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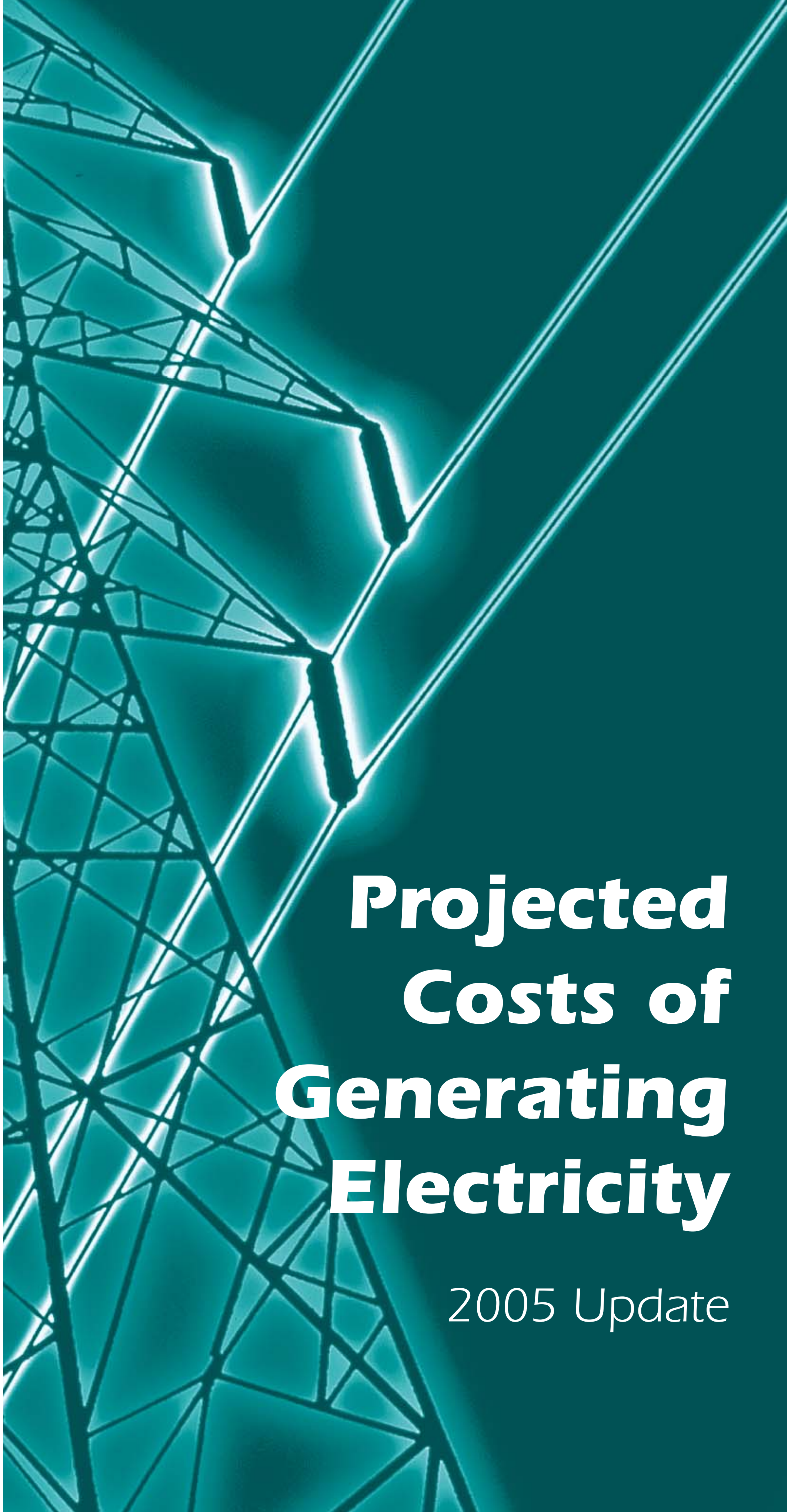

Projected Costs of Generating Electricity

2005 Update

OECD

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NUCLEAR ENERGY AGENCY
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ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

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Publié en français sous le titre :
Coûts prévisionnels de production de l'électricité : Mise à jour 2005

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 28 OECD member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, Norway, Portugal, the Republic of Korea, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The Commission of the European Communities also takes part in the work of the Agency.

The mission of the NEA is:

- to assist its member countries in maintaining and further developing, through international co-operation, the scientific, technological and legal bases required for a safe, environmentally friendly and economical use of nuclear energy for peaceful purposes, as well as
- to provide authoritative assessments and to forge common understandings on key issues, as input to government decisions on nuclear energy policy and to broader OECD policy analyses in areas such as energy and sustainable development.

Specific areas of competence of the NEA include safety and regulation of nuclear activities, radioactive waste management, radiological protection, nuclear science, economic and technical analyses of the nuclear fuel cycle, nuclear law and liability, and public information. The NEA Data Bank provides nuclear data and computer program services for participating countries.

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

INTERNATIONAL ENERGY AGENCY

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

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

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

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

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Foreword

This report is the sixth in a series of studies on projected costs of electricity generation. Previous reports in the series were issued by the Nuclear Energy Agency (NEA) in 1983 and 1986. Since 1989, studies jointly carried out by the International Energy Agency (IEA) and the NEA were published by the OECD in 1989, 1993 and 1998.

The present study was conducted by a group of experts from nineteen member countries and two international organisations, the International Atomic Energy Agency (IAEA) and the European Commission (EC). The latter provided input data from three non-OECD countries. The plants included in the study rely on technologies available today and considered by participating countries as candidates for commissioning by 2010-2015 or earlier.

The report presents and analyses projected costs of generating electricity calculated with input data provided by participating experts and generic assumptions adopted by the Group. The levelised lifetime cost methodology was applied by the joint IEA/NEA Secretariat to estimate generation costs for more than a hundred plants relying on various fuels and technologies, including coal-fired, gas-fired, nuclear, hydro, solar and wind power plants; cost estimates are provided also for combined heat and power plants using coal, gas and combustible renewables. The appendices to the report address a number of issues such as generation technology, methodology to incorporate risks in cost estimates, impacts of integrating wind power into electricity grids and effect of carbon emission trading on generation costs.

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

Acknowledgements

The Joint Secretariat – Peter Fraser and Ulrik Stridbaeck from the IEA, and Evelyne Bertel from the NEA – acknowledges the valuable contribution of the Expert Group which provided data and reviewed the successive drafts of the report. Marius Condu from the IAEA collected input data from non-member countries. The Group was co-chaired by Dr. Gert van Uitert from the Netherlands and Prof. Alfred Voss from Germany.

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Executive Summary

The overall objective of the study is to provide reliable information on key factors affecting the economics of electricity generation using a range of technologies. The report can serve as a resource for policy makers and industry professionals seeking to better understand generation costs of these technologies.

The study was carried out by an *ad hoc* group of officially appointed national experts. Cost data provided by the experts were compiled and used by the joint IEA/NEA Secretariat to calculate generation costs.

Cost data were provided for more than 130 power plants. This comprises 27 coal-fired power plants, 23 gas-fired power plants, 13 nuclear power plants, 19 wind power plants, 6 solar power plants, 24 combined heat and power (CHP) plants using various fuels and 10 plants based on other fuels or technologies. The data provided for the study highlight the increasing interest of participating countries in renewable energy sources for electricity generation, in particular wind power, and in combined heat and power plants.

The technologies and plant types covered by the present study include units under construction or planned that could be commissioned in the respondent countries between 2010 and 2015, and for which they have developed cost estimates generally through paper studies or bids.

The calculations are based on the reference methodology adopted in previous studies, i.e., the levelised lifetime cost approach. The calculations use generic assumptions for the main technical and economic parameters as agreed upon in the *ad hoc* group of experts, e.g., economic lifetime (40 years), average load factor for base-load plants (85%) and discount rates (5% and 10%).

Electricity generation costs calculated are busbar costs, at the station, and do not include transmission and distribution costs. The costs associated with residual emissions – including greenhouse gases – are not included in the costs provided and, therefore, are not reflected in the generation costs calculated in the study.

The cost estimates do not substitute for detailed economic evaluations required by investors and utilities at the stage of project decision and implementation that should be based on project specific assumptions, using a framework adapted to the local conditions and a methodology adapted to the particular context of the investors and other stakeholders.

Moreover, the reform of electricity markets has changed the decision making in the power sector and led investors to take into account the financial risks associated with alternative options as well as their economic performance. In view of the risks they are facing in competitive markets, investors tend to favour less capital intensive and more flexible technologies. The used methodology for calculating generation costs in this study does not take business risks in competitive markets adequately into account.

The introduction of liberalisation in energy markets is removing the regulatory risk shield where integrated monopolies can transfer costs and risks from investors to consumers and taxpayers. Investors now have additional risks to consider and manage. For example, generators are no longer guaranteed the ability to recover all costs from power consumers. Nor is the future power price level known. Investors now have to internalise these risks into their investment decision making. This adds to the required rates of return and shortens the time frame that investors require to recover the capital. Private investors' required real rates of return may be higher than the 5% and 10% discount rates used in this study and the time required to recover the invested capital may be shorter than the 30 to 40 years generally used in this study.

Main results

Coal-fired generating technologies

Most coal-fired power plants have specific overnight construction costs ranging between 1000 and 1 500 USD/kWe. Construction times are around four years for most plants. The fuel prices (coal, brown coal or lignite) assumed by respondents during the economic lifetime of the plants vary widely from country to country. Expressed in the same currency using official exchange rates, the coal prices in 2010 vary by a factor of twenty. Roughly half of the responses indicate price escalation during the economic lifetime of the plant while the other half indicates price stability.

At 5% discount rate, levelised generation costs range between 25 and 50 USD/MWh for most coal-fired power plants. Generally, investment costs represent slightly more than a third of the total, while O&M costs account for some 20% and fuel for some 45%.

At 10% discount rate, the levelised generation costs of nearly all coal-fired power plants range between 35 and 60 USD/MWh. Investment costs represent around 50% in most cases. O&M cost account for some 15% or the total and fuel costs for some 35%.

Gas-fired generating technologies

For the gas-fired power plants the specific overnight construction costs in most cases range between 400 and 800 USD/kWe. In all countries, the construction costs of gas-fired plants are lower than those of coal-fired and nuclear power plants. Gas-fired power plants are built rapidly and in most cases expenditures are spread over two to three years. The O&M costs of gas-fired power plants are significantly lower than those of coal-fired or nuclear power plants. Most gas prices assumed in 2010 are ranging between 3.5 and 4.5 USD/GJ. A majority of respondents are expecting gas price escalation.

At a 5% discount rate, the levelised costs of generating electricity from gas-fired power plants vary between 37 and 60 USD/MWh but in most cases it is lower than 55 USD/MWh. The investment cost represents less than 15% of total levelised costs; while O&M cost accounts for less than 10% in most cases. Fuel cost represents on average nearly 80% of the total levelised cost and up to nearly 90% in some cases. Consequently, the assumptions made by respondents on gas prices at the date of commissioning and their escalation rates are driving factors in the estimated levelised costs of gas generated electricity. The current gas prices are on a relatively high level. The gas price projections in 2010 of some of the respondents in the study are higher than the current level and a few are lower than the current level. The IEA gas price assumptions given in *World Energy Outlook 2004* (IEA, 2004) are markedly different.

At a 10% discount rate, levelised costs of gas-fired plants range between 40 and 63 USD/MWh. They are barely higher than at the 5% discount rate owing to their low overnight investment costs and very short construction periods. Fuel cost remains the major contributor representing 73% of total levelised generation cost, while investment and O&M shares are around 20% and 7% respectively.

Nuclear generating technologies

For the nuclear power plants the specific overnight investment costs, not including refurbishment or decommissioning, vary between 1 000 and 2 000 USD/kWe for most plants. The total levelised investment costs calculated in the study include refurbishment and decommissioning costs and interest during construction. The total expense period ranges from five years in three countries to ten years in one country. In nearly all countries 90% or more of the expenses are incurred within five years or less.

At a 5% discount rate, the levelised costs of nuclear electricity generation ranges between 21 and 31 USD/MWh except in two cases. Investment costs represent the largest share of total levelised costs, around 50% on average, while O&M costs represent around 30% and fuel cycle costs around 20%.

At a 10% discount rate, the levelised costs of nuclear electricity generation are in the range between 30 and 50 USD/MWh except in two cases. The share of investment in total levelised generation cost is around 70% while the other cost elements, O&M and fuel cycle, represent in average 20% and 10% respectively.

Wind generating technologies

For wind power plants the specific overnight construction costs range between 1 000 and 2 000 USD/kWe except for one offshore plant. The expense schedules reported indicate a construction period of between one to two years in most cases.

The costs calculated and presented in this report for wind power plants are based on the levelised lifetime methodology used throughout the study for consistency sake. This approach does not reflect specific costs associated with wind or other intermittent renewable energy source for power generation and in particular it ignores the need for backup power to compensate for the low average availability factor as compared to base-load plants.

For intermittent renewable sources such as wind, the availability/capacity of the plant is a driving factor for levelised cost of generating electricity. The reported availability/capacity factors of wind power plants range between 17 and 38% for onshore plants, and between 40 and 45% for offshore plants except in one case.

At a 5% discount rate, levelised costs for wind power plants considered in the study range between 35 and 95 USD/MWh, but for a large number of plants the costs are below 60 USD/MWh. The share of O&M in total costs ranges between 13% and nearly 40% in one case.

At a 10% discount rate, the levelised costs of wind generated electricity range between 45 and more than 140 USD/MWh.

Micro-hydro generating technologies

The hydro power plants considered in the study are small or very small units. At a 5% discount rate, hydroelectricity generation costs range between some 40 and 80 USD/MWh for all plants except one. At a 10% discount rate, hydroelectricity generation costs range between some 65 and 100 USD/MWh for most plants. The predominant share of investment in total levelised generation costs explains the large difference between costs at 5 and 10% discount rate.

Solar generating technologies

For solar plants the availability/capacity factors reported vary from 9% to 24%. At the higher capacity/availability factor the levelised costs of solar-generated electricity are reaching around

150 USD/MWh at a 5% discount rate and more than 200 USD/MWh at a 10% discount rate. With the lower availability/capacity factors the levelised costs of solar-generated electricity are approaching or well above 300 USD/MWh.

Combined heat and power generating technologies

For combined heat and power the total levelised costs of generating electricity are highly dependent on the use and value of the co-product, the heat, and are thereby very site specific. The expert group agreed on a pragmatic approach of calculating the levelised costs of generating electricity for this study. At a 5% discount rate, the levelised costs range between 25 and 65 USD/MWh for most CHP plants. At a 10% discount rate, the costs range between 30 and 70 USD/MWh for most plants.

Other generating technologies

Levelised costs were also computed for the remaining technologies. Considering the low number of responses for these technologies the results cannot be used outside the context of each specific case.

Conclusions

The lowest levelised costs of generating electricity from the traditional main generation technologies are within the range of 25-45 USD/MWh in most countries. The levelised costs and the ranking of technologies in each country are sensitive to the discount rate and the projected prices of natural gas and coal.

The nature of risks affecting investment decisions has changed significantly with the liberalisation of electricity markets, and this has implications for determining the required rate of return on generating investments. Financial risks are perceived and assessed differently. The markets for natural gas are undergoing substantial changes on many levels. Also the coal markets are under influence from new factors. Environmental policy is also playing a more and more important role that is likely to significantly influence fossil fuel prices in the future. Security of energy supply remains a concern for most OECD countries and may be reflected in government policies affecting generating investment in the future.

This study provides insights on the relative costs of generating technologies in the participating countries and reflects the limitations of the methodology and generic assumptions employed. The limitations inherent in this approach are stressed in the report. In particular, the cost estimates presented are not meant to represent the precise costs that would be calculated by potential investors for any specific project. This is the main reason explaining the difference between the study's findings and the current global preference in reformed electricity markets for gas-fired technologies.

Within this framework and limitations, the study suggests that none of the traditional electricity generating technologies can be expected to be the cheapest in all situations. The preferred generating technology will depend on the specific circumstances of each project. The study indeed supports that on a global scale there is room and opportunity for all efficient generating technologies.

Introduction

Background

This study is the sixth in a series on projected costs of generating electricity carried out and published by the OECD. It has been undertaken jointly by the Nuclear Energy Agency (NEA) for the Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle (NDC) and by the International Energy Agency (IEA) for the Standing Group on Long-Term Co-operation (SLT). In order to conduct the study, the two agencies convened an *ad hoc* group of experts which met three times between December 2003 and November 2004.

National experts nominated to participate in the study were drawn from ministries or other governmental bodies, universities, research institutes, utilities and one nuclear power plant manufacturer. Nineteen OECD countries – Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Italy, Japan, the Republic of Korea, the Netherlands, Portugal, the Slovak Republic, Switzerland, Turkey, the United Kingdom and the United States – and two international organisations – the International Atomic Energy Agency (IAEA) and the European Commission (EC) – were represented in the *ad hoc* Expert Group in charge of the study. The IAEA provided generation cost information obtained from three of its Member States not members of OECD – Bulgaria, Romania and the Republic of South Africa. The list of members of the *ad hoc* Expert Group is given in Appendix 1.

Objectives and scope

The overall objective of the studies in the series is to provide reliable information on the economics of electricity generation. The study is to serve as a resource for policy makers and industry professionals as an input for understanding generating costs and technologies better. For this purpose, cost data provided by national experts participating in the studies are compiled and used by the joint IEA/NEA Secretariat to estimate generation costs using a commonly agreed methodology and generic assumptions selected by the group for the main technical and economic parameters (e.g. economic lifetime, average load factor for base-load plants and discount rates).

The present study uses the reference methodology adopted in previous studies, i.e. levelised lifetime cost approach. However, the group recognised the increasing importance of investment risks in the context of liberalised electricity markets and their potential impacts on technology choices which may not be captured fully with the levelised lifetime cost methodology. Methodological issues associated with incorporating financial risks in generating cost estimates are addressed in Appendix 6.

Like each study in the series, the present one aimed at covering state-of-the-art technologies for electricity generation commercially available at the time of publication. Accordingly, emphasis was placed in the present update on including a broad range of generation sources and technologies covering the span of alternatives considered in participating countries for power plants under construction in 2003-2004 and/or planned to be connected to the grids within a decade or so.

The technologies and plant types covered by the present study include units under construction or planned that could be commissioned in the respondent countries between 2010 and 2015, and for which they have developed cost estimates generally through paper studies or bids. However, some participating experts included plants recently connected to the grid that they considered representative of state-of-the-art technologies in their respective countries. Also, for some newer technologies with relatively steep learning curves, state-of-the-art technology today may have improved by 2010-2015.

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. The answers received are indicative of the type of power plants that are commissioned or planned to be built in the respondent countries in the short and medium term, although cost estimates for a generation technology may exist irrespective of decisions or committed plans to build a new power plant relying on that technology.

As compared with previous studies, significant evolutions may be noted on the technologies and plant types for which data were provided (see Chapter 2 for details on responses to the questionnaire). For the first time, at the request of participating experts, the scope of the study was extended to include hydro power plants. A larger number of countries provided cost information on combined heat and power (CHP) plants, using coal, gas and various renewable fuels, than in previous studies. Similarly, more cost information was given on a larger number of wind power plants, showing an increasing interest in this renewable source for electricity generation. On the other hand, only one country provided cost data for distributed generation plants, although they seem to attract investors' interest in several countries.

The generation cost estimates presented in the report result from calculations carried out with a methodology agreed upon by the group and an internally consistent framework including generic assumptions that the participating experts considered representative of reference conditions. This approach provides a robust, transparent and coherent set of cost estimates for the power plants considered. Such estimates may be used to assess alternative options at the stage of screening studies. They do not substitute for detailed economic evaluations required by investors and utilities at the stage of project decision and implementation that should be based on project specific assumptions, using a framework adapted to the local conditions and a methodology adapted to the particular context of the investors and other stakeholders.

Evolution of decision making in the electricity sector[1]

Electricity markets are opening to competition in many countries. The introduction of competition in the generation and supply of electricity is expected to improve the economic efficiency of the power sector, to reduce overcapacity of generation and eventually to reduce electricity prices for consumers. Two issues raised by electricity market liberalisation are of special relevance in the context of the present study: impact of deregulation on technology choices; and adaptation of investors to risks associated with market competition. In the absence of market risk, investors in the power sector could increase prices to recover additional costs and, moreover, could predict demand with a reasonable level of certainty owing to regional or national monopoly situations. The reform of electricity markets has changed the decision making in the power sector and led investors to take into account the financial risks associated with alternative options as well as their economic performance. In this context, the total capital investment cost may become a more compelling criterion than the average lifetime generation cost. In the view of the risks they are facing in competitive markets, investors tend to favour less capital intensive and more flexible technologies.

1. This section of the report is drawn from the report published by IEA on *Power Generation Investment in Electricity Markets* (IEA, 2003a).

Uncertainties in future demand and price levels tend to lead investors towards flexible technologies with short return on investment period; short construction times and ability to switch fuels undoubtedly are attractive characteristics in liberalised markets. While the long-term nature of electricity infrastructure remains a fundamental aspect in decision making, investors are adopting new economic assessment approaches to quantify risks and opportunities associated with electricity price volatility.

In the light of the long lead times inherent to the electricity sector, the conventional discounted cash flow method has been used broadly in investment decisions for base-load generating capacity. However, investors are beginning to use discount rates varying from technology to technology reflecting their perception of financial risks associated with each alternative. The approach adopted in this report reflects this trend: the levelised lifetime generation cost method is used in the body of the report while Appendix 6 provides insights on the new approaches being developed to incorporate financial risks in economic assessments in the context of liberalised markets.

Past studies in the series

Six studies on costs of generating electricity have been published by the OECD in the series including the present edition. Eight countries – Canada, France, Italy, Japan, the Netherlands, Portugal, the United Kingdom and the United States – participated in all the studies. However, Portugal did not contribute data in the first study and the United Kingdom did not contribute data for the last two studies. Three international organisations – the European Commission, the International Atomic Energy Agency and the International Energy Agency – participated in all the studies and since the third edition the studies have been conducted jointly by the NEA and the IEA.

The first study in the series, initiated in 1982 and published in 1983 (NEA, 1983), focused on establishing a reference methodology and framework and, as far as technologies were concerned, considered only nuclear and coal-fired power plants. A 5% discount rate was used to calculate levelised costs and the reference monetary unit adopted was the European currency unit (ECU). Twelve countries participated in the study which concluded that, within the framework adopted, nuclear generated electricity was cheaper than coal generated electricity in all participating countries, except some parts of the United States.

The second study published in 1986 (NEA, 1986) also focused on methodological approach and considered only nuclear and coal-fired power plants. Seventeen countries participated. The reference monetary unit became the US dollar (USD) and a variant at 10% discount rate was included together with the reference 5% discount rate. Like the first report, the 1986 study stressed that international cost comparisons are affected by many factors such as exchange rate and local or regional economic differences. It concluded that nuclear is the cheapest option except in some parts of the United States.

The third study published in 1989 (IEA and NEA, 1989) was conducted jointly by the IEA and the NEA for the first time. Eighteen OECD countries participated and seventeen provided data. Cost data from five non-OECD countries were provided by the IAEA and included in the report. While the study focused again on nuclear and coal power plants, generation costs for gas- and oil-fired units as well as some renewable sources were discussed in an appendix. The report concluded that while nuclear generated electricity had a significant cost advantage in many countries, the decrease of expected future coal prices led to an economic advantage of coal over nuclear in several countries.

The 1992 update published in 1993 (IEA and NEA, 1993) included gas-fired and some renewable sources in the analysis and provided an analysis of projected cost trends based upon previous reports in the series. Twenty-two countries including six non-OECD countries participated in the study. The report concluded that there was no clear-cut winner between nuclear, coal and gas in all countries. Renewable sources analysed in the study were found to be uneconomic except for marginal supplies in remote locations and/or very favourable conditions. The generic economic assumptions remained unchanged including 5% and 10% discount rates as references.

The fifth study published in 1998 (IEA and NEA, 1998) analysed cost data for some seventy power plants including mainly nuclear, coal and gas units, and a few renewable sources. Fourteen OECD countries participated in the study and data for five non-OECD countries were provided through the IAEA. The report included sensitivity analyses on the effect on generation cost comparisons of variations in plant economic lifetimes and load factors and fossil fuel price escalation. The appendices to the report covered key issues such as environmental protection costs, impacts of electricity market liberalisation on costs and value of energy diversity and security. Several of these appendices remain relevant today and are referred to in the various chapters of the present report. Cost comparisons presented in the study showed an increasing competitiveness of gas-fired power plants but highlighted that no single technology was the clear winner in all countries.

Other relevant international and national studies

This section has been contributed by members of the Expert Group and covers relevant studies that they summarised for the purpose of the present report. A number of other studies covering various aspects of electricity generation economics have been published recently but an exhaustive list of this literature is beyond the scope of the present report.

International Atomic Energy Agency

In recent years, the IAEA has published a number of documents and developed databases on various economic aspects of nuclear power. The main outcomes of this work are briefly described below.

A technical report on market potential for non-electric applications of nuclear energy (IAEA, 2002a) assesses the market potential and economics of the use of nuclear energy in various non-electric applications, including district heating, the supply of process heat, water desalination, ship propulsion and outer space applications. It also gives an overview of promising innovative applications, such as fuel synthesis and oil extraction.

A technical document on cost drivers for the economic assessment of nuclear power plant life extension (IAEA, 2002b) contributes to a better understanding of the various cost elements and drivers in nuclear power plant (NPP) life extension, and providing some reference ranges for the main plant life extension costs through cost data collected from Member States.

The Nuclear Economic Performance Information System (NEPIS), a database on nuclear power plant (NPP) costs, has been established through the successful completion of the pilot project for the first module of this database, which deals with the operation and maintenance costs (IAEA, 2002c). The database is developed in co-operation with the US based Electric Utility Cost Group (EUCG). The results of the pilot project and also further directions for the development of the database are given in the report on *Developing an Economic Performance System to Enhance Nuclear Power Plant Competitiveness*. In the same framework a technical document is in printing on nuclear power plant economic performance indicators. The primary purpose of the document is to identify and define a number of economic performance measures for use at nuclear power plants operating in a deregulated market.

The present IAEA programme includes the development of a computer model for the economic assessment on NPP lifetime extension and of a new module of NEPIS dedicated to the capital costs of NPPs (mainly capital additions including plant lifetime extension).

International Energy Agency

The IEA has published studies that relate to many aspects of costs and value for different generation technologies. The most recent study concerning power generation investments in electricity markets was published in 2003 (IEA, 2003a). A study on distributed generation in liberalised electricity markets was published in 2002 (IEA, 2002) and a study on the status and prospects of renewable energy sources for power generation was published in 2003 (IEA, 2003b). The World Energy Outlook series presents IEA projections for the next 20-30 years, including the projected development in electricity generation capacity by technology (IEA, 2004).

OECD Nuclear Energy Agency

The NEA has published several studies related to the economics of nuclear power in recent years. A report issued in 2000 (NEA, 2000), analysed the potential for reducing nuclear power plant capital costs, which represent some 60% of the total nuclear electricity generation costs. A study on *Trends in the Nuclear Fuel Cycle* which was published in 2002 (NEA, 2002) includes several sections on economic aspects. In 2003, a booklet was issued addressing external costs of nuclear electricity and discussing issues associated with internalisation of externalities (NEA, 2003a). Finally, a study on policies, strategies and costs of decommissioning nuclear power plants published in 2003 (NEA, 2003b) presents data on decommissioning costs provided by 26 participating countries and analyses the main policy and strategy factors driving those costs.

France

The French ministry in charge of energy completed recently a study on reference generation costs in France. The study includes two parts, one dealing with base-load, grid-connected power plants published at the end of 2003 and one on renewable energy sources for electricity generation issued at the end of 2004. The study was carried out using the levelised lifetime cost methodology at 8% discount rate for the reference case with sensitivity analyses on discount rate (3, 5 and 11%) and several load factors (number of hours of operation at full power).

The main conclusion of the study for base-load power plants in the reference case is that nuclear power is the cheapest option for 5 000 hours of operation per year (57% load factor) or more while gas is the cheapest option for less than 5 000 hours of operation per year.

For renewable energy sources, wind power, small hydro power plants in good site conditions, and combined heat and power are mature technologies likely to become competitive with gas-fired gas turbines by 2015. Solar photovoltaic, although its cost is expected to decrease rapidly, is not likely to be competitive in the medium term, up to 2015. In the longer term, beyond 2015, promising options include fuel cells, binary geothermal plants on overseas sites and landfill gas could become competitive with gas turbines, while hot dry rock geothermal plants are not likely to reach competitiveness.

Slovak Republic

A study on development scenarios for the power industry in the Slovak Republic prepared by the state-owned Slovak utility *Slovenske Elektrarne, a.s.* (SE, a.s.) for the Ministry of Economy of the Slovak Republic was released in May 2004. The study focused on the economics of completing the two nuclear units VVER-440 which are half constructed as compared with alternatives, i.e., constructing new coal- or gas-fired power plants. The analysis, taking into account direct costs, security of supply and environmental aspects, concluded that completing the nuclear units was the most attractive option. The conclusions of the study were used to prepare the new national energy policy and the privatisation of *Slovenske Elektrarne, a.s.*

United States

In the United States, five studies published over the last few years, addressed the issue of the economics of building new nuclear power plants. Two of these studies (DOE, 2001 and 2002) either funded or undertaken by the Office of Nuclear Energy of the US Department of Energy (DOE) concluded that electricity generated by new built nuclear power plants is competitive. The third study (University of Chicago, 2004) found that nuclear generated electricity could become competitive if capital costs of new nuclear power plants would be reduced significantly as compared with present generation and if dramatic learning effects would occur. The studies carried out by the Massachusetts Institute of Technology (MIT, 2003) and by the Energy Information Administration (EIA, 2004) assume that building and operating nuclear power plants would involve financial risks and conclude that nuclear generated electricity would not be competitive.

Overview of the report

The body of the report presents projected costs of generating electricity calculated with commonly agreed generic reference assumptions. The appendices address specific issues of relevance for analysing the economics of alternative electricity generation sources. Chapter 2 explains the data collection process, summarises the information provided by participating experts and used to calculate generation cost estimates, outlines the methodology adopted and describes the generic assumptions adopted in the calculations.

Chapters 3 to 6 present results, i.e. levelised costs of generating electricity obtained in the study. The levelised cost methodology used to obtain those results is described in Appendix 5. Chapter 3 presents levelised generation cost estimates obtained for coal-fired, gas-fired and nuclear power plants. Chapter 4 covers costs of wind, hydro and solar power plants. Chapter 5 deals with combined heat and power (CHP) plants and includes some development on approaches to estimate electricity generation costs from CHP plants taking into account the benefits from heat generation and sales. A more theoretical approach to heat and power cost allocation is provided in Appendix 7. Chapter 6 covers generation cost estimates for the other power plants considered in the study, including distributed generation, waste incineration, combustible renewable, geothermal and oil plants. Chapter 7 provides some findings and conclusions drawn by the expert group from the cost estimates and their analysis.

Appendix 1 gives the list of experts who contributed directly in the study. Appendix 2 provides detailed lists of cost elements included in or excluded from the cost data reported in responses to the questionnaire and used to calculate generation cost estimates presented in the report. Appendix 3 is a compilation of country statements included in the responses to the questionnaire to expand on the overall context and specific characteristics of the electricity system in each country that may affect the economics of alternative technologies.

Appendix 4 gives some information on generation technologies considered in the report. Appendix 5 describes the levelised cost methodology (net present value approach) used in the body of the report. Appendix 6 elaborates on methodologies for incorporating risks into generation cost estimates. Appendix 7 deals with methodological issues for assessing the costs of electricity and heat delivered by cogeneration power plants.

Appendix 8 covers fossil fuel price escalation assumptions adopted by IEA in the 2004 *World Energy Outlook* and projected costs of uranium and fuel cycle services drawn from previous NEA publications. A more in-depth analysis of fossil fuel price trends may be found in an annex of the 1998 report in the series. Appendix 9 summarises the findings and conclusions from a workshop organised jointly by the IEA and the NEA on economic issues raised by the integration of wind power in electricity grids. Appendix 10 analyses the expected impacts of carbon emission trading on generation costs. Appendix 11 provides a list of the abbreviations and acronyms used in the report.

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Input Data and Cost Calculation Framework

Like the previous studies in the series, the present report is based upon technical information and cost data provided by experts from participating countries. Costs and technical data were collected through a questionnaire sent to members of the expert group and experts from countries which were not represented in the group but were willing to contribute information for the study.

Overview of the questionnaire

The questionnaire for the present study was developed by the Secretariat under the guidance of the expert group, drawing from the structure established in earlier studies. The main changes in the questionnaire as compared to its previous version resulted from the decision of the group to broaden the scope of the study, covering for the first time hydro power and distributed generation power plants. Also, some modifications were introduced to clarify tax issues and to collect the information needed for estimating the costs of electricity generation by combined heat and power (CHP) plants. In the light of the progressive implementation of policy measures and economic incentives to reduce greenhouse gas emissions in many countries, some questions on CO_2 emissions and national regulations related to global climate change were included. However, owing to the uncertainties remaining on the future value of carbon emissions, no attempt was made in the study to account for carbon emissions in the cost of electricity generated. Some aspects of the impacts of carbon emission trading on generation costs are addressed in Appendix 10, drawn from previous IEA studies.

The questionnaire included: an introduction providing background information on the study and guidance to respondents; sections devoted to each energy source and technology considered in the study, e.g. nuclear power plants, fossil-fuelled power plants, wind power plants; a section on results from cost calculations carried out with national assumptions; and a section calling for a country statement on the national electricity sector context.

For each power plant considered, the questions covered qualitative and quantitative information on technical characteristics and performance, site specific data, applicable emission standards and regulations, residual emissions, pollution control technologies included in the cost estimates reported, investment/capital costs, operation and maintenance costs, fuel costs, and details on the source and date of the cost estimates reported.

The cost data requested included all the information needed by the Secretariat to calculate levelised generation cost over the plant economic lifetime. For investment cost, for example, it includes total overnight construction cost and expense schedule, refurbishment costs, if applicable, and the schedule of refurbishment expenses, and decommissioning costs and schedule. Also, the expected escalation rates of fuel prices and operation and maintenance (O&M) costs during the economic lifetime of the plant are asked for in the questionnaire.

The costs reported are intended to be relevant with regard to choices that would be made by electricity producers among various alternatives. They include all technology and plant specific cost components borne by producers including investment, O&M and fuel costs. The costs of pollution control equipment, waste management and any required health and environmental protection measures should be included in the data reported. On the other hand, cost elements that do not affect the relative competitiveness of alternative options, such as overheads, and external costs not borne by producers should not be included in the reported costs. Appendix 2 provides a detailed compilation of cost items included or excluded in each response; significant deviations from the common framework are indicated in each table and noted in the presentation and discussion of cost results.

Coverage of responses

Eighteen OECD countries and three non-OECD countries responded to the questionnaire, providing cost data on more than 130 power plants. Table 2.1 provides an overview on the types of power plants included in national responses; a detailed list of the plants included in the responses is given in Table 2.3. In addition, Norway and the United Kingdom contributed some information on projected costs of generating electricity in their respective countries.

Table 2.1 – Overview of responses by country and plant type

Country	Coal	Gas	Nuclear	Wind	Hydro	Solar	CHP	Others
Canada	✔	✔	✔					
United States	✔	✔	✔	✔		✔	✔	✔
Austria				✔	✔		✔	
Belgium		✔		✔				
Czech Republic	✔	✔	✔	✔	✔	✔	✔	✔
Denmark	✔			✔		✔	✔	
Finland	✔		✔				✔	
France	✔	✔	✔					
Germany	✔	✔	✔	✔	✔	✔	✔	
Greece		✔		✔	✔			✔
Italy		✔		✔				
Netherlands		✔	✔	✔			✔	✔
Portugal		✔		✔				
Slovak Republic	✔	✔	✔		✔		✔	
Switzerland		✔	✔				✔	
Turkey	✔	✔						
Japan	✔	✔	✔		✔			
Korea, Rep. of	✔	✔	✔					
Bulgaria	✔				✔		[a]	
Romania	✔		✔					
South Africa, Rep. of	✔	✔			✔			
Number of plants	27	23	13	19	10	6	23	10

a. Bulgaria provided information on a CHP plant but the data provided were not sufficient for the Secretariat to perform cost estimates.

Eleven member countries and three non-member countries provided cost information on a total of 27 coal-fired power plants, mostly conventional boilers burning hard coal but also a few lignite-fired plants and some advanced coal gasification plants (integrated gasification combined cycle – IGCC). Details on the coal-fired power plants included in the study are provided in Table 2.4. The size of the coal units considered varies from 100 to 1 000 MWe. All coal-fired plants considered within the study are equipped with emission control devices for nitrous and sulphur oxides, dust and particulate matters; one of the plants considered in Germany includes a carbon dioxide capture device. The investment costs reported for those plants include the costs of pollution control equipment.

Fifteen member countries and one non-member country included one or more gas-fired power plants in their responses. All but one of the 23 gas-fired plants for which cost information was provided, are combined cycle gas turbine (CCGT) plants. The unit capacities of the gas-fired power plants considered vary between 100 and 1 600 MWe (see Table 2.5 for details on the gas-fired power plants considered in the study). Three of the plants included in the study use liquefied natural gas (LNG) as fuel.

Eleven member countries and one non-member country provided cost information on one or more nuclear power plants (NPPs). The NPPs considered (see Table 2.6 for details) are all water reactors with unit capacities ranging from 450 to 1 600 MWe. Most countries provided cost data for once-through fuel cycle; France, Japan and the Netherlands provided data for the closed cycle option.

Wind power plant data were included in the responses of ten member countries. The 19 wind plants considered are mostly onshore but data were provided for a few offshore units by three countries. Most wind power plants included in the study are multiple unit sites with the number of units varying from 10 or less to 100. The average capacity factors reported for wind power plants vary from 17% to 43%, the higher values referring to offshore sites. Table 2.7 provides details on the wind plants included in the study.

Hydro power plant data were provided by six member countries and two non-member countries. The ten plants for which data were reported include mainly small hydro power plants, three larger plants (capacity >10 MWe) and one pumped storage facility. Detailed information on those plants is provided in Table 2.8.

Data on six solar power plants were provided by four member countries. The plants considered include one thermal parabolic plant and five solar PV plants (see Table 2.7). The capacities of the plants included in the study are small, below 5 MWe except for the thermal plant in the United States. The average capacity factors of the plants considered are around 10% except in the United States where capacity factors of 24% for solar PV and 15% for solar thermal parabolic are reported.

Nine member countries provided data on twenty-three CHP plants fuelled with coal, gas and various combustible renewable (see Table 2.9 for details). The questionnaire asked for reporting data on CHP plants under a specific category, irrespective of the fuel and technology used, because the generation cost estimation method differs for this type of plants (see Chapter 5). Most of the plants included in the study produce heat for district heating of either residential or commercial buildings; some are used for industrial heat supply. The electrical capacity of the units varies from very small (less than 1 MWe) to medium (up to 500 MWe).

Other types of power plants (see Table 2.10 for details) for which cost data were provided include: gas-fired fuel cells (three plants); combustible renewable (two plants); waste incineration (two plants); oil (one plant); geothermal (one plant); and landfill gas (one plant). Only the fuel cell plants were classified in the distributed generation category.

Methodology and common assumptions

The constant-money levelised lifetime cost method was adopted to calculate the generation cost estimates presented in this report. This methodology, which has been used in all the reports in the series, is described in Appendix 5. While this approach is considered a relevant tool for comparing alternative options for electricity generation and assessing their relative competitiveness in a coherent and transparent framework, it does not reflect the investors' perception of financial risks in liberalised markets. Methodologies to address the impact of financial risks on technology choices are discussed in Appendix 6.

The levelised cost approach does not substitute for the economic analysis of electricity systems that needs to be carried out at the national level. However, it provides robust cost estimates for different generation sources and technologies that can serve as a reference for more detailed case-specific studies. In a nutshell, the costs calculated are intended to include all the direct cost elements borne by electricity generators which, thereby, have an impact on their technology and energy source choices.

The nature of the data collected and the choice to carry out cost calculations with generic assumptions for key parameters imply that the results presented in the report are not comparable with the outcomes of economic studies performed by investors or plant owners to support their decision-making process on a specific project. Nevertheless, the projected costs provided by the present study, together with the assumptions adopted in cost calculations, are of interest to investors for benchmarking purpose as well as to investigate the impact of various factors on generation costs.

The method adopted to collect data on cost elements aims at ensuring consistency in the way costs are reported. However, owing to national differences in accounting practices and context, it is impossible to harmonise fully the structure and coverage of cost elements. Appendix 2 contains a compilation of the elements included in the costs reported by each respondent for each generation technology and source.

The questionnaire called for reporting costs in constant money terms and expressed in national currency unit (NCU) of 1 July 2003. The Secretariat converted those costs in US dollars (USD) and euros (€) of the same date using the exchange rates at that date published by the OECD and the International Monetary Fund (see Table 2.2).

The choice of a common currency unit is convenient for presentation purposes but the bias introduced by converting currencies through exchange rates should not be overlooked. Exchange rates do not reflect purchasing power parities accurately, if at all, and their use affects cost comparisons between countries, introducing apparent differences that are not real. This point is illustrated by the fluctuating exchange rate between the USD and the euro, from 1 as of 1 January 2003 to 1.144 as of 1 July 2003, the reference date chosen for the present study.

Cost estimates are discounted to the date of commissioning of the plant, generally assumed to be 1 January 2010. This choice is not essential since the calculated levelised generation cost per unit of electricity output is independent of the selected date for discounting.

Like in previous studies, the reference discount rates adopted in the present report are 5% and 10% per annum real. Those values continue to be representative of the discount rates used in national calculations, although several countries use discount rates outside this range as indicated in Appendix 3.

The same 85% capacity factor was adopted to calculate generation costs for nuclear, coal-fired and gas-fired power plants. For other plants, the capacity factor indicated by respondents was used in the generic calculations. This is an important difference as compared with the 1998 study for which the experts adopted a 75% capacity factor that was found at the time representative of the average lifetime value for base-load plants.

The economic lifetime of the plant, i.e. the period of investment amortisation, used in calculating generation cost estimates is 40 years for nuclear and coal-fired power plants. For other power plants, the values provided in the responses to the questionnaire were adopted.

Table 2.2 – Exchange rates (as of 1 July 2003)

Code / Country		Currency unit	Equivalent USD	Equivalent euro (€)
CAN	Canada	CAD	0.7427	0.6492
USA	United States	USD	1	0.8741
	Euro area	EUR/€	1.144	1
AUT	Austria	EUR		
BEL	Belgium	EUR		
FIN	Finland	EUR		
FRA	France	EUR		
DEU	Germany	EUR		
GRC	Greece	EUR		
ITA	Italy	EUR		
NLD	Netherlands	EUR		
PRT	Portugal	EUR		
CZE	Czech Republic	CZK	0.0363	0.0317
DNK	Denmark	DKK	0.1541	0.1347
SVK	Slovak Republic	SKK	0.0275	0.0240
CHE	Switzerland	CHF	0.7415	0.6482
TUR	Turkey	1000 TRL	0.0007	0.0006
JPN	Japan	JPY	0.0084	0.0073
KOR	Korea, Rep. of	KRW	0.0008	0.0007
BGR	Bulgaria	BGR	a	a
ROU	Romania	ROL	a	a
ZAF	South Africa, Rep. of	ZAR	0.1387	0.1212

a. Cost information provided in € or USD.

Table 2.3 – List of responses[1]

Country	Nuclear	Coal (type) *Oil*	Gas	Wind *Solar*	Hydro	CHP (technology) MWe/MWth	Distributed generation	Others
Canada	2x703 (PHWR)	[3] 1x450	1x580					
United States	1x1 000 (GENIII)	1x600 1x550 (IGCC)	1x400 1x230	50x1 *1x100* *1x5*		40/45 (gas) 3/3.5 (gas)	1x10 (FC1/G) 1x2 (FC2/G) 1x1 (FC3/G)	1x30 (LG) 1x100 (CR) 50 (geoth.)
Austria				11x1.75	1x14 1x1.5	84/127 (CCGT) 8/20 (biomass) 105/110 (CCGT)		
Belgium			[2] 1x400	5x2				
Czech Republic	[3] 1x1 000 (PWR)	[6] 1x300 [6] 1x150 [5] 1x300 (IGCC) [6] 1x150	[5] 1x250	6x1.5 [4] *1x0.025*	1x3	300/120 (coal) 250/120 (CCGT)		1x10 (CR) 1x10 (WI)
Denmark		1x400		80x2 72x2.22 1x1.5 *500x0.001*		11/12 (gas) 485/575 (mix) 58/58 (gas) 350/455 (straw/coal)		
Finland	[3] 1x1 500 (PWR)	1x500				160/300 (coal) 470/420 (gas)		
France	[2/3] 1x1 590 (PWR)	1x900 1x600	1x900					
Germany	1x1 590 (PWR)	1x800 1x450 (IGCC) 1x425 (IGCC) 1x1050	1x1 000	100x3 10x1.5 10x1.5 *1x0.002* *1x0.5*	1x0.714	500/600 (coal) 200/280 (coal) 200/160 (gas) 200/190 (gas) 1/1.5 (biogas)		
Greece		*2x50*	1x377.7 1x476.3	17x0.835 16x0.75 7x0.6 5x0.6 7x0.6	2x2 2x60+1x3.5			
Italy			1x791 2x575 1x384	30x2 36x2				
Netherlands	1x1 600 (PWR)		[2] 1x500	60x2		81/65 (CCGT) 250/175 (CCGT)		[2]1x58.4 (WI)
Portugal			3x400	10x2				
Slovak Republic	[4] 2x447 (PWR)	2x114 1x114	1x391		2x1.35	19.5/98 (lignite)		
Switzerland	1x1 600 (BWR)		1x400 1x250 1x110			2.74/2.90 (gas) 0.526/0.633 (gas)		
Turkey		1x340 1x500 1x160	2x350 2x140					
Japan	1x1 330 (ABWR)	1x800	1 600		1x19			
Korea, Rep. of	[4] 2x953 (PWR) [4] 2x1 341.2 (PWR)	[8] 2x478 [6] 2x766.4	[8] 2x444.6					
Bulgaria		2x300			1x80	90/**ns**		
Romania	[3] 1x665 (PHWR)	[62] 1x315						
South Africa, Rep. of		6x641.67 2x233	5x387		4x332.5 (PS)			

1. Plant capacities are given in MWe: [number of units on the site if different from 1] number of units taken into account in the cost estimates x unit capacity.
A list of acronyms and abbreviations used in the following tables, and elsewhere in the report, is given in Appendix 11.

Table 2.4 – Coal plant specifications

Country	Abbrev. name of the plant	Plant type/emission control equipment incl. in costs	Net capacity (MWe)	Net thermal efficiency [LHV] (%)	Cooling tower	Site	CO_2 emission (t/MWh)	Cost estimation source/ date
Canada	CAN-C	PF(SC)/FGD, LNB, FF	[3] 1x450	38.7[a]	No	Existing	0.85	P/03
United States	USA-C1	PF/FGD, SCR, FF	1x600	39.3	No	New	0.8121	M/03
	USA-C2	IGCC/FGD, SCR, FF	1x550	46.3	No	New	0.8121	M/03
Czech Republic	CZE-C1	PF, brown coal/FGD, de NO_x, dust	[6] 1x300	37	Yes	Existing	0.99	P/03
	CZE-C2	FBC, brown coal/de S	[6] 1x150	37	Yes	Existing	0.99	P/03
	CZE-C3	IGCC/de SO_x, de NO_x	[5] 1x300	43	Yes	Existing	0.78	P/03
	CZE-C4	FBC, brown coal & biomass/de SO_x	[6] 1x150	37	Yes	Existing	0.78	P/03
Denmark	DNK-C	STC/FGD, SCR, ESP	1x400	48	No	Existing	0.71	P/03
Finland	FIN-C	(SC)/FGD, SCR, ESP	1x500	46	No	New	0.725	P/03
France	FRA-C1	PF(SC)/ns	1x900	47.1	ns	Existing	0.737	Q/03
	FRA-C2	FBC/ns	1x600	46.1	ns	Existing	0.748	Q/03
Germany	DEU-C1	PF/dust, FGD, SCR	1x800	46	Yes	New	0.728	Q/04
	DEU-C2	IGCC/dust, desulphurisation	1x450	51	Yes	New	0.656	Q/04
	DEU-C3	IGCC/dust, desulph., CO_2 capt.	1x425	45	Yes	New	0. 089	P/04
	DEU-C4	PF, lignite/dust, desulphurisation	1x1 050	45	Yes	New	0.796	Q/04
Slovak Republic	SVK-C1	FBC/de SO_x, de NO_x, ESP	2x114	34.7	No	Existing	0.865	P/03
	SVK-C2	FBC, lignite/de SO_x, de NO_x, ESP	1x114.4	34.5	Yes	Existing	0.973	P/03
Turkey	TUR-C1	PF, lignite/FGD, de NO_x	1x340	35	Yes	Existing	1.262	Q/01
	TUR-C2	PF/FGD, de NO_x	1x500	38	Yes	New	0.917	Q/01
	TUR-C3	FBC, Lignite/limestone	1x160	41	Yes	New	1.027	Q/01
Japan	JPN-C	PF/FGD, SCR, ESP	1x800	42.1	No	New	0.775	P/04
Korea, Rep. of	KOR-C1	PF/FGD, SCR, ESP	[8] 2x478	41.29	No	New	0.8924	P-O/03
	KOR-C2	PF/FGD, SCR, ESP	[6] 2x766.4	42.75	No	New	0.8419	P-O/03
Bulgaria	BGR-C	PF, lignite/de SO_x, de NO_x	2x300	34.8	ns	New	1.07	P/03
Romania	ROU-C	PF/de SO_x, de NO_x, particles	[2] 1x296	29.0	Yes	Existing	1.133	P-FS/03
South Africa, Rep. of	ZAF-C1	PF/FGD	6x642	34.59	Yes	New	ns	P/03
	ZAF-C2	FBC/ns	2x233	36.65	Yes	New	ns	P/03

a. Higher Heating Value (HHV) instead of Lower Heating Value (LHV).

Abbreviations: **ns** = not specified – **P** = Paper analysis – **O** = Ordered plant price(s)
Q = Quotation – **M** = Mixed – FS = Feasibility study

Table 2.5 – Gas plant specifications

Country	Abbrev. name of the plant	Technology/fuel/ emission control equipment incl. in costs	Net capacity (MWe)	Thermal efficiency [LHV] %	No. of turbines per unit	Cooling tower	Site	CO_2 emission (t/MWh)	Cost estimation source/ date
Canada	CAN-G	CCGT/LNB	1x580	55	2GT/1ST	No	Existing	0.35	P/03
United States	USA-G1	CT/SCR, FF	1x230	39.9	1	No	New	0.4219	M/03
	USA-G2	CCGT/SCR, FF	1x400	53.2	1	No	ns	0.4219	M/03
Belgium	BEL-G	CCGT/ns	[2] 1x400	55	1	Yes	Existing	0.360	P/02-03
Czech Republic	CZE-G	CCGT/de NO_x	[5] 1x250	56	1GT/1ST	Yes	Existing	0.36	P/03
France	FRA-G	CCGT/ns	1x900	59.1	2	ns	Existing	0.353	Q/03
Germany	DEU-G	CCGT/SCR	1x1 000	60	2GT/1ST	Yes	New	0.333	Q/04
Greece	GRC-G1	CCGT/de NO_x	1x377.7	54	1GT/1ST	No	Existing	0.38	O/03
	GRC-G2	CCGT/de NO_x	1x476.3	52	2GT/1ST	Yes	New	0.41	O/97
Italy	ITA-G1	CCGT/de NO_x	1x791	56.3	2	No	Existing	0.35	O/03
	ITA-G2	CCGT/de NO_x	x2x575	54.5	2/1	No	Existing	0.359	P/01
	ITA-G3	CCGT/de NO_x	1x384	55.8	1	Yes	New	0.412	Q/03
Netherlands	NLD-G	CCGT/ns	[2] 1x500	60	1	No	Existing	0.34	P/04
Portugal	PRT-G	CCGT/LNB	3x400	57	1	Yes	New	0.360	P/03
Slovak Republic	SVK-G	CCGT/LNB	1x391	54.5	1GT/1ST	Yes	Existing	0.337	P-FS/03
Switzerland	CHE-G1	CCGT/LNB	1x400	57.5	1GT/1ST	No	Existing	0.344	P-Q/04
	CHE -G2	CCGT/LNB	1x250	52.7	1GT/1ST	No	Existing	0.376	P-Q/04
	CHE -G3	CCGT/LNB	1x110	53	1GT/1ST	No	Existing	0.374	P-Q/04
Turkey	TUR-G1	CCGT/de NO_x	2x350	55	3	Yes	New	0.365	Q/02
	TUR-G2	CCGT/de NO_x	2x140	54	3	Yes	New	0.372	Q/02
Japan	JPN-G	CCGT, LNG/SCR	1600	52	2	No	New	0.308	P/04
Korea, Rep. of	KOR-G	CCGT, LNG/SCR	[8] 2x444.6	56.11	3	No	New	0.3758	P-O/03
South Africa, Rep. of	ZAF-G	CCGT/LNG/ns	5x387	47	ns	No	New	ns	P/03

Table 2.6 – Nuclear power plant specifications

Country	Abbrev. name of the plant	Reactor type/ fuel cycle option	Net capacity (MWe)	Net thermal efficiency (%)	Cooling tower	Site	Cost estimation source/date
Canada	CAN-N	PHWR/OT	2 x 703	34.6	No	Existing	P/03
United States	USA-N	GENIII/OT	1 x 1 000	32.8	ns	New	O/03[a]
Czech Republic	CZE-N	VVER/OT	[3] 1 x 1 000	30.8	Yes	Existing	P/03
Finland	FIN-N	PWR/OT	[3] 1 x 1 500	37.0	No	Existing	P/04
France	FRA-N	PWR/CC	[2/3] 1 x 1 590	36.1	ns	Existing	Q/03
Germany	DEU-N	PWR/OT	1 x 1 590	37.0	Yes	New	P/04
Netherlands	NLD-N	PWR/CC	1 x 1 600	37.0	No	Existing	P/04
Slovak Republic	SVK-N	VVER/OT	[4] 2 x 447	30.3	Yes	Existing	P-FS/02
Switzerland	CHE-N	BWR/OT	1 x 1 600	33.0	No	Existing	P/04
Japan	JPN-N	ABWR/CC	1 x 1 330	34.5	No	New	P/04
Korea, Rep. of	KOR-N1	PWR/OT	[4] 2 x 953	35.23	No	New	P/03
	KOR-N2	PWR/OT	[4] 2 x 1 341.2	35.40	No	New	P/03
Romania	ROU-N	PHWR/OT	[3] 1 x 665	30.7	No	Existing	P/03

a. Based upon costs of units built in the Far East.

Abbreviations: ns = not specified – P = Paper analysis – O = Ordered plant price(s)
Q = Quotation – M = Mixed – FS = Feasibility study

Table 2.7 – Wind and solar power plant specifications

Country	Abbrev. name of the plant	Technology	Net capacity (MWe)	Equipment availability (%)	Average load factor (%)	Site	Cost estimation source/date
United States	USA-W	Wind	50x1	96	41	New/Onshore	M/03
	USA-S1	Solar Thermal Parabolic	1x100	96	15	New/I	M/03
	USA-S2	Solar PV	1x5	96	24	New/I	M/02
Austria	AUT-W	Wind	11x1.75	98	22.4	New/Onshore	O/02
Belgium	BEL-W	Wind	5x2	97	25	New/Onshore	O/01
Czech Republic	CZE-W	Wind	6x1.5	87	17	New/Onshore	P/03
	CZE-S	Solar PV	[4] 1x0.025	90	9	Existing/C	P/03
Denmark	DNK-W1	Wind	80x2	95	43	New/Offshore	P-O/01
	DNK-W2	Wind	72x2.22	95	42	New/Offshore	Budget prices
	DNK-W3	Wind	1x1.5	98	27	New/Onshore	P/03
	DNK-S	Solar PV	500x0.001	100	9	New/R	Budget price/03
Germany	DEU-W1	Wind	100x3	95	34.7	New/Offshore	Q/03
	DEU-W2	Wind	10x1.5	97	17.7	New/Onshore	Q/03
	DEU-W3	Wind	10x1.5	97	23.8	New/Onshore	Q/03
	DEU-S1	Solar PV	0.5	99	10.3	New/R	P/02
	DEU-S2	Solar PV	0.002	99	10.8	New/C	P/02
Greece	GRC-W1	Wind	17x0.84	97-98	35	Existing/Onshore	O/99
	GRC-W2	Wind	16x0.75	97-98	36	Existing/Onshore	O/99
	GRC-W3	Wind	7x0.6	98.5	38	New/Onshore	P/03
	GRC-W4	Wind	5x0.6	98.5	38	New/Onshore	P/03
	GRC-W5	Wind	7x0.6	97	30	New/Onshore	O/01
Italy	ITA-W1	Wind	30x2	80	22	New/Onshore	P/04
	ITA-W2	Wind	36x2	95	22	New/Onshore	Q/03
Netherlands	NLD-W	Wind	60x2	ns	42	New/Offshore	Q/03
Portugal	PRT-W	Wind	10x2	98	28.5	New/Onshore	P/03

Table 2.8 – Hydro power plant specifications

Country	Abbrev. name of the plant	Plant type	Net capacity (MWe)	Equipment availability (%)	Average load factor (%)	Site	Cost estimation source/date
Austria	AUT-H1	Run of the river	14	95	59.5	New	P/99
	AUT-H2	Small hydro	1.5	99.5	36.5	New	P/99
Czech Republic	CZE-H	Small hydro	3	95	55	New	P/03
Germany	DEU-H	Small hydro	0.714	93	58	New	Q/04
Greece	GRC-H1	Run of the river	2x2	95	50	New	O/04
	GRC-H2	Dam	2x60+1x3.5	98	25	New	P/91-01
Slovak Republic	SVK-H	Run of the river small hydro	2x1.35	95	57	New	P/03
Japan	JPN-H	Run of the river	19	ns	45	New	P/04
Bulgaria	BGR-H	Dam	80	ns	23	New	P/03
South Africa, Rep. of	ZAF-H	Pumped storage	4x332.5	91.7	17	New	P/03

Abbreviations: ns = not specified – P = Paper analysis – O = Ordered plant price(s) – Q = Quotation – M = Mixed – C = Commercial – R = Residential – I = Industrial

Table 2.9 – Combined heat and power (CHP) plant specifications

Country	Abbrev. name of the plant	Fuel/technology/ emission control equipment incl. in costs	Net capacity (MWe/ MWth)	Average production (GWhe/ GWhth)	Thermal efficiency per unit [LHV] %	Cooling tower	Site/ Heat use	CO_2 emission 10^3 t/ year	Cost estimation source/ date
United States	USA-CHP1	Gas/ns/SCR, FF	40/45	280/316	38.5[a]	No	New/I	ns	O/03
	USA-CHP2	Gas/engine/SCR, FF	3/3.5	21/23.8	39[a]	No	New/I	ns	O/03
Austria	AUT-CHP1	Gas/CCGT/SCR, de SO_x	84/127	420/350	72	No	DH	230	Accounted
	AUT-CHP2	Biomass/ESP	8/20	50/150	80	No	New	–	Q/04
	AUT-CHP3	Gas/CCGT/LNB, SCR	105/110	700/440	75	No	Modern./DH	210[a]	O/03
Czech Republic	CZE-CHP1	Coal/B+ST/FGD, de NO_x, ESP	300/120	2 200/300	37[a]	Yes	Existing/DH	2300	P/03
	CZE-CHP2	Gas/CCGT/de NO_x	250/120	1 800/300	56[a]	Yes	Existing/DH	670.14	P/03
Denmark	DNK-CHP1	Gas/engine/SCR	2x5.5/2x6	82/89[b]	82	No	Existing/I	43	O/00
	DNK-CHP2	Multifuel[c]/ B+ST+GT/SCR, ESP, FGD	485/575	3 610/4 280	92(50[a])	No	Existing/DH	[c]	O/01
	DNK-CHP3	Gas/CCGT/LNB	58/58	290/290	88	No	New/DH	135	O/96
	DNK-CHP4	Straw-coal/ B-ST/de SO_x, de NO_x	350/455	125-1 650/ 215-1 550	79(42[a])	No	Existing/DH	1780[d]	O/02
Finland	FIN-CHP1	Coal/B-ST/SCR, de SO_x	160/300	910/1 710	88	No	Existing/DH-C	994	P/04
	FIN-CHP2	Gas/CCGT/ns	470/420	2 700/2 400	92	No	Existing/DH-C	1107	P/04
Germany	DEU-CHP1	Coal/ST extraction/ dust, desulph., SCR	500/600	2 960/4 480	35[e]	Yes	Existing/DH-R&C	1127	Q/04
	DEU-CHP2	Coal/ST back-pressure/ dust, desulph., SCR	200/280	1 490/2 110	36	No	Existing/I	582.3	Q/04
	DEU-CHP3	Gas/CCGT extraction/SCR	200/160	1 220/1 190	45[e]	Yes	Existing/DH-R&C	279	Q/04
	DEU-CHP4	Gas/CCGT back-pressure/SCR	200/190	1 490/1 440	45.5	No	Existing/I	337.2	Q/04
	DEU-CHP5	Biogas/engine/ns	1/1.5	7.4/11.5	35	No	Existing/DH-R	–	Q/03
Netherlands	NLD-CHP1	Gas/CCGT/ns	81/65	610/485	75	No	Existing/C-I	300	Q/ns
	NLD-CHP2	Gas/CCGT/ns	250/175	1 870/1 300	73	No	Existing/C-I	870	Q/ns
Slovak Republic	SVK-CHP	Lignite/FBC/de SO_x, de NO_x, ESP	19.5/98	101/117.6	88.2	Yes	Existing/DH-I	208	P/03
Switzerland	CHE-CHP1	Gas/engine/SCR	2.74/2.9	13.7/14.52	87.5	No	Onsite/I	0.638	P-Q/04
	CHE-CHP2	Gas/engine/SCR	0.526/0.633	2.63/3.165	86.3	No	Onsite/I	0.133	P-Q-O/04

a. Electricity only.
b. At 85% average annual load factor.
c. Gas, oil, straw and wood pellets; CO_2 emissions depend on fuel mix.
d. None can be allocated to co-firing with straw.
e. In the back-pressure mode.

Abbreviations: **ns** = not specified – **P** = Paper analysis – **O** = Ordered plant price(s) – **Q** = Quotation – **M** = Mixed – **C** = Commercial – **R** = Residential – **I** = Industrial

Table 2.10 – Other plant specifications

Country	Abbrev. name of the plant	Fuel/technology/ emission control equipment incl. in costs	Net capacity (MWe)	Thermal efficiency [LHV] (%)	Cooling tower	Site	CO_2 emission 10^3 t/ year	Cost estimation source/ date
United States	USA-Geo	Geothermal/None	1x50	-	No	New	-	P/97
	USA-CR	Comb. renew./FF, SCR	1x100	38.31	ns	New	-	M/03
	USA-LG	Landfill gas/None	1x30	25	No	New	ns	P/97
	USA-FC1	Gas/fuel cell/None	1x10	48.3	na	Offsite	107	M/03
	USA-FC2	Gas/fuel cell/FF, SCR	1x2	37.56	na	Offsite	15	M/03
	USA-FC3	Gas/fuel cell/FF, SCR	1x1	34.13	na	Offsite	25	M/03
Czech Republic	CZE-CR	Comb. Renew./FF, de NO_x, de SO_x	1x10	26	Yes	New	-	P/03
	CZE-WI	Municipal W./FF, de NO_x, de SO_x	[5] 1x10	26	Yes	Existing	88	P/02
Greece	GRC-O	Oil/Recip. Eng./de NO_x, de SO_x	2x50	45	No	New	0.62	O/02
Netherlands	NLD-WI	Municipal W./FF, scrubbers, evaporator	[2] 1x58.4	30	No	Existing	230	Q-O/02

Abbreviations: ns = not specified – na = not applicable
P = Paper analysis – O = Ordered plant price(s) – Q = Quotation – M = Mixed

Generation Costs of Coal-fired, Gas-fired and Nuclear Power Plants

This chapter gives an overview on the costs of electricity generation calculated with generic assumptions for the coal, gas and nuclear power plants considered in the study. It covers investment, operation and maintenance and fuel costs as well as levelised generation cost at 5% and 10% discount rates for a total of 63 plants (27 coal plants, 23 gas plants and 13 nuclear plants). The levelised generation costs were calculated assuming 85% average load factor. For coal and nuclear power plants the economic lifetime was assumed to be 40 years although many countries reported longer expected technical lifetimes.[1] For gas-fired plants, most countries reported shorter technical lifetimes, between 20 and 30 years, and in each case economic lifetime was assumed to be equal to technical lifetime. Fossil fuel prices and nuclear fuel cycle costs used in the calculations were those provided by respondents to the questionnaire. Costs and prices presented in this report are expressed in national currency unit, USD or euros (€) of 1 July 2003, except if otherwise stated.

For each technology, i.e. coal, gas and nuclear, the results presented include overnight construction costs and the expense schedule for the construction period. The levelised generation cost calculations take into account not only the expenses during construction but also, if applicable, refurbishment and decommissioning costs. Those elements, once discounted, account for a modest share of total costs but are by no means negligible. Regarding O&M costs and fuel prices, the cost calculations take into account, when applicable, escalation rates reported by respondents to the questionnaire which are noted in the relevant tables below.

Coal-fired power plants

Overnight construction costs

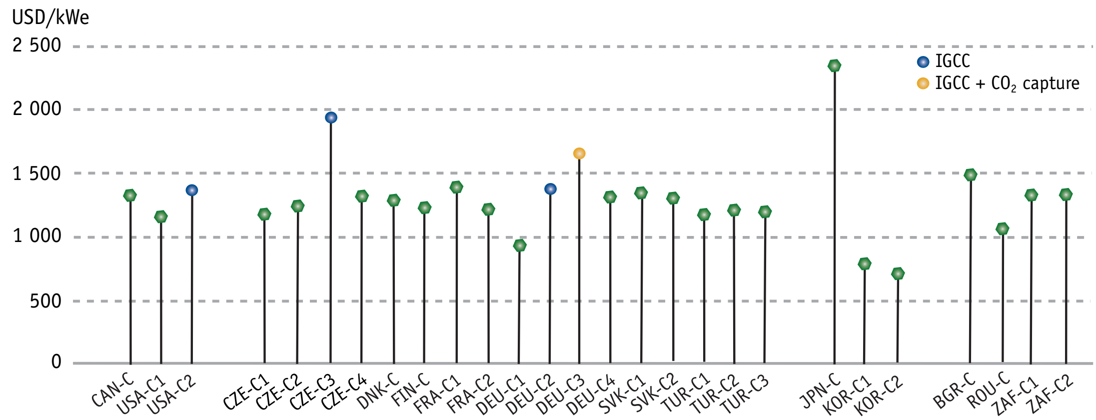
The overnight construction cost is defined as the total of all costs incurred for building the plant accounted for as if they were spent instantaneously. The specific overnight construction costs of the 27 coal-fired power plants included in the study are displayed on Figure 3.1; more information on coal plant characteristics and overnight construction costs are provided in Table 3.10 at the end of this chapter.

As noted in Chapter 2 and Table 3.10, the coal-fired power plants considered in the study use different quality of fuels, including lignite and brown coal, and different technologies, including fluidised-bed combustion and integrated gasification combined cycle (IGCC). Obviously such differences lead to variations in investment costs, efficiencies and total levelised costs of generating electricity.

Most coal-fired power plants have specific overnight construction costs ranging between 1 000 and 1 500 USD/kWe. However, the IGCC plant in the Czech Republic, the IGCC plant with CO_2 capture in

1. Romania reported a 15-year technical lifetime for its coal plant and, accordingly, calculations were made assuming a 15-year economic lifetime.

Figure 3.1 – Specific overnight construction costs of coal-fired power plants (USD/kWe)



Germany, the pulverised coal-fired plant in Japan and the fluidised-bed combustion plant of the Republic of South Africa have specific overnight construction costs higher than 1 500 USD/kWe and, on the other hand, the German pulverised coal plant has a specific overnight cost slightly lower than 1 000 USD/kWe.

Construction time

Table 3.1 provides the expense schedule for coal-plant construction showing the percentage of total overnight construction cost spent each year. Construction times, as reflected in expense schedules, are around four years for most plants and, when they exceed four years, the expenses during the first years often are marginal. Indeed, construction expenses are spread over a period of four to six years with, in most cases, 90% or more of the expenses incurred within four years or less.

O&M costs

The projected O&M costs reported for coal-fired power plants (Table 3.2) vary widely from country to country and sometimes from plant to plant in the same country. Most countries are not projecting escalation of O&M costs over time but the Czech Republic indicates a small increase of those costs during the economic lifetime of the plants.

Table 3.1 – Expense schedule for coal-fired power plant construction (% of total overnight construction cost)

	CAN	USA-C1	USA-C2	CZE-C1	CZE-C2	CZE-C3	CZE-C4	DNK-C	FIN-C	FRA-C1/2	DEU-C1/4
-6				0.1	0.2	0.1	0.2				
-5	8[a]			1.4	2.7	4.7	2.5			2.4	
-4	15	45	35	10.3	9.7	9.4	9.1	25	14.5	21.5	
-3	30	25	30	27.8	27.1	31.3	29.1	25	24	40.9	25
-2	30	20	25	41.2	38.8	34.4	39.1	25	42	25.5	40
-1	17	10	10	19.2	21.5	20.3	20	25	19.5	8.5	35
										1.2	

	SVK-C1	SVK-C2	TUR-C1	TUR-C2	TUR-C3	JPN-C	KOR-C1	KOR-C2	BGR-C	ROU-C	ZAF-C1	ZAF-C2
-6						19						
-5			3			8	1	3.5			7	3.5
-4	3	0.1	15	3.5	15	8.5	8	18.5	18		1.5	1
-3	14.5	35.2	35	27	28	31	40	44.5	32	20	36	51
-2	29	34.1	36.5	49.5	33.5	18.5	46	30	45	40	49.5	39.5
-1	53.5	30.6	10.5	20	23.5	15	5	3.5	5	40	6	5

a. Down payment.

Table 3.2 – Specific annual O&M costs (per kWe) for coal-fired power plants in 2010

	CAN	USA-C1	USA-C2	CZE-C1[a]	CZE-C2[a]	CZE-C3[a]	CZE-C4[a]	DNK-C	FIN-C	FRA-C1	FRA-C2
NCU	67.33	49.00	50.00	847	878	880	870	270	43.00	50.37	44.95
USD	50.01	49.00	50.00	30.75	31.87	31.94	31.58	41.61	49.19	57.62	51.42
€	43.71	42.83	43.71	26.88	27.86	27.92	27.61	36.37	43.00	50.37	44.95

	DEU-C1	DEU-C2	DEU-C3	DEU-C4	SKV-C1	SKV-C2	TUR-C1	TUR-C2	TUR-C3	JPN-C	KOR-C1	KOR-C2
NCU	56.70	80.50	96.90	43.30	2 597.9	2 628.3	40 962	80 633	59 619	7 807	47 500	38 402
USD	64.86	92.09	110.85	49.54	71.44	72.28	28.67	56.44	41.73	65.58	38.00	30.72
€	56.70	80.50	96.90	43.30	62.45	63.18	25.06	49.34	36.48	57.32	33.22	26.85

	BGR-C[b]	ROU-C[b]	ZAF-C1	ZAF-C2
NCU	-	-	125.28	204.61
USD	44.62	10.63	17.38	28.38
€	39.00	9.29	15.19	24.81

a. Increasing over time.
b. Costs reported in euros.

Table 3.3 – Coal price assumptions provided by respondents

Country/plant	2010		2020		2030		2040		2050		
	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	
CAN-C	1.9	1.41	1.9	1.41	1.9	1.41	1.9	1.41	1.9	1.41	≈
USA-C1/2	1.30	1.30	1.43	1.43	1.57	1.57	1.73	1.73	1.90	1.90	↑
CZE-C1/2 (brown coal)	35	1.27	37	1.34	40	1.45	50	1.82	55	2.00	↑
CZE-C3	55	2.00	55	2.00	60	2.18	70	2.54	80	2.90	↑
CZE-C4 (brown coal)	52	1.89	53	1.92	55	2.00	59	2.14	62	2.25	↑
DNK-C	12.5	1.93	13.3	2.05	14	2.16	14	2.16	14	2.16	↑
FIN-C	1.8	2.06	1.98	2.27	2.18	2.49	2.40	2.74	2.64	3.01	↑
FRA-C1/2	1.49	1.70	1.49	1.70	1.49	1.70	1.49	1.70	1.49	1.70	≈
DEU-C1/2/3	1.8	2.06	1.9	2.17	2.1	2.40	2.3	2.63	2.5	2.86	↑
DEU-C4 (lignite)	1	1.14	1.2	1.37	1.4	1.60	1.5	1.72	1.7	1.94	↑
SVK-C1	77.4	2.13	85.4	2.35	94.4	2.6	104.3	2.9	115.2	3.17	↑
SVK-C2 (lignite)	105.8	2.91	115.5	3.18	125.7	3.46	136.8	3.76	148.9	4.09	↑
TUR-C1 (lignite)	3 913.8	2.74	3 913.8	2.74	3 913.8	2.74	3 913.8	2.74	3 913.8	2.74	≈
TUR-C2	2 790.2	1.95	2 790.2	1.95	2 790.2	1.95	2 790.2	1.95	2 790.2	1.95	≈
TUR-C3 (lignite)	3 885.8	2.72	3 885.8	2.72	3 885.8	2.72	3 885.8	2.72	3 885.8	2.72	≈
JPN-C	252	2.12	266	2.23	280	2.35	296	2.49	313	2.63	↑
KOR-C1/2	1 448	1.16	1 448	1.16	1 448	1.16	1 448	1.16	1 448	1.16	≈
BGR-C[a] (lignite)	–	1.17	–	1.17	–	1.17	–	1.17	–	1.17	≈
ROU-C[a] (lignite)	–	2.29	–	2.29							≈
ZAF-C1	1.081	0.15	1.081	0.15	1.081	0.15	1.081	0.15	1.081	0.15	≈
ZAF-C2	0.7111	0.10	0.7111	0.10	0.7111	0.10	0.7111	0.10	0.7111	0.10	≈

a. Costs were reported in euros.

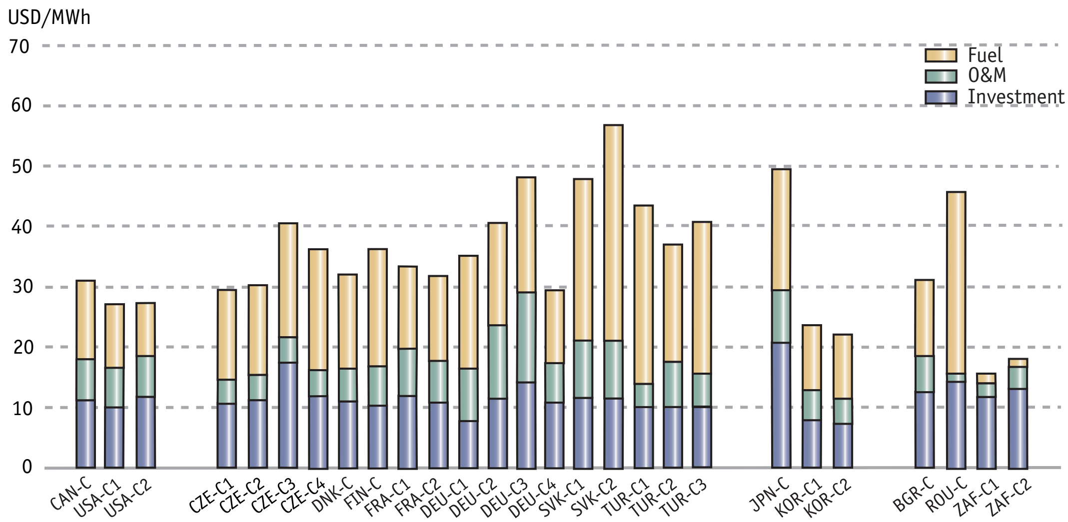
Fuel prices

The fuel prices (coal, brown coal or lignite) assumed by respondents during the economic lifetime of the plants are summarised in Table 3.3. The expected prices at the time of commissioning of the plant, i.e. generally 2010, vary widely from country to country. Expressed in the same currency using official exchange rates, the coal prices vary by a factor of twenty between the Republic of South Africa, where the prices are the lowest at 0.1/0.15 USD/GJ, and more than 2 USD/GJ in many European countries and in Japan. Roughly half of the responses indicate price escalation during the economic lifetime of the plant while the other half indicates price stability. When prices are assumed to increase, escalation rates lead to an average increase of some 50% between 2010 and the end of the plant economic lifetime, i.e. 2050.

Levelised generation costs

The levelised costs of electricity generated by the coal-fired plants considered in the study are shown in Figures 3.2 and 3.3 at 5% and 10% discount rates respectively. The detailed cost elements, i.e. total investment (including refurbishment, decommissioning and interest during construction), O&M and fuel, and their respective shares of the total levelised generation cost are provided in Tables 3.13 and 3.14 which include all the cost estimates for coal-fired, gas-fired and nuclear power plants considered in the study.

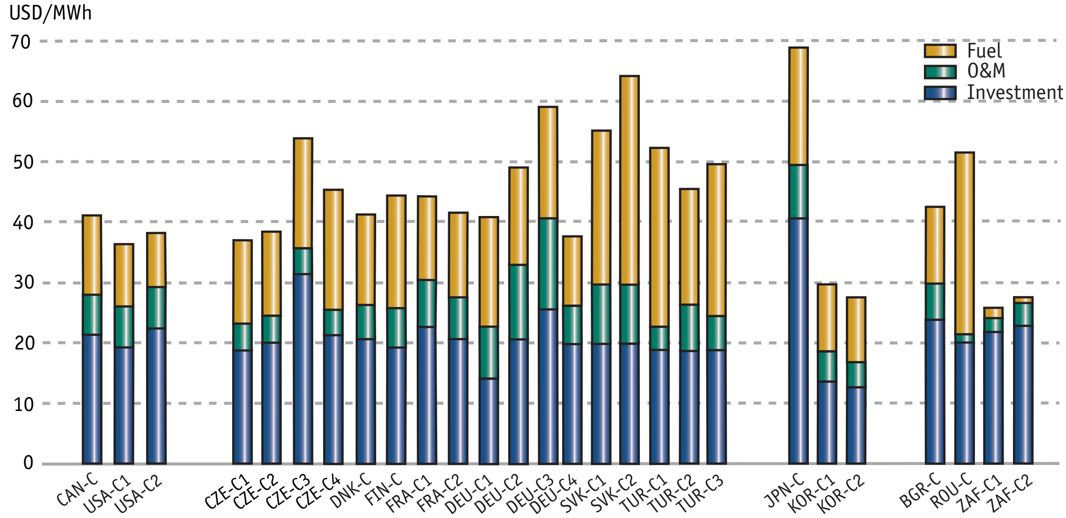
Figure 3.2 – Levelised costs of coal generated electricity at 5% discount rate (USD/MWh)



At 5% discount rate, levelised generation costs range between 25 and 50 USD/MWh for most coal-fired power plants. The only exceptions on the cheap side – just above or even below 20 USD/MWh – are the South African plants, the country having reported extremely low coal prices. On the other hand, the estimated levelised generation cost of the lignite-fuelled plant in the Slovak Republic is above 50 USD/MWh owing to the high lignite price reported. Generally, investment costs represent slightly more than a third of the total, while O&M costs account for some 20% and fuel for some 45%. It should be stressed, however, that those shares may vary widely from country to country depending on local conditions and in particular assumed coal prices. For example, in the Republic of South Africa where assumed coal prices are extremely low, investment costs represent three quarters or more of the total levelised costs.

At 10% discount rate, the levelised generation costs of nearly all coal-fired power plants range between 35 and 60 USD/MWh. Only the lignite-fuelled plant in the Slovak Republic and the plant of Japan have levelised costs higher than 60 USD/MWh while the two plants of the Republic of Korea and the two plants of the Republic of South Africa have levelised costs lower than 30 USD/MWh. Investment costs represent around 50% in most cases with the exception of the Republic of South Africa where the low fuel costs lead to an investment share exceeding 85%. O&M costs account for some 15% of the total and fuel costs for some 35%. Like at 5% discount rate, the variability of cost elements leads to significant differences in their respective shares of the total in different countries and sometimes for different plants in the same country.

Figure 3.3 – Levelised costs of coal generated electricity at 10% discount rate (USD/MWh)

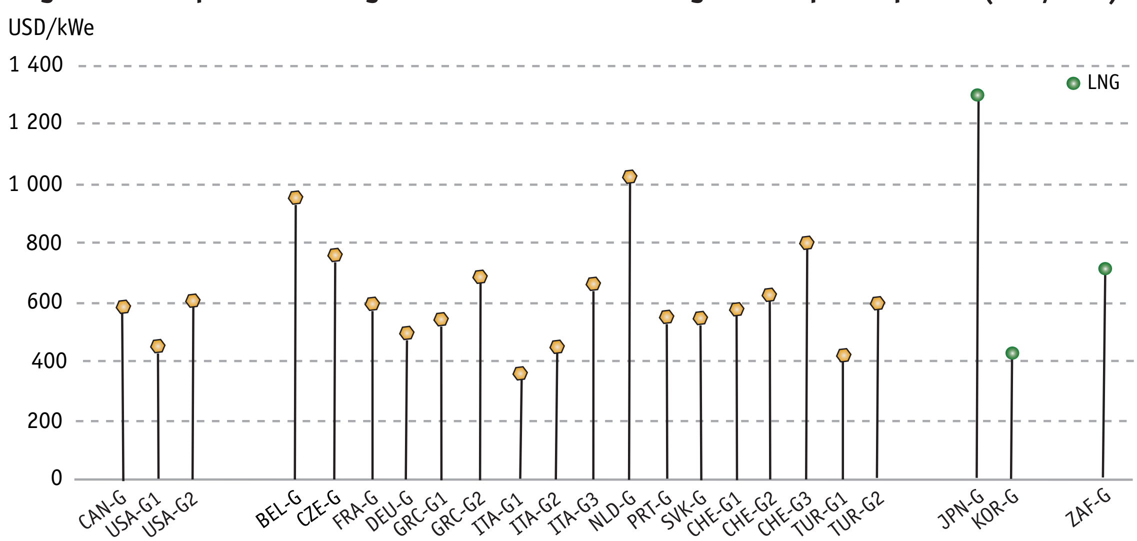


Gas-fired power plants

Overnight construction costs

The specific overnight construction costs of most gas-fired power plants considered in the study range between 400 and 800 USD/kWe (see Figure 3.4 and Table 3.11). Only three plants, in Belgium, the Netherlands and Japan, where the gas-fired plant is fuelled with LNG, have specific overnight construction costs above 800 USD/kWe. One plant in Italy (ITA-G1) has a specific overnight construction cost below 400 USD/kWe because it is not a new construction but re-powering of an existing plant. In all countries, the construction costs of gas-fired plants are lower than those of coal-fired or nuclear power plants.

Figure 3.4 – Specific overnight construction costs of gas-fired power plants (USD/kWe)



Construction time

Gas-fired power plants are built rapidly and the expense schedules reported show that in most cases expenditures are spread over two to three years (Table 3.4). In the case of Switzerland, all expenses are incurred in one year, and for one plant in the United States, 90% of the expenses are incurred in year -1. In a few cases, however, more than 10% of the overnight capital cost is spent more than three years before commissioning and, in the case of Japan, the bulk of the expenses occurs in years 4 and 5 before commissioning.

Table 3.4 – Expense schedule for gas-fired power plant construction (% of total overnight construction cost)

	CAN-G	USA-G1	USA-G2	BEL-G	CZE-G	FRA-G	DEU-G	GRC-G1	GRC-G2	ITA-G1	ITA-G2	ITA-G3
-6					0.2							
-5				1.6	2.7				11.2		26.9	
-4				2.6	9.5	3.0			15.9		57.1	
-3	8.0[a]		9.9	13.8	28.5	27.5		16.6	37.9	16.6	13.4	46.7
-2	46.0	10.0	20.0	34.5	41.0	44.5	50.0	42.3	25.3	49.2	2.6	33.9
-1	46.0	90.0	70.1	47.5	18.1	25.0	50.0	41.1	9.7	34.2		19.4

	NLD-G	PRT-G	SVK-G	CHE-G1-3	TUR-G1	TUR-G2	JNP-G	KOR-G	ZAF-G
-7							1.7		
-6							25.6		
-5							26.1		
-4			0.6				18.4		2.5
-3		10.0	2.4		9.0	13.0	16.3	18.8	4.9
-2	50.0	45.0	29.1		60.0	51.0	7.8	69.7	48.7
-1	50.0	45.0	67.9	100.0	31.0	36.0	4.1	11.5	43.9

a. Down payment.

O&M costs

The O&M costs of gas-fired power plants are significantly lower than those of coal-fired or nuclear power plants in all countries which provided data for the two or three types of plants. Like for other types of plants, however, O&M costs for gas-fired units vary widely from country to country. Greece and Turkey report projected annual O&M costs around 5 USD/kWe while the Slovak Republic and Switzerland report projected annual O&M costs above 40 USD/kWe. Most countries expect O&M costs to remain stable during the economic lifetime of the plants; however, Belgium, the Czech Republic and Italy (for one plant only) expect modest O&M cost escalation over time.

Table 3.5 – Specific annual O&M costs (per kWe) for gas-fired power plants in 2010

	CAN	USA-G1	USA-G2	BEL-G[a]	CZE-G[a]	DEU-G	FRA-G	GRC-G1	GRC-G2	ITA-G1	ITA-G2	ITA-G3[a]
NCU	25.86	14.00	26.00	25.00	406	30.50	33.94	15.00	4.30	11.37	12.72	26.43
USD	19.21	14.00	26.00	28.60	14.74	34.89	38.83	17.16	4.92	13.01	14.55	30.24
€	16.79	12.24	22.73	25.00	27.86	30.50	33.94	15.00	4.30	11.37	12.72	26.43

	NDL-G	PRT-G	SVK-G	CHE-G1	CHE-G2	TUR-G1	TUR-G2	JPN-G	KOR-G	ZAF-G
NCU	30.00	22.50	1 722	48.50	55.60	7 912	7 828	4 306	41 415	175.3
USD	34.32	25.74	47.36	35.96	41.23	5.54	5.48	36.17	33.13	24.31
€	30.00	22.50	41.39	31.44	36.04	4.84	4.79	31.62	28.96	21.25

a. Increasing with time.

Gas prices

Table 3.6 summarises gas price assumptions reported by respondents. Gas prices assumed by respondents in 2010, the reference year for plant commissioning, once expressed in USD/GJ using the official exchange rate of mid-2003, vary significantly from country to country but variations are less dramatic from region to region than it seems to be the case for coal. In this regard, it should be noted that for Japan and the Republic of Korea gas prices refer to liquefied natural gas (LNG) delivered at the plant.

Table 3.6 – Gas price assumptions provided by respondents

Country-Plant	2010		2020		2030		2040		2050		
	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	NCU/GJ	USD/GJ	
CAN-G	6.00	4.46	6.00	4.46	6.00	4.46	6.00	4.46	6.00	4.46	≈
USA-G1/2	4.58	4.58	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	↑
BEL-G	3.25	3.72	4.00	4.58	4.50	5.15					↑
CZE-G	150	5.45	155	5.63	160	5.81	165	5.99	170	6.17	↑
FRA-G	3.65	4.18	3.65	4.18	3.65	4.18	3.65	4.18	3.65	4.18	≈
DEU-G	4.40	5.03	5.10	5.83	5.80	6.64	6.60	7.55	7.30	8.35	↑
GRC-G1/2	5.00	5.72	5.00	5.72	5.00	5.72					≈
ITA-G1/2/3	4.94	5.65	5.61	6.42	6.09	6.97					↑
NDL-G	4.90	5.61	5.35	6.12	5.65	6.46	6.10	6.98			↑
PRT-G	3.86	4.42	3.86	4.42	3.86	4.42					≈
SVK-G	201	5.53	222	6.11	2.45	6.74	271	7.45	299	8.22	↑
CHE-G1/2/3	6.39	4.74	6.5	4.82	6.64	4.92	6.78	5.03	6.92	5.13	↑
TUR-G1/2	6 671	4.67	6 671	4.67	6 671	4.67	6 671	4.67	6 671	4.67	≈
JPN-G (LNG)	550	4.62	564	4.74	578	4.86	593	4.98	608	5.11	↑
KOR-G (LNG)	6 755	5.40	6 755	5.40	6 755	5.40	6 755	5.40			≈
ZAF-G (LNG)	25.6	3.55	25.6	3.55	25.6	3.55					≈

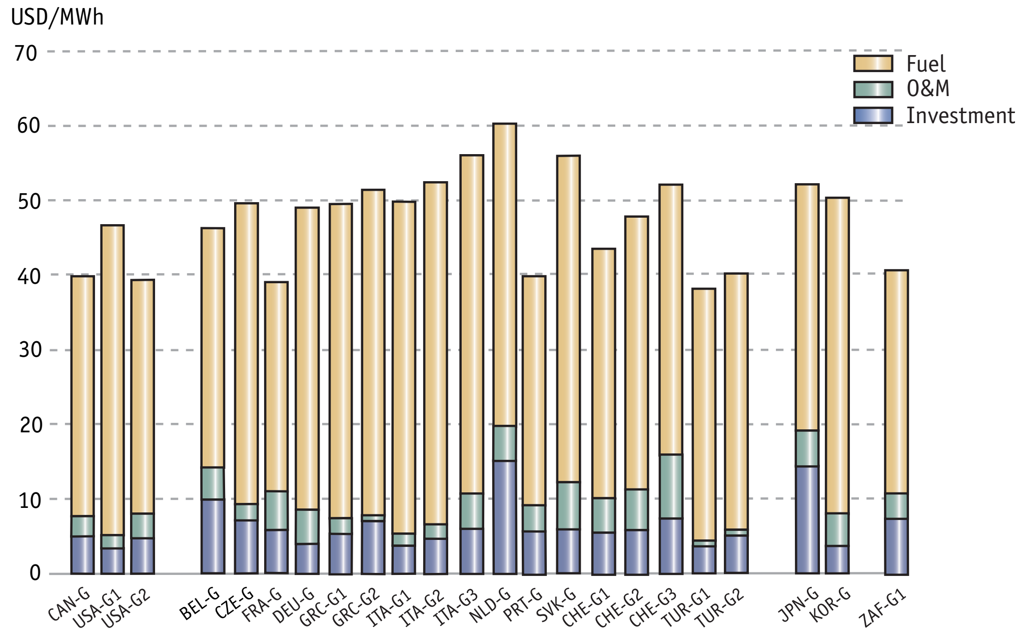
Most gas prices assumed in 2010 are ranging between 3.5 and 4.5 USD/GJ but several European countries and the Republic of Korea report gas prices higher than 5.5 USD/GJ. A majority of countries are expecting gas price escalation but Canada, France, Greece, Portugal, Turkey, the Republic of Korea and the Republic of South Africa are reporting stable gas prices over the economic lifetime of the gas-fired plants.

The current gas prices are on a relatively high level and can be expected to have an influence on price projections. The projections on gas prices in 2010 provided by Canada and the United States for the study are lower than the current import price level. Several of the projected gas price levels in 2010 of European respondents in the study are significantly higher than the current European import price level. The projected level used in the Japanese response for 2010 is lower than the current import price level. The IEA gas price assumptions for North America, Europe and Japan given in *World Energy Outlook* (WEO/IEA, 2004) are markedly different and are presented in Appendix 8. The gas price levels projected by respondents are in general significantly higher than WEO 2004 assumptions, in real terms. In several of the European cases, they are more than 50% higher.

Levelised generation costs

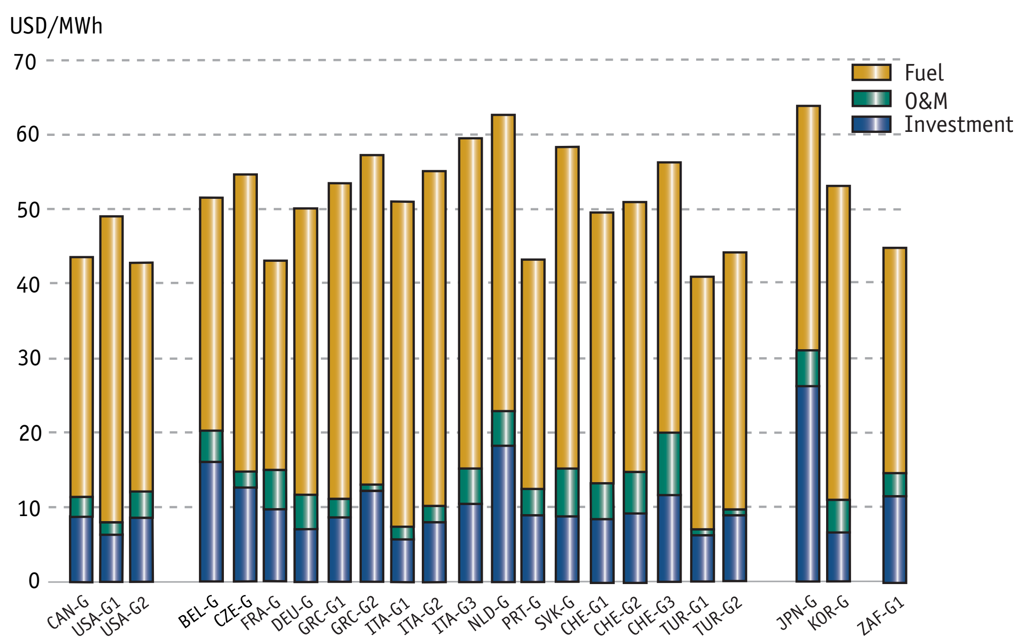
At 5% discount rate, the levelised costs of generating electricity from gas-fired power plants (Figure 3.5 and Table 3.13) vary between 37 USD/MWh and 60 USD/MWh but only four units, GRC-G2 in Greece, ITA-G2 in Italy and the gas plants in the Netherlands and the Slovak Republic have levelised costs higher than 55 USD/MWh. It should be noted that fuel cost represents in average nearly 80% of the total levelised cost and up to nearly 90% in some cases. Consequently, the assumptions made by respondents on gas prices at the date of commissioning and their escalation rates are driving factors in the estimated levelised costs of gas generated electricity obtained in the study. The investment cost represents a share less than 15%; O&M costs account for less than 10% in most cases and are sometime nearly negligible.

Figure 3.5 – Levelised costs of gas generated electricity at 5% discount rate (USD/MWh)



At 10% discount rate (see Figure 3.6), levelised costs of gas-fired plants range between 40 and 63 USD/MWh. They are barely higher than at 5% discount rate owing to their low overnight construction costs and very short construction periods. Fuel cost remains the major contributor to total generation cost with a slightly lower share – 73% – than at 5% discount rate, while investment and O&M shares are around 20% and 7%.

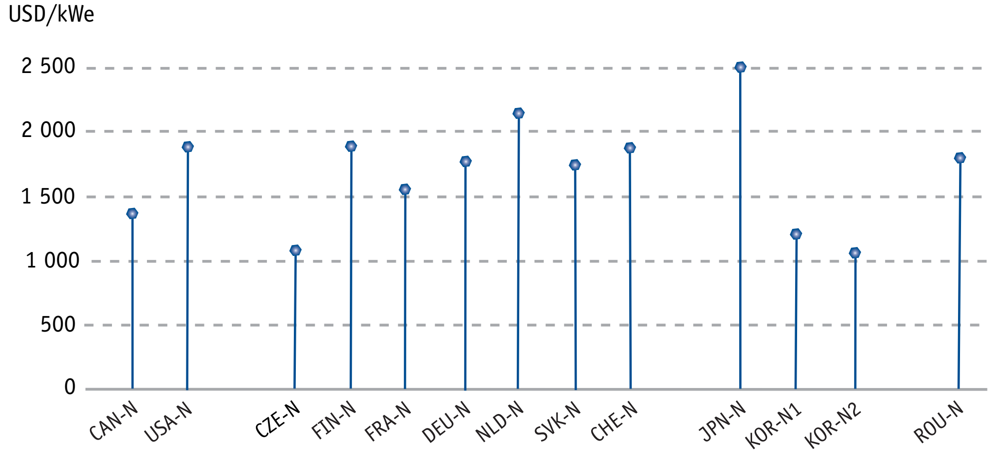
Figure 3.6 – Levelised costs of gas generated electricity at 10% discount rate (USD/MWh)



Nuclear power plants

Overnight construction costs

Figure 3.7 – Specific overnight construction costs of nuclear power plants (USD/kWe)



The specific overnight construction costs, not including refurbishment or decommissioning, of the nuclear power plants included in the study are displayed in Figure 3.7 and in Table 3.12 at the end of the chapter. Those costs vary between 1 000 and 2 000 USD/kWe for most plants. However, the nuclear plant in the Netherlands has an overnight construction cost slightly above 2 100 USD/kWe and the nuclear plant of Japan has an overnight construction cost exceeding slightly 2 500 USD/kWe. It should be noted that the total levelised investment costs calculated in the study and presented below include in addition to the construction cost, refurbishment and decommissioning costs and interest during construction.

Construction time

Although the construction times of nuclear power plants have been sometimes rather long in the past, many recent nuclear power plants were constructed and put into service within no more than four years. The schedules for construction expenses reported in the responses to the questionnaire vary significantly from country to country. As shown in Table 3.7, the total expense period ranges from five years in three countries to ten years in one country. In nearly all countries, however, 90% or more of the expenses are incurred within five years or less; the expenses during the earlier years generally correspond to activities prior to construction *per se*. For example in France, expenses during years -9 to -6 correspond to engineering studies and down payment of some components, in Romania expenses in year -6 and before correspond to preliminary studies and in Canada the expense schedule reflects down payments before construction also.

Table 3.7 – Expense schedule for nuclear power plant construction (% of total overnight construction cost per year)

	CAN[a]	USA	CZE	FIN	FRA[b]	DEU	NLD	SVK	CHE	JPN	KOR-N1	KOR-N2	ROU[c]
-9					1								
-8					1.5			1					16.5
-7					2			0.1				0.3	12.5
-6		10	1		7			2.9	3	5	2.5	3.5	12.5
-5	8	20	9	10	15.5	10	20	11	19	15	8	12.2	12.5
-4	22	20	17	22	22	15	20	18	19.5	20	24.5	24	12.5
-3	29	20	17	28	21	22	20	24.5	19.5	20	40	37.5	16.5
-2	21	20	33	20	18	30	20	26.5	19.5	18.5	22	20	12.5
-1	12.5	10	23	20	10	23	20	16	19.5	21.5	3	2.5	4.5
1	7.5				2								

a. Expenses in year -5 are down payment. b. Expenses in years -9 to -6 are for studies. c. Construction time is 5 years.

O&M costs

The specific annual O&M costs summarised in Table 3.8 show a variability from country to country reflecting largely differences in wages and equipment prices in different parts of the world. The lowest projected specific annual O&M costs are reported by Finland and France, and the highest by Japan; projected O&M costs reported by Japan are more than double of those reported by Finland or France expressed in USD. Only the Slovak Republic indicated an escalation of specific annual O&M costs with time, all other respondents assume that O&M costs will remain constant over the economic lifetime of the plant.

Table 3.8 – Specific annual O&M costs (per kWe) of nuclear power plants in 2010

	CAN	USA	CZE	FIN	FRA	DEU	NLD	SVK	CHE	JPN	KOR1	KOR2	ROU[b]
NCU	89.6	63	1 713	41.96	40.3	56.80	59	2 830[a]	72	12 810	86 243	72 526	–
USD	66.6	63	62.2	48.00	46.1	64.98	67.5	77.8	53.4	107.6	68.99	58.02	81.9
€	58.2	55	54.4	41.96	40.3	56.80	59	68	46.7	94	60.31	50.72	71.6

a. Increasing with time.
b. Costs reported in USD.

Table 3.9 – Nuclear fuel cycle costs (USD/MWh)

Country	At 5% discount rate			At 10% discount rate		
	Front end	Back end	Total	Front end	Back end	Total
Canada	2.53	1.04	3.57	2.53	1.04	3.57
United States	3.44	1.20	4.64	3.56	1.10	4.66
Czech Republic	ns	ns	4.50	ns	ns	4.70
Finland	ns	ns	5.13	ns	ns	4.90
France	4.30	0.70	5.00	4.80	0.50	5.30
Germany	ns	ns	4.78	ns	ns	4.78
Netherlands	4.00	4.00	8.00	4.00	4.00	8.00
Slovak Republic	3.90	1.90	5.80	3.96	1.90	5.86
Switzerland	3.49	1.10	4.59	3.49	1.10	4.59
Japan	5.88	5.88	11.76	6.97	4.79	11.76
Korea N1	ns	ns	3.55	ns	ns	3.98
Korea N2	ns	ns	3.56	ns	ns	3.98
Romania	2.00	0.80	2.80	2.00	0.80	2.80

Abbreviation: **ns** = not specified.

The nuclear fuel cycle includes several steps, from uranium mining to disposal of spent fuel or radioactive waste from reprocessing. For the purpose of this study, the levelised nuclear fuel cycle costs were not calculated by the Secretariat but asked for in the questionnaire. The responses provided at 5% and 10% discount rates are presented in Table 3.9 and were used in calculating levelised costs of generating electricity from nuclear power plants. Past trends have shown decreasing fuel cycle costs but all responding countries, except Finland which projects a 1% increase per year, expect those costs to remain stable during the economic lifetime of the nuclear power plants. In most cases, the impact of discount rate on levelised fuel cycle cost is estimated negligible by the respondents.

Levelised generation costs

The levelised costs of generating nuclear electricity are presented in Figures 3.8 and 3.9 and in the detailed tables of results for all power plants (Tables 3.13 and 3.14). The large increase in the levelised cost of nuclear generated electricity at 10% discount rate as compared with the levelised cost at 5% discount rate, visible on Figures 3.8 and 3.9, is a characteristic of nuclear energy and other capital intensive technologies for generating electricity.

At 5% discount rate, the levelised costs of nuclear generated electricity range between 21 and 31 USD/MWh except for the two plants in the Netherlands and Japan. Investment costs represent the largest share of total levelised costs, around 50% in average while O&M costs represent around 30% and fuel cycle costs around 20%. The cost structure, i.e. respective shares of the three components, remains fairly stable from country to country.

At 10% discount rate, the levelised costs of nuclear generated electricity are in the range 30 to 50 USD/MWh in all countries except the Netherlands and Japan. In Japan, the levelised cost exceeds largely 60 USD/MWh. The share of investment in total levelised generation cost is around 70% while the other cost elements, O&M and fuel cycle, represent in average 20% and 10% respectively.

Figure 3.8 – Levelised costs of nuclear generated electricity at 5% discount rate (USD/MWh)

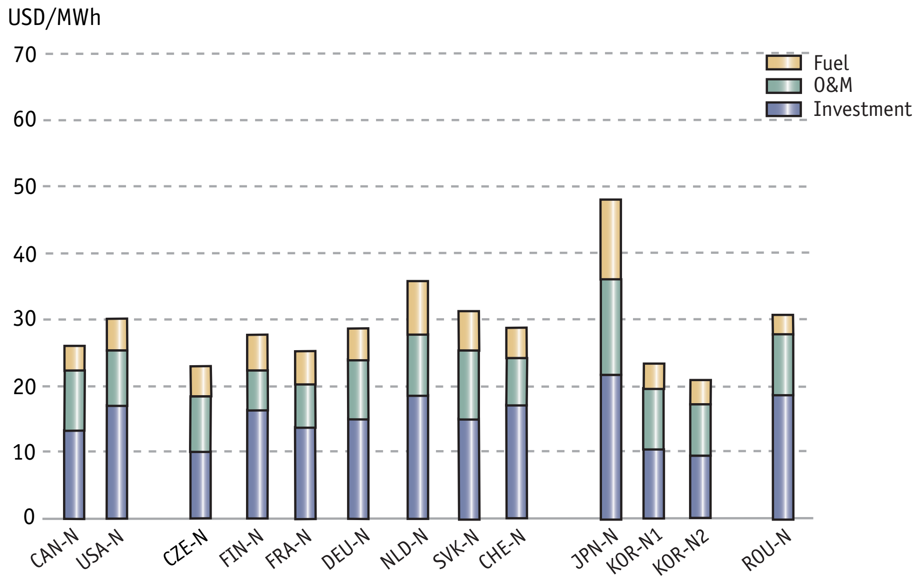
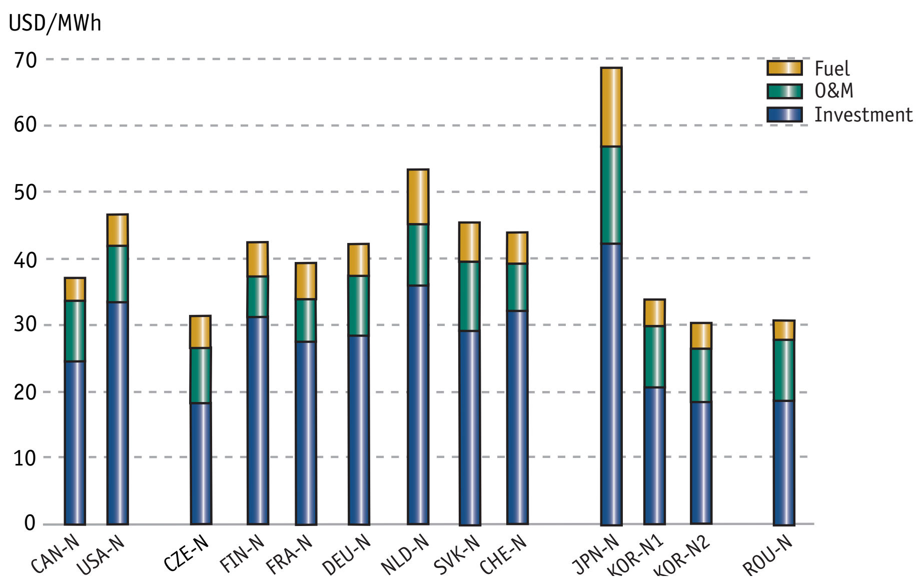


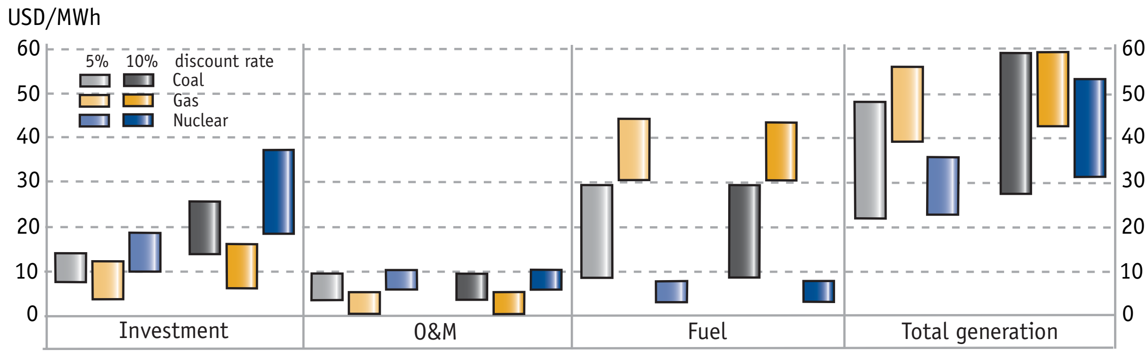
Figure 3.9 – Levelised costs of nuclear generated electricity at 10% discount rate (USD/MWh)



Cost ranges for coal, gas and nuclear power plants

Figure 3.10 summarises the ranges observed for levelised investment, O&M, fuel and total generation costs with the sixty three data sets provided for the study. In each category the 5% highest and lowest values have been excluded.

Figure 3.10 – Range of levelised costs for coal, gas and nuclear power plants (USD/MWh)



Cost ratios for coal, gas and nuclear power plants

Ten countries – Canada, the Czech Republic, France, Germany, Japan, the Republic of Korea, the Republic of South Africa, the Slovak Republic, Turkey and the United States – provided cost data for coal and gas power plants. Ten countries – Canada, the Czech Republic, Finland, France, Germany, Japan, the Republic of Korea, Romania, the Slovak Republic and the United States – provided data for coal and nuclear power plants. Ten countries – Canada, the Czech Republic, France, Germany, Japan, the Republic of Korea, the Netherlands, the Slovak Republic, Switzerland and the United States – provided data for gas and nuclear power plants. Figures 3.11, 3.12 and 3.13 show the cost ratios in each country between coal, gas and nuclear at 5% and 10% discount rates.

It should be stressed that the graphs show levelised costs in different countries and for different technologies within the same fuel class. For example, coal-fired plants include a broad range of technologies from traditional combustion to integrated coal gasification plants with carbon sequestration. Also, coal-fired units use various solid mineral fuels including lignite as well as hard coal. Similarly, gas-fired units include plants using liquefied natural gas requiring different infrastructure for transport and delivery at the plant than natural gas used by other CCGT plants.

At 5% discount rate

Coal is cheaper than gas by a margin of 10% or more[2] in seven of the countries and in Germany except for one plant (DEU-C3, IGCC with CO_2 capture) for which the difference in favour of coal is less than 10%. For one combination of plants in Turkey (TUR-C1 and TUR-G1) gas is cheaper by a margin of more than 10%.

2. In the light of the uncertainties in cost elements, in particular projected fuel prices but also projected O&M costs and even investments and expense schedules, differences of less than 10% in levelised generation costs of alternatives cannot be considered significant.

In seven countries for one or more combinations of plants, nuclear is cheaper than coal with a margin of 10% or more. Coal is cheaper than nuclear by a margin of 10% or more in one case in the United States.

Nuclear is cheaper than gas by a margin of 10% or more in nine countries. Gas is never cheaper than nuclear by a margin of 10% of more.

At 10% discount rate

Coal is cheaper than gas by a margin of 10% or more for all plants in the Republic of Korea, the Republic of South Africa and the United States, and in most cases in the Czech Republic and in Germany. In most cases in Turkey and for one plant in the Slovak Republic, gas is cheaper than coal by a margin of 10% or more.

In Canada, the Czech Republic, France, the Slovak Republic and for two plants in Germany, nuclear is cheaper than coal by a margin of more than 10%. Coal is cheaper than nuclear by a margin of 10% or more in the United States and for one plant in Germany.

In Canada, the Czech Republic, France, Germany, the Netherlands, the Slovak Republic, the Republic of Korea and for two plants in Switzerland, nuclear is cheaper than gas by a margin of 10% or more. The difference between gas and nuclear is less than 10% in the United States and Japan and for one plant in Switzerland.

Figure 3.11 – Cost ratios for coal-fired and gas-fired power plants at 5% and 10% discount rates

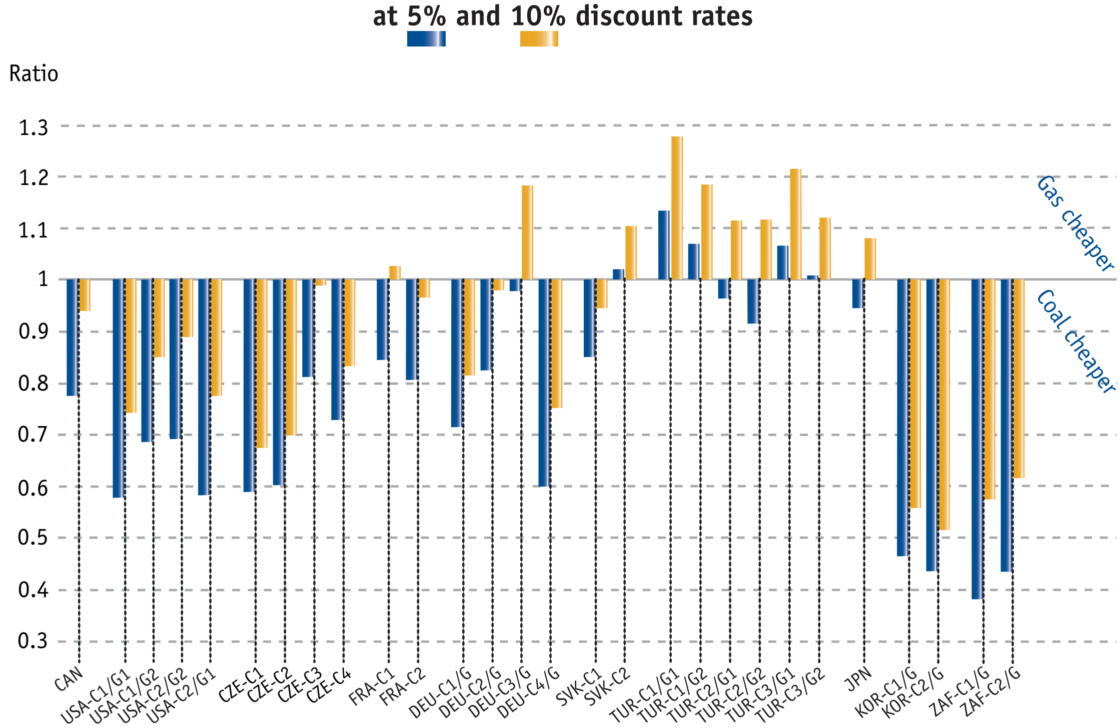


Figure 3.12 – Cost ratios for coal-fired and nuclear power plants at 5% and 10% discount rates

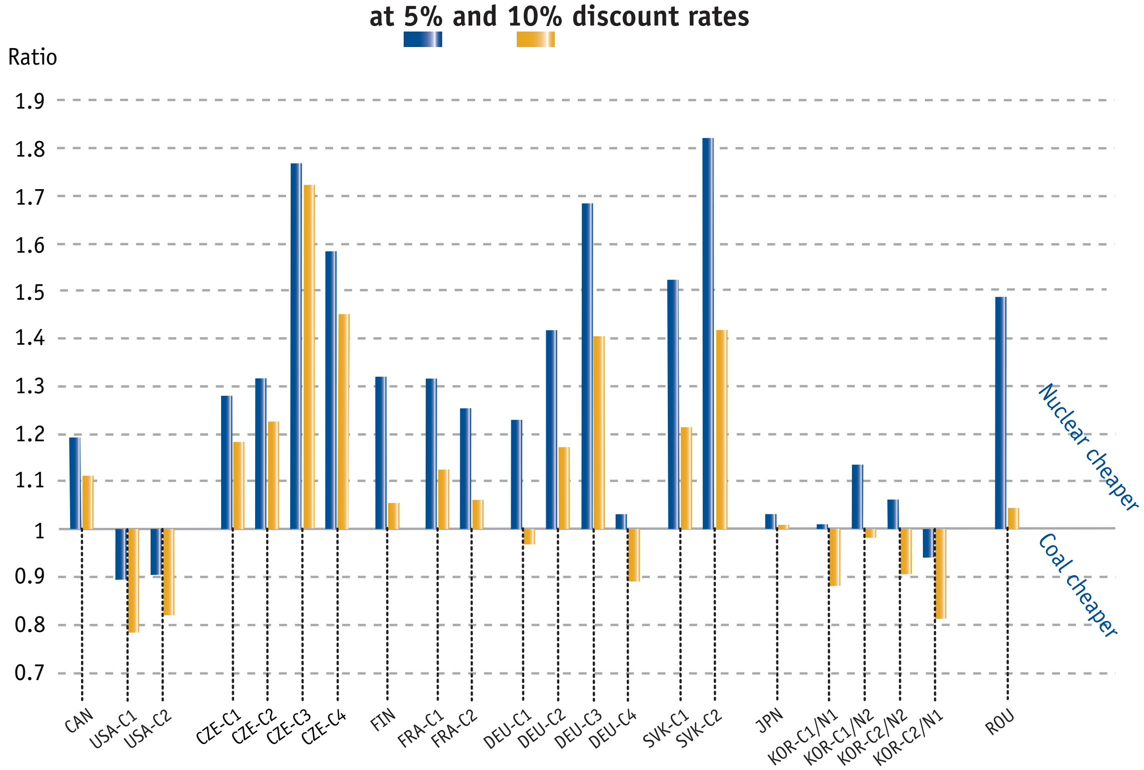


Figure 3.13 – Cost ratios for gas-fired and nuclear power plants at 5% and 10% discount rates

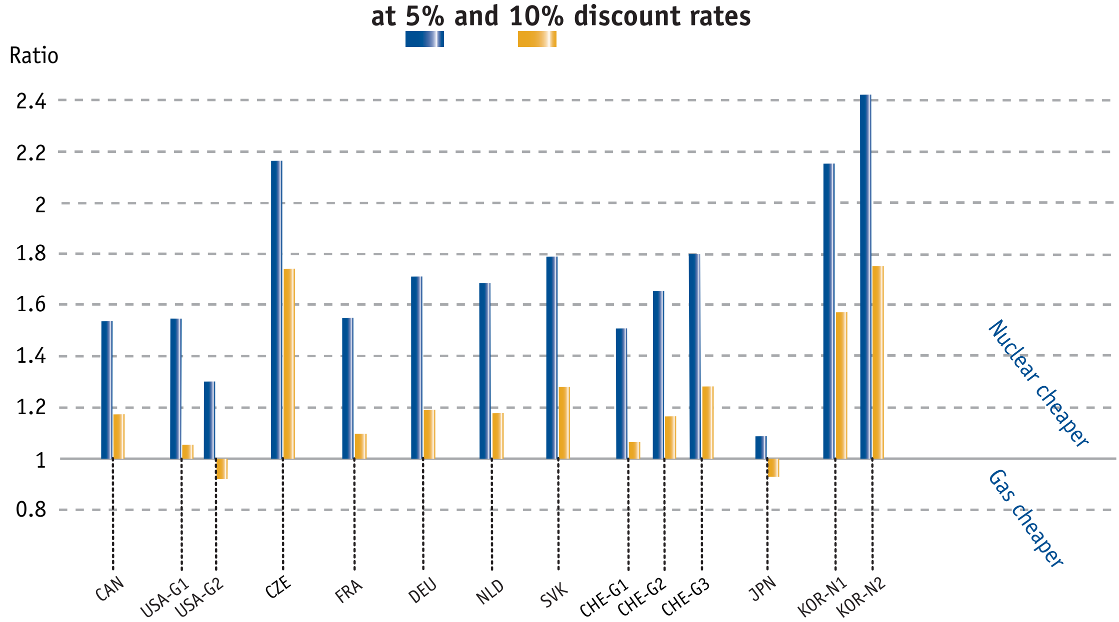


Table 3.10 – Overnight construction costs of coal-fired power plants

Plant-Abbrev. Name	Plant type/ emission control equipment included in costs	Net capacity in cost estimates (MWe)	Overnight construction costs			
			MNCU	MUSD	M€	USD/kWe
CAN-C	PF(SC)/FGD, LNB, FF	450	800	594	519	1 320
USA-C1	PF/FGD, SCR, FF	600	696	696	608	1 160
USA-C2	IGCC/FGD, SCR, FF	550	751	751	657	1 366
CZE-C1	PF/brown coal/FGD, de NO_x, dust	300	9 720	353	308	1 176
CZE-C2	FBC/brown coal/de SO_x	150	5 160	187	164	1 249
CZE-C3	IGCC/de SO_x, de NO_x	300	16 000	581	508	1 936
CZE-C4	FBC/brown coal & biomass/de SO_x	150	5 500	200	175	1 331
DNK-C	STC/FGD, SCR, ESP	400	3 360	518	453	1 294
FIN-C	(SC)/FGD, SCR, ESP	500	539	617	539	1 233
FRA-C1	PF(SC)/**ns**	900	1 096	1 254	1 096	1 393
FRA-C2	FBC/**ns**	600	666	762	666	1 270
DEU-C1	PF/dust, FGD, SCR	800	656	750	656	938
DEU-C2	IGCC/dust, desulphurisation	450	540	618	540	1 373
DEU-C3	IGCC/dust, desulphurisation, CO_2 capture	425	638	729	638	1 716
DEU-C4	PF, lignite/dust, desulphurisation	1 050	1 208	1 381	1 208	1 316
SVK-C1	FBC/de SO_x, de NO_x, ESP	228	11 200	308	269	1 351
SVK-C2	FBC, lignite/de SO_x, de NO_x, ESP	114.4	5 400	149	130	1 298
TUR-C1	PF, lignite/FGD, de NO_x	340	569 188	398	348	1 172
TUR-C2	PF/FGD, de NO_x	500	868 209	608	531	1 215
TUR-C3	FBC, lignite/limestone	160	276 072	193	169	1 208
JPN-C	PF/FGD, SCR, ESP	800	223 500	1 877	1 641	2 347
KOR-C1	PF/FGD, SCR, ESP	1 000	997 299	798	697	798
KOR-C2	PF/FGD, SCR, ESP	1 600	143 675	1 150	1 005	719
BGR-C[a]	PF, lignite/de SO_x, de NO_x	600	–	892	780	1 487
ROU-C[a]	PF, lignite/de SO_x, de NO_x, particles	296	–	314	274	1 060
ZAF-C1	PF/FGD	3 852	37 721	5 232	4 573	1 358
ZAF-C2	FBC/ns	466	4 506	625	546	1 341

a. Cost estimates reported in euros.

Abbreviation: **ns** = not specified.

Table 3.11 – Overnight construction costs of gas-fired power plants

Plant-Abbrev. name	Technology/ emission control equipment included in costs	Net capacity in cost estimates (MWe)	Overnight construction costs			
			MNCU	MUSD	M€	USD/kWe
CAN-G	CCGT/LNB	580	460	342	299	589
USA-G1	CT/SCR, FF	230	106	106	92	459
USA-G2	CCGT/SCR, FF	400	244	244	213	609
BEL-G1	CCGT/**ns**	400	335	383	335	958
CZE-G	CCGT/de NO_x	250	5 250	191	167	762
FRA-G	CCGT/**ns**	900	471	539	471	599
DEU-G	CCGT/SCR	1 000	440	503	440	503
GRC-G1	CCGT/de NO_x	377.7	181	208	181	549
GRC-G2	CCGT/de NO_x	476.3	287	328	287	688
ITA-G1	CCGT/de NO_x	791	252	288	252	364
ITA-G2	CCGT/de NO_x	1 150	460	526	460	457
ITA-G3	CCGT/de NO_x	384	224	256	224	667
NLD-G	CCGT/**ns**	500	450	515	450	1 030
PRT-G	CCGT/LNB	1 200	588	673	588	561
SVK-G	CCGT/LNB	391	7 825	215	188	550
CHE-G1	CCGT/LNB	400	315	234	204	584
CHE-G2	CCGT/LNB	250	213	158	138	631
CHE-G3	CCGT/LNB	110	119	88	77	801
TUR-G1	CCGT/de NO_x	700	424 458	297	260	424
TUR-G2	CCGT/de NO_x	280	239 599	168	147	599
JPN-G	CCGT (LNG)/SCR	1 600	246 100	2 067	1 807	1 292
KOR-G	CCGT (LNG)/SCR	889.2	476 015	381	333	428
ZAF-G	CCGT (LNG)/**ns**	1 935	9 797	1 359	1 188	702

Abbreviation: **ns** = not specified.

Table 3.12 – Overnight construction costs of nuclear power plants

Plant-Abbrev. name	Reactor type/ fuel cycle option	Net capacity in cost estimates (MWe)	Overnight construction costs			
			MNCU	MUSD	M€	USD/kWe
CAN-N	PHWR/OT	1 406	2 600	1 931	1 688	1 373
USA-N	GENIII/OT	1 000	1 894	1 894	1 656	1 894
CZE-N	VVER/OT	1 000	30 000	1 089	952	1 089
FIN-N	PWR/OT	1 500	2 485	2 843	2 485	1 895
FRA-N	PWR/CC	1 590	2 163	2 474	2 163	1 556
DEU-N	PWR/OT	1 590	2 456	2 819	2 465	1 773
NLD-N	PWR/CC	1 600	3 000	3 432	3 000	2 145
SVK-N	VVER/OT	894	56 780	1 561	1 365	1 747
CHE-N	BWR/OT	1 600	4 062	3 012	2 633	1 882
JPN-N	ABWR/CC	1 330	397 400	3 338	2 918	2 510
KOR-N1	PWR/OT	1 906	2 878 840	2 303	2 013	1 208
KOR-N2	PWR/OT	2 682.4	3 599 830	2 880	2 517	1 074
ROU-N[a]	PHWR/OT	665	–	1 200	1 049	1 805

a. Costs reported in USD.

Table 3.13 – Projected generation costs calculated with generic assumption at 5% discount rate (USD of 1 July 2003/MWh)

Country	Coal					Gas					Nuclear				
		Invest.	O&M	Fuel	Total		Invest.	O&M	Fuel	Total		Invest.	O&M	Fuel	Total
Canada	CAN-C	11.2	6.7	13.1	31.1	CAN-G	5.3	2.6	32.1	40.0	CAN-N	13.5	8.9	3.6	26.0
		36%	22%	42%	100%		14%	6%	80%	100%		52%	34%	14%	100%
United States	USA-C1	10.0	6.6	10.5	27.1	USA-G1	3.6	1.9	41.2	46.7	USA-N	17.0	8.5	4.6	30.1
		37%	24%	39%	100%		8%	4%	88%	100%		57%	28%	15%	100%
	USA-C2	11.7	6.7	8.9	27.3	USA-G2	4.9	3.5	30.9	39.3					
		43%	25%	32%	100%		12%	9%	79%	100%					
Belgium						BEL-G	10.1	4.2	32.1	46.4					
						25[a]	22%	9%	69%	100%					
Czech Rep.	CZE-C1	10.5	4.2	14.7	29.4	CZE-G	7.5	2.0	40.2	49.7	CZE-N	10.1	8.4	4.5	23.0
		36%	14%	50%	100%		15%	4%	81%	100%		44%	36%	20%	100%
	CZE-C2	11.2	4.3	14.7	30.2										
		37%	14%	49%	100%										
	CZE-C3	17.4	4.3	18.9	40.6										
		43%	11%	46%	100%										
	CZE-C4	11.9	4.3	20.1	36.3										
		33%	12%	55%	100%										
Denmark	DNK-C	10.9	5.6	15.4	31.9										
		35%	17%	48%	100%										
Finland	FIN-C	10.3	6.6	19.4	36.4						FIN-N	16.3	6.1	5.1	27.6
		29%	18%	53%	100%							59%	22%	19%	100%
France	FRA-C1	11.9	7.7	13.7	33.3	FRA-G	6.0	5.2	28.0	39.2	FRA-N	13.91	6.45	5.0	0.0
		36%	23%	41%	100%		16%	13%	71%	100%		55%	25%	20%	100%
	FRA-C2	10.9	6.9	14.0	31.7										
		34%	22%	44%	100%										
Germany	DEU-C1	7.7	8.7	18.7	35.2	DEU-G	4.1	4.7	40.3	49.0	DEU-N	15.1	8.7	4.8	28.6
		22%	25%	53%	100%		8%	10%	82%	100%		53%	30%	17%	100%
	DEU-C2	11.3	12.4	16.9	40.6										
		28%	30%	42%	100%										
	DEU-C3	14.1	14.9	19.2	48.2										
		29%	31%	40%	100%										
	DEU-C4	10.8	6.7	12.0	29.5										
		36%	23%	41%	100%										
Greece						GRE-G1	5.4	2.3	41.9	49.7					
						25[a]	11%	5%	84%	100%					
						GRE-G2	7.2	0.7	43.6	51.4					
						25[a]	14%	1%	85%	100%					
Italy						ITA-G1	3.6	1.7	44.4	49.7					
						25[a]	7%	4%	89%	100%					
						ITA-G2	4.8	2.0	45.8	52.6					
						25[a]	9%	4%	87%	100%					
						ITA-G3	6.2	4.7	45.2	56.1					
						30[a]	11%	8%	67%	100%					
Netherlands						NLD-G	15.4	4.6	40.4	60.4	NLD-N	18.7	9.1	8.0	35.8
						30[a]	25%	8%	67%	100%		53%	25%	22%	100%
Portugal						PRT-G	5.8	3.5	30.7	40.0					
						24[a]	14%	9%	77%	100%					
Slovak Rep.	SVK-C1	11.5	9.6	26.6	47.8	SVK-G	6.0	6.4	43.5	55.9	SVK-N	15.1	10.5	5.8	31.3
		24%	20%	56%	100%	20[a]	11%	11%	78%	100%		48%	33%	19%	100%
	SVK-C2	11.3	9.7	35.9	56.9										
		20%	17%	63%	100%										
Switzerland						CHE-G1	5.6	4.8	33.2	43.6	CHE-N	17.1	7.2	4.6	28.8
						25[a]	13%	11%	76%	100%		59%	25%	16%	100%
						CHE-G2	6.0	5.5	36.2	47.8					
						25[a]	12%	12%	76%	100%					
						CHE-G3	7.6	8.4	36.0	52.1					
						25[a]	15%	16%	69%	100%					
Turkey	TUR-C1	9.9	3.9	29.6	43.4	TUR-G1	3.9	0.7	33.6	38.2					
		23%	9%	68%	100%	30[a]	10%	2%	88%	100%					
	TUR-C2	10.1	7.6	19.4	37.1	TUR-G2	5.4	0.7	34.2	40.4					
		28%	20%	52%	100%	30[a]	13%	2%	85%	100%					
	TUR-C3	10.1	5.6	25.1	40.8										
		25%	14%	61%	100%										
Japan	JPN-C	20.6	8.8	20.0	49.5	JPN-G	14.5	4.9	32.8	52.1	JPN-N	21.8	14.5	11.8	48.0
		42%	18%	40%	100%		28%	9%	63%	100%		45%	30%	25%	100%
Korea, Rep. of	KOR-C1	7.9	5.1	10.6	23.6	KOR-G	3.9	4.4	38.1	46.5	KOR-N1	10.6	9.3	3.6	23.4
		33%	22%	45%	100%	30[a]	8%	10%	82%	100%		45%	40%	15%	100%
	KOR-C2	7.2	4.1	10.2	21.6						KOR-N2	9.4	7.8	3.6	20.8
		34%	19%	47%	100%							46%	37%	17%	100%
Bulgaria	BGR-C	12.6	6.0	12.7	31.3										
		40%	19%	41%	100%										
Romania	ROU-C	14.3	1.4	29.8	45.5						ROU-N	18.7	9.2	2.8	30.6
	15[a]	31%	3%	66%	100%							61%	30%	9%	100%
South Africa, Rep. of	ZAF-C1	11.7	2.3	1.6	15.7	ZAF-G	7.6	3.3	29.9	40.8					
		75%	15%	10%	100%	25[a]	19%	8%	73%	100%					
	ZAF-C2	13.1	3.8	1.0	17.9										
		73%	21%	6%	100%										

a. Economic lifetime assumed to calculate levelised costs if different from 40 years.

Table 3.14 – Projected generation costs calculated with generic assumption at 10% discount rate (UD of 1 July 2003/MWh)

Country		Coal					Gas					Nuclear			
		Invest.	O&M	Fuel	Total		Invest.	O&M	Fuel	Total		Invest.	O&M	Fuel	Total
Canada	CAN-C	21.4	6.7	13.1	41.2	CAN-G	8.9	2.6	32.1	43.6	CAN-N	24.6	8.9	3.6	37.1
		52%	16%	32%	100%		20%	6%	74%	100%		66%	24%	10%	100%
United States	USA-C1	19.5	6.6	10.5	36.5	USA-G1	6.4	1.9	40.8	49.0	USA-N	33.4	8.5	4.7	46.5
		53%	18%	29%	100%		13%	4%	83%	100%		72%	18%	10%	100%
	USA-C2	22.6	6.7	8.9	38.2	USA-G2	8.7	3.5	30.6	42.8					
		59%	18%	23%	100%		20%	8%	72%	100%					
Belgium						BEL-G	16.3	4.2	31.0	51.5					
						25[a]	32%	8%	60%	100%					
Czech Rep.	CZE-C1	19.0	4.1	14.0	37.1	CZE-G	12.9	2.0	39.7	54.6	CZE-N	18.3	8.4	4.7	31.7
		51%	11%	38%	100%		23%	4%	73%	100%		58%	27%	15%	100%
	CZE-C2	20.2	4.3	14.0	38.4										
		53%	11%	36%	100%										
	CZE-C3	31.6	4.3	18.2	54.0										
		58%	8%	34%	100%										
	CZE-C4	21.5	4.3	19.8	45.5										
		48%	9%	43%	100%										
Denmark	DNK-C	20.6	5.6	15.2	41.4										
		50%	13%	37%	100%										
Finland	FIN-C	19.3	6.6	18.6	44.5						FIN-N	31.2	6.1	4.9	42.2
		43%	15%	42%	100%							73%	15%	12%	100%
France	FRA-C1	22.8	7.7	13.7	44.2	FRA-G	9.9	5.2	28.0	43.0	FRA-N	27.5	6.4	5.3	39.3
		51%	18%	31%	100%		23%	12%	65%	100%		71%	16%	13%	100%
	FRA-C2	20.8	6.9	14.0	41.7										
		49%	17%	34%	100%										
Germany	DEU-C1	14.1	8.7	18.1	40.9	DEU-G	7.3	4.7	38.0	50.0	DEU-N	28.6	8.7	4.8	42.1
		35%	21%	44%	100%		15%	9%	76%	100%		68%	21%	11%	100%
	DEU-C2	20.6	12.4	16.3	49.3										
		42%	25%	33%	100%										
	DEU-C3	25.8	14.9	18.5	59.1										
		44%	25%	31%	100%										
	DEU-C4	19.7	6.7	11.3	37.7										
		52%	18%	30%	100%										
Greece						GRE-G1	8.8	2.3	41.9	53.0					
						25[a]	17%	4%	79%	100%					
						GRE-G2	12.3	0.7	43.6	56.5					
						25[a]	22%	1%	77%	100%					
Italy						ITA-G1	5.8	1.7	43.5	51.1					
						25[a]	12%	3%	85%	100%					
						ITA-G2	8.3	2.0	44.9	55.1					
						25[a]	15%	4%	81%	100%					
						ITA-G3	10.8	4.6	44.1	59.4					
						30[a]	18%	8%	74%	100%					
Netherlands						NLD-G	18.4	4.6	39.6	62.6	NLD-N	36.2	9.1	8.0	53.2
						30[a]	30%	7%	63%	100%		68%	17%	15%	100%
Portugal						PRT-G	9.1	3.5	30.7	43.3					
						24[a]	21%	8%	71%	100%					
Slovak Rep.	SVK-C1	20.2	9.6	25.5	55.2	SVK-G	9.0	6.4	42.9	58.3	SVK-N	29.1	10.5	5.9	45.5
		37%	17%	46%	100%	**20**[a]	15%	11%	74%	100%		64%	23%	13%	100%
	SVK-C2	20.1	9.7	34.6	64.4										
		31%	15%	54%	100%										
Switzerland						CHE-G1	8.6	4.8	33.1	46.5	CHE-N	32.0	7.2	4.6	43.8
						25[a]	19%	10%	71%	100%		74%	16%	10%	100%
						CHE-G2	9.3	5.5	36.1	51.0					
						25[a]	18%	11%	71%	100%					
						CHE-G3	11.9	8.4	35.9	56.2					
						25[a]	21%	15%	64%	100%					
Turkey	TUR-C1	18.9	3.9	29.6	52.3	TUR-G1	6.5	0.7	33.6	40.9					
		36%	7%	57%	100%		16%	2%	82%	100%					
	TUR-C2	18.7	7.6	19.4	45.7	TUR-G2	9.2	0.7	34.2	44.2					
		40%	17%	43%	100%		20%	2%	78%	100%					
	TUR-C3	18.9	5.6	25.1	49.6										
		38%	11%	51%	100%										
Japan	JPN-C	40.7	8.8	19.5	69.1	JPN-G	26.4	4.9	32.6	63.8	JPN-N	42.4	14.5	11.8	68.6
		59%	13%	28%	100%		41%	8%	51%	100%		62%	21%	17%	100%
Korea, Rep. of	KOR-C1	13.7	5.1	10.6	29.4	KOR-G	6.8	4.4	38.1	49.4	KOR-N1	20.6	9.3	4.0	33.8
		47%	17%	36%	100%	**30**[a]	14%	9%	77%	100%		61%	27%	12%	100%
	KOR-C2	12.7	4.1	10.2	27.1						KOR-N2	18.6	7.8	4.0	30.3
		47%	15%	38%	100%							61%	26%	13%	100%
Bulgaria	BGR-C	23.9	6.0	12.7	42.6										
		56%	14%	30%	100%										
Romania	ROU-C	20.2	1.4	29.8	51.5						ROU-N	37.3	9.2	2.8	49.3
	15[a]	39%	3%	58%	100%							75%	19%	6%	100%
South Africa, Rep. of	ZAF-C1	21.9	2.3	1.6	25.9	ZAF-G	11.6	3.3	29.9	44.8					
		85%	9%	6%	100%	**25**[a]	26%	7%	67%	100%					
	ZAF-C2	22.9	3.8	1.0	27.8										
		82%	14%	4%	100%										

a. Economic lifetime assumed to calculate levelised costs if different from 40 years.

Generation Costs of Wind, Hydro and Solar Power Plants

This chapter gives an overview on the costs of electricity generation for the wind, hydro and solar power plants considered in the study. The generic framework and assumptions adopted to calculate levelised generation costs for those plants have been adapted to reflect their specific characteristics. The economic lifetimes assumed for cost calculations are the technical lifetimes indicated in responses to the questionnaire; in most cases, those lifetimes are shorter than the 40 years adopted as generic assumption for coal and nuclear power plants. Also, the average availability/capacity factors reported for those plants and used to calculate levelised costs are significantly lower than the generic 85% adopted for coal, gas and nuclear power plants.

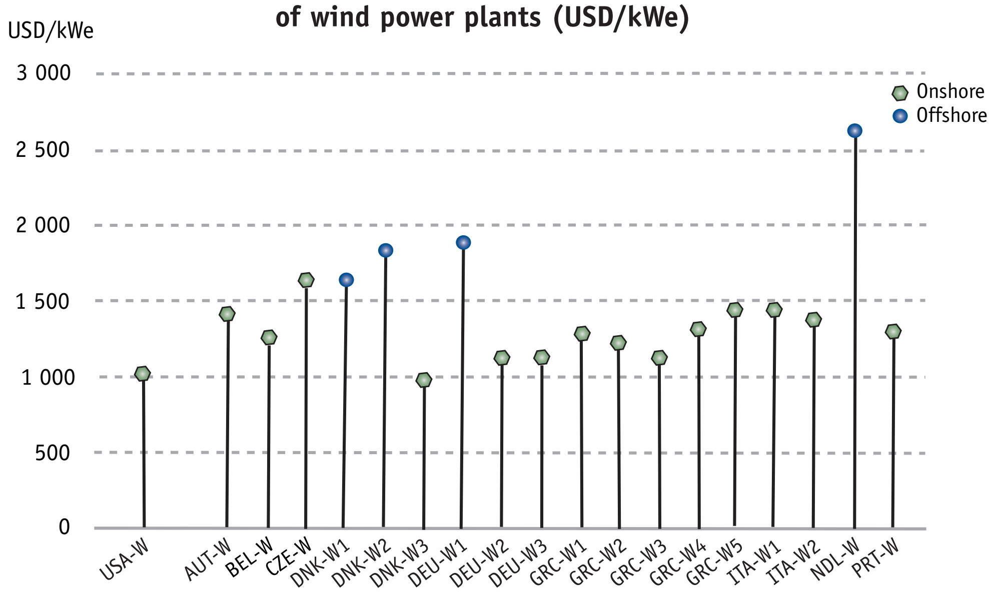
Wind power plants

Most wind power plants for which cost data were provided are onshore plants but Denmark (DNK-W1 and W2), Germany (DEU-W1) and the Netherlands provided data for offshore wind power plants. The installed capacities of the wind units included in the study range from 30 kWe to 2 MWe but the plants are multiple unit installations, generally comprising several tens of units – up to 100 for one plant in Germany – therefore their total installed capacities range between a few MWe and some 300 MWe.

Construction costs

The specific overnight construction costs of the 19 wind power plants included in the study are displayed on Figure 4.1; Table 4.4 provides more details on those costs together with the characteristics of the plants.

Figure 4.1 – Specific overnight construction costs of wind power plants (USD/kWe)



Except for the offshore plant in the Netherlands, the specific overnight construction costs of wind power plants are in the range 1000 to 2 000 USD/kWe. The rapid development of wind power technology during the recent years has already led to construction cost reductions, at least in some countries and the learning effect is expected to continue in the coming years, potentially bringing additional cost reductions. The expense schedules reported indicate that the construction of wind power plants is achieved within 1 to 2 years in most cases.

O&M costs

The reported specific overnight O&M costs for wind power plants vary widely from country to country, even in the same region (see Table 4.1). The specific O&M costs reported for offshore plants are higher than those reported for onshore plants in the same country or region. In general, specific O&M costs are projected to remain stable during the lifetime of the plant but Belgium and Denmark for one plant expect those costs to increase over time while Italy, for one plant, expect those costs to decrease over time.

Table 4.1 – Specific annual O&M costs (per kWe) for wind power plants in 2010

	USA-W	AUT-W	BEL-W[a]	CZE-W[a]	DNK-W1	DNK-W2[a]	DNK-W3	DEU-W1	DEU-W2/3
NCU	27.00	23.00	12.50	630.00	440.00	280.00	170.00	58.10	33.80
USD	27.00	26.31	14.30	22.87	67.80	43.15	16.20	66.47	38.67
€	23.60	23.00	12.50	20.00	59.27	37.72	14.16	58.10	33.80

	GRC-W1	GRC-W2	GRC-W3/4	GRC-W5	ITA-W1	ITA-W2[b]	NLD-W	PRT-W
NCU	13.03	16.70	18.30	25.20	25.00	13.90	115.00	25.20
USD	14.91	19.10	20.94	28.83	28.60	15.90	131.56	28.83
€	13.03	16.70	18.30	25.20	25.00	13.90	115.00	25.20

a. Increasing over time.
b. Decreasing over time.

Levelised generation costs

The costs calculated and presented in this report for wind power plants are based on the levelised lifetime methodology used throughout the study for the sake of consistency. This approach does not reflect specific aspects of wind or other intermittent renewable energy sources for power generation and in particular it ignores the need for backup power to compensate for the low average availability factor as compared to base load plants. Some of the issues related to the economic impacts of wind power integration into electricity grids are addressed in Appendix 9.

For intermittent renewable sources such as wind, the availability/capacity factor of the plant is a driving factor for levelised cost of generating electricity. The reported availability/capacity factors of wind power plants are shown in Figure 4.2. They range between 17% and 38% for onshore plants, and between 40% and 45% for offshore plants except in Germany.

The capacity factors reported were used for calculating the amount of electricity generated and the resulting levelised costs of wind power plants. The economic lifetimes of the wind power plants were assumed equal to the technical lifetimes reported, i.e. 20 years for all plants, except DNK-W2 in Denmark (25 years) and the US plant (40 years).

The levelised generation costs calculated at 5% and 10%, with the capacity factors and the economic lifetimes reported, are presented in Figures 4.3 and 4.4 and given in Tables 4.5 and 4.6.

Figure 4.2 – Capacity factors of wind power plants (%)

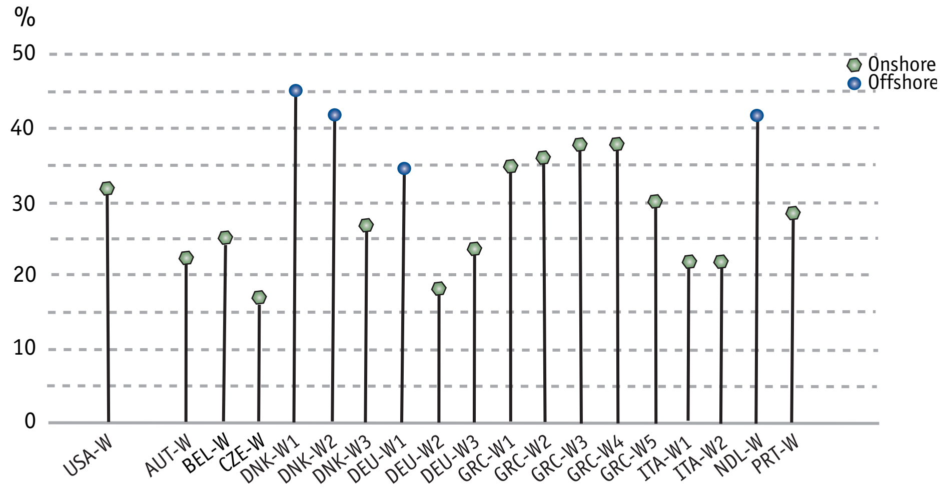


Figure 4.3 – Levelised costs of wind generated electricity at 5% discount rate (USD/MWh)

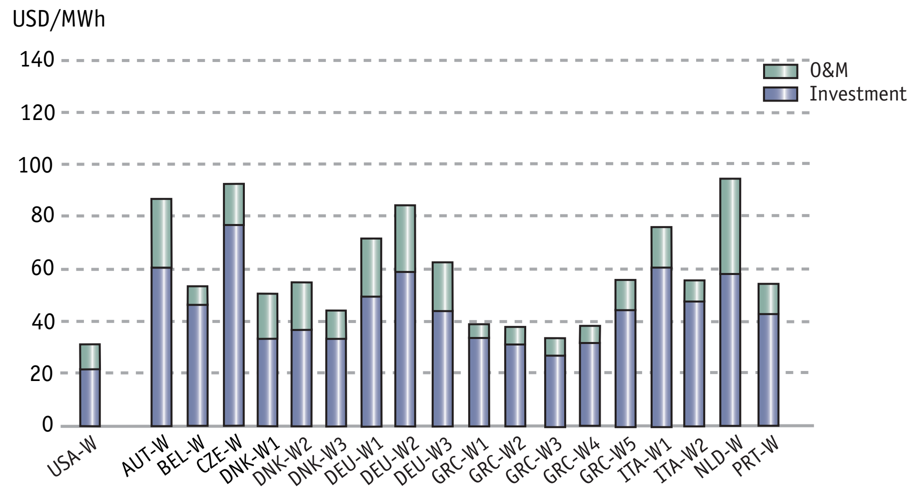
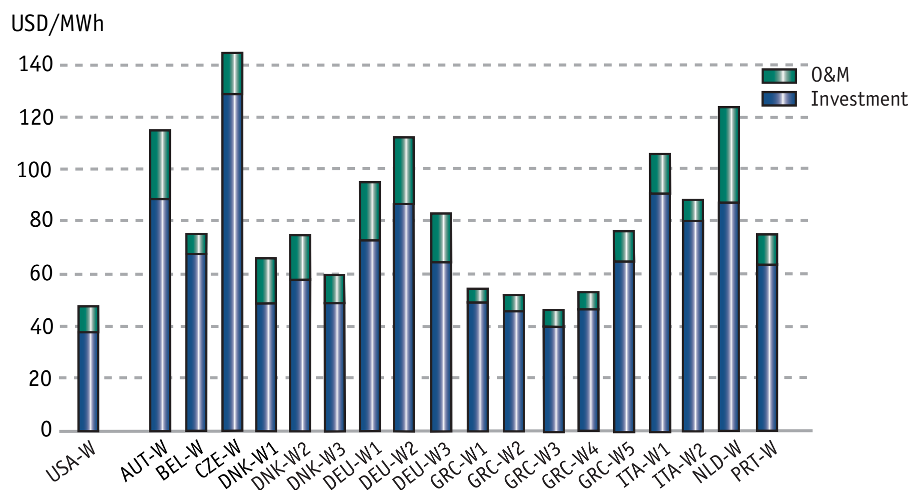


Figure 4.4 – Levelised costs of wind generated electricity at 10% discount rate (USD/MWh)



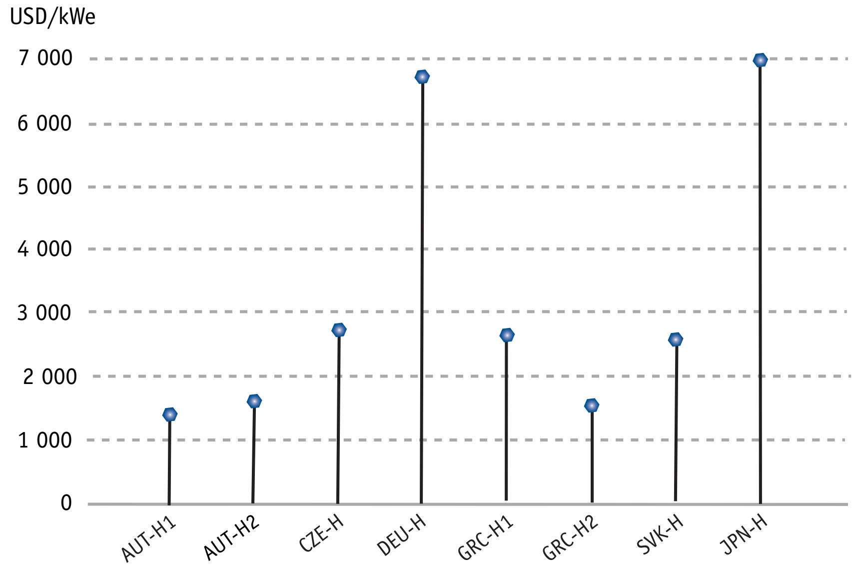
At 5% discount rate, levelised generation costs for the wind power plants considered in the study range between 35 and 95 USD/MWh but for a large number of plants the costs are below 60 USD/MWh. The share of O&M in total costs ranges between 13% and nearly 40% (for the offshore plant in the Netherlands).

At 10% discount rate, the levelised costs of wind generated electricity are significantly higher than at 5% discount rate owing to the predominant share of investment in the total. They range between 45 and more than 140 USD/MWh.

Hydro power plants

Data were provided for eight hydro power plants in six countries.[1] The specific overnight construction costs per unit of capacity reported (see Figure 4.5) vary widely, as may be expected, because hydro power plant construction costs depend mainly on site specific characteristics. The expense schedules reported for hydro power plants correspond to construction periods ranging from 1 to 5 years but in most cases most of the expenses are incurred in less than 3 years.

Figure 4.5 – Specific overnight construction costs of hydro power plants (USD/kWe)



The hydro power plants considered in the study are small or very small units, except the dam in Greece (GRC-H2) which has a total capacity of some 120 MWe. The very high specific construction costs reported for most of the hydro power plants considered in the study likely result from their small sizes, although in Austria the specific construction costs reported are lower for the smaller unit.

The specific annual O&M costs reported for hydro power plants are given in Table 4.2. Similarly to the construction costs they vary widely from plant to plant, even in the same country owing to the site specific characteristics of hydro power. Except in the Czech Republic, O&M costs are projected to remain constant during the lifetime of the plant.

Table 4.2 – Specific annual O&M costs (per kWe) for hydro power plants in 2010

	AUT-H1	AUT-H2	CZE-H[a]	DEU-H	GRC-H1	GRC-H2	SVK-H	JPN-H
NCU	44.82	19.18	1 389	58.80	78.80	3.00	1 577	14 837
USD	39.18	21.94	50.42	67.27	90.15	3.43	43.37	124.63
€	44.82	19.18	44.07	58.80	78.80	3.00	37.91	108.94

a. Increasing over time.

1. Also, Bulgaria and the Republic of South Africa provided information on pumped storage facilities for which generation costs cannot be estimated with the generic assumptions adopted within the study.

The availability/capacity factors reported are around 50% except for AUT-H2 in Austria (36.5%) and GRC-H2 in Greece (25%). The economic lifetimes of hydro power plants considered in the study vary from 30 years to 60 years.

The levelised costs of hydroelectricity obtained with the cost elements provided by respondent countries are displayed in Figures 4.6 and 4.7 at 5% and 10% discount rate respectively and given in Tables 4.5 and 4.6.

Figure 4.6 – Levelised costs of hydroelectricity at 5% discount rate (USD/MWh)

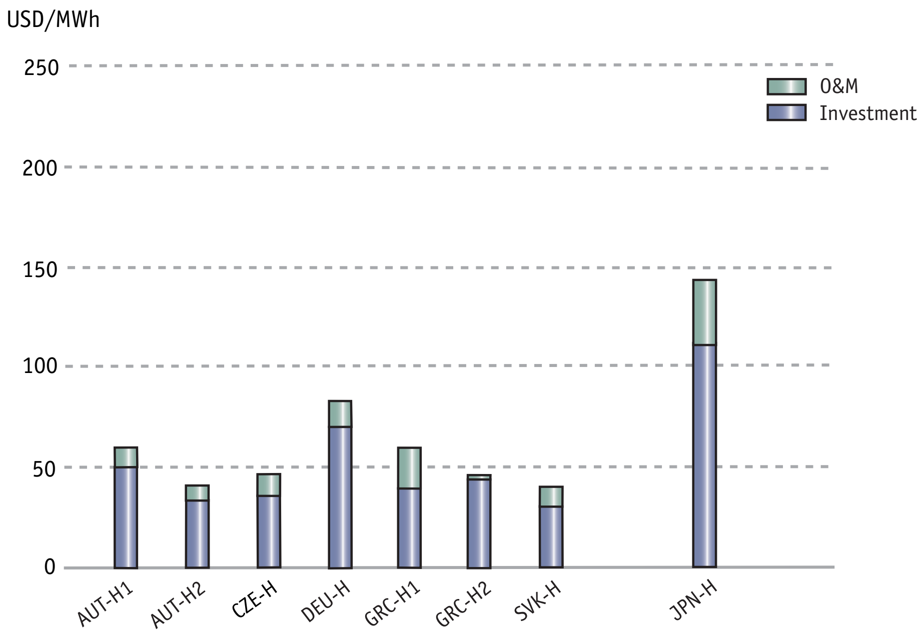
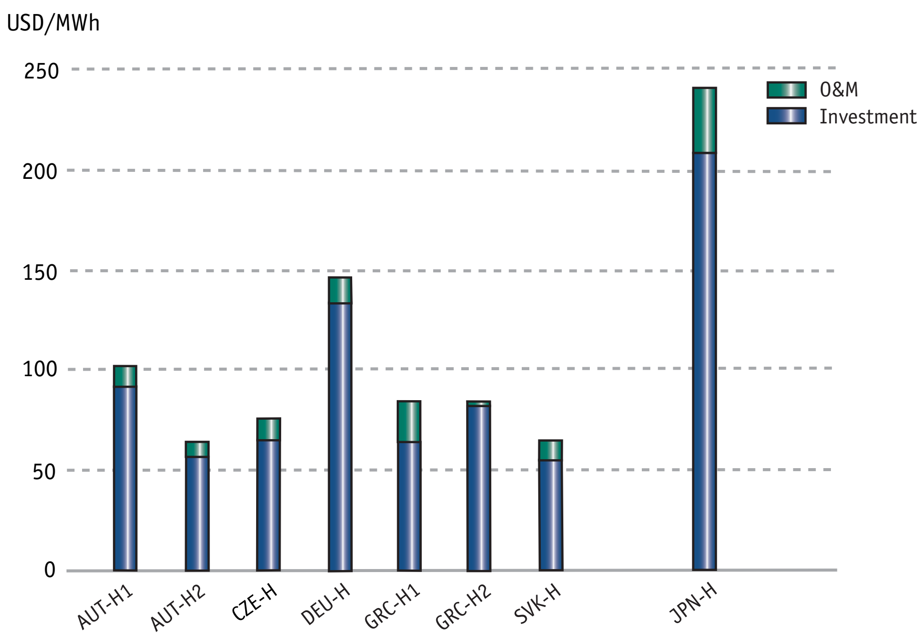


Figure 4.7 – Levelised costs of hydroelectricity at 10% discount rate (USD/MWh)



At 5% discount rate, hydroelectricity generation costs range between some 40 and 80 USD/MWh for all plants except in Japan where they reach more than 140 USD/MWh. O&M costs account in all cases for less than one third of total levelised generation costs.

At 10% discount rate, hydroelectricity generation costs range between some 65 and 100 USD/MWh for most plants but reach nearly 150 USD/MWh for the German plant and more than 240 USD/MWh for the Japanese plant. The predominant share of investment in total levelised generation costs explains the large difference between costs at 5% and 10% discount rate. The O&M costs, at 10% discount rate, are only a marginal component, representing some 10% or less except for GRC-H1 in Greece.

Solar power plants

Responses to the questionnaire provided input data for six solar power plants in four countries, including one solar thermal parabolic unit in the United States. The specific overnight construction costs reported are ranging between 2 775 USD/kWe for the thermal parabolic plant in the United States and 10 164 USD/kWe for the 100 (4 x 25) kWe solar PV plant in the Czech Republic (see Figure 4.8 and Table 4.4).

For all the solar power plants considered, the construction time is expected to be one year, except in the United States (three years for the thermal parabolic plant and two years for the solar PV plant). The plant capacities are very small, except for the 100 MWe thermal parabolic plant in the United States.

The specific annual O&M costs reported for solar power plants vary widely from plant to plant but generally are rather low, even zero in Denmark (see Table 4.3).

Figure 4.8 – Specific overnight construction costs of solar power plants (USD/kWe)

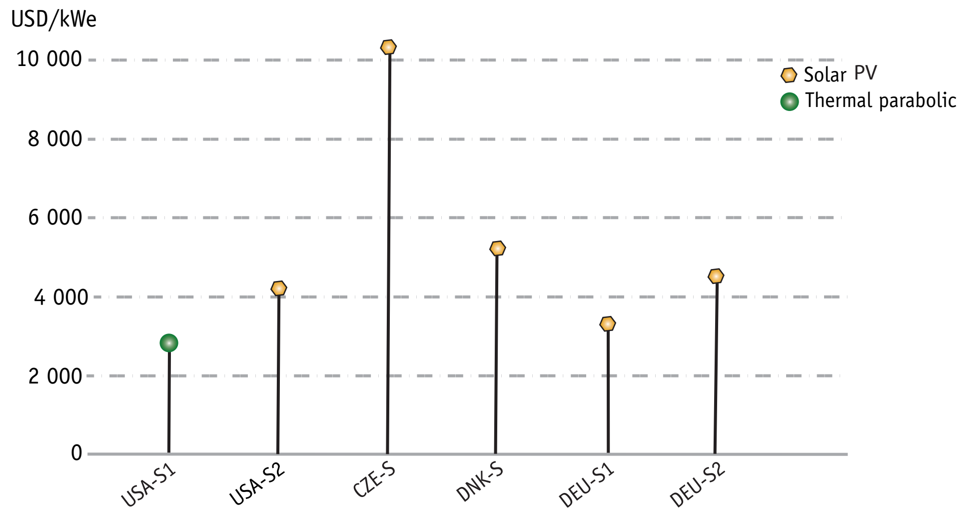


Table 4.3 – Specific annual O&M costs (per kWe) for solar power plants in 2010

	USA-S1	USA-S2	CZE-S	DNK-S	DEU-S1	DEU-S2
NCU	50.00	10.00	2 974	0	29.40	40.00
USD	50.00	10.00	107.96	0	33.63	45.76
€	57.20	11.44	94.37	0	29.40	40.00

The availability/capacity factors reported for solar plants vary from 9% in the Czech Republic and Denmark to 24% for the solar PV plant in the United States. The technical lifetimes reported for solar power plants vary from 20 years in the Czech Republic to 40 years, taken as a generic assumption for cost estimates, in the United States. The levelised cost calculations for solar power plants have been performed in the present study assuming that the economic lifetime equals the technical lifetime.

Figure 4.9 shows the levelised costs of solar generated electricity at 5% and 10% discount rates which are reported in Tables 4.5 and 4.6. Even in the United States, where reported investment costs are lower and capacity/availability factors higher, the levelised costs of solar generated electricity are reaching around 150 USD/MWh at 5% discount rate and more than 200 USD/MWh at 10% discount rate. In the other countries, the levelised costs of solar-generated electricity are close to or way above 300 USD/MWh.

Figure 4.9 – Levelised costs of electricity generated by solar power plants at 5% and 10% discount rates (USD/MWh)

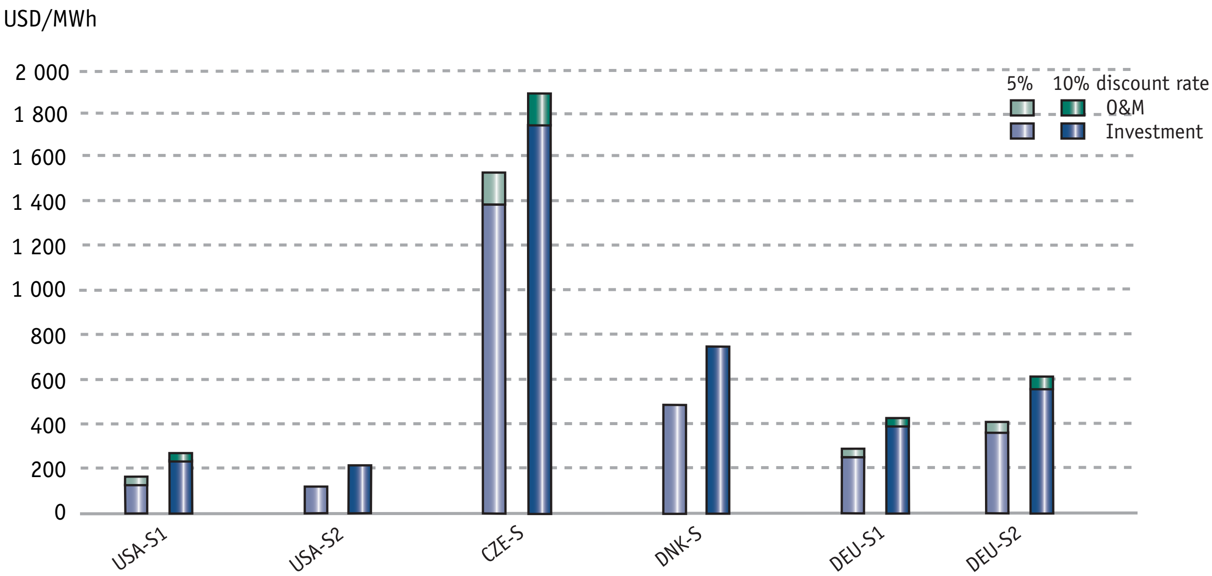


Table 4.4 – Overnight construction costs of wind, solar and hydro power plants

Plant name	Technology	Net capacity incl. in cost estimates (MWe)	Overnight construction costs			
			MNCU	MUSD	M€	USD/kWe
USA-W	Wind onshore	50	51.2	51.2	44.8	1 024
USA-S1	Solar thermal parabolic	100	277.5	277.5	242.6	2 775
USA-S2	Solar PV	5	20.8	20.8	18.2	4 160
AUT-W	Wind farm onshore	19.25	23.9	27.3	23.9	1 420
AUT-H1	Run of the river	14	52.4	59.9	52.4	4 282
AUT-H2	Small hydro	1.5	2.1	2.4	2.1	1 602
BEL-W	Wind onshore	10	11.1	12.7	11.1	1 267
CZE-W	Wind onshore	9	405.0	14.7	12.9	1 634
CZE-S	Solar PV	0.025	7.0	0.3	0.2	10 164
CZE-H1	Small hydro	3	226.0	8.2	7.2	2 735
DNK-W1	Wind offshore	160	1 700.0	262.0	229.0	1 637
DNK-W2	Wind offshore	159.84	1 900.0	292.8	255.9	1 832
DNK-W3	Wind turbine onshore	1.5	9.5	1.5	1.3	976
DNK-S	Solar PV	0.5	17.0	2.6	2.3	5 239
DEU-W1	Wind offshore	300	495.0	566.3	495.0	1 888
DEU-W2	Wind onshore	15	15.0	17.2	15.0	1 144
DEU-W3	Wind onshore	15	15.0	17.2	15.0	1 144
DEU-S1	Solar PV	0.5	1.47	1.68	1.47	3 363
DEU-S2	Solar PV	0.002	0.008	0.009	0.008	4 576
DEU-H	Small hydro	0.714	4.2	4.8	4.2	6 728
GRC-W1	Wind onshore	14.28	16.0	18.3	16.0	1 280
GRC-W2	Wind onshore	12	13.0	14.8	13.0	1 237
GRC-W3	Wind onshore	4.2	4.1	4.7	4.1	1 129
GRC-W4	Wind onshore	3	3.5	4.0	3.5	1 320
GRC-W5	Wind onshore	4.2	5.4	6.1	5.4	1 458
GRC-H1	Run of the river	4	9.2	10.6	9.2	2 639
GRC-H2	Dam	123.5	166.4	190.4	166.4	1 541
ITA-W1	Wind onshore	60	76.0	86.9	76.0	1 449
ITA-W2	Wind onshore	72	87.1	99.7	87.1	1 385
NLD-W	Wind offshore	120	275.0	314.6	275.0	2 622
PRT-W	Wind onshore	20	23.0	26.3	23.0	1 316
SVK-H	Run of the river small	2.7	250.0	6.9	6.0	2 546
JPN-H	Run of the river	19	15 800.0	132.7	116.0	6 985

Table 4.5 – Projected generation costs calculated with generic assumption at 5% discount rate (USD of 1 July 2003/MWh)

Country	Wind				Solar				Hydro			
		Investment	O&M	Total		Investment	O&M	Total		Investment	O&M	Total
United States	USA-W	21.5	9.6	31.1	USA-S1	127.4	38.1	165.5				
		69%	31%	100%		77%	23%	100%				
					USA-S2	115.9	4.8	120.6				
						96%	4%	100%				
Austria	AUT-W	60.5	26.3	86.8					AUT-H1	49.9	9.8	59.7
	20[a]	70%	30%	100%						84%	16%	100%
									AUT-H2	33.7	6.9	40.5
										83%	17%	100%
Belgium	BEL-W	46.4	6.9	53.4								
	20[a]	87%	13%	100%								
Czech Republic	CZE-W	76.8	15.5	92.3	CZE-S	1 382.2	137.9	1 520.1	CZE-H	35.9	10.6	46.4
		83%	17%	100%	**20**[a]	91%	9%	100%		77%	23%	100%
Denmark	DNK-W1	33.3	17.2	50.5	DNK-S	484.8	0	484.8				
	20[a]	66%	34%	100%	**25**[a]	100%	0%	100%				
	DNK-W2	36.6	18.3	54.8								
	25[a]	67%	33%	100%								
	DNK-W3	33.1	11.1	44.2								
	20[a]	75%	25%	100%								
Germany	DEU-W1	49.8	21.9	71.7	DEU-S1	252.2	35.6	287.8	DEU-H	70.0	13.2	83.2
	20[a]	70%	30%	100%	**25**[a]	88%	12%	100%	**60**[a]	84%	16%	100%
	DEU-W2	59.2	24.9	84.1	DEU-S2	359.8	50.7	410.6				
	20[a]	70%	30%	100%	**25**[a]	88%	12%	100%				
	DEU-W3	44.0	18.5	62.6								
	20[a]	70%	30%	100%								
Greece	GRC-W1	33.7	4.9	38.6					GRC-H1	39.2	20.6	59.8
	20[a]	87%	13%	100%					**30**[a]	66%	34%	100%
	GRC-W2	31.5	6.1	37.5					GRC-H2	44.1	1.6	45.4
	20[a]	84%	16%	100%					**50**[a]	97%	3%	100%
	GRC-W3	27.2	6.3	33.5								
	20[a]	81%	19%	100%								
	GRC-W4	31.8	6.3	38.1								
	20[a]	83%	17%	100%								
	GRC-W5	44.5	11.0	55.5								
	20[a]	80%	20%	100%								
Italy	ITA-W1	61.2	14.8	76.0								
	20[a]	80%	20%	100%								
	ITA-W2	48.0	7.7	55.7								
	30[a]	86%	14%	100%								
Netherlands	NLD-W	58.5	35.8	94.3								
	20[a]	62%	38%	100%								
Portugal	PRT-W	42.8	11.5	54.4								
	20[a]	79%	21%	100%								
Slovak Republic									SVK-H	31.0	8.7	39.7
										78%	22%	100%
Japan									JPN-H	111.3	31.6	142.9
										78%	22%	100%

a. Economic lifetime assumed to calculate levelised costs if different from 40 years.

Table 4.6 – Projected generation costs calculated with generic assumption at 10% discount rate (USD of 1 July 2003/MWh)

Country	Wind				Solar				Hydro			
		Investment	O&M	Total		Investment	O&M	Total		Investment	O&M	Total
United States	USA-W	38.1	9.6	47.8	USA-S1	231.4	38.1	269.4				
		80%	20%	100%		86%	14%	100%				
					USA-S2	204.4	4.8	209.1				
						98%	2%	100%				
Austria	AUT-W	88.4	26.3	114.7					AUT-H1	91.2	9.8	101.1
	20[a]	77%	23%	100%						90%	10%	100%
									AUT-H2	56.7	6.9	63.5
										89%	11%	100%
Belgium	BEL-W	68.0	6.9	74.9								
	20[a]	91%	9%	100%								
Czech Republic	CZE-W	128.8	15.4	144.2	CZE-S	1 738.7	137.7	1 876.4	CZE-H	64.9	10.5	75.5
		89%	11%	100%	**20**[a]	93%	7%	100%		86%	14%	100%
Denmark	DNK-W1	48.8	17.2	66.0	DNK-S	743.4	0.0	743.4				
	20[a]	74%	26%	100%		100%	0%	100%				
	DNK-W2	57.7	16.9	74.6								
		77%	23%	100%								
	DNK-W3	48.5	11.1	59.5								
		81%	19%	100%								
Germany	DEU-W1	72.9	21.9	94.8	DEU-S1	391.7	35.6	427.2	DEU-H	132.9	13.2	146.1
		77%	23%	100%	**25**[a]	92%	8%	100%	**60**[a]	91%	9%	100%
	DEU-W2	86.7	24.9	111.6	DEU-S2	558.7	50.7	609.4				
	20[a]	78%	22%	100%	**25**[a]	92%	8%	100%				
	DEU-W3	64.5	18.5	83.0								
	20[a]	78%	22%	100%								
Greece	GRC-W1	49.3	4.9	54.2					GRC-H1	63.9	20.6	84.5
	20[a]	91%	9%	100%					**30**[a]	76%	24%	100%
	GRC-W2	46.1	6.1	52.1					GRC-H2	83.4	1.6	84.9
	20[a]	88%	12%	100%					**50**[a]	98%	2%	100%
	GRC-W3	39.8	6.3	46.1								
	20[a]	86%	14%	100%								
	GRC-W4	46.6	6.3	52.9								
	20[a]	88%	12%	100%								
	GRC-W5	65.2	11.0	76.1								
	20[a]	86%	14%	100%								
Italy	ITA-W1	90.9	14.8	105.7								
	20[a]	86%	14%	100%								
	ITA-W2	80.5	7.8	88.2								
	30[a]	91%	9%	100%								
Netherlands	NLD-W	87.7	35.8	123.4								
	20[a]	71%	29%	100%								
Portugal	PRT-W	63.4	11.5	75.0								
	20[a]	85%	15%	100%								
Slovak Republic									SVK-H	56.6	8.7	65.3
										87%	13%	100%
Japan									JPN-H	210.3	31.6	241.9
										87%	13%	100%

a. Economic lifetime assumed to calculate levelised costs if different from 40 years.

Generation Costs of Combined Heat and Power (CHP) Plants

Background

Combined heat and power plants were considered in previous studies and methodological issues raised by estimating the costs of generating electricity and heat with dual-product plants were discussed, in particular in Appendix 4 of the 1998 update of the report (OECD, 1998). However, the analyses carried out so far in the context of studies in the series remained qualitative. In the present study, an attempt was made to provide quantitative estimates of electricity generation costs for CHP plants, relying on a generic approach and a methodology commonly agreed upon by the group of experts.

Nine OECD countries provided information and cost data on 23 CHP plants. The main characteristics of those plants and their estimated electricity generation costs[1] are presented briefly in this chapter (see Table 2.9 in Chapter 2 for details) as well as the approach adopted to calculate those cost estimations. The section of cost estimation approach included in the present chapter is based upon a working document prepared by the Danish participant in the study and describes the pragmatic approach adopted for estimating the levelised electricity generation costs presented at the end of the chapter. Appendix 7 elaborates on a theoretical approach for allocating costs to heat and electricity produced by a dual-purpose plant, based upon the laws of thermodynamics.

Characteristics of the CHP plants considered in the study

The CHP plants included in the study are fuelled with gas, coal or renewable combustible. A majority, 14 CHP plants, are gas-fired units. Five CHP plants are coal-fired, including one lignite-fired plant in the Slovak Republic and three CHP plants use biomass, including a multi-fuel plant in Denmark using gas, oil, straw and wood pellets and a biogas plant in Germany. It should be noted that some CHP plants are included in the present chapter although they could be considered as distributed generation because they were not put in that category by respondents. The size of the plants considered varies from a few MWe/MWth or less for gas engines in Denmark, Switzerland and the United States to a few hundred MWe/MWth. The heat production is delivered for either district heating or industrial use.

Cost estimation approach

The general idea to develop a practical approach for estimating the electricity generation costs for CHP plants is to postulate that the value of the produced heat can be subtracted from the total costs of constructing and operating the plant; the remaining costs are then the net costs needed for electricity generation.

1. One of CHP plants for which information was provided by Denmark is not included in this chapter because it has very specific characteristics making generic cost estimations not very relevant. Technical description and electricity generation cost estimates for that plant are given in the country report from Denmark in Appendix 3.

A CHP plant typically supplies heat to an already existing heat market, i.e. an industrial heating process, a district heating system, or – through heat transmission lines – a number of district heating systems. Therefore, electricity generation costs of the CHP plant may be expressed as follows:

Electricity generation cost = *Total cost of the plant – market value of the heat delivered by the plant*

While the formula is very simple, it may be applied in different ways. Two variations and the approach adopted for the present study are described briefly below.

Power-only calculation

The simplest method is to treat the CHP plant as a power-only plant. This is only applicable to extraction plants. The investment and O&M costs induced by the fact that the plant is a CHP plant are subtracted, and the plant is assumed to operate as a condensing unit all the time. It is equivalent to allocating the whole CHP advantage to the heat consumers in terms of lower heat prices and does not reflect the CHP advantage in the costs of generating electricity. Therefore, this method is not relevant in the present study which focuses on electricity generation cost estimates.

Full CHP calculation

The second method assumes that heat production costs by a CHP plant should be unchanged as compared with the heat production costs without CHP. If the resulting kWh cost from a CHP plant is lower than the kWh cost from a condensing unit and this is reflected in market prices, this means that the whole CHP advantage is allocated to the electricity consumers.

The production costs are calculated using the average lifetime levelised cost formula used for estimating generation costs in the present study:

$$EGC = \Sigma\ [(I_t + O\&M_t + F_t - H_t)\ (1+r)^{-t}]\ /\ \Sigma\ [E_t\ (1+r)^{-t}]$$

With:
- EGC = Average lifetime levelised electricity generation cost
- I_t = Investment expenditures in the year t
- $O\&M_t$ = Operations and maintenance expenditures in the year t
- F_t = Fuel expenditures in the year t
- H_t = Avoided heat production costs in the year t
- E_t = Electricity generation in the year t
- r = Discount rate
- t = year

Although this method is relevant to estimate and compare electricity generation costs, its application raises issues with regard to a fair estimation of the CHP advantages from the viewpoint of the heat consumer. In real conditions, using the full CHP calculation method is difficult because in most cases CHP production costs are site specific.

If the CHP plant supplies heat only to a local heat market, it is often reasonable to assume that no heat transmission lines are necessary, since the CHP plant could be placed at the same site as the district heating plant, which would otherwise supply the heat. In addition, there will be net savings in the electricity grid due to decentralisation of the electricity production. The disadvantage of the local CHP plant is that the size of the plant is limited by the size of the local heat market. This might lead to relatively high investment costs per unit of installed capacity.

The investment costs in heat transmission lines are very dependent on the location of the heat markets and the CHP plant. In some cases, an already existing heat transmission network may be fully or partially paid off, reducing average future production costs. The annual load factor for heat and power is generally not the same for an extraction plant. Finally, the saved heat production costs may be difficult to assess because the alternative fuel for heat production can be determined only with some ambiguity.

Simplified approach adopted in the study

A way to avoid the direct calculation of alternative heat production costs is to use a heat price, assuming that the CHP plant is selling heat to a district heating system. This means that heat sale is treated on an equal footing with fuel purchase (but with opposite sign). In principle, this method is not applicable to industrial CHP plants, where the alternative heat production normally would be undertaken by the industry itself. So, no heat price is available. Moreover, even in the case of a district heating system, the present heat price may be well known, but the future heat price may be difficult to assess.

For the purpose of the present study, it was agreed to adopt a pragmatic approach that could be applied to all the plants considered although their characteristics and the context in which they are operated vary widely. The rationale for the approach is based upon the recognition that, for each plant, the value of the heat generated will be determined by the local and regional markets and could not be assessed within a generic framework. Therefore, respondents were asked to provide the value of the heat generated (or heat credit) for each plant considered. These values were deducted from the overall costs, i.e. investment, O&M and fuel, incurred by the plant to estimate the residual cost of generating electricity.

Electricity generation cost estimates

Construction costs

The overnight construction costs of the CHP plants considered in the study are shown in Table 5.1 and Figure 5.1 displays the specific overnight construction costs of those plants in USD/kWe.

Recognising that the size and technologies of CHP plants considered vary widely, the wide range of overnight construction costs observed was to be expected. Not taking into account the combustible renewable fuelled plants, the specific overnight construction costs of the CHP plants considered in the study range between 560 and 1 700 USD/kWe. The two plants using exclusively combustible renewable as fuel, the biomass plant in Austria and the biogas plant in Germany have higher specific overnight construction costs, around 3 700 and 2 500 USD/kWe respectively. Most of the CCGT gas-fired plants have specific overnight construction costs in the lower part of the range.

Levelised cost of generated electricity

The cost estimates obtained for CHP plants, using the methodology described above and the cost elements provided by respondents, including heat value, are summarised in Table 5.2. The heat values provided generally represent more than a third (up to more than 80% in some cases) of the residual estimated costs of electricity generation. However, this share is in some cases much smaller; only a few percent in the Czech Republic and some 20% for biogas-fuelled plant (CHP5) in Germany. The share of heat credit tends to be significantly smaller at 10% discount rate than at 5% discount rate because the discounted investment costs are higher and thus the share of heat credit is lower.

Figure 5.2 shows the total levelised costs of generating electricity at 5% and 10% discount rates for the CHP plants considered in the study. At 5% discount rate, the levelised costs of generating electricity range between 25 and 65 USD/MWh for most CHP plants but reaches more than 120 USD/MWh for the small biomass-fuelled plant in Austria. At 10% discount rate, the costs range between 30 and 70 USD/MWh for most plants. The impact of discount rate is small for most CHP plants; costs at 10% discount rate are 10 to 20% higher than at 5% discount rate, except in a few cases.

Table 5.1 – Overnight construction costs of CHP plants

Country	Plant	Fuel/ technology	Net capacity included in cost estimates (MWe)	(MWth)	Overnight construction costs MNCU	MUSD	M€	USD/kWe
United States	USA-CHP1	Gas	40	45	27.2	27.2	23.8	0
	USA-CHP2	Gas engine	3	3.5	2.61	2.61	2.3	870
Austria	AUT-CHP1	Gas CCGT	84	127	100	114.4	100	1 326
	AUT-CHP2	Biomass	8	20	26	29.7	26	3 718
	AUT-CHP3	Gas CCGT	105	110	83	95	83	904
Czech Republic	CZE-CHP1	Coal boiler	300	120	11 000	399	349	1 331
	CZE-CHP2	Gas CCGT	250	120	6 000	218	190	871
Denmark	DNK-CHP1	Gas engine	11	12	54	8	7	756
	DNK-CHP2	Multifuel	485	575	4 080	629	550	1 296
	DNK-CHP3	Gas CCGT	58	58	590	91	79	1 568
Finland	FIN-CHP1	Coal boiler	160	300	176	201	176	1 258
	FIN-CHP2	Gas CCGT	470	420	230	263	230	560
Germany	DEU-CHP1	Coal	500	600	577	660	577	1 320
	DEU-CHP2	Coal	200	280	255	291	255	1 457
	DEU-CHP3	Gas CCGT	200	160	122	140	122	699
	DEU-CHP4	Gas CCGT	200	190	107	122	107	609
	DEU-CHP5	Biogas	1	1.5	2.3	2.6	2.3	2 562
Netherlands	NLD-CHP1	Gas CCGT	81	65	104	119	104	1 469
	NLD-CHP2	Gas CCGT	250	175	260	297	260	1 190
Slovak Republic	SVK-CHP	Lignite	20	98	1 100	30	26	1 551
Switzerland	CHE-CHP1	Gas engine	3	3	2.7	2.0	1.8	733
	CHE-CHP2	Gas engine	0.526	0.633	1.21	0.89	0.78	1 702

Figure 5.1 – Specific overnight construction costs of CHP plants USD/kWe

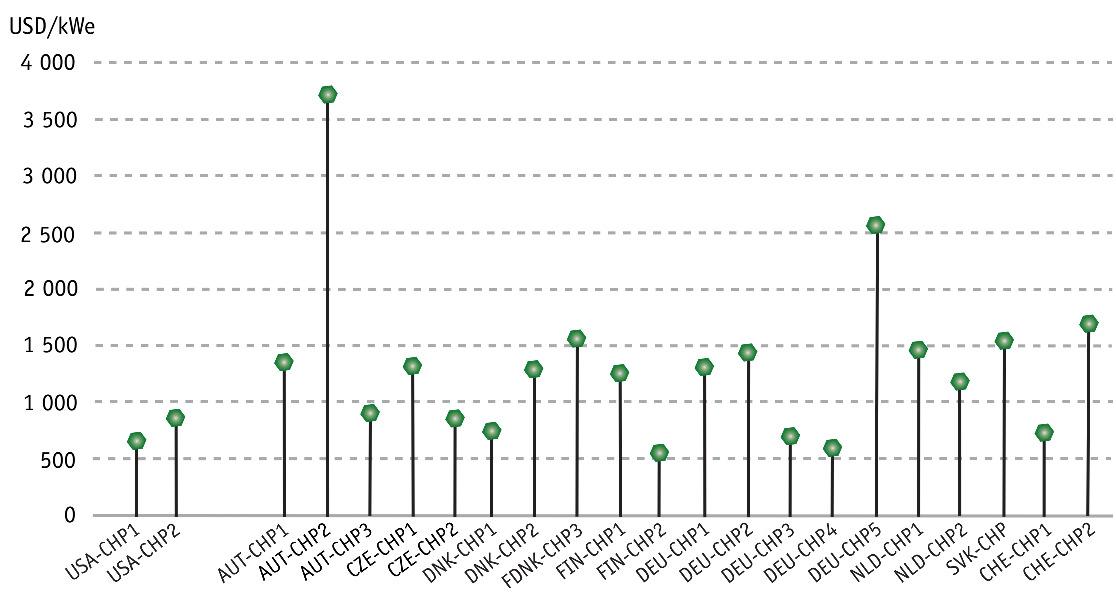


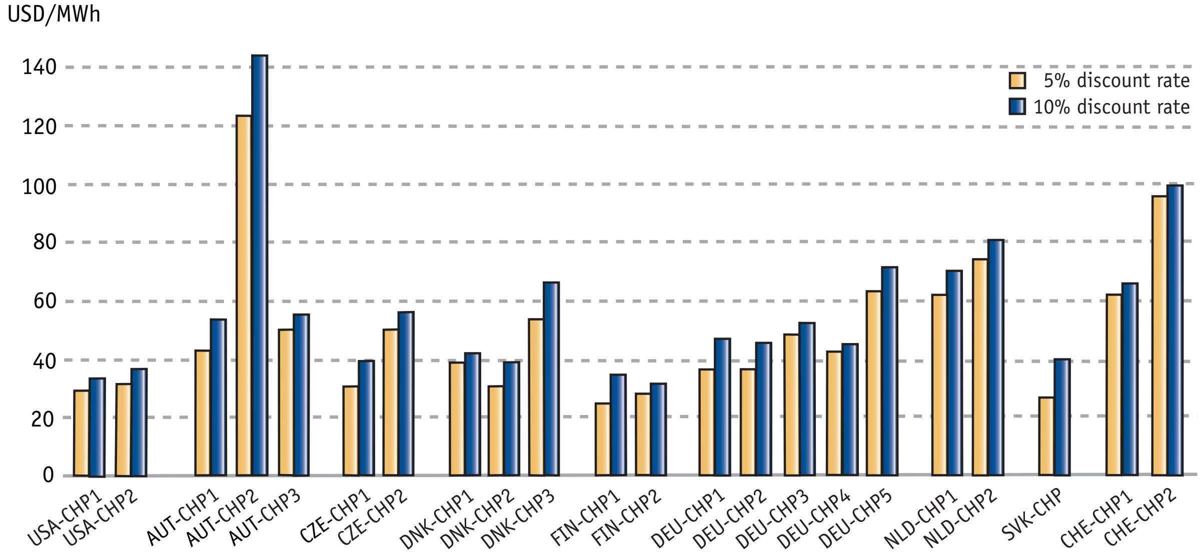
Table 5.2 – Levelised costs of electricity generated by CHP plants (USD/MWh) at 5% and 10% discount rates

(data in black = at 5% discount rate; data in green = at 10% discount rate)

Country	Plant	Investment	O&M	Fuel	Heat credit	Total
United States	USA-CHP1	5.7	1.0	43.8	21.1	29.4
		9.9	1.0	43.4	20.9	33.5
	USA-CHP2	7.2	2.1	43.2	21.1	31.5
		12.7	2.1	42.8	20.9	36.8
Austria	AUT-CHP1	19.3	6.3	41.4	23.8	43.2
	25[a]	30.0	6.3	41.4	23.8	53.9
	AUT-CHP2	57.3	27.5	124.6	85.8	123.5
	15[a]	78.2	27.5	124.6	85.8	144.4
	AUT-CHP3	13.1	4.6	43.3	10.4	50.6
	15[a]	17.8	4.6	43.3	10.4	55.2
Czech Republic	CZE-CHP1	12.0	4.6	14.7	0.7	30.6
		21.9	4.6	14.0	0.7	39.7
	CZE-CHP2	8.7	2.5	41.7	2.3	50.6
		15.2	2.5	41.1	2.2	56.6
Denmark	DNK-CHP1	7.2	7.6	45.9	21.7	39.1
	25[a]	11.2	7.6	44.8	21.7	42.0
	DNK--CHP2	12.4	5.2	42.2	28.9	30.9
	30[a]	20.7	5.2	41.6	28.9	38.5
	DNK--CHP3	25.8	7.7	40.3	20.0	53.8
	20[a]	38.7	7.7	39.6	20.0	66.0
Finland	FIN-CHP1	15.2	18.46	29.9	38.61	25.0
	30[a]	25.9	18.46	29.1	38.61	34.8
	FIN-CHP2	7.5	2.27	41.0	22.52	28.3
	30[a]	12.0	2.3	40.2	22.52	31.9
Germany	DEU-CHP1	14.2	12.1	24.4	14.1	36.7
	35[a]	25.3	12.1	23.6	14.1	46.9
	DEU-CHP2	12.5	13.7	23.7	13.2	36.8
	35[a]	22.2	13.6	23.0	13.2	45.7
	DEU-CHP3	8.4	12.0	51.0	22.7	48.8
	25[a]	13.3	12.0	49.6	22.7	52.2
	DEU-CHP4	6.0	9.5	49.9	22.4	42.9
	25[a]	9.5	9.4	48.5	22.4	45.0
	DEU-CHP5	35.2	17.8	22.0	12.0	63.0
	20[a]	43.6	17.8	22.0	12.0	71.4
Netherlands	NLD-CHP1	13.0	10.6	77.5	38.8	62.3
	30[a]	21.7	10.6	76.3	38.2	70.5
	NLD-CHP2	10.6	33.6	56.2	26.1	74.4
	30[a]	17.7	33.6	55.1	25.6	80.9
Slovak Republic	SVK-CHP	18.9	13.5	14.1	19.7	26.7
		32.8	13.5	13.5	19.7	40.0
Switzerland	CHE-CHP1	16.0	23.7	45.4	22.7	62.4
	20[a]	19.6	23.7	45.3	22.6	66.0
	CHE-CHP2	49.4	23.7	48.6	25.5	96.3
	20[a]	52.7	23.7	48.5	25.4	99.5

a. Economic lifetime assumed to calculate levelised costs if different from 40 years.

Figure 5.2 – Levelised costs of electricity generated by CHP plants (USD/MWh) at 5% and 10% discount rates



Other Generation Technologies

This chapter summarises the information collected and the results obtained for power plants relying on various technologies and energy sources besides the plant types covered in Chapters 3 to 5. Cost estimates calculated for those plants are presented below in five sections on distributed generation (3 plants), waste incineration and landfill gas (3 plants), combustible renewable (2 plants), geothermal (1 plant) and oil (1 plant). In the light of the limited number of data for each technology or energy source, the costs should be considered as indicative only and not necessarily representative of average trends.

Distributed generation

Distributed generation refers to the production of electric power at an electricity consumer's site or at a local distribution utility substation and the supply of that power directly to the on-site consumers or to other consumers through a distribution network. Distributed generation technologies include electric power generation by engines, small turbines, fuel cells and photovoltaic systems and other small renewable generation technologies such as small hydro or small wind systems. Although some small wind, solar and other power plants for which cost data were reported for the present study could be considered as distributed generation, only the United States chose to categorise some power plants (3 gas-fuelled fuel cells) in the category distributed generation.

Owing to the small number of distributed generation plants included in the present study, it is not possible to carry out a robust analysis of their specific economic characteristics. A comprehensive review of the economic benefits and drawbacks of distributed generation may be found in the IEA publication *Distributed Generation in Liberalised Electricity Markets* (IEA, 2002). Key issues on this topic are addressed briefly below, drawing from the IEA publication.

Distributed generation has some economic advantages over power from the high-voltage grid. It avoids transmission costs and reduces distribution costs, reduces distribution losses, enhances reliability of supply and adds flexibility to the overall generation system. Conventional cost assessments of generating options tend to understate the value of flexibility to the owner of a generating plant. Many distributed generation technologies are flexible in operation, size, and expandability. A distributed generator can respond to price incentives reflected in fluctuating fuel and electricity prices. When fuel prices are high and electricity prices are low, the distributed generator purchases from the electricity market. In the opposite situation, the producer supplies to the market. In other words, the availability of on-site power is a physical hedge for the customer against volatility in electricity prices. Thus, distributed generation is generally more economical for peak periods than for continuous use.

Market liberalisation greatly increases the value of flexibility of the distributed generator. In a liberalised market he can sell his excess production to any consumer in the same distribution network. That ability may allow the distributed generator to justify the purchase of a larger generating plant, which can lower unit capital and operating costs. The liberalised market also allows distributed generators to contract with other producers for backup electricity. The ability to source backup power competitively should reduce costs of this source of supply.

On the other hand, small distributed generation units are likely to have higher generation costs than large grid-connected units owing to higher specific investment costs per kWe installed, higher fuel delivery costs and lower efficiency, except in combined heat and power plants. Furthermore, the selection of fuels and technologies available for distributed generation is more limited than for grid-connected generation.

Also, charges for connection of distributed generation to the network may turn out to be higher than for large central generation – particularly if distributed generators are required to pay for all associated network upgrades (a requirement not normally imposed on large central plants). In addition to higher connection costs per kilowatt, distributed generators may face regulatory requirements of meeting air quality standards that result in higher costs per kilowatt. Emission control equipment generally has higher unit costs in smaller sizes. If identical NO_x emission standards are applied to fossil distributed generation and large fossil central generators the cost of controlling emissions of NO_x per kilowatt will be higher for distributed generation.

The three distributed generation plants of the United States are all fuel cells, fuelled with natural gas. Their sizes vary from 1 MWe to 10 MWe and their specific overnight construction costs (see Table 6.1) vary from less than 1 000 USD/kWe to more than 2 000 USD/kWe. Strangely, the larger the size, the higher the specific overnight construction cost.

Table 6.1 – Overnight construction costs of distributed generation plants (fuel cells)

Plant	Fuel/technology/ emission control equipment included in costs	Net capacity incl. in costs (MWe)	Overnight construction costs			
			MNCU	MUSD	M€	USD/kWe
USA-DG1	Gas/fuel cell/none	10	21	21	19	2 127
USA-DG2	Gas/fuel cell/FF, SCR	2	1.6	1.6	1.4	802
USA-DG3	Gas/fuel cell/FF, SCR	1	1.0	1.0	0.8	962

The construction time for those units is three years or shorter. The economic lifetime of the plants is 40 years. The fuel price assumptions are similar to those included in Table 3.6 on gas prices. The levelised costs of generating electricity at 5% and 10% discount rates are summarised in Table 6.2. As stated above, the number of plants in this category is not large enough to draw generic conclusions. While quite high as compared with traditional grid-connected generation technologies, the levelised generation costs of fuel cells included in the study are comparable with those obtained for some power plants using renewable technologies included in Chapter 4.

Table 6.2 – Levelised generation costs of distributed generation plants (USD/MWh)

Plant	5% discount rate				10% discount rate			
	Investment	O&M	Fuel	Total	Investment	O&M	Fuel	Total
USA-DG1	17.0	22.0	34.0	73.0	30.4	22.0	33.7	86.2
	23%	30%	47%	100%	35%	26%	39%	100%
USA-DG2	6.4	8.2	43.8	58.4	11.5	8.2	43.4	63.1
	11%	14%	75%	100%	18%	13%	69%	100%
USA-DG3	32.2	14.3	48.1	94.6	56.7	14.3	47.7	118.7
	34%	15%	51%	100%	48%	12%	40%	100%

Waste incineration and landfill gas

The Czech Republic and the Netherlands provided cost data on generation plants fuelled by municipal waste and the United States on a landfill-gas fuelled unit.

Table 6.3 – Overnight construction costs of waste incineration and landfill gas plants

Plant	Fuel/technology/ emission control equipment included in costs	Net capacity incl. in costs (MWe)	Overnight construction costs			
			MNCU	MUSD	M€	USD/kWe
CZE-WI	Municipal waste/FF, de NO_x, de SO_x	10	1 000	36	32	3 630
NDL-WI	Municipal waste/FF, scrubbers, evaporator	58.4	358	410	358	7 013
USA-LG	Landfill gas/none	30	44.3	44.3	38.7	1 476

The specific construction costs of the two municipal waste incineration plants are rather high, likely owing to their fairly small size and to technical requirements to burn waste. The landfill gas plant has a lower specific construction cost. The efficiencies of the waste incineration and landfill gas plants are on the low side, 30% or less. The technical lifetime reported for the plant in the Netherlands is 15 years; the two other plants have an assumed economic lifetime of 40 years. The availability factor of the plants equals or exceeds 85%.

For the two waste incineration plants, the reported fuel costs are negative reflecting the value of the service provided to society by burning municipal waste. For landfill gas, the fuel cost reported by the United States is zero. For the waste incineration plant in the Czech Republic, the levelised generation costs are very low, even negative at 5% discount rate. In the Netherlands, although the credit for burning waste is very large, the levelised costs of electricity generation remain positive owing to a very high levelised investment cost, especially at 10% discount rate.

Table 6.4 – Levelised generation costs of waste incineration and landfill gas plants (USD/MWh)

Plant	5% discount rate				10% discount rate			
	Investment	O&M	Fuel	Total	Investment	O&M	Fuel	Total
CZE-WI	35.6	25.7	-65.3	-4.0	60.3	25.7	-65.3	20.6
NLD-WI[a]	94.7	19.7	-109.8	4.6	142.4	19.7	-109.8	52.3
USA-LG	11.5	12.8	0	24.3	21.1	12.8	0	33.9

a. Cost estimated for a 15-year economic lifetime.

Combustible renewable

Two countries, the Czech Republic and the United States, provided cost data on power plants fuelled with combustible renewable (biomass). Austria and Denmark provided information on CHP plants using biomass which are included in Chapter 5.

The overnight construction costs of the two plants are shown in Table 6.5. The specific construction costs are rather high for thermal power plants, likely because the plants are small size units and the characteristics of the fuel are different from those of solid mineral fuels.

Table 6.5 – Overnight construction costs of combustible renewable plants

Plant	Technology/ emission control equipment included in costs	Capacity incl. in costs (MWe)	Overnight construction costs			
			MNCU	MUSD	M€	USD/kWe
CZE-CR	FF, de NO_x, de SO_x	10	600	22	19	2 178
USA-CR	FF, SCR	100	170	170	149	1 700

The economic lifetime is assumed to be 40 years for both plants and their availability factors are 83% and 85% for the United States and the Czech Republic respectively while efficiencies of the two plants are 38% and 25% respectively.

Table 6.6 – Levelised generation costs of combustible renewable plants (USD/MWh)

Plant	5% discount rate				10% discount rate			
	Investment	O&M	Fuel	Total	Investment	O&M	Fuel	Total
CZE-CR	19.0	13.4	52.8	85.2	34.3	13.4	52.8	100.5
	22%	16%	62%	100%	34%	13%	53%	100%
USA-CR	14.7	9.6	13.0	37.3	27.7	9.6	12.9	50.3
	39%	26%	35%	100%	55%	19%	26%	100%

The levelised generation costs at 5% and 10% discount rates (see Table 6.6) show that for both plants, fuel cost represents more than 25% of the total levelised cost even at 10% discount rate and for the Czech plant, at 5% discount rate, it exceeds 60%.

Geothermal

The United States provided cost data for one geothermal power plant. The capacity of the plant is 50 MWe and its overnight construction cost amounts to 108 M USD, i.e. a specific overnight construction cost of 2 160 USD/kWe. Taking into account O&M costs and assuming a 40-year lifetime, the levelised costs of generating electricity are 27.1 USD/MWh at 5% discount rate and 41.5 USD/MWh at 10% discount rate.

Oil

Greece provided cost data for a 100 MWe (two 50 MWe units) oil-fired power plant. The plant is a reciprocating engine equipped with emission control devices to limit sulphur and nitrogen oxide emissions. Its thermal efficiency is 41% and its availability factor 85%. The total overnight construction cost of the plant is 117 M €, i.e. a specific overnight construction cost of around 1 340 USD/kWe. The oil price provided in the response to the questionnaire is 5.3 €/GJ stable over the 25 years of economic lifetime of the plant. The levelised costs of generating electricity from this oil plant are 83.1 and 92.0 USD/MWh at 5% and 10% discount rates respectively.

Findings and Conclusions

Background

This study is based on data on cost elements contributed by officially appointed national experts. The generation cost calculations are carried out by the Secretariat using the levelised cost methodology and generic assumptions commonly agreed upon by the group of experts. The objective of the study is to assess important cost factors in power generation projects. The study is to serve as a resource for policy makers and industry professionals as an input for understanding generating costs and technologies better. It does not intend to replicate the investment decision that an investor is confronted with in a concrete project. The findings and conclusions drawn from the results presented in the report are valid within the limits of this framework and should not be interpreted beyond the context of the study.

A key feature of the levelised cost methodology used in the studies of the series is to integrate the time value of money through a discount rate. For this study, like for previous studies in the series, two discount rates, 5% and 10% real per year, were adopted. The responding countries which provided national cost estimates use a discount rate in this range, except Japan which uses discount rates between 1% and 4% in national estimates.

The costs taken into account in the study include all the investment, operation, maintenance and fuel costs borne by the electricity generator. Taxes and levies on electricity are not included. Impacts on society of building and operating a power plant are included in those costs to the extent that they are internalised through policy measures. For example, costs of complying with health and environmental protection norms and standards prevailing in each country are reflected, in principle, in the cost elements provided by respondents to the questionnaire. On the other hand, the costs associated with residual emissions – including greenhouse gases – are not included in the costs provided and, therefore, are not reflected in the generation costs calculated in the study.

Electricity generation costs calculated are busbar costs, at the station, and do not include transmission and distribution costs which may, in some cases, represent a significant part of the costs and could change the economic ranking of alternatives, in particular when comparing distributed generation with grid-connected centralised generation sources and technologies.

Scope of the study and limitations in the methodology used

Although it was anticipated that liberalisation of electricity markets, privatisation of utilities and increased competition in the sector could raise difficulties for obtaining cost data from participating countries, the information collected for the present study is very comprehensive, covering a large number of countries and energy sources and technologies for electricity generation. Eighteen member countries and three non-member countries provided cost data in a form that allowed the Secretariat to perform levelised cost calculation for some 130 power plants. While the number of participating countries contributing cost information is stable as compared to previous studies, the number and types of power plants included in the analysis have increased significantly for the present study.

The levelised lifetime cost methodology with the generic assumptions used in this study allows for a consistent calculation of cost estimates (see Appendix 5). This in turn allows for a comparison across technologies and countries, within the scope of the analysis. However, most of the generic assumptions will be different in real investment projects. Moreover, other factors which may be decisive for the choice of technology, plant size and timing are not taken into account. Because the methodology assumes a unique discount rate for all options considered, it does not fully reflect the consequences of the liberalisation of electricity markets. Appendix 6 elaborates on methodologies to incorporate risk into generating cost estimates.

Prior to the liberalisation of electricity markets, energy firms were able to operate as integrated monopolies. They were able to pass on all costs of investments to electricity consumers. There was no market risk. In such an environment, most of the risks associated with such investments are not directly a concern of the energy company. Increased costs, if demonstrated to be prudently incurred, can be passed on as increased prices. Risks are transferred from investors to consumers and/or taxpayers. In this situation, there is little incentive for companies to take account of such risks when making investment decisions.

The introduction of liberalisation in energy markets is removing the regulatory risk shield. Investors now have additional risks to consider and manage. For example, generators are no longer guaranteed the ability to recover all costs from power consumers. Nor is the future power price level known. Investors now have to internalise these risks into their investment decision making. This adds to the required rates of return and shortens the time frame that investors require to recover the capital. Private investors' required real rates of return may be higher than the 5% and 10% discount rates used in this study and the time required to recover the invested capital may be shorter than the 40 years generally used in this study.

When the level of the electricity price becomes uncertain it is of relatively greater value to be flexible. It is more important to commit capital only when needed. The flexibility of being able to build smaller plants and adjust them in smaller incremental steps is valuable. The flexibility of being able to adjust quickly with short construction times is of value. Prices in an electricity market tend to be volatile in response to the inherent volatility of electricity. There is a significant value of being able to adjust the production easily to the prices in the market. A minimum of capital commitment also makes the profitability less exposed to lower utilisation that may result from volatile prices. With its short construction time, modularity and low capital commitment, CCGT has been a preferred technology in many markets due to its flexibility. The factors that determine the value of flexibility are not adequately reflected in the levelised lifetime cost methodology. The study therefore does not signal that we are about to see a significant change to this global trend of "gas-to-power". The IEA "World Energy Outlook 2004" (IEA, 2004) projects a substantial relative increase in gas-fired power generation.

Other factors that are not reflected by the methodology include the value of price stability, which may be an important element in a risk hedging strategy by large industrial consumers competing with their energy intensive products on international markets. In markets where a financial contract market is not sufficiently developed to allow for proper management of risks it may be preferred to manage risks through direct ownership of production plant. Technologies with low marginal production costs, such as nuclear, may in such cases offer a guarantee of long-term price stability which is not provided by technologies such as CCGT gas-fired plants with high fuel cost related marginal costs of production.

The fuel price projections used in this study are the projections collected in each data case. As the fuel component in CCGT is very high compared to other technologies, the relative cost of CCGT compared with other technologies is under strong influence from this single factor. As it can be seen in Appendix 8 and Table 3.6 the gas price levels projected by the national experts are generally higher than price assumptions in WEO 2004 (IEA, 2004).

The framework of the present study excludes costs to society of emitting CO_2 when using fossil fuels because those costs are not borne by electricity generators and consumers as long as the regulations in place do not internalise them. Such costs will enhance the relative competitiveness of renewable and nuclear generated electricity compared with gas and particularly compared with coal generated electricity. The cost of a secure access to fuel, with the infrastructure and the certainty in supply that it requires, tend to favour nuclear and coal compared with gas. The value of security of fuel supply is difficult to quantify but is a key factor in national energy policies of many OECD countries.

Technology trends

Like in previous studies, energy sources and technologies for base-load, grid-connected electricity generation represent a large share of the data provided. A total of 63 coal, gas and nuclear power plants are included in the study. For those plants, noticeable technology progress is reported as compared to the data provided for the 1998 study but no technological breakthrough seems to have occurred since 1998 in these technologies.

Availability factor is a main driver for base-load electricity generation costs. Technology progress and market liberalisation have contributed to increase the availability of power plants through enhanced design and cost effective operation. Higher availability factors benefit capital intensive technologies, such as coal and nuclear power plants, more than gas-fired power plants. Availability factors exceeding 75% were common already for coal, gas and nuclear power plants at the end of the 90s when the previous study was completed. However, at that time, the expert group felt that 75% was representative of the average expectation for state-of-the-art power plants over their entire economic lifetimes. Today, industrial experience has demonstrated that an average lifetime availability factor reaching or exceeding 85% is achieved routinely for coal, gas and nuclear power plants.

Regarding renewable energy sources for electricity generation, responses to the questionnaire seem to indicate that wind power plants are the most often considered option (19 plants included in the study), solar and combustible renewable remaining a marginal option. The number of distributed generation plants was very limited.

Finally, the importance of combined heat and power (CHP) plants is stressed by the number of responses including this option with various fuels, coal, gas and combustible renewable. Although a robust economic analysis of CHP in an international framework is beyond the scope of the present study, the results presented are illustrative of some of the most important cost factors in this option at the national level in countries which provided data on it.

Coal, gas and nuclear electricity generation

In most countries which provided data on one or more of the three alternatives (coal, gas and nuclear) for the study, the least expensive alternatives have levelised generation costs ranging between 25 and 35 USD/MWh at a 5% discount rate and between 35 and 45 USD/MWh at a 10% discount rate. The only clear exceptions are Japan, Greece and Italy where levelised generation costs estimated with generic assumptions are significantly higher, and the Republic of Korea and the Republic of South Africa where those costs are significantly lower. The ranges of total levelised generation costs for the coal, gas and nuclear power plants included in the study are shown in Figure 3.13 and the cost ratios between the three alternatives in Figures 3.14, 3.15 and 3.16.

It should be stressed that the plant types for the same energy source vary widely from case to case depending on site specific conditions and requirements of the country. For example, coal-fired plants include a broad range of technologies from traditional combustion to integrated coal gasification plants with carbon sequestration. Also, coal-fired units use various solid mineral fuels including lignite as well as hard coal. Similarly, gas-fired units include plants using liquefied natural gas (LNG) requiring different infrastructure for transport and delivery at the plant.

Coal, gas and nuclear levelised generation costs result from three main components: investment, O&M and fuel. The shares of each cost component in the total vary from country to country and from plant to plant. However some generic driving factors may be identified for each option.

Coal-fired power plants are more capital intensive than gas-fired power plants but less than nuclear power plants. The relative importance of investment and fuel in total levelised generation costs vary depending on the discount rate. Investment cost represents only around a third of the total at 5% discount rate while it accounts for 50% at 10% discount rate. On the other hand, fuel cost represents the major component with 45% at 5% discount rate but only one third at 10% discount rate. Coal prices reported by participating countries (see Table 3.3) vary widely – from 0.1 to 2.9 USD/GJ in 2010 – owing to local conditions (e.g. power plant on the site of coal mines in the Republic of South Africa) and the different qualities of coal used (lignite to hard coal). Experts from seven countries assume coal price escalation while experts from six countries assume stable coal prices up to 2050. Operation and maintenance costs are not a driver for electricity generation cost from coal-fired plants.

For gas-fired plants, in average, investment represents some 15% of total levelised generation cost at 5% discount rate and some 20% at 10% discount rate while fuel cost accounts for some 75% of the total. Therefore, average lifetime levelised costs of electricity generated by gas-fired plants are not very sensitive to uncertainties in future demand which may lead to load factors lower than expected based on technical capability. On the other hand, generation costs of gas-fired plants are very sensitive to future gas prices. The gas prices assumed in the participating countries (see Table 3.6) at the date of commissioning, i.e. around 2010, vary between 3.5 and 5.7 USD/GJ. Prices reported for LNG by countries using it do not differ significantly from natural gas prices reported for other countries. Experts in nine countries assume gas price escalation while experts from seven countries assume stable gas prices during the economic lifetime of the plants, up to 2050. Operation and maintenance costs are a marginal contributor to total generation costs.

For nuclear power plants, investment costs are driving the total cost with an average share in total levelised generation cost of more than 50% at 5% discount rate and more than 65% at 10% discount rate, while nuclear fuel cycle cost accounts for some 20%. Therefore, average lifetime levelised costs of nuclear power plants are very sensitive to discount rate but not very sensitive to uranium and fuel cycle service price increase. All respondents, except Finland which reports a 1% per year increase, assume constant nuclear fuel cycle costs in real terms, but recent trends show a continuing decrease of those costs in most countries. Operation and maintenance cost is not a major contributor to total generation cost for nuclear power plants.

Renewable sources, CHP and other technologies

This study includes information on several renewable sources for electricity generation, other technologies including waste incineration and some distributed generation options and combined heat and power plants. Cost estimates for those options are presented and analysed in Chapters 5 and 6. The level of technical maturity and industrial development of those options vary widely from technology to technology and from country to country for the same technology. Therefore, it is not relevant to compare those alternatives based on the data collected within the study. The two options for which the most cost data were provided are wind power and CHP. Some generic findings drawn from the results of the study regarding those two options are summarised below.

The economics of the electricity generated by CHP plants is highly dependent on the use and value of the co-product (heat) which is site specific. This explains the variability of generation cost estimates obtained in the study. Most of the CHP plants considered are gas-fired units and have similar generation cost characteristics, e.g. low sensitivity to discount rate. In countries which provided cost data for CHP plants and power plants generating electricity only, with the same type of fuel, CHP generated electricity is cheaper except in very few cases.

The levelised cost drivers for wind generated electricity are discount rate and capacity factor. The data provided for the study indicate rather high capacity factors and in countries which provided data for wind and traditional base-load options (coal, gas or nuclear), the levelised costs of wind generated electricity generally are not very far from competitiveness. The levelised costs do not take the costs of handling the intermittency of wind into account. This will add to the costs of wind power as discussed in Appendix 9. At 5% discount rate, the levelised costs of wind power plants range between 35 and 55 USD/MWh for most plants but exceed 80 USD/MWh in several cases. At 10% discount rate, the levelised costs of wind power plants range between 50 and 95 USD/MWh for most plants but exceed 100 USD/MWh in several cases.

Generation cost trends

Recognising that the 1998 study was conducted with generic assumptions different from those adopted for the present one, comparing their results is rather difficult. Furthermore, the comparison between the present study and the 1998 study would be feasible only for coal, gas and nuclear power because other sources and technologies included in the present report were not addressed in details in the previous one.

The 1998 study assumed an average availability factor equal to 75% for coal, gas and nuclear power plants while the present study assumes 85%. Although this change is reflecting technological and operational progress during the period 1996 to 2003, comparing levelised costs estimated with different availability factors is not highly relevant for drawing conclusions on cost trends.

Although several countries provided cost data for coal, gas or nuclear power plants in the two studies, the specific technology for which data were provided evolved in many cases from one study to the other. Therefore comparing the results of the 1998 study to those of the present study is not relevant to identify real cost trends. For example, comparing costs for two coal-fired power plants based on different technologies does not illustrate the technology progress for any given technology.

Finally, and more importantly, the exchange rates from the national currency unit of participating countries and the USD varied widely between 1 July 1996 and 1 July 2003. Therefore, converting levelised costs estimated for different countries into 1 July 2003 USD does not reflect the impact of inflation in each country. Any meaningful analysis of cost trends in each country would require a comparison of levelised costs in national currency unit taking into account inflation and the respective shares of national and imported goods and services in the costs to be analysed.

One of the driving factors for the cost reduction of coal and nuclear generated electricity likely is the higher availability factor, 85% instead of 75% in the previous study. For gas-fired plants, the higher availability factor is not so important because the share of fuel in total generation cost is predominant, around 75% or more, and levelised costs of gas generated electricity are dependent mainly on projected gas prices and their escalation rate during the plant lifetime.

Concluding remarks

The lowest levelised costs of generating electricity from the traditional main base-load technologies are within the range of 25-45 USD/MWh in most countries. The levelised costs and the ranking of technologies in each country are sensitive to the discount rate and the projected prices of natural gas and coal.

The framework for determining the required rates of return on capital is currently changing significantly with the liberalisation of markets. Financial risks are perceived and assessed differently. The markets for natural gas are undergoing substantial changes on many levels. Also the coal markets are under influence from new factors. Environmental policy is playing a more and more important role indicating a development which will also influence fossil fuel costs in the future. Security of energy supply remains a concern for most OECD countries.

This study provides insights on the relative ranking of alternative options in the participating countries when projected generation costs are estimated with a uniform methodology and generic assumptions. The limitations inherent in a generic approach are stressed in the report. In particular, the cost estimates presented are not meant to represent the precise costs that would be calculated by potential investors for any specific project. This is the main reason for the difference with the clear market trend around the world that seems to favour gas-fired power generation.

The data provided for the study highlight the increasing interest of participating countries in renewable energy sources for electricity generation, in particular wind power, and in combined heat and power plants.

Within this framework and limitations, the study suggests that none of the base-load technologies, coal, gas and nuclear can be expected to be the cheapest in all situations. The preferred base-load technology will depend on the specific circumstances of each project. The study indeed supports that on a global scale there is room and need for all base-load technologies.

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Factors Covered in Reported Costs

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Table A2.10 – Wind plant investment cost coverage
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Table A2.16 – Other plant investment cost coverage
Table A2.17 – Other plant O&M cost coverage

Table A2.1 – Nuclear plant investment cost coverage

	CAN	CZE	FIN	FRA	DEU	JPN	KOR	NLD	SVK	CHE	USA	ROU
Overnight Capital Costs: Construction												
Direct costs												
- Site preparation	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Civil work	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Material, equipment & manpower	✔	✔	✔[2]	✔	✔	✔	✔	✔	✔	✔	✔	✔
Indirect costs			3									
- Design, engineering & supervision	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Provisional equipment & operation	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	x	✔
- Worksite administrative expenses	✔	x	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔
Owner's costs												
- General administration	✔	x	✔	✔	x	✔	✔	✔	✔	✔	✔	✔
- Pre-operation	✔	✔	✔	✔	x	✔	✔	✔	✔	✔	✔	✔
- R&D (plant specific)	✔	✔	ns	x	x	x	x	x	✔	x	x	ns
- Spare parts	✔	✔	✔	✔	x	✔	✔	x	x	✔	✔	✔
- Site selection, acquisition, licensing & public relations	✔	x	✔	✔	x	✔	✔	✔	x	✔	✔	✔
- Taxes (local/regional, plant specific)	✔	x	ns	x	x	x	x	✔	x	x	x	✔
Decommissioning												
- Design, licensing & public relations	✔	x	✔	✔	x	x	x	✔	✔	✔	✔	✔
- Dismantling & waste storage	✔	x	✔	✔	✔	✔	x	✔	✔	✔	✔	✔
- Waste disposal	✔	x	✔	✔	✔	✔	x	✔	✔	✔	✔	✔
- Site restoration	✔	x	✔	✔	✔	x	x	✔	✔	✔	✔	✔
Other overnight capital costs												
- First inventory of heavy water	✔	na	na	na	na	na	na	na	na	na	na	✔
- Major refurbishment	✔	✔	ns	x	x	x	x	x	x	x	x	✔
- Credits	x	x	ns	x	x	x	x	x	x	x	x	ns
- Contingency	✔	x	✔	✔	✔	x	✔	x	x	x	✔	✔
- Miscellaneous	✔[1]	x	ns	ns	ns	ns	ns	ns	✔	x	ns	✔

Notes:
1. First core inventory.
2. Including first core inventory.
3. Included in "Direct Costs".

Abbreviations: ✔ = included; x = excluded; na = not applicable; ns = not specified

Table A2.2 – Nuclear plant O&M cost coverage

	CAN	CZE	FIN	FRA	DEU	JPN	KOR	NLD	SVK	CHE	USA	ROU
Operation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Site monitoring	✔	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔
Maintenance (materials, manpower, services)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Engineering support staff	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Administration	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Operating waste management & disposal	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
General expenses of central services (outside the site)	✔	x	x	✔	x	✔	✔	✔	x	✔	✔	✔
Taxes & duties (plant specific)	✔	x	✔ [1]	x	x	x	x	✔	✔ [4]	x	x	✔
Insurance (plant specific)	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Major refurbishment	x	x	✔	x	✔ [2]	x	x	x	x	x	x	✔
Support to regulatory bodies	✔	✔	✔	✔	x	x	x	x	x	✔	✔	ns
Safeguards	✔	✔	x	✔	✔	ns	✔	x	✔	✔	✔	ns
Credits	x	x	x	x	x	x	x	x	x	x	x	ns
Others	x	x	x	x	x	x	✔ [3]	x	✔ [3]	x	x	ns

Notes:
1. Real estate tax.
2. Costs for refurbishment are included in the fixed operating costs.
3. Transfers to the State Fund for Decommissioning of Nuclear Power Installations, Spent Nuclear Fuel Handling and Radioactive Waste Treatment for financing of presented works after termination of the nuclear power plant operation.
4. The duties in an amount of 50 million SKK per year for the villages situated in the distance (range) 5, 10, 20 km from the nuclear facility in terms of the law no. 544/1990.

Table A2.3 – Nuclear fuel cycle cost coverage

	CAN	CZE	FIN	FRA	DEU	JPN	KOR	NLD	SVK	CHE	USA	ROU
Uranium concentrate	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Conversion to UF_6	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	na
Enrichment	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	na
Fuel fabrication	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Spent fuel transportation	✔	✔	x	✔	✔	✔	x	✔	✔	✔	✔	✔
Spent fuel encapsulation & disposal	✔	✔	✔	na	✔	✔	x	x	✔	✔	✔	✔
Reprocessing & waste conditioning	na	x	x	✔	na	✔	x	✔	x	x	x	x
Waste disposal	✔	x	x	✔	✔	✔	x	✔	x	✔	x	x
Credits	x	x	x	x	x	x	x	x	x	ns	x	x
First core inventory	x [1]	✔	x	✔	✔	✔	✔	✔	x [1]	✔	x	x
Taxes on nuclear fuel	✔	x	x	x	ns	x	✔	x	x	x	x	✔
Others	ns	x	x	ns	ns	ns	ns	ns	✔ [2]	ns	x	ns

Notes:
1. Included in investment.
2. Encapsulation and permanent (final) storage of spent fuel in the deep geological disposal.

Abbreviations:	✔ = included x = excluded	na = not applicable ns = not specified

Table A2.4 – Coal-fired plant (including CHP)and oil-fired plant investment cost coverage

	CAN	CZE	DNK	FIN	FIN CHP	FRA	DEU	GRC OIL	JPN	KOR	SVK	TUR	USA	BGR	ROU	ZAF
Overnight Capital Costs: Construction																
Direct costs																
- Site preparation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Civil work	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Material, equipment & manpower for construction	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Indirect costs																
- Design, engineering & supervision	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Provisional equipment & operation	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	x	✔	✔	✔		✔
- Worksite administrative expenses	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Owner's costs																
- General administration	✔	x	x	ns	x	✔	x	x	✔	✔	✔	x	✔	✔	✔	✔
- Pre-operation	✔	x	x	ns	x	✔	x	x	✔	✔	✔	✔	✔	✔	✔	✔
- R&D (plant specific)	✔	x	x	ns	x	x	x	x	x	x	x	x	x	✔	✔	x
- Spare parts	✔	✔	x	✔	x	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Site selection, acquisition, licensing & public relations	✔	✔	x	ns	x	✔	x	x	✔	✔	x	x	✔	✔	✔	✔
- Taxes (local/regional, plant specific)	✔	x	x	ns	x	x	x	x	x	x	x	✔	x [2]	✔	✔	✔
Others																
- Major refurbishment	x	✔	x	ns	✔	x	x	x	x	✔	✔	x	x	ns	✔	x
- Decommissioning	x	x	x	ns	x	✔	✔	x	x	x	x	x	x	ns	x	x
- Credits	x	x	x	ns	x	✔ [1]	x	x	x	x	x	✔	x	ns	✔	ns
- Contingency	✔	x	x	ns	x	✔	✔	x	x	✔	x	x	✔	ns	✔	x
- Miscellaneous	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	✔	ns

Notes:
1. Decommissioning expenses are balanced by credits.
2. General state and local taxes are included, but they are not technology specific.

Abbreviations: ✔ = included   x = excluded   ns = not specified

Table A2.5 – Coal-fired plant (including CHP) and oil-fired plant O&M cost coverage

	CAN	CZE	DNK	FIN	FIN CHP	FRA	DEU	GRC OIL	JPN	KOR	SVK	TUR	USA	BGR	ROU	ZAF
Operation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Maintenance (materials, manpower, services)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Engineering support staff	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	x	✔	✔	✔	✔	✔
Administration	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
General expenses of central services (outside the site)	✔	x	x	ns	✔	✔	x	✔	✔	✔	x	x	✔	✔	✔	✔
Taxes & duties (plant specific)	✔	x	x	ns	x	x	x	x	x	x	x	✔	x	✔	✔	x
Insurance (plant specific)	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	x	✔	x	✔	✔	✔
Major refurbishment	✔ [1]	x	x	ns	x	x	✔ [3]	x	x	x	✔ [5]	x	x	ns	ns	✔
Operating waste disposal (e.g., coal ash, sludge)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	ns	ns	✔
Credits	x	x	x	ns	✔ [2]	x	x	x	x	x	x	x	x	ns	ns	x
Others	x	x	x	ns	ns	x	ns [4]	ns	x	x	x	x	ns	ns	✔ [6]	ns

Notes:
1. Annual Capital Expenditure.
2. The value of CHP heat includes the costs of the alternative heat production (separate heating plants) as credits, including fuel (heavy fuel oil: 4.7€/GJ), O&M costs and the difference in the taxation between the coal used in CHP heat production and the oil used in separate heat production in heating plants.
3. Costs for refurbishment are included in the fixed operating costs and in the O&M costs reported in the questionnaire.
4. None for CHP plants.
5. Capital repairs which are provided/performed every fifth year of operation.
6. Chemicals, process water, reagents.

Table A2.6 – Coal-fired plant (including CHP) and oil-fired plant fuel cost coverage

	CAN	CZE	DNK	FIN	FIN CHP	FRA	DEU	GRC OIL	JPN	KOR	SVK	TUR	USA	BGR	ROU	ZAF
Fuel price (at the border or domestic mine)	✔	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Transportation within the country	✔	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	x	✔	✔	✔	x
Taxes on fuel (excluding existing CO_2 taxes)	✔	x	x	ns	x	x	x	✔	✔	✔	x	✔	✔	✔	x	x
Others	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns

Abbreviations: ✔ = included x = excluded ns = not specified

Table A2.7 – Gas-fired (including CHP and fuel cell) plant investment cost coverage

	BEL	CAN	CZE	DNK CHP	FIN CHP	FRA	DEU	GRC	ITA	JPN	KOR	NLD CHP	PRT	SVK	CHE	CHE CHP	TUR	USA	ZAF
Overnight Capital Costs:Construction																			
Direct costs																			
- Site preparation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Civil work	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Material, equipment & manpower	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Indirect costs																			
- Design, engineering & supervision	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Provisional equip-ment & operation	✔	✔	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	x	✔	✔	✔	✔ [8]	✔
- Worksite admin. expenses	✔	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Owner's costs																			
- General admin.	✔	✔	x	x	x	✔	x	x	x	✔	✔	✔	✔	✔	✔	✔	x	✔	✔
- Pre-operation	✔	✔	x	x	x	✔	x	x	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- R&D (plant specific)	✔	✔	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
- Spare parts	✔	✔	✔	x	x	✔	x	✔	[3]	✔	✔	x	✔	✔	x	x	✔	✔	✔
- Site selection, acquisition,licensing & public relations	ns	✔	✔	x	x	✔	x	x	x	✔	✔	✔	✔	x	✔	✔	✔	✔	✔
- Taxes (local/regional, plant specific)	ns	✔	x	x	x	x	x	x	✔	x	x	✔	✔ [5]	x	x	x	✔	x [9]	x
Others																			
- Major refurbishment	x	x	✔	x	✔	x	x	x	✔	x	x	✔	✔ [6]	x	✔ [7]	✔ [7]	x	x	x
- Decommissioning	✔	x	x	x	x	✔	✔	x	x [4]	x	x	✔	x	x	✔	✔	x	x	x
- Credits	ns	x	x	x	✔ [1]	✔ [2]	x	x	x	x	x	✔	x	x	ns	x	✔	x	x
- Contingency	✔	✔	x	x	x	✔	✔	x	✔	x	✔	✔	✔	x	x	x	x	✔	x
- Miscellaneous	ns	ns	ns	ns	x	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	x	ns	ns	ns

Notes:
1. The value of CHP heat includes the investment costs of the alternative heat production (separate oil burning heating plants) as credits.
2. Credits at decommissioning balance decommissioning costs.
3. Excluded in ITA-G1-2, included in ITA-G3.
4. Included in ITA-G2.
5. Project development and legal construction procedures.
6. Technical parts/spare parts linked to the main components.
7. Costs considered for replacement of total plant after 25 years at 95% costs of initial investment.
8. Excluded in USA-CHP1-2.
9. General state and local taxes are included, but they are not technology specific.

Abbreviations: ✔ = included x = excluded ns = not specified

Table A2.8 – Gas-fired (including CHP and fuel cell) plant O&M cost coverage

	BEL	CAN	CZE	DNK CHP	FIN CHP	FRA	DEU	GRC	ITA	JPN	KOR	NLD CHP	PRT	SVK	CHE	CHE CHP	TUR	USA	ZAF
Operation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Maintenance (materials, manpower, services)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Engineering support staff	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Administration	✔	✔	x	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
General expenses of central services	✔	✔	x	x	✔	✔	x	✔	x [6]	✔	✔	✔	✔	x	✔	✔	✔	✔	✔
Taxes & duties (plant specific)	✔	✔	x	x	x	x	x	x [4]	✔	x	x	✔	x	x	x [8]	x	✔	x	x
Insurance (plant specific)	✔	✔	x	✔	✔	✔	✔	x	x [6]	✔	✔	✔	✔	x	✔	✔	✔	x	✔
Major refurbishment	✔	x	x	✔ [1]	x	x	✔ [3]	✔ [5]	x [6]	x	x	x	x	✔	x	✔	x	x	✔
Operating waste disposal	ns	✔	✔	x	✔	✔	✔	x	✔	✔	✔	x	x	x	x	x	✔	✔	✔
Credits	ns	x	x	x	✔ [2]	x	x	x	x	x	x	x	x	x	x [9]	x	x	x [10]	x
Others	ns	x	x	x	ns	x	x	x	ns	x	x	x	✔ [7]	x	ns	x	x	ns	x

Notes:
1. Included for DNK-CHP1; excluded for DNK-CHP3.
2. The value of CHP heat includes the costs of the alternative heat production (separate heating plants) as credits, including fuel (heavy fuel oil: 4.7€/GJ), O&M costs and the difference in the taxation between the coal used in CHP heat production and the oil used in separate heating plants.
3. Costs for major refurbishment are included in the fixed operating costs.
4. Excluded for GRC-G1, included for GRC-G2.
5. Included for GRC-G1, excluded for GRC-G2.
6. Excluded for ITA-G1-2; included for ITA-G3.
7. Land rent.
8. Not applicable for CHE-G1.
9. Not specified for CHE-G1.
10. For USA-CHP1-2, costs are considered for replacement of total plant after 25 years at 95% costs of initial investment.

Table A2.9 – Gas-fired (including CHP and fuel cell) plant fuel cost coverage

	BEL	CAN	CZE	DNK CHP	FIN CHP	FRA	DEU	GRC	ITA	JPN	KOR	NLD CHP	PRT	SVK	CHE	CHE CHP	TUR	USA	ZAF
Fuel price (at the border or domestic mine)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Transportation within the country	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	x	✔	✔	✔	✔	x
Taxes on fuel	x [1]	✔	x	x [2]	x	✔ [3]	x	✔	x	✔	✔	✔	x	x	x	x	✔	✔ [4]	x
Others	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	ns	x	ns	ns	ns

Notes:
1. VAT and excise taxes not included.
2. In Denmark there are no taxes on fuels used for electricity production. In case of CHP production, only the share of fuel used for heat production is taxed.
3. TICGN: 1.19€/MWh of gas.
4. Embedded in the fuel prices given in the questionnaire are fuel specific state severance taxes.

Abbreviations: ✔ = included x = excluded ns = not specified

Table A2.10 – Wind plant investment cost coverage

	AUT	BEL	CZE	DNK W1	DNK W2	DNK W3	DEU	GRC W1	GRC W2	GRC W3-4	GRC W5	ITA W1	ITA W2	NLD	PRT	USA
Overnight Capital Costs: Construction																
Direct costs																
- Site preparation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Civil work	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Material, equipment & manpower for construction	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Indirect costs																
- Design, engineering & supervision	✔	✔	✔	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Provisional equipment & operation	✔	✔	✔	✔	✔	x	✔	✔	✔	✔	✔	✔	✔	✔		✔
- Worksite administrative expenses	✔	✔	✔	✔	✔	x	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Owner's costs																
- General administration	✔	✔	✔	✔	✔	x	x	✔	✔	✔	✔	✔	x	✔	✔	✔
- Pre-operation	✔	✔	x	✔	✔	x	x	✔	✔	x	✔	✔	x	✔	✔	✔
- R&D (plant specific)	✔	✔	x	✔	x	x	x	✔	✔	x	x	✔	x	x	x	x
- Spare parts	✔	✔	✔	x	✔	x	x	✔	✔	x	✔	✔	✔	x	✔	✔
- Site selection, acquisition, licensing & public relations	✔	✔	✔	✔	✔	x	x	x	x	x [2]	x	✔	x	✔	✔	✔
- Grid connection	✔	✔	✔	x	✔	x	✔	✔	x	✔	✔	✔	✔	✔	✔	x
- Taxes (local/regional, plant specific)	✔	x	x	x	x	x	x	✔	✔	x	x	✔	x	x	✔ [4]	x [5]
Others																
- Major refurbishment	✔	x	✔ [1]	x	x	x	x	x	x	x	x	✔	✔	x	x	x
- Decommissioning	x	x	x	x	✔	x	x	x	x	x	x	x	x	✔	x	x
- Credits	x	x	x	x	x	x	x	x	x	x	✔	x	✔	x	x	x
- Contingency	x	x	x	x	x	x	x	x	x	x	✔ [3]	✔	✔	x	✔	✔
- Miscellaneous	ns	ns	x	ns	ns	ns	ns	ns	ns	✔	ns	ns	✔	ns	ns	ns

Notes:
1. Replacement of most stressed parts (blades) according to their lifetime.
2. Applies only to GRC-W4.
3. On base construction only.
4. Project development and legal construction procedures.
5. General state and local taxes are included, but they are not technology specific.

Abbreviations: ✔ = included x = excluded ns = not specified

Table A2.11 – Wind plant O&M cost coverage

	AUT	BEL	CZE	DNK W1	DNK W2	DNK W3	DEU	GRC W1	GRC W2	GRC W3-4	GRC W5	ITA W1	ITA W2	NLD	PRT	USA
Operation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Maintenance (materials, manpower, services)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Engineering support staff	✔	✔	✔	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Administration	✔	✔	x	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
General expenses of central services (outside the site)	x	✔	x	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Taxes & duties (plant specific)	✔	x	x	ns	x	ns	✔	✔	✔	✔	✔	✔	✔	x	✔	x
Insurance (plant specific)	✔	✔	x	✔	✔	ns	✔	✔	✔	✔	✔	✔	✔	✔	✔	x
Major refurbishment	x	ns	x	✔ [1]	x	ns	x	x	x	x	x	✔	x	x	✔ [3]	x
Site leasing payments	ns	✔	✔	x	x	ns	✔	x	x	x	x	✔	✔	x	✔	✔
Credits	ns	ns	x	x	x	ns	x	x	x	x	x	✔	✔	x	x	x [4]
Others	ns	ns	x	✔	x	ns	ns	x	x	x	x	ns	✔	✔ [2]	x	ns

Notes:
1. Major overhauls foreseen twice during lifetime. Decommissioning costs are included in O&M budget as well.
2. Environmental monitoring programme (1.0 million €/year).
3. Increase of O&M costs from eleventh year onwards.
4. Specific network charges are included in the modelling and analysis, but because of the extreme variability, they are not included in the costs given in the questionnaire.

Abbreviations: ✔ = included x = excluded ns = not specified

Table A2.12 – Hydro plant investment cost coverage

	AUT Small	CZE Small	DEU Small	GRC H1 Small	GRC H2 Large	JPN Large	SVK Small	BGR Large	ZAF Large
Overnight Capital Costs: 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	x	✔	✔	✔	✔	✔	✔
- Pre-operation	✔	✔	x	✔	✔	✔	✔	✔	✔
- R&D (plant specific)	✔	x	x	x	x	x	✔	✔	x
- Spare parts	✔	✔	x	✔	✔	✔	✔	✔	✔
- Site selection, acquisition, licensing & public relations	✔	✔	x	x	✔	✔	✔	✔	✔
- Grid connection	✔	✔	✔	✔	x	x	✔	✔	x
- Taxes (local/regional, plant specific)	✔	✔	x	x	x	x	✔	✔	x
Others									
- Major refurbishment	x	✔ [1]	x	x	x	x	x	ns	x
- Decommissioning	x	x	x	x	x	x	x	ns	x
- Credits	x	x	x	✔	x	x	x	ns	x
- Contingency	x	x	x	✔ [2]	x	x	✔	ns	x
- Miscellaneous	ns	x	ns	ns	ns	ns	ns	ns	x

Notes:
1. Replacement of most stressed parts according to their lifetime.
2. On base construction only.

Table A2.13 – Hydro plant O&M cost coverage

	AUT Small	CZE Small	DEU Small	GRC H1 Small	GRC H2 Large	JPN Large	SVK Small	BGR Large	ZAF Large
Operation	✔	✔	✔	✔	✔	✔	✔	✔	✔
Maintenance (materials, manpower, services)	✔	✔	✔	✔	✔	✔	✔	✔	✔
Engineering support staff	✔	✔	✔	✔	✔	✔	✔	✔	✔
Administration	✔	✔	✔	✔	✔	✔	✔	✔	✔
General expenses of central services (outside the site)	✔	✔	✔	✔	✔	✔	✔	✔	✔
Taxes & duties (plant specific)	✔	✔	✔	✔	x	x	x	✔	✔
Insurance (plant specific)	✔	x	✔	✔	x	✔	x	✔	✔
Major refurbishment	x	x	x	x	x	x	✔	ns	✔
Site leasing payments	✔	✔	✔	x	✔	x	✔	✔	x
Water rentals	✔	✔	✔	x	x	✔	x	✔	x
Credits	x	x	x	x	ns	x	x	ns	x
Others	ns	x	ns	ns	x	x	x	ns	x

Abbreviations: ✔ = included x = excluded ns = not specified

Table A2.14 – Solar plant investment cost coverage

	CZE PV	DNK PV	DEU PV	USA Thermal	USA PV
Overnight Capital Costs: Construction					
Direct costs					
- Site preparation	✔	✔	✔	✔	✔
- Civil work	✔	✔	✔	✔	✔
- Material, equipment & manpower for construction	✔	✔	✔	✔	✔
Indirect costs					
- Design, engineering & supervision	✔	x	✔	✔	✔
- Provisional equipment & operation	✔	x	✔	✔	✔
- Worksite administrative expenses	✔	x	✔	✔	✔
Owner's costs					
- General administration	x	x	x	✔	✔
- Pre-operation	✔	x	x	✔	✔
- R&D (plant specific)	x	x	x	x	x
- Spare parts	✔	x	x	✔	✔
- Site selection, acquisition, licensing & public relations	x	x	x	✔	✔
- Grid connection	x	✔	✔	✔	✔
- Taxes (local/regional, plant specific)	x	x	x	x [3]	x [3]
Others					
- Major refurbishment	✔ [1]	✔ [2]	x	x	x
- Decommissioning	x	x	x	x	x
- Credits	x	ns	x	x	x
- Contingency	x	ns	x	✔	✔
- Miscellaneous	ns	ns	ns	ns	ns

Notes:
1. Replacement of most stressed parts.
2. Installation of new inverter after 12 years of operation.
3. General state and local taxes are included, but they are not technology specific.

Table A2.15 – Solar plant O&M cost coverage

	CZE PV	DNK PV	DEU PV	USA Thermal	USA PV
Operation	✔	✔	✔	✔	✔
Maintenance (materials, manpower, services)	✔	✔	✔	✔	✔
Engineering support staff	✔	x	✔	✔	✔
Administration	x	x	✔	✔	✔
General expenses of central services (outside the site)	x	x	✔	✔	✔
Taxes & duties (plant specific)	x	x	✔	x	x
Insurance (plant specific)	x	x	✔	x	x
Major refurbishment	x	x	x	x	x
Credits	x	x	x	x	x
Others	x	ns	ns	[1]	[1]

Note:
1. Specific network charges are included in the modelling and analysis, but because of the extreme variability, they are not included in the costs given in the questionnaire.

Abbreviations: ✔ = included x = excluded ns = not specified

Table A2.16 – Other plant investment cost coverage

	AUT CHP Biomass	CZE CR	CZE WI	DNK CHP Multifuel	DNK CHP Straw-coal	DEU CHP Biogas	NLD WI	USA CR	USA Geo-thermal	USA Landfill gas
Overnight Capital Costs: Construction										
Direct costs										
- Site preparation	X	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Civil work	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Material, equipment & manpower for construction	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Indirect costs										
- Design, engineering & supervision	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
- Provisional equipment & operation	X	✔	✔	ns	✔	✔	✔	✔	✔	
- Worksite administrative expenses	✔	✔	X	ns	✔	✔	✔	✔	✔	✔
Owner's costs										
- General administration	✔	X	X	ns	✔	X	✔	✔	✔	✔
- Pre-operation	✔	X	✔	ns	✔	X	✔	✔	✔	✔
- R&D (plant specific)	✔	X	X	ns	X	X	✔	X	X	X
- Spare parts	X	✔	✔	ns	✔	X	✔	✔	✔	✔
- Site selection, acquisition, licensing & public rel.	X	✔	✔	ns	✔	X	✔	✔	✔	✔
- Taxes (local/regional, plant specific)	X	X	X	ns	X	X	✔	X	X	ns
Others										
- Major refurbishment	X	✔[1]	✔[1]	✔	X	X	✔	X	X	X
- Decommissioning	X	X	X	✔	✔	X	✔	X	X	X
- Credits	X	X	X	X	X	X	✔	X	X	X
- Contingency	X	X	X	X	X	✔	✔	✔	✔	✔
- Miscellaneous	ns	X	X	ns	ns	ns	ns	ns	ns	ns

Note:
1. Replacement of most stressed parts according to their lifetime.

Table A2.17 – Other plant O&M cost coverage

	AUT CHP Biomass	CZE CR	CZE WI	DNK CHP Multifuel	DNK CHP Straw-coal	DEU CHP Biogas	NLD WI	USA CR	USA Geo-thermal	USA Landfill gas
Operation	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Maintenance (materials, manpower, services)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Engineering support staff	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Administration	X	X	X	ns	✔	✔	✔	✔	✔	✔
General expenses of central services (outside the site)	X	X	X	X	✔	✔	ns	✔	✔	✔
Taxes & duties (plant specific)	X	X	X	X	X	✔	✔[2]	X	X	X
Insurance (plant specific)	X	X	X	✔	✔	✔	✔	X	X	X
Major refurbishment	X	X	X	X	X	✔[1]	ns	X	X	X
Operating waste disposal (e.g. coal ash, sludge)	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Credits	X	X	X	X	X	X	ns	X	X	X
Others	ns	X	X	X	X	ns	ns	ns	ns	ns

Notes:
1. Included in the fixed operating costs.
2. VAT 19% on investment.

Abbreviations: ✔ = included X = excluded ns = not specified

Country Statements on Cost Estimates and Generation Technology

Austria

Basic data

Austria has about 8.1 million inhabitants and a total electricity consumption of about 63 TWh. The electricity generation in Austria is approximately in the same range as the electricity demand. Austria is a mountainous area with a high potential of hydro power which is already used and covers about 66% of Austria's electricity demand.

Austrian investment examples selected for cost calculation case studies

The contribution from the Austrian side for this report about generation costs of electricity is focused on generation by renewable sources and by fossil co-generation plants. The following examples of projects, which are currently invested or have been invested within the last one or two years, are presented:

- AUT-H1: Hydro power (run of the river) with 14 MWe.
- AUT-H2: Small hydro with high pressure with 1.5 MWe.
- AUT-W: Wind power with 11 units of 1.75 MWe each (total 19.25 MWe).
- AUT-CHP1: Combined heat and power with natural gas as fuel (CCGT), 84 MWe/127 MWth.
- AUT-CHP2: Combined heat and power with biomass as fuel, 8 MWe/20 MWth.
- AUT-CHP3: Combined heat and power with natural gas as fuel (CCGT), 105 MWe/110 MWth.

For a correct interpretation of the cost calculations the following specific conditions must be taken into consideration:

- The two investments AUT-H1 and AUT-H2 are hydro power projects with a relatively small capacity. The electricity production costs per kWh therefore are higher than the costs of large hydro in most cases would be.
- The wind power project AUT-W is in a mountainous region. The investment and operation costs therefore are higher than for an average wind power investment.
- The combined heat and power plants AUT-CHP1 (natural gas based) and AUT-CHP2 (biomass) are new investments.
- The combined heat and power plant AUT-CHP3 (natural gas based) is the modernisation of a power plant which was built in 1970 with two smaller boilers and now is substituted by one bigger boiler whose capacity is about double the total of the two former boilers. Because it is a modernisation the investment needed is smaller than it would have been with a completely new plant. However, the difference is probably not so large because the dimension of the new units is quite different than the former had been.

Cost structure of supported green electricity in Austria

Additionally to the presented investment examples, the funding scheme for electricity generation by renewable energy sources ("green electricity") which is presented in the following pages, reflects the cost structure on a more general basis with the conditions in Austria.

Renewable energy sources are dominant in the Austrian electricity production structure. About 70% of the total generation (which covers more or less the total electricity demand of Austria) is produced with renewable sources, about 56% with large hydro power (>10 MW, currently not financial supported), 8% with small hydro (<10 MW, supported with feed-in tariffs) and 3% with wind power and biomass. (The difference of about 3% comes from industrial plants fuelled with residues.)

The producers of green electricity, who invest in plants that enter operation in the year 2003 through the middle of 2006 (if they have the building permissions before end of 2004), receive a feed-in tariff for the green electricity which is fed into the public grid. This feed-in tariff is guaranteed for 13 years (from beginning of operation) and is not adjusted to the inflation rate. The feed-in tariff differs for the different renewable energy sources and in some cases it also varies with capacities (e.g. higher feed-in tariffs for more expensive smaller capacity units).

The values of the feed-in tariffs are fixed in accordance with the generation costs. The feed-in tariffs are intended to support investments to meet the Austrian legal green electricity target, which is to generate, by 2008, a minimum of 4% of total electricity (compared to the total amount distributed by the public grid) by wind power and biomass. The starting percentage was 0.8% in the year 2002. The fixed feed-in tariffs were accepted by the green electricity investors as very attractive, as shown by intensive investment programmes. The 4% target will be reached already in the year 2005.

For small hydro power (up to a capacity of 10 MW) the target for 2008 is 9% compared to a starting percentage of 8% in the year 2002.

The following feed-in tariffs are valid in Austria for electricity which is produced by renewable energy sources (if the plants go into operation between 2003 and 2006 the tariffs are guaranteed for 13 years):

- Small hydro power (SHP) (<10 MW), existing plants 3.15 - 5.68 €¢/kWh
- SHP with investments, 15% electricity production increase 3.31 - 5.96 €¢/kWh
- SHP new plants 3.78 - 6.25 €¢/kWh
- Wind power 7.80 €¢/kWh
- Biomass 10.20 - 16.00 €¢/kWh
- Biomass waste 6.63 - 12.00 €¢/kWh
- Biogas 10.30 - 16.50 €¢/kWh
- Biogas with co-fermentation of waste 7.73 - 12.38 €¢/kWh
- Photovoltaic 47.00 - 60.00 €¢/kWh

In Figure 1, these feed-in tariffs are compared with the base-load market price of the German Electricity Exchange Place in Leipzig EEX, which was 3.46 €¢/kWh on 1 July 2004 as average of the Futures till June 2005.

The economics and cost structures of electricity generation depend on (among others):

- Investment costs.
- Operation costs (primarily fuel costs).
- Availability of the plant (calculated full load hours per year).

Figures 2 and 3 give an overview of these parameters for electricity generation by renewable sources (compared with that by natural gas) considering the Austrian situation and as a range of average figures. In individual cases, considerable deviations from these average values are possible.

Figure 1 – Comparison of feed-in tariffs with base-load market price

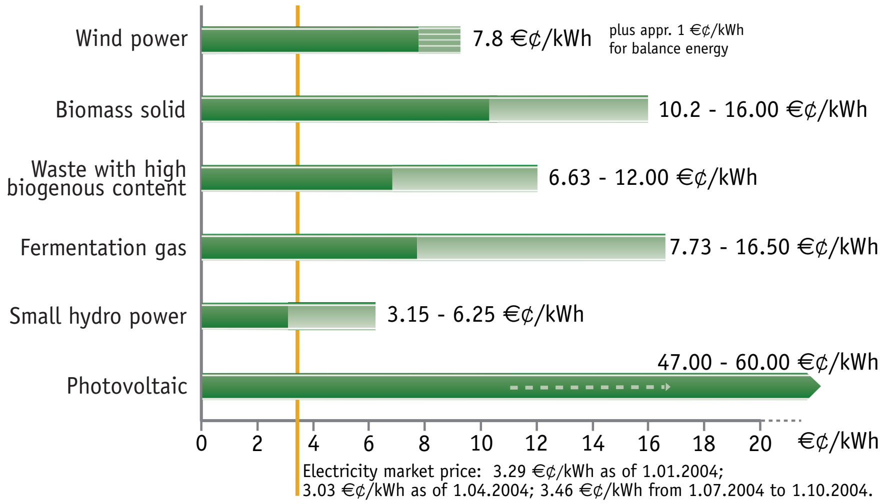


Figure 2 – Investment cost per kilowatt of capacity

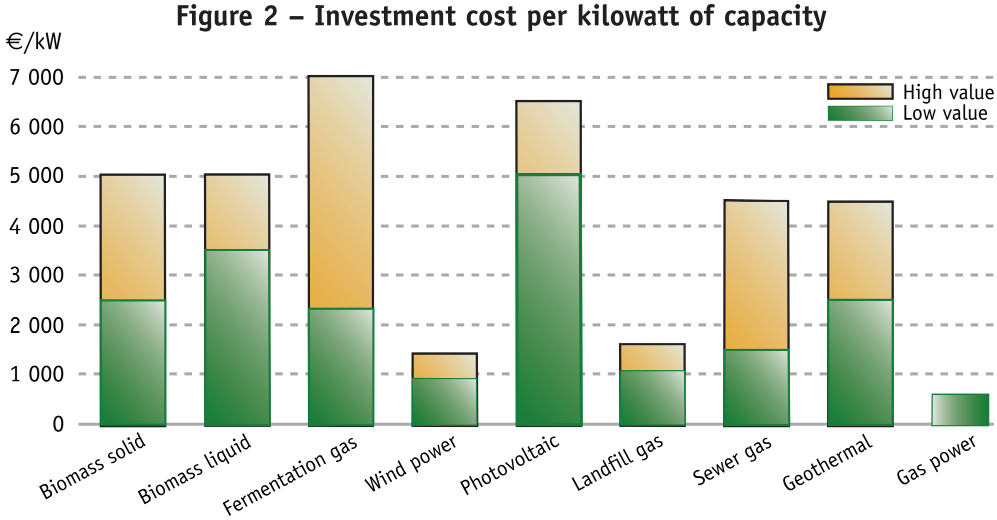
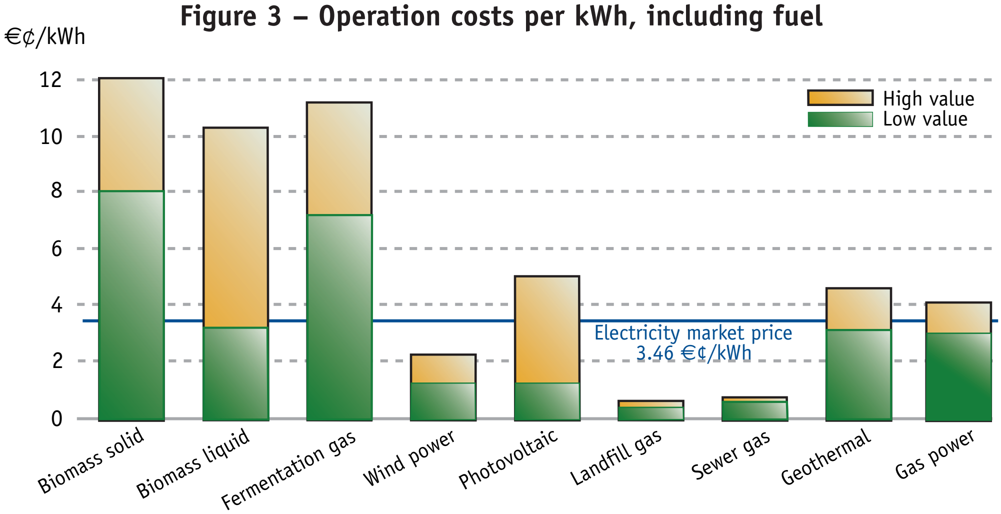


Figure 3 – Operation costs per kWh, including fuel

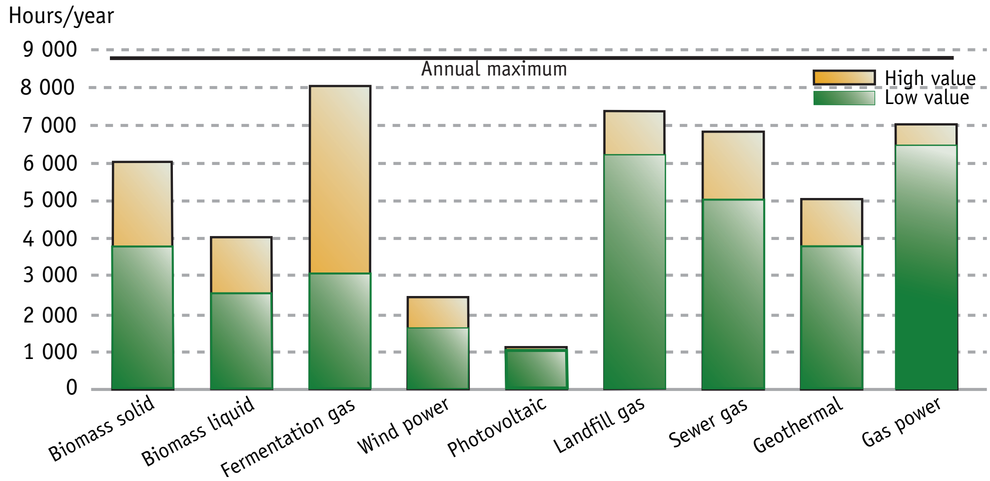


The highest investment cost arises for photovoltaic (although some new experiences indicate a lower cost of about 3 500 €/kW) and for biomass. For wind power, onshore, the investment cost is much lower than for the other renewables.

The operation costs are highest for biomass (both solid and gaseous). Most critical are the fuel costs; for some plants the fuel costs alone contribute more than 5 €¢/kWh. Another important issue is the electricity consumption for the operation of the plant itself and for the fuel preparation. For some plants in operation, it is more than 15% of the electricity generation cost.

The full load hours per year (calculated as produced electricity divided by the rated capacity of the plant) are the highest with plants that use storageable fuels. The full load hours are considerable lower for wind power (on shore) and for photovoltaic (see Figure 4).

Figure 4 – Full load operating hours per year (thousands)



Support schemes in Austria focused on EU-Targets

After the first steps of liberalising the internal European electricity market, with little or no focus on renewables, the European Union increasingly has moved to support generating electricity from Renewable Energy Sources (RES).

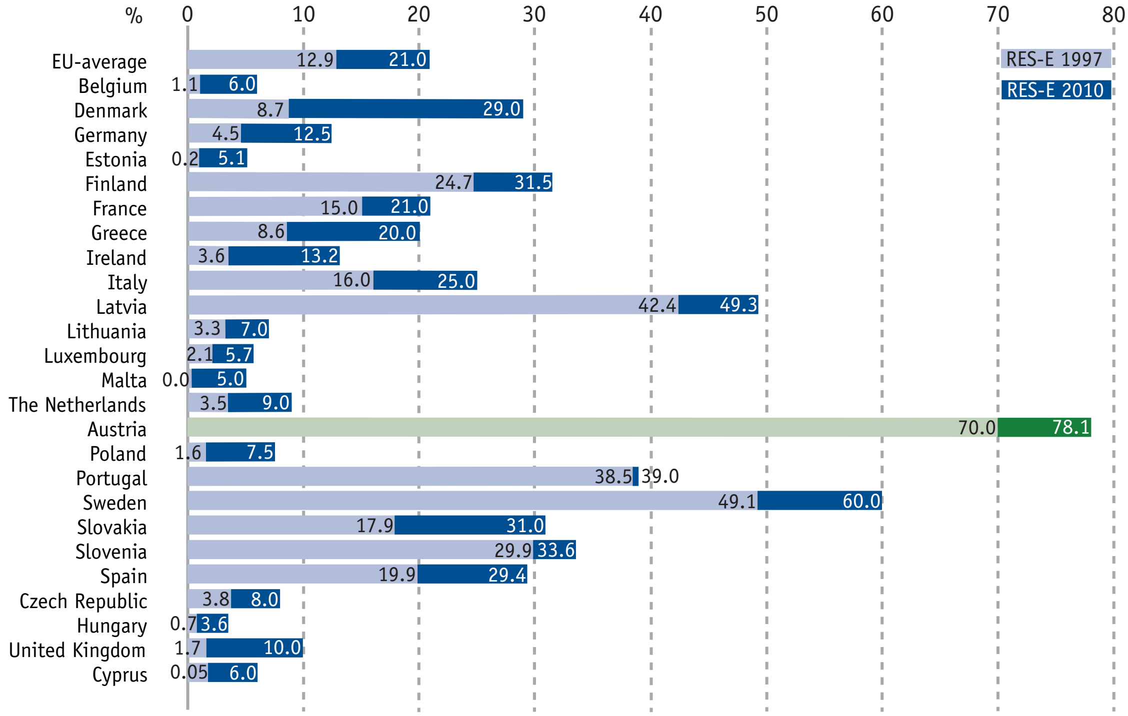
The "White Paper on Renewable Sources of Energy" was one of the first contributions to support the market for RES and the Directive 2001/77/EC (RES-E Directive, 27 September 2001) on the promotion of electricity produced from renewable energy sources in the internal electricity market was one of the most important steps.

With the adoption of the RES-E Directive, the European Union set the fundamental legislative basis for the actual support schemes in Europe and set indicative targets for each Member State to reach in 2010 (see Figure 5). The 78% target for Austria is related to an electricity consumption of 56.1 TWh. The real electricity consumption in the year 2010 will be higher. Because hydro power has not much additional potential in Austria, new investments into RES-E probably cannot cover the expected increase of electricity demand (about 1.6% per year).

In 2003, the trends of RES-E developments in Austria were as follows:

- **Wind power**: The expansion of installed wind power plants is exceeding expectations. By the end of 2004 the installed capacity was about 600 MW, reflecting at least 2.5% of the intended 4% share of "new" renewables in 2008. Additionally, about 200 MW wind power were commissioned and will be invested till June 2006.

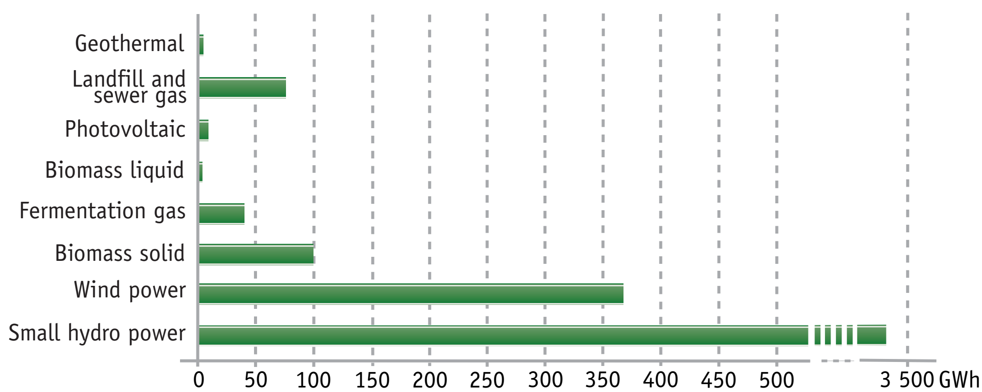
Figure 5 – Electricity from renewable energy sources (RES) 1997 and 2010



- **Biomass**: Due to longer lead times in comparison with wind power plants, the contribution of biomass which is funded with feed-in-tariffs is not at a high level at the moment, but will strongly increase till June 2006. For the year 2004, 250-300 GWh from biomass plants are expected and by 2007 the contribution of the already commissioned biomass plants (about 270 MW) will reach about 1 500 GWh.
- **Biogas**: In the years 2003 and 2004, more than 250 biogas plants were commissioned in Austria, having a total installed electric capacity of more than 50 MW. Most of these plants get a feed-in-tariff between 14 and 16.5 cent/kWh, guaranteed for 13 years from the plant's operation start..
- **Hydro power**: Only electricity produced in small hydro power plants (smaller than 10 MW) is supported via the Green Electricity Act (GEA) in Austria. An increase from 8% in the year 1997 to 9% in the year 2010 of the total demand in Austria is planned.

The amount of supported RES-E electricity production is shown in Figure 6.

Figure 6 – Supported RES-E production in 2003



The expected development of the percentage of wind power and biomass based electricity production from 2003 till 2007 in Austria is shown in Figure 7. Probably the percentages will be even higher, if the current supporting scheme will be extended, with some changes in detail. This prognosis include only that green electricity plants, which got heir building commissions till end of 2004 and will start operation till June 2006 latest. For additional new green electricity investments the funding programmes are not yet decided.

In Austria the three existing transmission system operators (TSOs) have to buy supported green electricity from the green electricity plant operators and have to pay a legal feed-in tariff which is higher than the market price. The TSOs sell this green electricity to all electricity traders who have to take the same percentage and have to pay a price of 4.5 €¢/kWh. The difference between this price and the feed-in tariffs is financed by a surcharge on network tariffs paid by all end consumers.

There is a legal budget restriction so that the average total cost burden for promoting green electricity, may not exceed the following numbers (fixed till the year 2004):

- 0.22 €¢/kWh for "new" renewables (wind power, biomass, photovoltaic).
- 0.16 €¢/kWh for small hydro power.
- 0.15 €¢/kWh for fossil CHP.

Continuing the implemented system requires a growth in the financial budget, which is shown in Figure 8 (compared with the limit of 0.22 €¢/kWh which will be increased from 2005 onwards).

Figure 7 – Development of RES-E in Austria 2003-2007, excluding hydro power

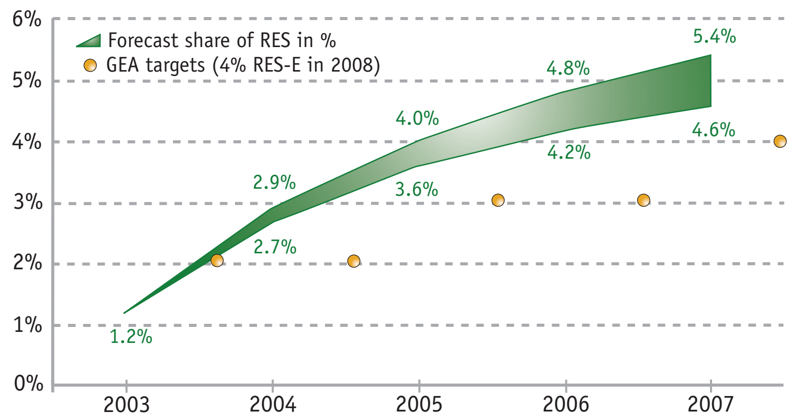
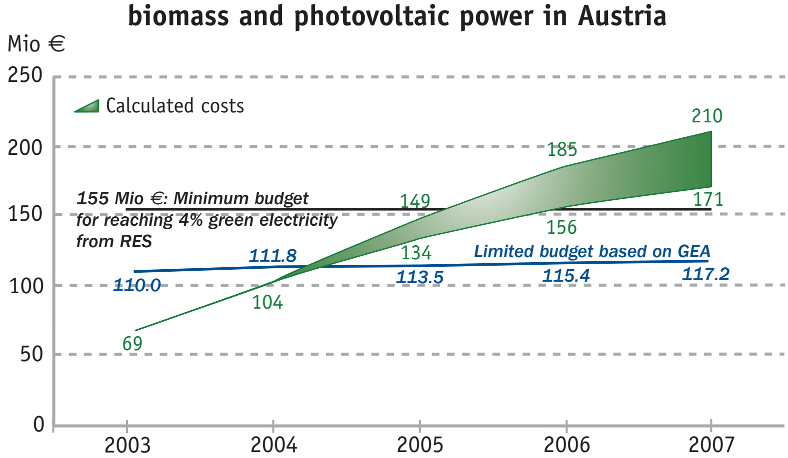


Figure 8 – Forecasted financial budget for the support of wind, biomass and photovoltaic power in Austria



Belgium

Legal and regulatory aspects

The *federal government* is responsible for "matters which, owing to their technical and economic indivisibility, require equal treatment at national level". Among others, this includes transmission and distribution tariffs, electricity generation, and the transmission of electricity at a voltage level above 70 kV.

The EU Directive 96/92 was transposed into the Belgian law by the federal law of 29 April 1999.[1] This latter law defines the general framework for the opening of the Belgian electricity market.

A Federal Regulatory Commission (CREG), was installed in 2000. The CREG regulates the electricity as well as the gas market and advises the federal authorities on the organisation and operation of the liberalised electricity and gas markets.

The *three Belgian regions* (Brussels, Flanders, Wallonia) are responsible for the distribution and local transmission of electricity over networks with a voltage level less than or equal to 70 kV. Regions also have authority over renewables and programmes for the rational use of energy. The three regions have also transposed the European Directive into the regional legislation.[2]

Three regional regulatory bodies,[3] one per region, monitor the operation of the electricity and gas markets at the regional level. These bodies are responsible for establishing the technical legislation regulating the distribution networks (up to 70 kV) and defining the eligibility conditions for customers connected to this grid (most SMEs and the households).

In Flanders, all electricity consumers are eligible since 1 July 2003. In Wallonia and Brussels, the industrial consumers are already eligible whereas the "smaller" professional and household customers will gradually become eligible in the coming years.

Electricity generation

Electricity generation is liberalised. In accordance with the European law, new generation units can be built following an authorisation procedure. Electricity generation by means of renewables and CHP technologies is stimulated via tariff measures and priority access to the transmission and distribution networks, at the federal as well as at the regional levels.

Three categories of electricity producers can be distinguished:

- **Electricity companies**. In 2003, these companies cover almost 98% of domestic production. The most important generators are Electrabel (owned by private sector) and SPE (owned by the public sector). Smaller generators are active in the field of renewables and co-generation. As of early 2003, electricity companies owned about 14 900 MWe of generation capacity in Belgium, about 96% of total installed capacity.

1. Published on 11 May 1999.
2. For Flanders, the decree of 17 July 2000; for Wallonia, the decree of 12 April 2001; and for Brussels, the decree of 19 July 2001.
3. In Flanders, the VREG; in Wallonia, the CWAPE; and in Brussels, the IBGE-BIM.

- **Autoproducers**. These firms (mainly in the chemical and metallurgic sector) generate their own electricity to cover their own needs. They represent about 1.5% of total generation.
- **Autonomous generators**. These firms generate electricity as a complementary activity, for example via waste incineration. Output is sold to third parties. These firms represent only 0.6% of the total generation.

Transmission and distribution

The transmission grid is operated by Elia, an independent company founded in June 2001. In order to comply with the federal requirements of independency, its former shareholders (Electrabel and SPE) had to reach an agreement with the federal government on the future shareholder structure. In 2003, Electrabel and SPE owned 70%, and a co-operative company, representing the Belgian municipalities, owned the remaining 30%. In the near future, Electrabel and SPE will reduce their share from 70% to 30%, by selling shares to the private sector via the stock exchange.

Before the liberalisation, several distribution companies were operating in Belgium, doing wholesale as well as retail transport. These companies (mainly intermunicipal companies) have been appointed as distribution network operators for their respective territory. In order to comply with the regional laws, these companies had to put their retail activities into separate companies.

Investment planning

In accordance with the Federal electricity law, the necessity of investment in generation capacity is assessed on the basis of so-called indicative programmes for electricity power generation capacities. These indicative programmes, belonging to the responsibility of the CREG, cover a period of 10 years and the first one covers the period 2002-2011.

This first indicative programme draws up an investment scheme for generation capacities enabling demand to be met economically and reliably, while taking into account Belgium's international commitments as regards the environment. These environmental concerns result in natural gas being favoured for the new thermal units.

Bulgaria

The national responsibility for the safety of nuclear installation is a fundamental principle. In this context, adequate legislation for the safety of nuclear installations and the management of radioactive wastes is a primary responsibility of Bulgaria and the government.

Bulgaria acknowledges that the International Atomic Energy Agency's (IAEA) standards and approaches, as reflected notably in the IAEA Safety Fundamentals and Safety Requirements Series, constitute an internationally recognised framework which national safety requirements use as a reference level.

During the last three years, the Government established the new legal basis and adopted completely new Bulgarian primary and secondary nuclear legislation in accordance with internationally recognised world-wide good practices. Similarly, principles of containment and safety are applied in conformity with the international standards and conventions of the IAEA. The important work already done provides a good basis for the future development of the nuclear sector as an inherent part of the Bulgarian energy mix.

Bearing in mind that the future development of nuclear power is now more a political and societal issue than a purely technical one, Bulgarian strategies have the objective to advise citizens of the possible energy solutions in a dispassionate way, and are aimed towards increasing citizens' involvement in the decision-making process. The national strategies integrate the technical, political and economic considerations specific to Bulgaria and to the region, leading to definition of the preferred solution by the Government, through the normal democratic processes.

The possibility of using nuclear energy to improve security of energy supply and to curb greenhouse gas emissions is causing more and more countries to re-evaluate their positions towards the current and potential role of nuclear power. Although the nuclear contribution is often taken for granted, all 'clean energy' options will have to be seriously considered if future energy needs are to be met in a way that is both sustainable and climate-friendly.

Electricity is a clean energy carrier, but to a large extent coal, oil and gas are burned to produce it. In the future, the emphasis in the power generation sector will have to be on cleaner production methods, such as wind, solar, biomass, hydro and nuclear energy. This change in emphasis will be needed to meet future electricity demand in a way that is low on greenhouse gas emissions and compatible with sustainable development. Nuclear power also generates electricity with hardly any emission of sulphur dioxide or nitrogen oxides, key agents for acid rain and photochemical air pollution.

Nuclear energy is – and will continue to be – part of the solution to meet our energy needs and to mitigate climate change. Nuclear power in Bulgaria contributes significantly to meet the electrical energy needs of the economy and the population of the country, as well as in the region. For the last 10 years Kozloduy nuclear power plant (NPP) has been providing 40-47% of the average annual electricity produced in Bulgaria.

In November 2003, the EU Atomic Question Group/Working Party on Nuclear Safety (EU AQG/WPNS) conducted monitoring under the "Peer Review" mechanism regarding the recommendations contained in the 2001 Reports on Nuclear Safety in Context of Enlargement and the 2002 Peer Review Status Report.

Following its technical evaluation of the information made available and taking into account its peer review mission to Bulgaria, the EU AQG/WPNS concluded that according to the objective of the Peer Review, the Ministry of Energy and Energetic Resources (MEER), the Kozloduy NPP and the Nuclear Regulatory Agency (NRA) have provided sufficient information on the implementation status of the recommendations contained in the 2001 Reports on Nuclear Safety in Context of Enlargement and 2002 Peer Review Status Report and all recommendations are adequately addressed by responsible authorities and implemented in accordance with the previously presented plans. The AQG/WPNS does not consider further monitoring activities to be necessary.

At the end of 2002, the Bulgarian government took a decision to perform feasibility studies for renewing the construction of the second Bulgarian NPP at the Belene site. Up to this moment, considerable work has been done for justification of the future activities on this project, including an Environmental Impact Assessment Report and a Feasibility Studies Report. After a public discussion in March 2004, it was concluded that the construction of the second NPP in Bulgaria has very strong political and public support at regional (more than 97%) and national level (more than 76%).

In April 2004 the government approved in principle the continuation of construction activities at the Belene site. The decision is based on the conclusion that nuclear energy is the main and most efficient way to meet future national electricity needs. It also provides high reliability of electricity generation with regard to minimization of the expenditures in the energy sector, enhancing security of supply, and contributing to compliance with international agreements on environmental protection.

According to the implementation schedule, the project will commence in 2005, with commercial operation of Belene NPP unit 1 to be achieved in 2010.

Canada

The electricity market situation in all regions of Canada has been influenced greatly by the following factors since the last study:

- Electricity market restructuring.
- Environmental concern: emission-free electricity generation.
- The 14 August 2003 black-out in North America (in particular Ontario and northeastern USA).

Electricity market restructuring has begun in Canada. Almost all provinces in Canada have implemented or are planning to implement wholesale access; however, the pace is different among provinces. The two lead provinces in electricity market restructuring are Alberta and Ontario. Alberta introduced full retail access on 1 January 2001 followed by Ontario on 1 May 2002. This accounts for about 40% of Canada's electricity market providing full retail competition. The initial shock to full retail access was a price hike in both provinces. The Alberta government responded by giving rebate to consumers and the Ontario government responded by putting a ceiling on the price to be paid by consumers.

Although restructuring should enhance competition, improve market efficiency and offer consumers more supply options, these have not happened yet. Its impact remains uncertain as the government is working on new policy to remedy the situation.

At the same time the electricity market is undergoing restructuring, both the industry and government have become more environmentally conscious. Renewable sources like wind and small hydro, and more environmental friendly fossil like natural gas have been proposed to fuel new and replace old generation plants.

For example in 2003, Ontario has close to 6 600 MW of new generation (mainly gas and wind) in the queue for connection assessment and approval under the Independent Electricity Market Operator (IEMO); however, minimal construction of new plants has begun. The lack of commitment from investors to build is in part due to the uncertainty in the regulatory environment from the government. Furthermore, high natural gas price[4] and the electricity price cap have caused uncertainty in the profitability of the projects.

Meanwhile, Ontario has relied on import to meet the needs of electricity demand. On many occasions, the import has reached the 4 000 MW limit of the transmission system. After the 14 August black-out in North America, the Ontario government recognised an urgent need to address Ontario's power needs and commissioned the Electricity Conservation & Supply Task Force (ECSTF) to provide recommendations to meet the challenge.

In January 2004, ECSTF released its final report[5] to the minister with the following highlights:

- Need substantial enhancement in the market approach and policy to meet Ontario needs.
- Create a "conservation culture" in Ontario to reduce demand.
- Recognise the demand-supply gap remains very wide even with strong pushes on conservation and renewables.
- Fill the gap with a diverse supply mix that is likely to include new renewables, natural gas-fired generation, waterpower, nuclear power and clean coal technologies if the latter are feasible within the target emission levels.

4. CAD 7.36 million/cubic feet at Dawn, Ontario on 20 February 2003.
5. "Tough Choices: Addressing Ontario's Power Need", ECSTF January 2004.

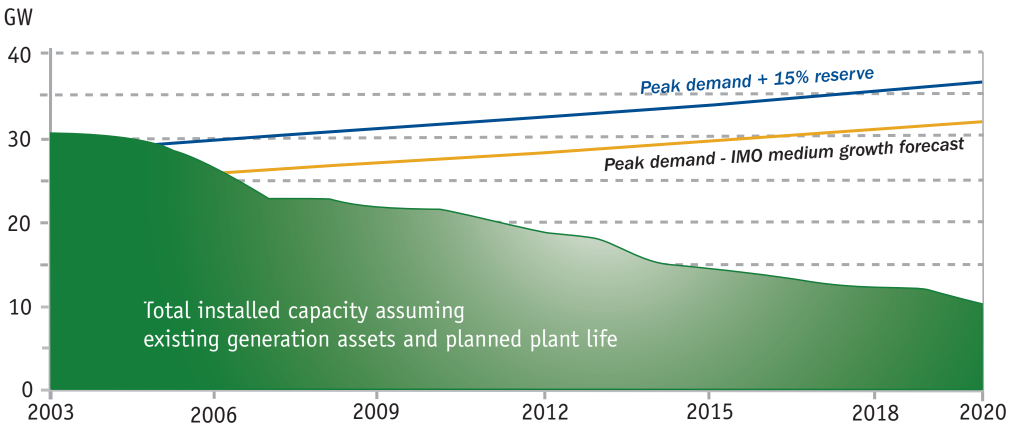
- A new emphasis on the transmission grid as essential public infrastructure connecting power producers and consumers.

In April 2004, the Ontario government announced a conservation plan to reduce consumption by 5% by 2007.[6] In parallel, the government also issued a Request for Qualification for proposals seeking 300 MW of new renewables as a first step to diversify the supply mix and increase the electricity capacity of Ontario to include intermittent resources like wind.

Electricity demand and supply in Ontario

Currently, Ontario has just over 30 000 MW of installed generation capacity. Just over a third is nuclear, followed by hydro, coal, oil/gas and miscellaneous like wood and waste-fuelled generation.[7] As power plants are taken out of service or retire, the shortfall will be over 20 000 MW by year 2020 (see Figure 1). To fill the gap, the ECSTF proposes a diverse energy mix of new generation.

Figure 1 – Existing generation vs. peak demand



Source: ECSTF[5]

Base-load generating options in Ontario

Among the types of new generation in the energy mix proposed by ECSTF, only nuclear, natural gas and clean coal power plants are available for producing large amount of electricity as base load to fill the gap in the forecast period. The generation costs of each type are presented in this study.

Nuclear – ACR-700

The ACR-700™ developed by the Atomic Energy of Canada is an evolutionary design based on proven nuclear power technologies that have been in operation worldwide over the past five decades. ACR-700 applies enhanced technologies and innovative construction techniques to be cost-effective while meeting high safety and performance standards.

6. "McGuinty Government Building Culture of Conversation", Press Release, 19 April 2004.
7. "18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System from January 2004 to June 2005", IEMO, December 2003.

Natural gas – combined cycle gas turbine (CCGT)

The 580 MW CCGT falls into the largest-size gas-fired power plant category being built in Canada. It consists of two state-of-art gas turbines and a single steam turbine to achieve high efficiency and low emissions.

Clean coal – supercritical pulverised coal combustion (PCC)

The supercritical PCC uses a single supercritical boiler and a high efficiency turbine. It includes a dry flue gas desulphurisation (FGD) unit for removing sulphur dioxide from fuel gas, low nitrogen oxides burners and a high-efficiency dust-collection system, using fabric filters to reduce particulate and associated mercury emissions.

Czech Republic

Electricity production in the Czech Republic is based on all the basic types of power plants. The highest share of total generation is produced by coal-fired plants (64% in 2003, domestic coal) and two nuclear power plants contribute a significant share (31% in 2003). Power plants with natural gas combustion in 2003 cover only about 3%, hydroelectricity plants in 2003 had a share of approximately 2%; the share of other sources (renewable sources, wind, solar) is minimal. The total production in 2003 was 83.2 TWh. The Czech Republic is a significant electricity exporter – 17 TWh were exported in 2003.

The biggest electricity producer is a joint-stock company called ČEZ, a.s., whose share in the total production is approximately 75%. It operates the two nuclear power plants, as well as 15 coal-fired plants and 13 hydroelectric plants, 7 of them being small ones.

As of 1 January 2002, the Czech Republic has started, in accordance with the "Energy Act", to gradually deregulate the electricity market, which is based on regulated access to the grid and to the distribution systems. Electricity market members are: producers, grid operators, distributors, market operator, commodity stock-exchange, businessmen and end customers. Enterprising in energy branches within Czech Republic territory is allowed only with a special license issued by the Energy Regulatory Office.

Since 2002, the first group of end customers with annual consumption higher than 40 GWh has the status of eligible customers, authorised for access to the national grid and to the distribution systems, having the right to select their electricity supplier. From 1 January 2006 all end customers will become eligible customers. Since 1 January 2002, the government regulates electricity prices for protected customers, as well as the electricity transmission and system service prices. With regard to the trend of increasing the share of renewable sources in the electricity production, the Energy Regulatory Office sets the purchase prices for electricity produced from these sources (such as small hydroelectric plants, wind and photovoltaic plants, biomass combustion – separately and in combination with fossil fuel). These prices are markedly higher than usual electricity prices; however, the distribution companies are obligated to buy the production from these sources.

At present, the Czech Republic is preparing an act, expected to become valid as of January 2005, in support of using energy from renewable sources. The act is based on the European parliament and European Council Directive 2001/77/EC "Support of electricity production from renewable sources under conditions of the unified energy market". The basic target of this act is for "renewable electricity" to reach 8% of national production by 2010.

Conventional fossil based power

Coal-fired sources could take into account well proven PC units (powdered fuel burners and subcritical steam parameters), fluidised-bed AFBC technologies (units with fluidised-bed burners and combustion products recirculation) and the integrated gasification and combustion of coal in units of the IGCC type (using imported black coal).

Another possible representative of classic technologies connected with the use of natural gas or low-sulphur oil fuel (in the Czech Republic, as a rule, oil is used only as a standby fuel in case there is a shortage of natural gas) could be steam-gas facilities referred to as GTCC or only CC. In the Czech Republic large sources are operated in both condensing arrangement and for combined heat and electricity supply – CHP (large cogeneration).

The construction of large units is planned in the existing plant sites. This opens up the possibility of gradually replacing units that are nearing the end of their service life; of making use of the available infrastructure and grid connection; and of continuing the general trend to not extend areas used for energy production. These factors help to achieve lower specific generation costs from new units.

Nuclear power

At present the Czech Republic's energy concept includes a role for nuclear energy in the future but does not assume that a new nuclear source will be put in operation before 2010.

Renewable energy sources

Hydro-energy potential on the Czech Republic territory is very much limited, especially for localities with installed capacity over 10 MW. Some reserves may be found (in addition to revitalising older waterworks) for small hydro plants on rivers with lower slope.

In the Czech Republic, the capacity of wind energy in operation is very small. Interest in extending existing installations (so-called wind farms), dates back to 2002. The share of the wind power is expected to grow; however, its significance probably will be very limited due to specific conditions of the Czech Republic.

Solar photovoltaic technology is undoubtedly the most expensive option for the Czech Republic. In the near future, therefore, no significant installation of this energy source is expected.

The use of biomass for energy production in the Czech Republic has been focused so far on the secondary raw materials arising as wastes from the processing of timber and food crops. It is to be expected that gradually there may be a market for "energy-rich" biomass grown specifically as fuel for energy production.

Denmark

Basic data

Denmark has about 5.4 million inhabitants and a total electricity consumption of about 33 TWh. The electricity generation is typically of the same magnitude or a little higher than the domestic consumption. A large share of the Danish buildings are heated by heat form district heating systems, and nearly all of the fuel-based power plants are able to produce both heat and power. Subsequently, a large share of the electricity is produced together with heat for the district heating systems or for industrial use. In recent years about 18 TWh/year (or approx. 55% of the domestic electricity consumption) has been produced together with heat.

Most of the electricity production is based on coal or natural gas. The share of renewable energy used for electricity production has been growing. In 2003, electricity from wind power plants and other renewable energy sources (including the biomass share of waste) accounted for 24% of the domestic consumption. Wind power alone accounted for 16%.

In Denmark, most of the produced electricity is sold at market conditions. A substantial share is still being sold at fixed prices, but this share will decrease fast in the coming years, due to new legislation.

Plant examples selected for cost calculation

Data has been collected for the following 9 plant examples:

- DNK-C: 400 MW coal-fired steam turbine plant
- DNK-W1: Offshore wind turbine park with 80 2 MW turbines
- DNK-W2: Offshore wind turbine park with 72 2.2 MW turbines
- DNK-W3: Single onshore 1.5 MW wind turbine
- DNK-S: 500 solar PV plants with an average capacity of 1 kW
- DNK-CHP1: Industrial gas motor combined heat and power plant, 11 MWe and 12 MW_{heat}
- DNK-CHP2: Large CHP plant for district heating, able to run on gas, oil, straw and wood pellets, 485 MWe and 575 MW_{heat}
- DNK-CHP3: Combined cycle CHP plant for district heating, 58 MWe and 58 MW_{heat}
- DNK-CHP4: Modification of existing coal-fired CHP plant to straw co-firing, capacity of total plant is 350 MWe and 455 MW_{heat}

Due to the large share of district heating in Denmark, all new fuel based power plants being built are CHP plants. Data for the above mentioned coal fired electricity only plant (DNK-C) is based on paper studies.

The two offshore wind turbine parks are ordered plants which were set in operation in 2003. Since wind power technology is improving very fast, an offshore wind turbine park to be set in operation in 2010 would produce electricity cheaper than the 2 selected plant examples. Below, data and electricity production costs for an onshore wind turbine and for an offshore wind turbine park to be set in operation in 2010 are presented.

The existing coal fired plant which is modified for part straw firing is difficult to compare with the other plants in this study, and therefore the resulting electricity production costs for this plant is not presented together with the other plants but in this country statement (also below).

Assumptions regarding calorific value of fuels and value of produced heat

Some general data for the fuels used by the 9 plant examples are given below.

Calorific values

For the fuels in question, the following calorific values have been used:

Natural gas:	39.6 MJ/m^3
Heavy fuel oil:	40.7 GJ/tonne
Hard coal:	25.2 GJ/tonne
Wood pellets:	17.5 GJ/tonne
Straw:	14.5 GJ/tonne

All the values are lower calorific values.

Additional data for CHP

Regarding the value of the produced heat in CHP plants, the following method for assessing the value has been used.

It is assumed that the calculation of avoided heat production costs can be simplified in the following way:

- The alternative boiler for heat production is located in the same place as the CHP plant. This means that no investments costs for heat transmission are necessary.
- The fuel used by the boiler is the same as the fuel used by the CHP plant.

For the four fuels natural gas, heavy fuel oil, straw and wood pellets, which are all used in CHP plants presented in the 2004 questionnaire for Denmark, the value of the produced heat has been calculated using this method. Table 1 shows the results.

In the same way, the avoided CO_2 emissions from the alternative heat production has been calculated. Table 1 shows the results.

Table 1 – Value of produced heat in DKK/GJ, price level 2003

Fuel and location	Value of produced heat DKK/GJ	CO_2 emission from alternative heat production kg/GJ produced heat
Natural gas, used at central CHP plant	28	57
Natural gas, used at local CHP plant	36	57
Heavy fuel oil, used at central CHP plant	28	82
Wood pellets, used at central CHP plant	60	0
Straw, used at central CHP plant	60	0

Additional data for wind power plants

The questionnaire from Denmark contains information on two offshore wind turbine parks and one onshore wind turbine. It should be noted that transmission costs specific to the plant is included for one of the offshore parks. For the other offshore park and for the onshore wind turbine it has not been possible to define transmission costs specific to the plants.

It should also be noted that even though the plants are supposed to be commissioned by 2010, today's technology and today's costs have been used, as the information is – for 2 of the 3 plants – based on data for existing plants.

In the future, both an increase in energy production and a decrease in specific costs of wind power plants is expected. Table 2 shows a forecast[8] for onshore and offshore wind power plants for the periods 2010/15 and 2020/30. Data for 2004 has been added for comparison. From 2004 to 2010/15 production costs will fall by 20-30%, and from 2004 to 2020/30 production costs will fall by approx. 40% for both onshore and offshore wind power plants.

Table 2 – Forecast for costs and performances of wind power plants

Onshore wind turbines	**2004**	**2010-15**	**2020-30**
Site	new	new	new
Net electrical power – Mwe	1.5	3	5
Technical lifetime, years	20	20	20
Equipment availability	98%	98%	98%
Average load factor	27%	29%	30%
Cost data	paper analysis	paper analysis	paper analysis
Date of cost study	2003	2003	2003
Capital costs, mio. DKK	9.5	15.7	21.0
O&M costs, DKK/kWe	170	150	140
Calculated electricity production costs, USD/MWhe			
5% discount rate	44.1	34.5	27.9
10% discount rate	59.4	46.3	37.1
Offshore wind turbines	**2004**	**2010-15**	**2020-30**
Site	new	new	new
Net electrical power (one turbine) – MWe	2.5	10	20
Technical lifetime, years	20	20	20[a]
Equipment availability	95%	95%[b]	95%[b]
Average load factor	45%	48%	48%[a]
Cost data	paper analysis	paper analysis	paper analysis
Date of cost study	2003	2003	2003
Capital costs, mio. DKK	30.6	84.2	153.0
O&M costs, DKK/kWe	390	320	260
Calculated electricity production costs, USD/MWhe			
5% discount rate	53.6	36.4	32.0
10% discount rate	71.3	47.9	42.4

a. Data for 2010-15 is used. b. Data for 2004 is used.

Coal-fired CHP plant with straw co-firing

By rebuilding existing coal fired power plants to straw co-firing, straw can be used for electricity production at moderate costs. In the example, a 350 MWe CHP plant is modified in a way that makes it possible to incinerate 7% straw. The electricity production costs based on straw firing turn out to be 47.5 USD/MWhe at 5% discount rate and 63.8 USD/MWhe at 10% discount rate. These costs include both investment in the original coal fired plant and in the equipment necessary for straw firing. Table 3 shows the costs split on items.

Table 3 – Electricity production costs based on straw firing in existing coal-fired CHP plants

Cost item (in USD/MWhe)	5% discount rate	10% discount rate
Investment in coal-fired plant	10.9	20.6
Additional investment in straw co-firing equipment	14.2	20.8
O&M, coal-fired plant	5.6	5.6
Additional O&M for straw firing	13.5	13.5
Fuel costs (straw)	60.5	60.5
Minus value of produced heat	-57.2	-57.2
Total costs	47.5	63.8

8. Based on the report "Technology data for electricity and heat generating plants", April 2004.

Finland

The power sector

The total electricity consumption was 85.2 TWh in 2003. Industry's share, 45 TWh (53%), explains the weight of industry in energy policies. Households accounted for 21% of the consumption and the share of services and commercial (including the public sector) amounted to 18%. Other consumption consists of electricity for traffic, agriculture and construction.

CHP accounted for 33% of the total consumption of electricity of 85.2 TWh in 2003 and the share of nuclear was 26%. The breakdown of the supply was as follows:

• Hydro	11.1%
• Wind	0.1%
• Nuclear	25.6%
• CHP, district heating	17.9%
• CHP, industry	14.9%
• Condensing	24.6%
• Net imports	5.7%

Coal is dominating fuel for condensing power plants. The fuels of CHP of district heating are coal, natural gas, peat and wood fuel. The last condensing power plant was built in the early nineties at Meri-Pori (560 MWe) on the west coast of Finland. So far there are no natural gas fuelled merely electricity producing power plants, but there are several gas-fired CHP plants with CCGT process.

The recent construction of new generation capacity has taken place in connection of CHP for district heating and industry. Biomass based fuel and natural gas have dominated for the new CHP plants. Furthermore, capacity increase has been achieved through modernisation of the existing nuclear power plants at Olkiluoto and Loviisa.

In 2003 the carbon dioxide emissions of the energy sector amounted to 70.5 million tonnes exceeding with 16.6 million tonnes the level of 1990.

Taxes in power generation

In the 1996 energy tax reform the taxes on fuels used in electricity generation were abandoned, and replaced by a tax on electricity consumption instead. Thus, the tax rate for electricity is the same on electricity generated by various energy sources, e.g. by using wind power, hydro power, wood, coal, natural gas, peat or nuclear. However, the rate is differentiated for consumers. Industry is taxed at the lower rate while other consumers have to pay the higher tax rate.

When coal, peat and natural gas are used for heating purposes, they are taxed according to their CO_2 emissions. The present rate of CO_2 tax (additional duty) is 18.05 €/tonne CO_2. However, natural gas receives a 50% rebate on this tax and peat is taxed using a different methodology, which results in lower taxes than would be the case when using the carbon content rate.

When electricity is produced in a combined heat and power plant, the duty on the fuels used for producing heat is calculated according to the tax table assuming that the amount of fuel used for heat production is 0.9 times the amount of heat produced ("useful heat").

The new nuclear unit and climate strategy

In January 2002 the Finnish Government made a favourable decision-in-principle on the fifth nuclear power plant unit, and the Parliament ratified the decision on 24 May 2002. The industry owned Finnish nuclear operator Teollisuuden Voima Oy (TVO) had submitted an application two years earlier for a 1 000-1 600 MWe LWR unit.

The new nuclear unit, Olkiluoto 3, will be located at the existing nuclear site of TVO at Olkiluoto. In January 2004 TVO submitted to the Government an application for a construction license for Olkiluoto 3, which is the pressurised water reactor type EPR (European pressurised water reactor), with electrical output of about 1600 MW. The granting of the construction licence is planned to take place in the beginning of 2005 and the commissioning in 2009. TVO has started preparatory works on Olkiluoto island in the beginning of 2004.

Even if TVO's basis for the new plant was the company's own interest, the government, according to the Nuclear Energy Act, had to consider whether the use of nuclear energy is in line with the overall good of society. The decision-in-principle ratified in 2002 supports the implementation of the national climate strategy adopted in 2001. It will help Finland meet its international emissions reduction commitments.

The decision-in-principle was based on the view that the nuclear power option is the most cost-effective alternative, both in terms of central government finances and national economy, for generation of base load power within the framework of the Kyoto Protocol. In addition, it will lead to a more stable price of electricity in Finland. The decision alone is, however, not sufficient for the climate strategy. The government is already actively supporting and will continue to support electricity produced from renewable energy sources by means of investment subsidies and tax concessions. Also, electricity demand is being curbed by promoting energy conservation measures.

The power plants for the study

The types of the power plants were selected among the existing baseload power plants in Finland in order to have reliable cost and performance data available. The power plants for the study were specified so that their performance data is based on the technologies now commercially available. The commissioning of the plants would take place in 2010.

For achieving realistic framework for the study, the input data were compiled by prominent companies within the Finnish power sector.

The following power plants were specified for the study:

- Coal-fired condensing power plant, 500 MWe, with pulverised burning and with net thermal efficiency of 46%.
- PWR type nuclear power plant, 1 500 MWe, with net thermal efficiency of 37%.
- Coal-fired CHP plant producing 160 MW electricity and 300 MW district heat with total energy (electricity and district heat) production efficiency of 88%.
- Natural gas CHP combined cycle gas turbine plant producing 470 MW electricity and 420 MW district heat with total energy (electricity and district heat) production efficiency of 92%.

The fuel prices for Finland in 2010 are assumed to be as follows (in 1 July 2003 money):

- Coal 1.8 €/GJ (= 6.48 €/MWh)
- Natural gas 4.0 €/GJ (= 14.40 €/MWh)

The growth rates of the fuel prices during 2010-2050 have been estimated as constant percentage annual growth during the whole period:

- Coal + 1.0% per annum
- Natural gas + 1.5% per annum
- Nuclear fuel + 1.0% per annum

Thus, in 2050 the coal price would be 2.68 €/GJ and the gas price 7.26 €/GJ, respectively.

France

Summary of the DGEMP study of reference costs for power generation

The first part of the 2003 study of reference costs for power generation has been completed. It was carried out by the General Directorate for Energy and Raw Materials (DGEMP) of the French Ministry of the Economy, Finance and Industry, with the collaboration of power-plant operators, construction firms and many other experts. A Review Committee of experts including economists (Forecasting Department, French Planning Office), qualified public figures, representatives of power-plant construction firms and operators, and non-governmental organization (NGO) experts, was consulted in the final phase. The study examines the costs of power generated by different methods – i.e. nuclear and fossil-fuel (gas-, coal-, and oil-fired) power plants – in the context of an industrial operation beginning in the year 2015.

The second part of the study is devoted to decentralised production methods (wind, photovoltaic, combined heat and power).

Study approach

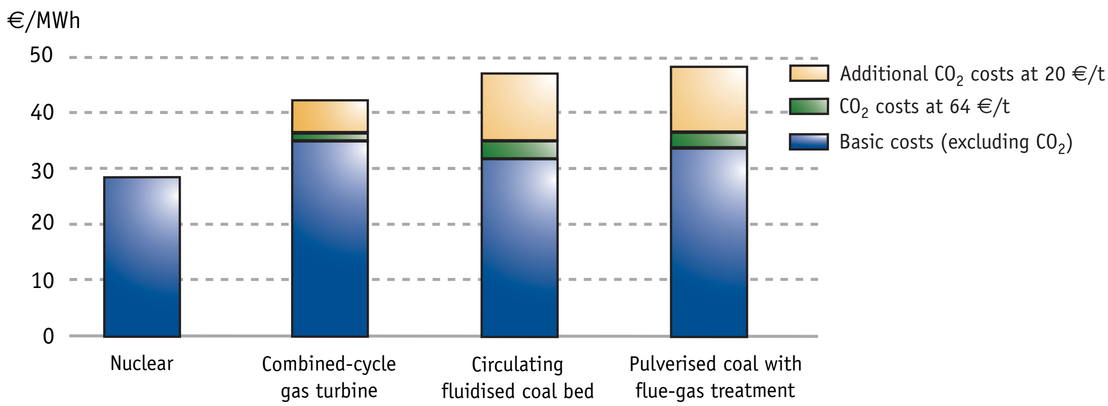
The study is undertaken mainly from an investor's perspective and uses an 8% discount rate to evaluate the expenses and receipts from different years.

In addition, the investment costs are considered explicitly in terms of interest during construction.

Plant operating on a full-time basis (year-round)

Figure 1 illustrates the main conclusions of the study for an effective operating period of 8 000 hours.

Figure 1 – Production costs (incl. tax), discounted at 8% and including CO_2 costs, for a full-time operation in 2015 (company perspective)



It can be seen that nuclear is more competitive than the other production methods for a year-round operation with an 8% discount rate applied to expenses. This competitiveness is even better if the costs related to greenhouse-gas (CO_2) emission are taken into account in estimating the MWh cost price. Integrating the costs resulting from CO_2 emissions by non-nuclear fuels (gas, coal), which will be compulsory as of 2004 with the transposition of European directives, increases the total cost per MWh of these power generation methods. Two hypotheses are considered in terms of CO_2 costs over the life span of the oil- and coal-fired power plants: 4 €/t CO_2 and 20 €/t CO_2. The hypothesis of 4 €/t CO_2 can be considered as very low – it will be significantly more expensive in 2015 and beyond (post-Kyoto period).

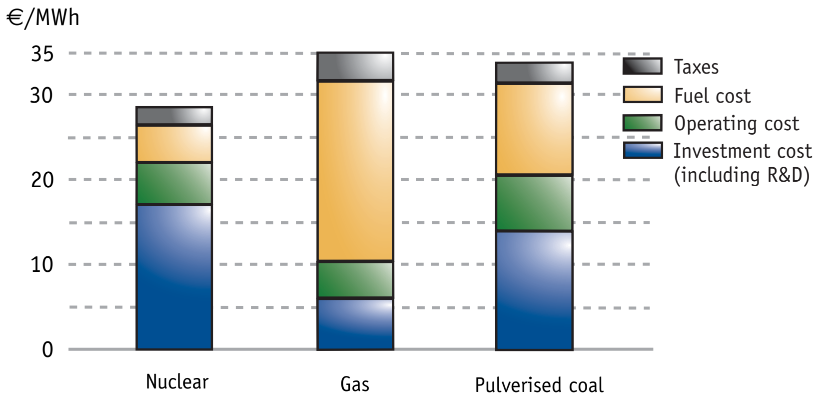
Table 1 gives variants on the discount rate for the best technologies for each fuel, i.e. nuclear, gas and coal.

Table 1 – Full-time production costs in 2015, with individualised CO_2 costs (2001 €/MWh, 1 USD = 1 €)

2015 – Mean value	Nuclear EPR (European pressurised water reactor)	Combined cycle gas turbine	Pulverised coal	Circulating fluidised coal bed
8% discount rate	28.4	35.0	33.7	32.0
5% discount rate	21.7	33.4	29.5	28.1
11% discount rate	37.0	36.9	38.5	36.4
CO_2 costs (4 €/t and 20 €/t)		1.4 – 7.1	2.9 – 14.6	3 – 15

The Figure 2 details the components of the tax-inclusive cost per MWh in 2015 for the different production sources (without CO_2 costs and with an 8% discount rate).

Figure 2 – Components of the discounted cost per MWh in 2015, without CO_2 costs and for a full-time operation

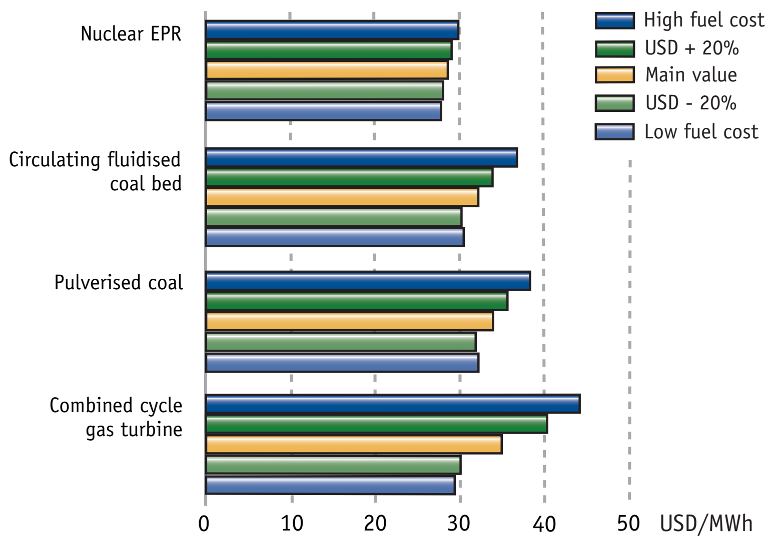


The choice of a discount rate respectively lower or higher than the baseline hypothesis of 8% will increase, or decrease, the competitiveness of nuclear-based power production compared to fossil-fuel methods of power productio n because the investment load, which is higher for nuclear than for the other methods, decreases or, conversely, increases. The 8% discount rate adopted here was the rate used by the French Planning Office and is compatible with the profitability requirements currently noted in the electricity sector.

Figure 3 shows the sensitivity of the production costs, exclusive of tax and exclusive of externalities, to fuel prices and to the euro/dollar exchange rate.

The different variants do not bring into question the order of competitiveness of the production methods.

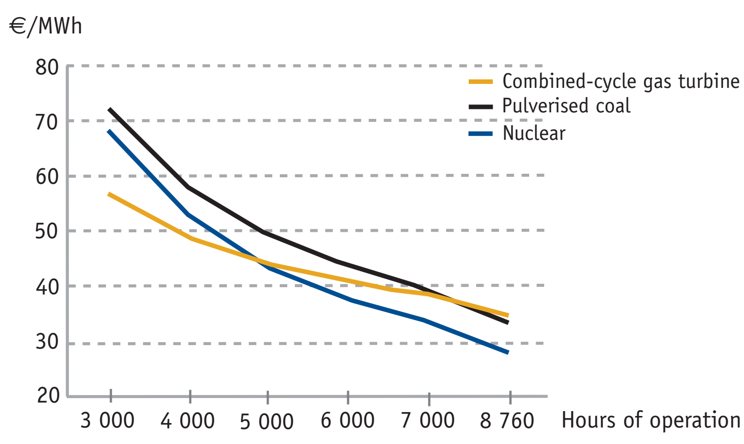
Figure 3 – Sensitivity of production costs in 2015(excluding tax) to dollar rate and fuel cost for a year-round production (at 8% discount rate)



Plant operating on a half-time basis (less than 5 000 hours/year)

Considering the size of the initial investment, a nuclear power plant's competitiveness requires that it operate all year round (see Figure 4). Should the nuclear power plant be operational for a shorter duration, then its competitiveness fades in favour of gas-fired power plants. More specifically, gas is more competitive than nuclear power (excluding externalities) for operating periods of less than 5 000 hours.

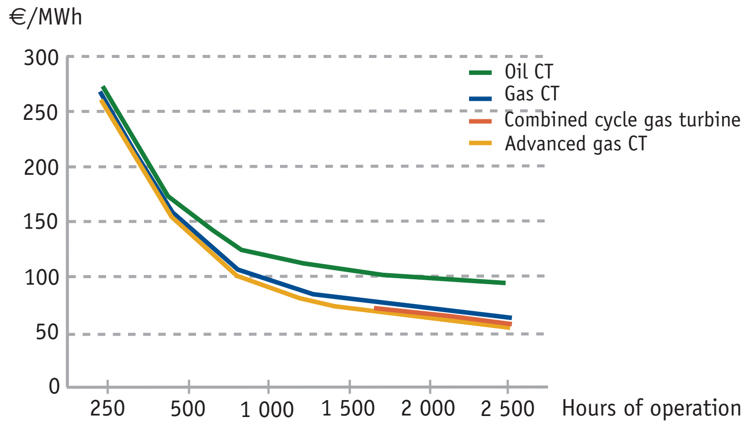
Figure 4 – Competitiveness of centralised power production plants in 2015 (including tax; excluding externalities)



Plant operating on a minimum basis (less than 3 000 hours/year)

Figure 5 details the costs for the different methods when used on a top-up basis. For short periods, the gas turbine is more competitive than the oil-fired turbine. The oil-fired turbine, however, is competitive for durations of less than 250 hours.

Figure 5 – Competitiveness of various power production plants, for short operation duration



Distributed generation

Hypotheses

The second part of the study "reference costs for power generating" is devoted to the decentralised production. This type of generation is based on renewable sources of energy and techniques allowing the saving in fossil fuels. Decentralised power plants, generally smaller than centralised ones, are supposed to be closer to the consumer and to avoid additional investments in the regional grid. These economies in grid investments have not been calculated.

The decentralised plants were divided into two great parts: on the one hand those whose maturity allows to consider a development in the short or medium term and for which the data are relatively certain (combined heat and power, small hydraulic, biogas, solar photovoltaic, onshore wind power), on the other hand those more prospective for which uncertainty in the data is larger (fuel cell, geothermal, marine energy). Biomass and offshore wind power will be studied in a later phase.

Some more details on the assumptions of cost of fuel must be brought for biogas and combined heat and power: for biogas (landfill gas or digester) only the over-cost of producing biogas for power generation compared to the alternative solution of processing waste without energy generation was taken into account. For combined heat and power, the net generating cost is calculated by cutting off from the rough cost the fuel and capital costs which would have been necessary to produce independently the quantity of heat provided by the combined heat and power plant.

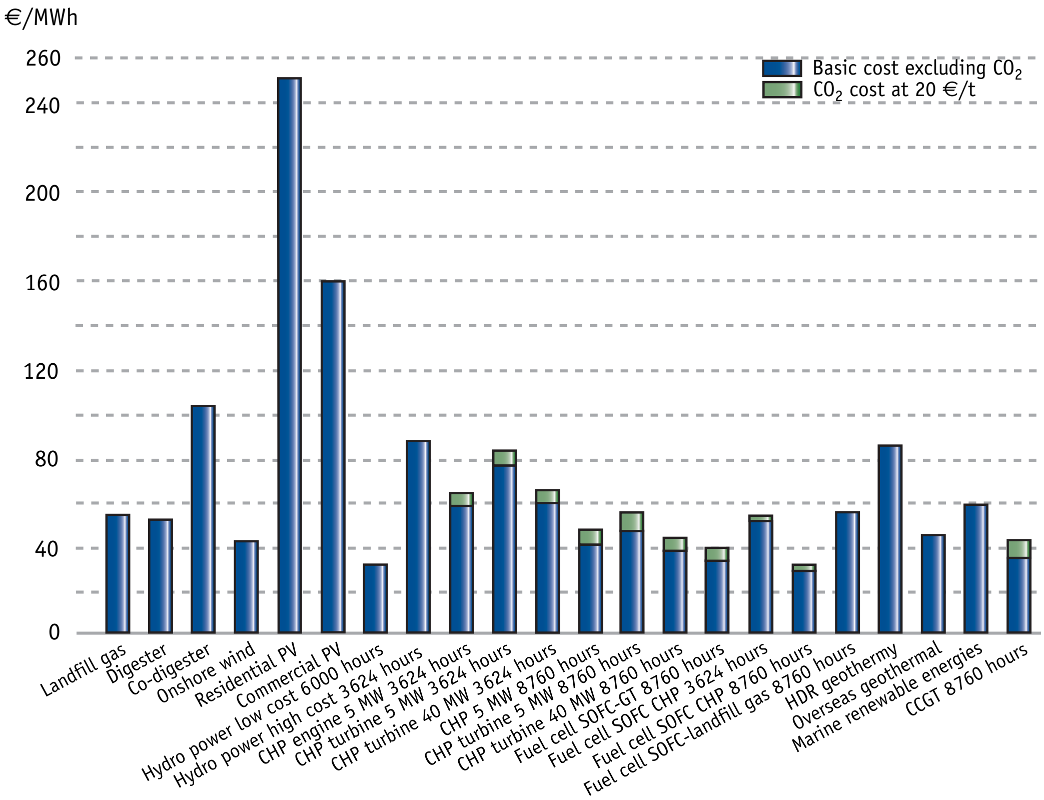
For wind power generation and solar photovoltaic, learning curves were used.

For onshore wind power generation, an additional cost for possible disturbance of the offer/demand equilibrium was calculated but not included in Figure 6.

Results

Wind power generation, small hydroelectricity under good conditions of site, and combined heat and power generation form part of the mature dies for which generation costs would be close, at horizon 2015 and taking into account their operation hours during the year, to combined cycle gas turbine working over the year generating costs. Photovoltaic generating costs should remain high event though it is expected that costs decrease rapidly (see Figure 6).

Figure 6 – Generating costs of various power production plants in 2015 at 8% discount rate



More prospective dies as the fuel cells and overseas binary geothermal power plants, could also have generation costs of electricity close to those of a combined cycle gas. Landfill gas and digester gas could be also very interesting if the over-cost compared to another waste management solution would decrease. Hot dry rocks (HDR) geothermy should have high generating costs by 2015.

Germany

Energy policy framework

Germany is one of the world's largest energy consumers and ranks third in total CO_2 emissions within the G-7, after the USA and Japan. Germany has a strong commitment to protect the environment. From the early 1990s, the Federal government's environmental policy has given increased emphasis to global warming issues. In 2000, Germany set a goal of reducing six greenhouse gases cited in the Kyoto Protocol by 21% between 2008 and 2012, within the context of the EU burden sharing programme. To fulfill these commitments, German energy policy is increasingly influenced by environmental concerns. The government has been promoting renewables and energy efficiency initiatives, aiming towards a mid-term goal to increase electricity generation of the renewable energy carriers to 20% by 2020. The energy markets of Germany have been fully liberalised and are completely opened up to competition.

In 1999 the Eco-tax was introduced with the goal of encouraging conservation, energy efficiency and the increasing use of renewable energies. The tax was levied on fuels (petrol and diesel), heating oil (light and heavy), gas and electricity, and was applied in five steps until 2003 and remains constant beyond

2004. It envisages the gradual increase of taxes on fossil fuels and electricity (refer to Table 1). For petrol and diesel the tax was increased annually by 3.07 €¢/liter and reached an amount of 15.35 €¢/liter in 2004. The Eco-tax for light oil was introduced in 1999 with 2.05 €¢/liter and for heavy oil the tax was levied in 2000 and was augmented in 2003 to a final tax amount of 0.97 €¢/kg. For gas the final Eco-tax was applied in two steps, 0.164 €¢/kWh in 1999 plus 0.202 €¢/kWh in 2003. The electricity tax was introduced at 1.02 €¢/kWh with an annual increase of 0.26 €¢/kWh from 2000-2003; reaching 2.06 €¢/kWh in 2004 (UBA, 2002). Since January 2004 all liquid biofuels are exempted from the fuel taxes. This applies for biodiesel (RME), bioethanol and for all other fuels from biogenic resources. Fossil fuels may be blended with 5% biofuels without explicit declaration.

Table 1 – Increasing rate of Eco-tax on fuels and electricity

Energy carrier	Unit	1. step April 1999	2. step Jan. 2000	3. step Jan. 2001	4. step Jan. 2002	5. step Jan 2003
Fuels	€¢/liter	3.07	3.07	3.07	3.07	3.07
Light oil	€¢/liter	2.05	–	–	–	–
Heavy oil	€¢/kg	–	0.26	–	–	0.71
Gas	€¢/kWh	0.164	–	–	–	0.202
Electricity	€¢/kWh	1.02	0.26	0.26	0.26	0.26

In April 2002 the new German CHP law, the "Law on the Conservation, Modernization and Development of Combined Heat and Power"[9] came into force. The law enacts a subsidy on the connection of certain types of CHP units to the public grid and on the purchase of their electricity production by the grid. On top of the agreed price for their deliveries to the grid, the operators of the units are entitled to obtain supplementary payments on each kWh delivered as given in Table 2. Also, the law establishes the statutory right of CHP operators to receive the market price for their electricity deliveries to the grid according to stock market value. The law thus increases the financial returns and it will therefore support the continued operation and modernisation of already existing CHP plant regardless of their size. It also aims to encourage the installation of new small-scale CHP units up to 2 MWe electrical capacity and applications based on fuel cell technology.

Table 2 – Supplementary payment for CHP electricity deliveries to the public grid

	2002	2003	2004	2005	2006 €¢/kWh	2007	2008	2009	2010
Existing old CHP plant (start of operation before 31/12/89)	1.53	1.53	1.38	1.38	0.97				
Existing new CHP plant (start of operation between 31/12/89 and the date when the new law came into effect)	1.53	1.53	1.38	1.38	1.23	1.23	0.82	0.56	
Modernised CHP plant (start of operation after the new law came into effect)	1.74	1.74	1.74	1.69	1.69	1.64	1.64	1.59	1.59
New small-scale CHP plant between 50 and 2 000 kWe	2.56	2.56	2.40	2.40	2.25	2.25	2.10	2.10	1.94
New small-scale CHP plant ≤ 50 kWe which start continuous operation before the end of 2005, and fuel cell units	5.11 €¢/kWh for a period of 10 years beginning from the start of continuous operation								
Supplementary payments for small scale CHP plant up to 2 MWe (this includes also units <50 KWe) will only be made up to a total electricity delivery of 17 TWh from these plants									

9. "Gesetz für die Erhaltung, die Modernisierung und den Ausbau der Kraft-Wärme-Kopplung".

The aim of the Renewable Energy Sources Act (EEG) is to double at least the amount of electricity generated from renewable energy sources by 2010 (12.5%) compared to 1999 (5.8%). Thus, electricity generation from renewable energy resources in Germany is supported by this act (renewed in 2004) which guarantees fixed feed-in tariffs. Electricity grid operators are obliged to give priority to the purchase of electricity from solar energy, hydropower, wind power, geothermal power and biomass and to pay a specified price for it, set by the law. The level of compensation is based on the production costs. Price premiums for these energy sources are passed on to the consumer in the form of increased electricity prices. The feed-in tariffs are differentiated according to energy forms, size of power plants, applied technology, (e.g. innovative technologies, etc.) and energy resource provision (e.g. for biomass).

Recent power plants fulfill the environmental requirements according to the environmental protection limits of the regulation of large combustion plants according to the Federal Immission Protection Law (13. BImSchV).[10] Its amendment passed the parliament on June 2004 and intensifies the reduction of emissions of power plants depending on their combustion capacity. The regulation is based on recent western standards. Future power plants will be designed with the environmental protection systems including pollution control equipment to comply with it.

Table 3 – Environmental limit values of emissions for large combustion plants as stipulated in the amendment of the 13. BImSchV

Pollutant	Unit	Coal	Oil	Gas
SO_2	mg/m^3	850[a]/200[bc]	850[a]/200-400[b]/200[c]	35
NO_x	mg/m^3	400[a]/200[bc]	200[ab]/150[c]	150[a]/100[bc]
CO	mg/m^3	150[a]/200[bc]	80	80
Dust	mg/m^3	20	20[ab]/10[c]	5

a. Plants with a combustion capacity between 50 and 100 MW.
b. Plants with a combustion capacity between 100 and 300 MW.
c. Plants with a combustion capacity greater than 300 MW.

On 26 April 2002, the “Act on the structured phase-out of the utilisation of nuclear energy for the commercial generation of electricity”[11] came into force. It makes fundamental amendments to the 1959 Atomic Energy Act by stipulating the phase out of the use of nuclear energy in a structured manner. Among the key points of the amendment is the ban on constructing new commercial nuclear power plants. The new act lays down a maximum permitted residual electricity volume for each existing individual nuclear power plant. The electricity volumes of older nuclear power plants can be transferred to newer plants and the on-going operation must be ensured up to the date of the plant’s discontinuation. The nuclear electricity production will gradually decrease and be phased out by the year 2022.

Electricity generation and generation capacities in 2002 and 2003

In 2003 the total amount of gross electricity supplied in Germany was about 642.7 TWh. This is an increase of about 2.4% in comparison to the previous year. About 93% of the power generation, corresponding to 597 TWh is produced indigenously and about 45.7 TWh is imported from abroad. The power plants of the public supply, including the power generation of the national railway organisation, generated about 526.8 TWh gross electricity and of the industry about 49 TWh. The electricity generation of the power plants for private uses accounts for 21.2 TWh; this is an increase of about 14.6% of the total generation in 2003 compared to 2002. The total electricity balance is shown in Table 4.

10. “Dreizehnte Verordnung zur Durchführung des Bundes-Immissionsschutzgesetzes (Verordnung über Grossfeuerungsanlagen – 13. BImSchV)”.
11. “Gesetz zur geordneten Beendigung der Kernenergienutzung zur gewerblichen Erzeugung von Elektrizität”.

Table 4 – Gross electricity supply in 2003 compared to 2002

	2002 TWh_{gross}	2003 TWh_{gross}	Change %
Public power plants [a]	515.2	526.8	2.3
Industry	47.5	49.0	3.2
Private	18.5	21.2	14.6
Import	46.2	45.7	-1.1
Total deposition	627.4	642.7	2.4

a. Including the power generation of the *Deutsche Bahn*, the national railway organisation.

The electricity supply in Germany is based on several production forms and fuels. The distribution of net electricity supply in Germany is shown in Table 5. Electricity production in 2003 was based mainly on coal-fired (hard coal and lignite) steam turbine (50.1%) and nuclear (27.9%) power plants. Natural gas has a share of about 9.8% of the total net power generation, an increase of about 7% compared to the year 2002. The supply of natural gas to Germany comes via pipelines from the Netherlands, Great Britain, Norway and Russia. The electricity production from oil is rather negligible at about 0.9% of the total generation.

As regards the use of renewable energies for electricity production, Germany can point to very high growth rates especially for wind energy. In 2003 about 50 TWh of net electricity (8.9% of the total net electricity generation) were produced from renewable resources, of which 50% is from hydro and 38% from wind power plants. Because of the impact of the Renewable Energy Source Act, over 14 600 MW capacity of wind power plants were installed in Germany by 2003; this is an increase of about 2 600 MW on the year 2002. Even so, hydro power, with a share of 4.5% of the total net electricity production, is still the largest renewable energy producer in Germany despite a decrease of hydro-power generation of about 10% compared to the year 2002 due to the very dry year of 2003. Other renewable energy carriers like biomass and photovoltaic account for about 1.1% of the total net electricity generation.

Table 5 – Net electricity generation by energy carrier in 2002 and 2003

	2002		2003		Change
	TWh_{net}	%	TWh_{net}	%	%
Nuclear	156.3	28.7	156.4	27.9	0
Lignite	145.2	26.6	146.4	26.1	1
Hard coal	124.0	22.8	134.4	24.0	8
Natural gas	51.3	9.4	54.9	9.8	7
Oil	5.8	1.1	5.3	0.9	-9
Hydro	27.9	5.1	25.0	4.5	-10
Wind	15.9	2.9	19.0	3.4	19
Other renewable [a]	5.2	1.0	6.0	1.1	15
Other [b]	13.4	2.5	13.0	2.3	-3
Total	545.0	100	560.4	100	3

a. Other renewable energy carriers like solar.
b. Other energy carriers like waste.

In Table 6 the installed net capacity of the power plants in Germany for the years 2002 and 2003 are shown for the public supply only, including the share of the national railway organisation.[12] In the year 2003 there was a total installed net capacity of 100 281 MW which is rather similar to the year 2002.

12. Most of the wind power capacities are installed by private producers which are not included in Table 6.

While the biggest increase of installed capacity is for hydro and lignite in comparison to the year 2002, the biggest decrease is for oil and the "other" category which includes the waste incineration power plants. Nuclear, lignite and hard coal power plants make up two-thirds of the installed net power capacity.

Table 6 – Installed net power capacity of the public supply including the national railway organisation in 2002 and 2003

	2002		2003		Change
	TWh_{net}	%	TWh_{net}	%	%
Nuclear	21 088	21	20 643	21	-2
Lignite	18 811	19	19 699	20	5
Hard coal	24 882	25	25 125	25	1
Natural gas	16 315	16	15 971	16	-2
Oil	6 668	7	5 996	6	-10
Hydro [a]	8 871	9	9 395	9	6
Wind / Sun	–	–	210	0	–
Other	3 600	4	3 242	3	-4
Total	100 235	100	100 281	100	0

a. Including pump storage.

In Germany there are many power plants, especially in the basic and mid load range, which were built in the 1970s. Because of the old inventory, there will be a need for replacement of about 40 000 MWe by new capacity which has to be installed at least by 2020. Additionally, there will be a capacity of about 20 000 MWe of the remaining nuclear power plants which have to be substituted by alternative power plants if the agreement on the phase out of nuclear energy is completely realised.

Characterisation of technologies

For the following power plants, costs estimates have been carried out.

- European pressurised water reactor (EPR) with a net capacity of 1 590 MWe and a net thermal efficiency of 37%.[13] The fuel enrichment of about 4.9% and the average burn-up of 65 MWd/kg are taken into account.
- Coal-fired pulverised-fuel steam plant (PFC (hard coal)) with overcritical conditions (285 bar/ 600°C) of the steam. The net capacity is 800 MWe and the net thermal efficiency is about 46%.
- Coal-fired integrated gasification combined cycle (IGCC hard coal) has a net capacity of 450 MWe and a net thermal efficiency of 51%.
- Coal-fired integrated gasification combined cycle with equipment for CO_2 capture (IGCC with CO_2 capture). This plant has a net capacity of 425 MWe and a net thermal efficiency of 45%.
- Lignite-fired pulverised-fuel (PFC (lignite)) steam plant, with new sophisticated technology for drying lignite (BoA+) and overcritical steam conditions. The net electrical capacity is 1 050 MWe with a net thermal efficiency of 45%.
- Combined cycle gas turbine (CCGT) plant with a net capacity of 1 000 MWe and a net thermal efficiency of 60%.
- Hydro power plant (run of the river) of 0.714 MWe of net capacity and an average load factor of 58%.
- Wind park [offshore wind (8.0)] of about 100 wind energy converters built offshore with a total net capacity of 300 MWe and an average wind velocity of 8 m/s at a height of 60 m. The average load factor is about 34.7%.

13. The net thermal efficiency is equivalent to the electrical efficiency.

- Wind park [onshore wind (5.5)] of about 10 wind energy converters built onshore with a total net capacity of 15 MWe and an average wind velocity of 5.5 m/s at a height of 50 m which corresponds to the height of the hub. The average load factor is about 17.7%.
- Wind park [onshore wind (6.5)] of about 10 wind energy converters built onshore with a total net capacity of 15 MWe and an average wind velocity of 6.5 m/s at a height of 50 m. The average load factor is about 23.8%.
- Photovoltaic power system built on roof [PV (roof panel)] with a net capacity of 0.002 MWe and an average load factor of 10.3%.
- Photovoltaic power system built in open space [PV (plant size)] with a total net capacity of 0.5 MWe and an average load factor of 10.8%.
- Coal-fired pulverised-fuel CHP steam plant with an extraction condensing turbine (CHP ST, extraction). The net capacity of the electrical power is 500 MWe and the net capacity of the thermal power is 600 MWth. The net thermal efficiency is 35% in the back-pressure mode.[13]
- Coal-fired pulverised-fuel CHP steam plant with a back-pressure turbine (CHP ST, back-pressure). The net capacity of the electrical power is 200 MWe and the net capacity of the thermal power is 280 MWth. The net thermal efficiency is 36%.
- Combined cycle gas turbine CHP plant with an extraction condensing turbine (CHP CCGT, extraction). The net capacity of the electrical power is 200 MWe and the net capacity of the thermal power is 160 MWth. The net thermal efficiency is 45% in the back-pressure mode.
- Combined cycle gas turbine CHP plant with a back-pressure turbine (CHP CCGT, back-pressure). The net capacity of the electrical power is 200 MWe and the net capacity of the thermal power is 190 MWth. The net thermal efficiency is 45.5%.
- Motor-driven biogas CHP unit (biogas unit) with a net capacity of the electrical power of 1.0 MWe and of the thermal power of 1.5 MWth. The electrical efficiency is 35%.

Cost estimates provided for the present study are taken from different studies and the literature, and are given after clearance with different manufacturers and electric utilities. All cost estimates for steam cycle plants are based on plant types already built or approved. For nuclear plants, costs incurred during the time between plant shutdown and plant decommissioning are also taken into account and are covered by the specific capital investment costs. Tables 7 to 9 show an overview of the input data of the analysed power plants from a national point of view.

The progressions of fossil fuel prices are taken from the *Enquete-Kommission*[14] and are given to the border of the power plant (refer to Table 10).

Table 7 – Technical and economical data of nuclear and fossil power plants

	Unit	EPR	PFC (hard coal)	IGCC (hard coal)	IGCC (with CO_2 capture)	PFC (lignite)	CCGT
Electrical capacity	MWe	1 590	800	450	425	1 050	1 000
Net thermal efficiency	%	37	46	51	45	45	60
Specific capital investment costs	€/kWe	1 550	820	1 200	1 500	1 150	440
Specific decommissioning costs	€/kWe	155	34.5	53.3	58.5	32.4	15.8
Specific fixed O&M costs	€/kWe/year	30.0	36.6	56.4	68.9	35.5	18.8
Specific variable operating costs without fuel costs	€/MWhe	3.6	2.7	3.2	3.8	1.0	1.6

14. *Enquete-Kommission* "Nachhaltige Energieversorgung unter Bedingung der Globalisierung und er Liberalisierung".

Table 8 – Technical and economical data of CHP plants

	Unit	CHP ST extraction	CHP ST back-pressure	CHP CCGT extraction	CHP CCGT back-pressure	Biogas unit
Electrical capacity	MWe	500	200	200	200	1.0
Thermal capacity	MWth	600	280	160	190	1.5
Net thermal efficiency	%	35 [a]	36	45 [a]	45.5	35
Specific capital investment costs	€/kWe	1 150	1 270	610	530	2 300
Specific decommissioning costs	€/kWe	34.5	34.5	15.7	15.7	0
Specific fixed O&M costs	€/kWe/ year	50.1	58.5	29.2	27.2	115.0
Specific variable operating costs without fuel costs	€/MWhe	2.7	2.7	1.6	1.6	0

a. In the back-pressure mode.

Table 9 – Technical and economical data of renewable power plants

	Unit	Run water	Wind on. (5.5)	Wind on. (6.5)	Wind off. (8.0)	PV roof panel	PV plant size
Electrical capacity	MWe	0.714	1.5	1.5	3	0.002	0.5
Net thermal efficiency	%	93	–	–	–	13.8	14.3
Specific capital investment costs	€/kWe	5 880	1 000	1 000	1 650	4 000	2 940
Specific decommissioning costs	€/kWe	0	0	0	0	0	0
Specific fixed O&M costs	€/kWe/year	58.8	33.8	33.8	58.1	40.0	29.4
Specific variable operating costs without fuel costs	€/MWhe	0	0	0	0	0	0

Table 10 – Fossil fuel prices to the border of the power plants

Year	Lignite €/GJ	Hard coal €/GJ	Gas €/GJ
2010	1.0	1.8	4.4
2020	1.2	1.9	5.1
2030	1.4	2.1	5.8
2040	1.5	2.3	6.6
2050	1.7	2.5	7.3

All fossil-fired power plants are provided with arrangements to comply with environmental protection limits as stipulated in 13. BImSchV (refer to Table 3). For coal-fired power plant with CO_2 capture (IGCC with CO_2 capture), a degree of segregation of 88% is taken into account.

In order to determine the total electricity generation costs of CHP plants, costs with regard to the production of heat are treated as heat credits and are deducted accordingly. Heat credits are determined by evaluating the heat generation of a reference system of the same energy carrier such as the analysed CHP plant. Thus, on the one hand a coal-fired boiler with an assumed thermal efficiency of 88% and on the other hand a gas-fired boiler with a thermal efficiency of 90% is taken into account. Besides, the CO_2 emissions as the result of the co-production of electricity and heat of CHP plants are reduced by the CO_2 emissions of the heat generation which would otherwise be emitted by the boiler of the same energy carrier.

Electricity generation costs

The total power generating costs consist of the overnight capital costs, operation and maintenance (O&M) costs and fuel costs. Costs for refurbishment are considered as "fixed operating costs" and are covered by the O&M costs. The credits of the heat generation of CHP plants are taken into account. For intermittent sources of electricity generation like hydro, wind and solar, additional costs have to be included considering adequate standby generation. This is done by accounting for the specific back-up costs. The method of determination of back-up cost is described later in this chapter. The resulting total specific power generating costs of the power plants considered are shown in Figure 1. Electricity generation costs are calculated with an interest rate of 5%. It is assumed that the depreciation time is equal to the technical lifetime of a plant and that the average load factor of the nuclear, fossil as well as of the CHP plants is 85%. Referring to Figure 1 the lowest power generation costs of about 23.8 €/MWh are determined for the European pressurised water reactor (EPR) and the highest costs of about 356 €/MWh are for the photovoltaic plant of roof panels [PV (roof panel)].

In Figure 2 the power generation costs of nuclear and thermal power plants as a function of the annual operation hours are shown. The investment costs are calculated with a discount rate of 5% and 10%. The coal-fired integrated gasification combined cycle with equipment for CO_2 capture (IGCC with CO_2 capture) has the highest costs of generating electricity, regardless of the amount of operating hours. At a 5% discount rate nuclear power has the lowest generation cost, whereas at a 10% discount rate the cost are lowest for the lignite power plant.

The impact of the emissions trading on the electricity generation cost of the various power plants is shown in Figure 3. The biggest impact is seen for the lignite-fired power plant [PFC (lignite)] followed by the hard coal-fired power plant [PFC (hard coal)]. With an assumed emission price of 20 €/tCO_2 the power generation costs of the lignite-fired power plant would increase by 63% from 25.4 €/MWh to 41.4 €/MWh, whereas the generation costs of the hard coal-fired [PFC (hard coal)] would rise by 48% from 30.2 €/MWh to 44.8 €/MWh. In the 20 €/tCO2 case generation cost of the coal-fired integrated gasification combined cycle (IGCC) would be highest (49.7 €/MWh) and extend the cost of the IGCC plant with CO_2 capture.

Figure 1 – Comparison of the power generation costs among the considered technologies

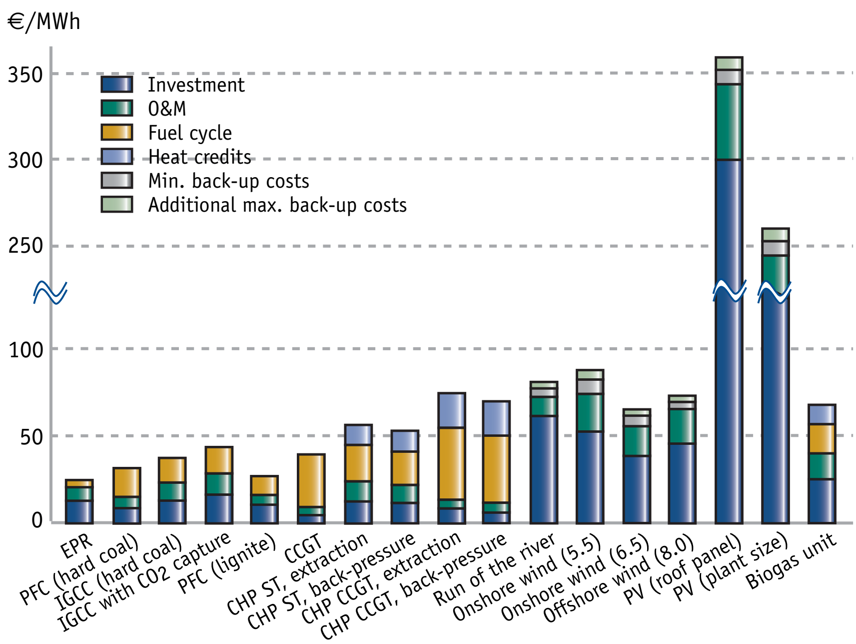


Figure 2 – Power generation costs as a function of the annual hours of operation

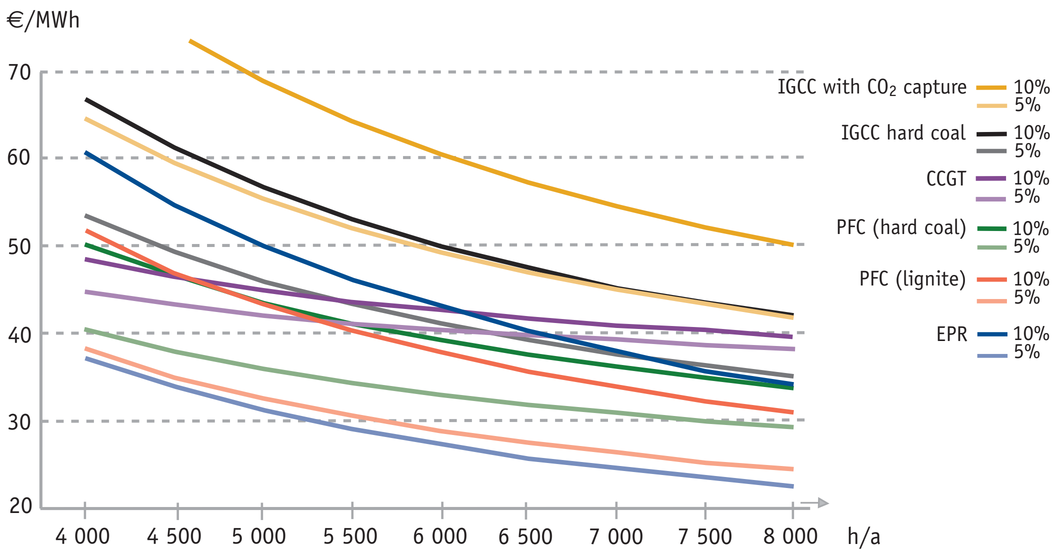
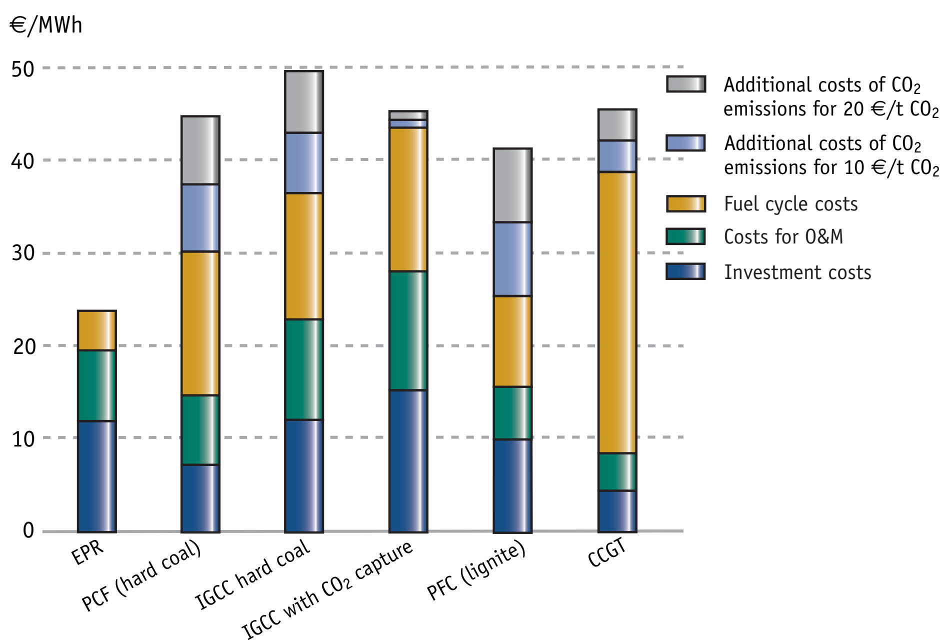


Figure 3 – Comparison of power generation costs showing the impact of emission trading



The method of calculating back-up costs

Wind or solar power corresponds with demand for electricity only to a limited extent. Therefore, storage systems or conventional power plants are necessary for power generation to coincide with demand.

The back-up costs can be calculated which correspond to the surcharge caused by this limited correspondence. They are added to the costs of power generated by the wind energy converter or photovoltaic device. Finally the sum can be compared with the costs of power generated by conventional power plants. The formula to calculate the back-up costs is given by:

$$K_{BU} = \frac{A_K}{h_v} - \frac{AK \,.\, L}{h_w} = A_K \cdot \left(\frac{1}{h_v} - \frac{L}{h_w}\right)$$

with, A_K annuity of investment per kW of the back-up-power plant;
h_v maximum hourly load of the back-up-power plant;
h_w maximum hourly load of "renewable" power plant;
L credit of capacity.[15]

The first term represents the additional costs caused by the fixed costs of conventional back-up power plants. The second term represents the bonus as a consequence of the credit of capacity which can be saved in installed conventional power. This term has to be added to the costs of wind and solar power generation in order to compare it with the costs of power generated by conventional power plants.

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Greece

The demand for electric energy in Greece during the past few years has shown an annual growth rate greater than the average in Europe. This growth rate is likely to continue, as the per capita consumption of electricity in Greece is considerably lower than the European mean average, and domestic tariffs of the main electricity supplier "Public Power Corporation" – PPC S.A. – are the lowest in Europe. The growth of the economy will drive a matching growth of electricity demand.

The electricity market

The regulatory framework for the Greek electricity industry has changed significantly over the past four years as a result of measures designed to introduce competition in the national electricity market. The Liberalisation Law (2773/1999) implemented a new regulatory framework, based on the 1996 Electricity Directive. In addition, the Greek parliament adopted in July 2003 Law 3175/03 (with effect from 29 August 2003) that significantly amended several provisions of the Liberalisation Law, in order to make Greek electricity market more attractive to investors.

15. The credit of capacity is equal to the conventionalpower plant capacity saved in a mixed (conventional/renewable) system having the same supply reliability.

The most significant changes to the Liberalisation Law and the secondary legislation are summarised as follows:

- Establishment of a mandatory day-ahead market that is structured on market-based bids made on an hourly basis, reflecting at least the variable operating costs of each unit.
- The Hellenic transmission system operator (HTSO) may enter into agreements with generators in order to ensure security of supply and the provision of ancillary services and reserve power on a minimum cost and non-discriminatory basis.
- Regarding secondary legislation, there is a public consultation process in progress concerning the amendment of the Grid and Power Exchange Code.

The interconnected transmission system is connected to the transmission systems of Albania, Bulgaria, the Former Yougoslav Republic of Macedonia (FYROM) and Italy. Greece has also started the construction of a 400 kV interconnection with Turkey. This project is scheduled to become operational at the end of 2006.

Moreover, the Greek Ministry of Development has undertaken initiatives that are fully supported by the European Commission for the establishment of the Regional Electricity Market (REM) in South East Europe. In this respect, two Memoranda of Understanding (MoU) were signed in Athens in 2002 and 2003 by the Ministries of the concerned SE Europe countries through the so-called Athens Process, and the Treaty for the Energy Community in South East Europe (ECSEE) is under preparation.

Electricity generation

At the end of 2003, the installed electric power generation capacity in Greece amounted to 12 696 MW as shown in Table 1. Out of the total installed capacity, 88% is on the mainland whereas 12% is on the so-called "Non Interconnected Islands", that is, on islands with autonomous systems not connected to the mainland grid. Additional generation capacity of about 50 MW was temporarily installed on the non-interconnected islands to provide additional electric power during the summer period of 2003 (June through September).

On mainland Greece, thermal power plants using domestic coal (lignite), heavy fuel oil and natural gas constitute a total of 70% of the installed generation capacity, 27% is large hydroelectric and about 3% is based on renewable energy sources such as wind, small hydro and biomass. On the Non-Interconnected islands, 93% of the installed capacity is thermal (heavy and light fuel oil) and about 7% is based on renewable energy sources. It should be noted that over the last two years, the installed capacity of power plants burning natural gas as the main fuel has increased by 53%.

Cost estimates

In this study, the generation cost estimates are based on real data and prior experience for power plants commercially available and paper analysis for plants planned to be available in the short-term. PPC S.A. as well as private companies of the electricity sector provided this information.

The power plants for which analysis was made and data were provided are: two natural gas plants (GRC-G1, G2), one power plant using heavy fuel oil low sulfur (1%) (GRC-OIL), two hydro plants (GRC-H1, H2) and five wind farms (GRC-W1, W2, W3, W4, W5).

Gas plants

GRC-G1 is a combined cycle plant of 377.7 MW (1 gas turbine & 1 steam turbine) with a thermal efficiency of 54%. This plant will be added at an existing power station.

GRC-G2 is a combined cycle plant of 476.3 MW (2 gas turbines & 1 steam turbine) with a thermal efficiency of 52%. This plant, commissioned in 2002, is a totally new one.

Table 1 – Installed electric power generation capacity in Greece (as of 31 December 2003)

2003	Installed capacity (MW)	Share (%)
Interconnected system		
Lignite	5 288	47
Oil	858	8
Natural gas	1 693	15
Hydroelectric	3 077	27
Wind and other renewable resources	308	3
Total Interconnected system	11 224	100
Autonomous Islands		
Lignite	-	-
Oil	1 365	93
Natural gas	-	-
Hydroelectric	0.3	0
Wind and other renewable resources	107	7
Total Autonomous Islands	1 472	100
Total Interconnected and Autonomous Islands		
Total Thermal	9 204	72
Total Hydroelectric	3 077	24
Total Wind and other renewable resources	415	3
Total	12 696	100

Source: Hellenic Regulatory Authority for Energy (RAE).

Oil plant

GRC-OIL is a plant of internal combustion engines of 100 MW (2 x 50) using heavy fuel oil low sulfur (1%) with a thermal efficiency of 45% on the island of Crete. The high construction cost of this plant is due to strict environmental protection limits for the island of Crete and the remarkable difficulties due to the land topology.

Wind farms

The technical assumptions for the wind plants used in the study are summarised in Table 2:

Table 2 – Wind plant characteristics

	Capacity	Location/site (MW)	Average load factor (%)
GRC-W1	14.2 (17 x 0.835)	interconnected system / existing	35
GRC-W2	12 (16 x 0.75)	interconnected system / existing	36
GRC-W3	4.2 (7 x 0.6)	island / new	38
GRC-W4	3 (5 x 0.6)	island / new	38
GRC-W5	4.2 (7 x 0.6)	island / new	30

It should be noted that the plants GRC-W3, W4, W5 are located in autonomous isolated islands (mostly on hills or mountains), a fact that raises significantly the cost due to the additional infrastructure for transportation, transmission etc.

Hydro plants

GRC-H1 is a run-of-river plant of 4 MW (2 x 2) with 95% availability factor and 50% average load factor.

GRC-H2 is a “dam” plant of 123.5 MW (2 x 60 + 1 x 3.5) with 98% availability factor and 25% average load factor. Both plants are to be developed at new sites.

Italy

The Italian electricity sector, since the entry into force of new legislation in 1999 aimed to the opening of the market to the competition, has achieved by the beginning of 2004 the fundamental target of starting the Italian Power Exchange (IPEX).

For the realisation of this liberalised market, the government required the former public company ENEL to divest 15 000 MW, which were sold to other competitors before the end of 2002.

The total electricity demand in 2003 was 320.7 TWh, following an average annual increase of 2.9% in the period 1998-2003. For the same year, the net imported power was approximately 51.0 TWh.

In order to improve the capacity of the Italian generation system, from the beginning of 2002 up to the end of 2003, the Ministry of Productive Activities has approved the construction of new plants with about 12 000 MW capacity, which are planned to be realised by the end of 2008.

In 2003 the available national capacity was 49 700 MW (78 250 MW installed[16]), of which 35 500 MW were thermal plants and 14 200 MW were hydro and other renewable energy source plants. The addition of imported maximum capacity (winter) of 6 050 MW contributed to the total available capacity of 55 750 MW that has covered the peak demand of 53 400 MW.

Concerning thermal generation in 2003, the natural gas share was 48.5%, the oil products share was 27.2% and solid (coal, lignite) 16.0%, while other gaseous or solid fuels, like industrial process fuels, contributed 8.3%.

The liberalised sector of power production is showing a substantial orientation of investors to realise new plants with the technology of combined cycle gas turbines. The main reasons for choosing this option can be explained by the cost-effective investments and relatively short time (3 years) of building the plants, low environmental impact and greenhouse gas emission compared to other combustion systems, high efficiency achievable (55-60%), modular installations, operational flexibility and the highest level of acceptance by both Italian public opinion and local government bodies.

In the field of renewable sources, an increase of generation by wind power plants has been recorded in the course of the last 5 years (from 120 MWh in 1997 to 1 460 MWh in 2003), with a forecasted further growth to 5 000 MWh in 2010.

The data provided in this report for the mentioned technologies of Combined Cycle Gas Turbine and Wind Power are representative examples from the Italian generation system. These data have been selected among the declarations received from electricity production companies operating in Italy. These companies have been willing to offer their contribution in a context of confidential exchange of information. The Directorate General for Energy and Mining Resources of the Ministry of Productive Activities is grateful to the management of these companies for their positive and constructive collaboration.

16. This is the total gross capacity that could be generated from all Italian electric power plants if they were operating at their full power rating and if they were available to supply electricity to the network. This amount includes, therefore, short/long term non-operating plants (i.e. for maintenance or re-powering), full capacity of generators operating temporarily at reduced power level due to climatic conditions or system failures etc.

Japan

Consumers in Japan are supplied with electricity by mostly 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), each of which is licensed by the Ministry of Economy, Trade and Industry (METI) 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 2003 which ended March 2004, the ten utilities together supplied 69% of the total electricity produced in Japan. The remaining 31% was produced by wholesale power producers, like Electric Power Development Co. and Japan Atomic Power Co., specified-scale electricity suppliers and non-utility power producers, especially industrial companies producing electricity for their own use.

The Agency of Natural Resources and Energy of METI has estimated standard generating costs for nuclear power, coal-fired, LNG-fired and oil-fired thermal power, and hydroelectric power plants since fiscal year (FY) 1982. These estimates are based on the same principle as that which is used in this study. The most recent estimates released, which were estimated by the Federation of Electric Power Companies, were for FY 2003. To compare nuclear power generating costs with the others in various cases, the discount rate used for these calculations is taken at 0%, 1%, 2%, 3% and 4% per year.

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 FY 2010:

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 safety.

The cost of nuclear power generation was estimated on the basis of eight ABWR (Advanced BWR) type plants, with a gross capacity of 1 380 MWe for each plant. This standardisation programme, reflects operating experience with conventional light water reactors and the achievements realised under the first and second improvement and standardisation programmes. With the best technologies available in Japan and abroad incorporated in terms of safety, reliability, operability and minimisation of occupational radiation exposure doses, this type of plants will be the mainstay of Japanese nuclear power generation in the year 2010 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. The projection of costs for FY 2010 was made with the annual increase rate of prices set at 0%.

The cost of nuclear plant decommissioning was estimated on the basis of reserve for decommissioning of the latest commissioned nuclear power unit.

Coal-fired thermal power plants are fitted with high-efficiency de NO_x and de SO_x equipment and electrostatic precipitators in such a way that these pollution control systems 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 in order to improve power generating efficiency.

The costs of generation were estimated on the basis of a "model" coal-fired thermal power plant, having a gross capacity of 860 MWe, with three such plants at a site. The model plant is based on an ultra-supercritical pressure steam cycle with an estimated design thermal efficiency of 41%. The model plant is designed from the most reliable perspectives of technology available now.

The ultra-supercritical pressure steam power generation system, the pressurised fluidised-bed combustion power generation system and some other technologies are being introduced and developed to improve the efficiency of coal-fired thermal power plants.

With IEA sources used as reference data, coal prices for these plants were estimated at 1.4 USD/GJ for the year 2010. Thereafter, the estimation predicts that prices will rise at a rate of some 0.8% per year.

The generating costs of gas combined cycle power plants were estimated on the basis of five model plants at a site with a combined gross capacity of 1 630 MWe. These models are in a 1 400°C class of plant designed from the most reliable perspectives of technology available now. Design thermal efficiency is estimated at 52%.

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

With IEA sources used as reference data, fuel prices for these plants were estimated at 4.3 USD/GJ for the year 2010. Thereafter, according to the estimation, the prices will increase at a rate of some 0.3% per year.

The generating costs of hydro power plants were estimated on the basis of four model plants with a gross capacity of 19 MWe each. These model plants are based on the "run of the river" type.

Photovoltaic, wind power and other renewable generation systems are considered to serve only as supplementary facilities for electric utilities because of their inadequate supply stability and unsuitability 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 these.

Republic of Korea

Long-term electricity supply and demand

Overview

Before restructuring the electricity industry, the Korean government had established a Long Term Power Development Plan (LPDP), and the Korea Electric Power Corporation (KEPCO), a vertically integrated utility, had implemented the LPDP in order to secure a stable electricity supply.

The Korean government decided to gradually restructure the electricity supply industry (ESI) in order to increase the efficiency of the industry and to promote consumer rights. With the ESI restructuring, the competitive market mechanism will be the dominant factor. Thus, the function of the former LPDP has inevitably changed into non-binding guidelines or reference.

The Korean government, in consultation with Korea Power Exchange (KPX), biennially establishes the Basic Plan of the Electricity Supply & Demand (BPE) just as it has prepared the LPDP. However, the

BPE will be established not as a binding force but as a tool providing market participants with appropriate information and market based solutions. The government of Korea revised the Fifth Long Term Power Development Plan (5^{th} LPDP) and released the First Basic Plan of Long Term Electricity Supply and Demand (1^{st} BPE) on 17 August 2002.

Electric demand forecasts

According to the 1^{st} BPE, the annual growth rate for electricity sales is expected to be 3.3% on average from 2001 to 2015. The annual growth rate for peak load is expected to be 3.4% on average for the same period. Consequently, total electricity sales are expected to be 311 056 GWh in 2005, and 391 950 GWh in 2015. For those years, annual peak demand is expected to be 51 859 MW and 67 745 MW, respectively.

Survey result on investors' generating capacity addition and retirement

KPX performed a survey to collect information on generating capacity addition and retirement from generating companies and potential investors in the mid and long term period. Generating companies and investors intend to build 97 generating units, totalling 41 150 MW, prior to 2015.

The survey indicated that the capacity addition of coal fired plants increased 3 400 MW and that of LNG fired increased 4 300 MW, while oil fired and hydro decreased 4 000 MW and 230 MW respectively, compared with the generating capacity additions in the 5^{th} LPDP. Generating companies intend to retire 6 570 MW between 2002 and 2015. (With plant life extension, the retirements are 2 910 MW less than in the 5^{th} LPDP).

Electric industry restructuring plan in Korea

Overview

In 1994, the Korean government carried out a two-year evaluation study of KEPCO's organisation to estimate the potentials of efficiency increase in the power sector. The result of this study suggested restructuring and gradual privatisation of the company.

Accordingly, in 1997, an Electricity Industry Restructuring Committee was established within the government, and prepared the Draft Plan for Restructuring of the Electricity Supply Industry. On 21 January 1999, taking into consideration this plan, the Ministry of Commerce, Industry and Energy (MOCIE) announced publicly the Basic Plan for Restructuring of the Electricity Supply Industry. According to this plan, the restructuring should:

- Implement a competitive market structure with full competition on the generation side and limited retail competition, leading ultimately to full retail competition circa 2009.
- Unbundle the existing vertically integrated utility, KEPCO, into five to seven generation companies (GenCos), a transmission company and multiple distribution companies.
- Retain nuclear generation assets in public ownership until a decision on whether or not to offer them for sale is determined at some future point.

The restructuring plan announced by the government involved a gradual transition to wholesale competition with the introduction of retail competition taking place after the year 2009.

The plan established that, in the initial period, KEPCO's generation assets would be divided into a number of companies for divestment and/or privatisation.

Current status of restructuring

The current electricity market, which began operation on 2 April 2001, is referred to as the first stage of restructuring and the Generation Competition Market. In this phase, multiple GenCos, one transmission/distribution company (KEPCO), and several IPPs exist in the market. The transmission and distribution sectors remain as part of the KEPCO.

The Electricity Business Act (the Act) calls for the creation of a Korean Electricity Commission, consisting of up to nine members and a Chairman, to act as the industry regulatory authority. Under the Act the Commission is an advisory and arbitration body. The MOCIE Minister appoints the members and has the authority to make important decisions after deliberation and resolution by the Committee.

KEPCO's fossil and hydro generators have been divided into five groups that are being established as separate generating companies, first as KEPCO subsidiaries and eventually as separate, private companies. The five groups/companies are similar in size and composition, with each having one large, base-load coal-fired plant and several smaller plants. The nuclear plants will remain together in a KEPCO-owned subsidiary. Transmission and distribution (T&D) will remain within KEPCO.

Korea power exchange

The Korea Power Exchange (KPX) called for in the Act has been created as an independent entity. KPX has assumed responsibility for finishing the work that was begun by KEPCO to design and implement a power pool.

The Act provides that KPX operates an integrated spot market/dispatch system, in which the dispatch instructions to generators are based on the quantities determined in KPX's market process. Such an integrated process provides a good basis for an efficient, reliable market that should prevent many of the serious problems encountered in the Californian market system.

The KEPCO/KPX/consultant process has produced a set of rules for the initial Cost-Based Pool (CBP). In the CBP, KPX determines system operations and market prices/quantities using regulated, cost-based offers from generators to supply energy. The CBP determines a single, Korea-wide System Marginal Price (SMP) for each hour representing the avoidable cost of the most expensive generating unit needed to meet demand in a notional unconstrained dispatch, in other words, a hypothetical dispatch indicating which generators would run if there were no transmission constraints.

Cost estimates and generation technologies

Nuclear

Korea established an overall nuclear technology self-reliance programme in 1984. Through this programme, Korea has developed Korean standard nuclear power plants (KSNP, PWR 1 000 MW) by use of accumulated experience in construction and operation of NPPs.

In addition to KSNP, Korea started a programme for development of the Advanced Power Reactor (APR), the second generation of KSNP. The key objectives of the APR development programme are enhancement of safety and economics. These reactors, KSNP and APR, are expected to be main elements in Korean export of nuclear technology.

The cost estimates of nuclear generation provided in this study were based on two units of KSNP at a site. The notable difference from the OECD/NEA method is that the O&M costs include decommissioning, spent fuel treatment and rad-waste treatment. The decommissioning cost was estimated at 161.9 billion won of 1 January 1992 for a 1 000 MW class reactor.

Coal

Coal fired power plants have been the main power source owing to their merits of stable fuel supply and economic viability. Recently Korea has constructed a standard 500 MW model with a thermal efficiency of 41%. It is a super critical steam condition system equipped with de-NO_x and de-SO_x facilities. The cost estimates for this study were made on the basis of constructing two standard 500 MW units at a site. According to results from the survey on generation companies' intention for power plant construction, larger coal fired plants seem to substitute for the standard 500 MW unit. In this study, the costs of 800 MW coal fired generating technology are also estimated on the basis of recently completed plants.

Natural gas

LNG Combined Cycle became one of the major power sources owing to its environmental merit and short construction period. LNG CC was first introduced with the intention of substituting oil fired plant which prevailed in Korea until the early 1980s. Considering the current rapid increase of peak load and increased concern about environmental issues, the share of LNG in the energy mix is expected to increase continuously in Korea. The cost estimate was made on the basis of constructing two units of 450 MW at site. Each unit is assumed to consist of two gas turbines (2 x 150 MW) and one steam turbine (1 x 150 MW).

The Netherlands

Dutch situation on electricity production

The Dutch electricity market is in good shape with adequate unbundling, the necessary bodies for regulation, transmission and market operation in place, and network use based on regulated TPA (Third Party Access). However it is important that government and TenneT (transmission system operator – TSO) continue to co-operate with neighbouring TSOs in order to increase the interconnector capacity. The reason is that electricity tariffs for households are among the highest in IEA member countries. Those for industries are also in the upper half and quite higher than those in neighbouring countries (*viz.* Belgium, France and Germany).

Electricity consumption is approximately 100 TWh of which 41% are used by industries, 31% by the service sector, 23% by households and 5% by agriculture and transport. Electricity imports amount to 21 TWh and exports to 4.5 TWh. The total domestic electricity generation equals 96 TWh. The break down in fuel type is as follows: gas-fired: 59.5%; coal-fired: 28%; waste incineration and renewables: 4.5%; nuclear: 4%; oil: 3% and miscellaneous: 1%. The share of autoproducers is about at 14%. Total capacity is estimated by TenneT at 19 600 MWe. The exact capacity is not known mainly because 40% (7 500 MWe) of the installed generating capacity is CHP on which there exists no complete information. At present there is one gas-fired plant under construction. It is a CHP 790 MWe CCGT unit. At least one other CCGT plant as well as one coal-fired power plant are in the planning phase. Both plants will be owned by autoproducers. Further, it is to be expected that in the years to come the decentralized electricity production capacity (mainly industrial gas-fired CHP) will grow by 20% (up to 9 000 MWe) in the year 2010 while the centralised capacity may shrink somewhat.

CCGT power plant

The electricity generating costs based on a CCGT plant have three components, e.g. investment, operation and maintenance, and fuel costs, with the fuel costs being dominant. The investment costs estimated in the present study have been based on the figure from the 1998 OECD cost study, which in turn was based on the Eemshaven CCGT power plant as well as on the evolution of CCGT technology. The operation and maintenance component has been based mainly on the 1998 cost study although a correction for income development has been taken into account. A prognosis for fuel costs for the period 2010 until 2040 has been prepared by the Netherlands Bureau for Economic Policy Analysis (CPB). The expected gas prices are:

Year	Gas price (€/GJ)
2010	4.90
2020	5.35
2030	5.65
2040	6.10

Nuclear power plant

There has been a lot of turbulence around the Borssele power plant, the only nuclear power plant in the Netherlands, in past years. However, the present government, which came into office in 2003, considers nuclear power as a viable option for the future, especially because of increased environmental concerns. Nevertheless, the government does not foresee the construction of new nuclear power plants in the near future. For nuclear power, the investment cost component is dominant in the electricity generating costs. The figure for the investment costs has been based on information received from Areva, with information from Westinghouse used as a check. The decommissioning costs are based on generally accepted assumptions and on the actual costs of conditioning the Dodewaard nuclear reactor for its 40-year waiting period. The operation and maintenance cost component as well as the component for the back-end of the fuel cycle, has been based on Borssele experience. Further the prognosis is that for the whole period from 2010 until 2050 costs for all components in the front-end of the fuel cycle will be constant in real terms (e.g. natural uranium price: 40 USD/kg; conversion: 6 USD/kg; enrichment: 110 USD/SWU).

Waste fired power plant

The disposal of waste from municipal and urban origin is a legal obligation in most European countries including the Netherlands. The waste has to be disposed of in an environmentally responsible manner and at acceptable costs. Although the economical value of municipal waste is quite low compared to primary commodities and materials, it has a high content of combustible material. Besides, the waste contains valuable inorganic components which may be re-used. Therefore waste can be characterised as follows:

- Municipal or urban origin.
- Legal obligation for disposal.
- Public responsibility on long term.
- Continuous flows of material.
- Sustainable resource for energy and recyclable materials.

A waste incineration power plant, called waste-to-energy power plant (WTE), situated to the west of the city of Amsterdam, has been operating since 1993. Its efficiency is 23% and its emissions are much lower than the very stringent Dutch norms. The operator of the WTE-plant, named the "Waste-to-energy Enterprise Amsterdam" (WEA), has developed a new highly-efficient waste incineration power plant concept, called waste-fired power plant (WFPP). This plant will have an electricity generating capacity of 58.4 MWe and an efficiency of over 30%. This higher efficiency is possible because of a technological break-through in steam production as well as the use of Inconel in the furnace to prevent corrosion. Its waste burning capacity will be 530 000 tons per year. It is under construction and will start operation at the beginning of the year 2006. The figures in the present study have been based on the WFPP concept.

A new sewage treatment plant with a capacity for processing the waste generated by 1 000 000 inhabitants is being constructed next to WEA. It will be put into operation in the years to come. Sludge, biogas and foul gases (stench prevention) from the sewage plant will be disposed of in WEA's furnaces. The WEA and the city of Amsterdam are willing to export this attractive set-up to all those municipalities in the European Union that have public responsibilities for waste disposal.

Wind power plant

Existing wind capacity which all is land-based amounts to nearly 1 000 MWe. However the indicative objective for offshore wind capacity is 6 000 MWe in 2020. Its realisation would mean that the share of wind power in electricity generation would be in the range from 10 to 25% in the year 2025.

There are two offshore wind projects in the planning phase. The first one is the near-shore wind farm (NSW) near the village of Egmond aan Zee (North-Holland) with a capacity of 100 MWe. It will be sited about 12 kilometers from the coast in water 15 to 20 metres deep. Its construction is expected to start in the year 2005. The operator is NoordZeeWind, a consortium consisting of Shell Renewables and Nuon. It will have 36 NEG-Micon 2.75 MW, 92 metre diameter wind turbines on monopiles. The costs of offshore wind power in the present study have mainly been based on NSW. The second project is the Offshore Q7-Windpark. The distance to the coast of IJmuiden (North-Holland) is 23 km. It will comprise 60 wind turbines with a capacity of 2 MW each in water 20 to 25 metre deep. The turbines will be supplied by Vestas and the monopiles by Smulders. Both the suppliers have offshore experience. The park will be realised by a consortium which is called E-connection, consisting of construction companies as well as banks. The Dutch Government is currently developing a licensing system for siting of windparks on the basis of the Public Works Act. It is foreseen that this system will come into force in 2005.

CHP plant

Existing installed CHP plant capacity is about 7 300 MWe for electricity generating in combination with 13 000 MWth for heat production. About 3 800 CHP units with an electrical capacity of 1 500 MWe are used for greenhouse heating. Industry uses 150 CHP units with a capacity of more than 3 800 MWe. Many of these units are owned by joint ventures of industry and electricity distributing utilities. A few industrial producers have formed their own Power Parks. The balance (1 920 MWe) is formed by district heating plants which are owned and operated by centralised power producers, who supply heat to 275 000 Dutch households (4%).

The large scale use of CHP is the result of an active promotion policy from the government aimed at realising environmental benefits. The expectation is that CHP capacity may grow to 9 000 MWe between now and 2010.

A precondition for efficient operation of CHP units is that the heat loads are relatively large and continuous. These conditions are found in Dutch agriculture (greenhouse heating) as well as in industry. At the moment a harmonisation for high quality CHP was prepared by the European Commission in the form of a directive. In addition, the forthcoming CO_2 emissions' trading may further improve the market potential for CHP in the Netherlands in near future. Recently, micro power units (in fact small CHP units) have been developed in the Netherlands. A field test to study their behaviour and characteristics as well as their influence on the electricity grid is underway.

The CHP investment cost figures in the present study have been derived from an ECN report. The assumption for future fuel (gas) prices is that they will be equal to the ones presented in the table for CCGT power plants.

Portugal

Legislative framework

Current organisation of the electrical system

The national electric system consists of a public electricity system and an independent electricity system. In the public electricity system generation, transport and distribution activities are undertaken under a public service regime, which is linked to the obligation of supplying electricity with adequate service quality standards and with the principle of uniformity of tariffs across the country.

Within the **public electricity system**, the commercial relationship between generation companies and the transmission company is based upon Power Purchase Agreements, which oblige the generators to sell all the electricity to the transmission company. The binding distributors are obliged to enter into a binding contract with the transmission company under which they guarantee to acquire most[17] of the energy and to supply customers in accordance with tariffs and conditions established by the energy services regulator.

Within the **independent electricity system** is the non-binding system, as well as the special regime producers. The non-binding system is a market-based system that enables unrestricted access to generating and supply activities, and in which the market agents are entitled to use the public system transport and distribution infrastructure against the payment of the respective tariffs. All customers with contracted capacity demand above 41.4 kW are free to choose their electricity supplier. The regulator is preparing the necessary regulations to extend, as soon as possible, this ability to all customers.

The **special regime** includes cogenerators, small hydroelectric producers (under 10 MW of installed capacity) and producers using other renewable energy sources. These producers sell their energy under specific legislation and are remunerated on the basis of costs avoided by the Public System, complemented by an environmental premium that reflects the benefits stemming from the use of renewable energies.

The Iberian market

As a result of the Lisbon Council of Europe held in March 2000, the Portuguese and the Spanish governments recognised the need for an Iberian electricity market, a regional market that would be a step towards the creation of the European electricity market. By the end of 2001, the Portuguese and the Spanish Governments signed a co-operation agreement, which establishes stages and procedures for the convergence of the two electricity systems.

The Iberian electricity market will be organised in two complementary systems:

- Bilateral contracts freely established between the parties;
- Contracts organised through the Iberian market operator, in which management of the daily and intraday markets will be in the hands of the Spanish pole and management of the forward markets will be the responsibility of the Portuguese pole.

The beginning of MIBEL is planned for mid 2005 and implies the modification of the legislative framework, now in progress, in order to bring the structure and exploitation of the national electric system in line with a competitive market regime.

17. At present, the binding distributors can buy up to 8% of their electricity needs from other companies.

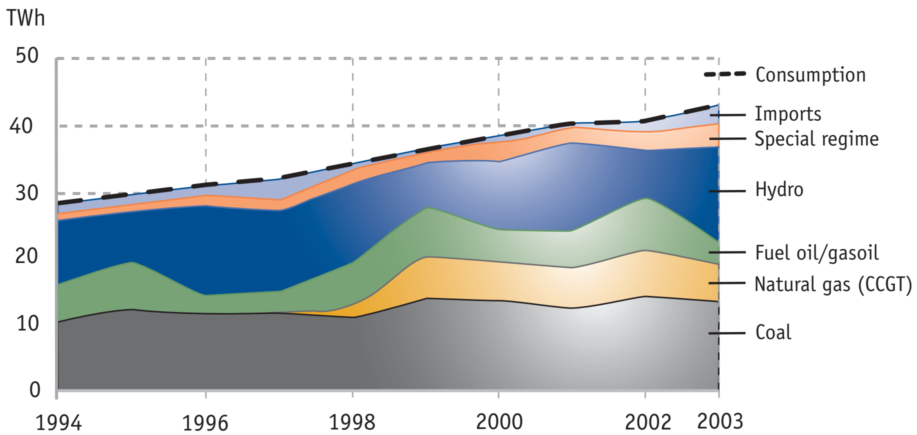
The interconnections between Portugal and Spain will be reinforced over the next years, helping the development of the Iberian electricity market. The new interconnections will allow the increase in commercial available capacity from about 650 MW nowadays to 1 700 MW in 2008/09.

At present, more than 70% of installed capacity has long-term contracts (power purchase agreements) with the transmission company. In the context of a competitive market in generation, these contracts constitute a market restriction and should be terminated. There will be stranded costs to cover the full difference between the value of these contracts and the expected revenues from the liberalised market for the entire duration of the contracts. To prevent any additional costs for consumers, the repercussions on the tariff will be diluted over time.

Generation

In Portugal, electricity is supplied by a combination of coal, hydro power, oil, gas, biomass and wind power. Coal is the largest source, supplying about 31% of electricity generation. Hydro power is a substantial source, but output is highly variable, supplying 15 TWh (34%) of power generated in 2003 but only 7.5 TWh (16%) of power generated in 2002. Gas-fired generation, mainly from new combined cycle power plants, contributed another 17%. Biomass generation produced about 4% of the power produced. Other renewables, mainly wind power, were responsible for only 1% of supply. However, this is expected to increase greatly in the coming years thanks to favourable policies for renewable energy. Figure 1 presents the generation and consumption evolution between 1994 and 2003.

Figure 1 – Generation and consumption evolution



At the end of 2003 Portugal had around 11 GW of installed capacity, of which 8.6 GW were in the public system and 2.3 GW were in the independent electricity system (2.1 in the special regime and around 0.3 in the non-binding system). Figures 2 and 3 present the mix of capacity in Portugal in 1994 and 2003.

The special regime wind capacity was almost non-existent up to 1996 but has been increasing rapidly, reaching 185 MW in 2002 and 300 MW in 2003. The expectations are that 3 750 MW of wind capacity will be installed by 2010. In 2004 the cumulative licenses issued to promoters of wind generation has already reached 3 000 MW.

In 1996 there was no power plant burning natural gas. Since 1997 two fuel-oil groups were converted in order to be able to burn both fuel-oil and natural gas, and in 1998 one combined cycle power plant began commercial operation. In the next years the expansion of the thermal capacity will be based on combined cycle power plants.

Figure 2
Mix of capacity in Portugal (1994)

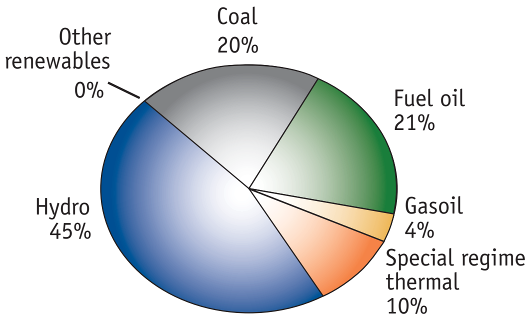
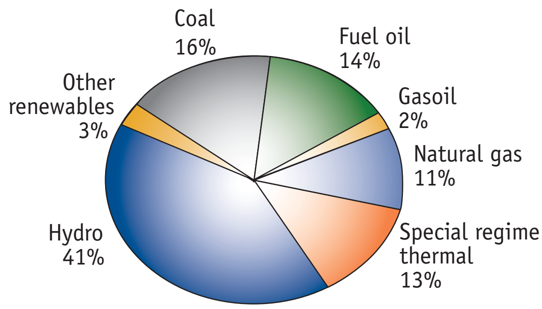


Figure 3
Mix of capacity in Portugal (2003)



During 2004 one hydro power plant and two natural gas combined cycle groups began commercial operation, representing more than 1 000 MW of net capacity.

Because of the fact that the most recent thermal capacity built were gas-fired combined cycle power plants and because of the expected boost of wind generation, the costs submitted to this study are related to these two technologies.

The levelised cost methodology is currently used as a preliminary basis for assessing the competitiveness of future plants operating under equivalent conditions. Different discount rates are used according to the technology risk profile. For instance, the methodology is used to perform scheduling studies of new hydro candidates.

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

Romania

The energy sector represents a strategic infrastructure of the Romanian National Economy on which relies the overall development of the country. At the same time, the energy supply represents a public service with an important social impact.

The energy policy treats this important sector of the Romanian National Economy as a public service which needs more commercial mechanisms and competitive environments, in which the prices will be established through a free competition between a diversity of suppliers and customers who gradually are free to choose their suppliers, as well as transparent and stable market mechanisms monitored by independent regulatory authorities and market operators.

The strategy for energy sector and energy efficiency in Romania is based on setting long-term objectives which reflect the needs of the national economy for:

- Secure energy supply and safety;
- Energy efficiency;
- Use of renewable energy sources;
- Environmental protection.

In order to respond to these basic principles, in line with the *"acquis communautaire"*, the orientation of the energy structure and energy market model is towards a fully competitive market. The safe, secure access to the grids and efficient functioning of the energy sector represents the basic and vital keystone for the Romanian economy.

This is why a coherent and economically viable strategy for the energy field is a fundamental pre-requisite for the attainment of national objectives for a sustainable growth and eradication of poverty. For the past decade, radical institutional, regulatory and structural reforms have been carried out all over the world with the main goal of deregulation in order to improve efficiency and quality of services.

The energy market model approach of Romania is based on the gradual opening of the market as an integral part of the overall philosophy of liberalisation of the national economy and free movement of goods and services.

The aim is to create structures and market mechanisms that respond to and cope with the increasingly integrated European energy market, where national markets are step by step losing their traditional borders and are becoming part of a common European market.

In the last three years, based on these trends, several important steps have been taken already in the Romanian energy sector, by implementation of a deregulation process, based on the need for enhancing market principles and free competition, as well as by promoting a sustained privatisation process.

Starting with the year 2000, the Romanian power sector has been fully restructured and the main activities of generation, transmission, distribution and supply have been unbundled. Independent commercial companies for electricity generation have been created (Termoelectrica, Hidroelectrica, SN Nuclearelectrica), and there are also a number of independent power producers represented by commercial companies created on the basis of CHP power plants which have been transferred to the local authorities (until 2002 belonged to Termoelectrica). Besides these producers there are a number of independent producers and self-producers of heat and electricity for large industrial plants. The producing units are scheduled daily by the system operator based on the merit order list established by the Electricity Market Administrator (OPCOM).

Transelectrica S.A. is a transmission system operator (TSO) tasked to provide transmission services for the electricity market participant (generators, distributors, independent suppliers and eligible customers) and to ensure the system operation through the national dispatched unit.

OPCOM is a subsidiary of Transelectrica S.A., structured as an independent commercial company, responsible for the administration of the wholesale electricity market, registration of all the contracts existing on the wholesale electricity market and providing the daily merit order list based on the generation bid in the terms of quantity and price. OPCOM calculates the hourly system marginal price and monthly system marginal price and it also provides the settlements establishing the payment obligations and the amounts of money to be received by the generators. The system operator manages also all the ancillary service contracts and is responsible for providing the balancing between the demand and supply in real time.

The National Regulatory Authority (ANRE), which has produced all the secondary legislation necessary for the operation of the electricity market, is responsible for the regulation of tariffs for the transmission and distribution services and for the portfolio contracts which cover the so-called regulated market.

In terms of market structure, two components can be defined: the regulated electricity market and the competitive electricity market.

The regulated electricity market represents the captive customers and, according to the legislation, it represents 60% of the market share. The competitive (open) market represents 40% and is expected to be 55% by the end of 2004, 80% by mid-year 2006 and starting with year 2007 the industrial market will be fully open and by the end of the year 2007 the domestic market will be fully open.

The wholesale competitive market has also two components: Bilateral contracts market and spot market.

As a complementary part of the electricity market, represented by power reserves, voltage control services and frequency regulation services, the wholesale competitive market is run on the basis of ancillary services contracts.

At the present moment it may be stated that the Romanian wholesale electricity market is a competitive market, but still in evolution.

Large-scale investments are needed in Romania for upgrading and reconstruction of the national energy system, as well as for expansion of the existing capacities and the construction of new capacities.

Despite the efforts already made in the generation field, it represents the most important target for upgrading, due to the fact that the equipment for more than 5 000 MW of thermal generation are very old. In the thermal field, more than 82% of the equipment is more than 20 years of age. In the hydro generation, 75% of the equipment is more than 20 years old. Consequently, a large number of units should be closed, as their rehabilitation or upgrading would be too expensive and the results uncertain. The closure programme foresees about 3 500 MW of thermal power plant capacity to be shutdown by 2015.

At the same time, it is planned to rehabilitate 2 825 MW of capacity in old thermal power plants (where the cost of rehabilitation is less than 50% of the cost for new units) and to install 529 MW of new capacity in hydro power plants and 1 945 MW in thermal power plants.

The new capacities to be built are determined based on the parallel programme of the capacities to be retired; the overall picture is as follows (in MW):

Sector	2003-2005		2006-2010		2011-2015	
	New capacities	Capacities to be retired	New capacities	Capacities to be retired	New capacities	Capacities to be retired
Hydro:	129		200		200	
New capacity	99		200		200	
Rehabilitation	30					
Thermal:	555	1 280	3 505	2 185	710	
New capacity			1 445		500	
Rehabilitation	555		2 060		210	
Nuclear			707		707	
Total	1 284	1 280	4 412	2 185	1 617	

The selection of the power projects to be promoted was based on the merit principle using the least cost calculation. According to the efficiency hierarchy, the following power projects should be considered.

Unit No. 2 (707 MW) and later on unit No. 3 (707 MW) at Cernavoda nuclear power plant. Nuclear energy is the main sector to cover the future increase of energy demand, represents one of the most efficient energies and is reducing the dependency on import of energy resources. Romania has a good infrastructure for this sector: fabrication plant for the nuclear fuel, using domestic uranium ore; heavy water plant for commissioning and operation of the nuclear units; several factories able to fabricate equipment for the nuclear power plants; and a good nuclear research and design institute.

Additional economically feasible, hydro power generation capacity, estimated at 500-900 MW.

Power generation based on lignite and hard coal by rehabilitation of some of the existing plants, where the upgrading costs are less than 50% of that for new capacity and/or construction of new units, at the following locations: Turceni, Rovinari, Isalnita, Deva-Mintia. The rehabilitation projects could represent 35-45% of the total needed additional power generation capacity.

Combined cycle gas turbines, but only 15% of the total power generation will be secured from natural gas.

The investment efforts required for these plants, for the period 2003-2015, represent 3 485 million USD for thermal, 1 610 million USD for hydro and 1 886 million USD for the nuclear power units. About 3 500 million USD will be necessary for the transmission and distribution grids.

The environment investment cost is estimated at 10% of the total investments effort.

The ongoing reform and restructuring of the energy field has as its main target to become attractive and convincing for the private investors, so that most of the necessary capital could be from the foreign sources, because of the limited financial capacity within the country.

The Romanian government strategy is to speed up the path of the privatisation process in the electricity distribution, gas distribution and the power generation activities starting by the most feasible ones. The main goal of privatisation is to secure the necessary capital and to strengthen the sector rather than maximisation of the proceeds, in order to have stronger and more competitive companies in the gas and power sectors after privatisation, as well as to avoid unnecessary increase of the tariffs. In this view, it is foreseen to use the revenues generated through privatisation in the energy sector for financing of energy projects with a considerable economic and social benefit, as well as for related social costs, for targeted support for low-income households, and for environmental investments.

Romania should play an important role in the electricity market in South-Eastern Europe and, along with systems in other countries, in ensuring the balance of capacities in the second synchronous zone.

The evolvement of contractual relations should lead to the establishment of a regional energy market in the context of the REM initiative of the countries in the region (Albania, Bosnia-Herzegovina, Bulgaria, Greece, FYROM, Romania, Serbia-Montenegro, and Turkey the newly accepted member).

The regional market, in which Romania will play an important role, will represent an important step for further integration with the EU energy market, and is expected to provide better opportunities for free trade and for marketing. In this respect has to be mentioned the initiative of Romania to set up in Bucharest a national/regional power exchange, for which negotiations are going on.

On 30 June 2004, Romania closed negotiations with the EC on Chapter 14 Energy, two years after they were launched. The provisional closure of this important chapter represents not only a political commitment, but also an important step in the development of the process of modernisation and restructuring of the energy system, as well as of an important part of the Romanian economy.

Slovak Republic

In the Slovak Republic, gross domestic electricity consumption reached 28.9 TWh in the year 2003, an increase of 0.8% over that in 2002. Maximum load demand of the power system was 4 338 MW. Domestic power sources provided a gross electricity generation of 31.1 TWh, which was adequate to cover national consumption and to allow a net (export – import) electricity export of 2.2 TWh.

Nuclear sources

Nuclear power plants are an important electricity source for the Slovak power system. They generated 17.9 TWh in 2003 and their share in total electricity generation was 57.4%.

Presently, three nuclear power plants with six nuclear units of the VVER 440 MW type, with a total installed capacity of 2 640 MW, are in operation. The Jaslovske Bohunice site has two V-1 nuclear units of VVER 440 type 230, which were put into operation between 1978 and 1980, followed by two V-2 units of VVER 440 type 213, which entered service in the years 1984 and 1985. Two units of VVER 440 type 213 located at Mochovce were put into operation in 1998 and 2000. Two nuclear units of the same type (with installed capacity of 2 x 440 MW) are under construction.

Thermal power plants

In the year 2003, thermal power plant installed capacity reached 3 202 MW, of which 1 842 MW belongs to the dominant electricity producer, *Slovenske Elektrarne a.s.* (SE a.s.). The remaining capacity is owned by independent electricity producers. In 2003, thermal power plants generated 9.7 TWh of electricity, representing 31% of total generation. The thermal plants use different types of fuels, including natural gas, hard coal, domestic brown coal and some heavy oil.

Renewables

Useable electricity generation potential for renewables represents around 10 TWh per year. Present use is on the level of 40% of the potential (4 TWh per year). Hydro power plants provide some 16-17% of total electricity generation.

The goal of 19% (5.8 TWh per year) of generation in the Slovak Republic being provided by renewables should be reached by the year 2010. There is a need for implementation of new mechanisms for stimulating intensified use of renewables, such as guaranteed electricity purchase, green certificates, low interest rates, easement of taxation and direct financial subsidies.

In the Slovak Republic there are very good natural conditions for exploitation of renewables, especially for hydro, biomass and wind power. Future development of hydro power plants focuses on reconstruction and modernisation of ageing plants, together with construction of new small and very effective units.

Small cogeneration units are beginning to be implemented with biomass fuels and with biogas coming mainly from waste water treatment plants. The possibility of co-firing of coal and wood chips is under serious consideration as well.

The beginning of operation of the wind park at Cerova (2.6 MW) in 2003 marked the start of development of wind energy power in the Slovak Republic. At present, a gross installed capacity of 5 MW is operated at three locations. About 100 MW of new wind energy capacity is in preparation.

Liberalisation

Basic restructuring of the power system was realised in the frame of the liberalisation process. The legal unbundling of generation, transmission and distribution was realised as well. The electricity sector regulatory authority was established by law in 2001.

SE a.s., as the dominant electricity producer in the Slovak Republic, operates about 85% of the total installed capacity. Independent electricity producers operate the other 15%, including CHP.

Slovenska elektrizacná prenosova sustava a.s. is the transmission system operator (TSO) in the Slovak Republic. It is a fully independent legal entity under state ownership.

The distribution networks are operated by three regional distribution companies. The private companies EON, EdF and RWE have a combined ownership share of 49%, with the remaining 51% being in state ownership.

Privatisation

The Ministry of Economy of the Slovak Republic is thinking about completing privatisation of all distribution power companies to the share level of 90%, during the year 2005.

The government of the Slovak Republic has decided to privatise 66% of the shares of SE, a.s. The transaction documents of the SE, a.s. privatisation are planned to be signed in 2005.

Legislative process

By government decree, three Acts concerning the power sector were approved in October 2004:

1. The Power Act that replaces the former Act No.70 from 1998 provides the basic business frame for the power industry. The main goal of this law is compliance of the Slovak power legislation to the EU legislation mainly on Directive 2003 /54/EC and to the Regulation No. 1228/2003 from 26 June 2003.
2. The new Regulation Act applying to transmission and distribution changed and complemented the Act of No. 276/2001.
3. The Heat Power Act regulates the conditions for both heat generation and supply as well as the heat economy.

Market opening

Full electricity market opening in the terms of EU Directive is expected by 2007.

Taxation

In the Slovak Republic, the taxes or tax allowances derived from power generation do not differ from plant type to plant type, nor does the rate of depreciation. The rate of taxation of income for all types of power plants is as high as 19%. That tax is not included in the costs of accounted cost items provided for this study.

In practice, there are effectively no subsidies for construction of new generation capacity nor for rehabilitation or upgrading of existing facilities.

Future of electricity supply

The funds accumulated for decommissioning of large power plants will be given out in the Slovak Republic in 2006 to 2008. Namely, the two V-1 nuclear units of VVER 440 type 230, with a total installed capacity of 880 MW, will be decommissioned together with some thermal power plants that do not meet the emissions standards. A total of 1794 MW of electric capacity, representing 8.0 TWh of annual generation, will be decommissioned by the year 2010.

In order to secure a proper balance between electricity generation and consumption, some 2 500 MW of new capacity will need to be installed by 2020. The total investment requirement for new capacity is some 106 billion SKK (2.8 billion €).

In this regard, SE a.s. was requested by the Slovak Ministry of Economy to develop studies in the framework of the national economy that should evaluate different electricity supply scenarios. The goal was to design solutions that should supply, in each case, a specified amount of electricity at the minimum cost. Moreover, it was also needed to evaluate further implications for society in the form of tax payments or various reductions. These would include, for example, the impacts on the environment, employment, payments to the Fund for nuclear power station decommissioning and radioactive waste handling, impacts in the event of non-completion of the 3rd and 4th units at the nuclear power station at Mochovce (MO-3 & 4), etc.

Seven scenarios were evaluated. These were compared to a reference scenario without investment for new power stations. This reference scenario was chosen on the grounds that it was the "“most inappropriate” from the point of view of cost of electricity purchases, employment, provisioning of the nuclear power station decommissioning and radioactive waste handling fund, stranded costs and security of electricity supply.

The important question of electricity import is the ability to transport large amounts of electricity through the transmission network and to provide adequate capacity for the needed stability regulation and control of the Slovak power network.

The study evaluated three scenarios alternatively with and without completion of the 3rd and 4th units of nuclear power station at Mochovce (MO-3 & 4) and at different alternatives of the V-1 nuclear power units at Jaslovske Bohunice (i.e. shutdown in 2006-2008, or lifetime extension up to 2015). All scenarios except the above-mentioned reference scenario, included also the construction of thermal power plants including gas-fired (CCGT) and renewables and cogeneration sources, the latter with a total electrical capacity of 799 MW.

From the individual producers point of view, the economic evaluation process allowed the choice of an optimum scenario, based on comparison of the annual utilisation of individual technologies as well as on evaluation of the economic effectiveness of sources during their life time. The costs of all power networks were evaluated also. The present value of fixed and variable costs were calculated up to the time horizon of the evaluation.

The damages to the environment, impacts on health of citizens, property, etc., were part of the analysis, including complex cost evaluations. These effects, known as "external costs", play an important role for some fuel cycles, but are not included in the electricity price. Therefore, they need to be taken into account in the strategic decision making process of central bodies responsible for the economy and the environment. The values of the external costs, derived from results of long term research initiated by European Commission, are as follows:

External costs for electricity production by different fuel cycles

Fuel cycles	Unit	Coal and lignite	Natural gas	Nuclear	Hydro
Mean value of external costs given by implementation of ExternE Project of EU 15	€/MWh	40.8-73.3	12.5-23.3	3.9	3.8-4.8
Adjusted external costs at currency rate of 41 SKK/Euro	SKK/MWh	1 673-3 005	512-955	160	154-195
Mean value included in study	SKK/MWh	2 339	734	160	175

The mean value of external costs for nuclear power stations is 160 SKK/MWh and is approximately on the level of renewables (hydro). For the power stations burning coal and lignite, the mean value of 2 339 SKK/MWh is nearly 15 times higher and that for natural gas is five times more than for nuclear power stations.

Figure 1a shows the comparison of costs for different annual time of plant utilisation. Clearly, the lowest electricity generation cost is for the Bohunice NPP V-1. The production cost from completion of Mochovce units 3 and 4 (MO-3 & 4) also are in the lower range of expected costs. For the fluidised-bed unit and CCGT, the costs are more than twice that for electricity generation in the NPP V-1. This results partly from the more than two- increase of natural gas price after the Slovak gas industry privatisation. After taking into account the external costs, the generation cost advantage of the NPPs was increased in comparison to the sources using fossil fuels (Figure 1b).

The time distribution and component structure of costs for Mochovce units 3 and 4 and for CCGT plants are shown in Figures 2a and 2b, respectively.

Figure 1a – Generation costs at different annual hours of plant utilisation (not including external costs)

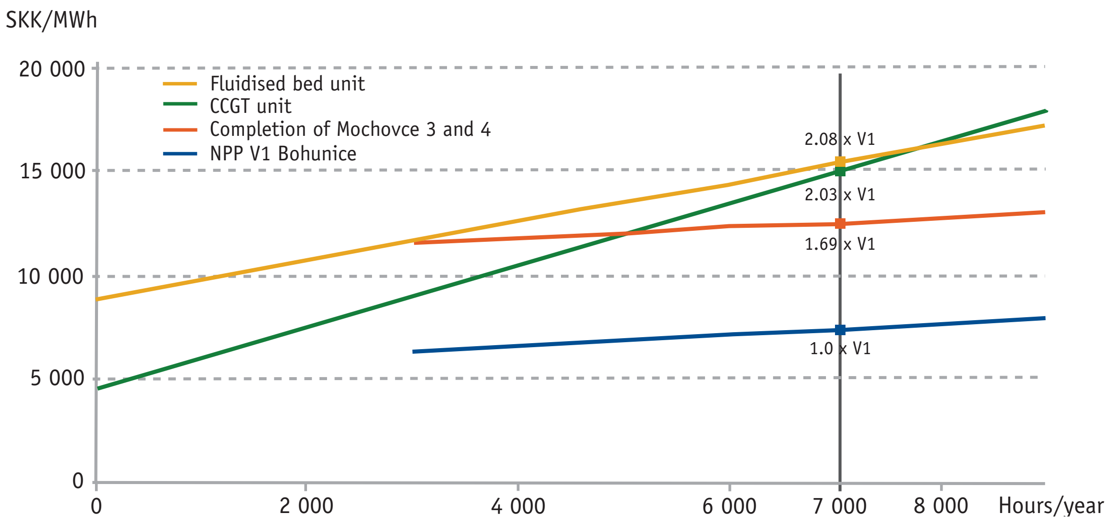


Figure 1b – Generation costs at different annual hours of plant utilisation (including external costs)

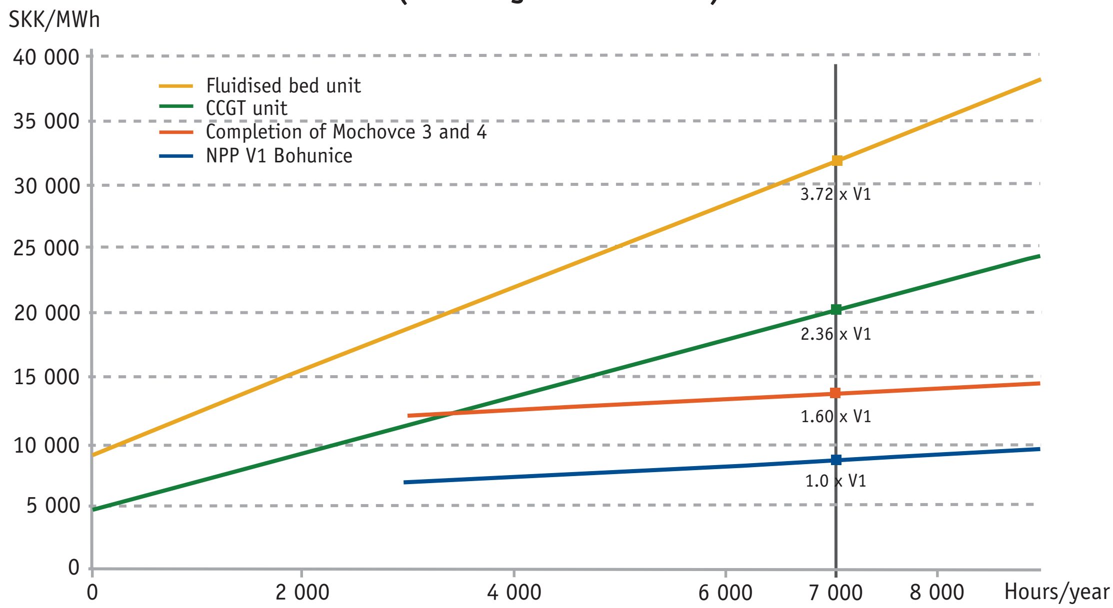


Figure 2a – Time distribution of different components of generation costs (NPP MO-3 & 4)

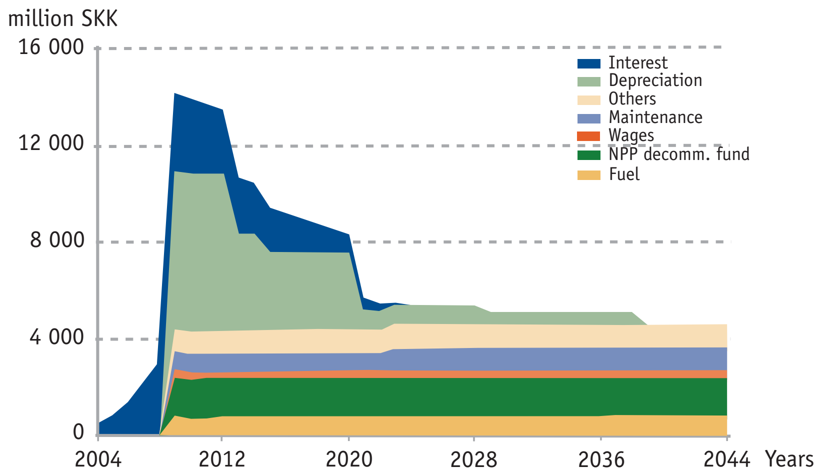
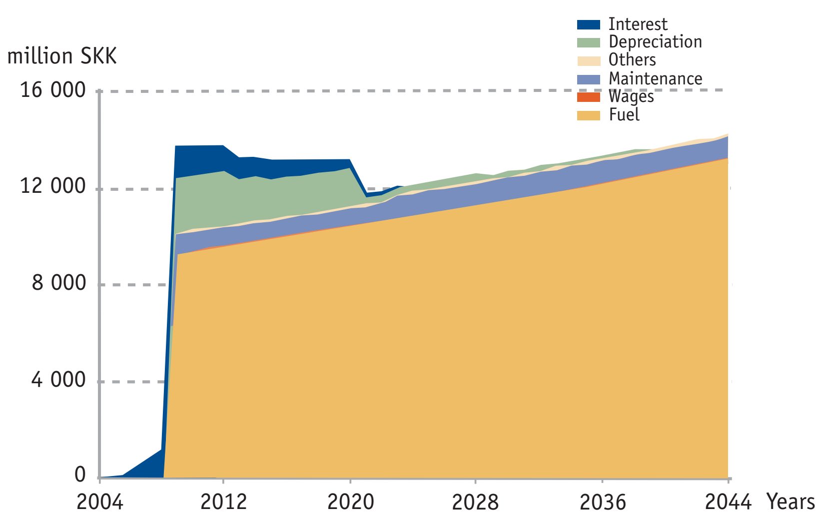


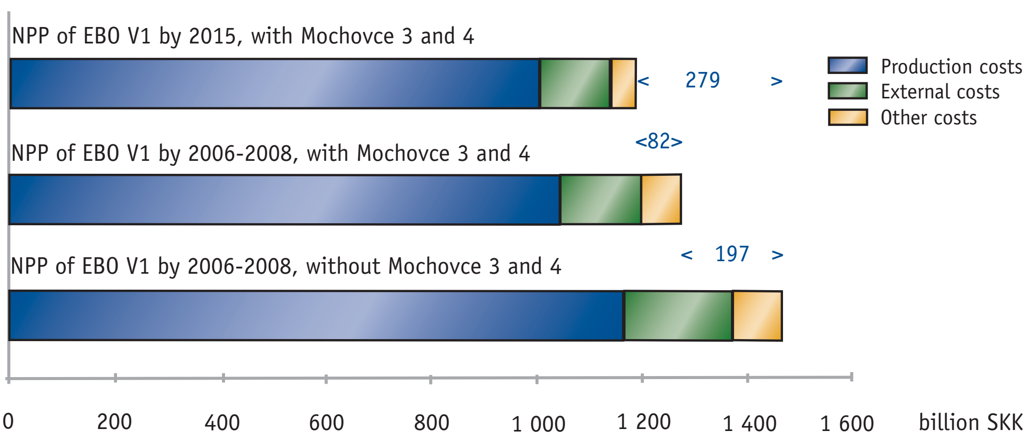
Figure 2b – Time distribution of different components of generation costs (CCGT)



At the beginning of plant operation, the costs of MO-3 & 4 are at the maximum value, and decrease after credits and property depreciation are paid off. The costs of CCGT power station, on the other hand, increase with time as a consequence of high fuel costs (yellow area). Over the lifetime of MO-3 & 4, the costs will reach the present costs of NPP V-1. Considering the fuel price and its development, the electricity production costs for the CCGT plant will be higher than for nuclear.

In the process of taking strategic decisions about power sources for meeting expected electricity demand growth, it is necessary to take into account the entire power production system and environmental protection, health of inhabitants, employment, etc. The results of different nuclear scenarios (with and without MO-3 & 4 are shown in Figure 3.

Figure 3 – Total costs of nuclear scenarios



In general, it was stated that the costs of electricity production are minimised for both the power system and damages to the environment by increase in the nuclear power generation, e.g. by further measures oriented to increasing output from the existing and operating nuclear sources. Other effects, for example effects on employment, stranded costs decrease, specific generation costs declining at nuclear power stations following the depreciation of investments, security for the Fund of nuclear power stations decommissioning, emphasised the need for completion of MO-3 & 4.

The projected costs for the scenario with MO-3 & 4 with NPP V-1 lifetime being extended up to 2015, were some 280 billion SKK (about 7 billion €) less than for the scenario without MO-3 & 4 and with NPP V-1 being shut down by 2006-2008. However, this scenario with NPP V-1 lifetime extension would raise issues concerning the commitment of the Slovak Republic to the European Union Access Treaty.

Under this treaty, the NPP V-1 units should be shut down in the period 2006 to 2008. Due to the higher security in connection with decommissioning NPP V-1, the Slovak Republic recommends to decommission both V-1 units at the same time in 2008. In any case, the completion of MO-3 & 4 is the best alternative. At this time, only one power station in the Slovak Republic is under construction, completion having reached approximately 70% in terms of buildings and 30% in terms of technology parts.

Additional potential shortfalls in electricity supply output can be covered by thermal power plants and to some extent by renewables and cogeneration sources. For the latter, however, the necessary supporting legislation and motivation are missing. The present electricity generation price of thermal power plants makes investments uncertain and risky. Following the above listed facts, it was expressly stated that completion of MO-3 & 4 are the only alternative through which the Slovak Republic could secure an adequate supply of electricity at an acceptable price level.

Turkey

Turkey has been experiencing an electricity demand increase on the average of 7-8% per annum for decades. This trend is expected to continue in the following years, stimulated by the gross domestic product (GDP) growth and new consuming attitudes as a result of modernisation. Demand forecast studies indicate that annual growth rates of around 6% will take place over the next decade.

By the end of 2003, total installed capacity reached around 36 GWe. At present, the electricity generation mix is dominated by natural gas, hydro and coal plants, with around 44%, 25% and 23% shares, respectively. The rest comes mainly from liquid fuelled power stations.

A competitive electricity market is in operation, with the enactment of a new Electricity Market Law in March 2001. The new market model is based on bilateral agreements between market participants, supplemented by a balancing and settlement mechanism. The whole electricity industry including generation was unbundled. According to the Electricity Market Law, new generation investments are envisaged to be undertaken mainly by private sector, based on an authorisation procedure by the Energy Market Regulatory Authority (EMRA). The Ministry of Energy and Natural Resources (MENR) would realise new generation plants through the State-owned Generation Company (EUAS), with due regard to concerns about security of supply, as a last resort in case the market fails to provide new capacity additions in a timely manner.

At present, more than half of the generation is being realised by the private sector plants, including autoproducers, those private generators built and operated under the competitive market conditions and those in operation based on BOO, BOT and Transfer of Operating Rights (TOOR) models. State-owned generation at present contributes 45% of total generation. The State's concentration in the generation market is expected to decrease, as the market enlarges through new capacity additions by private generators and following the privatisation of a significant portion of state-owned generation in the next few years.

There has been private sector interest in the generation side of the market since its opening in 2002. Several private power plants corresponding to a total capacity of around 3 500 MW have already been licensed by the EMRA. New generation investments have tended to focus mainly on natural gas-fired plants, while there has been a growing interest in wind power as well. Nonetheless, electricity supply and demand studies for the short and medium term indicate that there will be a need for new plants to be commissioned from 2008-2009 onwards, in order to cover the growing demand with sufficient reserve capacity.

One of the main principles of the competitive electricity market is the cost-reflecting pricing mechanism. The wholesale price of electricity will mainly activate new generation investments, whereas eligible consumers, which total around 29% of the market at present and are free to negotiate with suppliers directly, create a potential for the cost-effective generation options. The wholesale price of electricity is currently rather high (around 5-5.5 US cents/kWh) due to the stranded cost element of the market reform, namely the high prices arising from past experiences with BOO and BOT plants with long-term state guarantees. However, the price level is expected to decrease as the effect of high-priced PPAs diminishes gradually.

The domestic resources used for electricity generation are mainly hydro and lignite, while a considerable wind potential is estimated as well. Currently, around 35% of the country's economical hydro potential has been used, corresponding to 40 TWh per year. The government expects the use of economical hydro potential until 2020. The remaining generation potential of domestic lignite with low calorific value and high ash, moisture and sulphur content is estimated at around 70 TWh per year, and is envisaged to be used in the medium to long term through clean coal technologies.

A trend towards most-cost-effective technology is expected to shape the generation mix, in parallel with the main philosophy of the competitive market, though the MENR, driven by diversification objectives, can direct the market through suitable mechanisms. A separate legislation was recently drafted to promote renewable-based generation in competitive market conditions, without distorting the market. The supporting provisions reflected in the new law are expected to facilitate the development of small-scale hydro and wind power plants, up to the extent that reliable operation of the transmission system will not be distorted due to their intermittent nature. Securing supply in a reliable manner together with need for diversification would also promote interest in a role for nuclear power in the supply mix within the medium to long term.

Autoproducers, most of which are CHP plants, are contributing more than 15% of total generation at present, though there is no specific legislation at the moment to encourage CHP technology.

Figure 1 – Evolution of energy sources in Turkey

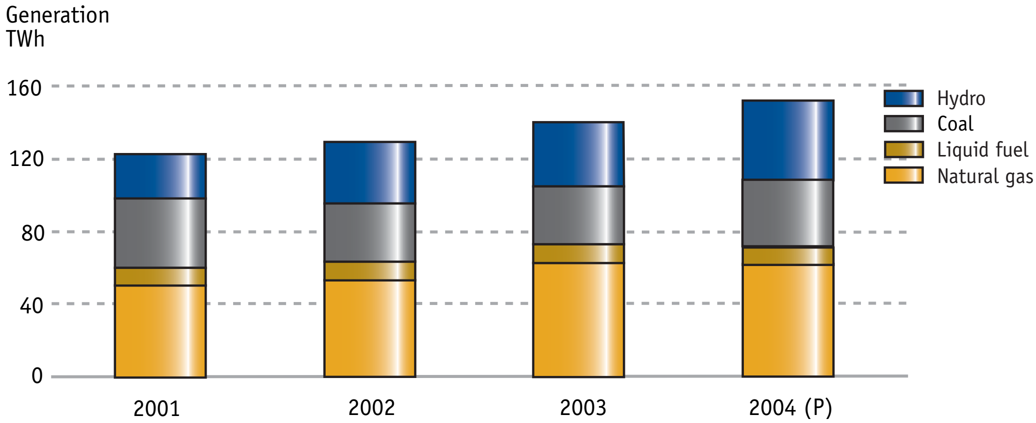
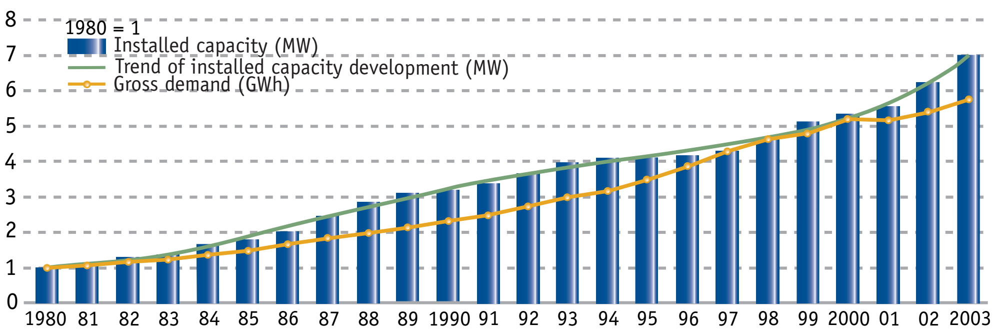


Figure 2 – Trends in electricity supply and demand



United Kingdom

Introduction

This note represents the United Kindgom's country statement as a contribution to the project. The figures are based on a variety of sources. The United Kingdom government did not send the questionnaire to power generation companies for completion. For some of the technologies, however, the industries were represented at a workshop at the Department of Trade and Industry (DTI) in 2002, at which assumptions about future generation costs were discussed. In the light of these discussions some of the estimates reflect the views expressed by the industries concerned, particularly for the capital cost of new plant.

Projections are provided for generation costs using different discount rates, including the United Kindgom generic set as well as 5% and 10% real. There are also projections for capital costs, fuel costs, operation and maintenance costs and load factors.

It has not been possible to provide projections for a number of technologies including:

- Different nuclear generation technologies, e.g. PBMR.
- Power plants using fuel oil.
- Solar power systems.
- Distributed generation power plants.

Methodology

The tables list as far as possible data for 13 generation technologies covering a range of established, emerging and future technologies. The projected costs have been derived from a series of modelling exercises for the Department of Trade and Industry undertaken over the last two years for the 2003 energy White Paper and a review of the prospects for renewable energy also completed in 2003. All the cost projections have been adjusted to mid-2003 prices using the UK GDP deflator.

The note covers three scenarios for final generation costs based on slightly different assumptions about discount rates and load factors. It has not covered the full range of plant lifetimes requested as it was considered that 60 years was too long for a plant lifetime. In general, the lifetimes were taken as either the technical lifetime of the plant in the case of wind turbines (20 years) or a shorter period (15 years) over which investors would expect to receive a return on their investment.

The most important factors affecting the cost projections are the assumptions made about capital costs and, for coal- and gas-fired generation, the level of fossil fuel prices. Projections for all the technologies are subject to uncertainty so a range of costs has been presented. The range is greatest for those technologies which are either not yet technologically proven (marine and generation from coal and gas involving CO_2 capture and storage) or are reliant on new designs from existing technologies (nuclear).

Results

Table 1 provides projected generation costs in 2010 using the United Kindgom's generic assumptions. There are a number of caveats to be borne in mind in interpreting the projections in this table. First, there is no realistic prospect of new nuclear build in the United Kingdom by 2010. The 2003 energy White Paper concluded that, while nuclear power is currently an important source of carbon free electricity, the current economics of nuclear power make it an unattractive option for new generating capacity and there are also important issues relating to nuclear waste to be resolved.

The White Paper did not contain proposals for building new nuclear power stations. It did not, however, rule out the possibility that at some point in the future new nuclear build might be necessary if the UK is to meet its targets for reducing carbon emissions. Before any decision to proceed with the building of new nuclear power stations, there would need to be the fullest public consultation and the publication of a white paper setting out the government's proposals. These factors mean that the timescale for planning and commissioning new nuclear power stations precludes their coming into operation by 2010.

Second, while the cost projections suggest that new nuclear build appears to be a cheaper option than offshore wind in 2010, this does not take account of the potential for further cost reductions in the costs of generation from renewables as a result of scale economies and learning effects. In particular, the modelling work undertaken for DTI suggests that the costs of offshore wind will have declined to 3.0-4.6 p/kWh by 2020 and onshore wind to 2.5-3.2 p/kWh by the same date. The cost of generation from energy crops is also projected to have declined by a further 15% by 2020 compared with its 2010 level. In contrast, we would not expect the costs of a more mature technology such as nuclear power to decline in the same way.

Third, the numbers in Tables 1-3 do not take into account the costs of holding or acquiring carbon emission allowances under the EU emissions trading scheme (or any similar scheme).

The discount rates used for each technology using the generic assumptions reflect a combination of those used in the modelling work for the 2003 Energy White Paper and the work undertaken for the renewables innovation review. In the case of renewables, those technologies which are more established such as onshore wind, landfill gas, waste and small hydro are lower than for technologies where there is still perceived to be greater technological or market risk, such as offshore wind or energy crops.

Table 2 shows the cost projections using a 5% real discount rate. The United Kingdom regards this as unrealistically low in a liberalised electricity market. The main impact is to reduce markedly the kWh costs of generation technologies where capital costs are an important component of total generation costs.

Table 3 shows cost projections using a 10% real discount rate. While a single discount rate is not necessarily appropriate for all technologies, this rate is more realistic than the 5% rate used above for the purposes of comparison.

Tables 1-3 – Projected generation costs in 2010 (p/kWh)

	Table 1: based on generic assumptions for discount rates		Table 2: based on 5% real discount rate		Table 3: based on 10% real discount rate	
Technology	Low	High	Low	High	Low	High
Coal	3.6	4.0	3.0	3.4	3.6	4.0
Gas	2.3	2.4	2.1	2.3	2.3	2.4
Nuclear	2.8	4.3	2.4	3.6	2.8	4.3
Coal (capture & storage)	2.8	4.3	4.3	5.4	4.9	6.2
Gas (capture & storage)	3.4	3.8	3.0	3.5	3.4	3.8
Onshore wind	2.7	3.6	2.4	3.2	3.2	4.2
Offshore wind	4.4	5.5	3.5	4.4	4.5	5.7
Energy crops	4.3	6.4	3.4	5.3	4.0	6.1
Small hydro	1.3	1.5	1.2	1.4	1.6	1.9
Waste	2.1	2.4	1.9	2.2	2.5	3.0
Marine	4.1	5.4	3.1	4.0	3.8	5.0
Landfill gas	2.7	3.2	2.4	2.9	3.3	3.9
Sewage sludge	2.1	2.5	1.9	2.3	2.5	3.0

Table 4 presents projections of capital costs for each technology reflecting a range of figures provided by the industries concerned and from the modelling work described above.

Table 4 – Projected capital costs for plant built in 2010 (GBP/kW)

Technology	Low	High
Coal	1 180	1 320
Gas	285	420
Nuclear	1 070	1 400
Coal (capture & storage)	1 450	1 600
Gas (capture & storage)	530	610
Onshore wind	550	750
Offshore wind	860	1 120
Energy crops	1 350	1 620
Small hydro	330	400
Waste	500	600
Marine	960	1 160
Landfill gas	1 220	1 460
Sewage sludge	820	990

Table 5 shows projections for fuel input costs in 2010, 2020 and 2040. The projections for coal and gas costs are those used in the modelling work for the Energy White Paper and are not necessarily consistent with those currently used in other projection work in the Department. They were, however, those agreed with the Department at the time. The coal projection is consistent with a delivered coal price of 33 GBP/tonne, while the gas projection is consistent with a gas price of 24.25 p/therm in 2010, 25.5 p in 2020 and 33 p in 2040.

Table 5 – Projected fuel costs over plant lifetime (p/kWh)

Technology	2010	2020	2040
Coal	0.466	0.466	0.466
Gas	0.827	0.870	1.126
Energy crops	1.8 - 3.6	1.4 - 2.9	1.4 - 2.9

Table 6 presents projections for operation and maintenance costs by technology in 2010 and 2020. Because of inconsistencies in the estimation of operating costs between the data sources, the numbers are shown only for the renewables technologies. For fossil fuel plants these costs are a small proportion of total generation costs and are not expected to change significantly from current levels. For most of the renewable technologies, operation and maintenance costs are not expected to decline significantly after 2020.

Table 6 – Projected operation and maintenance costs (GBP/kW/year)

Technology	2010	2020
Coal	na	na
Gas	na	na
Nuclear	na	na
Coal (capture & storage)	na	na
Gas (capture & storage)	na	na
Onshore wind	13 - 18	12 - 16
Offshore wind	31 - 37	29 - 35
Energy crops	41 - 49	32 - 39
Small hydro	10 - 12	10 - 12
Waste	15 - 18	15 - 18
Marine	39 - 46	35 - 42
Landfill gas	37 - 44	37 - 44
Sewage sludge	25 - 30	25 - 30

Abbreviation: na = not applicable.

Table 7 shows the projected load factors assumed for each type of plant. These form part of the generic assumptions used in each case in the results in Tables 1-3, including the use of different discount rates.

Table 7 – Load factors assumed for plant in 2010

Technology	%
Coal	85
Gas	90
Nuclear	85
Coal (capture & storage)	85
Gas (capture & storage)	90
Onshore wind	30
Offshore wind	35
Energy crops	85
Small hydro	35
Waste	34
Marine	30
Landfill gas	63
Sewage sludge	55

Table 8 shows the projected efficiency factors for fossil fuel plants or those using energy crops.

Table 8 – Efficiency factors assumed for plant in 2010

Technology	%
Coal	46
Gas	61
Coal (capture & storage)	40
Gas (capture & storage)	52
Energy crops	30

The size of plant on which the results above are based varies by technology. Table 9 describes the assumptions made for fossil fuel and nuclear generation.

Table 9 – Size of plant by technology

Technology	MW
Coal IGCC1	600 - 800
Coal pulverised fuel	1 000 - 2 000
Gas	400 - 500
Nuclear	1 000

1. Coal IGCC might involve three plants of this size to achieve economies in coal handling.

United States

The cost of generating electricity from a given technology is driven by the underlying assumptions about capital and operating costs. The United States costs reported here are those used by the Energy Information Administration (EIA) – the independent statistical and analytical agency within the US Department of Energy (DOE) – in their analytical and forecasting activities. Since most of EIA's analytical and forecasting products address broad issues, by necessity, their cost estimates tend to deal with generic technology forms. Thus, the estimates reported do not reflect the cost of a particular design of any given technology. Additionally, the estimates reflect the cost of building and operating a power plant at a typical generic site. Thus, because of siting issues, the estimates may be greater or less than the realised costs at a particular location.

The data presented generally reflect incremental improvements in costs and performance relative to 2003 levels. Estimates, shown in the table below, were prepared by some of the program offices within DOE and/or vendors of the technology. These estimates often assume much larger reductions in costs relative to the ones used by EIA. The larger reductions could be due to accelerated (and successful) R&D programmes and/or major technological innovations.

The United States levelised costs reported in the questionnaire for this study also include all relevant taxes and tax credits, whereas the ones computed by the OECD explicitly exclude corporate income taxes and technology-specific tax subsidies. For this reason among others, the levelised costs reported by EIA will be different from those presented by the OECD. Additionally, because of differences in taxes in various countries, even though the underlying cost estimates are similar, the levelised costs reported by various countries could be very different.

EIA also assumes that all United States power plants will be built in a competitive environment. Studies have shown that decision makers in such an environment tend to use relatively high discount rates and short-time horizons compared with those in regulated industries. Investments in power plants must compete with

Technology	n^{th} of a kind capital cost (2003 USD/kW)	n^{th} of a kind heat rate (Btu/kWh)	Capacity factor
Advanced nuclear	1 167	na	na
Geothermal	1 475	na	0.85
Landfill gas	1 426	na	0.9
Photovoltaic	1 173	na	0.24
Solar thermal	na	na	0.28
Biomass	1 308	na	0.8
Wind	887	na	0.48
Pulverised coal	1 127	8 600	na
Integrated gasification combined cycle power plants	980	5 687	na
Natural gas combined cycle	538	4 960	na
Combustion turbine	380	6 669	na

Abbreviation: na = not applicable because estimate is similar to the one reported in this study.

Note: The cost data includes all contingencies, but excludes "Interest During Construction".

Sources: Nuclear – Data are consistent with Vendor Estimates.
Renewables – Estimates correspond to Department of Energy Program Office data as found in National Renewable Energy Laboratory, 2003 Power Technologies Database.
Fossil Fuels – Estimates based on US Department of Energy, Office of Fossil Energy's Vision 2100 Programme.

other investment options available to equity investors with respect to risk and returns. Moreover, firms making investment decisions in competitive markets prefer to recover all their costs, including a return on their investment, over relatively short-time periods. Thus, the United States levelised costs shown in this questionnaire were computed over 20 years, whereas the ones derived by the OECD were estimated over 40 years. Everything else being equal, longer time horizons and lower discount rates tend to favour more capital intensive technologies.

The US Internal Revenue Service (IRS) permits firms to depreciate on an accelerated basis nuclear and base-load fossil over 15 and 20 years, respectively. Most renewables are depreciated over 5 years. Also, prior to 31 December 2003, wind, solar and geothermal technologies received some type of tax credit. These tax credits expired on 31 December 2003 and as of mid-February 2004, the law authorising these tax credit has not been renewed.

Generation Technology

This appendix 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 2010-2015. The basic base-load 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); “Combined cycle gas turbines” (Kelhofer, 1991); “Steam boiler electric generation” (Schultz, 1992); “Nuclear plants” (Glasstone, 1994); “Coal-fired plants” (Couch, 1997), “Renewable energy power plants” (IEA, 2003a) and “Research and Development Concept for Zero-emission Fossil-fuelled Power Plants, Summary of COORETEC” (BMWA, 2003).

Coal-fired power plants

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

Pulverised coal plants

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 cogenerating power plant, a back-pressure or extraction steam turbine is used. Many variations on the steam cycle are possible in either electricity-only or cogenerating 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 and temperature 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 from country to 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% 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% of plant output. The system also adds up to 100-250 USD/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% 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 USD/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 USD/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 used or 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 that increase efficiency compared with a conventional plant 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 previously noted, 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% (based on lower heating value) using subcritical steam cycles to 42-45% 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 two to three 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% of the capacity in new units built in Europe, Japan and Korea in the 1990s uses supercritical steam (Couch, 1997, page. 59). In contrast, 85% 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 gas, then burn it in a gas turbine combined cycle. This can additionally improve efficiency. 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 gas 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% 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, gas heat exchangers and gas cleaning systems are smaller because they do not need to process the large volume of nitrogen (80%) in air. Also, the heating value of the gas produced is closer to that of natural gas. The gas turbine therefore requires less modification to burn a gas 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 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.

Gas-fired power plants

Combined cycle gas turbines

All gas-fired power plants presented in this study are based upon the use of combined cycle gas turbine. 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 turbines 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 60% (LHV).

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 and little or no particulates. 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% 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.

CO_2 capture and storage

CO_2 capture and storage (CCS) involves three distinct processes: first, capturing CO_2 from the gas steams emitted during electricity production; second, transporting the captured CO_2 by pipeline or in tankers; and third storing CO_2 underground in deep saline aquifers, depleted oil and gas reservoirs or unmineable coal seams. All three processes have been used for decades, albeit not with the purpose of storing CO_2. Further development is needed, especially on the capture and storage of CO_2.

CO_2 can be captured either before or after combustion using a range of existing and emerging technologies. In conventional processes, CO_2 is captured from the flue gases produced during combustion (post-combustion capture). It is also possible to convert the hydrocarbon fuel into CO_2 and hydrogen, remove the CO_2 from the fuel gas and combust the hydrogen (pre-combustion capture).

CO_2 capture is most effective when used in combination with large-scale, high-efficiency power plants. For coal-fired plants, integrated gasification combined cycles fitted with physical absorption technology to capture CO_2 at the pre-combustion stage is considered to be promising. Coal-fired ultra supercritical steam cycles fitted with post-combustion capture technologies or various types of oxyfuelling technology (including chemical looping, where the oxygen is supplied through a chemical reaction), may emerge as alternatives. For natural gas-fired plants, oxyfuelling (including chemical looping), pre-combustion gas shifting and physical absorption in combination with hydrogen turbines, or post-combustion chemical absorption are promising options.

The prospects of CCS is discussed in IEA (2004).

Fuel cells

Fuels cells convert hydrogen, light hydrocarbons, or carbon monoxide directly into electricity via a thermochemical reaction much like a battery or "cell". The positive and negative electrodes of the cell are separate by an electrolyte (either liquid or solid) which carry the positive or negatively charged ions between the electrodes. The fuel cell reacts the hydrogen with oxygen from the air to produce electricity in the form of direct current and water. In some fuel cell designs, the exhaust 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.

Hydrogen in a fuel cell acts as the energy carrier and must be derived from an energy source. Hydrogen can be extracted from hydrocarbon fuels using a process known as reforming and from water by electrolysis using electricity from fossil or renewable fuels. While the use of fossil fuels releases CO_2 emissions into the atmosphere, expected improvements in the efficiency of fuel cells will result in much lower emissions compared to conventional coal or gas plants. Moreover, the CO_2 released is in concentrated form, which makes its capture and sequestration much easier.

A major advantage of fuel cells is their flexibility. They come in different sizes, from a few watts for specific applications to many megawatts, suitable for larger-scale electricity generation. Factors that limit their use now are their high capital cost compared to conventional alternatives, their relatively unproven status and limited commercialisation, and the fuel choice for hydrogen production and its cost.

There are many fuel cell technologies suitable for power generation, but the most prominent are:

- **Phosphoric acid fuel cells**: These were the first fuel cells to be commercialised, with more than 200 units in operation worldwide. Phosphoric acid fuel cells use liquid phosphoric acid as the electrolyte and operate at temperatures between 150°C and 200°C. Their electricity generation efficiency is relatively low, around 40% or less. If used in combined heat and power (CHP) mode, the efficiency can rise to 80%. Hydrogen comes from an external source, typically natural gas. These fuel cells now cost around 4 000 USD/kW. Because of their low efficiency, these systems are likely to be replaced in the future by more advanced technologies, offering much higher efficiencies.

- **Molten carbonate fuel cells**: These fuel cells use lithium-potassium carbonate salts, which are heated to around 650°C to conduct the ions to the electrodes. Because of this higher operating temperature, molten carbonate fuel cells can achieve much higher electricity-generating efficiencies, approaching 60%. The total efficiency can approach 85% if they produce heat along with electricity. The reform process takes place inside the cell, which eliminates the need for an external reformer and therefore reduces costs. Another advantage is that the electrodes can be made of nickel, which is cheaper than the platinum used in phosphoric acid systems. The main disadvantages are related to the durability of the stack, which is the electricity production unit of the fuel cell. Commercially available molten carbonate fuel cells are expected to have a stack lifetime of five years with 25 years for the balance of plant.

- **Solid oxide fuel cells**: These fuel cells use ceramic materials, which can achieve very high operating temperatures, reaching 1 000°C. The electricity-generating efficiency of these fuel cells can reach 50% and, combined with a gas turbine, efficiencies can reach 60% to 70%. The conversion of fuel to hydrogen takes place inside the cell. The use of solid materials is advantageous because it avoids electrolyte leakage and offers greater stability. The high operating temperature requires costly ceramic materials. Research is continuing to produce materials that would reduce costs. There are several projects at the demonstration stage.

- **Proton exchange membrane fuel cells**: These fuel cells, which use a polymer membrane as an electrolyte, operate at relatively low temperatures and are the leading choice for transportation applications. Consequently, significant investment is taking place to improve the performance of this technology and reduce its costs. It is also the preferred fuel cell technology for small stationary applications. Early field trials for power generation estimate efficiency of around 34%.

Current applications for fuel cells are mainly as a source of backup power for power users, taking advantage of high reliability, quiet operation and very low emissions. The major challenge facing fuel cells is their high initial cost compared to more conventional technologies. The development of less costly materials will help reduce costs. The conversion of fuel to hydrogen inside the cell will also lower costs. Moreover, higher operating temperatures allow for the exhaust heat to be used for space heating, water heating or additional power production.

Nuclear power plants

The nuclear power plants for which cost estimates are reported in the present study are based on water reactors including pressurised water reactors (PWRs or VVERs), boiling water reactors (BWRs) and pressurised heavy water reactors (PHWRs). The cost estimates provided by the United States are based on paper studies referring to a generic advanced light water reactor (ALWR).

At present, light water reactors (LWRs) represent more than 85% of the nuclear capacity in operation world wide (around 66% for PWRs, including VVERs, and 22% for BWRs) and more than 80% of the capacity under construction. PHWRs represent nearly 5% of the installed capacity in the world and some 10% of the capacity under construction. The remaining reactors in operation and under construction are based on various other designs.

Water-cooled nuclear power plants

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.

Light water reactors 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% in ^{235}U while natural uranium contains 0.71% 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 30% of total fuel cycle cost (NEA, 2002), fuel cycle costs are lower for PHWRs 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 (once-through cycle); and reprocessing (closed cycle). 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 separated into materials that can be used again in reactor fuel and waste material (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 provided cost estimates for closed cycle, i.e. with reprocessing of spent fuel and recycling of fissile materials.

Advanced reactor designs

New generations of nuclear power plants are being developed building upon the experience acquired through the commissioning and operation of existing units. Advanced nuclear power plant designs share common goals: improved economic competitiveness; enhanced safety; better use of natural resources; and strengthened security and proliferation resistance. Advanced designs pertain to two main categories: evolutionary and innovative (IAEA, 2004). Evolutionary designs, such as the Korean standard nuclear power plant (KSNP) and European pressurised water reactor (EPR), achieve improvements through relatively modest modifications, maintaining strong reliance on a proven design to minimise technological risks. Innovative designs, on the other hand, incorporate radical conceptual changes requiring extensive R&D programmes, including in most cases the construction and operation of a prototype or demonstration plant to demonstrate industrial feasibility.

Several nuclear power plants already commissioned, under construction, ordered or planned pertain to the evolutionary advanced design category. Examples are the Kashiwasaki Kariwa units 6 and 7 ABWR in operation in Japan, the Olkiluoto-3 EPR under construction in Finland, the Sin-Kori units 1 and 2 (KSNP) being implemented in the Republic of Korea and the EPR project in France. Most of the units for which cost estimates were provided for the present study fall within the category of evolutionary advanced reactors.

Advanced light water reactors under development cover a large range of capacity from less than 100 MWe to more than 1 500 MWe. Some examples of large size advanced LWR designs, beyond those already in operation or under construction mentioned above, include the ABWR, the BWR 90+, the simplified BWR (ESBWR), the AP-1000 and the VVER-1000/V-392. Small- and medium-size advanced LWR under development include AP-600, VVER-640/V-407, IRIS and SMART (IAEA, 2004). Advanced heavy water reactors are developed mainly in Canada, building upon the experience acquired through the operation of existing CANDU reactors.

The development of advanced reactors is not limited to water reactors. Gas-cooled reactors are attracting increasing interest, in particular in the context of hydrogen economy, in the light of their capabilities to deliver very high temperature heat. A significant effort is devoted to the small-size, modular pebble bed reactor PBMR and, for the longer term, the Generation IV International Forum (GIF, 2002) has selected two high temperature concepts – the gas fast reactor and the very high-temperature reactor – for further R&D efforts in an international context. Liquid metal-cooled fast reactors have been under development for many years in several countries and continue to be the focus of some efforts in particular in Japan and in the context of GIF. Other innovative designs under investigation at present include the supercritical water reactor, the molten salt reactor and a number of accelerator-driven systems aiming at enhance management of actinides.

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 improved construction methods, reduced construction time, design improvement, standardisation, placing series orders, building multiple units on the same site and improving project management (NEA, 2000). 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.

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.

Internal-combustion engines

Internal-combustion engines are used extensively in electricity generation in sizes ranging from a few kilowatts to over 60 MW. Because they have pistons that employ a back-and-forth motion, they are also classified as reciprocating engines. Reciprocating engine technology has improved dramatically over the past three decades, driven by economic and environmental pressures for power density improvements (more output per unit of engine displacement), increased fuel efficiency and reduced emissions.

There are two basic types of reciprocating engines – spark ignition (SI) and compression ignition (CI). Spark ignition engines for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or landfill gas. Compression ignition engines (often called diesel engines) operate on diesel fuel or heavy oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel.

Diesel engines have historically been the most popular type of reciprocating engine for both small and large power generation applications. However, in most industrialised nations, diesel engines are increasingly restricted to emergency standby or limited duty-cycle service because of air emission concerns. Consequently, the natural gas-fuelled SI engine is now the engine of choice for the higher-duty-cycle stationary power market (over 500 hr/yr) and is nowadays the primary focus of the electricity market.

Diesel engines

Compression ignition (diesel) engines are among the most efficient simple-cycle power generation options on the market. Efficiency levels increase with engine size and range from about 30% (HHV) for small high-speed diesels up to 42 to 48% (HHV) for the large bore, slow speed engines. By 2006, it is expected that efficiencies will improve to a maximum of 52% (HHV). High-speed diesel engines (1 200 rpm) are available up to about 4 MW in size. Low speed diesels (60 to 275 rpm) are available as large as 65 MW.

Natural gas spark ignition engines

Spark ignition engines use spark plugs, with a high intensity spark of timed duration, to ignite a compressed fuel-air mixture within the cylinder. Natural gas is the predominant spark ignition engine fuel used in electric generation and CHP applications. Other gaseous and volatile liquid fuels, ranging from landfill gas to propane to gasoline, can be used with the proper fuel system, engine compression ratio and tuning.

Natural gas spark ignition engine efficiencies are typically lower than diesel engines because of their lower compression ratios. However, large, high performance lean burn engine efficiencies approach those of diesel engines of the same size.

Hydro power

Hydro power plants vary enormously in size, from fractions of megawatts for some microhydro facilities to thousands of megawatts. Most of the hydro power plants included in this report are "small" hydro facilities (typically less than 10 MW).

The main criteria for a hydro power installation are elevation and depth. From an elevated head, either natural or artificial, water can be diverted through a headrace (tunnel or tube) into a turbine coupled to a generator that converts the kinetic energy of falling water into electricity. The water is then discharged through a tailrace, usually through a tunnel or canal, back into the river at a lower level.

The natural factors which affect hydro power potential are the quantity of water flow and the height of the head. Flow roughly relates to average annual precipitation and the head depends, basically, on topography. The theoretical power capacity in a flow of water (Q cubic metre per second) is the flow of the water times the height or head (H) the water can fall. In reality, losses due to imperfections in the design of machinery and waterways have to be considered in every hydro power system. Internal friction in pipelines and channels as water travels towards the turbine causes a loss of potential energy in the system.

Hydro power plants can generally be divided into three different categories depending on the type of head and the nature of the plant:

- High-head power plants are the most common and generally include a dam to store water at a higher elevation. These systems are commonly used in mountainous areas.
- Low-head hydroelectric plants generally use heads up to a few metres in elevation or simply function on the run of the river. Low-head systems are typically built along rivers.
- Multipurpose hydro power systems are generating facilities where the hydro power is subordinate to other activities like irrigation, industrial processes, drinking water supply or wastewater disposal. Electricity production is thus not the only objective of the plant but often a useful by-product.

The value of the hydro power produced often depends very much on the firm power which can be produced, which in turn depends on the possibilities to store water in the reservoir by the hydro power plant or in upstream reservoirs.

Wind power

The main components of a wind turbine are the rotor, generator, directional system, protection system and tower. Wind spins the rotor blades, driving the turbine generator. Sometimes gearing is used to increase the rotation speed for electricity generation. The generator transforms the mechanical energy from the rotating blades into electricity. Electricity is then transferred to the grid. Generator designs vary according to the system and wind regime. A directional system enables horizontal axis machines to swing into the wind: a tail assembly is often used for small machines, whereas a "servo mechanism" orients large machines to the direction of maximum power. Modern wind turbines are usually equipped with a protection system (variable orientation of blades, mechanical brakes, shut-down mechanisms) to prevent damage during excessive wind loads. The tower raises the turbines well above the ground in order to capture wind with higher speed and less turbulent currents.

Commercial and technological development has been closely related to turbine size. From ten metres in diameter (typically with 22 kW to 35 kW of installed power) in the mid-1970s, wind turbines have grown to diameters of 80 metres and more (with multi-MW installed power). Technology development has resulted, furthermore, in variable pitch (as opposed to fixed blades), direct drives (as opposed to classical drive trains), variable-speed conversion systems, power electronics, better materials and better ratio of weight of materials to capacity installed. One major trend is toward increasing rotor diameter in order to develop turbines and wind farms for offshore applications. The other major trend is toward larger markets for small-sized systems, e.g. in developing countries. The use of small grid-connected machines (10 kW) in the built environment and farms in the United States is relatively new.

Up-scaling and cost reductions can be achieved by incremental changes and "up-scaled design" on the same platform or by building a new platform with increased capacity, rotor diameter and new technological features. Not surprisingly, the first machines of a new generation can be more expensive per kW of rated capacity but they later become more competitive, thanks to higher electrical output and increased experience and manufacturing volume.

R&D activities by government and industry have contributed to major design improvements and increased the techno-economic performance of wind turbines. The overall system efficiency of present commercial wind turbines is close to what is theoretically feasible. Such improvements to overall system efficiency have been achieved by greater aerodynamic efficiency of the rotor blades, the use of high-efficiency electric conversion systems and better matching of the wind turbine rating to the local wind regime.

Ex-factory cost reductions of 15% to 20% can be expected from a combination of the following features in advanced wind turbines:

- Reduction of loads through the use of flexible blades, flexible hubs and variable-speed generator systems. This leads to lower weights and lower machine cost;
- Reduction in the number of components;
- Improved materials featuring higher strength-to-mass ratios and better internal damping.

Specific R&D and design improvements are needed for offshore applications to cope with different challenges and to reduce costs, allowing for large-scale use. The number of components can be reduced by incorporating direct-drive generators, passive blade pitch control in combination with variable-speed drive trains and passive yaw combined with a rotator located downwind. The use of direct-drive generators and power electronics eliminates the need for a heavy and expensive gearbox, reduces noise emission and can improve power quality at the connection to the grid. Dedicated turbine types should be developed for a variety of areas with special wind conditions, e.g. inland locations with low wind speed, locations with high wind speed, high turbulence, cold climates (heated, ice-free components), and offshore.

Solar photovoltaic (PV) systems

Photovoltaic (PV) technology transforms the energy of solar photons into direct electric current using semiconductor materials. The basic unit is a photovoltaic or solar cell ("**PV cell**"). When photons enter the cell, electrons in the semiconductor material are freed, generating direct electric current (dc). Solar cells are made from a variety of materials and come in different designs. The most common semiconductor materials used in PV cell manufacturing are single-crystal silicon, amorphous silicon, polycrystalline silicon, cadmium telluride, copper indium diselenide, and gallium arsenide. The most important PV cell technologies are crystalline silicon and thin films, including amorphous silicon.

PV cells connected together and sealed with an encapsulant form a **PV module** or *panel*. PV modules come in standard sizes ranging from less than a watt to around 100 watts. When greater amounts of electricity production are required, a number of PV modules can be connected together to form an **array**.

The components needed to transform the output of a PV module into useful electricity are called "balance of system" (**BOS**). BOS elements can include inverters (which convert direct to alternate current), batteries and battery charge controllers, dc switchgear and array support structures depending on the use. A PV module or array and BOS form a **PV system**.

A PV cell converts only a portion of the sunlight that it receives into electrical energy. This fraction is the "efficiency" of the PV. Laboratory research has recently achieved efficiencies of 32%. In practice, efficiencies are lower.

Photovoltaic technology has a wide range of applications. The applications directly linked with electricity production are outlined below.

Stand-alone off-grid systems: These are PV systems that produce power independently of the utility grid. Using stand-alone photovoltaic systems can be less expensive than extending power lines and more cost-effective than other types of independent generation. Most of currently profitable applications are remote telecommunications systems, where reliability and low maintenance are the principal requirements. PVs also have wide application in developing countries, serving the substantial rural populations who do not otherwise have access to basic energy services. PVs can be used to provide electricity for a variety of applications in households, community lighting, small enterprises, agriculture, healthcare and water supply.

Grid-connected systems in buildings: Where a grid is available, a PV system can be connected to it. When more electricity than the PV system is generating is required, the need is automatically met by power from the grid. The owner of a grid-connected PV system may sell excess electricity production. Net metering rules can promote this.

Utility-scale systems: Large-scale photovoltaic power plants, consisting of many PV arrays installed together, can provide bulk electricity. Utilities can build PV plants faster than conventional power plants and can expand the size of the plant as demand increases.

PV technology and applications are characterised by their modularity – PV has been implemented on scales of tens of watts to multiple megawatts. The expected life span of PV systems is between 20 and

30 years. PV is a form of distributed generation, delivering power directly to the end-user, avoiding the costs of transmitting power over the network.

Trends in projected costs vary considerably for individual PV cell and module technologies but have common aspects: R&D and increased volume can contribute to substantial overall cost reductions in the areas of feedstock, device and cell efficiency, and manufacturing processing.

Although modules represent about 60% of grid-connected system costs, reducing the cost of balance of system components is also important for bringing down total system costs. For instance, the efficiency rate of common inverters in the range of 1.5-3.3 kW was between 85.5% and 90% in the years 1988 to 1990. Today their efficiency is above 90%, even for smaller units (100-200 W), and is often close to 95% for the most common models. Technical improvements are expected to increase efficiency and extend their lifetime to 15-20 years. Costs for inverters, in particular, could be reduced through higher manufacturing volumes.

Concentrating solar power systems

At present, concentrating solar power (CSP) technology can be exploited through three different systems: parabolic trough, parabolic dish and power tower. All the CSP technologies rely on four basic elements: concentrator, receiver, transport-storage and power conversion. The concentrator captures and concentrates direct solar radiation, which is then delivered to the receiver. The receiver absorbs the concentrated sunlight, transferring its heat energy to the power-conversion system. In some CSP plants, a portion of the thermal energy is stored for later use. The parabolic trough system, commonly known as the "solar farm", uses linear parabolic mirrors to reflect sunlight. The parabolic dish system, generally known as a "dish/engine" system, collects sunlight through a round parabolic solar collector. The "power tower" system employs heliostats (large sun-tracking, reflecting mirrors) to concentrate sunlight onto a central tower-mounted receiver.

Although parabolic trough plants are currently the most mature CSP technology, they still have considerable potential for improvement. Power towers, with potentially low-cost and more efficient thermal-storage, could offer dispatchable power from solar-only plants with a high annual capacity factor in the medium term.

Dish/engine systems will be used in smaller, high-value applications. In theory, power towers and parabolic dishes can achieve higher solar-to-electric efficiencies and lower costs than parabolic trough plants. Parabolic dish systems are the most efficient of all solar technologies, with currently about 25% solar-to-electricity efficiency. The 4-95 stirling power conversion unit (PCU) now holds the world's efficiency record for converting solar energy into grid-quality electricity, with almost 30% efficiency at 1 000 watts per square metre.

Because of their thermal nature, each of the CSP system technologies can be "hybridised", or operated in combination with conventional fossil fuels. Hybridisation has the potential to dramatically augment the usefulness of CSP technology by increasing its dispatchability, improving its performance by making more effective use of power generation equipment, and reducing technological risk by using conventional fuel when needed.

Hybridisation efforts are currently focused mainly on the parabolic trough, but the learning from these studies may be transferred to the other types of systems. The integrated solar combined-cycle system (ISCCS) design offers a number of potential advantages to both the solar plant and the combined cycle plant. For power tower systems, hybridisations are possible with natural gas combined-cycle and coal-fired or oil-fired Rankine plants. Initial commercial-scale power towers will likely be hybridised with conventional fossil-fired plants. Because dish/engine systems use heat engines, they have an inherent ability to operate on fossil fuels. However, hybridisation for dish/engine systems is still a technological challenge.

Combustible renewables

Combustible renewable energy refers to the combustion of biological materials to produce useful heat and/or electricity. Combustible renewable energy is mainly used for heat production, but also in combined heat and power plants (CHP), and can be used and stored in different forms (solid, liquid, gaseous). Biomass energy conversion has both positive and negative environmental impacts: burning of organic and fossil material emits harmful gasses, while the disposal of agricultural and other organic waste utilises otherwise worthless material for energy and generates CO_2 neutral energy. Biomass differs from other renewables in that it links the farming and forestry industries, which provide the various feedstocks, to power generation, which utilises the converted fuels. The inclusion of municipal solid waste (MSW) as a feedstock further complicates this analysis, as the use of the solid waste is a substitute for other means of waste disposal. By contrast, useful biogas can also be extracted from waste treatment facilities that can be used to generate electricity.

The logistical chain and the economics of a biomass system depend entirely on both the location (e.g. climate, soil, crop) and the conversion technology. The economics are very site-specific. Biomass resources tend to be available in rural areas – with the exception of municipal and industrial wastes.

Conversion

Combustion is the most widely-used type of biomass-derived energy conversion. The burning of biomass produces heat and/or steam for immediate cooking, space heating and industrial processes, or for indirect electricity generation via a steam driven turbine. Most of today's biopower plants are direct-fired systems – the higher the steam temperature and pressure, the greater the efficiency of the overall plant. While steam generation technology is very dependable, its efficiency is limited. Bioenergy power boilers are typically in the 20-50 MW range, compared to coal-fired plants in the 100-1 500 MW range. The small-capacity plants tend to have lower efficiency because of economic trade-offs: efficiency-enhancing equipment cannot pay for itself in small plants. Although techniques exist to boost biomass steam generation efficiency above 40%, plant efficiencies today are typically in the 20% range.

Co-firing refers to the combustion of biomass with a fossil fuel in an existing power plant furnace. Often, the biomass is chipped wood that is added to the feed coal (wood being 5-15% of the total) and combusted to produce steam in a coal power plant. Co-firing is well developed in the United States but is still undergoing research as electricity companies examine the effect of adding biomass to coal, in terms of specific power plant performance and potential problems. Because much of the existing power plant equipment can be used without major modifications, co-firing is far less expensive than building a new biopower plant. Compared to the coal it replaces, biomass produces no additional CO_2, less sulphur dioxide (SO_2), nitrogen oxides (NO_x) and other air emissions. After "tuning" the boiler for peak performance, there is little or no loss in efficiency from adding biomass. This allows the energy in biomass to be converted to electricity with the high efficiency of a modern coal-fired power plant.

Pyrolysis is the process of decomposition at elevated temperatures (300-700°C) in the absence of oxygen. Products from pyrolysis can be solid (char, charcoal), liquids (pyrolysis oils) or a mix of combustible gases. Pyrolysis has been practised for centuries, e.g. the production of charcoal through carbonisation. Like crude oil, pyrolitic, or "bio-oil", can be easily transported and refined into a number of distinct products. Recently, the production of bio-oil has received increased attention because it has higher energy density than solid biomass and is easier to handle. Bio-oil yields of up to 80% by weight may be obtained by the process of fast or flash pyrolysis at moderate reaction temperatures, whereas slow pyrolysis produces more charcoal (35% to 40%) than bio-oil. A main advantage (with respect to energy density, transport, emissions, etc.) of fast pyrolysis is that fuel production is separated from power generation.

Gasification is a form of pyrolysis carried out with more air and at higher temperatures in order to optimise the gas production. The resulting gas is more versatile than the original solid biomass. The gas can be burnt to produce process heat and steam or used in internal combustion engines or gas turbines to produce electricity. It can even be used as a vehicle fuel. Biomass gasification is the latest generation of biomass energy conversion processes and offers advantages over direct burning. In techno-economic terms, the gas can be used in more efficient combined-cycle power generation systems, which combine gas turbines and steam turbines to produce electricity. The conversion process – heat to power – takes place at a higher temperature than in the steam cycle, making advanced conversion processes thermodynamically more efficient. In environmental terms, the biogas can be cleaned and filtered to remove problematic chemical components.

Anaerobic digestion (AD) is a biological process by which organic wastes are converted to biogas – usually a mixture of methane (40% to 75%) and carbon dioxide. The process is based on the breakdown of the organic macromolecules of biomass by naturally-occurring bacteria. This bioconversion takes place in the absence of air, thus anaerobic, in digesters, i.e. sealed containers, offering ideal conditions for the bacteria to ferment ("digest") the organic feedstock to produce biogas. The result is biogas and co-products consisting of an undigested residue (sludge) and various water soluble substances. Anaerobic digestion is a well-established technology for waste treatment. Biogas can be used to generate heat and electricity through gas, diesel or "dual fuel" engines at capacities of up to 10 MW. About 80% of industrialised global biogas production stems from commercially exploited landfills. The methane gas produced at landfills ("**landfill gas**") can be extracted from existing landfills by inserting perforated pipes through which the gas travels under natural pressure. If not captured, this methane would eventually escape into the atmosphere as a greenhouse gas. Another common way of producing biogas by AD is by using animal manure. Manure and water are stirred and warmed inside an air-tight container ("**digester**"). Digesters range in size from around 1 m^3 for a small household unit to as large as 2 000 m^3 for a large commercial installation.

Geothermal

Geothermal technology depends on the type and location of the natural resource. Since it is not practical to transport high-temperature steam over long distances by pipeline due to heat losses, most geothermal plants are built close to the resource. A geothermal system consists of three main elements: a heat source, a reservoir and a fluid – the last being the carrier for transferring heat from the source to the power plant. The heat source can be either a very-high-temperature (> 600°C) magmatic intrusion that has reached relatively shallow depths (5 to 10 km) or, as in certain low temperature systems, the Earth's normal temperature, which increases with depth. The heat source is natural, whereas the fluid and the reservoir can be introduced to the subterranean media by the project.

Geothermal power plants tend to be in the 20 MW to 60 MW range and the capacity of a single geothermal well usually ranges from 4 MW to 10 MW. Typical minimum well spacing of 200 m to 300 m is established to avoid interference. Three power plant technologies are being used to convert hydrothermal fluids to electricity. The type of conversion depends on the state of the fluid (steam or water) and on its temperature:

- **Dry steam power plants** use hydrothermal fluids primarily in the form of steam. The steam goes directly to a turbine, which drives a generator that produces electricity. This is the oldest type of geothermal power plant and was originally used at Larderello in 1904. This steam technology is still very effective and is used today at The Geysers in Northern California, the world's largest geothermal field.

- **Flash steam power plants** use hydrothermal fluids above 175°C. The fluid is sprayed into a tank (separator) held at a much lower pressure than the fluid, causing some of the fluid to vaporise rapidly, or "flash" to steam. The steam then drives a turbine.
- **Binary-cycle power plants** use hot geothermal fluid (below 175°C) and a secondary (hence, "binary") fluid with a much lower boiling point than water – both passing through a heat exchanger. Heat from the geothermal fluid causes the secondary fluid to flash to steam, which then drives the turbines. Because this is a closed-loop system, virtually no emissions are released into the atmosphere. Since binary-cycle generation system makes moderate-temperature geothermal fluids usable for power generation, many binary-cycle plants will be constructed in the future.

The total energy efficiency is 97% for CHP but only up to 7-10% for electricity production. Because geothermal power plants operate at relatively low temperatures compared to other power plants, they eject as much as 90% of the heat extracted from the ground into the environment. The minimum temperature for electricity generation is 90°C. The lowest-temperature commercial geothermal power plant in the United States has a resource temperature of 104°C. Below this critical temperature threshold, the required size of the heat exchanger would render the project uneconomical. The efficiency of conversion from heat to electricity drops to 2% for fluids at 85°C.

Despite the relatively low efficiency in power generation, geothermal has several positive features. Geothermal electric plants can operate 24 hours per day and thus provide base-load capacity. The power generation is not intermittent except for some seasonal differences in cycle efficiencies because, in winter, heat is rejected to a lower sink temperature and thus the plant output is higher. This is especially true for air-cooled plants.

A relatively new concept in geothermal power is hot dry rock (HDR), also known as hot wet rock (HWR), hot fractured rock (HFR) and enhanced geothermal systems (EGS). The basic concept is to increase the permeability of the natural fractures of the basement rocks, install a multi-well system, force the water to migrate through the fracture system ("reservoir") by using enhanced pumping and lifting devices and, finally, use the heat for power production. HDR is expected to contribute to further geothermal development in the decades to come.

Distributed generation

Distributed generation (DG) refers to the production of electric power at an electricity consumer's site or at a local distribution utility substation and the supply of that power directly to the on-site consumers or to other consumers through a distribution network. DG technologies include electric power generation by engines, small turbines, fuel cells and photovoltaic systems and other small renewable generation technologies such as small hydro or small wind systems. The economic characteristics of distributed generation are described further in IEA (2002).

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Cost Estimation Methodology

The adoption of a standardised methodology for cost calculations is a prerequisite for a fair comparison between different electricity generation options. This appendix describes the methodology adopted for calculating generation costs in the present report as well as in previous studies in this series on projected costs of generating electricity that have been carried out periodically by the OECD Nuclear Energy Agency (NEA) and the International Energy Agency (IEA), in co-operation with the International Atomic Energy Agency (IAEA).

This appendix explains the rationale for 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 hat might be chosen in different applications. More details on the methodology and its application may be found in the literature references provided in the bibliography. Other approaches may be used for economic assessment in various contexts to reflect the criteria and priorities of different economic actors. Appendix 6 addresses methodological issues raised by incorporating investment risk into generation costs in the context of market liberalisation.

The methodology adopted in the study allows calculating electricity generation costs on the basis of net power supplied to the station busbar, where electricity is fed to the grid. It is relevant to compare single units but may not reflect the full economic impact of a new power plant when it is connected to the grid within an existing electricity system. Therefore, it does not substitute for the full system cost analysis which compares alternative options to be introduced into a network. The system approach requires a model describing the existing system including its different power plants and assumptions – which might be derived from another model – on electricity demand pattern (load duration curves) and projected growth. It is relevant from the producer viewpoint to estimate the cost of an addition to the system but 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 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 annum discount rates, a range representative of the values adopted in most national responses to the questionnaire upon which are based the costs presented in this report.

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:

$$EGC = \Sigma\, [(I_t + M_t + F_t)\,(1+r)^{-t}] \,/\, \Sigma\, [E_t\,(1+r)^{-t}]$$

With:
- EGC = Average lifetime levelised electricity generation cost
- I_t = Investment expenditures in the year t
- M_t = Operations 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

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.

The coverage of capital, O&M and fuel costs is described in the main body of the report. In the context of the studies in the series, all the components of the capital, O&M and fuel costs falling on the utility that would, therefore, influence its choice of generation options are taken into account. For example, station specific overheads, insurance premium 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. In the other hand, tax on income and profit charged to the utility and any other overheads that do not influence the choice of technology are excluded. External costs that are not borne by the utility, such as costs associated with health and environmental impacts of residual emissions, are excluded also.

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 of the expenditures occur in multiple instances during the course of the year, rather than one single event, annual costs 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 capacity/load factor.

The levelised lifetime cost per kWh of electricity generated is the ratio of total lifetime expenses versus total expected outputs, expressed in terms of present value equivalent. This cost is 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.

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 the year of commissioning, generally 2010.

Generally, levelised cost estimations are carried out in constant money, i.e. in real value, and inflation is not taken into account in cost elements. Nevertheless, projected price escalation or decrease is taken into account in the real price of goods or services such as fossil fuels or staff salaries (within O&M costs), when applicable.

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. The cost data for the studies in the series are provided by participating experts in national currency unit (NCU), in principle of the reference date, i.e. for the present study of 1 July 2003. The levelised generation costs are calculated, for each country, in national currency unit and then converted into USD, using the official exchange rates prevailing at the date of reference, as published by the OECD and the IMF.

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Methodologies Incorporating Risk into Generating Cost Estimates

Introduction

Prior to the liberalisation of energy markets, energy firms were able to operate as integrated monopolies. They were able to pass on all costs of investments to energy consumers. For example, in the electric power sector, utilities could expect the cost of their prudently incurred investments in power generation, including an adequate rate of return, to be recovered from consumers. Many firms were state-owned and could borrow money backed implicitly or explicitly by the government's guarantee. In view of that guaranteed rate of return, utilities could finance their investment with a low share of equity and borrow at interest rates close to government debt yields. There was no market risk. The main risk was the risk of unfavourable regulatory decisions and cost overruns due to bad project management. Overinvestment could be accommodated as excess reserve margin since excess capacity did not create a reduction in electricity prices.

In such an environment, most of the risks associated with such investments were not directly a concern of the energy company. Increased costs, if demonstrated to be prudently incurred, could be passed on as increased prices. If the utility were able to borrow against the state guarantee, then the taxpayers were ultimately responsible if sufficient money could not be raised by raising power prices. In other words, it was not that risks did not exist in this situation, but merely that risks were transferred from investors to consumers and/or taxpayers. In this situation, there was little incentive for companies to take account of such risks when making investment decisions.

The introduction of liberalisation in energy markets is removing the regulatory risk shield. Investors now have additional risks to consider and manage. For example, generators are no longer guaranteed the ability to recover all costs from power consumers. Nor is the future power price level known.

Investors now have to internalise these risks into their investment decision making. The issue of interest here is how the internalisation of risks affects not only the profits required but the choices of generating technology. This appendix reviews how risks differ in the different technologies, and looks at new techniques for quantification of such risks.

Power generation investment risks in the liberalised market

Investment in power generation comprises a large and diverse set of risks. Business risks include:

- Economy-wide factors that affect the demand for electricity and availability of labour and capital.
- Factors under the control of the policy makers, such as regulatory (economic and non-economic) and political risks, with possible implications for costs, financing conditions and on earnings.

- Factors under the control of the company, such as the size and diversity of its investment programme, the choice and diversity of generation technologies, control of costs during construction and operation.
- The price and volume risks in the electricity market.
- Fuel price and, to a lesser extent, availability risks.
- Financial risks arise from the financing of investment. They can to some extent be mitigated by the capital structure of the company.[1]

The level of risk anticipated by an investor in a power plant will be reflected in the level of return expected on that investment. The greater the business and financial risks, the higher the return that will be demanded.

The most fundamental change affecting the value of investments in liberalised markets is the inherent uncertainty about electricity prices in electricity markets. The uncertain future level of prices from investment in generation creates a risk for the investor. While this risk affects all generating technologies, it does so in different ways.[2] Technologies which have a higher specific investment for capacity even though they may have relatively low fuel costs may be more greatly affected by this risk because of the relative importance of this risk to the total cost. Thus, although high capital cost and low fuel cost technologies will likely be short-run competitive and therefore produce electricity, they will be more exposed to cover capital employed.

High fuel cost options will be affected differently. Higher fuel costs mean a smaller margin over which the plant can make profits. A decrease in electricity price means that in relative terms, plant profits will be more volatile than for a low fuel cost option. However, since the share of capital cost is relatively low this profit volatility has a smaller impact on overall costs. Furthermore, high fuel cost technologies can respond by reducing output during hours in which the electricity has a price below its short-run marginal cost.[3]

Uncertain electricity prices also expose projects that have a long lead and construction time to additional risks. Economies of scale favour large power projects over small ones as capital costs per kW for a given technology generally decrease with increasing scale, or at least appear to do so. However, the combination of a long lead time, uncertain growth in demand for electricity and price, and uncertainty in the total cost of financing construction increase risks for larger projects. Furthermore, very large projects that must effectively be built as a single large plant (e.g. a very large hydro dam) are more vulnerable to this type of risk than projects for which development can be phased in as several smaller power plants in response to market conditions.

While uncertainty about prices elevates risks more for capital-intensive investments, fuel price risks are far more significant for technologies where fuel costs are a high proportion of total generating costs. Natural gas technologies are particularly sensitive to fuel prices and price volatility, as fuel costs tend to constitute the majority of generating costs.

Uncertainty in future natural gas prices is increased by the liberalisation of the natural gas market. Long-term contracts for the supply of natural gas for power generation are less common. High volatility of natural gas prices also will tend to increase short-term risks associated with natural gas. If rises in natural gas prices accompany falls in electricity prices, and the generator has not financed the project in recognition of this risk, the financial distress for natural gas power generators can be severe.

1. IEA, 1994.
2. Renewable energy technologies, for example, are favoured by long-term contracts at fixed prices, this significantly reduces this risk compared to technologies that would need to take an uncertain market price.
3. This point is analysed in more detail later in this appendix. See the section entitled "Uncertainty in revenues".

The situation for investors is further complicated by the outlook for resource availability and cost. Although sufficient economic resources exist for natural gas and other fuels used in power generation,[4] sufficient investment is needed in infrastructure to produce and transport fuels to power plants. Indeed, the IEA estimates that an investment in a natural gas-fired power plant must be matched by an upstream investment in gas production and transportation of the same magnitude.[5] A further consideration is the source of the future gas supplies. The source of natural gas supplies is expected to shift strongly over the next 30 years, resulting in a quadrupling of OECD natural gas import volumes, and increased reliance on production from outside the OECD.[6] While resource rents from the development of existing domestic natural gas resources or from gas imports from IEA countries have been relatively predictable, possible rent-seeking by non-IEA gas-producing countries may add uncertainty in the future.

The key question for an investor in fossil-fired power generation in an open market will be the level and development of the difference between the price of electricity and the cost of fuel used to produce it – the so-called "spark spread". The importance of the spark spread will depend on the type of power plant and how it is intended to be used. For base-load power plants, a relatively large favourable spark spread is desirable so that the plant can operate at all times to recover the specifically higher capital costs of such a plant over a large number of hours. For peaking load plants, with higher fuel costs, capital costs must be recouped over a smaller number of hours. Thus, peaking plant characteristics will favour a flexible generating plant that is able to take advantage whenever the spark spread is favourable. This requires not only technical flexibility to respond to changing prices but, in the case of natural gas, flexibility in starting and stopping gas offtakes in line with the spark spread.

The market rules themselves can be a source of risk and will affect different technologies differently. For example, changes in electricity market rules that put an opportunity cost on unreliability of output have affected the cost of wind power in the United Kingdom. Similarly, price signals that encourage more efficient use of the electricity grid will also favour technologies that can locate to take advantage of these incentives.

The costs of additional emissions controls, formerly passed directly on to consumers, must now also be considered as a risk to the profitability of power investments. Existing emissions controls on coal-fired plants include particulates and sulphur dioxide. Both coal and natural gas plants are covered by emissions controls on nitrogen oxides. However, future regulatory actions to lower allowable levels, or to introduce controls on other substances such as mercury, remain a risk for investors. Nuclear power plants are restricted in their emissions of radionuclides and may be subject to additional safety regulations.

Probably the greatest uncertainty for investors in new power plants will be controls on future carbon dioxide emissions. In the European Union, an emissions trading directive was issued in 2003, Directive 2003/87/EC. Canada has also indicated that they will use emissions trading to control emissions from large stationary sources of carbon dioxide (CO_2). The unknown value of carbon emissions permits and the mechanism chosen to allocate permits will become a very large and potentially critical uncertainty in power generation investment. This uncertainty will grow in the future, particularly as future restrictions on levels of carbon dioxide emissions beyond the first commitment period of the Kyoto Protocol are unknown. For investment in fossil-fired generation, the price of permits will directly affect the profitability of power plants. The price of the permit is also expected to have a strong influence on the price of electricity and will further increase uncertainty about future electricity prices.

The risks associated with gaining approval to construct a new power plant also differ by technology. The risk is lower and the time span for the approval process is usually shortest for gas-fired power plants

4. IEA, 2001.
5. IEA, 2003.
6. IEA, 2002b.

and small power plants. Although this risk already existed in regulated markets, the ability to pass through the approval costs to consumers is no longer automatic.

The important point for power generation is that the nature of the risks (the "risk profile") is different for different types of generation technology and fuels (Table A6.1). Thus, even when levelised costs are equivalent and technologies are commercially proven, different risk profiles of different technologies can influence the choice of power generation mix, the range of technologies offered, and the strategies for their development and operation.

Table A6.1 – Qualitative Comparison of Generic Features of Generating Technology

Technology	Unit size	Lead time	Capital cost/kW	Operating cost	Fuel prices	CO_2 emissions	Regulatory risk
CCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Medium	Medium	High	High
Nuclear	Very large	Long	High	Medium	Low	Nil	High
Hydro	Large	Long	Very high	Very low	Nil	Nil	High
Wind	Small	Short	High	Very low	Nil	Nil	Medium
Recip. engine	Small	Very short	Low	Low	High	Medium	Medium
Fuel cells	Small	Very short	Very high	Medium	High	Medium	Low
Photovoltaics	Very small	Very short	Very high	Very low	Nil	Nil	Low

Note: CO_2 emissions refer to emissions at the power plant only.

Gas-fired technologies have characteristics that should be favourable under these conditions. The relatively low capital cost, short lead time, standardised design and, for some technologies, flexibility in operation provide significant advantages to investors. On the other hand, natural gas price uncertainty remains a large risk to the investor.

Nuclear power plants, by contrast, have a relatively low proportion of fuel and operating costs but high capital cost. Furthermore, economies of scale have tended to favour very large plant (1 000 MW and above) resulting in a relatively large capital commitment to a single construction project and hence associated investment risk. Newer designs are more flexible with regard to operations which may change the perception of a favourable plant size. The potential economic advantages of building smaller, more modular nuclear plants are also being explored by some nuclear power plant designers.

Coal power projects have also tended to become more capital-intensive to take advantage of economies of scale, to meet tighter environmental standards more economically, and to improve fuel efficiency. As with nuclear plants, lead and construction times for coal-fired power plants can be long.

Hydro projects come in all scales. Larger ones demand substantial lead time and are exposed to considerable risks during the construction phase as the length of the project can be subject to delays. The cost of borrowing can also change and increase the cost of the project. Usually there is no borrowing available in accordance with the amortisation time of a hydro project. The prospects of further development of large scale hydro projects in developed countries are being exhausted for economic and environmental reasons. In some developing countries the large economic potential of hydro has not been fully developed because of the very substantial risk premium resulting from the high sovereign risk. Operations by contrast can be highly flexible and able to take advantage of market conditions to optimise profitability. Long-term shifts and variations in rainfall patterns, e.g. due to climate change, remain another risk factor.

Of other renewables, solar and wind capacity are also capital-intensive. These plants have some very attractive low-risk characteristics, including very short lead times, no fuel costs or emissions, and low operating costs (hence little effect should these costs escalate). However, the variability of output of wind power reduces the value of the power produced. On the other hand, the fact that solar electricity from photovoltaics is produced at the point of consumption and during daylight hours, when prices are generally higher, increases the value of its electricity.

Reciprocating engines and fuel cells are two distributed generation technologies that use fossil fuels. Like photovoltaics, these distributed generation technologies have very short lead times and can be installed directly at the site of an electricity consumer. Their flexibility of use means that they can be operated during hours when power prices are favourable.

The competitiveness of reciprocating engines is thus dependent on the cost of delivered electricity that the distributed technology replaces. When fuel prices are low and electricity prices high, owners of these distributed generation technologies can produce their own electricity and reduce purchases from the electricity market. Electricity consumers that own generation facilities thus have a kind of "physical hedge" on the marketplace that allows them to cap the prices they pay. Reciprocating engines are also portable, i.e. they can be sold and moved to another location.

Finally, but also quite significantly, investors will need to account for the effects of corporate tax on the profitability of investments (see box). Taxes on the profits earned by the project increase the profits required. Relatively capital-intensive technologies are thus more strongly affected.

The impact of corporate income taxes on financing investment

In the United States, firms are allowed to deduct interest costs (payments to debt-holders) as an expense when computing Federal income tax liabilities. However, for tax purposes, firms cannot deduct payments to shareholders from income as an expense. It can be shown that in a "perfect world" where payments to debt-holders and shareholder are treated the same for tax purposes, the discount rate, or the weighted average of the cost of debt and cost of equity, will not be affected by increasing the amount of debt. That is, the decrease caused by the increased use of low cost debt will just offset the increase caused by the increase in the cost of equity.[7] However, as just noted, in the United States there are differential tax benefits from using debt and equity capital, and because of this, up to a point, the risk (and tax) adjusted discount rate will fall as the amount of debt financing increases.

In short, the effects of debt financing on risk adjusted discount rates depends upon the nature of a country's tax laws. At least in the United States, up to some point, the overall discount rate will fall as the relative amount of debt financing increases. Increases in the debt component will cause risk to increase, and this will increase the cost of the equity component. However, this increase will be more than offset by reductions caused by the use of more tax beneficial debt capital.

Quantifying investment risks in power generation

While identifying investment risks in power generation may be straightforward, investors in power generation attempt to understand the relative importance of different risks by quantifying them where possible. For the more important risks, it will be prudent to adopt risk management strategies that can cost-effectively reduce exposure to such risks.

The levelised cost methodology, used in this study, has been a useful tool for investors and for overall economic analysis because it evaluated costs and energy production and discounted them to take account of the time value of money. It provided an objective basis on which to provide a comparison of different technologies, e.g. for base-load power generation. This approach reflected the reality of long-term financing, passing on costs to the (captive) customers, known technology paradigms, a predictable place in the merit order, a strong increase in consumption and a short build-up time for selling the output of a new plant.

7. This is essentially Modigliani and Miller's Propositions I and II.

The general approach remains useful for providing a comparison among power generation technologies. Power companies will apply this methodology based on an internal target for return on equity (the "hurdle rate") to make a decision whether to invest or not and to decide between different projects. To assess various risks, different scenarios or sensitivities will be calculated, which often give a good assessment of the risks involved.

However, in an electricity market, what matters to the investor is the profitability of the investment against the risk to the capital employed. Provided that the market is operating efficiently, the investors will make the choice of a generating technology that incorporates risks and is also the most economic choice available. Unfortunately, it is difficult for the levelised cost methodology to incorporate risks effectively. Thus it needs to be complemented by approaches that account for risks in future costs and revenues.

New financial techniques are becoming available that help quantify the impact of these risks on the costs of different options. Such assessments can help investors make better decisions. Investments with lower risk should have correspondingly lower "hurdle rates" for investment.

Choice of discount rates

The risk-adjusted discount rate can be viewed as a weighed average of the cost of funds obtained from shareholders ("cost of equity") and the cost of the monies borrowed from debt-holders ("cost of debt") with relative amounts of equity and debt being the respective weights. Since debt-holders have first claims on the assets of the firm in case of bankruptcy and their returns are fixed, the cost of debt will always be less than the cost of equity.[8] Thus, with everything else held constant, increases in the percentage of funds obtained from debt-holders will cause the discount rate to fall. (In other words, if the weights of the lower cost source of capital increase, the average will fall.) However, because of the leveraging effect just described, increases in the amount of debt financing will increase the variability of the cash flows, and thus the cost of equity capital will increase.

Increases in the amount of debt financing will, therefore, have two effects on the risk adjusted discount rate that work in opposite directions. Increases in debt financing will result in the substitution of relatively less expensive debt capital, and this will cause the discount rate (or weighted average cost of debt and equity capital) to decrease. However, the cost of the equity component will also increase, and this effect by itself will cause the discount rate to increase. Thus, the overall effect of increased debt financing on the discount rate will depend upon the relative size of these two effects.

Thus, as a point of departure, it is generally assumed that the project would be 100% equity financed, and the derivation of the discount rate would be based on that assumption. Then, any adjustments to the discount rate could be made for how the project will be financed.

To estimate the discount rate for the project assuming it is 100% equity financed, the most common practice is to add a project specific risk premium to the risk free rate of return.[9] Since governments seldom defaults on their bonds, the risk free rate of return is generally assumed to equal long term rates of return to government bonds. In the United States, in real terms over long time periods, the average rate of return to long term federal government bonds is about 3%. The estimation of risk premium is extremely complex and even a brief discussion of this issue is beyond the scope of this appendix. It should be noted

8. The cost of equity capital is the rate of return that the equity funds could have earned if they were invested in another project of equal risk in the market place. The estimation of this rate is discussed shortly.

9. The most common model used in this area is called the capital asset pricing model (CAPM) which assumes a linear relationship between the riskiness of a project and the rate of return that is earned. The riskiness is quantified by a parameter known as beta. A beta of 1 indicates that the project's risk is average and the required return is equal to the average return of the stock market.

that if the risk of the project in question is similar to the other ones undertaken by the firm, if the firm's common stock is traded on open markets, and if the past is a good predictor of the future, then in principle the risk premium can be estimated using published historical stock price data. If any one of these conditions is not valid, the entire effort becomes even more difficult.

In the case of the United States, it is possible to look at both the historical situation and to consider how to treat the impact of liberalisation of investment on the required rate of return. In particular, a financial analysis of US electric utility stock prices using data from the 1970s and 1980s when many utilities were constructing nuclear and coal-fired power plants reported results that implied that the average risk premium associated with electric utility investments was about 4%. About 50% of this risk premium was the result of leverage (the use of substantial amount of debt financing) with the remaining 2% resulting from the underlying risks of building and operating power plants. Thus, over the 1970-1984 time period, independent of financing issues, the discount rate for a typical utility investment project would have been about 5% (the 3% real risk free rate plus the 2% risk premium). This was in fact lower than the discount rate for typical US investments and reflected the fact that costs could in general to be passed on to consumers and that a large proportion of the investments were in relatively low risk projects, i.e. transmission and distribution.

However, in the more open electricity market environment, cost recovery is not guaranteed. The US Energy Information Administration (EIA) thus uses a different discount rate based on the stock prices of two industries whose "structure and size are an appropriate guide to the current and future utility industries." These two industries were airlines and telecommunication firms. EIA found that if the project was financed totally out of equity, the average risk premium using data from these two industries were about 7%. Thus, independent of financial issues, the discount rate used by EIA for evaluating utility investment were about 10% in real terms (the 3% risk free return plus the 7% risk premium.) In other words, EIA assumes that absent guaranteed cost and revenue recovery, building and operating any power plant is risky.

As is shown in the body of this report, the results are very sensitive to the assumed 5% and 10% discount rates that were used in the analysis. Again the discount rate depends upon the perceived risk of the project and under certain circumstances how it is financed. Since the analysis in this report abstracts from financing issues, the 5% discount rate is roughly consistent with the one that would be used to evaluate relatively low risk US utility investments made in a regulated environment. The 10% discount rate assumes that building and operating power plants is much more risky. Indeed, it is consistent with the one that would be used to evaluate relatively risky US airline or telecommunication investments. Note that the EIA assumes that risk of electric power plant investments in deregulated markets is comparable to investments in these two industries. Indeed, over the last few years a number of US firms building natural gas-fired power plants have been under financial duress implying that building power plants in deregulated markets is risky. The same has been true for a number of US airlines and telecommunication firms.

Technology specific discount rates

There are two basic reasons why different studies examining the economics of the same set of generating technologies might use different costs of capital. One of them deals solely with how the project is financed, and the other with differences in the underlying perceived risk of the project. These two issues are somewhat different. Thus, when making comparisons about discount rates, it is important to distinguish between differences in discount rates resulting from differing assumptions about the underlying risk of the project from those resulting from different financing assumptions.

One approach is to address different risks associated with different generating technologies by using different assumptions about how they can be financed. Technologies seen as financially risky may require a higher return on investment.

Two US economic analyses of nuclear power, one carried out at the Massachusetts Institute of Technology (the "MIT study")[10] and the second for the US Department of Energy (Near Term Deployment Group or NTDG)[11] attempt to correct for the additional risk involved with nuclear power investment in the United States. Both studies assumed that investors in nuclear power plants in the United States require higher returns on equity and a higher share of relatively costly equity in the capital investment for nuclear power investment compared to natural gas.

The analysis shows that inclusion of income tax also more heavily affects the more capital intensive technology. This observation has implications with respect to comparing the weighted average cost of capital used in various analyses of cost of generating electricity from various technologies.

The consequence of these analyses is to increase the weighted average cost of capital for nuclear power compared to natural gas. Table A6.2 shows the results for both analyses illustrating the impact of financing and tax on the weighted cost of capital for the two technologies. Although precise assumptions differ in the two cases, the financing effects alone raise the weighted cost of capital for nuclear power by around 2% as compared to natural gas. The impact of income taxes increases effective discount rates for both technologies, but increases the gap in discount rate for nuclear versus natural gas by a further 0.6%.

Table A6.2 – Comparative financial assumptions and effect on weighted average cost of capital for natural gas and nuclear power plants for two US studies (in %)

	DOE NTDG 2% inflation rate		MIT 3% inflation rate	
	Nuclear	Gas	Nuclear	Gas
Capital structure				
Equity share	40	30	50	40
Debt share	60	70	50	60
Return on equity	15	13	15	12
Interest on debt	10	9	8	8
Weighted average cost of capital (excluding tax)				
Nominal	12	10.2	11.5	9.6
Real	9.8	8	8.25	6.4
Income tax rate	35	35	38	38
Weighted average cost of capital (including tax)				
Nominal	15.2	12.3	16.1	12.5
Real	12.9	10.1	12.7	9.3

Source: DOE 2001, MIT 2003, Expert Group calculations.

The particular figures and the size of the gap between nuclear power and natural gas will vary by country given the different situation with regard to perceived risk of investment in different options and the cost of finance among other factors. For example, countries where perceived risks in nuclear power are lower might have a much smaller gap in the weighted cost of capital between the two options.

Furthermore, a particular firm might have rather different costs of capital. For example, a state-owned company borrowing on the sovereign guarantee with the costs of the power passed through to consumers

10. MIT, 2003.
11. DOE, 2001.

and with exemption from paying corporate income tax, would naturally change a particular firm's estimation of the cost of capital compared to that of a private firm raising capital from markets. However, it must be emphasised that access to cheaper capital does not reduce risks, but merely transfers these risks to others (e.g. the state or the power consumers). It is clear that neglecting to account of these risks may lead to different investment choices than those obtained in the market.

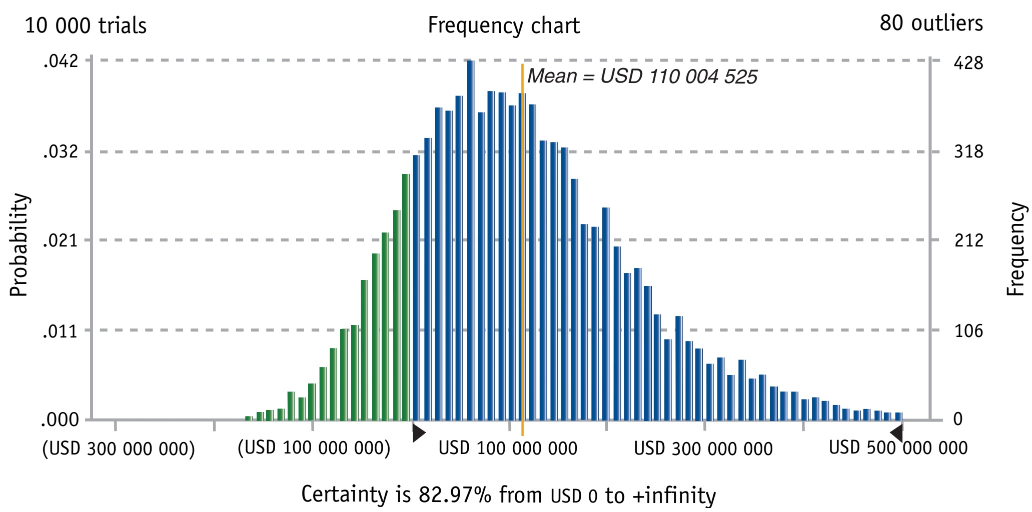
Uncertainty in fuel prices

The above technique illustrated the impact of risk on financing different technologies. But what about uncertainty in electricity prices and fuel costs. The latter is a critical consideration in investment in natural gas-fired power generation but not so critical for nuclear power where the share of fuel costs in total costs are much lower.

Dealing with the uncertainty in future fuel and electricity prices is very difficult to do. A standard approach is to simply use different price scenarios (e.g. high, medium and low prices) to incorporate the likely range of expected fuel prices. But this approach tends to neglect the role that the volatility of fuel (and power) prices can have on the profitability of an investment in power generation. Even when the average prices are known, the volatility of gas and power prices could have a large impact on the number of operating hours that a gas plant could operate profitably in a given year.

In this case, a Monte Carlo simulation was used to look at a wide range of uncertainties in key risks, e.g. natural gas costs and electricity prices. The resulting distribution of outputs gives both an expected value and a range of probabilities that an investment would be profitable. An analysis that assumes certain fuel and electricity prices yields a positive net present value. By contrast, a probabilistic assessment shows that the investment would stand about an 83% chance of being profitable over a 20-year period, given the forecast prices for electricity and natural gas and their uncertainty (Figure A6.1).

Figure A6.1 – Net present value (NPV) frequency range for CCGT investment



Source: Energy Information Administration.

Complicating matters further is the structure of volatility of the prices for natural gas, i.e., the fact that gas prices are highly volatile in the short run (where volatility reflects the rate of change of the uncertainty). If it is assumed that the greater the short-run volatility, the larger the long-term uncertainty in gas prices, corresponding to a "random walk", the impact of the uncertain fuel price on costs could be very important. The result, in effect, is that future fuel costs are discounted much less than in a conventional analysis (where they are discounted at the common discount rate). Some of the analyses that assume future prices follow a random walk based on short-run volatility show very large impacts of fuel price volatility on levelised generating costs for natural gas, coal and even nuclear power plants.

In the short term, fuel prices are sensitive to the supply and demand balance and have proven to be very volatile, a fact reflecting, among others, the relatively low short-term elasticity of demand for these commodities. In the long term, however, price movements are dictated by demand and supply fundamentals – e.g. when prices are high enough, new fuel supplies are added to pull prices back towards long-run marginal costs.[12] This phenomenon of "mean reversion" means that power prices – and costs of major components of those prices such as fuel costs – are less uncertain over the long term than implied by the short-term volatility.

Financial risk analysis of technologies must also take account of the different volume risk associated with different technologies. Hydro power and wind power output are subject to volume risk owing to natural variations in rainfall or wind speed respectively. Furthermore, depending on the market share of certain technologies these volume risks could be negatively correlated with price risk.

Uncertainty in revenues

Uncertainty in revenues also affects the investment decision. Electricity prices in power markets can be very volatile, though as with fuel prices, they can be expected to exhibit a mean-reverting behaviour over the longer term. Additionally, all power plants have unplanned, forced outputs, and in some cases, plants must be taken out of service for major repairs and retrofits. Thus, output is also uncertain. When evaluating the risk associated with uncertain prices/output and thus revenues, the structure of the operating costs – i.e. whether the bulk of the operating costs are fixed or variable – is important.

Looking first at output risk, nuclear power and most renewable technologies are relatively capital intensive, whereas others are fuel intensive. Since the bulk of the costs of a capital-intensive technology are fixed in the sense they would incurred regardless of the level of output, profits would be more sensitive to variations in output when compared to fuel intensive technologies. This is because fuel intensive technologies can reduce costs by reducing output. Therefore, with everything else being equal, the output risk would be greater for capital than for fuel intensive technologies, and this suggests that different discount rates might be used.

This point is illustrated in two Monte Carlo simulations of the economics of building and operating a hypothetical plant in a world where revenues are uncertain because output varies randomly.[13] In the first case, the firm can change total variable costs when there are unexpected changes in plant output (and/or demand). In the second simulation, all the operating costs are assumed to be fixed and thus, they will be incurred regardless of the level of plant output. Figure A6.2 shows the results of the first simulation where costs are variable. In particular, this figure is a plot of the relative frequency distribution of the net present value of the cash flows. That is, the Y-axis shows the relative frequency (fraction of the total number of observations) with present values as shown on the corresponding X axis.[14] Similarly, Figure A6.3 shows the relative frequency distribution when operating costs are fixed. In both cases, the average expected net present values of the cash flows are about 258 million USD. However, the variations in present value of the cash flows are greater when all the costs are fixed when compared to the case where some of the expenses are variable. Indeed, the standard deviation in the case when costs are fixed is roughly four times (59.7 million USD versus 15.5 million USD) the one when costs are variable.

12. See Frayer J. and Uludere N., 2001.

13. In this case, a triangular distribution was used to model the random variations in plant output. By assumption, the upper and lower bound capacity factors were 0.95 and 0.65 respectively, and the most likely value was 0.85.

14. The total number of observations was 10 000.

Figure A6.2 – Distribution of discounted net present values: output uncertain and all operating costs variable

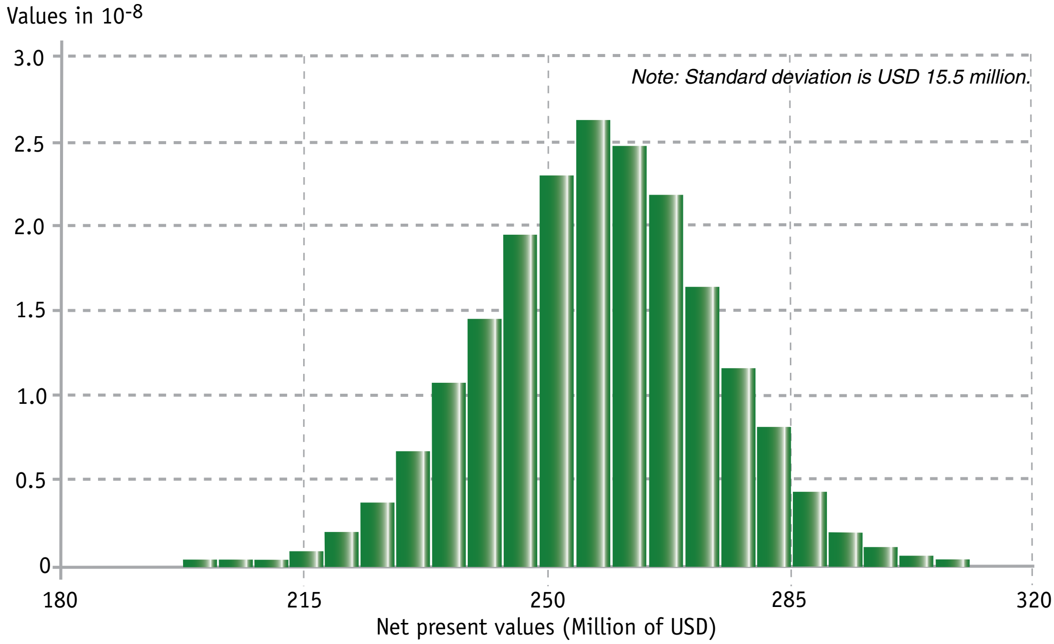
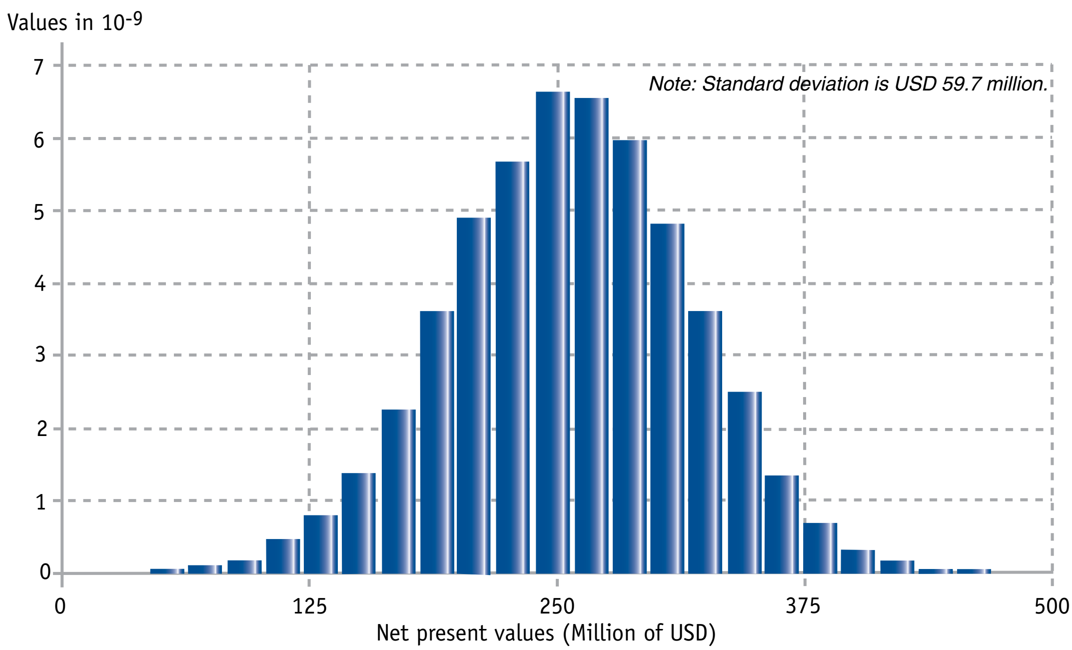


Figure A6.3 – Distribution of discounted net present values: output uncertain and all operating costs fixed

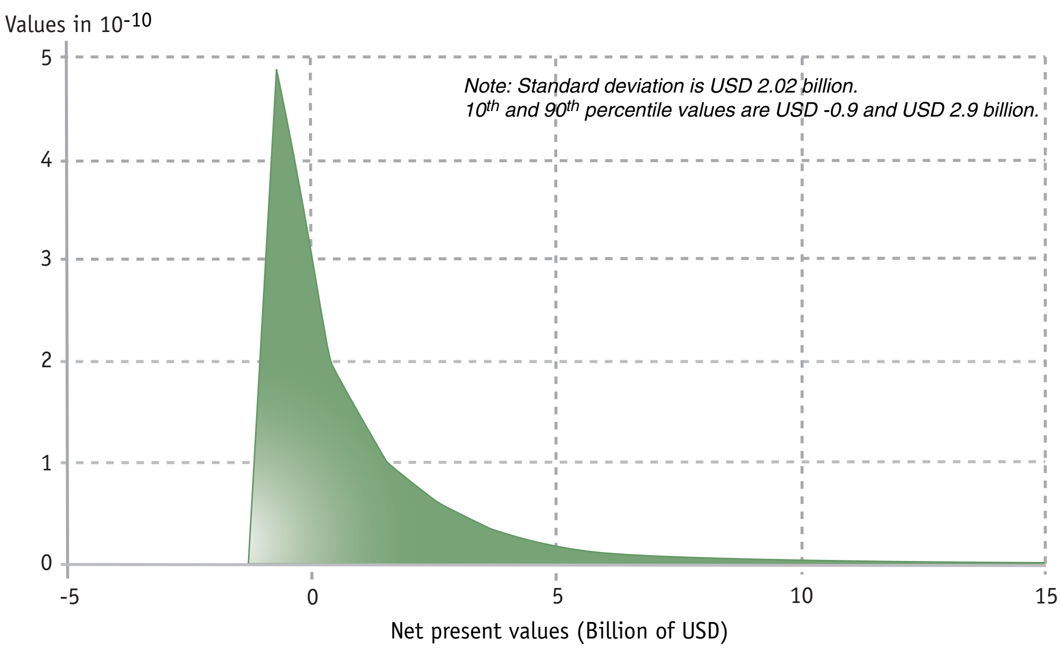


In other words, the ability to alter costs in a world where output is uncertain decreases losses when output must be reduced, and conversely, decreases profits when output is increased relative to the case when all costs are fixed. In finance this is called operating leverage. (Operating leverage increases as the fraction of the costs that are fixed increases.) The point here is that operating leverage magnified the variations in profits/losses – i.e. increases risk – caused by a given change in output.

The effects of price risk on technologies with different cost structures (capital versus fuel intensive plants) are more complex. Consider two technologies, one of which has high fixed costs and very low variable costs, and the second with lower fixed costs and higher variable costs. For the second technology, also assume that short run incremental (marginal) costs increases as output increases. For the first technology, it would be economic to operate the unit at maximum capacity unless output prices fell to very low levels. This means that when prices are high, profits for technology one would be correspondingly high. However, just the opposite would be true for this technology when prices are low. On the other hand, the second technology that has higher variable costs would be economic to operate at a lower level of output under normal circumstances. Additionally, since marginal costs are increasing as output increases, it would also be economic to increase output when prices are relatively high and reduce output when prices fall.

To determine the differential price risk for these two technologies, two Monte Carlo simulations were run. In the first case, it was assumed that under normal conditions when prices equalled their mean values, the plant would operate at a 75% capacity factor. However, in this case, when prices increased, it would be economic to increase output up to the maximum of 95% capacity factor, and when prices fell, and capacity factor would fall down to 5%.[15] The resulting relative frequency distribution is shown in Figure A6.4. In the second case, it was assumed that all the costs were fixed, and this plant would be run at a higher 95% capacity factor regardless of the level of output prices (Figure A6.5). As these two figures show, the standard deviation in the discounted net present values for the technology that is run at the maximum capacity all the time is about 15% greater when compared to the plant where output is adjusted to changes in output prices. The result will depend on the variation and mean value of the actual prices in the relevant market.[16]

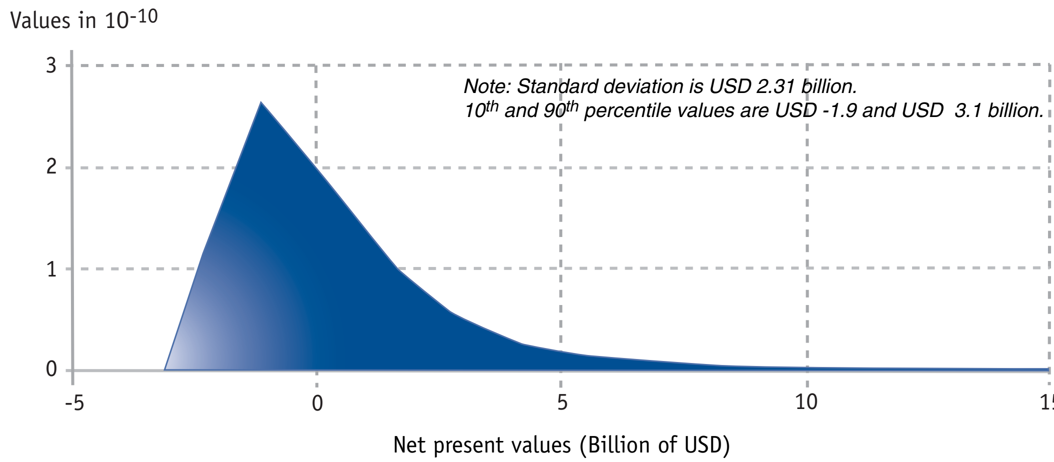
Figure A6.4 – Distribution of discounted net present values: electricity prices uncertain, output and operating costs variable



15. An alternative case was examined where the capacity factor could only fall to 55%, but if prices fell too low, the plant would be mothballed. The results of the analysis using this case were qualitatively similar to the ones shown here. Additionally, output prices were assumed to random and distributed normally with a standard deviation of 5 mills per kilowatt hour.

16. Note that technically risk is measured by the variance (the square of the standard deviation) in the cash flows. The standard deviations were presented because the units (billions of dollars) are more understandable.

Figure A6.5 – Distribution of discounted net present values: electricity prices uncertain, output and operating costs fixed



It is interesting to note that the 10th percentile cash flows are also much more negative when operating costs are fixed than when they are variable (-1.9 billion USD versus -9 billion USD, respectively). When prices are very low, it is economic to operate a plant when all the operating costs are fixed (unavoidable) and incur very large operating losses. However, when the operating costs are partly variable, some of the costs can be "avoided" by reducing output. This would suggest that the economics of the technology with very low variable operating costs may be more sensitive to price changes – i.e. with everything else being equal, the risks for this technology are greater. Indeed, this very point was stressed in British Energy's Prospectus when they were privatised in 1996, and this was one of the reasons for their financial problems in 2002.

However, as for fuel price risk, full incorporation of power price risk into investment analyses are still under development.

Optionality and real options

The impracticality of storing electricity and the inelasticity of electricity demand relative to price make the flexibility of the power generation supply system very valuable. In turn, the use of flexible supply sources that offer such flexibility adds to the value of a power plant. In addition to flexibility in operation, the ease of which new capacity can be added for a particular technology also can add value to the technology. A power plant that can be built quickly just as the anticipated increase in demand occurs entails less risk.

Traditional investment analyses place limited emphasis on the timing of the investment versus market conditions. In these approaches, the value of developing a single large plant is considered rather than a series of smaller plants, although the smaller plant strategy might have an advantage, e.g. if the growth in demand for electricity turned out to be lower than expected. Without a method to quantify the value of this flexibility, the economies of scale evident in larger power plants (in terms of installed cost per kW) trump any concern about risks of adding capacity in larger units.

The "real options" approach extends the traditional investment appraisal methodology by assisting in the valuation of additional options. Some of the most common options that cannot be captured by traditional analysis are the option to delay, the option to expand and the option to abandon.

The option to delay is embedded in projects where the investor firm has the exclusive rights of the project. Thus, it has the option to delay, until certain market and regulatory conditions are satisfied. Indeed, one of the early applications of the real options approach was to assess the value of phasing the development of oil fields versus a strategy of developing all at once.[17] The option to expand exists in the case where the investors take projects just because it allows them to take on another more interesting project or just to enter in a new market. In energy markets, where future prices are uncertain, investors are aware of the potential value of proceeding incrementally in developing new capacity. Quantitative methodologies that assess the value of being able to defer the decision on making part of the investment until market conditions become clearer are sought. Finally, the option to abandon is estimated in projects where the free cash flows do not cover the expectations.

The real options methodology permits the financial valuation of the previous options and adds considerable flexibility in the classic investment appraisal methodology. The flexibility to valuate other options, except the previously mentioned also exists, but it is out of the present scope and a matter of art for the investor analyser.

Research to apply the same techniques to assess the flexibility value of different strategies for power generation project development is still at an early stage. One study has applied the real options method to estimate the value of developing wind power projects in stages, rather than all at once, in recognition of the inherent flexibility of smaller plants.[18] Another study examined the cost-effectiveness of developing an IGCC plant in phases, initially using natural gas as a fuel and thereby delaying the decision as to when to convert the plant to using gasified coal.[19]

Despite these interesting academic results, the real options approach has achieved little acceptance by power generation investors to date. Calculating the real options value of a power plant has proven to be a less reliable indicator of value than financial options are in the stock market, for a variety of reasons. Unlike financial markets, forward markets for electricity and natural gas are not sufficiently liquid yet. They are under development in several countries and regions which may change the perspective in the future. For the time being the models must, however, rely on forecasts of future electricity and fuel prices. These forecasts, and the correlation between electricity and natural gas prices, are highly uncertain in light of changing volatility of these prices.

Summary

The reform of electricity markets has led to major changes in the way decisions are taken on power sector investment which is stressed even further by the simultaneous reform of gas markets. Opening the sector to competition has led to the internalisation of risk in investment decision-making.

The first impact of the internalisation of these risks has been a general rise in the discount rate used for the assessment of power generation investment. Interestingly, a US analysis suggests that the choice of a 5% and 10% discount rate may well reflect the risks appropriate to regulated US utility investment in the former case and investment in an open market environment in the latter.

However, some efforts are also being made to quantify the different investment risks posed by the different power generation technologies. Much of the quantification to date is largely reliant on expert judgment. Two US analyses suggest that the risks associated with US nuclear power, inclusive of the effects of tax might be around 2.5% higher than that for natural gas. However, this result is applicable only to the

17. McCormack and Sick, 2001.

18. Venetsanos *et al.*, 2002.

19. Smeers *et al.*, 2001.

US situation. Other markets, where perceived risk associated with nuclear power is lower (e.g. because of a longer history with good performance) may well change the relative risks of nuclear and gas power plants.

Attempts are also being made to develop more sophisticated methods to assess the profitability of power plants in light of uncertainties concerning fuel prices. Approaches using Monte Carlo simulations may well give a more accurate picture to decision makers of the risks associated with their investments and the likelihood of their profitability. The very fact that fuel prices are uncertain and volatile also implies that these costs might be discounted less than other cost factors. Estimating the long-term uncertainty in fuel prices remains difficult.

On the other hand, uncertainty in future electricity prices tend to favour less capital-intensive power generation investments. However, quantifying the impact of uncertain future electricity prices represents a new challenge for power generation investment analysts.

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Allocating the Costs and Emissions of CHP Plants to the Produced Electricity and Heat

The appendix introduces a theoretical approach to cost and emission allocation for a combined heat and power plant. This method was not used to estimate electricity generation costs of the CHP plants considered in the study (Chapter 5) but may be considered in future studies dedicated to dual product plants.

Endoreversible thermodynamics improves the insight in the behaviour of the efficiency for the conversion of heat into work. A new relation is derived which relates such an endoreversible efficiency to the efficiency of a real engine. The behaviour of this relation has been compared to existing ones, e.g. efficiency relations of Curzon-Ahlborn and Carnot. Further the behaviour of the efficiency of real engines is modelled as a function of upper and lower temperatures. The relations concerned are used to allocate costs and emissions of combined heat and power (CHP) plants to electricicty and heat produced.

1. Law of conservation of energy, which reads:

$$\Sigma Q_i + W = 0$$

where Q_i represent the heat flow per unit of time at temperature T_i and W is work flow per unit of time over one complete cycle of an engine.

2. Law of increase of entropy, which reads:

$$\nabla S \geq 0 \qquad \text{where} \qquad S_i = Q_i / T_i$$

Carnot engine

From these laws a Carnot engine can be defined (Figure A7.1), which has the following characteristics:

1. It possesses a high temperature heat reservoir (T_1) and a low temperature heat reservoir (T_4).

2. A work cycle of two adiabatic and two isothermal paths which form a closed cycle and which is completed in a reversible way. This means that:

$$\nabla S = 0 \qquad \text{or} \qquad Q_1 / T_1 - Q_4 / T_4 = 0 \qquad (1)$$

in which Q_1 is the heat flow from the high temperature heat reservoir to the engine and Q_4 the heat flow from the engine to the low temperature heat reservoir.

Figure A7.1
The Carnot engine

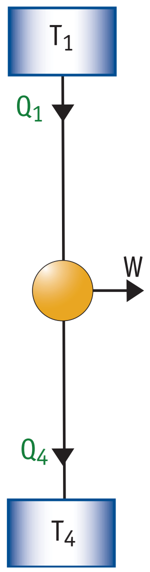
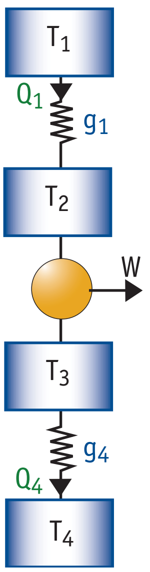


Figure A7.2
The Curzon-Ahlborn engine



The Carnot engine is characterised by a couple of relations, *viz*:

$$Q_1 / T_1 = Q_4 / T_4 \tag{2}$$

$$\eta_c = 1 - T_4 / T_1 \tag{3}$$

$$W = Q_1 - Q_4 = \eta_c Q_1 \tag{4}$$

where η_c is the Carnot efficiency and where in this case the work flow W is infinitely small. The Carnot efficiency η_c is the maximum value (in fact limit value) which can be reached in theory by heat engines, engines driven by temperature differences.

Curzon-Ahlborn engine

The assumption is that between the Carnot engine and the two heat reservoirs on both sides, heat resistors have been placed. These resistors, in fact their reciprocals, the heat conductances g_1 and g_4 have been shown in Figure A7.2.

In this case, the efficiency of the total (i.e. endoreversible) engine equels η. The efficiency of the core engine has the Carnot efficiency. Its reversible core works beetween the temperatures T_2 and T_3 (instead of between T_1 and T_4). The overall efficiency η is consequently equal to:

$$\eta = 1 - T_3 / T_2 \tag{5}$$

Note that, as long as $T_4 < T_3 < T_2 < T_1$, the efficiency η is lower than Carnot efficiency η_c given in equation (3). The relation for the entropy for the Carnot engine reads then:

$$\Delta S = 0 \qquad \text{or} \qquad Q_1 / T_2 - Q_4 / T_3 = 0 \tag{6}$$

Further Fourier's law for heat transport holds, *viz*:

$$Q \;= \lambda\ \nabla\ T \tag{7}$$

or $$Q_1 \;= g_1\ (T_1 - T_2) \tag{8}$$

and $$Q_4 \;= g_4\ (T_3 - T_4) \tag{9}$$

The substitution of equations (8) and (9) into (6) yields:

$$g_1 \;= (T_1 - T_2)\ /\ T_2 = g_4\ (T_3 - T_4)\ /\ T_3 \tag{10}$$

From the equations (5) and (10) an equation for T_2 can be obtained, which reads:

$$T_2 \;= g_1\ T_1\ /\ (g_1 + g_4) + g_4\ T_4\ /\ \{ (g_1 + g_4)\ (1 - \eta) \} \tag{11}$$

Substitution of equation (11) into equation (8) yields:

$$Q_1 \;= g\ (T_1 - T_4 - \eta\ T_1)\ /\ (1 - \eta) \tag{12}$$

where

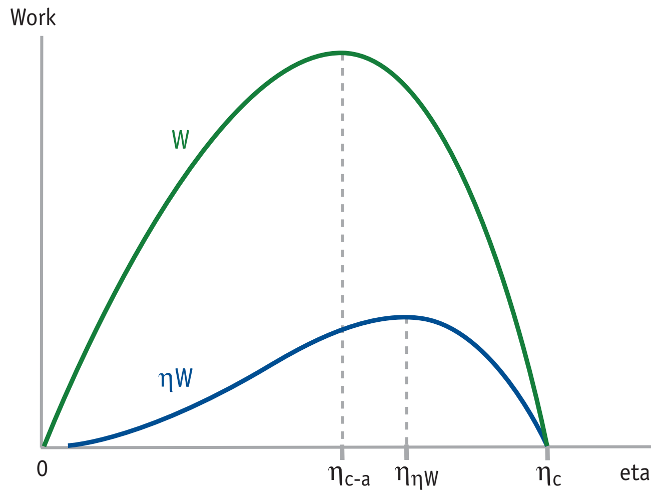
$$g \;= g_1\ g_4\ /\ (g_1 + g_4) \tag{13}$$

By multiplying equation (12) by efficiency η, an expression for work is found, *viz*:

$$W \;= g\ \eta\ (T_1 - T_4 - \eta\ T_1)\ /\ (1 - \eta) \tag{14}$$

The function for work W has been plotted as a funcction of η in Figure A7.3.

Figure A7.3 – The functions W and (ηW)
as efficiency η as a function of efficiency η temperature ratio T_4/T_1



It should be noticed that work W equals zero if either $\eta = 0$ or $= (1 - T_4 / T_1)$ and that it shows a maximum value somewhere between these points. The maximum value of work W is determined by setting $dW / d\eta = 0$, which yields a quadratic function in η, *viz*:

$$T_1\ \eta^2 - 2\ T_1\ \eta + T_1 - T_4 = 0 \tag{15}$$

This equation can be solved. It results in an important equation which first was found by Curzon and Ahlborn (Curzon, 1975), *viz*:

$$\eta_{c\text{-}a} = 1 - \sqrt{(T_4 / T_1)} \qquad (16)$$

The Curzon-Ahlborn engine is an example of an endoreversible engine, for which a definition has been given in Rubin, 1979. Such engines have finite cycling times for which irreversible processes occur hrough the coupling of the engine to the environment, while the working fluid in the engine is assumed to undeergo only reversible transformations. If the only irreversible process is heat conduction and work is maximised, then the Curzon-Ahlborn engine results.

Real heat engines

There are many other heat losses in reality than only heat conduction. Examples of such losses are eddy currents in work fluids, internal friction in work fluids, friction between work fluids and reaction chamber walls, hot temperature heat leakages to the environment, friction in bearings. Such losses are not modelled correctly by Fourier's law. Besides there may not a high temperature heat reservoir be present in the system but the system may have internal combustion instead and there may be phase shifts between dissipated and transferred heat and work. Consequently deviations from the Curzon-Ahlborn $\eta_{c\text{-}a}$ efficiency are observed in reality. If the real measured efficiency of a heat engine turns out to be equal to η_{eng} then a coefficient of utility is defined, which reads (Rubin, 1979):

$$\varepsilon\eta = \eta_{eng} / \eta_c \quad (0 < \varepsilon\eta < 1) \qquad (17)$$

It was already concluded dthat the Carnot efficiency η_c is the upper limit value for the efficiency of a heat engine which can only be reached in theory. As well can be concluded from the example of the nuclear power plant further on, that the Curzon-Ahlborn efficiency $\eta_{c\text{-}a}$ tends to result in values which are too low for modern engines.

The reason is that the Curzon-Ahlborn efficiency $\eta_{c\text{-}a}$ applies for maximum work W. In reality, the economics of an engine are determining its real efficiency η_{eng}, which may be higher than $\eta_{c\text{-}a}$. This means that an optimum for both work W and efficiency η should be looked for. Instead of determining the efficiency at the maximum value of work W, the maximum value of the function being the product of work W and efficiency η can be looked for. This value for η can easily be calculated from equation (14) by multiplying both the sides with η and setting $d(\eta W) / d\eta = 0$. From this another second order equation results which can be solved and which leads to:

$$\eta_{\eta w} = 1 - 0.25 \left[T_4 / T_1 + \sqrt{\{ (T_4 / T_1)^2 + 8 (T_4 / T_1) \}} \right] \qquad (18)$$

Figure A7.3 shows the curve for (ηW) as a function of η. Figure A7.4 shows the curves for η_c, $\eta_{c\text{-}a}$ and $\eta_{\eta w}$ as a function of T_4 / T_1.

The results which have been derived so far can be appliedd to a real nuclear power plant. For instance to Doel-4 (PWR, 1 049 MWe), a plant in Belgium. Its characteristics read (De Vos, 1992):

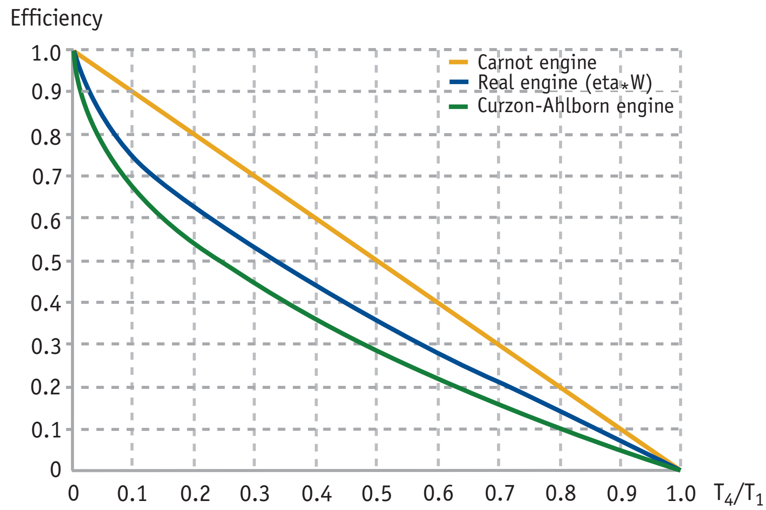
$$Q_1 = 3\,000 \text{ MW}; \; W = 1\,049 \text{ MW}; \; T_1 = 566 \text{ K}; \; T_4 = 283 \text{ K}$$

From these values, the following efficiencies have been calculated:

$\eta_{eng} = 1\,049 / 3\,000 = 0.350$ $\qquad$ $\eta_{\eta w} = 0.360$

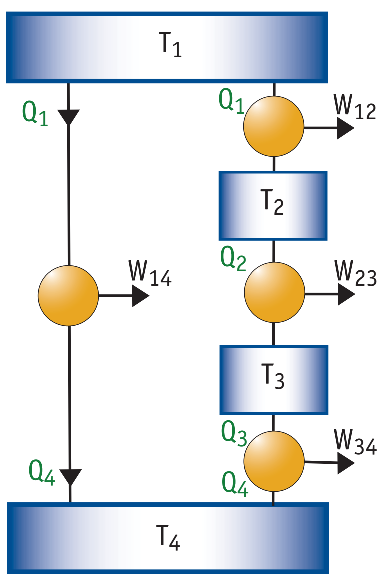
$\eta_{c\text{-}a} = 0.293$ $\qquad$ $\eta_c = 0.500$

Figure A7.4 – The energy conversion as energy conversion efficiency η as a function of temperature ratio T_4 / T_1



This example shows that equation (18) can be used to calculate an optimal efficiency for a real engine with a reasonably good outcome. However it does unfortunately not obey the laws of thermodynamics. This means that its use is restricted to the calculation of such optimal values. Its limited use becomes clear if the engine is split into three identical ones. Figure A7.5 shows four identical engines, where $T_4 < T_3 < T_2 < T_1$.

Figure A7.5 – Identical real heat engines



where: Q_1 = 100 MW, Q_2 = 70 MW, Q_3 = 52 MW, Q_4 = 42 MW, Q_5 = 18 MW

T_1 = 1300 K, W12 = 30 MW, T_2 = 800 K, W34 = 10 MW, T_4 = 380 K, T_5 = 283 K

In order to avoid any perpetual mobile, it is required that:

$$W_{14} = W_{12} + W_{23} + W_{34} \tag{19}$$

Assume that:

$$f\,(T_i \,/\, T_j) = Q_j \,/\, Q_i \tag{20}$$

Then the efficiency for the engine on the left hand side in Figure A7.5 reads:

$$\eta_{14} = (Q_1 - Q_4) \,/\, Q_1 = 1 - f\,(T_1 \,,\, T_4) \tag{21}$$

Equation (19), in combination with the first law of thermodynamics on conservation of energy, gives:

$$Q_1 - Q_4 = (Q_1 - Q_2) + (Q_2 - Q_3) + (Q_3 - Q_4) \tag{22}$$

Division of both sides of equation (22) by Q_1 yields:

$$\eta_{14} = \eta_{12} + (Q_2 / Q_1)\,\eta_{13} + (Q_2 / Q_1)(Q_3 / Q_2)\,\eta_{34} \tag{23}$$

Substitution of equations (20) and (21) into (23) results in:

$$f(T_1, T_4) = f(T_1, T_2) \,.\, f(T_2, T_3) \,.\, f(T_3, T_4) \tag{24}$$

Instead of the three identical engines at the right hand side in Figure A7.5, two or four or any other number of engines may be assumed, which leads to a similar result as equation (24). Therefore it is clear that the only solution is:

$$f(T_i, T_j) = Q_j / Q_i = (T_j / T_i)^{\varphi} \quad 0 < \varphi < 1 \tag{25}$$

and consequently:

$$\eta_{eng} = 1 - (T_4 / T_1)^{\varphi} \tag{26}$$

This result for η_{eng} means that the solution for η_{η_w} in equation (18) does not obey the starting point as represented in Figure A7.3 and equation (19). It should be noticed that equation (26) for the efficiency has a similar appearance as ones for the Carnot efficiency ($\varphi = 1$) as well as the one of the Curzon-Ahlborn efficiency ($\varphi = 0.5$). Besides in literature (De Mey, 1994), an example is given of an engine which has a couple of reversible Carnot engines encapsulated inside a network of losses. For this case an exponent of $\varphi = 1/3$ was found for the internal engines. From the values for Q_1, Q_4, T_1 and T_4, the value for the exponent φ can be calculated easily, *viz*:

$$\varphi = (\ln Q_1 - \ln Q_4) / (\ln T_1 - \ln T_4) \tag{27}$$

The allocation of costs and emissions over the produced heat and power

By applying equations (26) and (27) to CHP plants, a division between the costs for the heat component and the power component can be made. This calculus can most easily been shown by applying these equations to the Doel-4 power plant. From the normal operating values above as well as from equations (4) and (27), it can be calculated that:

$$\varphi = 0.621$$

Assume that this power plant could be operating as a large CHP unit and that it is producing heat at a temperature level of 370 K for an industrial application ($T_3 = 0370$ K). In this case, the electrical output decreases as well as its efficiency. The value of its new efficiency becomes:

$$\eta_{new} = 1 - (T_3 / T_1)^{\varphi} = 1 - (370 / 566)^{0.621} = 0.232$$

The corresponding electrical power level is equal to:

$$P(el) \approx W = \eta_{new}\, Q_1 = 0.232 \times 3\,000 = 696 \text{ MWe}$$

Consequently the thermal power being delivered to the industrial plant is 2 304 MWth. It is reasonable that the costs of produced heat make up for the costs of lost electricity. This means that 66.3% (*viz*. 696/1 049) of total costs (investment, O&M and fuel) have to be attributed to electricity production and 33.7% to heat production. Assume that the production costs of 1 kWh from the unmodified plant are equal to α. Then the production costs β of the heat from the modidfied plant are given by:

$$696\,\alpha + 2\,304\,\beta = 1\,049\,\alpha.$$

This yields:

$\beta = 0.153\ \alpha.$

If α equals 0.03 €/kWh, then β is equal to 1.28 €/GJ, *viz.* (1 049 – 696) x 0.03 / 2 304 / 0.0036.

Let C_y be the total yearly costs of the plant, C_{el} the costs to be attributed to the production of electricity and C_h the ones to the heat. Further $F_{el,x}$ the factor which relates C_{el} to C_y and $F_{h,x}$ a similar factor for the heat. The index x indicates that these factors are related to an exergy analyses. Consequently the following relations apply:

$$F_{el,x} + F_{h,x} = 1 \tag{28}$$

$$C_{el} = F_{el,x}\ C_y \tag{29}$$

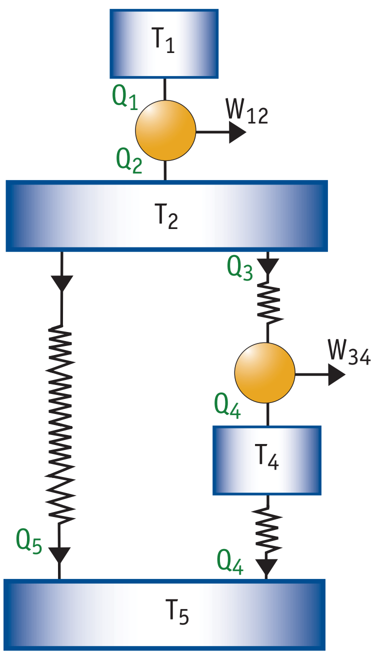
$$C_h = F_{h,x}\ C_y \tag{30}$$

$$F_{el,x} = (T_1{}^{\varphi} - T_3{}^{\varphi}) \ / \ (T_1{}^{\varphi} - T_4{}^{\varphi}) \tag{31}$$

In accordance with the results for the heat producing nuclear power plant above,

$$F_{el,x} = 0.663 \text{ and } F_{h,x} = 0.337.$$

Figure A7.6 – A model of a CCGT CHP plant



where: Q_1 = 100 MW T_1 = 1300 K W12 = 30 MW
Q_2 = 70 MW T_2 = 800 K W34 = 10 MW
Q_3 = 52 MW T_4 = 380 K
Q_4 = 42 MW T_5 = 283 K
Q_5 = 18 MW

A CCGT plant is often used for the production of combined heat and power (CHP). Such a plant incorporates two real engines: a gas turbine and a steam turbine. Figure A7.6 shows a simplified model of a CCGT unit with a back pressure steam turbine (Yantovskii, 1994), including a number of operating values for the heat flows, temperatures and power outputs (work). W_{11} and W_{34} represent the work produced respectively by the gas turbine and by the steam turbine. Q_4 and Q_5 represent the heat for the industrial application and the heat loss because of the flue gasses after the heat recovery steam generator. Its overall efficiency is 0.40. From the figures in the example, it appears that $\eta_{12} = 0.3$ and $\eta_{34} = 0.192$, while $\varphi_{12} = 0.735$ and $\varphi_{34} = 0.287$. By applying the above equations, theoretical maximum work can be calculated in case that the machine would only produce electricity (by giving T_4 the value of ambient temperature T_5). For this case it turns out that:

$$W_{34,max} = \{ 1 - (T_5 / T_2)^{\varphi_{34}} \} Q_3 = \{ 1 - (283 / 800)^{0.287} \} 52 = 13.4 \text{ MW}$$

As a consequence without the heat production, the maximum electricity producing power of the plant is equal to 43.4 MWe. This means that 92.2% (40/43.4) of total costs (investment, O&M and fuel) has to be attributed to electricity production and 7.8% to heat production. Or $F_{el,x} = 0.922$ and $F_{h,x} = 0.078$. Because of the methodology, the electricity production costs of the modified plant are equal to the ones of the unmodified plant. Assuming that, calculation shows that they would be 0.05 €/kWh. Then the production costs of the heat from the (unmodified) plant would be 1.12 €/GJ, *viz.* 0.078 x 43.4 x 0.05 / 42 / 0.0036.

A reason that in this example the value for η_{34} is so low may be that steam equipment is large and expensive. From an economical point of view it may be desirable to have suboptimal steam equipment. Assuming that $\varphi_{34} = 0.5$, which means that it has the Curzon-Ahlborn value, without heat production the maximum electricity producing power would be 51.1 MWe. With heat production it would be 46.2 MWe, because W_{34} is 16.2 MWe. For this case, $F_{el,x}$ and $F_{h,x}$ are respectively 0.904 and 0.096. Q_4, the amount of heat available for industry, is 365.8 MW. Calculation shows that the electricity production costs of the modified plant would be 0.05 €/kWh. This means that the additional income from power production fully bears the additional costs of the steam equipment. However in this case the production costs of the heat from the unmodified plant would become 1.90 €/GJ, *viz.* 0.096 x 51.1 x 0.05 / 35.8 / 0.0036. The reason for the higher heat price is mainly that although the electricity generating costs are not up, the total costs are while the heat production is down because of the higher efficiency for power generation. As a consequence, the former case is the more economical one.

For a system with two real engines, a similar relation as equation (31) can be derived as for a system with one engine. Let χ be a help variable.

$$\chi = (W_{34} + Q_4) / (W_{12} + W_{34} + Q_4) \qquad (32)$$

$$F_{el,x} = (T_2^{\varphi_{34}} - \chi \; T_4^{\varphi_{34}}) / (T_2^{\varphi_{34}} \; \chi \; T_5^{\varphi_{34}}) \qquad (33)$$

With equation (28) a value for $F_{h,x}$ can be calculated. This means that based on equations (28), (32) and (33), a division of the total yearly costs can be made over the electricity as well as the heat output of the plant. This division is fully based on exergy analyses. Although this division is in theory defendable it can be deduced from the examples above that the economical benefit fully goes to the heat component.

Instead of a division based on exergy analyses also a division based on energy analyses can be made. That is normal practise for emissions as well as for the fuel costs, because the fuel costs are the dominant factor both in the electricity and the heat generating costs. Let C_f be the total yearly fuel costs of the CCGT plant, $C_{el,f}$ the fuel costs to be attributed to the electricity and C_{elh} the ones to the heat. Further the factor $F_{el,en}$ relates $C_{el,f}$ to C_f and a similar factor $F_{h,en}$ for the heat is assumed. ($F_{el,x}$ Q_1) is the amount of energy which is needed for electricity production and Q_4 the amount of heat for the industrial application. By applying equation (33), the following relations can be derived:

$$F_{el,en} = F_{h,en} = 1 \qquad (34)$$

$$C_{el,f} = F_{el,en} \; C_f \qquad (35)$$

$$C_{h,f} = F_{h,en} \; C_f \qquad (36)$$

$$F_{el,en} = F_{el,x} \; Q_1 \; / \; (F_{el,x} \; Q_1 + Q_4) \qquad (37)$$

It is emphasised that depending on the number of engines present either equation (31) or (33) in combination with equations (34) and (37) is suitable to allocate emissions to the power as well as to the heat generation of a CHP plant.

Finally, a couple of assumptions can be made. They are:

1. The allocation of the yearly investment costs as well as the costs for operation and maintenance of the plant to the electricity and the heat component is based on energy analysis. The reason for this assumption is that electricity generating equipment is expensive and heat producing boilers are inexpensive. This allocation reflects the findings in the examples above that the largest part of the costs goes to the electricity component.

2. The allocation of the fuel costs is based on energy analysis.

Let C_i be the yearly costs component of the investment and C_{om} the yearly costs for operation and maintenance of the CCGT plant. A fair division of the costs towards the electricity production as well as to the heat production is then found by applying the following relations:

$$C_{el} = F_{el,x} \, (C_i + C_{om}) + F_{el,en} \, C_f \tag{38}$$

$$C_h = F_{h,x} \, (C_i + C_{om}) + F_{h,en} \, C_f \tag{39}$$

There exist different types of CHP plants. Some have a cycle with a steam turbine while others do not. An example of such a plant is a gas turbine with waste heat recuperation. The waste heat may for instance be used as industrial process heat. To make the division between the worth of the heat compared to the one of the electricity, an assumption has to be made for the amount of electricity which could be generated from this heat as well as of the investment costs of the extra equipment concerned. This means that a reasonable value for the efficiency has to be set. For instance, one based on the Curzon-Ahlborn relation, *viz.* equation (16). An alternative is the use of equation (18).

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Fuel Price Trends and Projections

Fossil fuels

The projected costs of generating electricity from fossil fuels presented in this study are highly dependent on the price of the fuels. In this and the previous study in the series, the prices of fossil fuels have been projected to increase by most participating countries. This appendix presents an overview of the historical trends, the assumptions used in the IEA *World Energy Outlook 2004* (IEA, 2004) and discusses the assumptions used in this study.

The price assumptions in WEO 2004 are summarised in Table A8.1.

Table A8.1 – Fossil-fuel price assumptions (in year-2000 USD)

	Unit	2003	2010	2020	2030
IEA crude oil imports	USD/barrel	27	22	26	29
Natural gas	USD/MBtu				
US imports		5.3	3.8	4.2	4.7
European imports		3.4	3.3	3.8	4.3
Japan LNG imports		4.6	3.9	4.4	4.8
OECD steam coal imports	USD/tonne	38	40	42	44

Source: IEA *World Energy Outlook 2004*.

Note: Prices in 2003 represent historical data. Gas prices are expressed on a gross-calorific-value basis.

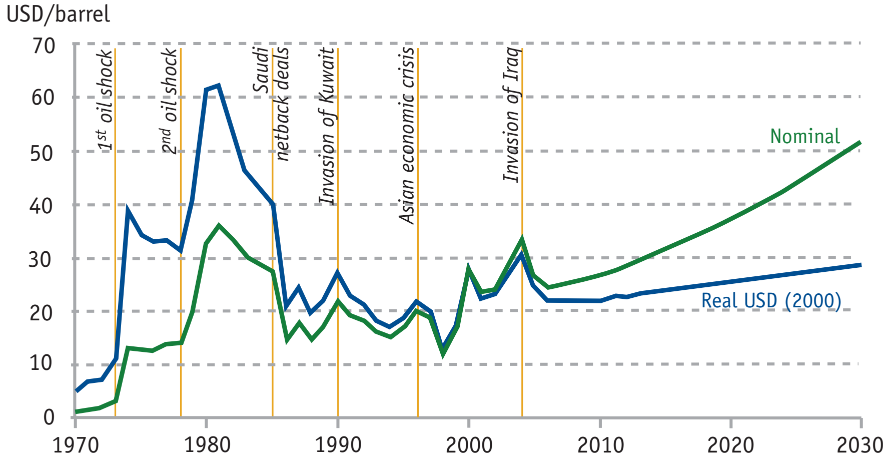
The price forecast reflects the judgment of the IEA on the prices that will be needed to encourage sufficient investment in supply to meet projected demand in the 2003-2030 timeframe. Although the price paths follow smooth trends this should not be taken as a prediction of stable energy markets. The volatility of prices may even increase.

The corresponding gas prices for 2004 are 5.2 for US import, 3.8 for European imports and 4.7 for Japan LNG imports, all prices in 2000 USD per MBtu. In 2003 USD the prices are 5.5, 4.0 and 5.0 respectively.

Oil prices

The past movements in yearly averages of oil prices (Figure A8.1) are a good illustration of the difficulty of making forecasts of that fuel price, and correspondingly of prices of fuels which are interlinked with the oil price.

Figure A8.1 – Historical and assumed future oil prices

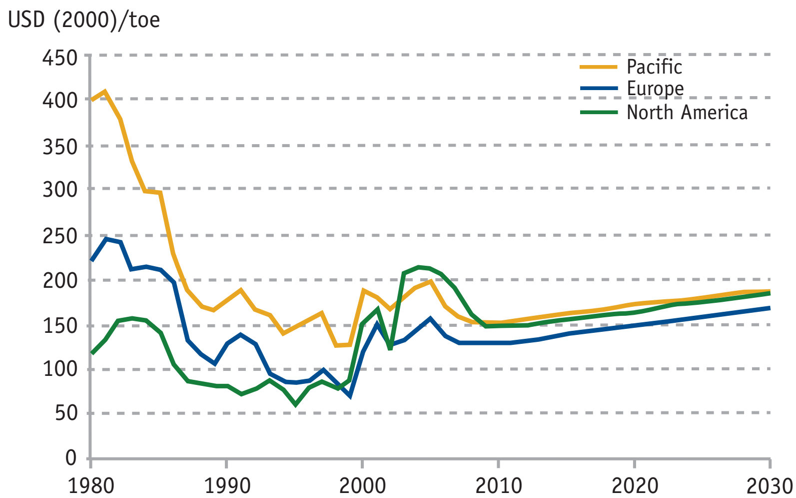


Source: *World Energy Outlook* (IEA, 2004)

Natural gas prices

Natural gas markets are highly regionalised, because it is costly to transport gas over long distances. Prices often diverge substantially across and within regions. Nevertheless, regional prices often move broadly in parallel with each other because of their link to the international price of oil, which reflects the competition between gas and oil products.

Figure A8.2 – Regional natural gas price assumptions



North American natural gas prices have surged in recent years owing to tight constraints on production and import capacities. In WEO 2004 it is assumed that prices will fall back in 2006 and then rise steadily from 2010 in line with oil prices. Rising supply costs also contribute to higher gas prices from the end of the current decade in North America and Europe. Increased short term trading in liquefied natural gas (LNG) will contribute to a higher convergence of regional markets.

Coal prices

International steam-coal prices have increased steadily in recent years, from 33.50 USD/tonne in 2000 to 38.50 USD in 2003 (in year-2000 dollars). Rising industrial production, especially in Asia, and higher gas prices have encouraged some power stations and industrial end-users to switch to coal. This has contributed to a boost of coal demand and prices.

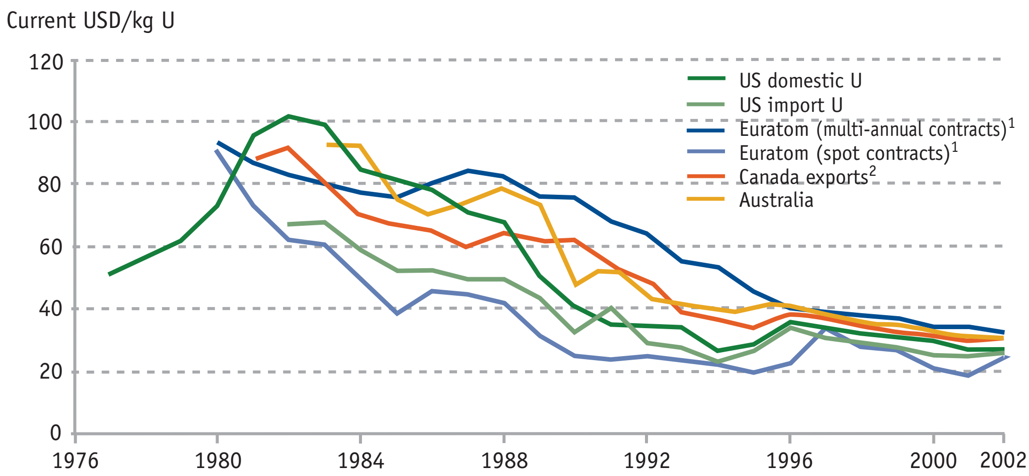
WEO 2004 expects market fundamentals to drive coal prices back down by 2006. After 2010 prices are assumed to increase slowly. The increase is slower than that of oil and gas. Rising oil prices will raise the cost of transporting coal but also make coal more competitive relative to natural gas with a strong linkage to oil prices. This creates a linkage between oil and coal prices but it is not as direct as with natural gas.

The international coal prices will be a reference for generators using coal, taking transport costs properly into account.

Uranium and nuclear fuel cycle service prices

This section is based on previous NEA studies on uranium (IAEA and NEA, 2004) and fuel cycle trends (NEA, 2002). Figure A8.3 shows the evolution of uranium prices during the last decades and Table A8.2 provides expected uranium and nuclear fuel cycle service price escalation, based upon published literature and views of experts in the field.

Figure A8.3 – Uranium price evolution



Notes:

1. Euratom prices refer to deliveries during that year under multiannual contracts.
2. Beginning in 2002, Natural Resources Canada has suspended publication of export price for 3-5 years pending a policy review.

Sources: Australia, Canada, Euratom, United States.

Table A8.2 – Expected lower and upper bounds to unit costs for specific fuel cycle activities[a]

Parameter	Unit	Lower bound	Upper bound	Description
$Cost_{U}$	USD/kg U_3O_8	20	80	Unit cost of natural uranium
$Cost_{Uconv}$	USD/kg U	3	8	Unit cost of conversion
$Cost_{Uenr}$	USD/SWU	80	120	Unit cost of enrichment
$Cost_{UOXfab}$	USD/kg UOX	200	300	Unit cost of UOX fuel fabrication
$Cost_{MOXfab}$	USD/kg MOX	1 000	1 500	Unit cost of MOX fuel fabrication
$Cost_{UOXrepro}$	USD/kg HM	500	900	Unit cost of UOX fuel reprocessing (as long as percentage of MOX-fuel is less than 20-30%)
$Cost_{MOXrepro}$	USD/kg MOX	500	900	Unit cost of MOX fuel reprocessing
$Cost_{UOXIntstore}$	USD/kg UOX	100	300	Unit cost of UOX fuel interim storage (2 years)
$Cost_{UOXgeo}$	USD/kg UOX	300	600	Unit cost of UOX fuel geological disposal
$Cost_{HLWgeo}$	USD/kg UOX	80	200	Unit cost of HLW geological disposal
$Cost_{FR\text{-}MOXfab}$	USD/kg MOX	1 200	2 000	Unit cost of FR-MOX fuel fabrication (including fertile blankets)
$Cost_{FR\text{-}MOXrepro}$	USD/kg MOX	1 000	2 000	Unit cost of FR-MOX reprocessing (+200 to 300 USD/kg FR-MOX for blankets)

a. Note that some values were converted from Euro to USD, assumusing that 1 € = 1 USD.

In the present study, nuclear fuel cycle costs were provided by respondents to the questionnaire directly in NCU per kWh at 5% and 10% discount rates.

References

IAEA and NEA (2004), *Uranium 2003: Resources, Production and Demand*, OECD, Paris, France.

IEA (2004), *World Energy Outlook 2004*, OECD/IEA, Paris, France.

NEA (2002), *Trends in the Nuclear Fuel Cycle*, OECD, Paris, France.

Economic Impacts of Wind Power Integration into Electricity Grids

Introduction

Several countries have renewables policies targeted specifically at wind power or targeted at goals that are expected to be met by wind power. The increasing shares of wind power draw attention to some important issues for the economic impact of integrating wind power into electricity systems:

- As the share of wind power increases, its intermittency increases the need for flexibility to maintain the system balance.
- Large shares of wind power change the way grids are planned, developed and operated. Single onshore wind turbines are usually connected to the grid at low voltage levels. Large offshore wind farms require the extension of the transmission grids to new territories. The intermittency puts new challenges on the control of the grid.
- Wind power may benefit substantially from international trade. Locations with the best wind resources are concentrated along coast lines and some mountainous regions. The load centers are often far away and the environmental benefits of using renewables for power production instead of Green House Gas emitting fuels are regional or global.

This appendix will address economic impacts of the technical and operational integration of wind power. A cost assessment of wind power should also take the economics of external effects of power generation in an international context into account. Costs and benefits should be addressed simultaneously.

A number of costs are incurred in "refining" and transporting the electricity production from a wind turbine to the final consumer. The most important of these cost factors are:

- Operational costs in managing the intermittency of wind power;
- Costs in keeping additional reserve generation as backup;
- Costs in reinforcing the grid and maintaining system control.

An assessment of these costs is intended to allow for more balanced and efficient investment and policy decisions. This will only be the case, however, if the wind integration costs are compared with the costs of integrating alternative options. There must be a level playing field. This may be met by pricing and allocating costs in a market, where all technologies have equal opportunities. An analytical assessment of the costs may be conducted by comparing total system costs in systems with and without wind power.

The NEA and the IEA arranged a joint half-day workshop on 25 May 2004 where the issues of integration of wind power into electricity grids were addressed. The presentations by the expert speakers and the lively discussions gave valuable inputs to this appendix.[1]

1. The presentations from the workshop are available on the NEA and IEA homepages (www.nea.fr and www.iea.org).

Reliability in electricity systems

The reliability of generation and distribution in meeting a varying demand has always been an issue for the planning and operation of electricity systems. The unbundling of electricity sectors and the development of markets has necessitated a more focused interest in the reliability of each separate technology and even each specific component in the value chain from generation to consumption. No technology, generation plant or transmission line is 100% reliable. All components in the value chain may fail and most need regular revisions. The intermittency of wind power draws attention to the issue of reliability but is thereby merely amplifying a process which has already been initiated by the introduction of markets. The introduction of competition and markets is generally driven by the objective of higher economic efficiency in the sector. Higher efficiency is achieved through changes in the ways electricity systems are planned, developed and operated. Whether the need for change comes from the characteristics of wind power or as a result of the decentralisation of decision making in markets is not always clear.

With that in mind it is important to note that costs from changes are only extra costs due to a larger share of wind power to the extent that the electricity system prior to the change was actually an efficient system. Business risks and economics of scale tend to be perceived differently in an environment with competition and decentralised decision making and this tends to lead to other outcomes than what could be observed before liberalisation. A drive for a change of the electricity system to better allow for the integration of wind power may also inherit benefits for other generation technologies, suppliers and consumers.

Managing the intermittency of wind power

There will only be wind power when there is wind. An electricity system needs access to alternative resources that are able to adjust to wind power. Increase in the share of wind power increases the need for alternative flexible resources.

The value and cost of flexibility

Electricity supply and demand must be balanced in every instant. Flexibility has a value. Generally, the needed flexibility comes at a cost. If a generator or a pool of generators is given some time to plan their operation, they will find the optimal dispatch to meet their sales obligations. Any deviation from this will generally add costs compared with the planned outcome, e.g. for thermal plants a deviation from optimum may decrease fuel efficiency. Frequent changes in the operation mode may also increase wear and tear of the plant.

With hydro power the cost of efficiency loss and wear and tear from changes in the operation is negligible. The only cost is the opportunity cost of deviating from the optimisation of the storage of water. This cost is generally low compared to the cost of balancing with thermal plants. This makes hydro power a highly flexible resource which is particularly well suited as backup for wind power.

A higher or perhaps just more transparent price on flexibility driven by increasing shares of wind power will attract attention. There will be an incentive for the introduction of new technologies or new implementations of known technologies that are able to provide flexibility at lower costs than traditional thermal power plants. Some of the developments that have already been observed is the use of emergency back-up generation as a flexibility resource for the whole system and participation from consumers who are able to shift consumption on a short notice at relatively low cost. Several projects with energy storage have also been under development. Modern offshore wind farms will probably also be able to participate in the real time balancing by diminishing the production when that option is economically viable.

The amount of flexibility

The ability to plan the production from wind turbines is dependant on the ability to forecast the wind. There have been extensive efforts to try to improve wind power forecasts. During the last years the wind has turned into an important fundamental driver for the electricity markets in e.g. Denmark and Germany. The forecasting efforts are not only important for the wind turbine owner and for system operation but also important for the market player's understanding of the overall price formation in those regional markets.

There are two key aspects in forecasting the wind power production. The first is the actual meteorological wind prediction. So far the meteorological efforts have traditionally been focused on other aspects of the weather, such as precipitation and temperature, with a lower resolution than is relevant for wind power. There are now increased efforts in the prediction of wind, where the common new elements seem to be an increased use of online measurements and statistical corrections. The other key aspect is the transformation of a wind prediction into a forecast of the wind power production. The system operators in all the regions with significant shares of wind power have wind power forecasting tools. Several research institutions have worked on the issue for many years.

Knowledge about wind power, demand, and availability of traditional generation capacity and transmission lines increase towards the moment of operation. The need for flexible resources will diminish with the increased knowledge. The need for flexibility may be reduced by increasing the number of planning cycles to decrease the time that elapses from planning to operation. A planning cycle also comes at a cost, however. Market participants must make an effort in every planning cycle. Each planning cycle will add transaction costs. The appropriate number of planning cycles will be a trade-off between the quality of forecasts and the transaction costs.

Assessed and experienced costs of intermittency of wind power

In a study commissioned by the UK Department of Trade and Industry,[2] the costs of handling the intermittency of wind power has been assessed by comparing modeled costs in the current electricity system with costs in a system with different quantities and dispersions of wind power. The model results for the balancing costs are 3-4 €/MWh of wind power at penetration rates of 20-30%.[3] These costs include some costs for keeping operational reserves.

Eltra, the transmission system operator (TSO) in the Western part of Denmark, reports that for the 3 368 GWh of wind power that they had the responsibility to handle in 2003, the total balancing costs were 65 million DKK (8.7 million €).[4] This corresponds to 2.6 €/MWh of wind power. Currently they make wind power forecasts with a 13-37 hour-time horizon that has an average error of 30-35%. The 13-37 hour-horizon is the relevant timeframe in the current Nordic market. This implies that for every 100 MWh of wind power alternative resources must adjust their operation with some 30-35 MWh on average. The quality of wind power forecasts increase significantly over the 36-hour period. The quality

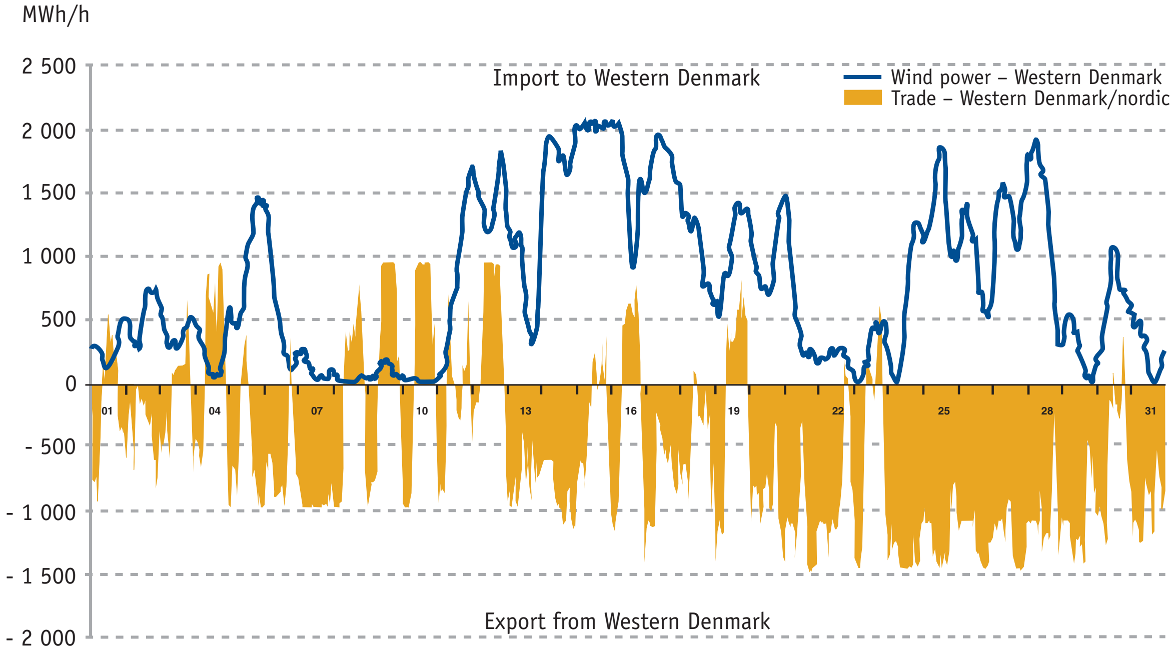
2. ILEX, 2002.
3. The ILEX study reports the total additional costs in a scenario where all new renewables will come from wind power. The 3-4 €/MWh of wind power is derived as the share of the total integration costs that comes from balancing costs, approximately 25%.
4. Eltra has the responsibility to handle the generation from a large share of Western Danish wind turbines. This will change with the implementation of the newly amended Electricity Act. Production from wind turbines in the Western part of Denmark can be sold in the spot market at the power exchange Nordpool. This trade is taking place at noon a day ahead of the day of operation, so the trade must be based on a wind power forecast of 12-36 hours ahead of operation. Any deviations from the forecast must be traded in the real time balancing market where the price is less favourable than in the spot market. Thereby there is a cost of deviations between the forecast and the actual production. The cost depends on the price in the balancing market and the size of these deviations.

is also highly dependent on the type of weather thereby indicating that the prospects for quality may be different in different regions. There are hopes and expectations of further improvements of wind forecasts.

In the ILEX study the balancing costs are modeled using a combined cycle gas turbine (CCGT) as the reference technology. In the Western Danish system the actual balancing is performed by the local thermal plants when the interconnections with Norway and Sweden are congested. If there is spare capacity on the interconnectors the hydro-based regulating power in Norway and Sweden is usually the cheapest alternative.

The interaction between Western Danish wind power and the Nordic hydro-based system is an interesting example of the possible role of markets and the importance of access to flexible resources. Figure A9.1 shows wind power production in the Western part of Denmark and flow on the transmission lines to Sweden and Norway in December 2003. In many hours a high production of wind power is exported to Norway and Sweden. The Nordic electricity market allows for an hourly optimisation across the whole Nordic region where the congestion management performed by the electricity exchange Nord Pool plays a central role. The open market is an important tool in maximising the value of wind power.

Figure A9.1 – Exchange between Western Denmark and Norway/Sweden and wind power in Western Denmark (December 2003)



Note: The market allows for a highly flexible utilisation of the transmission capacity. This facilitates the integration of wind power, hour by hour. Many other factors influence the flow, including especially the large share of local CHP.

Operational reserves for wind power

The operational costs of providing flexible resources in the real-time balancing of the system probably do not comprise the total costs of providing that service. The need for flexibility may arise on a short notice due to failures in thermal power plants or transmission lines or changes in demand or wind power supply. In that case additional resources must be available and they will probably require a scarcity rent. Most system operators have responsibilities that require them to have access to an appropriate amount of flexible resources enabling it to handle imbalances in real time with a satisfying probability. To the system operator there is a value in having the *option* to acquire flexible resources on a relatively short notice. This option comes at a cost. Many thermal power plants need time to warm up to be available in the moment of operation. If a producer is able to sell the production in the market at a price above its costs, holding back capacity implies a lost opportunity, in which case there is an opportunity cost. If the price in the market is lower than the costs of operating the plant, there is a cost of keeping it in operation. The system operator may acquire operational reserves and will probably have to pay a price for it.

The needed amount of operational reserves due to wind power will depend on the share of wind power in the system. Below a certain share the need for operational reserves as backup for other failures or sudden large imbalances in the system will also serve as backup for the intermittency of wind power. Above this threshold the need for operational reserves will increase with the share of wind power. The need for operational reserves will depend on the characteristics of the electricity system, including the ability to co-operate between regions.

The need for operational reserves will also depend on the method of acquiring these reserves. If the need for operational reserves is assessed and contracted on a daily basis the needed amounts may be adjusted to the wind power forecast. If operational reserves are contracted for longer periods, the system operator cannot benefit from the increased knowledge about the wind power closer to the moment of operation. The system operator will probably have to contract a larger amount to be prepared for more possible outcomes. If one possible outcome is that all wind power is scheduled to operate and it then turns out that the wind forecast was 100% wrong, then the system operator may be forced to contract operational reserves to replace all the wind power capacity. Large shares of wind power thereby calls for flexible approaches to acquiring operational reserves. In Germany the TSOs are acquiring some of the operational reserves on a daily basis on the morning the day before the day of operation. Alternatively there can be full reliance on the market, in which case the scarcity rent will be collected through price spikes when the system is close to shortage.

It may be considered to allocate the costs of operational reserves to the source of the need. If such a scheme is established to create good incentives for investors all technologies should be given equal opportunities. Wind power projects should not be the only technology that is charged specifically for operational reserves.

The capacity cost of wind power

During periods with no wind the electricity supply must come from other sources. The need for resources as backup for wind power may be denoted as the capacity cost of wind power. It can also be evaluated in terms of the amount of alternative capacity that wind power is replacing which is the capacity value of wind power. The distinction between costs for operational reserves and the capacity cost of wind power will probably depend on the organisation of the respective electricity system and electricity market. In a cost analysis the distinction must be treated with caution to avoid any double counting.

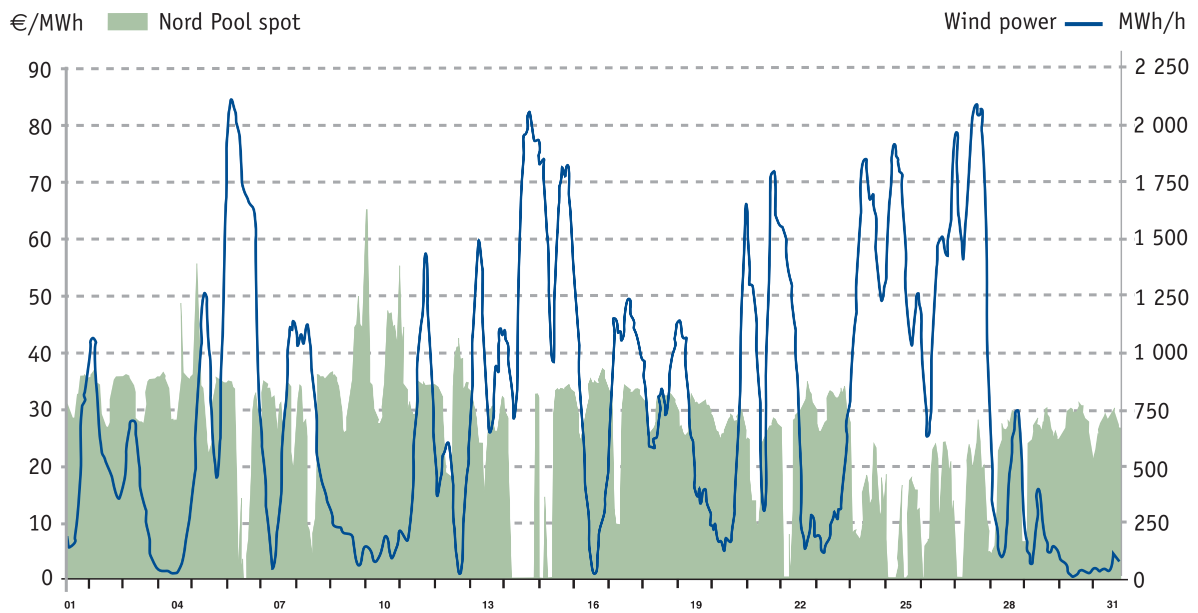
No technology is 100% reliable, so an evaluation of the capacity cost of wind power must be relative to the reliability of alternative resources. The capacity cost or value of a certain technology is not only depending on its reliability but also on the correlation of the availability with the load. The availability of a thermal power plant is generally non correlated or negatively correlated with peak load. The correlation between wind power and load will depend on the characteristics of the weather and the electricity system on a specific location but in general it has probably a fairly low correlation with the load. Here is an obvious benefit for photovoltaics. In locations where the availability of photovoltaics is high due to warm and sunny weather, the load is probably peaking on the warmest days in perfect correlation with the availability of photovoltaics.

In the ILEX study[5] and in another extensive study (GreenNet, 2004) a research project supported by the EC[6], the approach of assessing the capacity cost or value is to analyse the minimum level of wind power production that can be expected during periods with peak load. If the electricity system is dimensioned to meet the demand, the expected minimum level of wind power production during peak demand will correspond to the amount of alternative production capacity that is replaced by the wind power. The reliability of the alternative production is taken into due consideration. The GreenNet study reports capacity credits for wind power of 7-65% of traditional plants depending on level of penetration, time of year and onshore/offshore, and thereby clearly indicating that the capacity cost will be highly dependent on the characteristics of a specific system.

The specific assessment and pricing of the capacity value will only take place in markets with a specific capacity measure. In the PJM Interconnection,[7] there is an obligation to provide capacity. Here the capacity credit of intermittent resources like wind power is computed considering the statistics of production from the specific wind turbine during peak hours.

In markets where there is no specific capacity measure, the capacity cost or value of wind power is reflected in the prices in the market. This is very clear in Denmark and Germany at times. So far there is an excess of production capacity in that region so the costs has mainly been reflected through very low spot prices during some periods with much wind. This is shown in Figure A9.2 for Western Denmark. On 14 December 2003, the wind power was operating at almost full capacity and during several hours the price was zero.[8] The price stops at zero due to technical limitations in Nord Pool's market settlement. Nord Pool has announced plans to allow for negative prices.

Figure A9.2 – Spot prices and wind power in Western Denmark (hourly values, December 2003)



Note: Nord Pool spot prices and wind power production in the Western part of Denmark in December 2003. Price drops to zero in several hours coinciding with high levels of wind power.

5. ILEX, 2002.
6. Hans Auer *et al.*, 2004.
7. PJM Interconnection is a Regional transmission organisation for the whole or parts of the American states Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia. It operates the wholesale market in the region and co-ordinates the movement of electricity.
8. The Danish situation is also affected by the high share of combined heat and power (CHP). CHP plants produce electricity when there is a demand for heat. The Danish CHP plants will get more degrees of operational freedom with the new legislation which is currently being implemented.

Thereby some of the capacity cost is paid by alternative generators whose production plants stand idle. When the sector has been adjusted to the higher share of wind power, the costs will probably to a larger extent be reflected in high spot prices during periods with little wind.

The Danish and German examples are also good examples to further illustrate the complexity of a good assessment of the capacity credit of wind power and the complexity of finding efficient solutions through traditional planning with large shares of wind power. If the assessment of the capacity value is based on wind power's ability to supply electricity during periods with peak demand, the relevant peak demand must be specified. In a region with open markets, extensive cross-border trade and transit flows the relevant peak-load area is probably not well specified by country borders. Thereby it becomes very difficult to assess the capacity value of wind power when taking international trade into account. It also illustrates, that well-conceived markets which facilitate the flow of electricity across borders at the same time are a means of enhancing flexibility and thereby maximising the value of wind power.

The importance of open trade between regions is equally relevant in assessing the cost of the backup generation. The ILEX study assumes that "open cycle gas turbines" will be standing idle as backup. The characteristics of hydro power with reservoirs make it an ideal resource as backup for wind power. Open markets may enable good interaction between hydro power and wind power even if they are located in different regions. This would decrease the cost of backup generation.

The ILEX and the GreenNet studies assess the capacity costs of wind power. With a share of wind power of 20% of the consumption the ILEX study assess the capacity costs in United Kingdom to 6.7 €/MWh of wind power. The GreenNet study assess the capacity cost of wind power in several EU countries to 3-4 €/MWh of wind power at shares of approximately 20% of consumption.

Reinforcement of the grid due to wind power

Individual onshore wind turbines and small onshore wind farms are usually connected to the local low voltage grid. Large wind farms are often located in remote areas with little electricity demand and are connected to the grid at higher voltage level. Offshore wind farms are requiring the extension of the electricity system to new territories where there is no load, and their size will soon become comparable with traditional power stations. This will in many cases necessitate reinforcements of the grid as is the case for most new power plants, particularly if they are large. Adding the intermittency of wind power the connection of wind power to the grid poses new challenges for its control, operation and development.

Numerous wind power related effects on electricity grids have been identified through experiences in systems with large shares of wind power and through analysis and overall cost assessments. The most important effects are:

- Connection of production capacity on lower voltage levels and closer to the load than traditional power stations will reduce grid losses.
- At a certain share of wind power and with large wind farms far away from the load, the need for transports of electricity over longer distances will increase. There will be a need for reinforcement of transmission and distribution grids.
- Traditionally the generation has been concentrated on few large plants that are connected with the load through transmission lines in a hierarchal structure. The systems to monitor and control the grid have been developed for that. With large shares of wind power in the lowest level of the "hierarchy" close to the load, the control systems must be changed accordingly.

Many of the costs that will be incurred in meeting these challenges are not necessarily driven by the increase of wind power as such, but rather driven by the fact that the grid was developed to meet one set of needs, and now these needs are changing. The most obvious cost factor that is directly derived by an increasing share of wind is the need for transport of wind power from the wind resources to the load centers.

The effect wind power has on the transmission and distribution grid is highly system specific. In the ILEX study the grid costs of extending the share of wind power in the United Kingdom from 10% to 30% is assessed to 5.2 €/MWh of additional wind power. The costs of extending the share from 10% to 20% are 4 €/MWh of additional wind power. These assessments are based on a scenario where it is assumed that most of the wind power will be concentrated around the good wind resources in the north.

In the GreenNet study the assessment of the costs of reinforcing transmission and distribution grids is 2.5-3 €/MWh of wind power at penetration levels of approximately 20% of the consumption.

Overall assessment of the costs of integrating wind power into the electricity system

There are numerous studies that assess the costs of integrating wind power. Two such studies were chosen for the joint NEA/IEA workshop and are referred to in this appendix. Many other studies provide other estimates; the purpose of this appendix is to give a probable cost range.

The reported experiences and the reviewed studies tend to indicate that the costs of integrating wind power are depending on:

- **The share of wind power in the electricity system**. The costs per MWh of wind power tend to increase with the share. Particularly so when it comes to the capacity costs and the T&D costs.
- **The characteristics of the electricity system**. Generally the costs will depend on whether the needed alternative flexible resources are already accessible or if they have to be added to the system either directly or via new interconnections with other regions. The costs in small isolated systems tend to be higher than in large or highly interconnected systems.
- **The operational procedures and market design**. Large shares of wind power add new dimensions to an electricity system. If the operations procedures and market design are not adjusted to reflect the complexity of wind power, the costs may be higher than necessary.

These points must be kept in mind when assessing the costs of integrating wind power. The table summarises the experience and studies that were referred to at the joint IEA/NEA workshop held on 25 May 2004. It also lists the cost factors that have been identified, but the experience and studies do not allow for a clear cut distinction in all cases.

Experienced and modelled costs of integrating wind power (€/MWh of wind power)[a]

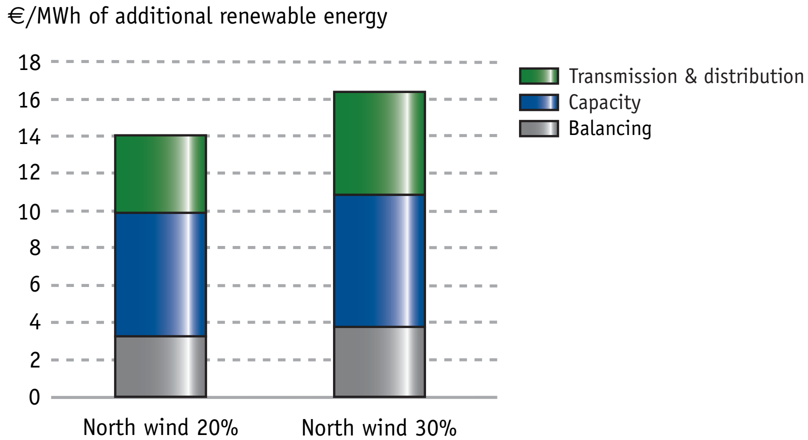
	E.ON Netz[b]	Eltra	ILEX study[c]	GreenNet study[c]
Balancing	7	2.6	3.3 (Balancing and operational reserves)	1.5-2
Operational reserves				
Capacity costs			6.7	3-4
Transmission & distribution			4	2.5-3

a. For comparison with other technologies it must be taken into account that all technologies require integration costs.
b. E.ON Netz (2004): app. 6 000 MW wind power in 2003 and costs of more than 100 million €. It is not clear what these costs include. Assuming a load factor of 25%, 100 million € corresponds to app. 7 €/MWh wind power.
c. At 20% wind power shares of consumption.

The table indicates actual operational balancing costs in the range of 2-3 €/MWh wind power. The lower figures are probably dependent on access to cheap regulating resources like hydro power, and the higher figures are probably realised when the regulation must be performed by thermal power plants. Apart from these costs it is still very difficult to draw firm conclusions on the total costs.

The high dependency between costs of integrating wind power and the characteristics of the specific electricity system is also illustrated in Figure A9.3.

Figure A9.3 – Cost assessments from ILEX study on different scenarios



The role of regulation and prices in minimising costs of wind power integration

A range of total costs of 5-15 €/MWh wind power first of all indicates that it is difficult to assess the costs in generalised terms. It also suggests that there are large potential gains of trying to push the costs to the lower end of the range. Significant gains can be made by establishing wind power in optimal locations through trade-offs between wind resources, proximity to load centers and access to cheap alternative flexible resources. There would also be benefits in establishing procedures that recognise the trade-offs between the prospects of wind forecasts, transaction costs in operations planning and the transaction costs in electricity trade.

Most OECD countries are in a process of electricity sector reform that will introduce competition and open electricity markets. Markets are driven by private economic incentives and decentralised decisions. This poses a limit to the way optimal solutions for wind power may be sought. Some measures to integrate wind power may critically distort open electricity markets. On the other hand, the prospect of using prices from markets as an instrument to achieve efficient integration of wind power is also an opportunity. A well functioning market will create clear and transparent price signals for the relevant services. There will be a price for electricity for every relevant location and time period. There will be a price for supply and use of flexibility. There may be a price for operational reserves. Clear and transparent price signals create incentives for investors and allows for efficient decisions where all the aspects of wind power integration is taken properly into account.

Using markets to value wind power

Balancing. It is the electricity consumer who makes use of wind power in the end. To the consumer the exact time and place of consumption is critical to the value of electricity. This calls for a pricing of electricity as close to the moment of operation as practically possible and for every relevant location. This goes well in hand with the challenges of planning of wind power, as the wind power forecast improves significantly during the last 36 hours before operation, particularly so if the specific location is important. On the other hand, the closer to the moment of operation the pricing is moved, the higher demands are put on the alternative resources that must be prepared to adjust their operation. This generally adds costs. The more time the traditional resources are given to plan the operation, the more carefully they will be able to work out the optimal operation and thereby minimise their costs. An appropriate timing and organisation of the trading possibilities and market settlement should be established bearing these trade-offs in mind.

Operational reserves. It is an operational challenge to make sure that there are sufficient flexible resources online, to mitigate any deviations between forecasted wind power and actual wind power. This is done by securing an adequate amount of operational reserves. The need for these reserves will decrease as the quality of the wind power forecast increases. Hence, the closer the decision of operational reserves can be moved to the time of operation, the less may be needed. The limit is the time it takes to bring the reserves online and the timing of the planning cycle. Operational reserves must be acquired before the planning cycle takes place.

Capacity credit/value/cost. The capacity credit or value of a particular technology is a necessary decision parameter in systems where the production capacity is subject to central decisions. In markets with no specific capacity measures the allocation of resources and investments is left for the market to decide. An "energy only" market is intended to create price incentives for an appropriate technology mix without any additional remuneration for capacity. The resulting technology mix will in that case be reflected in the market prices.

Using regulation to integrate wind power into the grid

Efficient integration of wind power into the electricity grid requires efficient decisions by wind power investors, transmission grid owners and distribution grid owners. Transmission and distribution is generally considered to be a monopoly, so efficient decisions by grid owners will necessitate regulation to create appropriate incentives.

The efficient location of wind power is a trade-off between the access to wind resources and the proximity to load centers. There are similar trade-offs for most generation technologies. Efficient solutions require that such trade-offs are reflected in the incentives that all investors in power plants and grid owners are faced with. A technology without such locational limitations should be correspondingly awarded for this flexibility.

An appropriately designed electricity market addresses the locational aspect via price signals. Thereby the constraints in the grid are reflected in the pricing of electricity. This could be done by organising a price settlement for every node or group of nodes (a zone) in the electricity grid. Then the price in one specific location will reflect supply, demand and constraints in the electricity grids.

Some of the grid-related issues of integrating wind power may be impractical to incorporate in a market scheme with locational pricing, e.g. integrating wind power into the grids has locational aspects on low voltage levels which may increase the amount of relevant nodes to a very high number. If the relevant locational aspects are not reflected in the market structure they may instead be reflected in the tariffs for the connection to and use of the grid.

Grid tariffs may be used to reflect several levels of locational aspects. The first level is to reflect the cost of the line that connects the wind power to the grid – the shallow costs. Many of the costs of connecting wind power to the grid are from the necessary reinforcement of the grid – the deep costs. The necessary reinforcement may be on several different voltage levels and in other geographical locations than the wind power that triggered the reinforcement. The connection of wind power in a specific location also affects grid losses.

The shallow costs are easy to identify and accredit to a specific wind power investor. On the other hand, the shallow costs are often only reflecting a minor part of the relevant locational grid aspects. The deep costs may perfectly be reflecting all the locational aspects in integrating wind power into the grid. However, it may be very difficult to allocate these costs to specific wind turbines.

Efficiency in investment decisions in grids and generation is only achieved if there is a level playing field among the alternative generation technologies. Wind power investments will not be efficient (and fair) if wind power is the only generation technology faced with locational tariffs. There seems to be a trend towards the reduction of grid tariffs for generators as electricity markets are opening. This seems to be under the argument that there should be a level playing field among competiting generators in different countries. This trend is an extra challenge in the establishment of efficient tariffs for wind power.

The implications for the grid of making offshore wind farms are good examples of the importance of creating the right incentives. For offshore wind farms the transmission grid must be extended to new areas where there is no load. Efficient investments require that the trade-off between good wind resources and higher transmission costs is taken properly into account. If the costs of connecting offshore wind power to the grid and operating that grid were not appropriately reflected in the investment incentives, investments could be distorted in favour of offshore wind power relative to other renewable alternatives.

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Impact of Carbon Emission Trading on Generation Costs[1]

A political commitment to reduce the emission of carbon is intended to put a price on the emission of carbon to reflect a negative external effect on the environment. Such commitments are being made in more and more OECD countries. The cost of carbon emission now or possibly in the future may affect the operation of power plants and the investment in new generation capacity, e.g. the choice of technology. This appendix is discussing this issue by exploring the relationship between different prices of carbon emission and different prices on fossil fuels under a certain set of assumptions about the costs of different technologies. The relationships are described to illustrate how the different cost factors are related, and not to suggest any specific costs or prices. The real relationships between factors and costs are probably also of a more dynamic nature than described here, further stressing that the costs suggested by the model should be treated with caution.

According to the *World Energy Outlook* (WEO 2004) Reference scenario which takes into account government policies and measures on climate change and energy security that had been adopted by mid-2004, global CO_2 emissions will increase by 1.7% per year from 2002 to 2030. From 12 446 Mt of CO_2 equivalent in 2002, emissions will reach 15 833 Mt in 2030 for OECD countries – an average increase of 1.1% per year. The power generation sector will contribute to almost half the increase in global emissions between 2002 and 2030, and will remain the single biggest CO_2-emitting sector in 2030. In OECD countries, its emissions will rise from 4 793 Mt of CO_2 in 2002 to 6 191 Mt of CO_2 in 2030, but the share will remain constant.

Today, power generation emits 65% of industrial emissions of carbon dioxide (CO_2) in OECD countries and is likely to become instrumental in countries' strategies to reduce greenhouse gas emissions. The European Union has decided to introduce a CO_2 emission trading scheme with a first phase to run from 2005-2007, and a second phase running from 2008-2012 to coincide with the first Kyoto Protocol commitment period. The scheme will cover CO_2 emissions from energy activities (combustion installations with a rated thermal input exceeding 20 MW, mineral oil refineries and coke ovens), production and processing of ferrous metals, mineral industry and some other activities (pulp, paper, and board).

The introduction of emission allowances will alter operating costs in the power generation sector and is expected to have an influence on the operation of existing generating capacity as well as the composition of future investment.

> The carbon "emission allowance" will increase the variable costs for fossil-fuelled power plants since an emission allowance will be needed for each unit of CO_2 produced. Coal-fired generation will be more strongly affected than gas-fired generation because of the higher (approximately double) carbon emission per unit of output.

1. This appendix is based on the IEA information paper *International Emissions Trading From Concept to Reality* (Reinaud, 2003).

The Kyoto Protocol and the European emissions trading scheme

Under the United Nations Framework Convention on Climate Change (UNFCCC), more than 180 countries have recognised the need to stabilise the concentration of greenhouse gases (GHG) in the atmosphere. Climate stabilisation will require tremendous changes in the way energy is produced and consumed. The efforts of policy makers are now focused on minimising the economic and social costs of changing the production and consumption patterns. Emission trading at an international level was introduced in the Kyoto Protocol for that purpose.[2] In 1997, the Kyoto Protocol set legally-binding GHG reduction targets for a number of industrialised countries once the Protocol had come into force. While implementation of the Kyoto Protocol still requires efforts from both national administrations and the international community, several countries and regions have decided to implement emission trading schemes. This is the case for the European Union (EU) which will start implementing an industry CO_2 emission trading scheme by 2005, and will introduce a cap-and-trade constraint for the first Kyoto Protocol commitment period (2008-2012).

Since the Russian parliament ratified the Kyoto Protocol in October 2004, it will come into force in early 2005. This will likely give rise to greater political impetus for new and additional policies and measures to mitigate GHG emissions, as current emissions trends indicate that most IEA countries are not on track to meet their commitments. Whatever happens to the Kyoto Protocol, many governments may start considering objectives for the future, beyond 2012, in order to provide clear signals to those investing in long-term capital projects with GHG implications.

On 13 October 2003, the European parliament approved the EU's carbon dioxide emissions trading scheme. As of October 2004, 24 EU member states had submitted their National Allocation Plan to the Commission. The European Commission's emissions trading scheme (ETS) covers two trading periods (2005-2007 and 2008-2012), the latter being the first commitment period of the Kyoto Protocol. Allowances will be allocated to operators of facilities throughout the EU, such as refineries, power stations, paper, pulp, metal and mineral plants.

The operator of each installation is allocated tradable emissions allowances by its national government, with one allowance equal to one metric tonne of carbon dioxide emissions. By 30 April the year after each compliance year, each operator will have to submit allowances equal to or greater than the volume of his emissions, or face a financial penalty of 40 €/additional tonne of CO_2 in 2005-2007, and 100 €/tonne from 2008. Operators of installations emitting fewer emissions than their target will be able to sell allowances, while operators of installations emitting more will have to buy in order to be in compliance. For the period 2005-2007, emission allowances will be allocated for free to owners of installations. Some member states plan to allocate a number of allowances smaller than the expected emissions to certain sectors.

Implications of carbon emission costs on market prices and generation costs[3]

The short-run marginal cost[4] represents a floor for electricity prices in liberalised markets. On a daily or weekly basis, companies will not produce electricity if the market price does not cover their variable

2. IEA, 2001: *International Emissions Trading from Concept to Reality*, IEA/OCDE, Paris, France.
3. In this short-run section, renewable technologies other than wind technology are not considered.
4. The short-run marginal cost is the change in total cost resulting from a one-unit increase (or decrease) in the output of an existing production facility. "The short run" indicates that adjustments in the capital stock (the collection of power plants) are being ignored. Adjustments in the output of existing plants are being considered. In the short-run marginal cost, only variable costs are included (e.g. fuel costs, variable operating and maintenance costs, etc.). "The long run" indicates that adjustments in the capital stock are not only being considered but are assumed to have come to completion. The long-run marginal cost includes fixed costs, investment costs and operating costs. The marginal costs, defined in the *MIT Dictionary of Modern Economics* (1992), are "the extra cost of producing an extra unit of output".

costs of generation. The introduction of a carbon "emission allowance" ought to be included in the companies' variable costs and thus in its short-term marginal costs (i.e. along with Operating and Maintenance costs, fuel costs, etc.) since an emission allowance will be needed for each unit of CO_2 produced. Allowances will initially be given for free but when allowances get a price, they will always constitute an opportunity cost. To evaluate the relation between this carbon cost and other cost factors, a model is presented based on assumptions about technology costs. The assumptions on technology costs are not intended to suggest any conclusion on such cost structures but are merely a necessary instrument to describe the relationship between the different cost factors. The model is static in its approach and it is expected that the final outcome of a CO_2 emission trading scheme will also depend on numerous interlinkages between the different factors. Numerous other analyses have been made of the effects of the EU ETS including e.g. a report by ILEX consulting (ILEX, 2003).

Implication of carbon allowances on generation costs

Short-run marginal costs play a key role in cost-based power auctions because they help determining the competitive price on the market. Many power markets rely on a central day-ahead auction in which generators submit individual bids of quantity and price and the system operator uses these to determine the price of the market based on the consumers' demand. To find the market supply curve, individual plants' supply curves are summed horizontally. To determine the merit order of the market, a ranking of generators with those with the lowest average variable costs to those with the highest was built using IEA data.

In power markets with surplus capacity, too much capacity is chasing too little demand. Electricity spot prices are determined by the marginal supplier who meets the demand. In such markets, merit order settles the daily market price. Therefore, if the short-run marginal plants' costs increase, spot market prices will follow this trend. To what degree the increase in costs will be reflected in the market price depends on several factors including market structure and competitive pressure from extra available generation capacity.

Figures A10.1 A and B illustrate the merit order of power generation on a market. By including an extra cost such as a carbon cost, not only has the market price increased, but there has been a change in the order of the plants' competitiveness. In Figure A10.1 B, plant 2 offers a better bid than plant 1, whereas in Figure A10.1 A, without the extra cost, plant 1 is more competitive.

Figure A10.1 A – Merit order

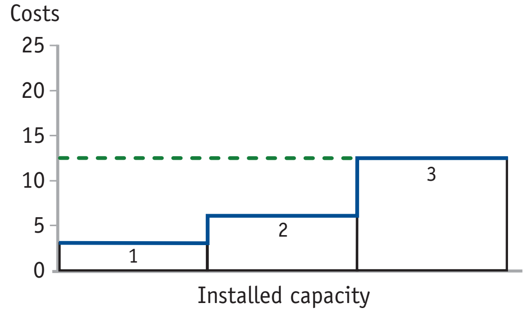
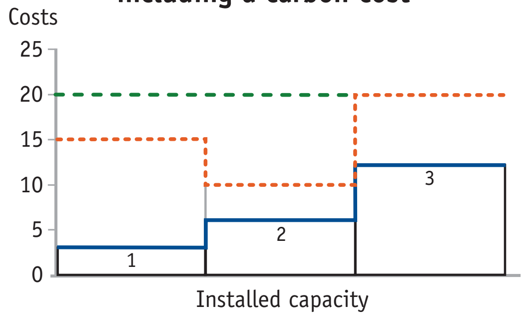


Figure A10.1 B – Merit order including a carbon cost



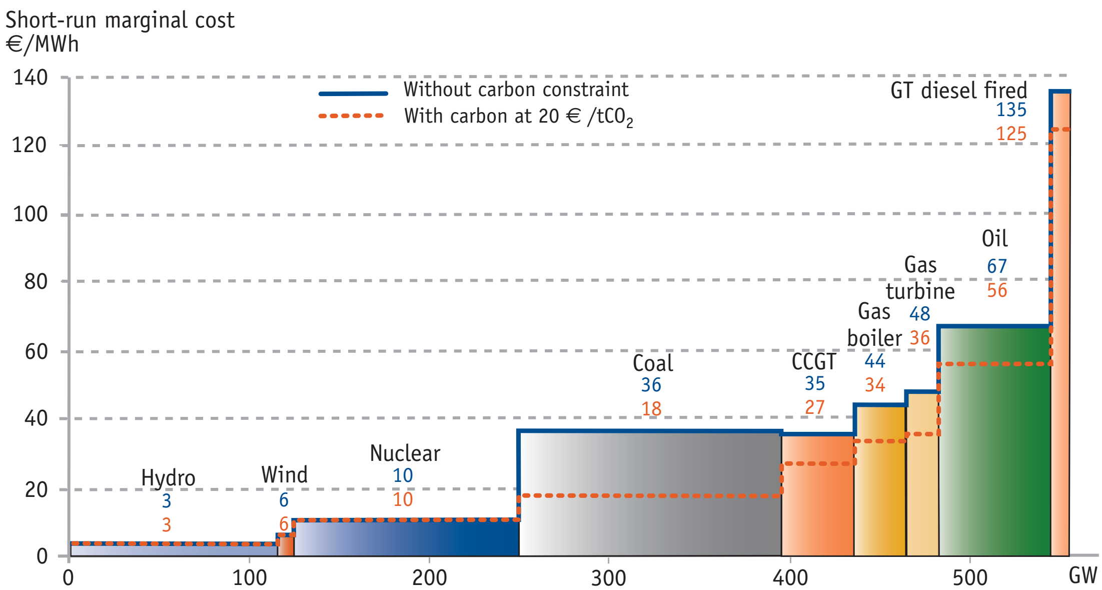
On a daily basis, as the marginal plant adds its cost of emissions into its bids, the resulting price rise is greater than the additional costs faced by most of the infra-marginal power stations. Because hydro and nuclear do not emit CO_2 and thus avoid any carbon constraint, they will benefit from the expected higher market prices. Less carbon intensive facilities will receive profits whatever the choice of allocation. Operating margins at existing generation plants could therefore, in the short run, increase drastically. To what extent asset values of carbon intensive facilities vary will depend on the percentage of allowances that will be auctioned to the companies.

Short-run marginal costs were calculated based on IEA data by adding fuel price and variable Operating and Maintenance costs for each type of plant.

For the construction of our merit order, the case of the EU is taken as an illustration, considering the total installed capacity of the EU15. The purpose is to look at the potential magnitude of the effects, so details of the market operation have been ignored.[5] To analyse the effects of carbon emission allowances on the merit order, allowances at an assumed price of 20 €/tonne of CO_2 have been included. It is still very difficult to make price forecasts and even more so to foresee how prices may develop over time.

Figure A10.2 represents an hypothetical merit order based on the total European installed capacity and facilities' operating costs. The question is whether the merit order is preserved after the introduction of a carbon emission allowance cost or whether certain power technologies become more competitive than others.

Figure A10.2 – European merit order and impact of a 20 €/t CO_2 carbon price



Source: IEA Data.

Table A10.1 – Cost assumptions for combined cycle gas turbine and coal-fired power plants

	Unit	CCGT	Coal
Fuel price at plant	€/GJ	3.5	1.5
Thermal efficiency	%	49	37
Fuel costs	€/MWh	25.7	14.5
Variable O&M costs	€/MWh	1.5	3.3
Short-run marginal cost	**€/MWh**	**27.2**	**17.9**
CO_2 cost	€/t	20	20
CO_2	t/MWh	0.412	0.918
CO_2 cost	€/MWh	8.2	18.4

According to the power plant assumptions detailed in Reinaud, 2003 (see Table A10.1), in terms of short-run marginal cost, conventional hydro, wind and nuclear plants are the most competitive on the market. Coal plants with a fuel price at 1.5 €/GJ and combined cycled gas turbines (CCGT) with a gas

5. Concerns about interconnection or transmission costs and constraints have been ignored in order to cnsider the EU power market as a single competitive market.

price at 3.5 €/GJ are the next facilities in the merit order. Their relative competitiveness is sensitive to fuel price. Gas prices have to decline to approximately 2.23 €/GJ before the two facilities have the same short-run marginal cost. At gas prices lower than this, CCGT technologies are more competitive.

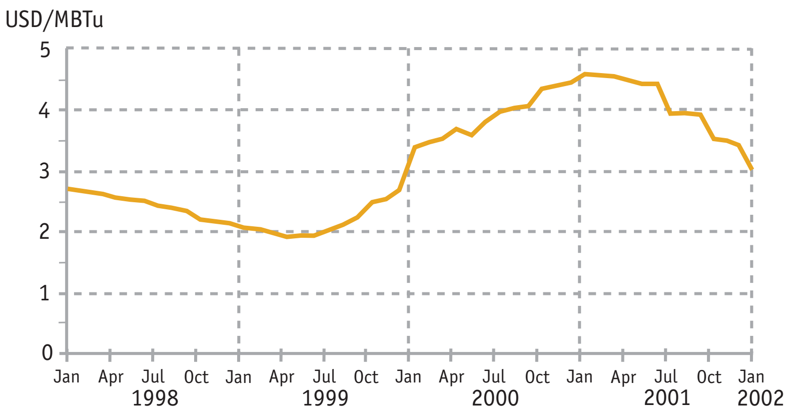
A variation in the carbon emission price has a similar effect on the plants' competitiveness as a change in fuel prices. There can be a change in merit order when a carbon emission price is included as an additional variable cost because gas has lower CO_2 emission per unit of power produced than coal. At a CO_2 price of 20 €/tonne, the competitiveness order for coal and CCGT power plants reverses.

This breakeven price between an existing coal-fired power plant and an existing gas-fired power plant is clearly sensitive to a number of the assumptions:

- **Gas prices**. Gas prices are volatile. According to the *World Energy Outlook 2002*, in 2010 the average gas price of European imports is projected to decrease to 2.8 USD/MBtu (or 3.1 €/GJ). This price is nevertheless expected to increase to 3.3 USD/MBtu in 2020. Therefore, as a CCGT would operate for approximately 25 years, the fuel costs would vary considerably which could in turn influence the plants' competitiveness.
- **Efficiency rate**. Some analysis suggest that the CCGT starting operation around 2010 could reach an average efficiency rate of 57%, which would bring down the costs for running such a plant as well as lower the carbon dioxide emissions. Similarly, a coal plant starting operation in 2010 could expect an efficiency of 46%.
- **Other costs driven by other environmental policies**. In the EU, the Large Combustion Plant Directive might also affect the plants' operating costs. Investment decisions made on implementing fluidised gas desulphurisation at coal plants could have impacts on the plants' emissions.
- **Operating and Maintenance costs**.

The scenarios for the range of gas prices are based on the average European gas import price from January 1998 to January 2002 (See Figure A10.3).

Figure A10.3 – Average European gas import price 1998-2002

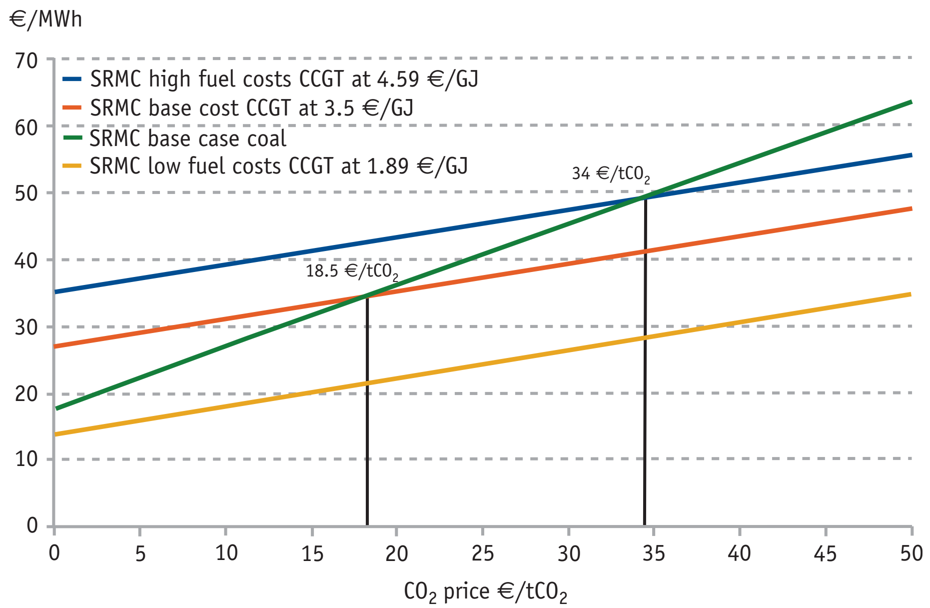


Source: IEA Data.

Figure A10.4 represents a simplified sensitivity analysis based on varying fuel prices. This was conducted to determine the implications of the variations in gas prices (both short-term volatility and long-term trends) on the short-run marginal cost and on the carbon emission price which equalises the competitiveness of coal and gas plants.

Figure A10.4 also shows the changes in CCGT plants' operating costs in relation to varying gas prices.[6] The issue here is to understand whether coal-fired or CCGT plants are more competitive at different fuel prices, and at what CO_2 price are these technologies equivalent in terms of competitive bids. The breakeven CO_2 price equals 18.5 €/tonne of CO_2 under the assumptions that the gas price is at 3.5 €/GJ, and the coal price is estimated at 1.5 €/GJ.

Figure A10.4 – Sensitivity of short-run marginal costs to gas price variations



This breakeven price of CO_2 is very sensitive to the fuel prices. If gas prices rise to 4.59 €/GJ, the maximum European gas import price over 1998-2001 period (see Figure A10.3), the carbon price would have to rise to 34 €/tonne of CO_2 to equalise the competitiveness of coal and gas. A 40% change in gas prices leads to an 84% change in the breakeven price. The relative competitiveness of coal and gas is twice as sensitive to gas price differentials as it is to CO_2 price. Given the sensitivity of the breakeven price to gas assumptions, the switch in competitiveness between the two technologies could occur in a range[7] of different CO_2 price, depending on plant specifics (location, fuel price, efficiency, etc.).

If, however, the gas price falls under 2.23 €/GJ, CCGT plants will always be more competitive than coal plants at a 1.50 €/GJ coal price, regardless of any carbon emission price. In this case, the price of coal as a fuel for power generation will naturally decline in order to allow a better competitiveness of this type of fuel. A response from coal producers would then be likely to occur in order to maintain their market shares.

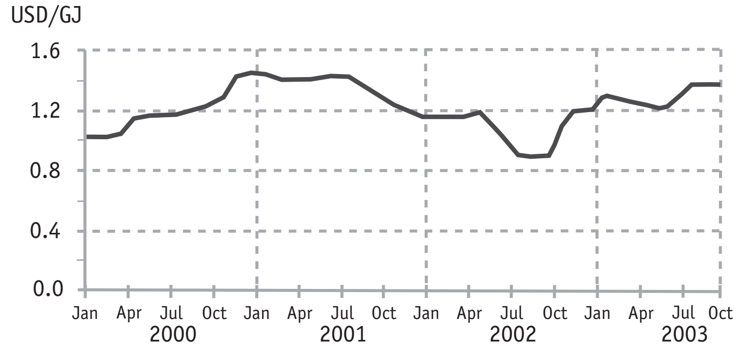
The scenarios for the range of coal prices are based on the ARA index variations between January 2000 and August 2003. During this period, the coal price varied between 0.95 €/GJ to 1.54 €/GJ (see Figure A10.5).

This breakeven price of CO_2 is also sensitive to the coal prices, but to a lesser extent than to gas price variations. If coal prices rise to 1.66 €/GJ, the maximum price forecasted in 2010, the breakeven CO_2

6. A similar sensitivity analysis could be made for varying coal prices.

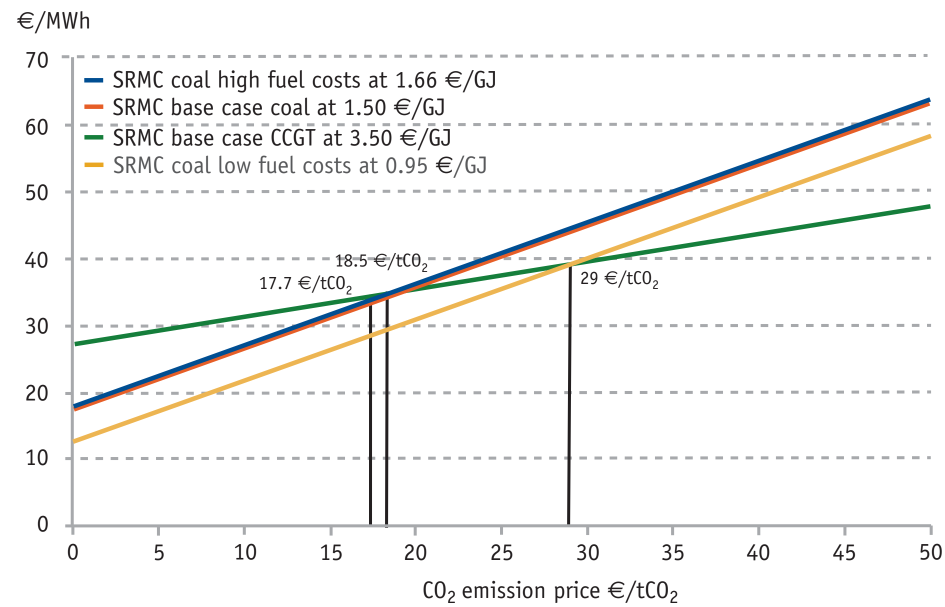
7. The range of CO_2 breakeven prices could be from zero (if the gas price makes the CCGT plant more competitive than the coal plant) to an upper end (34 €/tonne of CO_2).

Figure A10.5 – Steam coal price variations January 2000 to August 2003 (ARA Index)



Source: Datastream

Figure A10.6 – Sensitivity of short-run marginal costs to coal price variations



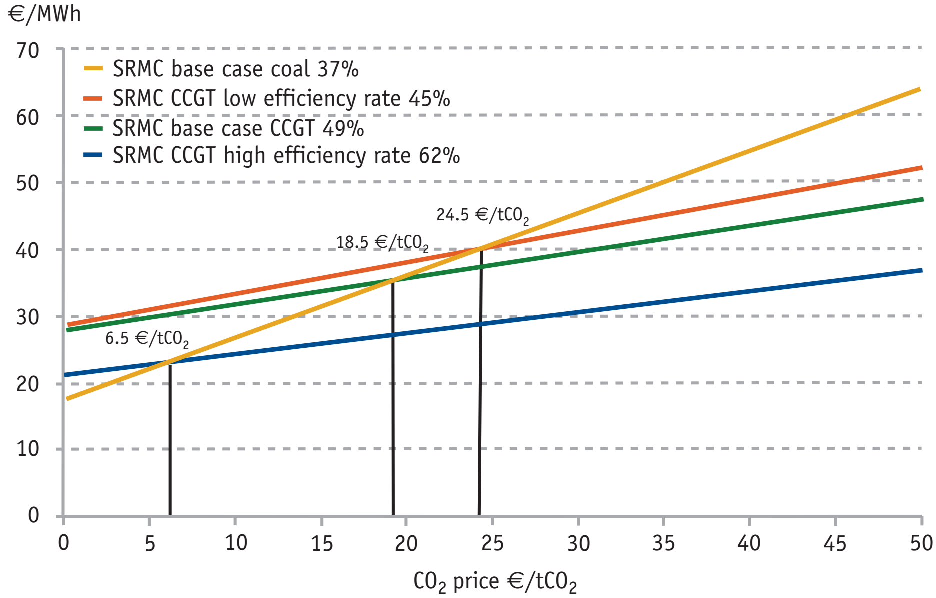
price decreases to 17.7 €/tonne of CO_2. If, however, the coal price falls to 0.95 €/GJ, the carbon price would have to rise to 29 €/tonne of CO_2 to equalise the competitiveness of coal and gas (see Figure A10.6). A 28% decrease in coal prices leads to a 57% increase in the breakeven point. In this case, the relative competitiveness of coal and gas is less than twice as sensitive to coal price differentials as it is to CO_2 price.

Similarly, a sensitivity analysis on the CCGT plants' efficiency highlights the effects on the CO_2 price which makes the two technologies equivalent in terms of competitiveness. The efficiency rate in the CCGT base case equals 49%.

As illustrated on Figure A10.7, at a low efficiency rate of 45% for existing plants, there is a 9% increase in the CCGT's fuel costs and an 8% increase in the short-run marginal cost (SRMC). Henceforth, the CO_2 price which equalises the competitiveness of coal and CCGT plants rises by 32% to 24.5 €/tonne of CO_2.

If the CCGT plant's efficiency rate reaches 62%, the maximum rate forecasted for plants built in 2030, the fuel costs decline by 22% and the SRMC by 20%. The breakeven CO_2 price falls by 65% to 6.5 €/tonne of CO_2.

Figure A10.7 – Sensitivity of short-run marginal costs to efficiency rate



Overall, the CO_2 emission price sensitivity to elements included in the power plants' variable costs is very significant. Variations in gas prices and improvements in CCGT efficiency will lead to a situation where gas and coal plants are occasionally reversed in the merit order due to additions of carbon prices within the expected range:

- The CO_2 emission price which makes CCGT and coal plants equal in terms of short-run marginal costs (the breakeven price) is estimated around 19 €/tonne of CO_2. Below this price, coal plants appear to be more competitive. Above this price, CCGT plants seem more competitive.[8]
- Starting from a price of around 19 €/tonne of CO_2, there appears to be a significant change in the electricity market merit order due to a reverse in the competitiveness based on short-run marginal cost of coal and combined cycle gas turbine plants.
- The sensitivity of this breakeven[9] price to changes in the underlying assumptions is high. For example, a 53% increase compared to the baseline gas price taken in the model leads to a 120% increase in the CO_2 breakeven price (rising from 19 € to 34 €/tonne of CO_2). Likewise, the sensitivity of the breakeven price to assumptions about plant efficiencies is even higher. If the CCGT plant's efficiency increases from 49% to 62%, the rate forecasted for plants built in 2030, the breakeven price falls by 71%.

8. It is important to note that this result is based on power plants' assumptions on an aggregate level and do not inclcude plant specificities. Therefore, in reality, this breakeven point should be considered as a proxy.

9. The breakeven price discussed is the CO_2 price which makes CCGT and coal plants equal in terms of short-run marginal cost.

The longer term impact on investment decisions

To encourage new capacity addition, expected wholesale prices have to cover the future long-run marginal costs of generation. These costs include operating and capital costs required for new capacity. It is only if the future market prices are expected to reach the long-run marginal cost of plants that investors decide on building new power plants. In liberalised markets, electricity prices that remain above this level will trigger the building of new plants which will push the prices back down. The long-run marginal costs of generation depends on the technology.

Changes in generation mix: directions and trends in investment

Table A10.2 gives a summary of the technical, economic and financial parameters assumed in a new CCGT and coal plant. The calculations in this model do not reflect all the details of an actual power plant project[10]. The assumptions and some justifications are detailed in Reinaud 2003.

Table A10.2 – Long-run marginal cost assumptions of new CCGT & coal plants

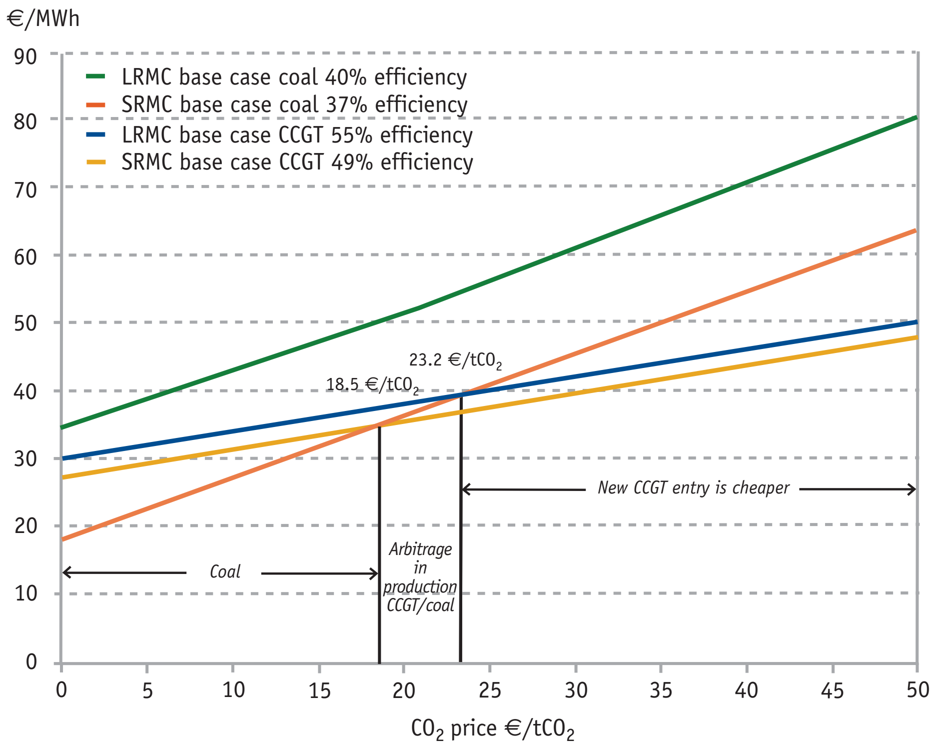
	Unit	CCGT	Coal
Plant Capacity	MW	600	750
Capital Costs	€ million	300	825
Economic Plant Life	Yrs	25	30
Capacity factor	%	80	80
Fuel Price	€/GJ[a]	3.00	1.66
Fuel Costs	€/MWh	19.6	14.93
Cost of Capital	€/MWh	5.75	12.65
Variable O&M Costs	€/MWh	1.50	3.33
Fixed O&M Costs	€/MWh	2.33	3.50
Thermal efficiency	%	55	40
Pretax return	%	8.06	8.06
Depreciation	€/MWh	2.85	5.23
Long-run marginal cost	**€/MWh**	**29.18**	**34.41**
CO_2 cost	€/t	20	20
Carbon emitted	t/MWh	0.367	0.85
CO_2 cost	€/MWh	7.344	17.028
LRMC with carbon	**€/MWh**	**36.95**	**51.43**

a. Conversion rate assumption is 1 USD = 1 €

Comparing short-run marginal costs with long-run marginal costs shows at which level it is more profitable to continue operating an existing coal-fired plant rather than build a new gas-fired one. Figure A10.8 shows which technology is more competitive in relation to a varying carbon emission price using a coal price at 1.50 €/GJ and a gas price at 3.5 €/GJ.

10. For additional information on investments required across all energy sectors, see *World Energy Investment Outlook*, IEA, 2003.

Figure A10.8 – Comparison between coal and CCGT plants' competitiveness



Source: IEA Data

Without any carbon emission price and under normal circumstances, operating costs of an existing coal plant are lower than full costs (or long-run marginal costs) of a new CCGT plant. However, in the decision making process, if a carbon emission price is introduced, depending on its level, it will be a decisive element in terms of running an existing plant or building a new one.

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List of Main Abbreviations and Acronyms

ABWR	Advanced boiling water reactor
ALWR	Advanced light water reactor
B	Boiler
BWR	Boiling water reactor
CC	Closed fuel cycle
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CR	Combustible renewable
CT	Combustion turbine
de NO_x	Unspecified NO_x control system
de SO_x	Unspecified SO_x control system
DH	District heating
DOE	Department of Energy (USA)
Dust	Unspecified particulate control system
EC	European Commission
EIA	Energy Information Administration
ESP	Electrostatic precipitator
EUCG	Electric Utility Cost Group
FBC	Fluidised bed combustion
FC/G	Fuel cell/gas
FF	Fabric filters
FGD	Flue gas desulphurisation
FP	Fission product
FR	Fast reactor
GCR	Gas-cooled reactor
GT	Gas turbine
GWe	Gigawatt electric
IAEA	International Atomic Energy Agency
IGCC	Integrated gasification combined cycle
kWh	Kilowatt-hour
LG	Landfill gas
LNB	Low NO_x burners
LNG	Liquefied natural gas
LWR	Light water reactor

MIT	Massachusetts Institute of Technology
NCU	National currency unit
NEPIS	Nuclear economic performance information system
NPP	Nuclear power plant
O&M	Operation and maintenance
OT	Once through fuel cycle
PBMR	Pebble bed modular reactor
PFC	Pulverised fuel (coal)
PHWR	Pressurised heavy water reactor
PS	Pumped storage
PV	Photovoltaic
PWR	Pressurised water reactor
R&D	Research and development
SC	Super critical steam cycle
SCR	Selective catalytic reduction (de NO_x)
SLT	Standing Group on Long-term Co-operation
ST	Steam turbine
STC	Steam turbine condensing plant
USD	US dollar
VVER	Russian type of pressurised water reactor
WI	Waste incineration

OECD PUBLICATIONS, 2 rue André-Pascal, 75775 Paris Cedex 16
PRINTED IN FRANCE
OECD No. 53955 2005
(66 2005 01 1 P) – ISBN 92-64-00826-8