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Projected Costs of Generating Electricity

PROJECTED COSTS OF GENERATING ELECTRICITY

UPDATE 1998

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ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

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

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

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

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 OECD Member countries, except New Zealand and Poland. The Commission of the European Communities takes part in the work of the Agency.

The primary objective of the 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, the 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.

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

It carries out a comprehensive programme of energy co-operation among twenty-four* of the OECD's twenty-nine 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, Hungary, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway (by special agreement), 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.*

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

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FOREWORD

This report is the fifth in a series of comparative studies of the projected costs of base-load electricity generation. Previous reports in the series were published in 1983 and 1986 by the OECD Nuclear Energy Agency (NEA) and, in 1989 and 1993, by the NEA jointly with the International Energy Agency (IEA). This update has again been conducted jointly by the NEA and the IEA. Experts from fourteen OECD countries and five non-OECD countries provided data on generating costs.

The study focuses on technologies and plant types that could be commissioned by 2005-2010. These include advanced coal-fired plants, combined cycle gas-fired plants, nuclear power plants, some technologies based on renewable energy sources and one combined heat and power plant.

Projected costs of generating electricity, calculated with common technical and economic assumptions at discount rates of 5 and 10 per cent per annum, are presented and analysed. The effects on costs of variations in economic and technical parameters are examined as are trends in generation costs by coal-fired, gas-fired and nuclear power plants. The annexes address specific issues related to generation costs, including fuel prices, environmental protection costs, electricity market liberalisation, energy security and diversity, and combined heat and power schemes.

The study is published on the responsibility of the Secretary-General of the OECD and the Executive Director of the IEA. The report reflects the collective views of the participating experts though not necessarily those of their parent organisations or their Member governments.

Acknowledgements

The principal authors of this report are Evelyne Bertel of the Nuclear Energy Agency and John Paffenbarger of the International Energy Agency.

The joint study Secretariat acknowledges the significant contribution of the expert group assembled for the study. The group provided all the cost data and reviewed successive drafts of the report. Mr. C. Randy Hudson of Technology Insights (Oak Ridge, Tennessee, USA) was the chairman of the group.

The participation of representatives from five non-member countries was made possible through the International Atomic Energy Agency. The Union of Producers and Distributors of Electrical Energy (UNIPEDE) and the European Commission also took part in the work of the study group.

Special thanks are given to Marie-Laure Peyrat, who provided principal secretarial support and ensured the final layout.

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EXECUTIVE SUMMARY

This fifth study on projected costs of generating base-load electricity was carried out by a Group of Experts convened jointly by the Nuclear Energy Agency (NEA) and the International Energy Agency (IEA). The International Atomic Energy Agency (IAEA) contributed to the study by providing experts from non-OECD countries. In addition, the International Union of Producers and Distributors of Electrical Energy (UNIPEDE) was represented in the Group.

Data and information for this study were provided by national experts from governmental bodies and utilities in fourteen OECD countries and five non-OECD countries. The projected costs of generating electricity presented in the report were calculated using a consistent, levelised lifetime cost methodology and commonly agreed assumptions for a reference case and sensitivity analyses.

The study focuses on base-load technologies and plant types that could be commissioned in the participating countries by 2005-2010 and for which they have developed cost estimates. Those include mainly advanced coal-fired, combined cycle gas-fired, and nuclear power plants. One country provided cost estimates for electricity generation by combined heat and power plants; three countries provided cost estimates for electricity generation by renewable energy sources; and one country provided cost estimates for electricity generation by an oil-fired power plant.

The projected generation costs presented include the costs associated with environmental protection norms and regulations in place in the participating countries. The impacts of those costs on the relative competitiveness of alternative options are discussed. The report also addresses the impact of electricity market liberalisation on generation costs and issues related to security of energy supply and diversity in electricity generation.

The generic approach used in this study, while useful, has its limitations. The costs calculated in the study are not meant to represent the "exact" costs of generating electricity that would be determined from specific generating plant projects. Evaluation methods and assumptions vary according to national conditions and practice. Therefore, projected costs using national calculation methods are also provided. It is considered that these results match more closely those that would be observed for some specific projects. Decisions by both governments and utilities will, in any case, be based upon more detailed evaluations specific to their situations.

Generation costs

As compared to previous studies in the series, the present study shows an increasing competitiveness of gas-fired power plants versus coal-fired and nuclear power plants. At a 5 per cent discount rate, gas was the least expensive (by a margin of at least 10 per cent) in three countries; coal was the least expensive (by a margin of at least 10 per cent) in three countries; nuclear was the least expensive (by a margin of at least 10 per cent) in five countries. In seven countries, there was less than a 10 per cent difference between the least cost technology and its next cheapest.

At a 10 percent discount rate, gas was the least expensive (by a margin of at least 10 per cent) in nine countries; coal was the least expensive (by a margin of at least 10 per cent) in one country; nuclear was the least expensive (by a margin of at least 10 per cent) in no country. In eight countries, there was less than a 10 per cent difference between the least cost technology and its next cheapest.

Only three countries provided cost estimates for renewable technologies. Those technologies, hampered economically by small unit size and/or technology immaturity relative to other generation options are generally not competitive as compared with coal, gas or nuclear power.

Fuel price assumptions

Nine countries, among the eighteen countries which provided cost estimates for coal-fired power plants, assumed constant coal prices from 1996 to the end of the economic lifetime of the plant; eight countries assumed increasing coal prices, and one country, the United States, assumed decreasing coal prices. The average real coal price escalation rate projected by respondent countries is 0.3 per cent per annum.

Ten countries, among the sixteen countries which provided cost estimates for gas-fired power plants, project an increase in real gas price during the economic lifetime of the plant. On average, real gas prices are projected to rise at 0.8 per cent per annum.

Trends in projected generation costs

In most countries which provided data for the 1992 and the 1997 studies, projected generation costs have decreased for coal-fired, gas-fired and nuclear power plants. Projected generation cost reductions vary widely from country to country and from technology to technology. However, generally, relative cost reductions between the two studies are higher for gas-fired power plants (16 to 54 per cent) than for coal-fired power plants (3 to 34 per cent) and nuclear power plants (from 2 to 27 per cent). Those trends refer to generation costs calculated at 5 per cent discount rate for 30-year economic lifetime, 75 per cent settled down load factor and national fuel price assumptions, and expressed in constant US dollars of 1 July 1996.

Decision criteria

A number of factors, besides direct generating cost, may influence capacity additions in particular in countries where governments wish to influence the choice of fuel or technology used in power plants. Among these factors are regional development, public preferences or opposition to certain types of plants, security of energy supply, or environmental concerns. Governments can influence plant choices through explicit limitations, regulation of monopoly suppliers, or fiscal influences such as taxes or subsidies.

The trend toward deregulation and privatisation of the power sector will place greater emphasis on competitiveness and risk minimisation. In this context, technologies with low capital and production costs, short construction schedules, capacity increments closely matched to load growth, and minimal regulatory/public acceptance problems are likely to be more attractive to investors.

Findings and conclusions

The study shows that no single technology is the clear winner economically in all countries. Specific circumstances within each country will determine the most economic choice. However, it should be noted that, relative to the previous reports in this series, gas-fired generation has become an attractive near-term option. This is due to several factors: relatively simple, low-cost construction and maintenance, lower fuel cost projections than previously envisaged, and low environmental protection costs as compared with other fossil-fuelled technologies.

Reflecting on the costs reported in this study, and in comparison to the costs reported in the earlier reports of this series, it would appear reasonable to project that the cost of base-load electricity on the whole will be stable over the near term. The particular technology and fuel that will be utilised during this period will differ from country to country based on fuel availability and relative costs.

INTRODUCTION

Objectives, participation and scope

This study is the fifth in a series on projected costs of generating electricity. The main objective of the series is to present and explain information on estimated costs of generating electricity by base-load power plants that are expected to be commercially available in the medium term. The costs presented and discussed in these studies are based upon data provided by national experts participating in the study at the request of their governments. For the present study, national experts were drawn from ministries, government nuclear institutions and corporations, nuclear utilities, non-nuclear utilities and one utility association. These costs are calculated using an agreed common methodology which is briefly presented in Chapter 2 of this report and is described fully in Annex 10. This methodology was used also in determining the cost of electricity in earlier reports in the series.[1,2,3,4] For the sake of consistency, common assumptions are adopted for the main technical and economic parameters used in calculating the costs presented in this report. Therefore, the report offers a consistent framework for comparing projected costs of generating electricity by various sources and technologies in different countries.

This study, like the last two in the series, has been undertaken jointly for the Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle of the Nuclear Energy Agency (NEA) and for the Standing Group on Long-Term Co-operation of the International Energy Agency (IEA). It was carried out in association with the International Atomic Energy Agency (IAEA) and the International Union of Producers and Distributors of Electrical Energy (UNIPEDE). Fifteen OECD countries (Belgium, Canada, Denmark, Finland, France, Hungary, Italy, Japan, the Republic of Korea, the Netherlands, Portugal, Spain, Turkey, the United Kingdom and the United States) and five non-OECD countries (Brazil, China, India, Romania and Russia) were represented in the working group which has overseen the study. The members of the working group are listed in Annex 1. Nineteen countries provided the Secretariat with data on projected costs of generating electricity by one or more energy source(s) and technology(ies).

The present study focuses on technologies and plant types that could be commissioned in the respondent countries by 2005-2010 and for which they have developed cost estimates. Therefore, the energy sources and technologies covered in the report include the options that, in those countries, are expected to be commercially available within the next 10 to 15 years and that have reached a stage of development permitting reliable cost estimations. The range of energy sources and technologies for which cost data were provided varies from country to country depending on their national energy resource and policy context. Although cost estimates might exist irrespective of decisions or committed plans to build a new power plant, the answers received are indicative of the type of power plants that might be built in the respondent countries in the medium term.

Data were provided mainly on advanced coal-fired power plants, combined cycle gas-fired power plants and nuclear power plants. In spite of the emphasis that a number of countries place on the development of renewable energy sources for electricity generation and of the important technology progress reported on those sources in the literature, few countries provided data on their expected costs. Only one country provided data on combined heat and power, i.e. cogeneration, plants.

The report presents comparative projected costs of generating electricity calculated with commonly agreed generic reference assumptions. It also includes sensitivity analyses to key technical and economic assumptions such as plant lifetime, discount rates and fuel price escalation rates. The trends in projected costs of generating electricity that have occurred over the past decade are reviewed and analysed based upon results from the successive studies in the series. The impacts of environmental protection norms and regulations on electricity generation costs are analysed, and the extent to which they could affect the relative competitiveness of alternative options is discussed. The report also addresses the consequences on comparative costs of recent developments in the electricity sector, such as technology progress and liberalisation of the sector.

Past studies

The first two studies of this series, published in 1983 and 1986, established the methodological framework and common assumptions relevant for assessing and comparing projected costs of generating electricity by different sources and technology. Both studies analysed the components of generating costs and investigated the reasons why costs differ from country to country, as well as their sensitivity to varying technical and economic assumptions.

Those studies concluded that projected costs were lower for nuclear power than for conventional coal-fired power plants in most OECD countries under both common reference assumptions and country specific assumptions. The exceptions were countries and regions with access to cheap coal such as some parts of North America. However, these studies pointed out that results were highly sensitive to the assumptions adopted on discount rates and fossil fuel price escalation rates. Therefore, the projected advantage of nuclear power as compared to coal would be reduced significantly, or even in some countries eliminated, if higher discount rates and/or lower coal prices were assumed for estimating projected costs.

The 1989 study, which was the first one to include data on non-OECD countries, concluded that for most countries the economic advantage of nuclear power versus coal-fired power plants was highly dependent on the assumptions adopted regarding, in particular, discount rates and coal price escalation rates. Gas-fired power plants did not appear competitive with nuclear or coal-fired power plants for base-load generation, although combined cycle gas turbines seemed already an attractive alternative in some countries where low gas prices were expected in the future.

The 1992 update of the study concluded that the relative competitiveness of alternative electricity generation options depended largely on country-specific economic conditions, domestic energy resources, and regulatory frameworks. It noted that, as compared to previous studies, projected costs of fossil-fired electricity generation had decreased, as a consequence of significantly lower assumptions on future fossil fuel prices, and that projected costs of nuclear generated electricity remained stable. It was pointed out that the development of combined cycle technology led to the emergence of natural gas as a serious competitor for base-load electricity generation. The data collected on renewable sources for electricity generation indicated large uncertainties on their projected costs and limited expectations on their competitiveness in the medium term.

The 1992 study indicated that projected costs of generating electricity by nuclear power or coal-fired power plants were the cheapest in most countries with an advantage for nuclear power in many countries at a 5 per cent discount rate. However, gas combined cycle generation was projected to be the cheapest option in some countries at a 10 per cent discount rate. The report noted the increasing awareness of environmental issues and their potential influence on future generation costs. There was no indication from the information collected of any technological breakthrough that would reduce dramatically generation costs from any fuel or power option.

It is difficult to draw conclusions on levelised cost trends from the series of studies carried out since 1983 as the list of participating countries has changed over time as well as the type of technologies for which cost estimates were provided. As mentioned above, gas-fired power plants were included for the first time in the 1989 study. Among the countries which provided cost estimates for coal-fired and nuclear power plants for the first study, in 1983, only three (France, Japan and the United States) provided data for both types of plants for the present study. Also, the common assumptions adopted for calculating levelised costs (e.g., economic lifetime and settled-down load factor) have evolved since the first study. Nevertheless, for both coal-fired and nuclear power plants, there is an overall decreasing trend in total levelised costs of generating electricity.

All these studies have stressed that international comparisons were not intended to substitute for country or utility economic assessment which would support their decision making. They recognised that countries and utilities will have differing views based on their own policy goals, economic and financial conditions, regulatory frameworks, and perceptions regarding fuel price evolution in the future.

Recent developments

Since the early 1990s, when the last study in this series was carried out, significant changes have occurred in the electricity sector that, in turn, have affected the generation sources and technology considered by countries and utilities. These changes also have affected projected electricity generation cost estimates. The main recent developments are: globalisation of world economies; trend to electricity market liberalisation (away from monopoly of electricity generation and distribution) and privatisation (away from state-owned utilities) in the electricity sector; and increasing stringency in health and environmental regulation of electricity generation.

There have been relatively few orders for large size power plants during the last years in OECD countries. Owing to an average growth rate in installed capacity of only 2 per cent per year and existing over-capacity in some countries, there has been limited need for additional base-load power capacity in those countries. This has limited the number and variety of power plant types submitted for this report. Also, the data were more often drawn from paper studies than from quotation or ordered plant prices.

The increasing awareness of environmental impacts, in particular of local and regional pollution but also of global climate change issues, has resulted in country commitments on atmospheric emission reduction. Therefore, energy sources and technologies that are more environmentally benign are likely to increase progressively their market share. For example, fossil-fired power plants for which cost estimates were provided for the present study are more efficient than those quoted in previous studies and generally are equipped with pollution control devices that reduce particulate matter, sulphur and nitrogen oxide emissions. Also, state-of-the-art nuclear power plants included in this study comply with increasingly stringent safety standards and regulations.

The desire to reduce environmental impacts has motivated efforts to value and internalise, insofar as is feasible, external costs of electricity generation. Although the cost estimates reported in this study do not include external costs, they include the costs borne by producers for complying with existing environmental norms and regulation such as those for atmospheric pollution control devices added to fossil-fired power plants and those incurred for ensuring the safety of nuclear power plants.

Restrictions on emissions of carbon dioxide have the potential to greatly affect the comparative economics of different fuels for electricity production. Any such restrictions or costs imposed for producing carbon dioxide would effectively internalise the perceived environmental costs related to their global warming potential. As with restrictions on emissions of sulphur dioxide or nitrogen oxides, restrictions on carbon dioxide emissions will economically favour those fuels which either produce smaller amounts of the gas or whose costs for engineered emission control systems (in the case of carbon dioxide, this means higher efficiency power cycles) are smaller. Non-fossil fuels could gain an advantage in this regard in relation to fossil fuels depending on the severity of restrictions and their ultimate cost-effectiveness in meeting limits.

Developments on world-wide energy markets are perceived as enhancing the stability of energy prices on international markets and the security of supply. Therefore, the expected economic advantage of non-fossil power plants predicated upon steadily increasing high fossil fuel prices has been eroded.

The trend towards privatisation and deregulation of the power sector has reduced captive markets and put pressure on electricity producers to improve their economic competitiveness. At the same time, electricity demand is growing slowly in most OECD countries. In this context, flexible strategies based on small size power plants with relatively low investment costs and short implementation times offer many advantages.

Recent technological progress that has affected actual and projected costs of generating electricity include: enhanced efficiency and reduced capital costs of gas-fired power plants; development of advanced coal-fired power plants with pollution control equipment; and development of power plants using renewable energy sources. Technological progress for nuclear power plants has focused on enhanced safety and performance improvements.

Other relevant studies

Besides the previous studies of this series, a number of NEA studies on different economic aspects of nuclear power have been published or are being carried out. A review of the policies and schemes in place in NEA countries for recognising, reporting and funding financial liabilities arising from the operation and decommissioning of nuclear facilities was published in 1996.[5] On-going studies include analyses of nuclear power plant refurbishment costs, a review of methodologies for assessing the consequences of nuclear reactor accidents and, in the fuel cycle field, low-level waste repository costs. In order to complement the present analysis of total levelised nuclear electricity generation costs, a study on capital costs of nuclear power has been undertaken with the objective of analysing in depth those costs and ways and means to reduce them.

The IEA has published reports dealing with the development of energy technology, including potential for cost reductions in power generation technology[6] and on the effect of energy market liberalisation on generation technology development.[7] The IEA's Coal Industry Advisory Board has published a series of three reports on its members' views of the development and economic competitiveness of clean coal power plants.[8,9,10]

The IAEA has published a number of documents on various economic aspects of nuclear power including: cost experience of nuclear and conventional base-load electricity generation[11]; economics of small and medium nuclear reactors in Egypt[12]; economic evaluation of nuclear power as a means to produce potable water through desalination of sea water[13,14]; and the influence of pollution abatement costs on the relative competitiveness of fossil-fuelled and nuclear power plants.[15] The IAEA programme of work on nuclear power development also covers bid evaluation (study to update a guidebook on economic evaluation of bids for nuclear power plants and development of a computer software for bid evaluation) and financial aspects and financing nuclear power projects in developing countries.[16] Regarding nuclear fuel cycle economics, the IAEA has carried out studies on comparative costs of waste management for alternative electricity generation options.

In the field of comparative assessment of nuclear power and alternative electricity generation options, the IAEA has pursued, in co-operation with other international organisations, including the NEA, the inter-agency joint project DECADES.[17] The main outcome from the project, which includes a technology data base, computer tools for comparative assessment and case studies on comparative assessment in support of decision making, was presented and discussed at an International Symposium held in 1995.[18] In 1997, a co-ordinated research programme was initiated within the DECADES project focusing on analysing cost-effectiveness of different energy systems and technology measures for mitigating emissions of greenhouse gases and other environmental burdens through case studies.

UNIPEDE has continued its series of studies on projected electricity generating costs and published, in 1997, a report on comparative costs of electricity generation by power plants to be commissioned in 2005.[19] The study covers projected costs of base-load electricity generation by large thermal and nuclear power plants. It concludes that within the range of discount rates considered, i.e. from 5 to 10 per cent, nuclear, coal-fired and gas-fired combined cycle power plants could be competitive in a medium fuel price scenario depending on the discount rate. In the low fuel price scenario, electricity generated by natural gas-fired combined cycle power plants is cheaper than electricity generated by coal-fired power plants while in the high fuel price scenario electricity generated by coal-fired power plants is cheaper whatever the discount rate is. The 1997 update also concludes that, as compared to the previous study in the series, investment costs of coal and gas-fired power plants have decreased as well as projected fossil fuel prices. It notes that, within UNIPEDE, the number of countries considering the nuclear option has decreased as compared to previous studies.

The European Commission published in 1995 a series of reports on the results from the ExternE studies on externalities of energy.[20] The reports describe the methodology developed for quantifying and valuing the environmental impacts of electricity generation by different sources and technology, and gives results on the analysis carried out for fossil fuel cycles, nuclear cycle and renewable sources for electricity generation.

In France, the Ministry of Industry carries out regularly studies on projected costs of generating electricity. The last report, published in 1997[21] covers projected costs of base-load electricity generation by large thermal and nuclear power plants in France. It concludes that, today, nuclear is a sound choice for base-load generation and that, at present low gas prices, it can be supplemented by combined cycle gas turbines. It stresses that, contrary to those of gas generated electricity, nuclear electricity costs are insensitive to fuel price variation.

Limitations of results

This study, like its predecessors, recognises the limitations of international generating cost comparisons. The generic evaluation assumptions, which are the basis for the reference calculations, are not necessarily those used in specific evaluations that are considered more appropriate in individual countries. Therefore, the generic results are not meant to represent the "exact" costs of generating electricity that would be determined from specific generating plant projects. In some cases, the relative ranking of generation options, as calculated using the generic report approach, differs from the ranking that is obtained according to preferred national methods (Table 17). It is considered that results obtained using national methods match more closely those that would be observed for some specific projects.

The data reported in this report were provided by Members of the Expert Group and do not reflect construction or planning commitments made by governments. Countries and utilities will assess fuel and generation costs differently depending on the scale and timing of their power system expansion programmes, and on the geographical, political and economic frameworks within which they operate. The comparative assessment of different electricity generation options and strategies will be carried out at the national or utility level, taking into account the impacts of alternative choices on the total electricity system costs and their own planning and policy criteria including security of energy supply, environmental protection goals, social objectives, and financial constraints.

METHODOLOGY, COVERAGE AND COMMON ASSUMPTIONS

Methodology

The method adopted for calculating generation costs in this study is the same constant-money levelised lifetime cost method that was used in previous reports on generation costs and fuel cycle economics. This methodology is described in detail in Annex 10 and is relevant for comparing alternative generation options and assessing their relative competitiveness within a comprehensive harmonised framework. It is adequate for economic comparison of different types of power plants that could be commissioned at a given date in the same country. It does not, however, replace a full electricity system cost analysis that would be carried out at the national or utility level in support of expansion planning and decision making. It also does not indicate the choices made by individual utilities in a liberalised or competitive market.

Annex 2 on "Country Statements on Costs Estimates and Generation Technologies" provides some supplementary information on the approach and assumptions adopted in different countries for estimating and reporting generation costs, as well as on the specific characteristics of the generation options considered in those countries. It updates and extends the information given in previous reports of the series.

Data source and coverage of the study

The data that are presented and discussed in this report were obtained by circulating a questionnaire to OECD Member countries and non-OECD countries which participated in the study through the IAEA. Similar to the previous study in the series, the questionnaire asked for information on all types of base-load power plants expected to be commercially available for commissioning by 2005-2010, except hydropower plants.

In addition to numerical data, the questionnaire sought qualitative information such as lists of elements included in the cost estimates and country specific accounting methodology that may impact costs and, thereby, explain significant differences among countries in the costs of generating electricity. The main assumptions and the cost estimate methodologies adopted in each country are described to a certain extent in Annex 2. Annex 7 provides check lists of the factors that were included in cost estimates reported by respondent countries.

In some countries it appears that up-to-date cost data were not readily available from sources typically drawn upon in the past for this study. For example, Germany and the United Kingdom, which participated in previous studies, did not provide responses to the questionnaire for the present study. This may be due in part to the approach of liberalisation of electricity markets in some countries. Information on generating costs is considered commercially sensitive and confidential by utilities which must compete on price for electricity sales. Although there is not yet competition among electricity generators in any of the study countries except Finland and, to a limited extent, in certain states of the United States, all of the countries which participated in the study are moving towards or are considering market liberalisation.

The technologies for which information could be provided included, primarily, state-of-the-art power plants (category A plants) as their performance and costs, based upon ordered plant prices, quotation or detailed paper analysis, are considered to be well established. Cost information was sought also on technologies under development that are expected to be commercially available by 2010 (category B plants). Although uncertainties might remain on cost estimates for category B power plants, the working group considered that including those plants in the study was relevant for assessing medium-term trends. Only three countries, Brazil, the Netherlands and the United States, provided cost estimates for category B power plants.

The information, provided by nineteen respondent countries for seventy two power plants, focuses essentially on three options, coal, gas and nuclear power (see Table 1, list of responses). Figure 1 illustrates the average size of the coal, gas and nuclear power plants considered in the present study. Some responses included cost estimates for alternatives such as biomass, wind, oil, and combined heat and power plants.

Cost estimates for power plants burning coal or lignite were provided by eighteen countries. The technologies considered were all conventional boilers except two advanced integrated coal gasification plants (in category B). Most of the coal-fired power plants for which cost estimates were provided would be equipped with pollution control devices that reduce atmospheric emissions of sulphur and nitrogen oxides, dust and particulate (see Table 3 Coal Plant Specifications). Although the unit capacities of the coal plants considered range from 100 MWe to 1 000 MWe, most of them are of medium size, around 500 MWe. Their net thermal efficiencies are generally close to or above 40 per cent based on lower heating value.

Sixteen countries provided cost estimates for gas-fired power plants, most of which are combined cycle gas turbines of medium size capacity, around 350 MWe. Two countries, Japan and Korea, provided information on gas turbine plants using liquefied natural gas (LNG). The net thermal efficiencies of the submitted gas-fired plants are generally above 50 per cent and reach around 60 per cent for category B plants.

Thirteen countries provided cost estimates for nuclear power plants including three reactor types: pressurised water reactors (PWR); boiling water reactors (BWR); and pressurised heavy water reactors (PHWR). All the nuclear units for which cost estimates were provided are evolutionary reactors based on proven concepts. The size of the nuclear units ranges from 455 MWe to 1 460 MWe. Three countries, France, Japan and China, estimated nuclear fuel cycle costs corresponding to a closed cycle with reprocessing and recycling, while the other countries provided cost estimates corresponding to an open cycle with direct disposal of spent fuel.

With the exception of Turkey, none of the responding countries provided cost data on oil-fired power plants. Since the oil shocks of the 1970s, oil-fired power generation has become uneconomic in most OECD countries for base-load power generation.[22] It is largely in areas where there are few economic alternatives that oil-fired plants are chosen for base-load supply. Island systems, isolated or remote electricity systems, or those growing faster than can be matched by fuel supply infrastructure may find base-load oil-fired generation economic. Otherwise, today oil-fired plants are used primarily for intermediate and peak load power production. This is unlikely to change in the near future.

Hydropower plants are excluded from this study as from previous studies in the series because their costs are site specific and, therefore, not relevant for comparison to other alternatives in the framework adopted. In OECD countries, the majority of favourable sites for hydropower plants have already been utilised. However, there is a significant potential for further exploitation of hydropower resources at competitive costs in non-OECD countries.

As in the previous study, cost data on technologies using renewable energy sources for electricity generation were sought. Although a number of renewable technologies, such as solar photovoltaic, biomass burning and wind turbines, are commercially available, only three countries, Denmark, Italy and the United States, provided data on projected costs of generating electricity by renewable sources (biomass and wind). Also, the degree of development and experience on renewable technologies might not be sufficient to permit cost estimates as robust as those provided for fossil-fuelled and nuclear power plants. Furthermore, the questionnaire sought information mainly on power plants capable of supplying base-load demand; therefore, some countries might have excluded available data on power plants using randomly variable sources, such as wind and sun. Qualitative information on renewable technologies have been included by some countries in their country statements (see Annex 2). Renewable technologies for electricity generation are described briefly in Annex 3.

Only one country, Denmark, provided cost data on combined heat and power schemes (CHP). Annex 4 addresses issues related to fuels, technology and economics of combined heat and power generation systems. CHP offers opportunities to enhance the overall efficiency of energy supply systems and to decrease their environmental impacts by reducing fuel consumption per unit of delivered energy available for end-use. The competitiveness of CHP schemes as compared with dedicated electricity generation options is difficult to assess (see Annex 4) and varies from country to country. It depends in particular on heat and electricity demands, the existence of heat distribution networks, and policy measures that might be implemented to enhance the economic attractiveness of CHP in the light of its environmental advantages. Most of the power plants submitted for this study can be used in combined heat and power schemes. In particular, fossil-fuelled, biomass and nuclear power plants could provide heat and power at the same time. Generally, heat demand load and the distribution, and the high cost and low efficiency of transporting heat favour small units located near to consumers. However, large scale CHP plants are in some cases competitive for base-load electricity generation when located near to large heat markets such as big cities.

Cost estimates are presented, discussed and compared in Chapters 3 and 4. The discussion focuses on analysis and comparison of costs of generating electricity by coal, gas and nuclear power plants of category A for which information was provided by most respondents. The information collected on other generation sources, i.e. oil, renewable energy sources and CHP, and category B plants is reported in the summary tables and discussed briefly. In the United States (see Annex 2) generation costs vary from region to region owing to differences in material, labor and fuel costs. The estimates presented in the body of this report for the United States refer to the Midwest region. National calculations of generating cost for the Eastern and Western regions are presented in Annex 2.

The common assumptions adopted in the reference cost estimates for some parameters are summarised below. Respondent countries provided also, whenever applicable, cost estimates calculated with specific national assumptions different from the common assumptions adopted in the reference cases. Those costs estimates are presented separately in the following chapters. Cost estimates calculated by the Secretariat for different assumptions on fuel cost escalation rates, discount rates and economic lifetimes of the power plants are presented in Chapter 4 which discusses the sensitivity of cost estimates to those parameters.

Assumptions adopted for the reference cases

Technical assumptions

A common commissioning date, first of January 2005, has been adopted for estimating projected costs of generating electricity by the power plants considered in the study, including category B plants. The adoption of a common commissioning date is relevant for harmonising assumptions on investment costs and fuel prices over the plant lifetimes. Also, it narrows the range of energy sources and technologies to those that could be brought into commercial operation around 2005. However, this date is only indicative and does not imply that respondent countries have firm plans for constructing such plants and putting them into service by 2005.

Based upon technical performance of state-of-the-art base-load power plants, a common economic lifetime of 40 years has been adopted for estimating average levelised costs of generating electricity. Longer technical lives are expected by designers and operators for some technologies, e.g. coal-fired and nuclear power plants. As illustrated by the sensitivity analysis, longer lifetimes reduce the average levelised generation costs, and capital intensive technologies, such as nuclear power plants, are especially sensitive to this parameter. For the power plants that are expected to have shorter technical lifetimes, major refurbishment and/or replacement costs incurred during the 40-year period, are accounted for in the cost estimates. Estimated salvage value of the plant at the end of a 40-year period is accounted for also whenever relevant.

For fossil-fuelled, nuclear and non-intermittent renewable sources, a 75 per cent settled-down load factor was assumed in generation cost estimates for the reference cases. In the calculations, it was assumed that a 75 per cent settled-down factor was obtained through 5 000, 6 000 and 6 626 full power operating hours during the first, second and subsequent years of operation respectively (see Annex 10). The average availability factors of some existing power plants already exceed 75 per cent. The sensitivity analysis illustrates generation cost reductions that can be obtained with higher load factors. For intermittent renewable sources the assumed load factors, that vary by plant type, are indicated in the tables summarising results and assumptions.

The technical assumptions adopted in this study reflect current experience and average performance expected by designers and operators for power plants that will be commissioned by 2005. It should be noted, however, that they are rather conservative and that most technologies under consideration are expected to have longer lifetimes and higher load factors.

Cost coverage and costing basis

Annex 7 summarises the cost elements included by each respondent in the data provided. The costs reported and discussed in this report are intended to be relevant with regard to choices that would be made by electricity producers among various alternatives for base-load electricity generation. Therefore, they include all technology and plant specific cost components borne by producers including investment, operation and maintenance (O&M) and fuel costs as well as costs related to pollution control, waste management and other health and environmental protection measures. On the other hand, cost elements that do not affect the relative competitiveness of alternative options, such as central overheads, transmission and distribution costs and taxes affecting all power plants, are excluded. Whenever the cost elements included in estimates provided by respondent countries differ from the common framework, it is noted in Annex 7 and indicated in the presentation and discussion of results.

Taxes on income and profit of the producer that do not affect the relative competitiveness of a specific plant are not included in the generation costs reported and presented in this report. On the other hand, plant-specific taxes that may differ from plant to plant according to their type and/or location, such as local taxes, should be included in costs. Similarly, existing taxes on fuels that affect fuel prices paid by electricity producers should be included in fuel costs.

Cost estimates presented and discussed in this report refer to net power supplied to the station busbar, where electricity is fed to the grid. Therefore, they exclude costs of the plant substation, transmission on the network and distribution to end-users. In general, transmission and distribution costs are similar for all grid connected power plants which are the main focus of this report; therefore, they do not affect the relative competitiveness of alternative options. This does not apply in the case of smaller plants, using renewable energy sources, for example, that might have lower or higher than average transmission and distribution costs. Those points are addressed in the presentation and discussion of generating costs by alternative technologies.

Costs related to capital investment include pre-construction, overnight construction, major refurbishment, and decommissioning costs; interest during construction is calculated using the relevant discount rate and is accounted for in the total levelised electricity generating costs. If dedicated fuel supply facilities must be constructed uniquely to provide fuel for the power plant, the investment costs of those facilities are accounted for. Decommissioning costs, including costs of decommissioning waste management and disposal, are included in investment costs. Credits arising from decommissioning such as incomes from recycled materials are included.

Those costs include also all plant specific pre-construction costs, such as costs associated with R&D, licensing, public hearings, plant specific safety studies, site investigation and preparation. On the other hand, infrastructure costs that are not specific to the plant, such as those associated with generic R&D, regulatory body establishment and management, are excluded. For nuclear power plants, the first inventory of heavy-water in pressurised heavy-water reactors (PHWR) is included in investment costs except in the case of China (see Annex 7).

Operation and Maintenance (O&M) costs include all costs borne by producers that do not fall within investment and fuel costs. For example, the costs of consumable materials and products, such as heavy-water supply during operation for PHWRs or sorbents and catalysts for emission control devices, are included in O&M costs. Credits from sale of by-products are taken into account when applicable. For fossil-fired power plants, costs related to treatment, storage, conditioning, and disposal of fossil fuel residues, e.g. disposal of coal ash, gypsum and waste are included in O&M costs. For nuclear power plants, the costs related to management and disposal of low- and intermediate-level radioactive waste arising during operation, are included in O&M costs.

Fuel costs include all costs related to fuel supply at the power plant. They include commodity price and transportation whenever applicable. Generally, credit for recycled materials such as aggregate from coal ash and other fuel cycle by-products are accounted for.

In the case of nuclear power, fuel cycle costs include all the costs related to the up-stream and down-stream steps of the cycle, and the costs of transportation between each step. This includes the costs of uranium (yellow-cake), conversion, enrichment, fabrication, spent fuel conditioning and disposal or reprocessing and reprocessing waste disposal, as applicable.

For fossil-fuelled power plants, fuel prices used in estimating generation costs include all the costs up to the power plant gate, including transportation infrastructure. For example, the cost of natural gas or petroleum pipelines, rail lines, and other transportation infrastructure are included in the prices of gas, oil and coal delivered at the gate of the power plant.

There is no common assumption on fossil fuel price increases over time. Fossil fuel price assumptions used for calculating generation costs in the reference cases are those provided by each country. However, the sensitivity analysis includes cost calculated assuming zero fuel price escalation for all plants.

The costs reported and discussed in this study do not include externalities. Previous studies in the series as well as other reports published by the NEA and by other international organisations have addressed extensively issues related to external costs that arise upstream or downstream from the electricity producer activities.

Economic assumptions

All the cost estimates reported by respondent countries were given in constant money terms and expressed in respective national currency units as of 1 July 1996; for this purpose, respondents used appropriate national currency deflators. Those cost estimates have been converted to US dollars of the same date by the Secretariat using the exchange rates given on Table 6. The cost estimates calculated by the Secretariat for sensitivity analysis are expressed in US dollars of 1 July 1996. Unless otherwise specified, costs and prices quoted below in US dollars are expressed in US dollars of 1 July 1996.

The choice of a common currency unit is essentially motivated by convenience for presenting summary tables on a common monetary basis. As pointed out in previous studies, exchange rates do not reflect purchasing power parities accurately and their use might affect cost comparisons between countries in a way that does not correspond to real cost differences. In particular, using exchange rates between US dollars and national currencies at a given date, 1 July 1996 for the present study, might distort comparisons between countries in case of fluctuations of exchange rates over time. Moreover, even if exchange rates would reflect purchasing power parities, the conversion in US dollars would not automatically lead to cost estimates that could be compared between countries. Previous reports have stressed that the conversion process does not allow the use of appropriate deflators for costs incurred in connection with imported goods and services. Therefore, the reader should be extremely cautious in comparing cost estimates from different countries although they are expressed in a common monetary unit. It should be noted that conversions in US dollars might be misleading for non-OECD countries especially as exchange rates for those countries generally are far from reflecting purchase power parities and might vary significantly over time.

As shown by previous studies and by the results presented in the present report, generating costs, and particularly their relative magnitudes, are highly sensitive to the discount rates used. In the present study, like in the previous one, the reference cost estimates have been calculated using two real discount rates, 5 per cent and 10 per cent per annum. Those values, which were adopted in the last UNIPEDE study also, are considered representative of the range of values used by electricity producers in most countries.

All respondent countries, except one, that provided cost estimates calculated with national/non-generic assumptions have used discount rates ranging between 5 and 10 per cent. For non-OECD countries, Brazil, China and India have assumed a 10 per cent discount rate in their cost estimates based upon national non-generic assumptions. In OECD countries, cost estimates based on non-generic assumptions, when they were provided, used the following annual discount rates: 5 per cent in Canada, Denmark, the Netherlands and the United States; 8 per cent in France, Hungary, Portugal and Turkey; 8.5 per cent in Korea; 8.6 per cent in Belgium; and 12 per cent in Italy. Japan and Spain provided cost estimates based on national assumptions at 5 and 10 per cent per annum discount rates.

The discount rate values adopted in national estimates support the adoption of both 5 and 10 per cent per annum for the reference cost estimates presented in this study. In practice, the choice of a discount rate for decision-making by a given utility will depend on its specific situation and the overall economic, regulatory and commercial framework of the country. Although there is extensive published literature on discount rates and their relationship with financial risks and required rates of return for private or public investors, there is no consensus view on that matter. The results presented below include cost elements and expense schedules that provide the reader with detailed information that can be used for estimating costs at any alternative discount rates which would correspond best to their respective situation.

For the sake of simplicity and consistency, the interest during construction and the present worth of deferred back-end costs, i.e. decommissioning and radioactive waste management costs, have been calculated for this study using the appropriate discount rate as the interest rate. Although this is in line with common practice in most OECD countries, some countries adopt lower discount rates for long-term financial liabilities corresponding to a long-run real rate of return that can be confidently expected to be earned on funds set aside to meet deferred costs. The NEA study on future financial liabilities[5] describes the various schemes adopted by different countries in this regard. The effect on levelised costs of adopting lower discount rates for future financial liabilities is small, as shown by the results presented later in this report.

Cost estimates have been calculated taking the date of commissioning, i.e. 1 January 2005 for this study, as the discounting date. This choice is not essential since the calculated levelised generation cost per unit of electricity output is independent of the selected base date for discounting. However, as pointed out above, the levelised cost of electricity generation is dependent on the date of commissioning if there is any variation of the real costs of plant, fuel or services during construction and operation.

OVERVIEW OF RESULTS

Investment costs

The information provided on projected investment costs is summarised on Tables 7, 8 and 9 for nuclear, coal-fired, gas-fired and other power plants respectively. Base construction costs were reported by respondents in NCU 1 July 1996 and converted in US$ 1 July 1996 by the Secretariat using the exchange rates given on Table 6. The other elements of investment costs include: interest during construction calculated at 5 and 10 per cent per annum discount rate; contingency, whenever allowances for contingency were reported separately from base cost; major refurbishment, e.g. steam generator replacement for nuclear power plants; and decommissioning when applicable. Total investment costs at 5 and 10 per cent discount rate per annum include "other costs" reported by some countries (see Annex 2 and Annex 7 for detail).

Table 7 and Figure 2 show projected base (overnight) construction costs for nuclear power plants. In OECD countries, projected overnight construction costs for nuclear power plants range from less than 1 500 US$/kWe in the United States for a category B plant to more than 2 000 US$/kWe in Finland, Japan and Spain. In non-OECD countries, the range of projected overnight costs is narrower: from around 1 020 US$/kWe in China, for Qinshan 2, to 1 840 US$/kWe in India. Decommissioning cost estimates may vary significantly from country to country depending on national standards, regulations and accounting schemes (see Annex 2). Nuclear power plant decommissioning costs and their variability are discussed in previous reports of the series and in other NEA reports.[23-24] The share of decommissioning costs in total levelised investment costs of nuclear power plants is small in all cases, less than 1 per cent at 10 per cent per annum discount rate and a few per cent at 5 per cent per annum discount rate. Reported capital expenditure schedules vary widely (from four to nine years) between countries, as shown on Table 10. Those differences affect interest during construction and levelised generation costs significantly.

Projected investment costs for coal-fired power plants are shown on Table 8 and Figure 3. In countries which provided data for both type of plants, overnight construction costs are generally lower for coal-fired than for nuclear power plants, with the exception of Japan. In most OECD countries, coal-fired power plant overnight construction costs range from around 1 000 US$/kWe to around 1 350 US$/kWe. On the lower side, Canada reports projected overnight construction costs of 837 US$/kWe for four 750 MWe pulverised coal combustion (PF) units on the same site. On the higher side, Japan and Portugal report overnight construction costs, also for PF units, reaching or exceeding 2 000 US$/kWe. Reported overnight construction costs for category B coal-fired power plants (PF in the Netherlands, and IGCC in the Netherlands and the United States) are slightly higher than those of category A plants in both countries. In non-OECD countries, coal-fired power plant overnight construction costs range from 772 US$/kWe in China to 1 258 US$/kWe in Brazil. Decommissioning costs are estimated negligible by all respondent countries on the grounds that already small decommissioning expenses will be largely repaid by benefits from value of the site and sale of reusable material recovered in the process. Some countries report major refurbishment costs incurred during the economic lifetime of the plant for its extensive maintenance and/or replacement when its technical lifetime is expected to be shorter than the 40-year economic lifetime assumed in the generic cases. Major refurbishment costs represent no more than a few per cent of total levelised investment costs at 10 per cent per annum discount rate and less than 18 per cent at 5 per cent per annum discount rate. Expenditure schedules for coal-fired power plants (see Table 10) vary from four to eight years in both OECD and non-OECD countries for category A or B plants. In most countries projected expenditure schedules are slightly shorter for coal-fired than for nuclear power plants.

Projected investment costs for gas-fired power plants are shown on Table 9 and Figure 4. All gas-fired power plants are combined cycle gas turbines, except for one gas-fired steam turbine in Denmark and a fuel cell plant of category B in the United States. Generally, construction costs for gas-fired power plants are much lower than those of nuclear or coal-fired power plants. Projected overnight construction costs for gas-fired power plants are lower than 800 US$/kWe with few exceptions in both OECD and non-OECD countries for plants in category A and B as well. Like for coal-fired power plants, decommissioning costs are negligible. On the other side, significant major refurbishment expenses, corresponding to the replacement of major plant components after 20-25 years, are reported by a number of countries. In those countries, refurbishment costs represent between 2 and 27 per cent of total investment costs at 5 per cent discount rate, and between 1 and 13 per cent of total investment costs at 10 per cent discount rate. Expenditure schedules for gas-fired power plants are shorter than for coal-fired or nuclear power plants in all countries except Spain (see Table 10), varying from two years in the United States to six years in Denmark. Therefore, total investment costs are lower for gas-fired power plants than for coal-fired or nuclear power plants at 5 or 10 per cent per annum discount rate.

In the light of the limited number of countries which provided information on other technologies, and of the small number of plants for which data were submitted, the cost estimates reported for those technologies are not likely to be representative of the cost range for technologies available world-wide. The overnight costs for other technologies shown on Table 9 and Figure 5 are generally in the same range as overnight costs for coal-fired power plants with the exception of the straw-fired steam turbine in Denmark. The information provided by Denmark and Italy on wind turbines indicates very short construction times, one or two years. In Denmark, overnight construction costs for off-shore wind turbines are twice as high as those for other wind turbines, although the total installed capacity off-shore would be more than ten times higher. The high construction and O&M costs of off-shore wind turbines should be seen in the light of an achievement of a 35 per cent availability factor, as compared with a maximum 25 per cent in the case of land based wind turbines.

The reasons for differences in investment costs for power plants of similar technologies and size in various countries have been discussed in detail in earlier reports of the series. The major factors leading to investment cost variability across countries are: labour cost; domestic prices for material and equipment; institutional and regulatory frameworks; infrastructure; and site specific conditions. Expressing investment costs in US dollars induces an additional cause of variability in the light of the variability of currency markets.

Operation and maintenance costs

Projected operation and maintenance costs (O&M) are shown on Table 11. O&M costs are reported in US$ per kWe net of capacity per year. Annex 7 provides a check list of the items included in O&M costs by each country. As in the last report of the series, the breakdown of O&M costs into their components has not been analysed since it does not provide relevant information owing to differences in accounting rules and practices in various countries. For all technologies, O&M costs are projected to remain the same, in constant money, during the entire economic lifetime of the plant, in all countries except Hungary, Brazil, China and Russia. O&M costs are projected to increase for the gas-fired plant in Hungary and for all power plants in Brazil while they are projected to decrease for the PHWR/Candu6 in China. O&M costs are projected to increase for coal and gas-fired power plants in Russia.

In OECD countries, projected O&M costs in 2005 for nuclear power plants range from 39 to 62.5 US$ per kWe capacity per year, except in Japan where they exceed 100 US$. In most non-OECD countries, O&M costs in 2005 for nuclear power plants are projected to be lower than in OECD countries, ranging from 29 to 43 US$ per kWe capacity per year, except for the PHWR unit in Romania (75 US$ per kWe capacity per year) and for the PHWR/Candu6 unit in China (decreasing from 57.6 US$ per kWe capacity per year in 2005 to 40.6 US$ in 2025 and remaining constant thereafter).

Projected O&M costs for coal-fired power plants lie in the range 26 to 75 US$ per kWe capacity per year in OECD countries, except in Japan where those costs exceed 80 US$ per kWe capacity per year. In non-OECD countries, projected O&M costs for coal-fired power plants are generally lower than in OECD countries, ranging from 17.5 to 36 US$ per kWe capacity per year. Although the ranges of projected O&M costs for coal and nuclear power plants overlap, in countries which reported cost estimates for both technologies, O&M costs are generally lower for coal-fired than for nuclear power plants, with the exception of Finland and France.

Projected O&M costs for gas-fired power plants range from 6 to 50 US$ per kWe capacity per year, except Finland where they are higher than projected O&M costs for coal-fired or nuclear power plants and exceed 70 US$. For other technologies, projected O&M costs vary in a wide range owing to the variety of plant type and size. For wind turbines, projected O&M costs are rather low, around 15 US$ per kWe capacity per year for on land plants and 42 US$ per kWe capacity per year for the off-shore plant in Denmark.

The O&M costs for similar technologies in different countries vary within a rather wide range. This variability results from differences between countries in a number of factors, such as wages of staff, productivity and regulations, that affect O&M costs. As in investment costs, the use of a common monetary unit is an additional source of variability.

Nuclear fuel costs

Table 12 shows the main components of nuclear fuel cost, i.e. uranium, enrichment and fabrication services, when they were reported. Six countries reported projected uranium prices. In Canada, France, Korea and the United States, uranium prices vary between 42 and 65 US$/kgU and are projected to remain stable during the entire economic lifetime of the plants. India is assuming uranium prices to remain constant at 169 US$/kgU. Brazil assumes that uranium prices will increase progressively from around 44 to nearly 54 US$/kgU between 1996 and 2045. Those projected prices are higher than current uranium prices on the spot market but similar to contract prices.[25]

The aggregated nuclear fuel cycle costs per kWh, including uranium, front-end and back-end services, are shown on Tables 15 and 16 for generic assumptions at 5 and 10 per cent per annum discount rate respectively, and on Table 17 estimated with national assumptions. At 5 per cent per annum discount rate with generic assumptions, nuclear fuel cycle costs represent between 13 and 29 per cent of total levelised generation costs for LWRs, and between 8 and 23 per cent for PHWRs. At 10 per cent per annum discount rate, the share of fuel cycle costs in total levelised generation costs range between 8 and 18 per cent for LWRs and between 5 and 14 per cent for PHWRs. The last NEA study on economics of the fuel cycle[26], published in 1994, showed that there is a decreasing trend in projected nuclear fuel cycle levelised costs over time owing to improved fuel and reactor performance factors and to reduction in projected uranium and fuel cycle service prices. In recent years, fuel cycle service prices have been stable or decreasing. Although uranium prices increased significantly on the spot market, the average price paid by utilities getting their supply mainly under long term contracts has remained stable in real terms (see Annex 5 on fuel prices).

Coal price assumptions

Projected coal prices assumed by respondent countries are shown on Table 13 and Figure 6 and discussed in Annex 5. Prices are expressed in US$/Gigajoule to reflect real energy content of the coal taking into account varying calorific values of different coals. The prices are given at the mine or the domestic border and at the power plant. Projected prices at the power plant have been used for calculating levelised generation costs presented on Tables 15, 16 and 17. In OECD countries, excluding domestic lignite, projected coal prices at the power plant at the date of its commissioning, i.e. 2005, vary from 1 US$/Gjoule in the United States to 2.8 US$/Gjoule in Italy and the Netherlands. In non-OECD countries, coal prices at the power plant are projected to range between 1.3 and 3.2 US$/Gjoule. Nine among the eighteen countries which provided cost estimates for coal-fired power plants, assumed constant coal prices from 1996 onwards to the economic lifetime of the plant; eight countries assume increasing coal prices and one country, the United States assumes decreasing coal prices. The average real coal price escalation rate projected by respondent countries is 0.3 per cent per annum. Levelised generation costs, calculated assuming a zero coal price escalation, are presented on Tables 19 and 20.

Gas price assumptions

Projected gas price assumptions are shown on Table 14 and Figure 6 and discussed in Annex 5. In 2005, the date of assumed plant commissioning, gas prices at the power plant are projected to range between 1.6 US$/Gjoule, in the United States, and 5.35 US$/Gjoule, in Italy. Ten countries, among the sixteen countries which provided cost estimates for gas-fired power plants, project an increase in real gas price during the economic lifetime of the plant. On average (see Annex 5), real gas prices are projected to rise at 0.8 per cent per annum. Levelised fuel costs for gas-fired power plants calculated for generic and national assumptions are shown on Tables 15 to 17. Levelised generation costs, calculated assuming a zero fuel price escalation, are presented on Tables 19 and 20. Figure 7 shows the expected ratios of gas to coal price in 2005 in countries that provided data for both fuels. The ratios range from 1.2 in Turkey to nearly 3 in Korea. Japan and Korea, which rely on liquefied natural gas, have the highest ratios of gas to coal price. Brazil is the only country in which gas is assumed to be less expensive than coal (case C1).

Overall generation costs

Projected levelised generation costs calculated with generic assumptions (i.e. 75 per cent settled down load factor and 40-year lifetime) expressed in US$ per kWh are shown on Tables 15 and 16 at

5 and 10 per cent per annum discount rate respectively. For wind turbines, normalisation to 75 per cent settled down load factor would be meaningless, therefore, cost estimates presented on Tables 15 and 16 are those reported by respondents. Projected levelised generation costs calculated with national assumptions (see Table 5) are presented on Table 17. Figures 8 and 9 show generation costs calculated with common assumptions levelised at 5 and 10 per cent discount rate respectively for all the power plants considered in the present study.

The following discussion refers exclusively to costs calculated with generic assumptions. The relative competitiveness of coal, gas and nuclear differs in some countries, such as Japan, when considering projected costs calculated with national assumptions (see Table 17). Also, in the United States, the relative competitiveness of coal, gas and nuclear differs according to the region of the country considered (see Annex 2).

Ratios of nuclear, coal and gas generation costs, calculated at 5 and 10 per cent per annum discount rates with generic assumptions are summarised in Table 18. Other technologies are not included in the table in the light of the scarcity of the information provided and, moreover, because their costs are generally not comparable to those of the three main generation sources, i.e. coal, gas and nuclear. As indicated in Chapter 2, only eight OECD countries and two non-OECD countries provided cost estimates for coal-fired, gas-fired and nuclear power plants. However, most countries provided data for at least two technologies.

The generation cost ratios between nuclear and coal, nuclear and gas, and coal and gas are illustrated on Figures 10, 11 and 12 respectively, at both 5 and 10 per cent per annum discount rates. At 5 per cent discount rate: the ratio of nuclear and coal generated electricity costs lies in the range 0.6 to 1.3; the ratio of nuclear and gas ranges from 0.7 to 1.4; and the ratio of coal and gas is in the range 0.7 to 1.3 (except in Brazil where the single 315 MWe coal plant is nearly twice as expensive as gas). At 10 per cent discount rate, the ratios are in the range: 0.75 to 1.5 between nuclear and coal; 0.95 to 2.0 between nuclear and gas; and 0.7 to 1.9 between coal and gas.

As compared to previous studies in the series, the ratios between cost estimates calculated with common assumptions show an increasing competitiveness of gas-fired power plants versus coal-fired and nuclear power plants. Projected generation costs are lower for nuclear power than for gas-fired power plants at both 5 and 10 per cent discount rate in two countries, France and Japan. In Canada, Korea, Spain and Russia, generation costs are lower for nuclear than for gas-fired power plants at 5 per cent discount rate but are higher at 10 per cent discount rate. In the four other countries, Finland, Turkey, the United States and Brazil, which provided cost estimates for nuclear and gas-fired power plants, gas is projected to be the cheaper option at both 5 and 10 per cent discount rate.

In most countries which reported cost data for coal and gas-fired power plants, gas is cheaper at both 5 and 10 per cent discount rate. However, coal is cheaper than gas in Denmark and Finland, and in Japan and Korea where gas-fired power plants are fuelled with liquefied natural gas (LNG). In France, Italy, and Spain gas is more expensive than coal at 5 per cent discount rate but cheaper at 10 per cent discount rate. In Canada, Hungary and the United States, gas is cheaper than coal at 5 per cent discount rate for some of the plants considered. In both non-OECD countries which provided data for coal and gas-fired power plants, gas is cheaper at both 5 and 10 per cent discount rate.

The competitiveness between coal and nuclear varies from country to country and within the same country from plant to plant. In France and China nuclear is cheaper at both 5 and 10 per cent discount rate. In Finland, Japan and the United States coal is cheaper at both 5 and 10 per cent discount rate. In the seven other countries which provided data for nuclear and coal-fired power plants the cost ratios are higher or lower than one depending of the discount rate and/or the plant considered.

Figures 8 and 9 illustrate the ranking of the options for which data were provided. The option against which the cheapest plant competes is relevant, and varies between countries reporting in this study. Generally, when nuclear is cheapest it competes against coal, and the fossil fuels gas and coal are in competition with each other. The only exceptions to this general observation are Japan, where coal is cheapest and competes against nuclear; France, where nuclear at 10 per cent discount rate is cheapest and competes against gas; Turkey, where gas at 5 per cent discount rate is cheapest and competes against nuclear; and Russia, where gas competes against nuclear and either can be cheapest, depending on the discount rate.

Local cost factors and the local mix of capital, O&M, and fuel costs are the ultimate determinants of which fuel/technology combination is the cheapest in a given country. Only a local, detailed evaluation of options can provide meaningful local comparisons. Consequently, it is difficult to generalise across countries on the cost factors having the most important influence in determining the cheapest option. Several limitations of this study's estimates are that rigorous statistical relationships cannot be established because of the small number of countries providing data, the fact that only 10 countries provided data for all three basic baseload options, and in seven or eight of the 18 countries providing comparisons, the difference between the cheapest option and the next cheapest option is less than 10 per cent. Nonetheless, a few simple factors can be sought among the cost elements collected for this study. They are by no means determinant influences or sufficient in themselves to make the given technology the cheapest in any given country, but they do indicate instances where international averages may be of relevance. With these limitations in mind, the following discussion is based upon, in all cases: A plants only; generation costs estimated using common assumptions; for each country, the lowest cost baseload option in each fuel/technology type.

Nuclear cheapest

In France and China, nuclear power plants have the lowest levelised costs at both 5 and 10 per cent discount rate. In Canada, Korea, Spain, India and Russia, nuclear plants were the cheapest option at 5 per cent only. The next least expensive alternative in all these countries is coal-fired power, except in Russia, and in France at 10 per cent discount rate only. Although the small number of plants (as in other cases) makes comparisons difficult, several conditions may be associated with the estimated nuclear cost advantage for the reference cases in these countries:

- Below-average nuclear plant capital costs. All seven countries but Spain have nuclear plant capital costs below the average of capital costs reported by all countries. As a group, the seven countries excluding Spain estimated capital costs some 15 per cent less than those of other countries providing nuclear plant capital costs. In the cases of France, Korea, and Russia, economies of scale in large, multi-unit nuclear power plants or in multi-plant nuclear construction programmes may help in this regard. France and Korea provided estimates for units within nuclear plants of over 2 000 MWe in total capacity. The French estimates assume a construction program of 10 reactors with a total capacity of 14 600 MWe, the Korean estimates are based upon six reactors of 6 000 MWe total capacity, and the Russian estimates assume a series of 5 reactors of 3 000 MWe total capacity;

- Below-average O&M costs. France, Canada, China, India and Russia have O&M costs about one third lower than the average for all nuclear plants; and

- Below-average efficiency of coal plants. The average thermal efficiency of hard coal plants in Canada, Spain, China, India and Russia (37 per cent) was 5 percentage points below that of those in all other countries providing estimates of hard coal-fired plants (42 per cent).

Coal cheapest

In Denmark, Finland and Japan coal plants have the lowest levelised costs at both 5 and 10 per cent discount rate. Coal plants in Hungary, Italy, and the United States are cheapest at 5 per cent only, and in Korea and India coal is the cheapest option at 10 per cent. In all but Japan the next cheapest option is a gas-fired CCGT and India did not provide an estimate for a gas-fired CCGT. The advantage to coal in these eight countries may be related partly to:

- Below-average capital cost ratios of coal and gas-fired plants. Denmark, Finland, Japan, and Italy have below-average ratios of overnight capital cost in coal-fired plants compared to gas-fired plants. Although capital costs of coal-fired power plants in Finland, India and the United States are below average, the average for the eight countries above is close to the average for all countries reporting coal plants; and

- Below-average O&M cost ratios of coal and gas-fired plants. Denmark, Finland, Hungary, Japan and the United States have below-average ratios of O&M costs in coal-fired plants compared to gas-fired plants.

Gas cheapest

Gas is the cheapest option at 5 and 10 per cent discount rate in Belgium, the Netherlands, Portugal, Turkey and Brazil. In Canada, Italy, Spain, the United States, and Russia, gas becomes the cheapest option at 10 per cent discount rate only. In all cases the gas-fired plants were CCGTs and in all cases, except Turkey at 5 per cent discount rate and Russia, the next cheapest option is coal. Only one factor could be identified with the advantage of gas-fired plants in these estimates:

- Low O&M costs. Except for Belgium, the Netherlands, and Spain, all the countries in which gas was the cheapest option had lower than average O&M costs for gas-fired plants.

Otherwise, no significant differences in plant size, efficiencies or capital costs are clearly identifiable between gas-fired power plants in those countries and other CCGTs considered in the study. Although fuel cost accounts for about 60 per cent of the cost of gas-fired power production, on average, there is no systematic advantage to gas-fired power in countries with low gas prices or systematic disadvantage to it in countries with high gas prices. The ratio between gas prices and coal prices may be a more indicative factor. In Belgium, the Netherlands, the United States and Russia relatively low gas prices compared to coal are assumed (see Figure 7).

Sensitivities

Levelised electricity generation costs are sensitive to the economic and technical assumptions adopted in the calculations. The sensitivity to discount rate is shown by the results presented above and summarised on Tables 15 and 16, at 5 and 10 per cent per annum discount rate respectively. The range 5 to 10 per cent includes discount rates used by all respondent countries, except Italy, in their national calculations. Tables 19 and 20 show the sensitivity of levelised costs to settled down load factor, economic lifetime of the plants and fuel price escalation assumptions. Twelve sensitivity cases, including the two generic cases, have been investigated to illustrate the variation of levelised generation costs for alternative assumptions regarding those parameters. These cases include three variants of settled down load factor (65, 75 and 80 per cent), three variants of economic lifetime (25, 30 and 40 years) and two fuel price escalation variants (national assumptions and zero real fuel price escalation).

The range of settled down load factors covered in the sensitivity analysis is thought to be representative of the most likely operating conditions for base-load power plants world-wide. However, state-of-the-art coal-fired, gas-fired and nuclear power plants are achieving already availability factors higher than 80 per cent and the design objectives for advanced power plants are often higher than 85 per cent.

The economic lifetime range covered in the sensitivity analysis covers expected technical lifetimes of the power plants considered. However, for coal-fired and nuclear power plants, 40 years is on the conservative side as technical lifetimes beyond 50 years are currently envisaged by designers and operators.

The sensitivity analysis on fuel prices illustrates the impact on relative competitiveness of nuclear, coal and gas of constant fuel prices. Past trends and projections of fuel price escalation rates are discussed in Annex 5.

Discount rate

Previous studies in the series have shown that capital intensive options such as nuclear power are more competitive at low discount rates while low capital options such as gas-fired power plants increase their competitiveness at high discount rates. Figures 10, 11 and 12 illustrate the impact of raising the discount rate from 5 to 10 per cent on the relative competitiveness of nuclear, coal and gas. They show that in about half the countries (10 of 18 with two or three options) and for most power plants considered, the cheapest option at 5 per cent discount rate remains cheaper at 10 per cent discount rate. However, in some cases increasing the discount rate from 5 to 10 per cent changes the ranking of alternative options.

Settled down load factor

For all power plants, increasing the load factor decreases the levelised cost of electricity generation. However, capital intensive options are more sensitive to load factor variation than low capital intensive options. On average, for the nuclear power plants considered in the present study (assuming a 30-year economic lifetime and national fuel price escalation rates) when settled down load factors increase from 65 to 80 per cent levelised generation costs at 5 or 10 per cent discount rate decrease by some 15 per cent; for coal-fired power plants, levelised generation costs decrease by around 10 per cent at 5 per cent and by around 11 per cent at 10 per cent discount rate; for gas-fired power plants, levelised generation costs decrease by around 5 per cent at 5 per cent discount rate and 7 per cent at 10 per cent discount rate. As the levelised generation cost of gas-fired power plants is not very sensitive to load factor variation, they tend to be the preferred choice for peak load generation and when uncertainties on future demand are large. The sensitivity of levelised nuclear generation cost to load factor variation has led designers and utilities to place emphasis on enhancing availability factors of nuclear reactors (e.g., European and American advanced light water reactors are designed for availability factors higher than 87 per cent).

Economic lifetime

Generally, increasing the economic lifetime of a power plant decreases its lifetime levelised generation cost. However, this is not the case if lifetime extension requires extensive refurbishment costs and/or if fuel prices are assumed to increase rapidly in the long term. Also, at 10 per cent discount rate levelised generation costs are less sensitive to economic lifetime extension than at 5 per cent discount rate because expenses and incomes occurring more than 25 years after commissioning contribute little to overall generating costs. On average, for the power plants considered in the present study, assuming national fuel price escalation rates and 75 per cent settled down load factor, levelised generation costs at 5 per cent discount rate decrease by some 11 per cent for nuclear power plants and 5 per cent for coal-fired plants when economic lifetime increases from 25 to 40 years; at 10 per cent discount rate, levelised generation costs decrease on average by 5 and 3 per cent for nuclear and coal-fired power plants respectively. For gas-fired power plants, capital costs represent only a small share of total levelised costs and, therefore, increasing the economic lifetime has little influence on levelised generation costs. In countries where gas prices are assumed to increase significantly, levelised gas generation costs increase when economic lifetime is extended. On average, for the gas-fired power plants considered in the study, assuming national fuel price escalation rates and 75 per cent settled down load factor, levelised generation costs decrease by around 1 per cent when economic lifetime increases from 25 to 40 years.

Fuel price

The cost of generating electricity by fossil-fuelled power plants is very sensitive to fuel price escalation. Gas generation costs, in which fuel generally accounts for more than 60 per cent of total generation costs, are the most sensitive to fuel prices. At the other extreme of the range, some renewable resources such as wind turbines have no fuel cost component at all. Nuclear generation costs, in which fuel costs generally account for around 15 per cent at 10 per cent discount rate and less than 25 per cent at 5 per cent discount rate, are not very sensitive to fuel price escalation. Table 15 and 16 show the share of fuel costs in total levelised generation costs, at 5 and 10 per cent discount rates respectively, calculated with national fuel price assumptions.

Annex 5 elaborates on past and present fossil fuel price projections. In the present study, two variants of real fuel price escalation have been investigated: zero escalation; and national assumptions, which correspond to average real escalation rates of 0.3 and 0.8 per cent per annum in the case of coal and gas respectively. Tables 19 and 20 show the sensitivity of fossil-fuelled generation costs to coal and gas price escalation at 5 and 10 per cent discount rates respectively.

The reductions of levelised generation costs resulting from assuming zero fuel price escalation depend on the price escalation rates assumed by each country. In the eight countries which have assumed coal price escalation, assuming zero price escalation lowers generation costs (for 30-year economic lifetime and 75 per cent settled down load factor) by 3 to 29 per cent at 5 per cent discount rate and by 2 to 22 per cent at 10 per cent discount rate. In the ten countries which have assumed gas price escalation, assuming zero price escalation lowers generation costs (for 30-year economic lifetime and 75 per cent settled down load factor) by 1 to 31 per cent at 5 per cent discount rate and by 1 to 26 per cent at 10 per cent discount rate.

Figures 13 to 16, show the influence of assuming constant fuel prices on the relative competitiveness of nuclear, coal and gas (for 30-year economic lifetime and 75 per cent settled down load factor) in countries that have not assumed constant fossil fuel prices. In a few countries, the assumption of constant fossil fuel prices changes the relative ranking of generation options, but in most cases the coal or gas option simply improves its relative competitiveness as compared with nuclear, or gas improves its relative competitiveness as compared with coal. In Japan and Russia, where assumed annual gas price escalation rates are over 2.4 per cent, gas becomes cheaper than nuclear at 5 per cent discount rate. The slight advantage of nuclear over gas in Japan at 10 per cent discount rate disappears if gas price is assumed to remain stable. In China and Russia, coal-fired generation decreases to approach the cost of nuclear at 5 per cent and becomes cheaper at 10 per cent. Gas becomes cheaper than coal in Italy at a 5 per cent discount rate and in Denmark and Japan at both 5 and 10 per cent discount rates. In Brazil, coal is assumed to rise in price faster than natural gas, so a constant fuel price assumption improves coals competitiveness compared to gas.

Other factors

A number of other factors have an impact on generation costs and the relative competitiveness of alternative options. It is beyond the scope of the present study to examine systematically the sensitivity of levelised generation costs to all parameters for the range of options and plants for which data were provided. This type of analysis may be carried out in an efficient and relevant manner only at the country or utility level in the process of decision-making for system expansion.

Capital cost reductions or increases may change the relative competitiveness of alternative options. Technologies such as nuclear power and renewable sources for which investment cost is the largest component of generation costs may enhance their competitiveness significantly by reducing capital costs.

The share of O&M costs in total generation costs vary widely from technology to technology and from country to country but tends to increase as investment costs and fuel prices decrease. Generally, O&M costs represent a smaller share of total generation costs in non OECD countries owing to lower cost of manpower inter alia. In OECD countries, at 5 per cent per annum discount rate, O&M costs represent around 20 per cent of total generation costs for coal and nuclear, and 10 per cent for gas. Therefore, lowering O&M costs might have a significant impact on the competitiveness of nuclear and coal versus gas especially in countries where the competitive margin of gas is rather small.

The size of generation plants has an influence on their generation costs. Both unit size and total plant size are relevant: larger unit sizes take advantage of economies of scale in equipment manufacturing and construction, while large plant sizes typically take advantage of economies of scale in providing common plant services and site infrastructure. Beyond project-level economics, the construction of a series of similar plants can lower costs through lower engineering, manufacturing, and other costs.

Gas turbines are manufactured in series and take advantage of standardised design and factory labour to reduce unit costs. The largest industrial gas turbines today are generally between 150 and 200 MWe in size. Adding a steam turbine to create a combined cycle adds another 50 per cent power output, so single units of 200 to 300 MWe are common. Using two gas turbines and one steam turbine results in 400 to 600 MWe, still based upon factory-manufactured major equipment. In contrast, large boilers firing fossil fuels must be constructed on site. This tends to result in economies of scale and typical plant sizes of 500 MWe or larger. Engineering expenses and on-site construction costs are higher and so multiplying the number of on site-units helps to reduce unit costs. Nuclear power plants have the strongest economies of scale because of heavy engineering and construction costs and the expense of certain on-site services such as safety controls, fuel and radioactive waste handling.

Estimates provided by participants show the difference in average unit and plant sizes which are considered for nuclear, coal, and gas-fired power plants. In round figures, average unit capacities for all countries are 400 MWe for gas-fired, 450 MWe for coal-fired, and 950 MWe for nuclear power plants (see Figure 1). In OECD countries, all nuclear power plant units included are larger than 1 000 MWe except for the Canadian Candu plants. At the site level, the total installed capacity shows an even greater difference in size between gas, coal, and nuclear plants. Coal plants are, on average, double the size of gas-fired installations, while nuclear installations are over four times as large.

The length of time over which costs are incurred for project development (normally closely linked to construction time) depends on plant size. Figure 17 shows that expenditures for gas-fired plants are made over four years, on average, while those of nuclear plants take about seven years.

Trends in projected generation costs

Figure 18 illustrates the evolution of projected costs of electricity generation by nuclear, coal-fired and gas-fired power plants between the 1992 study and the present study. The Figure shows levelised generation costs for coal-fired, gas-fired and nuclear power plants calculated at 5 per cent discount rate for a 30 year economic lifetime, 75 per cent settled down load factor and national fuel price assumptions, expressed in US dollars of 1 July 1996. In most countries which provided data for the two studies, projected generation costs have decreased for the three technologies. However, projected generation costs have increased in Finland for nuclear and in Denmark for gas. In the case of Denmark, gas generation costs calculated with present study assumptions at zero gas price escalation are lower than the costs reported in the 1992 study for which Denmark had assumed constant gas prices.

Projected generation cost reductions vary widely from country to country and from technology to technology. Generally, relative cost reductions between the two studies are higher for gas-fired power plants (16 to 54 per cent) than for coal-fired power plants (3 to 34 per cent) and nuclear power plants (from 2 to 27 per cent).

DISCUSSION AND CONCLUSIONS

Among the nineteen countries that provided cost estimates, eighteen reported at least one type of fossil plant, thirteen reported at least one nuclear plant, and three reported at least one renewable technology.

An analysis of the data contained in Chapter 3 indicates that fossil-fuelled power stations (i.e. fuelled by coal or gas) are projected to be the least expensive means of generating electricity in the near term for most participating countries.

Factors other than pure generating cost influence capacity additions in some countries where governments wish to influence the choice of fuel or technology used in power plants. Among these factors are regional development, public preferences or opposition to certain types of plants, security of energy supply, or environmental concerns. Governments can influence plant choices through explicit limitations, regulation of monopoly suppliers, or fiscal influences such as taxes or subsidies. The advent of market liberalisation in many countries will draw attention to existing government policies affecting choice of fuel or technology and will change the way in which policies are implemented. However, factors other than pure levelised costs will remain important in plant selection.

The report makes clear the limitations inherent in a generic calculation method, which is not meant to evaluate the precise costs that would be obtained for specific evaluations considered more appropriate in individual countries. Using more detailed evaluations, the relative rankings of technologies in each country may vary from those presented in the report.

At a 5 per cent discount rate

Of the eighteen countries reporting, at least two technology/fuel types (i.e. coal, gas, nuclear, or renewable): gas was the least expensive (by a margin of at least 10 per cent) in three countries; coal was the least expensive (by a margin of at least 10 per cent) in three countries; nuclear was the least expensive (by a margin of at least 10 per cent) in five countries. In seven countries, there was less than a 10 per cent difference between the least cost technology and its next cheapest.

At a 10 per cent discount rate

Of the eighteen countries reporting, at least two technology/fuel types (i.e. coal, gas, nuclear, or renewable): gas was the least expensive (by a margin of at least 10 per cent) in nine countries; coal was the least expensive (by a margin of at least 10 per cent) in one country; nuclear was the least expensive (by a margin of at least 10 per cent) in no country. In eight countries, there was less than a 10 per cent difference between the least cost technology and its next cheapest.

Conclusions

From these results, one observes that no single technology is the clear winner economically in all countries. Specific circumstances within each country will determine the most economic choice. However, it should be noted that, relative to the previous reports in this series, gas-fired generation has become an attractive near-term option. This is due to several factors: relatively simple, low-cost construction and maintenance, lower fuel cost projections than previously envisioned, and low environmental emissions compared to other fossil-fuelled technologies.

As mentioned, structural changes are underway in the electricity sector of many of the participating countries. Deregulation and privatisation are placing greater emphasis on competitive economics and risk minimisation. Technologies with low capital and production costs, short construction schedules, capacity increments closely matched to load growth, and minimal regulatory/public acceptance problems are generally more desirable in this type of environment. Gas-fired technologies appear to fit that description well, and as a result, are currently a favoured technology for new electric generation plants.

Costs of renewable technologies were reported by three countries. Recognising that this report specifically excluded hydro generation from consideration (owing to its site specificity), the renewable technologies reported here are hampered economically by small unit size and/or technology immaturity, relative to other generation options.

Reflecting on the costs reported in this study, and in comparison to the costs reported in the earlier reports of this series, it would appear reasonable to project that the cost of base-load electricity on the whole will be stable over the near term. The particular technology and fuel that will be utilised during this period will differ from country to country based on fuel availability and relative costs.

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Table 1. **List of responses**[1]

Country	Type of power plant [Number of units on site] Number of units included in cost estimates x Unit capacity in MWe {plant type}[2]			
	Nuclear {PWR}	Coal {Pulverised Fuel}	Gas {CCGT}	Others
Belgium	–	1 x 400	1 x 350	–
Canada	2 x 665 {PHWR}	4 x 750	2 x 750	–
	2 x 881 {PHWR}	4 x 200 {CFB}	–	–
Denmark	–	1 x 400	1 x 337	1 x 2 {CHP Gas motor}
	–	–	1 x 400 {B}	1 x 10 {Straw}
	–	–	–	20 x 0.6 {Wind on shore}
	–	–	–	100 x 1.5 {Wind offshore}
Finland	1 x 1000 {BWR}	1 x 500	2 x 350	–
France	[4] 1 x 1460[3]	[2] 1 x 572	1 x 660	–
Hungary	–	1 x 120	1 x 389	–
	–	2 x 459 {Lignite}	–	–
Italy	–	4 x 617	2 x 350	20 x 0.6 {Wind}
Japan	[4] 1 x 1303 {BWR}	[4] 1 x 930	[4] 2 x 343	–
Korea	[2] 1 x 1000[3]	[2] 1 x 500	[2] 1 x 450	–
Netherlands	–	1 x 600	[2] 1 x 250	–
	–	[2] 1 x 600[B]	[2] 1 x 350 {ACCGT}[B]	–
	–	[2] 1 x 800 {IGCC}[B]	–	–
Portugal	–	1 x 315	1 x 326	–
	–	1 x 411	1 x 459	–
Spain	1 x 1000	[2] 1 x 500	[2] 1 x 315	–
Turkey	1x 1000	[2] 1 x 500	2 x 340	[2] 1 x 150 {Fuel Oil}
	–	4 x 85 {Lignite}	–	–
United States	1 x 1300[B]	1 x 300	1 x 250	1 x 100 {Biomass}
	–	1 x 380 {IGCC}[B]	1 x 350 {ACCGT}[B]	–
	–	–	1 x 10 {Fuel cell}[B]	–
Brazil	[3] 1 x 1229	[6] 1 x 315	2 x 450	–
	1 x 1229[B]	1 x 315	1 x 450	–
China	2 x 592	2 x 600	–	–
	2 x 935	–	–	–
	2 x 665 {PHWR}	–	–	–
India	2 x 455 {PHWR}	2 x 460	–	–
Romania	[5] 1 x 707 {PHWR}	–	–	–
Russia	[5] 1 x 604 {VVER}	4 x 300	4 x 360	–

1 Power plants for which cost estimates were provided.

2 Power plants are of the type specified in the column heading unless otherwise specified.

3 Cost estimates based upon a series of 10 units in France and of 6 units in Korea.

B Power plants expected to be commercially available by 2005-2010.

Table 2. **Nuclear power plant specifications**

	Country	Abbreviated name of the plant	Reactor type/ Fuel cycle option	Net Capacity (MWe)*
A	Canada	CA-N1	PHWR/OT	2 x 665
		CA-N2	PHWR/OT	2 x 881
	Finland	FI-N	BWR/OT	1 x 1000
	France	FR-N	PWR/CC	[4] 1 x 1460
	Japan	JP-N	ABWR/CC	[4] 1 x 1303
	Korea	KR-N	PWR/OT	[2] 1 x 1000
	Spain	SP-N	PWR/OT	1 x 1000
	Turkey	TK-N	PWR/OT	1 x 1000
	Brazil	BR-N1	PWR/OT	[3] 1 x 1229
	China	CN-N1	PWR/CC	2 x 592
		CN-N2	PWR/CC	2 x 935
		CN-N3	PHWR/OT	2 x 665
	India	IN-N	PHWR/OT	2 x 455
	Romania	RO-N	PHWR/OT	[5] 1 x 707
	Russia	RU-N	VVER/OT	[5] 1 x 604
B	United States	US-N	PWR/OT	1 x 1300
	Brazil	BR-N2	PWR/OT	1 x 1229

* [number of units on the site, if more than 1] number of units included in cost estimates x unit capacity.

A: power plants commercially available.

B: power plants expected to be commercially available by 2005-2010.

Reactor Type

BWR: Boiling Water Reactor.
ABWR: Advanced Boiling Water Reactor.
PWR: Pressurised Water Reactor.
PHWR: Pressurised Heavy Water Reactor.
VVER: PWR of Russian design.

Fuel Cycle Option

OT: Once through.
CC: Closed cycle.

Table 2. **Nuclear power plant specifications**

Net thermal efficiency (%)	Cooling tower	Site	Cost estimation source/date	Country	
31.2	No	New	O/96	Canada	**A**
31.2	No	New	Q/96		
33.0	No	New	P/96	Finland	
33.0	Yes	New	Q/96	France	
33.0	No	New	P/96	Japan	
35.1	No	New	O/95	Korea	
34.0	Yes	New	P/96	Spain	
34.5	Yes	New	P/95	Turkey	
34.6	No	Existing	Q/95	Brazil	
29.6	No	New	P/96	China	
32.2	No	New	FS/96		
29.1	No	New	FS/96		
29.0	No	Existing	P&O/97	India	
31.0	No	Existing	O&P/95-97	Romania	
33.3	No	Existing	Q/96	Russia	
32.0	Yes	New	P/96	United States	**B**
35.0	No	New	P/96	Brazil	

A: Power plants commercially available.

B: Power plants expected to be commercially available by 2005-2010.

Estimation Source

O: Ordered plant.
P: Paper analysis.
Q: Quotation.
FS: Feasibility study.

Table 3. **Coal plant specifications**

	Country	Abbreviated name of the plant	Plant type/Emission control equipment	Net Capacity (MWe)*
A	Belgium	BE-C	PF/ FGD, deNOx, ESP	1 x 400
	Canada	CA-C1	PF/FGD, SCR	4 x 750
		CA-C2	CFB/FGD	4 x 200
	Denmark	DE-C	PF(SC)/FGD, deNOx, ESP	1 x 400
	Finland	FI-C	PF/FGD, SCR	1 x 500
	France	FR-C	PF(SC)/FGD, SCR, ESP	[2] 1 x 572
	Hungary	HN-C1	PF	1 x 120
		HN-C2	PF, Lignite/FGD	2 x 459
	Italy	IT-C	PF(SC)/FGD, SCR, ESP	4 x 617
	Japan	JP-C	PF/FGD, deNOx, dust	[4] 1 x 930
	Korea	KR-C	PF(SC)/FGD, SCR	[2] 1 x 500
	Netherlands	NL-C1	PF/FGD, SCR	1 x 600
	Portugal	PT-C1	PF/FGD, SCR, ESP	1 x 315
		PT-C2	PF/FGD, SCR, ESP	1 x 411
	Spain	SP-C	PF/FGD, LNB, ESP	[2] 1 x 500
	Turkey	TK-C1	PF/FGD, deNOx, dust	[2] 1 x 500
		TK-C2	PF, Lignite/FGD, deNOx, dust	4 x 85
	United States	US-C1	PF/FGD, LNB, ESP	1 x 300
	Brazil	BR-C1	PF/ESP	[6] 1 x 315
		BR-C2	PF/ESP	1 x 315
	China	CN-C	PF (SC)/FGD, ESP	2 x 600
	India	IN-C	PF/ESP	2 x 460
	Russia	RU-C	PF/FGD	4 x 300
B	Netherlands	NL-C2	PF(SC)/FGD, SCR	[2] 1 x 600
		NL-C3	IGCC/FGD, deNOx	[2] 1 x 800
	United States	US-C2	IGCC/LNB, ESP	1 x 380

* [number of units on the site, if more than 1] number of units included in cost estimates x unit capacity

A: Power plants commercially available.
B: Power plants expected to be commercially available by 2005-2010.

Coal Combustion Systems
PF: Pulverised coal combustion.
CFB: Circulating fluidised bed.
IGCC: Integrated gasification combined cycle.

Steam Cycle
(SC): Supercritical.

Pollution Control Systems
FGD: Flue gas desulphurisation.
LNB: Low NOx burners.
SCR: Selective catalytic reduction (deNOx).
deNOx: Unspecified NOx control system.
ESP: Electrostatic precipitator.
dust: Unspecified particulate control system.

Table 3. **Coal plant specifications**

Net thermal efficiency [LHV] (%)	Cooling tower	Site	Cost estimation source/date	Country	
43.17	No	Existing	P/95	Belgium	**A**
38.6	No	New	P/97	Canada	
33	No	New	P/97		
47.5	No	Existing	Q/97	Denmark	
42	No	New	O/96	Finland	
42	Yes	Existing	Q/96	France	
41.5	Yes	Existing	FS/97	Hungary	
38.61	Yes	New	P/96		
44	No	New	P/96	Italy	
42**	No	New	P/96	Japan	
41	No	New	O/95	Korea	
45	No	Existing	O	Netherlands	
39.92	No	New	P/97	Portugal	
41.65	No	New	P/97		
36.7	Yes	Existing	PrE/96	Spain	
37	Yes	New	P/95	Turkey	
34	Yes	Existing	Q/95		
40	Yes	New	P/96	United States	
33	Yes	New	P/95	Brazil	
35	No	New	P/95		
39	No	New	P/96	China	
34	Yes	New	P/96	India	
38	No	New	P/96	Russia	
47	No	Existing	P	Netherlands	**B**
47	No	Existing	P		
49	NS	New	P/96	United States	

** HHV

Cost Estimation Source

O: Ordered plant.
P: Paper analysis.
Q: Quotation.
FS: Feasibility study.
Pr E: Previous experience.

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

	Country	Abbreviated name of the plant	Technology/ Emission control equipment	Net Capacity (MWe)*
			GAZ	
A	Belgium	BE-G	CCGT/LNB	1 x 350
	Canada	CA-G	CCGT	2 x 750
	Denmark	DE-G1	CCGT/deNOx	1 x 337
		DE-G2	B (SC)/deNOx	1 x 400
	Finland	FI-G	CCGT	2 x 350
	France	FR-G	CCGT/LNB	1 x 660
	Hungary	HN-G	CCGT	1 x 389
	Italy	IT-G	CCGT/LNB	2 x 350
	Japan	JP-G	CCGT, LNG/deNOx	[4] 2 x 350
	Korea	KR-G	CCGT, LNG/LNB	[2] 1 x 450
	Netherlands	NL-G1	CCGT	[2] 1 x 250
	Portugal	PT-G1	CCGT/LNB	1 x 326
		PT-G2	CCGT/LNB	1 x 459
	Spain	SP-G	CCGT/LNB	[2] 1 x 315
	Turkey	TK-G	CCGT/deNOx	2 x 680
	United States	US-G1	CCGT/SCR	1 x 250
	Brazil	BR-G1	CCGT	2 x 450
		BR-G2	CCGT	1 x 450
	Russia	RU-G	CCGT	4 x 360
B	Netherlands	NL-G2	CCGT	[2] 1 x 350
	United States	US-G2	ACCGT/SCR	1 x 350
		US-FC	Fuel cell/LNB, ESP	1 x 10

A	Denmark	DE-CHP	CHP - gas motor	1 x 2
		DE-ST	Straw-fired steam turbine	1 x 10
		DE-W1	Wind turbines on land	20 x 0.6
		DE-W2	Wind turbines off shore	100 x 1.5
	Italy	IT-W	Wind turbines on land	20 x 0.6
	Turkey	TK-FO	B, Fuel oil/deSOx, deNOx	2 x 150
	United States	US-BIO	Biomass	1 x 100

* [number of units on the site, if more than 1] number of units included in cost estimates x unit capacity

A: Power plants commercially available.
B: Power plants expected to be commercially available by 2005-2010.

Pollution Control Systems

FGD: Flue gas desulphurisation.
LNB: Low NOx burners.
SCR: Selective catalytic reduction (deNOx).
deNOx: Unspecified NOx control system.

Gas Combustion Systems

B: Boiler.
CCGT: Combined cycle gas turbine.
GM: Gas motor.
ACCGT: Advanced CCGT.
LNG: Liquefied natural gas fuel.
CHP: Combined heat and power system.

Steam Cycle

(SC): Supercritical.

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

Thermal efficiency [LHV] (%)	Number of turbines per unit	Cooling tower	Site	Cost estimation source/date	Country	
GAS						
52.6	1	No	Existing	P/95	Belgium	**A**
45	3 GT + 1 ST	No	New	P/97	Canada	
57	1	No	New	P/97	Denmark	
50	1	No	Existing	O/97		
56**	1	No	New	P/96	Finland	
52	2 GT + 1 ST	Yes	Existing	Q/96	France	
48.7	2 GT + 1 ST	No	Existing	FS/97	Hungary	
53	2	Yes	New	P/96	Italy	
48***	2	No	New	P/96	Japan	
53.1	2 GT + 1 ST	No	New	O/95	Korea	
54	1	No	Existing	O	Netherlands	
52.3	1	No	New	P/97	Portugal	
51.5	1	No	New	P/97		
51	1 GT + 1 ST	Yes	Existing	P	Spain	
54	3	No	New	Q/95	Turkey	
50	1	NS	New	P/96	USA	
50	1	No	New	P/95	Brazil	
50	1	No	New	P/95		
56	1	NS	New	P/96	Russia	
60	1	No	Existing	P	Netherlands	**B**
60	1	NS	New	P/96	USA	
58	1	NS	New	P/96		
OTHERS						
41	1	No	New	Q/97	Denmark	**A**
25	1	No	New	Q/97		
100	1	No	New	Q/97		
100	1	No	New	P/97		
100	1	No	New	P/96	Italy	
39	NS	NS	New	Q/95	Turkey	
NS	1	NS	New	P/96	USA	

NS: Not specified.

** Peak at 5°C.

*** HHV.

GT: Gas Turbine.
ST: Steam Turbine.

Cost Estimation Source:

O: Ordered plant.
P: Paper analysis.
Q: Quotation.
FS: Feasibility study.

Table 5. **Assumptions adopted in national cost estimates**

Country	Abbreviated name of the plant	Discount rate (% p.a.)	Settled down load factor (%)	Economic lifetime (years)	Remarks
Belgium	All plants	8.6	62.7	20	
Canada	CA-N1/N2	5	85	40	
Denmark	DE-C/G1/G2	5	75	30	
	DE-W1	5	25	20	
	DE-W2	5	35	20	
	DE-ST	5	65	20	
	DE-CHP	5	65	20	
Finland		–	–	–	Not provided.
France	FR-C	8	90.2	30	Fuel prices calculated for 1 US$ = 5.75 FF.
	FR-G	8	90.2	25	
	FR-N	8	85.5	30	
Hungary	HN-C1	8	75	30	
	HN-C2	8	75	30	
	HN-G	8	75	20	
Italy	IT-C/G	12	68.5	25	
	IT/W	12	23	20	
Japan	JP-C/N	5 & 10	75	40	National levelised cost calculation method.
	JP-G	5 & 10	75	20	
Korea	KR-C/N	8.5	75	25	
	KR-G	8.5	75	20	
Netherlands	All plants	5	75	40	
Portugal	PT-C1/C2	8	82	30	Total generating costs include coal stock costs.
	PT-G1/G2	8	88	25	
Spain	SP-C/N	5 & 10	85	30	
	SP-G	5 & 10	85	25	
Turkey	TK-N	8	80	30	
	TK-C1/FO	8	75	30	
	TK-C2	8	75	25	
United States	All plants	5	75	40	Levelised costs for the Eastern and Western regions are given in Annex 2.
Brazil	All plants	10	80	25	
China	CN-C/N1/N2	10	70	25	
	CN-N3	10	80	25	
India	IN-C/N	10	68.5	25	Credit for heavy water inventory deducted from decommissioning cost.
Romania		–	–	–	Not provided.
Russia		–	–	–	Not provided.

Table 6. **Exchange rates**

Country	National Currency Unit (NCU)		NCU per US$ at 1st July 1996
Belgium	Franc	(BEF)	31.331
Canada	Dollar	(CAD)	1.3651
Denmark	Krone	(DKK)	5.8699
Finland	Markka	(FIM)	4.6439
France	Franc	(FRF)	5.1526
Hungary	Forints	(HUF)	153.05
Italy	Lira	(ITL)	1534.5
Japan	Yen	(JPY)	109.42
Korea	Won	(KRW)	810.64
Netherlands	Gulden	(NLG)	1.7082
Portugal	Escudo	(PTE)	156.65
Spain	Peseta	(ESP)	128.21
Turkey	Lira	(TKL)	81487
United States	Dollar	(USD)	1
Brazil	Real	(BRR)	1.0046
China	Yuan	(CHY)	8.3223
India	Rupee	(INR)	35.061
Romania	Leu	(ROL)	3028.1
Russia	Rouble	(RFR)	5108.4

Source: IMF, International Financial Statistics (September 1996)

Table 7. **Nuclear power plant investment costs discounted**

	Country	Abbreviated name of the plant	Reactor type	Base construction cost	5% Discount rate		
					Contingency	Interest during construction	Major refurbishment
A	Canada	CA-N1	PHWR	1697	85	271	75
		CA-N2	PHWR	1518	76	208	67
	Finland*	FI-N	BWR	2256	113	148	0
	France	FR-N	PWR	1636	49	274	0
	Japan	JP-N	ABWR	2521	0	289	0
	Korea*	KR-N	PWR	1637	0	287	0
	Spain	SP-N	PWR	2169	0	364	0
	Turkey	TK-N	PWR	1968	55	252	0
	Brazil	BR-N1	PWR	1550	155	248	292
	China	CN-N1	PWR	1020	85	262	0
		CN-N2	PWR	1458	76	399	0
		CN-N3	PHWR	1353	112	320	0
	India**	IN-N	PHWR	1840	54	231	47
	Romania	RO-N	PHWR	1557	0	244	0
	Russia	RU-N	VVER	1521	350	271	0
B	United States	US-N	PWR	1441	144	151	271
	Brazil	BR-N2	PWR	1530	153	196	289

* Decommissioning costs are included in O&M.
** Contingency minus credit for heavy water inventory.

to the date of commissioning (US$ of 1st July 1996/kWe)

5% Discount rate		10% Discount rate						
Decom-missioning	Total	Contingency	Interest during construction	Major refurbishment	Decom-missioning	Total	Country	
11	2139	85	577	24	1	2384	Canada	**A**
10	1878	76	438	21	1	2053		
0	2516	113	303	0	0	2672	Finland*	
29	1988	49	592	0	3	2280	France	
38	2848	0	621	0	4	3146	Japan	
0	1924	0	623	0	0	2260	Korea*	
7	2540	0	787	0	1	2957	Spain	
0	2274	55	529	0	0	2552	Turkey	
30	2275	155	527	122	5	2359	Brazil	
18	1386	85	584	0	3	1692	China	
26	1959	76	894	0	4	2432		
23	1809	112	702	0	4	2171		
19	2191	86	514	14	3	2457	India**	
0	1801	0	525	0	0	2082	Romania	
13	2155	350	575	0	2	2448	Russia	
72	2079	144	310	158	11	2065	United States	**B**
30	2197	153	411	121	5	2219	Brazil	

A: Power plants commercially available.
B: Power plants expected to be commercially available by 2005-2010.

Table 8. **Coal-fired power plant investment costs discounted**

	Country	Abbreviated name of the plant	Plant type/ Emission control equipment*	Base construction cost	5% Discount rate	
					Contingency	Interest during construction
A	Belgium	BE-C	PF/ FGD, deNOx, ESP	1386	0	136
	Canada	CA-C1	PF/FGD, SCR	837	42	94
		CA-C2	CFB/FGD, deNOx	1360	68	153
	Denmark	DE-C	PF(SC)/FGD, deNOx, ESP	1329	0	118
	Finland	FI-C	PF/FGD, SCR	885	44	54
	France	FR-C	PF(SC)/FGD, SCR, ESP	1346	67	170
	Hungary	HN-C1	PF/FDG	1227	61	25
		HN-C2	PF, Lignite/FGD	1318	0	98
	Italy	IT-C	PF(SC)/FGD, SCR, ESP	1173	0	142
	Japan	JP-C	PF/FGD, deNOx, dust	2561	0	178
	Korea	KR-C	PF(SC)/FGD, SCR	1174	0	126
	Netherlands	NL-C1	PF/FGD, SCR	1254	63	148
	Portugal	PT-C1	PF/FGD, SCR, ESP	1999	80	209
		PT-C2	PF/FGD, SCR, ESP	1902	76	198
	Spain	SP-C	NS/FGD, LNB, ESP	1326	0	164
	Turkey	TK-C1	PF/FGD, deNOx, dust	1019	28	89
		TK-C2	PF, Lignite/FGD, deNOx, dust	1476	0	164
	United States	US-C1	PF/FGD, LNB, ESP	1009	75	103
	Brazil	BR-C1	PF/ESP	1258	126	50
		BR-C2	PF/ESP	1094	109	43
	China	CN-C	PF(SC)/FGD, ESP	772	64	130
	India	IN-C	PF/ESP	935	28	39
	Russia	RU-C	PF/FGD	1291	0	148
B	Netherlands	NL-C2	PF(SC)/FGD, SCR	1450	72	171
		NL-C3	IGCC/FGD, deNOx	1553	78	183
	United States	US-C2	IGCC/LNB, ESP	1154	83	118

A: Power plants commercially available.
B: Power plants expected to be commercially available by 2005-2010.

Coal Combustion Systems
PF: Pulverised coal combustion.
CFB: Circulating fluidised bed.
IGCC: Integrated gasification combined cycle.

Steam Cycle
(SC): Supercritical.

Pollution Control Systems
FGD: Flue gas desulphurisation.
LNB: Low NOx burners.
SCR: Selective catalytic reduction (deNOx).
deNOx: Unspecified NOx control system.
ESP: Electrostatic precipitator.
dust: Unspecified particulate control system.

NS: Not specified.

to the date of commissioning (US$ of 1.7.1996/kWe)

5% Discount rate			10% Discount rate							
Major refurbishment	Decommis-sioning	Total	Contingency	Interest during construction	Major refurbishment	Decommis-sioning	Total	Country	
0	0	1523	0	285	0	0	1671	Belgium	**A**
160	0	1133	42	196	89	0	1164	Canada	
222	0	1804	68	319	124	0	1872		
0	0	1447	0	246	0	0	1574	Denmark	
0	0	983	44	110	0	0	1039	Finland	
0	0	1584	67	357	0	0	1770	France	
0	0	1313	61	51	0	0	1339	Hungary	
0	3	1419	0	205	0	0	1523		
51	0	1365	0	302	15	0	1490	Italy	
0	0	2739	0	369	0	0	2930	Japan	
0	0	1300	0	264	0	0	1438	Korea	
24	5	1494	63	312	5	1	1635	Netherlands	
0	0	2288	80	434	0	0	2513	Portugal	
0	0	2176	76	413	0	0	2391		
0	0	1490	0	345	0	0	1671	Spain	
0	0	1137	28	183	0	0	1231	Turkey	
0	0	1641	0	342	0	0	1819		
90	0	1277	75	212	52	0	1348	United States	
302	0	1735	126	101	105	0	1589	Brazil	
262	0	1509	109	87	91	0	1381		
0	0	966	64	278	0	0	1114	China	
0	0	1002	28	85	0	0	1048	India	
0	0	1439	0	310	0	0	1601	Russia	
24	5	1722	72	360	5	1	1888	Netherlands	**B**
24	5	1842	78	386	5	1	2022		
90	0	1445	83	242	52	0	1532	United States	

Table 9. **Gas-fired and other power plant investment costs discounted**

	Country	Abbreviated name of the plant	Technology/Emission control equipment*	Base construction cost	5% Discount rate Contingency	Interest during construction	Major refurbishment
			GAS				
A	Belgium	BE-G	CCGT/LNB	761	0	59	0
	Canada	CA-G	CCGT	536	27	35	154
	Denmark	DE-G1	CCGT/deNOx	809	0	78	0
		DE-G2	B(SC)/deNOx	885	0	34	0
	Finland	FI-G	CCGT	622	31	36	0
	France	FR-G	CCGT/LNB	739	37	51	95
	Hungary	HN-G	CCGT	595	60	53	0
	Italy	IT-G	CCGT/LNB	652	0	39	0
	Japan	JP-G	CCGT, LNG/deNOx	1640	0	63	0
	Korea	KR-G	CCGT, LNG	583	0	35	43
	Netherlands	NL-G1	CCGT	725	36	66	40
	Portugal	PT-G1	CCGT/LNB	790	32	53	0
		PT-G2	CCGT/LNB	697	28	46	0
	Spain	SP-G	CCGT/LNB	663	0	90	0
	Turkey	TK-G	CCGT/deNOx	402	11	27	0
	United States	US-G1	CCGT/SCR	422	22	22	36
	Brazil	BR-G1	CCGT	677	68	15	242
		BR-G2	CCGT	766	77	31	261
	Russia	RU-G	CCGT	721	0	61	0
B	Netherlands	NL-G2	CCGT	664	35	61	40
	United States	US-G2	ACCGT/SCR	419	33	0	0
		US-FC	Fuel cell/LNB, ESP	1408	70	104	36
			OTHERS				
A	Denmark	DE-CHP	CHP - gas motor	937	0	90	0
		DE-ST	Straw-fired steam turbine	3407	0	326	0
		DE-W1	Wind turbines on land	998	0	0	0
		DE-W2	Wind turbines off shore	1945	0	0	0
	Italy	IT-W	Wind turbines on land	1173	0	12	447
	Turkey	TK-FO	B, Fuel oil/deSOx, deNOx	1141	32	127	0
	United States	US-BIO	Biomass	1342	97	137	36

A: Power plants commercially available.

B: Power plants expected to be commercially available by 2005-2010.

Pollution Control Systems

FGD: Flue gas desulphurisation.
LNB: Low NOx burners.
SCR: Selective catalytic reduction (deNOx).
deNOx: Unspecified NOx control system.

Gas Combustion Systems

B: Boiler.
CCGT: Combined cycle gas turbine.
GM: Gas motor.
ACCGT: Advanced CCGT.
LNG: Liquefied natural gas fuel.
CHP: Combined heat and power system.

Steam Cycle

(SC): Supercritical.

to the date of commissioning (US$ of 1.7.1996/kWe)

5% Discount rate		10% Discount rate						
Decommis-sioning	Total	Contingency	Interest during construction	Major refurbishment	Decommis-sioning	Total	Country	
GAS								
0	820	0	123	0	0	884	Belgium	**A**
0	752	27	72	98	0	733	Canada	
0	887	0	162	0	0	971	Denmark	
0	920	0	71	0	0	957		
0	689	31	74	0	0	727	Finland	
0	923	37	105	38	0	918	France	
0	708	60	108	0	0	762	Hungary	
0	691	0	80	0	0	732	Italy	
0	1703	0	132	0	0	1771	Japan	
0	661	0	72	17	0	671	Korea	
3	871	36	137	10	1	909	Netherlands	
0	875	32	108	0	0	930	Portugal	
0	771	28	95	0	0	820		
0	753	0	191	0	0	854	Spain	
0	440	11	55	0	0	468	Turkey	
0	502	22	45	21	0	509	United States	
0	1001	68	31	86	0	861	Brazil	
0	1134	77	63	95	0	1001		
0	782	0	126	0	0	847	Russia	
3	804	35	126	10	1	836	Netherlands	**B**
0	452	33	1	0	0	453	United States	
0	1618	70	211	21	0	1710		
OTHERS								
0	1027	0	90	0	0	1027	Denmark	**A**
0	3734	0	680	0	0	4087		
0	998	0	0	0	0	975		
0	1945	0	0	0	0	1900		
0	1631	0	24	178	0	1375	Italy	
0	1300	32	263	0	0	1436	Turkey	
0	1612	97	282	21	0	1742	United States	

Table 10. **Construction cost/expense schedule**

Nuclear

Year	Abbreviated name of the plant								
	CA-N1	CA-N2	FI-N	FR-N	JP-N	KR-N	SP-N	TK-N	US-N[B]
-10									
-9									
-8				2.0	1.0	2.5			
-7				2.0	2.0	3.3	5.0		
-6	1.1			7.9	3.2	9.5	11.0	2.4	
-5	6.1	1.9	2.2	16.7	9.8	15.0	16.0	6.1	
-4	13.2	9.7	5.0	21.7	17.7	24.3	18.0	19.1	1.5
-3	22.3	20.2	11.2	19.7	18.2	20.5	19.0	33.7	39.0
-2	28.2	30.9	25.2	14.8	16.3	17.7	20.0	25.9	53.2
-1	21.7	27.3	56.4	9.8	15.5	5.8	11.0	12.8	6.3
0	7.3	10.0		5.5	16.3	1.4			
1									
2									

Coal

Year	Abbreviated name of the plant										
	BE-C	CA-C1/2	DE-C	FI-C	FR-C	HN-C1	HN-C2	IT-C	JP-C	KR-C	NL-C1/2/3
-7											
-6			2.0		1.0			5.0		1.4	3.0
-5	5.0	3.1	3.0		4.0		3.0	11.0	0.5	4.2	5.0
-4	18.0	16.1	11.0	5.0	23.0		10.0	19.0	2.5	16.7	20.0
-3	22.0	30.8	16.0	11.5	34.0	1.7	20.0	20.0	8.7	25.9	22.0
-2	25.0	34.1	38.0	25.7	25.0	21.7	25.0	20.0	12.6	31.9	25.0
-1	25.0	15.9	26.0	57.8	10.0	39.6	30.0	17.0	31.7	17.7	25.0
0	5.0		3.0		3.0	37.0	10.0	8.0	32.2	2.2	
1			1.0				2.0		11.8		
2											

Gas

Year	Abbreviated name of the plant									
	BE-G	CA-G	DE-G1	DE-G2	FI-G	FR-G	HN-G	IT-G	JP-G	KR-G
-7										
-6										
-5			6.0						1.0	
-4	15.0		10.0	5.7	3.1	2.0			3.0	1.6
-3	20.0	12.0	26.0	13.6	11.7	20.0	15.1	20.0	13.1	11.4
-2	25.0	50.0	31.0	13.6	26.2	37.0	78.9	34.0	20.2	46.1
-1	30.0	38.1	24.0	34.1	59.0	37.0	6.1	40.0	28.3	36.7
0	10.0		3.0	31.8		4.0		6.0	35.3	4.2
1				1.1						
2										

Others

Year	Abbreviated name of the plant			
	DE-CHP/ST	DE-W	IT-W	US-BIO
-7				
-6				
-5	6.0			
-4	10.0			15.0
-3	26.0			39.0
-2	31.0			53.2
-1	24.0		69.9	6.3
0	3.0	100.0	30.1	
1				
2				

B Power plants expected to be commercially available by 2005-2010.

(% of total overnight cost by year)

Nuclear

Abbreviated name of the plant								Year
BR-N1	CN-N1	CN-N2	CN-N3	IN-N	RO-N	RU-N	BR-N2[B]	
								-10
	3.0	2.5		0.6				-9
	6.0	6.7	3.0	2.3				-8
	10.0	15.8	8.0	7.0				-7
6.1	15.0	18.9	17.0	11.0	9.1	4.2	1.5	-6
12.7	19.0	19.9	20.0	12.7	27.3	14.4	5.5	-5
22.9	20.0	17.5	27.0	13.7	18.2	24.4	18.5	-4
28.2	16.0	11.5	12.0	13.0	9.1	24.4	34.0	-3
19.4	9.0	5.3	9.0	10.6	13.6	22.4	23.0	-2
8.3	2.0	1.9	4.0	7.1	22.7	10.2	13.0	-1
2.4				12.2			4.5	0
				9.8				1
								2

Coal

Abbreviated name of the plant										Year
PT-C1/2	SP-C	TK-C1	TK-C2	US-C1/2	BR-C1	BR-C2	CN-C	IN-C	RU-C	
										-7
	2.0						5.0	0.2		-6
	10.0		3.7				18.0	6.6		-5
18.5	20.0	5.2	15.1	1.5	1.0		24.0	11.2	30.0	-4
31.7	26.0	26.2	34.2	39.0	6.5	7.5	25.0	14.3	30.0	-3
31.2	27.0	48.2	35.5	53.2	18.5	20.0	24.0	20.2	25.0	-2
11.3	10.0	20.4	11.5	6.3	60.0	57.5	4.0	22.2	10.0	-1
7.3	5.0				14.0	15.0		15.2	5.0	0
								10.2		1
										2

Gas

Abbreviated name of the plant										Year
NL-G1	PT-G1/2	SP-G	TK-G	US-G	BR-G1	BR-G2	RU-G	NL-G2[B]	US-FC[B]	
										-7
		5.0								-6
2.5		15.0						2.6		-5
8.0		20.0						7.4		-4
23.7	25.0	20.0	9.8			7.5	45.0	23.9		-3
37.5	35.1	25.0	58.7	50.0	20.0	27.5	35.0	37.8	7.0	-2
28.3	30.0	10.0	31.5	50.0	50.0	45.0	10.0	28.2	75.0	-1
	9.9	5.0			30.0	20.0	10.0		18.0	0
										1
										2

B Power plants expected to be commercially available by 2005-2010.

Table 11. **Projected O&M costs in 2005 (US$ of 1.7.1996/kWe net capacity per year)**

Country	Nuclear		Coal		Gas		Others	
	Abbreviated name of the plant	O&M costs	Abbreviated name of the plant	O&M costs	Abbreviated name of the plant	O&M costs	Abbreviated name of the plant	O&M costs
Belgium			BE-C	66.80	BE-G	45.32		
Canada	CA-N1	54.94	CA-C1	26.01	CN-G	13.04		
	CA-N2	38.82	CA-C2	50.55				
Denmark			DE-C	43.87	DE-G1	27.80	DE-CHP	85.18
					DE-G2	37.05	DE-ST	136.29
							DE-W1	14.20
							DE-W2	42.42
Finland	FI-N	51.68	FI-C	57.71	FI-G	70.63		
France	FR-N	44.06	FR-C	64.43	FR-G	28.53		
Hungary			HN-C1	58.35	HN-G [6]	21.17		
			HN-C2	37.73				
Italy			IT-C	39.75	IT-G	16.94	IT-W	16.29
Japan	JP-N	109.50	JP-C	81.33	JP-G	51.11		
Korea	KR-N	62.44	KR-C	53.13	KR-G	21.80		
Netherlands			NL-C1	53.35	NL-G1	24.59		
			NL-C2[B]	53.35	NL-G2[B]	23.71		
			NL-C3[B]	54.51				
Portugal			PT-C1	74.76	PT-G1	16.10		
			PT-C2	73.85	PT-G2	15.04		
Spain	SP-N	52.95	SP-C	39.72	SP-G	31.37		
Turkey	TK-N	55.21	TK-C1	58.13	TK-G	6.07	TK-FO	26.70
			TK-C2	49.18				
United States	US-N[B]	57.63	US-C1	33.50	US-G1	18.09	US-BIO	46.24
			US-C2[B]	32.84	US-G2[B]	17.42		
					US-FC[B]	27.48		
Brazil	BR-N1 [1]	42.76	BR-C1 [4]	17.50	BR-G1 [7]	8.39		
	BR-N2[B] [2]	40.62	BR-C2 [4]	17.69	BR-G2 [7]	8.62		
China	CN-N1	37.01	CN-C	36.05				
	CN-N2	37.97						
	CN-N3 [3]	57.56						
India	IN-N	39.50	IN-C1/C2	27.89				
Romania	RO-N	75.05						
Russia	RU-N	28.92	RU-C [5]	32.99	RU-G [8]	20.09		

B Power plants expected to be commercially available by 2005-2010.

Notes:

[1] Growing to 72.15 US$ per kWe per year in 2045.
[2] Growing to 68.53 US$per kWe per year in 2045.
[3] Decreasing to 40.61 US$ per kWe per year in 2025; constant thereafter.
[4] Growing to 31.99 US$ per kWe per year in 2045.
[5] Growing to 56.42 US$ per kWe per year in 2015; constant thereafter.
[6] Growing to 26.56 US$ per kWe per year in 2045.
[7] Growing to 12.06 US$ per kWe per year in 2045.
[8] Growing to 29.84 US$ per kWe per year in 2015; constant thereafter.

Table 12. **Projected fuel prices (Nuclear)**

Country		Uranium and fuel cycle service prices								
		1996			2005			2015		
		Uranium (US$/kg)	Enrichment (US$/SWU)	Fabrication (US$/kgHM)	Uranium (US$/kg)	Enrichment (US$/SWU)	Fabrication (US$/kgHM)	Uranium (US$/kg)	Enrichment (US$/SWU)	Fabrication (US$/kgHM)
Canada	CA-N	41.8	NA	44.7	41.8	NA	44.7	41.8	NA	44.7
Finland	FI-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
France	FR-N	65.2	97.0	388.2	65.2	97.0	388.2	65.2	97.0	388.2
Japan	JP-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
Korea	KR-N	44.8	121.8	286.3	44.8	121.8	286.3	44.8	121.8	286.3
Spain*	SP-N	1559.9		351.0	1559.9		351.0	1559.9		351.0
Turkey	TK-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
United States	US-N	40.6	92.7	257.0	43.1	102.5	258.0	43.1	101.5	258.0
Brazil	BR-N1	43.9	179.2	199.1	46.3	180.2	199.9	51.3	181.2	200.8
	BR-N2	43.9	142.3	158.0	46.3	147.3	166.7	51.3	151.3	174.2
China	CN-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
India	IN-N	116.9	NA	168.3	116.9	NA	168.3	116.9	NA	168.3
Romania	RO-N	NS	NA	NS	155.0	NA	235.1	157.3	NA	237.5
Russia	RU-N	NS	NS	NS	NS	NS	NS	NS	NS	NS

Country		Uranium and fuel cycle service prices								
		2025			2035			2045		
		Uranium (US$/kg)	Enrichment (US$/SWU)	Fabrication (US$/kgHM)	Uranium (US$/kg)	Enrichment (US$/SWU)	Fabrication (US$/kgHM)	Uranium (US$/kg)	Enrichment (US$/SWU)	Fabrication (US$/kgHM)
Canada	CA-N	41.8	NA	44.7	41.8	NA	44.7	41.8	NA	44.7
Finland	FI-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
France	FR-N	65.2	97.0	388.2	65.2	97.0	388.2	65.2	97.0	388.2
Japan	JP-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
Korea	KR-N	44.8	121.8	286.3	44.8	121.8	286.3	44.8	121.8	286.3
Spain*	SP-N	1559.9		351.0	1559.9		351.0	1559.9		351.0
Turkey	TK-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
United States	US-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
Brazil	BR-N1	52.5	181.2	201.2	53.1	183.2	201.6	53.8	183.2	202.4
	BR-N2	52.5	154.3	179.5	53.1	155.3	182.1	53.8	156.3	184.0
China	CN-N	NS	NS	NS	NS	NS	NS	NS	NS	NS
India	IN-N	116.9	NA	168.3	116.9	NA	168.3	116.9	NA	168.3
Romania	RO-N	159.7	NA	239.9	162.1	NA	242.3	164.5	NA	244.7
Russia	RU-N	NS	NS	NS	NS	NS	NS	NS	NS	NS

* Total projected cost of enriched uranium in US$/kg.
NA Not applicable.
NS Not specified.
US$ US$ of 1 July 1996.

Table 13. **Projected coal prices (US$ of 1.7.1996/Gjoule)**

	Country	Abbreviated name of the plant	1996		2005		2015		2025		2035		2045	
			M	P	M	P	M	P	M	P	M	P	M	P
	Belgium	BE-C	1.72	2.00	1.72	2.00	1.72	2.00	1.72	2.00	1.72	2.00	1.72	2.00
	Canada	CA-C1/C2	NS	1.64	NS	1.64	NS	1.64	NS	1.64	NS	1.64	NS	1.64
↗	Denmark	DE-C	NS	1.86	NS	2.40	NS	2.40	NS	2.40	NS	2.40	NS	2.40
	Finland	FI-C	NS	1.67	NS	1.67	NS	1.67	NS	1.67	NS	1.67	NS	1.67
	France	FR-C	1.93	2.64	1.93	2.64	1.93	2.64	1.93	2.64	1.93	2.64	1.93	2.64
	Hungary	HN-C1	NS	2.06	NS	2.06	NS	2.06	NS	2.06	NS	2.06	NS	2.06
		HN-C2*	NS	1.78	NS	1.78	NS	1.78	NS	1.78	NS	1.78	NS	1.78
↗	Italy	IT-C	2.02	2.54	2.26	2.78	2.47	2.99	2.50	3.02	2.53	3.05	2.53	3.05
↗	Japan	JP-C	1.89	2.05	1.97	2.13	2.07	2.22	2.16	2.31	2.27	2.42	2.37	2.52
	Korea	KR-C	NS	1.69	NS	1.69	NS	1.69	NS	1.69	NS	1.69	NS	1.69
↗	Netherlands	NL-C1/C2/C3	NS	2.68	NS	2.78	NS	3.00	NS	3.00	NS	3.00	NS	3.00
↗	Portugal	PT-C1/C2	1.75	2.01	1.83	2.09	1.92	2.18	2.02	2.28	2.12	2.38	2.23	2.49
	Spain	SP-C	NS	2.36	NS	2.36	NS	2.36	NS	2.36	NS	2.36	NS	2.36
	Turkey	TK-C1	NS	2.15	NS	2.15	NS	2.15	NS	2.15	NS	2.15	NS	2.15
		TK-C2*	NS	3.26	NS	3.26	NS	3.26	NS	3.26	NS	3.26	NS	3.26
↘	United States	US-C1/C2	NS	1.06	NS	1.06	NS	0.99	NS	0.92	NS	0.86	NS	0.80
↗	Brazil	BR-C1	1.06	1.14	1.18	1.28	1.35	1.46	1.53	1.66	1.75	1.90	1.99	2.16
		BR-C2	2.73	2.87	3.07	3.23	3.49	3.66	3.98	4.17	4.53	4.75	5.16	5.42
↗	China	CN-C	NS	1.67	NS	1.80	NS	1.89	NS	1.99	NS	2.09	NS	2.20
	India	IN-C/F1	0.66	1.88	0.66	1.88	0.66	1.88	0.66	1.88	0.66	1.88	0.66	1.88
		IN-C/F2	1.05	2.27	1.05	2.27	1.05	2.27	1.05	2.27	1.05	2.27	1.05	2.27
↗	Russia	RU-C	NS	1.18	NS	2.01	NS	2.50	NS	3.05	NS	3.72	NS	4.53

↗ Coal prices projected to increase.
↘ Coal prices projected to decrease.

* Domestic lignite.

M: At the mine or national border.
P: At the power plant.

NS: Not specified.

Table 14. **Projected gas prices (US$ of 1.7.1996/Gjoule)**

	Country	Abbreviated name of the plant	1996		2005		2015		2025		2035		2045	
			M	P	M	P	M	P	M	P	M	P	M	P
	Belgium	BE-G	NS	3.19	NS	3.19	NS	3.19	NS	3.19	NS	3.19	NS	3.19
↗	Canada	CA-G	NS	1.81	NS	2.05	NS	2.53	NS	2.94	NS	3.44	NS	3.96
↗	Denmark	DE-G1/G2/CHP	NS	3.06	NS	5.20	NS	5.20	NS	5.20	NS	5.20	NS	5.20
	Finland	FI-G	NS	2.96	NS	2.96	NS	2.96	NS	2.96	NS	2.96	NS	2.96
	France	FR-G	3.95	5.05	3.95	5.05	3.95	5.05	3.95	5.05	3.95	5.05	3.95	5.05
↗	Hungary	HN-G	NS	3.04	NS	3.42	NS	3.42	NS	3.42	NS	3.42	NS	3.42
↗	Italy	IT-G	NS	4.05	NS	5.35	NS	5.62	NS	5.62	NS	5.62	NS	5.62
↗	Japan	JP-G	3.73	3.90	4.78	4.95	6.31	6.48	8.33	8.50	10.98	11.15	14.48	14.65
	Korea	KR-G	NS	4.93	NS	4.93	NS	4.93	NS	4.93	NS	4.93	NS	4.93
↗	Netherlands	NL-G1/G2	NS	3.75	NS	4.24	NS	4.80	NS	4.87	NS	4.87	NS	4.87
↗	Portugal	PT-G1/G2	2.55	3.76	3.25	4.46	3.77	4.97	3.93	5.14	3.93	5.14	3.93	5.14
	Spain	SP-G	NS	5.17	NS	5.17	NS	5.17	NS	5.17	NS	5.17	NS	5.17
	Turkey	TK-G	NS	3.88	NS	3.88	NS	3.88	NS	3.88	NS	3.88	NS	3.88
↗	United States	US-G1/G2	NS	1.58	NS	1.58	NS	2.25	NS	3.19	NS	4.53	NS	6.44
↗	Brazil	BR-G1/G2	0.98	2.49	0.99	2.51	1.00	2.53	1.01	2.56	1.02	2.58	1.03	2.61
↗	Russia	RU-G	NS	2.01	NS	2.68	NS	3.48	NS	4.24	NS	5.17	NS	6.30

↗ Gas prices projected to increase.

M: At the mine or national border.
P: At the power plant.

NS: Not specified.

Table 15. **Projected generation costs calculated**

Country	Coal					Gas				
		Investment	O&M	Fuel	Total		Investment	O&M	Fuel	Total
Belgium	BE-C	13.32	10.27	16.69	40.28	BE-G	7.18	6.97	21.84	35.99
		33%	26%	41%	100%		20%	19%	61%	100%
Canada	CA-C1	9.91	4.00	15.30	29.21	CA-G	6.58	2.01	21.45	30.03
		34%	14%	52%	100%		22%	7%	71%	100%
	CA-C2	15.78	7.77	17.90	41.45					
		38%	19%	43%	100%					
Denmark	DK-C	12.65	6.75	18.17	37.56	DK-G1	7.76	4.28	32.87	44.90
		34%	18%	48%	100%		17%	10%	73%	100%
						DK-G2	8.04	5.70	37.47	51.21
							16%	11%	73%	100%
Finland	FI-C	8.60	8.87	14.35	31.82	FI-G	6.03	10.86	19.03	35.92
		27%	28%	45%	100%		17%	30%	53%	100%
France	FR-C	13.85	9.91	22.62	46.38	FR-G	8.07	4.39	34.96	47.42
		30%	21%	49%	100%		17%	9%	74%	100%
Hungary	HN-C1	11.48	8.97	17.91	38.37	HN-G	6.19	3.53	25.31	35.03
		30%	23%	47%	100%		18%	10%	72%	100%
	HN-C2	12.41	5.80	16.62	34.84					
		36%	17%	48%	100%					
Italy	IT-C	11.94	6.11	24.19	42.24	IT-G	6.04	2.61	37.90	46.55
		28%	14%	57%	100%		13%	6%	81%	100%
Japan	JP-C	23.95	12.51	19.35	55.81	JP-G	14.89	7.86	56.34	79.10
		43%	22%	35%	100%		19%	10%	71%	100%
Korea	KR-C	11.37	8.17	14.86	34.40	KR-G	5.78	3.35	33.39	42.52
		33%	24%	43%	100%		14%	8%	79%	100%
Netherlands	NL-C1	13.07	8.20	23.58	44.85	NL-G1	7.62	3.78	31.22	42.62
		29%	18%	53%	100%		18%	9%	73%	100%
	NL-C2[B]	15.06	8.20	22.57	45.84	NL-G2[B]	7.03	3.65	28.10	38.77
		33%	18%	49%	100%		18%	9%	72%	100%
	NL-C3[B]	16.11	8.38	22.57	47.07					
		34%	18%	48%	100%					
Portugal	PT-C1	20.01	11.50	20.02	51.53	PT-G1	7.65	2.48	33.79	43.92
		39%	22%	39%	100%		17%	6%	77%	100%
	PT-C2	19.03	11.36	19.19	49.58	PT-G2	6.74	2.31	34.34	43.40
		38%	23%	39%	100%		16%	5%	79%	100%
Spain	SP-C	13.03	6.11	23.11	42.24	SP-G	6.58	4.82	36.50	47.91
		31%	14%	55%	100%		14%	10%	76%	100%
Turkey	TK-C1	9.94	8.94	20.96	39.84	TK-G	3.85	0.93	25.89	30.67
		25%	22%	53%	100%		13%	3%	84%	100%
	TK-C2	14.35	7.56	34.48	56.39					
		25%	13%	61%	100%					
United States	US-C1	11.20	5.15	8.70	25.05	US-G1	4.39	2.78	19.97	27.14
		45%	21%	35%	100%		16%	10%	74%	100%
	US-C2[B]	12.65	5.05	7.10	24.79	US-G2[B]	3.95	2.68	16.64	23.27
		51%	20%	29%	100%		17%	12%	71%	100%
						US-FC[B]	14.15	4.23	17.21	35.59
							40%	12%	48%	100%
Brazil	BR-C1	15.18	3.30	16.91	35.39	BR-G1	8.76	1.50	18.29	28.55
		43%	9%	48%	100%		31%	5%	64%	100%
	BR-C2	13.19	3.30	39.95	56.45	BR-G2	9.92	1.51	18.29	29.72
		23%	6%	71%	100%		33%	5%	62%	100%
China	CN-C	8.45	5.54	17.82	31.82					
		27%	17%	56%	100%					
India	IN-C/F1	8.76	4.29	19.92	32.97					
		27%	13%	60%	100%					
	IN-C/F2	8.76	4.29	24.02	37.07					
		24%	12%	65%	100%					
Romania										
Russia	RU-C	12.59	7.72	26.01	46.32	RU-G	6.84	4.19	24.38	35.41
		27%	17%	56%	100%		19%	12%	69%	100%

B Power plants expected to be commercially available by 2005-2010.

with generic assumptions at 5% p.a. discount rate (USmill of 1.7.1996/kWh)

	Nuclear					Others				Country
	Investment	O&M	Fuel	Total		Investment	O&M	Fuel	Total	
										Belgium
CA-N1	18.71	8.45	2.42	29.57						Canada
	63%	29%	8%	100%						
CA-N2	16.43	5.97	2.27	24.67						
	67%	24%	9%	100%						
					DK-CHP	8.98	13.10	45.70	67.78	Denmark
						13%	19%	67%	100%	
					DK-ST	32.65	20.96	40.62	94.24	
						35%	22%	43%	100%	
					DK-W1	*27.26*	*6.98*	*0.00*	*34.24*	
						80%	20%	0%	100%	
					DK-W2	*37.31*	*9.54*	*0.00*	*46.85*	
						80%	20%	0%	100%	
FI-N	22.01	7.95	7.32	37.28						Finland
	59%	21%	20%	100%						
FR-N	17.39	6.77	8.07	32.24						France
	54%	21%	25%	100%						
										Hungary
					IT-W	*46.05*	*8.73*	*0.00*	*54.78*	Italy
						84%	16%	0%	100%	
JP-N	24.91	16.84	15.71	57.45						Japan
	43%	29%	27%	100%						
KR-N	16.83	9.60	4.27	30.70						Korea
	55%	31%	14%	100%						
										Netherlands
										Portugal
SP-N	22.21	8.14	10.69	41.04						Spain
	54%	20%	26%	100%						
TK-N	19.89	8.49	4.44	32.82	TK-FO	11.37	4.11	23.24	38.72	Turkey
	61%	26%	14%	100%		29%	11%	60%	100%	
US-N[B]	18.20	8.86	6.22	33.28	US-BIO	14.11	7.11	8.74	29.95	United States
	55%	27%	19%	100%		47%	24%	29%	100%	
BR-N1	19.90	7.72	9.14	36.76						Brazil
	54%	21%	25%	100%						
BR-N2[B]	19.22	7.34	6.59	33.15						
	58%	22%	20%	100%						
CN-N1	12.12	5.69	7.56	25.37						China
	48%	22%	30%	100%						
CN-N2	17.14	5.84	7.83	30.81						
	56%	19%	25%	100%						
CN-N3	15.82	7.84	3.03	26.69						
	59%	29%	11%	100%						
IN-N	19.16	6.07	7.59	32.82						India
	58%	19%	23%	100%						
RO-N	15.75	11.54	4.55	31.84						Romania
	49%	36%	14%	100%						
RU-N	18.85	4.45	3.58	26.88						Russia
	70%	17%	13%	100%						

Note: Figures in *italics* correspond to national estimates. [B] Power plants expected to be commercially available by 2005-2010.

Table 16. **Projected generation costs calculated**

Country	Coal					Gas				
		Investment	O&M	Fuel	Total		Investment	O&M	Fuel	Total
Belgium	BE-C	25.38	10.40	16.69	52.47	BE-G	13.42	7.06	21.84	42.33
		48%	20%	32%	100%		32%	17%	52%	100%
Canada	CA-C1	17.68	4.05	15.30	37.03	CA-G	11.13	2.03	19.88	33.04
		48%	11%	41%	100%		34%	6%	60%	100%
	CA-C2	28.42	7.87	17.90	54.19					
		52%	15%	33%	100%					
Denmark	DK-C	23.90	6.83	18.17	48.90	DK-G1	14.74	4.33	32.87	51.94
		49%	14%	37%	100%		28%	8%	63%	100%
						DK-G2	14.52	5.77	37.47	57.77
							25%	10%	65%	100%
Finland	FI-C	15.77	8.99	14.35	39.11	FI-G	11.03	11.00	19.03	41.07
		40%	23%	37%	100%		27%	27%	46%	100%
France	FR-C	26.88	10.03	22.62	59.54	FR-G	13.94	4.44	34.96	53.35
		45%	17%	38%	100%		26%	8%	66%	100%
Hungary	HN-C1	20.34	9.09	17.91	47.33	HN-G	11.58	3.49	25.31	40.37
		43%	19%	38%	100%		29%	9%	63%	100%
	HN-C2	23.13	5.88	16.62	45.62					
		51%	13%	36%	100%					
Italy	IT-C	22.63	6.19	23.91	52.73	IT-G	11.11	2.64	37.57	51.32
		43%	12%	45%	100%		22%	5%	73%	100%
Japan	JP-C	44.48	12.66	19.00	76.14	JP-G	26.89	7.96	49.54	84.40
		58%	17%	25%	100%		32%	9%	59%	100%
Korea	KR-C	21.83	8.27	14.86	44.96	KR-G	10.19	3.39	33.39	46.98
		49%	18%	33%	100%		22%	7%	71%	100%
Netherlands	NL-C1	24.82	8.31	23.36	56.48	NL-G1	13.80	3.83	30.68	48.31
		44%	15%	41%	100%		29%	8%	64%	100%
	NL-C2[B]	28.66	8.31	22.36	59.33	NL-G2[B]	12.69	3.69	27.62	43.99
		48%	14%	38%	100%		29%	8%	63%	100%
	NL-C3[B]	30.70	8.49	22.36	61.55					
		50%	14%	36%	100%					
Portugal	PT-C1	38.15	11.64	19.64	69.44	PT-G1	14.11	2.51	33.17	49.79
		55%	17%	28%	100%		28%	5%	67%	100%
	PT-C2	36.29	11.50	18.83	66.62	PT-G2	12.45	2.34	33.70	48.49
		54%	17%	28%	100%		26%	5%	70%	100%
Spain	SP-C	25.38	6.18	23.11	54.67	SP-G	12.97	4.88	36.50	54.36
		46%	11%	42%	100%		24%	9%	67%	100%
Turkey	TK-C1	18.69	9.05	20.96	48.70	TK-G	7.11	0.94	25.89	33.94
		38%	19%	43%	100%		21%	3%	76%	100%
	TK-C2	27.61	7.66	34.48	69.74					
		40%	11%	49%	100%					
United States	US-C1	20.54	5.22	8.95	34.71	US-G1	7.73	2.82	16.82	27.37
		59%	15%	26%	100%		28%	10%	61%	100%
	US-C2[B]	23.28	5.11	7.31	35.70	US-G2[B]	6.87	2.71	14.02	23.60
		65%	14%	20%	100%		29%	11%	59%	100%
						US-FC[B]	25.97	4.28	14.50	44.75
							58%	10%	32%	100%
Brazil	BR-C1	24.13	3.12	15.95	43.20	BR-G1	13.07	1.45	18.21	32.73
		56%	7%	37%	100%		40%	4%	56%	100%
	BR-C2	20.97	3.14	37.70	61.80	BR-G2	15.19	1.47	18.21	34.87
		34%	5%	61%	100%		44%	4%	52%	100%
China	CN-C	16.91	5.61	17.44	39.96					
		42%	14%	44%	100%					
India	IN-C/F1	15.91	4.34	19.92	40.17					
		40%	11%	50%	100%					
	IN-C/F2	15.91	4.34	24.02	44.27					
		36%	10%	54%	100%					
Romania										
Russia	RU-C	24.31	7.35	23.68	55.34	RU-G	12.85	4.05	22.09	38.99
		44%	13%	43%	100%		33%	10%	57%	100%

B Power plants expected to be commercially available by 2005-2010.

with generic assumptions at 10% p.a. discount rate (USmill of 1.7.1996/kWh)

	Nuclear				Others					Country
	Investment	O&M	Fuel	Total		Investment	O&M	Fuel	Total	
										Belgium
CA-N1	36.20	8.55	2.49	47.24						Canada
	77%	18%	5%	100%						
CA-N2	31.17	6.05	2.34	39.56						
	79%	15%	6%	100%						
					DK-CHP	17.07	13.26	45.70	76.03	Denmark
						22%	17%	60%	100%	
					DK-ST	62.05	21.22	40.62	123.90	
						50%	17%	33%	100%	
					DK-W1	*47.70*	*6.98*	*0.00*	*54.69*	
						87%	13%	0%	100%	
					DK-W2	*65.59*	*9.54*	*0.00*	*75.13*	
						87%	13%	0%	100%	
FI-N	40.56	8.05	7.32	55.93						Finland
	73%	14%	13%	100%						
FR-N	34.61	6.86	7.69	49.15						France
	70%	14%	16%	100%						
										Hungary
					IT-W	*66.52*	*8.73*	*0.00*	*75.25*	Italy
						88%	12%	0%	100%	
JP-N	47.76	17.05	14.76	79.57						Japan
	60%	21%	19%	100%						
KR-N	34.30	9.72	4.27	48.30						Korea
	71%	20%	9%	100%						
										Netherlands
										Portugal
SP-N	44.90	8.25	10.69	63.83						Spain
	70%	13%	17%	100%						
TK-N	38.74	8.60	4.44	51.78	TK-FO	21.81	4.16	23.24	49.21	Turkey
	75%	17%	9%	100%		44%	8%	47%	100%	
US-N[B]	31.38	8.97	5.81	46.17	US-BIO	26.47	7.20	8.74	42.41	United States
	68%	19%	13%	100%		62%	17%	21%	100%	
BR-N1	35.82	7.40	8.24	51.46						Brazil
	70%	14%	16%	100%						
BR-N2[B]	33.69	7.03	5.94	46.66						
	72%	15%	13%	100%						
CN-N1	25.69	5.76	7.56	39.01						China
	66%	15%	19%	100%						
CN-N2	36.92	5.91	7.83	50.67						
	73%	12%	15%	100%						
CN-N3	32.96	8.38	3.03	44.37						
	74%	19%	7%	100%						
IN-N	37.30	6.15	7.59	51.04						India
	73%	12%	15%	100%						
RO-N	31.61	11.69	4.54	47.83						Romania
	66%	24%	9%	100%						
RU-N	37.17	4.50	4.85	46.52						Russia
	80%	10%	10%	100%						

Note: Figures in *italics* correspond to national estimates. [B] Power plants expected to be commercially available by 2005-2010.

Table 17. **Projected generation costs calculated**

Country	Coal					Gas				
		Investment	O&M	Fuel	Total		Investment	O&M	Fuel	Total
Belgium	BE-C	30.32	11.17	16.92	58.41	BE-G	15.96	8.30	21.70	45.96
		52%	19%	29%	100%		35%	18%	47%	100%
Canada										
Denmark	DK-C	15.84	6.64	18.40	40.89	DK-G1	9.20	4.26	32.88	46.34
		39%	16%	45%	100%		20%	9%	71%	100%
						DK-G2	9.88	5.62	37.82	53.32
							19%	11%	71%	100%
France	FR-C	17.86	8.73	22.71	49.30	FR-G	9.70	4.27	34.93	48.91
		36%	18%	46%	100%		20%	9%	71%	100%
Hungary	HN-C1	23.69	8.88	22.35	54.92	HN-G	12.24	3.35	25.36	40.96
		43%	16%	41%	100%		30%	8%	62%	100%
	HN-C2	24.85	5.74	24.70	55.30					
		45%	10%	45%	100%					
Italy	IT-C	29.70	6.51	23.82	60.03	IT-G	14.30	2.74	38.21	55.25
		49%	11%	40%	100%		26%	5%	69%	100%
Japan	JP-C5%	24.09	12.66	20.77	57.38	JP-G5%	18.42	7.95	46.86	73.22
		42%	22%	36%	100%		25%	11%	64%	100%
	JP-C10%	45.23	12.82	20.40	78.45	JP-G10%	28.70	26.31	45.12	100.13
		58%	16%	26%	100%		29%	26%	45%	100%
Korea	KR-C	22.20	8.65	15.95	46.80	KR-G	11.30	3.39	34.18	48.87
		47%	18%	34%	100%		23%	7%	70%	100%
Netherlands	NL-C1	12.94	8.14	23.53	44.61	NL-G1	7.55	3.75	31.09	42.38
		29%	18%	53%	100%		18%	9%	73%	100%
	NL-C2[B]	14.88	8.14	22.54	45.55	NL-G2[B]	6.97	3.63	27.98	38.58
		33%	18%	49%	100%		18%	9%	73%	100%
	NL-C3[B]	16.04	8.31	22.54	46.89					
		34%	18%	48%	100%					
Portugal	PT-C1	27.74	11.01	19.78	58.52	PT-G1	10.21	2.29	32.23	44.73
		47%	19%	34%	100%		23%	5%	72%	100%
	PT-C2	26.39	10.88	18.95	56.22	PT-G2	9.01	2.14	32.75	43.91
		47%	19%	34%	100%		21%	5%	75%	100%
Spain	SP-C5%	13.03	8.03	22.62	43.68	SP-G5%	7.25	5.46	36.27	48.98
		30%	18%	52%	100%		15%	11%	74%	100%
	SP-C10%	23.71	8.11	22.39	54.21	SP-G10%	12.64	5.62	36.11	54.36
		44%	15%	41%	100%		23%	10%	66%	100%
United States	US-C1	11.30	5.00	8.70	25.00	US-G1	4.40	2.70	20.10	27.20
		45%	20%	35%	100%		16%	10%	74%	100%
	US-C2[B]	12.80	4.90	7.00	24.70	US-G2[B]	4.40	2.60	16.70	23.70
		52%	20%	28%	100%		19%	11%	70%	100%
						US-FC[B]	14.40	4.10	17.30	35.80
							40%	11%	48%	100%
China	CN-C	19.60	6.43	17.34	43.37					
		45%	15%	40%	100%					
India	IN-C1	20.82	4.85	21.68	47.35					
		44%	10%	46%	100%					
	IN-C2	20.82	4.85	26.24	51.91					
		40%	9%	51%	100%					

B Power plants expected to be commercially available by 2005-2010.

with national assumptions (USmill of 1.7.1996/kWh)

Nuclear					Others					Country
	Investment	O&M	Fuel	Total		Investment	O&M	Fuel	Total	
										Belgium
CA-N1	16.26	7.33	2.42	26.01						Canada
	63%	28%	9%	100%						
CA-N2	14.87	5.20	2.27	22.34						
	67%	23%	10%	100%						
					DK-CHP	14.99	14.99	45.66	75.64	Denmark
						20%	20%	60%	100%	
					DK-ST	54.35	24.19	40.55	119.08	
						46%	20%	34%	100%	
					DK-W1	37.48	6.98	0.00	44.46	
						84%	16%	0%	100%	
					DK-W2	51.45	9.54	0.00	60.99	
						84%	16%	0%	100%	
FR-N	25.62	6.60	8.73	40.95						France
	63%	16%	21%	100%						
										Hungary
					IT-W	75.43	8.73	0.00	84.16	Italy
						90%	10%	0%	100%	
JP-N5%	23.95	16.95	15.72	56.63						Japan
	42%	30%	28%	100%						
JP-N10%	46.44	17.17	14.80	78.41						
	59%	22%	19%	100%						
KR-N	32.51	9.96	4.27	46.73						Korea
	70%	21%	9%	100%						
										Netherlands
										Portugal
SP-N5%	22.62	9.28	9.83	41.73						Spain
	54%	22%	24%	100%						
SP-N10%	42.12	9.44	10.69	62.24						
	68%	15%	17%	100%						
US-N[B]	17.80	8.60	6.10	32.50	US-BIO	14.30	6.90	8.80	30.00	United States
	55%	26%	19%	100%		48%	23%	29%	100%	
CN-N1	30.02	6.61	7.57	44.19						China
	68%	15%	17%	100%						
CN-N2	43.15	6.58	7.85	57.58						
	75%	11%	14%	100%						
CN-N3	34.27	8.94	3.03	46.24						
	74%	19%	7%	100%						
IN-N	48.20	6.85	7.42	62.46						India
	77%	11%	12%	100%						

Table 18. **Generation cost ratios – Generic assumptions**

Country	Plant	Nuclear/Coal		Nuclear/Gas		Coal/Gas	
		5%	10%	5%	10%	5%	10%
Belgium						1.12	1.24
Canada	C1/N1	1.01	1.28	0.98	1.43	0.97	1.12
	C1/N2	0.84	1.07	0.82	1.20	–	–
	C2/N1	0.71	0.87	–	–	1.38	1.64
	C2/N2	0.60	0.73	–	–	–	–
Denmark	C/G1	–	–	–	–	0.84	0.94
	C/G2	–	–	–	–	0.73	0.85
Finland		1.17	1.43	1.04	1.36	0.89	0.95
France		0.69	0.83	0.68	0.92	0.98	1.12
Hungary	C1/G	–	–	–	–	1.10	1.17
	C2/G	–	–	–	–	0.99	1.13
Italy		–	–	–	–	0.91	1.03
Japan		1.03	1.04	0.73	0.94	0.71	0.90
Korea		0.89	1.07	0.72	1.03	0.81	0.96
Netherlands	C1/G1	–	–	–	–	1.05	1.17
	C1/G2[B]	–	–	–	–	1.16	1.28
	C2[B]/G1	–	–	–	–	1.08	1.23
	C2[B]/G2[B]	–	–	–	–	1.18	1.35
	C3[B]/G1	–	–	–	–	1.10	1.27
	C3[B]/G2[B]	–	–	–	–	1.21	1.40
Portugal	C1/G1	–	–	–	–	1.17	1.39
	C1/G2	–	–	–	–	1.19	1.43
	C2/G1	–	–	–	–	1.13	1.34
	C2/G2	–	–	–	–	1.14	1.37
Spain		0.97	1.17	0.86	1.17	0.88	1.01
Turkey	C1	0.82	1.06	1.07	1.53	1.30	1.43
	C2	0.58	0.74	–	–	1.84	2.05
United States	N[B]-C1-G1	1.33	1.33	1.23	1.69	0.92	1.27
	N[B]-C1-G2[B]	–	-	1.43	1.96	1.08	1.47
	N[B]-C2[B]-G1	1.34	1.29	–	–	0.91	1.30
	N[B]-C2[B]-G2[B]	–	–	–	–	1.07	1.51
Brazil	N1-C1-G1	1.04	1.19	1.29	1.57	1.24	1.32
	N2[B]-C1-G1	0.94	1.08	1.16	1.43	–	–
	N1-C2-G1	0.65	0.83	–	–	1.98	1.89
	N2[B]-C2-G1	0.59	0.75	–	–	–	–
	N1-C1-G2	–	–	1.24	1.48	1.19	1.24
	N2[B]-C1-G2	–	–	1.12	1.34	–	–
	C2-G2	–	–	–	–	1.90	1.77
China	N1	0.80	0.98	–	–	–	–
	N2	0.97	1.27	–	–	–	–
	N3	0.84	1.11	–	–	–	–
India	C1	0.995	1.27	–	–	–	–
	C2	0.89	1.15	–	–	–	–
Romania		–	–	–	–	–	–
Russia		0.58	0.84	0.76	1.19	1.31	1.42

B Power plants expected to be commercially available by 2005-2010.

Table 19. **Sensitivity analysis at 5% p.a. discount rate**

a. Nuclear generation costs (USmill of 1.7.1996/kWh)

Country	Load factor (%)	65	75				80
	Lifetime (y)	30	25	30		40	30
	Fuel price escalation	Nat.	Nat.	0%	Nat.	Nat.	Nat.
Canada	CA-N1	36.12	33.44	31.80	31.80	29.57	30.05
	CA-N2	30.20	28.06	26.62	26.62	24.67	25.17
Finland	FI-N	44.59	42.03	39.82	39.82	37.28	37.88
France	FR-N	38.29	36.33	34.42	34.42	32.24	32.85
Japan	JP-N	67.14	63.27	60.56	60.56	57.45	57.88
Korea	KR-N	36.81	34.34	32.64	32.64	30.70	30.95
Spain	SP-N	48.49	45.92	43.65	43.65	41.04	41.68
Turkey	TK-N	39.63	37.13	35.12	35.12	32.82	33.29
United States	US-N	39.84	37.52	35.54	35.54	33.27	33.79
Brazil	BR-N1	42.27	39.97	38.03	38.03	36.76	36.31
	BR-N2[B]	38.44	36.23	34.36	34.36	33.14	32.70
China	CN-N1	29.72	28.19	26.88	26.88	25.37	25.73
	CN-N2	36.64	34.82	32.95	32.95	30.81	31.45
	CN-N3	32.63	30.72	28.84	28.84	26.69	27.30
India	IN-N	38.93	36.24	34.92	34.92	32.82	33.29
Romania	RO-N	37.93	35.24	33.66	33.66	31.84	31.92
Russia	RU-N	32.89	31.10	29.13	29.13	26.88	27.61

B Power plants expected to be commercially available by 2005-2010.

Table 19. **Sensitivity analysis at 5% p.a. discount rate**

b. Coal generation costs (USmill of 1.7.1996/kWh)

Country	Load factor (%)	65	75				80
	Lifetime (y)	30	25	30		40	30
	Fuel price escalation	Nat.	Nat.	0%	Nat.	Nat	Nat.
Belgium	BE-C	45.51	43.16	41.82	41.82	40.28	40.32
Canada	CA-C1	32.37	31.03	30.18	30.18	29.21	29.29
	CA-C2	46.72	44.41	43.03	43.03	41.45	41.53
Denmark	DK-C	42.09	40.30	34.98	39.02	37.56	37.78
Finland	FI-C	35.53	33.68	32.81	32.81	31.82	31.71
France	FR-C	51.70	49.37	47.98	47.98	46.38	46.47
Hungary	HN-C1	42.89	40.85	39.69	39.69	38.37	38.39
	HN-C2	39.18	37.55	36.29	36.29	34.84	35.11
Italy	IT-C	46.37	44.12	40.23	43.53	42.24	42.38
Japan	JP-C	64.11	60.65	56.77	58.36	55.81	56.03
Korea	KR-C	38.78	36.86	35.71	35.71	34.40	34.47
Netherlands	NL-C1	49.40	47.38	43.98	46.10	44.85	44.76
	NL-C2[B]	50.95	48.80	45.29	47.33	45.84	45.85
	NL-C3[B]	52.50	50.26	46.65	48.68	47.07	47.13
Portugal	PT-C1	58.57	55.50	51.93	53.61	51.53	51.60
	PT-C2	56.34	53.36	49.95	51.56	49.58	49.63
Spain	SP-C	46.78	45.06	43.75	43.75	42.24	42.52
Turkey	TK-C1	43.93	41.99	40.98	40.98	39.84	39.79
	TK-C2	61.51	59.49	58.04	58.04	56.39	56.64
United States	US-C1	28.93	27.48	27.05	26.35	25.01	25.30
	US-C2[B]	29.07	27.53	26.84	26.27	24.79	25.13
Brazil	BR-C1	37.41	35.70	30.90	34.73	35.38	33.65
	BR-C2	57.34	55.34	45.92	54.99	56.45	54.05
China	CN-C	34.76	33.29	30.34	32.57	31.82	31.68
India	IN-C/F1	36.05	34.87	33.98	33.98	32.97	33.14
	IN-C/F2	40.15	38.96	38.08	38.08	37.07	37.24
Russia	RU-C	49.31	46.56	32.85	46.20	46.32	44.94

B Power plants expected to be commercially available by 2005-2010.

Table 19. **Sensitivity analysis at 5% p.a. discount rate**

c. Generation costs – Gas and other power plants (USmill of 1.7.1996/kWh)

	Country	Load factor (%)	65	75				80
		Lifetime (y)	30	25	30		40	30
		Fuel price escalation	Nat.	Nat.	0%	Nat.	Nat.	Nat.
GAS	Belgium	BE-G	39.02	37.54	36.82	36.82	35.99	35.92
	Canada	CA-G	31.19	30.00	23.82	29.87	30.03	29.34
	Denmark	DK-G1	47.70	46.58	32.28	45.80	44.90	45.03
		DK-G2	54.30	52.95	36.73	52.14	51.21	51.27
	Finland	FI-G	39.20	37.22	36.62	36.62	35.92	35.57
	France	FR-G	50.31	49.16	48.35	48.35	47.42	47.55
	Hungary	HN-G	37.22	36.29	32.84	35.69	35.03	35.07
	Italy	IT-G	48.46	47.61	36.83	47.10	46.55	46.55
	Japan	JP-G	79.71	75.43	53.74	76.30	79.09	74.94
	Korea	KR-G	44.63	43.77	43.19	43.19	42.52	42.61
	Netherlands	NL-G1	44.88	43.61	37.07	43.15	42.62	42.45
		NL-G2[B]	40.87	39.66	33.77	39.25	38.77	38.59
	Portugal	PT-G1	46.19	45.22	36.90	44.61	43.92	43.98
		PT-G2	45.39	44.50	36.15	43.99	43.40	43.42
	Spain	SP-G	50.46	49.34	48.67	48.67	47.91	47.95
	Turkey	TK-G	31.89	31.51	31.12	31.12	30.67	30.81
	United States	US-G1	26.48	24.75	19.04	25.44	27.14	25.02
		US-G2[B]	22.89	21.40	16.59	21.92	23.27	21.53
		US-FC[B]	38.18	35.76	29.80	35.32	35.59	34.16
	Brazil	BR-G1	30.95	28.43	29.00	29.33	28.54	28.67
		BR-G2	32.58	29.75	30.42	30.74	29.72	30.00
	Russia	RU-G	36.40	34.62	24.68	34.75	35.41	34.08
OTHERS	Denmark	DK-ST	106.43	101.29	98.00	98.00	94.24	94.58
		DK-CHP	72.20	69.71	50.02	68.81	67.78	37.78
	Turkey	TK-FO	42.50	41.18	40.03	40.03	38.72	39.03
	United States	US-BIO	34.88	32.92	22.80	31.54	29.95	30.18

B Power plants expected to be commercially available by 2005-2010.

Table 20. **Sensitivity analysis at 10% p.a. discount rate**

a. Nuclear generation costs (USmill of 1.7.1996/kWh)

Country	Load factor (%)	65	75				80
	Lifetime (y)	30	25	30		40	30
	Fuel price escalation	Nat.	Nat.	0%	Nat.	Nat.	Nat.
Canada	CA-N1	54.94	49.85	48.56	48.56	47.24	45.97
	CA-N2	30.20	28.06	26.62	26.62	24.67	25.17
Finland	FI-N	64.32	58.96	57.38	57.38	55.93	54.57
France	FR-N	56.39	51.88	50.46	50.46	49.15	48.06
Japan	JP-N	90.60	83.33	81.36	81.36	79.56	77.62
Korea	KR-N	55.79	50.85	49.51	49.51	48.30	46.97
Spain	SP-N	73.04	67.21	65.44	65.44	63.83	62.37
Turkey	TK-N	59.92	54.67	53.16	53.16	51.78	50.42
United States	US-N	53.21	48.86	47.44	47.44	46.13	45.10
Brazil	BR-N1	58.50	53.81	52.38	52.38	51.46	49.90
	BR-N2[B]	53.28	48.87	47.52	47.52	46.66	45.18
China	CN-N1	44.49	41.07	39.99	39.99	39.01	38.17
	CN-N2	58.22	53.63	52.09	52.09	50.67	49.60
	CN-N3	51.64	47.18	45.72	45.72	44.37	43.32
India	IN-N	58.50	53.43	52.29	52.29	51.04	49.78
Romania	RO-N	55.11	50.18	48.95	48.95	47.83	46.46
Russia	RU-N	53.87	49.40	47.90	47.90	46.52	45.48

B Power plants expected to be commercially available by 2005-2010.

Table 20. **Sensitivity analysis at 10% p.a. discount rate**

b. Coal generation costs (USmill of 1.7.1996/kWh)

Country	Load factor (%)	65	75				80
	Lifetime (y)	30	25	30		40	30
	Fuel price escalation	Nat.	Nat.	0%	Nat.	Nat.	Nat.
Belgium	BE-C	58.46	54.35	53.37	53.37	52.47	51.31
Canada	CA-C1	40.70	38.23	37.61	37.61	37.03	36.35
	CA-C2	46.72	44.41	43.03	43.03	41.45	41.53
Denmark	DK-C	54.13	50.68	45.71	49.75	48.90	47.97
Finland	FI-C	43.18	40.28	39.67	39.67	39.11	38.25
France	FR-C	65.74	61.53	60.49	60.49	59.54	58.36
Hungary	HN-C1	52.23	48.84	48.05	48.05	47.33	46.35
	HN-C2	50.59	47.37	46.45	46.45	45.62	44.78
Italy	IT-C	57.58	54.08	50.42	53.49	52.73	51.84
Japan	JP-C	85.78	79.31	76.27	77.64	76.14	74.35
Korea	KR-C	50.02	46.58	45.74	45.74	44.96	44.00
Netherlands	NL-C1	61.96	58.23	55.35	57.28	56.48	55.38
	NL-C2[B]	50.95	48.80	45.29	47.33	45.84	45.85
	NL-C3[B]	68.11	63.73	60.70	62.55	61.54	60.30
Portugal	PT-C1	77.79	72.12	69.26	70.71	69.44	67.84
	PT-C2	74.62	69.17	66.44	67.83	66.62	65.08
Spain	SP-C	60.07	56.56	55.57	55.57	54.67	53.75
Turkey	TK-C1	53.30	50.08	49.36	49.36	48.70	47.76
	TK-C2	75.75	71.80	70.73	70.73	69.74	68.69
United States	US-C1	39.05	36.19	35.92	35.38	34.63	33.90
	US-C2[B]	40.57	37.43	36.96	36.52	35.68	34.88
Brazil	BR-C1	46.90	43.85	39.90	43.13	43.20	41.61
	BR-C2	64.69	61.77	53.72	61.40	61.80	60.08
China	CN-C	43.67	41.07	38.49	40.48	39.96	39.19
India	IN-C/F1	43.63	41.36	40.74	40.74	40.17	39.57
	IN-C/F2	47.73	45.46	44.84	44.84	44.27	43.67
Russia	RU-C	60.02	56.08	43.67	55.60	55.34	53.81

B Power plants expected to be commercially available by 2005-2010.

Table 20. **Sensitivity analysis at 10% p.a. discount rate**

c. Generation costs – Gas and other power plants (USmill of 1.7.1996/kWh)

	Country	Load factor (%)	65	75				80
		Lifetime (y)	30	25	30		40	30
		Fuel price escalation	Nat.	Nat.	0%	Nat.	Nat.	Nat.
GAS	Belgium	BE-G	45.70	43.32	42.80	42.80	42.33	41.62
	Canada	CA-G	31.19	30.00	23.82	29.87	30.03	29.34
	Denmark	DK-G1	55.18	53.04	38.95	52.46	51.94	51.36
		DK-G2	61.17	58.84	42.87	58.28	57.77	57.11
	Finland	FI-G	44.56	41.87	41.45	41.45	41.07	40.19
	France	FR-G	56.46	54.38	53.84	53.84	53.35	52.78
	Hungary	HN-G	42.91	41.20	37.91	40.76	40.37	39.90
	Italy	IT-G	53.6	52.0	41.6	51.7	51.3	50.9
	Japan	JP-G	88.42	83.54	65.07	83.66	84.39	81.76
	Korea	KR-G	49.27	47.73	47.34	47.34	46.98	46.56
	Netherlands	NL-G1	51.1	49.1	43.0	48.7	48.3	47.7
		NL-G2[B]	46.6	44.7	39.3	44.3	44.0	43.4
	Portugal	PT-G1	52.54	50.67	43.02	50.21	49.79	49.27
		PT-G2	50.92	49.24	41.54	48.85	48.49	48.02
	Spain	SP-G	57.36	55.32	54.82	54.82	54.36	53.79
	Turkey	TK-G	31.89	31.51	31.12	31.12	30.67	30.81
	United States	US-G1	24.46	22.99	19.32	23.17	23.60	22.66
		US-G2[B]	48.10	44.32	34.57	43.30	42.38	41.36
		US-FC[B]	49.21	45.50	40.98	44.97	44.75	43.26
	Brazil	BR-G1	35.19	32.81	32.85	33.13	32.73	32.29
		BR-G2	37.75	35.03	35.09	35.37	34.87	34.41
	Russia	RU-G	41.21	38.98	30.25	38.89	38.99	37.96
OTHERS	Denmark	DK-CHP	80.91	77.28	57.83	76.62	76.03	47.97
		DK-ST	137.96	128.51	126.10	126.10	123.90	121.30
	Turkey	TK-O	42.50	41.18	40.03	40.03	38.72	39.03
	United States	US-BIO	63.22	56.91	55.52	55.52	54.26	52.40

B Power plants expected to be commercially available by 2005-2010.

Figure 1. **Average size of the power plants considered in the study (MWe)**

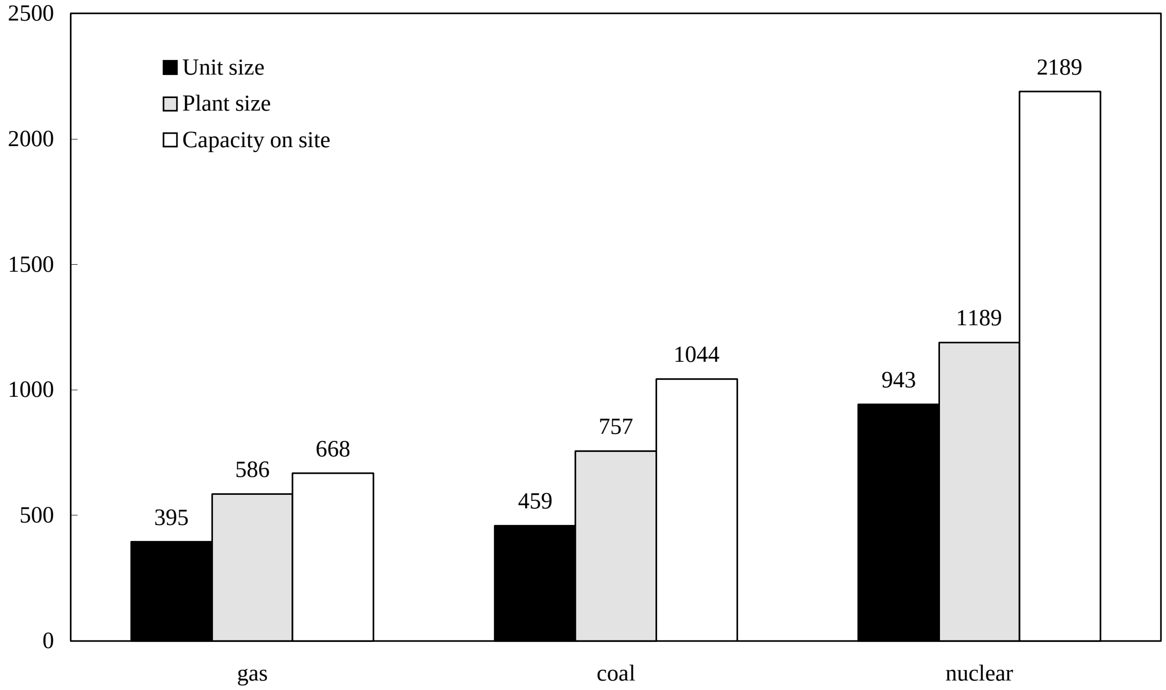


Figure 2. **Nuclear power plant investment costs (US$ 1.7.1996/kWe)**

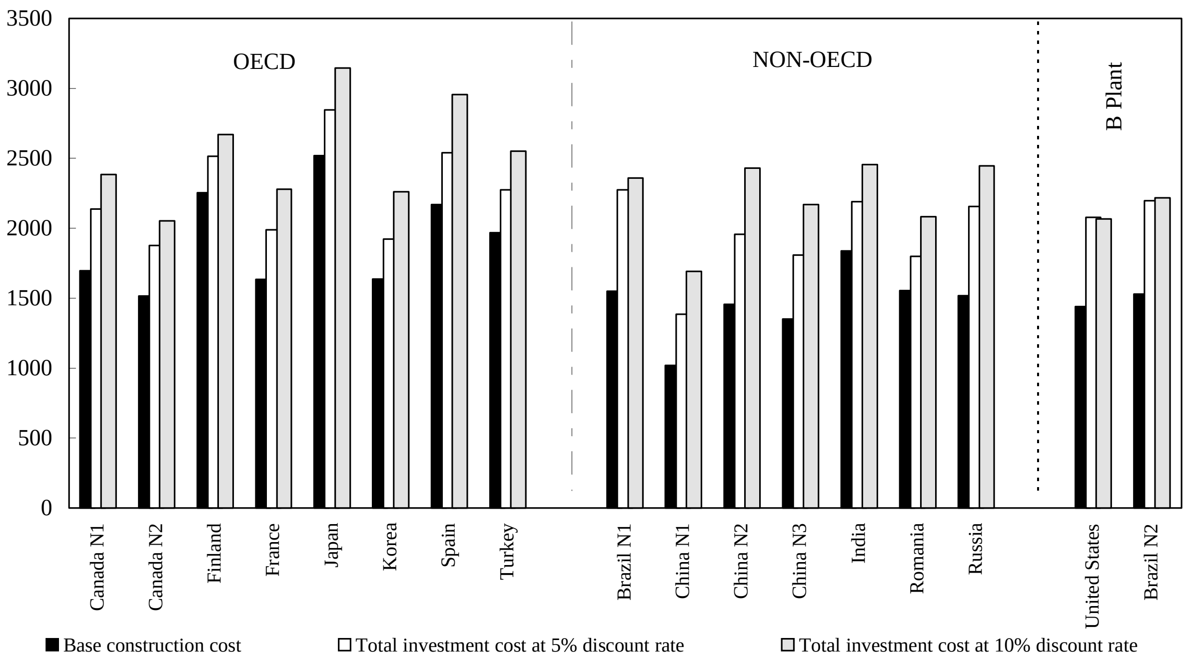


Figure 3. **Coal-fired power plant investment costs (US$ 1.7.1996/kWe)**

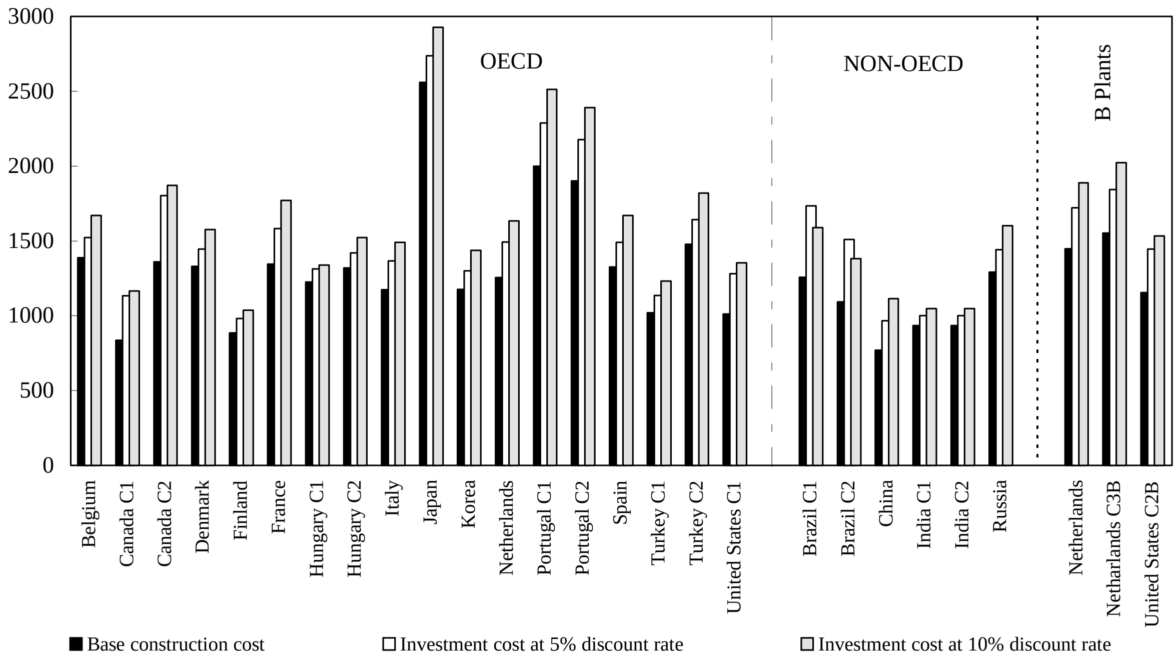


Figure 4. **Gas-fired plant investment costs (US$ 1.7.96/kWh**)

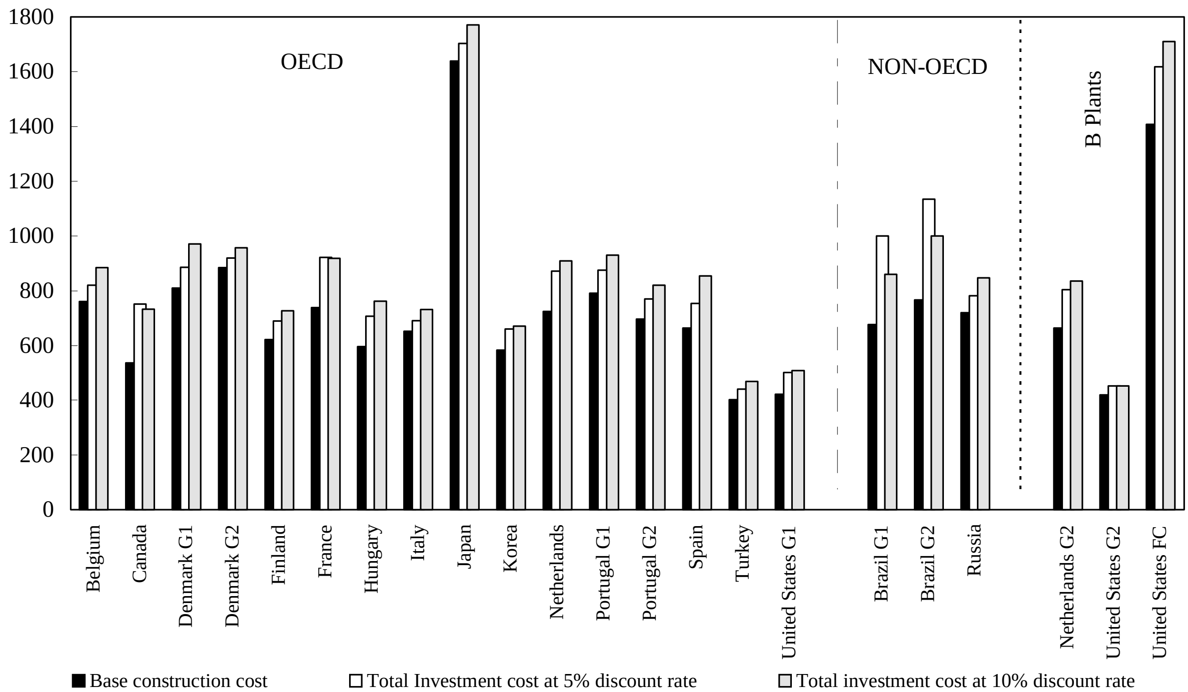


Figure 5. **Other plant investment costs (US$ 1.7.96/kWh)**

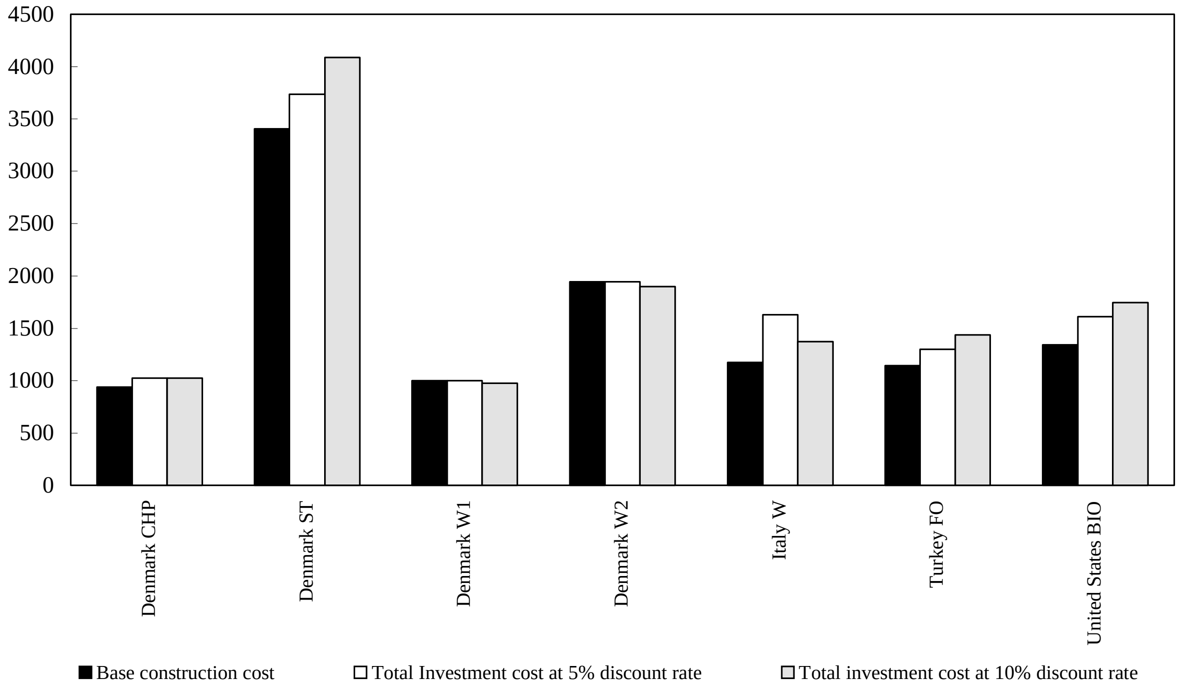


Figure 6. **Assumed coal and gas prices in 2005 (US$/Gjoule)**

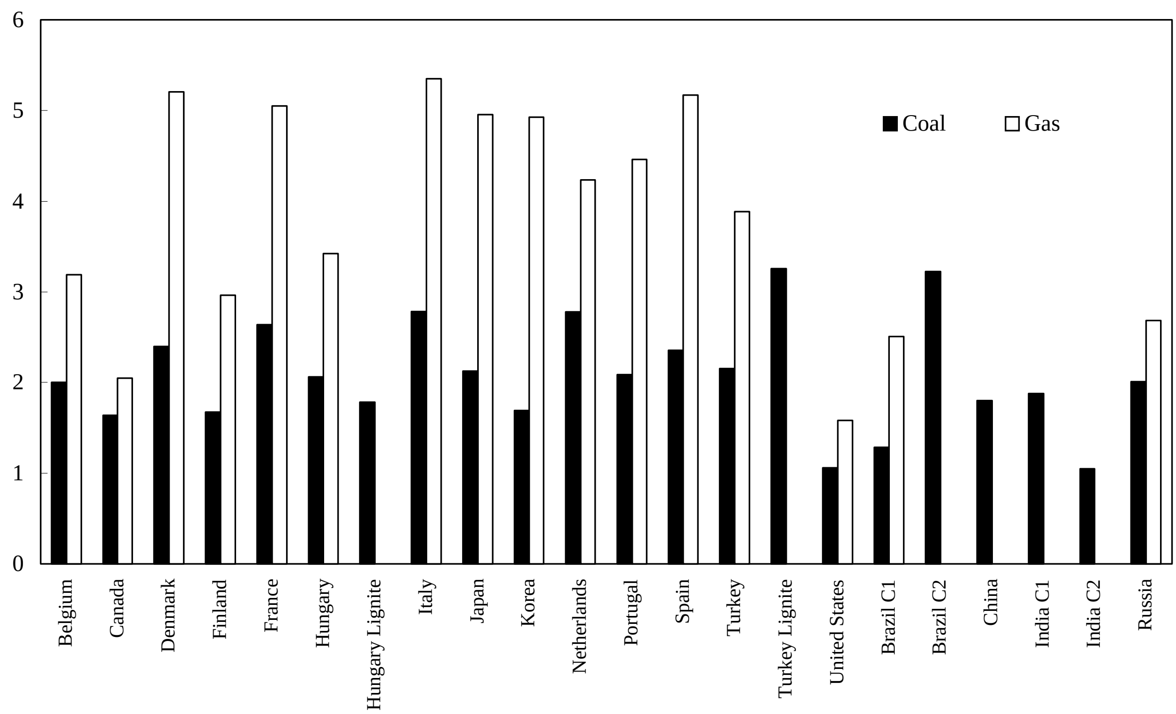


Figure 7. **Ratios of gas price to coal price in 2005**

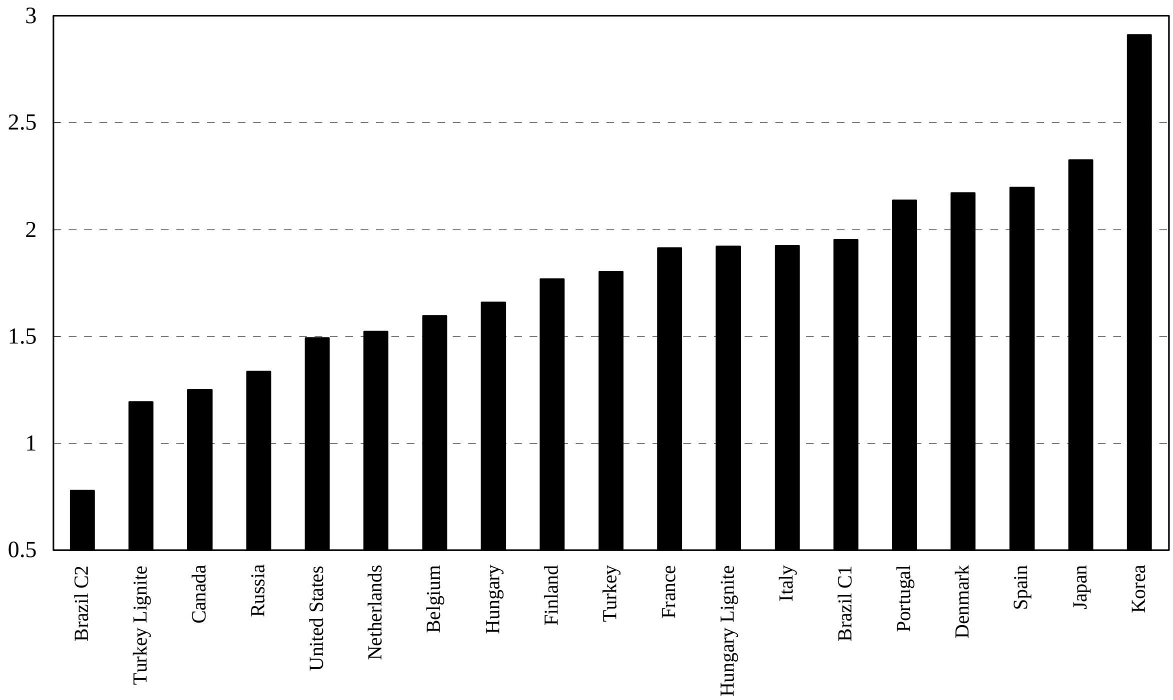


Figure 8a. **Levelised electricity generation costs calculated with common assumptions at 5% discount rate (USmill/kWh)**

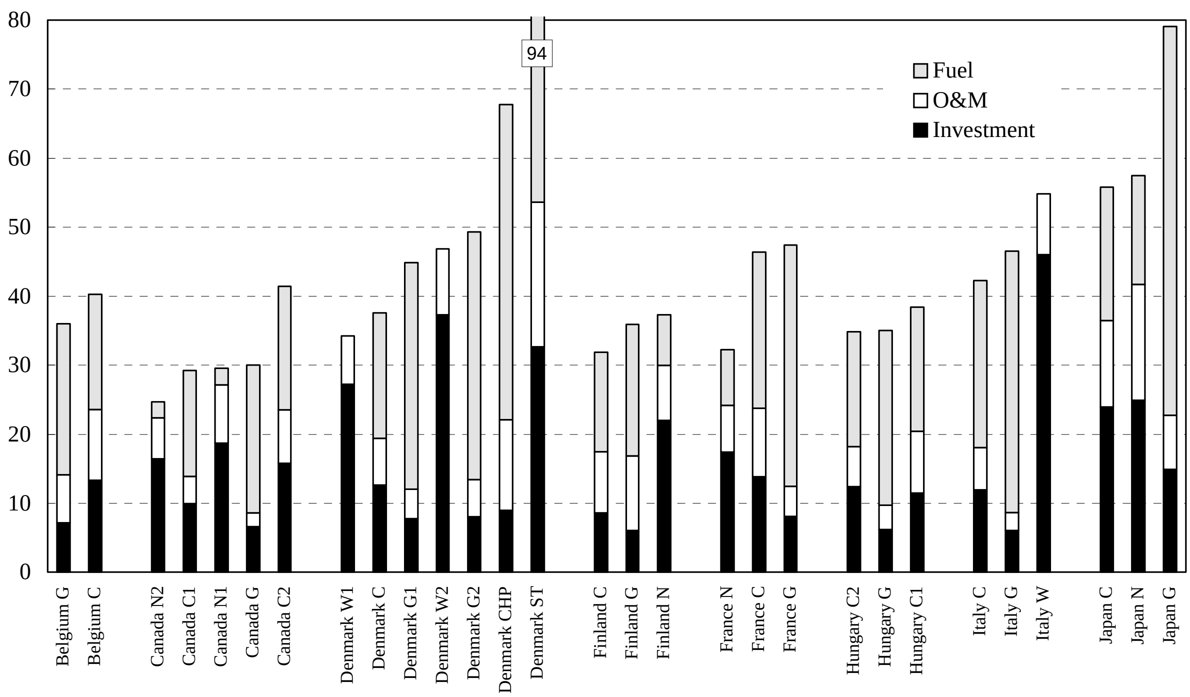
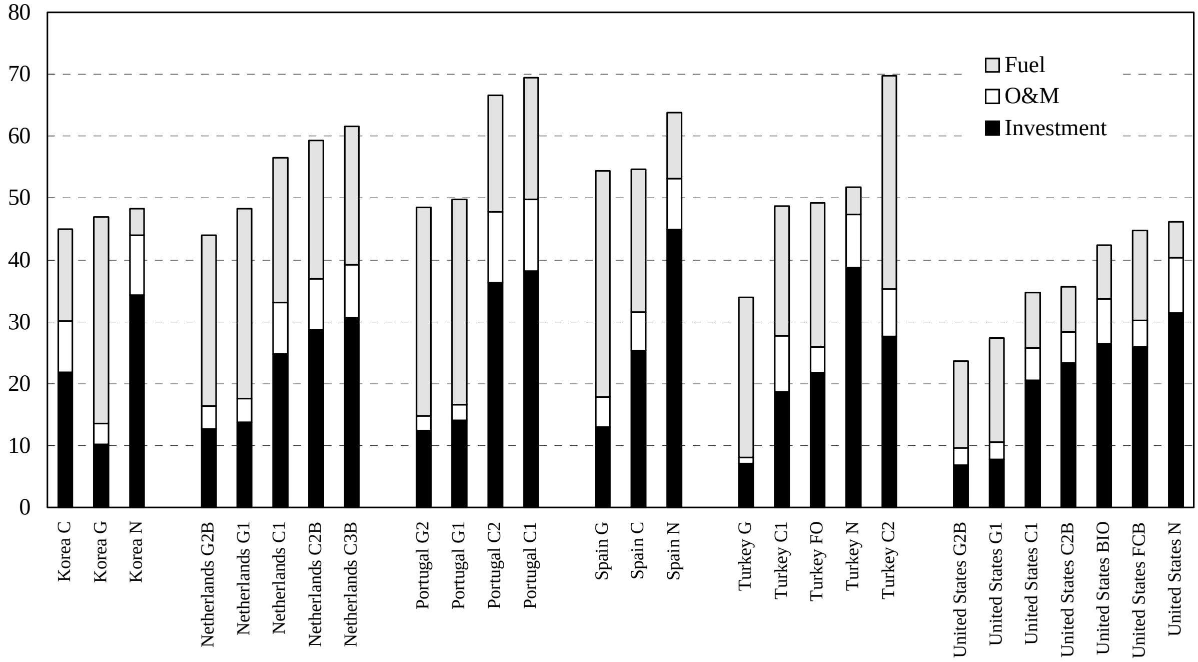


Figure 8b. **Levelised electricity generation costs calculated with common assumptions at 5% discount rate (USmill/kWh)**



Note: US results refer to the Midwest region. National calculations for the Eastern and Western regions are given in Annex 2.

Figure 8c. **Levelised electricity generation costs calculated with common assumptions at 5% discount rate (USmill/kWh)**

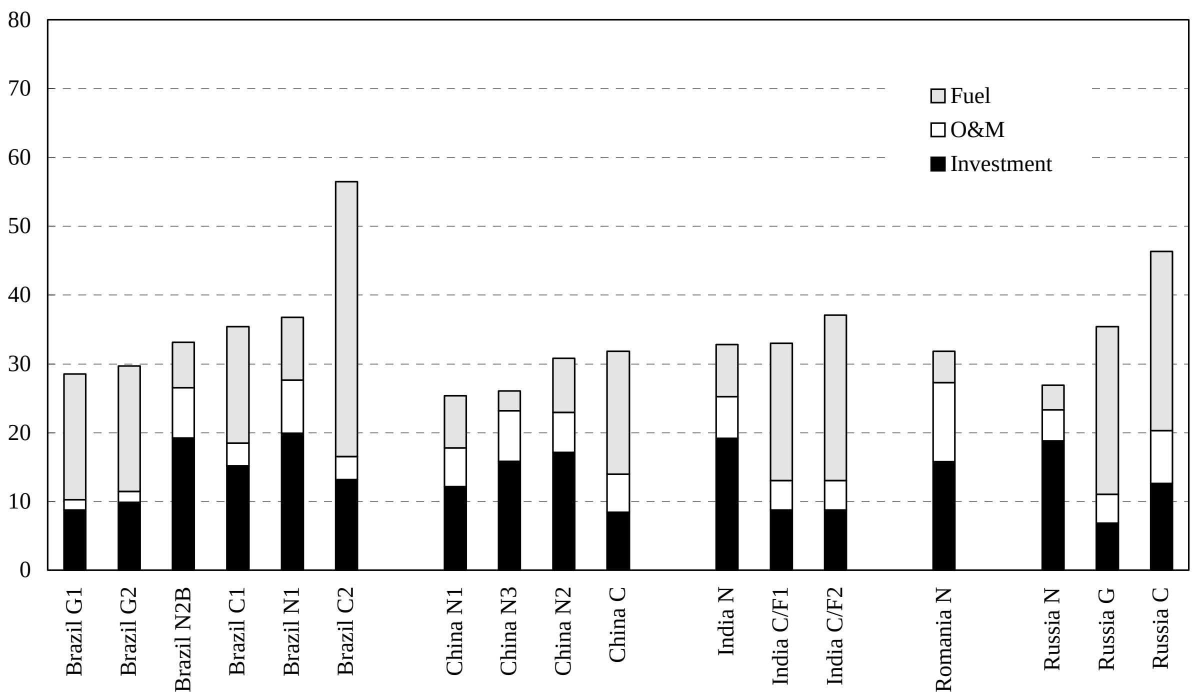


Figure 9a. **Levelised electricity generation costs calculated with common assumptions at 10% discount rate (USmill/kWh)**

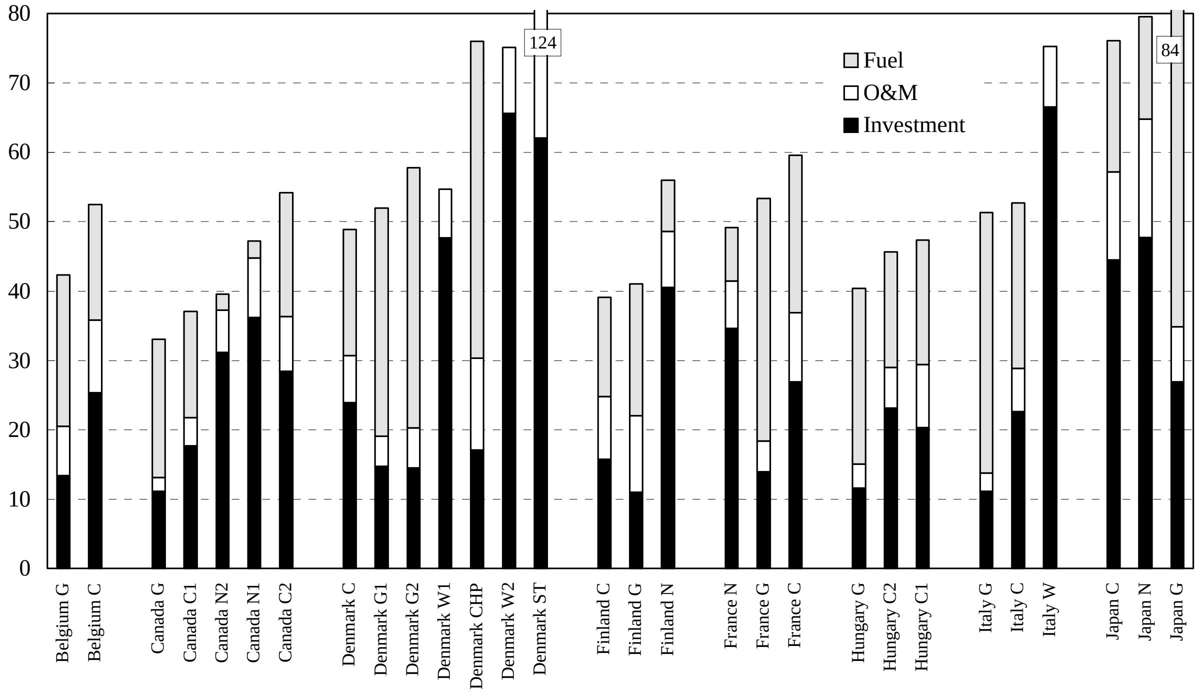
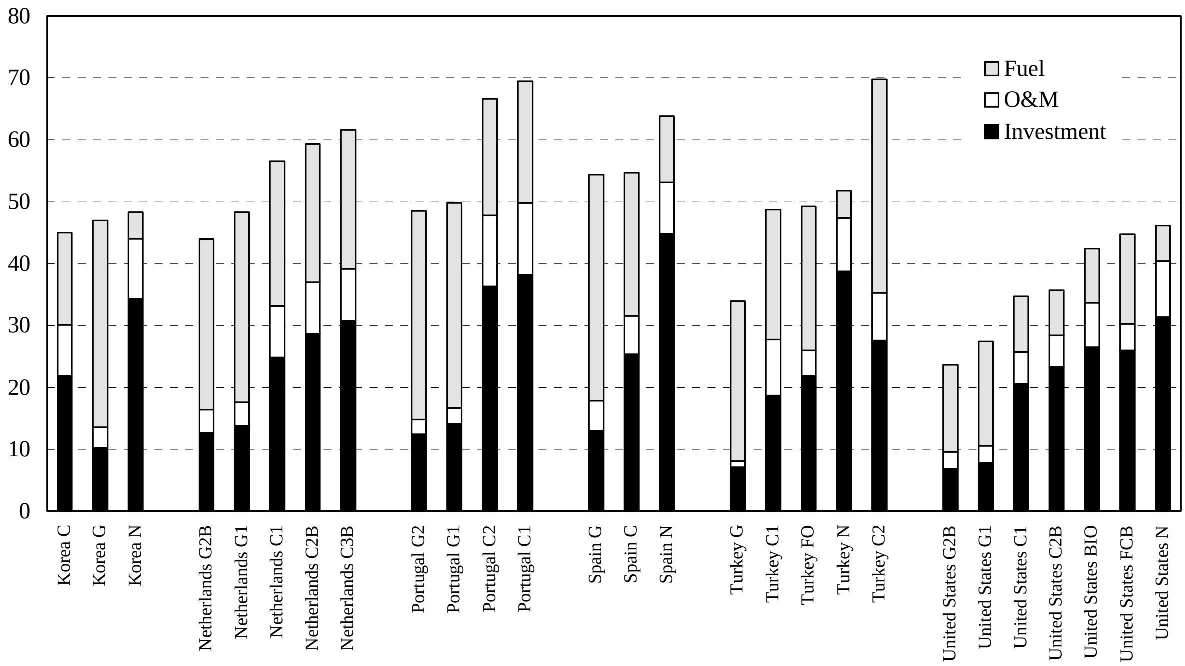


Figure 9b. **Levelised electricity generation costs calculated with common assumptions at 10% discount rate (USmill/kWh)**



Note: US results refer to the Midwest region. National calculations for the Eastern and Western regions are given in Annex 2.

Figure 9c. **Levelised electricity generation costs calculated with common assumptions at 10% discount rate (USmill/kWh)**

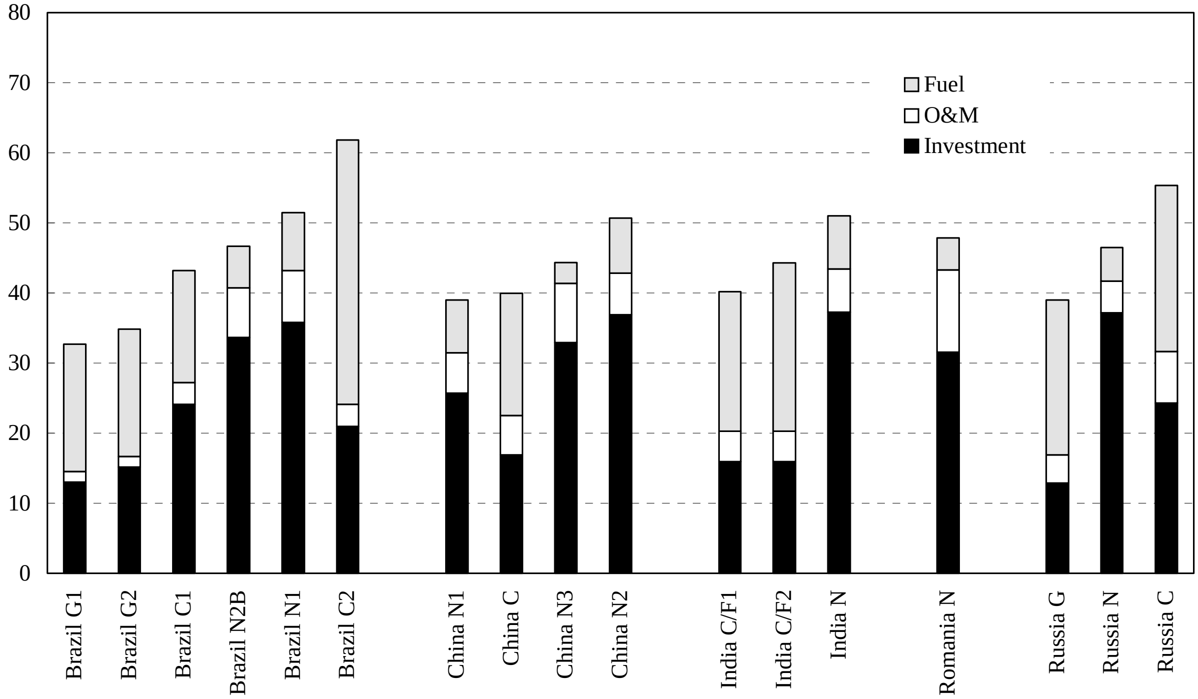


Figure 10. **Nuclear/coal generation cost ratios with common assumptions**

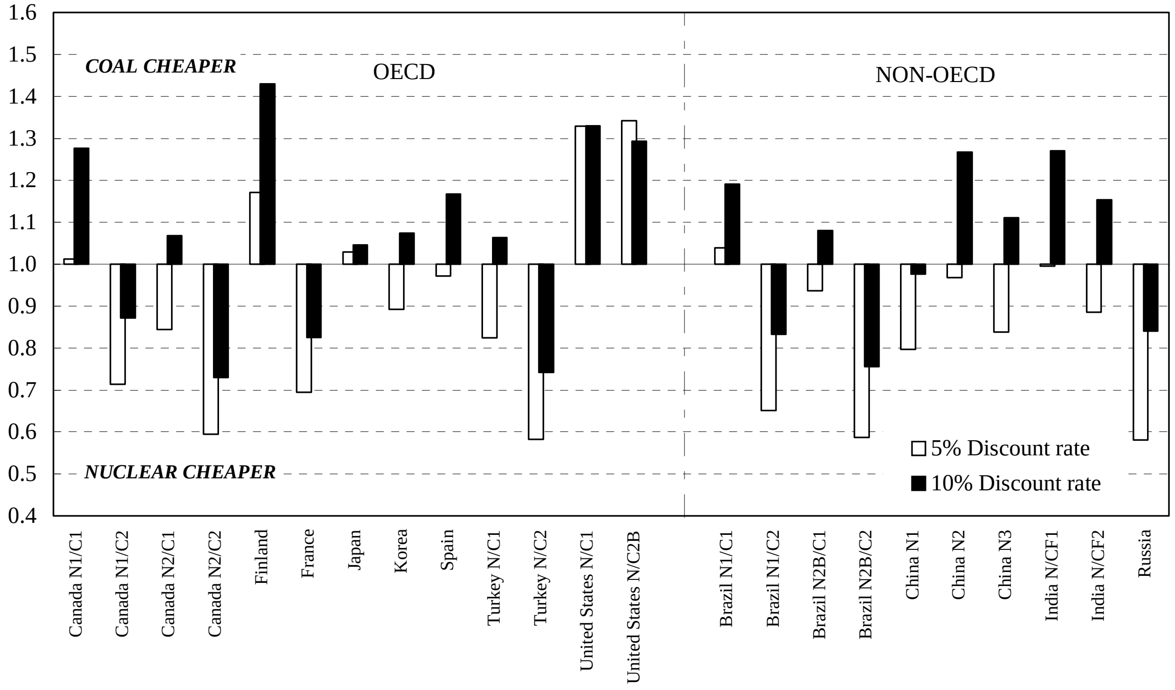


Figure 11. **Nuclear/gas generation cost ratios with common assumptions**

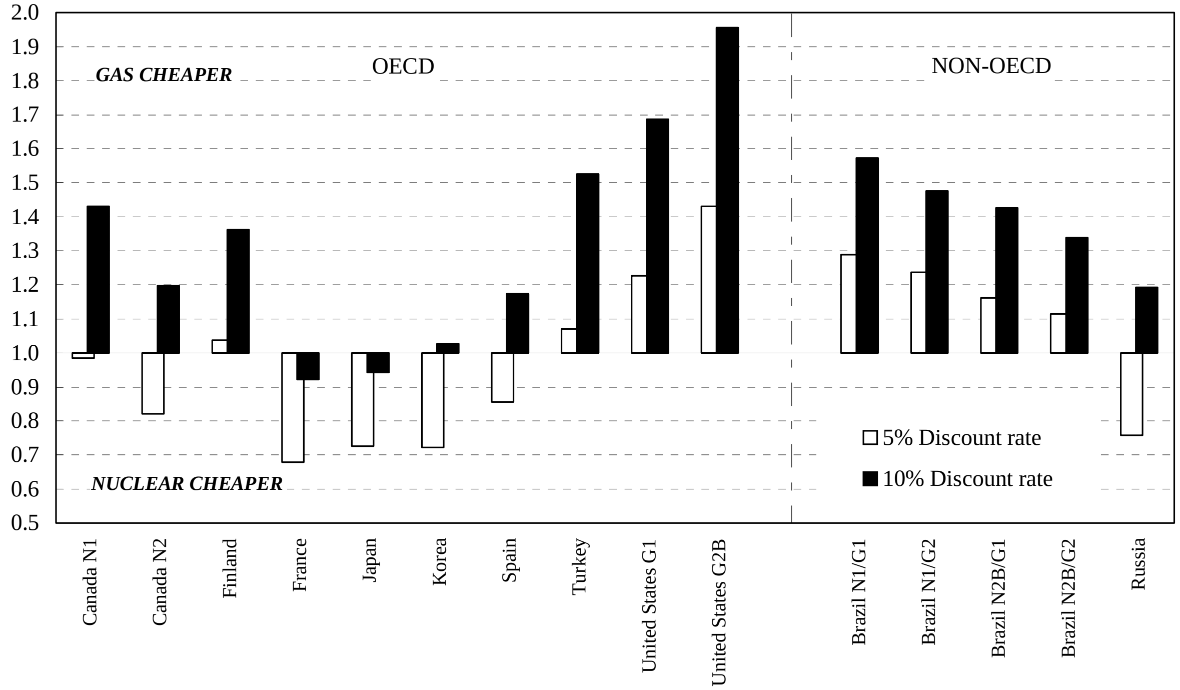


Figure 12. **Coal/gas generation cost ratios with common assumptions**

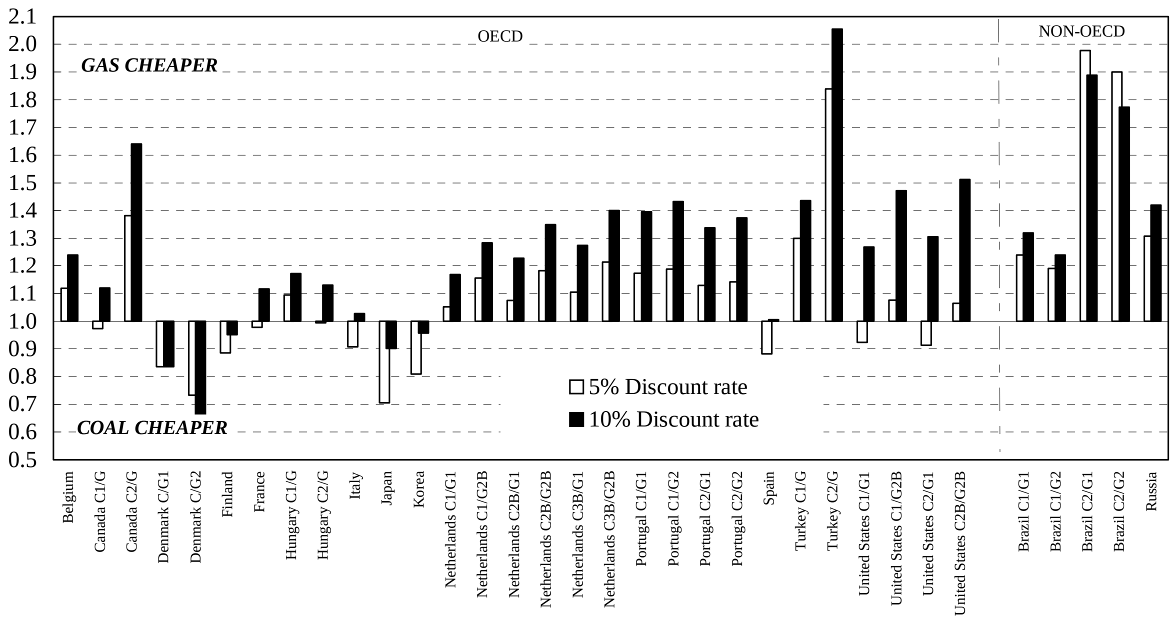


Figure 13. **Effect of constant fossil fuel price assumption on nuclear/coal and nuclear/gas generation cost ratios – 5% discount rate, 30-year lifetime, 75% load factor**

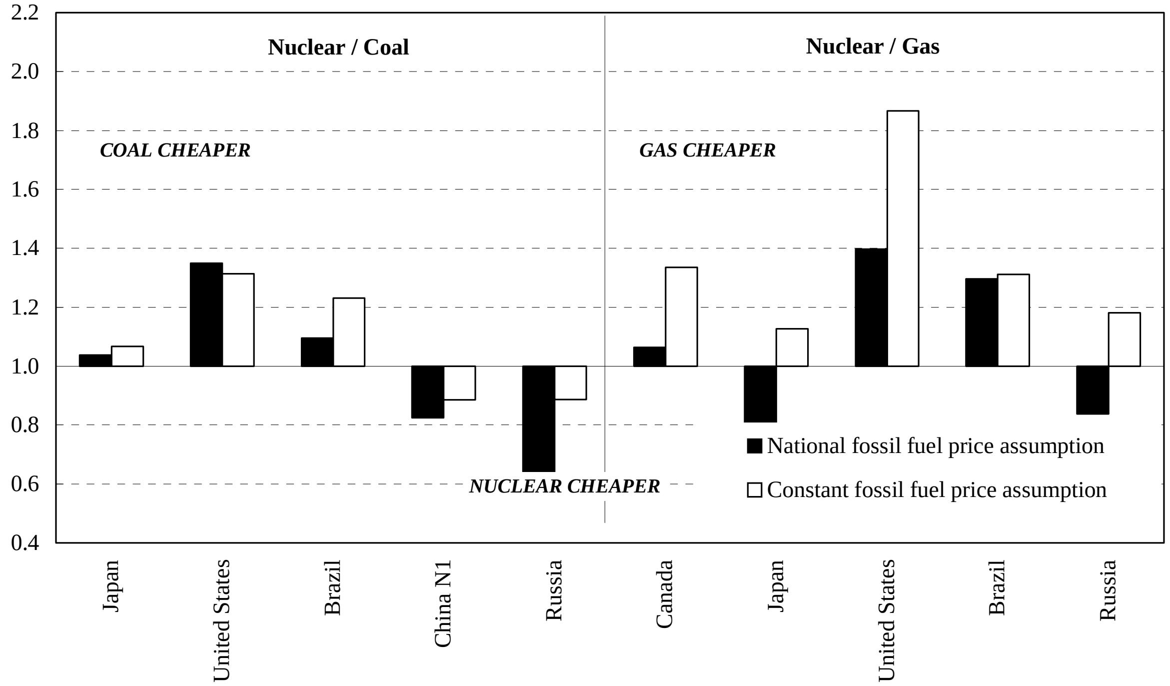


Figure 14. **Effect of constant fossil fuel price assumption on nuclear/coal and nuclear/gas generation cost ratios – 10% discount rate, 30-year lifetime, 75% load factor**

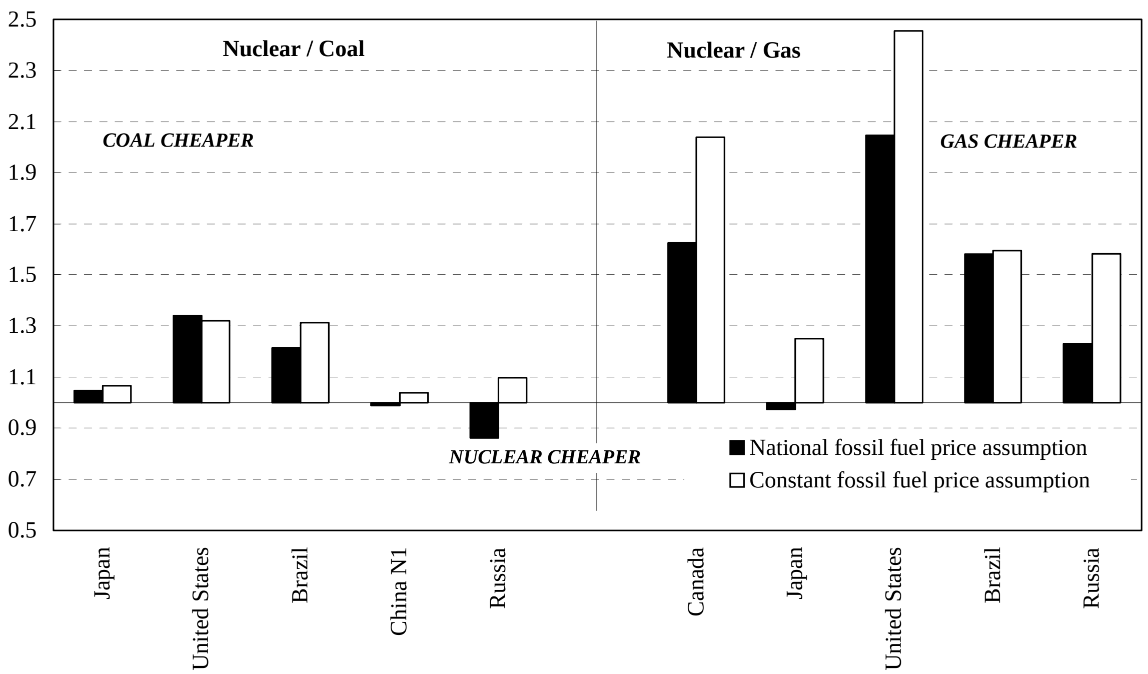


Figure 15. **Effect of constant fossil fuel price assumption on coal/ gas generation cost ratios 5% discount rate, 30-year lifetime, 75% load factor**

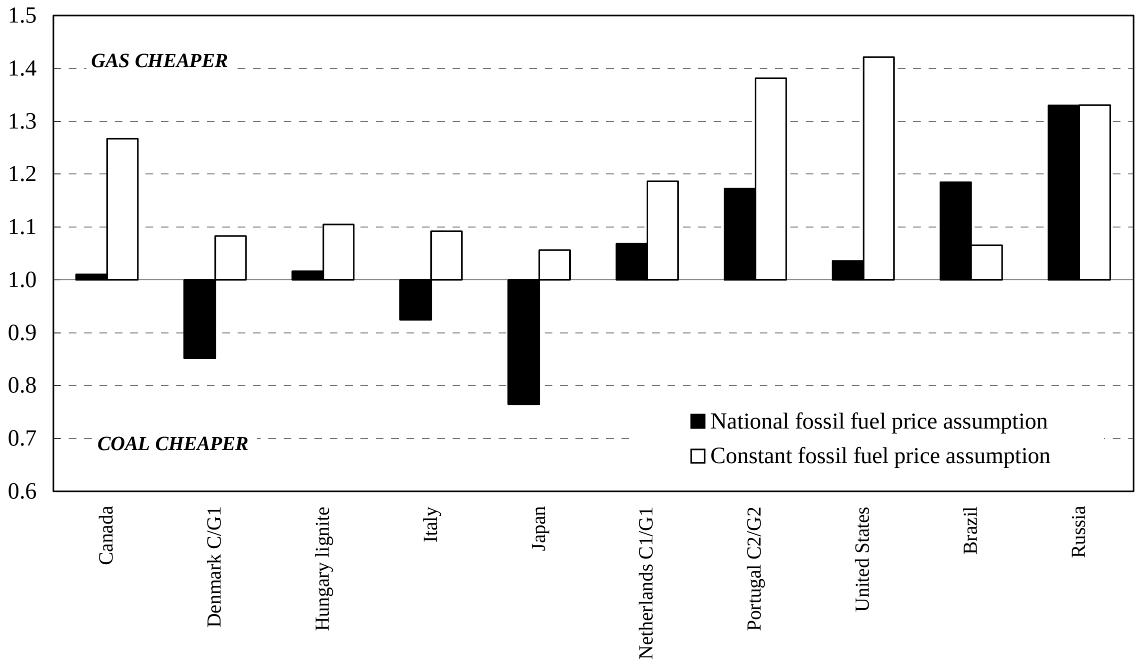


Figure 16. **Effect of constant fossil fuel price assumption on coal/ gas generation cost ratios 10% discount rate, 30-year lifetime, 75% load factor**

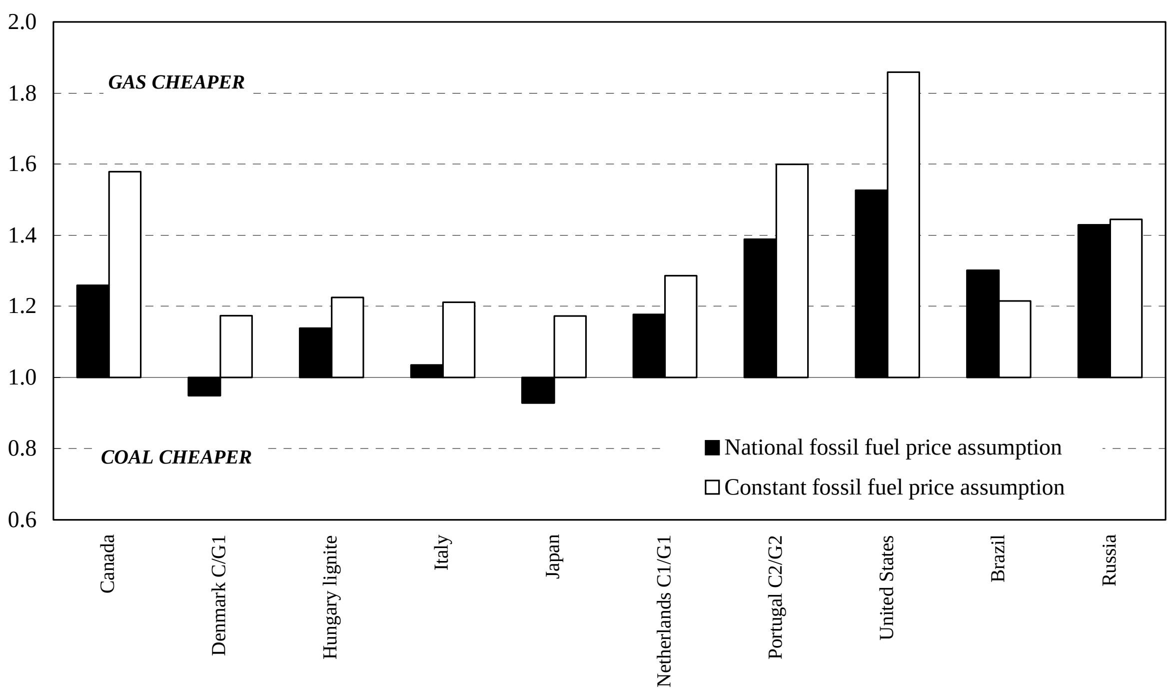


Figure 17. **Expenditure schedule versus plant size**

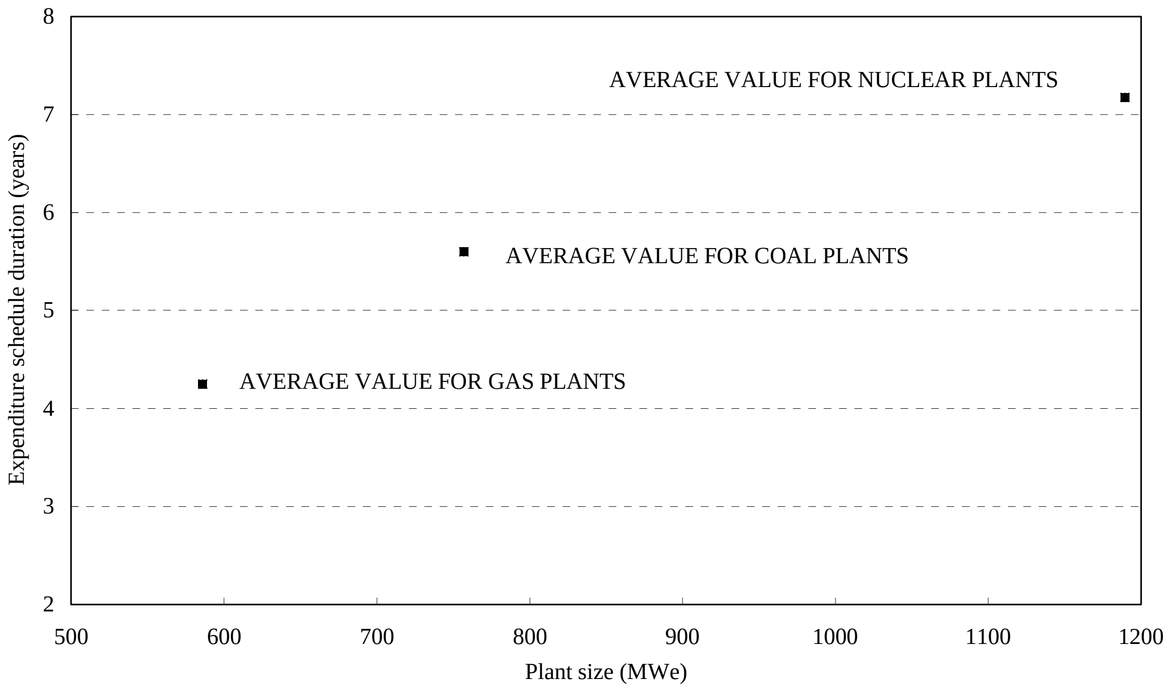
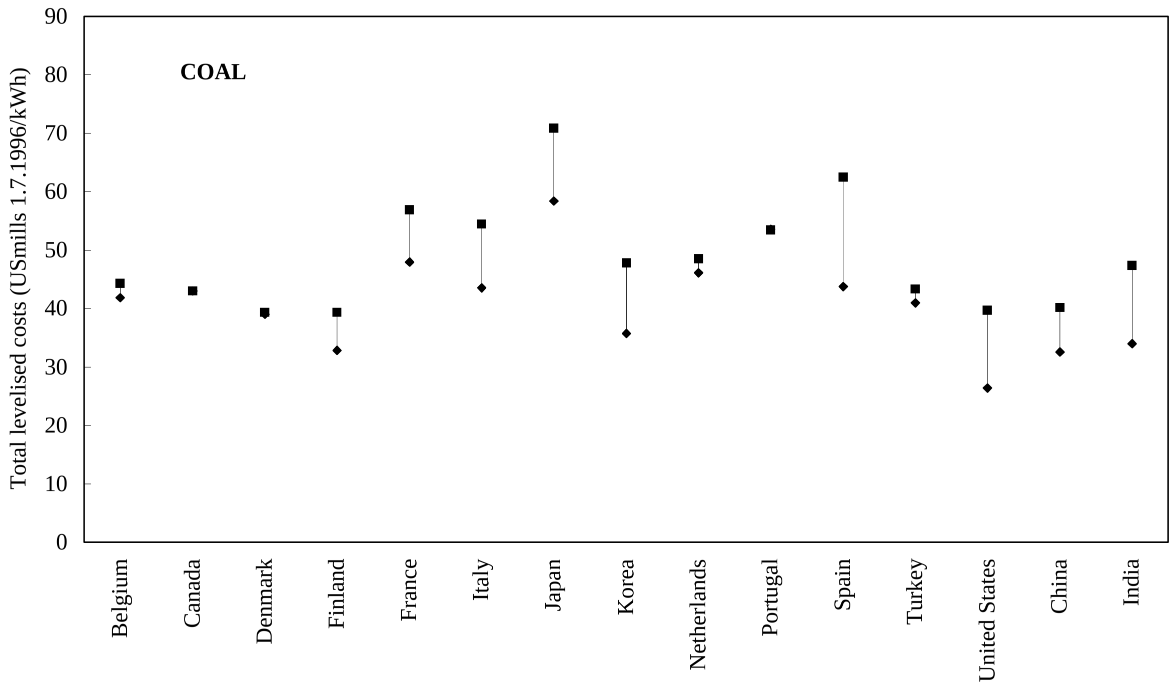
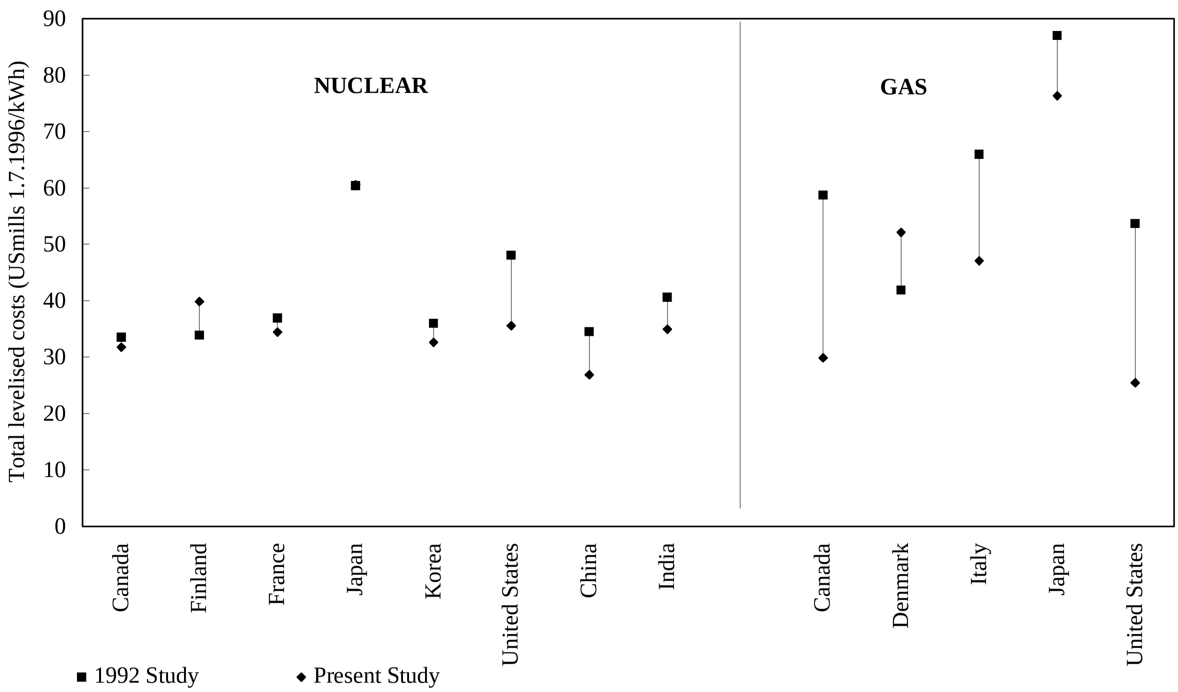


Figure 18. **Trends of projected generation costs**
5% discount rate, 75% settled down load factor, 30 year lifetime





Annex 1

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Mr. Linkang YUE	Guangdong Nuclear Power Joint Venture Co. Ltd.
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Mr. Anders H. KRISTENSEN	Danish Energy Agency
Ms. Anne H. SIMONSEN	Danish Energy Agency
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Annex 2

COUNTRY STATEMENTS ON COST ESTIMATES AND GENERATION TECHNOLOGY

BELGIUM

Electricity generation and trade

Electricity generation in 1995 amounted to 73.4 TWh, an increase of 2.8 per cent over 1994. Between 1973 and 1990, the average annual growth rate was 3.3 per cent. It fell to 0.9 per cent per year between 1990 and 1995.

Belgium’s situation in the centre of the West European grid means that trade in electricity – both imports and exports – is a significant activity of the power industry.

Over the past 25 years, the fuel mix for electricity generation has changed drastically. In 1973, more than 53 per cent of electricity generation was based on oil, followed by gas with 23.7 per cent (Dutch gas), and domestic coal with 21.7 per cent. The share of nuclear was very small with only 0.2 per cent.

After the first oil shock, strong emphasis was placed on the development of a nuclear programme. In 1995, nuclear was the main source of electricity production with 56.3 per cent followed by solid fuels – mainly imported steam coal – with 26.3 per cent. Fuel oil was used to generate only 1.8 per cent of Belgian power. Imported natural gas increased its share from 7.7 per cent in 1990 to 13.9 per cent in 1995.

Industry structure

The electricity supply industry is subject to direct Government regulation; there is a continuous dialogue between the Government and the Belgian Federation of Electricity and Gas companies. Government responsibility for the electricity supply industry rests at the Federal level with the Minister of Economic Affairs.

In 1995 about 92 per cent of Belgian electricity was generated by Electrabel, which is owned by Tractebel, a large conglomerate majority owned by the mixed public/private group Société générale de Belgique and the Groupe Bruxelles Lambert. The remaining electricity is generated by the public sector Société Coopérative de Production d’Electricité (SPE) and by autoproducers.

Municipalities have a legal monopoly over the distribution of electricity in their area for customers using a maximum of 1 MWe via networks with a voltage lower than 30 kV. Currently, the mixed sector in which municipalities join forces with a private company (= Electrabel) via the so-called "intercommunales mixtes" – intermunicipal companies – to organise distribution management and investment activities represents 80 per cent of distribution.

The national equipment programme for electrical energy production and transport

In November 1995 the Management Committee of Electricity Companies, composed of representatives of the private electricity company Electrabel and the public sector SPE, submitted to the Government a proposal for a new ten-year plan for the electricity sector. The main lines of the Plan were approved by the Federal Government in January 1996.

The final version of the plan calls for:

- Decommissioning of 24 units spread over 14 sites for a total of 3 890 MWe of installed capacity, mainly comprising 125 MWe coal-fired units that have been in operation for more than 200 000 hours.

- Upgrading existing sites by some 355 MWe, by replacing steam generators and turbines and by repowering some coal-fired units.

- Building 1 885 MWe already included in the previous ten-year Equipment Plan 1988-1998, i.e. the Belgian share of 725 MWe in the French nuclear station Chooz B and the completion of the two combined cycle stations at Herdersburg (460 MWe), near Bruges, and at Ringwaart (350 MWe), near Ghent, to be operational in 1997. Baudour has been selected as the site for the third combined cycle station (350 MWe). The three combined cycle stations mentioned have been built for base load centralised production.

- Construction of 2 250 MWe of new capacity (three 350 MWe combined cycle stations and three 400 MWe coal-fired plants). Chosen technologies: for gas-fired units; the single shaft-type; for coal-fired units: the ultra supercritical unit.

- Development of 1 000 MWe of decentralised power production, mainly industrial co-generation, and the use of renewable energy sources.

The plan does not include construction of any new nuclear plant in the next ten years.

BRAZIL

Introduction

In 1996 Brazil had a gross domestic product (GDP) cost of R$ 779 billion, equivalent to US$ 775 billion, corresponding to US$ 4 933 per capita income per annum for the total population of 157.08 million. The inflation rate had fallen from 40.28 per cent in June 1994 to 1.85 per cent in August 1994 and to 0.02 per cent in September 1996 and the economy has been stable since July 1994, which have led to a significant increase in consumption growth, including electric energy.

Restructuring and deregulation of electric power sector are underway. Given a new view of the role to be played by the Federal and State Governments, the privatisation of government owned power utilities is in progress. Four have already been privatised and the majority is expected to be privatised by the end of 1998.

To prepare the transition from predominantly hydropower to thermal generation, the electric power sector is gradually introducing thermal power plants to its expansion programmes.

With sufficient uranium reserves for a multi-unit programme, nuclear power seems to be a future alternative as a means of preparing the country for the period following depletion of the competitive hydroelectric potential. For this effort, Government decided to continue the nuclear programme reconsidering the completion of Angra II and construction of the Angra III Nuclear Power Plant.

Electric power industry

The Brazilian electric power industry comprises four Federal Government controlled companies, twenty five State Government controlled companies, one city owned company, one binational company (Itaipu Hydro), a small number of private and municipality owned utilities and a great number of self-producers. The Departamento Nacional de Águas e Energia Elétrica (DNAEE) is the grantor authority and regulatory and supervisory agency of power sector activities, under the Ministry of Mines and Energy (MME).

As a “holding company” of the electric power sector in Brazil, Centrais Elétricas Brasileiras S.A. (Eletrobrás) is a Government-owned company in charge of planning, financing and co-ordinating the execution of the country’s electric energy programme and operation of the electric power systems. It controls the four regional subsidiary companies, whose areas of operation cross state boundaries and Electrobrás whose share is 47.3 per cent of total installed capacity and 44.2 per cent of total electricity generation.

The electric power system consists of two large interconnected systems, which comprise public service utilities and account for approximately 97 per cent of the country’s total installed generating capacity. There are also roughly over 300 isolated systems, of varied size and complexity.

Regulatory norms had been restructured and means established to attract private investors, amongst which the approval of a law to permit independent power producers (IPP), to share with existing power companies the conclusion of many power plants under construction and to build new hydro and thermal power plants.

As part of the electric power sector restructuring programme, in 1993, the National Electric Power Transmission System (SINTREL) was created, with the object of allowing free access of all power sector agents to the transmission and distribution systems of power utilities, to assure the conditions under which energy can be transported from given projects via the federal grid to the consuming points.

To establish the division of costs and benefits pertaining to the use of fossil fuels in electric power generation, fossil fuel consumption accounts (CCC) were created in 1973. The invoicing amount of fuel burned by each utility, which pertains to the interconnected system, is divided for all utilities connected to the same system.

On 31 December 1996, there was 57 232 MWe of total installed generating capacity, of which 52 427 MWe (91.6 per cent) was hydro and 4 805 MWe (8.4 per cent) thermal power, including 657 MWe nuclear power. The generation of electricity was 273 827 GWh, of which 95.7 per cent was shared by hydropower plants and the other 4.3 per cent by nuclear (0.9 per cent), coal-fired (1.4 per cent), diesel oil-fired (0.9 per cent) and fuel oil-fired (1.1 per cent) power plants.

Electric power system planning

The National Electric Energy Plan 1993/2015 (The 2015 Plan), published in 1994, is the basic tool for long-term planning in the Brazilian power sector. In forecasting the electric energy market, adopted the assumption that the real growth of tariffs to a national average of 67 mills/kWh at December 1991 price level.

According to the 2015 Plan scenarios, the market for Brazil's electric systems is projected to grow from a yearly consumption of 227 TWh (27 GWyear requirements) in 1993 to 534 TWh in 2015, in the lowest Scenario I, and adding total losses between consumption and production, overall energy needs and maximum generation demand are arrived at as shown in Table 1.

Table 1. **Projected electric energy market 2015**

Scenario	Consumption [1] TWh	Generation requirements GWyear	Generation requirements GW
I	534.1	68.1	89.7
II	593.0	75.8	100.1
III	661.9	84.7	111.8
IV	743.3	95.1	125.6

1. Losses by private producers not included.

Energy resources and costs

Hydraulic

Hydraulic potential is the energy source offering the best prospects for development in Brazil in the period covered by the 2015 Plan. Strategically, it is fundamental for the power sector to proceed with development of such potential in the medium and long term.

Mineral coal

Coal is expected to play a significant role in the country's economic and energy context beginning in 2005-2010, when a substantial and competitive expansion of coal-burning generation is projected to occur. Given the features of domestic coal, as well as environmental restrictions, the use of coal requires adequate technology in circulating fluidised bed boilers, while transportation costs will probably limit use to locations close to deposits. Uncertainties with respect to environmental restrictions on construction of hydroelectric projects suggest the possibility of using domestic coal in the middle term and imported coal in the long term.

Nuclear

Brazil has sufficient uranium reserves for a multi-unit nuclear programme. Nuclear energy is a long-term thermoelectric alternative within the 2015 Plan, preceded by programmes based on coal, natural gas, other oil derivatives and biomass.

In the short term, Electrobrás will seek to resume construction work on Angra II at a normal pace. As for Angra III, measures will be taken to preserve equipment already purchased, with plant implementation plan being prepared so that start-up could occur in 2005.

Given reference costs of 60 to 70 mills/kWh (December 1991), nuclear-based electricity will not be competitive with that produced in hydroelectric plants over the period covered by the 2015 Plan. However, the Government deems it desirable not to discard access to nuclear energy as a future alternative, as a means of preparing the country for the period following depletion of the competitive and environmentally feasible hydroelectric potential, when thermoelectric generation will have to be expanded.

Natural gas and petroleum products

Brazilian reserves of natural gas and oil are small and do not warrant heavy investment in power plants burning these fuels. Following displacement as a result of the use of natural gas, fuel oil may become available for thermal generation, in addition to heavy residues (asphaltic and viscous) in integrated oil/electricity programmes. In the case of small, isolated systems, diesel oil will continue to be used in electricity production.

Sugarcane residues and biomass

Readily available, sugarcane residues offer great possibilities, one of which involves private cogeneration projects, in conjunction with sugar and alcohol manufacturers. Autoproducers may sell their surplus electricity power utilities at prices competitive with the marginal costs of system expansion in the short term.

Approximately 30 per cent of the total green coverage in the world is located in Brazil – something like 280 million hectares of tropical forests. As for using biomass products for generating electricity, fuel is amply available in the country. Table 2 shows the forest biomass potential in the Northeast region of Brazil. Current limitations will have to deal with the related technologies and resulting energy costs. Depending on the outcome of an ongoing development programme, which includes gasification of firewood and the use of efficient gas turbines, this alternative may effectively contribute to the energy balance in the medium and long term.

Table 2. **Northeast forest biomass potential**

Description	Area and potential
Total area	1 543 000 km^2
Area recommended for reforestation	505 000 km^2
Annual potential using up to 5% of the area	20 000 MWyr
Annual potential for all usable areas (32.7% of the region's total)	61 000 MWyr

Alternate sources and others

As for alternate sources, wind energy may be used in small isolated systems in conjunction with thermal units fuelled by oil products, as well as in the interconnected system, cost savings being realised via energy storage. Also to be considered is the use of solar energy, including photovoltaic utilisation, in the short term and in small isolated systems, depending on the development of the related techniques and eventual cost reductions. Because of technological difficulties, other sources such as schist, hydrogen, tidal energy, organic residues, peat and lignite offer no great promises for use in the time period covered, limited to specific uses and locations, as is the case of organic residues, which may be an attractive environmental solution in large urban centres.

In some cases, electricity trade with neighbouring countries can be an economic operation, especially for optimisation purposes such as reducing oil consumption and deficit risks in electric systems.

Generation costs

In the Table 3 are shown the main energy resources, as regards hydroelectric, coal and nuclear, for generating electricity and its cost, and in the Table 4 the other sources.

Table 3. **Energy resources for generating electricity**

Source	Potential GWyear	Potential GW	Cost mills/kWh[1]
Hydraulic[2]	123.5	247.0	33% below 40; 39% 40 to 70; 28% above 70
Coal[3]	12.0	18.0	50 to 65
Nuclear[4]	15.0	25.0	60 to 70
Total	150.5	290.0	–

1. Costs include investment, operation/maintenance and fuel (constant December 1991 USD).
2. Includes 95 per cent of total potential, for which costs are available; it estimated that roughly two-thirds of the hydroelectric potential is economically competitive and environmentally feasible; approximately 25 per cent corresponds to plants in operation or under construction.
3. Includes the potential associated with open pit mining for thermal generation only.
4. Includes recoverable reserves of domestic uranium (120 tons of U_3O_8) only, with recycling of residual uranium and plutonium.

Table 4. **Other energy resources for generating electricity**

Source	Cost mills/kWh[1]	Source	Cost mills/kWh[1]
Natural gas	40 to 50	Wind	40 to 80
Oil products	50 to 60	Solar thermal	100 to 200
Biomass/sugarcane residues	40 to 80	Solar photovoltaic	250 to 500
Organic residues	45 to 90	Shale/hydrogen/peat/lignite	N/A
Tidal	50 to 110	Interchange with neighbouring countries	–

1. Constant December 1991 US$.

Under a Government programme, several new projects using wind and photovoltaic technologies will be developed in locations lacking electric energy.

The design of an innovative thermal solar plant has been consolidated and is now in the financing procurement stage.

A 30 MW biomass power demonstration project, based on firewood IGCC, is in progress and its construction is expected to begin in the near future. Its operation for demonstration is planned to begin in 1999 and commercial operation in 2001. The cost of the project is estimated to be US$ 110 million. It is funded by the Global Environmental Facility (GEF). The main technical and economic parameters of the project are shown in the Table 5.

Table 5. **Thirty (30) MW Biomass demonstration project technical and economic parameters**

Description	Parameters
Installed capacity	40.4 MW
Net output	31.9 MW
Thermal efficiency	40.1 %
Load factor	80%
Electricity generation	223 000 MWh/yr
Fuel consumption	242 000 m^3/yr 1.08 m^3/MWh
Forest area	96.8 $10^6 m^2$

Description	Parameters
Heat recovery boiler	55 t/h
Steam temperature	480°C
Steam pressure	64 bar
Gas turbine	24.3 MW
Steam turbine	16.1 MW
Investment cost	2 750 $/kWe
O&M cost	5 mills/kWh
Generating cost	53 mills/kWh

Cost estimates provided for the present study

With the beginning of privatisation of electric power sector, budgets and cost estimates of power plants are re-evaluated to meet the real market price. The nuclear sector is also reviewing the design concept and the cost of the new power plant. Costs presented in the questionnaire took into account these new concepts.

Fuel prices were assumed to rise at a 3 per cent real escalation rate. Coal prices currently used by utilities were projected according the 2015 Plan. Natural gas prices were estimated based on Brazil-Bolivia Gas Pipeline Agreement and the uranium prices according to the tendency in the world market. Operation and maintenance costs, as well as investment costs, were calculated based on recent projects costs and past experience.

Interest during construction, as well as the generating costs, was calculated using the methodology of International Atomic Energy Agency (IAEA), as presented in the Technical Reports Series No. 241 – A Guidebook for Expansion Planning for Electrical Generating Systems (1984).

Usually, 80 per cent capacity factor for thermal plant base load and 10 per cent discount rate are used in national cost estimates. However, for sensitive studies alternative discount rates of 12 and 15 per cent are adopted. For the national electric energy expansion studies, the marginal cost methodology is used to calculate the generating cost of system expansion.

CANADA

Compared to previous studies, a smaller set of cost data for Canada has been provided for this year’s study.

For the 1992 study, Canada provided cost data for four different regions of the country: Ontario, Alberta, Nova Scotia and New Brunswick along with generic Candu data by Atomic Energy of Canada Limited. The electricity market situation in all regions of Canada has evolved dramatically since the last study. Because of trends towards deregulation in the North American electricity market and introduction of competitiveness and privatisation in Nova Scotia, New Brunswick and Alberta, these utilities indicated that they were unable to participate in this year's cost study. Ontario Hydro which is also faced with the same pressures was able to provide only a small set of data based on their most recent paper cost studies.

Atomic Energy of Canada Limited (AECL) has provided cost data for a Candu 6 station (2x665 MWe) and for a Candu 9 station (2x881 MWe). The Candu technology for the 2x665 MWe plant presented in the study is an upgraded version of the technology used for Candu 6 plants in operation or under construction in Quebec, New Brunswick, Korea, Argentina, Romania and China. The Candu technology for the 2x881 MWe plant is a larger Candu design and an upgraded version of the four 881 MWe units in operation at Darlington, Ontario.

Ontario Hydro has provided some cost data for combined cycle gas, conventional coal and fluidised bed combustion. Gaps in the data provided by Ontario Hydro have been filled with estimates obtained from other sources in Canada including the Canadian National Energy Board.

In essence, two types of approaches have been used by utilities for planning purposes: the annual average cost approach and the Levelised Unit Energy Cost or LUEC cost approach. The LUEC is the approach adopted by the NEA and is also used by AECL the Canadian Power utilities and the Department of Natural Resources for comparison of different types of new generation to meet future needs.

In their evaluation of new nuclear plants, AECL has adopted a fundamental set of principles and economic assumptions in order to ensure relevance for future base load nuclear systems. These are: a 5 per cent real interest rate, a 40-year life of plant and an 85 per cent capacity factor for base load plants. Comprehensive cost models are used by AECL which define all components of the capital, operations, maintenance and administration and fuelling costs. These models are used to calculate LUECs 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 these are reflected in the capital cost account.

The capital costs for the nuclear units also include initial load of heavy water, initial fuel and decommissioning costs. Front-end and back-end fuel costs (excluding initial fuel) are reflected in the fuel costs while operation of waste systems is included in O&M costs.

With respect to spent nuclear fuel, spent fuel is put into water-filled bays or dry storage containers at plant sites for a planned period of ten years. The utilities include capital and operating costs of these bays and containers in their normal annual generation costs and these are incorporated in electricity rates charged to consumers. In addition, a charge is also added to generation costs (and utility rates as a provision for subsequent costs of transportation, immobilisation and ultimate disposal. A similar provisioning is added for station decommissioning and these costs are passed on to consumers.

Canada has no plans to reprocess its spent fuel. A concept has been developed for the encapsulation and ultimate disposal of the fuel in hard rock of the Canadian shield. The concept is undergoing review in Canada by an environmental assessment panel. The panel undertook public hearings on the concept in 1996-97 and is to release its report in early 1998.

Fuel prices have declined slightly since the last study. Relatively low nuclear fuel costs estimates for the Candu are largely due to the fact that Canada uses natural uranium as fuel in its reactors. Candu fuel does not require enrichment. Like several other participants in the OECD study, Canada is able to avoid the additional uranium enrichment costs. Furthermore, the uranium price is expected to remain at its presently low value over the economic lifetime of the plants considered in this study.

Construction schedule for nuclear is about six years for a Candu 6 and about five years for a Candu 9. The Candu 9 is expected to take less time to build because of its advanced design employing an open-top construction method.

CHINA

In the mainland of China, the first nuclear power unit, 300 MWe PWR unit at Qinshan, the Zhejiang Province, started to be built in the 1980s. Since then, more and more coastal provinces in the east and southeast of China have been interested in introducing nuclear power to electric systems. The central government is also encouraging these provinces to build nuclear power units through providing policy support and construction fund. The reason is very clear that the energy resources in the area could not meet the requirement of the economic growth and social development for electricity supply, and that the utilisation of fossil fuel in the electric industry has already brought and will continuously bring on serious environmental pollution in the area.

Nuclear power development

During the period of the Ninth Five-year Plan (1996-2000) the following four nuclear power projects with 8 units will be constructed in China:

1. the second phase of the Qinshan Project (2x600 MWe PWR);

2. the third phase of the Qinshan Project (2x700 MWe CANDU);

3. the Lingao Project at the Guangdong Province (2x1 000 MWe PWR); and

4. the Lianyungang Project at the Jiangsu Province (2x1 000 MWe VVER), instead of the originally-planned project at the Liaoning Province.

According to the plan, these four projects will be completed around 2003. However, only the information of the first three projects are provided here, because the fourth project, the Lianyungang Project, is still under negotiation.

China will need the electricity generation capacity of 550 GWe totally in 2010, and among them about 20 GWe (about 3.6 per cent of total) are assumed to be nuclear power units.

However, apart from the safety character of nuclear power, the development of nuclear power in China will decisively depend on the economic competitiveness with coal-fired power units.

At present, nuclear power development in China is still in its initial stage. The domestic industrial capabilities could not meet the demands of utilities for nuclear power units of a large size. However, the imported nuclear units are normally much more expensive than coal-fired units in specific investment (the investment per kWe). As an example, the investment cost was about 2 000 US$/kWe (including interests during construction) for Daya Bay nuclear power plant of 2x900 MWe units when it was completed. But, the capital cost of coal-fired units, at the time, was about 600-800 US$ per kWe. Even current cost estimates are around 700-1 000 US$/kWe for a new coal-fired power plant of two units of 300-600 MWe size without desulphurisation which will be put into operation around 2000. In this case, the generation costs of imported nuclear power units are certainly higher than that of coal units.

Among the above four new nuclear projects, only Qinshan Phase 2 will be mainly home-made with a certain extent of foreign co-operation and, hence, its capital investment cost per kWe will be lower than that of other projects. In order to promote nuclear power development, the authorities concerned are paying more and more attention to the self-reliance for the nuclear programme of the next century, which will finally lead to reducing the construction and generation costs of nuclear power. But up to now, it has not been decided which type of nuclear units will be mainly developed in the next step. The technical line to develop nuclear power in China was determined in the 1980s, that is, the PWR type with 300 MWe of each loop would be dominantly developed and constructed. This technical line was followed in the Qinshan nuclear project of Phases 1 and 2, and will be followed, at least, in the first decade of next century. However, the conventional types of PWR could not meet the requirements in the near future for improving safety and economic characteristics. In some countries, several kinds of evolutionary, innovative and revolutionary types of nuclear reactors are under development or even constructed. According to the above-mentioned technical line of nuclear power development, China has made efforts for some years to develop a passive type of pressurised water reactor, e.g. AC600. Apart from this, other types of new nuclear units for the next century are also under consideration now. But the decision has not been made yet. So, in this study, the information on nuclear units, available during 2005-2010, was not provided.

Cost estimates

In this study cost estimates were provided for three new nuclear power plants and one coal-fired power plant. All the plants were assumed to be built in the coastal area of the East and South-east China, and completed by 2005 in order to be consistent with the common assumption adopted by the Expert Group regarding commissioning date.

Cost estimates for the nuclear projects were based upon their feasibility studies. They were adjusted and expressed in national currency unit of 1 July 1996 taking into account inflation, interest rates and the exchange rate between Chine RMB Yuan and foreign currencies in the past years.

Regarding to the Qinshan phase 2, its budgetary estimate of capital investment will be adjusted officially this year due to the high inflation and interest rates and the changes of exchange rates of foreign currencies to RMB in recent years. In this case the data on the construction cost of the 2x600 MWe PWR, presented in this study, was just re-estimated privately by the expert group participant.

Based on the Detailed Performance Rules of Economic Evaluation for Electric Power Construction Projects, issued by the authorities concerned, the capital investment costs of projects are distinguished into three types: base cost (overnight cost), fixed cost and total construction cost.

For a nuclear project the base cost of capital investment is normally composed of the following items:

1. expenses at leading time including land cost and site preparation cost;
2. equipment purchasing, transportation and insurance fee;
3. construction and erection costs;
4. costs of design, engineering and services;
5. project management cost;
6. start-up cost;
7. two third (for PWR) or total (for PHWR) cost of nuclear fuel of the first core; and
8. contingency allowance.

The contingency allowance, as a matter of fact, in the base cost includes the real escalation during construction period, which may be different from other countries.

The fixed cost of the project is equal to the sum of its base cost and escalation allowance related to the inflation.

The total construction cost consists of the fixed cost, interests during construction and other financing fees.

The base costs (including contingency) of Qinshan 3 and Lingao projects were adjusted to the date of 1.7.1996, being 1 465 and 1 534 US$/kWe, respectively, and differing from those in their feasibility study reports. For Qinshan 3 the initial heavy water cost was not included in its base cost and was treated as part of O&M cost due to repaying it during the first 15 years of operation period.

The O&M cost estimates include the so-called overhaul fund, calculated as a percentage of the project's assets, which covers refurbishment costs. For imported nuclear units, the overhaul fund represents 1 per cent of the fixed asset; for units such as Qinshan Phase 2, the overhaul fund represents 1.5 per cent of the fixed asset.

As to the decommissioning cost, it was estimated at a rate of 10-15 per cent of the fixed asset of project, depending upon the unit size. In this study 10 per cent was employed.

The front-end cost of nuclear fuel for PWR unit in past several years raised at a rate lower than that of inflation, so that a zero escalation was adopted for the front-end cost of nuclear fuel.

The back-end cost of fuel cycle includes the items of transportation of spent fuel, reprocessing and waste conditioning, and 800 US$/kgU with zero escalation was estimated for PWR according to experiences of other countries.

In this comparison, 2x600 MWe super-critical pulverised coal combustion units with desulphurisation equipment were assumed to be constructed in the same area as nuclear units will be.

For coal-fired power projects, the overhaul funds in O&M cost estimate take 2.5 per cent of the fixed assets of projects according to the relevant rules.

Now it is very difficult to make projection of coal price in the next two or three decades. During 1995-1996 the price of raw coal from Datong Coal Mine in North China rose from 230 to 290 Yuan/ton at Shanghai port. The real annual escalation rate was about 1.4 per cent. Also, it should be pointed out that the market coal prices are significantly different in the coastal areas of China such as Zhejiang, Fujian and Guandong provinces. However, the majority of coal supply for all state-owned coal-fired power plants has been met by the so called “electricity coal”, the prices of which are lower than those on the international coal market.

DENMARK

Denmark has, due to a 1985 decision by Parliament, no nuclear power. Electricity production is based mainly (approximately 75 per cent) on coal-fired steam turbine plants. Most of the steam turbine plants are extraction units, where a varying part of the heat is used for district heating.

Wind power produces approximately 3 per cent of domestic electricity consumption. Natural gas and biomass were introduced as fuels for electricity production a decade ago. The share of electricity produced on these fuels is rising. In 1996 approximately 20 per cent of the production for domestic use was based on these fuels.

Natural gas is an indigenous resource from the Danish part of the North Sea. Natural gas is mainly used in small scale district heating CHP plants and for industrial cogeneration. Extensive CHP programmes were approved by parliament in 1986 and 1990. Today 1 400 MW based on natural gas, biomass and waste is commissioned or approved. The Danish power and heat sector is obliged to use at least 19.5 PJ biomass in year 2000.

A 396 MWe gas-fired steam turbine plant was commissioned in 1997 and a 385 MWe coal-fired steam turbine with supercritical steam cycle and an electric efficiency of 47 per cent is to be commissioned in 1998. A 400 MW gas-fired steam turbine plant has been approved for commissioning in 2003.

Denmark has set a national target of reducing CO_2 emissions by 20 per cent in 2005 as compared to 1988. In the government’s most recent energy plan, Energy 21, it is assumed that coal is not used in new power plants (plants not yet approved). Coal is, according to the energy plan, to be completely phased out in 2028. New capacity will be based on natural gas and biomass.

Denmark has a surplus capacity for power production as compared to domestic demand, however new capacity are being built for other reasons. For example, new plants will be built to cover a greater share of the heat demand by CHP. Also, they will be introduced to obtain other environmental improvements by switching away from coal to biomass, natural gas, renewables, wind power etc.

Taxes and subsidies

Electricity production in Denmark is non-profit and tax free. To encourage a conversion from simple district heat production to combined heat and power production a subsidy is granted to electricity produced on small scale CHP based on gas and renewables. The subsidy is intended to support electricity generation options that produce no carbon dioxide or that produce less carbon dioxide than others, because, in Denmark, there are no CO_2 taxes on fuels used for electricity generation. The subsidy is a means to compensate the low or no-emitting fuels for the lack of such a CO_2 tax. Furthermore there is an additional subsidy to electricity based on renewables including wind.

There is a carbon tax on electricity consumption equalling 17 US$/ton CO_2.

Market conditions

The Danish utilities are regulated by the Electricity Supply Act (ESA). In June 1996 the Danish Parliament passed a bill which allowed for third party access (TPA) to the grid that came into force on 1 January 1998 after its approval by the European Commission. Among other things the TPA-law ensures an option to protect heat customers in the (unlikely) case that the power necessarily produced from CHP cannot be sold at a price covering costs.

The generation cost estimates

The generation cost estimates are based on information in the Danish Energy Agency's so-called Technology Catalogue, published in December 1995, as part of the preparations for the governments action plan on energy – Energy-21. The information contained in the Technology Catalogue was provided by utility experts, and has been confirmed and, where necessary, updated in spring 1997 for the purpose of this study.

All cost estimates for steam cycle plants are based on plant types already built or approved. They are all CHP-plants but the cost estimates for the power production will be the same for these plant types, irrespective of whether or not the heat option is built.

The cost estimate for a 100 x1.5 MW off-shore wind-turbine park is drawn from two small-scale demonstration projects and from a draft report of the off-shore wind turbine committee, where A.O. the Danish Energy Agency and the utilities participate. The cost estimate for off-shore wind turbines is a maximum as there are several options for saving costs as the off-shore technology matures. The most expensive part off-shore is the foundation and the tower construction which is designed for a 40-year lifetime. After 20 years new rotor blades and turbines are provided.

For the two types of wind turbine parks, we have not included costs of back-up power. As long as wind energy is only contributing marginally in the energy system, specific back-up is not needed. In a longer term perspective, the combination of wind energy and easily modulated gas turbines seems to render benefits in terms of cheap and flexible back-up.

For all technologies, Denmark has also provided cost calculations with non-generic assumptions. For the straw-fired plant, the gas motor and the land-based wind turbines, a lifetime of 20 years is assumed and a base load factor below the 75 per cent. We have not calculated cost estimates prolonging the lifetime from 20 to 40 years (the generic assumption) as estimating cost profiles of new (replacement) technologies available 20 years from now is flawed with great uncertainty.

For the steam plants non-generic assumptions are 30-year economic lifetime and 75 per cent load factor. The Danish experience points out that once a coal-fired plant is 25-30 years old, prolonging its life is seldom economically founded but may be desirable for the utility for other reasons. For example, a new plant using the same fuel or new site would not be approved or the energy authorities might not demand environmental measures to be taken on an old plant with a limited lifetime left but would for a new plant. Therefore societal economic considerations point to total replacement rather than just refurbishment of the plant after approximately 30 years of operation.

FINLAND

In June 1995, the Electricity Market Act came into effect. This act removed a number of licences on power plant construction as well as imports and exports of electricity; opened up the network to third parties whose consumption exceeds 500 kW (power restriction was removed in January 1997); improved transparency by separating the accounts of monopoly and competitive business with the power companies and eliminated exclusive franchise rights in sales. The Electricity Market Authority is responsible for monitoring network companies and transmission rates.

In the Finnish electricity supply system, some 370 power plants are owned by about 130 power producers. The producers can be divided into three ownership categories: state power companies (40 per cent share of the generation), energy-intensive industry (40 per cent share of the generation) and municipalities (20 per cent share of the generation) which are operating on a non subsidised, competitive market basis. The largest generators are state-owned Imatran Voima Oy and Pohjolan Voima Oy (an industry consortium dominated by pulp and paper enterprises). The four nuclear power plants are owned by Imatran Voima Oy (two reactors) and Teollisuuden Voima Oy (two reactors), which is a subsidiary of Pohjolan Voima Oy.

As the power generation is based on competition and no licences are needed for power generation and construction of power plants (licences for nuclear and hydropower plants are needed according to specific legislation), there are no central planning procedures in Finland. Thus, the Finnish cost estimates are made by the Finnish energy consultant Energia-Ekono. The costs for the coal-fired condensing power plant are based on an ordered plant while the costs for the natural gas combined cycle power plant and the nuclear power plant are paper studies. Cost comparisons are made on constant money basis using a discount rate of 5 and 10 per cent. The technical life time is assumed to be 40 years. The fuel prices of the calculations are based on the current levels.

In 1996, 32 per cent of the Finnish generation was produced in CHP plants. One of the main advantages of CHP plants is high total efficiency for electricity and heat generation of some 80 per cent.

The technical assumptions of the power plants are as follows:

- Coal-fired condensing power plant is based on a 500 MWe pulverised technology with low-NO_x-burners and catalytic reduction for NO_x (50 mg NO_2/MJ fuel). Net thermal efficiency is 42 per cent.

- Natural gas combined cycle power plant is based on two 350 MWe units with dry-low-NO_x-burners (emission level 45 mg NO_2/MJ fuel). Net thermal efficiency is equal to 56 per cent (at temperature -5°C).

- Nuclear power plant is 1 000 MWe (3 000 MWth) BWR plant.

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. The last report of this group has been published in 1997, and the French responses to the questionnaire have been established on these data.

The method to compare the cost of different generating stations is performed using the discounting method in constant francs. The same approach is used for the OECD cost study. The discount rate used in France and set by the government for all national public investment is 8 per cent per year, nevertheless the DIGEC study gives also results with a 5 per cent discount rate.

Nuclear generation costs are related to a PWR 1 450 MWe second sub-series. This power plant is very similar to the N4 series under construction or in commercial operation (three reactors were in commercial operation in 1997: Chooz B-1 and B-2, Civaux 1) with some differences in civil works which achieve an even higher level of safety.

The cost presented in this study corresponds to a power plant located at an average site (sea water cooling) with four reactors. These costs are based on a programme of ten reactors which allows for a construction cost reduction. In French economic studies a lifetime of 30 years is assumed for a nuclear plant, but technical studies show that nuclear can operate for around 40 years. The load factor used by the DIGEC study is 84 per cent.

Uranium is enriched to 4 per cent and the burn-up is 43 500 MWd/t. Spent fuel is reprocessed. Costs take into account radioactive waste storage. The price of uranium used by the French delegation for the OECD study is constant, equal to 22.5 \$/lb U_3O_8 over the economic lifetime of the plant. This value corresponds to the average of the DIGEC scenarios.

Coal generation costs are based on a 570 MWe pulverised coal technology with gas treatment (selective catalytic reduction for NO_x, $NO_x < 200$ mg/Nm^3, flue gas desulfurisation,

SO_2 < 200 mg/Nm^3 and electrostatic precipitation dust < 50 mg/Nm^3). The lifetime used is 30 years and the net thermal efficiency is 42 per cent (LHV).

In France, a large share of the coal used for electricity generation is imported, therefore the projection for coal prices are made on a world price basis. An assumption of $45 per tonne is retained over the economic lifetime of the plant. This value corresponds to the average of the scenarios used by DIGEC.

For a gas unit, we retain a 660 MWe combined cycle plant burning natural gas. Low NO_x emissions would be met using dry low NO_x burners (NO_x < 200 mg/Nm^3). Net thermal efficiency is equal to 52 per cent (LHV). For this power plant a lifetime of 25 years is assumed with a load factor of 90.2 per cent.

The assumption for natural gas price is 3.3 $/MBtu over the economic lifetime of the plant. This value corresponds to the average of the DIGEC scenarios.

The main conclusions stressed by the DIGEC study are:

- Today nuclear is a sound choice for base-load generation, even if this choice can be supplemented by gas-fired combined cycle plant at present low gas prices. Moreover, there is little uncertainty on future nuclear fuel prices and nuclear generation costs are not very sensitive to fuel price escalation. On the other hand, the cost of gas generated electricity is very sensitive to gas price escalation and there are uncertainties on gas price escalation.

- The study highlights the importance of constructing a series of plants on nuclear competitiveness.

- Gas-fired combined cycles appear clearly as the most competitive option for intermediate load factors.

HUNGARY

The Hungarian Power Sector has been restructured recently, therefore the data provided are from privatised power companies. Capacities in the future are considered to be procured in competing biding procedures, therefore there are no data available for units to be commissioned after the year 2005. Regarding the power plants that could be commissioned by 2005 in Hungary data provided as follows:

- the combined cycle gas turbine units are based on reliable feasibility studies and basically realised by PPA and offer of EPC contractor;

- the FBC boiler unit, data is based on a feasibility study and basically realised by PPA; and

- the lignite fired power plant is in preparation phase and data are taken from feasibility study. It is assumed that the costs should be justified on the basis of commercial offers.

No new studies were prepared on nuclear units during the past 5-6 years, so cost estimates cannot be provided for nuclear power plant.

In connection with energy conservation, a lot of studies have been done in Hungary on renewable energy sources. However, power plants using renewable energy have not yet come into existence.

The environment regulation is under development in Hungary, but in the near future there is no sign of the introduction of carbon tax so the generation costs presented in this study do not include any type of environment tax.

The draft environment regulation is based on recent western standards and so the plant investors can and will prepare the environmental protection systems including pollution control equipment to this publicly known draft. So both the lignite plant and fluid-bed combustion plant will be built to fulfil the following environmental requirements:

Dust	≤ 50 mg/m^3
SO_2	≤ 400 mg/m^3
NO_x	≤ 400 mg/m^3
CO	≤ 250 mg/m^3

The technical solution will be e.g. in the lignite fired plant case that flue gas desulphurisation equipment will be built in dry cooling tower.

INDIA

India is witnessing a rapid growth in demand for power. Electricity generation has been increasing at a compounded annual growth rate of about 7.5 per cent per annum during the last 50 years. The present level of energy electricity generation in India is about 375 TWh per year. In a developing country such as India, the growth rate of demand for power is generally higher than that of Gross Domestic Product (GDP). The projected average growth in GDP is about 7 per cent per annum in the next 10 years. The growth of economy calls for matching growth of power. It is estimated that the demand for electricity in India will grow at about 9 per cent per year compounded during the next 10 years.

Power Sector in India has been plagued by shortage of supply as compared with demand. The current level of peaking (capacity) shortage is about 17 per cent, and energy shortage (generation) is about 8 per cent. Considering the expected growth of demand, the present level of shortages are expected to continue for some more time.

Presently, a large percentage of electricity generation is based on thermal and hydro power plants as shown below:

Table 1. **Distribution of generating capacity**

Source	**Share (%)**
Thermal	72
Hydro	25
Nuclear	2
Others	1

The transmission and distribution losses are alarmingly high in India. They are of the order of 20 per cent. This indicates a substantial potential energy saving obtainable by modernising transmission and distribution which have been neglected for sometime.

The present per capita consumption of electricity is about 325 kWh per year. In fact the per capita consumption has been increasing during the last 5 years at a compounded rate of 7 per cent.

Based on the uranium resources available in the country, it is possible to build a maximum of about 10 000 MWe of PHWR capacity. However, by adopting the fast breeder technology there is potential for substantial contribution to the energy need of the country. India embarked upon development of nuclear power generation with an ultimate aim of using its vast resources of thorium for significant level of power generation on long-term basis. All the developments made so far have been with this objective in view.

Presently, the total installed capacity of nuclear power in India is 1 840 MWe. Four more reactor units of capacity of 220 MWe each are at advanced stages of construction. It is also planned to begin construction of two 500 MWe units and four 220 MWe units during the next 3 years. The nuclear power generation capacity in the country is expected to grow to 20 000 MWe by the year 2020.

Non-conventional energy is another source which promises to reduce the yawning gap between demand and supply. The Ministry of Non-conventional Energy Resources is planning to harness 2 000 MWe of power from sun, wind and ocean.

The expected capacity built up during the next 10 years is about 120 000 MWe. The investments in the power sector for the capacity addition is expected to be funded by public and private sector sources.

To attract private entrepreneurs to the power sector, the government has announced a number of incentives including: 100 percent foreign equity participation; five-year tax holiday; lowering of excise and customs duty on capital goods and power equipment; structuring of a two-part tariff which ensures 16 per cent return on equity at 68.5 per cent plant load factor (PLF); an additional incentive of 0.7 per cent for every one per cent rise in PLF; and allowance of high debt-equity ratio of 4 to 1.

Basic technological features of the plant

Nuclear

The units considered for the study are 2x500 MWe units of pressurised heavy water reactors. These units would be built for the first time in India. Their construction is expected to start shortly. Auxiliary power consumption requirement for these units would be about 9 per cent of the gross capacity. These units are located near the sea and cooling method adopted is once through cooling system using sea water. The plant uses natural uranium as fuel and the average fuel burn-up is estimated at 6 800 MWd/t of uranium. The spent fuel from the reactors is sent for reprocessing for the recovery of plutonium. However, the cost of reprocessing is not included in the fuel cycle cost and no credit is taken into account for the plutonium recovered. The capital cost considered in the study is for the first set of units; it is higher than the capital cost of standardised units of the same design and capacity. Reduction in the capital costs by 15 to 20 per cent could be achieved by repeated constructions of similar units. The costs of heavy water inventory in the reactor is capitalised and a credit is taken into account for salvage value of heavy is given at the end of the useful life of the units. The cost of radioactive waste management at station is included in the operation costs. Costs associated with the management of radioactive waste arising from spent fuel reprocessing are excluded.

Thermal

The units considered are 2x500 MWe coal-fired units located at about 1 000 km away from the coal colliery. The auxiliary power consumption requirement of the unit is about 8 per cent of the gross power capacity. Since the price of coal vary widely depending on the collieries where it is mined, two cases have been considered: low and high coal price. The cost of coal transportation by rail over 1 000 km has been taken into account. With regard to emission control equipment, electrostatic precipitators are included in the plant cost.

ITALY

In Italy, the electricity services are provided by multiple operators: ENEL, more than 150 local utilities (Municipal companies) and several hundred small private enterprises. Furthermore, a substantial share, 17 per cent, of electricity is generated by industrial autoproducers, which is not subject to particular constraints.

In recent years, the structure of the Italian electricity industry has undergone two main changes. Firstly, in January 1991 generation by non-utility generators was liberalised and encouraged. Secondly, ENEL, a State Power Board since 1963, was transformed into a joint stock company (up to now totally owned by the Italian Treasury) by an Act of Parliament of 11 July 1992 under a governmental programme of privatisation of the major public undertakings. Time-scales and modes of ENEL's privatisation, together with the rules for the new organisation of the electricity industry, are still under debate.

As from 1 January 1997, ENEL has implemented a new organisation based on unbundling of its three operational activities (generation, transmission and distribution) as well as its service departments (engineering, R&D, telecommunications, etc.).

At this time, ENEL has the same tasks as in the previous State Power Board. Its role is to generate, import and export, transmit, transform, distribute and sell electricity in Italy and elsewhere, being in charge of any other related or complementary activities.

ENEL's responsibility to ensure a reliable electricity supply for the whole country materialises with the "ENEL Investment Plan" which formulates the projected development of the overall Italian power system. For this purpose, ENEL has always adopted the logic of the "year-by-year" planning method to take into consideration the real progress of projects and the evolution of the economic and energy picture.

In July 1990, ENEL signed preliminary agreements with a number of large industrial autoproducers, which should allow for a substantial increase of the electricity generated on behalf of ENEL, through repowering or installation of combined-cycle units in existing industrial installations. In January 1991, laws No. 9 and 10 were passed by the Government. They set out implementing regulations which involve radical innovations in terms of deregulation of electricity generation and rational use of energy (namely cogeneration and energy recovery from industrial processes). Generally speaking, they set up the criteria and procedures to ensure the necessary co-ordination of the electric sector's activities concerning safety, quality and cost effectiveness of the electric service. The new norm establishes that every six months a verification of the proposals of new plants from non-utility generators (NUGs) should be carried out, looking at the compatibility of the proposed initiatives. This is done according to a priority ranking which takes into account *inter alia*: energy sources used; national targets of diversification and independence on foreign countries; technologies; energy efficiency; and location of plants in relation to the energy deficit of the region where they are going to be located.

Generating programmes

The ENEL programme of new plants to be placed into operation between 1996 and 2000 include: 1 900 MW (under construction) of conventional thermal power plants; 900 MW of new combined-cycles plants; 360 MW due to repowering; new hydro plants totalling 360 MW and an increase in the energy capability from natural flows of ENEL plants of 0.5 TWh; new geothermal plants for about 290 MW. Out of a wider programme of new sources plants, two wind-farms (20 MW and three photovoltaic plants (0.5 MW) are under construction.

As far as the contribution of NUGs is concerned, the aforementioned new norm was applied making a huge effort to assess the compatibility of the new proposals in terms of safety, quality and cost effectiveness of the overall electric service. The proposals received by 30 June 1996 were for a total capacity of roughly 18 000 MW. Out of these, as indicated by ENEL, the Ministry of Industry accepted about 8 000 MW of capacity from renewable and "like" sources. The electricity so produced will be supplied to ENEL's network. As a result, by the year 2001 the amount of the production capacity for ENEL should be 8 GW, of which 3.1 GW fuelled with natural gas, 2.6 GW with syngases and derived gases, 2.0 GW with renewable sources. It is noteworthy that most of NUGs' initiatives would cause lack of flexibility in the ENEL system, especially during low-load hours.

As far as the development of the generating facilities after 2000 is concerned, neither has the government given guidelines, nor has ENEL taken an official position in this connection. In terms of general planning it can be assumed that, due to the growth of the electricity demand and to the expected decommissioning, the necessary new base generation capacity will consist of units fuelled by natural gas or derived gases (further repowering and combined-cycle) for most of the requested new capacity.

Generation cost estimates

The national cost estimates are based on paper analysis of power plants commercially available.

They assume 25 years as economic lifetime (20 for gas-fired plants), 68.5 per cent as load factor and 12 per cent as real discount rate.

The coal plant (four units of 617 MWe net) has pulverised fuel boilers, supercritical steam cycle and the following emission control equipment: flue gas desulfurisation (SO_2 < 400 mg/Nm^3), selective catalytic reduction (NO_x < 200 mg/Nm^3) and electrostatic precipitation (dust < 50 mg/Nm^3). The net thermal efficiency is 44 per cent (LHV).

The projected coal prices are related to imported coal and are based on a hypothesis of light rise of the world prices (about 1 per cent per year up to 2015).

The gas-fired plant is a combined cycle gas turbine (2 units of 350 MWe net), with low NO_x burners (NO_x < 100 mg/Nm^3); the net thermal efficiency is 53 per cent.

The assumptions on the natural gas prices, based on a rise of about 2 per cent per year up to 2015, take into account also one supply contract of liquefied natural gas.

JAPAN

Consumers in Japan are supplied with electricity by ten private electric utilities (Hokkaido Electric Power, Tohoku Electric Power, Tokyo Electric Power, Chubu Electric Power, Hokuriku Electric Power, Kansai Electric Power, Chugoku Electric Power, Shikoku Electric Power, Kyushu Electric Power and Okinawa Electric Power companies), each of which is licensed by the Ministry of International Trade and Industry (MITI) to operate in one of the ten service areas into which the country is divided. These utilities are responsible for supplying electricity at the request of customers in their respective service areas. In the fiscal year 1995 which ended March 1996, the ten utilities together supplied 75 per cent of the total electricity produced in Japan. The remaining 25 per cent was supplied by Electric Power Development Co. and Japan Atomic Power Co. – both wholesale power producers – and non-utility power producers, especially industrial companies producing electricity for their own use.

The Agency of Natural Resources and Energy of MITI has estimated standard generating costs for nuclear power, coal-fired, LNG-fired and oil-fired thermal power, and hydroelectric power plants since fiscal 1982. These estimates are based on the same principle as that which is used in this study. The most recent estimates released were for fiscal 1992. The discount rate used for these calculations is set at 5 per cent based on prevailing real interest rates.

The cost estimates presented by Japan for this case study were calculated as follows based on model plants that are assumed to be commissioned in fiscal 2005:

1. Nuclear power plants are rated highly in Japan for their superiority in terms of constant fuel supply, stable fuel price, economical performance and environmental protection. These plants will continue to be developed actively in the years ahead, with careful consideration given to the safety.

   The cost of nuclear power generation was estimated on the basis of four ABWR (Advanced BWR) type model plants at a site with a gross capacity of each plant being 1 350 MWe. This standardisation programme, reflecting operating experience with conventional light water reactors and achievements realised under the first and second improvement and standardisation programmes. With the best technologies available in Japan and abroad incorporated in them, these plants are expected to attain the highest level LWRs have reached in terms of safety, reliability, operability and minimisation of occupational radiation exposure doses. These types of plants will be the mainstay of Japanese nuclear power generation in the year 2000 and beyond.

   The nuclear fuel prices were estimated on the basis of prevailing market prices for uranium acquisition and enrichment and reprocessing services with consideration given to relevant data, such as the cost estimates of high-level radioactive waste disposal and MOX fuel fabrication provided in NEA reports. The projection for fiscal year 2005 was made with the annual increase rate of prices set at 0 per cent.

   The cost of nuclear plant decommissioning was estimated on the basis of 30 billion yen for a 1 100 MWe class reactor stated in a 1985 report published by the Nuclear Energy Subcommittee of the Advisory Committee for Energy, an advisory organ to the Minister for International Trade and Industry, with the cost of radioactive waste disposal set at 15 per cent of such amount. The decommissioning cost thus calculated was included in the estimates Japan presented for the case study.

2. As their effective environmental control features, coal-fired thermal power plants are fitted with high-efficiency de-NO_x and de-SO_x equipment and electrostatic precipitators in such as way that these pollution control equipment work in harmony with the plants themselves. New power generation systems with ultra-supercritical steam conditions and pressurised fluidised bed combustion are being considered for introduction to improve power generating efficiency.

   The costs of generation were estimated on the basis of four coal-fired thermal power model plants at a site with a gross capacity of 1 000 MWe each.

These model plants are based on an ultra-supercritical pressure steam cycle with an estimated design thermal efficiency of 42 per cent. The model plant is designed from the most reliable perspectives of technology available now.

While some projects are under way to introduce the ultra-supercritical pressure steam power generation system, demonstration tests are being conducted on the pressurised fluidised bed combustion power generation system to pave the way for its commercialisation. These and some other technologies are being developed to improve the efficiency of coal-fired thermal power plants.

With IEA, DOE and other sources used as reference data, coal prices for these plants were estimated at 2.0 US$/GJ for the year 2005. Thereafter, the estimation predicts, the prices will rise at a rate of some 0.5 per cent a year.

3. The generating cost of gas combined cycle power plants was estimated on the basis of four model plants at a site with a gross capacity of 700 MWe each. These models are in a 1 300°C class of plant designed from the most reliable perspectives of technology available now. Design thermal efficiency is estimated at 48 per cent.

   High-temperature turbines and other advanced technologies are being developed, with the objective of introducing them in 1 500°C firing temperature power plants.

   Using DOE and other projections as reference data, fuel prices for these plants were estimated at 4.8 US$/GJ for the year 2005. Thereafter, according to the estimation, the prices will increase at a rate of some 2.8 per cent a year.

4. Fuel cell, photovoltaic and wind power generation systems are considered to serve as only supplementary facilities for electric utilities because of their inadequate supply stability and unsuitableness for large power supply. Accordingly Japanese electric utilities are now studying how to ensure higher technical reliability and lower costs for these systems.

   The utilities are not in a position to provide any official data for estimating the power generating costs of the systems.

KOREA

In Korea, construction of electric power plants is based on the official long-term power system expansion planning (ESEP) initiated by the MOTIE (Ministry of Trade, Industry and Energy). Once the plan is fixed, the power plants are constructed and run under the control of KEPCO (Korea Electric Power Corp., the sole electric power company in Korea). The estimation of electricity power generation costs plays an important role in the decision on the long-term power plan.

On the other hand, many factors affecting the estimation of power generation cost such as discount rate, load factor, and lifetime are determined by the MOTIE through the consensus among universities, institutes, and the utility. These factors are periodically reviewed in accordance with biennial review of ESEP.

In the generation cost estimation of 1995's ESEP, the official real discount rate 8.5 per cent was adopted. The lifetime of nuclear and coal power plants was assumed to be 25 years and the lifetime of LNG-fired plant was assumed to be 20 years.

Nuclear and coal-fired power generation have been two major power sources in Korea. However, according to the 1995's ESEP, 17 440 MW of LNG-fired power generation was introduced from 1995 to 2010 to meet the recent rapid increases both in the demand for electricity and peak demand.

The generation cost estimation is based on the lifetime levelised cost methodology. Investments and O&M costs are projected from the country's construction and operation experience.

The generation cost categorisation in Korea is quite different from that of OECD 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 Member countries. In case of nuclear power, decommissioning cost, spent fuel treatment cost and radioactive waste disposal costs are added to the base O&M cost. The cost bases of each item was established in 1984. Each year, certain amounts of money are deposited in the utility's fund pool for the above three items and these are utilised as the basis of economic analysis.

THE NETHERLANDS

Electricity policy

At the end of 1995, the "Third White Paper on Energy" was sent to Parliament by the Minister of Economic Affairs. In this paper the Electricity Act of 1989 was evaluated and major changes in the electricity structure were announced. These changes included the preparation of a new Electricity Act. In addition the case was made out for a merger of the four present generating companies of the country and Sep (their umbrella organisation) into a single large-scale production company. The new production company is expected to start the second quarter of 1998.

In view of the international developments, energy conservation and the need for a more liberal energy market, the Government of the Netherlands has prepared a set of new rules relating to the production, transport and supply of electricity (Electricity Act). It was sent to Parliament in September 1997. The Act follows the European rules and is expected to come into effect from 1 January 1999 on. In the new Act an open market for electricity is foreseen, in which eventually the domestic customers will become non-captive users, free to choose their own (distant) supplier of electricity. The new Act implies a separation between the transport and trading function, to achieve a genuinely independent network. It is a major operation to separate these functions, which have been closely integrated up to now. Consequently the new Act implies a new electricity structure resembling a market with freedom of imports, exports and generation of electricity. All networks will be accessible for transport. The high voltage network as well as the distribution networks will be controlled by an independent operator. Supply to non-captive users is based on contractual relationships. Their choice of a supplier will be free. The liberalisation of the market will be gradual, viz. in three steps in the period up to 2007. Consequently, in the beginning a number of captive users will remain and this number will decrease in time. Companies will be free to pursue their own purchasing policy: they will be able to purchase electricity from foreign or domestic suppliers produced in large scale or small scale plants.

In the Netherlands the combined production of heat and power either by electricity generating companies, or other generators including distributors, was stimulated by the Government in order to achieve goals for the reduction of CO_2 emissions. In particular, gas-fired CHP has been officially promoted. Consequently, distributors increased the number of gas-fired combined heat and power units significantly. Often such units are nowadays exploited in joint ventures between industrial companies and electricity distributors in order to supply heat to the industrial concern and electricity to the distributor. Subsidies have led to quite an increase in other generator capacity and generation. Centralised capacity amounts at the moment to 15.5 GWe. Of this about 2.3 GWe is combined heat and power, especially district heating and large industrial cogeneration. Decentralised capacity is 4.6 GWe. Total combined heat and power generation is expected to grow to 8 GWe in the year 2000. The share of other electricity generators, which in 1996 was 24 per cent, is expected to increase considerably over the decades to come.

However the policy of Dutch Government is to keep the nuclear option open.

Gas-fired power plants

The CCGT unit of 250 MWe, which has been presented in the tables, is indicative for larger combined heat and power units to be constructed in near future. From the year 2005 on, new centralised CCGT plants (e.g. with a power of 350 MWe and a lower heat demand) are expected to be ordered. The cost figures for this unit are based on the most modern technology available as well as on the experience with the newest CCGT units (5 units of 335 MWe each) commissioned in the Netherlands in the period 1996/1997.

Coal-fired and nuclear power plants

Recently two pulverised coal units entered their commercial operation phase. By raising the temperature and the pressure the overall efficiency of pulverised coal units may increase even further form 45 per cent at present towards 47 per cent without a significant increase of the investment costs. The cost figures of this type are based on the availability of high quality materials for the pressure parts.

Further into the future IGCC might be a more sensible alternative to pulverised coal technology. In Buggenum a prototype IGCC unit (“Willem Alexander plant”) recently entered into operation. The cost estimate in the tables for a 800 MWe unit has been based on experience with this unit. Furthermore, it has been assumed that the 800 MWe unit is equipped with two directly coupled gas turbines. The expectation is that for the first commercial IGCC units the investment costs will be significantly higher than those for advanced pulverised coal units. However in the long term the difference in the busbar costs might decrease, which will depend both on a further reduction of investment costs and on the use of cheaper coal.

One commercial nuclear power plant has been in operation since 1973 at Borssele (PWR, 450 MWe) in the south-western part of the country. It is expected to continue operation until 2004. There are at the moment no projects for the planning or construction of new nuclear power plants.

PORTUGAL

Portugal has very few fossil energy resources, and depends almost 90 per cent on imports and around 70 per cent on oil imports. This situation led to the development of hydro resources, the most promising among renewables, and the increasing development of wind and geothermal resources, as well as the promotion of co-generation. Hydropower accounts for 30 per cent of total power generation on average. For the time being, thermal power generation depends on oil and coal, but natural gas is expected to be used in a new combined-cycle power plant, starting operation in 1998.

In recent years the national electricity sector has been subject to profound changes as a result of market liberalisation. The objectives were the introduction of competition in generation and private financing into the expansion of the electric system, reducing costs and diversifying inputs to generation.

The access to the electricity market was liberalised through Law 110/88, which put an end to the exclusive rights conferred to Electricidade de Portugal (EDP). The publication of Decree-Law 189/88 was the first step in opening up power generation to economic agents.

In 1991 the legal status of EDP was changed to a limited liability company and it was later split into six main enterprises (one for power generation, another for transmission and four others for distribution of electricity) and other subsidiaries having as their object several activities in the area of services.

Simultaneously the restructuring of the electricity sector was prepared. The result was that the existing legal framework was changed and seven new Decree-Laws, that sanction the change in the sector and translate into law that new structural configuration, were published in August 1995. Recently some adaptations were made, translated in some new legislation published in March 1997.

The new legislation frames in a single concept – that of the National Electric System (SEN) – all the players of the sector. The National Electric System can be split into two different systems: the Public Service Electric System (SEP), and the Independent Service Electric System (SEI), which includes the non-binding electric system, mini-hydro power stations up to 10 MWe, generators using other renewable energy and co-generators.

Since 1993, a new coal power plant, Tejo Energia, has been in operation. This power plant, has two units of 300 MWe, and belongs to a private consortium. It is part of the binding system SEP. A new natural gas combined-cycle power plant with three units of 330 MWe, owned by private shareholders, is expected to start operation in the first quarter of 1998.

The main current issue in the electricity supply industry is its privatisation. A stake of 30 per cent of the holding company EDP was privatised in June 1997. An implementing committee of the electricity regulatory authority was created in July 1996. Its statutes were approved by the Council of Ministers, published in February 1997 and are in force.

The completion of the questionnaire was made with the collaboration of EDP and some private power generation plants.

The main assumptions for the cost estimates and generation technologies used for this study are described in the next paragraphs.

Data from Portugal was based on paper analysis from February 1997, and includes two conventional coal-fired boilers (344 MWe and 450 MWe) and two combined cycle gas-fired (332 MWe and 468 MWe).

In national assumptions for the coal-fired boilers, it was assumed a settled-down load factor of 82 per cent and an economic lifetime of 30 years. For the combined cycles, a settled-down load factor of 88 per cent and an economic lifetime of 25 years were assumed. The discount rate assumed in both cases was 8 per cent.

For the generating cost calculations, in the case of the coal-fired boilers, fuel costs include a stockpile cost.

Investment costs for coal-fired boilers include wet limestone for desulphurisation and selective catalytic reduction for denitrification, as well as electrostatic precipitators. Natural gas combined cycles investment costs also include emission control equipment.

The prices assumed for coal and natural gas include the price at the border plus transportation costs. For coal, it was assumed an increase of 0.5 per cent a year for the price at the border and a stable price for transportation over the period of study. For natural gas the price at the border is related to the oil price. The oil price scenario assumed considers an increase of 4 per cent a year from 1997 to 2000, 2.8 per cent a year from 2001 to 2005, 2.5 per cent a year from 2006 to 2010, 1 per cent a year from 2011 to 2020 and a constant price after that.

ROMANIA

The present transition period to a free market economy requires deep and radical changes of legislation and consequently a totally different approach in defining cost structures and transparent financing resources.

For the energy and electricity production sector, this set of regulations, which implies also deregulation and privatisation of state-owned generating units is not yet in place. The new Energy Law is under debate within the Government.

Under these circumstances, the estimates provided in this report for a nuclear generation technology (Cernavoda – PHWR CANDU Unit 3 – scheduled to be in commercial operation at the end of 2005) do not reflect the tendencies described in the above mentioned set of regulations.

This is the reason why there are no provisions for decommissioning and intermediate and final disposal of spent fuel costs to be included as part of the electricity generation cost structure.

The methodology used to provide data to the report was typical UNIPEDE.

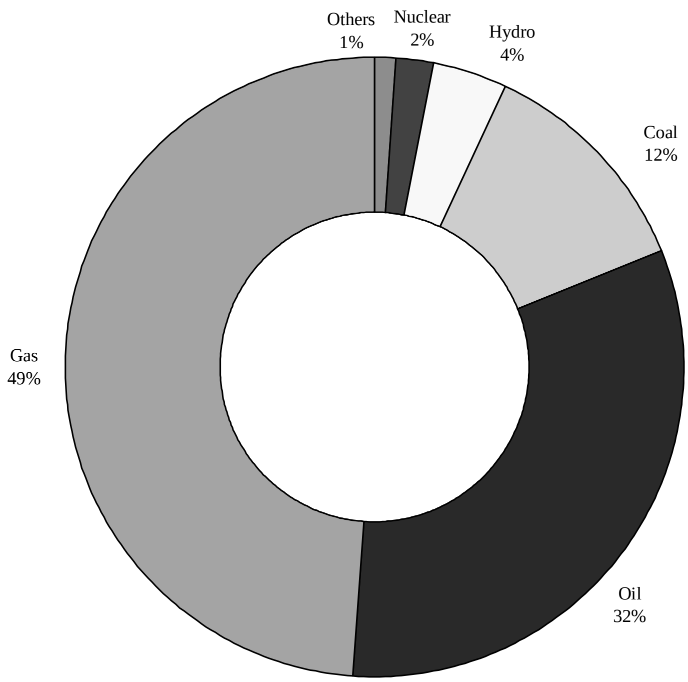
According to RENEL's (utility) strategy, the only new power generating units to be commissioned up to 2005 will be nuclear units (including Cernavoda Unit 2 in 2002 and Unit 3 in 2005). For all the other conventional power capacities some major refurbishment is being planned. This will increase nuclear energy's production share to 30 per cent.

RUSSIA

Energy balance

The structure of the current energy balance is presented in Figure 1. Total energy production in 1995 was 1 380 Mtce (million tonnes of coal equivalent). The figure shows the key role played by oil and gas (more than 80 per cent).

Figure 1. **Structure of primary energy production in Russia**



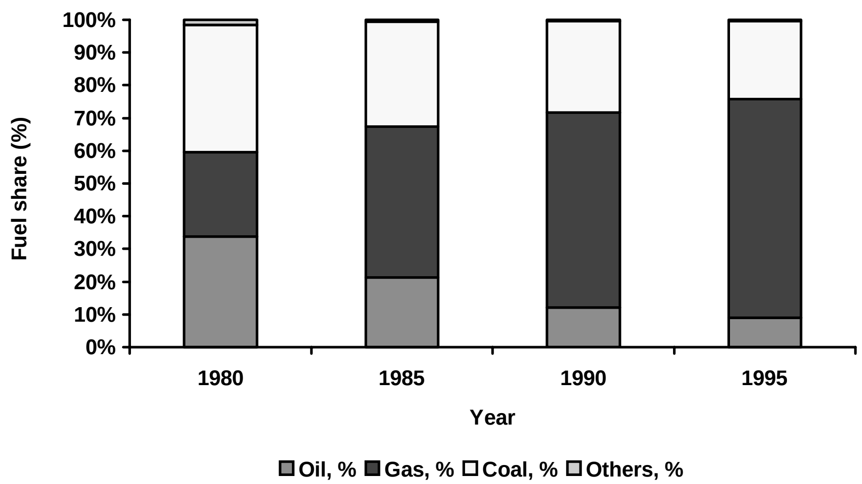
Electric power

The power sector of Russia is structured as the Integrated Power System (IPS). The Russian IPS (including the power supply of the Far East) accounts for 96 per cent of electrical power generation and for approximately 94 per cent of the installed capacity of electrical power plants in Russia. The generation capacity and the percentage shares of different types of power plant in the Russian IPS at the end of 1995 are given in Table 1, which shows that approximately 70 per cent of the total power generation capacity is concentrated in the European part of Russia; all nuclear power plants are located in the European part of Russia; most of the existing capacity (68 per cent) is concentrated in fossil fuelled thermal power plants; the thermal capacity is represented by combined heat and power plants (CHPs), which account for 36 per cent of the total capacity, and condensing power plants, which account for 32 per cent of the total capacity. Figure 2 shows the shares of the different fuels used in Russian condensing power plants in the period 1980-1995. The proportion of hydropower plants varies widely in the different regions; in the European part of Russia they account for only 13 per cent of the total capacity and in the Eastern part they account for 38 per cent.

Table 1. **Generating capacity in Russia**

Type of plant	**IPS of Russia**		**European part (including the Urals)**		**Eastern part (including Tyumen)**	
	GWe	**Share (%)**	**GWe**	**Share (%)**	**GWe**	**%**
Hydro	41.7	21	18.1	13	23.6	38
Nuclear	21.2	11	21.2	16	0	0
Thermal	135.8	68	98.1	71	37.7	62
CHP	*72.7*	*36*	*53.9*	*39*	*18.8*	*31*
Condensing	*63.1*	*32*	*44.2*	*32*	*18.9*	*31*
TOTAL	**198.7**	**100**	**137.4**	**100**	**61.3**	**100**

Figure 2**. Fuel shares in Russian condensing power plants in the period 1980-1995**



As can be seen from Figure 2, the Russian power system is becoming heavily dependent on only one energy resource, natural gas, and it is very dangerous for the following reasons:

- The estimates of natural gas reserves need to be more precise, both in terms of the volume and the potential cost of extraction, which will undoubtedly increase.
- The gas fields are a very long way from the places where the gas is utilised on a large scale and so there is a need to build gas storage facilities with a sufficient volume for the level of consumption.

- The risk associated with large-scale utilisation of gas is extremely high and it is difficult to predict the impacts of large-scale gas extraction and transportation.

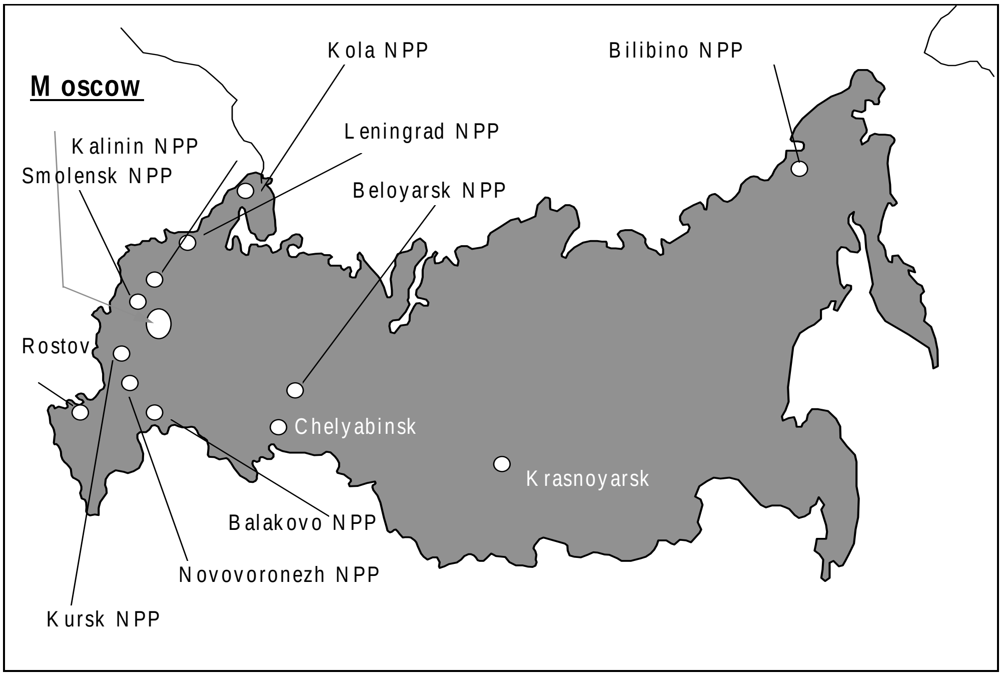
All of these factors pose a serious threat to the strategic safety of Russia's power industry.

In this respect the existence of a sound nuclear sector in Russia might provide a substantial protection against events that might threaten the availability and costs of fossil fuel supplies.

Nuclear power

As of 1 January 1996 there were in Russia 29 units on nine sites, representing a total capacity of 21.242 GWe, i.e. about 11 per cent of the total installed electricity generation capacity. Figure 3 shows that Russian nuclear power plants are located mainly in the European part of Russia, near the main centres of electricity demand. In 1996, Russian nuclear power plants produced some 108.8 TWh of electric energy.

Figure 3. **Map of nuclear power plants in Russia**



Several types of power reactors are in commercial operation in Russia:

- RBMK-1000, a graphite moderated, pressure-tube, low enriched reactor rated at 1 000 MWe, designed for on-line refuelling;

- VVER-440 (models V-179, V-230 and V-213), a pressurised water reactor rated at 440 MWe; and

- VVER-1000, a pressurised water reactor (models V-187, V-338, and V-320) rated at 1 000 MWe.

In addition, a liquid metal-cooled fast reactor (BN-600) is connected to the grid in the Ural region and four small (12.5 MWe) water-cooled graphite moderated channel type reactors (EGP-6 model) operate isolated from the grid in the north of the far eastern portion of Russia.

For the total energy sector of the country the role of nuclear energy might not seem to be very important. The share of nuclear energy in the total energy balance of Russia is only about 2 per cent, far below the dominating share of oil and natural gas. But one must note that nuclear power is one of the major electricity sources in the country. In 1996, the share of nuclear electricity in total electricity generation was about 11.4 per cent (108.8 TWh). Electricity generation by nuclear power plants has remained relatively stable even in the last years when economic difficulties and other factors caused a noticeable decline in the generation by fossil-fuelled plants.

The importance of nuclear power greatly varies from region to region. For example, in the regions with the most developed nuclear power – the North-West, Central and Middle Volga power pools – nuclear shares of electricity generation were, in 1994, 45.7 per cent, 20.7 per cent and 16.3 per cent respectively. Thus, regional factors play an important role for nuclear power planning in Russia. The reasons are the large dimensions of the country and the high dependence (for fossil-fuelled plants) of electricity generation costs on fuel transportation distances.

Russia has developed several advanced nuclear power plant concepts with enhanced safety features, including the 635 MWe VVER-640 and the 1 000 MWe NP-1000. For example, the VVER-640 nuclear power plant project has a double protective containment shell, advanced passive safety systems, additional active safety systems and operational systems, important for safety, with enhanced reliability and redundancy. The plant is of compact design leading to reduced material quantities and more effective space utilisation. Projected man-power requirements are substantially less than for operating Russian nuclear power plants. Nuclear power plants of this type are planned as replacement capacities at several new sites.

At present, the basic planning document for the development of the Russian energy sector is the Russian Energy Strategy issued in 1994. This document was prepared by an Interdepartmental Commission that included high-level representatives of all branches of the Russian fuel and energy complex. The behaviour of the share of the nuclear sector under these scenarios is shown in Table 2.

Table 2. **Scenarios of nuclear power development in Russia**

Scenario	***Electricity generation by NPPs, TWh***		
	1995	***2000***	***2010***
Necessary	115	120	125
Maximum	120	125	160

Traditionally, in centrally planned economies, the annual cost approach for evaluating the actual generating cost from existing power plants was used. In this case all necessary data are available to calculate annual generating costs for the system as a whole, as well as for individual units. The levelised cost methodology is being used as a basis for assessing the inter-fuel competitiveness of future plants operating under equivalent conditions. But at the present time data necessary for evaluating projected costs of generating electricity practically are not reliable and in some cases are not available. For example, in Russia, we have not yet regularly evaluated the discount rate or the escalation factors, which are very important for future cost evaluation.

SPAIN

Electricity generation in 1996

The most outstanding characteristic of 1996 with regard to the overall electricity sector has been a moderate 2.9 per cent rise in electricity consumption as compared to 1995.

During 1996 the UNESA companies commissioned two new hydropower plants, two new coal-fired power plants and the Puertollano IGCC plant owned by ELCOGAS. In addition, the capacity of several hydro and nuclear power plants was increased. The total nuclear power plant capacity increase was 81 MWe, distributed as follows: 5 MWe in Vandellós II, 36 MWe in Asco II, and 40 MWe in Almaraz I.

Table 1 shows electricity generation capacity owned by the UNESA[1] member companies and production in 1996. The contribution from autoproducers has grown rapidly in the recent years. As compared to 1995, hydro electricity production increased by 70.5 per cent, nuclear generated electricity increased by 1.6 per cent, and fossil-fuelled electricity generation decreased by 11.6 per cent.

Table 1. **UNESA electricity capacity and generation in 1996**

	Capacity (GWe)	**Production (TWh)**
Hydropower	16.547	37.694
Conventional thermal	21.345	62.640
Nuclear power	7.498	56.329
TOTAL	45.390	156.663

With regard to international trade, the final balance for 1996 shows imports amounting to 1 064 million kWh, this representing a reduction of 76.3 per cent over the previous year.

The new model for the electricity industry

On 11 December 1995, the Ministry of Industry and Energy and the Electric Utilities Iberdrola, ENDESA, Unión Eléctrica-Fenosa, Compania Sevillana de Electricidad and FECSA as well as UNESA signed a "*Protocol for the establishment of a new system of regulation of the national electricity system*", the ultimate aim of which is to achieve generation of suitable quality at the lowest possible cost. The Protocol aimed to increase the competitiveness of Spanish industry, facilitate Spain's incorporation in the European Monetary Union, and comply with the commitments made in relation to the Maastricht agreements and the provisions of the European Union Directives.

1. UNESA is the association of the main Spanish electric utilities.

This Protocol establishes the "*operating bases which are to govern the operation of the National Electricity System*" through liberalisation of the market and the introduction of a higher degree of competition. It defines the terms, measures and safeguards required during a period of adaptation to the new framework and the payment to be received for activities performed within the natural monopoly system.

Two essential aspects included in the foreword to the document are:

- Firstly, the protocol includes the commitment of the signing companies to make efforts to achieve the final objective. In other words, the reduction of the kWh price will be achieved by reducing the income of the companies.

- Secondly, the signing parties recognise that both the Law governing the organisation of the National Electricity System, Law 40/94 of 30 December (LOSEN), and the European Directive on Common Rules for the Internal Electricity Market, approved on 19 December 1996, constitute the pillars on which the new model of the Electricity Sector is to be built.

Two basic "tools" have been agreed on for the achievement of the final objective, i.e. the lowering of the kWh price while maintaining adequate levels of quality in the service provided: on the one hand is the introduction of competition in generation, and on the other, the gradual liberalisation of supply. It is agreed that in the year 2001, the operation of the new model will be completely revised and that modifications will be proposed in view of the experience acquired.

The basic principles on which the new electricity system will be based are the following:

- liberalisation of electricity supply so that a progressively greater number of consumers might choose their supplier and agree freely on both tariffs and service conditions;

- introduction of competition in electricity generation, allowing complete freedom for the construction of new power plants and for the establishment of a bidding system;

- liberalisation of the access to primary energy sources used for electricity generation and establishment of a specific regulation for domestic coal;

- guaranteed decrease of electricity prices between 1997 and 2001; and

- definition of deadlines and transient measures in order to allow for an adequate transition to the new model of the electricity industry.

These principles are contained in a bill for the electricity industry which has been approved by the Spanish Government of 23 May 1997 and which is presently going through the parliamentary process for approval. It should be emphasised that the criteria for liberalisation and competition in the future Electricity Act are similar to those applied in the restructuring of the electricity industry in a wide range of industrialised nations such as: Sweden, Norway, United States, United Kingdom, Canada, Finland, Netherlands, Australia and New Zealand, among others.

The electricity sector will face important challenges in the near future so that service cost can be reduced while improving service quality. All of this must be carried out in an environment of increased competition, both at national and international levels with the setting up of the European single market for energy.

Generation cost estimates

Cost estimates are based on a paper analysis in the case of nuclear and natural gas and on prior experience in the case of coal-fired plant.

The nuclear plant is a 3-loop PWR with a rated power of 1 000 MWe, of the same technology as the most modern nuclear power plants operating in Spain. The plant has a natural draft cooling tower and 2 low pressure turbine sections.

The natural gas plant is a combined cycle gas turbine (2 units of 315 MWe net), with a thermal efficiency of 51 per cent and low NO_x burners.

The coal plant (2 units of 500 MWe) uses only imported coal and is equiped with natural draft cooling towers. Net thermal efficiency is 36.7 per cent and the turbines are a tandem compound (1 HP, 1 IP and 2 LP). Pollution control devices (electric high efficiency particulate filters, flue gas desulfuration and low NO_x burners) are included in the cost estimates.

TURKEY

The power system of Turkey has developed very rapidly during the last two decades. In connection with the fast development in the industrial sector, high growth rate in population and significant migration from rural to urban areas, peak load and electrical energy consumption have increased greatly each year. Because of the increase in both peak load and energy consumption, it had been necessary to extend the power system by adding new generation units. These units are mainly hydro and coal-fired power plants. Since 1985, Turkey has also used natural gas as a new fuel type for electricity production.

At the end of 1996, the total installed capacity of Turkey reached 21 164 MW, with 53 per cent of the total installed capacity being thermal and 47 per cent hydro. Total gross electricity production reached 95 billion kWh in 1996.

In 1996, the Turkish Electricity Generation-Transmission Corporation's electricity production was 90 per cent of the national electrical energy production. The share of production by private companies was 3.5 per cent of the total production and the remaining 6.5 per cent came from autoproducers.

The most important primary resources which are currently being utilised for electricity production are domestic hydro and lignite reserves. In recent years, imported natural gas has also played an increasingly important role in power generation. In contrast, fuel oil's share of generation is steadily getting smaller.

The total hydro potential for electricity generation is estimated at 125 TWh/year of which at present only 29 per cent is being utilised. Domestic lignite and hard coal reserves are capable of producing about 120 TWh/year. The lignite is of low calorific value and high sulphur, moisture and ash content. Presently, production capacity of existing lignite and hard coal-fired power plants is about 42 TWh/year, which is 35 per cent of the total potential. The share of imported natural gas in the total electricity generation was 18 per cent in 1996. Nuclear power and imported coal are considered in generation planning studies.

A demand projection study was carried out using the MAED Model. According to results of this study, the electrical energy demand is expected to reach 134 TWh in 2000, 290 TWh in 2010 and 547 TWh in 2020. This represent an average growth rate of 8.0 per cent per annum. The corresponding peak demand is expected to reach 21 600 MWe in 2000, 46 200 MWe in 2010 and 88 100 MWe in 2020.

The future expansion of the electricity generation system of Turkey is carried out by using a two-phased approach. The first phase, called “Middle Term Generation Planning Study”, covers the period 1997-2001. The second phase of the study, which is called “Long-Term Generation Expansion Planning Study of Turkey”, covers the years 2002-2020 and is analysed by using the WASP III model. The objective of this study is to find out the optimum expansion programme satisfying the predicted electricity demand over the planning period at minimum costs while meeting certain constraints on system reliability and the number of plant additions by year. The overall economic criterion is the minimum discounted cost of expansion, including investment costs of all plants added by the programme reduced by their respective salvage value at the horizon, total operating costs of the system per year including fuel costs of the thermal plants, operating and maintenance costs of each plant, plus the costs of non served energy.

The results of this study are:

- The installed hydropower capacity amounts to 40 per cent of total installed capacity in 2010 and this share decreases to 28 per cent for the year 2020.

- The share of coal-fired power plants using imported coal will reach to 8 per cent in the year 2020.

- First nuclear unit will be added to the system in 2005 and by the end of 2010 there will be two nuclear units of 1 000 MW each.

- While the contribution of domestic lignite and hard coal to overall generation capacity amounts to 20 per cent in 2005, the contribution decreases to 16 per cent in 2020. For the natural gas, this contribution increases to 31 per cent by the end of 2020.

- In order to meet the energy and power demand, it will be necessary to increase installed capacity about 4 000 MW for each year of the planing period.

UNITED STATES

Like many other countries, the electricity industry in the United States is embarking down the path which leads from cost-of-service/rate-of-return regulation to open competition. Although electricity suppliers and regulators in the US are currently at the beginning of this path, there seems to be agreement among industry analysts, regulators and legislators that some degree of movement towards competition is inevitable. However, the magnitude of this movement and the period of time over which it occurs is unpredictable. Nevertheless, evidence is mounting that electricity suppliers are anticipating a competitive era and changing their business practices to adapt to a competitive industry. To improve their competitive positions, several US utilities have recently merged. Other utilities are in the process of applying for mergers or investigating the synergy resulting from possible mergers. Between 1990 and 1994 US utilities have reduced their work force by 3 per cent annually (65 000 total positions). During this same period, operating and maintenance expenses for existing generating technologies have also declined at 3 per cent annually. It would be unreasonable to assume that the costs and efficiencies of new generator capacity will remain immune to these market forces. Consequently, cost and performance assumptions that were used under a cost-of-service/rate-of-return model may be inappropriate for the future.

For example, in calculating the levelised busbar cost of electricity, the current trend of US utilities is to use a 30-year or shorter plant lifetime (sometimes much shorter – as low as 20 years). In today’s business environment US utilities recognise that there is uncertainty regarding long-range analysis. Changes in public policy or strict application of market forces could erase the prospect of lower operating and fuel costs for “long-term payback” technologies such as nuclear or pulverised coal and favour shorter term technologies like gas turbines. Consequently, levelised costs calculations based on a 40-year operating life may not reflect the reality of future US electricity markets.

Conversely, using the same capacity factor for each technology (even if they are all “base-load” technologies) leads to inappropriate results. For example, nuclear capacity factors in the US increased from 70 per cent in 1990 to 77 per cent by 1995. If capacity factors this high can be achieved using existing nuclear generating stations, then it is reasonable to assume that newly designed reactors could surpass these factors by a significant amount.

By benefiting from the lessons learned in operating existing units, new reactors would be expected to achieve capacity factors in excess of today’s average. A settled down capacity factor of 85 per cent for advanced reactor designs is plausible under this scenario. The value assumed for the average capacity factor has a potent effect on the levelised busbar cost of electricity. The effect becomes more acute, given the large plant sizes reflected by nuclear technologies.

In addition to operating expenses, there is also evidence that construction and equipment costs for new generator capacity are declining in response to market conditions. Because they have shorter construction lead times and lower capital costs than pulverised coal and nuclear units, natural gas turbines and combined-cycle units have become the technology of choice in recent years for utility capacity expansion. And although the cost of gas is higher than coal on a dollar per million Btu basis, the higher efficiencies and lower operating costs of turbine technologies offset much of this disadvantage. Nevertheless, coal and nuclear technology vendors are responding to this environment by developing standard designs and shifting some of the traditional onsite construction work to modular, factory-built components. Since 1993 the construction and equipment costs for pulverised coal plants have fallen by one-third, while operating expenses for new coal plants are expected to be one-half of the 1993 values. Nuclear vendors are similarly proposing modular, standardised designs.

Consequently, conclusions drawn from comparative studies that constrain generating parameters to a single "representative" value should be examined carefully. By limiting all technologies to a common characteristic, the strengths and weaknesses of each technology within the study are respectively diminished and overstated. Utilities would not use such a methodology to choose the best technology for new capacity additions.

Regional cost estimates

Because of regional variations in material, labour and fuel costs, generation costs will vary by region. Thus, levelised costs for all the technologies considered in this study for plants located in the Eastern or Western United States will differ from those given in the body of the report for plants located in the Midwest region. The 2005 fuel prices and real escalation rates for the two regions are shown in Tables 1 and 2, respectively. Table 3 and Figures 1 and 2 show levelised costs for the three regions of the United States.

Table 1. **2005 fuel prices in east and west regions (1995 dollars per MBTU)**

Fuel	East	West
Nuclear fuel	0.55	0.55
Coal	1.74	1.19
Natural gas	2.52	3.58
Biomass	1.26	NA

Table 2**. Real fuel price escalation rates in east and west regions (per cent/year)**

Fuel	East	West
Nuclear	0	0
Coal	-0.75	-0.75
Natural gas	3.22	2.67
Biomass	0	NA

Table 3. **Projected Costs in East, Midwest and West regions of the United States at 5% and 10% discount rates, 40 year lifetime, 75% load factor (USmill of 1.7.1996/kWh)**

	Region	Coal					Gas					Nuclear & Others				
			Invest.	O&M	Fuel	Total		Invest.	O&M	Fuel	Total		Invest.	O&M	Fuel	Total
5%	East	C1	12.93	4.96	13.51	31.40	G1	4.96	2.74	28.57	36.27	N[B]	20.09	8.57	6.13	34.79
			41%	16%	43%	100%		14%	8%	79%	100%		58%	25%	18%	100%
		C2[B]	14.66	4.90	10.91	30.47	G2[B]	5.06	2.55	23.75	31.36	BIO	16.47	6.95	10.15	33.57
			48%	16%	36%	100%		16%	8%	76%	100%		49%	21%	30%	100%
							FC[B]	16.52	4.15	24.56	45.23					
								37%	9%	54%	100%					
	Midwest	C1	11.33	4.96	8.69	24.98	G1	4.36	2.74	20.08	27.18	N[B]	17.75	8.57	6.13	32.45
			45%	20%	35%	100%		16%	10%	74%	100%		55%	26%	19%	100%
		C2[B]	12.83	4.90	7.02	24.75	G2[B]	4.43	2.55	16.69	23.67	BIO	14.34	6.95	8.77	30.06
			52%	20%	28%	100%		19%	11%	71%	100%		48%	23%	29%	100%
							FC[B]	14.39	4.15	17.27	35.81					
								40%	12%	48%	100%					
	West	C1	12.83	4.96	9.22	27.01	G1	4.93	2.74	36.89	44.56	N[B]	19.94	8.57	6.13	34.64
			48%	18%	34%	100%		11%	6%	83%	100%		58%	25%	18%	100%
		C2[B]	14.54	4.90	7.44	26.88	G2[B]	5.02	2.55	30.66	38.23					
			54%	18%	28%	100%		13%	7%	80%	100%					
							FC[B]	16.38	4.15	31.72	52.25					
								31%	8%	61%	100%					
10%	East	C1	24.61	4.96	13.92	43.49	G1	8.87	2.74	24.65	36.26	N[B]	37.18	8.57	5.67	51.42
			57%	11%	32%	100%		24%	8%	68%	100%		72%	17%	11%	100%
		C2[B]	28.00	4.90	11.24	44.14	G2[B]	9.04	2.55	20.49	32.08	BIO	32.00	6.95	10.15	49.10
			63%	11%	25%	100%		28%	8%	64%	100%		65%	14%	21%	100%
							FC[B]	31.41	4.15	21.19	56.75					
								55%	7%	37%	100%					
	Midwest	C1	21.47	4.96	8.96	35.39	G1	7.75	2.74	17.02	27.51	N[B]	32.59	8.57	5.67	46.83
			61%	14%	25%	100%		28%	10%	62%	100%		70%	18%	12%	100%
		C2[B]	24.41	4.90	7.23	36.54	G2[B]	7.89	2.55	14.15	24.59	BIO	27.82	6.95	8.77	43.54
			67%	13%	20%	100%		32%	10%	58%	100%		64%	16%	20%	100%
							FC[B]	27.32	4.15	14.63	46.10					
								59%	9%	32%	100%					
	West	C1	24.41	4.96	9.50	38.87	G1	8.80	2.74	32.71	44.25	N[B]	36.88	8.57	5.67	51.12
			63%	13%	24%	100%		20%	6%	74%	100%		72%	17%	11%	100%
		C2[B]	27.77	4.90	7.67	40.34	G2[B]	8.96	2.55	27.19	38.70					
			69%	12%	19%	100%		23%	7%	70%	100%					
							FC[B]	31.15	4.15	28.12	63.42					
								49%	7%	44%	100%					

B Power plants expected to be commercially available by 2005-2010.

Figure 1. **Levelised electricity generation costs in the East, Midwest and West regions of the USA 5% discount rate, 40 year lifetime, 75% load factor (USmill/kWh)**

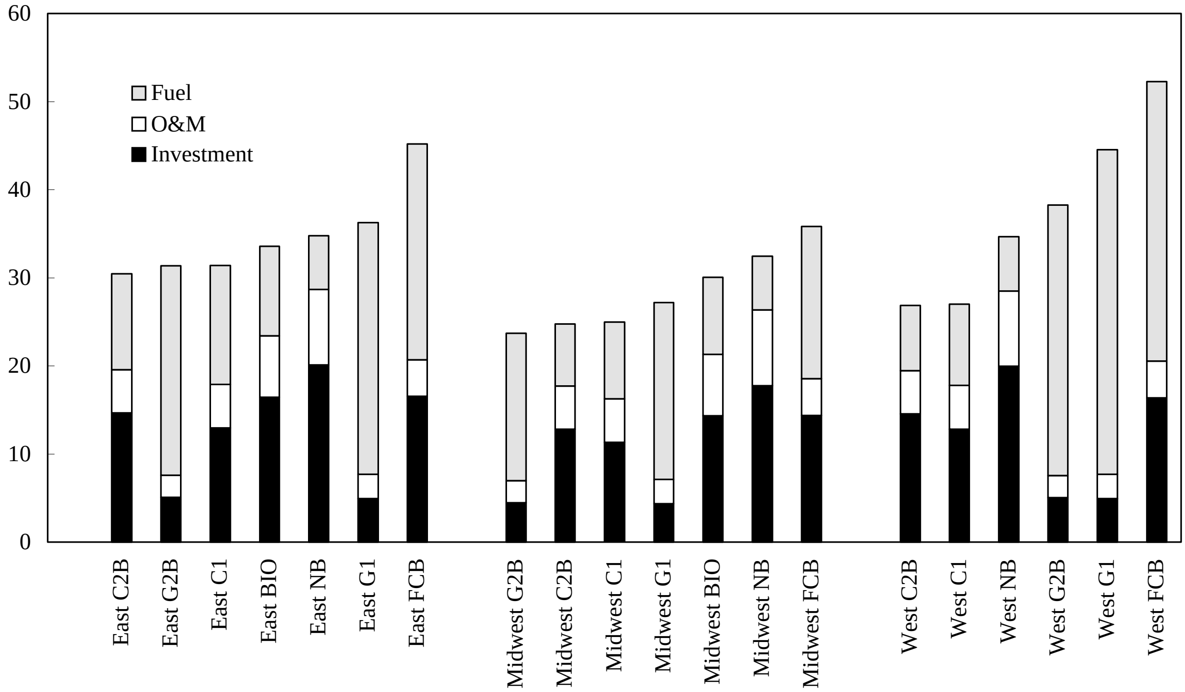
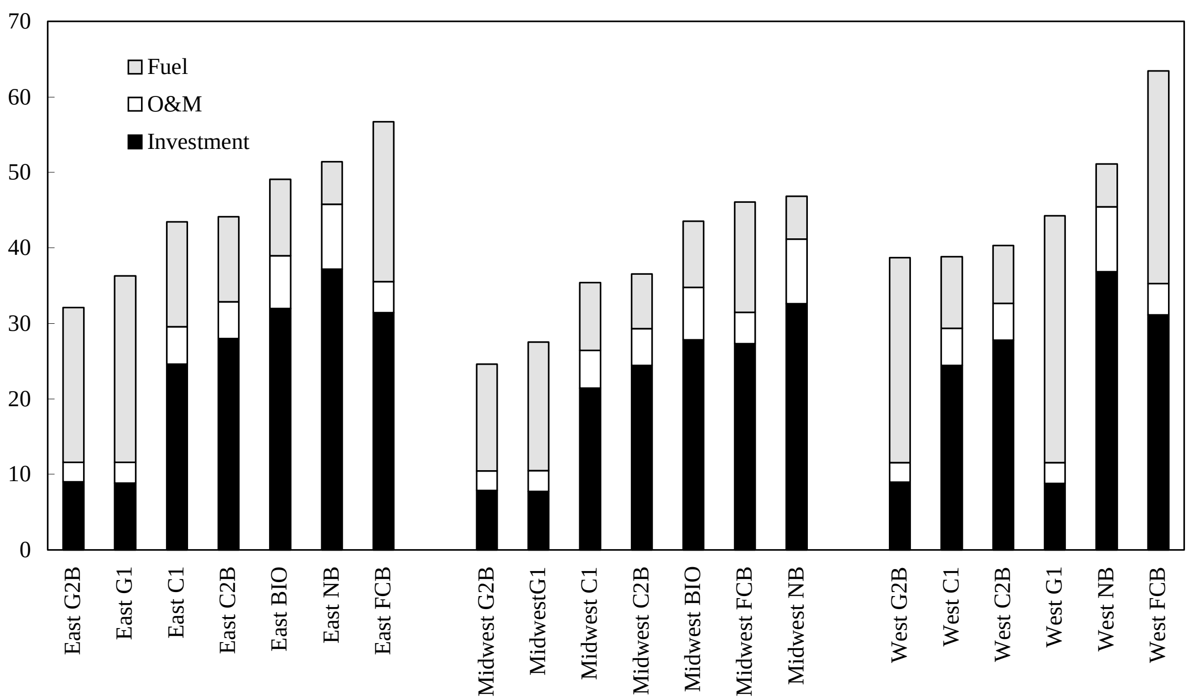


Figure 2. **Levelised electricity generation costs in the East, Midwest and West regions of the USA 10% discount rate, 40 year lifetime, 75% load factor (USmill/kWh)**



Technology characterisations

The technical characteristics of the technologies included in this submission are described below:

- Pulverised Coal Steam 300 megawatts:

  – Wet flue gas desulfurisation (95 per cent sulphur removal); and
  – Low NO_x burners.

- Integrated Coal Gasification Combined-Cycle (Oxygen Blown Destec Process) with high performance turbine 380 megawatts:

  – Transport hot gas desulfurisation (99 per cent sulphur removal);
  – Hot gas barrier filter;
  – GE "H" class gas turbine;
  – Steam cycle conditions 16.5 MPa/566°C (2 400 psig/1 050°Fahrenheit); and
  – Process control with artificial intelligence.

- Conventional Combined-Cycle-"F" Frame Turbine 250 megawatts:

  – GE "F" class gas turbine;
  – Turbine exhaust gases less than or equal to 538°C (1 000°Fahrenheit);
  – Performance data assume ISO conditions of 15°C (59°Fahrenheit), 60 per cent relative humidity, at sea level; and
  – NO_x emissions less than 9 parts per million by steam injection and selective catalytic reduction.

- Advanced Combined-Cycle-"G" Frame Turbine 350 megawatts:

  – GE "G" or "H" class turbine;
  – Turbine exhaust gases greater than 538°C (1 000°Fahrenheit);
  – Performance data assume ISO conditions of 15°C (59°Fahrenheit), 60 per cent relative humidity, at sea level; and
  – NO_x emissions less than 9 parts per million by steam injection and selective catalytic reduction.

- Molten Carbonate Fuel Cell 10 megawatts:

  – Molten carbonate electrolyte;
  – Operating temperature 650°C (1 200°Fahrenheit);
  – Nickel and stainless steel construction; and
  – Combined emissions of SO_x and NO_x less than one pound per megawatt-day.

- Generic Advanced Light-Water Reactor 1 300 megawatt:

  – Generic Light Water Reactor with design improvements over current generation of light water reactors.

- Biomass:
  - Gasification Combined Cycle Systems;
  - High-pressure direct gasification assumed, although costs are similar for low pressure systems;
  - 100 MW unit size; and
  - Wood chip fuel is used for plant characterisation, however fuel supply could be from dedicated crops (wood or grasses) after 2010.

Construction expenditure profiles

A single cost expenditure profile was used in the calculations because of the absence of technology specific expenditure information. A single expenditure profile was assumed for all technologies that have a common construction period. For example, nuclear, pulverised coal steam, biomass, and integrated coal gasification are assumed to require four years to build. As a result, these technologies have the same construction expenditure profile.

Annex 3

GENERATION TECHNOLOGY

This annex briefly describes the power generation technologies which are the basis of cost estimates presented in this report. These technologies are available currently or could be available by 2005. The basic baseload technologies and options are described for coal-fired, gas-fired, and nuclear power plants. Several other plant types not falling under the most common technological choices are also described.

Other sources describe these technologies in greater detail. Several useful references are:

General power plant design	Sorenson (1983)
Steam boiler electric generation	Schultz (1992)
Coal-fired plants	Couch (1997)
Combined-cycle gas turbines	Kehlhofer (1991)
Nuclear plants	Glasstone (1994)

Coal-fired power plants

Most cost estimates for coal-fired power plants presented in this study are based upon combustion of pulverised coal in conventional subcritical boilers. Several were based upon supercritical boilers, fluidised bed boilers, or integrated gasification combined cycles (IGCC).

Basic plant features

Conventional pulverised coal combustion burns finely ground coal particles in a boiler with water-cooled walls. Steam is raised in these walls and a series of heat exchangers which cool the hot combustion gases. In the case of an electricity-only power plant, the steam is passed through a condensing steam turbine which drives a generator. In the case of a co-generating power plant, a back-pressure or extraction steam turbine is used. Many variations on the steam cycle are possible in either electric-only or co-generating power plants. For example, in a reheat steam cycle the steam, after partially expanding through the steam turbine, is brought back to the boiler and reheated to peak temperature again in order to improve overall power generation efficiency. The basic configuration of steam generation followed by expansion in a steam turbine is used in all boiler steam-electric power plants.

The pressure at which steam is generated is a key design feature. The majority of coal-fired boilers built in the OECD to date have been subcritical. This means steam pressure is below the critical pressure of water, or approximately 22 MPa (218 atmospheres). Supercritical boilers raise steam above this pressure. By doing so, the efficiency of power generation is improved, but the cost of the boiler, steam turbine, and control valves is increased. The materials of construction of these components must be resistant to the high-pressure steam and so are more expensive alloys. The choice of sub- or supercritical design depends on the local balance of fuel costs, which are reduced by higher efficiency, and capital costs, which are increased due to more expensive materials.

The impurities contained in coal are released during combustion. In addition, nitrogen oxides (NO_x) are formed by the combustion process itself by reactions with nitrogen contained in the coal and in the combustion air. Toxic by-products found in combustion gases include sulphur dioxide, nitrogen oxides, halogens, unburned hydrocarbons, and metals. Ash remains from the non-combustible portion of coal feed and unburned carbon. Typically half is collected in the bottom of the boiler and the remainder is carried along in the combustion gases as fly ash. Various environmental control systems must be incorporated into the plant design to limit the formation of pollutants (nitrogen oxides) or remove them from flue gases.

Pollution control systems

The pollutants controlled from coal-fired plants and the levels to which they are controlled are key cost factors. The tighter the emissions limits, the more expensive the pollution control systems will cost to build and operate, and the more energy they will consume. All the coal-fired plants in this study meet national pollution control requirements, which vary by country. The IEA (1997) summarises major pollution control standards for coal-fired power plants within IEA Member countries. The pollutants controlled and environmental protection measures associated with coal combustion are nonetheless similar for all the plants in this study. The major pollutants of concern are airborne emissions of sulphur dioxide, nitrogen oxides, and particulate matter.

Sulphur dioxide is controlled in all cases presented in this report, except Brazil and India, by flue gas desulphurisation systems. The predominant wet scrubber design consists essentially of a reaction vessel in which the sulphur dioxide is absorbed from the flue gas stream by a slurry of limestone or other reagent. Sulphur removal efficiencies of 95 per cent or more are possible. This type of desulphurisation system is expected to be installed on most new coal-fired power plants. Other configurations are possible, including spray dryer systems, dry sorbent injection and regenerable systems (Soud and Takeshita, 1994).

The energy needed to operate a wet scrubber system consumes up to 1 per cent of plant output. The system also adds up to 100-250 $/kWe to plant capital cost (Takeshita, 1995), and also adds to operating and maintenance costs. Energy consumption and costs are closely related to the permissible level of sulphur dioxide emissions from the plant.

Nitrogen oxides are controlled by modifications to the coal combustion system itself, to minimise their formation, and post-combustion removal. Staging air within the combustion zone (overfire air) and the use of low-NO_x burners are the two primary combustion techniques which result in an immediate reduction in NO_x production of up to 60 per cent compared to uncontrolled coal combustion. Low-NO_x burners are standard or the minimum NO_x control requirement in many countries. Capital costs for these burners are not a significant cost element: typically 10-30 $/kWe. If NO_x emissions must be reduced below levels obtainable using combustion modifications, dedicated NO_x removal systems must be installed. Generally selective catalytic reduction (SCR) systems are used for coal fired stations. These involve the injection of ammonia or urea into the flue gas and the catalytically enhanced reaction of the reagent with NO_x to form nitrogen and oxygen. SCR is the most effective NO_x control technology, but is relatively expensive. All the flue gas must pass through catalyst beds. The catalyst reactor adds some 50-90 $/kWe to the capital cost and induces higher plant electrical consumption. The catalyst itself must be periodically replaced at some expense. Half of the conventional coal-fired plants in this study in OECD Member countries are fitted with SCR. None of the plants in non-Member countries have post-combustion NO_x control. Soud and Fukusawa (1996) describe developments in control of NO_x emissions.

The third major airborne pollutant from coal-fired stations is particulate matter. This is essentially the ash carried along with the combustion gases. Control of particulate matter has been incorporated in nearly all coal-fired power stations in OECD Member countries for many years. One of two basic systems is included in all plants of this study. Electrostatic precipitators function by drawing particulate matter to electrically charged plates along the flue gas path. Fabric filters, installed in "baghouses," mechanically separate out the airborne particles in a large number of fabric bags arranged in parallel. The choice of system depends upon particulate emission limits, fly ash characteristics, total flue gas volume flow, and other factors.

Several advanced emission control systems are able to remove two or three of the major pollutant streams in a single system. For example, the E-beam process irradiates dirty flue gas with electron beams to remove sulphur dioxide and nitrogen oxides in a single process. Other catalytic and chemical combined removal processes are under development. However, these systems have not seen substantial commercial use yet.

Other systems are typically required to control pollution from solid or liquid discharges from coal fired stations. For example, waste water from power plant processes and runoff from coal and ash storage areas is typically treated before release. Coal ash must be disposed of in an environmentally acceptable way, which requires, in some instances, special ash treatment to stabilise leachable materials found in coal ash.

Fluidised beds

Large coal-burning circulating fluidised beds operating at atmospheric pressure may be considered as commercially proven technology. They function by burning coal in a "bed" or dense cloud of aerodynamically suspended particles. The airflow suspending the particles is sufficiently strong that a portion of the particles is entrained out of the boiler and then recirculated to it via cyclones. As in conventional pulverised coal boilers, the heat released by combustion is captured within the boiler in water-cooled walls and then a series of heat exchangers which cool the combustion gases. Heat exchangers cooling the recirculated coal and ash particles are also used in the production of steam in some designs. The steam raised may be subcritical or supercritical, although to date fluidised bed boilers have employed subcritical steam systems.

Sulphur dioxide emissions can be controlled by the addition of limestone or other sorbent to the bed. The limestone captures SO_2 in solid form, primarily as calcium sulphate, and thus avoids the need for post-combustion flue gas desulphurisation. Although NO_x formation is minimised because of lower bed temperatures compared to those in a pulverised coal flame, post-combustion NO_x control may still be required. The same post-combustion NO_x control systems used in conventional coal plants may be used in fluidised bed plants. Some form of particulate control is typically required (electrostatic precipitator or baghouse).

Pressurised fluidised beds are similar in design to atmospheric fluidised beds, but their combustion chamber is held at pressure. This allows them to be combined with gas turbines which compress the combustion air and provide the expansion turbine for hot gases. Systems for cleaning the hot combustion gases must be used in this arrangement in order to protect gas turbine blading from entrained particulate and gas impurities. Pressurised fluidised beds may also be used to gasify coal for power production. No commercial plants of either type have been constructed, although a number of demonstration plants have been built and operated. Rather than circulating fluidised beds, these plants have used "bubbling" beds, or beds of lower fluidising velocity. No pressurised fluidised beds were included in the cost estimates of this study.

Advanced steam cycles

As noted above, by using steam above its supercritical pressure the efficiency of steam power cycles may be increased, whether in pulverised coal or fluidised bed boilers. Overall plant efficiency can be increased from roughly 38 per cent (based on lower heating value) using subcritical steam cycles to 42-45 per cent with supercritical steam. Steam conditions above 25 MPa (245 atmospheres) and 566°C, or "ultra-supercritical" conditions, have the potential to increase cycle efficiencies an additional 2 to 3 percentage points. Special steels capable of resisting higher temperatures and pressures while still resisting corrosion are key to the use of supercritical cycles. Other cycle improvements, such as double reheat, once-through steam heating, enhanced feedwater heating, and reduced piping pressure drops can also improve cycle efficiency, albeit at the cost of increased expense for equipment and materials.

Almost 90 per cent of the capacity in new units built in Europe, Japan, and Korea in the 1990s uses supercritical steam (Couch, 1997: p. 59). In contrast, 85 per cent of the new capacity of plants built in Australia, Canada, and the United States built in the 1990s uses subcritical steam. The technology choice follows from fuel price and the cost of equipment prevailing locally. Improved supercritical plant designs could in the future improve its cost effectiveness compared to subcritical plants.

Pollution control systems for coal-fired plants are the same regardless of the steam pressure employed. For example, flue gas desulphurisation, low-NO_x burners and flue gas de-NO_x, and particulate control would all typically be required whether the plant employed a subcritical or supercritical steam cycle. Plants employing more efficient steam cycles do have marginally less expensive pollution control systems because less coal is burned per unit of electrical output.

Integrated gasification combined cycle

IGCC plants convert coal to a combustible fuelgas, then burn this fuel in a gas turbine combined cycle. The principal components are thus a coal gasification facility, typically including an oxygen production plant and gas cleaning facility, and a combined cycle power plant (see description below). The gasifier functions by only partially combusting the coal. This partial combustion provides enough energy to drive off volatile compounds and drive gasification reactions to create hydrogen, carbon monoxide, and methane gas. This fuelgas or "synthetic natural gas" also contains sulphur compounds which are removed in gas cleaning systems. Compared to conventional coal combustion, the sulphur compounds are present at relatively high concentration and may be removed at high efficiency (98 per cent or greater) without undue incremental expense.

A key design feature of the gasification plant is the choice of oxygen or air as the source of oxygen for gasification. Most plants to date have used oxygen. The IGCC plants included in this study are based on designs using oxygen. This choice means that key process components, particularly the gasifier, fuelgas heat exchangers, and gas cleaning systems, are smaller because they do not need to process the large volume of nitrogen (80 per cent) in air. Also, the heating value of the fuelgas produced is closer to that of natural gas. The gas turbine therefore requires less modification to burn a fuelgas produced in an oxygen-consuming gasifier. The main disadvantage is that a dedicated cryogenic oxygen production facility must be used. There has been considerable development work on gasification systems using air, but few past or operating IGCC systems using them. Various gasifier types have been developed, including entrained-flow, fluidised bed, and fixed bed. Entrained flow gasifiers, typically using oxygen, have dominated IGCC applications to date.

The clean fuel gas produced in the gasification facility is burned in a combined cycle of generally standard configuration. There are various opportunities for integration of the combined cycle and gasification facility through exchange of steam flows and air flows which tend to increase thermal efficiency at the expense of greater process and operational complexity. Advances in gas turbine technology will tend to improve the efficiency and cost effectiveness of IGCC plants in parallel.

Other coal-fired options

No cost estimates for other types of coal-fired power plants have been presented in this report.

Gas-fired power plants

Basic plant features

All gas-fired power plants presented in this study (except one gas boiler and one fuel cell) are based upon the use of gas turbine combined cycles. Gas turbines, also known as combustion turbines, have been in existence since World War II, when they were developed for use as aircraft engines. The engine exhaust stream is sufficiently hot that it may be used to raise steam for electricity production from a steam turbine. The combination of gas and steam turbine is called a combined cycle gas turbine (CCGT). Gas turbine technology benefited greatly during the 1980s from developments in military jet aircraft engines and the increased availability of gas and liberalisation of gas markets in many countries. Currently, CCGT plants have thermal efficiencies of 50 to 55 per cent.

More than other power plant types, gas turbines thermal efficiencies are affected by ambient temperatures. As ambient air temperature increases, plant output decreases due to reduced mass flow through the turbine itself. As with other plant types, the design point efficiencies are typically higher than the average efficiency obtainable on an annually averaged basis because of variations in ambient conditions and in off-design point operating regimes.

Heat recovery steam generators have typically used two pressure levels of steam in order to maximise the heat recovery from the gas turbine exhaust stream. Boilers on advanced turbines will take advantage of higher exhaust stream temperatures by using three pressure levels of steam.

Gas turbines are compact devices and are produced in factory series. The boilers used to recover heat from the turbine exhaust (heat recovery steam generators) and the steam turbines are also relatively standardised. The use of standardised components allows manufacturers to market modular power plants with reduced design and construction costs.

Pollution control systems

Natural gas normally has little or no sulphur. Therefore flue gas desulphurisation systems are not needed. However, as with coal-fired plants, nitrogen oxides are produced during the combustion process. Low-NO_x burners can partially reduce the production of NO_x in gas turbine combustors and are now almost standard on new turbines. Injection of steam or water into the combustors can also be used to reduce NO_x production, but this reduces thermal efficiency and so is less common in new machines. In areas where strict NO_x emission regulations are in effect, additional measures are normally needed. Post-combustion systems, mainly selective catalytic reduction, can be used.

Advanced gas turbine plants

Advanced gas turbines currently under development, such as so-called "G" designs, will have efficiencies approaching 60 per cent through the use of high combustion temperatures, steam-cooled turbine blading, and more complex steam cycles. A number of advanced power cycles involving gas turbines are under development or being demonstrated. These aim to maximise the efficiency of the steam cycle or to integrate more tightly the gas and steam cycles. Examples are the HAT and CHAT cycles (humid-air and cascaded humid-air turbine); intercooled, reheat turbine cycles; STIG cycle (steam injected), Kalina cycle (ammonia/water steam cycle); and thermochemical exhaust heat recovery.

Fuel cells

Fuels cells convert hydrogen, light hydrocarbons, or carbon monoxide directly into electricity via a thermochemical reaction carried out in a "cell" with no moving parts. Natural gas must be converted to a hydrogen-rich fuel in a reformer for most fuel cells. The fuel cell proper reacts the hydrogen with oxygen from the air to produce water vapour and electricity in the form of direct current. In some fuel cell designs, the exhaust gas may be sufficiently hot to drive a steam cycle or other heat recovery system. A power conditioner is required to convert the direct current into alternating current for use in conventional electrical systems. The thermochemical reaction of fuel produces very little NO_x compared to normal combustion. Post-combustion de-NO_x would not be required.

Fuel cells have several different basic designs, all having an anode, cathode, and electrolyte between the two. Molten carbonate and phosphoric acid fuel cells rely upon a liquid electrolytes, while solid oxide fuel cells use zirconium oxide as a high-temperature solid electrolyte. Operating temperatures vary among the different fuel cell types, from 80°C in alkaline fuel cells to 1 000°C in solid oxide fuel cells. The cells most suitable for large baseload power generation appear to be molten carbonate fuel cells (costed in this study) and solid oxide fuel cells (Hirschenhofer and McClelland, 1995).

At present there are no large commercial fuel cell systems such as might compete with gas turbines or coal-fired power plants. The high capital cost remains the most important disadvantage of current fuel cell designs. In principle a fuel cell power plant could run on a coal-based fuelgas rather than natural gas. The combination of a coal gasification facility and fuel cell power plant would have an overall efficiency as high as 60 per cent, but the capital cost of such a combination is currently prohibitive.

Nuclear power plants

The nuclear power plants for which cost estimates are reported in the present study are based on light water reactors or pressurised heavy water reactors (PHWRs). Light water reactors include pressurised water reactors (PWRs) and boiling water reactors (BWRs). The plants referred to in this report include some advanced or evolutionary features, but are in category A plants, i.e., commercially available, except for the American plant and the Brazilian standardised PWR. Cost estimates were not provided for other types of reactor such as high temperature gas cooled reactors or liquid metal reactors.

At present, light water reactors represent more than 85 per cent of the nuclear capacity in operation world wide (around 64 per cent for PWR and 22 cent for BWR) and nearly 80 per cent of the capacity under construction. PHWRs represent some 5 per cent of the installed capacity in the world and nearly 15 per cent of the capacity under construction.

Basic plant features

Each reactor type is characterised by the choice of a neutron moderator and a cooling medium which lead to different fuel designs. Pressurised and boiling water reactors use light water (ordinary water) as moderator and coolant. In pressurised water reactors, water is maintained liquid by high pressure while in boiling water reactors water is allowed to boil in the reactor core. In either type, the heat removed from the core ultimately is used to raise steam which drives an ordinary steam turbine-generator.

Steam conditions in existing plants have generally been limited compared to fossil-fuelled plants. In pressurised water reactors, the steam temperature is generally less than 350°C, whereas typical subcritical fossil boilers will produce steam at 540°C. The less severe steam conditions in nuclear plants have been chosen to minimise capital cost, particularly that of the reactor pressure parts, while still maximising fuel efficiency. Thermal efficiencies of operating plants are typically 30 to 33 per cent.

Both reactor types require enriched uranium fuel (containing more ^{235}U, the fissile isotope, than natural uranium) in order to maintain a chain reaction in spite of the absorption of neutrons by the moderator. Fuels used in light water reactors of current generation use uranium enriched at some 3 to 5 per cent in ^{235}U while natural uranium contains 0.7 per cent of ^{235}U. Light water reactors also can use fuel containing recycled materials, plutonium and uranium, recovered through reprocessing of spent fuel. Pressurised heavy water reactors use heavy water (deuterium oxide) as coolant and moderator. This choice makes it possible to utilise natural uranium as fuel. The use of pressure tubes rather than a single large pressure vessel around the core facilitates refuelling while the reactor is in operation.

For light water reactors the main front-end (before fuel loading in the reactor) fuel cycle steps are: uranium mining and milling; conversion; enrichment; and fuel fabrication. For PHWRs the enrichment step is not necessary. As enrichment accounts for some 40 per cent of the levelised front end fuel cost (NEA, 1994), fuel cycle costs are lower for PHWR than for light water reactors. At the back-end of the fuel cycle, after unloading of spent fuel from the reactor, two options are available: direct disposal of spent fuel; and reprocessing. In the first option, spent fuel is conditioned after a period of cooling into a form adequate for final disposal in a high level radioactive waste repository. In the second option, spent fuel is reprocessed to separate materials (plutonium and uranium) that can be used again in reactor fuel from residual waste fission products which are conditioned, after interim storage for cooling, to be disposed of in a high level waste repository. There appears to be little difference in overall cost between the once-through and recycling options (NEA, 1994). For all reactor types and fuel cycle options, radioactive waste arising at each step of the fuel cycle are sorted and conditioned for disposal according to their level of radioactivity.

Most countries provided nuclear fuel cost estimates for reactors operating on once-through fuel cycles, i.e., with direct disposal of spent fuel. Three countries, France, Japan and China (for PWRs) provided cost estimates for closed cycle, i.e., with reprocessing of spent fuel and recycling of fissile materials.

Advanced reactor designs

Advanced nuclear power plant designs and concepts have focused on improved reliability, better economics and enhanced safety (Juhn, 1997). Design improvements have been introduced mainly in an evolutionary fashion through small modifications taking advantage of successful, proven design features and new technological developments, including in non-nuclear areas such as control and instrumentation.

Several nuclear power plants commissioned recently already incorporate a number of advanced reactor key features. Examples are: the first two 1 315 MWe advanced boiling water reactors, Kashiwasaki Kariwa 6 and 7, commissioned in 1996 and 1997 in Japan; the N4 1 400 MWe units Chooz B1, B2 and Civaux 1, in France. Most of the units for which cost estimates were provided for the present study fall within the category of advanced reactors.

Advanced light water reactors under development include large size units (1 200 to 1 300 MWe), and mid size plants (~ 600 MWe) using passive safety systems and inherent safety features. Important programmes in advanced light water reactor development were initiated in the mid 1980s in the United States including large and mid size PWRs and BWRs. Two large evolutionary plants, the System 80+ and the Advanced Boiling Water Reactor received design certification from the US Nuclear Regulatory Commission (NRC) in 1997. The AP 600 is under NRC review and a final design approval is likely in 1998. In Europe, France and Germany are developing jointly a 1 500 MWe advanced PWR, the European pressurised water reactor, with enhanced safety features meeting the requirements of French and German safety authorities. Advanced light water reactor development efforts are pursued in other OECD and non OECD countries such as Finland, Japan, Korea, China and Russia. Advanced evolutionary heavy water reactors are under development in Canada and India.

All advanced reactors under development are aiming at enhancing the competitiveness of nuclear power as compared to fossil-fuelled power plants, especially gas fired plants, while maintaining high safety standards. Owing to the cost structure of nuclear generated electricity, designers have focused their efforts on reducing capital costs. Significant capital cost reduction can be obtained by standardisation, building multiple units on the same site, placing series orders, shortening construction times and improving project management (NEA, 1990). The benefits of standardisation and series orders are illustrated, for example, by the French REP 2000 series which is estimated to have led to savings of 20 per cent in capital costs (Bacher, 1995). Standardisation and series orders also have induced economic benefits through, for example, reducing expenses for staff training and spare part stocking.

Shortening construction times reduces interest during construction which is a significant component of nuclear investment costs. Progress has been made already in this regard; for example nuclear units commissioned recently in Japan and Korea were built in 4 to 5 years. At the same time, advanced reactors are designed to last longer – 50 to 60 years. Extending operating lifetime decreases levelised electricity generation costs (see Tables 21 and 22).

Simplification is a key goal in the design of advanced reactors as reducing the complexity of nuclear steam supply system components both reduces costs, makes operation and maintenance easier, and improves safety. Advanced reactor designs aim at more compact, simplified plant layout, smaller buildings and structures, fewer safety related valves, pumps and piping, and simplified steam turbines.

Another area of cost reduction is in fuel utilisation. Advanced reactor designs aim to improve fuel energy utilisation ("fuel burn-up") and lower the total cost of fuel fabrication and other cost components related to the mass of fuel handled.

Other power plant technologies

Only a few fuel/technology combinations other than those described in the preceding sections were included in the cost comparisons of this report. They are boilers fired on a fuel other than coal, biomass gasification, and wind turbines.

Non-coal boilers and gasification

Boilers fired on gas and oil were included in this study. The basic technologies applicable are the same as for coal-fired boilers, as described above. However, the details of boiler design and auxiliary systems vary according to the fuel. For example, the different combustion characteristics influence the radiant heat transfer within the combustion chamber. Also, flue gas heat exchanger designs vary markedly due to the different composition and ash loading of the flue gases. Flue gas desulphurisation and flue gas de-NO_x may be required depending on the sulphur content and combustion characteristics of the fuel. In the case of oil, the requirements for soot-blowing and ash removal are much less compared to coal-fired boilers because of oil's low ash content. Flue gas desulphurisation and de-NO_x would typically be required for new baseload oil-fired plants.

Biomass is relatively non-uniform and has a high moisture content compared to fossil fuels. These characteristics make fluidised bed combustion an effective boiler technology for biomass combustion. Biomass may also be consumed in gasification combined cycle power plants similar in basic process design to coal-fired IGCC plants. The gasifier choice depends heavily on the biomass characteristics, but, as in simple biomass combustion, fluidised bed gasifiers are well adapted for biomass. The economic size for biomass-fuelled plants is smaller than for fossil fuelled plants because of limited quantity of biomass typically available within a given distance of the power plant.

Beyond certain distances the cost of transporting biomass, with its high moisture content, becomes excessive.

Wind turbines

Wind energy is one of the fastest growing renewable energy sources in the OECD. Over 1990 to 1995 generation from wind power increased an average of over 70 per cent per year in IEA Member countries, with particularly rapid growth in Germany, the United Kingdom, and Spain. This growth has been made possible by decreasing costs for wind power, combined with government policies designed to promote it.

The installed capacity of wind turbines has shown rapid technological progress in recent years. The predominant design is the horizontal axis turbine in which two or three airfoils, gearing, and generator are mounted at the top of a tower. Unit capacities of mass-produced machines have steadily increased as design and operational experience has grown. For example, Zond Corporation (USA) reports wind turbine sizes increased from 25 kW in 1981 to 750 kW in 1997, a factor of 30, even while cost increased only by a factor of nine. Average installed Danish wind turbine size has increased from 31 kW in 1983 to 350 kW in 1995. The trend to increasing size takes advantage of economies of scale in wind turbine design.

Another key factor in wind turbine cost is the weight of equipment mounted on the tower. Lighter systems allow the cost of the supporting tower to be reduced as its design load is lowered. They also tend to be simpler and more reliable because of fewer parts. The combination of design factors and improved operational experience has lowered specific capital costs by 50 per cent and generation costs by two thirds compared to values obtainable in the early 1980s.

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Annex 4

COMBINED HEAT AND POWER

Combined heat and power (CHP) production has been assessed in the previous generating cost studies (1989, 1992). Technology, fuels, economics, technical analysis and methodology have been described in a broad outline of CHP. This annex focuses on the development since the 1992 study. Key topics are the rising acknowledgement of the importance of energy efficiency and efficient resource utilisation, environmental impacts (and costs) of electricity and heat generation, energy policy costs, and finally the impact of electricity market liberalisation on CHP.

The development in factors influencing the costs of generating energy (apart from technology) is assessed in other annexes of this study. Expectations of cost development at the investment decision point of time are crucial: fuel prices, emission limits (CO_2, SO_2, NO_x), security of supply and how regulation will be imposed on individual plants (taxes, subsidies, emission quotas etc.).

This annex distinguishes the different types of CHP: small scale, large scale and industrial cogeneration. The purpose is to put the impact of combined heat and power production on the electricity generation costs in a broad context. Previous studies examined CHP cost issues quite in depth.

Basic CHP economic considerations

Inevitably, power production from thermal power plants leads to a certain heat rejection to the environment. This side effect can either be neutralised by cooling away the heat or it can be utilised as a “supplemental” source of energy. Also the production of heat for district heating purposes and industrial processing and green houses leaves opportunity for a certain co-production of power and thereby a larger combined energy efficiency than could be reached by separate production. Whether or not the combined electricity and heat production is more economic depends upon site specific factors.

Producing heat and power combined, as opposed to separate production of each, means a more efficient energy/resource utilisation and may provide an economic advantage (when only considering direct production cost). For instance, Denmark has experienced a power system efficiency improvement of almost 15 per cent during the last 20 years, primarily due to an increased share of CHP. Typically, fuel savings of around 30 per cent can be achieved by CHP compared to separate production[1]. The distribution of this advantage between each product (heat and power) is a key question when assessing the impact of CHP on electricity generation costs; the distribution is affected strongly by which output is considered to be the primary product (electricity or heat).

The cost distribution methods described in the previous generating cost studies are based on a centralised system for electricity production and a decentralised system for heat production. In the 1992 study (annex 7) two "extremes" are distinguished, which in summary are:

1. Electricity is regarded as the primary product: only costs in excess of condensing production of electricity is allocated to the heat side. By this method, the entire cost advantage is allocated to the cost of heat production.

2. Heat is regarded as the primary product: only costs in excess of alternative heat production is allocated to the electricity side. Under certain conditions this gives the whole CHP cost advantage to electricity production.

There is no thermodynamically "correct" formula for the allocation of CHP production costs[1] which means that cost estimates cannot avoid an element of hypothetical preconditions concerning determination of the alternative production costs e.g. "If the heat was to be produced in a stand alone boiler, what would the price then have been?".[2]

The nature of CHP gives the concept a certain degree of site specificity. Costs will vary with the temperature level of the heat generated, the number of heat consumers and their distance from the CHP plant. The structure of residential heating (collective or individual supply) is an important determinant of the scope for large and especially small scale CHP; the industry structure (the extent of heating for process purposes) is an important factor in the scope for industrial cogeneration[2].

As with other energy projects, the investment decision will be based on a total economic evaluation of the cogeneration plant. Experience in Denmark and the Netherlands shows that, for industrial cogeneration, the pay-back time is crucial and prohibitive if in excess of 4-5 years. Also, the energy-intensity inherent to each industry is important, as is the relative gain from cogeneration, which basically depends on the share of energy costs compared to total expenses in each industry.[3]

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1. For the purpose of this study, the Netherlands' representative investigated whether an exergy approach would contribute with a new "objective" method to the distribution of the cost advantage. However the conclusion was that an exergy approach did not yield reasonable results and will therefore not be discussed in this annex.

2. As an illustration of the two cost allocation methods, consider a plant with a 45 per cent thermal electricity efficiency in condensing mode, a 38 per cent thermal electricity efficiency in CHP mode and a 50 per cent thermal heat efficiency.

   If ***method 1*** is applied 84 per cent (38/45) of the fuel cost is allocated to the electricity production and only 16 per cent is allocated to the heat production. This approach results in a heat efficiency used in the cost calculation of 280 per cent. This efficiency is exclusively used in the cost distribution and has nothing to do with a conventional thermodynamic efficiency. In this method the electricity side is indemnified and the CHP advantage is given to the heat side.

   If ***method 2*** is applied instead, the fuel cost is distributed relatively to the output. This is also called the *pro rata principle*. Now 43 per cent of the fuel cost is allocated to the electricity and 57 per cent to the heat. This gives a calculated electricity efficiency of 88 per cent which means that the whole CHP advantage is given to the electricity side.

3. For example, if 5 per cent of an industry's productions costs is due to energy use, the impact on total cost due to a saving of e.g. 30 per cent on energy costs is only 1.5 per cent. It is possible that a corresponding investment elsewhere in the process could yield a greater impact on overall costs.

Owing to the higher economic value of electricity, the CHP plants normally will be designed for the highest possible electricity output.

Tax-incentives promoting CHP: the Danish experience

In Denmark a subsidy of 0.07 or 0.10 Dkr/kWh is granted to power delivered to the grid from small scale CHP (capacity varying from 0.5-100 MW) when fuelled by natural gas. If fuelled by biomass an additional subsidy of 0.17 Dkr/kWh is granted. An additional incentive for industrial CHP is an investment subsidy given by the authorities covering up to 30 per cent of total investment costs.

Denmark has no taxes on fuels for electricity production. Instead a tax is collected from the end consumer. The subsidy of 0.07 or 0.10 Dkr/kWh is a compensation for the lack of a CO_2 tax on fuel, and gives an incentive for CHP investments which would otherwise not be attractive from the investors point of view.[4]

Also the small scale plant owners by law are guaranteed a price for power delivered to the grid which gives credit for the long run (avoided) capacity costs to the utility buying the power. CHP also has a de facto priority in the load dispatching. The legislation has been changed to state explicitly this priority for CHP.

Joint ventures promoting CHP: experience from the Netherlands

The main barrier to the application of industrial cogeneration is the shorter depreciation time in industry, which can be overcome by joint-ventures between industry and energy companies. If the conditions are equal between central power production and cogeneration (a level playing field for electricity prices), no other incentives are necessary.

A comparison of production costs, based on equal conditions for central power production and cogeneration, shows that CHP leads to lower electricity production costs. Industrial cogeneration is able to compete successfully with base load electricity production, while local CHP is an interesting option for middle load electricity production.[5]

CHP in the open electricity market: the Finnish experience

Owing to the cold climate and energy intensive industry, the share of power generation from CHP is 34 per cent of the total Finnish power production. About 13 TWh is produced in district heating CHP plants and about 10 TWh in industrial cogeneration plants, which in total gives 23 TWh electricity from CHP. These figures do not include auxiliary condensing power in district heating CHP plants or process condensing power. In industrial cogeneration plants, the main fuels are

4. Recently the Parliament decided to lower the subsidy also for existing plants to 0.07 Dkr/kWh and to introduce a time limit (corresponding to pay-back time). However the change is not in effect yet, as it is awaiting approval by the European Commission.

5. The precise competitive position of CHP in the Netherlands is difficult to distinguish based on market performance because the Government has maintained a policy of CHP promotion since the 1989 electricity Act. A capital of subsidy of 17.5 per cent and avoided cost purchase requirements were put into place to promote the development of CHP. The capital subsidy was removed in 1995.

renewable sources, like waste wood and liquors from pulp and paper industry. The unused CHP potential is quite limited. However, there is a potential for increasing capacity in pulp and paper industry by replacement of the old CHP plants with new ones, where the power to heat ratio is higher (e.g. gas fired combined cycle CHP plants).

The existing CHP capacity in Finland has been built without any major government subsidies. It means that CHP production is competitive also in the open electricity market (see tables on projected generating costs in the present report). On the other hand, the production costs traditionally have been calculated in a way that regards heat as the primary product. In Finland, CHP does not have any priorities in dispatching.

As in Denmark, there are no taxes on fuels for electricity production and the tax is collected from the end consumer. In heat production (in CHP plants and in separate heat production) there is a tax based on CO_2 emissions.

CHP in EU-15: existing capacity and potential

Compared to the total power production in European countries, the share of power from combined production is relatively limited. According to Eurostat, the EU-12 in 1994 had a total of 205 TWh of electricity produced by CHP, which corresponds to 9 per cent of total electricity production in the same year.

There are however reasons for this. An important economic obstacle for the use of CHP is the cost of introducing large scale heat transmission networks. Small scale CHP (when there is already a district heating network in place) and industrial cogeneration does not face this obstacle of bearing the costs of large heat distribution networks; in principle, the only excess cost in this case is a grid connection for the power. Accordingly, it is mainly industrial cogeneration plants which currently are being established in Europe.

A number of national and international assessments of CHP potentials have been made. The Danish Energy Agency has in June 1997 estimated the CHP potential for EU-15 as an input to the EU Ad-Hoc Group on Climate[3]. This paper estimates the near-term economic potential and the long-term (to 2020) technical potential. The long-term total technical potential is estimated at approximately 900 TWh in EU-15 (see Table 1).

According to the Danish paper, the most economic potential is found to be in industrial cogeneration, large buildings establishing their own CHP plants and in existing district heating areas. The remainder of the potential (46 per cent) is found in urban areas without existing district heating networks. The total potential corresponds to 40 per cent of 1994 electricity production (including the 9 per cent of power production which is already CHP) and is very unevenly distributed between the countries.[6]

6. Denmark and Finland already have moved past this share of CHP electricity. In Denmark, it is expected that by 2005 the share of CHP in total electricity generation will be 65 per cent.

Table 1. **Potential CHP electricity in EU-15 until year 2020 (TWh)**

Country	Industrial cogeneration	Large and small scale CHP	Total technical potential 2020
Austria	6	29	35
Belgium	9	27	36
Denmark	3	16	19
Finland	15	12	27
France	37	56	93
Germany	69	302	371
Greece	2	0	2
Ireland	2	3	5
Italy	29	10	39
Luxembourg	1	1	2
Netherlands	21	42	63
United Kingdom	32	96	128
Portugal	5	0	5
Spain	19	0	19
Sweden	21	39	60
Total EU-15	**271**	**635**	**906**

Source: EU (see reference 4).

Owing to the lack of national estimates with common assumptions, a common methodology is set up and applied in the study from which this table is drawn. Therefore, the figures do not necessarily reflect national estimates.

The role of CHP in energy policy

The European Cogeneration Review 1997[4] gives more detailed information on the share of CHP in electricity production in each EU country as well as on CHP targets and CHP promotional policies and tariff/price examples. The economic evaluation of CHP projects from the point of view of non-utility investors is discussed[5].

The European Commission proposed in 1997 to commit EU Member States to an overall 15 per cent CO_2 reduction target in 2010 compared to 1990, depending however on the result of the climate convention conference in Kyoto in December 1997.

CHP could be an important technology to achieve CO_2 emission reductions. If CHP electricity replaces coal-based electricity, the CO_2 reduction from 1 MWh CHP electricity is 0.4-0.9 tonne, depending on which fuel the CHP plant uses. The Danish CHP programme alone is expected to save more than half of the national targeted 20 per cent CO_2 reduction in 2005 (compared to 1988).

When considering costs of CO_2 reducing measures, CHP may offer a cost effective means of meeting energy policy targets of reducing greenhouse gas production. In this broader context, costs of CHP should be compared to costs of other means of reducing CO_2 emissions, and not solely to cost of electricity generation.

The impact of European electricity market liberalisation

The Council Directive on the internal market for electricity was approved in December 1996. By February 1999 most EU Member States must implement the EU directive on an internal electricity market in national legislation. A point of major importance to CHP are the provisions on priority production and the possibility of considering CHP as a "Public Service Obligation"[6]. The current status of electricity market liberalisation varies between the EU countries. Accordingly the actual role of CHP in the countries' energy mix remains to be seen.

However, most European countries have an over capacity in power production owing to many years of protection of utility sector market position. There will be little need in the near term for new capacity of any type, including CHP. During a period of market and capacity adjustment this may constitute a problem for investments in CHP, especially where no heat distribution networks are already in place.[7]

Therefore, if CHP is to play a key role in the achievement of an EU greenhouse gas emission reduction strategy as, for example, the Danish Energy Agency hopes[7], the EU may choose to implement community wide policy instruments favouring CHP.

Also, electricity market deregulation in energy systems with existing CHP leaves the question of how to deal with cost allocation when heat supply retains monopoly status. Power companies have an incentive to maximise the income from heat sales in order to strengthen competitiveness on electricity prices. It therefore depends on regulatory arrangements whether no more than a fair share of costs of cogeneration can be allocated to heat customers. However, the method of calculating cost and benefits still will be within the framework outlined above and there is no way to point out a "correct" method concerning this question either.

7. Electricity (spot) price development in already deregulated markets, UK and Norway, does not unambiguously point in this direction. However, experience is not yet substantial enough to draw sound conclusions concerning future developments.

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Annex 5

FUEL PRICES

The projected costs of generating electricity presented in this report depend strongly on the fuel price projections assumed in each national calculation. Fossil fuel prices, unlike operating and maintenance costs, have typically been assumed to be subject to sustained periods of real price increases. This assumption stems from the abrupt price increases seen in energy markets following the 1970s oil shocks, and the continued view that gas and energy resources are limited and destined for depletion as world energy demand inexorably rises. This annex presents recent historical experience in fuel prices and their inter-relationships, the limitations of fuel price projections, fuel price projections of this and past NEA/IEA studies, and other fuel price projections.

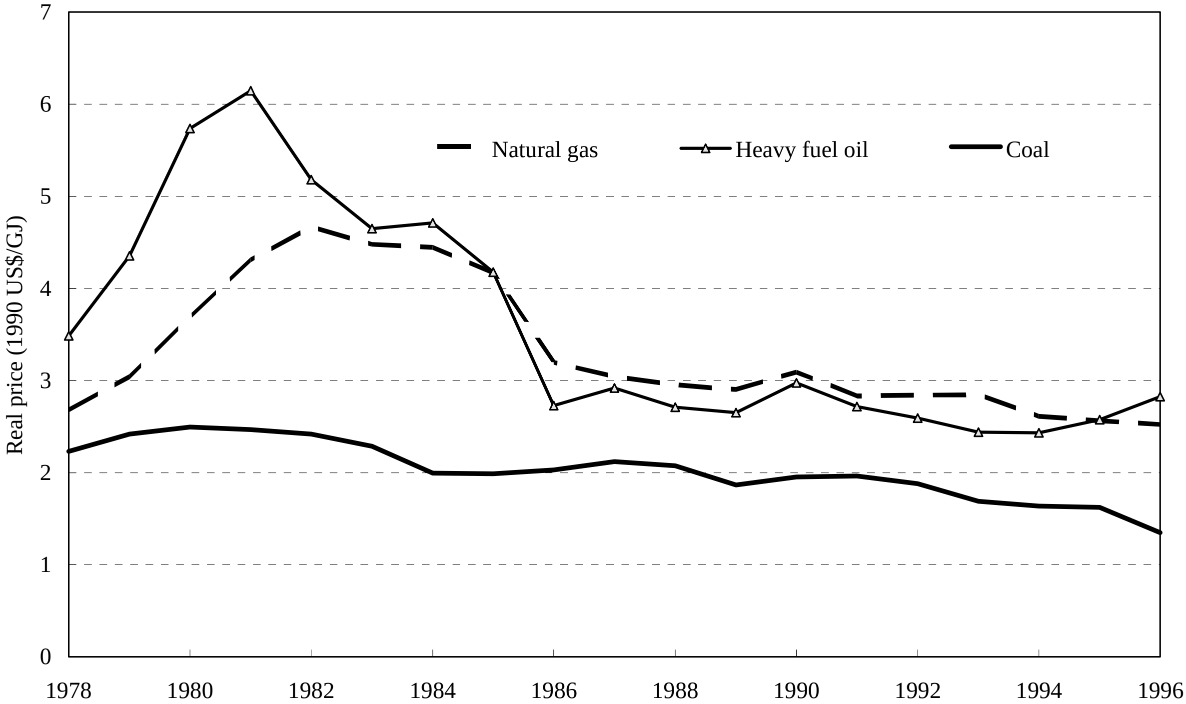
Fossil energy price linkages

Figure A5-1 presents real prices of coal, oil and natural gas sold to power plants since 1974 in the OECD. The graph illustrates several key relationships between fuel prices: the close relationship between prices of fuel oil and natural gas and the weaker, diminishing link between prices of fuel oil and coal. The oil price shocks led to substantial increases in prices of natural gas as well as oil. Natural gas and fuel oil are often in direct competition in industrial and power end-uses, so there is a competitive demand-side price link between the two energy sources. In addition, in many markets natural gas prices were contractually linked with those of crude oil or fuel oil. The price swings of oil products were therefore followed in natural gas markets as well.

In contrast, prices of coal for power production rose less in response to the increases in oil. The demand for coal increased as power plants and industrial users substituted coal for heavy fuel oil, which before the oil shocks was used extensively in baseload plants in some regions. The rising prices for coal in the 1970s and early 1980s reflected the ability of high-cost coal producers to obtain prices needed to sustain their operations, including incremental supply (ACA, 1994). However, within several years coal supply markets adjusted to the increased demand as investments were made in mining and transport capacity. This began to lower prices well before the 1986 oil price "countershock." Real coal prices have declined throughout the OECD since 1982, and in most countries have remained within 10-15 per cent of the average over the last 10 years.

Structural changes in demand for power plant fuels have also weakened the price link between coal and oil. Compared to the situation before the oil shocks, fuel oil use has been significantly reduced in baseload power production and in industry. Fuel oil's sustained price increase relative to coal has constrained it to providing mainly peaking and intermediate loads. Coal has become less of a substitute for fuel oil. Thus if the price of oil rises, only a relatively small proportion of total generation could shift to coal. Future changes in oil prices would have only a small effect on the demand for baseload power plant fuels and their prices.

Figure A5-1. **Real prices of fossil fuels supplied to OECD power plants, 1987 to 1996**



Source: IEA, Energy Prices and Taxes (OECD, Paris).

Liberalisation of both coal and natural gas markets is also tending to reduce the supply-side links between their prices and oil product prices. Throughout the OECD, governments are reducing subsidies to domestic coal mining and allowing power plant consumers to choose the most economical coal supplier. This weakens the ability of high-cost producers to impose higher prices on domestic consumers in response to increased prices of competing fuels. France, Germany, Japan, Spain, Turkey and the United Kingdom are all in the process of reducing coal mining subsidies. Gas markets have also been moving towards more competitive systems. Gas wellhead prices were decontrolled in the United States beginning in 1978 and in Canada in 1985, and the North American gas transportation system has been restructured to introduce competition. The European Union has developed a directive on gas market liberalisation that will introduce elements of competition, and supply contracts for liquefied natural gas in Japan and elsewhere are moving away from price formulas strictly related to crude or fuel oil prices. Contract pricing increasingly takes into account spot market prices, supply costs, and the value of energy end-use (so-called "net back pricing").

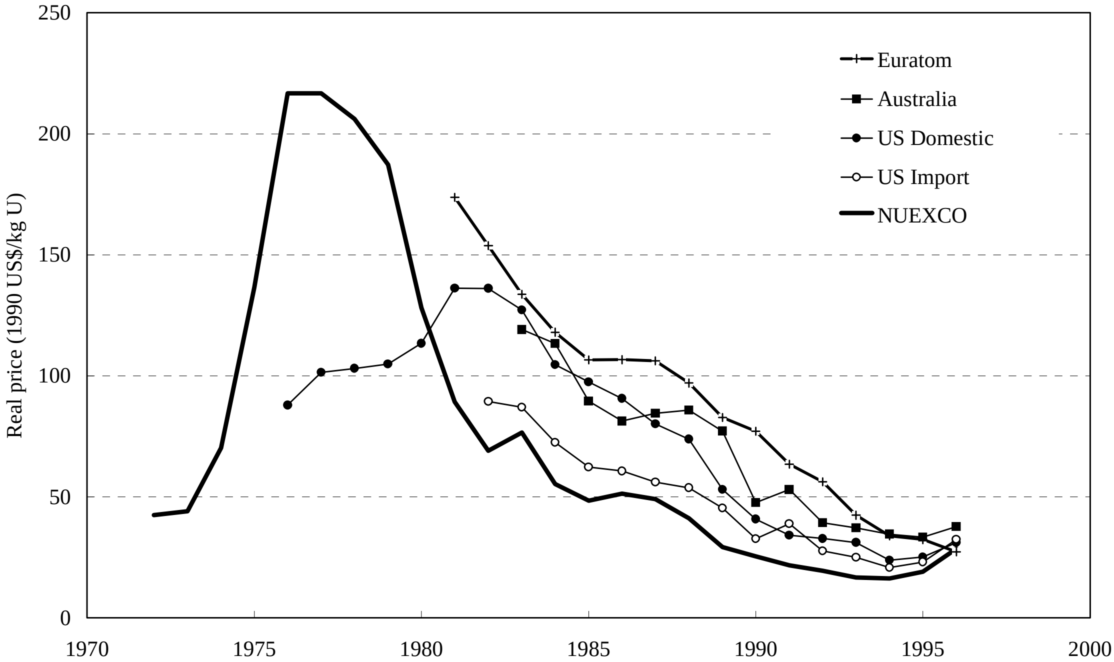
In summary, prices for potential baseload fossil fuels, namely coal and natural gas, have become less closely linked to oil prices. This trend is likely to continue. The implication is that future swings in oil prices would have less effect on interfuel competition among baseload plants than was the case in the past.

Uranium and nuclear fuel prices

Prices of nuclear fuel as delivered to utilities have not followed the same patterns as those of fossil fuels. Although the late 1970s and early 1980s saw relatively high uranium prices, fuel prices began falling well before the 1986 oil price countershock.

Figure A5-2 shows trends in real uranium price since the 1970s, based on a mix of long-term and spot market purchases reported by several sources. Uranium prices differed by a factor of over two throughout the 1980s, but have begun to converge in the 1990s. Real prices have declined substantially, from over 150 $/kg contained uranium in 1980 to about 30 $/kg U in 1996, based on 1990 dollars. The convergence and decline of prices in different markets reflects the gradual movement towards a more integrated world-wide uranium markets and increased spot market sales.

Figure A5-2. **Real uranium prices in the OECD, 1972 to 1996**



Source: NEA (1998).

Notes: Euratom prices deflated by OECD Europe GDP deflator, all others deflated by US GDP deflator. Euratom prices based on multiannual contracts. Others reflect a mix of spot and multiannual contract prices.

In contrast to fossil fuels, most of the cost of nuclear fuel does not depends on the raw commodity, uranium. Table A5-1 gives fuel cost components for pressurised water and Candu reactors. Only about one third of the cost of fuel for pressurised water reactors, as delivered to a utility, is based upon the cost of uranium itself. The remaining two thirds is due to conversion, enrichment, and fuel fabrication costs, each of which is generally handled by separate entities. For heavy water reactors, conversion and enrichment are not necessary, but uranium still only accounts for about half the delivered price of fuel. Nuclear fuel prices do not obey typical patterns seen in pure commodity markets.

Table A5-1. **Levelised nuclear fuel cost components, pressurised-water and Candu reactors**

	PWR	**Candu**
Uranium	35%	54%
Conversion	4%	n.a.
Enrichment	40%	n.a.
Fuel fabrication	21%	46%

Source: NEA, 1994.

Note: PWR values are for the “reference case” at 5 per cent discount rate.

Figures A5-3 and A5-4 shows trends in prices for conversion and enrichment services. Note that these prices do not represent real OECD averages (as do those of Figure A5-1). Rather, they are nominal estimates in individual markets calculated using different averaging and sampling methods. They merely give an indication of nuclear fuel services tendencies in recent years.

Figure A5-3. **Long-term and spot price of uranium conversion services, 1982 to 1997**

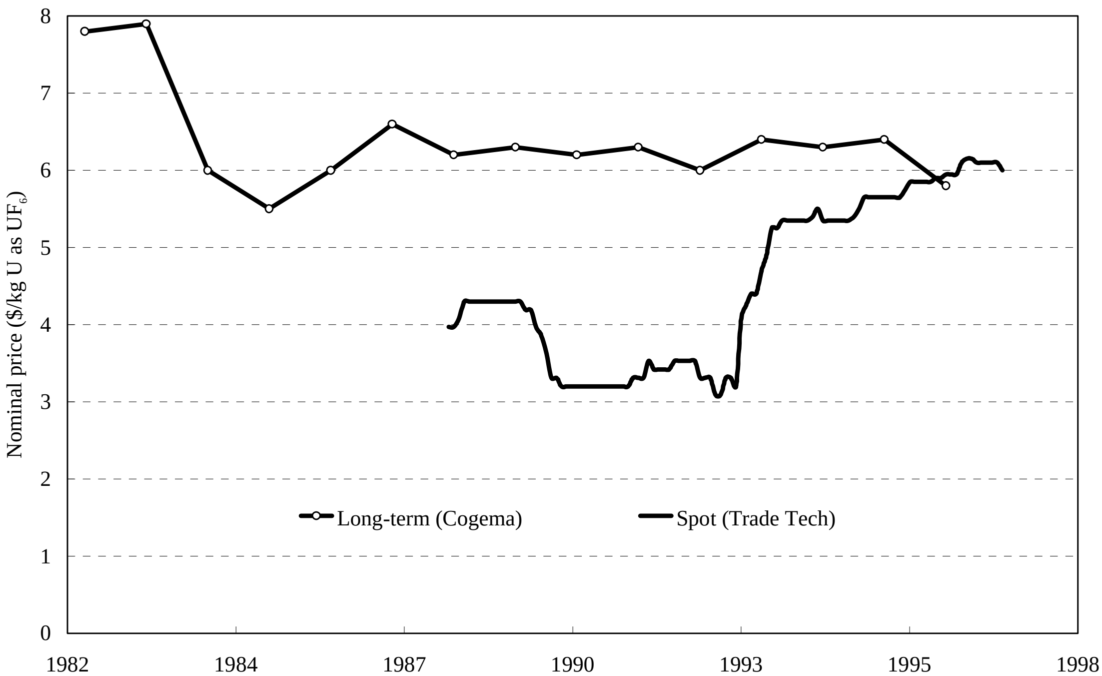
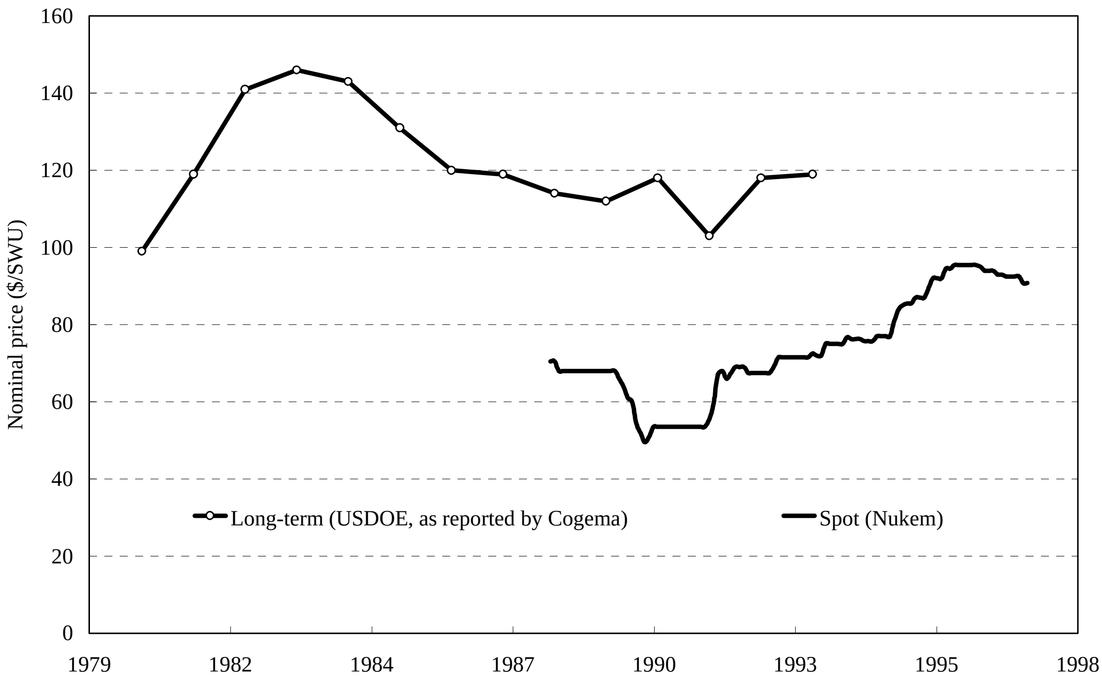


Figure A5-4. **Long-term and spot price of uranium enrichment services, 1980 to 1997**



Note: SWU ("separative work unit") is a standard measure of uranium enrichment services.

Until about 1995 prices of long-term contracts for conversion services, as reported by the French fuel services provider Cogema, were relatively steady, and from 1.5 to 2 times an indicative spot price. Following the closure of a large US conversion plant (Sequoyah) in 1992, conversion overcapacity was reduced somewhat and the two have tended to converge. More recently both long-term and spot prices have been decreasing in response to the expected arrival of uranium from dismantled nuclear weapons (USDOE, 1996). The conversion market is today a relatively competitive component of the fuel services chain.

An overcapacity in enrichment services has put downward pressure on contract prices, but uncertainties in the enrichment market have tended to increase spot prices since 1991. The impending privatisation of the United States Enrichment Corporation, increasing competition among suppliers, and surplus military uranium are likely to lower prices in the medium term.

There is no transparent market for fuel fabrication services, which have in the past been tightly linked with the vendor of the power plant in which the fuel is used. It is apparent, however, that the market for fuel fabrication services is becoming more competitive, as suppliers are beginning to provide fuel for use in systems not based on their own designs.

There are several reasons why it is difficult to generalise about future trends in nuclear fuel markets. Two important ones are:

- nuclear fuel markets have not been fully competitive and are influenced strongly by political decisions;
- there has been a persistent imbalance in uranium production versus consumption.

The markets for uranium and nuclear fuel supply services have generally not been fully competitive. This is because certain parts of the nuclear fuel supply chain were or continue to be operated by government entities, political decisions can strongly influence supply and costs, and there exist legal and technical constraints to the emergence of competitive markets. Uranium enrichment has been in the hands of government entities since the beginning of nuclear power. It was not until 1979 that a large OECD enrichment plant operating outside the United States (Tricastin, France) was opened. Only now the dominant supplier, the United States Enrichment Corporation, is being privatised. In the political area, the United States and the European Union restrict the supply of uranium and the provision of conversion services from states of the former Soviet Union. The United States has agreed to purchase enriched uranium from stocks of highly enriched uranium in former Soviet states. Furthermore, demand projections in the OECD (long-term) depend strongly on political decisions regarding continued operation of existing plants and construction of new ones.

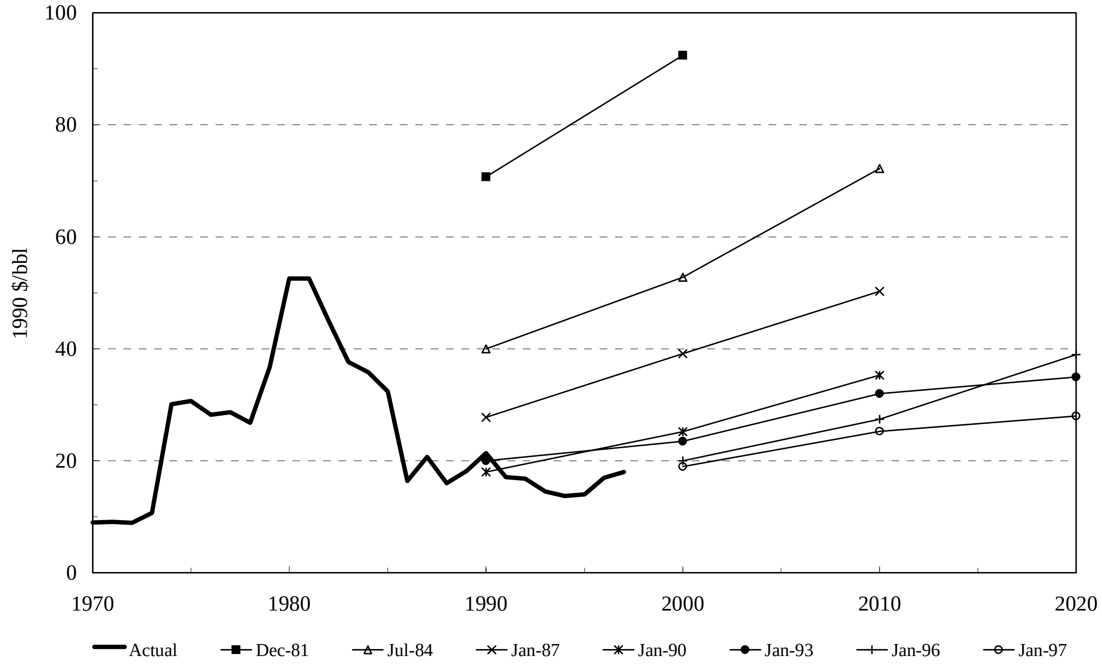
The second factor introducing considerable uncertainty in the future price trends is the historic lack of supply-demand balance in the uranium market. Up until the late 1980s, the uranium market was characterised by an over supply situation, mainly due to a lower-than-expected nuclear electricity generation growth rate (NEA, 1998). After 1990, total world uranium production fell below annual requirements and net stock drawdowns have been 20 000 tonnes uranium or greater since 1992. The absence of a long-term equilibrium makes commodity price forecasting difficult.

The general tendency is towards introduction or further development of competition in all parts of the nuclear fuel supply chain.

Difficulties of fuel price projections

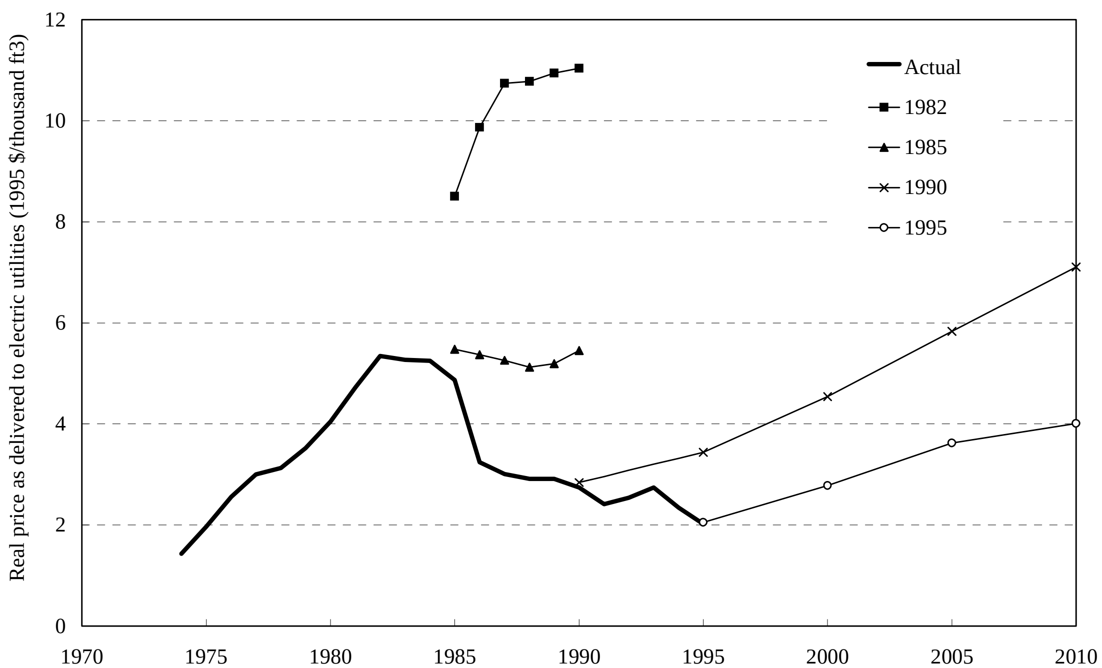
Figures A5-5 and A5-6 provide illustrations of successive oil price projections by the International Energy Workshop (Schrattenholzer, 1997) and US gas price projections by the United States Department of Energy (EIA, 1995).

Figure A5-5. **IEW consensus projections of crude oil prices**



Source: IEW (Schrattenholzer, 1997).

Figure A5-6. **US DOE/EIA projections of natural gas prices to electric utilities, 1982 to 1995**



Source: United States Department of Energy (EIA, 1995).

These represent consensus views of future energy price trends since the 1980s. The graphs illustrate past errors in forecasting oil prices, and energy prices in general. Since the oil shocks, the prevailing view has been that energy prices would rise in real terms from the price prevailing at the time (Streifel, 1995). This view continues today, but the projected rates of real fuel price escalation have dropped dramatically in the years since the oil shocks. This is consistent with the substantial evolution of energy markets, including the development of non-OPEC oil and gas supplies, increased world trade in natural gas and coal, and absence of indications of long-term price increases.

The potential for interfuel substitution places a limit on the maximum price that any single fuel might reach over time. A clear example is that the price of natural gas would not rise permanently above the price at which substitute fuel gas could be synthesised from coal or “non-conventional” oil products such as tar sands or oil shale. Even given long-term investments in gas supply infrastructure, coal gasification plants could provide economic substitutes for natural gas as they did in the early 1900’s in hundreds of town gas plants in OECD countries. Nuclear power and renewable energy sources could be expected to place similar, although higher, caps on fossil fuel prices in general.

Because of such substitutes, it is clearly unrealistic to project indefinitely increasing energy prices at high escalation rates. Using a constant annual escalation rate of 2.3 per cent over a 30-year period results in a doubling of energy price. For most fuels such an increase would result in substitute energy sources being called into greater use and competing on price.

Forecasting of long-term energy prices must be considered a failure. The notions of resource scarcity or cartel behaviour upon which many models have been built, or other assumptions about supply-driven price increases, have not proven to be adequate to describe oil market or energy market behaviour. Furthermore, the links between oil prices and prices of fossil fuels used for baseload power generation, as argued above, are likely to become weaker. Upon what basis, then, should fuel price projections be made?

Unfortunately there is no satisfactory “global” answer to this question. Although there is no method to accurately predict energy prices, neither is there any reason to believe that energy prices will follow the same trends everywhere, whatever they may be. On the one hand, increased international trade in coal and natural gas and energy market liberalisation will tend to reduce price differences between regions and to constrain regional differences in price evolution. On the other hand, it is reasonable to expect that local access to fuels and evolution of fuel markets will have different effects on price developments on a regional basis.

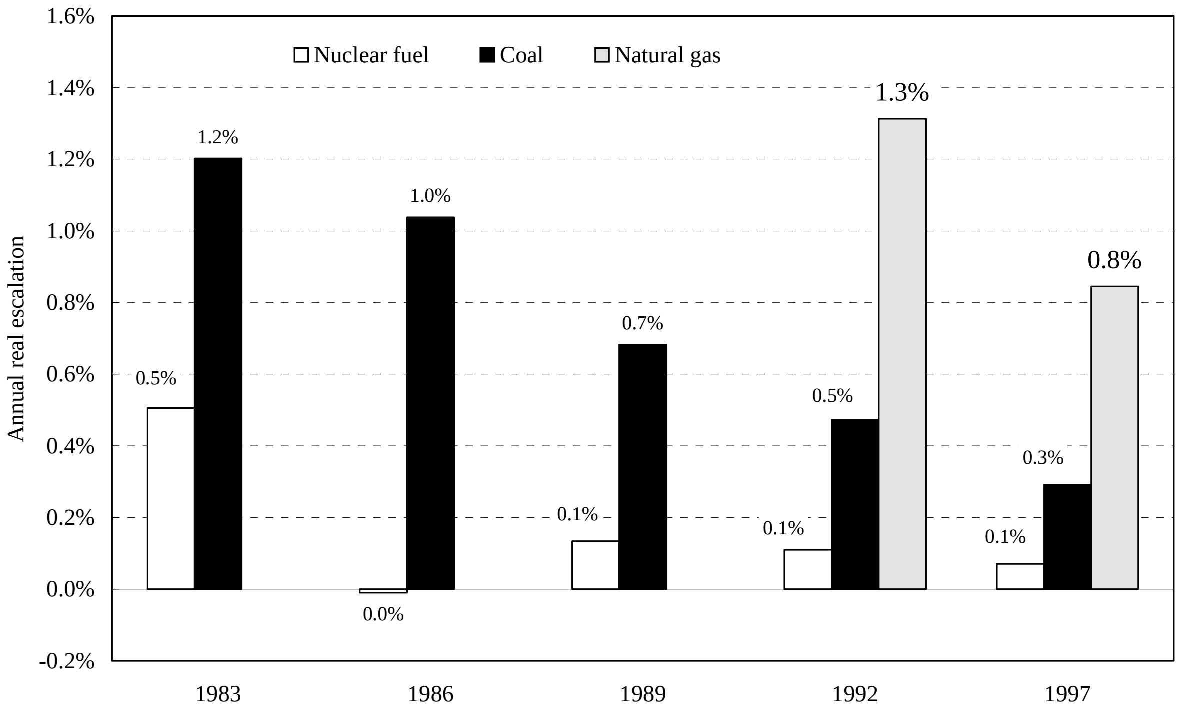
Projections assumed in this study

In the absence of a convincing argument for uniform price projections by fuel, this report has taken the view that national fuel price projections illustrate a range of possible developments. The projections reflect the availability of energy resources within each country, but also attitudes towards the likelihood and size of fuel price increases. Values assumed in national calculations are shown on Tables 12 to 14 in the main body of the report. The annual rates of real price escalation vary from 0.0 per cent to 0.5 per cent for nuclear fuel, -0.7 per cent to 2.1 per cent for coal, and from 0 per cent to 3.75 per cent for gas. The average real price escalation assumed for gas by national respondents is roughly three times that for coal.

The following “study” average has been used for comparative purposes. For each national fuel price, the time-average fuel price escalation rate is calculated as the single, constant escalation rate over 40 years which results in the same final fuel national price at the end of the projection period. The study average is then taken as the simple average of the national time-averaged values. In the case of calculating an average nuclear fuel escalation rate for the present (1997) study, fuel fabrication services are assumed to remain at a constant price (i.e. have an escalation rate of 0 per cent), and the separate escalation rates of uranium, enrichment, and fabrication are weighted by the reference values given in Table A5-1. Using the foregoing assumptions, real fuel escalation values of 0.1 per cent for nuclear fuel, 0.3 per cent for coal, and 0.8 per cent for gas are calculated.

Figure A5-7 presents the study-averaged escalation rates for nuclear fuel and coal over the entire series of electricity generating cost studies since 1983 and gas escalation rates for this current study and the last one. Nuclear fuel escalation rates include only cost components related to delivery of fuel to the power station, not back-end costs. Nuclear fuel escalation rate assumes no escalation of conversion service price for 1997 and the 1992 figures and no escalation of enrichment or fabrication for 1992 figure. Nuclear fuel escalation rates have been between 0 per cent and 0.1 per cent for all studies except the 1983 study, in which an average of 0.5 per cent was observed. Projected rates of coal price real escalation have fallen steadily by about 0.2 percentage points in each successive study. The study-averaged real gas price escalation rate dropped from 1.3 per cent (1992 study) to 0.8 per cent in the current study.

Figure A5-7. **Projected real price escalation rates of fuels average values assumed in successive EGC studies**



Source: NEA and NEA/IEA Projected Costs of Generating Electricity.

Note: See text for explanation of study averages. Nuclear fuel escalation rates include only cost components related to delivery of fuel to the power station, not back-end costs. Nuclear fuel escalation rate assumes no escalation of conversion service price for 1997 and 1992 figures and no escalation of enrichment or fabrication for 1992 figure.

Since 1983 coal's real price for power generation has decreased or remained stable in most OECD countries. The study coal price projections have therefore been tending towards a closer agreement with historical experience. The decreasing values indicate decreasing expectations of energy market disruptions more than significant changes in the underlying economics or supply situation in coal and gas markets. Nine national calculations provided for this study assume no real price escalation for coal (constant or decreasing real prices) over a 40 year plant lifetime. Six assume constant real gas prices.

The variation in fuel price projections among respondents makes the final electricity costs difficult to compare based on today's fuel prices. A significant fraction of the estimates assume no real price escalation. For these reasons, a sensitivity case was calculated in which fuel prices do not increase (see Tables 19 and 20 in the main body of the report).

Other projections

To provide additional points of reference on fossil fuel price estimates, a number of other forecasts or scenarios are given below.

Table A5-2**. Projections of real fossil fuel price escalation rates (%)**

This study, 2005 to 2040	**Range**	**Average**
Coal	-0.7 – 2.1	0.3
Gas	0.0 – 3.8	0.8
EU industry end user prices*, to 2020	**1992 to 1995**	**1995 to 2020**
Coal	6.5	1.8
Gas	1.6	2.0
Fuel oil	2.8	2.4
US electricity industry fuel prices, to 2015		
Coal	-0.9	
Gas	1.0	
Fuel oil	0.9	
Various projections of crude oil price**		
Petroleum Economics Limited (to 2010)	-1.8	
Petroleum Industry Research Associates (to 2005)	-1.6	
Gas Research Institute	-0.2	
Natural Resources Canada	0.4	
NatWest Securities	0.4	
WEFA Group	0.7	
EIA International Energy Outlook (ref. case)	1.0	
DRI/McGraw Hill (base case)	1.4	

* Average figures based upon France, German, Italy, and the United Kingdom, "conventional wisdom scenario".

** As cited in EIA (1997). See EIA document for complete references to original sources.

Source: Capros (1995), Streifel (1995), EIA (1996), EIA (1997: Table 17).

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Annex 6

ENVIRONMENTAL PROTECTION COSTS OF ELECTRICITY GENERATION

This annex identifies the environmental protection costs of the power plants considered in this study. It does not attempt to quantify costs in detail, but to distinguish the various aspects of plant design and operation affected by environmental controls. Power plants built today, throughout the world, are subject to many aspects of environmental control. Most governments have recognised the potentially harmful effects of uncontrolled emissions from power plants and have implemented a wide variety of regulations to minimise environmental degradation. These include controls on:

- airborne emissions;
- liquid discharges;
- solid waste disposal;
- thermal emissions;
- land use.

Nuclear power plants, because of the unique characteristics of their energy source, are regulated according to largely separate criteria designed to ensure that radioactivity is contained within plant confines. The potential environmental harm from releases of radionuclides is such that special regulations relating to safe design and operation of nuclear plants have been developed in all countries relying on nuclear power.

General influence of environmental regulations

Most environmental regulation of power plants today is in the form of limits on emissions or quality of by-products. For example, the European Union limits emissions of sulphur dioxide to 400 mg/Nm^3 in flue gases from large power plants. The simple existence of limits on the discharge of polluting by-products from power production can have a large effect on electricity generating costs. Typically this is because separate control systems and measures not otherwise needed must be put in place to reduce pollutant emissions. The capital cost of the pollution control system, plus ongoing costs related to operation, maintenance, reagents, and other input materials, increase the overall cost of electricity production. All the plants included in this study meet local environmental control requirements.

Beyond the presence of limits, the exact value defined in the limits is a key determinant of cost. As stringency of environmental regulations increase, generally the cost of complying with them does also. In other words, the lower the limit, the higher the cost. In the first place, physical limitations of pollution control processes (especially pollutant removal processes) tend to increase design and operating costs. For example, the cost of consumables or internal electricity consumption of pollution control processes might increase. In the second place, once certain levels of stringency are reached, entirely new engineered systems may be required, typically with a step increase in costs. An example is given by NO_x emissions limits: as allowable emissions decrease, at some point flue gas de-NO_x must be added, because low-NO_x burners are not sufficient to meet the lowest limits.

In some instances, environmental regulations effectively require the use of certain technologies, regardless of emissions limits. So called "best available control technology" (BACT) or "best available technology not entailing excessive cost" (BATNEET) may be required. As technology evolves, the cost of including BACT or BATNEET technology will change as well.

The approaches to environmental regulation described above have been effective in reducing pollution from power production, especially air pollution. However, they may not have done so at the least cost for the desired level of pollution control. Some plants can bear disproportionately high costs for only small reductions in the amount of pollution released. For this reason, in recent years the potential utility of economic or "market-based" instruments for reducing the environmental impacts of power plants has been recognised (OECD, 1994). Broadly defined, economic instruments attempt to place a monetary value on the environmental impact of emissions and effluents in such a way that these costs can be incorporated into commercial decisions. Companies that emit large amounts of pollutants having costly environmental impacts thus have a strong incentive to reduce their emissions in order to remain competitive. Examples of economic environmental policy instruments are:

- taxes or charges on fuels, fuel components, emissions, or effluents;
- deposit/refund systems for potentially polluting materials;
- creation of markets for pollutant emission rights (allowances);
- requirement of liability insurance policies or contribution to a liability fund.

Each of these instruments is currently in use in one or more OECD countries. For example, France and Sweden levy taxes on SO_2 and NO_x emissions. In the United States, SO_2 emissions above those permitted by allowances are taxed. Sweden imposes a tax on the sulphur content of oil, coal, and peat. Companies may respond to market-based instruments by either paying the defined price (or tax) or installing pollution control equipment and modifying operating procedures to reduce the production of taxable pollutant. The use of market-based instruments is likely to become more common in coming years.

Environmental regulations may increase costs of some plants by constraining their operation under certain weather conditions. For example, in a number of large cities around the world, fossil power plants with high sulphur dioxide or nitrogen oxides emissions may be required to reduce output when peaks of pollution are reached. Under conditions of low seasonal rainfall, cooling water intake (and corresponding electrical output) of riverside thermal plants might be reduced in order to avoid drawing too much water or overheating river water. Costs such as these are not reflected in the values presented in this study.

Externalities

This appendix does not discuss environmental "externalities" or "external costs." These are, broadly defined, environmental costs related to electricity generation not borne by the electricity producer or consumer. Examples are the cost of reduced agricultural output due to acid gas emissions, the cost of health care for individuals affected by pollutant emissions, or reduced land values due to the construction of a power plant. Unless environmental costs are connected with specific operational cash flows or design features having identifiable capital costs, they have not been included in the costs presented in the body of this report.

The literature on externalities is extensive (see, for example, Ottinger, 1991, ch. 8 or Goldsmith, 1994, ch. 3). It has developed as governments and environmentalists have tried to incorporate in power system planning the consideration of environmental effects beyond those mitigated by existing environmental regulations. In some countries, regulatory bodies have explicitly required the evaluation of externalities in the planning process for new power plants. The objective has been to make sure that choices of fuels and technologies are based on minimising costs not only to the electricity producer, but to society as a whole. In the United States, 16 states assign quantitative values to externalities, and 9 states treat externalities qualitatively (GAO, 1995). The practice of "integrated resource planning" has been used in the United States and elsewhere to compel consideration of external costs.

The DECADES project of the International Atomic Energy Agency aims to support comparative assessment of power planning decisions by providing a computer model and other tools which recognise externalities and their implied costs (Semenov, 1995). The project has devoted a significant effort to enumerating and quantifying the health and environmental impacts from all forms of electricity production, including toxicological information on various pollutants. Other work similarly treats environmental externalities in depth, such as Ottinger (1991).

The values assigned to externalities are hotly debated. This is not least because the specific values chosen affect the relative economics of different generation options. Proponents of different options therefore tend to advocate externality values that place their preferred option in the best economic light. Different preferences for environmental versus other goods and lifestyle features are also key parts of the valuation difficulty. There remain fundamental debates on even what environmental costs should be considered as externalities, as well as, inevitably, their valuation.

To date, the use of externalities in economic evaluations of power plants appears to have had only a small effect in comparison with more direct regulatory requirements. In the United States, for example, consideration of externalities has generally had no effect on the selection of renewable energy sources (OTA, 1994). Existing environmental regulations have required utilities to reduce external environmental costs to levels acceptable to broadly based political bodies. As views change, environmental regulations can be modified also to further reduce environmental effects further and, consequently, external environmental costs.

Control of gaseous emissions

The largest cost for environmental control in fossil-fuelled power production is that of air pollution control. In pulverised coal-fired plants the capital cost of emission control equipment can reach almost that of the boiler itself and twice that of the steam turbine (Couch, 1997: p. 77). The combustion of solid and heavy liquid fuels releases sulphur dioxide, nitrogen oxides, particulate matter, and other by-products into flue gases. The combustion of clean gaseous fuels such as natural gas releases nitrogen oxides. Most governments regulate the allowable levels of these in flue gases released to the atmosphere.

Coal-fired power plants

Takeshita (1995) provides a comprehensive review of air pollution control costs for coal-fired power stations. Coal-fired plants have the highest emission control costs of fossil-fuelled stations because coal combustion releases more pollutants than does combustion of other fossil fuels. Coal often has percentage levels of sulphur, and its combustion produces NO_x and fine particulate matter, even in specially designed boilers. The capital and operating costs of emission control systems depend strongly on the physical characteristics of the fuel, including sulphur content, ash content, and flyash electrical resistivity, as well as the type and value of emission limits.

Table A6-1 shows estimated ranges of capital cost and levelised generation cost for various types of flue-gas desulphurisation (FGD) systems operating at 90 per cent sulphur removal efficiency on flue gases from coal-fired boilers. Wet scrubbers are the most common type of system installed world-wide. In round figures, they cost about 200 US$/kWe. Figure A6-1 shows that specific capital cost ($/kWe) of wet FGD systems tends to decrease as plant size increases, indicating an economy of scale. Scrubber costs are decreasing as experience builds with this technology which saw its first widescale application in the late 1970s and 1980s. Capital costs of 100 US$/kWe have been projected for larger sizes of advanced scrubber systems. Factors tending to decrease the cost of FGD are (Takeshita, 1995):

- simplified systems;
- elimination of redundant components through increased reliability;
- increasing absorber (reactor tower) capacity;
- increasing sulphur dioxide removal efficiency;
- improved management of scrubber system by-products (sludge vs. gypsum).

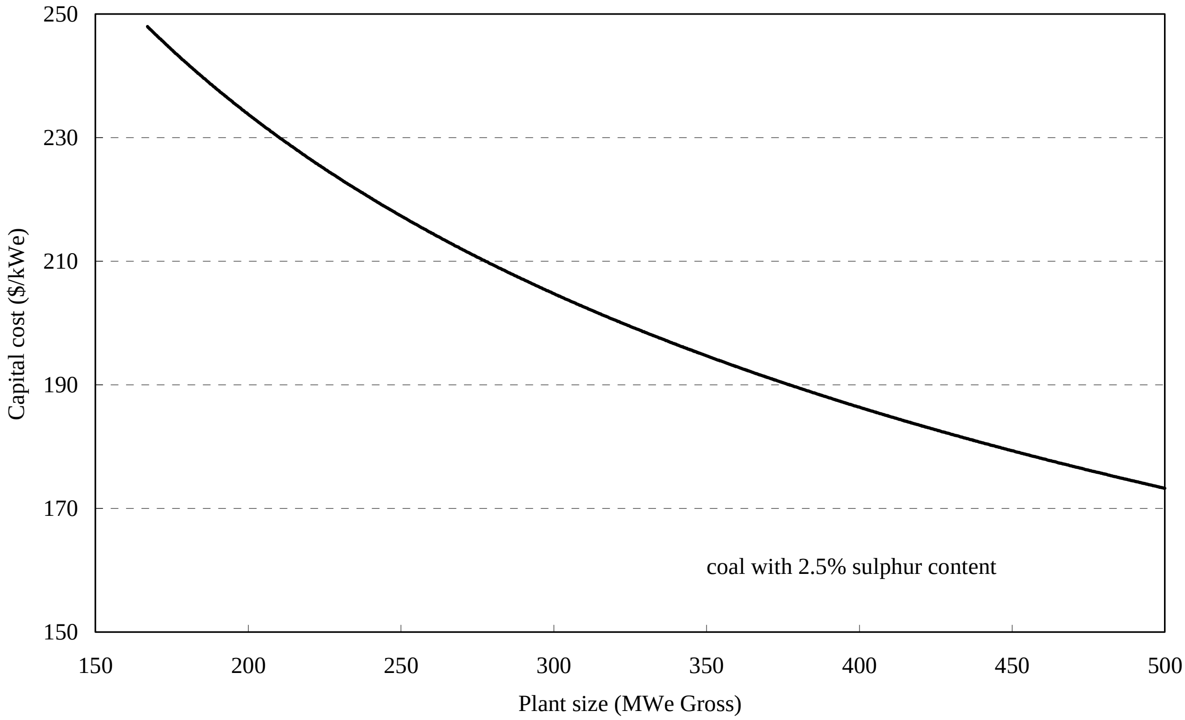
Table A6-1. **Cost estimates for flue gas desulphurisation in coal-fired power plants, 90% sulphur removal efficiency**

Type of FGD process	Capital cost (1990 US$/kWe)	Levelised cost (1990 US¢/kWh)
Wet scrubbers	190 – 235	0.72 – 0.75
Spray dry scrubber	173	0.68
Regenerable processes	240 – 283	0.84 – 0.87
Dual alkali	203 – 228	0.73 – 0.74
Bubbling liquid-phase reactor	190 – 230	0.60 – 0.69

Note: Values are illustrative only. Costs depend on many plant- and fuel-specific factors.
Source: Takeshita (1995): Table 2.

The second most costly component of air pollution control for coal-fired plants is control of nitrogen oxides. It is the largest air pollution control cost component, and usually the only component, in gas-fired power plants. Nitrogen oxides are generated during combustion from complex chemical reactions involving nitrogen in the air and, in the case of oil or coal, in the fuel itself. An initial reduction in the amount of nitrogen oxides produced can therefore be obtained by relatively low-cost combustion modifications. This is not an option available for reduction of sulphur dioxide, which depends entirely on the sulphur content of the fuel.

Figure A6-1. **Capital costs of wet flue gas desulphurisation, coal-fired plants**



Source: Takeshita (1995), Figure 1a.

Beyond a given level of NO_x reduction, say 50 to 60 per cent of uncontrolled levels, NO_x must be actively removed from flue gases. The most common process to do this, selective catalytic reduction (SCR), involves relatively expensive catalytic reactors. To a greater degree than sulphur dioxide removal, the cost of NO_x removal depends strongly on the strictness of the emissions limit. Catalytic reduction on coal-fired plants has been used mainly in Austria, Germany, and Japan, where NO_x emission limits have been strictest among OECD countries. Table A6-2 provides various estimates of capital cost and levelised cost for SCR systems.

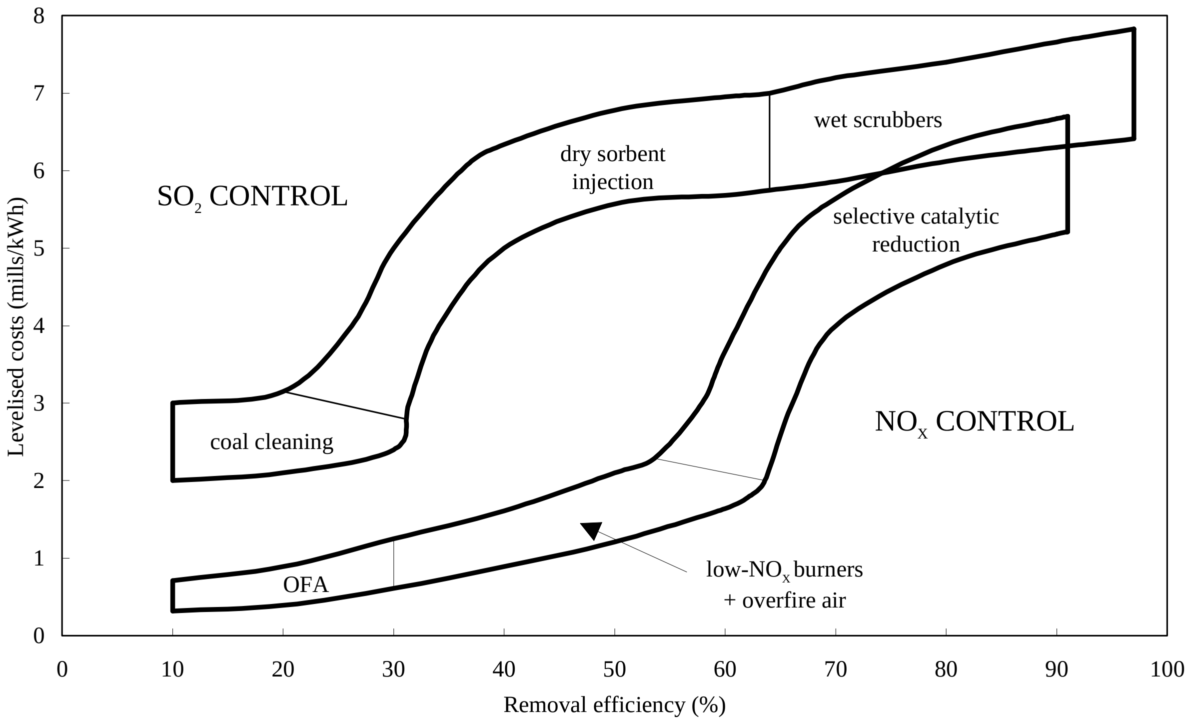
Table A6-2. **Cost estimates for selective catalytic reduction in coal-fired power plants, 80% NO_x removal efficiencys**

Comment	**Capital cost (US$/kWe)**	**Levelised cost (US cent/kWh)**
DOE estimates		
500 MWe	50 – 80	0.32 – 0.38
460 MWe, variations in ammonia escape	70 – 77	0.31 – 0.41
500 MWe, variations in ammonia escape	78 – 87	0.53 – 0.59
GRI estimates		
500 MWe, 70-80% removal	90 – 125	–
250 MWe	50 – 70	–

Note: Values are illustrative only. Costs depend on many plant- and fuel-specific factors.
Source: Takeshita (1995): Table 7; Soud (1996): Tables 30 & 31.

Figure A6-2 shows the effect of required removal efficiency on the cost of emissions controls in coal-fired plants. The figure shows that, as noted above, the cost of controlling both sulphur dioxide and nitrogen oxides rises dramatically as emissions limits become more stringent and required removal efficiencies increase.

Figure A6-2. **Levelised costs of air pollution control for coal-fired plants**



Source: Takeshita (1995), Figure 8a.

The third main area of air pollution control cost is particulate control. This is primarily a requirement for coal-fired boilers, although oil-fired plants may also have particulate control depending on fuel characteristics. Electrostatic precipitators and fabric filters are the most commonly used systems to control particulates. Particulate control has generally been required for many decades on OECD coal-fired power plants. Since it involves physical separation of material from the flue gas stream, rather than chemical separation, it is less costly than FGD or de-NO_x systems.

The cost of particulate control using fabric filters (baghouses) is not very sensitive to emissions limits. It is most dependent on the size of particulate matter removed from the flue gas stream and the ratio of airflow to fabric surface area. The type of system to clean the filters during continuous operation, “reverse air” or “pulse jet,” is also an important variable. Capital costs vary from 50 to 80 US$/kWe. The cost of electrostatic precipitators is more variable because both flyash characteristics and particulate emissions limits have strong effects on design requirements. Capital costs may vary from 30 to over 100 US$/kWe.

Other potentially harmful compounds are found in the flue gases of fossil-fired power plants, and these are coming under increasing scrutiny for emissions limits. Examples are trace metals such as mercury or vanadium, volatile organic compounds, or products of partial combustion such as carbon monoxide or aromatic organic compounds. In some cases the compounds could be reduced by modifications to existing pollution control systems, such as adding a reagent to an existing FGD process stream. In other cases, dedicated removal systems might be required. Mercury and other volatile compounds might be controlled by using adsorption beds of activated carbon or zeolites. As with other airborne pollutants, the removal cost will vary dramatically according to the emission limit and the fuel characteristics. Trace pollutants are of concern primarily for coal-fired and oil-fired plants.

Gas-fired power plants

Natural gas typically contains no sulphur or only small amounts as hydrogen sulphide. Pollutants from natural gas combustion are limited to combustion by-products (mainly NO_x and carbon monoxide) and ammonia or urea from NO_x control systems. The cost of NO_x control varies, as in coal or oil-fired plants, as a function of allowable emission levels.

In gas fired boilers, NO_x emissions are lower than from solid or liquid fuelled boilers. Typically NO_x can be controlled through the use of appropriate burners and combustion modifications without the use of selective catalytic reduction. If the latter were needed, its capital cost would fall at the low end of the values given in Table A6-2 above for coal plants. Although flue gas volumes are roughly the same, initial NO_x levels produced by gas combustion are lower and so equipment and operating costs for reducing NO_x emissions are lower as well.

New single fuel, gas-fired boilers are unlikely to be built for power production because power plants based on gas turbines normally offer better economic performance. Therefore, NO_x control in gas fired plants is relevant primarily for gas turbine cycles. Water or steam injection, low NO_x burners, and selective catalytic reduction are the systems potentially required for gas turbine systems.

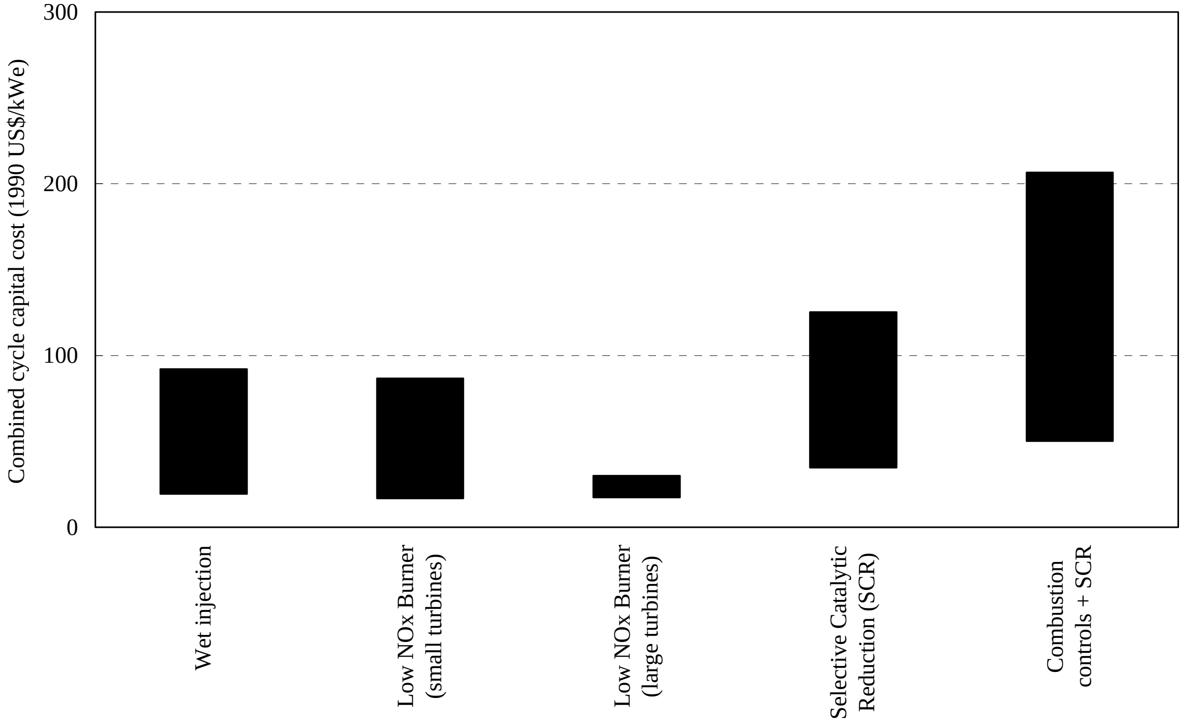
Water or steam injection into gas turbine combustors is the method commonly used for turbines without low-NO_x burners available from the manufacturer. By injecting water into the combustion zone, peak temperatures and, consequently, NO_x production are reduced. The system components include water purification equipment, pumps, metering, and controls. The capital cost is roughly 40 US$/kWe (Snyder, 1993: Figure 2-3), although for small turbines (below 10 MWe), the capital cost can be above 100 US$/kWe.

Low-NO_x burners also function by reducing peak combustion temperatures. The “lean premixed” burner design is available for most large, heavy duty gas turbines. Its incremental cost compared to ordinary burners is roughly 30 US$/kWe for large gas turbines, and up to 114 $/kWe for small turbines.

Selective catalytic reduction can be required for gas turbine power plants in some countries. As with SCR systems in coal-fired plants, ammonia is sprayed into the flue gas to react with and reduce NO_x in a downstream catalytic reactor. In all cases it is most economic to use combustion control of NO_x emissions (low-NO_x burners or water/steam injection) in combination with the SCR system. SCR systems cost approximately 50 US$/kWe for large turbines. For small systems the cost can exceed 180 US$/kWe.

Figure A6-3 summarises the range of capital costs for NO_x control in gas turbine power plants, assuming a simple cycle plant. In baseload combined-cycle plants, the gas turbine accounts for about 2/3 of total power output, so the values of Figure A6-3 must be multiplied by 2/3 to obtain equivalent figures for combined cycle power plants.

Figure A6-3. **Capital costs for gas turbine NO_x control**



Source: Snyder (1993), Figure 2-11.
Note: Simple cycle source data have been multiplied by 2/3 to account for typical difference between simple cycle and combined cycle plant output.

Developments in air pollution regulation

Air pollution control regulations have consistently increased in strictness throughout OECD countries for many years now. New legislation further limiting emissions of pollutants has been recently implemented or is under discussion in a number of countries. Examples are:

- in mid 1997, the US Environmental Protection Agency proposed new rules on "soot and smog" which will, among other measures, regulate particulate matter down to 2.5 microns in size;
- in the year 2000, tighter and broader emissions limits on SO_2 and NO_x will come into effect in the United States as part of Phase II of the 1990 amendments to the Clean Air Act;
- the European Commission has proposed revisions to the large combustion plant directive governing SO_2 and NO_x emissions;
- the Czech Republic recently passed law 117/1997 SB which imposes tighter limits on emissions of particulate matter, SO_2, and NO_x from power plants down to 0.2 MWe in size.

Market-based instruments are being used increasingly to regulate airborne pollutants. In the United States, the 1990 amendments to the Clean Air Act set up a system of tradable SO_2 allowances which effectively set a price for emissions of any quantity of SO_2. Utilities have the option of purchasing allowances rather than installing engineered control systems or taking other measures to minimise SO_2 emissions. This has led to a major switch to low-sulphur coal rather than retrofitting of scrubbers in existing plants. New plants may use scrubbers more effective than strictly necessary in order to "bank" credits or avoid more expensive SO_2 reduction measures elsewhere in their systems. The allowance system has the potential to reduce costs of reducing emissions compared to traditional emissions limits.

Denmark, France, Japan, Sweden have imposed taxes on SO_2 or NO_x emissions. In the case of SO_2, values vary from roughly 10 to 2 100 US$/tonne SO_2 emitted. The effect upon generating costs varies according to the differences in tax. At high tax levels, utilities have an incentive to minimise emissions, to the greatest extent possible with engineered plant systems, in order to minimise total emissions taxes. Tax paid may then be small, but capital and operating costs of the pollution control system will be higher than otherwise. At low tax levels, less efficient pollution control equipment may be used at a savings in capital and operating cost, but at a higher tax cost.

In summary, costs of controlling air pollution from power plants have been, in the past, clearly identifiable as the cost of installing and operating equipment to meet defined emissions limits. Existing emission limits will not be removed, but there is likely to be additional flexibility in meeting national and international limits on airborne pollution as the use of economic instruments increases in environmental regulation.

Water quality

Power plants typically discharge water streams which have been treated first to avoid harming the environment. The cost of treating wastewater before discharge can be considered an environmental protection cost. All OECD countries have regulations concerning the quality of water discharged from industrial facilities, including power plants.

The main sources of wastewater production are:

- cooling tower blowdown, i.e., the purge stream from recirculating cooling water systems;
- purge streams from forced oxidation FGD systems;
- waste streams from other plant process operations, such as boiler blowdown, demineralisation system effluent, or gasification system effluents;
- wastewater from occasional cleaning or maintenance operations;
- water collected from site area drains, including around coal piles.

The biggest use of water within plants is as a cooling medium within steam cycle condensers. Water can either be used once for cooling, then discharged back to the source at higher temperature, or used continuously within a "closed-loop" or recirculating cooling system with cooling tower or cooling pond. In the former "once-through" system, there is generally no contamination of the water as it passes through clean process piping. Although the flows to and from the environment are large, there is no expense for water treatment. The majority of plants included in this study use once-through systems (i.e. do not have cooling towers).

The purge streams from closed-loop cooling systems contain chemicals to inhibit fouling of cooling towers and to inhibit corrosion of process equipment. These include chlorine, zinc compounds, and silicate. Although this so-called "cooling tower blowdown" stream is relatively small compared to the water discharge from a once-through system, it must be treated to remove those chemicals. Concerns about water availability and thermal discharges are likely to increase the proportion of plants using recirculating cooling water systems and, therefore, the expense of treating cooling water. Generating costs related to controlling thermal discharges are discussed below.

In FGD plants producing sludge rather than commercial quality gypsum, water leaves the system in the waste solids and so a dedicated FGD wastewater treatment plant is not needed. This type of system was common on earlier FGD systems. However, since the 1980s many new plants have used forced oxidation systems, which do require wastewater treatment. Most FGD plants in Japan and Europe use forced-oxidation processes, and new facilities in the United States tend to also. As of 1994, almost two thirds of wet FGD capacity on coal-fired plants world-wide used forced-oxidation systems (Soud, 1994).

Water from forced oxidation FGD systems leaves as a separate liquid stream containing solids, trace amounts of heavy metals such as arsenic, cadmium, chromium, copper, nickel, and zinc, and soluble compounds such as boric acid, chlorides, fluorides, sulphates, and nitrates. The source of much of the contamination is ultimately materials present in the coal feed and limestone used to capture sulphur dioxide. The water from FGD plants requires a dedicated water treatment plant.

The wastewater streams from other plant processes and occasional cleaning or maintenance operations are smaller in size than FGD or cooling water blowdown, are often discontinuous, but may require a dedicated plant. Coal and ash storage areas may leach harmful compounds as rainwater or dust control water filters through them, so special collection systems and treatment must sometimes be installed to prevent this water from draining to groundwater supplies, depending on the characteristics of the coal or ash.

The wastewater treatment capacity of coal gasification plants can be four times that of conventional pulverised coal-fired plants (Meij, 1993). This is due to the wastewater streams generated from fuelgas cleaning.

It is becoming more common for power plants to be required to avoid any discharges of water at all. In such cases, internal wastewater streams must be cleaned and recycled. The “zero discharge” systems to accomplish this add further to the cost of the plant. A by-product of zero discharge systems is a solid residue with soluble compounds and concentrated heavy metals. This adds to the solid waste stream from the plant.

Waste water treatment plants do not account for a large fraction of power plant capital costs but are nonetheless large in absolute terms. A large coal fired plant might require an investment of roughly 10 US$/kWe for wastewater treatment and 6-8 US$/kWe for treatment of FGD system purge. A gas-fired combined-cycle power plant could require 3-7 US$/kWe for its wastewater treatment plant.

Solid waste disposal

The cost of disposal of solid wastes is significant for coal, which produces large quantities of ash and by-products of flue gas desulphurisation. The systems and cost of preparing solid wastes for disposal vary according to the characteristics of the combustion process, coal ash, flyash, sorbent, and FGD system by-products. Apart from conditioning of solid wastes within the power plant, the site to hold large volume solid wastes must be prepared in order to minimise the risk from leaching of pollutants as rainwater filters through the waste landfill. In most countries, coal plant solid wastes are not classified as hazardous. Because of this, most ash landfills have not employed special liners to impede the flow of leachates away from the landfill.

All thermal power plants produce smaller quantities of process-related solid wastes. Sludges from water treatment and wastewater treatment processes are commonly generated and often are hazardous because of heavy metal residues.

In the OECD as a whole, about half of the ashes from coal-fired boilers have been disposed of in piles or landfills and half have been reused in some way. The fraction of ash used varies greatly by region and country. In North America, only one quarter of ashes have been reused, in OECD Pacific countries one half have been, and in OECD Europe two thirds of ashes have been reused (Sloss, 1996: Table 1). In Germany and the Netherlands, nearly all coal ash is reused. Generally, if ashes are reused, the cost to prepare or condition them is greater, but disposal costs are less or negative, as they may be sold to replace other materials. The cost of disposal and regulations governing ash disposal are the most important factors in determining whether or not ash is recycled or thrown away. Options for ash use include mine backfill, material for cement, concrete, and grout, road construction, and secondary construction materials such as bricks and tiles.

A scarcity of suitable disposal sites in some countries and increasing difficulty in siting waste disposal areas are tending to increase the fraction of coal plant solid wastes that are recycled.

The cost of preparing ash for either disposal or recycling depends on the combustion process. Pulverised coal combustion and oxygen blown gasification produce ash which is relatively inert. The latter produces a glassy slag which immobilises leachable species to a greater degree. On the other hand, ash from fluidised bed combustion or gasification processes, since they also contain desulphurisation sorbent and ash produced at lower combustion temperatures, often must be treated before disposal or reuse.

By-products from flue gas desulphurisation add to solid wastes produced at coal-fired power plants. Most solids from forced-oxidation FGD systems are in the form of marketable gypsum, and so solid wastes are relatively low in volume. However, wet FGD processes using incomplete oxidation produce large volumes of moist sludge which must be disposed of. Spray dryer systems also produce a solid waste.

Thermal discharge

The heat released to cooling water streams represents one to two times the amount of electrical energy produced in a power plant. The higher the steam cycle efficiency, the lower the amount of heat rejected to the environment via cooling water. Thermal discharges to rivers and inland bodies of water have become more tightly controlled over time, which has increased generation costs through the limitation of water temperature increase. Temperature rise is typically limited by regulation to 3 to 10°C in order to protect the aquatic ecosystems in the water bodies receiving the cooling water. As water temperature increases, the oxygen concentration of the water decreases, potentially adversely affecting the metabolism and activities of aquatic organisms. The choice of site for a power plant depends in part on the availability of an adequate supply of cooling water.

Once-through cooling is the most economical method for dissipating the steam cycle's waste heat. Water is simply drawn into the system, warmed as it cools the condensing steam, and pumped back out to the water source. Many power plants are located on rivers, large inland bodies of water, or the coast in order to take advantage of the economies of once-through cooling. For example, in Japan all large power plants have been built on the coast, with only a few exceptions. For coastal power plants or plants located on large rivers, the environmental cost implications of thermal discharge limits are minor. They consist of design choices to make sure that discharge temperature and temperature rises are within regulatory limits.

Riverside power plants with once-through cooling systems can face output limitations if river flow is lower than normal due to low rainfall. This relates to water availability as well as temperature rise. Reduced output due to lack of cooling water will increase the lifetime average generating cost of the plant.

Gas-fired combined cycles have the highest efficiencies of thermal power plants, and so require the least cooling water per unit output. Nuclear power plants have the lowest efficiencies because of limitations in steam cycle conditions. In addition, they do not reject heat to the environment via flue gases, as do fossil-fuelled power plants. These two characteristics make the cooling water flow requirements per unit output the highest for nuclear plants.

Limitations on cooling water availability or thermal discharges can be overcome by using recirculating cooling water systems. In such systems the warm cooling water is itself cooled in a cooling tower or a specially build pond or lake which add to the cost of supplying cooling water. The added expense of using a recirculating cooling water system may be regarded as an environmental expense if it is required to avoid excessive thermal discharges to its source of cooling water.

Environmental costs for nuclear

It is difficult to identify specific cost elements in nuclear power production related to environmental protection because plants are designed with a multitude of features to prevent ongoing or accidental releases of radioactivity to the environment. Environmental protection relies heavily on plant safety. Arguably the fraction of electricity generating costs related to environmental protection is greater in nuclear plants than in any other plant type because many elaborate and costly systems are safety-related: Forsberg and Reich (1991) suggest that up to 60 per cent of the capital cost of nuclear power is related to health, safety, and the environment. Taking levelised capital costs to represent between half and three fourths of total levelised generation cost, this implies up to 45 per cent of nuclear generation cost is related to environmental protection systems. Significant safety-related features and systems include:

- containment building;
- cooling system;
- redundant reactor controls;
- seismic isolation design;
- emergency core cooling system;
- emergency diesel generators;
- vent filtering;
- hydrogen suppression.

The cost of design features specifically related to safety has been increasing over time. Fox (1995) compares the materials required to construct a 1330 MWe boiling water reactor commissioned in 1975, Trojan, with a 1 100 MWe pressurised water reactor commissioned in 1984, WNP-2. The later plant, although 17 per cent smaller in electrical capacity, contains 2.4 times the volume of concrete, 2.4 times the cable trays, and six times the amount of electrical conduit. The difference in basic reactor designs account for some of the difference, but he attributes most of it to more extensive safety regulations and related design requirements.

The time taken to build and license nuclear plants in the United States rose from an average of five years prior to 1979 to nearly 12 years afterwards. The average cost increased by a factor of nearly 10 (NEI, 1996b). The increasing time needed to build nuclear plants again reflects, in part, increasing safety requirements ultimately related to environmental protection.

As with other thermal plants relying on steam cycles, nuclear power plants produce sludge from water treatment and wastewater treatment processes. Various systems are in place to ensure that vent flows or other ongoing gas discharges contain no radioactivity. There are no costs associated with air pollution control in bulk gas discharges, as in fossil-fuelled plants.

Radioactive waste disposal is an area of significant cost for nuclear power plants. The cost of disposal of long-lived radioactive wastes are, in this study, included primarily in fuel cycle costs. These entail temporary storage of fuel elements, transportation, and disposal of high level wastes from fuel and reprocessed fuel. All these elements have significant costs associated with environmental protection. As a rough indication, the backend costs of a once-through fuel cycle could be thought to represent primarily environmental protection costs. Back-end costs represent about 10 to 15 per cent of levelised PWR fuel cycle costs and about 22 per cent of Candu fuel cycle costs. Total levelised fuel costs account for 10 to 25 per cent of levelised electricity generation cost, according the results presented in the body of this report. Therefore, environmental costs related to high-level waste disposal might represent some 1 to 4 per cent of levelised generation cost.

Large volumes of low-level waste are produced when decontaminating and dismantling retired nuclear plants. The cost of disposing of plant decommissioning wastes is in principle fully included in decommissioning cost estimates. These must be disposed of in repositories with properly engineered features to contain radioactivity and allow it to decay while protecting the environment.

During normal operations, nuclear power plants generate streams of low-level and intermediate-level waste. These arise as contaminated water from different parts of the reactor system or plant, and solids such as filters, valves, pipes, protective clothing, and trash. Most of the solid waste is generated during maintenance and repair work. Both liquid and solid radioactive wastes are often concentrated to reduce their volume and disposal cost outside the plant.

Estimates of the volume of low-level waste produced per unit of electricity vary considerably, partly because of different waste treatment processes and partly because of the different definitions of waste type. Low-level waste is produced from various miscellaneous activities of nuclear power plant operation, and hence, there is no strong linkage between the volume of the waste and electricity generated. Values between 10 and 100 m^3/TWh are reported in a current NEA study (NEA, 1998). The International Atomic Energy Agency (IAEA, 1994) reported a value equivalent to about 20 m^3/TWh. The reported costs of disposal also vary considerably, from 1 000 to 10 000 $/$m^3$ in a number of NEA Member countries. MacKerron (1993) reports values of 2 000 to 14 000 $/$m^3$ in France, Germany, the United Kingdom, and the United States.

Considering a range of waste volumes and disposal costs, low-level disposal could cost 0.02 to 0.17 US mills/kWh. At the high end of estimated costs, disposal of low-level wastes represent a small fraction of electricity generating cost from nuclear power plants.

Land use

The cost of land for any power plant is not normally considered an environmental cost. Routine operations of power plants are not expected to seriously degrade the immediate area around the plant and various measures, some of which described above, are taken to avoid harmful impacts on the local environment. For example, plants cannot produce either water or solids without first ensuring that their effect on the environment will be minor. However, certain cost elements of land use by power plants can be considered as environmental costs.

Planning permission for power plants is required before construction and operation can begin, and typically an environmental impact assessment is part of this permission. This assessment will examine potential harmful environmental effects of the plant and ensure that adequate measures are taken by the plant owner to avoid them. Environmental impact assessments have become more costly over time as governments have become more sensitive to the need to avoid damage to ecosystems surrounding industrial facilities. Higher standards of scientific proof have been demanded to show that plant by-products and possible plant accidents will cause no harm. The cost of environmental impact statements, particularly for nuclear plants, can be more expensive than many key plant systems.

In Japan, the Ministry of Trade and Industry provides funds to local governments who host nuclear power plants within their jurisdictions. The subsidies might be considered as land use fees to compensate plant neighbours for ongoing plant operations. The subsidies amount to about 0.74 $/kWe (MPS, 1996). The funds are provided by the central government and so do not represent costs to individual Japanese utilities.

Power plants may be required to incorporate more expensive design features which minimise total land area occupied, not because of land cost, but because of environmental concerns. For example, a plant owner may possess a given plot but be required to restrict construction to only a part of it in order to protect sensitive environmental areas such as wetlands or unique coastal land. Likewise plant construction costs can include costs of civil works for parks or improved environmental protection of surrounding land.

Power plants are sometimes designed with identified aesthetic objectives. These might be considered as entailing land use costs to protect the visual environment around the plant or at least reduce the plant’s negative visual impact. For example, building or other plant structures may be designed to mesh more attractively with the local environment. Artwork has often been painted on large power plant structures such as cooling towers. Or plants may be constructed with a larger fraction underground than might otherwise be the case. It is common for transmission lines to be buried to reduce their visual impact. Land use requirements or restrictions may have indirect costs if they cause a plant to be sited away from where it might otherwise be located.

In summary, land use requirements are often linked to environmental requirements and they entail costs in both construction and operation of power plants.

Cost of administering environmental regulations

There are costs of electricity generation associated with measuring, verifying, documenting, and communicating compliance with environmental regulations. As the level of detail of environmental regulations increases, so do the costs of administering them within individual power plants.

For each regulated effluent or discharge from a power plant, a corresponding set of measurements must be taken to verify that the relevant regulation is satisfied. As an example, one such set of measurements for air pollution control might include:

- stack gas velocity and calculated volume flow;
- stack gas temperature;
- SO_2 content;
- NO_X content;
- particulate matter content;
- oxygen level;
- coal flow (for per cent reduction regulation);
- coal sulphur level (for per cent reduction regulation).

The cost of each measurement varies considerably depending on the frequency and the nature of the physical quantity measured. Sophisticated, sensitive equipment may be required to determine the amounts of pollutants present in small quantities in flue gases. There will be a fixed cost component for instrumentation and an ongoing cost for materials, reagents, and operators.

The cost of continuously monitoring levels of a given effluent represents an upper limit of cost. In the United States, continuous emission monitoring systems became required for most power plants affected by the 1990 Clean Air Act Amendments. These systems typically sample the exhaust flue gas and send the samples through special measurement devices to determine pollutant concentrations. Concentration measurements taken directly on flowing flue gases ("in-situ" measurements) are also possible. Gas flowrates and pollutant concentrations are combined to provide estimates of total pollutant flows. DOE (1994) estimated that the average capital cost of a continuous emissions monitoring system needed to meet US regulations is $850 000, and that average annual operations and maintenance costs for such systems are $425 000. Among six representative utilities affected by the 1990 Clean Air Act Amendments, the capital cost of emissions monitoring systems represented 9 per cent of total capital costs incurred for compliance with the regulations (DOE, 1997).

Solid and liquid discharges must also be checked to determine the level of potential contaminants. Water quality checks must often verify the level of dozens of specific substances such as arsenic, cadmium, chromium, copper, lead, various salts, and organic substances. Leach testing of coal ash is commonly required. Measurement of a suite of compounds in solids or liquids can cost several thousand US dollars per sample. Many power plants maintain analytical laboratories to assist in environmental compliance measurements.

In addition to physical measurements, analysis and formal documentation of results are typically required to communicate the results to responsible government authorities. It is not unusual for power plants to maintain a team of people in an environmental compliance unit to provide engineering and legal support for this purpose.

Nuclear power plants bear particularly heavy compliance costs because of the complexity and detail of nuclear safety regulation. Any change to operating procedures or plant safety-related equipment will require analysis and review with nuclear safety authorities. In the United States, at least two full-time resident inspectors from the Nuclear Regulatory Commission (NRC) are assigned to every nuclear power plant site. The NRC also conducts regular and unannounced inspections. On average, a nuclear power plant receives between 4 000 and 8 000 hours of inspections every year, over and above the daily oversight of the resident inspectors (NEI, 1996a). In addition, the NRC evaluates plant performance every 18 months through a Systematic Assessment of Licensee Performance. This examines all plant operations, maintenance, engineering and support services.

Carbon dioxide

The climate change debate has brought attention to the production of carbon dioxide from power plants, which account for roughly one third of all world-wide emissions. The previous study of electricity generating costs (OECD, 1993) outlined the climate change issues relevant to the power sector. Parties to the Framework Convention on Climate Change have been discussing and debating policies to curb greenhouse gas emissions since 1992. Under the 1995 Berlin Mandate to the Convention, certain parties to the Convention are to develop “quantified emission limitation and reduction objectives” which would effectively limit or reduce national emissions of greenhouse gases to arrive at a globally sought target after 2000. The 1997 Kyoto Conference of Parties to the convention established legally binding targets. The details of actual policies that would meet the objectives of the Convention are complicated by issues of equity among countries, differentiation of objectives according to national situations, timing of policies, and the practical matters of implementation.

Despite the current focus on climate change, few binding policies specifically related to reduction of CO_2 emissions from power plants have been promulgated to date. The greatest attention has been on CO_2 or fossil energy taxes applied generally but, with only a few exceptions, not applied to power generation. Today then, there are essentially no direct power plant environmental costs associated with measures to reduce CO_2 production.

In the future this might not be so. The cost of fossil-fuelled power generation is sensitive to measures designed to reduce CO_2 production since the primary by-product is combustion gas containing CO_2. For a given amount of electricity production, the amount of CO_2 production depends on the fuel used and the efficiency of generation. Measures to reduce CO_2 production in the power sector could thus act effectively by influencing these two key variables. Fuels producing less CO_2 per unit of output and fuel/technology combinations with higher efficiency would be favoured. Generally the denser the fuel, the higher the carbon content and the higher the production of carbon dioxide per unit of fuel energy. Coal-fired power production produces 75-100 per cent more CO_2 per kWh than gas-fired combined cycles because of the higher carbon content per unit energy of fuel and the lower efficiency of generation.

Measures to reduce CO_2 production from power generation would therefore tend to increase the cost of coal-fired power generation compared to oil and gas-fired generation. Nuclear power and renewables, which produce no CO_2 directly from generation, would be unaffected by CO_2 reduction measures, and their relative economics compared to fossil-fuelled power production would improve. Quite logically, measures to reduce CO_2 emissions would improve the economics of power sources producing no CO_2. In countries where new nuclear power plants are not an option, the economics of renewables would improve. Beyond these elementary observations, the actual values and effect on the competitiveness of different baseload generating options are not known. They will depend on the ultimate depth of commitment to reduce CO_2 emissions and the form of CO_2 policies adopted.

Significance of environmental cost items

As the preceding sections have indicated, environmental costs of electricity production are significant. They depend on many factors related to fuel, power plant technology, and environmental regulation at the national and local level. Environmental control costs emerge as a critical factor in interfuel competition. Table A6-3 provides several summary estimates of the magnitude of environmental costs already included in overall electricity generation costs.

Table A6-3. **Environmental cost as a fraction of total generation cost, summary estimates**

Cost item	Environmental cost fraction	Source of estimate
Coal-fired Boilers		
Air pollution control	6-18%	UNIPEDE, 1995
Cooling	0-2%	UNIPEDE, 1995
Waste disposal	0%	UNIPEDE, 1995
Environmental charges	0-9%	UNIPEDE, 1995
Total	10-26%	UNIPEDE, 1995
SO_2 & NO_X control	15-20%	Takeshita, 1995
Particulate control	3-4%	Takeshita, 1995
Total	12-42%	CIAB, 1983
Gas-fired CC		
Air pollution control	0-6%	UNIPEDE, 1995
Cooling	0-3%	UNIPEDE, 1995
Environmental charges	0-5%	UNIPEDE, 1995
Total	0-9%	UNIPEDE, 1995
Nuclear		
Fuel disposal	1-4%	Secretariat estimates
Systems related to safety, health, and the environment*	15-45%	Forsberg and Reich (1991); IEA Secretariat estimates

* Estimates of the costs of safety-related systems and features in nuclear power plants are difficult to establish because of the multiple functions that such systems may perform (not safety only).

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Annex 7

FACTORS COVERED IN COSTS

Table A7.1 **Coverage of investment costs: nuclear**

	CA	FI	FR	JP	KR	SP	TK
Construction							
Direct costs							
• Site preparation	√	√	√	√	X [2]	√	√
• Civil work	√	√	√	√	√	√	√
• Material, equipment & manpower	√	√	√	√	√	√	√
Indirect costs							
• Design, engineering & supervision	√	√	√	√	√	√	√
• Provisional equipment & operation	√	√	√	√	√	√	√
• Worksite administrative expenses	√	√	√	√	√	√	√
Owner's costs							
• General administration	√	√	√	√	√	√	X
• Pre-operation	√	√	√	√	√	√	√
• R&D (plant specific)	√	√	X	X	X [2]	√	X
• Spare parts	√	√	√	√	√	√	√
• Site selection, licensing & public relations	√	√	√	√	√	√	√
• Taxes (local/regional, plant specific)	√	√	X	X	√	√	X
Other overnight capital costs							
• First inventory of heavy water	√	NA	NA	NA	NA	NA	NA
• Major refurbishment	X	X	X	X	X	X	X
• Credits	X	X	X	X	X	X	X
Decommissioning	[1]				[2]		
• Design, licensing & public relations	√	√	√	X		√	X
• Dismantling & waste storage	√	√	√	√		√	√
• Waste disposal	√	√	√	√		√	√
• Site restoration	√	√	√	X		√	X
Contingency (share of base cost when specified)	5%	5%	3%	X	3%[3]	√	√

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Stage 1 for 35 years, then proceed to stage 3.
2. Included in indirect costs.
3. Per cent of direct domestic investment costs.
4. Revenue from pre-commercial operation, scrap materials and heavy water recovered from decommissioning/dismantling.

Table A7.1 **Coverage of investment costs: nuclear**

US	BR	CH-N1/2	CH-N3	IN	RO	RU	
							Construction
							Direct costs
√	√	√	√	√	√	√	• Site preparation
√	√	√	√	√	√	√	• Civil work
√	√	√	√	√	√	√	• Material, equipment & manpower
							Indirect costs
√	√	√	√	√	√	√	• Design, engineering & supervision
X	√	√	√	√	√	√	• Provisional equipment & operation
√	√	√	√	√	√	√	• Worksite administrative expenses
							Owner's costs
√	√	√	√	√	√	√	• General administration
√	√	√	√	√	√	√	• Pre-operation
X	√	√	√	√	X	X	• R&D (plant specific)
X	√	√	√	√	√	√	• Spare parts
X	NS	√	√	√	√	√	• Site selection, licensing & public relations
X	X	√	√	√	√	X	• Taxes (local/regional, plant specific)
							Other overnight capital costs
NA	NA	NA	X	√	√	NA	• First inventory of heavy water
X	√	X	X	√	X	X	• Major refurbishment
X	X	X	X	√[4]	X	X	• Credits
	NS						**Decommissioning**
√		√	√	√	X	√	• Design, licensing & public relations
√		√	√	√	X	√	• Dismantling & waste storage
√		√	√	√	X	√	• Waste disposal
√		√	√	√	X	X	• Site restoration
10%	10%	√	√	5%	X	23%	**Contingency** (share of base cost when specified)

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Note:

4. Revenue from pre-commercial operation, scrap materials and heavy water recovered from decommissioning/dismantling.

Table A7.2 **Coverage of O&M costs: nuclear**

	CA	FI	FR	JP	KR	SP	TK
Operation	√	√	√	√	√	√	√
Site monitoring	√	√	√	√	√	√	√
Maintenance (materials, manpower, services)	√	√	√	√	√	√	√
Engineering support staff	√	√	√	√	√	√	√
Administration	√	√	√	√	√	√	√
Operating waste management & disposal	√	√	√	√	√	√	√
General expenses of central services	√	√	√	√	√	√	√
Taxes & duties (plant specific)	√	√	X	X	√	√	√
Insurance (plant specific)	√	√	√	√	√	√	√
Major refurbishment	X	√ [1]	X	X	√	X	X
Support to regulatory bodies	√	√	√	X	√	√	NS
Safeguards	√	√	√	√	√	√	X
Others	X	√ [NS]	X	X	√ [2]	X	X

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. 1.2 per cent of total investment costs per annum.
2. R&D plant specific and general, decommissioning, spent fuel management and waste disposal.
3. First inventory of heavy water spread over the first 15 years of operation.

Table A7.3 **Coverage of fuel costs: nuclear**

	CA	FI	FR	JP	KR	SP	TK
Uranium concentrate	√	√	√	√	√	√	√
Conversion to UF_6 (LWR)/UO_2 (PHWR)	√		√	√	√	√	√
Enrichment	NA	√	√	√	√	√	√
Fuel fabrication	√	√	√	√	√	√	√
Spent fuel transportation	√	√	√	√	X [1]	NS	√
Spent fuel encapsulation & disposal	√	√	NA	NA	X [1]	NS	√
Reprocessing & waste conditioning	NA	NA	√	√	X [1]	NA	NA
Waste disposal	√	√	√	√	X [1]	√	X
First core inventory	√	√	√	√	X	X	X
Taxes on fuel	X	√	X	X	X	X	X

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Note:
[1] Included in O&M costs.

Table A7.2 **Coverage of O&M costs: nuclear**

US	BR	CH-N1/2	CH-N3	IN	RO	RU	
√	√	√	√	√	√	√	Operation
√	√	√	√	√	√	√	Site monitoring
√	√	√	√	√	√	√	Maintenance (materials, manpower, services)
√	√	√	√	√	√	√	Engineering support staff
√	√	√	√	√	√	√	Administration
√	√	√	√	√	√	√	Operating waste management & disposal
√	√	√	√	√	√	X	General expenses of central services
√	X	√	√	X	√	X	Taxes & duties (plant specific)
√	√	√	√	√	√	X	Insurance (plant specific)
X	X	√	√	X	X	X	Major refurbishment
X	√	√	√	X	√	√	Support to regulatory bodies
√	NS	√	√	X	√	√	Safeguards
X	X	X	√ [3]	X	X	X	Others

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

3. First inventory of heavy water spread over the first 15 years of operation.

Table A7.3 **Coverage of fuel costs: nuclear**

US	BR	CH-N1/2	CH-N3	IN	RO	RU	
√	√	√	√	√	√	√	Uranium concentrate
√	√	√	√	X	X	√	Conversion to UF_6 (LWR)/UO_2 (PHWR)
√	√	√	NA	NA	NA	√	Enrichment
√	√	√	√	√	√	√	Fuel fabrication
√	X	√	√	√	√	√	Spent fuel transportation
√	X	NA	√	X	√	√	Spent fuel encapsulation & disposal
NA	NA	√	NA	NA	NA	NA	Reprocessing & waste conditioning
X	X	X	X	X	X	√	Waste disposal
X	√	X	X	√	X	√	First core inventory
X	X	X	X	X	X	X	Taxes on fuel

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Table A7.4 **Coverage of investment costs: coal**

	BE	CA	DE	FI	FR	HN-C1	HN-C2	IT	JP	KR
Construction										
Direct costs										
• Site preparation	√	√	√	√	√	√	√	√	√	X [2]
• Civil work	√	√	√	√	√	√	√	√	√	√
• Material, equipment & manpower	√	√	√	√	√	√	√	√	√	√
Indirect costs										
• Design, engineering & supervision	√	√	√	√	√	√	√	√	√	√
• Provisional equipment & operation	√	√	√	√	√	√	√	√	√	√
• Worksite administrative expenses	√	√	√	√	√	√	√	√	√	√
Owner's costs										
• General administration	√	√	X	√	√	√	√	√	√	√
• Pre-operation	√	√	√	√	√	√	√	√	√	√
• R&D (plant specific)	√	√	X	X	X	√	√	√	X	X [3]
• Spare parts	√	√	√	√	√	√	√	√	√	√
• Site selection, licensing and public relations	X	√	√	√	√	√	√	√	X	√
• Taxes (local/regional, plant specific)	X	√	√	√	X	√	√	√	X	√
Other overnight capital costs										
• Major refurbishment	X	X	X	X	X	X	X	√	X	X
• Decommissioning	X	X	X	√	√ [1]	X	√	X	X	X
• Others	X	X	X	X	X	X	X	X	X	X
Contingency (share of base cost when specified)	X	5%	X	5%	5%	5%	X	X	X	3% [4]

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Expenses are balanced by incomes from material recycling.
2. Included in indirect costs.
3. Included in O&M costs.
4. Per cent of domestic direct costs.
5. Annual post-operational capital expenditures of US$ 5 per kWe per year.
6. 7.4 and 7.2 per cent of base cost for C1 & C2 respectively.

Table A7.5 **Coverage of O&M costs: coal**

	BE	CA	DE	FI	FR	HN-C1	HN-C2	IT	JP	KR
Operation	√	√	√	√	√	√	√	√	√	√
Maintenance (materials, manpower, services)	√	√	√	√	√	√	√	√	√	√
Engineering support staff	NS	√	√	√	√	√	√	√	√	√
Administration	√	√	√	√	√	√	√	√	√	√
General expenses of central services	√	√	X	√	√	X	√	X	√	√
Taxes & duties (plant specific)	√	√	√	√	X	X	X	√	X	√
Insurance (plant specific)	√	√	√	√	√	√	√	√	√	√
Major refurbishment	X	X [2]	X	√ [3]	X	√	√ [4]	X	X	√
Operating waste disposal (e.g., coal ash, sludge)	X [1]	√	X	√	√	√	√	√	√	√
Others	X	X	X	X	X	X	X	X	X	√ [5]

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Included in fuel cost.
2. Included in overnight construction costs.
3. 1.2 per cent of investment costs per annum.
4. 1.5 per cent of investment costs.
5. R&D plant specific and general.

Table A7.4 **Coverage of investment costs: coal**

NL	PT	SP	TK	US	BR	CH	IN	RU	
									Construction
									Direct costs
√	√	√	√	√	√	√	√	√	• Site preparation
√	√	√	√	√	√	√	√	√	• Civil work
√	√	√	√	√	√	√	√	√	• Material, equipment & manpower
									Indirect costs
√	√	√	√	√	√	√	√	√	• Design, engineering & supervision
√	√	√	√	X	√	√	√	√	• Provisional equipment & operation
√	√	√	√	√	√	√	√	√	• Worksite administrative expenses
									Owner's costs
√	√	√	X	√	√	√	√	√	• General administration
√	√	√	√	√	√	√	√	√	• Pre-operation
√	√	√	X	X	X	√	X	√	• R&D (plant specific)
√	√	√	√	X	√	√	√	X	• Spare parts
√	√	√	X	X	X	√	√	X	• Site selection, licensing and public relations
√	X	X	√	X	X	√	√	X	• Taxes (local/regional, plant specific)
									Other overnight capital costs
X	X	X	√	X	√	X	X	X	• Major refurbishment
√	X	√	√	X	X	X [3]	X	X	• Decommissioning
X	X	X	X	√ [5]	X	X	X	X	• Others
5%	4%	X	X	√ [6]	10%	√	3%	NS	**Contingency** (share of base cost when specified)

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Expenses are balanced by incomes from material recycling.
2. Included in indirect costs.
3. Included in O&M costs.
4. Per cent of domestic direct costs.
5. Annual post-operational capital expenditures of US$ 5 per kWe per year.
6. 7.4 and 7.2 per cent of base cost for C1 & C2 respectively.

Table A7.5 **Coverage of O&M costs: coal**

NL	PT	SP	TK	US	BR	CH	IN	RU	
√	√	√	√	√	√	√	√	√	Operation
√	√	√	√	√	√	√	√	√	Maintenance (materials, manpower, services)
√	√	√	√	√	√	√	√	NS	Engineering support staff
√	√	√	√	√	√	√	√	√	Administration
√	√	√	X	X	√	√	√	X	General expenses of central services
√	√	X	√	X	X	√	√	X	Taxes & duties (plant specific)
√	√	X	√	X	NS	√	√	X	Insurance (plant specific)
X	X	X	√	X	X	√	X	X	Major refurbishment
√	√	√	√	√	√	√	√	NS	Operating waste disposal (e.g., coal ash, sludge)
X	X	X	X	X	X	X	X	X	Others

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Included in fuel cost.
2. Included in overnight construction costs.
3. 1.2 per cent of investment costs per annum.
4. 1.5 per cent of investment costs.
5. R&D plant specific and general.

Table A7.6 **Coverage of fuel costs: coal**

	BE	CA	DE	FI	FR	HN-C1	HN-C2	IT	JP	KR
Fuel price at the border or domestic mine	√	√	√	√	√	√	√	√	√	√
Transportation to the power plant	√	√	√	√	√	X	NA [2]	√	√	√
Taxes on fuel	X	√	√	√	√	X	X	X	X	√
Others	√ [1]	X	X	X	X	X	√ [3]	X	X	X

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Operating waste disposal.
2. The power plant is close to the lignite mine.
3. Overall cost of the lignite mine and oil for starting the boiler.
4. For TK-C1; for TK-C2, domestic lignite fuel transportation cost is negligible.

Table A7.7 **Coverage of investment costs: gas**

	BE	CA	DE	FI	FR	HN	IT	JP
Construction								
Direct costs								
• Site preparation	√	√	√	√	√	√	√	√
• Civil work	√	√	√	√	√	√	√	√
• Material, equipment & manpower	√	√	√	√	√	√	√	√
Indirect costs								
• Design, engineering & supervision	√	√	√	√	√	√	√	√
• Provisional equipment & operation	√	√	√	√	√	√	√	√
• Worksite administrative expenses	√	√	√	√	√	√	√	√
Owner's costs								
• General administration	√	√	X	√	√	√	√	√
• Pre-operation	√	√	√	√	√	√	√	√
• R&D (plant specific)	√	√	X	X	X	√	√	X
• Spare parts	√	√	√	√	√	√	√	√
• Site selection, licensing & public relations	X	√	√	√	√	√	√	X
• Taxes (local/regional, plant specific)	X	√	√	√	X	√	√	X
Other overnight capital costs								
• Major refurbishment	X	X	X	X	√ [1]	X	X	X
• Decommissioning	X	X	X	√	√ [2]	X	X	X
• Others	X	X	X	X	X	X	X	X
Contingency (share of base cost when specified)	X	5%	X	5%	5%	10%	X	X

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Replacement of the plant by an identical one at the end of its 20 year technical lifetime.
2. Expenses are balanced by incomes from material recycling.
3. Included in indirect costs.
4. Included in O&M costs.
5. Per cent of domestic direct investment costs.
6. Post-operational capital expenditures of US$ 2 per KWe per year.
7. 5.2 and 8 per cent of base cost for G1 and G2 respectively.
8. 75 per cent of invesment costs at the 20th year of operation.
9. Included in base cost.

Table A7.6 **Coverage of fuel costs: coal**

NL	PT	SP	TK	US	BR	CH	IN	RU	
√	√	√	√	√	√	√	√	√	Fuel price at the border or domestic mine
√	√	√	√ [4]	√	√	√	√	X	Transportation to the power plant
√	X	X	√	√	X	√	X	X	Taxes on fuel
X	X	X	X	X	X	X	X	X	Others

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Operating waste disposal.
2. The power plant is close to the lignite mine.
3. Overall cost of the lignite mine and oil for starting the boiler.
4. For TK-C1; for TK-C2, domestic lignite fuel transportation cost is negligible.

Table A7.7 **Coverage of investment costs: gas**

KR	NL	PT	SP	TK	US	BR	RU	
								Construction
								Direct costs
X [3]	√	√	√	√	√	√	√	• Site preparation
√	√	√	√	√	√	√	√	• Civil work
√	√	√	√	√	√	√	√	• Material, equipment & manpower
								Indirect costs
√	√	√	√	√	√	√	√	• Design, engineering & supervision
√	√	√	√	√	X	√	√	• Provisional equipment & operation
√	√	√	√	√	√	√	√	• Worksite administrative expenses
								Owner's costs
√	√	√	√	X	√	√	√	• General administration
√	√	√	√	√	√	√	√	• Pre-operation
X [4]	√	√	√	X	X	X	√	• R&D (plant specific)
√	√	√	√	√	X	√	X	• Spare parts
√	√	√	√	√	X	X	X	• Site selection, licensing & public relations
√	√	X	X	√	X	X	X	• Taxes (local/regional, plant specific)
								Other overnight capital costs
X	X	X	X	X	X	√ [8]	X	• Major refurbishment
X	√	X	√	X	X	X	X	• Decommissioning
X	X	X	X	X	√ [6]	X	X	• Others
3% [5]	5%	4%	X	X	√ [7]	10%	√[9]	**Contingency** (share of base cost when specified)

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Replacement of the plant by an identical one at the end of its 20 year technical lifetime.
2. Expenses are balanced by incomes from material recycling.
3. Included in indirect costs.
4. Included in O&M costs.
5. Per cent of domestic direct investment costs.
6. Post-operational capital expenditures of US$ 2 per KWe per year.
7. 5.2 and 8 per cent of base cost for G1 and G2 respectively.
8. 75 per cent of invesment costs at the 20th year of operation.
9. Included in base cost.

Table A7.8 **Coverage of O&M costs: gas**

	BE	CA	DE	FI	FR	HN	IT	JP
Operation	√	√	√	√	√	√	√	√
Maintenance (materials, manpower, services)	√	√	√	√	√	√	√	√
Engineering support staff	NS	√	√	√	√	√	√	√
Administration	√	√	√	√	√	√	√	√
General expenses of central services	√	√	X	√	√	√	X	√
Taxes & duties (plant specific)	√	√	√	√	X	X	√	X
Insurance (plant specific)	√	√	√	√	√	√	√	X
Major refurbishment	X	X	X	√ [2]	X	√	X	X
Operating waste disposal (e.g., coal ash, sludge)	X [1]	X	X	√	√	X	√	√
Others	X	X	X	X	X	X	X	X

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Notes:

1. Included in fuel cost.
2. 1.3% of investment costs per annum.

Table A7.9 **Coverage of fuel costs: gas**

	BE	CA	DE	FI	FR	HN	IT	JP
Fuel price at the border or domestic mine	√	√	√	√	√	√	√	√
Transportation to the power plant	√	√	√	√	√	X	√	√
Taxes on fuel	X	√	√	√	√	X	X	X
Others	√ [1]	X	X	X	X	X	X	X

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Note:

1. Operating waste disposal.

Table A7.8 **Coverage of O&M costs: gas**

KR	NL	PT	SP	TK	US	BR	RU	
√	√	√	√	√	√	√	√	Operation
√	√	√	√	√	√	√	√	Maintenance (materials, manpower, services)
√	√	√	√	√	√	√	X	Engineering support staff
√	√	√	√	√	√	√	√	Administration
√	√	√	√	√	X	√	X	General expenses of central services
√	√	√	X	√	X	X	X	Taxes & duties (plant specific)
√	√	√	X	√	X	NS	X	Insurance (plant specific)
√	X	X	X	X	X	X	X	Major refurbishment
√	√	X	√	√	√	X	X	Operating waste disposal (e.g., coal ash, sludge)
√ [3]	X	X	X	X	X	X	X	Others

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Note:

3. R&D plant specific and general

Table A7.9 **Coverage of fuel costs: gas**

KR	NL	PT	SP	TK	US	BR	RU	
√	√	√	√	√	√	√	√	Fuel price at the border or domestic mine
√	√	√	√	√	√	√	√	Transportation to the power plant
√	√	X	X	√	√	X	X	Taxes on fuel
X	X	X	X	X	X	X	X	Others

Abbreviations: NA = not applicable; NS = not specified; √ = included; X = excluded

Annex 8

IMPACTS OF ELECTRICITY MARKET LIBERALISATION ON GENERATION COSTS

This annex describes how liberalisation of electricity markets is likely to affect the costs of electricity generation. Market liberalisation refers to the trend both in the OECD and throughout the world which aims to improve the economic efficiency of electricity supply industries by introducing elements of competition and moving towards market-based pricing. It shifts decision-making from government entities to the market. A basic objective of market liberalisation is to reduce prices paid by consumers for electricity. Where electricity has not been priced to reflect the full costs incurred in supplying it, as in some developing countries, market liberalisation aims to bring prices up to fully cover expenses. Other key objectives of market liberalisation may be to reduce government funding of state-owned utilities and to improve the international competitive position of domestic industries (and utilities).

Market liberalisation is expected to affect not merely price levels, but the underlying cost structure. Profit margins on costs of supply, costs of transmission and distribution, and costs of generation will all be affected by market liberalisation. Generation cost is the focus of the following discussion.

Today there are few quantitative results on the cost effects of electricity market liberalisation because the movement to liberalised markets is a recent phenomenon. Within the OECD, only a few countries have moved far down the path towards competitive generation: national or state spot markets for electricity have been created in Australia, Finland, Norway, Sweden, the United Kingdom and the United States, all in the 1990s. Non-utility generators are allowed to sell electricity to third parties (i.e. companies other than the monopoly utility) in at least six other OECD countries. Most countries made the legal changes allowing such sales in the 1990s, although the US PURPA legislation dates from 1978. The European Union Directive on electricity market liberalisation was agreed only in 1996. Therefore, the reasoning presented in this annex rests primarily on economic expectations, but has not yet had the time to be tested or observed widely in national markets. Some observations of cost trends in markets that have been liberalised are given below.

Market liberalisation

The term “market liberalisation” covers a number of related reforms to electricity supply industries which are not necessarily all pursued at the same time. They are:

- corporatisation – placing state-owned utilities into commercially structured and commercially oriented companies;
- privatisation – transfer of assets of the electricity industry from state to privately owned organisations;

- deregulation – reducing direct state control or oversight of various aspects of industry operations;
- introduction of competition – allowing more than one electricity supplier to compete for customers in a given market.

Transmission and distribution of electricity are commonly considered today as monopoly system elements not subject to competition. Introducing competition in generation has therefore been the focus of much reform effort to date. The marketing of electricity to end-users is also potentially a competitive component of the electricity supply industry.

The approach to market liberalisation in each market depends intimately on the starting point of the industry. This is defined by ownership, horizontal and vertical structure of sub-sectors, and existing regulation of the industry. State ownership of the industry is common. Beyond this generality there is an enormous variation in the existing situation of different electricity systems. In some countries there are literally thousands of privately owned electricity generators and/or suppliers, while in others there is one dominant utility in nearly all cases owned by the state. Regulation ranges from no formal control whatsoever, as is common in systems with large, state-owned utility companies, to independent, adversarial regulation as in the United Kingdom or the United States.

The different potential reforms pursued to liberalise electricity markets can have different effects and provide different incentives to electricity generators to change their economic behaviour. Clearly, however, a primary focus will be to reduce power generation costs ($/MWh). Corporatised state-owned utilities may reduce costs as more transparent accounting procedures reveal sub-optimal or politically constrained spending patterns if they exist. Privatised utilities may reduce costs in order to increase profits for their new owners. Generators in newly competitive markets will try to reduce costs in order to compete effectively by lowering prices. In all cases, market liberalisation is expected to:

- concentrate efforts to reduce expenditure on generation and maximise returns by plant owners;
- re-orient decision-making to incorporate private rather than public economics;
- lead to more transparent and effective pricing to better reflect costs.

The potential for cost reduction varies by country and utility. Some systems are relatively efficient already, while others may have large scope for cost improvements. There are wide variations in cost structure among utilities. For example, the average accounting value of thermal and nuclear plant capital costs vary by factors of 4.5 and 4.8 among UNIPEDE member countries (Olarreaga, 1993: p. 8). Among OECD Member countries, system losses vary from 2 per cent to over 15 per cent, and nationally averaged efficiencies of thermal power plants vary by over 10 percentage points (IEA, 1997). Not all such system cost and performance variations are due to uncontrollable, local factors such as accounting conventions, plant mix, or plant ages. Some are attributable to real variations in the efficiency of use of factor inputs. One study of US utilities suggests that efficiency of operations accounts for 60 per cent of the variations in average system prices (Haeri, 1997).

Short-term actions taken in response to market liberalisation differ from actions possible in the long term. In the short term, the capital stock is not changeable, so generators will focus on reducing operating and maintenance expense, improving asset management, and improving capital (financial) management. In the long-term, new investments and new technology will be sought to provide a new generation plant mix having lower total cost.

Transparency of public policy objectives and costs

One effect of many approaches to market liberalisation is to expose the cost of meeting public policy objectives. In non-competitive environments, governments have had available a number of mechanisms to accomplish public policy objectives without any identifiable public or private expense. The essential lever was obtained by assigning the responsibility for executing policies to utilities, which, through state ownership, regulation, or in a "co-operative spirit" bore the costs. The expenses could be passed on quietly and diffusely to ratepayers. In the case of state-owned utilities, the costs could be recouped by reducing contributions to government treasuries (low or no dividends) or by obtaining larger yearly operating funds from the government. Regardless of ownership, the mechanisms have often not been transparent.

Examples of public policy objectives implemented by governments via electric utility companies are given in Table A8-1.

Table A8-1. **Examples of public policy objectives implemented by utilities**

Policy objective	**Mechanism via requirements on utilities**
Support domestic coal mining	• Domestic coal purchase agreements • Utility ownership of un-economic coal mines
Promote energy security	• Selection of particular fuel sources for power generation • Prohibition on specific fuels
Support domestic equipment suppliers	• Use of non-competitive procurement procedures • Selection of non-commercial generation technology
Support employment	• Over-use of labour by state-owned utilities
Reduce pollutant emissions	• Selection of specific environmental control technologies (not necessarily needed to meet environmental regulations) • Selection of particular generation technologies
Promote renewable energy	• Selection of renewable technologies • Required purchase of power produced using specific renewable sources • Favourable pricing for purchases of electricity produced using renewables

Note: Example mechanisms are actions utilities may be required or encouraged to take even in the absence of specific regulation or legislation.

All of the mechanisms noted in Table A8-1 can result in the selection of generating capacity on non-economic criteria. The cost of using more expensive generation options may thus not be discernible within the cost of the overall generating mix.

In markets where generation becomes open to competition, individual decisions on generating capacity will no longer incorporate non-economic requirements unless they are made explicit by regulation and all potential competitors are subject to them. Individual plant developers will aim to provide electricity at the lowest possible cost by minimising cost of fuel, equipment, and labour within the set of environmental regulations applicable to all competitors (note parallel with examples in Table A8-1). Any potential generator required to fulfil certain objectives while others are exempt can justify a claim of discriminatory treatment and will call attention to the effects of the policy requirements. Policy costs previously borne by the generation sector in non-competitive systems will thus be made transparent with the arrival of competition.

State-owned companies are apt to benefit from special financial advantages which help them to fulfil a policy role. For example, they may pay no income taxes, may have access to less expensive debt through government bond markets, or may have access to certain government services at no cost. Corporatisation or privatisation of state-owned electric utilities, even without introducing competition, may expose some of these off-book financial benefits. This in itself is a major impact of privatisation.

Although the advent of competition can expose the cost of public policies administered through electric utilities, many of the policy goals remain valid. Long-standing policy objectives, such as security of supply, environmental protection, and social objectives, must be explicitly considered in new arrangements for the electricity sector (OECD, 1997; Tonn, 1995). As an example, security of supply is discussed in Annex 9 of this report.

Allocation of risks

Market liberalisation has the effect of increasing risks borne by investors in the electric supply industry and decreasing price risk to consumers. In the non-competitive model, many mis-calculations of future costs can be passed on to electricity consumers in higher prices. In state-owned systems, the state can choose to accept lower returns from its utilities or provide direct financial support in order to compensate for mis-calculations. In contrast, investors in electricity utility companies bear more of the overall business risk in liberalised markets. Electricity generation becomes more like any other business, where consumers reward companies which are well managed and avoid companies which err.

Examples of the types of risks faced in generating electricity are given in Table A8-2. These risks are present regardless of the regulation and organisation of the industry. What varies is the actions utilities take to protect against these risks, and who ultimately bears the cost of these risks should they arrive.

Since most expenses reasonably incurred could be passed on to consumers or borne by state owners, the tendency in traditional electricity markets has been for utilities to avoid risks through extra investment in advance of possible problems and to avoid negotiating too aggressively in plant procurement, particularly with equipment suppliers. The balancing of potential risk and actual expenditure to avoid risk did not necessarily seek to minimise costs of generation, but to minimise risks (financial, political, or other) to the utility itself. The conservative or "risk-averse" attitude of many monopoly supply utilities is well known. As a result, many argue that utilities have probably spent more on generating assets than they would have in competitive markets by over-designing and over-building plant capacity. "Over-designing" refers to incorporating power plant features which increase the unit cost of electricity without satisfying a fundamental design constraint such as performance or safety. Over-building refers to providing amounts of plant capacity to meet conservative (high) estimates of growth in electricity demand. The result of this has been relatively high reserve margins in some electricity supply systems.

Table A8-2. **Typical risks faced by electricity generators**

Type of risk	Outcome compared to expectation
Construction	
Cost overruns	Construction costs more
Schedule delays	Long construction time; purchased replacement power may be needed to meet shortfall
Technology	Poor plant performance, especially when using new technology; low plant efficiency; low plant availability
Financial	High plant financing costs
Operating	
Market	Low electricity sales, leading to excess capacity; major customers find alternate supplies; low electricity sales price
O&M	High labour or material costs
Fuel	High fuel price; inadequate fuel quantities
Financial	Returns are lower than expected; capital is poorly structured
Policy	
Regulatory	Regulations require higher costs; tax burden increases
Environmental	Environmental laws become stricter; environment assessment criteria change
Siting	Land purchased for a plant becomes ineligible

Utilities may have also spent more on plant operations than they would have in competitive markets. Potential costs that might have been avoided through, for example, contractual means were not necessarily considered carefully if not ultimately borne by the utility owners. Examples include accepting ambitious construction schedules without builder guarantees, use of unproved technology without vendor guarantees, or acceptance of long-term fuel supply contracts at premium prices.

The development of Independent Power Producers (IPPs) has, in many electricity supply systems, made the nature of electricity supply risks particularly evident (see Paffenbarger, 1997a). Being outside of the traditional supply system, IPPs were not able to pass on risks through the monopoly regulatory arrangements. Rather, IPPs have generally relied upon a series of contracts to allocate risks explicitly. Fixed-price construction contracts transfer some construction risks to the architect-engineer. Operations and maintenance agreements transfer O&M risk to a separate operating contractor. Most importantly, a power purchase agreement often transfers market, fuel, regulatory, and environmental risks to the monopoly utility which purchases the electricity produced. This utility has normally been required to purchase the electricity from a defined set of eligible producers at regulated prices, and has been allowed to pass the cost of these electricity purchases to its own customers. Ultimately then, many of the risks faced by IPPs have been passed on to electricity customers through the purchasing utility, but through explicit contracts. These contracts are not feasible in competitive electricity generation markets.

Private owners of electric utilities have historically enjoyed stable returns on their investments due to the traditional allocation of risks. In the United States, for example, return on utility bonds have been only slightly above those earned on US Treasury bonds, an essentially risk-free investment. The variability of returns on US utility assets has been among the lowest of any industry (Brealey, 1984).

In liberalised electricity markets, investors are likely to face greater variability in their returns, which should move toward the average for similar industries. Unexpected costs can be passed on to consumers only to the extent that all utilities face the same costs and attempt to reflect the costs in their prices. Utilities that do not make adequate provisions for minimising risk, or which over-spend to avoid risk, will not be able to recover costs in their prices, which are set by the market rather than by regulation. Utility investors must absorb such costs.

Investors include two broad categories: debt holders and shareholders. Of the two, shareholders face the most risk. Shareholders are not guaranteed fixed dividends, but obtain their returns from the profits of the company. On the other hand, debt holders have invested in loans and bonds with defined rates of return. In the case of severe business difficulties debt holders have first right to the assets of the utility, and so are more likely to recover their investment than share holders. Both classes of investor will face increased risk in liberalised markets.

There is some debate as to what increased investor risk will do to overall costs of capital for electric power generation. It is clear that increased risk will translate into higher cost of equity since shareholders will seek a higher return in compensation. This is an implication of cost of capital models such as the capital asset pricing model or the discounted cash flow model of dividends. However, the size of the increase required to compensate for the increased risk is not easily predictable. It depends on industry performance over a period of years, in turn influenced by the nature of industry competition and regulation. The cost of debt may, on average, increase, but this also is difficult to predict. Even under non-competitive systems electric utilities face financial difficulties and bankruptcy, and the arrival of competition will not necessarily lead to lower average quality of debt in the industry and, as a result, higher average costs of debt. The effect of discount rate on investment costs is discussed further below.

Market liberalisation is likely to reduce costs of generation by better allocating risk to those parties that can take action to mitigate it. In non-competitive systems consumers implicitly absorb risks, but can take no organised action to reduce them, such as switching to a different electricity supplier with a better risk management strategy. In liberalised markets, that option may be open to them. In competitive markets, utility investors have stronger incentives to reduce risks cost effectively. They are in the best position to allocate risks by establishing better contractual arrangements, entering into new business relationships, purchasing financial hedging instruments, purchasing insurance, and taking other actions. They are under competitive pressures to avoid incurring excessive costs, so over-designing and over-building are less likely to be successful business strategies.

Investment costs

The debate on "stranded assets" in liberalising markets indicates that investment costs under traditional electricity markets have not always been as low possible. Stranded assets are those unamortised costs of prior investments that would be recovered by monopoly supply utilities but which would not be recovered under competition due to lower electricity prices. High capital costs are not the only source of stranded assets, but they are a significant component. US Department of Energy estimates of stranded assets in the United States range from US$ 72 to 169 bn, out of a total asset value of about $400 bn (EIA, 1997) if regional competitive markets were in place at the beginning of 1998. The 1996 privatisation of the nuclear generating utility British Energy brought in £1.4 bn, even though the company's newest generating station, Sizewell B, was completed in 1995 at a total cost of over £3 bn. This is not to suggest that only traditional electricity markets are subject to problems of stranded investments. Liberalised markets cannot avoid losses in plant investment values either, but it is true that they will provide stronger incentives to avoid excessive investments.

Emphasis on economic designs

As noted above, there are strong disincentives to over-designing power plants. Liberalised markets focus attention on the choice of power plant features and technology which result in lowest product cost. Extraneous design features or design constraints which may be common, but which do not provide a clear economic advantage, are likely to fall from use. Utilities in turn put pressure on equipment suppliers to rationalise designs and cut costs of major equipment.

There is some evidence of this in the United States, where most states have been preparing for or debating the introduction of competition for several years. Costs for coal-fired power plants have declined by one third since 1993 (see Annex 2). Capital costs for combined cycle power plants in the United States have declined from over 600 $/kWe in the early 1990s to below 400 $/kWe in 1996 (Hansen, 1996). Designs of combined-cycle plants have become simpler over time and manufacturers have responded to cost pressures by developing standardised plant designs.

Admittedly the precise influence of competition is difficult to discern because of parallel developments in technology and among power equipment suppliers. Technological developments in gas turbines have certainly aided the world-wide decline in turbine prices in the last decade. Equipment suppliers have been under pressure not only from generators facing the prospects of competition, but also from equipment manufacturing over capacity, particularly among boiler manufacturers.

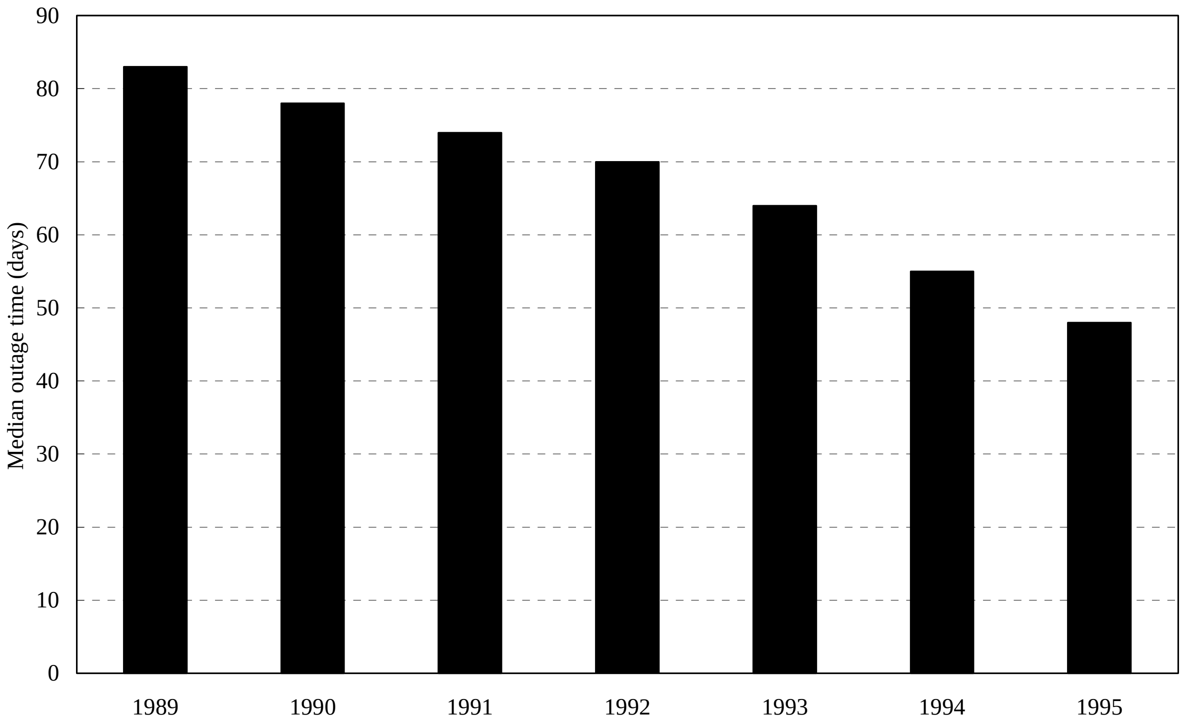
Improved use of generation capacity

Capacity utilisation is likely to increase in liberalised markets. That is, generators will make every effort to ensure that capacity factors of generating plants are as high as possible, that plant production is maximised when electricity prices are highest, that unplanned outages are minimised, and that rarely used capacity is minimised. As is clear from the sensitivity results on load factor presented in the body of this report, higher capacity factors can dramatically lower the final cost of generation as capital costs are spread over more units of electrical output.

Again the United States provides an indication of the trend towards higher capacity utilisation in liberalising markets. From 1984 to 1993 in the United States, the average availability of coal-fired plants increased from 76 to 81 per cent (EIA, 1997: p. 16), and from 1990 to 1995, the average capacity factor of nuclear plants rose from 72 to 79 per cent (NEI, 1996). In Australia, the percentage availability of the Yallourn 1 and Hazelwood coal-fired plants operating in the competitive Victoria power market increased from the low 60s in 1991/92 to the 80s in 1995/96 (Dillon, 1996). A third plant, Loy Yang A, increased its availability from 78 per cent to over 90 per cent in the same period. In the United Kingdom, the availability of National Power’s power stations increased by 3 percentage points in the five years following privatisation (NP, 1995).

There has been a world-wide trend in recent years towards improved utilisation of nuclear plants. Part of this improvement is due to technological progress and accumulation of operating experience, but part may also be attributed to competitive pressures in some nuclear markets (Finland, Sweden, the United Kingdom and the United States). Outage times for both refuelling and other common procedures such as steam generator replacements have been steadily declining. In the United States, nuclear refuelling outages have been dropping steadily since 1989, as shown in Figure A8-1, and the record time continues to fall at individual plants.

Figure A8-1. **US median nuclear plant outage times, 1989-1995**



Source: Strauss, 1995.

System reserve margins are likely to fall in competitive markets, as generators strive to minimise unused generation. Depending on how the electricity market is structured, demand-side bidding for capacity can promote this. Demand-side bidding provides a means for customers to sell capacity into a spot electricity market by reducing load during periods of peak demand. This effectively reduces the requirement for providing infrequently used peak capacity. Another feature of liberalising markets which tends to reduce the need for peak capacity is time-of-use pricing. This sets electricity price over time periods (daily or seasonal) to better match the marginal costs of production. When production costs are high, for example during the peak demand period of the day, prices will be higher. Electricity consumers thus have an incentive to reduce demand when production costs are highest. This pricing scheme is by no means unique to competitive markets, but may be introduced or strengthened at the same time as market restructuring. In systems with spot markets for electricity, the wholesale electricity price automatically follows the variations in production cost through generator price bids. Development of less expensive, more sophisticated metering might lead to real time pricing and help to reduce peak load demand from domestic and commercial consumers.

Repowering

Repowering of old facilities can provide a means to increase the effectiveness of existing capacity and minimise capital investment in new capacity. Repowering means the replacement of a significant portion of the plant to improve its performance and reduce costs. Old facilities are often dispatched infrequently because of high marginal operating costs or operational constraints. Thermal efficiency may be low. Repowering can in some instances effectively provide new capacity at lower installed cost by taking advantage of existing investments in infrastructure, manpower, and fuel supply.

Competitive procurement

Liberalising markets can result in a weakening of links between national or state-owned utilities and domestic equipment suppliers. Monopsony buying of power generation equipment and services has been raised as an issue by equipment manufacturers felt to be excluded from some markets and by international bodies concerned with trade (OECD, 1995). Monopsony markets are ones in which there is only one major buyer or a few buyers. In power generation equipment, a dominant national utility may rely on higher-priced domestic equipment as a matter of government policy or guidance. It can be argued that governments have explicitly encouraged reliance on domestic equipment suppliers as an element of industrial or regional development policy, employment policy, or technology policy. The US turbine manufacturer General Electric argued in a highly publicised 1993 court case that the German utility VEAG unfairly excluded it from a supply contract in favour of a domestic supplier. The Italian competition authority criticised the state supplier ENEL in 1996 for relying almost exclusively on Italian equipment suppliers (PIE, 1996), who provided 99 per cent of ENEL's equipment over 1991 to 1994. In addition, the authority noted that suppliers tended to offer very similar prices, indicating a lack of competition.

There are, naturally, advantages to working with local firms since they share the same language, business practices, and technical standards and are often the closest geographically. However, as liberalising markets introduce transparency and emphasise cost-effectiveness, utilities will put pressure on domestic equipment suppliers to compete more squarely on price. This is likely to reduce equipment costs in some electricity markets. The drop in equipment prices in recent years is thought to be due, at least in part, to the pressure arising from deregulation and privatisation of electricity markets around the world (Wagstyl, 1997).

Cost of capital

It was noted above that utility owners will bear increased commercial risks in generating electricity in liberal markets. Private owners of generating capacity will require higher returns on their equity investments than public owners. Market liberalisation will thus increase the cost of both raising equity and debt for utility companies. The cost of capital for new generation capacity will likely be higher for plants in competitive markets than in traditional monopoly markets. Discount rates used for project evaluation will therefore be higher as well. In the United Kingdom, for example, the real rate of return of the electricity industry increased dramatically following privatisation, beginning from a value of less than 3 per cent under state ownership. In the five years following corporatisation of the New Zealand state-utility, its rate of return on equity increased from 4 per cent to 12 per cent (Culy, 1996: p. 347).

The sensitivity analyses of the body of this report show the effect of discount rate on levelised generation costs. If generators in liberalised markets use higher discount rates than previously, the capital component of generating costs will increase. There could be some effect upon the choice of technology and fuel as well. Higher discount rates will tend to favour less capital-intensive technologies and those with shorter construction times.

The magnitude of this effect is difficult to assess. In cases where a state-owned utility used a low discount rate, say 3 per cent, it is likely that a private generator will arrive at quite different choices in investment and design. Without access to capital at low, government-backed interest rates, a private utility will clearly have a greater incentive to minimise capital costs. However, it is not clear that many systems will see changes in discount rates large enough to change investment decisions. In recent years the trend towards the selection of gas turbines and combined cycles, particularly in the United Kingdom and the United States, is often cited as evidence of the use of higher discount rates and shorter payback periods by generators. However, gas-fired plants in these markets often appear to be the most economical choice over a range of discount rates used by incumbent utilities, independent power producers, and autoproducers.

In recent years, some regulated monopoly supply systems have themselves provided less certain returns for utilities because of a tendency to more critically evaluate costs incurred. That is, the risk of regulatory changes, still within a monopoly supply situation, has increased business risks for utilities. The dis-approval of certain expenditures for nuclear power plants has been a visible example of this. Some utilities in Germany, Spain, the United Kingdom, and the United States faced considerable uncertainty as to their ability to recover costs for construction of nuclear power plants which were subsequently cancelled or not allowed to enter into operation. Some US utilities approached bankruptcy before the issues were resolved fully. So-called “prudency reviews” in the United States dis-allowed other costs thought to be reasonable by the utility but not so by state regulatory authorities. Regulatory risk has increased uncertainty and raised the cost of capital in some markets.

Competition in generation could reduce this component of regulatory risk, since generators are responsible primarily to shareholders to see that expenses are incurred wisely. The market, rather than government, determines what expenses may be passed on to consumers and which must be borne by investors. The reduction in regulatory risk (at least for generation costs) could partially offset the increase in business risk introduced by competition.

In addition to access to debt at low interest rates, state-owned utilities may be able to provide minimal or no return on the state’s equity investment. Whereas private owners insist upon a regular stream of dividends on their equity, government owners may expect no income stream from the utility, or may allow substantial variations depending upon the utility’s annual financial results. This also contributes to a low cost of capital for some state-owned utilities which would increase with privatisation.

An opposite development could occur in markets where public owners use the electricity monopoly to fund government activities. This is a well established situation among municipal or local utilities in OECD countries. Public owners may be able to withdraw more cash through high profit requirements than would be possible by private owners or owners operating in a competitive market. In such situations, market liberalisation might tend to decrease returns on equity and decrease the effective cost of capital.

O&M costs

Non-fuel O&M expenses are typically the largest single cost element of utility operations. They are a variable cost tied to output to a lesser degree than fuel, and so are the object of particular scrutiny in utilities operating in liberalised markets. Utility labour and operating productivity have risen in many markets undergoing liberalisation.

Labour productivity

Table A8-3 summarises decreases in electricity utility employment in systems undergoing market liberalisation. The decreases stem mainly from improvements in labour productivity and not decreases in electricity production. Utilities facing competition have significantly improved the use of labour for technical tasks, but have also improved personnel management practices. The latter can be expected to minimise non-productive time such as from shift scheduling conflicts, absenteeism, or sickness. Some utilities have developed multi-discipline training and more flexible team formation to cut labour costs. They have reduced their workforces and lowered payroll expenses through attrition, layoffs, and early retirements.

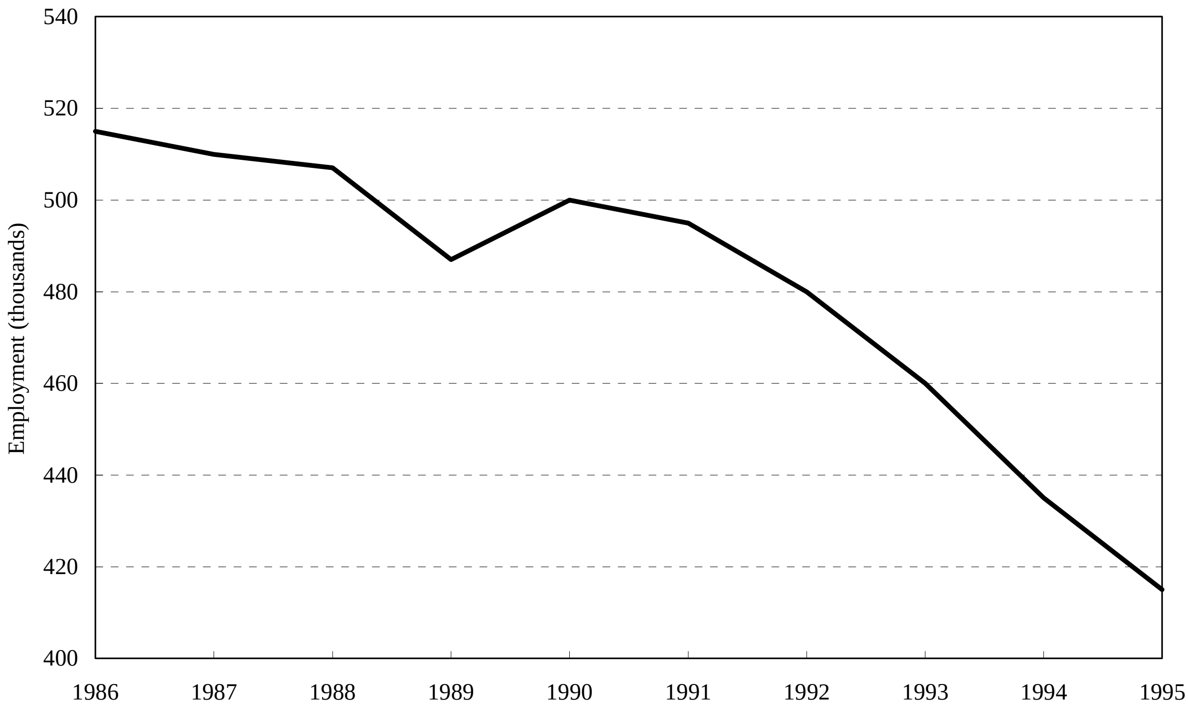
Table A8-3. **Average annual decrease in utility employment due to market liberalisation**

Country	**Form of liberalisation**	**Decrease (% of initial value)**	**Time period**
Victoria, Australia	Privatisation, competition	10%	1989-96
Hungary	Privatisation	4%	1995-97
New Zealand	Corporatisation	10%	1987-92
United Kingdom	Privatisation, competition		
National Power		13%	1990-95
PowerGen		10%	1990-95
British Energy		*8%	1996-98
United States	Impending competition	**3%	1990-96

Source: Dillon, 1996 (Victoria); this study, Annex 2 (Hungary); Culy 1996: p.348 (New Zealand); corporate annual reports (National Power and PowerGen); PUK, 1996 (British Energy); EIA, 1996: p. 87 (US).
Note: * Projected by company. ** Major investor-owned utilities.

Other deregulated industries provide indications that liberalisation typically improves labour productivity. In the United States, deregulation of the trucking industry led to 25 per cent drop in labour costs. In commercial passenger air transport, yearly earnings of flight attendants and pilots dropped by 40 per cent and 20 per cent following deregulation (EIA, 1997: p. 68). In the US electricity industry, the real value of salaries and wages decreased by 28 per cent from 1986 to 1995 as the industry has prepared for the arrival of competition (EIA, 1996: p. 86). Figure A8-2 shows the marked trend towards decreasing employment by investor-owned utilities since 1990. Staff reductions and salary pressures are likely to continue as competition emerges in individual state markets.

Figure A8-2. **Employment trends in US investor-owned utilities, 1986-1995**



Source: EIA, 1996; p. 87.

In nuclear power generation, staffing represents a relatively high proportion of non-fuel O&M costs. Improvements in labour productivity appear as particularly likely for nuclear utilities entering liberalised markets.

Operating productivity

Non-labour improvements in operating productivity are also likely in liberalising markets. This includes, for example, reductions in expenses for supplies, tools, or materials, improvements in the utilisation of equipment, and increased maintenance effectiveness. Preventative maintenance is likely to be relied upon more effectively to balance maintenance costs with costs due to unplanned equipment failures.

In New Zealand following the corporatisation of state-owned generator, unit operating costs in power stations decreased by 13 per cent over the period 1987 to 1992 (Culy, 1996: p. 347). In the United States, anticipated competition has contributed to a 50 per cent reduction in expected operating expenses for new coal-fired plants (US country statement) compared to 1993 values.

In nuclear plants, there has been a world-wide trend in recent years towards improved O&M cost performance. The trend towards reduced time for maintenance activities requiring plant outages was noted above. At least part of these trends may be due to the arrival or imminence of competition. In the United Kingdom, for example, the nuclear utility Nuclear Electric reported that it cut the cost of its per unit operating and maintenance expenses by 40 per cent in the period 1989 to 1994 at the same time as competition was introduced beginning in 1990 (NW, 1994). In the United States, among other areas of improvement in recent years, the volume of low level wastes has decreased and fuel reliability has increased (NN, 1997).

Fuel costs

In most monopoly supply systems, fuel costs are passed on to final consumers. There is often little incentive to change the fuel mix or minimise fuel costs once plant technology/fuel choices have been made. In contrast, market liberalisation will tend to promote the use of the most economic fuel for local conditions while complying with the relevant local constraints, including the costs of meeting environmental standards. Competitive markets tend to put pressure on utilities to reduce fuel costs through a variety of means: increasing plant efficiency, changing the plant fuel mix, and improving fuel contracting.

In the United Kingdom, National Power reduced its fuel costs per unit of electricity by 13 per cent following privatisation (NP, 1995). Part of this was due to increased reliance on natural gas and less on relatively expensive domestic coal. In the United States, real O&M costs have decreased by 22 per cent from 1986 to 1995, most of which was due to the reduction in total fuel expenses of the total plant mix (EIA, 1996: p. 86). Lower fuel prices and transportation certainly played the most important role, but part of the pressure on prices and transportation costs came from utility awareness of impending competition. American coal-fired power plants have increasingly sought low-cost fuels compatible with coal co-firing. The use of petroleum coke has increased dramatically in American utility boilers in recent years (Paffenbarger, 1997b: p. 38) because of its low price and compatibility with existing plant systems. In addition, automobile tires and palletised wastes have been tested in a number of coal-fired boilers.

A move to shorter term fuel supply contracts is likely, coupled with strategies to secure some measure of price stability. For example, some utilities may find it advantageous to take financial stakes in fuel suppliers. It is likely that a greater variety of contract forms and pricing structures will emerge in liberalised markets. The parallel movement towards liberalised gas markets in Europe will provide opportunities for utilities to revise their fuel purchasing strategies.

There are potential pitfalls to changing fuel purchase arrangements. Focusing too much on minimising short-term fuel costs while not taking adequate precautions against longer-term or sudden price rises could lead to higher total fuel bills for individual utilities. For example, the use of interruptible gas supply contracts without adequate backup fuel supply could lead to this result. The skill with which utilities balance short-term fuel bills and price risk will determine the extent of real savings.

Fuel costs may be lowered in multi-fuel power plants by taking advantage of relatively brief movements in relative fuel prices. If, for example, there is a seasonal or short term increase in price of natural gas relative to fuel oil, a generator with access to both fuels may switch a plant from natural gas to fuel oil to obtain a lower fuel cost. The reverse sequence is equally possible if it is fuel oil that increases in price. Dual firing allows the plant operator to reduce the economic risk of movements in fuel prices and minimise total fuel costs at the expense of small capital investment (less than 5 per cent of boiler investment cost for dual gas/oil firing).

An additional economic advantage can accrue to owners of dual-fuel plants with firm fuel supply contracts: the ability to profit from a difference between the contract and spot market fuel price. Take the example of a dual fuelled plant supplied under a non-interruptible natural gas contract. If the spot price rises relative to the contract price, and fuel oil is available from the spot oil market or in utility storage tanks, the utility could switch the plant from natural gas to oil and sell natural gas on the natural gas spot market. The utility will profit when the difference in price between spot and contract gas prices is greater than the extra cost of operation on fuel oil. Price differentials of this sort are normally of short duration because supply contracts are typically indexed to spot market prices with some time lag and averaging calculation. The technical ability to switch rapidly between fuels is therefore key. The ability to realise arbitrage gains of this type depends on competitive gas supply markets.

The increased policy transparency that often accompanies market liberalisation is likely to reinforce the trend of reduced support of domestic coal mining industries through electric utilities. France, Germany, Japan, Spain, Turkey, and the United Kingdom have all had policies which effectively encouraged or required utilities to purchase certain amounts of expensive domestic coal. These policies have been recognised as undesirable and all the countries above have taken steps to reduce such implicit subsidies in favour of explicit government support and eventual phase-out. In the case of the United Kingdom this process has been speeded by the move to a competitive electricity market. Upon privatisation of the state-owned utility, its private successor companies have decreased the use of domestic coal, largely by increasing the use of natural gas. When long-term domestic supply contracts expire in 1998, it is expected that coal costs for British plants will decrease further.

Separation of functions

In markets where competitive generation is introduced, responsibility for electricity network functions formerly provided by generating plants may be assigned to a network operator or another party. The total cost of generation and supply of ancillary network functions many not decrease, and in fact is likely to increase, but it is possible that generating costs could decrease with the separation of generation and supply of ancillary functions.

Ancillary services are bundled with electricity generation in traditional electricity supply systems. These services include functions which ensure the stable operation of the network as loads shift in size and location on the grid:

- controlling power flow and frequency;
- supplying reactive power;
- providing reserve capacity.

When ancillary services are provided jointly with generation, individual plants may not be operated in the most efficient way for power generation alone. By separating generation and system functions, costs of providing each will be made explicit and transparent in financial accounts. It seems reasonable to expect that generators, by focusing on minimising “raw” generating costs, will be able to better minimise generating costs while drawing in a separate revenue stream for providing system functions. Still, the actual effect on generating costs is uncertain (Hill, 1996).

Conclusions

Market liberalisation is likely to focus attention on the costs of generation and provide strong incentives for generators to reduce their costs. For publicly owned utilities, a key factor in improving cost performance is the greater transparency in implementing public policy measures brought about by corporatisation or privatisation. For utilities with supply monopolies, the loss of captive customers and price competition are the essential drivers. Markets, rather more than governments, will allocate costs between customers and utility investors, providing generators with new motivation for efficient operation.

There are some indications of these trends in liberalising markets, although they are early and not conclusive. The anticipation of competition, notably in the United States, appears to be responsible for the improving efficiency of utility operation and generation in particular. Generators in the United Kingdom, Australia, and New Zealand have shown substantial gains in productivity as competition has been introduced. Cost improvements have been seen in other markets moving towards liberalisation and this will accelerate as liberalisation takes hold in more countries both in OECD and around the world.

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Annex 9

ENERGY SECURITY AND DIVERSITY IN ELECTRICITY GENERATION

Introduction

Electricity markets in IEA Member countries and elsewhere have become increasingly competitive over the last half decade, a trend that is set to continue for a while. Liberalised power markets have, it is often argued, an inherent tendency to produce the lowest-cost outcome, thus increasing micro-economic efficiency in the sector, but omit taking into account other societal goals such as the important goal of a secure supply of energy. If indeed cost minimisation is the prevailing behaviour in power generation, it seems logical that the relative prices of inputs, especially of fuel inputs, should trigger construction of only the cheapest type of power generation, leading to an increasing share, and, if the market conditions prevail for a sufficiently long time, a "monoculture" of the cheapest generating option. The United Kingdom and its "dash for gas" is often taken as a real world example of this type of market behaviour.

This annex discusses the issue of energy security, its relevance to the electricity market, ways in which it can be sought, and the need for governments to address it within the electricity supply industry. It does not discuss the related issues of system reliability nor the question whether competitive power markets can "keep the lights on", i.e. will generate sufficient investment in supply options. This annex specifically deals with the question what role the power sector plays in ensuring energy security and what is the optimal fuel choice in power generation. The issue is complex, because it goes beyond the electricity market as such. The power sector is the focus of much attention regarding energy security, because it appears to offer more, or cheaper, substitution possibilities than most others: substituting oil in the transport sector seems very difficult and costly, and fuel choice in the industrial and residential (buildings) sector is perceived as less easily influenced by governments seeking to improve security in the entire energy market.

Attempting to identify the need for governments to implement measures to improve energy security raises at least three important questions.

1. Would a supply disruption to certain fuels impose a cost upon society beyond mere fuel cost, and how large would be this cost?

2. Is this cost taken into account in the decisions of individual decision-makers? Has it already been internalised by government action such as import tariffs, taxation, strategic energy stockpiling requirements etc.?

3. What is the appropriate role of the government in ensuring energy security? Is it at the regional, national, or international level? Is it in the power sector or in the energy market at large?

What is the cost of energy supply disruptions?

The first difficulty in addressing energy security is defining what is meant by the energy security problem. Security is not an economic notion; it is of political/military origin. The economic incentive for a supplier to withhold supplies under an already agreed transaction, if there is one, is generally much reduced by the loss of revenue from such action. In addition, failure to supply usually causes penalties. This, of course, holds only if the legal provisions and enforcement institutions exist, which is not necessarily the case in international trade.

Energy security appears to refer to the physical availability of supplies to satisfy demand at a mutually agreed price. This means that the security problem refers to a number of different risks: a quantity risk (will there be "enough" supply?) and a price risk. In addition, it has a long-term and a short-term component: a long-term trend of, say, rising prices for energy imports has different implications for an economy than a sudden price hike or price volatility. The matter is complicated by the fact that energy security worries, including all of their aspects quoted in this paragraph, almost always refer to the two oil crises in 1973/4 and 1979/80. This means that empirical evidence on the societal cost of a primary energy supply crisis is, in most cases, heavily influenced by the specific historical coincidences of those crises and the geopolitical situation at the time they occurred. However, non-fuel raw materials such as iron ore, manganese, bauxite, and many others share some of the features that make energy supplies appear insecure, e.g. large import dependency of OECD countries from politically unstable countries (Maull, 1984).

Quantity risk

Addressing the quantity issue first, it is important to note that long-term physical unavailability of energy resources appears highly unlikely in OECD countries, provided prices are allowed to fluctuate more or less freely. No country is geographically isolated to the extent that a large amount of excess demand for energy resources could not be met in alternative ways or from other suppliers, albeit at a higher price. This would apply in the short term as well.

Fuel substitution will take place where it is possible to replace "missing" fuel supplies in the case of a disruption. The IEA carried out a study on the security of natural gas supply in 1995 (IEA, 1995), which investigated the effects of sudden, short-term supply disruptions such as political instability (related to European gas supplies from Algeria and Russia), dramatic cold spells (North American gas supply), or sudden, unforeseen inoperability of one or several re-gasification terminals in Japan. One of the study's conclusions is that this type of supply disruption would result in substitution by other supplies or other energy resources in the medium or even short term. Unavailability of natural gas for power generation, for example, would lead to more use of oil products (light distillates in combined-cycle gas turbines, heavy fuel oil in oil plants that may have been used for peaking purposes only and are run during longer hours during a shortage), fuel-switching to coal and oil in multi-firing units, or production increases in non-fossil plant such as hydro, in cases where there is spare capacity.

There are limits to short-term fuel substitution. Switching immediately to the next least expensive fuel might not be possible because equipment capable of using the substitute fuel might not be available or the supply infrastructure for the substitute fuel might not be adequately developed. Capital stock in energy markets is slow to change, mainly because of the comparatively long life time of investment in energy production, transportation and transformation equipment, and because of the lack of fungibility of certain assets. Thus, changes in equipment to respond to an energy supply disruption cannot be expected in the short term to reduce the demand for the missing fuel. Substitution is thus limited in the short term by the availability of substitute fuels and adequate equipment.

Any demand for a fuel that is not met by substitution will be quickly translated into price rises. More expensive suppliers, end-users willing to forego the use of functioning sources of supply, and other sources of supply will appear as the price rises. Demand will naturally fall in response to these rises, and a market equilibrium will finally be established relatively quickly. In conclusion, it is difficult to speak about a pure "quantity" risk since physical unavailability of an energy source will give rise to fuel substitution and price rises to reduce the demand of the missing fuel.

Price risk

Although supply disruptions are extremely unlikely to bring parts or the entire economy to a grinding halt, energy price increases might nevertheless have dramatic, economy-wide effects. Table 1 provides a taxonomy of the potential damaging effects on the economy of pronounced, unforeseen price increases. Various studies attempt to establish whether or not these adverse effects are empirically observed and what their magnitude might be.

Table 1. **Potential economic effects of energy price increases**

<table>
<tr><th>Direct microeconomic effects</th><th>Indirect macroeconomic effects</th></tr>
<tr><td colspan="2">A. Long-term costs</td></tr>
<tr><td rowspan="2">A.1 Higher costs of energy resource imports</td><td>A.2 Wealth transfer and its effects on:
• trade balance
• long-term productivity growth
• employment</td></tr>
<tr><td>A.3 Effects of wealth transfer on long-term inflation</td></tr>
<tr><td colspan="2">B. Market disturbances</td></tr>
<tr><td>B.1 Spikes in energy resource import costs</td><td>B.2 Changes in economic performance induced by price spikes</td></tr>
<tr><td colspan="2">B.3 Increases in future risk of disruptions caused by long-term demand growth</td></tr>
<tr><td colspan="2">C. Military expenditures related to energy security</td></tr>
</table>

Source: Bohi and Toman, 1996.

As mentioned above, research into energy security focuses on the two oil crises, which led to a quadrupling of real oil prices from their long-term value of around US$ 10 per barrel.[1] More recent

1. Real oil prices had remained stable at roughly this value for nearly one century before the first oil crisis (Bohi and Toman, 1996) and are not far from this value today.

studies also include the time period 1984-85 when oil prices collapsed; those studies attempt to identify whether effects are symmetrical. The results of this empirical research remain inconclusive.

Bohi and Toman (1996) provide a recent, comprehensive overview (the following draws heavily on their conclusions). As far as the direct micro-economic effects are concerned, there is wide-spread controversy over the market power the Organisation of Petroleum Exporting Countries (OPEC) was effectively able to exert during the oil crises. Consequently, there is no econometric evidence of whether the price increases reflect cartel rents, i.e. the skimming-off of wealth due to market power, or scarcity rents, which might have been due to the prevailing strong oil demand growth at the time in combination with the time lag required to build up new supply capacity. In addition, it is noteworthy that oil stocks appear to have increased during the first oil crisis, which might indicate that contrary to conventional economic logic, supplies were not released but withdrawn from the market as prices rose, thus exacerbating scarcity through hoarding, in the new and unexpected situation of scarcity. It is suggested that even during the second oil crisis, there was a fair amount of "irrational (panic) investment in the sense that inventories were purchased at high prices and sold at low prices" (Bohi, 1983), aggravating the economic burden from the original shortage. While it is obvious that price increases were very large, it is less clear whether estimates of the direct effects from past experience in the oil market are good indicators for future supply disruptions.

The econometric evidence on the indirect effects of the oil price shocks is, if anything, even less clear. One effect listed in Table 1 above is the effect on the so-called terms of trade (item A.2). This term describes the amount of goods and services imports a given unit of exports commands in the international market. Increasing prices of imported energy means that the country under consideration must export more goods to buy the same amount of imports. A deterioration in the terms of trade is tantamount to a deficit in the balance of payments, or a depreciation of the importing country's currency. However, even conceptually it is unclear whether an increase in energy resource prices must cause a deterioration in the importing country's exchange rate. This is due to the fact that the exchange rate is determined by *relative* capital flows, i.e. it also depends on the exporting country's willingness to hold the importing countries currency. Empirical studies appear to show that the terms-of-trade effect of higher oil prices can be positive or negative for any oil-importing country, depending on the specific circumstances (Marion and Svensson, 1986). Inflationary and labour-market effects follow this pattern: while increased energy resource prices will raise prices in a one-off inflationary shock, *sustained* inflationary pressure requires an increase in the *growth rate* of oil prices – in other words, oil prices must increase faster and faster. An inflationary spiral as experienced in the 1970 requires an additional explanation, e.g. excess demand, inflationary expectations, and/or flawed monetary policies. Sustained mass unemployment may owe as much or more to labour market rigidities, and notably wage rigidity, than to an external energy price shock.

Empirical studies of the overall effect differ enormously in their assessment. Moreover, the effects differ between countries. The United Kingdom, the then West Germany, and Japan appear to be less sensitive to oil price shocks than the United States is; Japan even managed to avoid a recession after the second oil crisis while the other countries did not. However, the United Kingdom experienced a much deeper recession after 1979 than the other countries (Mork, Myson and Olsen, 1989; Bohi, 1989). The wide variety of estimates of total cost to society from the oil price shocks are illustrated by the results of two studies: whereas the Energy Modelling Forum (Hickman, Huntington and Sweeny, 1987) estimates the damage in the first year to be in the order of magnitude of US$ 47 bn (1983 dollars), another study by Greene and Leiby (1983), situated at the other end of the range of estimates, estimates the cumulative effect between 1972 and 1991 to amount to US$ 4 000 bn (1990 dollars). To make matters worse, if there were a significant effect of oil prices on the economy, the 1986 oil price decrease should have caused an economic upswing, but this upswing fails to materialise in many econometric studies.

In summary, this brief discussion shows that none of the potential costs to society set out in Table 1 are clearly attributable to energy resource price increases, at least as judged from analysis of the 1970s oil shocks.

Energy security externalities

Externalities are costs (or benefits) related to the production and use of goods or services that are not borne by the producer or consumer. Environmental externalities are best known. In power production they might arise when, for example, a power plant damages the local or regional environment due to its airborne emissions. The cost of such damage might be borne by forest owners or farmers whose crops were reduced in output, or the general population in the form of higher medical bills from respiratory problems. Such costs would be "external" to the production of power since they are not borne by the power plant or only consumers of electricity.

The concept of externalities can be applied to energy security as well. An "energy security externality" can be defined as a cost to the economy as a whole arising from the use of specific fuels which is not borne directly by the fuel user. By using a particular fuel, an energy consumer might reduce the probability that others be supplied with the goods they demand at prevailing market prices in the event of a supply disruption. Those others then might have to pay higher prices without compensation.

In principle, the means to avoid an externality is to ensure that it is accounted for and borne by the producer or consumer. Doing so is said to "internalise" the costs. There are various ways to do this, but they almost inevitably involve government action. Taxation, regulation, or creating a restricted market for the product or activity causing the externality can all be a means of internalisation. The resulting higher prices will cause people to lower consumption of the offending good.

Security externalities in the oil market

As shown above, establishing the economy-wide cost of dramatic energy resource price increases is fraught with difficulty, and does not necessarily provide ready-to-use guidance to policy-makers on the kind of policy instruments they might wish to use to protect the economy from damage, nor on how much this policy action should cost in addition to the market solution. However, the figures quoted above, imperfect as they may be, are not even the relevant indicator: they do indicate cost to society, but they do not indicate how much of the cost is external. As noted in the introduction, a cost to society that energy consumers take into account in their private decisions may be painful to bear, but it is an unavoidable aside to resource consumption itself, and individuals or companies are free to seek risk insurance against it. Only if this is not the case, i.e. if the potential security cost to society is external, is there a need for governments to step in and take protective measures.

One example of an energy security externality related to item A.1 in Table 1 above is the so-called "monopsony wedge". This terms describes a situation in which the aggregated demand of a large economy such as the United States (or China in the future) is so large that it influences world-wide price levels in the energy market. Even incremental demand increases from such a country can significantly reduce surplus capacity and thus make energy imports more expensive for every user in the country, not only the ones which demand the extra quantities – and for everybody else in the market. Expressed in economic terms, marginal demand influences the price for all demand. This constitutes an externality, since the marginal consumer is generally unaware that he is imposing an extra cost on others. In this kind of situation, governments may have a role in signalling to the marginal consumers what cost burden they impose on society as a whole, and may, for instance, resort to taxation in order to internalise the externality.

Another example of a specific energy security externality is under item C of Table 1: the cost of military intervention to secure energy supplies. While it is useful to illustrate what an energy security externality is, item C is based on various misconceptions, not least the fact that it attempts to measure the size of the problem via the means used to abate it – which may be grossly out of proportion compared to the problem.

Existing estimates of the aggregated security externalities encompass varying cross-sections of the items listed in Table 1, and show discrepancies as wide as the total cost estimates in the previous section. Earlier estimates were much higher than more recent ones, and several estimates were reconsidered and revised downwards. One study was carried out by the US Department of Energy (DOE, 1990). Its estimate of annualised external cost for the time period 1990-2020 lies in the range of US$ 0.44-1.27 per barrel of oil consumed. It is reduced to US$ 0.17-0.49/bbl if the Strategic Petroleum Reserve is taken into account. This amounts to some 1-3 per cent of current crude oil spot prices in the United States. A recent study by the US General Accounting Office supports these findings and states that further reductions in dependence on foreign oil imports would prove costly to the economy while providing little additional protection from oil supply disruptions (GAO, 1996).

Most of the costs noted above in the discussion on the energy security problem contain a market failure or externality element, but the externality is notoriously difficult to disentangle from the "ordinary" cost of energy imports. As with economy-wide costs, external costs of energy supply disruptions are difficult to determine. This brief review does indicate that there is not a large security externality linked to overall oil consumption.

Security externalities in the electricity market

How should the cost of energy externalities be borne in the electricity market, if at all, as opposed to the energy market as a whole? The logical response to security externalities from oil *imports* would be to adjust the security closest to its origin in order to allow substitution along the entire energy chain. The argument goes as follows. If, say, imported oil carried large security externalities, then the best solution would be to impose an import tariff at the border. This would influence the prices for oil products derived from the imported oil, and cause all consuming sectors to adjust to the measure. Not only would electricity generation from oil be reduced, but people might decide to use their cars less, freight might be shipped by train (or more energy-efficient barges) more, or lubricants might be produced from non-mineral oils more. If the tariff were high enough, people might start using natural gas or electric vehicles instead of petrol and diesel-fuelled cars. An additional research effort might be also triggered to try to replace oil. In contrast, if only the electricity sector were targeted for government action, electricity generation from oil would be reduced, but none of the other substitution possibilities would be exploited. A logical response to the externality noted above would then be to impose a duty on imported oil at the point where it enters the country.

Research into the micro- and macro-economic effects of the two oil crises and the oil price collapse in 1986 shows that the largest part of the externality tends to be the "monopsony wedge", which is necessarily linked to large amounts of demand. If the electricity sector were to demand only very small quantities of oil, then it would be particularly illogical to place a large amount of the burden of adjusting to the externality on this sector. However, if oil use in power generation were significant, there might be a case for internalising part of the energy security externality directly in power generation.

In practice, oil's share of power generation is small in most OECD countries. In 1994, oil accounted for only 9 per cent of total OECD electricity generation. More significantly, OECD use of petroleum products for power generation amounted to merely 7 per cent of total oil demand and 5 per cent of world oil consumption in the same year. In the United States, the figures are 3 per cent of national oil demand and 0.7 per cent of world oil consumption. For the United States and the OECD as a whole, the relative amounts are so small that even oil's total elimination from the power sector would affect only a small share of world oil demand. At such low levels, it is unlikely to generate large "monopsony wedge" costs (Bohi and Toman, 1996). The case may be different in countries with relatively large use of petroleum products in power generation (for example, above one quarter of total power generation), such as Mexico, Italy, Portugal, or Japan.

Due to the overwhelming focus of research on oil supply and its potential disruptions, and the relative scarcity of studies on other primary fuels, the analysis is incomplete. A fuller picture could be to be presented if further research were to be carried out, preferably into the security costs of all power generation input fuels, and especially natural gas, which seems set to become ever more the fuel of choice, especially where power markets liberalise, and which shows a higher fuel share than oil in the electricity generation, domestic and industrial sectors in the European Union (EU 12) (Mitchell, 1994). The 1984/85 coal miners' strike in the United Kingdom illustrates that even the comparatively smooth operation of the coal market might give rise to some, although probably very small, security externalities.

The conclusion of this discussion is that the optimal government response to security concerns related to primary energy supply would be to act directly to influence the cost of primary fuels or their availability in a disruption, and let the electricity sector adjust freely. Imposing import duties and developing oil stockpiles are two actions taken by governments in the past in response to concerns about energy security in relation to oil. Only if actions related to primary energy supplies were not feasible or practicable should measures targeted towards the electricity market be used to address concerns about the security of energy supplies.

Diversity as a means to improve energy security

Given the current state of the energy markets, and research results to date, it is difficult to derive an imperative need for government action in the power sector. However, it may be interesting to look at possible means to improve energy security by applying policy measures in the power sector. Since measures such as stockpiling are suited for primary energy markets only, the obvious response for a conversion technology such as electricity would be an optimal level of diversity in the choice of conversion technology and input fuels. Diversity acts as an insurance against various kinds of problems; diversity of plant technology, for example, reduces the risk of basic design flaws causing large numbers of plant having to be shut down for repair or retrofitting. It simply reflects the idea not to put all eggs in one basket. This advantage of diversity can come at a cost, namely reduced economies of scale in plant manufacturing.

The question is whether liberalised electricity markets reduce diversity below an acceptable threshold and thus incur large energy security externality costs. The issue of an optimal plant mix in the presence of uncertainty is often discussed in the framework of portfolio theory. This theoretical framework has been developed to determine an investor's optimal financial portfolio. It takes into account that in real world decisions, high-return financial assets are often more risky than lower-return assets, and provides a method which enables investors to optimise both the return and the risk of their portfolio, given their risk preference – they can be risk-averse, risk neutral or risk takers. The method can, however, be used for many other decision making problems, including an optimal power plant portfolio.

In the case of power plant investment decisions, the trade-off is made between low expected prices, but with a high level of uncertainty, and higher expected prices, but with a lower level of uncertainty. Adding some higher-cost generating options then acts as an "insurance policy" against large price increases in fuels consumed in low-cost plants. It is argued that higher discount rates, as might be expected in more competitive power markets, reduce the incentive for society to insure itself against these risks by reducing the expected value of future electricity cost increases stemming from fossil price increases.

A study carried out for Scottish Nuclear in September 1994 (Scottish Nuclear, 1994), based on portfolio analysis, does indeed implicitly predict that competitive power markets provide less diversity. The study argues that it is advantageous for society to insure itself against the risk of price increases from fossil fuels by opting for diversity, and notably by using non-fossil, especially nuclear energy, as an insurance. As a central result, it states that nuclear power significantly reduces risk at little extra cost. A portfolio with 30 per cent nuclear generation has an expected generation cost of 3.47 pence/kWh with a 1 in 90 chance of rising to 4 p/kWh. Generating costs of 4 p/kWh and above are defined as indicative of high cost in the study. In contrast, a portfolio with 4 per cent nuclear has average costs of 3.33 p/kWh, but with a 1 in 30 chance of rising to 4 p/kWh.

The first portfolio, i.e. the 30 per cent nuclear scenario, constitutes an optimal solution. It is not much higher than generation from existing nuclear plant at the time the study was conducted: in 1993, the United Kingdom nuclear generation amounted to 27.8 per cent (IEA, 1994). This basically means that maintaining existing nuclear capacity, and possibly adding one more big reactor, e.g. the Sizewell C plant (2 000 MW), would be an optimal strategy. In the longer run, i.e. when nuclear plants have reached the end of their technical and economic lifetime, maintaining this optimum would require new nuclear investment. Some sensitivity analyses have been carried out as well. The insurance value of nuclear power is positive if consumers are strongly risk-averse, but remains positive if they are only moderately risk-averse. Risk neutral consumers would, in any case, not accept to pay any insurance premium. Risk-seeking behaviour was not modelled.

The central recommendation of the study is that the difference in cost between the mix of plants chosen by the market and the optimal portfolio solution should be borne by governments.

The study acknowledges that the portfolio approach does not entirely fit the reality of a competitive market. In a free market, there would be no such thing as overall cost and risk optimisation. Rather, all consumers would decide for themselves where they want to position themselves in the trade-off between current prices and price risk. In fact, one of the elements of centralised power systems that were especially suspected to give rise to inefficiencies was precisely the lack of choice for ultimate consumers in this area, and related areas such as prices and reliability. Moreover, the aggregation required for this kind of analysis poses fundamental methodological problems, which somewhat reduces the validity of the results. The authors argue that their results are meaningful as long as not all consumers have full access to competition, and as long as the appropriate contractual arrangements even for residential customers are lacking to fully express their price/risk preference. Drawing a comparison between the full opening of the United Kingdom electricity market in 1998 and fixed-interest arrangements in the mortgage market, they reckon it might take many years until all mechanisms, including intermediaries such as power marketing organisations, are built up, and until consumers themselves have gathered sufficient expertise to ensure their preferences are optimally reflected in investment choices. This is disputable, since, in the meantime, numerous energy firms (such as British Gas), and even supermarket chains (such as Sainsbury's) have positioned themselves to market electricity to residential consumers as of 1998.

As competitive electricity markets evolve, consumers and suppliers learn to take the diversity issue into account themselves, and develop the appropriate coping mechanisms. Once the appropriate contractual arrangements are in place for everybody, the need for governments to centrally alter the plant mix on behalf of consumers' security needs is vastly reduced. The only reason which might justify government action once liberalised power markets have matured is external security cost, as discussed in the last two sections above.

Diversification of energy supplies need not be pursued only between input fuels. Diversification of supply sources of one and the same fuel is another option, although it would be somewhat less effective, because markets tend to even out price differentials. Generally speaking, the less prices of energy sources are linked to each other, the greater the value of a diversification strategy. Where substitution between fuels is easy, and fuel markets are competitive, the prices of different fuels per unit of energy content lie close to each other. This has been traditionally the case for oil and gas. Supply disruptions and the resulting price surges in either market would thus quickly spill over into the other. In microeconomic terms, this relationship would be described as one showing high cross price elasticity; in econometric terms high covariances; or as a strong statistical link. If governments believe that security externalities of the existing fuel mix are high, they might wish to diversify further and bring in fuels or suppliers that have shown lower covariances with the fuels already used. Coal might be one of these, as might be nuclear or renewables.

In any case, market conditions, especially input fuel prices, are bound to change every once in a while, and these changes could lead to more variety than the above study seems to suggest. This is due to the long lifetimes of power plants, which, if depreciated, may be very successful in competing against new construction. This factor explains why, despite the much-debated "dash for gas" in the United Kingdom, the actual share of gas in power generation was still only at 14.4 per cent, whereas coal still accounted for over 50 per cent.

Diversity index

A diversity index developed by Stirling (1994) helps to describe the level of diversity in electricity systems. The Stirling index was developed based on the premise that much of the uncertainty surrounding fuel prices is actually not risk but ignorance. From this he concludes that portfolio analysis is inappropriate to apply to electricity supply systems.

Risk is generally defined as uncertainty in the value of a certain variable, but where there is an objective method of assigning probabilities to the outcomes, e.g. tossing a coin. Uncertainty, or ignorance, occurs where such a mechanism is lacking, i.e. where the outcome is simply totally unpredictable. As mentioned above, the notion of energy security is not a purely economic one but rather one that straddles foreign and military policy as well as economics. The events that led to the big post-war oil price movements were caused at least as much by political and military events – such as the Yom Kippur war which played an important role in triggering the first oil shock – as they were caused by economic factors. This means that fuel price uncertainty falls into the category of ignorance rather than risk, which would make its treatment under portfolio analysis inappropriate, since portfolio analysis relies on the notion and methodology of risk.

Stirling thus abandons attempting to attribute probability distribution functions to fuel prices (the problem), and attempts to provide a solution based on a diversity index borrowed from physics, the "Jaynes' uncertainty measure", which is used in statistical mechanics as well as in entropy in thermodynamics. The diversity index H is defined as follows:

$$H = -\sum_i p_i \ln p_i$$

whereby p_i represents the proportion of fuel type i in an overall portfolio. The formula multiplies the proportion of each fuel type by its natural logarithm (ln), and then adds these values together. Because the natural logarithm of a fraction is always negative, the minus sign at the beginning of the equation ensures that the index is positive. The index increases as the number of different supply sources increases. It is essentially a measure of the "evenness" of the plant mix. The index yields a lower value, i.e. less diversity, for five technologies, each with the same share of output, than for 50 technologies each with an equal share, and a higher value for five technologies with an uneven share.

Based on the United Kingdom government quantity and cost data and forecasts, and his index, Stirling calculates an optimal electricity supply system for the United Kingdom. This was done running an optimisation model that balances plant financial performance, and the diversity of the plant portfolio as a whole as expressed by the above index. In keeping with the behaviour of the index described above, the optimal result is vastly different from the existing system in the United Kingdom at the time. Both are compared in Table 2 below.

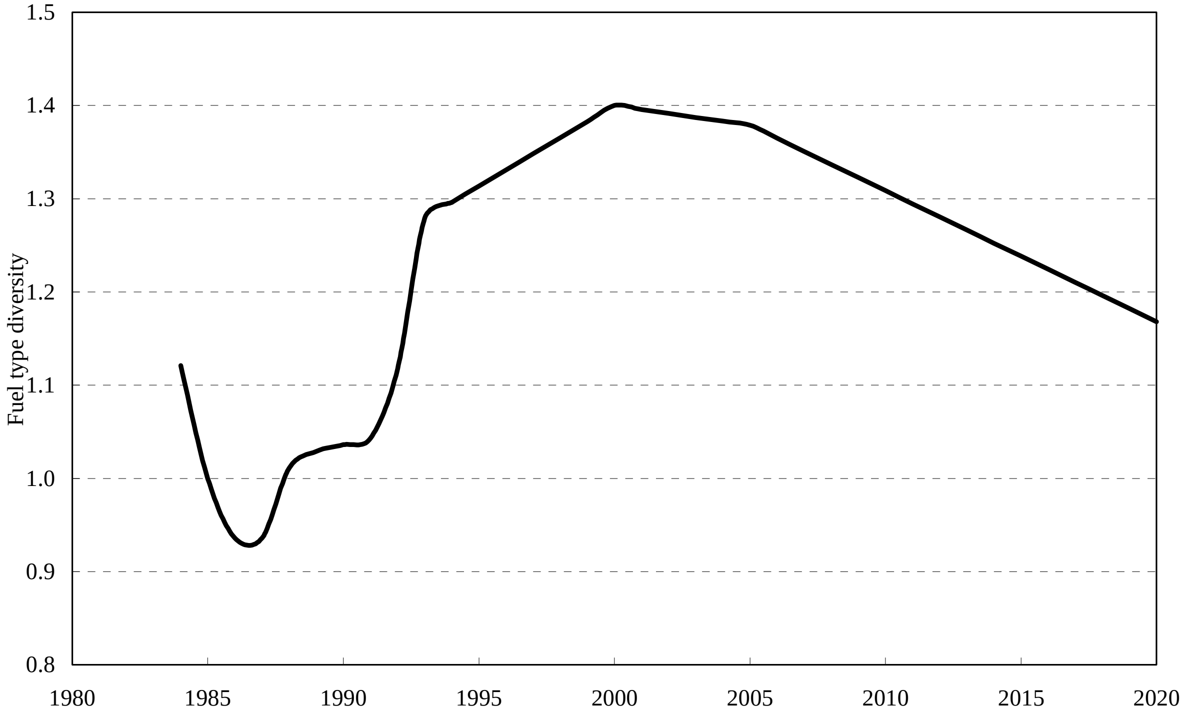
Table 2. **Existing and optimal United Kingdom electricity supply system according to the stirling index (1990), in percentage**

	Existing system	**Stirling optimum**
Nuclear	22	14
Coal	66	27
Oil	9	7
Gas	1	20
Renewables:		
intermittent	0	13
firm	0	17

Source: Stirling, 1994.

The index has also been derived as a time series. Based again on United Kingdom government data, it produces the diversity curve depicted in Figure A9-1. This graph shows higher diversity in 1984 and 1985, when coal burning was reduced due to the miners' strike, and when substitute oil use increased diversity. After the strike, and after falling back to its previous level, it rose again in the late 1980s as coal began to lose ground to nuclear power, and subsequently to natural gas. The index peaks in 2000, but declines again afterwards, when gas increasingly dominates the fuel mix.

Figure A9-1. **Diversity index for UK electricity generation, 1984 to 2020**



Source: Stirling, 1994.

The proposed index is very controversial (Lucas et al., 1995; Brower, 1995; Stirling, 1995), and most commentators agree that it has one large drawback: it treats diversity (and "evenness") as desirable in their own right and makes no distinction between desirable and undesirable states of the world. The case of a hypothetical utility that has only coal and oil plants helps to illustrate this. To diversify, a third and/or forth input energy should be employed, but the question is whether it should be natural gas, nuclear or renewables. The answer, of course, depends on which risks or uncertainties one regards as most serious: the lack of safe, long-term storage for radioactive waste, the potential security concerns associated with natural gas, or the uncertain costs and performance of renewables.[2] The Stirling index does not provide any guidance on the optimal outcome, because it does not incorporate expected values of these variables. Its greatest strength, dispensing with the need to assume probability distributions for these variables, is also its greatest weakness. However, as an additional variable to be consulted in addition to more conventional probability analysis, it may still hold information value.

2. Although, of course, renewables often have either no fuel input or fuel input that is purely domestic. Fuel cost escalation is thus not a problem – but capacity cost overruns and underutilisation can still cause vast cost uncertainty.

The value of diversity in electricity generation

No matter how diversity is measured, the basic need remains to compare the extra cost to society of more diversity in the power market with the value of energy security externalities this diversity is intended to reduce. The evaluation entails two parts:

- estimating the difference in electricity cost between plants intended to provide more diversity, and from plants that would be chosen otherwise;
- estimating the value of energy security externalities for various energy sources (presumably dominated by fossil fuel energy security externalities).

In practice this means comparison of the cost of increasing diversity through non-fossil fuelled plants with the value of energy security obtained through this strategy.[3] The value of energy security is the avoided energy security externality. If the energy security externality proves to be as large as or larger than the extra cost of increasing diversity, governments might wish to take action to internalise the externality and encourage non-fossil power plant investment.

Oil security externalities have been studied much more than security externalities in other fossil fuel markets. They were found to be in the order of magnitude of 1-3 per cent of oil prices. In other words, they are fairly small. Gas and coal security externalities have undergone significantly less scrutiny; to the author's knowledge, no analysis has been carried out on coal. It is reasonable to assume that oil externalities are higher than those attached to gas and coal, since a large part of the externality is linked to market power in the world market. The international coal market is small in comparison to total production, and market power does not appear to be a problem. The only cause of a major supply shortfall could be an exceptionally long strike – something that has happened without large consequences on the international coal market in the United Kingdom in 1984/85. Thus, a security externality for coal can safely be assumed to be very small.

This highlights an interesting point. The damage caused to the economy, and thus the size of the externality, are linked both to the extent and the duration of a supply disruption. The time period between 1973 and 1986 represent the period for which reduced availability (or high prices, which amounts to the same) of primary fuels have so far prevailed (in modern times and during times of general peace). If addressing the security problem required investing in expensive plant capacity that lasts 30 to 40 years to address much shorter-term supply disruptions, the cost of diversity could be much higher than the externality it addresses.

Gas markets are regional, and although there are concerns about market power, these are lesser than the ones prevailing in the oil market during the oil crises. The market power issues are most pronounced in Europe, which depends to a significant degree on a small number of outside suppliers, essentially Russia and Algeria, which are politically unstable (for this and the following, see IEA, 1995). A number of factors limit the impact of supply disruptions: gas can be substituted more easily than oil, and is, outside of North America, traded under long-term contracts, which might help limit price increases. Most European countries have diversified gas supply sources where possible, and can use interruptible contracts and stockdraw. Even under a worst case scenario, such as total disruption of Russian gas supplies to OECD Europe, which amounts to 25 per cent of the region's gas supplies, the impact of a year-long disruption on final supplies is small: the shortfall of gas to end users (on

3. In principle, the private cost of power generation from different fuels would have to cover the value of *all* externalities, including environmental externalities, in order to yield optimal fuel choice for society.

firm supply contracts) represents only 2.5 per cent of demand. The burden of this shortfall is unevenly distributed, such that some countries are far more affected, but the result nevertheless shows that gas security externalities are either not very large or that they have already been partly internalised. Gas security externalities thus are probably smaller than oil externalities.

In most OECD countries, additional hydroelectric resources are limited. Therefore, nuclear power and non-hydro renewables are the main non-fossil generating options that could reduce society's cost of security externalities. Most renewable energies either have no fuel supply or domestic fuel supply. In this sense, they offer security benefits. If either nuclear power or renewables could compete on electricity cost alone, they might be chosen without specific consideration of security externalities. In this case, they would automatically appear in the national fuel mix to help displace fuels that pose a security problem. However, neither appear to be the most economic generation choice in many countries. Would the improvement in fuel supply diversity due to the use of nuclear, for example, outweigh its higher costs today in many electricity markets?

Using the example of the United States, it appears that the cost gap between new nuclear and new gas is quite large: nuclear is at least two-thirds more expensive than gas fired combined-cycle plants. Assuming that the security externality for gas is less than that quoted above for oil (since the US has indigenous supplies of gas), this means that even taking into account security costs, gas-fired plants would still be cheaper than nuclear, and that the externality would not be large enough to alter marginal investment decisions. If the externality were addressed at the source, e.g. at the point of importation, which would be the most efficient option, the security externality would not alter incremental investments. If the externality were not already addressed, no additional government intervention in the power market in favour of nuclear would be justified, unless other policy considerations provided additional justification.

In countries which are highly import-dependent, the total amount of external security costs are probably higher than elsewhere, simply because the country has no indigenous supply source and is more exposed to market power in the international market. The conclusion could be reversed for such countries.

The value of maintaining diversity

A related point of interest in the United States currently is the question of whether existing nuclear should be kept running on security grounds even if this is uneconomic. To assess this we must assess the cost of maintaining nuclear plants and then the security benefit this might bring. The security benefit should be greater than the "diversity" cost to justify maintaining their operation.

First, how much would it cost to maintain operation of nuclear plants whose costs of operation exceed the competitive market price? This relates back to the controversial issue of stranded investment. Estimates of stranded investment range from some US$ 50 bn to US$ 500 bn. Several studies yield a figure of US$ 120-135 as the most likely figure (e.g. Moody, 1995; Yokell, Doyle and Koppe, 1995) for total stranded cost. The share of nuclear stranded cost is estimated to lie in the range of US$ 63-74 bn (ibid; ED, 1996), although this figure crucially depends on when liberalisation takes place. The reason for this is that the later competition is phased in, the smaller the amount of unamortised investment will be. The figures quoted here assume quick, large-scale liberalisation, i.e. before the year 2000. In a recent study by the US Department of Energy (DOE, 1997), stranded costs, summed over the next 17 years, are estimated to lie in the range of US$ 72-169 bn, but could, under certain (not very realistic) assumptions, be as high as US$ 408 bn.[4]

Second, how much would nuclear be able to contribute to reducing oil security externalities? Not much, it appears, because nuclear can do little to replace oil-fired generation, even in the long term. This is because oil-fired generation is used primarily to provide peaking and intermediate load duty throughout the OECD. Such a service role is not technically possible for nuclear plants. Furthermore, oil-fired generation, as noted earlier, provides only a small proportion of total OECD power generation. In the United States, 3 per cent of the fuel oil price times total fuel oil used in power generation amounts to about less than US$ 0.5 bn, or well less than the estimated stranded nuclear costs noted above.

This reasoning leads to the conclusion that it would not be cost effective to maintain uneconomic American nuclear plants in operation merely for the sake of maintaining greater oil energy security.

The same conclusion can be reached for gas energy security. The oil security externalities discussed in this annex can be expected to lie towards the high end of the externalities that could be anticipated for the gas market, since a large part of the externalities stem from world trade and market power in the respective world market. At least for gas, no such world market exists. In the United States, most natural gas is domestically produced, reducing the threat of political disruption of gas supply. Furthermore, gas is used largely in non-baseload plants, as is oil. Therefore, since the gas security externality should be smaller than the oil security externality, nuclear would not provide cost-effective insurance against a gas supply disruption.

Conclusions: what role for governments?

The results of the discussion in this annex are the following. Estimating precise values for security externalities is as complex, and involves as much uncertainty as does calculating the cost of providing diversity that generating options such as nuclear might provide. It appears, though, that they are roughly in the same order of magnitude. This is confirmed by the portfolio approach. Although the latter has its weaknesses, diversity indices such as the Stirling index, point even more strongly to the diversity value of non-fossil generating options. Even if those other indices have shortcomings of their own, what can be retained is that non-fossil generating options yield their security benefits primarily because they are much less statistically linked to fossil fuels than the various fossil fuels are among each other.

Liberalised markets have so far shown a tendency to favour fossil fuels, and it might thus be concluded that there is a case for government intervention to ensure sufficient fuel diversity. But the above discussion indicates that, for many countries, the additional energy security obtained is likely to be worth less than the cost of obtaining diversity.

Furthermore, even if the security externality is of the same order of magnitude as the cost of diversity, the incorporation of environmental externalities could alter a decision to support a particular technology or fuel for reasons of energy security. If externalities are to be addressed by governments, all the relevant, identifiable externalities need to be internalised in a consistent,

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4. The high figure assumes zero cost reduction even under competitive pressure. In light of already existing empirical evidence, this is very unrealistic.

even-handed manner, and it would be inefficient to internalise security externalities but not take environmental costs into account. The environmental externalities attached to non-fossil sources of energy, particularly nuclear and renewables, could alter the net value of supporting them compared to the value from energy security alone.

The mechanisms that governments can use to increase diversity in a liberalised power market bear a lot of resemblance to the instruments they can use to promote renewable energy sources or to address environmental externalities: firstly, taxation of the option to be avoided, i.e. the pollutant or the imported fuel, and secondly, subsidies to the desired options, possibly in the form of a diversity premium paid by governments to non-fossil suppliers, and perhaps funded by a tax on the electricity wires. Before any such measure should be taken, governments need to carefully assess whether they are justified, because any such action necessarily increases generating costs and electricity prices to end users.

This means that governments have to check whether part of the perceived externality has already been internalised. This may have been done through strategic stockpiling or existing import tariffs and taxation.

Moreover, measures have to be adopted at the appropriate level. Security externalities are attached to primary energies, and should be internalised into the price of primary energies. Only if this is not possible or practicable should they resort to intervening into the market for final energy.

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Annex 10

LEVELISED COST METHODOLOGY

This annex describes the methodology adopted for calculating generation costs in the present report as well as in previous studies in this series. It explains the rationale of the approach, provides the equations used for calculating levelised costs and highlights the main parameters needed for the calculations. However, it does not discuss in detail the concept of discount rate or the discount rate values adopted.

The adoption of a standardised methodology for cost calculations is a prerequisite for a fair comparison among different electricity generation options. The levelised lifetime cost methodology calculates costs on the basis of net power supplied to the station busbar, where electricity is fed to the grid. It does not substitute for the full system cost analysis that establishes the overall economic impact of a power plant introduced into an existing generation system. The system cost analysis, which is relevant from the producer viewpoint to estimate the cost of an addition to the system, has not been adopted in the studies of this series because its results are essentially system specific and cannot be interpreted readily for international comparison purposes.

The levelised cost methodology discounts the time series of expenditures and incomes to their present values in a specified base year by applying a discount rate. The discount rate that is considered appropriate for the power sector may differ from country to country, and, in the same country, from utility to utility. Applying a discount rate takes into account the time value of money, i.e., a sum earned or spent in the past or in the future does not have the same value as the same sum (in real terms) earned or spent today. The discount rate may be related to rates of return that could be earned on typical investments; it may be a rate required by public regulators incorporating allowance for financial risks and/or derived from national macroeconomic analysis; or it may be related to other concepts of the trade off between costs and benefits for present and future generations. In the present study, levelised generation costs are presented at 5 and 10 per cent per annum discount rates. This range is representative of the values adopted in most national responses to the questionnaire upon which are based the costs presented in this report.

According to the objectives and scope of the study, all the components of the costs falling on the utility, i.e., that would influence its choice of generation options, are taken into account. In this connection, tax on income and profit charged to the utility and any other overheads that do not influence technology choices are excluded. External costs that are not borne by the utility, such as costs associated with health and environmental impacts of residual emissions, are not included either. On the other hand, station-specific overheads, insurance premiums and R&D expenditures borne by producers are included, as well as the costs associated with environmental protection measures and standards, e.g., implementation of abatement technologies and emission permits.

Cost elements used in the calculations are expressed in constant monetary terms as it is generally accepted that calculations performed in constant money are suited best for international comparisons.

The date selected as the base year for discounting purpose does not affect the levelised cost comparison between different plants. The absolute values of levelised costs will, however, differ from base year to base year in periods of inflation or deflation. In the present study, the base year for discounting is 2005 (the year of commissioning). In order to facilitate the presentation of results in the report, levelised costs for all countries are expressed in a common monetary unit, usually dollars of the United States, applying exchange rates published by the International Monetary Fund (IMF) for the year of the study. The costs presented in the present study are expressed in United States dollars of 1 July 1996.

Applied to generation costs, the levelised lifetime methodology provides costs per unit of electricity generated which are the ratios of total lifetime expenses versus total expected outputs, expressed in terms of present value equivalent. Those costs are equivalent to the average price that would have to be paid by consumers to repay exactly the investor/operator for the capital, operation and maintenance and fuel expenses, with a rate of return equal to the discount rate.

When this method is applied, the economic merits of different candidate power plants are derived from the comparison of their respective average lifetime levelised costs. Technical and economic assumptions underlying the results are transparent and the method allows for sensitivity analysis showing the impact of different parameter variations on the relative competitiveness of the alternative technologies considered.

The formula applied to calculate, for each power plant, the levelised electricity generation cost (EGC) is the following:

$$EGC = \sum_t [(I_t + M_t + F_t)(1+r)^{-t}] / \sum_t [E_t (1+r)^{-t}]$$

With:

	EGC	=	Average lifetime levelised electricity generation cost per kWh
	I_t	=	Capital expenditures in the year t
	M_t	=	Operation and maintenance expenditures in the year t
	F_t	=	Fuel expenditures in the year t
	E_t	=	Electricity generation in the year t
	r	=	Discount rate
	$\sum_t$		is the summation over the period including construction, operation during the economic lifetime and decommissioning of the plant as applicable.

The cost estimates presented in the study were calculated with the above formula, using input parameters provided by respondents and/or defined by the Expert Group within the common framework agreed upon for generic and sensitivity cases.

The coverage of capital, O&M and fuel costs is described in the main body of the report. Capital expenditures in each year, including construction, refurbishment and decommissioning expenses when applicable, are provided in a table of expense schedule covering the entire period during which expenses are expected to be incurred. O&M costs per unit of net installed capacity and per year are provided for the period covering the entire economic lifetime of the plant. Fuel costs, at the power plant boundary, are provided for the year of commissioning and an escalation rate in each year is given, when applicable, during the economic lifetime of the plant. As most expenditures occur in multiple instances during the course of the year, rather than one single event, annual coats have been assumed to occur at mid-year for discounting purposes.

With regard to outputs from the power plants, electricity generation in the year t was calculated taking into account the net capacity of the unit and the assumed settled down load factor. In the generic case (75 per cent settled down load factor, 40 year economic lifetime) it was assumed that the power plants would operate at full power during 5 000 hours during its first year of operation, 6 000 hours during the second year and 6 626 hours per year during the rest of the plant economic lifetime. As with annual expenditures, annual generation has been assumed to occur at mid-year for discounting purposes.

Load factors for sensitivity cases use the same assumed values for hours of operation in the first year, but adjust the annual operating hours for years two onward to give a lifetime averaged load factor equal to the desired value, i.e., 65, 75 or 80 per cent. The annual operating hours are the following:

Settled-down load factor (%)	65	75	80
1st year of operation	5 000 hrs/y	5 000 hrs/y	5 000 hrs/y
2nd year of operation	5 700 hrs/y	6 000 hrs/y	6 000 hrs/y
3rd and subsequent years of operation			
40 year economic lifetime	5 712 hrs/y	6 626 hrs/y	7 087 hrs/y
30 year economic lifetime	5 719 hrs/y	6 646 hrs/y	7 116 hrs/y
25 year economic lifetime	5 724 hrs/y	6 663 hrs/y	7 139 hrs/y

It should be stressed that there is no unique and universal methodology to estimate generation costs. The levelised lifetime generation cost method based on discounting all costs and revenues expressed in constant money terms, offers a sound basis for comparing the relative costs of alternative power plants performing similar functions, e.g., base-load electricity supply, and therefore constitutes an appropriate basis for undertaking international comparisons.

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