 1995 prices and exchange rates.
13. Toe per person.
14. "Energy-related CO_2 emissions" have been estimated using the IPCC Tier I Sectoral Approach. In accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2002 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.

e = estimate.

ANNEX B

GOVERNMENT ENERGY R&D BUDGETS

Table B1

IEA Government R&D Budgets in National Currencies

(millions except for Japanese, Korean and Turkish currencies. which are in billions)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	367.6	315.7	322.0	322.0	300.6	265.9	249.6	248.6	266.5	293.2	298.4	335.6
United States	2 174.5	2 172.6	2 441.6	2 409.1	2 149.9	1 965.7	2 024.6	2 293.8	2 266.7	2 814.4	2 847.3	2 750.0
Australia	..	110.4	..	116.3	..	157.6	..	..	..	..	..	..
Japan	392.9	404.7	433.9	445.7	459.1	437.7	441.8	433.2	436.3	433.5	..	..
Korea	..	..	..	..	..	..	..	..	..	..	110.3	..
New Zealand	..	4.7	3.8	4.4	5.3	5.1	6.4	6.1	6.4	8.9	10.1	11.5
Austria	15.3	20.8	23.6	24.1	24.3	25.7	27.4	26.5	23.3	29.9	29.2	..
Belgium	..	..	41.4	43.8	56.4	54.5	70.4	49.7	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	310.0	302.0	259.0	245.1	217.6	258.3	316.2	312.6	327.1	328.0	167.9	177.3
Finland	38.3	39.8	48.2	58.2	56.1	79.4	81.9	77.9	65.5	62.7	70.5	..
France	444.3	448.9	424.3	501.9	483.2	488.2	527.1	617.1	586.7	441.6	403.5	..
Germany	363.1	366.0	300.0	262.2	285.0	259.2	280.1	187.7	268.6	292.5	264.5	266.0
Greece	3.5	3.3	3.3	6.1	7.5	14.3	..	..	5.7	7.0	8.8	..
Hungary	..	..	..	..	..	..	..	..	584.6	562.9	788.6	836.8
Ireland	..	..	..	..	..	..	..	..	..	..	3.7	6.8
Italy	..	229.7	225.4	243.8	237.8	221.9	222.1	..	262.7	283.0	300.1	302.2
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	136.0	153.6	165.9	121.2	127.1	146.2	140.1	140.7	126.4	159.3	140.2	..
Norway	391.9	366.5	355.7	304.4	288.3	281.8	277.4	371.6	370.0	384.5	392.9	383.8
Portugal	4.7	3.2	2.7	1.4	1.7	1.2	1.6	2.0	1.5	1.0	1.9	1.5
Spain	66.0	58.0	64.1	60.0	59.3	60.3	47.4	50.0	49.3	49.7	45.7	47.0
Sweden	714.1	553.1	598.0	452.9	413.1	467.0	440.0	590.0	647.0	763.0	853.0	885.0
Switzerland	220.6	223.3	220.8	215.1	206.7	196.9	182.6	179.9	166.8	172.8	180.0	190.0
Turkey[2]	23.6	41.2	42.1	189.1	274.8	1 608.9	1 387.8	1 406.3	2 170.6	3 656.2	4 085.4	8 273.5
United Kingdom	133.5	98.8	50.9	52.9	36.4	49.3	43.8	42.8	48.0	30.4	..	..
European Commission[3]	..	..	..	..	..	..	..	..	..	..	..	..

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. The strong increase in the budget is due to high inflation rate in Turkey and to new RD&D activities.
3. No information on R&D budgets has been provided by the European Commission.

Note: Budgets provided for recent years by some countries may have been estimated.

Source: Country submissions.

Table B2

IEA Government R&D Budgets in 2003 National Currencies

(millions except for Japanese, Korean and Turkish currencies. which are in billions)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	440.6	373.1	376.2	368.1	338.0	295.5	278.4	272.7	280.9	306.1	308.4	335.6
United States	2 657.7	2 595.3	2 858.5	2 762.2	2 420.4	2 175.9	2 217.8	2 476.8	2 393.7	2 905.2	2 893.8	2 750.0
Australia	..	135.1	..	139.1	..	181.3	..	..	..	..	..	..
Japan	358.2	367.2	393.3	406.0	421.6	400.7	404.9	402.7	414.1	417.5	..	..
Korea	..	..	..	..	..	..	..	..	..	..	112.7	..
New Zealand	..	5.5	4.5	5.0	5.9	5.7	7.0	6.7	6.9	9.1	10.3	11.5
Austria	18.4	24.3	26.8	26.7	26.5	27.9	29.5	28.4	24.6	30.9	29.8	..
Belgium	..	..	47.2	49.4	62.9	60.0	76.1	53.0	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	382.2	367.3	309.6	288.0	249.4	289.9	351.2	341.0	346.6	340.5	171.4	177.3
Finland	47.5	48.2	57.3	66.1	63.9	88.6	88.3	84.2	68.5	63.7	71.0	..
France	521.6	514.5	477.8	555.6	527.5	526.2	563.2	656.9	619.8	459.0	409.4	..
Germany	421.7	410.1	327.9	280.8	302.2	273.0	291.8	194.6	279.0	300.1	267.0	266.0
Greece	7.1	5.8	5.3	8.8	10.0	17.8	..	..	6.4	7.5	9.2	..
Hungary	..	..	..	..	..	..	..	..	744.8	660.4	850.0	836.8
Ireland	..	..	..	..	..	..	..	..	..	..	3.7	6.8
Italy	..	312.5	296.4	305.3	282.8	257.7	251.2	..	286.2	300.3	309.0	302.2
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	179.3	198.9	210.0	150.4	155.8	175.8	165.5	163.8	141.6	169.2	144.2	..
Norway	553.9	506.0	491.8	409.1	372.1	353.8	350.9	440.9	378.6	389.1	404.1	383.8
Portugal	7.4	4.7	3.7	1.8	2.2	1.5	1.9	2.3	1.7	1.0	1.9	1.5
Spain	98.3	82.7	87.8	78.5	74.9	74.5	57.1	58.6	55.9	54.1	47.6	47.0
Sweden	873.7	656.3	694.1	508.4	457.9	509.7	476.8	634.8	687.1	792.1	872.8	885.0
Switzerland	240.5	237.6	231.4	223.6	215.1	205.1	190.7	186.6	171.6	176.7	182.1	190.0
Turkey	5 529.3	5 750.6	2 848.5	6 836.9	5 587.2	18 017.0	8 846.4	5 762.3	5 933.7	6 456.1	5 005.1	8 273.5
United Kingdom	176.6	127.1	64.5	65.4	43.4	57.2	49.5	47.3	52.2	32.3	..	..
European Commission[2]	..	..	..	..	..	..	..	..	..	..	..	..

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. No information on R&D budgets has been provided by the European Commission.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B3

IEA Government R&D Budgets

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e	2003 exch. rates (Unit per $)
Canada[1]	314.7	266.5	268.7	262.9	241.4	211.0	198.9	194.8	200.6	218.7	220.3	239.7	1.400
United States	2 657.7	2 595.3	2 858.5	2 762.2	2 420.4	2 175.9	2 217.8	2 476.8	2 393.7	2 905.2	2 893.8	2 750.0	1.0
Australia	..	87.6	..	90.2	..	117.6	..	..	..	..	..	..	1.542
Japan	3 091.0	3 168.4	3 393.8	3 503.0	3 637.7	3 457.6	3 493.9	3 474.3	3 572.6	3 602.1	..	..	115.90
Korea	..	..	..	..	..	..	..	..	..	..	94.6	..	1 191.0
New Zealand	..	3.2	2.6	2.9	3.4	3.3	4.1	3.9	4.0	5.3	6.0	6.7	1.724
Austria	20.7	27.4	30.2	30.2	30.0	31.5	33.4	32.1	27.8	34.9	33.6	..	0.885
Belgium	..	..	53.4	55.8	71.1	67.7	86.0	59.9	..	..	..	..	0.885
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..	28.13
Denmark	58.1	55.8	47.0	43.7	37.9	44.0	53.3	51.8	52.6	51.7	26.0	26.9	6.584
Finland	53.7	54.4	64.7	74.7	72.2	100.1	99.7	95.1	77.5	72.0	80.2	..	0.885
France	589.3	581.3	539.9	627.8	596.0	594.6	636.4	742.2	700.3	518.7	462.6	..	0.885
Germany	476.5	463.4	370.5	317.3	341.5	308.5	329.7	219.9	315.3	339.1	301.7	300.6	0.885
Greece	8.0	6.5	5.9	9.9	11.3	20.1	..	..	7.2	8.5	10.4	..	0.885
Hungary	..	..	..	..	..	..	..	..	3.3	2.9	3.8	3.7	224.3
Ireland	..	..	..	..	..	..	..	..	..	..	4.2	7.7	0.885
Italy	..	353.2	335.0	344.9	319.5	291.2	283.8	..	323.4	339.3	349.1	341.5	0.885
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..	0.885
Netherlands	202.6	224.8	237.3	169.9	176.1	198.7	187.1	185.0	160.0	191.2	162.9	..	0.885
Norway	78.3	71.5	69.5	57.8	52.6	50.0	49.6	62.3	53.5	55.0	57.1	54.2	7.078
Portugal	8.4	5.4	4.2	2.0	2.5	1.6	2.2	2.6	1.9	1.2	2.2	1.7	0.885
Spain	111.1	93.5	99.3	88.7	84.6	84.1	64.5	66.2	63.1	61.1	53.8	53.1	0.885
Sweden	108.2	81.2	85.9	62.9	56.7	63.1	59.0	78.6	85.1	98.1	108.0	109.6	8.08
Switzerland	178.5	176.4	171.8	166.0	159.7	152.2	141.6	138.5	127.4	131.2	135.2	141.1	1.347
Turkey	3.7	3.8	1.9	4.6	3.7	12.0	5.9	3.8	3.9	4.3	3.3	5.5	1502 500
United Kingdom	289.5	208.4	105.8	107.2	71.2	93.8	81.2	77.5	85.6	53.0	..	..	0.610
Estimated IEA Total[2]	8 854.4	8 595.2	8 826.8	8 774.7	8 477.3	8 058.5	8 140.5	8 358.5	8 410.4	8 865.7	..	..	
European Commission[3]	..	..	..	..	..	..	..	..	..	..	..	..	0.885

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.
3. No information on R&D budgets has been provided by the European Commission.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75.*, OECD Paris, 2004, and country submissions.

Table B4

IEA Government Budgets on Energy R&D

(per thousand units of GDP)

	R&D/GDP including nuclear research								
	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	0.40	0.36	0.30	0.27	0.25	0.25	0.26	0.26	0.28
United States	0.33	0.28	0.24	0.23	0.25	0.23	0.28	0.27	0.25
Australia	0.24	..	0.29	..	..	..	..	..	..
Japan	0.90	0.90	0.84	0.86	0.85	0.85	0.86	..	..
Korea	..	..	..	..	..	..	..	0.16	..
New Zealand	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.08	0.09
Austria	0.14	0.14	0.14	0.14	0.13	0.11	0.14	0.13	..
Belgium	0.22	0.27	0.25	0.31	0.21	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..
Denmark	0.24	0.21	0.23	0.27	0.26	0.26	0.25	0.12	0.13
Finland	0.61	0.57	0.74	0.70	0.65	0.50	0.46	0.50	..
France	0.42	0.40	0.39	0.40	0.46	0.41	0.30	0.26	..
Germany	0.15	0.16	0.14	0.15	0.09	0.13	0.14	0.13	0.12
Greece	0.08	0.09	0.15	..	..	0.05	0.05	0.06	..
Hungary	..	..	..	..	..	0.04	0.04	0.05	0.05
Ireland	..	..	..	..	..	..	..	0.03	0.05
Italy	0.26	0.24	0.22	0.21	..	0.23	0.23	0.24	0.23
Luxembourg	..	..	..	..	..	..	..	..	..
Netherlands	0.40	0.40	0.44	0.40	0.38	0.31	0.37	0.32	..
Norway	0.32	0.28	0.25	0.25	0.30	0.25	0.25	0.26	0.24
Portugal	0.02	0.02	0.01	0.02	0.02	0.01	0.01	0.01	0.01
Spain	0.14	0.13	0.12	0.09	0.09	0.08	0.08	0.07	0.06
Sweden	0.26	0.23	0.25	0.22	0.28	0.29	0.34	0.36	0.36
Switzerland	0.58	0.55	0.52	0.47	0.45	0.40	0.41	0.42	0.44
Turkey	0.02	0.02	0.06	0.03	0.02	0.02	0.02	0.01	0.02
United Kingdom	0.07	0.05	0.06	0.05	0.05	0.05	0.03	..	..

	R&D/GDP including nuclear research								
	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	0.19	0.20	0.17	0.16	0.17	0.18	0.21	0.20	0.22
United States	0.26	0.24	0.20	0.20	0.22	0.20	0.25	0.24	0.22
Australia	0.22	..	0.29	..	..	..	..	..	..
Japan	0.22	0.22	0.21	0.25	0.24	0.25	0.26	..	..
Korea	..	..	..	..	..	..	..	0.12	– 0.05
New Zealand	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.08	0.09
Austria	0.13	0.13	0.13	0.13	0.12	0.10	0.12	0.12	..
Belgium	0.10	0.10	0.08	0.09	0.04	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..
Denmark	0.24	0.20	0.23	0.25	0.23	0.23	0.23	0.11	0.11
Finland	0.55	0.49	0.67	0.64	0.57	0.45	0.41	0.45	..
France	0.04	0.04	0.03	0.03	0.04	0.04	0.05	0.06	..
Germany	0.06	0.07	0.06	0.06	0.05	0.06	0.08	0.07	0.06
Greece	0.07	0.08	0.14	..	..	0.04	0.05	0.05	..
Hungary	..	..	..	– 0.00	– 0.01	0.03	0.02	0.03	0.03
Ireland	..	..	..	..	..	..	..	0.03	0.05
Italy	0.16	0.14	0.12	0.12	..	0.13	0.14	0.16	0.16
Luxembourg	..	..	..	..	..	..	..	..	..
Netherlands	0.35	0.36	0.38	0.36	0.34	0.26	0.32	0.27	..
Norway	0.27	0.23	0.21	0.19	0.25	0.21	0.21	0.22	0.21
Portugal	0.02	0.02	0.01	0.02	0.02	0.01	0.01	0.01	0.01
Spain	0.07	0.07	0.06	0.05	0.05	0.04	0.04	0.03	0.03
Sweden	0.22	0.20	0.22	0.20	0.26	0.27	0.32	0.34	0.34
Switzerland	0.42	0.39	0.36	0.33	0.34	0.27	0.29	0.30	0.33
Turkey	0.02	0.01	0.05	0.02	0.02	0.02	0.02	0.01	0.02
United Kingdom	0.04	0.03	0.04	0.03	0.03	0.03	0.02	..	..

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B5

IEA Government R&D Budgets for Conservation

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	27.0	29.5	43.8	42.8	43.9	42.3	43.1	45.8	35.8	45.5	55.7	52.4
United States	348.2	367.3	500.9	580.4	465.1	429.2	461.5	518.6	569.0	600.3	587.5	391.8
Australia	..	5.3	..	10.8	..	7.6	..	..	..	..	..	..
Japan[2]	17.1	26.4	221.5	236.1	269.7	262.4	423.7	516.0	562.1	598.6	..	..
Korea	..	..	..	..	..	..	..	..	..	..	17.8	..
New Zealand	..	0.5	0.4	0.7	0.6	0.5	0.3	0.6	0.6	0.4	0.5	0.9
Austria	6.6	9.8	12.1	11.0	11.0	10.4	8.3	9.2	8.5	10.7	9.1	..
Belgium	3.7	8.0	10.8	9.8	12.6	11.1	16.2	4.9	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	11.0	7.9	6.5	5.6	5.9	8.9	10.2	11.4	15.4	12.1	0.4	1.3
Finland	16.8	17.5	19.3	26.6	25.7	42.8	51.8	43.1	32.3	28.7	30.5	..
France	20.8	13.5	9.2	8.9	8.0	5.2	7.3	13.9	14.2	13.9	21.7	..
Germany	13.9	13.1	15.1	17.3	25.1	16.3	14.7	13.5	10.6	27.4	17.7	18.3
Greece	0.3	0.3	1.6	1.9	2.4	6.1	..	..	0.6	0.6	1.7	..
Hungary	..	..	..	–	–	..	–	..	1.1	0.2	0.2	0.2
Ireland	..	..	..	..	..	..	..	..	..	..	2.9	5.4
Italy	..	64.1	60.5	63.8	64.7	59.9	59.7	..	28.4	30.0	29.1	29.6
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	53.6	76.9	59.2	62.7	72.0	75.0	75.0	75.9	49.0	67.9	49.4	..
Norway	18.4	17.6	10.1	2.4	2.2	2.0	1.9	1.8	1.9	1.7	2.2	2.3
Portugal	0.7	1.2	0.5	1.0	0.8	0.8	0.1	0.2	0.3	0.4	–	–
Spain	15.3	5.9	9.6	7.5	4.6	4.5	8.5	4.0	5.2	2.9	2.3	2.3
Sweden	33.3	26.6	25.2	22.9	26.6	19.8	16.6	24.9	30.7	39.7	49.6	50.8
Switzerland	27.0	28.8	32.8	31.3	29.4	23.2	22.1	24.5	19.0	19.8	22.5	25.2
Turkey	–	1.3	–	0.2	0.2	0.1	0.2	0.2	0.5	1.6	0.4	0.3
United Kingdom	37.8	42.7	4.8	3.0	2.6	1.9	1.0	1.3	2.6	–	–	–
Estimated IEA Total[3]	**721.9**	**763.9**	**1 049.8**	**1 144.5**	**1 079.6**	**1 023.9**	**1 231.5**	**1 361.2**	**1 401.4**	**1 518.2**	**..**	**..**

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. The items included in Conservation were expanded in 1994. Earlier budgetary data are not comparable.
3. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B6

IEA Government R&D Budgets for Oil & Gas

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	79.2	56.7	45.6	42.2	49.7	41.6	42.6	42.9	39.4	48.2	42.4	42.4
United States	105.7	189.3	114.9	127.0	87.3	75.5	80.1	78.9	91.4	115.5	104.2	86.8
Australia	..	37.7	..	31.4	..	65.3	..	..	..	..	..	..
Japan	102.8	108.4	114.8	130.9	129.5	125.5	94.5	32.0	25.5	32.9	..	..
Korea	..	..	..	..	..	..	..	..	..	..	0.9	1.1
New Zealand	..	1.5	0.6	0.5	0.6	0.6	0.7	0.7	0.7	1.8	2.7	2.4
Austria	0.9	0.4	0.3	0.4	0.7	0.3	0.3	0.2	–	0.3	0.2	..
Belgium	–	–	–	–	0.1	0.1	–	0.3	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	3.0	3.5	3.8	4.0	3.3	2.9	2.4	2.9	2.2	2.1	–	–
Finland	–	–	–	–	–	2.5	2.8	3.1	1.5	3.0	3.1	..
France	40.6	37.7	37.6	36.0	35.5	35.1	34.8	34.7	36.4	39.7	32.6	..
Germany	7.6	4.5	3.2	0.8	–	–	–	–	–	–	–	–
Greece	0.1	0.1	0.7	1.3	1.4	2.1	..	..	..	..	..	..
Hungary	..	..	..	–	–	..	–	–	0.6	0.2	0.2	0.2
Ireland	..	..	..	..	..	..	..	..	..	..	–	0.2
Italy	..	–	–	–	–	–	–	..	–	–	2.3	2.3
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	8.5	12.0	15.3	10.9	10.9	12.1	10.1	9.7	10.7	9.3	18.5	..
Norway	22.3	19.5	30.9	28.8	25.3	24.1	23.1	37.4	28.9	27.0	21.6	26.0
Portugal	–	–	0.3	0.2	0.1	0.1	0.1	0.2	0.1	–	–	–
Spain	–	–	–	–	–	–	–	0.1	1.8	–	–	–
Sweden	1.3	–	–	–	–	–	–	–	..	–	–	–
Switzerland	13.8	13.9	13.1	12.5	9.8	10.7	9.3	8.9	8.1	8.4	9.0	8.9
Turkey	0.3	0.1	0.1	3.1	2.2	4.5	0.9	0.1	0.1	0.1	0.1	0.2
United Kingdom	7.8	7.2	5.6	12.1	5.7	8.4	6.7	4.5	5.0	3.8	1.4	1.5
Estimated IEA Total[2]	**420.0**	**492.8**	**421.4**	**440.8**	**402.8**	**409.5**	**367.9**	**310.7**	**299.7**	**353.7**	**..**	**..**

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B7

IEA Government R&D Budgets for Coal

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	20.8	12.6	9.1	11.4	8.2	2.8	4.6	5.9	3.5	3.6	3.0	4.5
United States	376.6	282.8	453.5	219.2	299.9	106.8	114.4	136.6	127.7	248.7	327.2	329.1
Australia	..	15.9	..	15.4	..	19.4	..	..	..	..	..	..
Japan	215.1	245.2	243.2	224.5	200.4	177.7	161.4	124.3	78.9	41.7	..	..
Korea	..	..	..	..	..	..	..	..	..	..	11.1	11.5
New Zealand	..	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.2	0.2	-
Austria	0.6	1.3	0.8	0.6	1.4	1.8	0.4	0.6	0.5	0.4	0.3	..
Belgium	1.5	1.3	1.9	1.6	1.8	2.5	0.5	0.7	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	7.5	6.1	5.4	3.2	0.9	-	0.1	-	-	-	-	-
Finland	5.4	3.4	4.3	3.7	4.1	4.1	3.4	3.5	3.1	2.5	2.9	..
France	6.1	6.3	6.2	6.3	5.8	5.8	0.1	-	..	-	-	..
Germany	47.2	28.0	20.4	14.7	4.0	1.6	1.4	11.7	10.7	20.3	15.4	13.7
Greece	0.7	0.5	0.5	0.9	0.8	2.5	..	..	..	..	..	..
Hungary	..	..	..	-	-	..	-	..	..	0.3	0.3	0.2
Ireland	..	..	..	..	..	..	..	..	..	..	-	-
Italy	..	-	-	-	-	-	-	..	-	-	13.4	13.0
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	8.9	9.2	15.8	4.2	4.1	3.5	2.4	1.0	0.2	0.1	2.7	..
Norway	0.1	0.1	-	-	-	-	-	-	-	-	-	-
Portugal	2.0	0.7	-	-	-	-	0.2	0.3	0.3	0.2	0.7	1.3
Spain	3.0	1.9	5.3	5.9	5.1	4.8	3.3	6.3	2.2	5.3	3.0	3.1
Sweden	1.7	0.9	0.8	0.5	0.2	0.1	0.1	0.1	0.2	0.2	0.1	0.1
Switzerland	0.2	0.2	0.4	0.5	-	-	-	-	-	-	-	-
Turkey	0.7	0.4	0.1	0.2	0.1	3.5	1.8	1.5	0.5	0.6	0.2	0.7
United Kingdom	8.7	15.5	6.7	9.9	9.4	4.6	2.5	1.1	2.9	6.4	5.1	3.4
Estimated IEA Total[2]	**729.2**	**632.0**	**789.2**	**522.1**	**566.6**	**339.3**	**314.5**	**310.1**	**245.8**	**349.3**	**..**	**..**

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.
Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions

Table B8

IEA Government R&D Budgets for Conventional Nuclear

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	135.4	132.0	132.0	129.2	98.2	95.0	79.3	60.4	53.2	44.7	44.8	46.9
United States	267.1	139.8	111.5	96.6	44.0	62.5	21.9	24.3	36.7	48.8	50.0	130.0
Australia	..	0.9	..	6.1	..	0.9	..	..	..	..	..	..
Japan	1 734.2	1 791.6	1 842.7	2 018.1	2 132.4	2 045.7	2 010.0	2 040.9	1 946.1	2 041.6	..	..
Korea	..	..	..	..	..	..	..	..	..	..	26.3	30.5
New Zealand	..	–	–	–	–	–	–	–	–	–	–	–
Austria	0.5	0.7	0.7	0.6	1.0	0.7	–	0.5	–	0.3	0.2	..
Belgium	..	..	20.5	27.1	39.8	40.7	55.0	42.2	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	0.9	0.9	0.9	0.6	0.6	0.6	3.4	3.3	3.2	2.8	2.2	2.0
Finland	10.2	9.5	8.2	7.0	8.9	8.1	8.5	9.3	7.2	6.6	4.5	..
France	431.7	424.2	398.5	511.1	482.2	490.4	528.4	619.6	576.5	393.5	310.7	..
Germany	110.7	98.4	80.9	79.4	62.2	44.1	42.1	23.6	27.1	19.0	33.5	27.3
Greece	–	–	0.2	0.3	0.3	0.3	..	..	..	..	..	..
Hungary	..	..	..	–	–	..	0.3	0.5	1.1	1.1	1.1	1.2
Ireland	..	..	..	..	..	..	..	..	..	..	–	–
Italy	..	61.8	62.1	49.5	44.6	44.1	39.6	..	57.1	55.6	54.1	51.4
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	37.9	31.1	15.5	14.7	13.0	14.3	8.8	9.4	17.4	17.0	10.4	..
Norway	10.4	10.4	9.8	10.0	9.5	9.2	10.4	9.7	8.8	8.6	8.7	8.5
Portugal	1.4	0.4	2.7	0.1	0.2	0.1	–	–	–	–	–	–
Spain	27.3	23.8	22.5	21.1	21.1	20.8	9.7	6.3	17.1	17.5	16.1	15.8
Sweden	1.8	1.7	1.6	1.5	1.3	4.7	4.7	4.7	4.6	4.5	4.9	4.8
Switzerland	27.2	26.9	27.0	26.1	22.8	23.3	21.9	15.9	21.7	20.3	18.8	17.8
Turkey	1.0	1.4	1.0	0.7	0.9	1.3	0.9	0.2	0.2	0.2	–	0.1
United Kingdom	41.7	23.2	16.6	14.8	7.8	1.9	3.7	–	–	–	–	–
Estimated IEA Total	..	..	..	..	..	..	..	..	..	..	..	..

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B9

IEA Government R&D Budgets for Nuclear Breeders

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	–	–	–	–	–	–	0.2	0.5	0.4	0.5	0.5	0.1
United States	–	–	–	–	–	–	–	–	–	–	–	–
Australia	..	–	..	–	..	–	..	..	..	..	..	..
Japan	462.5	460.0	414.7	323.7	299.7	257.6	222.5	205.7	351.3	290.0	..	..
Korea	..	..	..	..	..	..	..	..	..	..	–	–
New Zealand	..	–	–	–	–	–	–	–	–	–	–	–
Austria	–	–	–	–	–	–	–	–	–	–	–	..
Belgium	..	..	..	–	–	–	–	–	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	–	–	–	–	–	–	..	–	–	–	–	–
Finland	–	0.1	–	1.0	–	–	–	–	–	–	–	..
France	32.4	51.5	41.3	17.5	16.9	13.6	24.8	22.9	13.1	–	4.6	..
Germany	4.6	–	–	–	–	–	–	–	–	–	–	–
Greece	–	–	–	–	–	–	..	..	..	..	..	..
Hungary	..	..	..	–	–	..	–	–	..	–	–	–
Ireland	..	..	..	..	..	..	..	..	..	..	–	–
Italy	..	–	–	–	–	–	–	..	–	–	–	–
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	0.6	0.6	27.3	–	–	–	–	–	–	–	4.3	..
Norway	–	–	–	–	–	–	–	–	–	–	–	–
Portugal	–	–	–	–	–	–	–	–	–	–	–	–
Spain	–	–	–	–	–	–	–	–	1.0	–	–	–
Sweden	5.2	5.1	4.9	4.5	3.9	..	..	..	..	..	..	..
Switzerland	1.5	1.3	0.5	1.0	1.1	0.4	0.1	0.1	0.1	0.1	–	–
Turkey	–	–	–	–	–	–	–	–	–	–	–	–
United Kingdom	111.9	52.8	2.1	0.2	–	–	–	–	–	–	–	–
Estimated IEA Total	..	..	..	..	..	..	..	..	..	..	..	..

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B10

IEA Government R&D Budgets for Nuclear Fusion

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	10.9	7.1	7.0	6.9	7.6	–	2.8	0.1	0.9	0.9	0.9	0.4
United States	406.0	400.3	384.7	422.4	269.0	242.9	238.0	238.2	251.6	256.5	245.0	240.7
Australia	..	–	..	–	..	–	..	..	..	..	..	..
Japan	255.6	275.7	278.7	286.6	318.3	296.8	240.5	236.8	228.9	197.7	..	..
Korea	..	..	..	..	..	..	..	..	..	..	–	–
New Zealand	..	–	–	–	–	–	–	–	–	–	–	–
Austria	1.8	2.1	1.3	1.4	0.8	1.4	2.9	3.1	3.2	3.6	3.8	..
Belgium	..	..	10.4	4.0	5.5	5.8	6.0	6.7	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	2.4	1.5	–	–	–	–	2.1	2.2	2.2	1.5	1.5	1.2
Finland	–	–	–	–	1.1	1.8	1.2	2.9	1.7	1.4	3.8	..
France	48.9	41.7	41.1	42.1	41.9	41.2	36.3	36.1	34.6	37.6	43.6	..
Germany	147.0	149.4	128.9	110.4	118.1	129.1	143.9	72.4	143.6	127.7	100.4	126.6
Greece	–	–	–	–	–	–	..	..	..	..	..	..
Hungary	..	..	..	–	–	..	–	–	..	–	–	–
Ireland	..	..	..	..	..	..	..	..	..	..	–	–
Italy	..	100.9	81.7	82.5	89.8	88.1	84.5	..	74.6	72.7	58.1	55.8
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	31.1	17.5	19.7	8.6	7.3	9.9	9.2	10.0	11.2	8.9	6.2	..
Norway	–	–	–	–	–	–	–	–	–	–	–	–
Portugal	1.2	1.1	–	–	–	–	–	–	–	–	–	–
Spain	12.2	12.8	20.6	19.6	19.6	19.4	18.0	20.2	12.6	12.6	12.4	12.4
Sweden	10.1	10.5	11.0	2.0	1.8	1.5	1.5	1.3	1.4	1.3	1.4	1.4
Switzerland	25.9	25.4	21.9	19.4	22.9	23.7	19.2	19.4	18.5	18.4	18.8	18.6
Turkey	–	–	–	–	–	–	–	–	–	–	–	–
United Kingdom	35.4	33.8	33.3	32.1	23.5	32.4	24.1	26.1	30.4	25.5	..	..
Estimated IEA Total[2]	**1 103.5**	**1 086.2**	**1 040.3**	**1 038.0**	**927.1**	**893.9**	**830.0**	**755.2**	**822.6**	**773.0**	**..**	**..**

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B11

IEA Government R&D Budgets for Renewables

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	12.2	11.0	12.7	12.4	12.3	9.5	9.8	11.9	22.1	19.6	19.7	30.0
United States	156.6	142.9	258.8	313.1	231.1	218.0	268.1	279.4	222.5	258.5	251.4	242.7
Australia	..	8.7	..	4.2	..	6.1	..	..	..	..	..	..
Japan	106.5	110.9	102.5	103.1	105.0	104.2	115.4	123.0	147.9	134.6	..	..
Korea	..	..	..	..	..	..	..	..	..	..	10.4	12.7
New Zealand	..	0.9	1.0	1.1	1.5	1.4	1.7	1.2	1.2	2.2	1.6	2.2
Austria	4.7	6.5	8.3	9.8	7.6	9.1	12.0	11.2	7.8	9.3	11.2	..
Belgium	2.3	2.7	2.8	4.5	3.4	3.7	1.5	1.2	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	22.5	24.0	20.9	19.5	15.7	20.3	22.3	19.3	19.4	21.9	11.2	11.0
Finland	2.4	6.0	6.6	6.7	8.5	13.7	10.0	11.2	10.3	9.5	11.2	..
France	8.8	6.4	6.0	5.9	5.6	3.4	4.6	15.0	15.7	21.1	27.2	..
Germany	134.1	146.3	96.7	85.3	105.9	82.9	92.9	81.9	85.8	81.7	86.1	73.6
Greece	5.7	4.0	2.2	3.9	3.6	7.6	..	..	2.2	3.3	3.8	..
Hungary	..	..	..	0.5	0.1	..	–	–	0.5	1.2	2.1	1.9
Ireland	..	..	..	..	..	..	..	..	..	..	0.7	1.6
Italy	..	32.4	36.7	50.0	46.7	43.0	40.1	..	27.5	45.3	60.5	61.5
Luxembourg	–	0.1	–	–	0.1	0.4	0.2	0.6	0.4	..	..	..
Netherlands	25.2	25.2	31.4	28.1	33.9	45.0	49.5	51.5	38.6	49.2	51.1	..
Norway	13.9	11.0	9.0	5.9	5.5	5.4	6.4	6.3	6.2	4.9	4.7	4.1
Portugal	2.9	1.9	0.7	0.7	1.4	0.7	1.5	1.6	1.0	0.5	1.4	0.4
Spain	27.8	25.1	18.3	17.8	17.8	17.7	22.1	18.9	20.5	19.2	18.8	18.3
Sweden	30.5	15.2	18.4	14.2	9.1	9.3	15.1	14.8	28.6	30.8	28.9	29.2
Switzerland	42.5	44.4	41.9	41.1	39.3	41.5	40.5	41.5	30.2	29.4	30.0	31.9
Turkey	1.4	0.3	0.4	0.1	0.1	2.2	1.8	1.2	1.4	0.5	1.1	1.2
United Kingdom	34.9	32.0	18.9	18.4	12.1	8.2	6.0	8.3	7.9	10.6	17.7	19.8
Estimated IEA Total[2]	**674.8**	**653.6**	**698.1**	**741.9**	**667.3**	**645.6**	**728.1**	**739.6**	**702.4**	**757.3**	**..**	**..**

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B12

IEA Government R&D Budgets for Power and Storage

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	9.6	10.5	9.8	9.5	8.1	4.5	4.8	5.0	17.0	21.7	22.0	27.3
United States	48.9	50.5	135.8	150.9	136.2	139.0	138.4	137.4	130.7	139.6	147.3	163.8
Australia	..	6.5	..	5.2	..	4.8	..	..	..	..	..	..
Japan	94.3	58.2	66.6	66.6	69.4	71.4	123.0	128.2	159.3	183.2	..	..
Korea	..	..	..	..	..	..	..	..	..	..	16.7	24.4
New Zealand	..	–	–	0.1	0.3	0.3	0.2	0.7	0.7	0.5	0.6	–
Austria	4.0	4.1	5.3	4.4	5.1	4.5	5.1	3.7	3.8	5.4	4.4	..
Belgium	2.9	8.5	4.7	6.5	6.5	2.1	5.5	3.2	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	5.6	6.5	4.7	4.5	4.9	4.9	5.0	4.6	4.2	4.5	4.0	4.2
Finland	15.8	14.8	18.9	18.6	14.3	19.4	17.5	17.5	15.0	15.6	16.3	..
France	–	–	–	–	–	–	–	–	0.8	2.3	5.2	..
Germany	5.4	2.9	3.5	2.4	13.7	23.8	25.2	9.0	24.7	48.3	39.6	34.7
Greece	0.1	–	0.1	0.1	0.1	0.3	..	..	2.7	2.8	3.0	..
Hungary	..	..	..	–	–	..	0.2	–	..	–	–	–
Ireland	..	..	..	..	..	..	..	..	..	..	0.5	0.2
Italy	..	13.5	23.5	18.7	19.2	17.7	18.5	..	96.3	93.8	91.0	88.4
Luxembourg	–	–	–	–	–	0.6	–	–	–	..	..	..
Netherlands	24.8	40.7	44.0	18.8	21.3	21.7	14.8	12.4	11.7	10.4	11.2	..
Norway	3.7	3.6	3.6	4.5	3.4	3.0	2.7	2.3	6.5	3.2	4.5	4.3
Portugal	–	–	–	–	–	–	–	–	–	0.1	–	–
Spain	–	–	–	0.4	0.4	0.4	0.5	1.5	2.0	1.1	–	–
Sweden	2.2	4.2	10.2	4.8	1.2	11.7	8.3	17.3	8.9	10.7	11.2	11.4
Switzerland	28.2	23.7	20.6	20.8	22.2	17.5	19.3	18.7	20.4	23.7	24.0	25.2
Turkey	–	0.1	0.1	–	–	0.2	0.1	0.5	1.3	0.8	1.1	1.3
United Kingdom	3.5	–	7.8	6.2	2.2	2.1	2.2	2.5	3.0	2.8	7.3	4.9
Estimated IEA Total[2]	**285.5**	**248.3**	**364.9**	**343.0**	**333.4**	**349.0**	**396.7**	**412.6**	**517.6**	**580.5**	**..**	**..**

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B12a

IEA Government R&D Budgets for Energy Systems Analysis & Others

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Canada[1]	19.6	7.3	8.8	8.6	13.4	15.4	11.7	22.2	28.3	34.1	31.2	35.7
United States	948.7	1 022.4	898.4	852.5	887.9	901.9	895.5	1 063.3	964.0	1 237.2	1 181.2	1 165.1
Australia	..	12.6	..	17.2	..	13.4	..	..	..	..	..	..
Japan	102.8	92.0	109.1	113.5	113.4	116.1	102.9	67.3	72.6	81.7	..	..
Korea	..	..	..	..	..	..	..	..	..	..	11.4	18.8
New Zealand	..	–	0.2	0.2	0.1	–	0.7	0.3	0.4	0.1	0.3	1.2
Austria	1.7	2.5	1.4	2.0	2.4	3.3	4.4	3.6	3.9	4.9	4.5	..
Belgium	2.6	1.5	2.2	2.2	1.4	1.7	1.2	0.7	..	..	..	..
Czech Republic	..	..	..	..	..	..	..	..	..	..	..	..
Denmark	5.1	5.4	4.7	6.4	6.6	6.5	8.0	8.1	6.1	6.8	6.7	7.3
Finland	3.1	3.2	7.4	11.1	9.6	7.7	4.7	4.4	6.5	4.6	7.9	..
France	–	–	–	–	–	–	–	–	9.0	10.6	17.2	..
Germany	6.1	20.8	21.8	7.0	12.6	10.6	9.4	7.8	12.8	14.6	9.0	6.4
Greece	1.1	1.6	0.7	1.6	2.6	1.3	..	..	..	..	..	..
Hungary	..	..	..	–	–	..	0.3	–	..	–	–	–
Ireland	..	..	..	..	..	..	..	..	..	..	0.1	0.4
Italy	..	80.4	70.5	80.4	54.5	38.4	41.4	..	39.5	42.0	40.7	39.5
Luxembourg	..	..	..	..	..	..	..	..	..	..	..	..
Netherlands	12.0	11.6	9.2	22.0	13.6	17.1	17.3	15.3	21.3	28.3	9.1	..
Norway	9.5	9.3	6.0	6.2	6.7	6.2	5.1	4.8	1.1	9.6	15.4	9.1
Portugal	0.2	–	–	–	–	–	0.2	0.3	0.2	–	–	–
Spain	25.5	24.0	22.9	16.4	16.1	16.4	2.5	8.9	0.7	2.5	1.2	1.3
Sweden	22.1	17.1	13.8	12.5	12.5	16.0	12.8	15.6	10.7	10.9	11.9	11.9
Switzerland	12.1	11.8	13.5	13.3	12.1	12.0	9.2	9.4	9.3	11.1	12.0	13.4
Turkey	0.2	0.2	0.1	0.3	0.2	0.2	0.1	0.1	0.1	0.3	0.4	1.7
United Kingdom	7.8	1.3	10.0	10.3	8.0	34.4	35.0	33.6	33.8	3.8	1.7	0.7
Estimated IEA Total[2]	**1 346.7**	**1 323.2**	**1 214.8**	**1 182.2**	**1 186.2**	**1 217.4**	**1 174.8**	**1 321.1**	**1 234.4**	**1 520.9**	**..**	**..**

1. All data refer to the fiscal year. April 2003 to March 2004 for 2003.
2. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.

Note: Budgets provided for recent years by some countries may have been estimated.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Table B13

IEA Government Energy R&D Expenditure by Country, 2002 and 2003

(US$ million at 2003 prices and exchange rates)

	Australia 2002 $	%	2003e $	%	Austria 2002 $	%	2003e $	%
1.1 Industry	..	..	..	..	2.76	8.21	..	..
1.2 Residential. Commercial	..	..	..	..	4.68	13.91	..	..
1.3 Transportation	..	..	..	..	0.94	2.78	..	..
1.4 Other Conservation	..	..	..	..	0.75	2.24	..	..
TOTAL CONSERVATION	..	..	..	..	**9.13**	**27.14**	..	..
2.1 Enhanced Oil & Gas	..	..	..	..	0.11	0.32	..	..
2.2 Refining. Transp. & Stor.	..	..	..	..	0.03	0.08	..	..
2.3 Oil Shale & Tar Sands	..	..	..	..	–	–	..	..
2.4 Other Oil & Gas	..	..	..	..	0.02	0.06	..	..
Total Oil & Gas	..	..	..	..	0.15	0.45	..	..
3.1 Coal Prod.. Prep.. & Trans.	..	..	..	..	–	–	..	..
3.2 Coal Combustion	..	..	..	..	0.12	0.36	..	..
3.3 Coal Conversion	..	..	..	..	–	–	..	..
3.4 Other Coal	..	..	..	..	0.20	0.60	..	..
Total Coal	..	..	..	..	0.32	0.96	..	..
TOTAL FOSSIL FUELS	..	..	..	..	**0.47**	**1.41**	..	..
4.1 Solar Heating & Cooling	..	..	..	..	1.64	4.87	..	..
4.2 Solar Photo-Electric	..	..	..	..	1.60	4.75	..	..
4.3 Solar Thermal-Electric	..	..	..	..	0.11	0.32	..	..
Total Solar	..	..	..	..	3.34	9.94	..	..
5. Wind	..	..	..	..	0.45	1.34	..	..
6. Ocean	..	..	..	..	–	–	..	..
7. Biomass	..	..	..	..	6.76	20.10	..	..
8. Geothermal	..	..	..	..	0.15	0.43	..	..
9.1 Large Hydro (>10 MW)	..	..	..	..	0.12	0.35	..	..
9.2 Small Hydro (<10 MW)	..	..	..	..	0.34	1.02	..	..
Total Hydro	..	..	..	..	0.46	1.37	..	..
TOTAL RENEWABLE ENERGY	..	..	..	..	**11.16**	**33.18**	..	..
10.1 Nuclear LWR	..	..	..	..	–	–	..	..
10.2 Other Converter Reactors	..	..	..	..	–	–	..	..
10.3 Nuclear Fuel Cycle	..	..	..	..	0.19	0.58	..	..
10.4 Nuclear Supporting Tech.	..	..	..	..	–	–	..	..
10.5 Nuclear Breeder	..	..	..	..	–	–	..	..
Total Nuclear Fission	..	..	..	..	0.19	0.58	..	..
11. Nuclear Fusion	..	..	..	..	3.80	11.30	..	..
TOTAL NUCLEAR	..	..	..	..	**4.00**	**11.88**	..	..
12.1 Electric Power Conversion	..	..	..	..	1.72	5.11	..	..
12.2 Electricity Transm., & Distr.	..	..	..	..	1.72	5.11	..	..
12.3 Energy Storage	..	..	..	..	0.93	2.77	..	..
TOTAL POWER & STORAGE	..	..	..	..	**4.37**	**12.98**	..	..
13.1 Energy Systems Analysis	..	..	..	..	1.54	4.58	..	..
13.2 Other Tech. or Research	..	..	..	..	2.97	8.84	..	..
TOTAL OTHER TECH./RESEARCH	..	..	..	..	**4.51**	**13.41**	..	..
TOTAL ENERGY R&D	..	..	..	..	**33.64**	**100.00**	..	..

1. All data refer to the fiscal year, April 2003 to March 2004 for 2003.
Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Belgium 2002 $	Belgium %	Belgium 2003e $	Belgium %	Canada[1] 2002 $	Canada[1] %	Canada[1] 2003e $	Canada[1] %	Denmark 2002 $	Denmark %	Denmark 2003e $	Denmark %
..	..	..	..	20.27	9.20	17.42	7.27	0.42	1.61	0.08	0.28
..	..	..	..	10.78	4.90	13.26	5.53	–	–	0.88	3.27
..	..	..	..	20.27	9.20	17.56	7.32	–	–	–	–
..	..	..	..	4.34	1.97	4.21	1.76	–	–	0.30	1.13
..	**..**	**..**	**..**	**55.66**	**25.27**	**52.45**	**21.88**	**0.42**	**1.61**	**1.26**	**4.68**
..	..	..	..	5.15	2.34	4.76	1.98	–	–	–	–
..	..	..	..	4.33	1.97	4.59	1.92	–	–	–	–
..	..	..	..	18.28	8.30	17.74	7.40	–	–	–	–
..	..	..	..	14.69	6.67	15.29	6.38	–	–	–	–
..	..	..	..	42.44	19.27	42.38	17.68	–	–	–	–
..	..	..	..	0.32	0.15	0.33	0.14	–	–	–	–
..	..	..	..	0.45	0.21	2.11	0.88	–	–	–	–
..	..	..	..	1.47	0.67	1.42	0.59	–	–	–	–
..	..	..	..	0.74	0.33	0.66	0.28	–	–	–	–
..	..	..	..	2.99	1.36	4.52	1.88	–	–	–	–
..	**..**	**..**	**..**	**45.42**	**20.62**	**46.90**	**19.56**	**–**	**–**	**–**	**–**
..	..	..	..	1.51	0.69	1.82	0.76	–	–	0.03	0.11
..	..	..	..	2.48	1.12	8.77	3.66	–	–	1.25	4.63
..	..	..	..	0.45	0.20	0.25	0.11	–	–	–	–
..	..	..	..	4.44	2.01	10.85	4.53	–	–	1.28	4.74
..	..	..	..	1.67	0.76	1.80	0.75	10.38	39.88	8.16	30.29
..	..	..	..	–	–	–	–	–	–	0.09	0.34
..	..	..	..	7.84	3.56	10.25	4.28	0.81	3.10	1.43	5.30
..	..	..	..	0.45	0.21	0.86	0.36	–	–	–	–
..	..	..	..	3.14	1.42	3.54	1.48	–	–	–	–
..	..	..	..	2.22	1.01	2.71	1.13	–	–	0.09	0.34
..	..	..	..	5.35	2.43	6.25	2.61	–	–	0.09	0.34
..	**..**	**..**	**..**	**19.75**	**8.97**	**30.02**	**12.52**	**11.19**	**42.98**	**11.04**	**41.01**
..	..	..	..	0.48	0.22	0.05	0.02	–	–	–	–
..	..	..	..	42.41	19.25	45.04	18.79	–	–	–	–
..	..	..	..	0.50	0.22	0.05	0.02	–	–	–	–
..	..	..	..	1.46	0.66	1.77	0.74	2.23	8.57	1.97	7.33
..	..	..	..	0.48	0.22	0.05	0.02	–	–	–	–
..	..	..	..	45.33	20.58	46.97	19.59	2.23	8.57	1.97	7.33
..	..	..	..	0.91	0.41	0.39	0.16	1.47	5.64	1.17	4.34
..	**..**	**..**	**..**	**46.23**	**20.99**	**47.36**	**19.76**	**3.70**	**14.22**	**3.14**	**11.68**
..	..	..	..	11.10	5.04	14.83	6.18	1.21	4.63	1.27	4.71
..	..	..	..	4.38	1.99	3.12	1.30	0.23	0.89	–	–
..	..	..	..	6.56	2.98	9.31	3.88	2.57	9.87	2.95	10.94
..	**..**	**..**	**..**	**22.04**	**10.01**	**27.26**	**11.37**	**4.01**	**15.40**	**4.21**	**15.65**
..	..	..	..	1.87	0.85	1.32	0.55	1.69	6.49	1.35	5.02
..	..	..	..	29.30	13.30	34.43	14.36	5.02	19.31	5.91	21.97
..	**..**	**..**	**..**	**31.17**	**14.15**	**35.75**	**14.91**	**6.71**	**25.79**	**7.27**	**26.99**
..	**..**	**..**	**..**	**220.27**	**100.00**	**239.73**	**100.00**	**26.03**	**100.00**	**26.93**	**100.00**

Table B13 *(continued)*

IEA Government Energy R&D Expenditure by Country, 2002 and 2003

(US$ million at 2003 prices and exchange rates)

	Finland[1]				France			
	2002		2003e		2002		2003e	
	$	%	$	%	$	%	$	%
1.1 Industry	18.17	22.65	..	..	4.59	0.99	..	..
1.2 Residential. Commercial	2.72	3.39	..	..	3.55	0.77	..	..
1.3 Transportation	5.33	6.64	..	..	7.80	1.69	..	..
1.4 Other Conservation	4.29	5.35	..	..	5.73	1.24	..	..
TOTAL CONSERVATION	**30.51**	**38.03**	**..**	**..**	**21.67**	**4.68**	**..**	**..**
2.1 Enhanced Oil & Gas	–	–	..	..	–	–	..	..
2.2 Refining. Transp. & Stor.	3.10	3.86	..	..	4.47	0.97	..	..
2.3 Oil Shale & Tar Sands	–	–	..	..	–	–	..	..
2.4 Other Oil & Gas	–	–	..	..	28.09	6.07	..	..
Total Oil & Gas	3.10	3.86	..	..	32.56	7.04	..	..
3.1 Coal Prod.. Prep.. & Trans.	0.01	0.01	..	..	–	–	..	..
3.2 Coal Combustion	0.07	0.08	..	..	–	–	..	..
3.3 Coal Conversion	–	–	..	..	–	–	..	..
3.4 Other Coal	2.81	3.51	..	..	–	–	..	..
Total Coal	2.89	3.60	..	..	–	–	..	..
TOTAL FOSSIL FUELS	**5.99**	**7.46**	**..**	**..**	**32.56**	**7.04**	**..**	**..**
4.1 Solar Heating & Cooling	0.16	0.19	..	..	1.38	0.30	..	..
4.2 Solar Photo-Electric	–	–	..	..	14.56	3.15	..	..
4.3 Solar Thermal-Electric	0.36	0.45	..	..	–	–	..	..
Total Solar	0.52	0.64	..	..	15.94	3.44	..	..
5. Wind	1.80	2.25	..	..	4.59	0.99	..	..
6. Ocean	–	–	..	..	–	–	..	..
7. Biomass	8.87	11.05	..	..	3.90	0.84	..	..
8. Geothermal	–	–	..	..	2.64	0.57	..	..
9.1 Large Hydro (>10 MW)	–	–	..	..	–	–	..	..
9.2 Small Hydro (<10 MW)	0.06	0.07	..	..	0.11	0.02	..	..
Total Hydro	0.06	0.07	..	..	0.11	0.02	..	..
TOTAL RENEWABLE ENERGY	**11.25**	**14.02**	**..**	**..**	**27.17**	**5.87**	**..**	**..**
10.1 Nuclear LWR	2.94	3.67	..	..	21.78	4.71	..	..
10.2 Other Converter Reactors	–	–	..	..	19.49	4.21	..	..
10.3 Nuclear Fuel Cycle	0.93	1.16	..	..	99.75	21.56	..	..
10.4 Nuclear Supporting Tech.	0.59	0.74	..	..	169.68	36.68	..	..
10.5 Nuclear Breeder	–	–	..	..	4.59	0.99	..	..
Total Nuclear Fission	4.47	5.57	..	..	315.29	68.15	..	..
11. Nuclear Fusion	3.79	4.73	..	..	43.57	9.42	..	..
TOTAL NUCLEAR	**8.26**	**10.30**	**..**	**..**	**358.86**	**77.57**	**..**	**..**
12.1 Electric Power Conversion	12.82	15.98	..	..	5.16	1.12	..	..
12.2 Electricity Transm., & Distr.	3.42	4.27	..	..	–	–	..	..
12.3 Energy Storage	0.09	0.11	..	..	–	–	..	..
TOTAL POWER & STORAGE	**16.33**	**20.36**	**..**	**..**	**5.16**	**1.12**	**..**	**..**
13.1 Energy Systems Analysis	7.30	9.10	..	..	17.20	3.72	..	..
13.2 Other Tech. or Research	0.59	0.74	..	..	–	–	..	..
TOTAL OTHER TECH./RESEARCH	**7.89**	**9.84**	**..**	**..**	**17.20**	**3.72**	**..**	**..**
TOTAL ENERGY R&D	**80.23**	**100.00**	**..**	**..**	**462.62**	**100.00**	**..**	**..**

1. Other coal refers to peat.
Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2003, and country submissions.

Germany 2002 $	Germany %	Germany 2003e $	Germany %	Greece 2002 $	Greece %	Greece 2003e $	Greece %	Hungary 2002 $	Hungary %	Hungary 2003e $	Hungary %
7.76	2.57	6.21	2.07	..	..	..	..	0.18	4.76	0.18	4.78
7.19	2.38	9.27	3.08	..	..	..	..	0.04	0.95	0.04	1.20
–	–	–	–	..	..	..	..	–	–	–	–
2.74	0.91	2.82	0.94	..	..	..	..	–	–	–	–
17.68	**5.86**	**18.31**	**6.09**	**1.71**	**16.52**	**..**	**..**	**0.22**	**5.71**	**0.22**	**5.98**
–	–	–	–	..	..	..	..	–	–	–	–
–	–	–	–	..	..	..	..	–	–	–	–
–	–	–	–	..	..	..	..	–	–	–	–
–	–	–	–	..	..	..	..	0.17	4.50	0.16	4.24
–	–	–	–	..	..	..	..	0.17	4.50	0.16	4.24
–	–	–	–	..	..	..	..	–	–	–	–
11.06	3.67	8.25	2.74	..	..	..	..	0.25	6.63	0.23	6.25
4.33	1.44	5.42	1.80	..	..	..	..	–	–	–	–
–	–	–	–	..	..	..	..	–	–	–	–
15.40	5.10	13.67	4.55	..	..	..	..	0.25	6.63	0.23	6.25
15.40	**5.10**	**13.67**	**4.55**	**0.60**	**5.78**	**..**	**..**	**0.42**	**11.13**	**0.39**	**10.49**
11.29	3.74	4.63	1.54	..	..	..	..	0.62	16.40	0.60	16.13
26.92	8.92	19.89	6.62	..	..	..	..	–	–	–	–
8.21	2.72	7.23	2.41	..	..	..	..	–	–	–	–
46.42	15.39	31.75	10.56	..	..	..	..	0.62	16.40	0.60	16.13
16.08	5.33	13.56	4.51	..	..	..	..	0.29	7.61	–	–
–	–	–	–	..	..	..	..	–	–	–	–
12.20	4.05	16.95	5.64	..	..	..	..	1.14	30.12	1.29	34.66
11.41	3.78	10.17	3.38	..	..	..	..	–	–	–	–
–	–	–	–	..	..	..	..	–	–	–	–
–	–	1.13	0.38	..	..	..	..	–	–	–	–
–	–	1.13	0.38	..	..	..	..	–	–	–	–
86.11	**28.54**	**73.56**	**24.47**	**3.82**	**36.89**	**..**	**..**	**2.05**	**54.13**	**1.89**	**50.79**
23.27	7.71	18.87	6.28	..	..	..	..	–	–	–	–
–	–	–	–	..	..	..	..	–	–	–	–
10.27	3.40	8.47	2.82	..	..	..	..	–	–	–	–
–	–	–	–	..	..	..	..	1.10	29.04	1.22	32.75
–	–	–	–	..	..	..	..	–	–	–	–
33.53	11.12	27.34	9.10	..	..	..	..	1.10	29.04	1.22	32.75
100.37	33.27	126.55	42.11	..	..	..	..	–	–	–	–
133.91	**44.39**	**153.90**	**51.20**	**1.28**	**12.31**	**..**	**..**	**1.10**	**29.04**	**1.22**	**32.75**
28.17	9.34	28.02	9.32	..	..	..	..	–	–	–	–
7.98	2.65	5.54	1.84	..	..	..	..	–	–	–	–
3.42	1.13	1.13	0.38	..	..	..	..	–	–	–	–
39.58	**13.12**	**34.69**	**11.54**	**2.95**	**28.50**	**..**	**..**	**–**	**–**	**–**	**–**
1.25	0.42	0.34	0.11	..	..	..	..	–	–	–	–
7.76	2.57	6.10	2.03	..	..	..	..	–	–	–	–
9.01	**2.99**	**6.44**	**2.14**	**..**	**..**	**..**	**..**	**–**	**–**	**–**	**–**
301.69	**100.00**	**300.56**	**100.00**	**10.36**	**100.00**	**..**	**..**	**3.79**	**100.00**	**3.73**	**100.00**

Table B13 *(continued)*

IEA Government Energy R&D Expenditure by Country, 2002 and 2003

(US$ million at 2003 prices and exchange rates)

	Ireland				Italy			
	2002		2003e		2002		2003e	
	$	%	$	%	$	%	$	%
1.1 Industry	0.42	10.08	0.66	8.54	11.63	3.33	11.86	3.47
1.2 Residential. Commercial	2.46	58.99	4.72	61.02	17.45	5.00	17.74	5.20
1.3 Transportation	0.06	1.36	0.01	0.10	–	–	–	–
1.4 Other Conservation	–	–	–	–	–	–	–	–
TOTAL CONSERVATION	**2.94**	**70.44**	**5.38**	**69.66**	**29.08**	**8.33**	**29.60**	**8.67**
2.1 Enhanced Oil & Gas	–	–	0.12	1.58	–	–	–	–
2.2 Refining. Transp. & Stor.	–	–	–	–	–	–	–	–
2.3 Oil Shale & Tar Sands	–	–	–	–	–	–	–	–
2.4 Other Oil & Gas	–	–	0.10	1.32	2.33	0.67	2.26	0.66
Total Oil & Gas	–	–	0.22	2.89	2.33	0.67	2.26	0.66
3.1 Coal Prod.. Prep.. & Trans.	–	–	–	–	–	–	–	–
3.2 Coal Combustion	–	–	–	–	4.07	1.17	3.95	1.16
3.3 Coal Conversion	–	–	–	–	4.65	1.33	4.52	1.32
3.4 Other Coal	–	–	–	–	4.65	1.33	4.52	1.32
Total Coal	–	–	–	–	13.38	3.83	12.99	3.81
TOTAL FOSSIL FUELS	**–**	**–**	**0.22**	**2.89**	**15.71**	**4.50**	**15.25**	**4.47**
4.1 Solar Heating & Cooling	–	–	0.31	4.02	4.65	1.33	4.63	1.36
4.2 Solar Photo-Electric	0.02	0.54	0.08	1.10	11.63	3.33	11.64	3.41
4.3 Solar Thermal-Electric	–	–	0.05	0.60	40.95	11.73	41.69	12.21
Total Solar	0.02	0.54	0.44	5.72	57.24	16.39	57.97	16.98
5. Wind	0.23	5.45	0.51	6.64	0.58	0.17	0.90	0.26
6. Ocean	0.28	6.68	0.11	1.36	–	–	–	–
7. Biomass	0.11	2.72	0.35	4.59	2.68	0.77	2.60	0.76
8. Geothermal	–	–	0.17	2.18	–	–	–	–
9.1 Large Hydro (>10 MW)	–	–	–	–	–	–	–	–
9.2 Small Hydro (<10 MW)	0.02	0.54	–	–	–	–	–	–
Total Hydro	0.02	0.54	–	–	–	–	–	–
TOTAL RENEWABLE ENERGY	**0.66**	**15.94**	**1.58**	**20.48**	**60.50**	**17.33**	**61.47**	**18.00**
10.1 Nuclear LWR	–	–	–	–	–	–	–	–
10.2 Other Converter Reactors	–	–	–	–	–	–	–	–
10.3 Nuclear Fuel Cycle	–	–	–	–	54.10	15.49	51.41	15.06
10.4 Nuclear Supporting Tech.	–	–	–	–	–	–	–	–
10.5 Nuclear Breeder	–	–	–	–	–	–	–	–
Total Nuclear Fission	–	–	–	–	54.10	15.49	51.41	15.06
11. Nuclear Fusion	–	–	–	–	58.05	16.63	55.82	16.35
TOTAL NUCLEAR	**–**	**–**	**–**	**–**	**112.15**	**32.12**	**107.23**	**31.40**
12.1 Electric Power Conversion	0.11	2.72	0.12	1.54	34.90	10.00	33.90	9.93
12.2 Electricity Transm., & Distr.	0.40	9.54	0.03	0.41	41.88	12.00	40.68	11.91
12.3 Energy Storage	–	–	–	–	14.19	4.07	13.79	4.04
TOTAL POWER & STORAGE	**0.51**	**12.26**	**0.15**	**1.94**	**90.98**	**26.06**	**88.36**	**25.88**
13.1 Energy Systems Analysis	–	–	0.03	0.42	–	–	–	–
13.2 Other Tech. or Research	0.06	1.36	0.35	4.59	40.72	11.66	39.55	11.58
TOTAL OTHER TECH./RESEARCH	**0.06**	**1.36**	**0.39**	**5.01**	**40.72**	**11.66**	**39.55**	**11.58**
TOTAL ENERGY R&D	**4.17**	**100.00**	**7.73**	**100.00**	**349.14**	**100.00**	**341.47**	**100.00**

Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Japan				Korea				Luxembourg			
2002		2003e		2002		2003e		2002		2003e	
$	%	$	%	$	%	$	%	$	%	$	%
..	..	..	..	9.47	10.01	..	..	..	..	..	..
..	..	..	..	6.21	6.56	..	..	..	..	..	..
..	..	..	..	0.20	0.21	..	..	..	..	..	..
..	..	..	..	1.92	2.03	1.63	..	..	..	..	..
..	**..**	**..**	**..**	**17.79**	**18.80**	**..**	**..**	**..**	**..**	**..**	**..**
..	..	..	..	–	–	–	..	..	..	..	..
..	..	..	..	0.91	0.96	0.64	..	..	..	..	..
..	..	..	..	–	–	–	..	..	..	..	..
..	..	..	..	–	–	0.43	..	..	..	..	..
..	..	..	..	0.91	0.96	1.08	..	..	..	..	..
..	..	..	..	–	–	–	..	..	..	..	..
..	..	..	..	9.31	9.84	10.69	..	..	..	..	..
..	..	..	..	1.39	1.47	0.50	..	..	..	..	..
..	..	..	..	0.36	0.39	0.31	..	..	..	..	..
..	..	..	..	11.06	11.69	11.50	..	..	..	..	..
..	**..**	**..**	**..**	**11.97**	**12.66**	**12.58**	**..**	**..**	**..**	**..**	**..**
..	..	..	..	1.16	1.22	0.60	..	..	..	..	..
..	..	..	..	2.73	2.88	3.25	..	..	..	..	..
..	..	..	..	–	–	–	..	..	..	..	..
..	..	..	..	3.88	4.10	3.85	..	..	..	..	..
..	..	..	..	2.31	2.44	2.88	..	..	..	..	..
..	..	..	..	–	–	0.25	..	..	..	..	..
..	..	..	..	1.83	1.94	2.15	..	..	..	..	..
..	..	..	..	–	–	0.65	..	..	..	..	..
..	..	..	..	2.20	2.32	2.52	..	..	..	..	..
..	..	..	..	0.19	0.20	0.36	..	..	..	..	..
..	..	..	..	2.39	2.53	2.88	..	..	..	..	..
..	**..**	**..**	**..**	**10.42**	**11.02**	**12.66**	**..**	**..**	**..**	**..**	**..**
..	..	..	..	–	–	–	..	..	..	..	..
..	..	..	..	–	–	–	..	..	..	..	..
..	..	..	..	17.46	18.46	21.54	..	..	..	..	..
..	..	..	..	8.82	9.32	8.99	..	..	..	..	..
..	..	..	..	–	–	–	..	..	..	..	..
..	..	..	..	26.28	27.78	30.53	..	..	..	..	..
..	..	..	..	–	–	–	..	..	..	..	..
..	**..**	**..**	**..**	**26.28**	**27.78**	**30.53**	**..**	**..**	**..**	**..**	**..**
..	..	..	..	1.87	1.98	2.47	..	..	..	..	..
..	..	..	..	13.63	14.40	19.66	..	..	..	..	..
..	..	..	..	1.19	1.26	2.30	..	..	..	..	..
..	**..**	**..**	**..**	**16.69**	**17.64**	**24.43**	**..**	**..**	**..**	**..**	**..**
..	..	..	..	1.46	1.55	2.29	..	..	..	..	..
..	..	..	..	9.98	10.55	16.53	..	..	..	..	..
..	**..**	**..**	**..**	**11.45**	**12.10**	**18.83**	**..**	**..**	**..**	**..**	**..**
..	**..**	**..**	**..**	**94.61**	**100.00**	**..**	**..**	**..**	**..**	**..**	**..**

Table B13 *(continued)*

IEA Government Energy R&D Expenditure by Country, 2002 and 2003

(US$ million at 2003 prices and exchange rates)

	Netherlands				New Zealand			
	2002		2003e		2002		2003e	
	$	%	$	%	$	%	$	%
1.1 Industry	18.13	11.13	..	..	0.23	3.91	–	–
1.2 Residential. Commercial	18.16	11.15	..	..	0.16	2.72	0.46	6.86
1.3 Transportation	12.92	7.93	..	..	–	–	–	–
1.4 Other Conservation	0.14	0.08	..	..	0.10	1.60	0.46	6.82
TOTAL CONSERVATION	**49.35**	**30.30**	**..**	**..**	**0.49**	**8.23**	**0.92**	**13.68**
2.1 Enhanced Oil & Gas	11.17	6.85	..	..	2.33	39.06	2.23	33.26
2.2 Refining. Transp. & Stor.	2.49	1.53	..	..	–	–	–	–
2.3 Oil Shale & Tar Sands	–	–	..	..	–	–	–	–
2.4 Other Oil & Gas	4.86	2.98	..	..	0.41	6.92	0.18	2.72
Total Oil & Gas	18.51	11.36	..	..	2.74	45.98	2.41	35.98
3.1 Coal Prod.. Prep.. & Trans.	0.21	0.13	..	..	0.06	0.93	–	–
3.2 Coal Combustion	0.06	0.04	..	..	0.10	1.61	–	–
3.3 Coal Conversion	–	–	..	..	0.07	1.11	–	–
3.4 Other Coal	2.45	1.51	..	..	–	–	–	–
Total Coal	2.72	1.67	..	..	0.22	3.65	–	–
TOTAL FOSSIL FUELS	**21.23**	**13.03**	**..**	**..**	**2.96**	**49.63**	**2.41**	**35.98**
4.1 Solar Heating & Cooling	1.66	1.02	..	..	–	–	–	–
4.2 Solar Photo-Electric	18.70	11.48	..	..	0.18	3.08	1.06	15.79
4.3 Solar Thermal-Electric	–	–	..	..	0.07	1.22	0.20	2.99
Total Solar	20.36	12.50	..	..	0.26	4.30	1.26	18.78
5. Wind	13.67	8.39	..	..	0.14	2.28	–	–
6. Ocean	–	–	..	..	–	–	–	–
7. Biomass	13.50	8.29	..	..	0.33	5.46	0.30	4.55
8. Geothermal	3.52	2.16	..	..	0.86	14.42	0.64	9.53
9.1 Large Hydro (>10 MW)	–	–	..	..	–	–	–	–
9.2 Small Hydro (<10 MW)	–	–	..	..	–	–	–	–
Total Hydro	–	–	..	..	–	–	–	–
TOTAL RENEWABLE ENERGY	**51.05**	**31.34**	**..**	**..**	**1.58**	**26.46**	**2.20**	**32.86**
10.1 Nuclear LWR	2.31	1.42	..	..	–	–	–	–
10.2 Other Converter Reactors	1.94	1.19	..	..	–	–	–	–
10.3 Nuclear Fuel Cycle	2.96	1.82	..	..	–	–	–	–
10.4 Nuclear Supporting Tech.	3.20	1.97	..	..	–	–	–	–
10.5 Nuclear Breeder	4.28	2.63	..	..	–	–	–	–
Total Nuclear Fission	14.69	9.02	..	..	–	–	–	–
11. Nuclear Fusion	6.25	3.84	..	..	–	–	–	–
TOTAL NUCLEAR	**20.93**	**12.85**	**..**	**..**	**–**	**–**	**–**	**–**
12.1 Electric Power Conversion	6.71	4.12	..	..	0.60	10.00	–	–
12.2 Electricity Transm., & Distr.	3.91	2.40	..	..	–	–	–	–
12.3 Energy Storage	0.56	0.34	..	..	–	–	–	–
TOTAL POWER & STORAGE	**11.19**	**6.87**	**..**	**..**	**0.60**	**10.00**	**–**	**–**
13.1 Energy Systems Analysis	0.28	0.17	..	..	0.13	2.19	0.47	6.99
13.2 Other Tech. or Research	8.86	5.44	..	..	0.21	3.49	0.70	10.49
TOTAL OTHER TECH./RESEARCH	**9.14**	**5.61**	**..**	**..**	**0.34**	**5.69**	**1.17**	**17.48**
TOTAL ENERGY R&D	**162.89**	**100.00**	**..**	**..**	**5.97**	**100.00**	**6.69**	**100.00**

Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Norway				Portugal				Spain			
2002		2003e		2002		2003e		2002		2003e	
$	%	$	%	$	%	$	%	$	%	$	%
0.15	0.25	0.14	0.26	–	–	–	–	0.59	1.10	0.58	1.09
2.05	3.59	2.12	3.91	–	–	–	–	0.74	1.38	0.76	1.42
–	–	–	–	–	–	–	–	0.98	1.81	0.92	1.73
–	–	–	–	–	–	–	–	–	–	–	–
2.19	**3.84**	**2.26**	**4.17**	**–**	**–**	**–**	**–**	**2.31**	**4.29**	**2.26**	**4.25**
4.26	7.46	5.41	9.98	–	–	–	–	–	–	–	–
1.74	3.05	2.16	3.99	–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–	–	–	–
15.63	27.39	18.38	33.90	0.03	1.32	0.03	1.63	–	–	–	–
21.64	37.90	25.95	47.87	0.03	1.32	0.03	1.63	–	–	–	–
–	–	–	–	0.35	15.89	0.31	17.86	–	–	–	–
–	–	–	–	0.25	11.53	0.56	32.14	2.69	5.01	2.84	5.34
–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	–	0.11	4.95	0.40	23.34	0.26	0.48	0.24	0.45
–	–	–	–	0.71	32.37	1.27	73.34	2.95	5.48	3.08	5.79
21.64	**37.90**	**25.95**	**47.87**	**0.74**	**33.68**	**1.30**	**74.97**	**2.95**	**5.48**	**3.08**	**5.79**
0.36	0.64	0.07	0.13	0.81	36.74	0.10	5.80	0.34	0.62	0.32	0.60
1.50	2.62	1.41	2.61	0.08	3.84	0.04	2.22	3.20	5.95	3.35	6.31
–	–	–	–	–	–	–	–	7.59	14.11	7.80	14.69
1.86	3.26	1.48	2.74	0.89	40.58	0.14	8.02	11.13	20.68	11.47	21.59
0.73	1.27	1.07	1.98	0.25	11.16	0.16	9.13	3.59	6.68	2.66	5.01
0.19	0.33	0.08	0.16	0.14	6.42	0.07	4.17	–	–	–	–
0.67	1.17	0.51	0.94	0.14	6.58	0.06	3.26	3.67	6.82	3.84	7.22
–	–	0.14	0.26	0.03	1.16	0.01	0.46	–	–	–	–
1.24	2.16	0.85	1.56	–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–	0.42	0.78	0.34	0.64
1.24	2.16	0.85	1.56	–	–	–	–	0.42	0.78	0.34	0.64
4.68	**8.20**	**4.14**	**7.64**	**1.45**	**65.89**	**0.43**	**25.03**	**18.81**	**34.95**	**18.32**	**34.47**
–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–	–	–	–
3.63	6.36	3.53	6.51	–	–	–	–	10.25	19.05	9.65	18.16
5.09	8.91	4.94	9.12	–	–	–	–	5.88	10.93	6.14	11.55
–	–	–	–	–	–	–	–	–	–	–	–
8.72	15.27	8.48	15.64	–	–	–	–	16.13	29.97	15.78	29.71
–	–	–	–	–	–	–	–	12.38	23.01	12.40	23.33
8.72	**15.27**	**8.48**	**15.64**	**–**	**–**	**–**	**–**	**28.52**	**52.99**	**28.18**	**53.04**
1.02	1.78	1.22	2.24	0.01	0.42	–	–	–	–	–	–
1.95	3.41	2.26	4.17	–	–	–	–	–	–	–	–
1.53	2.67	0.79	1.46	–	–	–	–	–	–	–	–
4.49	**7.86**	**4.27**	**7.87**	**0.01**	**0.42**	**–**	**–**	**–**	**–**	**–**	**–**
2.01	3.51	2.20	4.05	–	–	–	–	0.02	0.04	0.02	0.04
13.37	23.42	6.92	12.77	–	–	–	–	1.20	2.24	1.28	2.41
15.37	**26.93**	**9.12**	**16.82**	**–**	**–**	**–**	**–**	**1.23**	**2.28**	**1.30**	**2.45**
57.09	**100.00**	**54.22**	**100.00**	**2.20**	**100.00**	**1.73**	**100.00**	**53.81**	**100.00**	**53.13**	**100.00**

Table B13 *(continued)*

IEA Government Energy R&D Expenditure by Country, 2002 and 2003

(US$ million at 2003 prices and exchange rates)

	Sweden				Switzerland			
	2002 $	%	2003e $	%	2002 $	%	2003e $	%
1.1 Industry	9.14	8.46	14.73	13.45	2.25	1.67	2.97	2.11
1.2 Residential. Commercial	5.25	4.86	5.57	5.08	6.76	5.00	7.42	5.26
1.3 Transportation	31.52	29.17	26.74	24.41	7.51	5.56	8.17	5.79
1.4 Other Conservation	3.67	3.40	3.72	3.40	6.01	4.44	6.68	4.74
TOTAL CONSERVATION	**49.58**	**45.88**	**50.76**	**46.33**	**22.53**	**16.67**	**25.24**	**17.89**
2.1 Enhanced Oil & Gas	–	–	–	–	9.01	6.67	8.91	6.32
2.2 Refining. Transp. & Stor.	–	–	–	–	–	–	–	
2.3 Oil Shale & Tar Sands	–	–	–	–	–	–	–	–
2.4 Other Oil & Gas	–	–	–	–	–	–	–	
Total Oil & Gas	–	–	–	–	9.01	6.67	8.91	6.32
3.1 Coal Prod.. Prep.. & Trans.	–	–	–	–	–	–	–	–
3.2 Coal Combustion	–	–	–	–	–	–	–	–
3.3 Coal Conversion	–	–	–	–	–	–	–	–
3.4 Other Coal	0.12	0.11	0.15	0.13	–	–	–	–
Total Coal	0.12	0.11	0.15	0.13	–	–	–	–
TOTAL FOSSIL FUELS	**0.12**	**0.11**	**0.15**	**0.13**	**9.01**	**6.67**	**8.91**	**6.32**
4.1 Solar Heating & Cooling	1.59	1.47	1.88	1.72	5.26	3.89	5.20	3.68
4.2 Solar Photo-Electric	1.64	1.52	2.77	2.53	12.77	9.44	13.36	9.47
4.3 Solar Thermal-Electric	–	–	–	–	0.75	0.56	1.48	1.05
Total Solar	3.22	2.98	4.65	4.24	18.78	13.89	20.04	14.21
5. Wind	3.50	3.24	5.57	5.08	1.50	1.11	1.48	1.05
6. Ocean	–	–	–	–	–	–	–	–
7. Biomass	16.80	15.55	16.71	15.25	5.26	3.89	5.94	4.21
8. Geothermal	4.46	4.12	1.31	1.20	2.25	1.67	2.23	1.58
9.1 Large Hydro (>10 MW)	–	–	–	–	0.75	0.56	0.74	0.53
9.2 Small Hydro (<10 MW)	0.96	0.89	0.96	0.87	1.50	1.11	1.48	1.05
Total Hydro	0.96	0.89	0.96	0.87	2.25	1.67	2.23	1.58
TOTAL RENEWABLE ENERGY	**28.94**	**26.78**	**29.19**	**26.65**	**30.05**	**22.22**	**31.92**	**22.63**
10.1 Nuclear LWR	..	..	..	..	0.75	0.56	0.74	0.53
10.2 Other Converter Reactors	..	..	..	..	1.50	1.11	1.48	1.05
10.3 Nuclear Fuel Cycle	..	..	..	..	3.76	2.78	2.97	2.11
10.4 Nuclear Supporting Tech.	..	..	..	..	12.77	9.44	12.62	8.95
10.5 Nuclear Breeder	..	..	..	..	–	–	–	–
Total Nuclear Fission	4.88	4.51	4.77	4.35	18.78	13.89	17.82	12.63
11. Nuclear Fusion	1.38	1.28	1.39	1.27	18.78	13.89	18.56	13.16
TOTAL NUCLEAR	**6.26**	**5.79**	**6.15**	**5.62**	**37.56**	**27.78**	**36.38**	**25.79**
12.1 Electric Power Conversion	8.96	8.29	8.97	8.19	6.01	4.44	5.94	4.21
12.2 Electricity Transm.. & Distr.	1.92	1.78	1.47	1.34	6.01	4.44	6.68	4.74
12.3 Energy Storage	0.33	0.31	0.98	0.89	12.02	8.89	12.62	8.95
TOTAL POWER & STORAGE	**11.21**	**10.38**	**11.42**	**10.42**	**24.04**	**17.78**	**25.24**	**17.89**
13.1 Energy Systems Analysis	2.96	2.74	3.13	2.86	9.01	6.67	9.65	6.84
13.2 Other Tech. or Research	8.98	8.31	8.76	7.99	3.00	2.22	3.71	2.63
TOTAL OTHER TECH./RESEARCH	**11.94**	**11.06**	**11.89**	**10.85**	**12.02**	**8.89**	**13.36**	**9.47**
TOTAL ENERGY R&D	**108.04**	**100.00**	**109.56**	**100.00**	**135.21**	**100.00**	**141.05**	**100.00**

Note: Budgets provided for recent years by some countries may have been estimated.
Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

Turkey				United Kingdom				United States			
2002		2003e		2002		2003e		2002		2003e	
$	%	$	%	$	%	$	%	$	%	$	%
0.12	3.46	0.17	3.08	–	..	–	..	146.49	5.06	96.82	3.52
0.01	0.19	0.01	0.11	–	..	–	..	127.27	4.40	58.33	2.12
0.23	6.85	0.10	1.87	–	..	–	..	250.16	8.64	174.17	6.33
0.01	0.23	0.01	0.17	–	..	–	..	63.61	2.20	62.49	2.27
0.36	**10.73**	**0.29**	**5.24**	**–**	**..**	**–**	**..**	**587.53**	**20.30**	**391.82**	**14.25**
0.03	0.88	–	–	–	..	–	..	76.58	2.65	63.32	2.30
– 0.01	0.23	0.04	0.71	–	..	–	..	14.42	0.50	11.37	0.41
–	–	0.00	0.07	–	..	–	..	–	–	–	–
– 0.10	2.94	0.14	2.60	1.45	..	1.49	..	13.18	0.46	12.15	0.44
0.13	4.05	0.19	3.38	1.45	..	1.49	..	104.18	3.60	86.84	3.16
0.07	2.08	0.04	0.75	–	..	–	..	4.98	0.17	5.81	0.21
0.02	0.58	0.13	2.32	5.08	..	3.37	..	223.57	7.73	223.98	8.14
0.07	2.20	0.05	0.97	–	..	–	..	25.41	0.88	21.43	0.78
0.07	2.17	0.48	8.72	–	..	–	..	73.23	2.53	77.84	2.83
0.23	7.02	0.70	12.76	5.08	..	3.37	..	327.19	11.31	329.06	11.97
0.37	**11.07**	**0.89**	**16.14**	**6.53**	**..**	**4.87**	**..**	**431.37**	**14.91**	**415.90**	**15.12**
0.04	1.18	0.12	2.22	–	..	–	..	4.79	0.17	..	..
0.34	10.20	0.22	3.98	3.38	..	6.56	..	72.72	2.51	..	..
0.02	0.54	0.02	0.36	–	..	–	..	13.40	0.46	..	..
0.40	11.92	0.36	6.56	7.60	..	7.38	..	90.91	3.14	82.33	2.99
0.03	0.98	0.06	1.16	3.38	..	3.93	..	38.84	1.34	41.64	1.51
–	–	–	–	4.22	..	3.28	..	–	–	–	–
0.08	2.51	0.12	2.09	2.53	..	4.92	..	89.12	3.08	85.28	3.10
0.54	16.21	0.70	12.75	–	..	–	..	27.48	0.95	28.39	1.03
–	–	–	–	–	..	–	..	..	..	..	..
–	–	–	–	–	..	0.33	..	..	..	..	..
–	–	–	–	–	..	0.33	..	5.07	0.18	5.02	0.18
1.05	**31.62**	**1.24**	**22.57**	**17.73**	**..**	**19.84**	**..**	**251.40**	**8.69**	**242.66**	**8.82**
–	–	–	–	–	..	–	..	..	..	..	..
–	–	–	–	–	..	–	..	..	..	..	..
0.02	0.51	0.02	0.27	–	..	–	..	..	..	..	..
–	–	0.07	1.20	–	..	–	..	50.05	1.73	130.03	4.73
–	–	–	–	–	..	–	..	–	–	–	–
0.02	0.51	0.08	1.48	–	..	–	..	50.05	1.73	130.03	4.73
0.01	0.37	0.01	0.24	..	..	..	..	245.04	8.47	240.70	8.75
0.03	**0.87**	**0.09**	**1.72**	**..**	**..**	**..**	**..**	**295.09**	**10.20**	**370.73**	**13.48**
0.21	6.39	0.01	0.11	3.21	..	1.15	..	76.00	2.63	78.56	2.86
0.87	26.00	1.28	23.18	2.36	..	2.13	..	..	..	..	..
–	–	–	–	1.69	..	1.64	..	71.28	2.46	85.26	3.10
1.08	**32.39**	**1.28**	**23.28**	**7.26**	**..**	**4.92**	**..**	**147.29**	**5.09**	**163.82**	**5.96**
0.20	5.99	0.37	6.72	–	..	–	..	..	..	..	..
0.24	7.32	1.34	24.33	1.69	..	0.66	..	1 181.17	40.82	1 165.13	42.37
0.44	**13.32**	**1.71**	**31.05**	**1.69**	**..**	**0.66**	**..**	**1 181.17**	**40.82**	**1 165.13**	**42.37**
3.33	**100.00**	**5.51**	**100.00**	**..**	**..**	**..**	**..**	**2 893.84**	**100.00**	**2 750.05**	**100.00**

Table B14

Estimated IEA[1] Government Energy R&D Expenditure

(US$ million at 2003 prices and exchange rates)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003e
Industry	282.2	281.2	375.9	396.4	409.6	424.4	631.8	712.7	733.8	778.3	..	..
Residential. Commercial	183.0	157.8	276.0	304.6	278.1	232.7	233.8	266.4	232.2	263.2	..	..
Transportation	214.6	245.4	332.6	374.4	331.8	308.5	303.3	319.0	338.4	374.3	..	..
Other Conservation	42.3	79.4	65.4	69.1	60.1	58.3	62.7	63.0	97.0	102.4	..	..
TOTAL CONSERVATION	**721.9**	**763.9**	**1049.8**	**1144.5**	**1079.6**	**1023.9**	**1231.5**	**1361.2**	**1401.4**	**1518.2**	**..**	**..**
Enhanced Oil & Gas	43.7	229.2	144.1	151.6	108.6	100.9	127.8	134.3	126.1	138.0	..	..
Other Shale & Tar Sands	30.2	17.3	19.4	15.5	24.3	28.7	30.1	14.6	15.5	19.4	..	..
Other Oil & Gas[2]	346.1	246.3	258.0	273.7	269.9	279.9	210.0	161.7	158.1	196.3	..	..
Coal Combustion	119.1	126.0	490.8	247.2	328.3	152.1	137.9	146.1	111.7	225.6	..	..
Coal Conversion	159.1	152.7	161.9	170.6	157.0	118.9	111.5	92.7	67.1	37.0	..	..
Other Coal[3]	451.1	353.3	136.5	104.3	81.3	68.3	65.1	71.3	67.0	86.6	..	..
TOTAL FOSSIL FUELS	**1149.3**	**1124.7**	**1210.7**	**962.9**	**969.4**	**748.8**	**682.5**	**620.8**	**545.5**	**703.0**	**..**	**..**
Solar Heating and Cooling	59.8	64.1	64.6	54.0	36.8	38.7	36.7	33.8	44.0	37.8	..	..
Solar Photo Electric	250.7	255.4	239.0	257.8	237.1	234.9	265.0	282.9	296.5	271.3	..	..
Solar Thermal Electric	56.4	58.7	67.9	55.4	48.5	47.3	34.1	35.0	23.6	46.5	..	..
Wind	97.5	89.4	96.5	123.0	118.3	100.7	109.0	109.9	93.8	111.0	..	..
Ocean	3.4	4.7	4.3	2.4	2.3	2.2	11.8	7.4	8.0	11.2	..	..
Biomass	98.8	89.9	147.6	152.0	139.3	140.3	191.7	189.6	164.6	196.8	..	..
Geothermal	89.5	80.8	65.3	81.5	71.8	69.9	69.3	65.4	53.8	65.0	..	..
Large Hydro (>10MW)	9.5	9.1	10.9	13.7	10.0	8.0	6.9	7.7	13.1	11.3	..	..
Small Hydro (<10MW)	9.3	1.6	1.9	2.0	3.3	3.6	3.7	7.9	5.0	6.4	..	..
TOTAL RENEWABLE ENERGY	**674.8**	**653.6**	**698.1**	**741.9**	**667.3**	**645.6**	**728.1**	**739.6**	**702.4**	**757.3**	**..**	**..**
Total Nuclear Fission	3572.7	3395.4	3248.1	3362.2	3314.3	3179.8	3096.8	3148.0	3186.5	3012.8	..	..
Nuclear Fusion	1103.5	1086.2	1040.3	1038.0	927.1	893.9	830.0	755.2	822.6	773.0	..	..
Electric Power Conversion	204.9	143.8	214.3	193.1	197.2	207.0	242.4	243.7	287.9	326.8	..	..
Electricity Transm. & Distr.	29.2	55.5	98.2	101.0	90.3	85.1	98.6	102.4	153.1	179.4	..	..
Energy Storage	51.4	49.0	52.4	48.9	45.9	57.0	55.6	66.5	76.6	74.3	..	..
TOTAL POWER & STORAGE	**285.5**	**248.3**	**364.9**	**343.0**	**333.4**	**349.0**	**396.7**	**412.6**	**517.6**	**580.5**	**..**	**..**
TOTAL OTHER TECH./RESEARCH	**1346.7**	**1323.2**	**1214.8**	**1182.2**	**1186.2**	**1217.4**	**1174.8**	**1321.1**	**1234.4**	**1520.9**	**..**	**..**
TOTAL ENERGY R&D	**8854.4**	**8595.2**	**8826.8**	**8774.7**	**8477.3**	**8058.5**	**8140.5**	**8358.5**	**8410.4**	**8865.7**	**..**	**..**

1. IEA totals include estimates where data are not available. The following countries have not been included in the total: the Czech Republic, Greece, Hungary, Ireland, Korea and Luxembourg.
2. Other Oil & Gas includes refining, transportation and storage.
3. Other Coal includes production, preparation and transport.

Sources: *OECD Economic Outlook No 75*, OECD Paris, 2004, and country submissions.

INTERNATIONAL ENERGY AGENCY "SHARED GOALS"

Member countries of the 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 sub-stantial 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 IEA members wish to retain and improve the

* Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

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.)

GLOSSARY AND LIST OF ABBREVIATIONS

In this report, abbreviations are substituted for a number of terms used within the International Energy Agency. Although these terms are generally written out on first mention and abbreviated subsequently, this glossary provides a quick and central reference for many of the abbreviations used.

AFC	advanced fuel cells
AGCC	ASEAN Gas Consultative Council
AHGSET	Ad Hoc Group on Science and Energy Technologies
AMEM	ASEAN Energy Ministers' Meeting
APAEC	ASEAN Plan of Action for Energy Co-operation
APEC	Asian Pacific Economic Co-operation
APG	ASEAN Power Grid
APM	Administrative Pricing Mechanism
APSA	ASEAN Petroleum Security Agreement
ASCOPE	ASEAN Council on Petroleum
ASEAN	Association of South East Asian Nations
bcf	billion cubic feet
bcm	billion cubic metres
BWR	boiling water reactor
CBT	cross-border trade
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CDM	clean development mechanisms
CERM	co-ordinated emergency response mechanism
CERT	Committee on Energy Research and Technology
CHP	combined production of heat and power; sometimes, when referring to industrial CHP, the term "co-generation" is used
CNG	compressed natural gas
CO_2	carbon dioxide
CRE	Energy Regulatory Commission
CSD	Commission for Sustainable Development
CSLF	Carbon Sequestration Leadership Forum
CTI	Climate Technology Initiative

ECAR	East-Central Area Co-ordination Agreement
EPA	Environmental Protection Agency
ERGEG	Energy Regulators Groups for Electricity and Gas
ETSO	European Transmission System Operators
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
EU-ETS	European Union GHG Emissions Trading Scheme
FERC	Federal Electricity Regulatory Commission
FSU	former Soviet Union
GDP	gross domestic product
GGP	Guidelines for Good Practice
GHG	greenhouse gas
GSF	Global Science Forum
HAPUA	Heads of ASEAN Power Utilities and Authorities
HCG	Hydrogen Co-ordination Group
HIA	Hydrogen Implementing Agreement
IA	implementing agreement
IEA	International Energy Agency whose members are Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States
IEF	International Energy Forum
IEP	International Energy Program
IMF	International Monetary Fund
IPP	independent power producers
ISO`	independent system operator
JCC	Japanese crude cocktail
JI	joint implementation
JODI	Joint Oil Data Initiative
kb/d	thousand barrels per day
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
LSFO	low-sulphur fuel oil
LWR	light water reactor
mb/d	million barrels per day
MBtu	million British thermal units
mcm	million cubic metres
MEDT	Ministry of Economic Development and Trade
mt	million tonnes
Mtoe	million tonnes of oil equivalent; *see* toe
NAF	national average fuel consumption
NAP	National Allocation Plan
NBP	National Balancing Point (UK)
NGO	non-governmental organisation
NIMBY	not in my back yard
NMVOC	non-methane volatile organic compound
NSO	Neutral Transmission System Organisation
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PPPs	purchasing power parities
PSA	production sharing agreement
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
RTO	regional transmission organisations
SOME	ASEAN Senior Officials Meeting on Energy
TAGP	Trans-ASEAN Gas Pipeline
tcf	trillion cubic feet
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
TPA	third-party access
TREC	Tradable Renewable Energy Certificates
TPES	total primary energy supply
TTF	Title Transfer Facility
UCTE	Union for the Co-ordination of Transmission of Electricity
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
UKCS	United Kingdom Continental Shelf
VA	voluntary agreement
WPFF	Working Party on Fossil Fuels
WSSD	World Summit for Sustainable Development
WTI	West Texas Intermediate
WTO	World Trade Organization
ZET	zero emission technologies
1Q	first quarter
2Q	second quarter
3Q	third quarter
4Q	fourth quarter

Average exchange rates in 2003 were as follow:

Australia	A$ 1	= US$ 0.647
Europe	€ 1	= US$ 1.126
Canada	C$ 1	= US$ 0.714
Czech Republic	CZK 1	= US$ 0.035
Denmark	DKr 1	= US$ 0.151
Hungary	HUF 1	= US$ 0.004
Japan	¥ 1	= US$ 0.009
Korea	KRW 1	= US$ 0.001
New Zealand	NZ$ 1	= US$ 0.578
Norway	NKr 1	= US$ 0.141
Sweden	SKr 1	= US$ 0.123
Switzerland	SF 1	= US$ 0.741
Turkey	TL 1 000	= US$ 0.001
United Kingdom	£ 1	= US$ 1.629

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, liquid biomass, biogas, 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 1995 prices and exchange rates.
13. Toe per person.
14. "Energy-related CO_2 emissions" have been estimated using the IPCC Tier I Sectoral Approach. In accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2002 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.

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