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Projected Costs of Generating Electricity

Update 1992

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

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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) and New Zealand (29th May 1973). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

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NUCLEAR ENERGY AGENCY

The OECD Nuclear Energy Agency (NEA) was established on 1st February 1958 under the name of the OEEC European Nuclear Energy Agency. It received its present designation on 20th April 1972, when Japan became its first non-European full Member. NEA membership today consists of all European Member countries of OECD as well as Australia, Canada, Japan, Republic of Korea and theUnited States. The Commission of the European Communities takes part in the work of the Agency.

The primary objective of NEA is to promote co-operation among the governments of its participating countries in furthering the development of nuclear power as a safe, environmentally acceptable and economic energy source.

This is achieved by:

- *encouraging harmonization of national regulatory policies and practices, with particular reference to the safety of nuclear installations, protection of man against ionising radiation and preservation of the environment, radioactive waste management, and nuclear third party liability and insurance;*
- *assessing the contribution of nuclear power to the overall energy supply by keeping under review the technical and economic aspects of nuclear power growth and forecasting demand and supply for the different phases of the nuclear fuel cycle;*
- *developing exchanges of scientific and technical information particularly through participation in common services;*
- *setting up international research and development programmes and joint undertakings.*

In these and related tasks, NEA works in close collaboration with the International Atomic Energy Agency in Vienna, with which it has concluded a Co-operation Agreement, as well as with other international organisations in the nuclear field.

INTERNATIONAL ENERGY AGENCY

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-three* of the OECD's twenty-four Member countries. The basic aims of the IEA are:

i) co-operation among IEA participating countries to reduce excessive dependence on oil through energy conservation, development of alternative energy sources and energy research and development;

ii) an information system on the international oil market as well as consultation with oil companies;

iii) co-operation with oil producing and other oil consuming countries with a view to developing a stable international energy trade as well as the rational management and use of world energy resources in the interest of all countries;

iv) a plan to prepare participating countries against the risk of a major disruption of oil supplies and to share available oil in the event of an emergency.

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

FOREWORD

Previous reports in this series were published by the Nuclear Energy Agency in 1983 and 1986 and by the Nuclear Energy Agency jointly with the International Energy Agency in late 1989. These reports established a standard economic methodology for calculating generation costs over the expected lives of new base load plants, and presented projected costs for future nuclear and coal-fired plants that were expected to be available for commercial deployment in OECD countries. With the assistance of the International Atomic Energy Agency, the last report in the series extended the coverage to some non-OECD countries. In addition and for the first time, it attempted to introduce data on other generation technologies, including gas-fired plant and renewable sources.

This study, also conducted jointly by the NEA and IEA, in close association with the IAEA and the International Union of Producers and Distributors of Electrical Energy (UNIPEDE), has extended the focus on mainstream nuclear and coal-burning technologies, with well established costs, to include gas combined cycle plants. It has also reviewed the position of combined heat and power schemes and gathered some data on new and emerging technologies, including advanced coal burning and renewables, which could be available for commercial deployment at the turn of the century or very soon thereafter. As in the earlier studies, the sensitivity of cost comparisons to the technical and economic assumptions is examined. Trends in nuclear and coal-fired generation costs over the 10 year period covered by the successive studies are also discussed.

The study was overseen by a working group of experts drawn from sixteen OECD countries and four international agencies. Six non-OECD countries have participated in the study, either directly or indirectly, as part of the IAEA contribution. One of these countries is the former Czech and Slovak Federal Republic (CSFR). The country separated into the Czech Republic and the Slovak Republic after the completion of the study.

The report, which is published on the responsibilities of the Secretary-General of the OECD and the Executive Director of the IEA, represents the collective view of the participating experts and does not necessarily represent the views of their parent organisations or their member governments.

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Background

This is the fourth in a series of comparative studies of projected base load electricity generation costs conducted under the auspices of the OECD energy agencies (NEA and IEA) in close association with the International Union of Producers and Distributors of Electrical Energy and the International Atomic Energy Agency.

Scope

Data on the projected costs from nuclear, coal-fired, gas-fired and renewable sources have been obtained from utilities or government agencies in 16 OECD countries and 6 non-OECD countries, all using the same standardized lifetime levelised cost methodology.

The study has focused on plants that could be commercially available for commissioning in the year 2000 or shortly thereafter, and submissions received have related mainly to light-water-cooled pressurised water and boiling water reactors (LWRs), pressurised heavy water reactors (PHWRs), pulverised fuel coal burning plants, some fluidised bed coal burning plants and gas combined cycle plants. Relatively few data have been provided on other advanced technologies or renewable sources.

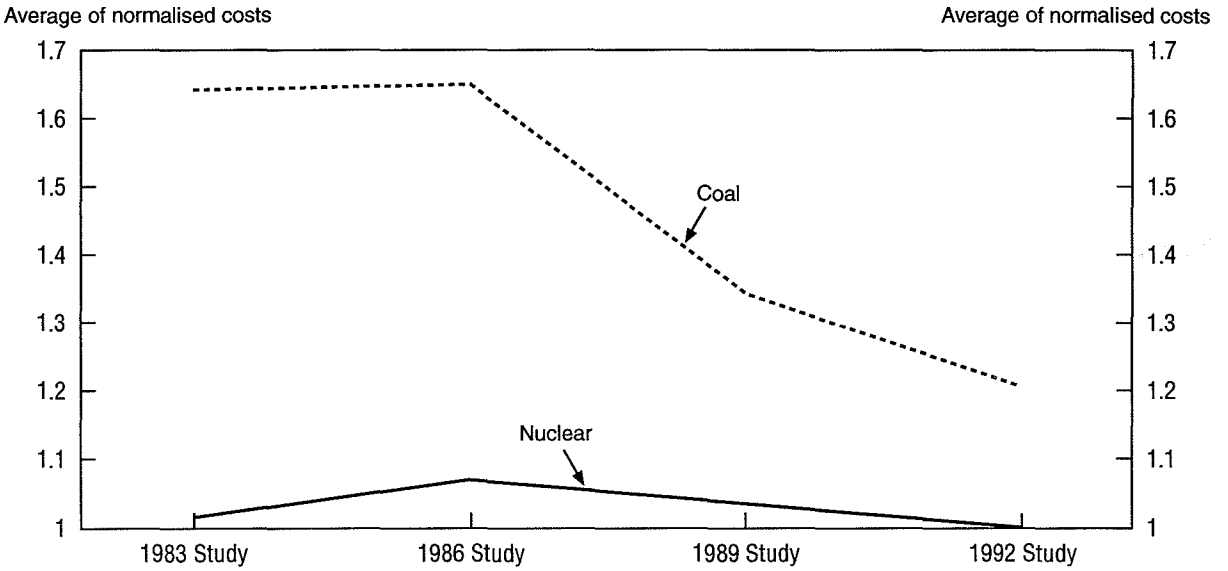
Cost stability and changes

In almost all countries that have provided data over the past decade, projected nuclear generation costs for LWRs and PHWRs have shown greater stability over time than the projected cost of generation from fossil fuels. Indeed, in most cases, projected nuclear costs, on a common price basis and standardized discount rates, lifetimes and load factors, have not varied by more than around 10 per cent, as reductions in projected nuclear fuel costs have offset any projected increases in nuclear investment and operations costs (Figure S1). There have, however, been significant cost changes in individual cost elements in some countries.

The optimism that prevailed in the early 1980s over the near term economic attractiveness of nuclear power has been moderated by subsequent developments in fossil fuel prices. These fell sharply in the mid-1980s and there is now a widely held view that the lower prices will be maintained without major escalation for some time. The projected overall costs of coal-fired generation have therefore declined over the past decade (Figure S1).

The present study has also revealed an upward shift over the past three years in the discount rates used by some governments and utilities. Any such shift increases the levelised cost of capital intensive technologies, like nuclear power or most renewable energy sources, relative to less capital intensive technologies like gas combined cycle generation.

Figure S1. **Trends of generation costs**



Cost results of Belgium, Canada-Centre, Finland, France, Germany, Japan, U.K., and U.S.A.-midwest were converted into July 1991 money, standardised to 5% p.a. discount rate, 30 year lifetime, and 75% load factor, and normalised to 1992 study nuclear cost results.

Relative generation costs

Despite this three of the five OECD countries and four of six non-OECD countries providing relevant nuclear cost data, using their own criteria, still project nuclear power to be the cheapest source of base load electricity from plants for commissioning at the turn of the century (eleven OECD countries did not provide nuclear cost data based on their own criteria). This result is sensitive, however, in the majority of countries, to the discount rate, to fossil fuel price expectations, and, possibly, to their future policy decisions concerning environmental standards and regulation. The position in different countries is also sensitive to the level of their industrial capabilities and to the extent of desired national participation in plant construction, particularly in developing countries.

Thus, at 5 per cent per annum real discount rate, using the reference performance assumptions, nuclear power would be the preferred option in thirteen of the fifteen countries that provided nuclear cost data for the study, with the exception of regions with direct access to cheap coal (e.g. Western USA, Western Canada, and North West China) or gas (e.g. United Kingdom) and the Netherlands. At this rate of return coal is also projected to be cheaper than or comparable to base load gas combined cycle generation in all countries except the United Kingdom and Hungary.

At a 10 per cent per annum real discount rate, again using the reference performance assumptions, nuclear power only retains its projected advantage over coal in five countries, with three finding the two fuels break-even (to within 5 per cent) and five finding coal to be the cheaper option. At this higher rate, gas combined cycle generation is projected to be the cheapest option of those reported in Belgium, parts of Canada, Denmark, Finland, Portugal, Spain, the United Kingdom, parts

of the United States and Hungary. Among the countries supplying data for all three technologies, nuclear power is projected to retain its overall advantage over fossil fuels in France and Japan.

Advanced and renewable technologies

Few data have been supplied on the advanced technologies that might become commercially available around the year 2000 or shortly after, or on renewable energy sources. This reflects in part the considerable uncertainty that surrounds the costs, performance and the availability for commercial application of such technologies, and in part the perception that on cost or resource grounds their potential contributions do not merit detailed consideration for large scale base load supply. Institutional factors may also contribute, since renewable sources other than major hydropower, barrage or geothermal schemes are often undertaken by smaller independent power producers rather than the larger utilities or agencies participating in this study.

Such data as have been provided suggest that waste incineration, geothermal, and small scale hydropower may make small, resource limited, but economic contributions to power supplies. Wind turbines, which are the most widely commercially exploited renewable source after large scale hydropower, are still projected to be expensive relative to conventional fossil-fired and nuclear generation, although they can provide economic fuel saving in remote locations where they displace more costly small scale diesel generation, for example.

Environment and externalities

Whilst coal and nuclear fuel prices look likely to be stable in the early part of the next century, uncertainty remains about long term gas prices and availability, and the effects of environmental policies on the costs of fossil-fuelled generation. Other NEA studies[22] have suggested that the external costs associated with nuclear generation and the sulphur dioxide and nitrogen oxide emissions from future fossil-fired plants are small relative to the direct generation costs reported here, provided the coal-fired plants are equipped with appropriate desulphurisation and denitrification technologies. The costs of nuclear plant decommissioning and spent fuel and waste management are included in overall nuclear costs already, as are the costs of solid wastes and sludges from coal burning plant. Greenhouse gas emissions, mainly carbon dioxide, from fossil fuel combustion remain an imponderable which could affect the price of fossil-fuelled electricity to an extent which is likely to be determined by political and technical considerations. Carbon taxes at levels considered necessary to reduce growth in fossil fuel use in OECD countries significantly, would add considerably to electricity prices.

Future development

There is no indication of any imminent technological breakthrough that will materially reduce generation costs from any fuel or power source. There is scope however, for improvement on current economic and technical performance in many countries, through the application of consistent planning, good project management and plant replication and collocation. This is particularly important in the case of capital intensive nuclear projects. Apart from this the costs of generation from future new plants should remain broadly stable unless there will be major fuel price, regulatory or fiscal changes.

Decision criteria

Countries and utilities will have differing views on their preferred options for future base load capacity, based on their own assessments, on economic conditions and on their expectations concerning the evolution of the regulatory and fiscal framework, and of fuel prices. Other considerations such as the security of future fuel supplies, the reduction of risk to supplies through diversity, the wish to reduce dependence on energy imports for economic, employment or security reasons, industrial development policy and, importantly, public acceptance of individual technologies, will also play a major part in national preferences.

Chapter 1

INTRODUCTION

Objectives and participation

This study is the fourth in a series on projected electricity generation costs. Like its predecessors its main objective is to review and explain in simple terms the costs that would be expected for base load power generation options that could be commercially available in the medium term, on the basis of an agreed common economic methodology. Whereas in previous studies the choice had been considered to be limited to large scale coal-fired pulverised fuel plants or large scale water-cooled nuclear plants, the situation is now less clear cut. Other plant types, including gas combined cycle plants, advanced coal-burning plants and some renewable technologies are now regarded as serious contenders for new base load capacity in a number of countries. The contribution from combined heat and power schemes has also been growing in OECD.

The changed perceptions arise partly from the economic consequences of technological development, partly from revised expectations concerning fossil fuel prices and availability, partly from environmental concerns and partly from the changes in the structure and regulation of the electricity supply industry in some countries.

This report concentrates on the projected economics of those systems that could be available for commercial deployment around the turn of the century or shortly thereafter, and for which consistent cost data are available. It also comments on divergences of view, where these occur, explores the sensitivity of comparative generation costs to input assumptions, and reviews and discusses the trends in costs that have occurred over the past decade. The possible economic implications of changing environmental, regulatory and tax regimes are discussed. Most of the basic information and calculated results have been provided by utilities (at the request of governments) or in some cases by government agencies.

This study, like the third in the series, has been undertaken jointly for the NEA Nuclear Development Committee (NDC) and the Standing Group on Long Term Cooperation (SLT) of the International Energy Agency (IEA), in association with both the International Atomic Energy Agency (IAEA) and the International Union of Producers and Distributors of Electrical Energy (UNIPEDE). The members of the working group which has overseen the study are listed in Annex 1.

The provision of data by any country is not necessarily indicative of its current plans, but represents the best judgements currently available of the costs that would be expected to be incurred should any of the technical options covered in the study be selected for construction and commissioning around the year 2000 or shortly thereafter. Contributions were necessarily limited to the technologies for which individual countries have developed cost data. The range of such technologies differs from country to country depending on their circumstances and policies.

Despite the expert group's agreement that inclusion of emerging advanced and renewable technologies was important, data provided on their costs was disappointingly limited. This was attributed to a number of factors, including the continued unavailability of reliable cost data in a realistic operational environment, lack of interest in small scale "marginal" supply technologies on the part of large utilities, and the difficulty of providing meaningful data for plants whose costs varied greatly with their location and use.

Past studies

The 1983 study[1] concentrated on reviewing the methods used in different OECD Member countries for the calculation and presentation of comparative generation costs. It concluded that the lifetime levelised cost method was appropriate for economic intercomparison of base load generation costs and adopted this as a standard method. This was then applied to a comparison of nuclear and coal-fired plants for commissioning around the year 1990, with stress laid on the comprehensive inclusion of all direct incremental costs associated with nuclear power, from planning to ultimate decommissioning and the final disposal of decommissioning and fuel cycle wastes.

The 1986[2] study repeated the analysis for a larger group of OECD countries and undertook more detailed sensitivity analysis of the results to the input assumptions. This was repeated in 1989[3] with the first inclusion of data from non-OECD countries, with yet more detailed sensitivity analysis and the inclusion of descriptive and some quantitative data on other emerging generating technologies. The information gathered on costs was constrained by the requirement that it should be well authenticated and relate to plants whose costs were not exclusively site specific (i.e. large hydropower schemes, tidal barrages and geothermal sources would have been omitted even if data had been provided). In the event disappointingly little data was made available for gas-fired plants, advanced coal-fired and renewable technologies. Only five countries contributed gas generation costs and three provided wind turbine costs.

The earlier studies all concluded that, on the economic reference assumptions and the assumptions of the utilities themselves, nuclear power was projected to be cheaper than conventional coal-fired plant for base load power generation in most OECD countries, except in regions with direct access to cheap coal — notably in parts of North America. The 1989 study yielded broadly similar results for the non-OECD countries with nuclear power cheaper or breaking even with coal, except in the low cost coal regions of Brazil, China and India.

The conclusions were sensitive, however, to the rates of return on capital (discount rates) and to expectations concerning future fossil fuel price movements. Adoption of significantly higher rates of return and lower fossil fuel prices would have reduced or, in a number of countries, eliminated the projected nuclear advantage.

It was also noted that the radical changes in perceptions of long term fossil fuel prices, that had occurred during the 1980s, had materially reduced the projected coal/nuclear generation cost ratios in most countries. In 1983 and 1986 oil and gas were projected to be too expensive to merit serious consideration for base load power generation. By 1989 this conclusion was less clear cut, although the data provided still indicated that gas was expected to be expensive relative to coal and nuclear power for base load generation.

Recent developments

In the past two years many utilities have turned to gas for future generation capacity and, in some countries, it has been claimed to be economically competitive with coal and nuclear power for base load generation in the medium term, as well as having environmental advantages over coal and much shorter construction lead times than nuclear plant.

On the time horizon selected for this study, namely plant to be commissioned around the year 2000, developing trends have increased the importance of including good quality data on gas combined cycle plants. However, the increased political interest in environmental matters, particularly with regard to reducing sulphur dioxide and nitrogen oxide emissions, which contribute to acid rain, and greenhouse gas (mainly carbon dioxide) emissions from coal-burning plants, has led to intensified development of a range of advanced coal-burning technologies, renewable technologies and waste incineration technologies, as well as giving fresh impetus to energy-efficient and environmentally attractive combined heat and power schemes.

Many of these newer technologies have yet to deployed on a significant scale and their performance over time remains to be established. Their lifetime costs cannot be considered to be "well authenticated", nevertheless they could be available for commercial deployment by 2000 or shortly thereafter, and their exclusion from this study could be potentially misleading. For this reason the study has sought to collect data in two categories defined as A and B; "well authenticated" and "best estimates" respectively. The former is restricted to commercially available technologies with a significant history of practical experience, and the latter to technologies which are major extrapolations in scale or technology from the well established plants, or where prototype plant has been in operation for a limited period. Costs for the latter category are clearly much less certain than those in the former and it is stressed that direct comparisons between the two categories have to be treated with great caution. The state of development of technologies ranges in a continuous spectrum from the long established to the laboratory prototype, so that their categorisation as A or B is inevitably arbitrary and will differ among countries, depending on their experience and expectations.

The study is restricted to base load plant, i.e. it specifically excludes plant types with high operating costs that are used solely at time of peak power demand. Some renewable sources, such as biomass or waste incineration are clearly capable of near continuous base load operation if their costs justify it. Other renewables like wind turbine generators provide variable power. Nevertheless, their low running costs would ensure their use when operating and, in suitable locations, they can contribute to firm base load capacity on a basis statistically related to their average output and the extent of their penetration of the power network. They are therefore included in the study.

As in the previous studies, renewable plants whose costs are almost entirely determined by their location, e.g. large scale hydropower and tidal barrages, are excluded from the comparisons because their costs are not transferable. Nevertheless, reference is included in the text where data on such sources has been made available to the group, e.g. Italian data on geothermal plants.

The results of this study, like its predecessors, are sensitive to some of the input assumptions. These assumptions are discussed in the text, but the detailed analysis of their justification, conducted for the 1989 study, is not repeated unless some substantive change is considered to merit it.

Other relevant studies

In addition to the earlier reviews of generation costs, reference should be made to related studies such as the 1991/92 NEA update[4] of the 1985 study[5] on the Economics of the Nuclear Fuel Cycle, the 1989 assessment of the use of Plutonium Fuels[6], the analysis of Decommissioning Costs and the reasons for their variability published in 1987[7] and 1991 respectively[8], the proceedings of the 1991 International Seminar on Decommissioning[9] and the analysis of the costs of waste repositories[10]. The International Energy Agency has published analyses of world coal[11] and gas prospects[12] and policies, including views on future fossil fuel price movements. They have also published studies on electricity supply in OECD countries[13] and on policy and technological means of reducing greenhouse gas emissions[14].

UNIPEDE has continued its series of studies on projected generation costs in Member countries[15] and recently held an international conference on nuclear generation plant performance[16]. The IAEA continues its sponsorship of technical conferences and studies on nuclear energy technology, some of which cover aspects of economics. Generation cost data obtained subsequent to the 1989 OECD study[3] from CSFR, Hungary, Poland and Yugoslavia have appeared in IAEA publications[17], as have some data on costs of waste management[18]. A study covering nuclear and conventional generation cost experience in some non-OECD and OECD countries will be published in the near future[19].

Importantly, the renewed interest in environmental issues has led to a number of conferences and studies aimed at establishing the wider impacts of electricity generation technologies. The environmental impacts were reviewed in detail in the inter-agency sponsored Helsinki Conference in May 1991[20] and moves towards greater quantification and economic evaluation have been initiated under the auspices of the IAEA. Following the Helsinki Conference IAEA was invited to submit documentation to the UN Conference on Environment and Development in Rio de Janeiro, June 1992. The documents included the key issues, findings and conclusions of the Helsinki Symposium as well as reports on nuclear safety, radioactive waste and the nuclear contribution to sustainable development[20, 21].

The NEA has recently completed a study of the broader impacts of nuclear power, covering macroeconomic, strategic and environmental aspects[22]. The study concluded that the microeconomic cost analyses, of the type presented in this report, did capture all significant nuclear costs, and that there were no subsidies, benefits or externalities associated with incremental investment in new nuclear plant to modern designs, in OECD countries with existing nuclear programmes, that would lead to a significant divergence between their microeconomic costs and their social costs.

The study[22] also concluded that the same was probably true for modern coal plant fitted with effective flue gas desulphurisation and denitrification technologies to eliminate acid gas emissions. However there are some residual external cost associated with the uncontrolled release of carbon dioxide from all fossil-fired plants, which could be avoided using nuclear or renewable generation technologies. The magnitude of this external cost, or the costs of means of eliminating greenhouse gas releases or ameliorating their effects, remain highly uncertain. They could be significant relative to the direct microeconomic costs of fossil-fuelled generation, but it will be some years before the implications and the best means of dealing with this problem and its consequences can be established with any confidence.

Despite this some countries have already taken policy decisions to "internalise" the hypothesised external environmental costs by means of carbon taxes which will increase the price of carbonaceous fuels and fossil-fuel based electricity to the user, in order to discourage their use[23].

To avoid confusion, this study makes explicit the inclusion of any taxes of this type, where they are already in place. No assumptions are made concerning future policy decisions on the imposition or removal of such taxes, other than pointing in the discussion to the possible consequences for comparative generation costs of the scale of taxes that have been discussed in the literature.

The position and prospects for the use of combined heat and power systems was considered in depth at a conference in Copenhagen organised by the International Energy Agency in 1988[24].

Costs and policies

This study, like its predecessors, recognises that countries and utilities will see fuel and generation costs differently depending on the scale and timing of their power programmes, and on the geographical, political and economic frameworks within which they operate. The study also recognises that countries will review their overall generation and fuel policy options in the light of the impacts of the alternative choices on total electricity systems costs, taking due account of their own planning criteria, which will include energy security, environmental, financial and social policy objectives.

Chapter 2

METHODOLOGY, SCOPE AND COMMON ASSUMPTIONS

Methodology

The method adopted for calculating generation costs in this report is the same constant-money levelised lifetime cost method described fully in the earlier NEA[1-5] reports on generation costs and fuel cycle economics. It is appropriate for the economic comparison of different types of base load plant performing similar functions, e.g. for base load electricity supply from a specified plant commissioning date. It is not a substitute for a full system's cost analysis that would be used to establish the economic impact of investment choices within a national or utility power network. This latter approach is specific to the individual network and its anticipated development, and is, therefore, unsuitable for the type of comparison undertaken in this and earlier NEA and NEA/IEA studies.

Annex 2 contains some supplementary information on the appraisal techniques, assumptions, plants and energy background for some participating non-OECD and OECD countries. It updates and extends similar information given in the earlier reports of this series. Where countries' approaches remain unchanged no information is included.

Scope of the study

Unlike its predecessors this study focuses on gas-fired plant in addition to water-cooled reactors and coal-fired stations. The nuclear reactors include light-water-cooled pressurised and boiling water reactors (PWRs and BWRs) and pressurised heavy-water-cooled reactors (PHWRs). The coal plants are mainly conventional pulverised fuel combustion plants (PFCs), although some atmospheric circulating fluidised bed plants are included.

Until relatively recently there were no realistic alternatives, to nuclear or coal-fired PFC plants, other than oil-fired plants or site-specific hydropower, for base load large scale electricity generation. By the mid-1970s oil had become too expensive and, despite the drop in its price in the mid 1980s, doubts have persisted about its supply on an assured basis in the long term.

For this reason no countries have seriously contemplated the construction of new large oil-fired plants and data on their costs have not been included in this or the earlier studies. Indeed, it has been an agreed policy in IEA Member countries that oil should not be used for large scale generation. Some utilities have been looking, however, at the possibility of using oil gasification combined cycle plant in association with refineries and others at a cheap heavy-oil/water emulsion, Orimulsion, as a low-cost substitute fuel in modified oil-burning plants. The high sulphur content of this latter fuel and its

potential environmental impacts have been a major cause of concern. No utilities participating in the study have supplied date on the costs of the fuel or its future use.

The majority of sites for large hydropower plants in OECD Member countries have already been utilised and their costs are wholly site specific so they too have been omitted from the studies. There is still significant potential for further exploitation of this source in some non-OECD countries, e.g. China and India, but its environmental and social effects are not wholly benign and this has led to a constraint on its expansion in some countries.

The last few years have also seen the development of a number of new fossil-fuelled technologies that are potential contenders for commercial deployment around the year 2000, the commissioning date selected as the bench-mark for this study, or shortly thereafter (Annex 3). These include the high thermal efficiency combined cycle gas turbine system (CCGT) (Annex 4) and a range of advanced coal burning technologies. Additionally some advanced evolutionary designs of nuclear plants are at a stage where they could be ordered should utilities wish to use them, and other cost reducing technologies are being implemented (Annex 5).

A number of renewable technologies are also commercially available (Annex 6) and data for those whose costs are not site dominated were sought for the study. Some data were obtained on wind turbines, waste incineration, landfill gas and small scale hydropower plants. Italy (Annex 2) provided data on geothermal plant costs.

The study was confined to base load plants capable of contributing a firm power supply. This includes, in principle, randomly variable sources like wind turbines and wave power generators which can contribute to firm supplies on a statistical basis and would be used, once built, whenever they were providing output. It also includes, in principle, large solar powered plants which experience large diurnal and stochastic output variations. The significance of their variability is discussed later in the report.

Previous studies have only included data on costs of plants for which there was sufficient practical experience to give confidence that the unit costs of the electricity they would produce were well founded, subject only to the assumptions on fuel prices and the cost of capital.

However, even now, many of the technologies that could be commercially commissioned at the base-line date adopted for this study have not been brought to the point where their costs and performance can be considered to be "well established". The working group considered that their exclusion from the study would reduce its value considerably. The group was also conscious of the risks of misleading readers if no distinction is drawn between well established costs (Category A) and best current estimates of the costs of new technologies (Category B). For these reasons a clear distinction is drawn between the data sets and they are separately identified in the tables of results. For those less established technologies that find favour, the costs will harden in time and they should move into the "well authenticated" category A in due course.

In practice technologies range in a continuous spectrum from the long established PFC coal-burning plants, through demonstrated but largely unexploited technologies like integrated coal gasification combined cycle combustion (IGCC), to unproven technologies like nuclear fusion. The division into two categories is therefore arbitrary. Atmospheric circulating fluidised bed coal combustion plants, gas combined cycle plants, wind turbines, and orimulsion burning plants might be regarded as well advanced in the transition process, insofar as the technologies exist and the costs of the plants are well established in the market place: all that remains to be tested is their long term

performance under base load power production conditions. IGCC, nuclear reactors with enhanced passive safety features, fuel cells, and large scale solar power sources, on the other hand, are still some way from commercialisation. Views on the correct categorisation of technologies are likely to differ from utility to utility depending on their experience.

All technologies potentially suitable for inclusion in this study are briefly described in Annexes 3 to 6, which expand and update the description given in Annex 7 of the 1989 report[3]. A list of plants for which costs were supplied is given in Table 1, with relevant technical data in Tables 2 to 4.

The group has revisited the question of combined heat and power schemes (CHP) which have become increasingly popular, particularly, but not solely, in industrial companies with large scale heat demands (Annex 7). Because of their high efficiency in fuel use, CHP plants offer an attractive means of reducing fuel consumption and harmful environmental emissions. Several countries have adopted policies that have improved the economic attractiveness of these plants through facilitating the sales of surplus electricity to their power grids. However, in most countries, dedicated electricity producing plants will continue to dominate power supplies in the foreseeable future and the economics of CHP plants will be very dependent on local conditions and the existence of stable heat loads. Annex 7 briefly describes the means available for assessing CHP schemes and the difficulties in comparing their power costs directly with other generating options. It should be noted that nuclear[25] and some renewable as well as fossil-fuelled plants can be used in combined heat and power schemes, although the size of stable heat loads and the high costs of transporting heat generally favours smaller dispersed plant rather than the large scale centralised plants favoured for dedicated electricity production.

The study reviews and comments on the data collected and discusses reasons for significant divergences where these occur. In the case of fuel price assumptions, comparisons are made with projections taken from other responsible studies of similar scope (Annexes 8 and 9). Apart from the common assumptions described in the following section, no attempt was made to reach consensus on capital costs, fuel costs or operating costs since these can differ significantly from country to country and even between regions within countries. Previous studies have shown that the differences cannot be eliminated by standardization, and, even if they could, little purpose would be served by so doing, since the variations reflect the reality faced by the participating countries.

Common assumptions

a) Technical assumptions

The common commissioning date for plants considered in this study has been taken to be the year 2000. This date has relevance to fuel price assumptions and will influence the range of technologies considered and, possibly, projected plant costs. However, the submission of data for this date does not necessarily mean that there are firm plans for the construction of such plants. The date is only for guidance, so that technologies that could be brought into commercial operation before or shortly after are not excluded, although they are all treated as though they were to be commissioned in 2000. This practice is also adopted for Category B plants with the proviso that they should be potentially available for commercial deployment and commissioning around 2000, with a cut-off date of 2005.

Nuclear and conventional coal-fired plant (PFC) operational lifetimes (reference case) are assumed to be 30 years, although longer technical lives are confidently predicted for both. Variants

of 25 years (for continuity with earlier studies) and 40 years are adopted for sensitivity analysis. The economic life assumptions normally adopted in participating countries are summarised in Table 5.

The settled down equilibrium load factor achieved by mature nuclear and coal-fired plants has been taken to be 75 per cent (6 600 hours at full load p.a.), with variants of 65 per cent (5 700 hours) and 80 per cent (7 000 hours) for sensitivity analysis. Allowing for the initial time taken to build up to full power (Table 6), these figures correspond for the reference cases to levelised lifetime load factors of 73.8 per cent at a 5 per cent discount rate, or 73 per cent at a 10 per cent discount rate. Customary national assumptions for the parameter are included in Table 5.

The justification for the above assumption, which is consistent with the good experience of several OECD Member countries, was discussed in Annex 2 of the previous report in this series[3]. The position has been supported by more recent experience[26]. It should be noted that load factors for nuclear and coal-fired plants in some countries are significantly below their technical availabilities, mainly for operational or policy reasons.

b) Costing basis

The costs reported for electricity generation include all components of new plant costs falling on the utility that would influence its choice of generation options. Some country-specific variations in cost coverage are documented in Annex 11. The investment costs include the planning stages and make allowance for interest paid during construction, the ultimate costs of dismantling the plant and the disposal of decommissioning wastes (Annex 11, Table 11.1). For all OECD countries except Japan, and most non-OECD countries, the fuel costs for nuclear plant cover all stages of the fuel cycle including spent fuel storage, its treatment and the disposal of fuel wastes (Annex 11, Table 11.3). India and Korea include some back-end fuel costs with operations and maintenance (O&M) costs rather than fuel cycle costs. Both initial and final fuel charges are included in the levelised overall fuel costs. The precise timing and policies adopted for both decommissioning and the nuclear fuel cycle are those appropriate to individual countries. They have not been standardized.

Other fuels, materials and services purchased by electricity utilities are charged at cost to the utility, regardless of any taxes, costs or financial assistance they include, either because they are not relevant or because they defy meaningful quantification. Examples include "upstream" assistance provided to (or taxes paid by) suppliers of goods, transport and materials, including fuels, within their countries of origin or use. "Assistance" here applies equally to direct payments in the form of grants, subsidies, tax-relief, interest concessions or capital write-offs, and to indirect support through the provision of a publicly funded infrastructure including health and social welfare, central safety, security and inspection services, transport and communications.

Similar indirect support to the generating industry through the national infrastructure, including R&D expenditures incurred by governments and not charged to utilities, are excluded from the costs. However, R&D incurred by utilities in support of their planned generation development are included, as are any plant specific charges levied by government for the provision of public services (such as safety inspections, planning inquiries, etc.).

Taxes on income and profit charged to the utility are excluded, as are central unattributed overheads that are not altered by the choice of plant. Station specific overheads, insurance premiums and, as indicated above, R&D expenditures are included, as are other specific costs such as emission permits, where applicable.

These exclusions were considered in some detail in the previous study[3] and again in the study of the Broad Impacts of Nuclear Power[22]. It has been concluded that the excluded incremental costs associated with the construction of new plant are trivial relative to the direct generation costs, for countries with an established nuclear infrastructure.

External costs that arise downstream from the electric utilities activities are also excluded from the analysis where these do not fall on the utilities themselves. These include the effects of routine emissions by the fuel and electricity industries within the statutory limits which society currently accepts, but that might nevertheless affect health, property, environment or the climate. They also include the effects of potential accidents. The nature, magnitude and significance of these costs has been considered in detail elsewhere[22], for both nuclear and fossil-fuelled plant. There will be qualitative differences for the non-OECD countries which were not covered by the NEA study[22], which concluded that the nuclear industry in OECD countries has largely "internalised" such costs through the adoption of strict emission and safety standards — the costs of which are reflected in its capital, fuel, operational costs and decommissioning costs.

As in previous studies, the costs are calculated on the basis of net power supplied to the station bus-bar, where electricity is fed to the grid. The costs of transmission and distribution are assumed to be similar for large scale base load power plants and are therefore excluded. This assumption may not be valid for some of the widely distributed and often remote low density power sources such as waves. For this reason the need for special transmission costs is identified where it is known to occur. Some smaller scale plants located close to demand centres might have lower overall transmission and distribution costs, and this too is noted.

All costs are expressed in constant money terms and have been converted to national currency of July 1st 1991 using appropriate national currency deflators. They have then been converted to US mills (US$0.001) of the same date using the exchange rates set out in Table 7. Even if exchange rates at the selected date accurately reflected purchasing power parities, the conversion procedure could lead to minor anomalies in intercountry comparisons where a significant part of the cost was incurred for goods or services provided from outside the country, since they could be subject to different inflationary pressures to those employed in the calculation. However, the anomalies should be small, since the national cost studies underlying this report were undertaken at dates close to the study reference date (Tables 2, 3, 4). One effect of this procedure is that year 2000 (or later) fuel prices denominated in 1991 international dollars may differ from the $ prices actually expected to prevail, due to the introduction of assumptions about the future parity between national currencies and international dollars.

As was demonstrated in the first study of this series[1], purchasing power parities are not accurately reflected by exchange rates, and the date adopted for the currency unit has a significant influence on inter-currency conversions which can alter the apparent cost relativities between countries considerably. For this reason the reader should be extremely cautious in making such comparisons.

The choice of reference date was particularly difficult on this occasion because of major swings in relativities between the US$ and other currencies in 1991 and 1992. A further complication arises in relation to the currencies of the former COMECON countries which have also been disturbed by the economic and political restructuring of the past two years. In consequence, Hungary has opted to calculate all its costs directly in US$ since it expects to import any new plant and the fuel it requires. The Russian position is more complex. Not only is there no clearly appropriate parity for the Russian rouble at the present time, but the country's internal pricing structure is in a state of flux, with different fuels and technologies at different stages in the move towards market determined values. Whilst

internal interfuel comparisons in the past reflected relative indigenous costs, their conversion to US$ would be highly arbitrary. Equally comparisons at present (1991-1992) prices could be highly misleading. For this reason Russian data for 1988-89 have been used and left in the national currency unit. As explained in the Russian Annex (Annex 2), the relative cost of the different options could be very different in the future when the Russian economy has settled down.

CSFR and China have an indigenous technological capability and are not in the same position as Hungary, but there are some concerns that the conversion of their costs to the common currency unit may be misleading. This is a matter of degree rather than principle, however, and reinforces the cautionary note against reading too much into inter-country comparisons, since some distortion is inevitable for almost all countries.

c) Discount and interest rates

In earlier studies generation costs were calculated at real discount rates of 5 per cent p.a. and 10 per cent p.a. with sensitivity analyses in the 1989 study at 3 per cent and 7 per cent p.a. Five per cent was previously adopted as the reference value because it was consistent with the values adopted in the majority of OECD countries. Ten per cent was included to demonstrate sensitivity and because it was consistent with the highest rate used in participating countries (including non-OECD countries) for their own analyses.

The values currently in use in the countries participating in this study are summarised in Table 5, together with the basis underlying their use. Five per cent remains the most frequently used value for OECD countries and ten out of fifteen countries showing preference use values of 7 per cent or less. Only two countries use the highest reported value of 10 per cent p.a. This is, nevertheless, a change of balance compared with earlier studies, which arises because discount rates (or required real rates of return) have been increased in some participating countries (Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States). The non-OECD countries' values are somewhat higher at 8 per cent to 12 per cent p.a. (even 15 per cent p.a. for gas combined cycle plant in Russia). The table also brings out the fact that Government and utility practice differs in some countries.

These values support the adoption of both 5 per cent and 10 per cent p.a. as the reference discount rates for the present study, leaving individual utilities to decide on the values best matched to their circumstances. Some of the arguments on the choice of discount rates (or required rates of return on capital) for project appraisals were presented in Annex 4 of the previous report[3]. Since it was written, a significant body of literature has built up in some countries on the topic of the relationship between financial risk and rates of return required in equity and bond markets. There is as yet no clear consensus on the applicability of such approaches to investment by regulated electricity suppliers, or those operating in the public sector or in competitive "free" markets.

The rather higher discount rates favoured by non-OECD countries reflect their need to impose capital rationing, and may in some cases reflect different levels of perceived financial risk on the part of potential investors, but the number of countries is too small to draw strong conclusions.

For simplicity, the interest during construction and the present worth of deferred back-end costs for decommissioning and radioactive waste management, have been calculated for this study using the appropriate reference discount rate, i.e. 5 per cent or 10 per cent p.a., as is the practice in most OECD Member countries. A few countries, however, use a lower rate of discount for long term liabilities corresponding to a long run risk free real rate of return that can be confidently expected to be earned

on funds set aside to meet deferred costs (see UK and USA country annexes). The effect of this practice on levelised costs is small, as will be shown in the sensitivity analysis presented later.

It will be noted that the date for discounting is often taken to be the date of plant commissioning. This is not essential and its choice has no influence on the value of the derived levelised generation cost. The assumed date of commissioning itself can affect levelised costs, however, if real escalation in factor costs, such as fuel costs, is expected to occur.

Chapter 3

REVIEW OF RESULTS: NUCLEAR, COAL AND GAS

General

The data contained in this and the following chapter were obtained by means of a questionnaire circulated to OECD Member countries and those non-OECD countries participating through IAEA. The questionnaire included a number of questions designed to check the comprehensiveness of the cost data in national returns, and to establish whether there were any significant differences among countries in the way costs were assembled (Annex 11, Tables 11.1 to 11.9).

A number of countries have changed the structure of their electricity supply industries since the previous study in this series. In the newly privatised industry in the United Kingdom there is competition between suppliers which leads individual suppliers to regard information concerning future plans and cost estimates as commercially confidential. The UK inputs have therefore been derived largely from authoritative published studies, modified to the format and assumptions adopted for this study.

Many countries have been unable to provide data for all of the three principal fuels (coal, gas, nuclear). This is due to the absence of detailed recent studies for one or more fuels, either as a result of specific national policy decisions or because specific options are not being considered for use by the utilities on the timescale adopted for the present study.

In addition to the data collected on the common basis, countries were invited to supply information about their own standard assumptions and the costs calculated using these assumptions. The responses are included in Tables 5 and 22 respectively. Significant differences in methodology are described in Annex 2.

Data are divided into the two categories A and B, corresponding to respondents' judgements on whether the technologies are well established and the costs well authenticated and predictable with confidence, or whether they are less well established with higher uncertainty about both costs and the plant's technical performance. Category A data, which are in the large majority, are directly analogous to the data gathered in previous studies. Little information was submitted on category B technologies.

Investment costs

Tables 8 to 10 summarise the information provided on projected investment costs for nuclear, coal-fired (mainly PFC), and gas-fired (mainly CCGT) plants respectively. The capital cost figures include allowances for any anticipated real cost escalation to 2000 and indicate, where provided, the

contributions from contingency allowances, interest during construction and capitalised decommissioning allowances. The latter have been capitalised in this manner throughout this series of generation cost studies. The sums included would, with compound interest earned at a rate equal to the relevant discount rate, meet the ultimate costs of all stages of decommissioning when they were incurred. (Note that some countries have adopted the practice of assuming lower rates of interest than their standard discount rates for the purposes of funding long-term back-end and decommissioning costs).

The projected expenditure profiles for initial investment expenditure and nuclear plant decommissioning costs are summarised in Tables 11 and 12. These provide the basis for the calculation of interest during construction and the capitalised decommissioning costs. Investment costs for some countries extend beyond the nominal commissioning date for two main reasons. Countries planning a twin or multiple station site as a single investment project sometimes prefer to take the base date for discounting mid-way through the commissioning process when half the planned capacity is in operation. This has no effect on levelised costs but does result in expenditure on completion of the later units appearing beyond the nominal "commissioning date". Canada and Russia are the most obvious examples of countries following this practice. Other countries incur some post operative capital expenditures for landscaping and provision of other facilities not directly linked to plant operation.

The decommissioning costs for nuclear plants are consistent with those provided by participants in the recent NEA decommissioning cost studies, in which the variability of cost estimates and the reasons underlying them have been fully described and discussed[7-9]. Despite the apparent variability, these decommissioning cost estimates are based on well established procedures and experience in a number of countries and form only a relatively small proportion of the total investment cost. Undiscounted decommissioning costs for LWRs of around 1000 MWe capacity are projected to be some 10 per cent to 20 per cent of the initial total investment cost, and a much smaller fraction when discounted (Table 12).

As in previous studies, data for the USA and Canada have been provided on a regional basis. This can influence nuclear costs if local network requirements call for plants of different capacity (as in Canada's case) or if there are geological and geographical siting implications (e.g. mode of cooling or seismic protection requirements) which influence plant design. However, the main reason for including regions separately stems from fossil fuel price variations, as will be described later.

The projected investment costs for coal-fired plant and gas-fired plant are included in Tables 9 and 10 respectively, with their interest during construction, contingency and decommissioning components. The time profiles for construction are presented in Table 11. Similar comments to those given above for nuclear plants apply.

One obvious characteristic is that the fossil-fired plants, particularly the gas turbines, are both cheaper per kWe capacity and quicker to build than nuclear plants. Because of the shorter construction times the interest during construction, expressed as a percentage, is lower for the non-nuclear plants. Their decommissioning costs are negligibly small because of the absence of the radioactivity which complicates nuclear plant decommissioning. The non-nuclear plant decommissioning costs are largely repaid by the value of the site and the scrap steel and re-usable components obtained in the decommissioning process. Most utilities therefore ignore this component (CSFR is exceptional in finding coal plant investment costs higher than those of nuclear plant, due to the lack of recent experience and indigenous sources for the former).

Table 13 indicates that almost all participating OECD Member countries expect that any coal-fired plants built for commissioning around the year 2000 will be fitted with desulphurisation technologies and low-NOx burners or catalysers to reduce nitrogen oxide emissions, and the costs are included in their projections. Korea, Hungary and Russia also include the costs for similar environmental controls. China and CSFR include costs for desulphurisation technology, but India includes costs only for removing particulates.

Table 13 also provides data on the levels of sulphur and nitrogen oxide emissions that utilities expect to meet (or better) in different countries. The cost of achieving reductions in sulphur dioxide and nitrogen oxide emissions is sensitive to the standards required and to the quality of fuels used, as reported by IEA[27]. The costs of controls for new plants are less than those of retrofitting old plants and the incorporation of control technologies can reduce thermal efficiencies and reduce the output of plant[27]. This has been taken into account in the generation cost calculations.

The treatment of emissions from individual future fossil-fuelled plants will depend on the form of national or regional regulations and the optimal means of meeting them. Thus the European Communities' large combustion installation directive required overall reductions in national emissions that could be met through some combination of reduced fuel consumption, switching to cleaner fuels, or adoption of control technologies on new or older plants, together with specific emission control standards for all new plants.

It can be seen from Tables 8 to 10 that there remain considerable differences in investment cost expectations among countries for most types of plants. The base nuclear construction costs span a three fold range from the CSFR's figure of $960/kWe to the high $2 800/kWe at the top of the United Kingdom's range. Eight of the thirteen countries (excluding Russia) providing data, project costs in the range $1 150 to $1 800/kWe. Projected coal-fired base construction costs show a smaller range of variation from $815 to $1 930/kWe, with thirteen out of twenty countries projecting costs between $1 000 and $1 500/kW. The range for gas combined cycle plants in OECD is similar to nuclear plants, with all countries falling in the range $400 to $1 230/kWe and nine of the thirteen respondents quoting costs between $550 and $800/kWe. One of two non-OECD respondents, Hungary, gives costs for gas plants well below the full OECD range, based on quotations from vendors.

It is appropriate to note that subsequent to data being gathered for this study the UK utility, Nuclear Electric, has quoted base construction costs for a twin 1 300 MWe PWR station equivalent to $2 100/kWe in July 1991 money values (see page 133).

The reasons for the cost differences have been examined in earlier studies[1-3]. They arise from a number of factors. Designs used in different countries differ to match their own regulatory and siting requirements. The scale of plants differs; contractual arrangements and factor costs (including wages, services, materials and equipment) differ; and costs can be significantly influenced by whether a plant is seen as one in a developed series or a new design. Some countries plan to install several plants at a site, benefiting from common infrastructure and services; others plan on the basis of single plants. There are also differences in the organisational, managerial and institutional frameworks. The factor costs are particularly low in some non-OECD countries and differences in their experience and indigenous capability can have a strong influence on relative costs. This is particularly noticeable with the CSFR's costs for nuclear and coal-fired plant.

One major factor, that affects apparent cost relativities between countries, is the exchange rate, values for which may change rapidly in financial markets. The base date adopted for the common currency unit therefore has a considerable influence on apparent relativities. The US dollar of

1 January 1991 was considerably depressed relative to other major currencies by the threat of the Gulf War. This was the principal reason for choosing July 1st 1991 as the base date for this study, since the dollar had by then returned somewhat closer to what might be regarded as a more typical value. Nevertheless, as in earlier studies, the reader is cautioned against reading too much into relative differences, particularly in view of the instability in currency markets that has accompanied the political developments and economic restructuring over the past two years.

Operations and maintenance costs

The projected operations and maintenance costs (O&M) per unit of electricity sent out are summarised in Tables 14 to 16. Contrary to previous studies we have not sought to break these down into component costs, since the breakdown has provided no useful guidance on the reasons for differences between countries. A simple check list has been employed to establish whether there are significant differences in the items included in the operating and maintenance cost categories in different countries (Annex 11, Tables 11.2, 11.5 and 11.8). The responses for nuclear power plants are summarised in Tables 14 and 11.2. It should be noted that the O&M costs for the pressurised heavy water reactors in India and Korea include charges for heavy water. Canada includes heavy water in its capital costs with only make-up heavy water requirements included in O&M. The O&M costs for nuclear plant are largely fixed and independent of the plant load factor (Table 14). The values for LWRs lie in the range $30 to $110/kWe plant capacity per year at 75 per cent load factor. The USA's $108/kWe capacity per year is the only example where O&M costs considerably exceed the nuclear fuel costs. However, contrary to the previous study[3], the USA is no longer unique among OECD countries in having relatively high O&M costs. The O&M costs for Indian and Korean PHWRs reflect their inclusion of heavy water charges and some back-end fuel costs (Table 11.2).

O&M costs for coal-fired plants include a significant variable component (Table 15) arising from fuel and waste handling and the costs associated with materials used in emission control. They lie in the range $25 to $100/kWe capacity per year at 75 per cent load factor. The range essentially overlaps that projected for nuclear plants, although the majority of respondents project O&M costs for coal at 75 per cent load factor to be lower than those for nuclear plants. The biggest coal/nuclear divergences for LWR operators are shown for Belgium, Japan, and the USA. A few countries (Hungary, Germany and the United Kingdom) project coal-fired plant O&M costs to be higher than those of LWRs.

The O&M costs for gas combined cycle plants (Table 16) are projected to lie in the range $10 to $50/kWe capacity per year at 75 per cent load factor. Like nuclear power, gas O&M costs are largely fixed and independent of plant load factors. In all cases the O&M costs are expected to be less than those for nuclear or coal-fired plant, generally by a significant margin. This reflects the comparative simplicity of gas plant compared with nuclear plants and solid fuel combustion plants.

Nuclear fuel costs

The costs per kWh of nuclear fuel are included in Tables 20 and 21. Some variations are to be expected due to different national strategies for spent fuel management (Annex 11, Table 11.3), different plans concerning fuel specification and burnup, and different expectations concerning the prices of uranium (Table 17) and fuel cycle services.

The cost of nuclear fuel for LWRs is projected to lie in the range 5 to 11 mills/kWh, with the exception of Japan (18.3 mills/kWh) due to transportation for reprocessing spent fuel overseas and little reflection of decreasing uranium prices under long-term contracts. The cost for unenriched PHWR fuel is, as in the past, lower at 1.8 to 3.0 mills/kWh for Canada and Korea, although Indian fuel costs are projected to be higher at 7.1 mills/kWh, due to reliance on indigenous plant and projected exchange rate effects. Neither Korea nor India include the back-end spent fuel disposal costs in their fuel costs although these are around 22 per cent of the costs of the Canadian CANDU reactor fuel costs[4].

A recent NEA study has reviewed the component and overall costs of the nuclear fuel cycle in some detail[4] and we have therefore not gathered the data on the fuel-cycle cost breakdown for this analysis, other than the underlying uranium price assumptions shown in Table 17.

Long run uranium prices will be dependent on the rate of growth of nuclear powered electricity generation. At the present time uranium prices and separative work prices on spot markets are very depressed, due to an excess of production capacity in western countries and the entry of former Eastern Bloc countries into the world market. Both prices remain vulnerable to a continuing run-down of stockpiles, and to the possible release of fissile materials recovered from weapons into civil markets. The projected prices in Table 17 reflect anticipated changes in currency parities as well as any real price escalation, so they do not necessarily correspond to individual utilities' views on actual dollar prices of uranium in the year 2000. (France is a case in point with the tabulated $ price being higher than they expect to see in US$ terms.)

Coal price assumptions

The participating utilities' assumptions concerning coal prices and origins (indigenous or imported) are given in Table 18. Prices are expressed in US$ per Gigajoule to take account of the varying calorific value (energy content per tonne) of coal. Some of the price differences reflect the source and quality of the coal assumed to be used, i.e. its sulphur and ash content.

For coal importing countries the projected prices in Table 18 are those for fuel delivered, carriage, insurance and freight paid (c.i.f.) to appropriate ports, and exclude transport and handling costs from the port to power station. For plants situated close to coal mines (as in some North American regions, North West China and North East India) the transport costs are small and coal relatively cheap, but in other cases, such as Japan or Europe, world traded coal has to be shipped by sea as well as incurring any land transport and handling costs between mine and port or port and power station. The fuel costs in Table 18 in common with the spot prices commonly quoted for world traded coal, which also relate to the price at the dock side in the receiving country (c.i.f.), have to add port to power plant transport and handling costs, when calculating their contribution to generation costs. The difference is only in the region of 10-15 per cent for inland power stations[3]. For large countries like the USA, Canada, China, India and Russia inland transport costs can add considerably to coal prices away from the mines. This is illustrated by the regional price variations in Canada and the United States (Table 18).

OECD countries' expectations for coal prices in the year 2000 centre quite closely around $2/GJ (average $2.08/GJ) for importing countries without access to cheap indigenous supplies. There is greater divergence in expectations concerning future real price escalation with one-third of the OECD respondents projecting constant prices and two-thirds projecting increases in the range 6 per cent to 56 per cent by 2030, with an overall average of 0.7 per cent per annum.

As in the case of uranium, the coal prices projected by utilities in national currencies implicitly contain any allowances felt necessary to take account of future changes in relative currency values. The conversion to the common currency unit (July 1991 US$) using the 1991 exchange rate may not yield dollar coal prices that equate to the individual utility's own future dollar price expectations.

Gas price assumptions

The electrical utilities' expectations of gas prices, delivered to the power station, are summarised in Table 19. These prices may differ marginally from the border prices of gas frequently quoted in the literature, which exclude transport of gas from the border to the plant. Prices are quoted in US$ per Gigajoule.

Projected prices range from around US$3 to $5/GJ in 2000 (OECD average $3.7/GJ) with almost all those providing data projecting real price escalation ranging from 20 per cent to over 200 per cent by 2030 (averaging 2.1 per cent per annum over the period for OECD). Further comment and analysis appears later.

In projecting future world traded gas prices utilities will have allowed for changes in the national currency's parity with the US$ so that, as indicated previously for uranium and coal, projected dollar prices for gas in Table 19 may not correspond exactly with utilities' own future dollar price expectations.

Overall generation costs

The projected levelised generation costs are summarised for coal-fired, gas-fired and nuclear power in Tables 20 and 21. Table 20 presents data at 5 per cent discount rate for the reference plant assumptions (30 year life, 75 per cent settled-down load factor for coal and nuclear plants), whilst Table 21 presents the same reference cases at a 10 per cent discount rate. The gas plants have not been standardized and separate national assumptions are used for both lifetime and load factor, as indicated in the tables. Calculations based on utilities' own assumptions are presented in Table 22.

As in previous studies the ratios of coal, nuclear and gas generation costs to each other are included in the Table 23. These ratios go some way to eliminating the effect of currency exchange rate anomalies, although they can still influence cost relativities to the extent that they affect the elements in overall costs that arise from imported technology or fuel.

With the exception of the United Kingdom, Western USA and Western Canada, all participants providing data for both options, project nuclear power to be cheaper than coal-fired generation at a 5 per cent discount rate. At the same discount rate, coal is projected to be cheaper than gas combined cycle generation in seven countries. Six countries show near break-even and two (UK, and Hungary) show gas to be cheaper. Nuclear power is projected to be cheaper than gas in all countries except the United Kingdom.

At a discount rate of 10 per cent p.a. (Table 23) the position of the less capital intensive technologies is greatly improved relative to the more capital intensive ones, with only five countries projecting nuclear electricity to be significantly cheaper than coal-fired generation. Three countries show the two fuels breaking even (to within 5 per cent) and five (including the Netherlands) project

coal to be the cheaper option. Estimates in the USA and Korea depend on regional condition and type of nuclear reactor, respectively.

(Note that the lower nuclear construction costs recently claimed in the UK would reduce projected nuclear generation costs by about 10 mills/kWh at 5 per cent discount rate and about 20 mills/kWh at 10 per cent discount rate, bringing them into line with the costs of category B plant described below).

At the higher discount rate, gas combined cycle generation is projected to be the cheapest base load option in Belgium, parts of Canada, Denmark, Finland, Portugal, Spain, the United Kingdom, parts of the United States, and Hungary. Nuclear power is only projected to retain its overall advantage in France and Japan, amongst the countries supplying data for all three technologies.

Category B technical options

Few data have been provided on the new fossil and nuclear technologies that utilities believe they might be deploying around 2000 or shortly thereafter. The main submission in this area has come from the United Kingdom, where the projected competition from gas combined cycle plants and intense coal v. nuclear competition within the framework of environmental concerns, plus the requirements of the newly privatised electricity supply industry have led to fresh consideration of advanced options.

Tables 20 and 21 indicate that UK projected costs for an evolutionary PWR design are considerably below those for the Sizewell-B based derivatives in category A, whilst the pressurised fluidised bed category B coal-fired plant has generation costs marginally below those projected for the atmospheric circulating fluidised bed plant submitted under category A (Tables 20, 21). If the projected improvements are realised it would bring UK nuclear costs closer to those of the majority of OECD countries and close to the UK's coal-fired electricity costs at 10 per cent p.a. discount rate. At 5 per cent nuclear would be cheaper than coal and projected gas-fuelled generation costs, with coal and gas breaking even, although gas would remain the cheapest overall option at 10 per cent p.a., by a significant margin.

Canada supplied data on a first-off prototype CANDU-3 plant in New Brunswick, the costs of which are not strictly comparable with replicated coal-fired plant (see Annex 2). Netherlands category B data relate to a simplified BWR and an integrated coal gasification combined cycle plant.

Fuel cells are also a category B technology under development in several countries, which could eventually contribute to base load power generation. No data on their costs have been provided due to lack of confidence of the utilities in the data currently available.

Sensitivities

Data are presented in Tables 24 and 25 for the overall generation costs calculated using the alternative assumptions for plant life and plant load factor set out in Chapter 2.

It will be seen that overall generation costs are relatively insensitive to variations of plant life over the range 25 to 40 years. They are however sensitive to variation of the plant load factor.

Table 26 indicates the factor by which investment costs would have to change for break-even between the generation options. It also indicates the factor by which plant load factors and O&M costs would need to change to achieve the same result. Table 27 gives the values of discount rate at which nuclear would break-even with coal and gas, based on the data provided for this study. Table 28 presents the factor by which fuel costs would have to change for break-even between the generation options.

a) Capital costs

The investment costs are the largest single component of nuclear generation costs accounting for some 40-60 per cent of LWR costs at 5 per cent p.a. discount rate or 55-75 per cent, at a 10 per cent p.a. rate. From Table 26 it can be seen that nuclear investment costs would have to increase by some 10 per cent to 120 per cent, for it to lose its advantage over coal at 5 per cent p.a. discount rate, in most contributing countries. At 10 per cent p.a. it is already projected to be dearer in several countries without cost escalation.

Capital costs are a smaller component of fossil-fuelled generation costs; typically 20-40 per cent for coal-fired (PFC) and within the range 10 per cent to 25 per cent for gas-fired plants in most countries, both at 5 per cent discount rate. The sensitivity of overall generation costs to variations in fossil fuel plant capital costs is correspondingly less than that for nuclear generation.

b) Nuclear fuel costs

Nuclear fuel costs, inclusive of all front-end and back-end stages of the fuel cycle, are a relative minor part of overall nuclear generation costs (10-35 per cent for LWRs at 5 per cent discount rate) and, although there are variations between countries expectations (Tables 20 and 21), the values reported for LWRs are broadly consistent with those of a recent more detailed analysis[4]. Because of their small contribution, overall generation costs are insensitive to nuclear fuel cost variations. This is even more true of PHWRs whose natural uranium based fuels are even cheaper than the enriched uranium LWR fuels, except in the case of India.

Projected nuclear fuel costs for LWRs, which lie within the range 5.2 to 11 mills/kWh for countries other than Japan, compare with 5.4-6.2 mills/kWh in the detailed review of nuclear fuel cycle economics[4]. PHWR fuel costs compare with 2.9 mills/kWh in the latter study. (The fuel study[4] is not yet finalised and these figures may be revised in the final document.)

c) Operations and maintenance costs

As reported in the previous study[3], operations and maintenance costs, which had in the past been comparatively small relative to overall generation costs and about equal for the coal-fired and nuclear plants then considered, had assumed greater significance since the decline in world fossil fuel prices had reduced the gap between nuclear and coal-fired generation costs. This remains true.

At 5 per cent discount rate nuclear O&M costs for LWRs range from about 20-30 per cent of total generation costs in most countries (Tables 20, 21), whilst those for coal lie mainly in the range 10-20 per cent and for gas in the range 5 per cent to 11 per cent. The contributions for all fuels are smaller at the 10 per cent discount rate. The greater contribution of nuclear O&M costs to overall generation costs, particularly in the United States, increases the significance of this cost component for nuclear power's competitiveness. Nuclear O&M costs are also high in India due to heavy water leasing and top-up costs.

At 5 per cent discount rate increases of nuclear O&M costs of 40 per cent to well over 100 per cent would still be needed to raise nuclear generation costs above those of coal and gas in most countries. At 10 per cent discount rate reductions in O&M costs would be needed in many countries for nuclear to break even with the fossil-fuelled options.

The lower contribution of O&M costs to overall coal generation costs and particularly to gas generation costs leaves these fuels relatively insensitive to variations in this parameter. Nevertheless a 50 per cent increase in coal O&M costs would make coal generation dearer than gas, even at 5 per cent discount rate, in more than half of countries where the latter is currently projected to be dearer.

d) Discount rate

The results in this study have been presented at 5 per cent p.a. and 10 per cent p.a. discount rates in Tables 20 and 21. It is readily apparent that the relative attractiveness of different technical options is very sensitive to this parameter, with the lower rate favouring the more capital intensive options like nuclear power while the higher rate favours higher fuel cost, low capital cost options, particularly gas turbines.

Break-even discount rates are presented in Table 27. They range from below 5 per cent to well over 15 per cent for coal/nuclear break-even, depending on the circumstances of individual countries.

The break-even discount rates for gas combined cycle and nuclear plants are generally lower than those for coal/nuclear because of the smaller capital component in gas generation costs.

e) Fossil fuel prices

Unlike nuclear plants with relatively low fuel costs (and renewable sources like wind generators with no fuel costs), the fossil-fired options are very sensitive to fuel price assumptions. This is particularly true for gas-fired plants because of their very low specific capital costs (capital costs/kWe net capacity).

At 5 per cent discount rate coal costs are projected to be, typically, 40-60 per cent of overall coal-fired generation costs, while gas costs are projected to be some 60-80 per cent of gas-fired generation costs for base load plants commissioned in the year 2000. The contributions are somewhat smaller at a 10 per cent discount rate.

Table 28 shows the factor by which fossil-fuel costs would have to decrease (or increase), relative to utilities' expectations, to break even with nuclear generation and with each other at 5 per cent p.a. and 10 per cent p.a. discount rates.

For most countries other than the UK levelised fossil-fuel prices would have to be significantly less than those projected for fossil-fired generation to break even with nuclear generation at 5 per cent p.a. discount rate. At 10 per cent p.a. discount rate levelised gas and coal prices would have to rise above those projected in a majority of countries for them to lose their overall cost advantage.

f) Other factors

As noted earlier from Tables 24 and 25 the generation costs for coal and nuclear plant are not very sensitive to plant life assumptions. They are however sensitive to load factor, particularly nuclear generation with its larger share of fixed costs, both in its investment and operational cost components.

Gas combined cycle plants have comparatively low fixed investment costs so that their overall generation costs are insensitive to load factor or plant life, provided fuel costs are variable.

Any reduction in economic plant life or load factor will then favour gas relative to coal and nuclear, and coal relative to nuclear generation. Conversely any increase in either will improve the more capital intensive options. The importance of both parameters is such, however, that the capital intensive plants are designed to achieve long life and high availability, thus minimising unit levelised costs of generation.

In some cases fuel contracts (coal or gas) may contain a significant fixed "take-or-pay" element which, if ability to resell unconsumed fuel is limited, will alter the sensitivity of overall costs to load factor and plant life.

g) Multiple parameter changes

As noted in the previous study, the examination of the sensitivity of overall generation costs to changes in any single parameter, whilst all others remain fixed, highlights the parameters of particular importance. It says nothing, however, concerning the likelihood of any given deviations from expectation. Thus nuclear costs are sensitive to changes in parameters that affect the capital component of overall generation cost (investment, discount rate and load factor) but if all these are well defined this sensitivity would not affect confidence in decisions based on the cost projections. Similarly coal and gas generation costs are sensitive to fuel prices, but the importance of this to decision making rests in the likelihood that expectations could be radically in error.

The previous study[3] described in its Annex 9 how such uncertainties could be accommodated by statistical treatments that were based on inherently subjective judgements of the probability that individual parameters could deviate by given amounts in the future from current expectation. Because of its subjective nature and the inevitable differences in the probability density functions of different countries or regions within countries, there is no point in seeking to apply such quantitative techniques to data gathered in an international study. Individual utilities may however find the approach a useful decision aid.

Chapter 4

REVIEW OF RESULTS: RENEWABLE ENERGY TECHNOLOGIES AND COMBINED HEAT AND POWER

General

The results for renewable energy technologies which could be commercially available around the year 2000 or shortly thereafter, are presented in this chapter. Some technologies are already well established, whilst others are considered more speculative because they have not been demonstrated on an appropriate scale or because they lack significant international operational experience. Technical details of the technologies and estimates of their potential contribution to power supply are included in Annex 6.

The technologies for which some data have been provided are wind turbines, small scale hydropower and waste incineration and landfill gas. Italy (Annex 2) has provided generalised data on geothermal power sources. It is noticeable, however, that few technologies have reached the stage where utilities have sufficient confidence in their costs to include them in the returns to the questionnaire. Even the data provided have wide ranges quoted for costs. Reasons advanced by participants in the present study for failure to provide cost information, include the institutional divisions which, in many countries, result in concentration of expertise on renewable energy technologies in smaller independent generators rather than large utilities; general lack of commercial experience of the technologies, their performance and costs; questionable quality and lack of consensus on costs, even within countries.

Data for combined heat and power plants are included in Annex 7 and reported in this chapter, even though some of the plants are fossil-fuelled, because of the problems of making direct comparisons with dedicated electricity generating plants (see Annex 7).

Base load operation

This study is confined to base load generation technologies and, by analogy with coal-fired, oil-fired, and nuclear and hydropower plants, this is generally regarded as relating to plants with relatively lower operating costs which can be relied on to provide power through most of the year with a high technical availability.

Renewable energy plants with variable output which, individually, may provide little or no output for extended periods, e.g. solar plants and wind turbines, or those which have highly cyclical power availability, e.g. tidal plants, are often regarded as possible fuel saving plants rather than base load

contributors. Since there is no simple cost-effective means of storing electricity on a large scale, variable renewable sources alone are not able to provide reliable firm power, and some conventional plant capacity is required to cover periods when the renewable output is low. The exceptions to this generalisation are geothermal and hydropower and the limited use that can be made of hydraulic pumped storage schemes to provide assured power on demand. Even hydropower can show significant seasonal fluctuations in some regions and may be affected by drought.

However, even for sources like wind turbines and wave power, where the dominant fluctuations are random, albeit with some superimposed seasonal variability, the technical availability is a statistical function. Thus, whilst different in degree, is similar in kind to the unplanned outages from nuclear and conventional plant. The only difference is that individual weather dependent renewable energy technologies may all be subject to simultaneous low availability.

Detailed statistical analysis for tranches of variable renewable energy sources, dispersed geographically, in a network containing the so-called firm sources (fossil and nuclear powered) indicate that, for small shares of variable renewable energy capacity, the contribution to firm capacity is equal to the average power output from the plants[28, 29]. As the renewable share increases the capacity contribution falls progressively further below the average power. The effect is trivial up to 5 per cent penetration and, according to some analyses[30], not very significant up to penetrations of around 20 per cent based on average renewable energy available capacity as a fraction of total system capacity. Some would argue[28] that even higher shares are possible, particularly given a balanced mix of different renewable and conventional power plants.

Dutch studies for the European Economic Community[29], on the other hand, have suggested that there are "potentially devastating" load-following and spinning-reserve penalties on the economics of wind power at above 10 per cent capacity penetration in the absence of associated energy storage technologies.

Whilst it is appropriate to regard the randomly variable renewables, as well as hydropower and waste incineration, as potential contributors to base load capacity on an interconnected network with an adequate back up from conventional firm sources, the appropriate capacity credit and the economics of running sizeable tranches of variable renewable capacity cannot be regarded as fully resolved at this time.

Investment costs

The investment costs for the renewable energy technologies are presented in Table 10. They dominate generation costs for wind turbines and other non-fuel options (Tables 20 and 21). The specific investment costs ($/kWe) submitted for wind turbines differ significantly between countries.

It should be noted that base construction costs for variable renewable energy plants are expressed in terms of $ per peak kW sent out. In one sense this is analogous to the situation for fossil-fired, nuclear, waste incineration and biomass plants, whose investment costs are specified on the basis of design power capacity sent out. However, these latter base load plants are normally expected to operate at about design capacity whenever they are in use (except in cases where, for technical demand reasons, they are used in load following mode), whereas the variable renewables like wind turbines operate at their design peak load for only a small part of the time. Thus, although their technical availability may be as high or higher than conventional plants, their average output will be considerably

lower; e.g. the wind turbines in Tables 20 and 21 are projected to have outputs of around 25 per cent of their peak capacity.

This average performance can differ significantly depending on siting and whether a single machine or a large array of machines is constructed. For this reason the average unit cost of electricity from variable renewable sources is significantly dependent on the number of such machines built, with costs increasing as the most favoured sites are used up, and, for variable sources, as penetration of the power network increases.

It has to be noted, also, that transmission costs for electricity from renewable plants may differ significantly from those of large scale fossil-fuelled or nuclear plants. Small scale waste incineration plants may be located close to the centres of population that produced the waste and have relatively low transmission and distribution costs. On the other hand wave powered and some wind powered plants may be located in climatically and geographically favoured regions remote from major demand centres, incurring higher transmission costs, unless the output from small tranches can be absorbed locally. Their attributes can, however, make them particularly suitable for supplying isolated or island communities; especially those that are not linked to the main grid system and rely on expensive small scale diesel generators for much of their power. Siting of larger conventional plants may also be constrained by their need for access to cooling water and environmental considerations.

Because most renewable plants are physically small their construction times are short (Table 11) and interest charges during construction are negligible. Large scale hydropower schemes and geothermal plants would be exceptions to this generalisation.

Operations and maintenance costs

For the most part, O&M costs would be expected to be modest for the non-fuel renewables, provided they are designed to resist physical damage from their environment. In practice, however, they appear to be significant (Table 16) and are equal to or greater than those for fossil-fired and nuclear plants on a mills/kWh basis (Tables 20, 21). For sources dependent on wastes or other low density, low calorific content fuels such as biomass, the handling and maintenance costs can be much higher than for conventional high calorific content fuels.

Fuel costs

Renewables sources relying on natural forces incur no fuel costs. The same is generally true of landfill gas combustion (Tables 20, 21). Although in principle such gas has an opportunity cost and could be sold for non-electricity use, the gas is, in practice, of too low and variable a quality for this to be a viable option. The cost of municipal and industrial wastes for use as fuels lies mainly in the costs of their collection, transport and handling. However, many of these costs would be incurred anyway and the costs of transport to and purchase of landfill sites are avoided. For municipalities or companies, the savings may justify paying a generator to take and incinerate the wastes, giving the fuel a negative cost (Tables 20, 21).

Overall generation costs

The overall costs of renewables generation technologies vary significantly (Tables 20 and 21 and Italian contribution to Annex 2 on geothermal sources). Some are clearly economic in competition with conventional base load power sources, provided the renewables can satisfy environmental standards. Others appear, on the basis of submissions to this study, to be dearer. A great deal depends on siting and local conditions even when the basic technology is well established.

Sensitivities

No detailed sensitivity analysis has been done for the renewable sources because the possible range of costs is large and very dependent on their siting and scale of contribution. This dependence has not been brought out in the cost data supplied for this study.

Scale of contribution

The potential scale of renewable contributions to base load power supply in most countries is limited. The quantities of combustible or digestible wastes yielding combustible gases, although large in themselves, are small relative to total power needs. Additionally, the technically acceptable contribution from variable sources to an integrated power network is generally measured in tens of percent, even if the theoretically available resource is much larger, as previously described in the section (this chapter) on renewable source contributions to base load operation.

With the exception of hydropower, in suitably endowed countries, the contribution of renewables to overall power supplies in OECD countries is projected to be relatively small in the early years of the next century (Annex 6).

Combined heat and power

Combined heat and power plants are already widely deployed in OECD countries (Annex 7) and make major contributions to power production and district heating schemes in some countries in Eastern Europe, and the former East Germany, in particular. Smaller plants owned by municipalities or industrial companies can supply power to the main utilities' grids and, in some countries, payment rules have been designed to encourage this, since CHP is seen as energy efficient and environmentally beneficial.

As remarked earlier, CHP plants can be based on fossil fuels or nuclear heat sources but the data in this study have been supplied for a straw fired renewable plant (Denmark) and fossil-fired plants. They are summarised in Annex 7. The Danish figures are based on a cost net of the value of heat produced, but different methods for heat valuation or different pricing policies would have a significant impact on the values cited. This is discussed further in Annex 7.

Chapter 5

DISCUSSION AND CONCLUSIONS

Coverage

The number of countries with clear plans or expectations for new or replacement nuclear capacity at or about the year 2000 has decreased in recent years. At the same time there has been a marked upsurge of interest and, in many countries, in planned investment in combined cycle gas-fired generation plants. The reasons behind these changes are complex, but investment choices still need to be taken with as full an appreciation as possible of the comparative economics of the technical options.

The changing situation has had the effect of reducing the number of inputs on nuclear costs from OECD countries to this study. Of the contributors to earlier studies, Italy, Spain and Turkey have now confined inputs on thermal systems to fossil-fired plant, whilst Switzerland provided no cost inputs on thermal plants at all. This reduces the comprehensiveness of the analysis, although this has been partially redressed by the active participation of five non-OECD countries (CSFR, Hungary, India, Korea and Russia) and provision of data by a sixth (China).

Several participating countries or their utilities still use discount rates of about 5 per cent p.a., but they are no longer in the majority amongst OECD contributors, with an equivalent number now using around 7 or 8 per cent and two 10 per cent, so that the average discount rate has risen. Bearing in mind the preference of participating non-OECD countries for higher rates of 8 to 12 per cent p.a., it was concluded that rates of 5 per cent and 10 per cent should be used jointly as the basis for presenting the data collected in this study.

The growth of interest in gas-fired generation has led to an extensive set of inputs on the cost of such plants, whilst the coverage of coal as a baseline technology remains almost complete.

Countries' own assessments

With the exception of Netherlands (Category B plant) and the cheap coal regions of North America and India (and China), those countries providing data on both nuclear and coal-fired plant on their own assessment criteria, project nuclear to be the cheaper option for base load plants for commissioning in the year 2000, when using their own economic, technical and fuel cost assumptions (Table 22). Coal and nuclear powered generation break-even in the Mid-West USA. These were responses from five of the sixteen OECD countries participating and all six non-OECD countries.

Gas-fired generation using high thermal efficiency combined cycle plants is generally projected in OECD countries to be dearer for base load operation than either nuclear or coal-fired plant, except in Portugal where electricity from gas combined cycle plants is projected to be significantly cheaper than electricity from imported coal, in the USA, and in Denmark and Finland where gas and coal are projected to break even.

Gas is currently accepted to be the cheapest option for new base load capacity in the United Kingdom although no costs are included in Table 22 since there are no agreed common assessment criteria in that country. On the 8 per cent p.a. real return applied for general public sector projects in the UK, cost projections for new base load plant in the year 2000 have suggested that gas combined cycle plants will be the cheapest option, a conclusion that has been reflected in the planned new investments in that country.

Gas is projected to be the cheapest source of power in Hungary, and competitive with coal-fired but not nuclear electricity in CSFR and Russia. Its more favourable position in the countries of Eastern Europe will lie in part with the higher discount rates they employ, which favour the lower capital investment options.

Investment in new gas combined cycle capacity has been favoured recently even in countries where coal or nuclear plant would be considered to offer cheaper base load power. This is due in part to the environmental attractions of gas vis-à-vis coal; in part to the lower investment cost and shorter construction times, which reduce financial risk vis-à-vis both coal and nuclear plants; and because the economic attractiveness of gas increases relative to the more capital intensive options at lower load factors. Gas is therefore seen as a good fuel for mid-merit order operation, if not for base load, in many countries, on the basis of current fuel price expectations.

Data submitted, overall, on renewable energy sources has been very limited, partly because utilities do not expect them to make significant contributions on the timescale of this study; partly because of the wide diversity of potential sources and the sensitivity of their costs to local factors, which has been judged to preclude meaningful submissions; partly because their costs are still regarded as highly uncertain, and partly because they are not yet regarded as economically competitive. No countries have provided renewable electricity cost data on the basis of their own assessment criteria that permit comparisons with the fossil-fired and nuclear plants.

When considered in terms of cost relativities between nuclear, coal-fired and gas-fired sources there are no major differences between OECD and non-OECD countries own assessment conclusions, other than those arising from access to cheap fossil fuel supplies and a tendency to favour gas in the non-OECD countries due to their higher average discount rates; differences that also occur within OECD and within individual OECD countries.

Common basis

Investment costs

There continue to be significant variations among countries in the projected generation costs for both nuclear and coal-fired electricity. Nuclear, coal-fired and gas combined cycle plant overnight investment costs (i.e. excluding interest during construction and decommissioning allowances) span a considerable range. LWRs span $960/kWe to $2 800/kWe whilst coal spans $815/kWe to $1 930/kWe. The full range for gas combined cycle plants in OECD is $400/kWe to $1 230/kWe. If the extremes

are removed the ranges are considerably reduced and fall to a more reasonable range of 1.5 for each of the three technologies, within which the costs of the majority of participants are encompassed (1 150 to 1 800 for nuclear; 1 000 to 1 500 for coal; 550 to 800 for gas).

Some of the wide range of base construction costs and of absolute generation costs will be attributable to countries where the exchange rate adopted for conversion to US mills is out of line with the purchasing power parity costs they experience. Hungary submitted its data in US$ on the basis that it would import both technology and fuels, whilst the Russian Republic preferred to present data in roubles (1989), noting that official exchange rates have had little meaning over the recent period of economic transition.

For CSFR nuclear base construction costs are projected lower than those for coal-fired plant. This reflects the country's greater indigenous experience and manufacturing capability for the former.

The high United Kingdom projected investment costs for Category A nuclear plant, which lead nuclear to be no cheaper than coal-fired generation (imported coal) at 5 per cent p.a. discount rate, are projected to reduce considerably for an advanced evolutionary PWR design that might be ordered for post-2000 commissioning (see however page 133).

The reasons for the variations in investment costs have previously[1,2,3] been attributed to design and siting differences, factor cost differences, and different planning and construction practices and experience, including replication, collocation and shared services. This is in addition to the important effect of exchange rate anomalies mentioned above, which are particularly acute for some of the non-OECD countries at this time.

Decommissioning costs

The significance of nuclear plant decommissioning costs, which are capitalised in the levelised cost methodology adopted for this study, is relatively small. The undiscounted costs span a range between 10 per cent and 20 per cent of initial investment cost for LWRs, but when discounted contribute only a few per cent to the total investment cost and an even smaller fraction to overall generation costs. Even a doubling of decommissioning costs would add little to electricity costs from nuclear plants and would not influence their competitiveness. These conclusions are still valid if the practice of using a lower discount rate for long term liabilities, adopted in a few countries, is followed. Reasons for the variability in decommissioning cost estimates have been explored elsewhere[8].

Overall generation cost ratios

The overall generation costs at 5 per cent and 10 per cent discount rates are presented in Tables 20 and 21 and Figures 1 and 2. To overcome, partially, the problems of divergence of investment costs, attention is focused on generation cost ratios and their sensitivity to changes in input data and assumptions. These go some way to removing the variability arising from exchange rates and factor costs, but leave the national differences in design criteria, siting constraints and construction practices. Problems of factor costs and exchange rates are not wholly eliminated, since different technologies can have different reliance on indigenous and imported components and fuels.

Cost ratios for the main generation technologies at 5 per cent and 10 per cent discount rates are shown in Table 23 and Figures 3 to 5. On the basis of the common assumptions and employing a 5 per cent p.a. real discount rate, nuclear power is projected to be cheaper than coal-fired power in twelve of the thirteen countries providing data for both, and in the Mid-West and North East regions

of the United States. The one exception is the United Kingdom, whose nuclear investment costs for a 2000 commissioned plant are significantly higher than those for other OECD and non-OECD countries, with overall generation costs projected for nuclear close to break even with coal-fired plant using imported coal, although nuclear would be cheaper than plants using domestically produced coal at current prices. (See note on page 33 however.)

Coal-fired electricity is projected to be the cheaper option in the Western region of the United States, due to the significantly lower costs of coal fuel in those regions than in other areas in the USA. The same would be true in Western Canada where coal prices are projected to be even lower than those in the USA, and in the cheap coal areas of countries like China and India, although no data were provided for such plants.

At 5 per cent discount rate gas combined cycle plants are projected to provide dearer base load electricity than nuclear plants in eight of the nine countries providing data for both types, with the UK projecting gas to be the cheaper. Gas is projected to be dearer than coal-fired generation in seven countries, with the UK and Hungary projecting gas to be cheaper than coal and Belgium, Denmark, Finland, Portugal, Spain and Sweden projecting break-even between coal and gas (to within 5 per cent).

At a 10 per cent discount rate the position of gas-fired generation is markedly improved relative to both coal and nuclear plants, whilst coal plants also gain against nuclear. Gas-firing becomes cheaper than coal in six countries, with two projecting it to be dearer, and six showing break-even. It is also cheaper in most of the USA. Gas-based generation is cheaper than nuclear generation in five of the nine countries providing data for both, breaks even in one, and dearer in the remaining three. Coal-based generation is cheaper than nuclear generation in four countries, dearer in five and breaks even in three. The position is similarly balanced for the regions of the USA. In Korea the projected costs of generation in PHWR reactors remains cheaper than coal-based generation although their projected LWR costs break even.

The reason for the shift of advantage is the effect of the discount rate on the capital component of generation costs, which is highest for nuclear and lowest for gas-fired plant.

The results and conclusions may be compared with those of the most recent (1990) UNIPEDE study[15] in which plants for commissioning in 2000 were compared with a reference discount rate of 5 per cent, a load factor of 75 per cent and plant lives of 30 years for nuclear and coal-fired, and 25 years for gas combined cycle generation. Using the UNIPEDE common fuel price medium scenarios, all countries providing related data found nuclear generation to be cheaper than world traded coal and coal to be cheaper than gas. The same was true at 8 per cent discount rate, except in the case of the United Kingdom, which then found gas cheaper than nuclear power generation. Canada and the Netherlands supplied data for integrated gasified coal combustion plant, which was projected to be dearer than direct coal combustion (PFC), but cheaper than gas combined cycle generation. Data supplied by the Netherlands for this study (NE-C2) has confirmed this finding at both 5 per cent and 10 per cent discount rates (Tables 20, 21).

It should be noted that the UNIPEDE medium gas price scenarios have prices rather above those projected in this study at $5.0/GJ in 2000 rising to $6.4/GJ in 2020, whilst their coal prices start at $2.1/GJ in 2000 rising to $2.8/GJ in 2030, both in average October 1989 to March 1990 money values. This compares with the $3 to $5/GJ in year 2000 for gas and, typically, $1.9 to $2.1/GJ for coal in the same year, used by the utilities in this study. (OECD averages $3.7/GJ rising at 2.1 per cent p.a. and $2.08/GJ rising at 0.7 per cent p.a. respectively.)

The higher UNIPEDE figures were based on a consensus view of the future escalation of fossil fuel prices, but higher and lower prices were also included as variants. At the time of the UNIPEDE study rapid growth was foreseen for gas demand which influenced the price expectations.

Sensitivity to discount rate

From the foregoing discussion, it will be apparent that the attractiveness of the three main technical options for large base load power stations for commissioning around the year 2000 is critically dependent, in many countries, on the discount rate required by the utility or government. Higher discount rates favour the low investment cost option, gas, whilst lower discount rates favour the more capital intensive nuclear option. The discount rate considered appropriate will differ among countries and even within countries as their circumstances or the structure and regulation of their electricity supply industry changes.

Approximate break-even discount rates are presented in Table 27. They span a range from below 5 per cent to well above 10 per cent, depending on the fuels being compared and the circumstances of different countries.

Fuel prices

With few exceptions nuclear fuel costs remain a relatively small part of overall generation costs (10 per cent to 35 per cent at 5 per cent discount rate) for countries using LWRs (Tables 20, 21), and even smaller for PHWRs. There is no expectation of significant nuclear fuel price escalation and, even if uranium prices were to rise as some project, the effect on overall fuel costs and generation costs is small.

Some of the spread in nuclear fuel costs and the values lying outside the range arise from the use of indigenous fuel facilities and fuels at costs that deviate from the typical international values set out in the recent study on nuclear fuel cycle economics[4].

Coal fuel costs for countries using world traded coal are projected to be some 40-60 per cent of total generation costs at 5 per cent discount rate, with some countries projecting no increase in real terms to 2040, whilst others project a doubling relative to the price in year 2000. The average projected increase in OECD is 0.7 per cent p.a.

World traded coal prices delivered to European or Japanese power stations are generally projected to be around $2/GJ in 2000, with lower prices in cheap coal regions of the USA, Canada, China and India. This world price is consistent with the expectations of the Coal Industries Advisory Board (CIAB), as conveyed to the International Energy Agency for this study (Annex 8). They project on average a 1 per cent p.a. real price increase post 2000.

This consistency contrasts with a degree of divergence between predictions in the previous study[3]; adoption of CIAB coal price projections as a standardized basis would not alter the balance of the projected competitive position between fuels presented in this study, for countries where world traded coal is the basis of assessment.

Most countries have supplied generation cost data based on projected expectations for internationally traded coal prices, allowing for shipping costs, which are a significant element of total

costs. Where use of indigenous coal is planned this is shown in the tables. Countries with indigenous coal may have cheaper supplies (Western USA, Western Canada, North East India, North West China) or dearer (Spain, Germany, UK). Coal-fired generation costs are significantly higher in the latter countries if preference is given to domestic coal and its price does not fall to that prevailing in world markets. Coal prices are, of course, sensitive to coal quality and sulphur content and the fuel chosen will be influenced by national circumstances and environmental regulations. Exchange rates are also a significant factor. The US$ has been undervalued on a purchasing power parity basis relative to many other major OECD currencies over the past two years[31], and this can have a significant effect on the relationship between indigenous fuel prices and international fuels traded in dollar terms.

Gas fuel costs are an even larger share of total generation costs; considerably exceeding 60 per cent in most countries' projections. Projections for gas prices on international markets are more difficult. Whereas a large spot market exists for coal alongside the standard coal contracts, most gas is supplied on long term contracts with prices often indexed to a mix of fuels (oil, coal) and to general price indices. Price has been very dependent on the source, the scale of the demand and the contractual arrangements for possible interruption of supply.

Typical price estimates lie in the range $3 to $5/GJ in the year 2000 (OECD average $3.7/GJ) with projected increases to the year 2030 ranging from zero to over 200 per cent (OECD average 2.1 per cent p.a.). These figures can be compared with those of the International Energy Agency's analysis[12] where resource costs for gas supplies to Europe are projected to rise to around $2.5 to $4 per GJ by 2010, subject to demand. The actual prices at the burner tip could be somewhat higher and IEA scenarios[13] suggest that prices could rise to $3 to $6/GJ by the year 2000 in 1991 money terms, a figure that is not inconsistent with the utility views.

Gas, with a reserves/production ratio higher than that of oil, is not as plentiful as coal, and supplies are less widely distributed geographically than coal, with 70 per cent of world proven reserves in the former Soviet Union and Middle East countries, and only 10 per cent in OECD. At present around 50 per cent of world gas consumption occurs in OECD countries and independent forecasts project increases in global demand of some 40 per cent by 2010. World reserves/production (R/P) ratios for gas currently stand at 58.7 years, compared with 43.4 years for oil, 239 years for coal including lignite[32] and about 100 years for uranium based on reserves and production outside the former centrally planned economies[33]. The latter would rise by a factor of 50 to about 5 000 years, given the eventual deployment of fast breeder reactors. The R/P ratios for gas, which increased steadily from 1965 to 1983, have since flattened off[32]. (It should be noted that reserves are limited to currently known economically recoverable resources and that further quantities of all fuels will be added to reserves in the future as exploration and exploitation continue.)

Gas is expensive to transport if transmission by pipeline is impracticable, and liquefaction and sea transport is required. Its cleanliness and the simplicity and the low cost of gas-fired plant are major attractions for users within and outside the electricity supply industry, so that as indicated above, demand is widely projected to grow rapidly in the developed world. These factors combine to make price predictions more risky than those for the more abundant coal, and price fluctuations cannot be ruled out if new supplies fail to be developed at adequate rates or if supplies are disrupted by conflict or political actions.

Because gas fuel costs are such a major part of the generation cost, the attractiveness of gas-fired base load generation will be sensitive to any swings or trends in gas prices in the future.

Some independent projections of gas prices are summarised in Annex 9. It was noted earlier that UNIPEDE have used a range of fossil fuel price scenarios for their recent studies[15], with medium scenario prices somewhat higher than those employed by many respondents to this study. This serves to underline the greater degree of uncertainty that exists at the present time concerning the future evolution of gas prices compared with those of coal, at least in the judgements of participating utilities and agencies.

Operations and maintenance costs

Countries differ on whether the operations and maintenance costs of nuclear or coal-fired plants are the higher, although gas plant is clearly projected to have lower costs (Tables 14-16, 20, 21). In most cases the O&M costs of nuclear plants are comparable to the fuel costs (except for low fuel cost PHWRs), and therefore of similar importance in terms of contributions to overall costs.

Only in the United States is there a major deviation from this generalisation, and their O&M costs are three times their projected levelised nuclear fuel costs. This repeats the finding of the previous study in this series[3] for which no clear explanation was offered. Other countries having relatively high O&M costs also have above average fuel costs. The United States Annex (Annex 2) sets out in some detail the situation in that country.

Tables 11.2, 11.5 and 11.8 in Annex 11 show significant divergences among countries in the costs taken into account in operations and maintenance, and some also incorporate heavy water charges for PHWRs and back-end fuel cycle costs. More detailed analysis was beyond the scope of this study and further work is being considered by NEA to give a clearer understanding of the reasons behind the O&M cost variations for nuclear plant in particular.

Renewables

The amount of data obtained for renewable sources was disappointing. Wind turbines are in operation on an experimental basis in several countries and sizeable tranches are in place in the USA and Denmark. Most such developments to date have benefited from government incentives or subsidies, and unsubsidised costs are still projected by participants in this study to be above those for conventional large scale thermal base load generation. They have environmental attractions (and detriments) and can already fill an economic niche in situations where they can substitute for expensive small scale diesel powered generators (e.g. remote or island communities).

Wind generation costs may come down in the future but wind turbines are not currently seen in most countries as being a major contributor to base load plant for commissioning around 2000 or shortly thereafter.

On the basis of the limited data provided, small scale hydroplants, geothermal plants and waste and landfill gas incineration appear to be potentially competitive in suitable locations, subject to environmental constraints, but their overall contribution is limited in most countries by their small scale and the availability of the free fuel or power.

A growing contribution from these sources can be expected unless high rates of return are sought, which would affect their costs adversely due to their comparative capital intensity.

Trends in costs

A number of OECD countries have contributed to the series of four generation cost studies undertaken over the past decade. It is therefore interesting to look at cost trends over the period. This is best done on a country by country basis in constant national currency terms (see Annex 11 of reference 3). However, some of the technical assumptions have changed over time so that the basic data have to be standardized. For simplicity, this has been done by converting data taken from the earlier studies[1-3] to a common 75 per cent settled down load factor and 30 year plant life. Results are only tabulated for the 5 per cent discount rate case since the direction of the trends would be essentially the same at higher or lower rates.

Examination of the data in Table 29 and Figure 6 shows that, in general terms, overall projected nuclear costs have remained stable in national currency terms, with the exception of Finland whose cost projection estimates have declined considerably. For most countries nuclear fuel cost projections have decreased significantly, offsetting increases in capital and operations costs. Finland is an example of a country importing both plant and fuel where the cost trend arises mainly from changes in purchasing power parity. In US$ terms Finnish costs have been stable.

Table 30 shows the break-down of cost changes from 1983 to 1992 into the three main components, expressed as percentages of costs projected in the 1983 study[1]. Many OECD countries have shown increases in real terms in nuclear capital cost projections and all, except Japan, have shown decreases in projected nuclear fuel costs. A majority have projected increases in nuclear operations and maintenance costs. The net effect for all countries except Finland (see above) has been a relatively minor movement in the overall projected nuclear generation cost.

However, projected coal-fired generation costs have declined (Table 29), due almost entirely to the changed expectations concerning future coal prices (Table 30), which are no longer expected to escalate in the manner that was widely predicted during the 1970s and early 1980s. These reductions, although partly offset by increased investment costs where additional environmental protection measures have been adopted, have resulted in marked improvement in coal's projected attractiveness relative to nuclear power (Figure 6).

Data on gas combined cycle plant was not obtained prior to the 1989 study[3] and even then few countries responded. For this reason no analysis of trends is possible. However, projected generation costs using gas combined cycle plant have declined in those countries that did provide data to the 1989 study[3] and this one. This decrease also arises from a general reduction in projected fuel prices following the reassessment of gas resources that has taken place over the past few years.

A recent publication[34] has claimed that nuclear overnight investment costs (and overall costs) have persistently risen and, during the 1970s, this was undoubtedly true. The data contained in the "analysis" do not however provide evidence that this trend continued into the 1980s. Indeed the more detailed data presented by its author suggest that investment costs had, if anything, levelled off. The data which, despite the authors' criticisms of such sources, are largely based on official figures, are not inconsistent with the findings of this study, namely that overall projected nuclear costs appear to have stabilized during the 1980s with any capital cost and O&M cost increases largely offset by reduction in nuclear fuel costs.

The future

From a global perspective the direct economic costs projected for the early 21st century for the three base load electricity generation technologies on which this study has focused, coal-fired, nuclear and gas combined cycle, have costs that are sufficiently close in most countries for their ranking to be very sensitive to required discount rate or rate of return on investment and to fossil fuel prices. Straightforward economic choices would therefore be expected to differ from country to country, even in the absence of specific policy choices, depending on their economic circumstances, on their expectations concerning medium term access to cheap fossil fuels and even on the regulatory framework adopted for their electricity supply industry.

Future costs will be influenced by several factors which are discussed below:

a) Environmental concerns

One major unknown at the present time is how attitudes to environmental protection will evolve. Nuclear power is already heavily regulated with permitted emission levels in OECD countries set to ensure negligible risks to the workforce and public, and design criteria that call for the risks and consequences of accidents to be reduced to levels that are in economic terms very small compared with direct generation costs[22]. A recent study undertaken by the NEA[22] indicates that nuclear environmental costs are effectively internalised and reflected in generation costs. The study also suggests that the external costs associated with residual low level emissions and accident risks are small relative to the overall costs of electricity production[22].

This is not true for many existing coal-fired stations, which emit environmentally damaging gases; sulphur dioxide and nitrogen oxides which have health effects and contribute to corrosive and ecologically harmful acid rain; and the greenhouse gases, carbon dioxide and nitrous oxide, which could contribute to global climate change. However, most of the coal-fired plants for which costs are included in this study incorporate effective technologies for reducing gaseous sulphur and nitrogen oxide emissions to levels at which any residual environmental damage is small in relation to the direct generation costs, so that their costs are largely internalised[22].

The big uncertainty surrounds the effects of greenhouse gas emissions, which are an unavoidable product of combustion of all fossil fuels, albeit higher per GJ of delivered energy from coal than from oil or gas[35].

Nuclear power and most renewable sources contribute little or nothing to atmospheric carbon dioxide or sulphur and nitrogen oxide levels. Apart from waste incineration technologies, which may have overall beneficial effects compared with biodegradation, the only emissions are those associated with the use of fossil fuels in material extraction, fabrication and transport.

There is at present no clear way of evaluating the costs of greenhouse gas effects and estimates of control or amelioration costs are also very tentative (see Annex 10). The likelihood is that decisions on greenhouse gas control will be made on the basis of scientific and political judgement rather than via economic assessment and welfare optimisation[22].

If such judgements are taken they may be implemented through direct regulation on emissions, through the introduction of tradeable emission permits, or through the introduction of fiscal measures such as a tax on the carbon content of fuels (Annex 10). Any such measures would influence the effective costs of electricity production from carbonaceous fuels. For example, IEA has estimated[14]

that a carbon tax of $130/tonne of emitted carbon would treble the price of internationally traded coal by adding $90/tonne, add $16 per barrel to oil prices and $2/GJ to natural gas. Even this was considered likely to no more than reduce growth in OECD carbon dioxide emissions from 22 per cent to 7 per cent between 1990 and 2005 (Annex 10), and as such would not reach the goal of stabilization that many countries have considered desirable (Table 10.2, Annex 10). Such a tax would add about 30 mills/kWh to coal-fired electricity prices and 20 mills/kWh to gas combined cycle electricity.

In practice the costs of nuclear and renewable energy based electricity would also be affected through the effects of any restraining measures on the costs of fossil fuels used in materials extraction, transport and construction. However, these effects are small compared with the direct consequences for fossil fuel fired generation.

A number of OECD Member country governments (Annex 10, Table 10.3) already have taxes on fossil fuels; some of them as large as the $130/tonne carbon used illustratively by IEA. At the present time it is far from clear what actions governments will eventually take, if any, or to what extent they will favour overall energy conservation and improved efficiency routes (such as combined heat and power plants) to attain their environmental goals. It has to be noted, however, that decisions which do impose differential costs on the generation options could materially alter their relative economic attractiveness to the generators. The $130/tonne carbon emissions tax would, for example, add some 50 per cent to 100 per cent to coal-fired generation costs if it were to be adopted, and 25 per cent to 50 per cent to gas combined cycle generation, based on the costs in Tables 20 and 21.

The imposition of taxes on fossil fuels should decrease demand and would therefore be expected to reduce basic fuel prices so that the full effect of the tax might be less than anticipated.

Nuclear power costs could be increased by any further tightening of emission and safety regulations or, relative to renewable sources, by any energy tax aimed at reducing the use of finite resources, although, logically, such a tax should also be applied to renewable sources to allow for the relatively large quantities of materials required for their construction. Environmentally, contrary to some perceptions, the use of electricity can have significant benefits compared with the direct use of fossil fuels, in a number of applications[36, 37, 38].

b) Fuel security

Concern about the future availability and price of fuels has influenced generation technology development and investment choices in many countries in the past. There is still concern about the security of world oil and gas supplies in many quarters because of the concentration of known reserves in relatively few regions of the world. This is not reflected in the standard economic comparisons and it is difficult if not impossible to set a meaningful value to the benefit of energy supply diversity[22].

Provided hydrocarbon fuels supplies are not subject to artificial constraints and demand growth does not greatly exceed expectations, the proven reserves are more than adequate to meet the lifetime requirements of plants constructed for commissioning in 2000. The position for coal and uranium is even better, so that the concept of employing depletion premia for fuels in generation cost calculations will have no role for a long time to come.

c) Technological development

The costs of gas-fired power generation have been significantly reduced by the development in recent years of combined cycle technology with its high thermal efficiency and low investment costs.

Further improvements in thermal efficiency are predicted which will help to maintain or even reduce costs in the future as gas prices rise. Smaller improvements are in progress using advanced coal burning technologies although only fluidised bed (atmospheric and pressurised) are expected by most countries to be commercially deployable around the turn of the century. Further development of integrated coal gasification combined cycle and other coal-based technologies (Annex 3) may improve energy efficiency, but as yet there is no reason to suppose that these environmentally better processes will provide significantly cheaper electricity than the plants currently available. Indeed figures published by UNIPEDE[15] and repeated here by the Netherlands suggest that IGCC provides dearer electricity than conventional coal combustion.

Nuclear development is still concentrated on large scale plant with efforts to reduce the dominant specific investment costs both by design improvements and improved planning and management of construction. Lesser gains are being sought from improved fuel cycles including higher burnup. Some countries currently favour alternative design concepts, such as smaller plants with greater reliance on passive safety features, whilst others have been pressing ahead with the design and development of commercial fast reactors for deployment in the 21st century. There is, as yet, no reason to suppose that these new technologies will provide electricity at prices significantly below those of commercial designs that are currently available[25].

The considerable spread of investment and O&M costs for nuclear and fossil-fuelled plants suggests that many countries have scope for reducing them. Investment costs are particularly significant for nuclear plants, and there is reason to believe that there is room for nuclear generation cost reductions in a number of countries which have so far failed to reap the benefits of replication, coherent construction programmes and systematic collocation of plants, which have marked the more successful nuclear investment programmes[26].

Renewable and waste powered electricity generation are resource constrained (Annex 6) and, apart from large scale hydropower, are likely to make only modest contributions to overall base load generation in the foreseeable future. Those that prove economic and environmentally acceptable will be adopted but there is as yet no sign that any radical or major breakthrough, resulting from technological development, is in the offing (Annex 6).

No data on fuel cells have been provided for this study, although they are being vigorously developed in several countries. At current costs they are uncompetitive but a recent consultant's study has suggested that with further development they could come into the same cost range as existing technologies early next century[39].

Improved techniques for fuel exploration and technologies for fuel extraction and processing will help to stabilize prices and counteract the effects of fuel depletion and environmental regulations.

Overall there appears to be no immediate prospect of any major cost reductions in electricity supply, other than those arising from more efficient planning and construction programmes, where such improvements are possible.

Conclusions

The projected costs of fossil-fired electricity generation in constant money terms have declined over the past ten years, as a result of significantly lower fossil fuel prices, and a widespread expectation that such prices will be maintained with, at worst modest escalation in the near term. The projected costs of nuclear generation, on the other hand, have remained relatively stable over the same period, and this has moderated the optimism over the near term economic attractiveness of nuclear power which prevailed in the early 1980s.

Despite this, seven of the eleven countries providing relevant data, using their own assessment criteria, still project nuclear power to be the cheapest source of base load power from plants for commissioning around the turn of the century. (Eleven other participants provided no nuclear data on the basis of their own criteria). The comparison is sensitive, however, in the majority of countries, to investment costs and plant performance, to the discount rates adopted, to fossil fuel price expectations, and, possibly, to policy decisions concerning environmental standards and regulation.

Thus, at a 5 per cent p.a. real discount rate nuclear power is projected to be the cheapest option for which data were provided in thirteen of the fifteen countries supplying nuclear cost data for the study. Exceptions were regions with direct access to cheap coal (e.g. Western USA and Western Canada) or gas (United Kingdom), and the Netherlands where nuclear and coal generation cost projections are similar. At a 10 per cent discount rate only five of the participating countries would project nuclear power to have a clear economic advantage over coal and five countries would project gas combined cycle plants to be their preferred option over nuclear, with three more non-nuclear participants preferring gas to coal. This sensitivity to discount rates arises directly from their effects on investment costs, which are highest for nuclear (and renewable) sources and lowest for gas-fired generation.

The appearance of gas as a serious base load contender is a new phenomenon, arising partly from the development of combined cycle technology and partly from changed attitudes to gas use for electricity production.

Whilst there is no reason to anticipate significant escalation in coal or nuclear fuel prices during the early part of the next century, both being relatively abundant and widely distributed geographically, there is greater uncertainty about long term gas prices and availability, and about the effects of environmental policies on the costs of fossil-fuelled generation in particular. Current environmental concern over acid gas and greenhouse gas emissions from fossil fuel burning favour use of gas over coal and favour nuclear power and renewables to an even greater extent, although how much influence this will have on investment choice in the future is a matter of speculation.

There is no indication of any imminent technical breakthrough that will materially reduce electricity generation costs from fossil, nuclear or renewable sources, although there is scope for improvement on current economic and technical performance in many countries, particularly in the case of nuclear power. Overall generation costs from future new plants should remain broadly stable unless there are regulatory or fiscal changes that lead to increases.

Under the circumstances countries and utilities will have different views on their preferred options based on their assessments, economic conditions, and their expectations concerning the evolution of the regulatory and fiscal framework and fuel prices.

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Table 1 **List of responses**

Country	Nuclear abbreviation	Coal abbreviation	Gas abbreviation	Others energy	Others abbreviation
Belgium	BE-N	BE-C	BE-G	-	-
Canada (a)	CA1-N - - CA4-N *	CA1-C CA2-C CA3-C * CA4-C	CA1-G CA2-G - -	-	-
Denmark (b)	-	DE-C	DE-G1 DE-G2	Wind	DE-W
Finland	FI-N	FI-C	FI-G	-	-
France	FR-N	FR-C	FR-G	-	-
Germany (c)	GE-N	GE-C1 GE-C2	-	-	-
Italy	-	IT-C	IT-G	-	-
Japan	JP-N	JP-C	JP-G	-	-
Netherlands (d)	NL-N *	NL-C1 NL-C2 *	NL-G	-	-
Portugal (e)	-	PT-C	PT-G1 PT-G2	-	-
Spain (f)	-	SP-C1 SP-C2	SP-G	-	-
Sweden	-	SW-C	SW-G	-	-
Switzerland	-	-	-	SSH (g)	SL-S
Turkey	-	TK-C	-	-	-
United Kingdom (h)	UK-N1 UK-N2 *	UK-C1 UK-C2 UK-C3 *	UK-G	MWI (i) LFG (j) Wind SSH (g)	UK-M UK-L UK-W UK-S
United States (k)	US1-N US2-N US3-N	US1-C US2-C US3-C	US1-G US2-G US3-G	-	-
China	CH-N	CH-C	-	-	-
CSFR (l)	CS-N	CS-C	CS-G	-	-
Hungary (m)	HN-N	HN-C1 HN-C2	HN-G	-	-
India	IN-N	IN-C	-	-	-
Korea (n)	KR-N1 KR-N2	KR-C	-	-	-
Russia	RF-N	RF-C	-	-	-

(a) CA1 : Centre. CA2 : West. CA3, CA4 : East.
(b) DE-G1 : Combined cycle gas turbine plant (CCGT). DE-G2 : Gas conventional plant.
(c) GE-C1 : Domestic coal. GE-C2 : Imported coal.
(d) NL-C1 : Pulverised coal combustion. NL-C2 : Integrated gasification combined cycle (IGCC).
(e) PT-G1 : Reference fuel price projection. PT- G2 : Low case of fuel price projection.
(f) SP-C1 : Domestic coal. SP-C2 : Imported coal.
(g) Small Scale Hydro.
(h) UK-N1 : PWR. UK-N2 : Advanced PWR (APWR). UK-C1 : Pulverised coal combustion.
UK-C2 : Coal-fired Atmospheric Circulating Fluidised Bed Combustion. UK-C3 : Coal-fired Pressurised Fluidised Bed Combustion.
(i) Municipal Waste Incineration.
(j) Land Fill Gas.
(k) US1 : Midwest. US2 : Northeast. US3 : West.
(l) Czeck and Slovak Federal Republic.
(m) HN-C1 : Pulverised lignite combustion. HN-C2 : Pulverised coal combustion.
(n) KR-N1 : PWR. KR-N2 : PHWR.
* Category-B.

Table 2 **Nuclear plant specifications**

Country	Abbreviation of estimate	Reference plant(s)				Reference site		Estimate	
		Reactor type	Number of units x MWe (net)	Thermal efficiency (%)	Cooling tower	New/ existing	Number of planned units	Date of estimate	Data based on (a)
Belgium	BE-N	PWR	1 x 1390	NS	Yes	NS	1	91	P
Canada	CA1-N	PHWR	4 x 881	31.8	No	exist	4	91	P
Finland	FI-N	BWR	1 x 1000	35	No	exist	3	91	P
France	FR-N	PWR	4 x 1400	34	No (b)	exist (c)	4	91	Q + O
Germany	GE-N	PWR	1 x 1258	33	Yes	new	1	92	P + O
Japan	JP-N	LWR	4 x 1350 (d)	34	No	new	4	92	P
United Kingdom	UK-N1	PWR	1 x 1245~1400	34.5	No	exist	1	92	P
United States	US1-N US2-N US3-N	ELWR (e)	1 x 1200	33.5	Yes	new	1	91	P
China	CH-N	PWR	2 x 600	33.3	No	new	4	92	P
CSFR	CS-N	PWR	1 x 1081	34.4	Yes	new	1	92	P
Hungary	HN-N	PWR	2 x 1002	34	No	exist	2	91	P
India	IN-N	PHWR	2 x 193.6	30	Yes	new	2	91	B + D
Korea	KR-N1	PWR	2 x 940	32.2	No	exist	2	91	Q
	KR-N2	PHWR	2 x 658	29.3	No	exist	2	91	Q
Russia	RF-N	VVER	4 x 1000	31.7	No	exist	4	91	P
(Category B)									
Canada	CA4-N	CANDU-3	1 x 450	31.2	No	exist	2	92	P
Netherlands	NL-N	SBWR (f)	1 x 600	33.3	No	exist	1	92	P
United Kingdom	UK-N2 (g)	APWR (h)	1 x 1400	35	No	new	1	92	P

(a) Abbreviations : P = paper analysis Q = quotation O = ordered plant B = available bids D = cost data base NS : Not specified
(b) Mean of seaside plant and riverside plant with cooling tower.
(c) Average of existing plants.
(d) Gross capacity.
(e) Evolutionary Light-Water Reactor.
(f) Simplified BWR.
(g) Lifetime 40 years. Load Factor 75%.
(h) Advanced PWR.

Table 3 **Coal plant specifications**

Country	Abbreviation of estimate	Reference plant(s)				Reference site		Estimate	
		Plant type / Emission control equipment (a)	Number of units x MWe (net)	Thermal efficiency (%) (H/L) (b)	Cooling tower	New/ existing	Number of planned units	Date of estimate	Data based on (c)
Belgium	BE-C	PCC(SB) / ESP, FGD, LNB, SCR	1 x 750	38.6 (L)	Yes	new	1	92	P
Canada	CA1-C	PCC(SB) / WLS, SCR	4 x 749	36.5 (H)	No	exist	4	91	P
	CA2-C	PCC(SB) / FGD, SCR	2 x 370	34.3 (H)	No	new	2	91	P
	CA4-C	PCC(SB) / ESP, FGD, SCR	4 x 440	36 (H)	No	exist	4	92	P
Denmark	DE-C	PCC(SP) / ESP, FGD, $deNO_x$	1 x 385	47 (L)	No	exist	1	92	P
Finland	FI-C	PCC(SP) / ESP, WLS, SCR	2 x 500	41 (L)	No	exist	2	91	P + O
France	FR-C	AFBC / ESP	2 x 560	36 (H)	No	new	2	89	Q
Germany	GE-C1&C2	PCC(NS) / ESP, FGD, LNB, SCR	1 x 700	38 (L)	Yes	new	1	92	P + Q
Italy	IT-C	PCC(SP) / ESP, FGD, LNB, SCR	4 x 610	39 (L)	No	new	4	92	O
Japan	JP-C	PCC(SP) / FGD, $deNO_x$	4 x 700 (d)	39 (H)	No	new	4	92	P
Netherlands	NL-C1	PCC(SP) / ESP, FGD, SCR	2 x 600	41 (L)	No	exist	2	92	O
Portugal	PT-C	PCC(SB) / ESP, FGD, LNB	4 x 276	37.8 (L)	Yes	new	4	92	P
Spain	SP-C1	PCC(NS) / ESP, FGD, LNB	2 x 315	35.6 (NS)	Yes	exist	2	92	E
	SP-C2	PCC(NS) / ESP, FGD, LNB	1 x 500	35.6 (NS)	No	exist	1	92	E
Sweden	SW-C	PCC(NS) / ESP, SCR	1 x 600	42 (NS)	No	new	1	90	P
Turkey	TK-C	NS / WLS, $deNO_x$	2 x 461.5	39.5 (H)	No	new	2	92	Q
United Kingdom	UK-C1	PCC(NS) / FGD, ESP	1 x 200	38.8 (H)	NS	new	1	91	P
	UK-C2	AFBC / ESP	1 x 200	39.6 (H)	NS	new	1	91	P
United States	US1-C	PCC(SB) / FGD, ESP	2 x 600	35.4 (H)	Yes	new	2	88	P
	US2-C	PCC(SB) / FGD, ESP	2 x 600	35.4 (H)	Yes	new	2	88	P
	US3-C	PCC(SB) / FGD, ESP	2 x 600	35.4 (L)	Yes	new	2	88	P
China	CH-C	PCC(SB) / FGD	2 x 600	36.1 (H)	No	new	4	92	P
CSFR	CS-C	PCC(SB) / ESP, FGD	1 x 524	34.9 (L)	Yes	exist	1	92	P
Hungary	HN-C1 (e)	PLC(SB) / $deSO_x$, LNB	3 x 400	35 (L)	Yes	new	3	91	P
	HN-C2	PCC(SP) / $deSO_x$, LNB	3 x 500	42 (L)	No	new	3	90	P
India	IN-C	PCC(SB) / ESP	4 x 190	35 (L)	Yes	new	4	91	B + D
Korea	KR-C	PCC(SP) / ESP, FGD, LNB	2 x 455	33.0 (H)	No	exist	2	91	Q
Russia	RF-C	AFBC / FGD	8 x 317	35.0 (NS)	No	new	8	90	P
(Category-B)									
Canada	CA3-C	CFBC / FGD, $deNO_x$	1 x 165	33 (H)	No	exist	3	92	P
Netherlands	NL-C2	IGCC / (f)	1 x 600	46 (NS)	NS	NS	2	92	P
United Kingdom	UK-C3	PFBC / WLS	1 x 200	41.4 (H)	NS	new	1	91	P

(a) AFBC : atmospheric fluidised bed combustion (circulating bed) PFBC : pressurised fluidised bed combustion
PCC : pulverised coal combustion PLC : pulverised lignite combustion IGCC : integrated gasification combined cycle
ESP : electro-static precipitator FGD : flue gas desulphurisation system LNB : low NO_x burner
SCR : selective catalytic reduction SB : sub-critical SP : super-critical WLS : wet limestone process
(b) H : higher heating value L : lower heating value
(c) Abbreviations: P = paper analysis Q = quotation O = ordered plant B = available bids D = cost data base E = recent experience
(d) Gross capacity.
(e) 65% of load factor and 30 years of lifetime are assumed.
(f) Gas is cleaned behind the gasifier.
NS : Not specified.

Table 4 **Plant specifications (Gas-fired and others)**

Country	Abbreviation of estimate	Reference plant(s)					Reference site		Estimate			
		Technology (a)	Number of units x MWe (net)	Thermal efficiency (%) (H/L) (b)	Number of turbine per unit (c)	Cooling tower	New/ existing	Number of planned units	Date of estimate	Data based on (d)	Plant lifetime (year)	Settled-down load factor (%)
(Gas)												
Belgium	BE-G	CCGT	1 x 460	51 (L)	2GT+1ST	Yes	new	1	92	P+O	20	75
Canada	CA1-G	CCGT	2 x 731	44 (NS)	3	No	exist	2	91	P	30	75
	CA2-G	CCGT	1 x 100	~40 (NS)	2	Yes	new	1	91	P	35	76
Denmark	DE-G1	CCGT	1 x 337	54 (L)	2	No	exist	1	90	P	30	75
	DE-G2	GCP	1 x 396	49 (L)	1	No	exist	1	92	P	30	75
Finland	FI-G	CCGT	1 x 180	49.5 (L)	2GT+1ST	No	new	1	91	P	25	80
France	FR-G	CCGT	2 x 600	45 (NS)	2	No	new	2	90	P + Q	20	83
Italy	IT-G	CCGT	1 x 345	46 (L)	2GT+1ST	Yes	new	1	92	O	30	75
Japan	JP-G	CCGT	4 x 700 (e)	47 (NS)	2	No	new	4	92	P	30	75
Netherlands	NL-G	CCGT	2 x 250	53 (L)	2	No	exist	2	92	O	25	75
Portugal	PT-G1&G2	CCGT	2 x 441	48.0 (NS)	2GT+1ST	No	new	2	92	P	25	85
Spain	SP-G	CCGT	1 x 300	47.4 (NS)	2	Yes	new	1	92	P	20	75
Sweden	SW-G	CCGT	1 x 600	51 (NS)	2	No	new	1	90	P	25	75
United Kingdom	UK-G	CCGT	1 x 1000	~50 (NS)	NS	NS	new	NS	90	P	30	90
United States	US1-G) US2-G) US3-G)	CCGT	2 x 600	46.8 (NS)	2	Yes	new	2	89	P	30	75
CSFR	CS-G	CCGT	1 x 288	47.0 (L)	3	Yes	new	1	92	P	25	75
Hungary	HN-G	CCGT	1 x 230	54 (L)	2	No	exist	1	89	P	20	85
(Others)												
Denmark	DE-W	Wind	20 x 0.5	-	-	-	new	20	91	P	20	25
Switzerland	SL-S	SSH	5 x 18.6	-	2	-	new	5	92	P	80	54
United Kingdom	UK-W	Wind	1 x 0.4	-	1	-	new	10	NS	Q	15	27
	UK-L	LFG	1 x 1	NS	1	No	new	1	91	D	15	95
	UK-M	MWI	1 x 29	20	NS	No	new	1	91	O	20	80
	UK-S	SSH	1 x 5	-	-	-	new	1	91	P	20	60

(a) CCGT : combined cycle gas turbine plant GCP : natural gas conventional plant LFG : land-fill gas MWI : municipal waste incineration SSH : small scale hydro
(b) H : higher heating value L : lower heating value
(c) ST : steam turbine GT : gas turbine
(d) Abbreviations : P = paper analysis Q = quotation D = demonstration data O = ordered plant
(e) Gross capacity.

NS : Not specified.

Table 5 **Economic parameters used in national calculations**

Country	Nuclear			Coal			Gas			Others			Discount rate (% p.a.)	
	Correspond-ing estimate	Plant lifetime (year)	Load factor (%)	Correspond-ing estimate	Plant lifetime (year)	Load factor (%)	Correspond-ing estimate	Plant lifetime (year)	Load factor (%)	Correspond-ing estimate	Plant lifetime (year)	Load factor (%)		
Belgium	BE-N	20	75	BE-C	20	75	BE-G	20	75	-	-	-	8.6	In accordance with national equipment plan.
Canada	CA1-N CA4-N	40 30	80 75	CA1-C CA2-C CA3-C CA4-C	40 35 30 30	80 82 80 75	CA1-G CA2-G	30 35	40 82	-	-	-	4.75 - 6	Based on utility recommendations (which are based on market rates).
Denmark	-	-	-	DE-C	30	75	DE-G1,G2	30	75	DE-W	20	25	5 - 7	Utilities use 5-6%, government uses 7%.
Finland	FI-N	25	80	FI-C	25	80	FI-G	25	80	-	-	-	5	Based on prime rates.
France	FR-N	25	75	FR-C	30	79	FR-G	20	83	-	-	-	8	Government advice.
Germany	GE-N	30	75	GE-C1&C2	30	75	-	-	-	-	-	-	5	Based on market rates.
Italy	-	-	-	IT-C	25	68.5	IT-G	25	68.5	-	-	-	5	Based on market rates.
Japan	JP-N	16	70	JP-C	15	70	JP-G	15	70	-	-	-	5	Based on market rates.
Netherlands	NL-N	30	75	NL-C1	30	75	NL-G	25	75 a)	-	-	-	5	Used by utilities (based on market rates).
Portugal	-	-	-	PT-C	30	80	PT-G1	25	85	-	-	-	10	In accordance with National Energy Plan.
Spain	-	-	-	SP-C1&C2	30	75	SP-G	20	77	-	-	-	5 - 10	The higher or lower rates are used by utilities or government depending on the type of study.
Sweden	-	-	-	SW-C	25	75	SW-G	25	75	-	-	-	7	The largest utility uses 7%. Discount rates between 5 and 10% are generally used for public comparisons of electricity generation costs.
Switzerland	-	-	-	-	-	-	-	-	-	SL-S	40 - 80	54	7	Based on market rates. Rates differ between companies.
Turkey	-	-	-	TK-C	30	68.5	-	-	-	-	-	-	10	Government advice.
UK	UK-N1&N2	40	75	UK-C1,C2, & C3	-	-	UK-G	-	-	UK-M UK-L UK-S UK-W	- - - -	- - - -	-	There is no common rate applicable in the UK because of competitive supply industries. For instance, 8% p.a. is used by the nuclear industry but higher rates are employed by private generating sectors. A rate of 2% p.a. is used for nuclear back-end and decommissioning provisions.
US	US1-N	30	70	US1-C	30	70	US1-G	30	70	-	-	-	7	Based on cost of capital and capital structure of investor owned utilities and public utilities.
China	CH-N	30	65	CH-C	30	65	-	-	-	-	-	-	8, 10	8% for nuclear and 10% for coal is advised by the China National Nuclear Corporation.
CSFR	CS-N	30	75	CS-C	30	51 b)	CS-G	25	40	-	-	-	9, 10	Utilities use 10%, government uses 9%.
Hungary	HN-N	30	75	HN-C1 HN-C2	30 30	65 75	HN-G	20	85	-	-	-	12	Based on tradition over 30 years.
India	IN-N	25	62.8	IN-C	25	62.8	-	-	-	-	-	-	10	
Korea	KR-N1&N2	30	75	KR-C	30	75	-	-	-	-	-	-	8	Government advice.
Russia	RF-N	30 - 40	75	RF-C	40	75	-	20	80	-	-	-	10, 15	10% is used for nuclear and coal, and 15% for gas.

(a) Load factor is dependable of the local situation. High load factors (75%) for plants with industrial heat production and low load factor for plants with no heat production.
(b) The reasons for lower load factor are: (1) poor quality of domestic coal; (2) operational mode (fossil-fired plants are often CHP plants).

Table 6 **Basic assumptions applied to cost calculations**

1. Common assumptions to all generating options

- Base date of currency value	1st July 1991
- Discount rate in constant money	Reference 5% and 10% p.a.
- Date of commercial commissioning	1st July 2000 (approximate)

2. Assumptions applied only to nuclear and coal-fired power stations (a)

- Operating lifetime	Reference	30 years
	Variants	25 and 40 years
- Settled-down load factor	Reference	75%
	Variants	65 and 80%

- Operating time of units in full power operating hours

(hours/year)

Settled-down load factor (%)	65	75	80
1st year of operation	5000	5000	5000
2nd year of operation	5700	6000	6000
3rd and subsequent years of operation	5700	6600	7000

3. Discounted levelised load factor and discounted amount of operating time at the date of commercial commissioning (for reference cases)

At a discount rate of 5% p.a.

- Years	15.75	year
- Total operating hours	101 845	hr
- Operating hours per year	6 466	hour/year
- Levelised load factor	73.8	%

At a discount rate of 10% p.a.

- Years	9.89	year
- Total operating hours	63 209	hr
- Operating hours per year	6 391	hour/year
- Levelised load factor	73.0	%

(a) Operating lifetimes and load factors for other power plants than these were determined by each respondent.

Table 7 **Exchange rates**

Country	National Currency Unit (NCU)		NCU per USD at 1st July 1991
Belgium	Franc	(BEF)	37.28
Canada	Dollar	(CAD)	1.14
Denmark	Krone	(DKK)	6.98
Finland	Markka	(FIM)	4.28
France	Franc	(FRF)	6.13
Germany	Mark	(DEM)	1.81
Italy	Lira	(ITL)	1343.15
Japan	Yen	(JPY)	137.84
Netherlands	Gulden	(NLG)	2.041
Portugal	Escudo	(PTE)	157.25
Spain	Peseta	(ESP)	113.50
Sweden	Krona	(SEK)	6.49
Switzerland	Franc	(SFR)	1.55
Turkey	Lira	(TRL)	4330
United Kingdom	Pound	(GBP)	0.62
United States	Dollar	(USD)	1.00
---	ECU		0.88
China	Yuan	(CHY)	5.35 (a)
CSFR	Koruna	(CSK)	31.03 (b)
Hungary	Forints	(HUF)	76.97 (b)
India	Rupee	(INR)	23.11 (c)
Korea	Won	(KRW)	725.9
Russia	Rouble	(RFR)	- (d)

(a) Official exchange rate.
(b) Commercial exchange rate. The rate of 30th June 1991.
(c) The exchange rate, slightly devaluated, of 26.0 INR/USD was adopted for the purpose of the analysis.
(d) Russian data not converted to US dollars because of rapid exchange rate changes. See text.

Table 8 **Breakdown of investment costs (Nuclear)**
(Discounted to the date of commissioning)

(USD of 1.7.1991/kWe)

Country	Abbreviation of estimate	Reactor type	5% Discount rate						10% Discount rate					
			Base construction costs	Contingency	Interest	Decommis-sioning costs	Others	Total	Base construction costs	Contingency	Interest	Decommis-sioning costs	Others	Total
Belgium	BE-N	PWR	1746	0	278	29	0	2053	1746	0	609	5	0	2360
Canada	CA1-N	PHWR	1783	0 (a)	370	14	230	2397	1783	0 (a)	854	1	192	2830
Finland	FI-N	BWR	1509	116	268	30	0	1922	1509	116	576	6	0	2206
France	FR-N	PWR	1179	52	174	29	41	1475	1179	52	378	5	44	1658
Germany	GE-N	PWR	2400	0 (b)	415	0 (c)	201	3016	2400	0 (b)	795	0 (c)	222	3417
Japan	JP-N	LWR	2154	0	296	34	0	2483	2154	0	779	6	0	2938
United Kingdom	UK-N1	PWR	2512-2871	0 (d)	452-532	49	-	3010-3450	2512-2871	0 (d)	1000-1177	31	-	3540-4080
United States	US1-N	ELWR (e)	1237	247	306	80 (f)	274	2145	1237	247	665	50 (f)	181	2380
	US2-N	ELWR (e)	1307	261	323	80 (f)	274	2246	1307	261	702	50 (f)	181	2501
	US3-N	ELWR (e)	1200	240	298	80 (f)	274	2093	1200	240	650	50 (f)	181	2321
China	CH-N	PWR	1074	119	298	35	0	1526	1074	119	665	11	0	1869
CSFR	CS-N	PWR	960	0	236	42	0	1238	960	0	530	10	0	1500
Hungary	HN-N	PWR	1576	0	279	62	0	1918	1576	0	610	11	0	2198
India	IN-N	PHWR	1249	63	331	12	0	1654	1249	63	746	2	0	2059
Korea	KR-N1	PWR	1495	137	340	0 (c)	0	1972	1495	137	746	0 (c)	0	2378
	KR-N2	PHWR	1424	120	159	0 (c)	0	1703	1424	120	334	0 (c)	0	1879
Russia (g)	RF-N	VVER	(520)	(65)	(60)	(50)	(0)	(695)	(520)	(65)	(155)	(20)	(0)	(760)
(Category-B)														
Canada	CA4-N	CANDU-3	2409	0	372	0	0	2782	2409	0	801	0	0	3211
Netherlands	NL-N	SBWR (h)	1911	0 (b)	254	65	0	2231	1911	0 (b)	533	15	0	2459

(a) Included in "Base construction costs". Contingency is 15% of original base construction cost.
(b) Included in "Base construction costs".
(c) Included in O&M costs.
(d) Included in "Base construction costs". Contingency is 18% of original base construction cost.
(e) Evolutionary Light-Water Reactor.
(f) Decommissioning costs are included as an annual investment and are assumed invested with 2.5% real return so that value at the end of operating life equals decommissioning cost.
(g) Roubles of 1989/kWe.
(h) Simplified BWR.

Table 9 **Breakdown of investment costs (Coal)**
(Discounted to the date of commissioning)

(USD of 1.7.1991/kWe)

Country	Abbreviation of estimate	Plant type/ Emission control equipment (a)	5% Discount rate					10% Discount rate				
			Base construction costs	Contingency	Interest	Others	Total	Base construction costs	Contingency	Interest	Others	Total
Belgium	BE-C	PCC(SB) / ESP, FGD, LNB, SCR	1252	0	90	0	1342	1252	0	187	0	1439
Canada	CA1-C	PCC(SB) / WLS, SCR	1167	0 (b)	110	243	1520	1167	0 (b)	239	149	1555
	CA2-C	PCC(SB) / FGD, SCR	996	0 (c)	106	0	1101	996	0 (c)	222	0	1218
	CA4-C	PCC(SB) / ESP, FGD, SCR	1318	0 (d)	121	0	1440	1318	0 (d)	253	0	1572
Denmark	DE-C	PCC(SP) / ESP, FGD, deNO_x	1005	0	104	0	1109	1005	0	218	0	1223
Finland	FI-C	PCC(SP) / ESP, WLS, SCR	816	82	93	0	990	816	82	197	0	1093
France	FR-C	AFBC / ESP	1025	48	105	20	1197	1025	48	219	20	1313
Germany	GE-C1&C2	PCC(NS) / ESP, FGD, LNB, SCR	1495	0 (d)	127	63	1685	1495	0 (d)	259	62	1815
Italy	IT-C	PCC(SP) / ESP, FGD, LNB, SCR	1739	0 (d)	212	0	1951	1739	0 (d)	451	0	2190
Japan	JP-C	PCC(SP) / FGD, deNO_x	1932	0	165	0	2097	1932	0	480	0	2412
Netherlands	NL-C1	PCC(SP) / ESP, FGD, SCR	1072	0 (d)	120	5	1197	1072	0 (d)	254	3	1329
Portugal	PT-C	PCC(SB) / ESP, FGD, LNB	1454	67	181	45	1747	1454	67	390	45	1956
Spain	SP-C1	PCC(NS) / ESP, FGD, LNB	1752	0 (d)	253	245	2250	1752	0 (d)	532	245	2529
	SP-C2	PCC(NS) / ESP, FGD, LNB	1495	0 (d)	215	204	1914	1495	0 (d)	453	204	2151
Sweden	SW-C	PCC(NS) / ESP, SCR	1418	154	195	128	1895	1418	154	408	128	2108
Turkey	TK-C	NS / WLS, deNO_x	1128	0	131	108	1367	1128	0	274	155	1557
United Kingdom	UK-C1	PCC(NS) / ESP, FGD	1823	0 (c)	145	0	1968	1823	0 (c)	226	0	2048
	UK-C2	AFBC / ESP	1532	0 (c)	81	0	1613	1532	0 (c)	169	0	1702
United States	US1-C	)	1223	183	284	81	1771	1223	183	615	54	2075
	US2-C	) PCC(SB) / ESP, FGD	1183	178	275	163	1799	1183	178	595	110	2066
	US3-C	)	1159	174	269	109	1711	1159	174	583	74	1990
China	CH-C	PCC(SB) / FGD	815	91	148	0	1054	815	91	318	0	1224
CSFR	CS-C	PCC(SB) / ESP, FGD	1104	0	137	16	1257	1104	0	287	4	1395
Hungary	HN-C1	PLC(SB) / deSO_x, LNB	1650	0	221	0	1870	1650	0	462	0	2112
	HN-C2	PCC(SP) / deSO_x, LNB	1266	0	224	0	1490	1266	0	485	0	1751
India	IN-C	PCC(SB) / ESP	1012	51	185	0	1248	1012	51	397	0	1459
Korea	KR-C	PCC(SP) / ESP, FGD, LNB	902	90	108	0	1100	902	90	225	0	1217
Russia (e)	RF-C	AFBC / FGD	(545)	(0)	(113)	(24)	(682)	(545)	(0)	(245)	(3)	(793)
(Category-B)												
Canada	CA3-C	CFBC / FGD, deNO_x	1108	19	74	0	1201	1108	12	151	0	1271
Netherlands	NL-C2	IGCC/ (f)	1342	0	150	5	1497	1342	0	315	3	1660
United Kingdom	UK-C3	PFBC / WLS	1500	0 (c)	81	0	1581	1500	0 (c)	210	0	1710

(a) AFBC : atmospheric fluidised bed combustion (circulating bed) PFBC : pressurised fluidised bed combustion
ESP : electro-static precipitator FGD : flue gas desulphurisation system IGCC : integrated gasification combined cycle
LNB : low NO_x burner PCC : pulverised coal combustion PLC : pulverised lignite combustion
SCR : selective catalytic reduction SB : sub-critical SP : super-critical WLS : wet limestone process
(b) Included in "Base construction costs". Contingency is 7% of original base construction costs.
(c) Included in "Base construction costs". Contingency is 10% of original base construction costs.
(d) Included in "Base construction costs".
(e) Roubles of 1989/kWe.
(f) Gas is cleaned behind the gasifier.

Table 11 **Progress payment dates for initial investment costs**

(%)

Year after (+) or before (-) year of commissioning			-12	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	Year of commis-sioning	+1	+2	+3	+4	+5
NUCLEAR	BE-N						3	4	7	11	13	15	17	15	10	5				
	CA1-N	(a)	0.3	0.9	1.1	1.6	2.1	2.3	2.6	3.5	5.8	9.9	14.3	16.9	15.4	11.7	7.1	3.2	1.1	
	FI-N							4	7	18	20	22	22	7						
	FR-N						1	2	5	9	14	18	16	15	12	6	2			
	GE-N	(b)										100								
	JP-N						1.0	2.0	3.2	9.8	17.7	18.2	16.3	15.5	16.3					
	UK-N1							6	10	12	20	21	14	11	6					
	US1-N							1.0	3.0	7.2	17.1	28.5	26.6	13.2	3.3					
	US2-N							1.0	3.0	7.2	17.1	28.5	26.6	13.2	3.3					
	US3-N							1.0	3.0	7.2	17.1	28.5	26.6	13.2	3.3					
	CH-N						4	6	10	14	20	30	11	4	1					
	CS-N						8	5	10	13	18	19	14	9	4					
	HN-N								6.0	8.4	13.6	18.0	19.0	16.0	10.5	6.0	2.5			
	IN-N					2.5	7.5	10.0	12.5	17.5	17.5	12.5	10.0	7.5	2.5					
	KR-N1	(c)						1.9	7.3	15.5	23.5	22.6	14.3	7.8	4.5	2.5				
	KR-N2	(c)								1.9	4.2	15.3	28.4	24.2	20.1	6.0				
	RF-N	(a)					0.4	0.7	1.4	2.5	3.5	5.0	8.0	14.0	15.0	15.0	13.0	11.0	8.0	3
COAL	BE-C										5	18	22	25	25	5				
	CA1-C	(d)			0.2	0.3	0.7	1.4	2.8	4.6	7.9	14.1	20.7	18.2	14.4	10.0	4.0	0.9		
	CA2-C									6	8	20	29	24	11	2				
	CA4-C										2.7	12.0	21.5	37.9	25.9					
	DE-C								1	4	9	21	26	22	14	3				
	FI-C								1.5	7.0	17.0	23.5	17.5	20.0	12.5	1.0				
	FR-C									1	6	18	29	27	14	4	1			
	GE-C1&C2	(b)											100							
	IT-C								2	8	15	20	20	19	14	2				
	JP-C								0.5	2.6	8.7	12.6	31.7	32.2	11.8					
	NL-C1								3	5	20	22	25	25						
	PT-C	(a)							0.2	4.1	6.9	14.2	17.9	18.7	18.3	11.1	6.2	2.2	0.2	
	SP-C1									12	20	26	31	11						
	SP-C2									12	20	26	31	11						
	SW-C		NS																	
	TK-C										14	20.6	39.9	25.5						
	UK-C1		NS																	
	UK-C2		NS																	
	US1-C							1.0	0.7	4.6	21.1	27.9	28.5	12.9	3.2					
	US2-C							1.0	0.7	4.6	21.1	27.9	28.5	12.9	3.2					
	US3-C							1.0	0.7	4.6	21.1	27.9	28.5	12.9	3.2					
	CH-C									9	17	25	26	17	6					
	CS-C										13	20	26	21	20					
	HN-C1									0.5	5.0	19.5	25.0	27.5	17.5	5.0				
	HN-C2									11	15	19	20	20	10	5				
	IN-C							1	4	10	25	30	25	4	1					
	KR-C	(c)									7.3	20.3	31.3	26.9	13.1	1.2				

GAS	BE-G										15	20	25	30	10				
	CA1-G						0.4	1.4	2.2	7.9	11.6	19.8	29.4	21.1	5.8	0.4			
	CA2-G											3	45	52					
	DE-G1								6	10	26	31	24	3					
	DE-G2							1	4	9	21	26	22	14	3				
	FI-G										7	24	55	14					
	FR-G										15	35	30	15	5				
	IT-G									2	15	29	32	22					
	JP-G								1	3	13	20	28	35					
	NL-G									11.5	18.5	45	25						
	PT-G1&G2 (e)									0.7	13.1	18.1	27.1	22.0	14.4	4.7			
	SP-G								15	20	25	30	10						
	SW-G	NS																	
	UK-G	NS																	
	US1-G									1.5	3.4	34.1	45.9	15.1					
	US2-G									1.5	3.4	34.1	45.9	15.1					
	US3-G									1.5	3.4	34.1	45.9	15.1					
	CS-G									10	25	45	15	5					
	HN-G									4.1	11.4	50.2	34.3						
Others	DE-W													100					
	SL-S	NS																	
	UK-W												100						
	UK-L												100						
	UK-M											50	50						
	UK-S												100						

(a) The schedule is for 4-unit station. The first unit is commissioned in the year "0", and subsequent units in 1-year intervals.
(b) Payments are given as in the center of gravity of payments.
(c) The schedule is for 2-unit station. The first unit is commissioned in the year "0", and the second unit in the next year.
(d) The schedule is for 4-unit station. The year "0" is the mid-point of in service dates.
(e) The schedule is for 2-unit station. The first unit is commissioned in the year "0", and the second unit in the year "+2".

NS : Not specified.

Table 12 **Decommissioning costs of nuclear power plants**

Country	Estimate	Decommissioning costs						Stage (a) achieved	Progress payment of decommissioning costs (%)							
		Absolute value (MUSD of 1.7.1991/unit)			% of total investment				Year after operation closure							
		Undis-counted	5% discounted	10% discounted	Undis-counted	5% discounted	10% discounted		0	5	10	20	30	50	75	100
Belgium	BE-N	270	40	7	10	1.4	0.2	NS			100					
Canada	CA1-N	203	12	1	10	0.6	~0	stage 3		5.3	2.1	6.9	4.9	80.8		
Finland	FI-N	175	30	6	10	1.6	0.3	stage 3 (b)		40	60					
France	FR-N	370	41	7	18	2.0	0.3	stage 3	NS							
Germany	GE-N	440	92	20	NS	2.4	0.5	NS	NS							
Japan	JP-N	267	44	8	8.7	1.4	0.2	stage 3		100 (c)						
United Kingdom	UK-N1	532	61-69	39-43	12-15	1.4-1.6	0.8-0.9	stage 3	NS							
United States	US1-N	275	96	60	13	3.7	2.1	stage 3		80	20					
	US2-N	275	96	60	13	3.6	2.0	stage 3		80	20					
	US3-N	275	96	60	14	3.8	2.2	stage 3		80	20					
China	CH-N (d)	NS	21	6	10	2.3	0.6	NS	NS							
CSFR	CS-N	193	45	11	16.2	3.4	0.7	stage 3	NS							
Hungary	HN-N	400	62	11	20	4	0.6	stage 3	10	50	40					
India	IN-N	24	2.4	0.3	9.5	0.7	0.1	stage 3		15	15	17	13	40 (e)		
Korea	KR-N1	NS (f)	NS	NS	NS	NS	NS	stage 3	NS							
	KR-N2	NS (f)	NS	NS	NS	NS	NS	stage 3	NS							
Russia	RF-N	NS	NS	NS	100	12.5	2.4	NS		57	38.5	4.5				

(a) State of condition of a facility after decommissioning activities.
stage 1 : storage with surveillance, stage 2 : restricted site release, stage 3 : unrestricted site release.
(b) Non-radioactive parts will not be dismantled.
(c) 7 years after operation closure.
(d) China has no experience with decommissioning of nuclear facilities. The undiscounted decommissioning cost is estimated as 10% of total investment.
(e) At the end of 40 years after operation closure.
(f) See country annex.

NS : Not specified.

Table 10 **Breakdown of investment costs (Gas-fired and others)**
(Discounted to the date of commissioning)

(USD of 1.7.1991/kWe)

Country	Abbreviation of estimate	Technology (a)	5% Discount rate					10% Discount rate				
			Base construction costs	Contingency	Interest	Others	Total	Base construction costs	Contingency	Interest	Others	Total
(GCC)												
Belgium	BE-G	CCGT	771	0	40	0	811	771	0	83	0	854
Canada	CA1-G	CCGT	613	0 (b)	49	172	834	613	0 (b)	103	103	819
	CA2-G	CCGT	921	0 (c)	24	0	945	921	0 (c)	47	0	968
Denmark	DE-G1	CCGT	658	0	81	0	739	658	0	170	0	828
	DE-G2	GCP	651	0	67	0	718	651	0	141	0	792
Finland	FI-G	CCGT	406	40	21	117	584	406	40	43	117	606
France	FR-G	CCGT	557	34	53	6	650	557	34	110	6	707
Italy	IT-G	CCGT	950	0 (d)	70	0	1019	950	0 (d)	144	0	1094
Japan	JP-G	CCGT	1229	0	63	0	1292	1229	0	219	0	1448
Netherlands	NL-G	CCGT	782	0 (d)	68	5	854	782	0 (d)	140	3	926
Portugal	PT-G1&G2	CCGT	593	27	59	0	679	593	27	124	0	744
Spain	SP-G	CCGT	705	0 (d)	104	88	897	705	0 (d)	220	88	1013
Sweden	SW-G	CCGT	665	53	89	56	863	665	53	186	56	960
United Kingdom	UK-G	CCGT	685	NS	32	0	718	685	NS	64	0	750
United States	US1-G	)										
	US2-G	) CCGT	472	71	69	22	634	472	71	143	15	701
	US3-G	)										
CSFR	CS-G	CCGT	537	0	76	0	613	537	0	160	0	697
Hungary	HN-G	CCGT	280	0	27	0	306	280	0	55	0	334
(Others)												
Denmark	DE-W	Wind	931	0	0	0	931	931	0	0	0	931
Switzerland	SL-S	SSH	4130	620	560	520	5830	4130	620	1190	520	6460
United Kingdom	UK-W	Wind	1815	NS	~0	0	1815	1815	NS	~0	0	1815
	UK-L	LFG	1129	NS	0	0	1129	1129	NS	0	0	1129
	UK-M	MWI	3339	NS	50	0	3389	3339	NS	100	0	3439
	UK-S	SSH	968-3226	97-323	0	0	1065-3549	968-3226	97-323	0	0	1065-3549

(a) CCGT : combined cycle gas turbine plant GCP : natural gas conventional plant
LFG : land-fill gas MWI : municipal waste incineration SSH : small scale hydro
(b) Included in "Base construction costs". Contingency is 7% of original base construction cost.
(c) Included in "Base construction costs". Contingency is 10% of original base construction cost.
(d) Included in "Base construction costs".

NS : Not specified.

Table 11 **Progress payment dates for initial investment costs**

(%)

Year after (+) or before (-) year of commissioning			-12	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	Year of commis-sioning	+1	+2	+3	+4	+5
NUCLEAR	BE-N						3	4	7	11	13	15	17	15	10	5				
	CA1-N	(a)	0.3	0.9	1.1	1.6	2.1	2.3	2.6	3.5	5.8	9.9	14.3	16.9	15.4	11.7	7.1	3.2	1.1	
	FI-N							4	7	18	20	22	22	7						
	FR-N						1	2	5	9	14	18	16	15	12	6	2			
	GE-N	(b)										100								
	JP-N						1.0	2.0	3.2	9.8	17.7	18.2	16.3	15.5	16.3					
	UK-N1							6	10	12	20	21	14	11	6					
	US1-N							1.0	3.0	7.2	17.1	28.5	26.6	13.2	3.3					
	US2-N							1.0	3.0	7.2	17.1	28.5	26.6	13.2	3.3					
	US3-N							1.0	3.0	7.2	17.1	28.5	26.6	13.2	3.3					
	CH-N						4	6	10	14	20	30	11	4	1					
	CS-N						8	5	10	13	18	19	14	9	4					
	HN-N								6.0	8.4	13.6	18.0	19.0	16.0	10.5	6.0	2.5			
	IN-N					2.5	7.5	10.0	12.5	17.5	17.5	12.5	10.0	7.5	2.5					
	KR-N1	(c)						1.9	7.3	15.5	23.5	22.6	14.3	7.8	4.5	2.5				
	KR-N2	(c)								1.9	4.2	15.3	28.4	24.2	20.1	6.0				
	RF-N	(a)					0.4	0.7	1.4	2.5	3.5	5.0	8.0	14.0	15.0	15.0	13.0	11.0	8.0	3
COAL	BE-C										5	18	22	25	25	5				
	CA1-C	(d)			0.2	0.3	0.7	1.4	2.8	4.6	7.9	14.1	20.7	18.2	14.4	10.0	4.0	0.9		
	CA2-C									6	8	20	29	24	11	2				
	CA4-C										2.7	12.0	21.5	37.9	25.9					
	DE-C								1	4	9	21	26	22	14	3				
	FI-C								1.5	7.0	17.0	23.5	17.5	20.0	12.5	1.0				
	FR-C									1	6	18	29	27	14	4	1			
	GE-C1&C2	(b)											100							
	IT-C								2	8	15	20	20	19	14	2				
	JP-C								0.5	2.6	8.7	12.6	31.7	32.2	11.8					
	NL-C1								3	5	20	22	25	25						
	PT-C	(a)							0.2	4.1	6.9	14.2	17.9	18.7	18.3	11.1	6.2	2.2	0.2	
	SP-C1									12	20	26	31	11						
	SP-C2									12	20	26	31	11						
	SW-C		NS																	
	TK-C										14	20.6	39.9	25.5						
	UK-C1		NS																	
	UK-C2		NS																	
	US1-C							1.0	0.7	4.6	21.1	27.9	28.5	12.9	3.2					
	US2-C							1.0	0.7	4.6	21.1	27.9	28.5	12.9	3.2					
	US3-C							1.0	0.7	4.6	21.1	27.9	28.5	12.9	3.2					
	CH-C									9	17	25	26	17	6					
	CS-C										13	20	26	21	20					
	HN-C1									0.5	5.0	19.5	25.0	27.5	17.5	5.0				
	HN-C2									11	15	19	20	20	10	5				
	IN-C							1	4	10	25	30	25	4	1					
	KR-C	(c)									7.3	20.3	31.3	26.9	13.1	1.2				

GAS	BE-G										15	20	25	30	10				
	CA1-G						0.4	1.4	2.2	7.9	11.6	19.8	29.4	21.1	5.8	0.4			
	CA2-G											3	45	52					
	DE-G1								6	10	26	31	24	3					
	DE-G2							1	4	9	21	26	22	14	3				
	FI-G										7	24	55	14					
	FR-G										15	35	30	15	5				
	IT-G									2	15	29	32	22					
	JP-G								1	3	13	20	28	35					
	NL-G									11.5	18.5	45	25						
	PT-G1&G2 (e)									0.7	13.1	18.1	27.1	22.0	14.4	4.7			
	SP-G								15	20	25	30	10						
	SW-G	NS																	
	UK-G	NS																	
	US1-G									1.5	3.4	34.1	45.9	15.1					
	US2-G									1.5	3.4	34.1	45.9	15.1					
	US3-G									1.5	3.4	34.1	45.9	15.1					
	CS-G									10	25	45	15	5					
	HN-G									4.1	11.4	50.2	34.3						
Others	DE-W													100					
	SL-S	NS																	
	UK-W												100						
	UK-L												100						
	UK-M											50	50						
	UK-S												100						

(a) The schedule is for 4-unit station. The first unit is commissioned in the year "0", and subsequent units in 1-year intervals.
(b) Payments are given as in the center of gravity of payments.
(c) The schedule is for 2-unit station. The first unit is commissioned in the year "0", and the second unit in the next year.
(d) The schedule is for 4-unit station. The year "0" is the mid-point of in service dates.
(e) The schedule is for 2-unit station. The first unit is commissioned in the year "0", and the second unit in the year "+2".

NS : Not specified.

Table 12 **Decommissioning costs of nuclear power plants**

Country	Estimate	Decommissioning costs						Stage (a) achieved	Progress payment of decommissioning costs (%)							
		Absolute value (MUSD of 1.7.1991/unit)			% of total investment				Year after operation closure							
		Undis-counted	5% discounted	10% discounted	Undis-counted	5% discounted	10% discounted		0	5	10	20	30	50	75	100
Belgium	BE-N	270	40	7	10	1.4	0.2	NS			100					
Canada	CA1-N	203	12	1	10	0.6	~0	stage 3		5.3	2.1	6.9	4.9	80.8		
Finland	FI-N	175	30	6	10	1.6	0.3	stage 3 (b)		40	60					
France	FR-N	370	41	7	18	2.0	0.3	stage 3	NS							
Germany	GE-N	440	92	20	NS	2.4	0.5	NS	NS							
Japan	JP-N	267	44	8	8.7	1.4	0.2	stage 3		100 (c)						
United Kingdom	UK-N1	532	61-69	39-43	12-15	1.4-1.6	0.8-0.9	stage 3	NS							
United States	US1-N	275	96	60	13	3.7	2.1	stage 3		80	20					
	US2-N	275	96	60	13	3.6	2.0	stage 3		80	20					
	US3-N	275	96	60	14	3.8	2.2	stage 3		80	20					
China	CH-N (d)	NS	21	6	10	2.3	0.6	NS	NS							
CSFR	CS-N	193	45	11	16.2	3.4	0.7	stage 3	NS							
Hungary	HN-N	400	62	11	20	4	0.6	stage 3	10	50	40					
India	IN-N	24	2.4	0.3	9.5	0.7	0.1	stage 3		15	15	17	13	40 (e)		
Korea	KR-N1	NS (f)	NS	NS	NS	NS	NS	stage 3	NS							
	KR-N2	NS (f)	NS	NS	NS	NS	NS	stage 3	NS							
Russia	RF-N	NS	NS	NS	100	12.5	2.4	NS		57	38.5	4.5				

(a) State of condition of a facility after decommissioning activities.
stage 1 : storage with surveillance, stage 2 : restricted site release, stage 3 : unrestricted site release.
(b) Non-radioactive parts will not be dismantled.
(c) 7 years after operation closure.
(d) China has no experience with decommissioning of nuclear facilities. The undiscounted decommissioning cost is estimated as 10% of total investment.
(e) At the end of 40 years after operation closure.
(f) See country annex.

NS : Not specified.

Table 13 **Emission control levels** (a)

	Country	Estimate	Emission control levels [mg/Nm³]			Emission control equipment (b)
			SO_x	NO_x	Particulates	
(Coal)	Belgium (c)	BE-C	250	200	50	ESP, FGD, LNB, SCR
	Canada (d)	CA1-C	90% removal	0.25 g/kWh	123	WLS, SCR
		CA2-C	740	245	123	FGD, SCR
		CA4-C	740	285	123	ESP, FGD, SCR
	Denmark (e)	DE-C	400	200	50	ESP, FGD, $deNO_x$
	Finland	FI-C	400	145	429	ESP, WLS, SCR
	France (f)	FR-C	400	650	50	AFBC, ESP
	Germany	GE-C1,C2	400	200	50-150	ESP, FGD, LNB, SCR
	Italy	IT-C	400	200	50	ESP, FGD, LNB, SCR
	Japan	JP-C	0.04 ppm (g)	0.04-0.06 ppm (g)	50-300	FGD, $deNO_x$
	Netherlands	NL-C1	200	200	50	ESP, FGD, SCR
	Portugal	PT-C	400	650	-	ESP, FGD, LNB
	Spain	SP-C1	(h)	650	200-500	ESP, FGD, LNB
		SP-C2	800	350	200-500	ESP, FGD, LNB
	Sweden	SW-C	85	145	57-100	SCR, ESP
	Turkey	TK-C	1000	800	150	WLS, $deNO_x$
	United Kingdom	UK-C1	90% removal	500-600	143-857	ESP, FGD
		UK-C2	90% removal	100-300	143-857	AFBC, ESP
	United States	US1-C	150	740	37-61 (i)	ESP, FGD
		US2-C	150	740	37-61 (i)	ESP, FGD
		US3-C	150	740	37-61 (i)	ESP, FGD
	China	CH-C	NS	NS	NS	FGD
	CSFR	CS-C	400	200	NS	ESP, FGD
	Hungary (j)	HN-C1,C2	400	300-650	NS	$deSO_x$, LNB
	India	IN-C	NS	NS	100	ESP
	Korea	KR-C	770	720	NS	ESP, FGD, LNB (k)
	Russia	RF-C	200	200	NS	AFBC, FGD
	(Category B)					
	Canada	CA3-C	740	490	123	FGD, $deNO_x$
	United Kingdom	UK-C3	NS	NS	143-857	WLS
(Gas) (l)	Belgium	BE-G	35	100	NA	LNB
	Canada	CA1-G	NS	0.25 g/kWh	NA	SCR
		CA2-G	740	740	NA	FGD, $deNO_x$ (m)
	Denmark	DE-G1	NS	NS	NA	none
		DE-G2	35	225	NA	none
	Finland	FI-G	NS	170	NA	LNB
	France (f)	FR-G	NS	130	NA	$deNO_x$
	Italy	IT-G	NS	150	NA	LNB
	Japan	JP-G	0.04 ppm (g)	0.04-0.06 ppm (g)	NA	$deNO_x$
	Netherlands	NL-G	NS	185	NA	none
	Portugal	PT-G1,G2	250	150	NA	LNB
	Spain	SP-G	35	350	NA	none
	Sweden	SW-G	-	145	NA	SCR, WI
	United Kingdom	UK-G	NS	NS	NA	none
	United States	US1-G	NS	75 ppm	NA	SCR, WI
		US2-G	NS	75 ppm	NA	SCR, WI
		US3-G	NS	75 ppm	NA	SCR, WI
	CSFR	CS-G	500	200	NA	none
	Hungary (j)	HN-G	35	300	NA	$deSO_x$, LNB
(Others)	UK	UK-M	NS	NS	NA	NS

See footnotes next page.

Table 13 (continued)

(a) See Annex 12 for control measures in the EC.

(b) Abbreviations: AFBC = Atmospheric Fluidised Bed Combustion
ESP = Electro-Static Precipitator
FGD = Flue Gas Desulphurisation System
LNB = Low NO_x Burner
SCR = Selective Catalytic Reduction
WI = Water Injection
WLS = Wet Limestone Process

(c) New coal plant > 50 MW.

(d) All new utility boilers > 264 GJ/h.

(e) New utility boilers > 50 MW, monthly average.

(f) Present standard for coal (at 6% O_2); expected standard for CCGT (at 15% O_2).

(g) Standard for overall air quality.

(h) Desulphurisation of at least 60%.

(i) 99% removal for units > 73 MW built after 1978.

(j) Standards are to be adopted in 1993.

(k) See country annex.

(l) Particulates emissions from gas turbines are negligible.

(m) Steam injection or dry NO_x control.

Notes: Conversion factors 100 mg/Nm³ = 35 g/GJ
1 lb/MBtu = 430 g/GJ
Conversion units have been rounded, so the levels shown are approximate.
This conversion factor was corresponded on the bases of the assumed characteristics of combustion of a high calorific value coal (30 MJ/kg) at 30% excess air (6% O_2 in the flue gas).

NA : Not available.

NS : Not specified.

Table 14 **Projection of operations and maintenance (O&M) costs (Nuclear)**

Country	Abbreviation of estimate	O&M costs for the year 2000 (USD of 1.7.1991 per year, per kWe net capacity)	% of fixed costs at 75% load factor	Projected O&M costs (Normalized to the cost projection for the year 2000) 2000	2010	2020	2030
Belgium	BE-N	48 (a)	NS	NS			
Canada	CA1-N	33.3	95	1	1	1	1
Finland	FI-N	35.5	46	1	1	1	1
France	FR-N	54.3	90	1	1.16	1.35	1.56
Germany	GE-N	82.5 (b)	NS	NS			
Japan	JP-N	70.8	100	1	1	1	1
United Kingdom	UK-N1	69.1-77.7	100	1	0.87	0.97	1.12
United States	US1-N US2-N US3-N	108	94	1	1	1	1
China	CH-N	39.5	86	1	1.03	1.07	1.12
CSFR	CS-N	47.5	100	1	1	1	1.08
Hungary	HN-N	30.9	100	1	1	1	1
India	IN-N	76.6	90	1	1	1	1
Korea (c)	KR-N1	47.4	100	1	1	1	1
	KR-N2	76.0	100	1	1	1	1
Russia (d)	RF-N	(35)	100	1	0.76	0.76	0.76
(Category-B)							
Canada	CA4-N	81.5	NS	1	1	1	1
Netherlands	NL-N	89	100	1	1	1	1
United Kingdom	UK-N2	64	100	NS			

(a) Approximate number.
(b) Average over 30 years lifetime.
(c) In Korea, O&M costs are evaluated based on historical data, and treated as a fixed cost.
(d) Roubles of 1989/kWe per year.

NS : Not specified

Table 15 **Projection of operations and maintenance (O&M) costs (Coal)**

Country	Abbreviation of estimate	O&M costs for the year 2000 (USD of 1.7.1991 per year, per kWe net capacity)	% of fixed costs at 75% load factor	Projected O&M costs (Normalized to the cost projection for the year 2000) 2000	2010	2020	2030
Belgium	BE-C	32 (a)	NS	NS			
Canada	CA1-C	28.3	35	1	1	1	1
	CA2-C	47.4	NS	1	1	1	1
	CA4-C	42.7	NS	1	1.17	1.17	1.17
Denmark	DE-C	47.6	60	1	1	1	1
Finland	FI-C	35.2	32	1	1	1	1
France	FR-C	50.6	93	1	1.16	1.35	1.56
Germany	GE-C1&C2	97.8	85	NS			
Italy	IT-C	53.7	70	1	1	1	1
Japan	JP-C	51.2	100	1	1	1	1
Netherlands	NL-C1	31 (a)	85	1	1	1	1
Portugal	PT-C	40.9	50	1	1	1	1
Spain	SP-C1	37.8	78	1	1	1	1
	SP-C2	29.1	78	1	1	1	1
Sweden	SW-C	54.7	48	1	1	1	1
Turkey	TK-C	NS	NS	NS			
United Kingdom	UK-C1	85	62	NS			
	UK-C2	74	62	NS			
United States	US1-C	67.3	36	1	1	1	1
	US2-C	63.4	38	1	1	1	1
	US3-C	48.2	49	1	1	1	1
China	CH-C	31.3	89	1	1.02	1.05	1.09
CSFR	CS-C	44.0	67	1	1.09	1.16	1.16
Hungary	HN-C1	62.5	100	1	1	1	1
	HN-C2	31.3	100	1	1	1	1
India	IN-C	26.6	90	1	1	1	1
Korea (b)	KR-C	56.7	100	1	1	1	1
Russia (c)	RF-C	(35)	75	NS			
(Category-B)							
Canada	CA3-C	39.9	100	1	1	1	1
Netherlands	NL-C2	37 (a)	84	1	1	1	1
United Kingdom	UK-C3	74	62	NS			

(a) Approximate number.
(b) In Korea, O&M costs are evaluated based on historical data, and treated as a fixed cost.
(c) Roubles of 1989/kWe per year.

NS : Not specified.

Table 16 **Projection of operations and maintenance (O&M) costs (Gas-fired and others)**

Country	Abbreviation of estimate	O&M costs for the year 2000 (USD of 1.7.1991 per year, per kWe net capacity)	% of fixed costs at 75% load factor	Projected O&M costs (Normalized to the cost projection for the year 2000) 2000	2010	2020	2030
(Gas)							
Belgium	BE-G	32 (a)	NS	NS			
Canada	CA1-G	14.2	90	1	1	1	1
	CA2-G	28.1	NS	1	1	1	1
Denmark	DE-G1	19.6	100	1	1	1	1
	DE-G2	21.3	100	1	1	1	1
Finland	FI-G	17.2	72	1	1	1	1
France	FR-G	26.4	96	1	1.16	1.35	1.56
Italy	IT-G	26.8	100	1	1	1	1
Japan	JP-G	44.8	100	1	1	1	1
Netherlands	NL-G	20	100	1	1	1	1
Portugal	PT-G1&G2	19.5	62	1	1	1	1
Spain	SP-G	37.8	85	1	1	1	NS
Sweden	SW-G	32.2	53	1	1	1	1
United Kingdom	UK-G	51	100	NS			
United States	US1-G	)					
	US2-G	) 16.5	37	1	1	1	1
	US3-G	)					
CSFR	CS-G	13.1	100	1	1	1	NS
Hungary	HN-G	9.5	100	1	1	1	1
(Others)							
Denmark	DE-W	18.6	100	1	1	1	1
Switzerland	SL-S	81.9	NS	1	1	1	1
United Kingdom	UK-W	28.2	100	1	1	1	1
	UK-L	185.5	100	NS			
	UK-M	520	55	NS			
	UK-S	19.4-64.5	100	NS			

(a) Approximate number.

NS : Not specified.

Table 17 **Projection of fuel price (Uranium)**

Country	Abbreviation of estimate	Projected price of uranium for the year 2000 (USD of 1.7.1991/kgU)	Uranium price projection (Normalized to the price projection for the year 2000) 2000	2010	2020	2030
Belgium	BE-N	60	1	1	1	1
Canada	CA1-N	NS	NS			
Finland	FI-N	75	1	1	1	1
France	FR-N	81.6 (a)	1	1.10	1.22	1.34
Germany	GE-N	69.6	1	1.05	1.10	1.16
Japan	JP-N	NS	1	1.01	1.02	1.03
United Kingdom	UK-N1	NS	NS			
United States	US1-N	)				
	US2-N	) 47	1	1	1	1
	US3-N	)				
China	CH-N	56.1	1	1.05	1.10	1.16
CSFR	CS-N	50.3	1	1.08	1.17	1.25
Hungary	HN-N	60	1	1	1	1
India	IN-N	73.1	1	1	1	1
Korea	KR-N1&N2	65	1	1	1	1
Russia (b)	RF-N	(60)	1	1	1	1
(Category-B)						
Canada	CA4-N	NS	NS			
Netherlands	NL-N	84.7	1	1.10	1.22	1.35
United Kingdom	UK-N2	NS	NS			

(a) FF 500/kgU. (b) Roubles of 1989/kgU.

NS : Not specified.

Table 18 **Projection of fuel price (Coal)** (a)

Country	Abbreviation of estimate	Projected price of coal for the year 2000 (USD of 1.7.1991/GJ)	HHV or LHV used in the projection (b)	Imported or domestic coal	Coal price projection (Normalized to the price projection for the year 2000) 2000	2010	2020	2030	2040
Belgium	BE-C	2.0	L	I	1	1	1	1	1
Canada	CA1-C	1.5 (c)	H	I	1	1.24	1.24	1.24	NS
	CA2-C	0.6	H	D	1	1.11	1.22	1.33	1.43
	CA4-C	1.5	H	I	1	1.10	1.20	1.30	1.42
Denmark	DE-C	2.1	L	I	1	1	1	1	1
Finland	FI-C	1.9	L	I	1	1	1	1	1
France	FR-C	1.9	H	I	1	1.08	1.18	NS	NS
Germany	GE-C1	5.3	L	D	1	0.90	0.82	0.75	NS
	GE-C2	1.7	L	I	1	1.05	1.10	1.16	NS
Italy	IT-C	2.0	L	I	1	1.03	1.06	1.08	1.11
Japan	JP-C	2.1	H	I	1	1.16	1.35	1.56	1.82
Netherlands	NL-C1	2.6	L	I	1	1.10	1.10	1.10	1.10
Portugal	PT-C	2.0	L	I	1	1.14	1.32	1.52	1.76
Spain	SP-C1	4.7	L	D	1	1.12	1.22	1.34	1.50
	SP-C2	2.5	L	I	1	1.13	1.22	1.35	1.49
Sweden	SW-C	2.4	NS	I	1	1.04	1.06	1.06	1.06
Turkey	TK-C	NS	-	-	NS				
United Kingdom	UK-C1&C2	2.1	H	I	1	1	1	1	1
United States	US1-C	1.6	H	D	1	1	1	1	1
	US2-C	2.2	H	D	1	1	1	1	1
	US3-C	1.0	L	D	1	1	1	1	1
China	CH-C	1.6 (d)	H	D	1	1.22	1.49	1.81	2.21
CSFR	CS-C	1.0	L	D	1	1.22	1.49	1.81	2.21
Hungary	HN-C1	1.4	L	D	1	1	1	1	1
	HN-C2	2.7	L	I	1	1	1	1	1
India	IN-C	2.1 (e)	L	D	1	1	1	1	1
Korea	KR-C	2.1	H	I	1	1	1	1	1
Russia (f)	RF-C	(1.1)	NS	D	NS				
(Category-B)									
Canada	CA3-C	1.6 (c)	NS	I	1	1	1	1	1
Netherlands	NL-C2	2.6	L	I	1	1.10	1.10	1.10	1.10
United Kingdom	UK-C3	2.1	H	I	1	1	1	1	1

(a) Price is C.I.F. price and excludes internal transport and handling costs.
(b) HHV: higher heating value. LHV: lower heating value.
(c) Price in 1991.
(d) Price at plant site (including transport charge).
(e) The price of coal at a coal mine is 0.7 USD/GJ. 2.1 USD/GJ includes transportation charges.
(f) Roubles of 1989/GJ.

NS : Not specified.

Table 19 **Projection of fuel price (Natural gas)**

Country	Abbreviation of estimate	Projected price of natural gas for the year 2000 (USD of 1.7.1991/GJ)	HHV or LHV used in the projection (a)	Natural gas price projection (Normalized to the price projection for the year 2000) 2000	2010	2020	2030
Belgium	BE-G	3.6	L	1	1.17	1.22	NS
Canada	CA1-G	4.6	H	1	1.24	1.24	1.24
	CA2-G	1.5	H	1	1.37	1.74	2.11
Denmark (b)	DE-G1&G2	3.6	L	1	1	1	1
Finland	FI-G	3.4	L	1	1	1	1
France	FR-G	3.7	H	1	1.17	1.31	NS
Italy	IT-G	4.5	L	1	1.21	1.47	1.77
Japan (c)	JP-G	4.4	H	1	1.48	2.19	3.26
Netherlands	NL-G	4.0	L	1	1.19	1.19	1.19
Portugal	PT-G1	4.1	L	1	1.30	1.72	2.29
	PT-G2	4.1	L	1	1.11	1.30	1.57
Spain	SP-G	4.7	L	1	1.13	1.30	NS
Sweden (d)	SW-G	NS	-	NS			
United Kingdom	UK-G	2.9	H	1	1.16	1.32	1.58
United States	US1-G	3.4	H	1	1.54	1.77	1.92
	US2-G	3.9	H	1	1.47	1.67	1.80
	US3-G	3.6	H	1	1.50	1.71	1.86
CSFR	CS-G	3.2	L	1	1.10	1.22	1.35
Hungary	HN-G	4.9	L	1	1	1	1

(a) HHV : higher heating value. LHV : lower heating value.
(b) In Danish estimates, gas price is assumed to follow coal price.
(c) LNG is assumed to be used.
(d) Swedish utilities expect a natural gas price that will make the production costs from gas-fired power plants inferior to, or equally expensive as those of, coal-fired power plants.

NS : Not specified.

Table 20 **Summary of levelised**
(Discount rate: 5%) (For Nuclear and Coal; Lifetime: 30 years. Load Factor: 75%)

Country	Nuclear					Coal					
	Estimate	Investment	O&M	Fuel	Total	Estimate	Investment	O&M	Fuel	Total	Estimate
Belgium	BE-N	20.2 (0.56)	7.5 (0.21)	8.3 (0.23)	35.9 (1.00)	BE-C	13.2 (0.34)	5.0 (0.13)	21.2 (0.53)	39.4 (1.00)	BE-G
Canada	CA1-N (c)	22.8 (0.76)	5.3 (0.18)	1.8 (0.06)	29.8 (1.00)	CA1-C (c)	14.4 (0.42)	4.1 (0.12)	15.5 (0.46)	34.0 (1.00)	CA1-G (
						CA2-C	10.8 (0.43)	7.2 (0.28)	7.5 (0.30)	25.4 (1.00)	CA2-G
						CA4-C	14.1 (0.37)	7.5 (0.20)	16.6 (0.43)	38.2 (1.00)	
Denmark	-	-	-	-	-	DE-C	11.2 (0.32)	7.3 (0.21)	16.5 (0.47)	35.0 (1.00)	DE-G1
											DE-G2
Finland	FI-N	18.9 (0.63)	5.4 (0.18)	5.8 (0.19)	30.1 (1.00)	FI-C	9.8 (0.28)	6.7 (0.19)	18.6 (0.53)	35.0 (1.00)	FI-G
France	FR-N	14.5 (0.44)	10.0 (0.30)	8.3 (0.25)	32.8 (1.00)	FR-C	11.7 (0.23)	9.5 (0.19)	29.4 (0.58)	50.6 (1.00)	FR-G
Germany	GE-N	29.6 (0.56)	12.7 (0.24)	10.8 (0.20)	53.1 (1.00)	GE-C1	16.9 (0.20)	15.1 (0.19)	48.1 (0.60)	80.1 (1.00)	-
						GE-C2	16.9 (0.25)	15.1 (0.22)	35.4 (0.53)	67.4 (1.00)	
Italy	-	-	-	-	-	IT-C	19.1 (0.40)	8.3 (0.17)	20.9 (0.43)	48.4 (1.00)	IT-G
Japan	JP-N	24.4 (0.45)	10.9 (0.20)	18.3 (0.34)	53.7 (1.00)	JP-C	20.6 (0.33)	7.9 (0.12)	34.5 (0.55)	63.0 (1.00)	JP-G
Netherlands	-	-	-	-	-	NL-C1	11.8 (0.28)	4.7 (0.11)	24.8 (0.60)	41.3 (1.00)	NL-G
Portugal	-	-	-	-	-	PT-C	17.1 (0.36)	6.4 (0.13)	24.1 (0.51)	47.5 (1.00)	PT-G1
											PT-G2
Spain	-	-	-	-	-	SP-C1	24.6 (0.31)	5.7 (0.07)	50.1 (0.62)	80.4 (1.00)	SP-G
						SP-C2	20.9 (0.38)	4.4 (0.08)	30.2 (0.54)	55.5 (1.00)	
Sweden	-	-	-	-	-	SW-C	18.6 (0.38)	8.8 (0.18)	21.4 (0.44)	48.8 (1.00)	SW-G
Switzerland	-	-	-	-	-	-	-	-	-	-	-
Turkey	-	-	-	-	-	TK-C	13.3 (0.34)	6.4 (0.17)	18.8 (0.49)	38.5 (1.00)	-
United Kingdom	UK-N1	30.6-32.3	9.7-11.3	8.1	48.4-51.6	UK-C1/C2	16.1-19.4	11.3-12.9	19.4	46.8-51.6	UK-G
United States	US1-N	21.1 (0.49)	16.4 (0.38)	5.2 (0.13)	42.7 (1.00)	US1-C	17.4 (0.39)	10.2 (0.23)	17.1 (0.38)	44.7 (1.00)	US1-G
	US2-N	22.1 (0.50)	16.4 (0.38)	5.2 (0.12)	43.7 (1.00)	US2-C	17.7 (0.34)	9.6 (0.19)	24.0 (0.47)	51.3 (1.00)	US2-G
	US3-N	20.5 (0.49)	16.4 (0.39)	5.2 (0.12)	42.1 (1.00)	US3-C	16.8 (0.48)	7.3 (0.21)	11.2 (0.32)	35.3 (1.00)	US3-G
China	CH-N	15.0 (0.49)	6.6 (0.21)	9.1 (0.30)	30.7 (1.00)	CH-C	10.3 (0.29)	5.2 (0.14)	20.2 (0.57)	35.7 (1.00)	-
CSFR	CS-N	12.1 (0.42)	7.4 (0.26)	9.4 (0.32)	28.9 (1.00)	CS-C	12.3 (0.37)	7.5 (0.23)	13.3 (0.40)	33.1 (1.00)	CS-G
Hungary	HN-N (c)	18.9 (0.62)	4.5 (0.15)	6.9 (0.23)	30.3 (1.00)	HN-C1 (c,f)	21.4 (0.41)	11.0 (0.21)	19.4 (0.38)	51.8 (1.00)	HN-G (c
						HN-C2 (c)	14.0 (0.34)	4.7 (0.11)	22.6 (0.55)	41.3 (1.00)	
India	IN-N	17.2 (g) (0.47)	11.9 (0.33)	7.1 (0.20)	36.1 (1.00)	IN-C	12.5 (g) (0.30)	4.1 (0.10)	25.5 (0.61)	42.1 (1.00)	-
Korea	KR-N1	19.4 (0.61)	7.3 (0.23)	5.3 (0.17)	32.0 (1.00)	KR-C	10.8 (0.25)	8.8 (0.21)	22.9 (0.54)	42.5 (1.00)	-
	KR-N2	16.7 (0.53)	11.8 (0.37)	3.0 (0.09)	31.5 (1.00)						
Russia (h)	RF-N (c)	[0.72] (0.45)	[0.23] (0.15)	[0.64] (0.40)	[1.59] (1.00)	RF-C (c)	[0.58] (0.31)	[0.53] (0.29)	[0.75] (0.40)	[1.86] (1.00)	-
(Category-B) Canada	CA4-N	27.3 (0.64)	12.3 (0.29)	2.9 (0.07)	42.5 (1.00)	CA3-C	11.8 (0.34)	6.2 (0.18)	16.8 (0.48)	34.7 (1.00)	
Netherlands	NL-N	21.9 (0.49)	13.8 (0.31)	8.7 (0.20)	44.4 (1.00)	NL-C2	14.7 (0.35)	5.7 (0.13)	22.1 (0.52)	42.5 (1.00)	
United Kingdom	UK-N2 (i)	22.6-24.2	9.7	8.1	40.3-41.9	UK-C3	16.1 (0.36)	11.3 (0.25)	17.7 (0.39)	45.2 (1.00)	

electricity generation costs

a proportion of the total generation cost is indicated in the parentheses under each cost item

(USmill of 1.7.1991/kWh)

Gas						Others							
Assumptions (a)		Investment	O&M	Fuel	Total	Estimate	Technology (b)	Assumptions (a)		Investment	O&M	Fuel	Total
LT (yr)	LF (%)							LT (yr)	LF (%)				
20	75	9.1 (0.22)	5.2 (0.13)	26.6 (0.65)	40.8 (1.00)	-	-	-	-	-	-	-	-
30	75	8.2 (0.16)	2.2 (0.04)	41.8 (0.80)	52.2 (1.00)	-	-	-	-	-	-	-	-
35	76	8.2 (0.28)	3.1 (0.11)	17.5 (0.61)	28.8 (1.00)								
30	75	7.5 (0.21)	3.6 (0.10)	23.9 (0.68)	35.0 (1.00)	DE-W	Wind	20	25	34.1 (0.80)	8.5 (0.20)	0	42.7 (1.00)
30	75	7.2 (0.19)	3.6 (0.10)	26.4 (0.71)	37.2 (1.00)								
25	80	5.8 (0.16)	4.0 (0.11)	25.5 (0.72)	35.3 (1.00)	-	-	-	-	-	-	-	-
20	83	7.0 (0.13)	4.2 (0.08)	43.6 (0.80)	54.8 (1.00)	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	75	10.0 (0.17)	4.2 (0.07)	44.4 (0.76)	58.6 (1.00)	-	-	-	-	-	-	-	-
30	75	12.7 (0.16)	6.9 (0.09)	57.7 (0.75)	77.3 (1.00)	-	-	-	-	-	-	-	-
25	75	9.2 (0.18)	3.1 (0.06)	40.1 (0.77)	52.4 (1.00)	-	-	-	-	-	-	-	-
25	85	6.3 (0.13)	2.6 (0.06)	38.0 (0.81)	46.9 (1.00)	-	-	-	-	-	-	-	-
25	85	6.3 (0.15)	2.6 (0.06)	32.2 (0.78)	41.1 (1.00)								
20	75	11.5 (0.20)	5.7 (0.10)	39.5 (0.70)	56.7 (1.00)	-	-	-	-	-	-	-	-
25	75	8.5 (0.17)	5.5 (0.11)	< 34.8 (d) (0.71)	< 48.8 (d) (1.00)	-	-	-	-	-	-	-	-
-	-	-	-	-	-	SL-S	SSH	80	54	62.9 (0.78)	17.3 (0.22)	0	80.2 (1.00)
-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	90	6.5 (0.14)	6.5 (0.14)	32.3 (0.71)	45.2 (1.00)	UK-W	Wind	15	27	74.5 (0.87)	11.3 (0.13)	0	85.5 (1.00)
						UK-L	LFG	15	95	14.5 (0.36)	25.8 (0.64)	0	40.3 (1.00)
						UK-M	MWI	20	80	38.7	74.2	- 83.9 (e)	29.0
						UK-S	SSH	20	60	16.1-48.4	3.2-12.9	0	19.4-61.3
30	75	6.2 (0.13)	2.5 (0.05)	39.0 (0.82)	47.7 (1.00)	-	-	-	-	-	-	-	-
30	75	6.2 (0.12)	2.5 (0.05)	42.4 (0.83)	51.1 (1.00)								
30	75	6.2 (0.13)	2.5 (0.05)	40.4 (0.82)	49.1 (1.00)								
-	-	-	-	-	-								
25	75	6.6 (0.18)	2.8 (0.08)	26.9 (0.74)	36.3 (1.00)								
20	85	3.6 (0.09)	2.3 (0.06)	32.5 (0.85)	38.4 (1.00)								
-	-	-	-	-	-								
-	-	-	-	-	-								
-	-	-	-	-	-								

(a) LT : Lifetime LF : Settled-down Load Factor
(b) LFG : Land Fill Gas Plant
MWI : Municipal Waste Incineration
SSH : Small Scale Hydro
(c) Data were calculated with slightly different assumptions on operating hours from those shown in Table 6.
(d) Swedish utilities expect a natural gas price that will make the production costs from gas-fired power plants inferior to, or equally expensive as those of, coal-fired power plants.
(e) The figure is negative because of the credit for avoidance of transport and landfill site costs.
(f) Load factor is 65%.
(g) Working capital estimated approximately 2% of the investment costs are included.
(h) 0.01 rouble of 1989/kWh.
(i) Lifetime is 40 years.

Table 21 **Summary of levelised**

(Discount rate: 10%) (For Nuclear and Coal; Lifetime: 30 years. Load Factor: 75%) -

Country	Nuclear					Coal					
	Estimate	Investment	O & M	Fuel	Total	Estimate	Investment	O & M	Fuel	Total	Estimate
Belgium	BE-N	37.3 (0.70)	7.4 (0.14)	8.5 (0.16)	53.2 (1.00)	BE-C	22.8 (0.47)	5.0 (0.10)	21.2 (0.43)	48.9 (1.00)	BE-G
Canada	CA1-N (c)	42.3 (0.85)	5.4 (0.11)	1.8 (0.04)	49.5 (1.00)	CA1-C (c)	23.3 (0.54)	4.0 (0.09)	15.6 (0.46)	43.0 (1.00)	CA1-G (c
						CA2-C	19.3 (0.57)	7.3 (0.22)	7.3 (0.22)	33.9 (1.00)	CA2-G
						CA4-C	24.9 (0.52)	7.3 (0.15)	15.8 (0.33)	48.0 (1.00)	
Denmark	-	-	-	-	-	DE-C	20.3 (0.46)	7.3 (0.16)	16.5 (0.37)	44.1 (1.00)	DE-G1
											DE-G2
Finland	FI-N	35.0 (0.75)	5.4 (0.12)	6.3 (0.13)	46.7 (1.00)	FI-C	17.5 (0.40)	7.9 (0.18)	18.6 (0.42)	43.9 (1.00)	FI-G
France	FR-N	26.3 (0.58)	9.6 (0.21)	9.3 (0.21)	45.2 (1.00)	FR-C	20.7 (0.35)	9.1 (0.15)	28.9 (0.49)	58.9 (1.00)	FR-G
Germany	GE-N	54.3 (0.70)	13.1 (0.17)	10.0 (0.13)	77.4 (1.00)	GE-C1	29.3 (0.31)	15.0 (0.16)	49.3 (0.53)	93.6 (1.00)	-
						GE-C2	29.3 (0.37)	15.0 (0.19)	35.8 (0.45)	80.1 (1.00)	
Italy	-	-	-	-	-	IT-C	34.6 (0.54)	8.4 (0.13)	20.8 (0.33)	63.8 (1.00)	IT-G
Japan	JP-N	46.5 (0.62)	11.1 (0.15)	17.1 (0.23)	74.6 (1.00)	JP-C	38.2 (0.48)	8.0 (0.10)	33.4 (0.42)	79.6 (1.00)	JP-G
Netherlands	-	-	-	-	-	NL-C1	21.0 (0.42)	4.7 (0.09)	24.5 (0.49)	50.3 (1.00)	NL-G
Portugal	-	-	-	-	-	PT-C	30.8 (0.51)	6.4 (0.11)	23.2 (0.38)	60.4 (1.00)	PT-G1
											PT-G2
Spain	-	-	-	-	-	SP-C1	44.5 (0.45)	5.7 (0.06)	48.7 (0.49)	98.9 (1.00)	SP-G
						SP-C2	37.8 (0.53)	4.4 (0.06)	29.5 (0.41)	71.8 (1.00)	
Sweden	-	-	-	-	-	SW-C	33.4 (0.52)	9.1 (0.14)	21.4 (0.33)	63.9 (1.00)	SW-G
Switzerland	-	-	-	-	-	-	-	-	-	-	-
Turkey	-	-	-	-	-	TK-C	24.6 (0.56)	5.0 (0.11)	14.7 (0.33)	44.3 (1.00)	-
United Kingdom	UK-N1	61.3-62.9	9.7-11.3	8.1	77.4-80.6	UK-C1/C2	27.4-33.9	11.3-12.9	19.4	58.1-66.1	UK-G
United States	US1-N	37.7 (0.63)	16.4 (0.28)	5.5 (0.09)	59.6 (1.00)	US1-C	32.8 (0.55)	10.2 (0.17)	17.1 (0.28)	60.1 (1.00)	US1-G
	US2-N	39.6 (0.64)	16.4 (0.27)	5.5 (0.09)	61.5 (1.00)	US2-C	32.7 (0.49)	9.6 (0.14)	24.0 (0.35)	66.3 (1.00)	US2-G
	US3-N	36.7 (0.63)	16.4 (0.28)	5.5 (0.09)	58.6 (1.00)	US3-C	31.5 (0.63)	7.3 (0.15)	11.2 (0.22)	50.0 (1.00)	US3-G
China	CH-N	29.6 (0.64)	6.7 (0.15)	9.9 (0.21)	46.2 (1.00)	CH-C	19.3 (0.44)	5.3 (0.12)	19.2 (0.44)	43.8 (1.00)	-
CSFR	CS-N	23.7 (0.59)	7.4 (0.18)	9.3 (0.23)	40.4 (1.00)	CS-C	22.1 (0.52)	7.5 (0.18)	12.5 (0.30)	42.1 (1.00)	CS-G
Hungary	HN-N (c)	34.8 (0.78)	4.4 (0.10)	5.5 (0.12)	44.7 (1.00)	HN-C1 (c,f)	39.3 (0.56)	11.0 (0.16)	19.4 (0.28)	69.7 (1.00)	HN-G (c)
						HN-C2 (c)	25.6 (0.48)	4.7 (0.09)	22.6 (0.43)	52.9 (1.00)	
India	IN-N	33.7 (g) (0.64)	12.0 (0.23)	7.1 (0.13)	52.9 (1.00)	IN-C	23.4 (g) (0.44)	4.2 (0.08)	25.5 (0.48)	53.1 (1.00)	-
Korea	KR-N1	37.6 (0.74)	7.4 (0.15)	6.0 (0.12)	51.1 (1.00)	KR-C	19.3 (0.38)	8.9 (0.17)	22.9 (0.45)	51.1 (1.00)	-
	KR-N2	29.7 (0.66)	11.9 (0.27)	3.2 (0.07)	44.8 (1.00)						
Russia (h)	RF-N (c)	[1.25] (0.57)	[0.23] (0.11)	[0.69] (0.32)	[2.18] (1.00)	RF-C (c)	[1.12] (0.47)	[0.53] (0.22)	[0.75] (0.31)	[2.41] (1.00)	-
(Category-B) Canada	CA4-N	50.8 (0.77)	12.2 (0.18)	2.9 (0.04)	65.8 (1.00)	CA3-C	20.1 (0.47)	6.2 (0.14)	16.8 (0.39)	43.1 (1.00)	
Netherlands	NL-N	38.9 (0.63)	14.0 (0.23)	8.6 (0.14)	61.5 (1.00)	NL-C2	26.3 (0.49)	5.7 (0.11)	21.9 (0.41)	53.8 (1.00)	
United Kingdom	UK-N2 (i)	40.3-45.2	9.7	8.1	58.1-62.9	UK-C3	29.0 (0.50)	11.3 (0.19)	17.7 (0.30)	58.1 (1.00)	

electricity generation costs
a proportion of the total generation cost is indicated in the parentheses under each cost item

(USmill of 1.7.1991/kWh)

Gas						Others							
Assumptions (a)		Investment	O & M	Fuel	Total	Estimate	Technology (b)	Assumptions (a)		Investment	O & M	Fuel	Total
LT (yr)	LF (%)							LT (yr)	LF (%)				
20	75	15.0 (0.32)	5.2 (0.11)	26.6 (0.57)	46.7 (1.00)	-	-	-	-	-	-	-	-
30	75	13.1 (0.23)	2.2 (0.04)	40.7 (0.73)	56.0 (1.00)	-	-	-	-	-	-	-	-
35	76	14.4 (0.44)	3.1 (0.10)	14.9 (0.46)	32.4 (1.00)								
30	75	13.8 (0.33)	3.6 (0.09)	23.9 (0.58)	41.3 (1.00)	DE-W	Wind	20	25	50.0 (0.86)	8.5 (0.14)	0	58.5 (1.00)
30	75	13.2 (0.31)	3.7 (0.09)	26.4 (0.61)	43.2 (1.00)								
25	80	9.3 (0.23)	5.4 (0.13)	25.5 (0.63)	40.2 (1.00)	-	-	-	-	-	-	-	-
20	83	10.9 (0.19)	4.1 (0.07)	42.9 (0.74)	57.9 (1.00)	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	75	17.3 (0.27)	4.2 (0.07)	42.0 (0.66)	63.5 (1.00)	-	-	-	-	-	-	-	-
30	75	22.9 (0.28)	7.0 (0.09)	51.4 (0.63)	81.3 (1.00)	-	-	-	-	-	-	-	-
25	75	15.2 (0.26)	3.1 (0.05)	39.5 (0.68)	57.8 (1.00)	-	-	-	-	-	-	-	-
25	85	10.4 (0.21)	2.6 (0.05)	35.7 (0.73)	48.8 (1.00)	-	-	-	-	-	-	-	-
25	85	10.4 (0.23)	2.6 (0.06)	31.3 (0.71)	44.3 (1.00)								
20	75	18.8 (0.30)	5.7 (0.09)	38.9 (0.61)	63.4 (1.00)	-	-	-	-	-	-	-	-
25	75	15.3 (0.24)	5.9 (0.09)	<42.8 (d) (0.67)	<63.9 (d) (1.00)	-	-	-	-	-	-	-	-
-	-	-	-	-	-	SL-S	SSH	80	54	136.7 (0.89)	17.3 (0.11)	0	154.0 (1.00)
-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	90	9.7 (0.21)	6.5 (0.14)	30.6 (0.65)	46.8 (1.00)	UK-W	Wind	15	27	101.0 (0.89)	12.1 (0.11)	0	112.9 (1.00)
						UK-L	LFG	15	95	21.0 (0.45)	25.8 (0.55)	0	46.8 (1.00)
						UK-M	MWI	20	80	58.1	74.2	-83.9 (e)	48.4
						UK-S	SSH	20	60	21.0-72.6	3.2-12.9	0	24.2-85.5
30	75	11.0 (0.22)	2.5 (0.05)	36.7 (0.73)	50.1 (1.00)	-	-	-	-	-	-	-	-
30	75	11.0 (0.21)	2.5 (0.05)	40.1 (0.75)	53.5 (1.00)								
30	75	11.0 (0.21)	2.5 (0.05)	38.1 (0.74)	51.5 (1.00)								
-	-	-	-	-	-								
25	75	11.5 (0.28)	2.8 (0.07)	26.3 (0.65)	40.6 (1.00)								
20	85	5.6 (0.14)	2.2 (0.05)	32.3 (0.80)	40.2 (1.00)								
-	-	-	-	-	-								
-	-	-	-	-	-								
-	-	-	-	-	-								

(a) LT : Lifetime. LF : Settled-down Load Factor.
(b) LFG : Land Fill Gas Plant.
MWI : Municipal Waste Incineration.
SSH : Small Scale Hydro.
(c) Data were calculated with slightly different assumptions on operating hours from those shown in Table 6.
(d) Swedish utilities expect a natural gas price that will make the production costs from gas-fired power plants inferior to, or equally expensive as those of, coal-fired power plants.
(e) The figure is negative because of the credit for avoidance of transport and landfill site costs.
(f) Load factor is 65%
(g) Working capital estimated approximately 2% of the investment costs are included.
(h) 0.01 rouble of 1989/kWh
(i) Lifetime is 40 years.

Table 22 **Summary of electricity generation costs with national calculations** (a)

(USmill of 1.7.1991/kWh)

Country	Nuclear					Coal					Gas				
	Estimate	Invest-ment	O&M	Fuel	Total	Estimate	Invest-ment	O&M	Fuel	Total	Estimate	Invest-ment	O&M	Fuel	Total
Belgium	BE-N	-	-	-	-	BE-C	-	-	-	-	BE-G	-	-	-	-
Canada	CA1-N	23.8	6.5	2.4	32.6	CA1-C	14.8	5.0	16.0	35.8	CA1-G	16.0	4.2	43.9	64.0
						CA2-C	NS	NS	NS	29.8	CA2-G	NS	NS	NS	37.7
						CA4-C	14.1	7.5	16.6	38.2					
Denmark	-	-	-	-	-	DE-C	11.2	7.3	16.5	35.0	DE-G1	7.5	3.6	23.9	35.0
											DE-G2	7.2	3.6	26.4	37.2
Finland	FI-N	19.6	5.1	5.8	30.6	FI-C	10.3	6.5	18.7	35.5	FI-G	5.8	4.0	25.5	35.3
France	FR-N	22.2	9.6	9.1	40.9	FR-C	16.2	8.8	28.7	53.7	FR-G	9.1	4.1	43.2	56.6
Germany	GE-N	-	-	-	-	GE-C	-	-	-	-	-	-	-	-	-
Italy	-	-	-	-	-	IT-C	22.5	8.9	20.8	52.3	IT-G	11.8	4.5	42.9	59.1
Japan	JP-N	-	-	-	-	JP-C	-	-	-	-	JP-G	-	-	-	-
Netherlands	-	-	-	-	-	NL-C1	11.8	4.7	24.8	41.3	NL-G	9.2	3.1	40.1	52.4
Portugal	-	-	-	-	-	PT-C	28.0	5.8	23.1	57.0	PT-G1	10.4	2.6	35.7	48.8
											PT-G2	-	-	-	-
Spain	-	-	-	-	-	SP-C1	-	-	-	-	SP-G	-	-	-	-
						SP-C2	-	-	-	-					
Sweden	-	-	-	-	-	SW-C	-	-	-	-	SW-G	-	-	-	-
Turkey	-	-	-	-	-	TK-C	22.0	3.0	19.4	44.4	-	-	-	-	-
United Kingdom	UK-N1	-	-	-	-	UK-C1	-	-	-	-	UK-G	-	-	-	-
						UK-C2	-	-	-	-					
United States	US1-N	28.8	17.5	5.3	51.6	US1-C	24.4	10.5	17.1	52.0	US1-G	8.5	2.4	38.1	49.2
	US2-N	-	-	-	-	US2-C	-	-	-	-	US2-G	-	-	-	-
	US3-N	-	-	-	-	US3-C	-	-	-	-	US3-G	-	-	-	-
China	CH-N	26.0	7.5	9.7	43.2	CH-C	21.9	5.9	19.2	47.0	-	-	-	-	-
CSFR	CS-N	30.9	15.1	9.0	55.0	CS-C	39.5	20.9	12.5	72.9	CS-G	26.0	8.2	26.4	60.6
Hungary	HN-N	NS	NS	NS	52.7	HN-C1	NS	NS	NS	80.0	HN-G	NS	NS	NS	41.2
						HN-C2	NS	NS	NS	58.7					
India	IN-N	40.6	13.9	7.1	61.7	IN-C	28.3	4.8	25.6	58.7	-	-	-	-	-
Korea	KR-N1	29.4	7.4	5.7	42.5	KR-C	15.6	8.8	22.9	47.3	-	-	-	-	-
	KR-N2	24.0	11.8	3.1	39.0										
Russia (b)	RF-N	NS	NS	NS	(2.4)	RF-C	NS	NS	NS	(2.7)	-	NS	NS	NS	(2.5)
(Category-B)															
Canada	CA4-N	27.3	12.3	2.9	42.5	CA3-C	11.8	6.2	16.8	34.7					
Netherlands	NL-N	21.9	13.8	8.7	44.4	NL-C2	14.7	5.7	22.1	42.5					
United Kingdom	UK-N2	-	-	-	-	UK-C3	-	-	-	-					

(a) See Table 5 for parameters.

(b) 0.01 rouble of 1989/kWh

NS : Not specified.

Table 23 **Generation cost ratios**

Country	Nuclear / Coal		Nuclear / Gas		Coal / Gas	
	Discount rate		Discount rate		Discount rate	
	5%	10%	5%	10%	5%	10%
Belgium	0.91	1.09	0.88	1.14	0.97	1.05
Canada						
- centre	0.88	1.15	0.57	0.88	0.65	0.77
- west	-	-	-	-	0.88	1.05
Denmark						
CCGT	-	-	-	-	1.00	1.07
Gas conventional plant					0.94	1.03
Finland	0.86	1.06	0.85	1.16	0.99	1.09
France	0.65	0.77	0.60	0.78	0.92	1.02
Germany						
domestic coal	0.66	0.83	-	-	-	-
imported coal	0.79	0.97				
Italy	-	-	-	-	0.82	1.01
Japan	0.85	0.94	0.69	0.92	0.82	0.98
Netherlands	-	-	-	-	0.79	0.87
Portugal						
reference gas price	-	-	-	-	1.01	1.24
low gas price					1.16	1.36
Spain						
domestic coal	-	-	-	-	1.42	1.56
imported coal					0.98	1.13
Sweden (a)	-	-	-	-	1.00	1.00
United Kingdom (b)	1.02	1.27	1.11	1.69	1.09	1.33
United States						
- midwest	0.96	0.99	0.90	1.19	0.94	1.20
- northeast	0.85	0.93	0.86	1.15	1.00	1.24
- west	1.19	1.17	0.86	1.14	0.72	0.97
China	0.86	1.05	-	-	-	-
CSFR	0.87	0.96	0.80	1.00	0.91	1.04
Hungary						
coal	0.73	0.84	0.79	1.11	1.08	1.32
lignite	0.58	0.64			1.35	1.73
India	0.86	1.00	-	-	-	-
Korea						
PWR	0.75	1.00	-	-	-	-
PHWR	0.74	0.88				
Russia	0.78	0.80	-	-	-	-
(Category-B)						
Canada						
CA4-N/CA3-C	1.22	1.53	-	-	-	-
Netherlands						
NL-N/NL-C2	1.04	1.14	-	-	-	-
United Kingdom (b)						
UK-N2/UK-C3	0.91	1.04	-	-	-	-

(a) Swedish utilities expect a natural gas price that will make the production costs from gas-fired power plants inferior to, or equally expensive as those of, coal-fired power plants.
(b) Calculated using average numbers.

Table 24 **General summary of levelised electricity generation costs**
(Discount rate : 5% p.a.)

(USmill of 1.7.1991/kWh)

Country	Nuclear						Coal						Gas		
	Lifetime (yr)	25	30			40	Lifetime (yr)	25	30			40	Estimate	Lifetime (yr) / L.F. (%) (a)	Costs
	L.F. (%) (a) Estimate	75	65	75	80	75	L.F.(%) (a) Estimate	75	65	75	80	75			
Belgium	BE-N	NS	NS	35.9	NS	NS	BE-C	NS	NS	39.4	NS	NS	BE-G	20/75	40.8
Canada (b)	CA1-N (c)	31.8	34.2	29.8	28.1	29.3	CA1-C (c) CA2-C CA4-C	35.0 26.3 41.7	36.1 27.7 43.7	34.0 25.4 38.2	33.4 24.6 36.2	33.0 24.5 34.1	CA1-G (c) CA2-G	30/75 35/76	52.2 28.8
Denmark	-	-	-	-	-	-	DE-C	36.0	37.1	35.0	34.1	33.7	DE-G1 DE-G2	30/75 30/75	35.0 37.2
Finland	FI-N	32.0	33.2	30.1	29.0	27.8	FI-C	36.0	36.7	35.0	34.6	34.1	FI-G	25/80	35.3
France	FR-N	34.7	36.4	32.8	31.5	30.7	FR-C	54.0	53.5	50.6	49.4	46.7	FR-G	20/83	54.8
Germany	GE-N	55.8	62.0	53.1	50.9	50.1	GE-C1 GE-C2	81.7 NS	86.3 NS	80.1 67.4	79.0 NS	78.5 NS	-	-	-
Italy	-	-	-	-	-	-	IT-C	50.1	52.3	48.4	47.0	46.5	IT-G	30/75	58.6
Japan	JP-N	55.8	58.7	53.7	51.8	51.2	JP-C	64.1	67.0	63.0	61.5	62.1	JP-G	30/75	77.3
Netherlands	-	-	-	-	-	-	NL-C1	42.4	43.5	41.3	40.5	40.1	NL-G	25/75	52.4
Portugal	-	-	-	-	-	-	PT-C	48.6	50.8	47.5	46.2	46.6	PT-G1 PT-G2	25/85 25/85	46.9 41.1
Spain	-	-	-	-	-	-	SP-C1 SP-C2	NS NS	NS NS	80.4 55.5	NS NS	NS NS	SP-G	20/75	56.7
Sweden	-	-	-	-	-	-	SW-C	NS	NS	48.8	NS	NS	SW-G	25/75	< 48.8
Turkey	-	-	-	-	-	-	TK-C	NS	NS	38.5	NS	NS	-	-	-
United Kingdom	UK-N1	51.6-54.8	54.8-58.1	48.4-51.6	46.8-48.4	45.2-48.4	UK-C1&C2	53.2-54.8	51.6-56.5	46.8-51.6	45.2-50.0	45.2-50.0	UK-G	30/90	45.2
United States (d)	US1-N US2-N US3-N	44.0 NS NS	48.0 NS NS	42.7 43.7 42.1	40.6 NS NS	40.6 NS NS	US1-C US2-C US3-C	46.2 NS NS	47.8 NS NS	44.7 51.3 35.3	43.4 NS NS	43.0 NS NS	US1-G US2-G US3-G	30/75 30/75 30/75	47.7 51.1 49.1
China	CH-N	32.3	33.8	30.7	29.7	29.1	CH-C	36.1	37.8	35.7	35.0	35.9	-	-	-
CSFR	CS-N	30.1	32.3	28.9	27.7	27.6	CS-C	33.9	35.7	33.1	32.2	32.5	CS-G	25/75	36.3
Hungary	HN-N (c)	33.4	33.9	30.3	28.8	27.1	HN-C1 (c) HN-C2 (c)	NS 42.6	51.8 44.2	NS 41.3	NS 40.1	NS 39.8	HN-G (c)	20/85	38.4
India	IN-N	37.7	40.2	36.1	34.7	34.4	IN-C	43.3	44.5	42.1	41.2	40.8	-	-	-
Korea	KR-N1 KR-N2	33.8 33.0	35.9 35.5	32.0 31.5	30.6 30.0	29.9 29.7	KR-C	43.5	45.3	42.5	41.5	41.4	-	-	-
Russia (e)	RF-N (c)	(1.68)	(1.74)	(1.59)	(1.53)	(1.49)	RF-C (c)	NS	NS	(1.86)	NS	NS	-	-	-
(Category-B)															
Canada	CA4-N	46.5	48.6	42.5	40.3	38.0	CA3-C	35.8	37.3	34.7	33.8	33.5			
Netherlands	NL-N	46.6	49.5	44.4	42.5	41.9	NL-C2	NS	NS	42.5	NS	NS			
United Kingdom	UK-N2	NS	NS	NS	NS	40.3-41.9	UK-C3	NS	NS	45.2	NS	NS			

(a) Settled-down Load Factor.
(b) CA1 = Centre CA2 = West CA3 & CA4 = East
(c) Data were calculated with slightly different assumptions on operating hours from those shown in Table 6.
(d) US1 = Midwest US2 = Northeast US3 = West
(e) 0.01 rouble of 1989/kWh
NS : Not specified.

Table 25 **General summary of levelised electricity generation costs**
(Discount rate : 10% p.a.)

(USmill of 1.7.1991/kWh)

Country	Nuclear						Coal						Gas		
	Lifetime (yr)	25	30			40	Lifetime (yr)	25	30			40	Estimate	Lifetime (yr) / L.F. (%) (a)	Costs
	L.F. (%) (a)	75	65	75	80	75	L.F. (%) (a)	75	65	75	80	75			
	Estimate						Estimate								
Belgium	BE-N	NS	NS	53.2	NS	NS	BE-C	NS	NS	48.9	N.S.	N.S.	BE-G	20/75	46.7
Canada (b)	CA1-N (c)	51.1	56.8	49.5	46.5	48.9	CA1-C (c) CA2-C CA4-C	43.7 34.4 49.9	46.1 37.2 54.5	43.0 33.9 48.0	42.0 32.5 45.7	42.4 33.1 46.2	CA1-G (c) CA2-G	30/75 35/76	56.0 32.4
Denmark	-	-	-	-	-	-	DE-C	45.0	47.4	44.1	42.8	43.4	DE-G1 DE-G2	30/75 30/75	41.3 43.2
Finland	FI-N	48.1	51.9	46.7	44.9	45.3	FI-C	44.6	46.7	43.9	43.0	43.5	FI-G	25/80	40.2
France	FR-N	46.5	49.8	45.2	43.4	44.0	FR-C	60.7	63.0	58.9	57.4	57.1	FR-G	20/83	57.9
Germany	GE-N	79.5	86.4	77.4	74.1	75.5	GE-C1 GE-C2	98.5 NS	99.3 NS	93.6 80.1	90.2 NS	94.4 NS	-	-	-
Italy	-	-	-	-	-	-	IT-C	65.1	69.6	63.8	61.7	62.5	IT-G	30/75	63.5
Japan	JP-N	76.3	82.4	74.6	71.8	73.0	JP-C	80.6	85.8	79.6	77.4	78.8	JP-G	30/75	81.3
Netherlands	-	-	-	-	-	-	NL-C1	51.1	53.7	50.3	49.1	49.5	NL-G	25/75	57.8
Portugal	-	-	-	-	-	-	PT-C	61.4	65.2	60.4	58.4	59.6	PT-G1 PT-G2	25/85 25/85	48.8 44.3
Spain	-	-	-	-	-	-	SP-C1 SP-C2	NS NS	NS NS	98.9 71.8	NS NS	NS NS	SP-G	20/75	63.4
Sweden	-	-	-	-	-	-	SW-C	NS	NS	63.9	NS	NS	SW-G	25/75	< 63.9
Turkey	-	-	-	-	-	-	TK-C	NS	NS	44.3	NS	NS	-	-	-
United Kingdom	UK-N1	79.0-83.9	87.1-91.9	77.4-80.6	72.6-77.4	74.2-79.0	UK-C1&C2	59.7-67.7	64.5-72.6	58.1-66.1	56.4-62.9	56.4-64.5	UK-G	30/90	46.8
United States (d)	US1-N US2-N US3-N	61.1 NS NS	62.8 NS NS	59.6 61.5 58.6	53.2 NS NS	58.9 NS NS	US1-C US2-C US3-C	61.4 NS NS	59.7 NS NS	60.1 66.3 50.0	53.8 NS NS	59.0 NS NS	US1-G US2-G US3-G	30/75 30/75 30/75	50.1 53.5 51.5
China	CH-N	47.5	51.2	46.2	44.4	45.0	CH-C	44.3	47.0	43.8	42.7	43.6	-	-	-
CSFR	CS-N	41.4	45.2	40.4	38.8	39.5	CS-C	42.8	45.8	42.1	40.8	41.6	CS-G	25/75	40.6
Hungary	HN-N (c)	47.3	51.0	44.7	42.0	42.5	HN-C1 (c) HN-C2 (c)	NS 53.9	69.7 57.6	NS 52.9	NS 51.0	NS 52.0	HN-G (c)	20/85	40.2
India	IN-N	54.2	58.9	52.9	50.7	51.6	IN-C	54.0	56.8	53.1	51.8	52.2	-	-	-
Korea	KR-N1 KR-N2	52.6 46.0	57.3 50.5	51.1 44.8	48.8 42.8	49.7 43.7	KR-C	51.9	54.9	51.1	49.7	50.3	-	-	-
Russia (e)	RF-N (c)	(2.24)	(2.40)	(2.18)	(2.08)	(2.12)	RF-C (c)	NS	NS	(2.41)	NS	NS	-	-	-
(Category-B)															
Canada	CA4-N	68.4	74.7	65.8	62.6	63.4	CA3-C	43.9	46.7	43.1	41.8	42.4			
Netherlands	NL-N	63.3	68.7	61.5	59.0	59.9	NL-C2	NS	NS	53.8	NS	NS			
United Kingdom	UK-N2	NS	NS	NS	NS	58.1-62.9	UK-C3	NS	NS	58.1	NS	NS			

(a) Settled-down Load Factor.
(b) CA1 = Centre CA2 = West CA3 & CA4 = East
(c) Data were calculated with slightly different assumptions on operating hours from those shown in Table 6.
(d) US1 = Midwest US2 = Northeast US3 = West
(e) 0.01 rouble of 1989/kWh
NS : Not specified.

Table 26 **Factors to make generation costs break-even** (a)

Country	Nuclear to Coal						Nuclear to Gas						Coal to Gas					
	Factors for investment		Factors for load factor		Factors for O&M costs		Factors for investment		Factors for load factor		Factors for O&M costs		Factors for investment		Factors for load factor		Factors for O&M costs	
Discount Rate	5%	10%	5%	10%	5%	10%	5%	10%	5%	10%	5%	10%	5%	10%	5%	10%	5%	10%
Belgium	1.17	0.88	NS	NS	1.47	0.42	1.24	0.83	NS	NS	1.65	0.12	1.11	0.90	NS	NS	1.28	0.56
Canada																		
- centre	1.18	0.85	0.87	1.14	1.79	(c)	1.98	1.15	0.33	0.88	5.23	2.20	2.26	1.56	0.57	0.73	5.44	4.25
Denmark (DE-G1)	-	-	-	-	-	-	-	-	-	-	-	-	1.00	0.86	1.00	(d)	1.00	0.62
Finland	1.26	0.92	0.81	1.08	1.91	0.48	1.28	0.81	0.81	1.21	1.96	(c)	1.03	0.79	0.98	1.25	1.04	0.53
France	2.22	1.52	0.58	0.72	2.79	2.42	2.52	1.48	0.52	0.73	3.21	2.32	1.36	0.95	1.21	0.97	1.45	0.89
Germany (GE-C1)	1.91	1.30	0.61	0.81	3.13	2.24	-	-	-	-	-	-	-	-	-	-	-	-
Italy	-	-	-	-	-	-	-	-	-	-	-	-	1.53	0.99	0.71	1.01	2.23	0.97
Japan	1.38	1.11	0.85	0.94	1.85	1.45	1.97	1.14	0.69	0.92	3.16	1.60	1.69	1.05	0.82	0.98	2.80	1.22
Netherlands	-	-	-	-	-	-	-	-	-	-	-	-	1.94	1.36	0.63	0.80	3.16	2.40
Portugal (PT-G1)	-	-	-	-	-	-	-	-	-	-	-	-	0.96	0.62	1.04	(d)	0.91	(c)
Spain (SP-C2)	-	-	-	-	-	-	-	-	-	-	-	-	1.06	0.78	NS	NS	1.27	(c)
Sweden	-	-	-	-	-	-	-	-	-	-	-	-	(e)	(e)	(e)	(e)	(e)	(e)
United Kingdom																		
- PWR (b)	0.97	0.73	1.02	1.30	0.92	(c)	0.85	0.48	1.07	(d)	0.54	(c)	0.77	0.50	NS	NS	0.67	(c)
- APWR (b)	1.35	1.04	0.84	0.97	1.84	1.16	1.18	0.68	0.88	1.25	1.42	(c)						
United States																		
- midwest	1.09	1.01	0.96	0.99	1.12	1.03	1.24	0.75	0.90	1.19	1.30	0.42	1.17	0.70	0.94	1.20	1.29	0.02
- northeast	1.34	1.12	0.85	0.93	1.46	1.29	1.33	0.80	0.86	1.15	1.45	0.51	0.99	0.61	1.00	1.24	0.98	(c)
- west	0.67	0.77	1.19	1.17	0.59	0.48	1.34	0.81	0.86	1.14	1.43	0.57	1.82	1.05	0.72	0.97	2.89	1.21
China	1.33	0.92	0.82	1.08	1.76	0.65	-	-	-	-	-	-	-	-	-	-	-	-
CSFR	1.35	1.07	0.87	0.96	1.57	1.23	1.61	1.01	1.26	1.00	2.00	1.03	1.26	0.93	NS	NS	1.43	0.84
Hungary (HN-C2)	1.58	1.24	0.68	0.82	3.5	2.9	1.43	0.87	0.74	1.13	2.8	(c)	0.79	0.50	1.18	(d)	0.38	(c)
India	1.35	1.01	0.81	0.99	1.50	1.02	-	-	-	-	-	-	-	-	-	-	-	-
Korea - PWR	1.54	1.00	0.72	1.00	2.43	1.00	-	-	-	-	-	-	-	-	-	-	-	-
- PHWR	1.66	1.21	0.72	0.87	1.94	1.53	-	-	-	-	-	-	-	-	-	-	-	-
Russia	1.38	1.18	NS	NS	2.17	2.00	-	-	-	-	-	-	-	-	-	-	-	-

(a) Factors for investment costs (e.g. for Nuclear to Coal): When the investment cost of the nuclear generation is multiplied with the factor, the total generation cost should be equal to corresponding coal-fired generation cost.
Factors for load factor (e.g. for Nuclear to Coal): When the load factor of the nuclear generation is multiplied with the factor, the total generation cost should be equal to corresponding coal-fired generation cost.
Factors for O&M costs (e.g. for Nuclear to Coal): When the O&M costs of the nuclear generation is multiplied with the factor, the total generation cost should be equal to corresponding coal-fired generation cost.
(b) Based on average numbers in Tables 20 and 21.
(c) Since difference between the total generation costs of the two generating options is larger than the O&M costs, break-even cannot be achieved by reduction of the O&M costs.
(d) The correspondent multiplier would result in a load factor for nuclear or coal higher than 100%.
(e) Swedish utilities expect a natural gas price that will make the production costs from gas-fired power plants inferior to, or equally expensive as those of, coal-fired power plants.

NS : Not specified.

Table 27 **Break-even discount rates** (a)

Country	Nuclear to Coal	Nuclear to Gas	Coal to Gas
Belgium	NS	NS	NS
Canada			
- centre	7.0	12	22
Denmark (DE-G1)	-	-	5.0
Finland	8.6	7.4	5.3
France	18	15	NS
Germany (GE-C1)	NS	-	-
Italy	-	-	9.9
Japan	12.4	10.9	10.1
Netherlands	-	-	15
Portugal (PT-G1)	-	-	4.7
Spain (SP-C2)	-	-	NS
Sweden	-	-	(c)
United Kingdom			
- PWR (b)	4.7	4.3	4.9
- APWR (b)	8.1	6.9	-
United States			
- midwest	11.0	6.9	6.3
- northeast	15.5	7.6	5.0
- west	NS	7.7	10.5
China	7.8	-	-
CSFR	16.0	10.0	9.5
Hungary (HN-C2)	16.0	8.7	3.3
India	10.2	-	-
Korea - PWR	10.0	-	-
- PHWR	15.1	-	-
Russia	NS	-	-

(a) Break-even discount rates (e.g. for Nuclear to Coal): When discount rates are the same as the figures shown in the table, the total nuclear generation cost should be equal to corresponding coal-fired generation cost.

(b) Based on average numbers in Tables 20 and 21.

(c) Swedish utilities expect a natural gas price that will make the production costs from gas-fired power plants inferior to, or equally expensive as those of, coal-fired power plants.

NS : Not specified.

Table 28 **Break-even fuel costs**

Country	Coal to Nuclear		Gas to Nuclear		Gas to Coal	
	Factors for fuel costs of coal-fired plant (a)		Factors for fuel costs of gas-fired plant (a)		Factors for fuel costs of gas-fired plant (a)	
Discount Rate	5%	10%	5%	10%	5%	10%
Belgium	0.83	1.20	0.82	1.24	0.95	1.08
Canada						
- centre	0.73	1.41	0.46	0.84	0.56	0.68
Denmark (DE-G1)	-	-	-	-	1.00	1.12
Finland	0.74	1.15	0.80	1.25	0.99	1.15
France	0.39	0.53	0.49	0.70	0.90	1.02
Germany (GE-C1)	0.44	0.67	-	-	-	-
Italy	-	-	-	-	0.77	1.01
Japan	0.73	0.85	0.59	0.87	0.75	0.97
Netherlands	-	-	-	-	0.72	0.81
Portugal (PT-G1)	-	-	-	-	1.02	1.32
Spain (SP-C2)	-	-	-	-	0.97	1.22
Sweden	-	-	-	-	(c)	(c)
United Kingdom						
- PWR (b)	1.04	1.87	1.15	2.05	1.12	1.50
- APWR (b)	0.58	0.92	0.87	1.45	-	-
United States						
- midwest	0.88	0.97	0.87	1.26	0.92	1.27
- northeast	0.68	0.80	0.83	1.20	1.00	1.32
- west	1.61	1.77	0.83	1.18	0.66	0.96
China	0.75	1.12	-	-	-	-
CSFR	0.68	0.86	0.72	0.99	0.79	1.06
Hungary (HN-C2)	0.51	0.64	0.75	1.14	1.08	1.39
India	0.77	0.99	-	-	-	-
Korea - PWR	0.54	1.00	-	-	-	-
- PHWR	0.52	0.73	-	-	-	-
Russia	0.64	0.69	-	-	-	-

(a) Factors for fuel costs (e.g. for Coal to Nuclear): When the fuel costs of the coal-fired generation is multiplied with the factor, the total generation cost should be equal to corresponding nuclear generation cost.
(b) Based on average numbers in Tables 20 and 21.
(c) Swedish utilities expect a natural gas price that will make the production costs from gas-fired power plants inferior to, or equally expensive as those of, coal-fired power plants.

Table 29 **Ratio of overall generation cost to 1992 study cost on standard basis** (a)

Country		1983 study	1986 study	1989 study	1992 study
Belgium	N	1.07	1.08	0.98	1.00
	C	1.47	1.65	1.61	1.00
Canada - centre	N	0.96	0.96	0.98	1.00
	C	1.32	1.26	1.14	1.00
Finland	N	-	1.53	1.27	1.00
	C	-	1.83	1.32	1.00
France	N	0.97	1.08	1.00	1.00
	C	1.18	1.30	0.94	1.00
Germany	N	0.88	0.85	0.89	1.00
	C (b)	1.21	0.99	0.85	1.00
Japan	N	1.00	1.07	1.02	1.00
	C	1.38	1.29	1.12	1.00
Netherlands	N (c)	1.15	0.98	1.00	-
	C	1.58	1.30	0.93	1.00
United Kingdom	N	(d)	0.99	1.04	1.00
	C	1.88	1.76	1.13	1.00
USA - midwest	N	1.18	0.95	1.10	1.00
	C	1.23	1.04	0.96	1.00

(a) All costs in July 1991 money standardized to 5% p.a. discount rate, 30 year plant life and 75% settled down load factor.
(b) Indigenous coal.
(c) January 1987 money used as baseline.
(d) First-off costs not compatible with subsequent plants.

N : Nuclear C : Coal

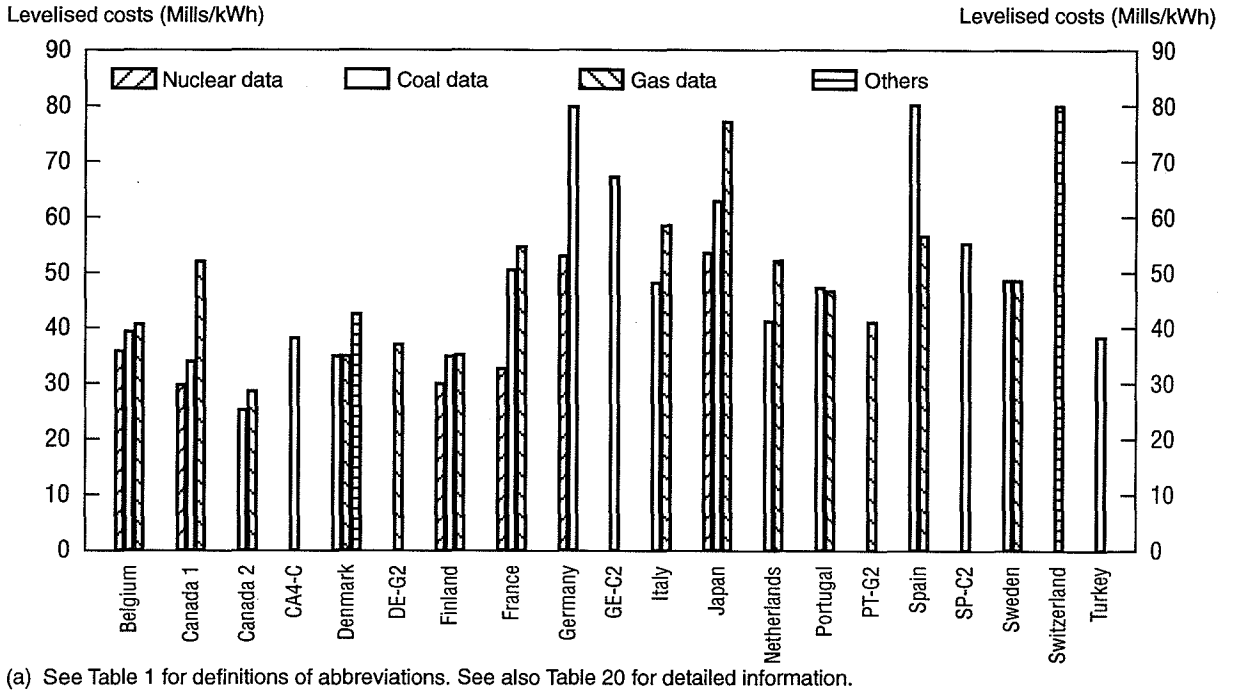
Table 30 **Change in component costs to 1992 study on standard basis** (a)

Country		Change in % (1992-1983)/1983			
		Investment	O&M	Fuel	Total
Belgium	N	+ 19.8	- 23.4	- 29.0	- 6.4
	C	+ 67.2	- 9.1	- 52.4	- 32.0
Canada - centre	N	+ 27.0	+ 36.4	- 73.5	+ 4.1
	C	+ 33.7	- 32.5	- 45.0	- 24.5
Finland	N (b)	- 24.8	- 21.2	- 58.2	- 34.6
	C (b)	- 32.4	- 18.7	- 55.0	- 45.4
France	N	+ 5.4	+ 60.4	- 30.6	+ 2.7
	C	+ 4.5	+ 89.1	- 32.1	- 15.0
Germany	N	+ 29.5	+ 45.4	- 29.1	+ 13.4
	C (c)	+ 47.9	+ 35.4	- 35.2	- 17.3
Japan	N	- 1.0	- 1.8	+ 1.9	- 0.0
	C	+ 17.9	- 20.4	- 41.8	- 27.3
Netherlands	N (d)	- 7.8	+ 15.7	- 30.5	- 13.3
	C	+ 9.1	- 34.8	- 47.4	- 36.6
United Kingdom	N (b)	+ 27.0	+ 11.3	- 46.3	+ 1.4
	C	- 21.4	+ 106.1	- 69.7	- 46.8
USA - midwest	N	- 28.0	+ 117.9	- 61.9	- 15.4
	C	+ 6.7	+ 35.5	- 44.7	- 18.4

(a) All costs in July 1991 money standardised to 5% p.a. discount rate, 30 year plant life and 75% settled down load factor.
(b) 1986 to 1992.
(c) Indigenous coal.
(d) 1983 to 1989.

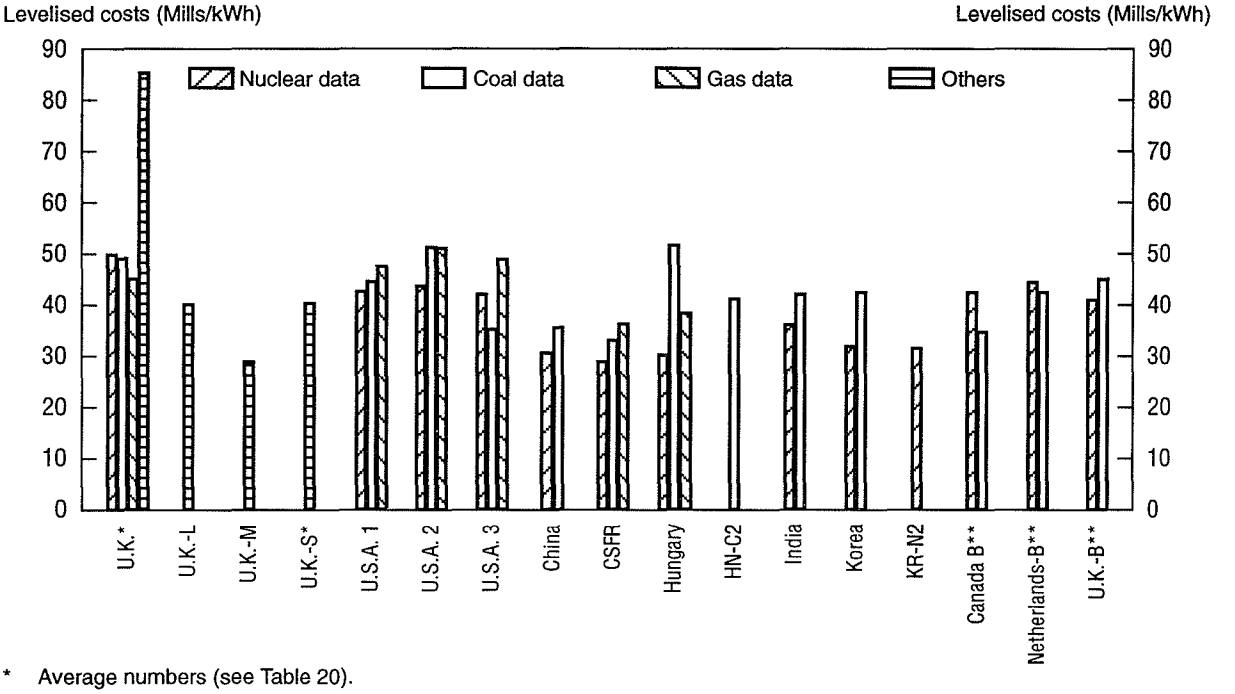
N : Nuclear C : Coal

Figure 1. **Summary of levelised electricity generation costs[a]**
Discount rate = 5% p.a.



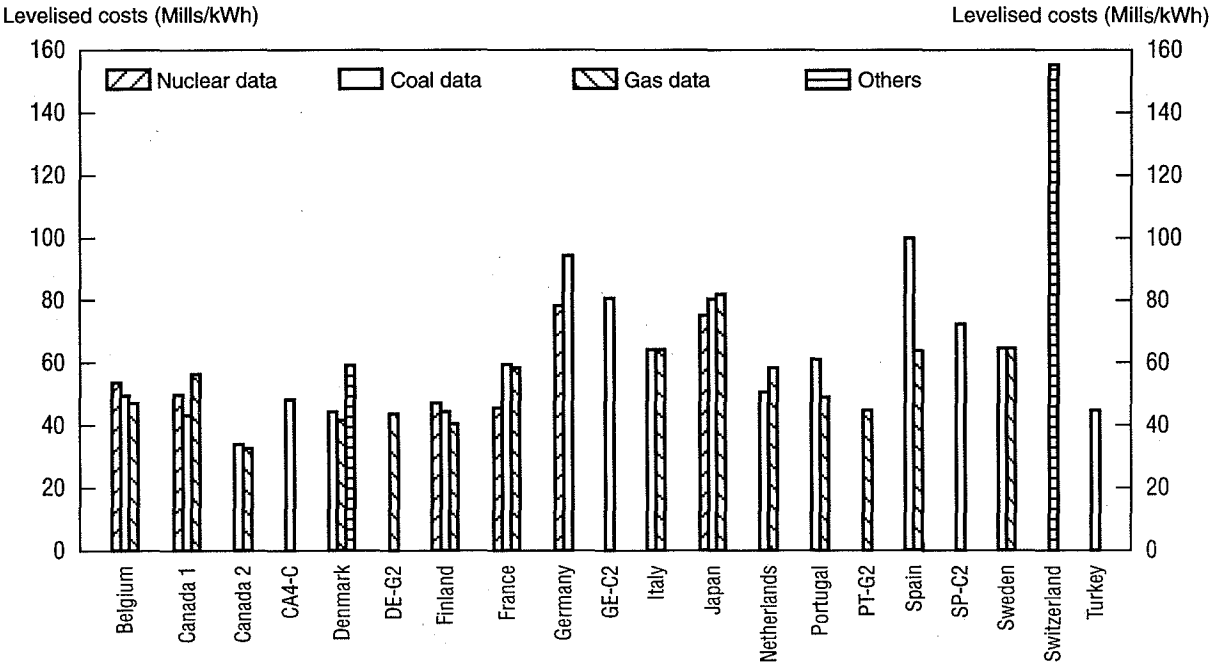
(a) See Table 1 for definitions of abbreviations. See also Table 20 for detailed information.

Figure 1(countinued). **Summary of levelised electricity generation costs**
Discount rate = 5% p.a.



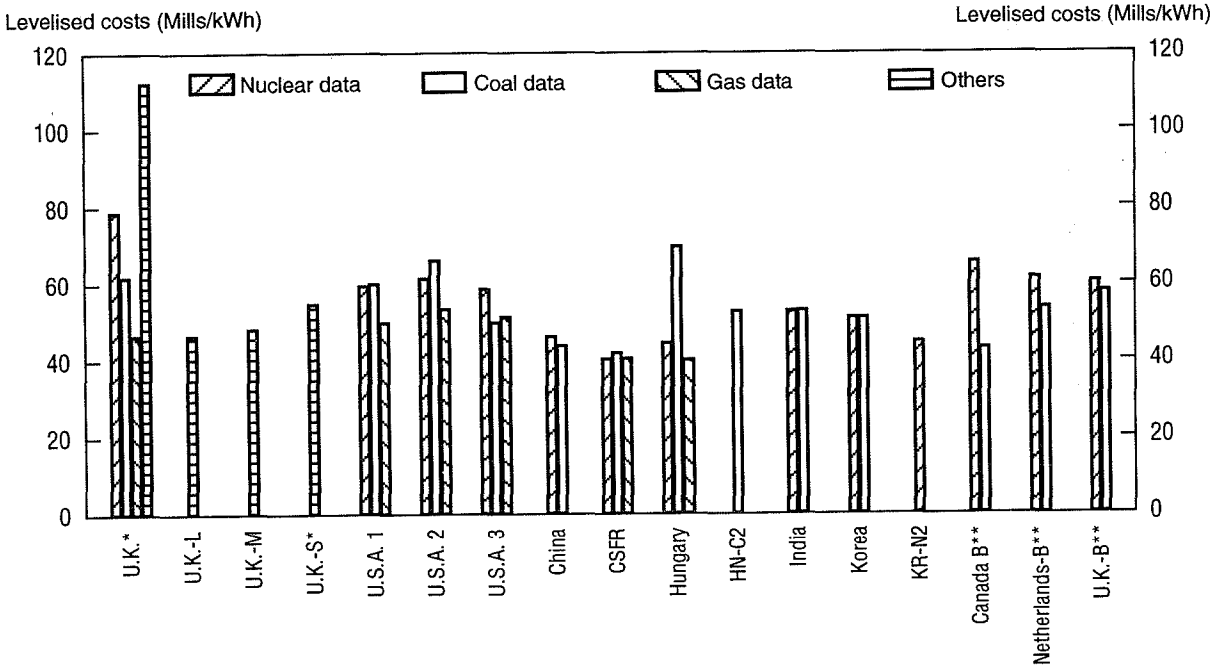
* Average numbers (see Table 20).
** Category-B estimates.

Figure 2. **Summary of levelised electricity generation costs**[a]
Discount rate = 10% p.a.



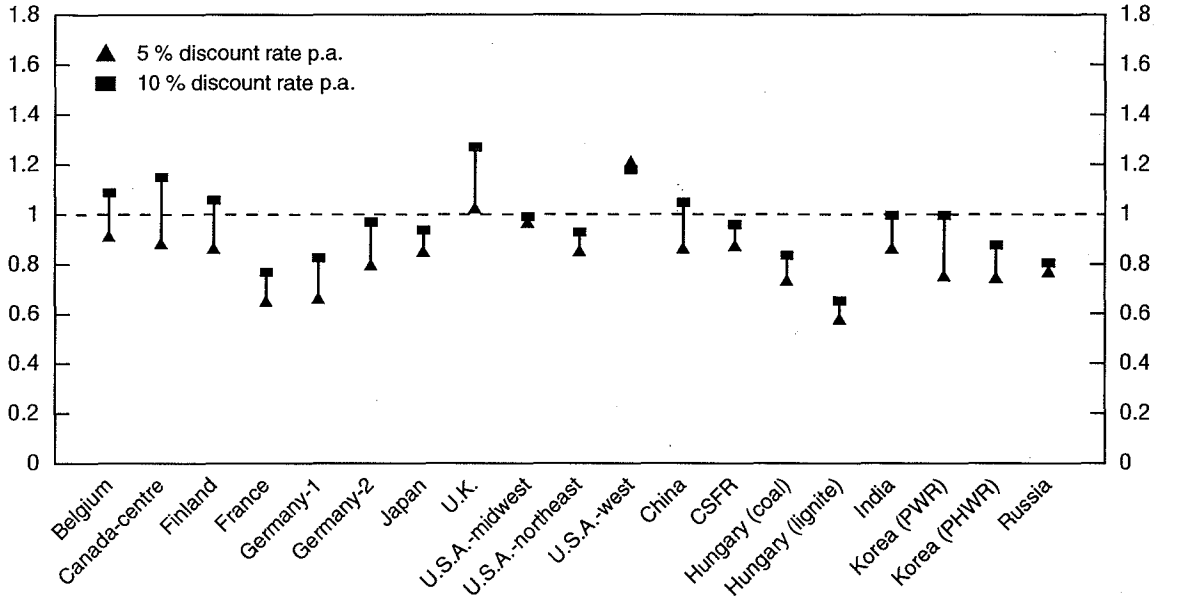
(a) See Table 1 for definitions of abbreviations. See also Table 21 for detailed information.

Figure 2 (continued). **Summary of levelised electricity generation costs**
Discount rate = 10% p.a.



* Average numbers (see Table 21).
** Category-B estimates.

Figure 3. **Generation cost ratio (Nuclear/Coal)**



1. Germany - Domestic coal.
2. Germany - Imported coal.

Figure 4. **Generation cost ratio (Nuclear/Gas)**

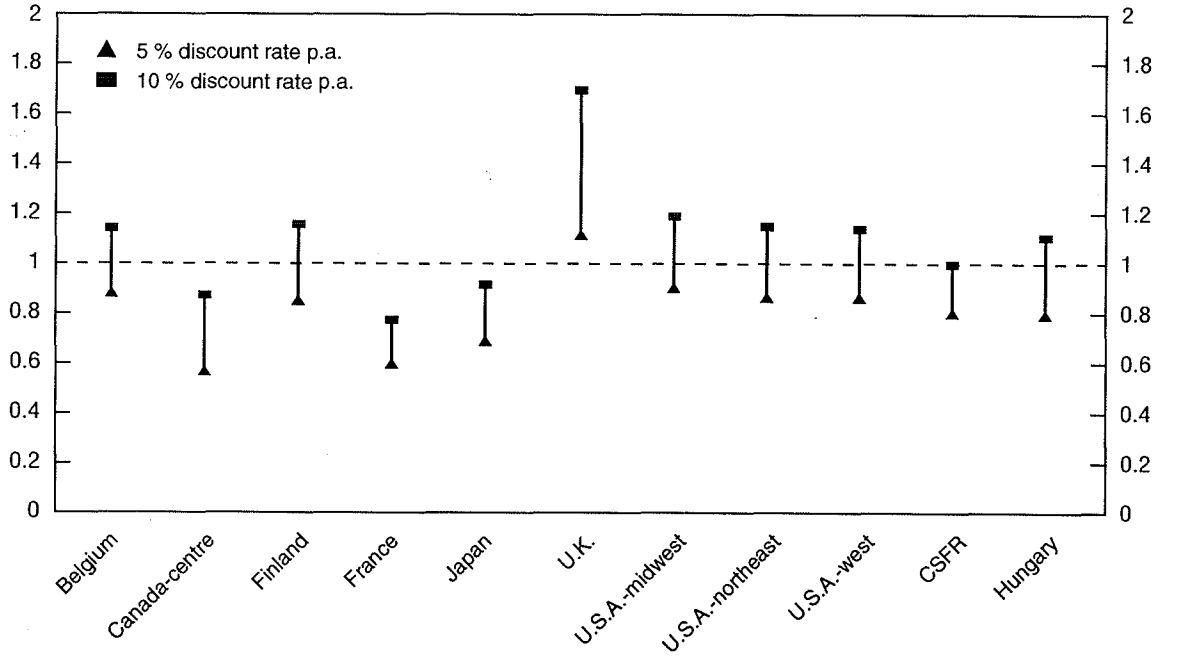
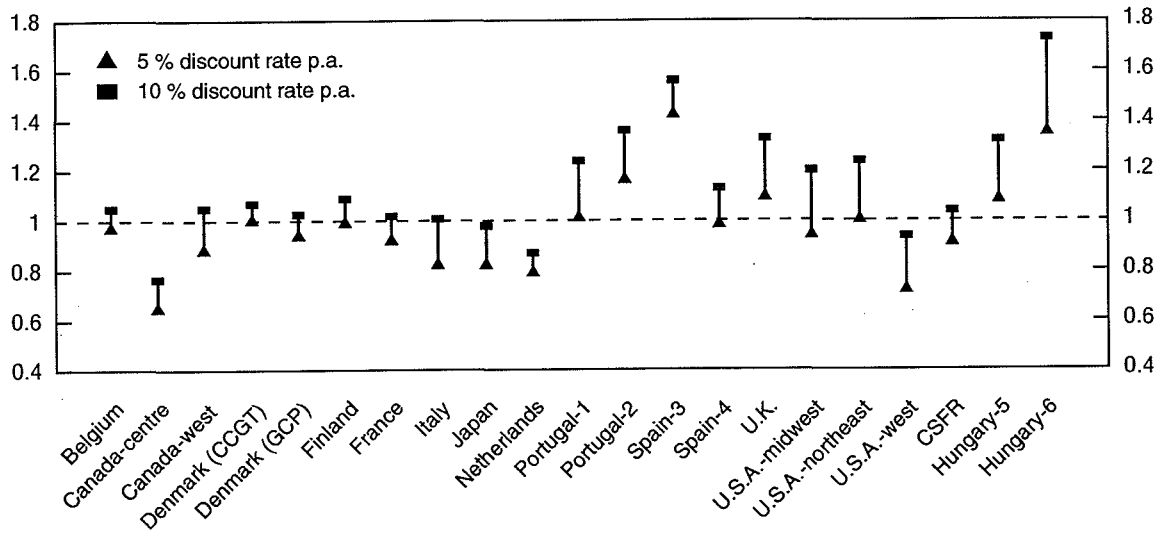
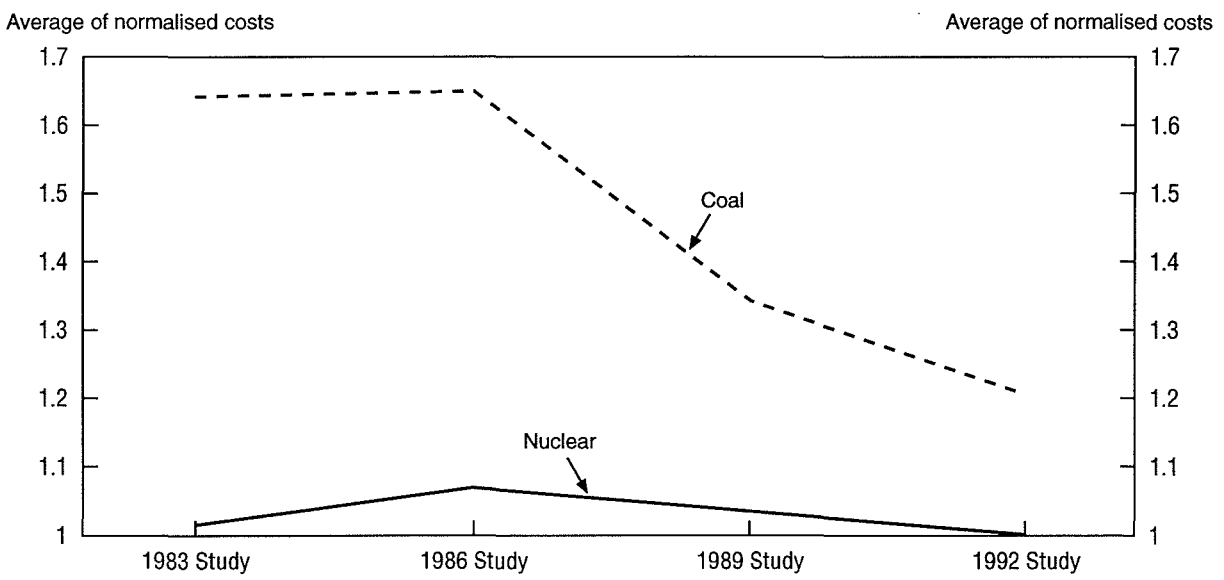


Figure 5. **Generation cost ratio (Coal/Gas)**



1. Portugal - Reference gas price.
2. Portugal - Low gas price.
3. Spain - Domestic coal.
4. Spain - Imported coal.
5. Hungary - Coal.
6. Hungary - Lignite.

Figure 6. **Trends of generation costs**



Cost results of Belgium, Canada-Centre, Finland, France, Germany, Japan, U.K., and U.S.A.-midwest were converted into July 1991 money, standardised to 5% p.a. discount rate, 30 year lifetime, and 75% load factor, and normalised to 1992 study nuclear cost results.

LIST OF ABBREVIATIONS AND GLOSSARY OF TERMS

Back-end (of the Fuel Cycle): Those nuclear fuel cycle processes and activities concerned with the treatment of spent fuel discharged from reactors.

Base load: The minimum load produced by an electricity network over a given period. A station used for a base load is a station that is normally operated to provide power continuously to meet the minimum load demands.

Burnup: The total energy released per unit mass of a nuclear fuel. Units normally used for are megawatt-days per tonne of uranium (MWd/tU), or heavy metal (MWd/tHM).

BWR: Boiling-Water Reactor.

CANDU: Canadian Deuterium Uranium Reactor; a type of pressurised heavy water reactor.

Carbon tax: A tax per unit of carbon ($ per tonne carbon, for example). In theory this tax would be applied to the amount of carbon emitted (in the form of CO_2, CO, or uncombusted carbon), but in practice it more likely would be applied to the carbon content of fuels.

Category A and Category B: These categories are set only for this study. Electricity generation technologies which are well established and the costs are well authenticated and predictable with confidence are called "Category A" technologies. Technologies which are less well established with higher uncertainty about both costs and the plant's technical performance are called "Category B" technologies. Distinctions between technologies were drawn corresponding to respondents' judgements.

CCGT: Combined Cycle Gas Turbine.

CHP: Combined Heat and Power.

CIAB: Coal Industry Advisory Board. An independent advisory body to the IEA whose membership includes representatives from coal producers, coal traders and electric utilities in OECD Member countries.

c.i.f.: Cost including carriage, insurance and freight.

Decommissioning: The work required for the planned permanent retirement of a plant from active service.

Denitrification: The actions taken to reduce nitrogen oxides in the exhaust gases from facilities using fossil fuels.

Desulphurisation: The actions taken to reduce sulphur dioxide in the exhaust gases from facilities using fossil fuels.

Discounting, Discount rate: Discounting is a procedure to convert the value of money earned or spent in the future to a present value. If one had $A and it could be invested to earn interest at a real money rate "r" per annum, in "t" years it would increase to become $\$A(1+r)^t$. A sum of $B earned or spent in t years time can be said to have a present value of $\$B/(1+r)^t$. The "r" is entitled a "discount rate".

Enrichment:

i) The fraction of atoms of a specified isotope in a mixture of isotopes of the same element when this fraction exceeds that in the naturally occurring mixture.

ii) Any process by which the content of a specified isotope (uranium-235, etc.) in an element is increased.

External cost (of generating electricity): Social costs which the actions of the electricity generators impose on others with no compensating payments, e.g. acid rain.

Fast reactor: A nuclear reactor in which no moderator is present in the reactor core or reflector. So the majority of fissions are produced by fast neutrons, which have high energy. If a fertile species (e.g. uranium-238) is present in the fast reactor core or in the blanket surrounding the core, it will be converted into fissile material (e.g. plutonium-239) by neutron capture. When more fissile material is produced than is used to maintain the fission chain, the reactor is called a breeder.

Fossil-fuel: A term applied to coal, oil and natural gas.

Front-end (of the Fuel Cycle): Those nuclear fuel cycle processes and activities concerned with the production of fuel for a reactor.

Fuel cycle: The sequence of processing, manufacturing, and transportation steps involved in producing fuel for a reactor, and in processing fuel discharged from the reactor. The uranium fuel cycle includes uranium mining and milling, conversion to uranium hexafluoride (UF_6), isotopic enrichment, fuel fabrication, reprocessing, recycling to recovered fissile isotopes, and disposal of radioactive wastes.

GJ: 1 Giga-joule equals 1 000 million joules, a unit of energy.

IAEA: International Atomic Energy Agency.

IEA: International Energy Agency.

IEA/SLT: Standing Group on Long-Term Co-operation of the International Energy Agency.

IGCC: Integrated Gasification Combined Cycle.

kWe: KiloWatt electric.

kWh: KiloWatt hour. One thousand watthours equals 3 600 000 joules.

Levelised cost: Levelised cost spreads total generation cost over total output to arrive at a figure which, if charged for each kWh, would exactly balance costs and income.

Levelised lifetime load factor: A ratio of discounted energy produced by a facility over its lifetime to discounted energy that it could have produced at maximum capacity under continuous operation during the whole of its lifetime.

Load factor: A ratio of the energy that is produced by a facility during the period considered to the energy that it could have produced at maximum capacity under continuous operation during the whole of that period.

LWR: Light-Water Reactor.

NEA: Nuclear Energy Agency.

NEA/NDC: Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle of the Nuclear Energy Agency.

OECD: Organisation for Economic Co-operation and Development.

Orimulsion: A 72 per cent bitumen and 28 per cent water emulsion from the Orinoco river basin of Venezuela. It has a thermal equivalent to heavy 4-5 per cent residual fuel oil, and a 2.8 per cent sulfur content.

O&M: Operations and Maintenance.

Peak load: The maximum load produced by a unit or group of units in a started period of time. A station used for peak load generation is a station that is normally operated to provide power during maximum load periods only.

PFC: Pulverised Fuel Combustion.

PHWR: Pressurised Heavy Water Reactor.

PWR: Pressurised-Water Reactor.

Renewable energy sources: Those resources that are considered to be practically inexhaustible because their energy source is not limited. Resources considered renewable include hydro, solar, wind, biomass, and ocean wave energy, among others. Other sustainable energy sources can include geothermal, municipal solid waste, and landfill gas.

Reprocessing: A generic term for the chemical and mechanical processes applied to fuel elements discharged from a nuclear reactor. The purpose is to remove fission products and recover fissile (uranium-233, uranium-235, plutonium-239), fertile (thorium-232, uranium-238) and other valuable material.

R/P: Reserves/Production Ratio.

Settled down load factor: A load factor achieved in equilibrium condition of a plant after a few years of initial period of commissioning in which the settled down load factor cannot be achieved.

Spent fuel: Irradiated fuel units not intended for further reactor service.

Waste management: All activities, administrative and operational, that are involved in the handling, treatment, conditioning, transportation, storage and disposal of waste.

UNIPEDE: International Union of Producers and Distributors of Electrical Energy.

US mill: A unit of currency. One-tenth of a US cent (US$0.001).

Annex 1

LIST OF MEMBERS OF THE EXPERT GROUP

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Canada	Ms. B. MARTIN Ms. S. GUINDON	Canadian Delegation to the OECD Energy, Mines and Resources
China	Mr. X. SHI	China Institute of Nuclear Industry Economics
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	Mr. M. SAKURADA **(Secretary)**	Nuclear Development Division
	Mr. G.H. STEVENS	Head, Nuclear Development Division
	Mr. M. YASUI **(Secretary)**	Nuclear Development Division

Annex 2

COUNTRY STATEMENTS ON COST METHODOLOGY AND TECHNOLOGIES

CANADA

Data for Canada has been provided by utilities in the following regions:

CA1: Central Region (Ontario)
CA2: Western Region (Alberta)
CA3: Eastern Region (Nova Scotia)
CA4: Eastern Region (New Brunswick)

Regional demand differences require smaller capacity additions in Eastern and Western Canada and this is reflected in the size of plants presented. Data on nuclear plants has been provided for CA1 and CA4. The nuclear data for CA1 relate to a 4 x 881 MWe CANDU plant while the nuclear data for CA4 relate to a single unit, 450 MWe CANDU plant. Nuclear costs in Western Canada would be approximately the same as those in Eastern Canada where utilities are too small to build and use the large stations of the type used in Central Canada. Canada has recommended to the NEA that the 450 MWe CANDU in CA4 which is a prototype CANDU 3 plant and the 165 MWe circulating fluidised bed plant in CA3 should be treated as "new technologies" for the purposes of this study.

With respect to the cost methodology, Canadian costs are expressed in many ways for different purposes, but generally Canadian utilities use two different approaches:

a) The annual cost approach for evaluating the actual generating costs from existing or future stations. This approach is based on accounting considerations and principles, and is usually referred to as the Total Unit Energy Cost or TUEC. For these calculations, current dollars as spent (i.e. variable money) are used together with assumptions on the rates of inflation and probable interest rates. This results in projections of annual generation costs which vary over the life of the station.

b) The lifetime cost approach for comparison of different types of future stations. This type of approach is used for planning purposes and is based on economic considerations and principles. It is usually referred to as the Levelised Unit Energy Cost or LUEC. This evaluation of new plants uses a more comprehensive system planning programme, uniquely relevant to individual future systems, with, typically, a 4.5 to 6 percent real interest rate, a 40 year life of plant and an 80 per cent capacity factor for base load plants. Comprehensive cost models for all types of future stations (nuclear, fossil, hydraulic and others) are used which define all subcomponents of the capital, operations, maintenance and administration and fuelling costs. These models are used to calculate LUEC's for the system as a whole

and for the individual new units proposed, for both existing and new sites. Plant modification costs are anticipated during the 40 years of plant life and are reflected in the capital cost account.

Spent fuel is put into water-filled bays or dry storage containers at plant sites for a planned period of about 10 years. The capital and operating costs of these bays and containers are included in normal annual generation costs. In addition, a charge is added to generation costs as a provision for subsequent costs of transportation, immobilisation and ultimate disposal. A similar provision is added for station decommissioning. Canada has no plans to reprocess its spent fuel and procedures have been designed for the encapsulation and ultimate disposal of the fuel following the once-through approach as the LWR's.

Several additional points are worth noting with respect to the data provided by Canada:

— The CANDU 3 cost data provided by New Brunswick reflects a higher LUEC at the 5 and 10 per cent discount rates than a coal plant of similar size for the province. This results in part from the use of a shorter lifetime and a lower capacity factor in the study than we use in Canada, both of which favour the lower capital cost coal-fired plant. As well, the utility has used estimates for the second coal-fired plant at an existing site in comparison with a first CANDU 3: this would give a 10 to 15 per cent bias in favour of coal. Thus, in total, the New Brunswick power data does not appear to be inconsistent with Canadian studies that show an economic advantage for CANDU 3 in New Brunswick.

— Data reflecting a 75 per cent load factor and a 30 year life for the gas plant in central Canada has been provided and included in the current draft to facilitate comparison with other data on gas-fired plants. However, Ontario Hydro has emphasized that the plant could not be used for base load: it is designed for operation at a 40 per cent load factor and could not be operated at 75 per cent. Even with the 75 per cent load assumption, the LUEC for the gas-fired plant is well above both coal and nuclear at the 5 and 10 per cent discount rates.

— Low nuclear fuel costs in Central Canada are largely due to the fact that Canada uses natural uranium fuel in its CANDU reactors. CANDU fuel does not require enrichment. Unlike other NEA Member country participants in the study, Canada is able to avoid the additional uranium enrichment costs. Furthermore, Ontario Hydro has cut its anticipated nuclear fuel cost in half compared to the previous study. A low future price for uranium is anticipated by the utility. (In the previous study, Ontario Hydro reported high uranium price expectations which were the result of long-term uranium contracts signed when uranium prices were high. It has since terminated those contracts.)

CHINA

1. Energy development

During the past decade remarkable progress has been achieved in energy industry and electric power industry in China. In 1990, the total primary energy production reached 1.04 billion tons of coal equivalent (tce). This is an increase of 21.6 per cent compared to 1985. The total installed generating capacity accounted for 137.9 GWe, and 621.3 TWh of electricity generation were produced in 1990.

As a main characteristic, energy supply in China is based on domestic energy resources. The country has abundant coal resources and great hydropower potential. The coal-fired power and hydropower generation shares were 71 per cent and 20 per cent in 1990, respectively. The remainder was produced by oil and gas. In December 1991, Qinshan nuclear power plant, a 300 MWe PWR, the first nuclear power plant on China's mainland, was connected to the grid. The imported 2 x 900 MWe Daya Bay nuclear power plant in Guangdong Province is under construction and is expected to start up in 1993.

The development of energy and electric power industry has become more and more important for the progress of the national economy and the improvement of the living standards. At present, energy and electric power shortages are a significant constraint on national economic development, even though an average of about 10 GWe generating capacity were installed annually during the period of 1985-1990. It is expected that the average growth rate of primary energy production and electricity generation will be over 3 per cent and 6 per cent, respectively, until the year 2000. The primary energy demand is projected to be above 1.43×10^9 tce and electricity generation should reach 1200×10^9 kWh with an installed capacity of 240 GWe by the end of this century.

2. Thermal power plants

Thermal power based on coal-fired plants will remain the main source for meeting electricity demand and the share of thermal power in the total electric generation will remain at about 75-77 per cent during the 1990s. Oil-fired power plants will no longer be constructed generally according to China's energy strategy.

The geographical distribution of coal reserves is quite uneven in China. About 80 per cent of existing coal reserves are concentrated in the north and northwest regions. However, about 74 per cent of the coal is consumed in the developed eastern and southern coastal areas of China. A massive coal flow has to be transported over a long distance. Insufficient transport capacity has substantially constrained the development of the electric power industry, resulting in an obstacle to economic progress in the coastal areas.

Most of the coal consuming facilities are operating without flue gas desulphurisation or other purifying systems in China. However, environmental control measures will be implemented at future plants. At most of newly built coal-fired power plants, high efficiency electrostatic precipitators will be employed. The wet sulphur scrubber imported from Japan in the Luohuang thermal power plant (under construction) marks the beginning of desulphurisation of thermal power plant in China.

The energy price system of China is very complex and distinct from other countries. For example, a multi-price system has been introduced for coal. Based on a quite low price, most state-run

coal mines suffered a deficit and had to be subsidised by the Government. The prices are distorted seriously and reflect neither their current production cost nor a reasonable profit. This causes problems in comparative assessment between nuclear and coal fired plants and leads to poor compatibility with international cost evaluations.

3. Nuclear power projections

Economic development in the coastal areas of China is faster than that in the inland regions. In response to serious power shortages, overload of coal transport, and environmental issues in the areas, nuclear power will play an important role in long-term energy strategy. The second phase of the Qinshan nuclear power station, a twin unit (2 x 600 MWe), will be initiated as the indigenous reference plant for a series of standardized plants that can be built quickly and economically as they become necessary. A second 300 MWe unit in the southeast coastal area is also projected. In this decade, it is intended to build two 1000 MWe reactors in Liaoning Province of the northeast China and two 1000 MWe reactors in the south of China by foreign suppliers.

4. Comparative economic analysis

For the comparative economic analysis of generating costs the nuclear and coal fired power plants are assumed to be built as twin units of 2 x 600 MWe at the coastal area in the southeast of China. The coal prices at the plant sites include transport charges. A real escalation of 2 per cent/year for coal price is taken into account during the plant lifetime. The projected coal-fired power plants will not be equipped with flue gas desulphurisation.

The credits of plutonium and uranium recovered from reprocessing of nuclear spent fuel are taken into account for nuclear fuel costs. Since China has no experience with decommissioning of nuclear power plants, the decommissioning cost is only a rough estimate of 10 per cent of initial investment.

For both nuclear and coal fired power plants a real escalation of 2 per cent/year is assumed for variable O&M costs. The starting dates of operation are proposed as January of the year 2000 and January of the year 2001 for units 1 and 2, respectively. The reference date for discounting is assumed to be January of the year 2001.

CZECH AND SLOVAK FEDERAL REPUBLIC (ČSFR)

Until 1989 the construction of electric power plants was based on the official long-term planning process initiated by the former Ministry of Fuel and Energy.

The basic philosophy of the new energy policy is to introduce so called market forces into the energy sector. In the framework of this policy it is not clear whether the government will be involved in the planning of the electric system development.

Two approaches in cost calculation methods are used in the ČSFR to express the electricity generation costs.

1. Annual cost approach for evaluating the actual generating costs from existing stations

This approach is based on the unified calculation method which was developed and approved in the centrally planned economy. Applying this method, all necessary data are available to calculate annual generating costs for the system as a whole and for the individual units. A revision of this method is now being prepared, of which application might be expected during the next two years.

2. The lifetime cost approach is used to compare different types of future stations for planning purposes

The general formula used in the central planned economy (further referred to as the CPE methodology) was as follows:

$$LC = \frac{\sum_{t=-CP}^{t=OL} (BCCt + IDCt + DCt + RCt + OMt + FCt)\,(1 + a)^{-t}}{N \sum_{t=0}^{t=OL} At.(1 + a)^{-t}}$$

CP - construction period
t=0 - date of commercial operation
OL - operating lifetime of the station
BCCt - basic construction cost
IDCt - interest during construction (t-th year)
DCt - decommissioning cost (t-th year)
RCt - reconstruction cost (t-th year)
OMt - operation and maintenance cost (t-th year)
FCt - fuel costs (t-th year)
N - net electric power
At - hours of utilisation (full-power) in the t-th year
a - annual discount rate.

The national calculations were performed according to the CPE methodology.

As compared with the UNIPEDE the CPE methodology is different in the following items:

— investment costs are incurred during the construction period according to the payment schedule;
— costs are referred to the beginning of the year.

Other calculations in this study were performed with the standard UNIPEDE methodology.

The discount rate used in the ČSFR is 9 per cent per year. This rate is set by the government.

Nuclear generation costs are based on the PWR technology (western standard). A load factor of 75 per cent is adopted; the lifetime for economic studies is 30 years. Decommissioning costs are 186 million USD per unit.

Coal generation costs are based on the Pulverized Coal (subcritical) technology with some environmental protection technologies (electro-static precipitator and flue gas desulphurisation system). For economic studies a lifetime of 30 years is adopted with a load factor of 75 per cent.

Combined cycle plants burning gas are the third option. For this power plant a lifetime of 25 years is assumed with a load factor of 75 per cent.

The ČSFR has an indigenous technological capability for power plant construction. The local industry commitment for different technologies differs. The highest is assumed for the nuclear power projects due to the fact that during last 10 years the new "big" power projects were nuclear. For other projects the industrial infrastructure cannot take the same high portion (at least for the first project). This is due to the following facts: 1) the last fossil-fired power plant was finished 20 years ago, 2) ČSFR companies do not supply the desulphurisation and other environmental technologies.

ČSFR currency is not convertible. At present there is a factor 3 between a "purchasing power parity" (PPP) and the external exchange rate. This situation will last to some extent until the turn of the century.

Differences between the PPP and external exchange rate together with different (but always high) local industry participation in the power plant projects explain: (1) why the base construction costs (BCC) are generally lower as compared with OECD countries, (2) the "nuclear" BCC are lower than for "coal".

For the future price of uranium a projection of 50 USD/kg U in 2000 is used with escalation up to 63 USD/kg U in 2030.

In the ČSFR, domestic coal is assumed with the price 1 USD/GJ (lower heating value was used in the projections) with a projection of 2.21 USD/GJ in 2040.

The assumption on the natural gas price is 3.2 USD/GJ in the year 2000 escalated to 4 USD/GJ (lower heating value).

The contribution of renewable energies is small and generally is not considered as a useful option for base load generation.

The ČSFR energy sector has large combined heat and power (CHP) production systems. Based on the 1988-1990 statistics CHP production in the public sector was about 5.5 TWh of the electricity and 100 000 TJ of heat (from about 1 600 MWe). The same figures for the industrial power plants are 10 TWh of electricity and 310 000 TJ of heat (from about 9 300 MWe).

Cost estimates used in this study are based on paper studies being developed within the electricty sector for a new plant planned to be ordered.

DENMARK

Denmark has, due to a 1985 Parliament decision, no nuclear power. Electricity production is based mainly (more than 90 per cent) on coal/oil-fired steam-turbine plants. More than 50 per cent of installed electrical capacity is in CHP-plants.

Wind power produces approximately 2 per cent of electricity consumption. Natural gas has recently been introduced into electricity production.

In 1986 and again in 1990, extensive small-scale CHP programmes were approved by Parliament. Until the mid-nineties, all new electric capacity installed will be small-scale CHP based on natural gas and biomass.

In 1992, two new steam-turbine plants were licensed. A 396 MWe natural gas-fired plant to be commissioned in 1997 and a 385 MWe coal-fired plant to be commissioned in 1998.

Denmark has set a political target of reducing CO_2-emissions by 20 per cent in 2005. A carbon tax was instituted by Parliament in December 1991.

FINLAND

The two largest power companies in Finland, Imatran Voima Oy (IVO) and Teollisuuden Voima Oy (TVO), together cover about 45 per cent of the total electricity generation. A large part of the remaining supply is produced by industrial or municipal companies for their own local networks. The four nuclear reactors in Finland are owned by TVO and IVO, two units by each. An important difference between the companies is that TVO does not have any other generation units besides its nuclear power plants, whereas IVO has a large amount of conventional condensing power and hydro power as well. Furthermore, TVO is a private company but IVO is owned by Government.

The largest Finnish electricity producers co-operate closely, and their estimates of the costs of the main electricity generating options are prepared under The Power Producers' Coordinating Council. The Finnish cost estimates used in this study are based on the latest updates of those estimates. The generating costs of a new light water reactor are based on the long operating experience of the existing plants and on paper studies for a new plant planned to be ordered by the companies for many years. Data from the present bids for a new plant have not been available. In the case of a coal-fired plant or a combined cycle gas-fired plant there are plants recently commissioned or under construction which have served as a solid basis for the estimates provided.

The cost calculation method employed by the Power Producers' Coordinating Council is very similar to the methodology used in the present study. Cost comparisons are made on constant money basis using a relatively low discount rate, typically 5 per cent. The use of a 5 per cent rate is consistent with average European prime rates. The impact of the choice of discount rate has been analysed in sensitivity studies. The technical life of both nuclear and coal-fired plants is assumed to be about 40 years, but a shortened amortisation life of 25 years is employed in Finnish cost comparisons. One purpose of the shortened economic life is to compensate for the exclusion of mid-life refurbishment costs from the estimates. Assumptions concerning load factor have been more

variable, but a factor of 80 per cent has been used by the Council as the basis for the comparison of base load generation options.

In the present study the Finnish projections for fuel prices have been set in accordance with the assumptions used by the Power Producers' Coordinating Council. For the future price of uranium a conservative projection of $75/kg U has been used for the year 2000 and onwards. The motivation behind the high projection is to avoid optimism in the cost estimate for nuclear power. Price projections for fossil fuels assume only a moderate rise in prices up to the year 2000. Price changes after 2000 have not been estimated.

Combined heat and power production makes an important contribution to the base load generation of electricity in Finland. Of the total electricity production, about 30 per cent was produced in CHP plants in 1990. Considerable potential to increase combined production for base load power still exist, especially in the pulp and paper industry. It could be realised by taking into use new, high-efficiency combustion technology, which can be utilised with a high power to steam ratio (IGCC, PFBC). As yet these technologies are, however, in such an early stage of development that they are not considered to have any significant contribution in Finland until about 2010.

Of the new renewable energy technologies wind power is expected to be in commercial scale operation after 2000. Nevertheless, wind power is not considered as a base load generation option in Finland because of its relatively small potential, and low utilisation factor.

FRANCE

The competitiveness of the various power generation systems is studied by a working group under the aegis of the Directorate of Gas Electricity and Coal (DIGEC) of the Ministry of Industry and Foreign Trade. The last report of this group was published in 1990; as it is based on 1988 economic conditions, the French responses to the questionnaire have been established on updated data from EDF which are in continuity with the former.

The method to compare the costs of different generating stations is accomplished by using the discounting method in constant francs. This is the same approach as that described in the last OECD/NEA generation cost study. The discount rate used in France is 8 per cent per year. This rate is set by the government for all national public investments.

Nuclear generation costs are related to a PWR 1 400 MWe of the N4 series. The N4 reactor is a French design, directly evolved and optimised from the previous 1 300 MW P'4 series, which will probably be used for all units to be built in the years to come. N4 requires low quantities of materials and equipment (mainly in civil works due to the use of prestressed concrete), compared to those of equivalent reactors in other countries and this, together with the series effect, explains the low nuclear investment costs in France.

The units to be built from the years 1998/2000 are to be placed in a new European framework. Thus an organisation is presently set up around:

— the development of an harmonized Franco-German project (European Pressurised Reactor);
— the harmonization of the European Utilities' requirements.

Such an harmonization is needed to produce a future reactor design which achieves a still higher level of safety and a good acceptability, and remains economically competitive.

These objectives will require some fairly extensive design alterations and in particular:

— improved protection against accidents which could result in significant radioactive releases under current designs;

— reinforced containment so that it can withstand a broader range of situations, in particular "gentle" core-melts beyond the reactor vessel and their potential consequences: hydrogen burning and release of radioactive materials;

— more straightforward operation and lower risk of errors thanks to simplified systems and components and increased automation;

— introduction of additional margins at the design stage: time available to the operators, linear power density of the fuel, operating temperature, etc.

Together these necessary features will probably result in some increase of the investment cost, which cannot yet be precisely assessed, since all the technical options are not finalised.

Technical studies have shown that nuclear as well as coal power plants can operate for around 40 years if extensive maintenance work is carried out when needed. But in French economic studies, a lifetime of 25 years is assumed for nuclear plant and no plant life extension and major refurbishment costs are included in investment or operation costs.

For the future price of uranium a high projection of FF 500/kg in 2000 is used with escalation up to FF 670/kg U in 2030. Indeed, the situation on the market after the year 2000 will probably be different and factors such as production costs will have more influence on the price than today.

For nuclear power plant, a load factor of 75 per cent is adopted.

Coal generation costs are based on units with circulating fluidised beds (CFB) technology. In a "moderately strict" environmental regulation situation, corresponding to reasonable predictions for the beginning of the 21st century, this technology will be the most competitive and represent the best cost-versus-pollution-control trade-off. For much stricter emission regulations (< 150 mg/Nm^3 for NO_x and SO_2), probably other more expensive systems will have to be used or additional treatment will be needed. An extensive R&D programme is being carried out by EDF to determine the limits of the CFB system in terms of size and emission, and to evaluate the other systems being developed (IGCC and PFBC in particular).

In France, imported coal is used, so the projections for coal price are made on world price basis and an assumption of $50/t in 2000 is used with escalation up to $60/t in 2020.

For economic studies, a lifetime of 30 years is adopted with a load factor of 79 per cent.

Combined cycle plants burning natural gas can make a contribution for middle load needs, at least as long as natural gas prices remain attractive. They have some advantages from an environmental point of view compared with other fossil fuels. Data used in this study are based on paper studies and quotations.

For this power plant a lifetime of 20 years is assumed with a load factor of 83 per cent.

The assumption on the natural gas price corresponds to an intermediate scenario with a price of 3.3 ECU/GJ in year 2000, at the point of import, escalated up to 4.3 ECU/GJ.

The contribution of renewable energies remains at a low level and generally is not considered as a significant option for base load generation.

HUNGARY

The energy supply of Hungary can be characterised first of all by the narrowness of resources and by its reliance on very large import volumes. This is not an unusual position but the fact that the natural gas, oil and electricity imports in the past originated exclusively from the Soviet Union explains why the latter's disintegration has caused a very grave situation. It is a very special case in Hungary that more than one quarter of the electricity consumption originated also from the USSR.

Electricity consumption per capita in Hungary is very low but high in relation to GDP. Taking into consideration this latter indicator it is clear that electricity consumption has decreased to the level of ten years ago in consequence of the ongoing restructuring of the economy and loss of markets. This decrease of demand has meant that Hungary has not had to face a catastrophic decrease in the reliability of supply. This is very important for the future from point of view of successful substitution and diversification of "energy" imports.

Domestic electricity production is distributed equally between an internationally acknowledged nuclear power plant and a recently reconstructed park of power plants using coal and a park of power plants using hydrocarbons.

At this time there is no significant power plant building activity in Hungary, and paper studies are in hand to determine future costs. The level of Hungarian energy reserves can be regarded as acceptable, but by European standards these reserves are insufficient. The supply of fuel to power plants using coal will deteriorate in the future, since domestic coal mining is not economic and the coal industry is facing problems. Replacement capacity matched to higher quality imported coal will be required in the near future. Possibilities for new capacity are:

1. In the short period

In the short term (from 1993) reliability will be achieved through a 550 MW connection between Gyor - Vienna with a direct current adapter.

Necessary capacity in the short term can be provided only through construction of gas turbine power plants with lead times of under 4 years, and one unit will operate from 1992. Use of gas turbines is also favoured for the following reasons:

— The present heat supply systems using hydrocarbon fuels are very favourable for combined heat and electricity generation (i.e. cogeneration) systems. In these power plants the allocation of costs to electricity generation is very difficult, but the costs are advantageous. The scale of building of these units is limited by the requirements for heat supply systems.

— Condensing systems based on combined cycle plants with favourable efficiency and flexible operation could substitute for the 200 MW units using hydrocarbons which were designed originally for base load. These units could match projected demand growth. Disadvantages of these units are their requirements for high quality fuel which is a factor of uncertainty in the calculation of primary costs.

— Building gas turbines for peak operation is favoured by their short construction period, the low investment level, and the fact that, because of lack of hydropower plants, Hungary has little capacity that can be quickly mobilised at times of peak demand. Calculation of primary production costs of electricity is difficult because of the complexity of taking into consideration the effect of new plants on the whole power generation system.

2. For a short and for a long period

In 8-12 years Hungary has to face the problem of the growing share of hydrocarbons in the electricity sector. This has to be compensated by building coal or nuclear power plants, but remembering that their costs and economic efficiency depend on the future prices of hydrocarbons fuels.

— Only one 1 200 MW power plant could be fuelled using domestic lignite. Because of the requirements for environmental protection and the poor fuel quality the costs of such a plant are relatively high, but establishment of this power plant would help the domestic power plant and lignite industries. Because of the unfavourable operational experience of the present Hungarian power plant using lignite, a very low load factor (below 65 per cent), is projected for a new plant, though successful reconstruction of the present power plant could lead to greater confidence. The investment costs of a power plant using lignite are very high, but the project contains less uncertainty and risk.

— Costs of establishing a power plant using imported coal cannot be easily estimated because of the uncertainty of the costs of coal transport. The possibility of shipping coal on the Danube will exist after construction of the Rhine-Main channel but there are many uncertainties. Costs have been estimated on the basis of quotations, and they are encouraging.

— Building a nuclear power plant involves the same advantages and disadvantages everywhere in the world. The present Hungarian power plant is out-of-date, but from the point of view of supply security it is one of the most reliable plants in the world. Hungary has the professional staff to build and to operate a new nuclear power plant which could be located at the site of the present power plant, although a new site might be preferable.

— Building a new nuclear power plant is a long term strategy which would require the restart of building nuclear power plants of the same type all over the world to encourage the domestic PWR programme. The costs are based on previous quotations, consequently they are uncertain and not specific for Hungary.

To support the generation cost analysis in Hungary the method of present value was used in the period of the planned economy, at least at the time of preparation for decisions. Costs and reliability were an important input into power system planning and methods are being adapted to match Hungary's new economic circumstances.

The Hungarian calculation method for determining levelised electricity cost takes into account the different commissioning dates of units in a power station; the basis for discounting is chosen according to these. Whereas the standard method used in this report includes a step of discounting operating hours, the method used un Hungary discounts the electricity units generated. This does not result in any significant difference in the levelised generating cost. The discounting procedure also takes full account of the timing of investment costs.

INDIA

The Indian economy — a mixed economy — has a GDP at factor cost of about 4.25 trillion Rupees in 1991-92 equivalent to 165 billion US dollars. Per capita income is about 230 dollars per annum. Population growth is about 2.1 per cent. Total population of 844 million is spread over 329 million sq.km leading to one of the highest concentrations of population in the world.

Power system

Installed capacity

Present installed capacity is about 70 000 MWe which consists of 28 per cent of hydro-electricity, 65.6 per cent of thermal (coal based), 3 per cent of gas based, and 2.4 per cent of nuclear and 1 per cent of other. The percentage of hydro-electricity contribution is decreasing. The future planning of the power system takes into account enhanced importance for hydro-electric power. Compared to hydro-electric plants, thermal projects are completed with less over-run of cost and time, due to the fact that equipment and construction procedures for thermal projects are largely independent of the site conditions.

Energy scenario

A peaking deficit of over 10 000 MWe and an energy shortage of about 21 billion kilowatt hours were estimated for 1990-91. The per capital energy consumption in India is about 236 KWh as of 1989-90 which is significantly lower than the levels prevailing in the developed countries.

The key reason for such a shortage is the insufficiency of financial resources. The outlay for the power sector in various five year plans has been at about 18 per cent of the total public sector outlay. One of the ways to increase the internal resources may be restructuring the tariff to reflect the full cost and also raising rate of return on investments. The subsidies provided for various sectors like agriculture should be reimbursed by the Government. Electricity Boards which are distributing power to various consumers should promptly pay the energy generating units. The availability and plant load factors of thermal power plants which are relatively low in India have substantial scope for improvement.

Due to peak power and energy deficiencies, several industrial and commercial establishments in urban areas have installed captive generation facilities which are contributing about 10 to 11 per cent of the total installed capacity.

Nuclear power

The contribution of nuclear power is only 2.4 per cent of the total installed capacity. With indigenously available natural uranium resources India can support a total nuclear power of 10 000 MWe based on thermal reactors. India has one of the largest deposits of thorium in the world (about 363 000 tons) which can support large nuclear power programme based on fast breeder technology.

Operating nuclear stations

Tarapur Atomic Power Station	(2 x 160 MWe)
Rajasthan Atomic Power Station	(2 x 210 MWe)
Madras Atomic Power Station	(2 x 220 MWe)
Narora Atomic Power Station	(2 x 220 MWe)

Nuclear projects under construction

		Expected completion year
Kakrapar Atomic Power Project 1&2	(2 x 220 MWe)	1992-93
Kaiga Atomic Power Project 1&2	(2 x 220 MWe)	1995-96
Rajasthan Atomic Power Project 3&4	(2 x 220 MWe)	1995-96

Construction for the 2 x 500 MWe Tarapur Atomic Power Project 3&4 is expected to begin shortly and the project is expected to be commissioned by the turn of the century.

Transmission and distribution

The transmission and distribution sector has not been given enough resources compared to the generating sector, with the result the reliability of transmission and distribution network has diminished. Transmission and distribution losses in Indian utilities have increased to a level of about 23 per cent during 1989-90.

Thermal power stations commissioned in India during 1980 to 1989 have shown a relatively consistent capital cost per KW installed (constant prices). During the period 1980 to 1989, the nuclear power stations have shown a diminishing trend in the capital cost (in constant Rupees) due to the learning curve effect. Even though the capital cost of nuclear power stations built during 1980-89 is higher than the capital cost of thermal power stations by about 40 per cent, the cost of energy generated from nuclear power stations is comparable with that from thermal power plants. However, it has been observed that nuclear power stations being built currently and also planned for the future would involve a significant increase in the capital cost for the following reasons:

— design modifications to meet the current international safety standards;
— developmental efforts for making the Indian nuclear industry self reliant;
— inadequate industrial infrastructure.

Due to the large gestation period experienced in India for nuclear power stations and also the high cost of capital, the financing charges for the nuclear power plants have become exorbitantly high.

Environmental protection at Thermal Power Stations

Environmental protection is considered important at the Thermal Power Stations in India. Various means are adopted for controlling the pollution of environment. These include installation of Electrostatic Precipitators for ash control (ash being disposed of in slurry form), neutralisation of liquid discharges before disposal, installation of cyclones and foggy nozzles at dust generating locations, water sprinkling methods — to reduce sulphur dioxide and nitrogen oxides emissions to atmosphere, etc. In future, desulphurisation units are also proposed to be installed.

Energy pricing

The Energy tariff is usually calculated on the "Return on Investment" method. For the nuclear stations presently a 12 per cent return on the net fixed assets is included in the tariff.

The unit energy cost for nuclear stations is calculated as follows:

$$\frac{\text{12\% return on net fixed assets + depreciation + operating expenses including fuel charges}}{\text{Saleable units of energy}} + \text{fixed decommissioning levy}$$

The unit energy cost for thermal stations is calculated as follows:

$$\frac{\text{10\% return on equity + depreciation + operating expenses including fuel charges and interest charges}}{\text{Saleable units of energy}}$$

Prevailing tariff rates in India are as follows:

Nuclear Stations		Unit energy cost (Mills per kWh)
RAPS	2 x 210 MWe	17.50
MAPS	2 x 220 MWe	21.67
TAPS	2 x 160 MWe	15.98
NAPP	2 x 220 MWe	34.78

Thermal Stations (representative of different regions)		Unit energy cost (Mills per kWh)
Gandhinagar	660 MWe	17.33
Badarpur	705 MWe	26.00
Neyvell	690 MWe	15.60
Ennore	450 MWe	26.33

ITALY

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Projections on future development of geothermal energy in Italy

Italian geothermal production has a long tradition. In fact, it was in the Larderello area (Tuscany) that the electrical exploitation of geothermal fluids was tested for the first time in the world, after geothermal fluids had been used for many decades both for the production of boric products and as a source of heat or mechanical power. Only at the end of the 1950s was geothermal research extended outside the traditional boraciferous region leading to the electrical utilisation of geothermal fluids in Monte Amiata. Finally, in the 1970s, as a consequence of the oil crisis, new research enabled the discovery of geothermal fields of industrial interest in Latium and Campania. The prospects opened up by geothermal activities in Italy have meant, in the 1980s, a substantial thrust to the industry in both the technical and organisational fields.

Three major technological aspects were investigated in detail:

1) improving the methodologies of surface investigation and of data analysis in order to reduce the mining risk that greatly affects production costs;

2) having drilling rigs and technologies available which are capable of reaching greater depths economically;

3) setting up a unified project of a geothermal power plant which is extremely flexible and adaptable to every geothermal fluid and which enables us to anticipate as much as possible the return of investment by a quick installation in the field.

As regards organisation, the aim was to use human and financial resources in a logical succession of Research, Exploration and Development Projects in order to permit easy programming during the period to harmonize development of all activity.

The results of this effort are evident from the following analysis of the situation as of December 1991 and those programmes already planned regarding aims and activities for the 1990s.

On the 31st December 1991 the installed geothermal power was 587 MW and the production of electricity had exceeded 3 TWh/year.

By the end of this century the aim is to reach the highest possible utilisation of geothermal resources for electricity production, using the technology available and as economically as possible. The aim of this programme ("Project 2000") for the year 2000 is to reach the value of 1 500 MW for installed power and 9 TWh/year for electricity production.

According to the organisation previously described, all the activities to be carried out are linked within Deep Exploration Projects, which are the result of Surface Exploration Projects and the resulting Developments Projects. Moreover, there are Renewal Projects, aimed at extending use of older fields and plants.

Taking into consideration the present situation, the carrying-out of this aim means the drilling of new wells for about 900 km and the installation of new power plants, in order to increase the total installed power by about 900 MW, also taking account of the dismantling foreseen in this period, equal to 250 MW.

However, 500 of the 900 MW by which the power installed on 31st December 1991 should be increased by the year 2000 is based on well researched Renewal and Development Projects where the estimate can be considered reliable. The further installation of 400 MW, which has been hypothesised on the basis of new Development Projects, should come from favourable results of intense Research and Exploration foreseen in the very first years of the programme in areas where thermal anomalies have been found.

The technical and economic characteristics of two illustrative examples of geothermal power plants are reported in Table 2.1.

Table 2.1 **Geothermal power plants in Italy — Illustrative examples**

		Superheated Dry Steam (Larderello)	Saturated Dry Steam (Amiata)
Resource characteristics			
- Reservoir temperature	(°C)	240 (5% CO_2)	330 (a) (10% CO_2)
- Flow rate of steam at the turbine inlet	(t/h)	110	110
- Depth of wells			
production wells	(m)	800	3 200
reinjection wells	(m)	800	3 200
- Plant design temperature	(°C)	230	210
- Plant design absolute pressure	(bar)	6	20
Technology performance			
- Thermal power extracted from the geothermal fluid (b)	(Gj/h)	295	285
- Total electric power production of the renewable system	(MWe)	15	17
- Electricity consumed in the system itself	(MWe)	1	1
- Net electric power	(MWe)	14	16
- Reinjection ratio	(%)	25	30
- Attenuation rate of wells	(%)	2	1
- Operating rate	(%)	90	90

(a) Temperature of the liquid water phase in the reservoir.
(b) The thermal power of the steam feeding the turbine is approximately 700 Gj/h (i.e. about 50% of the thermal power extracted from the field).

Table 2.1 (Continued)

	Larderello	Amiata
Capital cost (million U.S. dollar '92)		
- Exploration cost (a)	5.52	7.59
- Environmental survey cost	0.46	0.46
- Land cost	0.35	0.35
- Well cost	11.96	27.49
- Downhole pump cost	-	-
- Installation cost	17.02	17.02
- Hydraulic fracturing cost	-	-
- Building cost	2.07	2.07
- Interest during construction (b)	4.14	6.10
- Management expenses during construction	2.88	4.26
TOTAL	44.39	65.32
Unit construction cost (c) (10^3 U.S. dollars '92/kW)	2.22 (3.17)	2.18 (4.08)
Annual cost (million U.S. dollar '92/year)		
- Depreciation (d)	1.77	2.61
- Tax on fixed property (e)	0.01	0.01
- Interest (b)	1.37	2.02
- Maintenance cost	0.58	0.58
- Miscellaneous cost	0.12	0.12
- Labour force cost	0.35	0.35
- Management expenses after start-up	0.08	0.08
- Additional well cost	0.12	0.15
Total annual cost	4.38	5.91
Annual net electric power production (GWh/year)	110.4	126.1
Discounted average cost (U.S. cent '92/kWh)	3.97	4.69

(a) Including 1-2 exploratory wells.
(b) Real discount rate 5%.
(c) Referred to nominal installated capacity of 20 MW (dry steam) and of 30 MW (water dominated field, double flash) respectively. Data referred to net electric power in parenthesis.
(d) 25 years (annual charge 4% of capital).
(e) No capital taxes are applied in Italy on electric generation plants; only local taxes apply.

Table 2.2 **Costs of geothermal electric power generation**

	Unit costs		Share and total cost			
			Discount rate 6%		Discount rate 12%	
Technical activities	Steam-dominated reservoir	Water-dominated reservoir	Steam reservoir	Water reservoir	Steam reservoir	Water reservoir
- Surface exploration, including reconnaissance, pre-feasibility and feasibility studies over a final area of 100-200 km^2	\$30 000-60 000/km^2	\$30 000-60 000/km^2	≈1%	≈1%	≈1%	≈1%
- Drilling (1000-3000 m depth and 9-13 inches diameter) including related expenditures (access road, drilling site, water supply, move in/out) - Success ratio - Mean specific productivity - Well and field testing - Injection of spent water (cost increase per drilled meter)	\$1 000-1 650/m 0.50-0.75 2-5 MW/well \$45 000-70 000/well \$70-170/m	\$1 000-1 650/m 0.50-0.75 3-8 MW/well \$80 000-150 000/well \$350-850/m	36-55%	32-52%	40-58%	36-56%
- Gathering system - Power Plant Binary plant 1 MW Back-pressure plant 5 MW Back-pressure plant 15 MW Condensing plant 20 MW Condensing plant 30 MW Condensing plant 60 MW - Electric transmission line	\$200 000-270 000/well \$1 700/kW \$1 000/kW \$600/kW \$1 100/kW \$1 000/kW \$900/kW \$50 000-100 000/km	\$300 000-480 000/well \$1 700/kW \$1 000/kW \$600/kW \$1 100/kW \$1 000/kW \$900/kW \$50 000-100 000/km	29-40%	31-44%	32-44%	34-49%
- Field and plant operation and maintenance (a)			15-23%	16-23%	9-15%	9-14%
- Generation cost			30-80 mills/kWh		45-120 mills/kWh	

(a) Including environmental control costs.

It can be seen that the work on Geothermal Research Development over the next decade is decisive and the expected results are very important. Also the financial costs are considerable: they can be valued at approximately 3 000 billion Italian liras at present costs. Regarding technological development, apart from continuing commitment to the above mentioned fields, it is also necessary to devote resources to the development of the following aspects:

1) cycles and methodology for the economic exploitation of particularly scaling and corrosive fluids or of particularly complex hydrothermal systems (binary cycles, use of scaling and/or corrosion inhibitors, integrated cycles of chemical, electrical and thermal production, etc.);

2) technological solutions suitable for the further reduction of the negative impact on the environment both during the construction of plants (wells and power plants) and during the operating phase.

Generalised geothermal power costs are provided in Table 2.2.

JAPAN

General customers for electricity in Japan are supplied by privately owned electric power companies permitted by the Ministry of International Trade and Industry (MITI) each to operate in one of 10 regions of this country. (They are Hokkaido, Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, Kyushu and Okinawa Electric Power Companies.) Each of these companies is obliged to supply customers from its power stations and substations, using its transmission and distribution facilities. These companies combined produced 75 per cent of the total electricity generated in Japan during fiscal year 1991. The balance of Japan's total is produced by wholesale utilities permitted by MITI, Electric Power Development Co., Japan Atomic Power Co., 14 joint venture power companies, 5 hydroelectric power companies, 34 public power generating enterprises, and industrial self-generators supplying their own needs.

The Agency of Natural Resources and Energy of MITI has made standard estimates of generating costs for nuclear, coal-fired thermal, LNG-fired thermal, oil-fired thermal, and hydroelectric power plants in each year from fiscal year 1982. These estimates are based on the same idea that applies to the OECD/NEA method of calculation. The last of such estimates released are for fiscal year 1989. No estimates of generating costs have been attempted for the two ensuing years since the Gulf war made fuel prices unstable in 1990. A 5 per cent discount rate is used based on prevailing real interest rates.

The costs projection for this study (OECD NEA/IEA) is on the basis of a model plant assumed to go into commercial operation around fiscal year 2000.

1. Nuclear power plants are valued in Japan for their superiority in constant fuel supply, price stability, economic viability and environmental performance. They are among the base load plants that will continue to be developed actively with great care for safety.

   The cost of nuclear power generation has been estimated on the basis of four model plants of 1 350 MWe (gross capacity) each. This type of nuclear power plant comes under Japan's third improvement and standardization programme, reflecting operating experience with conventional

light water reactors and achievements brought about under the first and second improvement and standardization programmes. The plants will incorporate the best technologies available in Japan and other countries to ensure that they attain the highest levels that light water reactors have reached in terms of safety, reliability, operability and minimisation of occupational radiation exposure doses. They will be the mainstay of Japanese nuclear power plants in 2000 and beyond.

Nuclear fuel prices, when projected for 2000 on the basis of predictable price levels, are estimated to increase at the rate of some 0.1 per cent annually.

The cost of decommissioning nuclear power plants is included in the estimate on the basis of the 30 billion yen for a 1 100 MWe class reactor in the 1985 report of the Nuclear Energy Subcommittee of the Advisory Committee for Energy, an advisory organ to the Minister of International Trade and Industry. The cost of the final disposal of high level radioactive waste has not been taken into account.

2. Coal-fired thermal power plants, favoured with constant fuel supply and outstanding economic viability, are expected to continue serving as base and middle load stations. They are being fitted successfully with high-efficiency De-NO_x and De-SO_x equipment and electrostatic precipitators as effective environmental features. New generation systems with ultra super critical steam conditions and pressurised fluidised bed combustion are being considered for introduction to improve the efficiency of generation.

   The cost of generation has been estimated on the basis of four coal-fired thermal power plant models of 700 MWe (gross capacity) each. These models are based on a super critical steam condition system of generation designed from the most reliable perspectives on technology currently available, with designed thermal efficiency estimated at 39 per cent.

   Some plans for installation of an ultra super critical steam condition system of generation are being pursued after considering the expected economic benefit. Proving tests are being made on a pressurised fluidised bed combustion system of generation. These and other technologies are being developed to raise the efficiency of coal-fired thermal power plants.

   Fuel prices have been estimated, by reference to IEA, DOE and other projections, at 2.1 USD/GJ for the year 2000, with further increases at the rate of some 1.5 per cent annually.

3. Gas Combined Cycle power plants, outstanding in environmental performance, are being and will be used for middle and peak load stations.

   The cost of generation has been estimated on the basis of four GCC power plant models of 700 MWe (gross capacity) each. These models are in the 1300°C class of plant designed from the most reliable perspectives on technology currently available, with designed thermal efficiency estimated at 47 per cent.

   Heat-resistant turbines and other advanced technologies are being developed with the aim of introducing a 1500°C class of plant.

   Fuel prices have been estimated, by reference to DOE and other projections, at 4.4 USD/GJ for the year 2000, with further increases at the rate of some 1.5 per cent annually.

4. Fuel cell, photovoltaic and wind power generation are still in the proving test stage, with electric utilities now considering ways of assuring higher technical reliability and lower costs. They are not in a position to offer any official data for generating cost estimation.

REPUBLIC OF KOREA

In Korea, construction of electric power plants is based on the official long-term electric system expansion planning (ESEP) initiated by the Ministry of Energy and Resources. Once the plan is fixed, then the power plants are constructed and run under the control of Korea Electric Power Corp. (KEPCO), the country's only utility, which is partly owned by the government. The estimation of electricity power generation cost plays an important role in the decision on the long-term ESEP.

On the other hand, many factors affecting the estimation of power generation cost such as discount rate, load factor, and lifetime are determined officially by the Ministry of Energy through the consensus among universities, institutes, and the utility.

The official rate of discount has been continuously decreased from 13 per cent to 8 per cent reflecting the recent change of economic situation in Korea. A 75 per cent load factor is adopted officially based on the previous plant operation experience, while a conservative 25 year lifetime is adopted by the Ministry.

Nuclear and coal-fired power generation are two major power sources in Korea. However, recent rapid increases both in the demand for electricity and peak load have led to plans to introduce more liquified natural gas combined cycle plants in near future.

The estimation of power generation costs is mainly based on the country's experience. However, in the case of LNG combined cycle the estimation is highly dependent on the results of advanced countries such as the USA due to lack of indigenous experience.

The generating cost categorisation in Korea is quite different from that of OECD/NEA Member countries. The most notable difference is the broad content of O&M cost. It includes base O&M cost which is the same as that of most OECD/NEA countries, and in addition it includes decommissioning cost and spent fuel treatment cost and initial heavy water cost for nuclear power plant. The cost bases of decommissioning, spent fuel treatment and rad-waste treatment were established in 1984 for each item. Each year certain amounts of money are deposited in the utility's fund pool for the above 3 items and these figures are utilised as the basis of economic analysis. The heavy water cost for PHWR is included in annual O&M cost by applying a certain annuity factor.

— Decommissioning cost: 120 million USD was estimated as the cost basis of decommissioning 1 100 MWe class nuclear power plant in 1984. Each year's inflation effect is incorporated and the result is used as the basis of the economic analysis.

— Waste treatment cost: for a 1 000 MWe class PWR, annual rad-waste amounts to 1 500 drums. 365 USD per drum was estimated for the rad-waste treatment cost basis in 1984. For 700 MWe class PHWR, annual rad-waste amounts to 500 drums. As in the PWR case, 365 USD per drum (in 1984 constant money unit) was used for rad-waste treatment cost.

— Spent fuel treatment cost: for PWR 560 USD/kg uranium was estimated as the spent fuel treatment cost basis in 1984, and 140 USD/kg uranium was estimated for PHWR spent fuel treatment cost basis in 1984.

— Heavy water cost: 500 tons of heavy water for initial inventory and 238 USD/kg heavy water are used as the cost basis. For the annual charge for heavy water, 0.0937 was used as an annuity factor.

At present, the emission control standards of combustion facilities in Korea are not so severe as those of OECD countries. The emission control equipments now being used are electrostatic precipitators and low NO_x burners. However the emission control standards will become more strict in the near future and the SO_x emission limit will be decreased from the present 700 ppm (2 000 mg/Nm^3) to 270 ppm (770 mg/Nm^3) after 1999. Accordingly, 20 per cent of overnight cost is added to base construction cost for flue gas desulphurisation equipment installation.

PORTUGAL

A system approach methodology is used to calculate the costs of electricity generation where dynamic programming and non-linear techniques are used to search for the configuration that corresponds to the minimum discounted cost for the system.

The levelised cost methodology is currently used as a basis for assessing the inter-fuel competitiveness of future plants operating under equivalent conditions. Updates of electricity levelised generating costs with a reference discount rate of 10 per cent are made annually for investment analysis purposes.

Sensitivity analyses are also performed by varying some of the main parameters of the calculations, such as: discount rate, plant lifetime, number of annual utilisation hours and fuel cost.

RUSSIA

Introduction

There are two main reasons for reconsidering the energy situation in Russia at the moment. The first is that Russia has recently become an independent country with the territory, population, resources, technological base, etc., different from those of the former Soviet Union. The second is the on-going transition to a market economy which has resulted, among other consequences, in a sharp transformation of the price system.

In addition, ever since the Chernobyl accident, there have been calls for a clearer formulation of the role of nuclear power, taking into account both the lessons of the Chernobyl disaster and the existing specific potential of nuclear power in the country.

This annex offers a brief review of the electricity component of the energy situation in Russia today, with an emphasis on the possible role of nuclear power. Only a qualitative assessment is possible at present, because the economy of the country, the system of prices above all, is in the process of intensive transformation. However, some characteristic data are available and some conclusions can be drawn.

1. Current energy balance of Russia

A general view of Russia's energy balance of 1991 is presented in Table 2.3. The most characteristic features of the balance are:

— a key role of oil and gas, which share about 80 per cent of the primary energy produced;

— a relatively small share of coal in the balance (~13 per cent);

— a small share of hydro, nuclear and renewable energy sources in the balance (~6 per cent taken together);

— the importance of fuel exports for the balance (about 25 per cent of the fuel produced is exported).

It is worth noticing that about 25 per cent of primary energy goes to electricity generation and almost 30 per cent to heat generation.

Table 2.3 **Current (year 1991) energy balance of Russia** (a)

	Natural units	Mtce (b)	%
Primary Energy Production			
- Gas	643 bln m^3	740	43.3
- Oil	461 mln t	645	37.7
- Coal	353 mln t	220	12.9
- Hydro	-	52	3.0
- Nuclear	-	37	2.2
- Other	-	16	0.9
TOTAL PRODUCTION	-	1710	100.0
TOTAL EXPORT	-	445	-
Primary Energy Consumption			
- Electricity production	-	313	24.7
- Heat production	-	360	28.5
- Other sectors	-	592	46.8
TOTAL CONSUMPTION	-	1265	100.0

(a) *The Concept of New Politics in Power Production in Russia*, Russian Academy of Science, May 1992, Moscow.
(b) Million tonnes of coal equivalent.

2. Tendencies in the energy balance development

The development of Russia's energy balance over the last three years is characterised in Table 2.4. The share of gas in the balance will probably increase. There are not any significant trends in the development of non-fossil types of primary energy (hydro, nuclear, renewable).

Nevertheless, total primary energy production is declining. It fell by ~5 per cent in 1992. The prognosis shown in Table 2.4 assumes that the general decline will be overcome by 1995, but this is only an assumption.

It is clearly indicated in Table 2.4 that the export of primary fuel is the first to suffer from the production decline. However, the prognosticated data for 1992 signify that the domestic consumption begins to be discernably affected too. It means, in particular, that power generating capacities will be in real danger of fuel supply shortages in the near future.

Table 2.4 **Development of fuel balance in Russia in 1990-1995** (a)
[in Mtce (%)]

Fuel production	1990	1991	1992 (b)	1995 (b)
- Gas	735 (40%)	740 (43%)	745 (45%)	770 (45%)
- Oil	725 (40%)	645 (38%)	580 (35%)	590 (35%)
- Coal	250 (14%)	220 (13%)	220 (13%)	230 (14%)
- Hydro	52 (3%)	52 (3%)	50 (3%)	52 (3%)
- Nuclear	37 (2%)	37 (2%)	37 (2%)	37 (2%)
- Other	21 (1%)	16 (1%)	18 (1%)	21 (1%)
TOTAL PRODUCTION	1820 (100)	1710 (100)	1650 (100)	1700 (100)
TOTAL EXPORT	545 (30%)	445 (26%)	430 (26%)	500 (29%)
TOTAL CONSUMPTION	1275 (70%)	1265 (74%)	1220 (74%)	1200 (71%)

(a) *The Concept of New Politics in Power Production in Russia*, Russian Academy of Science, May 1992, Moscow.
(b) Assessment based on the trends up to 1991. A recent analysis of fuel production has indicated that the decrease of oil and coal production might sharpen, and the production of gas may go down, too.

3. Status and prospects of electricity generation

Fossil fuels are currently the decisive part of electricity and heat generation. As Table 2.5 shows, about 70 per cent of electricity and more than 99 per cent of heat are produced by fossil power plants.

This structure is likely to be preserved in the near future, but some factors are bound to influence electricity and heat generation substantially.

Table 2.5 **Current electricity and heat generation in Russia** (a)

Fuel type	Installed capacity		Electricity produced in 1991		Heat produced in 1991	
	GW(e)	%	TW(e).h	%	Mln.GCal	%
- Fossil fuel	131.9	67.6	729.3	71.7	821.2	99.6
- Hydro	42.3	21.7	166.8	16.4	-	-
- Nuclear	20.2	10.3	120.0	11.8	3.7	0.4
- Other	0.8	0.4	0.7	0.1	-	-
TOTAL	195.2	100.0	1016.8	100.0	824.9	100.0

(a) State Statistics Committee of the Russian Federation, Year 1991 Annual Report on Fuel Consumption and Electricity/Heat Generation, Moscow, 1992.

Table 2.6 **The current structure of fossil fuel consumption for electricity and heat generation in Russia** (a)

Fuel type	Fuel consumption in 1991	
	Mtce	%
- Gas	210.6	60.0
- Coal	93.1	26.5
- Oil	46.4	13.2
- Peat	0.9	0.3
TOTAL FOSSIL FUELS	351.00	100.0

(a) State Statistics Committee of the Russian Federation, Year 1991 Annual Report on Fuel Consumption and Electricity/Heat Generation, Moscow, 1992.

The first factor has to do with the fuel base development. Table 2.6 shows that the main fuel for fossil fuel power plants is natural gas (60 per cent of overall fossil fuel consumption) and in this Russia differs from most other countries where the main primary energy sources are oil and coal.

A direct conclusion would be that there is a secure fuel base for electricity generation in Russia, since natural gas is the only fuel resource whose production is increasing. However the increase in gas production could be used for restoring fuel exports, in preference to domestic consumption. Additionally, before the transition to the market economy began, gas was the cheapest fuel in Russia — due to the former pricing principles when price had nothing to do with value. Now, with floating prices, gas prices can and should rise faster than the prices of other fossil fuels, and, as the opportunities of switching to coal or oil are practically negligible (their production is steadily declining), the preservation of the current level of electricity and heat generation will be expensive.

The second important factor concerning the development of electricity generation is the plant replacement problem. A few years ago it was planned to use Nuclear Power Plants for both electricity generation expansion and for the replacement of oil fossil-fuelled thermal plants. Accordingly, not much attention was given to the development of new fossil fuel power plant projects which would be up-to-date technologically as well as environmentally. Now the lifetimes of existing fossil fuel power plants are expiring, but the way to replace them is not clear. The general crisis has influenced construction as well and only 42 per cent of the planned new capacity was commissioned in 1991, according to official statistics[1].

4. On the role of nuclear power in Russia

The current structure of nuclear electricity in Russia is presented in Table 2.7. A full list of NPPs operating in Russia is given in the Appendix.

Nuclear power in Russia is in crisis. All new construction activities have been cancelled, four NPP blocks which are more than 70 per cent completed have been deferred, no new units have been put in operation since 1990, and the question on the future of nuclear electricity remains unanswered.

From a purely economic viewpoint the prospects of nuclear power in Russia are very good. It is ready for development; there is the necessary technological, scientific and engineering base. There is no fuel problem; neither do the constraints of separative work supply exist[2]. Consequently, nuclear power is capable of solving the coming "plant replacement problem" and demand growth, as had been envisaged in the past.

Even from the environmental viewpoint nuclear power has its well known advantages — absence of ash, SO_2, NO_x, CO_2 and some other types of emissions.

Table 2.7 **Current structure of nuclear electricity in Russia** (a)

NPPs' types	Number of units	Installed capacity	
		GW(e)	%
WWER (PWR) - 1000	6	6.00	29.6
WWER (PWR) - 440	6	2.59	12.8
RBMK (LWGR) - 1000	11	11.00	54.4
BN (FBR) - 600	1	0.60	3.0
Other	4	0.05	0.2
TOTAL	28	20.24	100

(a) State Statistics Committee of the Russian Federation, Year 1991 Annual Report on Fuel Consumption and Electricity/Heat Generation, Moscow, 1992.

Reactor Type Identification:
PWR - Pressurised Water Reactor (Russian abbreviation WWER)
LWGR - Light Water cooled Graphite moderated Reactor (Russian abbreviation RBMK)
FBR - Fast Breeder Reactor (Russian abbreviation BN)

Table 2.8 **Comparison of electricity cost for fossil fuel and nuclear power plants in Russia** (a)
[in kop/kW(e).h) = 0.01rbl/(kW(e).h)]

Year	Fossil fuel plant	Nuclear power plant	Nuclear/Fossil
1988	1.24	1.04	0.84
1989	1.26	1.04	0.83
1990	1.31	1.11	0.85
1991	1.33	1.99	1.50

(a) *The Concept of New Politics in Power Production in Russia*, Russian Academy of Science, May 1992, Moscow.

The economic viability of nuclear power is questionable now (see Table 2.8), due to the necessity of urgent additional safety measures at all the nuclear plants, but the prices of fossil fuels are rising, especially gas, and one can expect that the competitive position of NPPs will be re-established. Existing nuclear power plants will be not only economically viable but very profitable in the near future.

These economic advantages are meaningless unless the safety of nuclear power is proven and society is convinced of it. The only way to use the advantages of nuclear power is to ensure a negligible probability of accidents at a nuclear power plant, consistent with the internationally accepted level, and to convince the public that it has been ensured.

Each of the existing reactor types in Russia now has its counterpart that is claimed to be really safe, but none of these projects are yet ready for implementation.

Russia has technologies and facilities for handling both discharged fuel and nuclear wastes. However, a comprehensive programme for handling the back-end of nuclear fuel cycle does not exist yet. This is another example of the present uncertainty about nuclear power in Russia.

Conclusion

The future of nuclear power in Russia is uncertain. The trends in the overall fuel balance as well as the ageing of existing power plants show that a substantial unsatisfied energy demand is likely to appear in the near future in Russia. If the safety of the new NPP projects is demonstrated in the short term, nuclear power could play an important role in satisfying the demand. Such an option is possible and attractive. If safety remains questionable, the current share of nuclear power will not increase, at best, and energy production will probably cost society a good deal more due to the rise in fossil fuel prices. In this case the role of nuclear power will be moved into an indefinite future.

References

1. Main Computing Center of the Ministry of Fuel and Energy of the Russian Federation, *The Analysis of Construction of Power Capacities in 1991*, Moscow, February 1992.

2. NIKIPELOV, B.V. and A.G. Chernov, *Uranium Industry in the USSR*, Atomic Energy, Vol. 68(4), pp. 227-229, April 1990.

Appendix

The most general parameters of the NPPs operating in Russia are shown in the table below.

NUCLEAR POWER PLANTS OPERATING IN RUSSIA

NPP Name & Location (Economic region)	Unit number	Reactor type	Installed capacity (MWe)	Start of operation (year)
1. Balakovskaya (Middle Volga region)	I	PWR	1000	1986
	II	PWR	1000	1988
	III	PWR	1000	1989
2. Beloyarskaya (Ural region)	I	Operation cancelled in 1983		
	II	Operation cancelled in 1990		
	III	FBR	600	1980
3. Bilibinskaya (Far East region)	I	NSR	12	1974
	II	NSR	12	1975
	III	NSR	12	1976
	IV	NSR	12	1977
4. Kalininskaya (Central region)	I	PWR	1000	1984
	II	PWR	1000	1987
5. Kolyskaya (North-West region)	I	PWR	440	1973
	II	PWR	440	1975
	III	PWR	440	1981
	IV	PWR	440	1985
6. Kurskaya (Central region)	I	LWGR	1000	1977
	II	LWGR	1000	1979
	III	LWGR	1000	1984
	IV	LWGR	1000	1986
7. Leningradskaya (North-West region)	I	LWGR	1000	1974
	II	LWGR	1000	1976
	III	LWGR	1000	1980
	IV	LWGR	1000	1981
8. Novo-Voronezhskaya (Central region)	I	Operation cancelled in 1985		
	II	Operation cancelled in 1990		
	III	PWR	417	1972
	IV	PWR	417	1973
	V	PWR	1000	1980
9. Smolenskaya (Central region)	I	LWGR	1000	1983
	II	LWGR	1000	1985
	III	LWGR	1000	1990

Total: 9 NPPs in Russia with 28 operating reactor units, the overall installed electricity generation capacity of which amounts to ~20.2 GW(e) including:

~ 8.6 GW(e)	(12 units) of PWRs	(~43%)
~11.0 GW(e)	(11 units) of LWGRs	(~54%)
~ 0.6 GW(e)	(1 unit) of FBRs	(~3%)
~ 0.05 GW(e)	(4 units) of NSRs	(<1%)

Reactor type identification:

PWR - Pressurised Water Reactor (Russian abbreviation WWER)

LWGR - Light Water cooled Graphite moderated Reactor (Russian abbreviation (RBMK)

FBR - Fast Breeder Reactor (Russian abbreviation BN)

NSR - Non-Standard Reactor (all other reactor types)

Note: Only the NPPs that report their operation to the Ministry of Fuel and Energy of Russia are considered in the table. For instance, the operation of the first NPP in Russia (in Obninsk) or of the NPP with the only BWR reactor (VK-50 Unit by Uliyanovsk) are not considered.

SPAIN

1. Demand

From the utility sector point of view there are some uncertainties in dealing with the demand (energy and power) growth rate from 1990 to the horizon year of 2000. Those uncertainties have to do with the evolution of the load pattern, the penetration of gas versus electricity as an energy vector, and the portion of the demand which could be covered by in-house supplies.

Even under those uncertainties a demand growth rate between 2.1 and 4 per cent per year with a reference value of 3.2 per cent per year is considered to be a reasonable value.

2. Resources

2.1 Nuclear

After the two 1 000 MW units which came into operation in 1988, there are no nuclear plants under construction in Spain. So the additions that could be foreseen within the horizon of year 2000, could come only from the two 1 000 MW units which — being about 40 to 50 per cent completed — were put under a continuing moratorium established by the 1983 National Energy Plan nowadays in force.

With no plants under construction, the basic uncertainties which will influence future decisions, costs, etc., have to do with the type of reactor that could be adopted (advanced or conventional), standardization — which would depend upon the size of the putative nuclear programme — and finally, public acceptance.

2.2 Domestic coal

Amongst the uncertainties associated with domestic coal as a candidate plant for future expansion of the generation system the possible reduction of domestic coal underground mining should be taken into account. The possibilities of reducing that mining could also be due to environmental protection considerations.

Some specialised resources, such as brown lignites feeding certain plants, could become exhausted in the medium term.

It is considered that at most, three more 950 MW domestic coal units could be added to the generation system within the horizon of the year 2000. Possible increases in domestic coal price due to mining reduction and exhausted resources would be compensated by the strategic value of using indigenous coal.

2.3 Imported coal

Because of the characteristics of the international coal market this is the fuel about which there is the least uncertainty in relation to a plan for expansion of the Spanish electric generation system. Only questions on transportation costs and environmental impacts could increase such uncertainty.

2.4 Gas

In spite of not being recommended in the past by the International Energy Agency or by the CEE, this fuel is becoming increasingly attractive because it is environmentally cleaner and because of its usefulness for peak demand coverage.

Spain does not yet have a well developed infrastructure for using gas for electricity generation, however gas is being considered for repowering projects.

One of the uncertainties associated with the use of gas for electricity generation concerns whether gas will be an economically dependable fuel or not in the future, and whether its price will be stable, once a massive use takes place after the current penetration phase.

2.5 Hydro

Hydro plays a very important role in the Spanish electricity generation system, the available projects for future system expansion — based on the remaining economical hydro potential — will consist mainly of power upgrading of some existing plants which will contribute to increase the system available capacity rather than the available energy.

2.6 Other

There are some other potential contributors to electricity generation which could soften the needs of the generation system expansion in the near future, they are: 1) Cogeneration and independent production; 2) Renewable energies which could make some contribution due to the development programme existing in Spain being enhanced and economically supported by the CEE; and 3) LIFE EXTENSION; there are projects currently under study by which the life of some 5 000 MW, which would be achieved 30 years before the horizon of the year 2000, could be extended at a competitive cost.

SWEDEN

The largest power company in Sweden is the state owned VATTENFALL AB (VAB) which alone covers about 45 per cent of the total electric production. The second largest power producer is the privately owned SYDKRAFT. The remaining supplies are produced by a number of power companies but industries and municipalities also contribute to the supply as cogenerators. KRAFTSAM is one of the joint organisations of the electric power producers in Sweden, being a forum for contracts and information among them. The activities of KRAFTSAM concentrate on the analysis of the energy market and follow-up of the electricity production system.

In the present situation almost all electricity production (140 TWh in the year 1990) is based upon hydro (44 per cent) and nuclear power (52 per cent). The remaining production is based upon cogeneration and oil-fired condensing plants. Due to the regulating capacity (load following capability) of the hydro power plants, gas turbines will operate only briefly, even during peaking periods, in an average year.

The Inter-Party Agreement on Energy Policy in Sweden 1991 states that the juncture at which the phase-out of nuclear power can begin and the rate at which it can proceed will hinge on the results of electricity conservation measures, the supply of electricity from environmentally acceptable power production and the possibilities of maintaining internationally competitive electricity prices. The 1980 parliamentary decision that the last nuclear reactor should be closed down by 2010 has not been reconsidered. The capacity for electric power production is expected to stay satisfactory at least until the year of 2000. For the same reasons, since no new capacity has been built since the late 70s, no data on new plant investment costs and operational costs carry any precision. Generally cost data are paper studies, and very seldom are based on actual bids. All data presented in the questionnaire are compiled by KRAFTSAM and reflect the planning situation around 1990. No new cost data has been compiled by KRAFTSAM, thus the performance data are not quite up-to-date.

The cost calculation methods used for the early planning phases very much resemble the method used in the present study. Cost comparisons are made in constant money based on a real interest rate of 5 per cent and 10 per cent. For VAB, however, the current real interest rate is 7 per cent. The technical life for the power plants being studied generally is between 30 and 40 years. For the economic cost comparisons only 25 years of project life is considered, regardless of type of production. This shortened amortisation period is expected to compensate for the exclusion of any mid-life refurbishment costs. The load factor being used in Sweden is generally 75 per cent corresponding to 6 600 of equivalent full load hours per year for a new condensing power station.

The projections on fossil fuel prices are also compiled by KRAFTSAM. The projections indicate a slow increase of the coal price up to year 2010 and thereafter it is expected to be level. Concerning the natural gas price, no relevant data is available. However, the power industry does not predict any shortages in the supply of gas, and it expects the gas price in the medium-long term to be set in competition with other fuels, i.e. the gas price would be adjusted so that the electricity production from a gas-fired combined power plant would not exceed the electricity production cost of a modern coal-fired plant. This is the gas price indication used in the questionnaire; consequently dramatic increase in natural gas price in the next 20 to 30 years is predicted.

SWITZERLAND

Following the 23 September 1990 referendum, nuclear energy will not be phased out by 2025 in Switzerland, but there will be an official moratorium on building nuclear plant until after the year 2000. The moratorium is not the beginning of the end for nuclear energy in Switzerland, but it clearly means that for the next 10 to 15 years (including the time needed for licensing and construction) no nuclear plant can be commissioned. Long term contracts with Electricité de France fill the electricity gap, in the nineties and the years after. Likewise, no coal plants are planned.

As a reaction to the referendum the government has launched an energy plan called "Energy 2000". This programme has several goals. It envisages stabilization at least of the total energy consumption and CO_2 emissions between 1990 and 2000, and their reduction afterwards. The growth of the electricity consumption will be damped and stabilized after 2000. The contribution of the renewables to electricity production will reach 0.5 per cent in the year 2000. The hydro production will be increased by 5 per cent. As the share of hydro production is 60 per cent, the resulting contribution to the total electricity production will be 3 per cent. The power output of the existing nuclear power stations will (and can) be increased by 10 per cent. As the share of the nuclear

production is 40 per cent, the resulting contribution to the total electricity production will be 4 per cent. Altogether the energy programme aims to increase electricity production by 7.5 per cent by the year 2000. The utilities (and other organisations and bodies) have declared willingness to cooperate in the government programme with certain reservations.

Concerning cost calculation, the levelised lifetime cost method is widely used to compare different types of base load plants or to compare different types of peak load plants. Different methods are used by different companies.

UNITED KINGDOM

The UK Electricity Supply Industry was privatised in 1990 and 1991 and the generation of electricity is now organised as a competitive market. The major generation companies in England and Wales are National Power, PowerGen and Nuclear Electric, with Scottish Power, Scottish Nuclear and Scottish Hydro-Electric in Scotland. Nuclear generation has been retained in the public sector in Nuclear Electric and Scottish Nuclear, with smaller contributions from British Nuclear Fuels and AEA Technology, both of which are wholly owned by Government. In addition to the major companies listed above, new private sector entrants to the generation industry are already constructing gas combined cycle and some renewable plants. Because of the diverse nature and sizes of existing and potential generators there is no longer a common approach to economic appraisal of generation options. Each generator determines his own investment strategy in the light of his perception of the future market and his ability to raise capital.

The existence of competition also means that companies are much less willing than the previous public sector monopoly generator (the Central Electricity Generation Board) to provide data on their cost expectations.

For this reason UK responses have had to be based on interpretation of the most authoritative published information, some of which is illustrative rather than definitive. Views on fossil fuel prices in particular are generally limited to illustrative ranges. Wherever possible data have been cross-checked and compared with material from other industry sources to ensure that gross discrepancies do not exist. The main sources and the different positions adopted for published assessments are described below.

Nuclear Generation Costs are currently being re-evaluated by the nuclear industry. They employ the technical life of plants (both nuclear and coal) for economic comparisons (typically 40 years), load factors of 75 per cent and the 8 per cent per annum real return on capital currently required by Government for public sector bodies trading in the private sector. Longer term liabilities for waste management and plant decommissioning are covered in assessments by fixed charges per unit of electricity sent out, which, if accumulated over the life of the plant and earning a compound rate of interest of 2 per cent per annum in real terms, would fully meet the liability costs as and when they were incurred.

This is the same approach as that described in the last OECD/NEA/IEA generation cost study. There is, however, one change. The costs were previously calculated on the basis of incremental costs to the generator and omitted non-specific central overheads, which were essentially fixed. With the division of the electricity supply industry and a focus on cost recovery and pricing, the nuclear industry

now includes pro rata allocation of central overheads in domestically quoted costs, even though this is not strictly correct for analysis of new investments. (The small fixed central overheads are omitted for this study).

The UK nuclear estimates provided for the study covered a possible range of costs, as judged in late 1991, for a repeat single Sizewell-B or Sizewell-B derivative design located at Hinkley Point (N1) and an evolutionary design (N2). These estimates have subsequently been overtaken by studies conducted during the summer of 1992 (see the end of the United Kingdom).

Coal Generation Costs have not been re-appraised by generators in published form. British Coal has however examined a wide range of advanced coal technologies and the data in this report are derived from their publications. They have employed shortened amortization lives of 15 or 25 years in their comparisons at a 10 per cent return on capital and 85 per cent load factor. Their studies have focused on smaller scale plants better suited to some of the advanced technologies, and in their view better matched to the potential requirements of the distribution companies.

British Coal's publications have used coal fuel prices of £1.9/GJ, which was equivalent to the price in their supply contracts with National Power and PowerGen. The generators have shown interest in using increased supplies of cheaper imported coal, with which British Coal's prices could be expected to converge in the long term. (The relative prices are very sensitive to exchange rates). In the past CEGB used world coal prices as the basis for its comparisons. In the present study the response is based on a constant imported coal price of £1.3/GJ in the year 2000, which is significantly below the current domestic coal price.

Gas Generation Costs are widely believed in the UK to be lower for new plants than those of the other thermal generation options. Many gigawatts of capacity are planned or under construction on the basis of take or pay long term indexed gas price contracts. The capital costs of combined cycle plants are fairly clear from contracts already placed.

The costs included in this study are however based on a Department of Energy response to the UK House of Commons Energy Committee, in which data were provided at 8 per cent and 10 per cent per annum real rates of return, 90 per cent load factor and plant amortization lives ranging from 20 to 40 years. The central 30 years has been adopted here, together with the Department's illustrative gas price scenario with gas at 17 p/therm (1990) rising at a steady 1.5 per cent per annum in real terms. The levelised gas price is higher in this study than in the Department's because of the later commissioning date (year 2000) being adopted here for the plant. The gas price is consistent with the indexed 22 p/therm that was proposed by British Gas for new contracts after the initial tranche of plants in 1991.

Generators appear to have been using somewhat higher real rates of return pre-tax than British Coal and relatively short amortization lives (15 years) for their internal assessments.

Renewables Generation Options additional to large scale hydropower are beginning to attract serious attention in the UK with a number of specific schemes in the planning and construction stage. Their overall contribution post-2000 remains a matter of speculation but is not expected to reach 20 per cent of power supply within the next 20 years.

For this study data have been obtained from the Energy Technology Support Unit which conducts assessments on contract to the UK Department of Energy (now Department of Trade and

Industry). They have adopted the standard conditions for rates of return specified for this study, together with reasonable estimates of technical lives and load factors for the technologies included.

The data for renewable plants are very site specific and scale dependent. The costs are therefore illustrative of modest tranches of plant to existing designs. At favoured sites costs could be lower whilst any large scale deployment would bring in less favoured sites with higher costs.

The waste incineration plants (landfill gas and municipal waste combustion) are projected to be capable of achieving high availabilities and would be used at high load factors because of their negligible fuel costs.

General: It will be apparent that with the use of diverse data sources there is a real risk of inconsistency in the approaches to costing — target v. central estimate costs, treatment of contingencies, etc., so that costs have all been quoted by the UK to only two significant figures and modest differences in costs between technologies cannot be regarded as definitive.

The provision of the UK data has been done independently of the Department of Trade and Industry, which has responsibility for energy matters in the UK.

At the time when this NEA/IEA study was being finalised the UK nuclear utility, Nuclear Electric, made public some fresh estimates of the costs of a twin Sizewell repeat station (Sizewell-C) at the Sizewell-B site. These figures, which have not been published in full, were too late to be used as replacements for UK data in the tables and main text of this report.

Nuclear electric have suggested that the twin station, with a slightly higher output per reactor than Sizewell-B, would have capital costs significantly lower due to avoidance of first-of-a-kind costs, and benefits from shared services, coherent construction programmes, etc. Their estimated base construction cost, including initial fuel, was reduced to £1 400/kWe (April 1992 money), corresponding to around $2 100/kWe on the definition and money values used in this study.

Nuclear Electric's estimated generation cost for the twin plant is around 3 p/kWh at an 8 per cent p.a. real discount rate, compared with 3.8 to 4.2 p/kWh for the category A plant submitted previously, both using the utility's own technical assumptions. If these estimates were to be confirmed, nuclear power's competitiveness in the UK could be significantly improved. The future prospects for nuclear power in the UK will be the subject of a Government review planned for 1994.

(Sources for recent data: J.G. Collier presentation to British Nuclear Forum Annual Conference, 23/24 June 1992, London, and Nuclear Electric's Supporting Paper P6 to the House of Commons Trade and Industry Committee's Inquiry into British Energy Policy and the Market for Coal, HC 236, 1993.)

UNITED STATES

The non-fuel operation and maintenance (O&M) cost estimates for the nuclear, coal-fired, and natural gas-fired combined cycle power plants for the United States are based on cost estimating relationships contained in an O&M cost model developed by Oak Ridge National Laboratory. The cost estimating relationships are derived from the cost experience of commercial power plants as reported to the U.S. Federal Energy Regulatory Commission. Electric utilities in the United States use a

Uniform System of Accounts for reporting costs. The Uniform System of Accounts categorises the costs as plant specific operation expenses and maintenance expenses, and utility reported administrative and general expenses. The administrative and general expenses are estimated for each plant type and included in this cost comparison because they differ significantly by plant type. However, some other cost studies do not include these costs.

The non-fuel O&M cost estimates for the nuclear power plant include expenses for on-site staff, fixed and variable expenses for maintenance materials and operating supplies and expenses, off-site technical support, and administrative and general expenses (pensions and benefits, nuclear regulatory fees, nuclear insurance premiums and other administrative and general expenses). Cost estimates for on-site staff include all personnel required for the plant whether they are employees of the electric utility or contractor personnel. The on-site staff include employees of the plant manager's office in addition to the plant manager and assistant manager. These employees perform public relations functions, environmental control, quality assurance, training, engineering for safety and fire protection, administrative services, and security. On-site operations staff members include supervisors, shift operators, and engineers. Maintenance staff consist of supervisors, craftsmen, engineers, peak maintenance workers, quality control staff, and storekeepers. On-site technical support staff perform reactor engineering, health physics, radiochemical and water chemical analysis, and technician support. The cost estimates are based on the expected staffing levels and the wage rates. Social security tax and unemployment insurance premiums are also included.

Maintenance materials include expendable materials and items that are replaced and are expensed for accounting purposes. Estimates of the cost of large replacement items and improvements that would be capitalised by an electric utility are included in the capital investment cost and amortized over 10 years for this study. Supplies and expenses include consumable materials that are unrecoverable after use such as chemicals, gases, lubricants, office and personnel supplies, monitoring and record supplies, data processing expenses, rents, and waste management expenses. No cost is included for water use such as cooling system water.

Costs for off-site technical support include costs for personnel to develop nuclear designs, to perform studies on engineering, quality assurance and fuel design, to perform research and development, and to prepare reports or studies required by the U.S. Nuclear Regulatory Commission. In addition to salaries, the costs include social security tax, unemployment insurance, and an overhead allowance of approximately 60 per cent of total salaries to account for office space.

The administrative and general expenses represent almost 30 per cent of the total non-fuel O&M cost of a nuclear plant. The pensions and benefits portion includes pensions paid to retired employees as well as accruals to provide for future pensions; payments for accident, sickness, hospital, and death benefits; payments for medical, educational, and recreational activities; and administrative expenses in connection with employee pensions and benefits. Nuclear Regulatory Commission fees collected from nuclear licensees represent another cost component. The fees are designed for recovery of the costs the Nuclear Regulatory Commission incurs for inspections, licence reviews, and reviews of other applications, etc. The nuclear insurance costs include the cost of commercial liability insurance and self insurance as defined by the Price-Anderson Act; the cost of property damage insurance to provide funds for plant clean up following a nuclear accident, and the cost of insurance to protect against replacement power costs for outages resulting from nuclear accidents. The final component of the administrative and general expenses consists of a prorata share of other overhead costs. It is estimated as 15 per cent of non-fuel O&M costs excluding administrative and general expenses.

Nuclear non-fuel O&M costs increased at an average annual real rate of 12 per cent p.a. from 1974 through 1984, but have increased by less than 5 per cent p.a. in 1985 through 1990. The increase is principally due to increases in staffing related costs. Increases in staffing levels (which rose largely to fulfil NRC requirements especially after the accident at Three Mile Island in 1979) have contributed significantly to the rise in O&M costs. Increases in wage rates were not much of a factor in the increases in O&M costs in 1974 through 1984, although they have become more important after 1981. The wage rates were almost constant in real terms from 1974 through 1981, but have increased since at an annual rate of almost 2 per cent above inflation. Therefore, some of the escalation in O&M costs has been due to the cost of labour, not just to increases in the quantities of labour and materials.

Other studies have examined the components of the increase in nuclear power plant O&M costs. One, which was based in part on detailed case studies of nuclear units in operation prior to 1980, identified several factors contributing to the escalation in O&M costs over time. In addition to rising utility on-site and off-site staffing levels, the study found that contractor costs for technical support such as steam generator inspections, planning, procedure rewriting, probabilistic risk assessment, and increased security requirements have also been rising. This technical support is in part due to the utility response to Nuclear Regulatory Commission requirements. Another case study of three utilities with multiple unit nuclear power plants found the increase in O&M costs to be mostly in the support area and not in the direct production-related area. Costs increased for administration, management information systems, training, chemistry control, and regulatory assurance. Costs that did not increase or declined in real terms included direct operating costs, direct maintenance costs, maintenance projects, and radiation protection. The issue of rising O&M costs continues to be studied to determine ways to reduce future costs.

The non-fuel O&M costs provided for this study represent current experience. When adjusted to eliminate administrative and general expenses for comparison, they are comparable to cost estimates developed by the Electric Power Research Institute for an evolutionary nuclear plant for their Technical Assessment Guide. However, as with any estimate, the future costs could be lower if staffing levels could be reduced, modifications minimised, maintenance optimised, and indirect costs associated with requirements of the nuclear Regulatory Commission and the Institute of Nuclear Power Operations reduced.

Annex 3

SOLID FUELS TECHNOLOGY

The purpose of this annex is to describe briefly what coal-fired technology is available or will be available by the turn of the century. Factors affecting decisions to invest in coal-fired capacity are described fully in the recent IEA publication *Electricity Supply in the OECD*.

In conventional pulverised coal-fired combustion units, coal is burned as finely pulverised particles. The most modern technologies can burn 99 per cent of the carbon, and conventional plants have thermal conversion efficiencies of 35-45 per cent depending on the technology, coal quality, and steam parameters. Average efficiencies currently tend to be less than 35 per cent. Because of the impurities in coal, pulverised coal-fired plants require additional emission control technologies to meet environmental standards. Contaminants include sulphur, nitrogen, halogens, alkali metals, and heavy metals.

Pre-combustion cleaning

Much raw coal is cleaned before it is used, which reduces not only the amount of undesirable mineral matter, including pyritic sulphur, but also the coal's bulk, lowering transport and handling costs. With advances in technology and more stringent emission limits, advanced coal cleaning methods, whose costs have been lowered and efficiency improved since the early 1970s, could be employed more widely. A pilot-scale plant in New South Wales, Australia, produces one metric ton per hour of "ultra-clean" coal with a higher heat content and an ash content of less than 0.5 per cent. However, costs are estimated to be around A$ 120* per metric ton, or A$ 3.80 per gigajoule.

Particulate matter

Technology to remove particulates from flue gas (cyclones, baghouse fabric filters and/or electrostatic precipitators) has reached a high state of development[1]. Most solid-fuel plants in OECD countries have some form of equipment capturing most particles before they can be released from the stack. The simplest devices, which attain removal efficiency of up to 90 per cent by weight, are cyclone separators that remove the heaviest particles from the air stream through gravity and inertia. Because regulatory requirements now usually demand higher removal rates, especially for small particles, such mechanical collectors are no longer used except as pre-collectors in combination with more advanced devices. Much more effective are electrostatic precipitators and fabric filters, or "baghouses". The former work by applying an electrical charge to the particles, which makes them adhere to one another and fall out of the flue gas stream. Fabric filters simply trap particles in inverted

* On average in 1990, A$ = US$0.78.

fabric cones. Precipitators can remove up to 99.9 per cent of particles by weight, and future designs could attain even higher efficiency.

Sulphur dioxide

Flue gas desulphurisation (FGD) can achieve very high levels of removal of sulphur dioxide (SO_2), though at the cost of a loss of thermal efficiency of approximately 1 to 2 per cent, and of the production of significant volumes of solid waste. The technology is deployed widely in the USA, Europe, and Japan. Technology development is directed towards reducing stack gas scrubber costs and improving handling and disposal of the sludge waste product, either by minimising volume, upgrading its physical and chemical characteristics or producing marketable byproducts. Over 100 types of flue gas desulphurisation (FGD) systems are in use or under development[2]. FGD systems may be broadly classified according to whether the reagent used for removing the SO_2 is regenerated and used again or not (regenerable or non-regenerable), the nature of the removal step (gas $\rightarrow$ solid, gas $\rightarrow$ liquid, or gas $\rightarrow$ gas), and whether the end product is dry or wet. The vast majority of the 500 or so FGD units currently installed on coal-fired power plants in OECD countries are non-regenerable, and of these slightly fewer than half produce gypsum as a by-product[3]. Such "scrubbers" are expected to be the predominant type of FGD system fitted to existing coal-fired units and installed on new units in the next five years.

Nitrogen oxides

Fuel-bound nitrogen is the major source of NO_x in pulverised coal combustion, typically accounting for more than 80 per cent of the total NO_x formed during combustion[4]. While the amount of fuel-bound nitrogen determines to a large extent the nitrogen susceptible to oxidation, the rate at which nitrogen is oxidised during combustion is a function of the temperature of combustion, the amount of oxygen in the furnace (the fuel/air mixing rate), the local stoichiometry, the combustion sequence, and the availability of NO_x-reducing agents. These factors vary with combustion system design and furnace size. Newer furnaces, designed with NO_x emissions in mind, tend to be much larger and employ more exacting control of air and coal flows and mixing rates. Considerable advances have been made over the last ten years in designing pulverised fuel burners that cut NO_x emissions by 70 per cent or more. Most boilers now being designed incorporate such improvements.

To reduce emissions even further, post-combustion devices must be installed. Three types of systems have been developed: selective catalytic reduction (SCR), selective non-catalytic reduction (SNR), and combined SO_2/NO_x/particulate reduction. The most advanced process is SCR, which achieves 65-80 per cent reduction. The technology has been widely demonstrated, though versions of the technology are in varying stages of demonstration and application. SNR is somewhat less efficient than SCR, consumes more reagent, produces corrosive by-products, and appears more temperature-sensitive. It costs less than SCR, however, and is generally easier to retrofit. One type of SNR process costs around $15-$20 per kilowatt of capacity to retrofit — one-tenth as much as retrofitting an SCR unit — and operates for about $1 500 per ton removed, or less than one-quarter the operating cost of an SCR unit.

Combined particulate/SO_2/NO_x control

A fundamental advantage of any combined control system is that its total costs will usually be lower than the combined costs of separate control systems. Experience with combined post-combustion technology also shows that it may use less energy than conventional FGD systems and produce less waste. One system is designed to remove SO_2, NO_x, and particulates from flue gas in a "hot catalytic scrubbing baghouse". In the basic process, a calcium- or sodium-based sorbent is injected into the hot flue gas to remove SO_2, while NO_x removal involves ammonia injection with a selective catalyst. Particulates and the spent SO_2 sorbent are collected in high-temperature bags made of woven ceramic fibre. Although this system has not yet been tested on full-size power plants, engineering cost studies suggest that the levelised annual costs of the system operating on a 500 MW power plant would be less than half the cost of a wet scrubber combined with an SCR unit.

Another process for combined control of particulate, SO_2, and NO_x, the SNOX process, is a catalytic process involving ammonia injection and a catalytic oxidation process in which SO_2 is converted to sulphuric acid. This process currently is in use at a 300 MW plant in Denmark, and is under consideration for the 400 MW plant to be commissioned in 1998 (shown as DE-C in the main tables).

Carbon dioxide

There are no carbon dioxide extraction technologies considered economically feasible. The approach to addressing CO_2 emissions is to improve the efficiency of generating electricity from coal. The advanced technologies discussed below in most instances improve thermal efficiencies from less than 35 per cent to greater than 45 per cent for electricity generation, and to greater than 75 per cent in combined heat and power configurations.

Advanced combustion technology

Advanced pulverised fuel units

The maximum thermal-electric conversion efficiency that can be achieved from subcritical pulverised fuel units is 38-40 per cent. In fluidised bed combustion, pulverised coal is combusted in suspension on jets of air. Combustion is more complete and heat transfer to boiler tubes is more efficient. Sorbents such as (pulverised) limestone can be introduced with the coal to capture sulfur dioxide before it leaves the furnace. Also, lower temperatures reduce NO_x production. Producing steam at supercritical pressure enables power stations to achieve net plant thermal-electric conversion efficiency of around 43 per cent. So-called advanced or "ultra supercritical" units, expected to become commercially available by the late 1990s, could attain net plant efficiency of more than 48 per cent before auxiliary power is deducted. Such improvements would bring pulverised fuel units up to the efficiency levels expected from more sophisticated technology[5].

Fluidised-bed combustion

The advanced coal combustion technique most developed commercially is the atmospheric fluidised-bed combustion (AFBC) boiler. The two major groups of AFBC technology are dense or bubbling bed, and circulating, atmospheric fluidised-bed. The former uses lower fluidisation velocities and is suitable for industrial and small-capacity installations. Electric utilities so far have shown an

interest mainly in circulating AFBC plants. Any type or size of boiler can be replaced by a circulating unit in the same amount of space, increasing the capacity of the power plant up to 15 per cent. These units are highly flexible with regard to fuel quality, especially sulphur content, and can operate on a relatively wide range of fuels*. Available plants can remove around 90 per cent of the SO_2 created during combustion, and removal efficiency as high as 95 per cent has been achieved[6]. Because the combustion temperature is low, not as much NO_x is formed as in pulverised fuel boilers.

Coal-fired AFBC plants are used on a commercial scale for a wide range of industrial and utility applications. About 15 000 MW are installed in commercial applications in IEA countries[7]. Most are small (25 to 30 MW) and use bubbling beds. The circulating units tend to be larger; the biggest such units being used for utility operations have thermal capacity of around 300 MW, equivalent to electrical output of around 120 MW. Larger units now under construction will have thermal output of more than 450 MW, or 150 MW. At this scale, circulating units can be considered viable alternatives to large-scale pulverised fuel furnaces.

Pressurised fluidised-bed combustion

Pressurised fluidised bed combustion technology is a development of the AFBC technology, and it exhibits similar advantages such as *in situ* removal of sulphur and the ability to handle a wide variety of coal or waste. Unlike an AFBC boiler, a PFBC boiler operates at 6 to 15 times normal atmospheric pressure. This technology has the technical potential to achieve net thermal efficiencies some 2-3 per cent higher than those of advanced pulverised coal-fired and AFBC technology. Also, it is characterised by very low emissions of SO_2 and NO_x. Because of PFBC's higher unit output and its modular design, its economic potential in the power sector in the medium term is projected to be significantly higher than is AFBC's. The first demonstration-scale units (100 MW or larger) using PFBC technology are expected to come into operation within the next few years. Though a number of technical issues have yet to be resolved before the technology will be commercially deployed, it is one of the most promising medium term coal use technologies. In Sweden, a 135 MWe/210 MWth coal-fired PFBC plant is being commissioned as a CHP plant in Stockholm.

In a combined cycle configuration, a PFBC plant can attain net plant thermal conversion efficiency of 40 per cent or better, compared with 36 per cent for a circulating AFBC plant. Because particles under pressure can quickly erode a gas turbine's blades, the combustion gas from a PFBC unit must be cleaned to a fairly high degree of purity. A second generation PFBC design employs a pyrolyser step to provide low BTU gas as a fuel source to raise turbine inlet temperature and, as a result, increase system efficiency.

Integrated coal gasification combined cycle

Integrated gasification combined cycle (IGCC) uses the output of a coal gasifier (rather than natural gas) to drive the gas turbines in combined gas and steam cycles. Different configurations of gasifiers ("fixed", "entrained", and "fluidised bed") and heat cycles are available. As with PFBC, IGCC can use lower quality fuels as feedstocks. Efficiency gains relative to conventional combustion are larger with lignites than for high quality coals. These systems can be designed to use any solid fossil fuel that can be pulverised, as well as fuel oil, Orimulsion, or natural gas, though once a unit is built

* Lurgi GmbH (Germany), for example, has tested over 50 fuels in its FBC research plants, including high-sulphur waste coal, high-ash coal, lignite, peat, anthracite culm, petroleum coke, oil shale, wood waste, bark, cow manure, and industrial sludge.

the range of solid fuels it can use is limited. Using a combined cycle turbine, an IGCC unit offers thermal conversion efficiency upwards of 40 per cent. Several entrained-bed processes are so far advanced that they may become commercially available for power plant application within the next few years. Because so few IGCC plants have been built, estimates of construction and running costs have to be made by extrapolation. Such engineering cost exercises suggest that the levelised costs of a 250 MW plant built today would be comparable with those of a standard pulverised coal unit with flue-gas cleaning devices[8].

This technology has the potential for thermal efficiencies even greater than those attained by PFBC, 98 per cent removal of sulphur and substantial reduction of NO_x. There is technical potential for further efficiency improvements as more advanced gas turbine technology (which would allow higher turbine inlet temperatures) is developed and higher levels of process integration are achieved. The technology also has a longer-term strategic significance in that it uses gasified coal relatively cleanly and efficiently. However, a number of important technical bottlenecks remain. The most important of these relate to the combination of the coal gas pollutants and the high gas temperature. The hot gas contains impurities including melted ash, acid gases, and vaporised alkali metals that are highly corrosive and erosive, particularly to turbine blades. Further development work is required to filter particulates in hot gas streams (as for PFBC) and to remove alkali metals without unacceptable losses in efficiency. Integration of the gasifier and combustion elements of the plant also require further development. There is a large potential market for IGCC technology, though commercially-demonstrated, high efficiency units are unlikely to be available until after the year 2000.

Less developed technology

The only other significant power-generating technologies designed to run on coal that might become available within the next 30 years are advanced fuel cells and magnetohydrodynamic power generation.

A fuel cell converts the chemical energy of a fuel into electrical energy by a direct electrochemical process that avoids the type of conversion losses inherent in steam condensing plants. Initial tests are being conducted with natural gas, which is simpler and less costly to use than other gases. Fuel cells based on gasified coal use a coal gasifier and gas cleanup system to supply a methane rich gas to the fuel cell stack, and net plant conversion efficiency is expected to be around 50 per cent. The technology is still in the pilot-plant stage, and fuel cells are unlikely to become commercially available until after 2005. Natural gas-fired fuel cells will be commercialised significantly before integrated gasification/fuel cells. Fuel cells may have particular advantages in small-scale applications in terms of efficiency, environmental performance, and site requirements.

In magnetohydrodynamics (MHD), a high-temperature combustion gas stream, seeded for electrical conductivity, is passed through a strong magnetic field to generate electricity. Either natural gas or coal-derived gases can be used, but coal is a more problematic fuel because of its higher levels of impurities. While the fundamental scientific principles have been demonstrated on a small-scale for short time periods, the remaining technical requirements for high temperature materials, heat and seed regeneration and power extraction are extensive. MHD is of interest because the technique offers conversion efficiency estimated at 60 per cent, and low SO_2 emissions. While the theory is simple, the extreme conditions needed to exploit the energy place great demands upon materials and technology. Considering the pace of development, coal-gas power generation based on this technology is not expected to reach the commercial stage until well into the 21st century[9].

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Annex 4

NATURAL GAS TECHNOLOGY

This annex looks briefly at new and developing technologies for gas-fired power generation. Since one such technology — combined cycle gas turbine systems — has moved into full commercial development and exploitation, its economics are covered in the main text. This annex looks only at some general aspects of the broader economic attractiveness of gas.

Technology

Recent technological advances have permitted natural gas to become a more competitive base load fuel for electricity generation. The most important advances are higher conversion efficiency in individual turbine systems and the commercial development of low cost modular combined cycle systems. High-efficiency gas turbines have become key components in industrial co-generation systems and in combined cycle systems for power generation.

The technological advances stem from developments in aircraft technology in such areas as heat-resistant materials, advanced cooling methods, and component design. New gas turbine systems may have peak inlet temperatures as high as 1300°C (compared with 900°C in earlier systems) as well as a high ratio of outlet to inlet pressures in the compressor. Both factors, but especially the increase in temperature, can boost overall conversion efficiency to 35 per cent or more, from 30 per cent in the previous generation, thus reducing fuel requirements. Within ten years turbine inlet temperatures are expected to be around 1370° and pressure ratios around 16:1.

Combined cycle and co-generation

Using a heat exchanger to recover some of the heat energy from the gas turbine exhaust can further increase overall conversion efficiency. The most important application of heat recovery in gas turbines is the combined cycle system, in which waste heat raises steam to drive a steam turbine. Such a dual system increases overall conversion efficiency to over 50 per cent. By the turn of the century, combined cycle conversion efficiency is expected to approach 60 per cent.

Combined cycle systems are flexible. For instance, the heat exchanger can be added to a peak load-operated gas turbine for use when base load demand increases. In a co-generation configuration, the recovered heat is used directly as industrial process heat, space heat, or in an absorption cycle for air conditioning. The overall efficiency of such an application depends on the ratio of power to heat production and on the conversion efficiency of the alternative separate systems, but efficiencies can be as high as 90 per cent. Integrated gasification combined cycle plant, or IGCC, based on the combined cycle technology, offers the option of installing a coal gasification plant and fuelling the gas turbine with the synthetic gas produced.

Regenerative cycle and steam-injected gas turbine cycle

An emerging fuel-efficient configuration is the steam-injected gas turbine cycle, a variation on the simple gas turbine cycle. Steam recovered from the turbine exhaust is injected into the combustor to augment power output and generation efficiency. Efficiency can exceed 47 per cent. Steam-injected systems appear to be a competitive option for applications around 50 MW.

Fuel efficiency also can be increased in a system using a regenerative gas turbine cycle. In such a system, a regenerator, or heat exchanger, captures exhaust heat, which is passed through the heat exchanger rather than into a separate steam turbine as in the combined cycle system. Thus, less fuel is required to produce a high turbine inlet temperature. NO_x emissions are low in the regenerative cycle, and conversion efficiency can be increased to 47 per cent. While the efficiency gain is substantial, disadvantages include the high cost of the heat exchanger and added system complexity.

Fuel cells

As indicated in the section on coal, fuel cells offer a method of converting the chemical energy of a fuel directly into electricity by an electrochemical process. In the longer term such cells may be powered by gasified coal. In the shorter term, testing and demonstration are concentrating on natural gas. A number of different processes are available with the main variant being the composition of the electrolyte. In Japan gas-fired fuel cells are at the stage of commercial demonstration. Conversion efficiencies can reach 50 per cent or more and the cells have the advantage of considerable modularity, as well as low emissions. However, they share these advantages with CCGT technology, and their capital costs tend to be higher. It is, therefore, not yet clear how large a part they can be expected to play.

Economic and environmental advantages

The cost of gas-fired generation is discussed in the main text. There is, however, a range of other wider economic factors which have recently added to the attractiveness of gas.

First, there are the technological developments indicated above which improve the efficiency and flexibility of gas-fired generation.

Second, CCGT technology enjoys low capital costs, short construction times, low requirements in terms of land use and high modularity — that is, economies of scale are not significant above a certain level and generating capacity can be expanded in relatively small tranches. These factors have become increasingly important in recent years for a number of reasons. Greater competition is likely to lead to more decentralisation of generation, leading to a preference for smaller units. Private investors may have a higher discount rate than public utilities and prefer lower capital cost options. In a situation where greater uncertainty is perceived and investors' time horizons are short, short construction times may take on a greater importance. The speed of bringing CCGTs on line and the small increments possible reduce the risks of incorrectly estimating demand growth. Finally, in many cases the fuel price risk can be contained by the long term contracts traditionally available in the gas industry.

Third, institutional and regulatory attitudes have changed. Although the view of gas as "too noble to burn" did not outlive the 1970s, in both the United States and the European Community

legislation limiting the use of gas for power generation remained in force for much of the 1980s — indeed the Community directive was only repealed in 1990. Although waivers were readily granted in most cases during the 1980s the persistence of the legislation reflected some residual resistance to a change in attitude.

Finally, perhaps most important, rapidly growing environmental concern over air pollutants has added to the attractiveness of gas. In relation to emissions of SO_2 and NO_x, natural gas can generally meet existing regulations at no, or minimal cost. Although its combustion produces CO_2, emissions are lower than for other fossil fuels. Gas therefore not only enjoys advantages now but also provides a degree of insurance against the possibility of tighter future environmental control requirements.

Annex 5

ADVANCED NUCLEAR REACTOR TECHNOLOGY

The purpose of this annex is to describe briefly what nuclear reactor technology is available or will be available before or soon after the year 2000. Many programmes on advancing nuclear reactor technology can be seen, and they have the common goals of improving public health and safety, occupational safety, and economics. This annex puts emphasis on the economic aspect of advanced nuclear reactor technology.

Technologies/designs available before 2000

Intensive efforts have been made and still are under way to apply advanced technologies to existing reactors in many countries. Examples include advanced reactor core and fuel designs which enhance safety margins and fuel utilisation, advanced control systems and human factors design for improvements in reliability of plants, use of advanced inspection technology or advanced materials for reduction of occupational exposure of workers and reduction in the volume of low level radioactive waste, and installation of new systems such as redundant emergency coolant systems or filtered vents on containments for reduction of the residual risk of reactor operation. Some advanced water-cooled reactor technology also incorporates basic improvements in reactor system configuration, characteristics, and plant architecture. These include, for instance, new plant designs with layouts and system designs that promote enhanced maintenance and reduced construction costs, and plant specification that eliminate certain systems or combine their separate functions[1].

In addition, there are widespread activities aimed at developing and introducing different reactor types or modified versions of current reactors for base load or intermediate load electricity production. The options include the so-called "evolutionary" designs, the revolutionary light water reactor designs, the gas cooled reactors and the metal cooled reactors.

The evolutionary designs are typically represented by large reactors such as those under construction in France (1 450 MW N-4 reactor at Chooz), Japan (1 356 MW ABWR plant at Kashiwazaki-Kariwa units 6 and 7), and the UK (1 175 MW PWR plant at Sizewell-B), as well as the large plant designs now available for construction that have been developed in Germany (Post Convoy), Japan (APWR), the United States (ABWR, WH-APWR, CE-APWR), and Sweden (BWR-90). Although the evolutionary trend is towards larger reactors there is a counter trend for small reactors for countries with small electrical grids and/or small load growths. Among the smaller reactors of an evolutionary design, one could cite the CANDU 3 and CANDU 6 Mark II[1].

All of the above reactor designs represent improvement over those reactor plants now operating. Goals of those new designs are primarily reduction of capital cost and construction time by simplifying construction, improvement of economics and prevention of accidents by improving reliability, and reduction of the residual risk to the public and financial risk to the plant owner by mitigating the

consequences of accidents which do occur. Aiming at the goals, these designs introduced numerous evolutionary improvements. These include improvements in the man-machine interface, use of the latest materials technology for components such as steam generators or reactor vessels, and advancement in system arrangement and layout to simplify construction and improve plant operability, maintainability, and availability.

Technologies/designs available soon after 2000

New types of large output reactors with improved safety designs are to be developed in order to be available for commissioning soon after the year 2000, such as the 1 450 MW EPR (European Pressurised Reactor) being developed by France and Germany.

Another approach of developing and introducing different reactor types is the so-called "revolutionary" designs more often represented in smaller plants (SMR Small & Medium Reactors) such as the GE-SBWR (Simplified BWR), SIR 300 (Safe Integral Reactor), HSBWR (Hitachi Small BWR), AP600 (Advanced Passive pressurised water reactor), PIUS (Process Inherent Ultimate Safety reactor) and SECURE-P (Safe Environmentally Clean Urban Reactor)[2] among others.

Common to most SMR developments is the pursuit of passive safety systems based on the premise that such systems are easier to implement in plants smaller than the current 1 000 - 1 300 MW units. The prime objective is, in case of an accident, to prolong the grace period before active measures are required for long-term cooling. In addition, there is no new SMR design which does not lay emphasis on simplification and the benefits that it is expected to produce. Examples of such simplifications include elimination of external primary system recirculation loops and pumps (integrated design), reduction of large bore primary piping, elimination of safety-grade coolant make-up systems, increased in-vessel heat storage capacity, application of passive emergency cooling systems, application of passive residual heat removal systems, location of reactor vessel penetrations in the upper part of the vessel, incorporation of large pressurisers, and minimisation of the number of seismic structures, simplification of the building concept and use of seismic isolation[2].

Significant simplification of the systems throughout the plant and increased application of modularised and prefabricated construction are key design features of the SMR technologies. In some countries the major reactor manufacturers have developed SMR designs that are claimed to be financially attractive because of the economic benefits that accrue from factors such as simplicity in design, extensive use of factory fabrication, shorter on-site construction times, lower up-front capital and earlier start to revenue earning. The proponents of large nuclear plant designs argue that many of these benefits are applicable to their plants, particularly if the installation programme is for a large series of replicate plant[2].

Both of the two approaches, evolutionary (to be introduced in the short or medium term) and revolutionary (to be introduced in the medium or long term) aim at improving safety and reducing costs. Because the new evolutionary designs will evolve from those currently in use, it is not expected to be necessary to build and operate demonstration reactors before the plants are available for commercial development. It is therefore possible that power plants of these designs could be commissioned by the year 2000. The revolutionary designs are expected several years after the year 2000.

Other technologies/designs exist for High Temperature Gas-cooled Reactors (HTGR) and Liquid Metal Cooled Fast Reactors (LMR)

Efforts to develop the High Temperature Gas-cooled Reactor (HTGR) aim at exploiting its high thermal efficiency and safety features. Liquid Metal Cooled Fast Reactor (LMR) development aims at security of power supply in the long term and improved characteristics of radioactive waste from the back-end of the fuel cycle. However, those reactors are longer term prospects and will not be commercially deployed on the time scale adopted for this study.

Reduction of generation cost

All options being developed, whether evolutionary or revolutionary water cooled reactors, gas cooled reactors or liquid metal cooled reactors, have to be competitive with coal-fired and gas-fired plants for base load operation and generally aim at, at least, a 10 per cent advantage[2].

Capital cost reductions both in existing and in future nuclear plant designs can be achieved without jeopardising safety by optimisation of plant size, construction of multi-unit plants, standardizing designs and components, improvement in construction efficiency, modularisation, improved project management, and use of specific design objectives such as simplification[3]. It is expected that the construction period for advanced (evolutionary/revolutionary) light water reactors will be shortened to four or five years instead of the six to nine year period experienced in many countries at present, therefore reducing interest during construction, a major cost component. As a result, further cost reductions are expected for future nuclear generation capacity.

Additional cost reductions can be achieved by better fuel-use practices that reduce uranium ore requirement and fuel fabrication. Improvement of the reactor core performance including fuel burnup extension which has been obtained (e.g. from 33 000 MWd/t to 42 500 MWd/t) has reduced fuel cycle costs by more than 10 per cent. Fuel cycle costs can be reduced more with further burnup extension (e.g. to 55 000 - 60 000 MWd/t)[4].

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Annex 6

RENEWABLE ENERGY SOURCES

The supply of most renewable forms of energy depends on local conditions, so estimates of "typical" costs per kilowatt hour are of little use without reference to a plant's specific operating conditions. Also, estimates differ according to assumptions regarding capacity factor, operation and maintenance costs, and operational life. An international effort is being made to obtain a set of reliable, comparable data for a wide range of electricity generating technologies, including those based on non-hydro renewables, but no results are available yet. More detailed, accurate assessments are being conducted at the national level. Discussion of the environmental effects of renewable energy sources may be found in the OECD's report on the Compass Project[1] and the proceedings of the interagency symposium on Electricity and the Environment held in Helsinki in May 1991[2]. Table 6.1 shows the current estimate of installed capacity by type of renewable energy source, and Table 6.2 shows the current estimate of the potential contribution from certain of these sources[3]. The information in Table 6.1 is presented graphically in Figures 6.1 to 6.3. The technologies described in the following paragraphs are presented because they are viewed as currently competitive or near-term technologies or because they are subject to active research and development activities and have a large potential. From 1979 to 1989, total installed non-hydroelectric renewables capacity doubled from 8-9 GW to about 18 GW of generating capacity, or 1 per cent of the total. This increase represents about 3 per cent of net capacity additions during that period. It appears that their share could rise to 4-5 per cent by 2005.

Biomass

Biomass comprises vegetative matter, crop residues, and animal wastes, as well as waste products from forestry and food processing (municipal waste and sewage are treated separately). The generation of electricity from crops or trees specially cultivated as fuel is not widespread. In the OECD, only a handful of small power plants use such fuel. Research is continuing on improving tree growth rates, developing machinery for harvesting, and estimating the life-cycle economics of plantations.

Biomass can be burned in any furnace that can handle solid fuel in bulk. Its main limitations are its non-uniformity and high moisture content, which effectively rules out direct combustion in pulverised fuel steam generators. General improvements in combustion technology, such as fluidised-bed combustion, can be applied with little modification to biomass. Biomass can also be gasified* under high heat and pressure with the technology used to gasify coal, and the resulting low-calorie gas can be burned in a combined cycle plant. Pyrolysis** could be used to generate methane for power

* Partial combustion of the material to produce intermediate combustion gases rich in carbon and hydrogen that can be combusted further.

** The destructive distillation of biomass in the absence of air, yielding a mixture of products consisting of varying proportions of carbon (charcoal), liquids, and gases, depending on the feedstock characteristics and reactor design.

Table 6.1 **Estimates of renewable-based generating capacity (utility and non-utility) in OECD countries (MW)** (a)

Country	Biomass (Agriculture or forest residue)	Municipal & industrial solid waste	Landfill gas	Gas from sewage or animal manure	Geothermal energy	Solar photo-voltaic	Solar thermal electric	Tidal energy	Wave energy	Wind energy	Total
Australia (b)	650	--	13	--	--	5.0	0	--	--	1	668
Austria	--	--	--	--	--	0.0	--	--	--	--	0
Belgium	--	--	--	--	--	--	--	--	--	5	5
Canada	774	11	--	0.1	--	0.0	--	18	--	8	810
Denmark (c)	31	55	1	4 (d)	--	--	--	--	--	445	536
Finland	1017	--	--	--	--	0.0	--	--	--	--	1017
France	--	--	--	--	4	--	--	240	--	0	244
Germany	--	194.1	8.5	0	22	0.34	0	0	0	41	265.94
Greece	--	--	--	--	2	0.3	--	--	--	11	13
Iceland	--	--	--	--	41	--	--	--	--	--	41
Ireland	--	--	--	--	--	--	--	--	--	0	0
Italy	1	--	--	--	521	0.4	--	--	--	2	524
Japan	--	--	--	--	215	2.0	--	--	--	2	219
Luxembourg	--	--	--	--	--	--	--	--	--	--	0
Netherlands	--	164	--	--	--	--	--	--	--	40	204
New Zealand	--	--	--	3.1	264	--	--	--	--	--	267
Norway	40	11	1	--	--	1.5	--	--	0.4	1	54
Portugal	201	--	--	0.4	3	0.4	--	--	--	1	206
Spain	--	--	--	--	--	--	1	--	--	6	7
Sweden	260	60	--	0.3	--	--	--	--	--	11	331
Switzerland	--	25	--	--	--	--	--	--	--	--	25
Turkey	--	--	--	--	21	--	--	--	--	--	21
UK	--	--	22	--	--	0.0	--	--	--	7	29
United States	7020	1420	208	0.8	2212	11.2	295	--	--	1407	12574
Total OECD	9967	1885	253	5	3305	21	296	258	0	1951	17941

(a) Date of last update : 1st September 1992.
(b) Capacity of biomass-fired plants is estimated from statistics on annual consumption in industry.
(c) Danish data refer to end of 1992.
(d) Sewage gas plants not included (rough estimate: 5 MW).

Source: IEA Secretariat.

generation[4]. R&D in biomass pyrolysis has concentrated mainly on small-scale production of gas for direct use. The main advance that may be expected to affect the use of this renewable resource will be in crop development. Recent breakthroughs have occurred, for example, in the cross-breeding of bamboo. Most of this type of research, however, has been directed towards crops for conversion to alcohol fuels for transport. The Sugar Research Institute of Australia has conducted studies that indicate that co-generation facilities in sugar mills, fired by bagasse*, meet the process heat and electricity requirements of the mills. The overall electricity generation costs are in the range of 5-8 Australian cents/kWh, with the variation in costs being a result of the range of plant sizes considered (10-50 MW) and the corresponding economies of scale[5].

Municipal solid waste

Municipal solid waste is a general term used to describe the predominantly dry refuse collected from residences, businesses, and small industries. In the United States in 1985, around 70 per cent of the total mass of such waste was organic — mainly paper and cardboard, plastics, textiles, rubber, wood, and waste from lawns and gardens. In Europe, municipal solid waste typically contains a higher ratio of plastics (which have a high thermal content) to paper than in North America, but because the mass produced per person is much less, the heating value of raw waste in Europe is about 25 per cent lower[6]. If all waste in OECD countries were burned for power generation, it could support 30-35 GW of generating capacity and produce 200-250 TWh. If one considers only waste not deposited in landfills, based on 1988 figures, the results would be about one-third of these levels.

The technology for burning municipal waste or converting it into combustible gas is similar to that for other kinds of biomass, though special precautions against disease-carrying microbes and toxic chemicals must be taken. Municipal solid waste can be burned in incinerators, digested to produce methane, or deposited in landfills, where it decomposes gradually, and produces combustible gas. Pyrolysis of municipal solid waste has been tried at the pilot plant level, but few commercial-scale plants have been built. By far the most commercially developed ways of exploiting the energy in municipal waste are direct combustion and use of landfill gas.

Landfill gas

Although the general trend in disposal of municipal solid waste is towards resource recovery and combustion, a high proportion is still buried in landfills — from 30 per cent in Japan and Denmark to 100 per cent in Greece, Ireland, and New Zealand, with most other countries in the range of 60 per cent to 90 per cent. Organic waste in landfills represents a sizeable potential energy resource. Anaerobic decay of buried organic compounds produces landfill gas. A recent study by the UK Department of Energy's Energy Technology Support Unit identified some 240 projects exploiting landfill gas world-wide. A medium-sized plant based on landfill gas typically consists of up to 50 polyvinyl-chloride pipes sunk into the ground and connected by other pipes to the power unit. Most landfills use internal combustion engines or gas turbines, depending on the amount of gas available. In a few cases landfill gas is used as a supplemental fuel in steam-generating power plant furnaces or CHP configurations. Most landfill sites can support only a few megawatts of capacity. Several sites in the United States, however, have installed capacity of 10 MW or greater; the largest, outside Los Angeles, supports a 50-MW unit.

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* Sugar cane residue.

Table 6.2 **Potential available energy from selected renewable energy sources**

Country	Municipal solid waste		Sewage	Land-based wind power					
				Installed capacity (MW)		Maximum potential dependable capacity (MW)		Maximum potential electrical output (TWh/year)	
	Electric power output equivalent (GWh/year)	Equivalent capacity (a) (MW)	Electric power output equivalent (GWh/year)	Total of wind energy classes III-VII (b)	Total of wind energy classes V-VII	Total of wind energy classes III-VII	Total of wind energy classes V-VII	Total of wind energy classes III-VII	Total of wind energy classes V-VII
Australia	4167	594	96	1156207	606076	289052	151519	2532	1327
Austria	1850	264	321	36879	36879	9220	9220	81	81
Belgium	2333	333	133	12941	5272	3235	1318	28	12
Canada	16324	2330	1001	3430807	923518	857702	230880	7513	2023
Denmark	1833	262	295	140041	60888	35010	15222	307	133
Finland	2518	360	217	42353	23294	10588	5824	93	51
France	18008	2569	1700	586197	343515	146549	85879	1284	752
Germany (c)	17051	2433	3223	100959	20824	25240	5206	221	46
Greece	1993	285	3	165807	91194	41452	22798	363	200
Iceland	67	9	7	577086	577086	144271	144271	1264	1264
Ireland	630	90	23	167371	114378	41843	28594	367	250
Italy	11879	1695	2015	255530	104105	63882	26026	560	228
Japan	57630	8223	2798	645452	189426	161363	47356	1414	415
Luxembourg	99	14	18	284	0	71	0	1	0
Netherlands	7310	1043	767	52610	7057	13152	1764	115	15
New Zealand	935	133	170	498002	422036	124501	105509	1091	924
Norway	1847	264	106	188237	171957	47059	42989	412	377
Portugal	1601	228	76	29507	6364	7377	1591	65	14
Spain	7670	1095	1095	451932	198216	112983	49554	990	434
Sweden	4613	658	469	73473	60756	18368	15189	161	133
Switzerland	3209	458	350	27239	27239	6810	6810	60	60
Turkey	7511	1072	69	1177086	0	294271	0	2578	0
United Kingdom	17003	2427	2808	670769	425459	167692	106365	1469	932
United States	112452	16047	10607	4124126	443750	1031031	110937	9032	972
Total OECD	300532	42884	28366	14610893	4859287	3652723	1214822	31998	10642

(a) Assuming 80% capacity factor.
(b) Wind Energy Classes are defined in "Electricity Supply in the OECD", 1992, IEA, OECD, Paris.
(c) "Germany" is the sum of what has been previously indicated as eastern and western Germany. Estimates for eastern Germany included information only for wind power.

Source: IEA, 1992, "Electricity Supply in the OECD", OECD, Paris. (Municipal solid waste data have been updated based on country submissions.)

Table 6.3 shows some of the cost information associated with a landfill gas project recently installed in Melbourne, Australia[5].

Table 6.3 **Project costs for landfill gas in Melbourne, Australia**
(Costs in 1991 Australian Dollars)

Power Plant Capacity	8.7 MW (gross)
Annual Net Output	60 GWh
Plant Lifetime	10 years
Cost per kWh	2.33 Australian cents (a)
Capital Costs	
Design and Management	$3.1 million
Building and Wellfield	$1.3 million
Generator and Pumps	$0.54 million
Operation and Maintenance	$0.76 million per annum

(a) IEA Secretariat estimate.

Sewage and animal waste

Waste from sewers, farms, and feedlots is rich in organic material that can be turned into combustible gas through digestion, or dried and burned directly. On a dry weight basis, sewer sludge contains around 40 per cent ash and a heat value between one-third and one-half that of coal (10-16 GJ per metric ton). The energy value of animal waste ranges from around 7 GJ/metric tonne for dried cow or horse dung to 14 GJ/metric ton for dried chicken droppings[7]. Dried sewer sludge and manure can be burned using technology similar to that for other biomass, but even where they are used for energy, they are usually supplemental fuels. The quantities often are not large enough to fuel a furnace and associated steam turbine, since the ash content, particularly from sewer sludge, is too high, and drying is troublesome and costly. Because of their high moisture content, these fuels commonly are digested wet. Anaerobic digestion produces a low-calorie gas while decontaminating the waste and turning it into high-quality fertiliser. The resulting biogas is 50-80 per cent methane and 20-50 per cent CO_2, with a calorific value between 5 000 and 6 000 kcal/m^3. Digesters operate on farms and at sewage treatment plants in several OECD countries[8], and in a few cases the gas is used to generate electricity. These systems are relatively common outside the OECD, especially in China and India. England's North West Water Authority uses methane gas from sewage to produce electricity and heat at ten sites[9].

Recent R&D work has concentrated on developing ways to burn sludge as a supplementary fuel and on improving digestion techniques and bacterial cultures. One technology that holds some promise for using sewage for power generation is gasification-combined cycle. In the United States, Texaco is conducting tests on combining dried sludge with pulverised coal at its 100-MW IGCC plant at Coolwater, California. Texaco expects that sewage can provide up to 25 per cent of the net input to the plant.

Geothermal energy[10]

As shown in Table 6.1, the countries with substantial geothermal-based electricity generating capacity are Iceland, Italy, Japan, New Zealand, and the United States. The conventional type of geothermal reservoirs used for electricity generation is hydrothermal (accumulations of hot water, liquid-dominated, or steam, vapour-dominated, trapped in fractured porous rock). Two other types of geothermal reservoirs, geopressured or magma, are regarded as unconventional or inaccessible. The fourth type of reservoir, hot dry rock, consists of accessible formations of rock, typically igneous, that are abnormally hot but contain little or no water. Water is introduced via an injection well and returned to the surface as hot water or steam via the production well. Accessing this resource is approaching economic viability[11].

Most electric power generated from geothermal energy is produced by running steam through turbine generators. Dry steam plants extract steam from vapour-dominated reservoirs and pipe it directly into a turbine. Flash steam plants produce electricity from liquid-dominated reservoirs that are hot enough (above 200°C) to flash a large proportion of the liquid to steam. Binary cycle plants, the most recently commercialised technology, are used in connection with liquid-dominated resources that are not hot enough for efficient flash steam production.

The country annex for Italy includes a full description of the economics of geothermal power generation. The results show that at a 6 per cent discount rate, production costs range between 30 and 80 mills/kWh, while at a 12 per cent discount rate they range between 45 and 120 mills/kWh.

Solar energy

The two basic ways to use solar energy for producing electricity — other than converting it into biomass — involve: 1) concentrating the sun's rays to produce hot air for running engines or steam for turbines (solar-thermal), or 2) converting the energy directly into electricity through photovoltaic cells.

Solar-thermal plants

One of the simplest technologies, using the Rankine cycle, involves line-focus collectors — troughs, usually parabolic in cross-section, that reflect sunlight onto a hollow tube running down the line of focus. Fluid passing down this tube is vaporised as it emerges from the other end, where it can be used to drive a turbine-alternator set. Line-focus collectors are the most widely used solar-thermal technology. Several such plants produce electricity in the United States, including the world's largest, the 80-MW SEGS VIII plant in southern California.

The sun's rays can be concentrated on one central receiver to drive a steam-condensing turbine. This method typically uses flat mirrors, or heliostats, arrayed in a field around a central tower on which a collector is perched. The heat collected is transferred to a fluid that drives a turbine. Because the temperatures can reach several thousand degrees Celsius, some systems heat liquid sodium or molten salt and transfer the heat to a boiler. High temperatures mean high thermal efficiency, but require expensive materials that can withstand extreme heat during the day and the relative cool of the night. Demonstration-scale plants have been built in France, Italy, Spain, and the United States. The largest, a 10-MW unit in California, produced electricity for the public grid from 1984 until 1988, when it was retired.

The Stirling engine is similar to an internal combustion engine in that it uses the force of gases expanding in a cylinder to drive a piston. In a Stirling engine the gas is expanded by heating the outside of the cylinder. Depending on the temperature applied (which, in the case of solar reflectors, can be quite high), the piston can be set in motion with great force. In a kinematic Stirling engine, a crankshaft connected to the piston or pistons drives a rotating alternator. In a free-piston Stirling engine, the piston moves freely back and forth. If a linear alternator is built into the cylinder, electricity can be generated by this repetitive motion[12].

Photovoltaics

The basic element of a photovoltaic system, the individual solar cell, consists of layers of semiconductor materials whose atoms absorb the photons in sunlight, freeing electrons and generating a current across the junction(s) between the semiconductors. This direct current can be used locally, or inverted to power a local, alternating current load or to feed into an electricity grid.

Single-junction cells were the first solar cells and are still the predominant type available commercially. They can be optimised only for a narrow band of the light spectrum, which limits their conversion efficiency. Multijunction cells are designed to overcome this limitation by stacking thin layers of dissimilar semiconducting materials, each layer attuned to different portions of the spectrum. Such a design allows the cell to absorb a broader band of sunlight and produce more electricity than a single-junction cell of the same size. Multijunction cell efficiency in the range of 25-30 per cent is considered achievable. For multijunction devices made from GaAs (Gallium Arsenide) or similar materials, the raw materials are costly and the manufacturing process is complex and requires great precision, but cell efficiency is between 25 per cent and 40 per cent.

In the United States, results of the PVUSA project (Photovoltaics for Utility Scale Applications) show measured efficiency between 3.5 per cent and 11 per cent, estimated efficiency of 15.1 per cent for a system yet to be installed, and average capacity factors of 22 per cent[13]. Installed costs for conceptual high-concentration systems with 27 per cent efficiencies were $3 210 to $3 410 per kW, with production costs of 13.3 cents/kWh in California, 12 cents/kWh in Texas, and 20 cents/kWh in Florida. Table 6.4 indicates current estimates of photovoltaic costs in the United States[14].

Table 6.4 **Cost of electricity from photovoltaics in the USA**

	Early 1980s	1992
Capital cost ($/kW)	$20 000	$8 000
O&M costs ($/kWh)	$0.02	$0.004
Module efficiency		
Flat plate	8%	13%
Concentrators	12%	17%
Cumulative industry investment	$500 million	$2 000 million
Costs per kWh ($/kWh)	$0.89 - 0.40	$0.20

Because individual solar cells produce very small amounts of power (e.g. one watt), they are usually combined into modules of around 100 cells. A grouping of modules is called an array. Simple, low-efficiency cells are usually arranged in flat-plate modules fixed at an optimal angle to the sun. High-efficiency cells are placed under concentrating lenses and connected to a tracking device

that keeps them perpendicular to the sun. Systems used for stand-alone or remote residential applications may comprise anywhere from 10 to 2 000 modules. A large central station is one with a peak capacity of 300 kW or greater.

Tidal power

Good information on the costs of producing electricity from tidal power exists, but the costs are highly site-specific, depending on the size of the barrage required in relation to the flow and the head of the water passing through the turbines. The best sites are in latitudes greater than 50°, especially at estuaries where the amplitude and flow of the tides are magnified through funnelling. The amount of energy available is approximately proportional to the square of the tidal amplitude, or range. Current technology requires a mean tidal range of more than five metres. At La Rance station in France, the turbines operate in one direction as the tide flows in and the other as it ebbs. Some smoothing of output is achieved through control of the outflow during ebb tide. Cost information has been published for the 20-MW Annapolis Tidal Power Project at Annapolis Royal, Nova Scotia, on the Bay of Fundy in Canada, which was commissioned in 1984. The total investment cost of this demonstration plant was approximately $53 million in 1984 US dollars, or $2 650 per kW of installed capacity. The levelised cost of the electricity generated was projected to be $0.027 per kWh.

Wave power

A typical wave with an amplitude of three metres has energy of 10 000 joules per square metre. If a wave's average velocity is ten metres per second, with ten seconds between crests, the theoretical power input per metre at right angles to the wave direction would be around 50 kW per metre[15]. Assuming conversion efficiency of 10 per cent, a 1 500-metre-long wave converter would produce 7.5 MW of power. As waves near shore, they lose much of their energy through turbulence and friction on the seabed. In gullies, whose narrowing walls squeeze the incoming waves into a climbing torrent, the power increases to 20-30 kW per metre[16]. Many wave-power development activities are focused at such locations.

Shore-based converters require no costly underground cabling and can be accessible from land. Two basic focusing devices have been demonstrated: the tapered channel (Tapchan) and the oscillating water column (OWC). The Tapchan creates a low hydrological head by channelling incoming waves up a slope into a reservoir. The water then drains back to the sea, driving a standard hydroelectric turbine on the way. The major advantage of the technology is that the concept is simple and the materials and components required are commercially available. The world's first Tapchan power plant, a 350-kW plant near Bergen, Norway, became operational in May 1986[16].

The OWC is also simple in concept. In essence, it is shaped like an open fireplace standing in the sea. As waves rise and fall, the column acts as a piston, pushing air up through the chimney on the upstroke, and sucking air in on the downstroke. The vertical motion of the water inside the column is many times that of the wave outside, which amplifies the force. Power is produced by a turbine in the air flow. An innovation crucial to the development of the OWC was an efficient air turbine that spins in the same direction irrespective of the direction of the air flow. The Wells turbine, used in nearly all OWC power plants, can capture up to 80 per cent of the kinetic energy — much more than other devices.

The enormous wave energy that makes a site attractive for a shore-mounted OWC plant also makes construction and maintenance expensive. At the Isle of Islay site off Scotland, the waves were so ferocious that the plant had to be constructed behind a protective barrier. This experience led to proposals to install OWC plants a few metres inland from open water and blast a channel to the sea. Waves can also wreak havoc on plants after they have been built. The 500-kW pilot plant at Toftestallen, Norway, was knocked off its foundation during a severe storm in December 1988. Engineers are confident that shore-mounted OWC plants can be built to withstand such storms.

Offshore wave energy converters are in the early stages of development. Of the hundreds of designs proposed to government funding agencies during the 1970s and early 1980s, only a few have led to prototypes. Most are either pressure-activated or surface-following. Some of the former use OWCs, which can be mounted on a floating superstructure or on the seabed. Such devices can serve a dual purpose as a source of electricity and as a breakwater. The first testing of a floating OWC device was done on the Kaimei II experimental research barge, which operated off Japan from 1979 through 1987[17].

The Japan Marine Science and Technology Centre has since developed a different type of floating OWC device, called the "Mighty Whale". It is shaped roughly like a segment of an airplane wing, with the leading edge — i.e. the air chamber — facing the open sea. Air flowing back and forth through an orifice near the top of the chamber drives a Wells turbine. Laboratory tests have indicated that the Mighty Whale can absorb up to 60 per cent of the incident wave power, yet because of its airfoil shape, its mooring forces are small. A 1.5-MW demonstration plant, 65 metres long, is expected to be built in Japan within the next few years. Another device that converts wave energy into flowing air is the "S.E.A. Clam". Initial results suggest measured conversion efficiency ranging from around 20 per cent for periods of ten seconds or more to over 60 per cent for periods shorter than seven seconds. Additional work on the design of the structure and development of the key components is necessary, but it is estimated that a full-scale prototype could be deployed within three to four years[18].

Wind energy

The amount of energy that can be extracted by a turbine from wind is proportional to the cube of the wind's speed. For electricity generation, constancy of wind velocity is desirable. Below about four metres per second, the wind is not strong enough to overcome the resistance of the turbine blades. Between four and twelve metres per second, power output increases rapidly with wind speed. Depending on the design, once the wind speed reaches twelve metres per second, power output is kept constant until the wind speed exceeds 25 metres per second, at which point the turbine automatically shuts down for safety reasons. From an energy production standpoint, the best sites for wind turbines have average wind speeds between 10 and 16 metres per second and little variation in wind velocity.

Most designs for wind energy conversion systems are either horizontal axis (the axis of rotation is parallel to the wind), or vertical axis (perpendicular to the wind). Much R&D effort in recent years has focused on design improvements to extract as much power from the wind as possible. Significant progress has been made, mainly through better aerodynamic design, and the use of lighter, sturdier materials in the blades. Two important parallel areas of R&D — energy storage systems and wind/diesel systems — could help expand the potential for wind-generated electricity. Both lines of research address a central limitation of wind power: its intermittency. Wind/diesel systems are interesting because diesel engines are most commonly used for power precisely where wind turbines are most cost-effective — on islands and in other remote areas.

The maximum potential installed capacity for land-based wind power in the OECD is 19.5 TW[3]. Translating this figure into dependable capacity, there is a maximum potential of 4.8 TW that could generate 43 000 TWh a year. If it is assumed that 90 per cent of sites are unavailable, the figures drop to 486 GW generating 4 000 TWh a year. Studies conducted by the Dutch Electricity Generating Board (SEP) indicate that between 1 000 and 1 600 MW of wind-based generating capacity (5-10 per cent of the total) could be incorporated into the generating mix without requiring electricity storage capability[19]. Penetrations above those amounts without storage capability were considered by SEP to have adverse effects on the load following capabilities and system spinning reserve.

Based on a 1989 survey of Danish wind turbine operators and given certain assumptions, costs for the size of wind turbine now manufactured commercially were Danish kroner 0.334/kWh*, or around $0.055 to $0.060/kWh. Modern commercial-scale wind turbines have been operating too little time for the expected lifetimes to be known with accuracy — they may vary from 15 to 25 years. Because the levelised costs of operating a wind turbine have declined substantially over the last decade as manufacturing costs have been reduced and O&M procedures streamlined, it is reasonable to expect that further reductions can be achieved. In Denmark, the levelised costs for new units declined by two-thirds between 1980 and 1988. Australia's National Institute of Economic and Industry Research reports a similar decline from 1981 to 1987 for wind turbines in California[20]. Table 6.5 shows estimated costs of electricity from wind in the United States[21]. Costs per kilowatt-hour for electricity generated from wind in the United States are projected to decline further to $0.04 by 2000.

Table 6.5 **Cost of electricity from wind in the United States**

	Early 1980s	1992
Capital costs ($/kW)	$2 200	$1 000
O&M costs ($/kWh)	$0.04	$0.01
Availability	50%-60%	95%
Capacity factor	13%	25%-35%
Cumulative industry investment	$10-20 million	$3 000 million
Costs per kilowatt-hour ($/kWh)	$0.37-0.12	$0.08

* On average in 1990, DKr = $0.162.

Figure 6.1 **Estimates of renewable-based generating capacity**
Estimated 1992

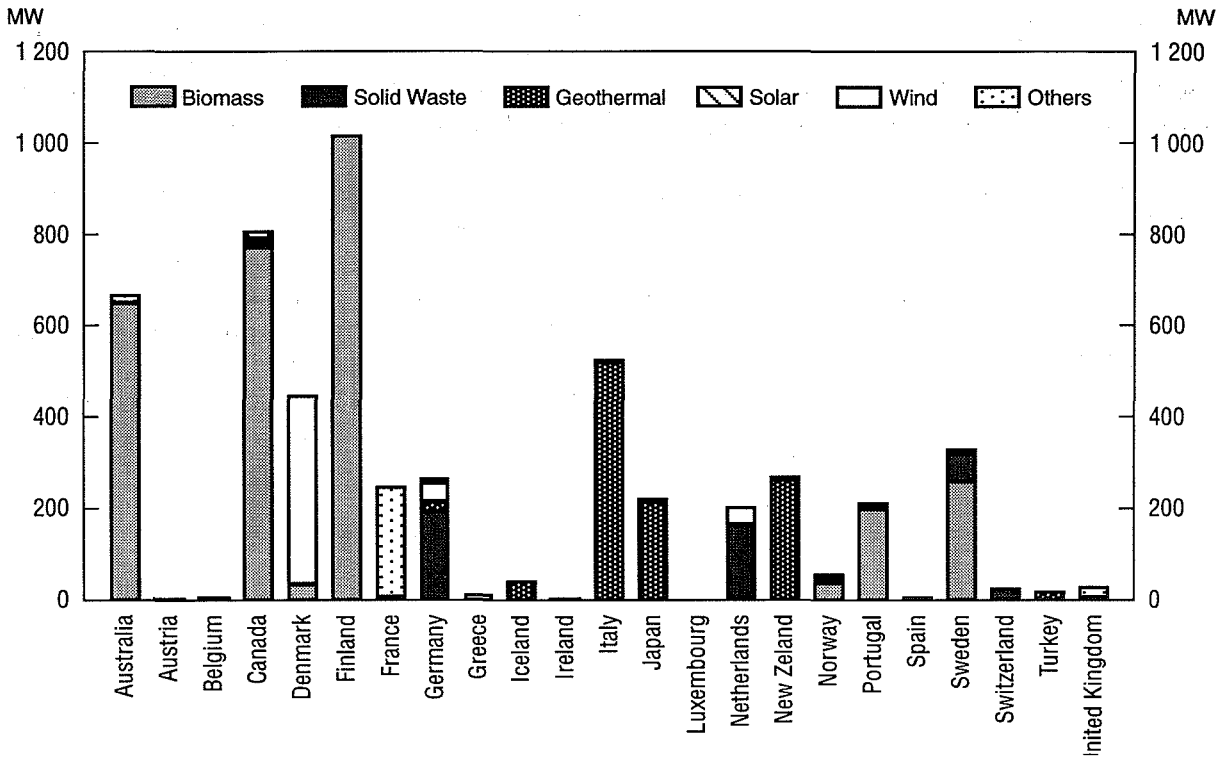


Figure 6.2 **Estimates of renewable-based generating capacity**
Estimated 1992

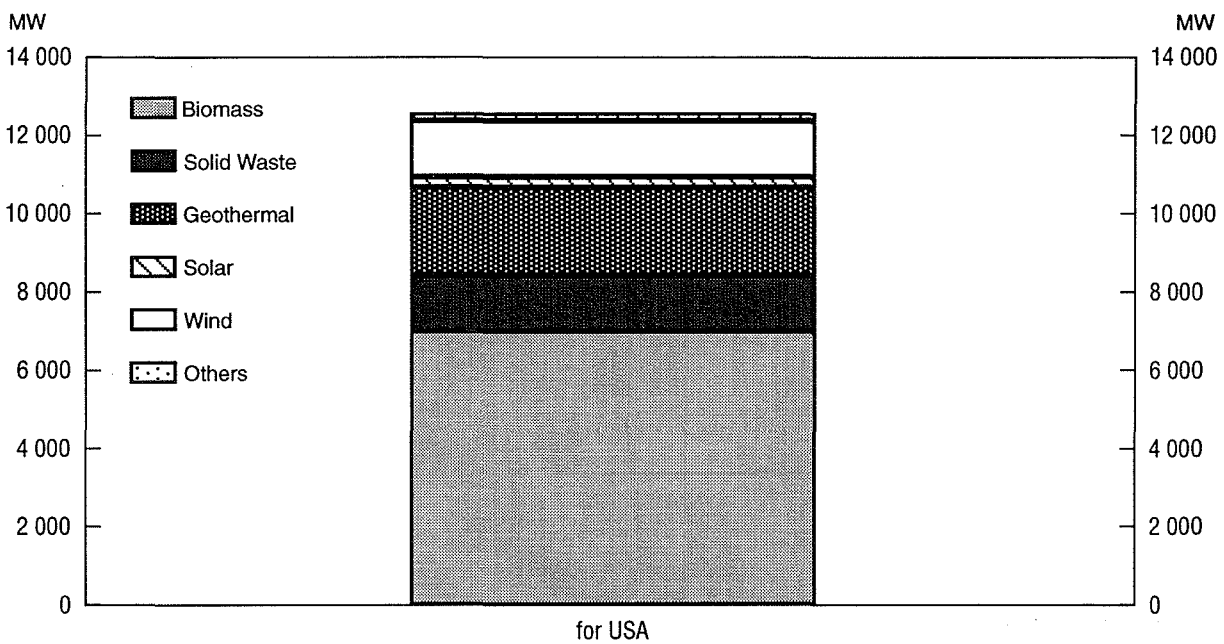
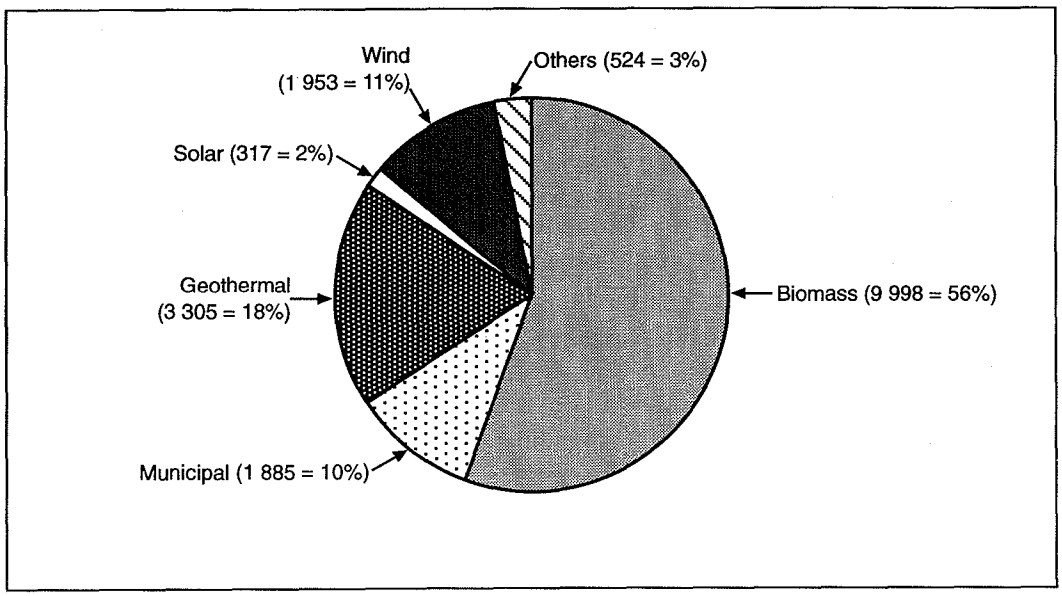


Figure 6.3 **Estimates of renewable-based generating capacity (MW)**



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Annex 7

COMBINED HEAT AND POWER

Issues associated with the fuels, technology, and economics of combined heat and power production systems were described fully in Annex 8 of the 1989 generating costs study[1]. That annex also set out the benefits of CHP, as well as describing the technical analysis and methods which industrial investors need to undertake in deciding on whether or not to build CHP units. This annex focuses on developments since the 1989 study. The IEA started a project in 1992 aimed at summarising the current status of combined heat and power production. In particular, the IEA is validating the information in its database to address certain anomalies that have been discovered. Meanwhile, the information in Table 7.1 is drawn from an early draft of that study and is included only for illustrative purposes. Information on CHP and district heating can be found in numerous publications, including IEA country reviews[2], Energy Statistics and Energy Balances of IEA countries[3], *Electricity Supply in the OECD*[4], *Energy Efficiency and the Environment*[5], the 1988 Proceedings of a workshop on combined heat and power held in Copenhagen[6], and the 1993 Proceedings of a conference on new electric generating technologies held in Tokyo in May 1992[7].

Technologies that combine the generation of useful heat and electric power (CHP) have been in existence for many decades. Historically, their most common applications have been in energy-intensive industries that use steam for process heat or in municipal district heating systems which raise steam to generate hot water. The basic economic attraction of a CHP plant is its overall thermal efficiency, which can be up to 90 per cent. Typically, fuel savings of around 30 per cent can be achieved by CHP compared to separate production[8]. CHP is a mature technology involving the production of power in a first step and the use of the heat by-product in subsequent steps. Essentially, any generating technology that produces a stream of useable heat (hot gas or steam) after generating electricity could be a candidate for CHP. In terms of the technology for generation, there are a number of possibilities, including conventional coal-fired steam turbine plants (extraction and back-pressure), gas turbines, gas engines, gas combined-cycle, steam turbine plants that use waste, wood, or straw, and gas engines based on biogas. Of particular interest recently are the combined cycle technologies (either natural gas-fired or fired with gas from gasification of coal, lignite, biomass, refinery bottoms, Orimulsion, etc.) whose conversion efficiencies can be over 85 per cent in a CHP configuration.

CHP is promoted by most OECD Member governments and by the governments of a number of other countries. The beneficial policy aspects of CHP plants derive from the fact that they use energy more efficiently than alternative ways of providing the same heat and power needs, and thereby avoid some of the environmental externalities that result from energy conversion and use. In the future, governments may also attach a value to ways of delivering useful energy that minimise the release of CO_2; promoting energy-efficient technologies, including CHP plants, could be seen as one way of furthering this objective.

Table 7.1 shows the development of CHP/DH electricity and heat generation in OECD countries from 1988 with projections to 2000. Though Table 7.1 shows minimal electricity generation from CHP in the United States, other sources[9] indicate a very strong growth in CHP in the USA since 1979. In

1979 there were 10.5 GW of operational capacity. As of September 1990, there were 29.2 GW operational, 23.0 GW under construction or on order, and another 15.0 GW planned. Of the operational capacity, 15.7 GW (54 per cent) were gas-fired. Further, 15 GW of capacity under construction or on order (65 per cent) and 10 GW of planned capacity (67 per cent) are to be gas-fired. In the United Kingdom, 2 GW of capacity is industrial co-generation[10]. The CHP Association of the UK claims that 20 GW of industrial co-generation is possible by 2020.

Forecasts for CHP in Sweden were for substantial increases by 2020. These forecasts were based strongly on the expectation that nuclear power would be phased out in Sweden by 2010. The phase-out is no longer clear cut, so the anticipated shortfall in electric generating capacity that was driving the CHP forecasts may not occur. Accordingly, the economics of new CHP plant are not clear cut either, and electricity prices would have to increase substantially before they became economic[11].

In Holland, the Dutch Electricity Generation Plan for the period 1993-2002 calls for the addition of 10 CHP units with a total capacity of 2 500 MWe. Heat from these systems will be provided as district heating for buildings and greenhouses and process steam heat for the processed-food industry and paper mills. Their pricing policy is such that the price of electricity from CHP does not affect the price for other users, so heat is priced at the incremental cost of producing the heat (plant equipment, transport and distribution, and incremental fuel). Non-utility CHP capacity at end-1992 is 2 700 MWe, with an additional 900 MWe expected by 2000.

Methods of calculating CHP electricity production costs

The financial attractiveness of a CHP unit will depend on a number of special factors, as well as upon the generality of factors that affect all investment projects. Schaffer[1] lists the following as most crucial: 1) the extent to which the capital and fixed operating costs of CHP plant are above those of 'package' boilers; 2) the expected economic life of the CHP plant, which will depend upon the input fuel, and its load factor; 3) the current and expected on-site heat-to-power ratio; 4) the price differential between the fuel consumed in the private generator's CHP plant and that used by the public power producers; 5) the price the CHP plant operator can obtain for electricity sales; and 6) the energy and capacity charges for backup power supplies. The economics will also depend on whether the installation is to be retrofitted at an existing site or built as part of a new development. In new construction of combined heat and power plant, the plant configuration can be designed to optimise production of heat and power. In other circumstances, whether an existing power plant or an existing district heating scheme, the plant configuration has to be modified to a combined heat and power system. Local conditions will often be the determining factor in the economic analysis. An existing heat distribution system will be less costly to retrofit. Heat demand is very different for industrial processes as compared with hot water for individual dwellings and offices. Also, heat load varies with time, as does the demand for electricity, so trying to combine heat and power generation imposes additional system constraints. In trying to calculate the levelised production cost estimates for the electricity produced by a CHP plant separately from the costs of producing the heat output of the plant, one is immediately confronted with what economists call the joint product problem. When two or more outputs can be produced in variable proportions from the same inputs (in the case of a CHP plant, the physical plant, labour, and fuel used to generate heat and power), one can estimate the marginal costs of producing each product, but there is no clear way of attributing the total average costs between them. Some arbitrary method has to be chosen if one wishes to make an explicit comparison of electric generating costs from CHP with costs of other forms of generation.

Table 7.1 **Combined heat and power in OECD countries from 1988 to 2000 (Electricity in net TWh, Heat in TJ)**

Country	1988		1989		1990		1995		2000	
	Electricity	Heat	Electricity	Heat	Electricity	Heat	Electricity	Heat	Electricity	Heat
Australia	0.74	3169.9	0.84	3567.0	0.63	2680.1	0.58	2510.0	0.58	2510.0
Austria	--	11200.8	--	11664.2	--	13134.0	--	36850.0	--	43970.0
Belgium	5.58	9205.2	5.74	9306.1	7.32	9399.1	5.81	8380.0	5.81	8380.0
Canada	--	16391.0	--	24432.2	--	21006.7	--	37690.0	--	41880.0
Denmark (a)	27.63	52912.1	21.43	50422.1	24.64	53149.9	29.42	77050.0	29.19	93390.0
Finland	14.18	182160.0	15.16	186000.0	16.33	190000.0	22.11	198000.0	28.60	208000.0
Germany	--	116138.2	--	114051.1	--	114051.1	--	--	--	--
Ireland	0.18	--	0.20	--	--	--	--	--	--	--
Italy	13.7	--	16.1	--	0.69	--	--	--	--	--
Netherlands (b)	65.92	11258.0	68.97	11642.8	56.04	11914.2	55.81	20940.0	55.81	29310.0
Norway	0.10	1649.1	0.10	1825.8	0.11	1910.0	--	--	--	--
Portugal	0.04	1263.8	0.24	1410.8	0.2	1188.0	0.23	1260.0	0.23	1260.0
Spain	0.05	678.8	1.43	665.0	0.30	670.0	--	--	--	--
Sweden	5.99	40791.9	5.39	34683.0	2.50	35111.0	4.42	35590.0	6.40	36430.0
Switzerland	1.10	11789.8	1.14	11869.8	0.69	11469.9	1.12	11600.0	1.44	11600.0
United Kingdom	0.06	484.1	0.08	518.8	0.03	530.2	--	--	--	--
United States	--	79474.0	--	94392.0	--	81308.2	--	--	--	--
N. America	--	95866.0	--	118824.1	--	102314.9	--	37690.0	--	41880.0
Europe	99.59	312423.8	98.94	302167.5	101.68	314087.1	118.33	266210.0	129.7	292170.0
Pacific	0.74	3169.2	0.84	3567.0	0.63	2680.1	0.58	2510.0	0.58	2510.0
OECD Total	100.33	411459.0	99.78	424558.6	102.31	419082.1	118.91	306410.0	130.28	336560.0

(a) The Danish numbers represent total electricity production from CHP plants, including electricity production by condensing units at CHP plants and by extraction units running entirely or partly in condensing mode. The data for Denmark indicate that most of Denmark's electricity is generated at CHP plants. CHP plants in Denmark are those defined as plants with at least one CHP unit on site. Since most Danish power plants have one or more CHP units, almost all electricity is allocated to CHP. Further, most of the CHP units in Denmark are extraction units and are capable of producing electricity without producing heat, so a so-called CHP unit can generate electricity without being in CHP mode. In 1990, CHP plants operating in CHP mode in Denmark generated 8.99 TWh rather than the 24.64 TWh shown in the table. The "correct" figure is not shown because equivalent figures are not available for the other years.

(b) The electricity production figures for the Netherlands appear to suffer the same problem of definition as the Danish data. Information on electricity production by CHP units in CHP mode are not available.

Pedersen[12] has described four approaches to evaluating the economics of CHP plants. A fifth method that applies the economic benefit of joint production neutrally to electricity and heat also is presented.

Method 1. The simplest method is to treat CHP plant as if it were a power-only plant. This is done by subtracting the added costs of the equipment and labour needed to extract useful heat — in the case of extraction CHP/DH systems these costs would include mainly the capital cost of the extra pipes, valves, controls, and heat exchangers and the costs of using more fuel than what would be consumed when running the plant in 100 per cent condensing mode. For large plants this incremental cost is a small proportion of the total. For example, one of Denmark's two power companies, Elsam, has estimated that an extra investment of only 90 Danish kroner ($13) per installed kilowatt would be required to build a 350 MW extraction CHP plant instead of a 350 MW condensing unit[13]. The above method was used by the Danish power companies in estimating the costs of new coal- and gas-fired plants for this study (since 1983, all new power plants built in Denmark have been CHP plants). It is of course equivalent to allocating the entire cost advantage of CHP (if there is any) to the cost of heat production.

Method 2. The second method calculates the electricity costs by subtracting from total costs the avoided cost of producing heat by the lowest-cost, non-CHP alternative. If the resulting price from a CHP plant is lower than the kilowatt-hour price from a condensing power plant, then the whole CHP cost advantage is allocated to electricity production. Electricity production costs are thus calculated using the following formula:

$$C = [I + PV(O\&M) + PV(Fuel) - PV(Heat)]/PV(kWh), \text{ where:}$$

I	=	investment costs, including interest incurred during construction,
PV(O&M)	=	present value of operation and maintenance costs,
PV(Fuel)	=	present value of fuel costs,
PV(Heat)	=	present value of production costs from one or more heat-only boilers,
PV(kWh)	=	present value of the electricity produced over the lifetime of the plant.

Method 3. An alternative to method 2, which avoids having to estimate directly the production costs from one or more heat-only boilers — a difficult task in assessing the economics of a CHP plant producing heat for an existing DH system — is to use the net-back price of heat. This method can be applied to CHP/DH schemes only, as the transfer price of heat in CHP/IND schemes is usually not known.

Method 4. *Same site-same fuel method.* This method is also a simplification of method 2. It is assumed that the calculation of avoided heat production costs can be simplified in the following way:

- The alternative boiler for heat source is located in the same place as the CHP plant. This means that no investment costs for heat transmission are necessary.

- The fuel used by the boiler is the same as the fuel used by the CHP plant.

Because of the site-specific nature of the heat delivery costs from CHP plants, they have been excluded from the range of plants for which generating costs are compared in this study. From what has been said in this annex, however, it is clear that CHP plants may be the preferred option in some circumstances.

Method 5. *Shared savings method.* If there is a real synergy between heat production and electricity generation, then the costs of producing both should be less than the costs of producing them separately. For any given amount of electricity generation, it is possible to calculate production costs on a per kWh basis, assuming stand-alone generation. Similarly for heat production, it is possible to calculate production costs on a per GJ basis. The combined production costs can also be calculated for the combined heat and power production (based typically on the heating load). All of these costs can be discounted to a present value and levelised. On a present value basis, the production costs saved through the synergy can be prorated according to the present value costs of the stand-alone systems. Subtracting the prorated savings from the separate system costs, one arrives at an estimate of allocated costs for determining the cost of electricity and heat in a combined system.

Tables 7.2 to 7.6 show several cost examples of CHP systems from Denmark and Sweden. These cost examples are presented here rather than in the main cost comparison tables because they are site-specific in nature. Frequently, cost analyses are incremental, based on an existing electric or heat load that must be satisfied with joint production of the other product being evaluated on an incremental cost basis. Because it is much more likely and simpler for electricity to be produced for sale via an available grid, it typically is the case that heat is the primary product for a heating scheme and the electricity production is the incremental activity. As mentioned above, these methods are arbitrary and are presented only in an attempt to compare electric generating costs via CHP with other means of generation. In fact, investment decisions will be made on a global basis (electricity and heat combined) for a specific location based on the heating and electric generating fuels displaced.

Table 7.2 **Production costs for a straw-fired CHP plant in Denmark**

Base date of currency unit: 1 July 1991
First operation year: 1998

Real discount rate	5%	
Plant lifetime	20 years	(20, 25, 30 or 40)
Description of plant	Straw-fired CHP plant	
Net electrical output	16.6	MW
Net electrical efficiency	25%	
Net heat efficiency	60%	
Heat efficiency of DH boiler	97%	
Power plant fuel	Straw	
Avoided boiler fuel	Gas	
Settled down load factor	75%	
	Mill.DKK	
Base construction cost	282	
Site specific cost	0	
Contingency cost	0	
Heat investment cost	10	
Avoided heat investment cost	0	

Power plant investment profile (year 0 = year of commissioning):

-6	-5	-4	-3	-2	-1	0	1
0.0%	0.0%	5.0%	21.0%	32.0%	35.0%	7.0%	0.0%

Fixed operating costs	0.75	Mill.DKK/MW/y
Variable operation costs	0	DKK/MWh e
Avoided heat operation costs	10	DKK/MWh heat

Straw-fired CHP plant	Mill.DKK	DKK/MWh
Levelised investment costs incl. interest	319	239
Levelised operation costs	122	92
Levelised fuel costs	85	64
Total levelised costs	526	395

Table 7.3 **Production costs for a natural gas-fired CHP plant in Denmark**

Base date of currency unit: 1 July 1991
First operation year: 1998

Real discount rate	5%	
Plant lifetime	20 years	(20, 25, 30 or 40)
Description of plant	NG-fired CHP plant (combined cycle)	
Net electrical output	17.1	MW
Net electrical efficiency	42%	
Net heat efficiency	46%	
Heat efficiency of DH boiler	97%	
Power plant fuel	Gas	
Avoided boiler fuel	Gas	
Settled down load factor	65%	
	Mill.DKK	
Base construction cost	106	
Site specific cost	0	
Contingency cost	0	
Heat investment cost	10	
Avoided heat investment cost	0	

Power plant investment profile (year 0 = year of commissioning):

-6	-5	-4	-3	-2	-1	0	1
0.0%	0.0%	0.0%	0.0%	50.0%	50.0%	0.0%	0.0%

Fixed operating costs	0.00	Mill.DKK/MW/y
Variable operation costs	45	DKK/MWh e
Avoided heat operation costs	10	DKK/MWh heat

NG-fired CHP plant (combined cycle)	Mill.DKK	DKK/MWh
Levelised investment costs incl. interest	124	103
Levelised operation costs	41	34
Levelised fuel costs	135	112
Total levelised costs	300	249

Interest during construction	7.6%	8
Operating costs first year		1.87
Normal operating costs		2.13

Table 7.4 **Production costs for a biomass-fired plant in Sweden**
8 MWe/20 MW heat

Electric efficiency	**24%**		
Total efficiency	**87%**		
Building time	**2 yrs**		
Availability	**90%**		
Investment	20200	SEK/kWe	excl. interest during construction
Interest during construction	1100	SEK/kWe	at 5% interest, 2160 SEK/kWe at 10%
Annual fixed O&M costs	540	SEK/kWe	excl. interest during construction
Fuels storage costs	--	SEK/kWe	at 5% interest, -- SEK/kWe at 10%
Fuel costs	0.105	SEK/kWh e	
Variable O&M costs	0.06	SEK/kWh e	

Table 7.5 **Production costs for a natural gas-fired plant in Sweden**
Diesel engine 10 MWe/10 MW heat - CHP plant

Electric efficiency	**42%**		
Total efficiency	**85%**		
Building time	**1 yr**		
Availability	**-%**		
Investment	8300	SEK/kWe	excl. interest during construction
Interest during construction	200	SEK/kWe	at 5% interest, 400 SEK/kWe at 10%
Annual fixed O&M costs	210	SEK/kWe	excl. interest during construction
Fuels storage costs	--	SEK/kWe	at 5% interest, -- SEK/kWe at 10%
Fuel costs (a)	--	SEK/kWh e	
Variable O&M costs	0.031	SEK/kWh e	

(a) Natural gas price not available.

Table 7.6 **Production costs for a natural gas-fired plant in Sweden**
Combined cycle 135 MWe/130 MW heat - CHP plant

Electric efficiency	**43%**		
Total efficiency	**85%**		
Building time	**3 yrs**		
Availability	**90-95%**		
Investment	5800	SEK/kWe	excl. interest during construction
Interest during construction	500	SEK/kWe	at 5% interest, 1000 SEK/kWe at 10%
Annual fixed O&M costs	210	SEK/kWe	excl. interest during construction
Fuels storage costs	--	SEK/kWe	at 5% interest, -- SEK/kWe at 10%
Fuel costs	--	SEK/kWh e	
Variable O&M costs	0.025	SEK/kWh e	

References and notes

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12. PEDERSEN, S.L. (1988), "Combined heat and power: possibilities for calculating production costs — a Danish view", mimeographed paper, Danish Energy Agency, Copenhagen, Denmark.

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Annex 8

COAL INDUSTRY ADVISORY BOARD ADVICE TO IEA FOR JOINT IEA/NEA STUDY ON UPDATING COMPARATIVE COSTS OF ELECTRICITY GENERATION

(March 1992)

The CIAB, which represents coal producers, electric utilities and coal traders in IEA countries has been asked to advise the IEA to assist the up-dating of the joint IEA/NEA study on projected electricity generating costs, previously published in 1989. For such a study, projections of future coal prices are essential.

For power stations in Western Europe and Japan/Pacific Rim, the relevant coal price will be the CIF price of internationally traded steam coal (to which would have to be added inland transport costs, on a case-by-case basis, for power stations not situated on the coast). Accordingly, CIAB Associates were asked for their projection for the range, and "best estimate" within that range, for the price of internationally-traded steam coal CIF Western Europe and Japan/Pacific Rim importing countries in mid 1991 US dollars for coal of an average quality (net as received) of 26 GJ per metric ton and with a sulphur content of around 1 per cent, in the year 2000. Associates were also asked to say, in broad terms, what trend they expected prices to take after 2000.

This note summarises the views in the 20 replies received (which were subject to initial editing by the IEA Secretariat so as to remove any indication of the sender or the company with which the sender was affiliated). The replies covered a range of coal producers, utilities and traders.

For CIF prices of traded coal in mid-1991 US dollars, for the year 2000, the averages for the "best estimates" are:

Western Europe	$51/metric ton	(range $38 - $70)
Japan/Pacific Rim	$53/metric ton	(range $40 - $70)

For the period beyond 2000, the majority of respondents were fairly evenly divided between those that foresaw no increase in "real" terms and those who foresaw modest increases. The average expectation among respondents giving quantified replies is for an increase of little more than 1 per cent p.a.

For the North American utility market, somewhat different parameters apply. Here, the sample of CIAB respondents is small (only 3 respondents). For 26 GJ/metric ton coal at mid-1991 dollars, they project on average a delivered price in the Chicago area of $34/metric ton.

Annex 9

FUEL PRICES

The comparison of the costs of generating electricity from base load plant to be commissioned around the year 2000 has been conducted based on certain assumptions regarding capital investment costs, construction lead times, cost of money and discount rates, operation and maintenance costs, and fuel costs, among others. These assumptions are described fully in the main text and tables. To provide the reader with some benchmark for the fuel cost assumptions, this annex presents a series of forecasts from other sources. Table 9.1 shows three of the crude oil price assumptions being used by the IEA in developing its current World Energy Outlook. The three scenarios shown are based largely on the US Department of Energy's Energy Information Administration outlook shown in Table 9.2. Not shown are six other scenarios under development that will be described more fully when the IEA's new World Energy Outlook is presented. Table 9.3 shows world fuel import prices for a number of fuels, and Table 9.4 shows the Commission's projection of the European Communities' average fuel import prices (CIF). Table 9.5 shows the fuel price assumptions from the UK Department of Trade and Industry's Energy Paper No. 59.

Table 9.1 **Crude oil price assumptions used by the IEA for modelling World Energy Outlook** (a)
(1990 US$ per barrel)

	1990	1995	2000	2005
Level	22.15	20.8	20.8	20.8
Rising price	22.15	28.8	35.5	35.5

(a) Source: IEA 1990 World Energy Outlook.

Table 9.2 **World oil prices from 1990 to 2010** (a)
(1990 US$ per barrel)

	1990	1995	2000	2005	2010
Low	21.78	16.00	17.90	20.10	22.60
Medium	21.78	20.80	26.40	30.50	33.40
High	21.78	25.30	31.80	36.90	40.20

(a) Source: **History**: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(91/12)(1991). **Projections**: Energy Information Administration, Oil Market Simulation Model User's Manual, DOE/EIA-MO28(92)(1992). Taken from Energy Information Administration, International Energy Outlook, 1992.

Table 9.3 **International import prices** (a)

US$ current prices (CIF)	Historical		Forecast		
	1985	1990	1995	2000	2005
per barrel Crude oil	27.75	22.66	22.25	32.55	48.68
In 1990 $	33.02	22.66	19.00	23.00	28.00
per mt (Rotterdam)					
Gasoline	273.1	274.9	264.9	398.2	621.7
Diesel oil	240.2	214.3	233.6	345.6	524.3
Residual fuel oil	151.4	100.1	79.2	114.3	168.3
per toe					
Steam coal	73.86	77.57	83.65	105.13	136.59
Metallurgical coal	89.96	94.80	102.05	128.26	166.64
per tce Steam coal	51.71	54.30	58.55	73.59	95.62
In 1990 $	61.52	54.30	50.00	52.00	55.00
per MMBtu Natural gas					
Norway/Netherlands	4.05	2.83	3.56	5.05	7.34
In 1990 $	4.82	2.83	3.04	3.57	4.22
per pound Nuclear fuel	23.58	24.66	25.79	26.97	28.21

(a) Source: Commission of the European Communities, September 1992, *Energy in Europe: A View to the Future*, CEC DG VII, Brussels.

Table 9.4 **Average European Community import prices** (a) (1990 US$)

	1985	1990	1995	2000	2005
Crude oil					
$/barrel	33.9	21.6	19.0	23.0	28.0
$/toe	247.4	157.7	138.7	167.9	204.4
Steam coal					
$/tce	61.5	54.3	50.0	52.0	55.0
$/toe	87.9	77.6	71.4	74.3	78.6
Natural gas (average CIF Europe)					
$/MMBtu	4.8	2.8	3.0	3.6	4.2
$/toe	191.3	112.3	120.6	141.7	167.5

(a) Source: Commission of the European Communities, September 1992, *Energy in Europe: A View to the Future*, CEC DG VII, Brussels.

Table 9.5 **Fuel price assumptions from Energy Paper No. 59 of the UK Department of Trade and Industry** (a)
(1990 US$)

	1990	1995	2000	2005	2020
Crude oil $/barrel					
High	23.30	27.00	32.50	35.00	42.60
Low	23.30	17.00	19.30	21.20	27.00
Steam coal $/tce					
High	48.2	50.00	55.00	55.00	55.00
Low	48.2	45.00	45.00	45.00	45.00
Natural gas [Gas beach price/pence per therm (b)]					
High	17.3	20.1	20.9	23.2	31.4
Low	17.3	15.5	16.7	17.6	22.8

(a) United Kingdom Department of Trade and Industry, "Energy Related Carbon Emissions in Possible Future Scenarios for the United Kingdom", *Energy Paper No. 59*, ISBN 0 11 414157 6, October 1992, London: Her Majesty's Stationary Office.

(b) The source document presents the assumptions about the real sterling/dollar exchange rate. These are as follow in $/£: April 1991 (base) = 1.76; 1992 = 1.70; 1993 = 1.70; 1994-2020 = 1.65.

Conversion units:

1 barrel of fuel oil #6 contains	≈	6.27/6.28 MMBtu
1 Btu	=	1.055 KJ
Btu/lb	=	0.555 kcal/kg
Btu/lb	=	0.002326 MJ/kg
Btu/lb * 0.022046	=	Therms/metric ton
1 calorie	=	4.1868 joules
kcal/kg	=	1.8 Btu/lb
kcal/kg	=	0.004187 MJ/kg
1 long ton	=	1.12 short tons
1 long ton	=	1.0160 metric tons
1 metric ton	=	0.9842 long tons
1 metric ton	=	1.102 short tons
MJ/kg	=	430 Btu/lb
MJ/kg	=	238.8 kcal/kg
1 short ton	=	0.893 long tons
1 short ton	=	0.907 metric tons
1 tce	=	0.7 toe
1 Therm	=	10^5 Btu
1 Therm	=	105.5 MJ
1 toe	=	10^7 kilocalories

Annex 10

CLIMATE CHANGE

The debates regarding energy and the environment are focusing mainly on greenhouse gas emissions and the possibility of global climate change. Man-made emissions of CO_2 form approximately 60 per cent of total greenhouse gas emissions in terms of the contribution over a 100-year period. Other principal greenhouse gases include methane, nitrous oxide, chlorofluorocarbons, water vapour, and tropospheric ozone. OECD countries are responsible for 45 per cent of total anthropogenic CO_2 emissions world-wide, and of this amount the electricity industry is the source of 29 per cent — that is, 8 per cent of total world-wide greenhouse gas emissions. While all generating technologies produce some emissions when considered on a full-cycle, construction-to-dismantling basis, the bulk of emissions are from the principal carbon-based fuels (coal, oil, and natural gas). Coal, with a higher proportion of carbon atoms, produces more CO_2 than does oil or natural gas for the amount of electricity delivered. The amounts may vary slightly, depending on the composition of the oil in particular, but in rough terms, per net unit of heat released, coal yields twice as much CO_2 as natural gas, and 50 per cent more than fuel oil. Emissions per kWh generated naturally depend upon the efficiency of electricity generation. The use of natural gas in combined cycle gas turbines, for example, produces less than half the CO_2 per kWh generated than coal in the current best coal-fired plant[1]. Renewable energy sources (hydroelectricity, solar, wind and sustainably-used biomass) and nuclear energy do not contribute significantly to CO_2 emissions. As noted in Annex 6, there can be significant emissions of CO_2 entrained in steam from geothermal reservoirs. The senior expert symposium on electricity and the environment held Helsinki in May 1991 describes the environmental issues associated with electricity[2].

The issue of greenhouse gases and their potential for causing global climate change are discussed in the 1991 IEA report *Greenhouse Gas Emissions: The Energy Dimension.* Although most OECD Member countries have started to examine possible measures for reducing emissions of CO_2, few have enacted radically new policies. The range of policies and policy initiatives to date are summarised in this section. A fuller description of climate change policies can be found in the IEA periodical publication *Energy Environment Update (August 1993),* a summary of countries' commitments to mitigate the possibility of climate change.

The scientific understanding of global climate change is not yet far enough advanced to enable an estimate to be made of the marginal external costs to society of emitting an extra unit of CO_2 — which is what would be required to set an efficient pollution tax on CO_2-emitting processes. In the absence of such a calculation, governments could decide on a target reduction in emissions of CO_2 and set a tax to achieve the desired reduction. Other policy instruments for addressing climate change include mandating fuel mix changes to less carbon-intensive fuels, encouraging renewables development through fiscal incentives, R&D support, or other funding, promoting nuclear power, and introducing trading mechanisms for emissions allowances.

Initial attempts to estimate the energy sector's response to a carbon tax illustrate the difficulties in calculating a tax level. The IEA Secretariat conducted preliminary evaluations of carbon taxes and their possible effects in 1989[3]. A tax of US$130 per metric ton of emitted carbon was assessed. This tax would be a substantial addition — in international trade, it could treble the price of coal by adding $90 per metric ton (~$3/GJ) and increase the prices of crude oil and natural gas by $16 per barrel (~2.42/GJ) and $2 per MBtu ($1.90/GJ), respectively. The effect would be to reduce the growth in OECD CO_2 emissions from 22 per cent in the IEA Reference Case Outlook to 7 per cent between 1990 and 2005. World CO_2 emissions would grow 33 per cent instead of the 40 per cent in the reference case. Revenue from the carbon tax is assumed to be offset by reductions in other taxes to maintain fiscal policies and the reference-case rate of economic growth. The main impact of the tax is to reduce demand for fossil fuels in OECD countries, partly by lowering demand for energy services and partly by encouraging energy efficiency. Demand for solid fuels (mostly coal) would decline 26 per cent from the base-case projection for 2005; petroleum use would decline 7 per cent; and natural gas use would be largely unaffected. The lower demand for coal in 2005 results in a lower pre-tax producer price, wiping out the 20 per cent real price increase estimated in the IEA Reference Case Outlook for coal between 1990 and 2005. The response of the pre-tax producer price of crude oil will depend on whether the oil producing countries seek to maintain production volume, price or revenue. In this analysis the pre-tax producer price of crude oil is assumed to be unaffected by the carbon tax. Its effect on OECD consumer energy prices would be less in relative terms because consumer prices are generally higher, as they include additional transport and distribution costs and other taxes. An additional effect is that outside the OECD, demand for coal actually increases slightly because of the resulting lower (untaxed) coal prices. Since this evaluation was conducted, the starting point and policy direction have changed substantially, and the IEA is revising its World Energy Outlook accordingly.

It should be noted that the level of tax evaluated by the IEA would only slow the growth in CO_2 emissions. In 1991, the OECD undertook an evaluation of energy prices, taxes, and carbon dioxide emissions[4]. This study found that carbon taxes would need to be large to achieve a significant reduction of future CO_2 emissions. Simulations with OECD's GREEN model suggest that a carbon tax on the order of $300 per metric ton of carbon would be needed to reduce CO_2 emissions in the developed countries to 20 per cent below their 1990 level by 2020. This amount would be equivalent to a price increase of $36 on a barrel of oil. The reader is referred to the reference document for all of the qualifications and assumptions associated with these conclusions. The study also observed that, in simple arithmetic terms, a tax of $100 per metric ton of carbon would add $12 to the price of a barrel of oil, more than double the 1988 steam coal price of $44 per metric ton to about $104, and increase the price of gas by about 60 per cent from its 1988 value. The $300 per metric ton tax would amount to a greater change in oil prices than that observed between the price peak of the early-1980s and the low of the mid-1980s.

More recently, the OECD has undertaken an evaluation of the implications of energy taxes for climate change policy[5]. The study evaluated four issues: 1) the magnitude of the variation in energy prices among OECD countries and the factors contributing to it; 2) the relationship between energy prices and emissions intensities (carbon emissions per unit of GDP); 3) the economic cost of superimposing carbon taxes on top of current energy taxes; and 4) whether or not restructuring of current energy taxes alone can achieve significant cuts in carbon emissions. According to the study, end-use energy prices among countries and between fuels differ mostly because of taxes. The current implicit average taxes on the carbon content of energy vary from US$28 per metric ton of carbon in the United States to over US$200 in France, Italy, and Sweden. There is considerable variation in before-tax prices (for instance, coal prices in Germany are three times higher than in the United States).

Non-tax effects are large for most energy products in Japan, for natural gas in Europe, and for coal in European coal-producing countries.

Replacing existing energy taxes by a carbon tax might reduce CO_2 emissions by 12 per cent compared with what they would otherwise be. The current implied average carbon tax equivalent is $70 per metric ton of carbon, of which oil taxation contributes about 90 per cent. Moving from existing energy taxes to a carbon tax or hybrid carbon/energy tax would therefore imply an important switch in the taxation of different fuels, which would result in a fall in end-user oil prices and increases in coal and gas prices.

The study also found, unsurprisingly, that countries with low energy prices have high emission intensities, while high-price countries have low ones. This result suggests that carbon taxes could be a powerful instrument to reduce emissions. The cost of superimposing carbon taxes on top of current energy taxes would be substantial. However, in some countries there could be scope to reduce both carbon emissions and the economic cost of taxation by reforming the current tax and regulatory structure. Large cuts in carbon emissions are likely to require sizeable increases in fossil-fuel taxation. The inter-relationship of economic structure and growth, energy costs and use, and environment make it important to structure carefully any interventions contemplated. A major difference could be made in the transition costs by making the revenues of taxes imposed as "revenue-neutral" as possible and finding ways to maximise the benefit of investment in new equipment and infrastructure occurring and contained within and outside OECD Member countries, thus achieving offsetting positive economic effects.

The position of the OECD countries cannot be addressed in isolation. Although cumulative OECD emissions of CO_2 constituted over 60 per cent of the world total up to 1990, in the early 1980s OECD emissions fell below half the world total. From 1990 up to the end of this century, non-OECD countries are expected to be responsible for 60 per cent of total cumulative emissions, and their share will continue to rise. CO_2 emissions from the energy sector in the OECD have varied considerably: between 1977 and 1983 they actually declined about 500 million metric tons. During those years the OECD experienced major increases in oil prices, a four-fold increase in the contribution of nuclear and the contemporaneous reduction of oil in electricity generation, along with a significant recession.

Status of commitments

International negotiations resulted in a Framework Convention on Climate Change in May 1992 that was signed subsequently by 154 countries and the European Community, including all OECD Member countries except Turkey. For the Convention to go into effect, at least 50 countries must take the further step of ratifying it, at which point they become Parties to the Convention. The Convention represents commitments to an overall global objective, guiding principles, actions and institutions. The objective is "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system". The commitments, legally binding obligations, include:

— preparation of national inventories of anthropogenic greenhouse gas emissions;

— programmes to mitigate greenhouse gas effects and measures to adapt to climate change;

— co-operation on technology related to greenhouse gas emissions;

— sustainable management of greenhouse gas sinks and reservoirs;

— integration of climate change considerations with other policies;

— research to reduce uncertainties concerning scientific knowledge of climate change, the effects of the phenomenon and the effectiveness of responses to it;

— exchange of information, including on technology and economic consequences of actions;

— education, training and public awareness raising; and

— communication of information on implementation.

Emissions stabilization, targets and complementary concepts

While no concrete targets with timetables for greenhouse gas emissions stabilization were included in the Convention, developed countries agreed in essence to adopt national policies and take measures consistent with the objective of returning their anthropogenic emissions of CO_2 and other greenhouse gases to 1990 levels by the end of this decade. A few countries have set unilateral targets, but many recognise the need for other countries to take similar commitments and make this a condition to achieving their own target. Several European countries still have no individual target commitment but were included under the European Community Council's agreement in 1990 to stabilize overall EC emissions of CO_2 at 1990 levels by the year 2000. Since then, a few have designated their own targets, e.g. Spain and Luxembourg. European Free Trade Association (EFTA) members in turn agreed in November 1990 to adopt the same overall CO_2 target as the European Community although most already had their own targets by this point. Only one, Spain, has a target adjusted for economic growth, though it might be assumed that Greece and Portugal will eventually adopt economic growth-adjusted targets. The European Community's own regional stabilization target is designed to balance out their growth in emissions by reductions in emissions by other EC Members. Two countries (France and Japan), adopted per-capita stabilization targets (which allows for some growth in emissions). Only the United States adopted a set of policies to reduce the growth in emissions. Differences among countries also occur in the base years chosen, although 1990 predominates, and on whether to stabilize or reduce CO_2 alone or all greenhouse gases.

OECD commitments made to date, if fully achieved, would account for slightly less than 3 per cent reduction of estimated global emissions of CO_2 in the year 2000. That is, instead of growing approximately 22 per cent in this time period, global emissions would only grow about 19 per cent. Clearly, even the ambitious commitments by OECD Member countries will be dwarfed by growth in emissions in the large, rapidly growing developing countries. Only a handful of OECD Member countries have funded action plans and/or carbon taxes in place to support their commitments, and even those countries with carbon or CO_2 taxes are still predicting that their greenhouse gas emissions in the year 2000 will exceed stabilization.

Outside the OECD group, few countries have made public statements about emissions stabilization. Notably, of the largest emitters outside OECD, only Poland has stated that its emissions would be no higher than 1988-89 in the year 2000, and Hungary has made a similar statement for different base years.

Joint implementation

A few countries, in analysing their forecasted emissions vis-à-vis their announced targets have acknowledged that meeting them might be harder (or more costly) than originally expected. Two of these countries (Norway and Germany) started investigations into the idea of investing in emissions reduction projects in other countries where such projects would be more cost-effective than trying to achieve an equivalent reduction within their own countries. This is a derivative of the idea of trading emissions permits and has been called variously, "clearinghouse for projects," "joint implementation" or "compensation measures". The common theme is achieving greater cost-effectiveness than could be achieved by solely investing in projects within national boundaries given that there are large differences in the opportunities for and national costs of response strategies.

Norway originated the idea of joint implementation as a system of credit towards the achievement of a national emissions target for a country investing in emissions reductions projects elsewhere (outside national boundaries). In discussions with other countries, Norway emphasized the need to develop a mechanism to implement the concept. Germany has found that its target would be difficult or impossible to reach without supplementary measures such as, *inter alia*, joint implementation. The concept again is that compensatory measures taken (including the creation of sinks) in one facility or country could be allowed to offset emissions in another.

Provision for joint implementation is allowed in the language of the Convention. The idea of joint implementation should be kept distinct from the joint target shared by countries which are members of the European Community. In this case, more aggressive targets in some countries would offset the economic-growth adjusted targets of others, such as that adopted by Spain. It is entirely possible that there could be joint implementation within the European Community as well as a joint target.

CO_2 and carbon taxes

Until recently, energy taxation generally has been used to raise government revenue. Energy or environmental policy considerations have not been a driving force behind the fiscal structure of energy products, with the exception of tax differentials between gasoline and diesel, and between leaded and unleaded gasoline. In many IEA countries, a tax advantage was given to diesel fuels after the first oil shock, in recognition of the higher energy efficiency of diesel engines.

Many IEA countries are rationalising and restructuring their fiscal policies. This is affecting the balance of taxes applied to different energy products and consumer categories. At the same time, the use of taxes to influence consumer behaviour and to internalise external costs, particularly environmental costs, is attracting growing attention from policy makers. In some countries, environmental taxes or charges (related to pollutant emission levels) on energy products or activities finance pollution control or energy efficiency measures, notably in the Netherlands and France. In the Netherlands, where the burden of environmental charges on energy products is among the highest in the OECD, taxes are used for revenue raising, particularly to transfer funds from the private sector to the public sector for the financing of environmental protection measures such as monitoring and enforcing regulations. In France, a tax on SO_2, NO_x and hydrochloric acid emissions is applied to all industries with combustion facilities of more than 200 MW. Revenue from the tax is used to finance air quality improvement and monitoring projects, including grants for the installation of pollution control equipment.

Over the last two years, carbon or CO_2 taxes have been enacted in Denmark, Finland, the Netherlands, Norway and Sweden, starting with Finland in 1990. The carbon or CO_2 taxes have been variously applied, i.e. with simultaneous reform of energy taxes (Sweden), with other environmental taxes (Netherlands, Finland), as a mixed tax on energy content and on carbon content (Denmark and in a later reform of its carbon/environmental tax, the Netherlands). Norway and the Netherlands increased their carbon taxes in 1992 and Sweden reduced its carbon tax for industry and raised it for residential users while simultaneously eliminating the energy tax for industry, beginning in 1993.

These CO_2 and related taxes have to be seen in the context of the sizeable taxes such as excise tax and VAT already imposed on fuels for fiscal or other reasons not necessarily related to the fuels' environmental effects. Thus the impact of carbon taxes tends to be moderated. Generally, the net price effect of the taxes cannot be expected to influence behaviour significantly. In addition, significant exemptions to the new taxes are extended everywhere except the Netherlands, to various categories of energy users, such as coal users, energy-intensive industries, electricity generators or international air or sea travel. In Sweden, though the carbon tax itself is relatively large, its effect is limited by the fact that its introduction was offset by substantial reductions in other energy taxes. The nominal rate on coal is significant in Sweden, but with exemptions granted for industry and power generation and a virtual absence of coal consumption in the non-industrial sectors, the amount of tax collected on coal use is very small. Given the exemptions and adjustments in various countries, the taxes cannot be said to be strictly based on the carbon content of fuels.

Other OECD countries and the European Community are considering a range of policy instruments, including carbon taxes, but most are reluctant to introduce such taxes unilaterally because of uncertainty about the effects and concerns that their international competitiveness might suffer. They are aware that models used to evaluate the impact of such policies are imprecise and that results of such modelling must therefore be considered in the context of the assumptions used. Different models produce widely different projections of CO_2 emissions from region to region. Even the same model can generate significantly different estimates on relatively small differences in assumptions about exogenous factors such as population growth rates or the rate of autonomous energy efficiency improvements. Furthermore, there is a wide range of estimates of the GDP losses that would occur by around 2050 if the OECD countries made sizeable cuts in their CO_2 emissions. There are also indications that during an initial adjustment period, the costs (including social adjustment costs) could be large owing to rapid down-sizing of energy-intensive industries; the international competitiveness of some energy-intensive sectors and energy-producing countries could be significantly reduced. The GDP costs of reducing CO_2 emissions would likely be less if measures were phased in rather than being introduced at once. The studies and modelling of carbon taxes by the IEA and the OECD Economics Department mentioned above have also shown that:

— it would take substantially different levels of tax between regions and countries to generate the same percentage of reduction in CO_2 emissions in each;

— to continue to be effective, carbon taxes have to increase over time to counteract the growth in energy demand that corresponds to economic growth;

— taxes imposed unilaterally or even regionally would have little effect on the level of world emissions — much less on long-term concentrations of CO_2 in the atmosphere — mostly because of the very strong economic growth and resulting growth in emissions taking place in countries outside the OECD that, as yet, do not plan to stabilize or reduce emissions, and possibly also because of the inevitable flight of carbon-intensive industry and production to regions or countries without such taxes;

— the availability of technologies and opportunities for fuel substitution are key; without non-fossil fuel options, the upper limit on the tax required rises, and the cost and availability of low-carbon or carbon-free technology is critical in limiting the level required; and

— eliminating energy subsidies (the vast majority of which exist outside OECD countries) would result in a significant reduction in emissions and yield net economic benefits, especially outside the OECD.

References and notes

1. THORNE, R., Business and Technical Analysis Manager, National Power, UK, personal communication, July 1991.

2. IAEA (International Atomic Energy Agency) (1991), *Senior Expert Symposium on Electricity and the Environment: Key Issues Papers*, Symposium held in Helsinki, Finland from 13th-17th May 1991, IAEA, Vienna.

3. The results of this analysis do not reflect IEA views nor those of its Member countries.

4. HOELLER, P., and M. Wallin (1991), "Energy Prices, Taxes, and Carbon Dioxide Emissions", *Economics and Statistics Department Working Paper No. 106*, OECD, Paris.

5. HOELLER, P. and J. Coppel (1992), "Energy Taxation and Price Distortions in Fossil Fuel Markets: Some Implications for Climate Change Policy", *Economics Department Working Papers #110*, OECD, Paris.

Annex 11

FACTORS COVERED IN COSTS

The tables in this annex are the check lists which indicate the factors specifically included in or excluded from national cost submissions to this study. Further explanations can be found in the country annexes, Annex 2, where participants have felt this appropriate.

Table 11.1 **Coverage of investment costs (Nuclear)**

	BE-N	CA1-N	CA4-N	FI-N	FR-N	GE-N	JP-N	NL-N	UK-N1	UK-N2	US1-N	US2-N	US3-N	CH-N	CS-N	HN-N	IN-N	KR-N1	KR-N2	RF-N
Base Construction Costs																				
Direct Costs																				
- Site preparation	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
- Civil work	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
- Material and manpower for construction	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Indirect Costs																				
- Design, engineering and supervision	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
- Provisional equipment and operation	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
- Worksite administrative expenses	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Owner's Costs																				
- General administration expenses	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
- Pre-operation expenses	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
- R & D	O	O	X	O	O	O	X	O	O	O	O	O	O	O	X	X	O	X	X	X
- Spare parts	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
- Licensing and public relations	X	O	O	O	O	O	O	O	O	O	O	O	O	O	O	X	O	O	O	O
- Taxes	X	O	O	X	O	X	X	X	O	O	X	X	X	O	O	X	O	O	O	X
Contingency on the Base Costs	X	O	X	O	O	O	X	O	O	O	O	O	O	O	X	X	O	O	O	O
Interest during Construction	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	X
Decommissioning Costs			(a)			(a)											(b)	(a)	(a)	
- Safe storage and dismantling	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
- Disposal of decommissioning waste	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
- Site restoration	O	O	X	X	O	O	O	O	O	O	O	O	O	X	O	O	NS	X	X	O
- Licensing and public relations	X	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
Other Costs																				
- First inventory of heavy-water	X	O	O	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X (c)	X
- Mid-life refurbishment	X (c)	O	X	X	X	X (d)	X	X	X (c)	X (c)	O	O	O	X (c)	X (c)	X	X	X	X	X
- Credit	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

(a) Decommissioning costs are included in O&M costs.
(b) Decommissioning costs are included in investment costs, but detailed coverage was not specified.
(c) Included in O&M costs.
(d) There is no special mid-life refurbishment, but continuous preventing refurbishment cost is included in O&M costs.

O = Included
X = Excluded

NS : Not specified.

Table 11.2 **Coverage of operations and maintenance (O&M) costs (Nuclear)**

	BE-N	CA1-N	CA4-N	FI-N	FR-N	GE-N	JP-N	NL-N	UK-N1	UK-N2	US1-N	US2-N	US3-N	CH-N	CS-N	HN-N	IN-N	KR-N1	KR-N2	RF-N
Operations	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Maintenance	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Technical and administration expenses	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Management and disposal of operating waste	O	O	O	O	O	O (a)	O	O	O	O	O	O	O	O	O	O	O	O	O	X
General expenses of central services	O	X	O	X	O	O	O	X	O	O	O	O	O	O	X	X	O	O	O	X
Taxes and duties	X	O	O	X	O	X	X	X	O	O	X	X	X	O	X	X	O	O	O	X
Insurance	X	O	O	O	O	O	O	O	O	O	O	O	O	X	O	X	O	O	O	X
Mid-life refurbishment costs	O	X	X	X	X	X (b)	X	X	O	O	X	X	X	O	O	X	X	X	X	X
Safeguards costs	X	O	O	O	X	O	O	X	O	O	O	O	O	O	O	O	O	O	O	O
Others	X	X	X	X	X	O	X	X	X	X	X	X	X	X	X	X	X	(c)	(c,d)	X

(a) Cost of final waste disposal is included in fuel costs.
(b) There is no special mid-life refurbishment, but continuous preventing refurbishment cost is included in O&M costs.
(c) Spent fuel disposal cost and decommissioning cost are included.
(d) Cost of initial heavy-water is included.

O = Included
X = Excluded

Table 11.3 **Coverage of fuel costs (Nuclear)**

	BE-N	CA1-N	CA4-N	FI-N	FR-N	GE-N	JP-N	NL-N	UK-N1	UK-N2	US1-N	US2-N	US3-N	CH-N	CS-N	HN-N	IN-N	KR-N1	KR-N2	RF-N
Price of ore concentrate	O	O	NS	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Conversion of UF_6	O	O	NS	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Enrichment	O	X (a)	NS	O	O	O	O	O	O	O	O	O	O	O	O	O	X	O	O	O
Fuel fabrication	O	O	NS	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Reprocessing	O	X	NS	X	O	O	O	X	O	O	X	X	X	O	X	X	X	X	X	X
Interim storage	O	O	NS	O	O	O	X	O	O	O	O	O	O	O	O	O	X (c)	X	X	O
Disposal	O	O	NS	O	O	O	X	O	O	O	O	O	O	O	O	O	X	X (c)	X (c)	O
Transportation	O	O	NS	O	O	O	O	O	O	O	O	O	O	O	O	O	X	X	X	O
Credit	O	X	NS	X	O	O	O	X	X	X	X	X	X	O	X	X	X	X	X	X
Fuel cycle strategy	R	D	D	D	R	R	R	D	R	R	D	D	D	R	D (b)	D (b)	R	D	D	D

(a) No enrichment is required for plant operation.
(b) National strategy has not yet been decided. The strategy is assumed only for the purpose of cost calculation.
(c) Included in O&M cost.

O = Included R = Reprocessing approach NS : Not specified
X = Excluded D = Direct disposal approach

Table 11.4 **Coverage of investment costs (Coal)**

	BE-C	CA1-C	CA2-C	CA3-C	CA4-C	DE-C	FI-C	FR-C	GE-C	IT-C	JP-C	NL-C1	NL-C2	PT-C	SP-C1, C2	SW-C	TK-C	UK-C1, C2,C3	US1-C	US2-C	US3-C
Base Construction Costs																					
Direct Costs																					
- Site preparation	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
- Civil work	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
- Material and manpower for construction	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
Indirect Costs																					
- Design, engineering and supervision	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
- Provisional equipment and operation	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
- Worksite administrative expenses	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
Owner's Costs																					
- General administration expenses	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	X	NS	O	O	O
- Pre-operation expenses	O	O	O	O	O	X	O	O	O	O	O	O	O	O	O	O	X	NS	O	O	O
- R & D	O	O	X	X	X	X	O	O	O	X	X	O	O	O	O	O	X	NS	O	O	O
- Spare parts	O	O	X	O	O	X	O	O	O	O	O	O	O	O	O	O	X	NS	O	O	O
- Licensing and public relations	X	O	X	O	O	X	O	O	O	O	O	O	O	O	O	O	X	NS	O	O	O
- Taxes	X	O	X	X	O	X	X	O	X	X	X	X	X	X	O	X	X	NS	X	X	X
Contingency on the Base Costs	X	(a)	(b)	O	(c)	O	O	O	O	(c)	X	O	O	O	(c)	O	X	NS	O	O	O
Interest during Construction	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
Other Costs																					
- Mid-life refurbishment costs	X	O	X	X	X	X (d)	X	X	X	X	X	X	X	X	X	X (d)	X (d)	NS	O	O	O
- Decommissioning costs	X	O	X	X	X	X	X	X	X	X	X	O	O	X	O	O	X	NS	X	X	X
- Credit	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	O	NS	X	X	X
- Others	X	X	X	X	X	X	X	X	X	X	X	X	X	(e)	X	(f)	X	NS	X	X	X

Table 11.4 (continued)

	CH-C	CS-C	HN-C1	HN-C2	IN-C	KR-C
Base Construction Costs						
Direct Costs						
- Site preparation	O	O	O	O	O	O
- Civil work	O	O	O	O	O	O
- Material and manpower for construction	O	O	O	O	O	O
Indirect Costs						
- Design, engineering and supervision	O	O	O	O	O	O
- Provisional equipment and operation	O	O	O	O	O	O
- Worksite administrative expenses	O	O	O	O	O	O
Owner's Costs						
- General administration expenses	O	O	O	O	O	O
- Pre-operation expenses	O	O	O	O	O	O
- R & D	O	X	X	X	X	X
- Spare parts	O	O	O	O	O	O
- Licensing and public relations	O	O	X	X	O	O
- Taxes	O	O	X	X	O	O
Contingency on the Base Costs	O	X	X	X	O	O
Interest during Construction	O	O	O	O	O	O
Other Costs						
- Mid-life refurbishment costs	X (d)	X (d)	X	X	X	X
- Decommissioning costs	X	O	O	O	X	X
- Credit	X	X	X	X	X	X
- Others	X	X	X	X	X	X

(a) Contingency (7% of base construction cost) is included in "base construction cost".
(b) Contingency (10% of base construction cost) is included in "base construction cost".
(c) Contingency is included in "base construction cost".
(d) Included in O&M costs.
(e) Cost for coal wagons for transportation.
(f) Cost for insurance and environmental emission control programme.

O = Included
X = Excluded

NS : Not specified.

Table 11.5 **Coverage of operations and maintenance (O&M) costs (Coal)**

	BE-C	CA1-C	CA2-C	CA3-C	CA4-C	DE-C	FI-C	FR-C	GE-C	IT-C	JP-C	NL-C1	NL-C2	PT-C	SP-C1, C2	SW-C	TK-C	UK-C1, C2,C3	US1-C	US2-C	US3-C
Operations	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
Maintenance	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
Technical and administration expenses	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
General expenses of central services	O	X	X	X	O	X	X	O	O	X	O	O	O	O	O	O	O	NS	O	O	O
Taxes and duties	O	O	O	O	O	X	X	O	X	X	X	X	X	O	O	O	O	NS	X	X	X
Insurance	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O
Mid-life refurbishment costs	X	X	X	X	X	O	X	X	X	X	X	X	X	X	X	O	O	NS	X	X	X
Others	X	X	X	X	X	X	(a)	X	X	(b)	X	X	X	X	X	(c)	X	NS	(d)	(e)	(f)

Table 11.5 (continued)

	CH-C	CS-C	HN-C1	HN-C2	IN-C	KR-C
Operations	O	O	O	O	O	O
Maintenance	O	O	O	O	O	O
Technical and administration expenses	O	O	O	O	O	O
General expenses of central services	O	X	X	X	O	O
Taxes and duties	O	X	X	X	O	O
Insurance	X	O	X	X	O	O
Mid-life refurbishment costs	O	O	X	X	X	X
Others	X	X	X	X	X	X

(a) Replacement of the catalyst in every 3 years and interest on coal stocks.
(b) Replacement of the catalyst in every 3 years and waste disposal.
(c) Interest on stored fuel.
(d) 1.0 mill/kWh for purchase of emission permits.
(e) 0.4 mill/kWh for purchase of emission permits.
(f) 0.24 mill/kWh for purchase of emission permits.

O = Included
X = Excluded
NS : Not specified

Table 11.6 **Coverage of fuel costs (Coal)**

	BE-C	CA1-C	CA2-C	CA3-C	CA4-C	DE-C	FI-C	FR-C	GE-C	IT-C	JP-C	NL-C1	NL-C2	PT-C	SP-C1, C2	SW-C	TK-C	UK-C1, C2,C3	US1-C	US2-C	US3-C
Coal price	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Internal transportation	O	O	X	O	X	O	O	O	O	O	O	X (a)	X	O	O	O	O	O	O	O	O
Waste disposal	O	X (a)	X	X	X	O	O	NS	O	X (a)	X (a)	X (a)	NS	O	O	O	O	X (a)	X	X	X
Taxes on fuel	X	O	O	X	X	X	O	X	X	X	X (a)	O	O	X	O	O	X	X	O	O	O
Other	(b)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Table 11.6 (continued)

	CH-C	CS-C	HN-C1	HN-C2	IN-C	KR-C
Coal price	O	O	O	NS	O	O
Internal transportation	O	O	O	NS	O	O
Waste disposal	O	O	O	NS	O	X
Taxes on fuel	X	O	O	NS	O	X
Other	X	X	X	NS	(c)	X

(a) Included in O&M costs.
(b) Cost for deSOx and deNOx
(c) Oil costs for supporting the facility.

O = Included
X = Excluded
NS : Not specified

Table 11.7 **Coverage of investment costs (Gas and Others)**

(Gas)	BE-G	CA1-G	CA2-G	DE-G1,G2	FI-G	FR-G	IT-G	JP-G	NL-G	PT-G1,G2	SP-G	SW-G	UK-G	US1-G	US2-G	US3-G	CS-G	HN-G
Base Construction Costs																		
Direct Costs																		
- Site preparation	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
- Civil work	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
- Material and manpower for construction	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
Indirect Costs																		
- Design, engineering and supervision	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
- Provisional equipment and operation	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
- Worksite administrative expenses	O	O	X	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
Owner's Costs																		
- General administration expenses	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	X
- Pre-operation expenses	O	O	O	X	O	O	O	O	O	O	O	O	NS	O	O	O	X	O
- R & D	O	O	X	X	O	O	X	X	O	O	O	O	NS	O	O	O	X	X
- Spare parts	O	O	X	X	O	O	O	O	O	O	O	O	NS	O	O	O	X	O
- Licensing and public relations	X	O	X	X	O	O	O	O	O	O	O	O	NS	O	O	O	X	X
- Taxes	X	O	X	X	X	O	X	X	X	X	O	X	NS	X	X	X	X	X
Contingency on the Base Costs	X	(a)	(b)	O	O	O	(e)	X	O	O	(e)	O	NS	O	O	O	X	X
Interest during Construction	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
Other Costs																		
- Mid-life refurbishment costs	X	O	X	X (c)	X	X	X	X	X	X	X	X (c)	NS	O	O	O	O	X
- Decommissioning costs	X	O	X	X	X	X	X	X	O	X	O	O	NS	X	X	X	X	X
- Credit	X	X	X	X	X	X	X	X	X	X	X	X	NS	X	X	X	X	X
- Others	X	X	X	X	(d)	X	X	X	X	X	O	X	NS	X	X	X	X	X

Table 11.7 (continued)

(Others)	DE-W	DE-H	SU-S	UK-W	UK-L	UK-M	UK-S
Base Construction Costs							
Direct Costs							
- Site preparation	O	NS	O	O	NS	O	O
- Civil work	O	NS	O	O	NS	O	O
- Material and manpower for construction	O	NS	O	O	NS	O	O
Indirect Costs							
- Design, engineering and supervision	O	NS	O	O	NS	O	O
- Provisional equipment and operation	O	NS	O	O	NS	O	O
- Worksite administrative expenses	O	NS	O	O	NS	O	O
Owner's Costs							
- General administration expenses	O	NS	O	O	NS	O	O
- Pre-operation expenses	X	NS	O	O	NS	O	O
- R & D	X	NS	O	O	NS	X	X
- Spare parts	X	NS	O	O	NS	X	O
- Licensing and public relations	X	NS	O	O	NS	O	O
- Taxes	X	NS	O	X	NS	O	O
Contingency on the Base Costs	X	NS	O	NS	NS	O	O
Interest during Construction	O	NS	O	O	NS	X	X
Other Costs							
- Mid-life refurbishment costs	X (c)	NS	X	X (c)	NS	O	X
- Decommissioning costs	X	NS	X	X	NS	O	X
- Credit	X	NS	X	X	NS	O	X
- Others	X	NS	X	X	NS	O	X

(a) Contingency (7% of base construction cost) is included in "base construction cost".
(b) Contingency (10% of base construction cost) is included in "base construction cost".
(c) Included in O&M costs.
(d) Connection charge for the gas network and construction cost for the reserve fuel storage cavern are involved.
(e) Contingency is included in "base construction cost".

O = Included
X = Excluded
NS : Not specified

Table 11.8 **Coverage of operations and maintenance (O&M) costs (Gas and Others)**

	(Gas)																	
	BE-G	CA1-G	CA2-G	DE-G1, G2	FI-G	FR-G	IT-G	JP-G	NL-G	PT-G1, G2	SP-G	SW-G	UK-G	US1-G	US2-G	US3-G	CS-G	HN-G
Operations	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
Maintenance	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
Technical and administration expenses	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	O	O
General expenses of central services	O	X	X	X	X	O	X	O	O	O	O	O	NS	O	O	O	O	X
Taxes and duties	O	O	O	X	X	O	X	X	X	O	O	O	NS	X	X	X	X	X
Insurance	O	O	O	O	O	O	O	O	O	O	O	O	NS	O	O	O	X	X
Mid-life refurbishment costs	O	X	X	O	X	X	X	X	X	X	X	O	NS	X	X	X	O	X
Others	X	X	X	X	(a)	X	X	X	X	X	X	(a)	NS	X	X	X	X	X

Table 11.8 (continued)

	(Others)						
	DE-W	DE-H	SU-S	UK-W	UK-L	UK-M	UK-S
Operations	O	NS	O	O	O	O	O
Maintenance	O	NS	O	O	O	O	O
Technical and administration expenses	O	NS	O	O	O	O	O
General expenses of central services	X	NS	O	O	O	O	X
Taxes and duties	X	NS	O	O	O	O	O
Insurance	X	NS	O	O	O	O	O
Mid-life refurbishment costs	O	NS	X	O	O	O	X
Others	X	NS	X	X	X	X	X

(a) Interest on stocks of reserve fuel. O = Included X = Excluded NS : Not specified

Table 11.9 **Coverage of fuel costs (Gas and Others)**

	(Gas)																		(Others)	
	BE-G	CA1-G	CA2-G	DE-G1, G2	FI-G	FR-G	IT-G	JP-G	NL-G	PT-G1, G2	SP-G	SW-G	UK-G	US1-G	US2-G	US3-G	CS-G	HN-G	DE-H	UK-M
Fuel price	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	NS
Internal transportation	O	O	X	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	NS	NS
Taxes on fuel	X	O	O	X	O	X	X	O	O	X	O	O	X	O	O	O	X	O	NS	NS
Others	X	X	X	X	X	X	X	X	X	(a)	X	X	X	X	X	X	X	X	NS	NS

(a) Cost for regasification. O = Included X = Excluded NS : Not specified

Annex 12

CONTROL MEASURES ON SO_2, NO_x AND DUST EMISSIONS IN THE EUROPEAN COMMUNITY

Setting up strict control measures for SO_2 and NO_x emissions has been subject to long negotiation in the European Community (EC). The main features of the directive approved in June 1988 by the Council of Ministers are:

— New plant emission limits are established as shown in Figures 12.1 - 12.5; SO_2 limits for solid and liquid fuels have a sliding scale for different plant capacities, with the tightest limit values for plants above 500 MWth capacity.

— If, due to the special nature of fuels, SO_2 emission limits for new solid fuel facilities cannot be achieved, then plants must comply with the overall reduction rates shown in Figure 12.6.

— The Commission is expected to present new proposals for second stage (post-1995) emission standards in the light of the technological developments.

— There is strict separation of emissions from existing plants and newly-authorised ones, the latter being subject to the Community emission standards.

— There is an ultimate Community objective of an overall SO_2 reduction of approximately 60 per cent compared to the 1980 levels from existing plants or plants authorised before mid-1987.

— Achieving the ultimate SO_2 objective for existing plants is to be done in three phases (1993, 1998 and 2003), with each Member state expected to make comparable, though not necessarily the same efforts.

— NO_x emission standards for new plants currently are achievable with moderate measures, i.e. combustion modifications, low-NO_x burners, etc.

— NO_x emissions from existing plants are to be reduced in two phases, with an overall Community objective of 40 per cent reduction by 1998.

Moreover, there are efforts under way to develop and implement a comprehensive strategy to combat emissions with the following elements:

— overall EC emissions of SO_2 and NO_x from all existing sources are to be reduced, with the major contribution coming from large combustion plants and mobile sources;

— emission standards for SO_2 and NO_x for new combustion plants below 50 MWth;

— emission standards for the incineration of toxic and dangerous waste;

— continuation of setting emission standards for the different categories of motor vehicles (CO, NO_x, VOC).

In March 1988, the Commission also submitted a proposal for a directive on the prevention of air pollution from new and existing municipal waste incineration plants to the Council.

Figure 12.1 **New plant emission limit values for SO_2 in mg/Nm³**
Solid fuels

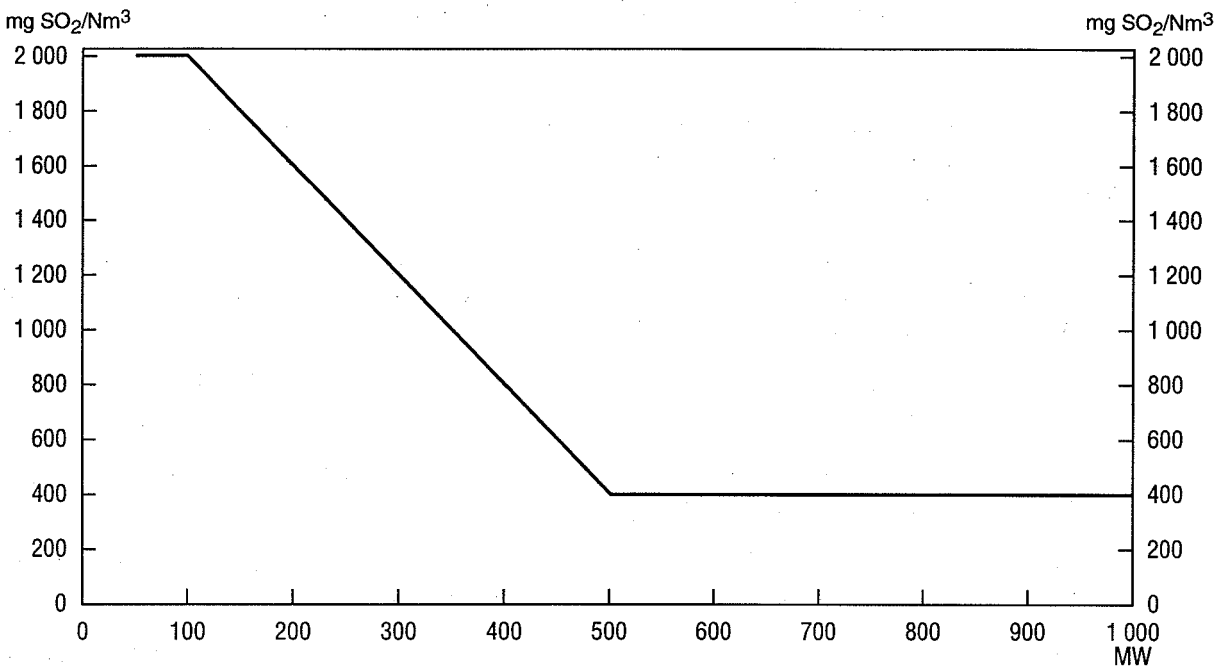


Figure 12.2 **New plant emission limit values for SO_2 in mg/Nm³**
Liquid fuels

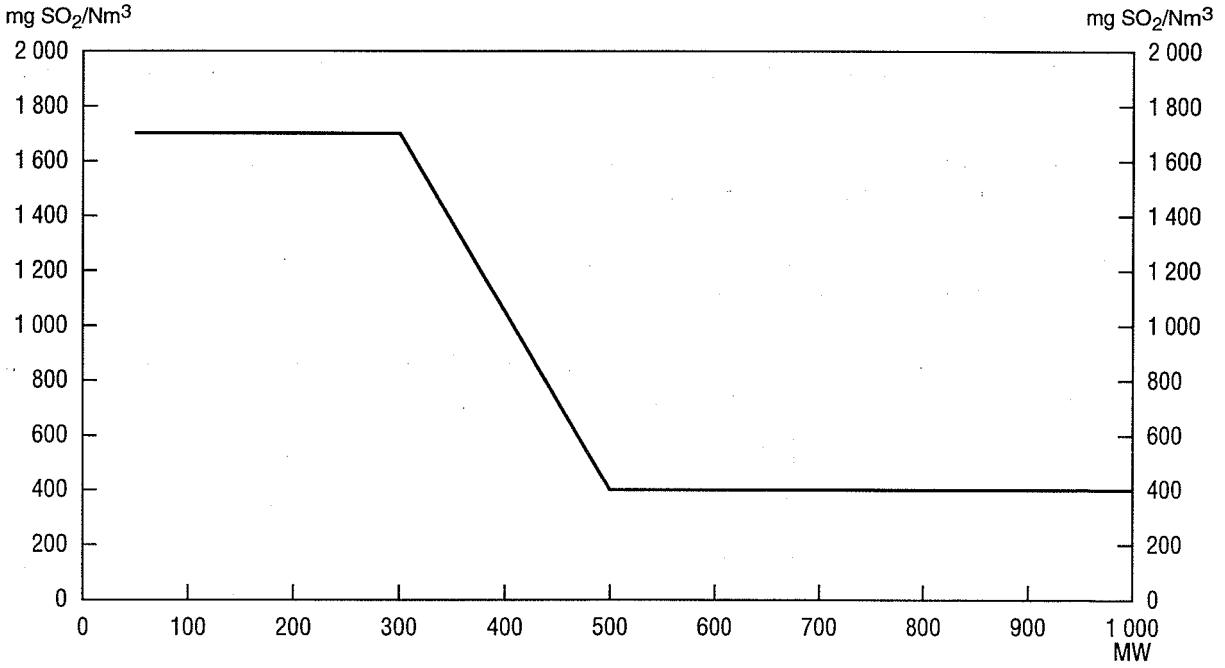


Figure 12.3 **New plant emission limit values for SO_2 in mg/Nm^3 Gaseous fuels**

Type of fuel	Limit values
Gaseous fuels in general	35
Liquefied gas	5
Low calorific gases from gasification of refinery residues, coke oven gas, blast-furnace gas	800
Gas from gasification of coal	*

* The Council will fix the limit values applicable to such gas at a later stage on the basis of proposals from the Commission to be made in the light of further technical experience.

Figure 12.4 **New plant emission limit values for NO_X in mg/Nm^3**

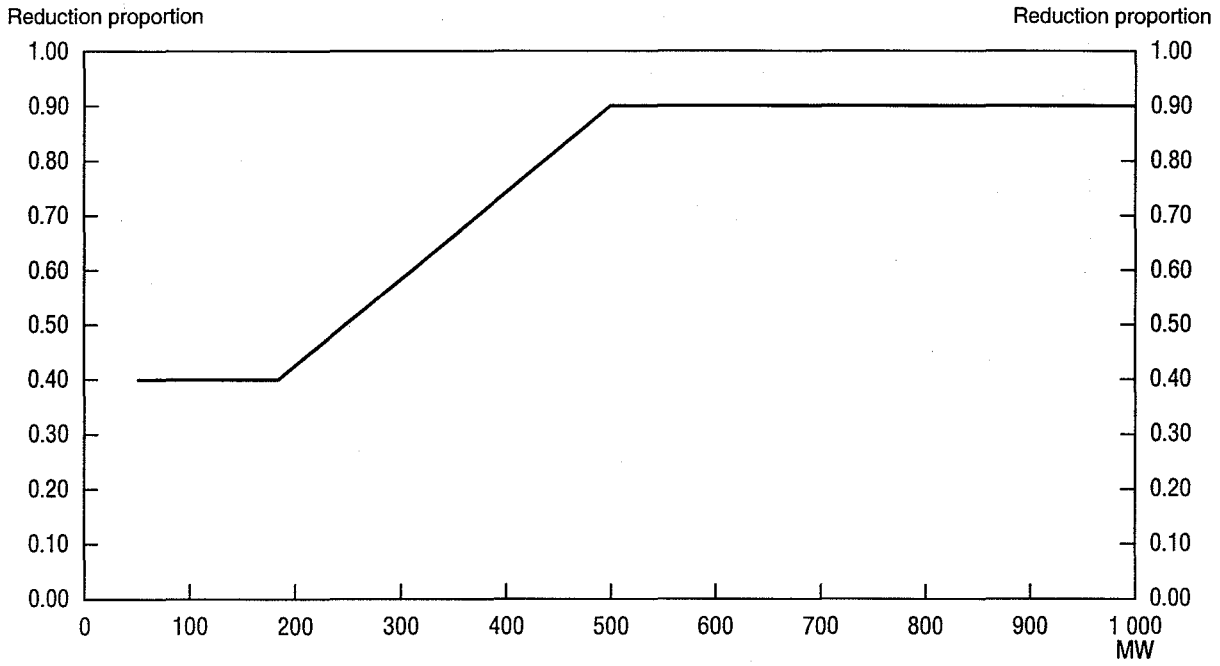
Type of fuel	Limit values
Solid in general	650
Solid with less than 10% volatile compounds	1300
Liquid	450
Gaseous	350

Figure 12.5 **New plant emission limit values for dust**

Type of fuel	Thermal capacity (MWth)	Limit values mg/Nm^3
Solid	≥ 500 < 500	50 100
Liquid*	all plant	50
Gaseous	all plant	5 as a rule but 10 for blast furnace gas and 50 for gases produced by the steel industry which can be used elsewhere

* A limit value of 100 mg/Nm^3 may be applied to plants with a thermal capacity of less than 500 MW burning liquid fuel with an ash content of more than 0.06%.

Figure 12.6 **Rates of desulphurisation**



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Update 1992

This is the fourth in a series of comparative studies of projected baseload electricity generation costs for power plants to be commissioned near the turn of the century. This report reviews the cost data of nuclear, coal-fired, gas-fired and renewable sources provided by sixteen OECD countries and six non-OECD countries. Sensitivity studies are included and trends in cost projections in the past decade are also discussed.

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