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INTRACERT: INCEPTION REPORT

The role of an integrated tradable green certificate system in a liberalising market

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Preface

This report is the first result of co-operation in the InTraCert project: 'The Role of an Integrated Tradable Green Certificate System in a Liberalising Market', funded by the European Commission in the Fifth Framework Programme (contract no. NNE5/1999/428). The project is co-ordinated by the Netherlands Energy Research Foundation (ECN). Other contractors are Zentrum für Europäische Wirtschaftsforschung (ZEW) in Germany, RISØ National Laboratory in Denmark, Universidad Autonoma de Madrid (UAM) in Spain and the Centre for Management under Regulation at the University of Warwick (CMUR) in the UK.

The chapters of this Inception Report have been written by UAM and are based on the underlying country reports that are included in the Annex of this Inception Report. Each project partner has written three country reports:

ECN	Belgium, Italy and the Netherlands,
CMUR	Greece, Ireland and the UK,
RISØ	Denmark, Finland and Sweden,
UAM	Luxembourg, Portugal and Spain,
ZEW	Austria, France and Germany.

Report on the home countries of the project partners, i.e. the UK, Denmark, Spain, Germany and the Netherlands are quite elaborated. The remaining EU countries have not been described as thoroughly.

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Abstract

The InTraCert project aims to explore the possibility of integrating the existing and planned Tradable Green Certificate (TGC) schemes in the European Union and, therefore, creating a plausible unified market for TGCs. Particular attention will be paid to the possibilities of integrating TGCs for green electricity, heat and gas. Furthermore, it intents to examine the possible interactions arising from such a system with more direct GHG abatement measures, i.e. Carbon Emissions Trading (CET). The scope of the InTraCert project requires specific information for EU-15 countries regarding, on the one hand, Renewable Energy Sources (RES) used for electricity, gas and heat generation and, on the other, GHG emission levels and national strategies. In order to account for this information need, specific country inventories have been designed and carried out by InTraCert members in this first phase of the project. The inventory shows that Belgium, Italy, Denmark, the Netherlands, Austria, Sweden and the UK seriously want to implement a TGC system. The systems will indeed be nationally oriented; hardly any provisions for international trade in the different TGCs will be put in place. An essential prerequisite for efficient cross border trade is agreement on the carbon credit that comes with RE production. What is the size of the carbon credit and will this credit be attached to the TGC while traded? These will be the main questions to be answered in the next phase of the InTraCert project.

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1 INTRODUCTION

Renewable energy is becoming one of the pillars through which the European Union plans to envisage the Kyoto Protocol commitment of reducing its emissions of greenhouse gases (GHG) by 8 per cent during the period 2008-2012 in comparison with its level in 1990. Specifically, the European Commission has advocated for the doubling of Renewable Energy Sources (RES) contribution to the EU energy balance, so that it reaches 12 per cent in 2010 (European Commission, 1997). The recently released proposal for a European directive on the promotion of electricity from RES shows that the Commission is serious in reaching this 12 per cent (European Commission, 2000).

In a context of progressively liberalising energy sectors in EU-15 countries, with different competitive levels and with diverse promotion schemes for RES, the policy integration process within the EU, regarding RES-promotion with Tradable Green Certificates (TGCs) and GHG abatement schemes, faces important challenges, which need thorough analysis and discussion.

The InTraCert project aims to explore the possibility of integrating the existing and planned TGC schemes in the European Union and, therefore, creating a plausible unified market for TGCs. Particular attention will be paid to the possibilities of integrating TGCs for green electricity, heat and gas. Furthermore, it intents to examine the possible interactions arising from such a system with more direct GHG abatement measures, such as Carbon Emissions Trading (CET).

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The structure of these Country Inventories has been intentionally designed to provide enough flexibility to allow the inclusion of all the important qualitative information required for the subsequent research phases of the project and, at the same time, to point out the specific relevant quantitative data available. The inventory for each country follows a unified pattern. First, a general introduction to the energy sector is given, in which a thorough analysis of the electricity sector is carried out based on the information from an earlier Altener project (Altener, 1999). Second, a historical background and overview of the liberalisation process as well as the relevant RES information are provided. Non-electric generation from RES, specifically green gas and green heat are addressed. Finally, the GHG emission sector is reviewed attending to comparative data.

This report draws from the Country Inventory reports submitted by the InTraCert participants. The major features of the set of inventories are briefly outlined and compared across countries. Further details and data on the relevant issues may also be consulted by taking a closer look at the country specific documents, which are attached in the Annex.

2 GENERAL OVERVIEW OF THE EUROPEAN ENERGY SECTOR

In static terms and concerning major sources of energy the reliance on fossil fuels is a major common feature of EU Member States. Differences appear, however, with regard to the percentage distribution in the use of coal, oil and natural gas, with different implications for achieving environmental goals.

By adopting a dynamic perspective, a change from some traditional sources of energy to alternative sources can be appreciated. For example, the increased use of natural gas seems to be a recent trend in some countries. A shift away from coal is also common to most countries. Both features are stressed, for instance, in the UK, Austrian and German reports. In Greece there is a strong dependence on traditional fuels but a rapid increase in the use of natural gas in the last five years. However, in Germany the use of oil has been predominant, the use of natural gas, nuclear energy, hydro power and wind energy has been increasing, while the use of coal has decreased. Italy and Portugal are moving strategically to natural gas, partly with the aim to reach their environmental targets. The use of coal has also gone down drastically in Belgium, up to the point where its exploitation has been phased-out. On the other hand, the nuclear electricity sector has been developed and natural gas imports promoted in the last years. In France, nuclear power and oil have dominated primary energy consumption for more than a decade. Dependence on nuclear power is especially significant in electricity production. An 'against the grain' in this respect is Italy's shift to coal in order to reduce energy dependency.

A high percentage of total primary energy consumption is covered by oil in the EU. Table 2.1 shows the share of different energy sources in gross inland consumption in the Member States and the evolution in time. In all countries oil is the predominant fuel in gross inland consumption, except in Finland, France and Sweden, where 'other fuel types' account for 39, 45 and 62 per cent of gross inland consumption respectively, and the Netherlands where natural gas has the highest share. Almost 100 per cent of the energy consumption in Luxembourg is covered through imports. Portugal also has a low degree of energy self-sufficiency; the ratio of total domestic production over gross consumption was 15 per cent in 1997.

Data on energy consumption classified by sectors is present in some of the reports. In Italy, industry accounts for 44 per cent of energy consumption and transport for 25 per cent. In Portugal industry is also the major consumer of energy (44 per cent) with transport lagging behind (34 per cent). In both the UK, Ireland and Luxembourg there has been a huge rise of energy use in transport between 1970 and 1998. In the UK a moderate increase in energy use in the domestic and service sectors has occurred. In Ireland the rise in energy consumption has been moderate in the residential sector and substantial in the tertiary service sector. There has also been an important decrease in energy use by industry in absolute terms in the UK, and in relative terms in Ireland.

With respect to data on renewables, the common feature is the low proportion of final energy consumption accounted by renewable energy sources. In Belgium, Germany, Ireland, Luxembourg, the Netherlands and the UK renewable sources of energy contributed less that 2 per cent in 1997. In France, the use of non-hydro renewable energy and waste amounted to 4.4 per cent of total primary energy supply in 1999 due mainly to the contribution of solid biomass. In Italy, the share of renewable energy in the primary energy mix was 7.2 per cent in 1998. The four countries where renewable energy sources represent the highest proportion of gross inland energy consumption (over 20 per cent - large hydro included) are Sweden, Austria, Finland and Portugal. In Sweden, RES covered 39 per cent of energy supply in 1996.

Table 2.1 *Percentage distribution of gross inland consumption by fuel type in 1990 and 1997*

Country	Solids	Oil	Natural gas	Other[1]
Austria 1997	12.7	41.2	22.9	23.2
Austria 1990	16.4	41.0	20.3	22.3
Belgium 1997	15.2	40.8	20.5	23.4
Belgium 1990	21.6	37.4	17.3	23.7
Denmark 1997	31.0	46.3	18.1	4.6
Denmark 1990	33.5	47.3	9.9	9.3
Finland 1997	22.0	30.1	8.7	39.2
Finland 1990	17.9	34.7	8.1	39.3
France 1997	6.0	36.0	12.9	45.0
France 1990	9.1	40.0	11.2	39.6
Germany 1997	25.2	39.9	20.7	14.1
Germany 1990	37.1	35.0	15.5	12.3
Greece 1997	34.4	59.0	0.8	5.9
Greece 1990	36.5	57.7	0.5	5.4
Ireland 1997	23.6	52.0	22.8	1.6
Ireland 1990	34.3	45.1	18.6	2.0
Italy 1997	6.7	55.1	28.3	9.9
Italy 1990	9.4	58.0	25.2	7.4
Luxembourg 1997	8.8	55.9	17.6	17.6
Luxembourg 1990	30.6	44.4	11.1	13.9
Netherlands 1997	12.1	36.4	47.1	4.3
Netherlands 1990	13.6	36.5	46.0	3.9
Portugal 1997	16.4	65.3	0.5	17.8
Portugal 1990	15.4	68.6	0.0	16.0
Spain 1997	17.5	53.0	10.7	18.9
Spain 1990	21.2	51.1	5.6	22.1
Sweden 1997	5.0	31.5	1.4	62.2
Sweden 1990	5.8	30.9	1.1	62.3
UK 1997	17.1	36.2	34.6	12.1
UK 1990	30.0	38.7	22.4	8.9
EU-15 1997	15.8	41.8	21.5	21.0
EU-15 1990	22.9	41.5	16.9	18.7

[1] Includes nuclear, hydro and wind, net imports of electricity and other energy sources.
Source: European Commission (1999).

Table 2.2 shows that nuclear power accounts for a high share of electricity production in Sweden, France and Belgium (47, 79 and 60 per cent in 1997, respectively). Slightly below the EU average are Spain, Germany, Finland and the UK. In the other countries nuclear power represents less than 5 per cent of electricity generation, in most of them the figure is zero. Hydro (including large hydro) and wind are the predominant sources of electricity generation in Austria and Luxembourg, accounting for 66 per cent and 75 per cent of gross electricity production, respectively. Finland, France, Italy, Portugal, Spain and Sweden are above the EU average. By taking a closer look at the figures in Table 2.2, we extract the conclusion that some countries have a relative advantage, as they benefit from a saving of thermal generation of electricity with respect to the EU average. The countries with significant savings in this regard are: Austria, Belgium, France, Luxembourg, Spain and Sweden.

Table 2.2 *Percentage share of energy sources in electricity generation (1997)*

Country	Nuclear	Hydro & wind[1]	Thermal
Austria	0	65.6	34.4
Belgium	60.1	1.6	38.3
Denmark	0	2.3	97.6
Finland	30.2	17.7	52.1
France	78.5	13.5	8.0
Germany	30.9	4.3	64.8
Greece	0	9.5	90.5
Ireland	0	5.0	95.0
Italy	0	18.6	81.4
Luxembourg	0	74.6	25.4
Netherlands	2.8	0.7	96.6
Portugal	0	38.6	61.4
Spain	29.6	19.4	51.0
Sweden	46.8	46.3	6.9
UK	28.4	1.8	69.8
EU-15	35.5	13.3	51.2

[1] Including pumping.
Source: European Commission (1999).

Finally, concerning thermal generation of electricity by fuel type, it is relevant to note that in most countries thermal electricity is generated mainly by solids (Denmark, Finland, France, Germany, Greece, Ireland, Portugal, Spain and the UK). In a few countries the predominant fuel in thermal electricity generation is natural gas (Austria, Luxembourg and the Netherlands). In Belgium both natural gas and solids have a relevant share in this respect. Oil is the most important fuel in Italy, while Sweden is an exemption, as biomass is the predominant source in thermal electricity generation.

Table 2.3 *Thermal electricity generation by fuel type (1997)*

Country	Solids	Oil	Natural gas	Biomass & geothermal[1]
Austria	25.3	12.0	49.4	13.3
Belgium	46.2	3.0	43.9	7.0
Denmark	63.7	16.5	14.7	5.1
Finland	58.5	3.4	20.9	17.1
France	58.1	12.9	16.5	12.5
Germany	81.3	1.7	15.4	1.7
Greece	77.6	21.4	1.0	0
Ireland	48.5	18.5	32.6	0.5
Italy	10.4	53.5	28.8	7.3
Luxembourg	0	0	70.0	20.0
Netherlands	29.1	3.8	61.3	5.9
Portugal	62.3	31.6	1.8	4.2
Spain	70.8	12.7	14.0	2.6
Sweden	19.4	19.7	13.9	47.4
UK	55.4	3.6	39.2	1.7
EU-15	55.3	14.2	25.8	4.7

[1] Geothermal is only relevant in Italy, where it accounts for 5.5 per cent of thermal power generation.
Source: European Commission (1999).

3 STRUCTURE OF THE ELECTRICITY SECTOR IN EUROPE

Although a detailed description of the European electricity market is a difficult task, due to the diversity of country situations and the liberalisation process, we will follow the criteria from Cross (1996), who distinguished between two types of structural systems: centralised and decentralised.

Centralised systems are characterised by one vertically integrated utility owned by the government that dominates the national electricity production and transmission, as well as a large part of the distribution sector. France, Ireland, Greece, Italy, Belgium and Austria (although this is arguable for Austria because rather regional energy policies dominate there) have a centralised system.

France
In France, Electricité de France has benefited from a quasi-monopoly of generation, transmission and distribution of electricity. It is centrally planned and controlled, being a clear example of a state monopoly. It owns more than 90 per cent of the installed electricity generation capacity and the grid systems in France. The Ministry of Industry has been directly in charge of the French power sector as a regulatory authority. On the other hand, electricity prices in France have been based on a price-equalisation principle (geographically uniform).

Ireland
In Ireland, the Electricity Supply Board (ESB) forms a vertically integrated electricity utility involved in electricity generation, grid transmission, distribution, and regulation of the industry, with the power to grant permits to other operators. However, as envisaged in the new arrangements of the Irish government the liberalisation process might slightly modify this picture. An independent Regulatory Authority will probably be established. The operation of the transmission system will be separated from ESB, placing it in a public limited company in State ownership. Other proposals are being considered (see Country Inventory for further details).

Greece
In Greece, the Public Power Corporation (PPC) operated the state monopoly in the electricity sector for five decades, being involved in production, transmission and distribution of electricity. These exclusive rights of PPC were softened in 1985, when some auto-production was permitted. Under the 1994 Law, independent producers and auto-producers activities were explicitly allowed, although electricity not used for auto-consumption had to be delivered to PPC under regulated tariffs.

Italy
In Italy, Ente Nazionale per l'Energia Elettrica (ENEL) is the state-owned Electricity Company, which had a practical monopoly in transmission and generation until 1999. ENEL, together with local municipally owned utilities, were the only bodies allowed to transmit and sell energy. Prices were set by the government and independent power production was only allowed for self supply and for some sales to ENEL under strict price control. ENEL owns 100 per cent of transmission, 85 per cent of generating capacity and 93 per cent of distribution in Italy and is also the country's cross-border trader.

Belgium
In Belgium, municipalities used to have a legal monopoly over the distribution of electricity in their area for most customers. Today, Electrabel, Belgiums main electricity supplier, via the mixed intermunicipal companies, controls management, investment activities and, more impor-

tantly, distribution of electricity to consumers but the situation is one marked by transition (see next section on the liberalisation process).

Austria
In Austria, Verbund, a federal state owned company, traditionally dominated generation and transmission. Today, Verbund controls 50 per cent of electricity generation. The organisational structure of the sector is formed by:
- Verbund, which operates most of the large hydro plants, some thermal generation and most of the transmission system.
- Nine utilities of the Länder, which are under regional control, operate most of the thermal power plants and some hydro.
- Municipal utilities. The larger ones operate CHP stations in district heating systems.

In *decentralised systems*, the electricity sector is characterised by the existence of various utilities. Electricity supply can be under public, private or mixed ownership. Finally, most of the decentralised systems have developed co-operative pooling mechanisms in order to gain the economic benefits deriving from larger interconnected power systems.

The Netherlands
In the Netherlands, electric utilities used to be owned by local authorities at the municipal and provincial level. They delivered electricity either directly to end-users or to local distribution companies, also owned by local authorities. The utilities that produced electricity collaborated at the national level through the Dutch Electricity Generation Board (Sep), which was responsible for the national transmission grid, import, export and co-ordinated the construction of new power plants. In 1989 an Electricity Law was approved that led to some changes in the structure of the sector. There are four territorially differentiated central electricity production companies. They co-operated in the Sep, which operates as an electricity pool (until the end of 2000). The production companies are obliged to sell the electricity from the power plants first to the Sep against standardised fees that reflect the production costs. The Sep levels the costs of the different production plants and sells back the electricity to the production companies at one national basis tariff that includes the coverage of Sep's own costs. The production companies sell the electricity to the distribution companies at a higher tariff, reflecting their transport costs. The distribution companies sell the electricity to the end users at a tariff that reflects the distribution costs.

Spain
In Spain, after the law 54/1997 was passed, Red Eléctrica de España (REE) that had been in charge of running the whole electricity system (both grid and market), was left with the sole responsibility of the technical maintenance of the grid system. A new company (OMEL) was created to act as the market administrator responsible for all the financial transactions associated with the production, transport and distribution of electricity. Compliance with effective competition and overall surveillance of the electricity system and market are the responsibility of an independent public body called CNSE (Comisión Nacional del Sistema Eléctrico). Separation of production from distribution has also been an important development of the above-mentioned law.

Germany
Eight supra-regional utilities, interconnected through capital links, have been dominating the electricity market in Germany before liberalisation. In addition there were 80 regional utilities and 900 local, mostly horizontally integrated utilities in mid-1998. After the full opening of the market in one step on 29 April 1998, the eight large utilities are still the main producers of electricity, with a share of 80 per cent in public supply and in the high-voltage grid, which guarantees them a dominant position in electricity transmission as well. Further influence has been secured through an immense number of shareholdings in regional and municipal power compa-

nies, a process that intensified when liberalisation started. Strategic alliance, take-over and merger activities in the sector have been the order of the day since then, especially among municipal utilities but also between the supra-regional utilities, which have started to merge with each other. It has been predicted that only three or four of them will survive in the medium-run.

Denmark
In Denmark, the generating companies use to be owned by the distribution utilities, which in turn belonged to municipalities and consumer co-operatives. The generating companies owned Elkraft and Elsam, which were responsible for co-ordinating supply and demand and managing the two transmission grids. The new Danish energy reform of 1999 restructures this organisation (see liberalisation process for details on restructuring).

Finland
In Finland, the main market participants are the national grid (Fingrid) and its licensed operators, regional network operators, local distribution network operators, electricity generators and retailers and the electricity exchange. Municipalities own the 115 distribution companies. There has been a liberalisation of power transmission at all voltages; any producer can sell electricity to any end-user or retailer throughout the country and all consumers are free to select their electricity supplier. Transmission prices of electricity are kept under the control of a new electricity market regulator. Also, the formerly vertically integrated power companies IVO and PVO saw their transmission assets merged into the new transmission company Fingrid.

Luxembourg
In Luxembourg, the generation system has a decentralised structure: there are a variety of utilities in the electricity sector. Electricity supply is publicly owned. The production system is based on an authorisation procedure. Concerning distribution/transmission, two separate grids coexist. One is operated by Sotel, privately owned, the other by Cegedel owned by the state and private companies. Luxembourg imports its electricity through both distribution networks. Sotel produces some of its own power and imports electricity from Belgium under a contract with Electrabel, while Cegedel supplies the public network. Actually, 72 per cent of national electricity demand is supplied by Cegedel. Supplies are either directly delivered to consumers or to small municipal and private suppliers. Third party access to the electricity network is restricted.

Portugal
Electricidade de Portugal (EDP) has traditionally dominated Portugal’s electricity sector. After 1991 EDP no longer had a monopoly in generation, but retained the monopoly in grid transmission and distribution. In 1994 EDP was unbundled. The new Grupo EDP is structured as follows: a 49 per cent privatised holding company (EDP), a production company which runs 43 power stations (CPPE), a grid company (REN) which owns and operates the transmission grid and is engaged in interconnections with Spain, four regional distribution companies and ten service companies. The system is under the control of the regulatory authority ERSE, which regulates the two-tier electricity market, that is, the centralised and closely regulated PES, as well as the independent IES. ERSE plays an important role in controlling the prices charged by the grid owner and by the suppliers.

Sweden
In Sweden*,* the electricity sector was an economically planned system, which consisted of decentralised regional monopolies, supplemented by state-company engagement (specially on the production side). After the Swedish electricity market reform in 1996, the grid was organisationally separated from the production services. A new state company (Svenska Kraftnät, SK) administers the national grid. For the regulation of the high-voltage grid, SK relies on operators working on a contractual basis. The low voltage grid is regulated by NUTEK (an extra ministerial authority). Vattenfall, the main power production company, remained in public hands. However, there is a large number of electricity producers, distributors and power plants that can

be owned by the State, by local authorities, by industry, or by commercial utilities. The distribution system operators are responsible in a given geographic area. A concession either for a service area or line operation from the State Energy Authority is necessary in order to be allowed to build and manage an electricity network.

The United Kingdom
The UK electricity supply industry was denationalised in 1989, divided into generation companies and 12 Regional Electricity Companies. Regulatory powers were given to the Secretary of State for Energy. The industry is currently divided into the following sections: generators (companies that produce electricity), the national grid company (the company that owns and operates the high voltage electricity grid system), distributors (companies that own and operate low voltage electricity distribution networks) and suppliers (companies that buy electricity from generators and sell it to consumers).

4 OVERVIEW OF THE LIBERALISATION PROCESS

The Council Directive 96/92/EC of 19 December 1996 has given the guideline for the future development of the electricity sector within the EU by setting common rules for the internal electricity market. The goal is to introduce free market mechanisms in the traditional regulated and protected markets of the Member States. It is expected that this process will lead to lower prices for electricity for all consumers and, therefore, to an increase in competitiveness of the entire industry in the EU.

The first step is to be made by unbundling the three main functions of the electricity business. In the future, generation, grid transmission and distribution will have to be administratively independent from each other.

The Directive requires the national parliaments to issue national laws on the introduction of the deregulated market. The creation of a free market does not need to occur at once; a step by step implementation is envisaged.

Certainly, countries differ on the extent to which they have liberalised, at least legally, their electricity and gas sectors. According to the country reports, a few countries seem to have advanced significantly on the liberalisation front (e.g. UK and Germany), while others fall far behind (e.g. France and Greece). Another group of countries has taken decisive measures to deregulate and liberalise, but it cannot be said that they achieved full liberalisation. In this section we briefly look at each country's efforts in this respect. The reader is encouraged to consult the Country Inventories for further details.

The heterogeneity of national situations concerning the degree of liberalisation of each respective electricity sector seems to be the most relevant conclusion we can infer from the country reports. Liberalisation in the electricity sector takes place in phases concerning the eligibility of consumers to choose their suppliers. Tentatively, countries could be grouped in three wide sets according to the degree of liberalisation introduced in their home electricity markets: proactive, reactive and the group in-between. Germany, UK, the Netherlands, Sweden, Finland and Denmark would form the proactive category, being the frontrunners of liberalisation.

Germany

The act for the revision of the German energy industry legislation came into force on April 29 1998, stating that the article of the Antitrust Law (which exempted some industry sectors from the general ban on cartels) was non applicable for the electricity (and gas) supply any longer. Contrary to the gradual approach envisaged in the EU Directive, both the German electricity and gas markets were 100 per cent opened in one step, at least legally. The Directive was translated into national legislation in time and the liberalisation efforts have gone far beyond liberalisation targets set by the Directive, establishing a universal access rule to the grid. The model provided under the new regulation is one of Negotiated Third Party Access (NTPA), where grid access rules and transmission tariffs are left to the industry itself. Separation of accounting has to be implemented but neither legal unbundling nor changes in network ownership or separation have been required. In spite of the liberalisation targets achieved, grid access rules and tariffs, which are the result of a voluntary agreement between German electricity utilities, industrial energy and power sector associations and industry associations, are considered to be an obstacle for real competition. However, electricity prices for all groups of customers have fallen dramatically already.

The United Kingdom

The UK already completed the liberalisation of energy markets in 1999. It has been an extensive process starting with the Electricity Act of 1989, which denationalised the industry and gave regulatory powers to the Secretary of State for Energy. The UK electricity market was liberalised in phases, with large customers (with consumption capacity over 100 kW) able to choose their supplier first. In theory, since early 1998 all consumers have been able to choose their electricity supplier. In practice, however, the industry was not completely ready for liberalisation on this scale.

The Netherlands

The Dutch Electricity Law was passed in Parliament in 1998 in order to implement the Directive. Currently, customers consuming over 2 MW annually and representing 33 per cent of electricity demand in 1995 can choose their supplier, while household consumers and small business will only be free to choose their supplier in the year 2004. However, consumers of RES are already eligible to switch supplier in 2001. Regulated Third Party Access (RTPA) is the mechanism used to regulate access to both the high-voltage grid and the distribution networks. There is legal unbundling of the main functions of the electricity business. Network owners are obliged to publish tariffs and the technical requirements for use of the network. Network management should be vested in a separate company ensuring independence from other activities of network owners.

Sweden

In Sweden, all customers are allowed, at least in theory, to choose their supplier since the 1996 electricity reform. In reality, however, high transaction costs prevent this from happening on a wide basis, specially for small customers and private households. The Swedish electricity market reform in 1996 demanded full organisational separation of the grid on the one hand and sales and production services on the other. The reform included a separation of the high voltage transmission system from the state power company Vattenfall. Now a new state company Svenska Kraftnät administers the national grid. For the regulation of the high-voltage grid, Svenska Kraftnät relies heavily on operators working on a contractual basis, especially on Vattenfall. The low voltage grid is regulated by NUTEK (an extra-ministerial authority). The reform opened up common carriage and third-party access for all domestic networks. The main part of the electricity system remains under public control. Finally, concerning property laws, power companies are open for private investors, foreign companies have been able to buy Swedish companies.

Finland

In Finland, all consumers were free to select their electricity supplier since January 1997, although hourly kWh metering was required until 1998. Since the revision of the Finnish Electricity Act in 1995, any producer could sell electricity to any end-user or retailer throughout the country. Licenses for electricity imports have been recently removed and thus the government no longer controls energy imports. The electricity market regulator keeps surveillance of transmission prices, however, due to monopoly nature of the transmission business.

Denmark

In Denmark, full marketing for all consumers will take place before 1 January 2003, as foreseen in the 1999 Danish Electricity Act, which also deals with the distribution of electricity functions. Four types of companies are envisaged, at least until 2003, and some restrictions apply to them:

- Production and trading companies. Ownership by these companies of more than 15 per cent of the other categories of companies will not be allowed.
- Grid companies, responsible for the management of the grid, energy savings and energy efficiency. Elected consumers will keep the controlling influence of these companies. In theory, everybody will have access to the grid against payment of non-discriminatory tariffs.

- Supply obligation companies. These companies must offer electricity to all consumers in a certain area against ‘reasonable conditions’. It can be expected that the commercial production and trading companies will more and more serve eligible consumers, as the number of free consumers will grow in the next three years. Therefore the supply obligation companies are typically companies that play a role in the transition period.
- System responsible companies will be responsible for the security of supply, co-ordination of the overall system and for the implementation of special demonstration and development programs. High profits for the owners of these companies will not be possible.

A new Energy Supervisory Board will be set up that will supervise the setting of the grid tariffs, will keep an eye on the quality of grid and system services, and take care that price structures are not discouraging energy savings

Included in the reactive group are Italy, Greece, France, Luxembourg and Portugal, which can be considered as the laggards in the liberalisation process.

Italy
In Italy, the legislation needed for the liberalisation of the electricity sector came only at the date of the deadline (19 February 1999).

Greece
Currently, the Greek government is reconsidering the regulation for the electricity sector, following the European Directive. The proposed legislation foresees a first step of deregulation of the electricity market for 19 February 2001. Consumers on the mainland with electricity consumption over 100 GWh/year, i.e. 23 per cent of the market, are the first to be liberalised. Furthermore, the new legislation foresees unbundling of the activities of the Public Power Corporation (PPC), the state monopoly in the production, transmission and distribution of electricity, and access to the grid for licensed electricity generators and traders.

France
In France, efforts to liberalise have been progressing very slowly, becoming one of the latecomers in the deregulation front. Market opening was to be oriented to the minimum stipulations of the Directive. 20 per cent of the French market was opened only when Community Law became immediate applicable legislation. France transposed the EU Directive on February 2000 (one year after the official deadline). Out of a total net industrial consumption of 390 TWh France has opened 115 TWh to competition (customers consuming more than 20 GWh/year). France has opted for RTPA. Setting the grid tariffs will be the job of the Ministry on advice from the regulator.

Luxembourg
Luxembourg is also one of the latecomers of liberalisation. Third party access to the electricity market is restricted due to fears that foreign suppliers take over the market. Therefore, the distribution and transmission systems adopted have been the RTPA. Market opening after liberalisation is considered to be around 45 per cent. Eligible consumers will be those utilities producing more than 100 GWh.

Portugal
Portugal’s restructuring of the electricity supply industry came in 1994 when the Electricidade de Portugal (EDP) Group, traditionally the core player in the Portuguese electricity market with a monopoly in generation, transport, distribution and public supply of electricity, was unbundled and partially privatised (although it remained in public hands). The system is under the control of the regulatory authority ERSE, which started its activities in 1997. ERSE regulates the two-tier electricity market formed by the PES (Public Electricity System), which represents the non-competitive market segment where tendering is necessary and by IES (Independent Electricity

System) which represents the competitive market segment based on authorisation. RTPA (and a single buyer) has been the distribution and transmission system chosen. Market opening has reached 26 per cent while eligible customers are those above 15 GWh/year.

Finally, a group of countries seems to be firmly progressing towards liberalisation or has already introduced significant liberalisation: Austria, Ireland, Belgium and Spain.

Australia
The Austrian Chancellor announced on March 28 2000 that, starting from 1 October 2001 every electricity consumer will be free to choose its electricity supplier. For the moment, the legislation passed as a reaction to the EU Directive and sets the system access on the basis of a single buyer system without obligation to purchase electricity contracted by eligible consumers. Up to now, eligible consumers are final industrial customers with a consumption above 20 GWh/year and distribution system operators which also operate transmission systems. 58 per cent of the market has been liberalised already. Tariffs for the use of the system are set by decree. No legal unbundling is required but a separate financial balancing of the different divisions is. The major Austrian generator remains with 51 per cent of the shares in public ownership. The model for access to the grid will be the RTPA.

Ireland
In Ireland, 28 per cent of all electricity is supplied within a liberalised market. Large customers (above 4 GWh/year) and renewable electricity customers can choose their supplier. In order to accomplish a full liberalisation process, however, ESB (the Electricity Supply Board), a vertically integrated electricity utility with a monopoly on generation, transmission and distribution and also responsible for the regulation of the industry, should be substituted by an independent regulatory regime. An independent role must be given to the function of dispatch of generating stations and the operation and planning of the transmission systems. While new arrangements have been proposed, nothing has yet been decided.

Belgium
Belgium's market opening will encompass 35 per cent by the end of 2000 and 100 per cent in 2007. Until 2007 eligible consumers will be the large consumers linked to the transmission grid and the distribution companies with an amount of electricity consumed by their customers larger than 40 GWh. The system chosen for access to the grid is NTPA. The Electricity Regulation Commission (ERC) is the new regulator responsible for the liberalised market, supervises the Transmission System Operator and may decide on maximum prices for eligible consumers. The distribution system used to involve about 600 municipal companies that have a monopoly regarding customers requiring less than 1 MW in supply. They organised in intermunicipal organisations partly owned by Electrabel. After the European Commission found that the dominant position of Electrabel in production and distribution markets violated the Community competition rules, both reached a compromise agreeing on cessation by Electrabel of exclusive supply of electricity by 2011. Thereafter all distribution companies will be free to choose their supplier. On the other hand, they agreed that mixed intermunicipal companies will have the right to obtain 25 per cent of its total requirements for electricity supply from third parties.

Spain
The basic regulation that led to the liberalisation of the Spanish electricity system was approved in 1997 (Electricity Law and accompanying Decrees). Of utmost relevance is to note the six elements of the liberalisation process:
1. Freedom of construction of new electricity generating plants.
2. Competition between electricity generators in an electricity market based upon a system of competitive bids of electricity.
3. Freedom of consumers to choose the supplier after negotiation of the conditions and price of kWh.

4. Freedom of electricity trade.
5. Freedom of access to the electricity distribution grid and transport network.
6. Freedom to buy or sell electricity to firms and consumers from other Member States.

5 RENEWABLE ENERGY PROMOTION STRATEGIES

The promotion of renewable energy (RE) has become an important tool for the EU countries to serve several purposes:
1. Reduce CO_2 emissions - Comply with the Kyoto Protocol commitments.
2. Promote local RES (biomass, wind, solar) - Create employment.
3. Promote a dynamic and innovative 'clean-tech' industry.
4. Reduce energy dependency ratios.
5. Diversify the energy mix and reinforce grid-systems (sometimes overload grid systems).
6. Generate positive effects on the environment.

As societies increasingly value the environment, environmental assets, such as renewable energy, become more and more integrated into markets. The institutional framework under which RE attempts to become competitive is of great relevance when trying to couple the need for liberalising and integrating energy markets in Europe.

This section provides some background information regarding different RES promotion schemes at the national, EU and international level. These interactions are at the centre of a medium-term strategy to integrate RE markets within the EU. However, it is important to note that the European Commission, with regard to support schemes for RES-E being currently operated in Member States, '...has concluded that insufficient evidence exists to provide, at this stage, for the introduction of a harmonised Community wide support scheme setting the price for RES-E through community-wide competition between RES-E generators, in particular with regard to direct price support being the most important form of support in practice' (European Commission, 2000).

An overview of the different RES promotion schemes operated in each country is given in Schaeffer et al., 1999 and in the Country Inventories in the Annex. RES promotion strategies may be classified as follows (see also the review report by the Green Electricity Cluster, Faber et al., 2000):

1. Direct promotion mechanisms - In the case of generation-based mechanisms, generators of electricity from RES, on the basis of state regulation, receive, directly or indirectly, financial support in terms of a subsidy per kWh supplied.
    - *Regulatory-Price driven strategies* - A specific price is set for RES-E accompanied by an obligation by electricity companies (distributors) to accept and pay all electricity coming from RE domestic producers at the determined price. The extra cost of electricity is usually transferred to final consumers through regulated tariffs. These schemes are mostly used in several EU countries, but notably in Germany and Spain (feed-in). However, a mixture of various strategies is found in all countries.

      Investment focussed
      - Investment subsidies
        The most widespread instrument to stimulate renewable energy sources has been subsidies. In general, they can be divided into subsidies on renewable energy capacity and subsidies on renewable energy output. Subsidies on installed capacity only stimulate supply but not demand of renewable electricity. Moreover, subsidies on installed capacity might be unfairly distributed if the total amount of subsidy is limited, and they have to be abolished if the technology that is stimulated becomes too widespread (Schaeffer et al., 1999). In general, relatively higher levels of subsidy are given to promote the technological development of the as yet less economical technologies, such as rooftop PV systems. Technologies closer to the market,

such as wind, do also in many cases profit from subsidies, albeit at relatively lower levels (Schaeffer et al., 1999).

- Tax rebates and incentives

Some EU countries support renewable electricity via the tax system. These schemes may take different forms. These forms range from rebates on general energy taxes, rebates from special emission taxes, proposals for lower VAT rates, tax exemption for green funds, to fiscal attractive depreciation schemes.

Generation based

- Feed-in tariffs
  Subsidies on output, in the form of guaranteed prices in combination with a purchase obligation by the utilities, have proved to be very successful in promoting the deployment of renewable energy sources. The levels of guaranteed prices vary considerably from country to country. On average, regulation in Germany, Denmark, Spain and Italy offer the highest prices. The appropriate regulatory authority to reflect falling prices due to technological progress may modify the fixed tariff. However, this may be resisted by existing RES-E generators. The tariff may also be supplemented with subsidies from the State, as e.g. in Denmark where a subsidy per kWh delivered to the grid is paid to independent producers (Schaeffer, et al., 1999).
- Rate-based incentives

- *Regulatory-Capacity driven strategies* - These type of strategies are based on the decision by the Member State on the desired level of RES-E penetration. The price is therefore set through competition between RES-E generators. These types of incentive schemes are used in the UK (bidding), Ireland (bidding), the Netherlands, Denmark and Belgium (green certificates). Again, these schemes are usually mixed with others like investment subsidies and tax rebates.

Non-tradable quotas

- Bidding procedures

One way to give all players an equal opportunity that includes a mechanism to drive down costs is to provide a limited subsidy on output that is awarded to only a limited number of investors. These investors will have to compete for the subsidy through a bidding system. For each bidding round only the most cost-effective offers will be selected to get the subsidy. The RES electricity is sold at market prices, while the difference between sale and purchase price is financed through a non-discriminatory levy on all domestic electricity consumption. The Member State decides on the desired level of RES, the mix between different renewable energy sources, their growth rate over time and the level of long-term security offered to producers over time. Bidding or tendering systems currently prevail in the United Kingdom and Ireland. France and Austria also use this instrument on a small scale.

- Renewable Portfolio Standards / Quotas

Tradable certificates

- Electricity based
- CO_2 based
- Integrated

2. Voluntary approaches - Based on the willingness to pay of consumers.
   - Investment focussed (shareholder programmes)
   - Generation based (green tariffs)
     Green energy in the form of green electricity has been offered as a product to customers since 1995, first in the Netherlands and later on also in other European countries (e.g. Finland, Sweden, UK, and Germany). Customers that buy green electricity pay a pre-

mium on their electricity price. Their utility guarantees that the same amount of electricity for which they pay a premium price has been produced at a renewable basis. This is monitored by an independent organisation, often NGOs such as the World Wildlife Fund. Green electricity pricing is a voluntary market initiative of the electricity sector.

3. Indirect promotion strategies - Regulatory decisions being taken affecting non-renewable sources of energy, have an indirect incidence on the RES market. For instance, coal subsidy reductions or higher oil taxes, may positively affect the deployment of RES-E.
   - Taxes on electricity produced with non-renewable sources
   - Taxes/permits on CO_2 emissions
   - Fossil and nuclear subsidy reductions

6 GHG EMISSOINS SECTOR IN EUROPE

The greenhouse gas (GHG) emissions sector is a newly emerging sector born from the need to reach International Agreements (UNFCCC) to prevent emerging climate change related problems due to GHG emissions into the atmosphere. Each Member State has presented its own communications to the UNFCCC on its CO_2 emission level and a joint commitment on the part of the EU countries has been approved and signed. This agreement theoretically allows the Community to allocate the burden of reduction in a more efficient way.

Over the 5 year commitment period the EU is allowed to emit a total of 5 times 92 per cent of its total 1990 GHG emissions. This allows for the fact that variations will occur in total GHG emissions from year to year, due to environmental, climatic and other factors. The EU's aggregate 8 per cent commitment to GHG reductions was divided between Member States in 1998. Table 6.1 shows that there is a wide range of commitment levels in the EU, which reflects many factors, including the current emissions total and the level of industrial activity in each State. The agreed levels were fiercely negotiated, and many States won relaxation of the level of emissions reduction proposed for them by the European Commission.

Member States may also have their own internal commitments to climate change actions. Table 6.2 gives an overview of the development in CO_2 emissions over the period 1990-1995 in the Member States.

Table 6.1 *Division of emissions reduction commitments for EU Member States [%]*

Country	Emissions reduction commitment
Austria	-13
Belgium	-7.5
Denmark	-21
Finland	0
France	0
Germany	-21
Greece	+25
Ireland	+13
Italy	-6.5
Luxembourg	-28
Netherlands	-6
Portugal	+27
Spain	+15
Sweden	+4
UK	-12.5
EU	*-8*

The Country Inventories contained in the Annex intent to provide enough information on the national approaches given to the commitments on this issue, as well as quantitative data on the emission levels and possible indicators.

Flexible mechanisms

The Kyoto Protocol incorporates several distinct mechanisms providing enough flexibility to subscribed nations to comply with their assigned amounts of GHG emissions reduction within the agreed period 2008 - 2012. These mechanisms, however, are not only the result of an intent to provide flexibility, but they should be understood in the context of an international stakeholder debate where, in most cases, national economic interests prevail over environmental concerns. Hence, the need to accommodate the views of all actors (in this case - signing Nations) generates complexity and uncertainty in the functioning of an international market aiming to reduce anthropogenic GHG emissions to the atmosphere.

The instruments described below (based on Grubb et al., 1998), if coherently implemented and coupled with credible international institutions, may provide enough integrity to the market as to succeed in attaining the end goal of the UNFCCC.

Bubbles
The Kyoto Protocol incorporates the ‘bubble’ concept into the final text of Article 4. Although originally conceived as a way of allowing the European Community as a regional economic integration organisation to accommodate its internal burden sharing of the Kyoto commitments among its member states, the final wording of the Article is framed in general terms. It allows a group of Annex I countries to jointly fulfil their commitments under Article 3, provided that their total combined aggregate GHG emissions do not exceed their assigned amounts. A bubble must be declared when the ratification is deposited. Once the terms of agreement have been registered with the UNFCCC Secretariat, the commitments agreed on cannot be revisited during the commitment period in question. The ‘bubble’ approach is often termed as ‘trading without rules’ because it sets few restrictions on trading between parties. If it turns out to be too difficult to agree on the common rules and guidelines for verification, reporting and accountability for emissions trading pursuant to the Kyoto Protocol, the ‘bubble’ approach at least opens the possibility of trading emissions permits within the voluntarily-formed group. In addition to the current EU bubble, the US has reached a conceptual agreement with Australia, Canada, Japan, New Zealand, Russia and Ukraine to pursue an umbrella group to trade emissions permits. Whether this develops into a fully-fledged bubble under Art. 4 remains to be seen.

Emissions Trading
The Kyoto Protocol also accepts the concept of emissions trading under Article 17, which allows one Annex B country to purchase the rights to emit greenhouse gases (GHG) from other Annex B countries that are able to cut GHG emissions below their ‘assigned amounts’ (AAs). Although Annex B to the Kyoto Protocol and Annex I to the UNFCCC are now identical in nature, this change from Annex I into Annex B potentially allows a developing country to engage in emissions trading if it voluntarily adopts an emissions target and is inscribed in Annex B. Because the emissions trading proposal was adopted at the very end of the Kyoto negotiations, designing ‘the relevant principles, modalities, rules and guidelines’ governing emissions trading has been deferred to a subsequent conference. Such design of a workable emissions trading scheme is essential to the success of emissions trading. The market-based emissions trading approach can only achieve significant cost reductions in cutting GHG emissions while also allowing flexibility for reaching compliance if it is structured effectively. The present study aims to facilitate the design of an international emissions trading scheme that is both workable for the parties eligible for emissions trading and acceptable to all the parties to the Protocol. Emissions trading transfers ‘assigned amount units’. Assuring that the post-transfer commitments are appropriately adjusted requires that the amount transferred should be added to the buyer’s assigned amounts and deducted from the seller’s assigned amounts (Art. 3 (10,11)).

Joint Implementation
Project-oriented emission reduction credited to the investing country is relevant for world wide cost minimisation. This possibility was named ‘Joint Implementation’ (JI) in the negotiations leading to the Rio Conference. In 1995, the Berlin Conference of the Parties decided on a pilot phase for JI without crediting called ‘Activities Implemented Jointly’ (AIJ). By 2000, it should be decided whether AIJ will be followed by JI with crediting. The Kyoto Protocol allows JI between Annex-I countries (Art. 6). It does not state, though, whether AIJ projects will automatically become JI after 2000. JI projects shall be approved by all involved parties and be ‘supplemental’ to domestic action (Art. 6 (1d)). Guidelines, verification and reporting rules will be defined (Art. 6 (1c)). Emission Reduction Units (ERUs) created through JI are treated in the

same way as ERUs from emissions trading under Art. 17 (Art. 3 (10,11)). ERUs from JI do not accrue if inventories are not submitted annually or do not use the agreed guidelines (Art. 5, Art. 7). ERUs questioned through expert review teams may be transferred but are ‘frozen’ until the question is resolved (Art. 6 (4)).

Clean Development Mechanism
The Kyoto Protocol includes a new way of linking emission reduction with economic development. A ‘Clean Development Mechanism’ can be set up, which has been defined only rather vaguely (Art. 12). It leads to the creation of ‘certified emission reductions’ (CERs) (Art. 3 (12)). Art. 12 (3) states that countries that fund projects through the CDM get credit for certified emission reductions from these projects provided ‘benefits’ accrue to the host country. Crediting will be only allowed for a certain percentage of the emission target. This percentage remains yet to be defined. Besides countries, companies are allowed to invest and execute projects (Art. 12 (9)). In contrast to the other flexibility mechanisms, CERs accrue for the whole period 2000-2012, not just for the commitment period (Art. 12 (10)). On the other hand it is unclear whether sequestration is covered. The CDM shall cover its administrative budget through project revenues. Moreover, a ‘part’ of these revenues shall be used ‘to assist developing country parties that are particularly vulnerable to the adverse effects of climate change to meet the costs of adaptation’ (Art. 12 (8)). It remains open who does certification of emission reduction but verification shall be done by independent bodies (Art. 12 (7)). The project criteria remain the same as for AIJ (Art. 12 (5)).

Table 6.2 *EU-15 CO_2 emissions change 1994/95 compared with 1990*

EU-15-Member States CO_2	1994 [Gg]	Change from 1990 [%]	1995 [Gg]	Change from 1990 [%]
Austria	59,467	-3.9	62,019	-0.2
Belgium	121,297	4.5	112,194	-3.4
Denmark	63,344	21.2	59,532	13.9
Finland	59,253	10.1	56,050	4.2
France	386,386	-1.5	398,636	1.7
Germany	904,500	-10.8	894,500	-11.8
Greece	89,005	5.2	90,492	7.0
Ireland	33,324	8.5	33,931	10.5
Italy	422,365	-4.4	447,644	1.4
Luxembourg	11,998	-9.8	9,322	-29.9
Netherlands	168,390	4.4	176,910	9.6
Portugal	50,841	7.9	50,841	7.9
Spain	231,370	2.2	231,370	2.2
Sweden	58,438	5.4	58,108	4.8
United Kingdom	581,979	-5.2	572,109	-6.8
EU-15	3,241,957	-3.7	3,253,658	-3.3

Source: European Commission, 1998.

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ANNEX
EU-15 INTRACERT COUNTRY INVENTORIES

A. AUSTRIA

A.1 Introduction

This report is based on previous country reports by Christoph Timpe from the Öko-Institut, Germany and by VPL and Draukraft as well as on energy data from the Energieverwertungsagentur and own research work. In addition, very helpful comments by Teresa Anderson have been integrated.

There is more information on the electricity sector than on gas and heat markets.

A.2 Energy sector

A.2.1 General overview

Primary energy consumption has changed substantially in the last four decades. As illustrated in Figure A.1 below, the share of coal in total primary energy has declined from 43% in 1960 to 12% in 1997 whereas the use of gas has increased, starting from 10% in 1960, building up to 22% in 1997. Hydro energy, electricity imports and other energies always made 20 to 26% of the total primary energy consumption. The use of oil increased rapidly up to the first oil crisis in the 1970s. In 1997, 40% of the total primary energy consumption was covered by oil.

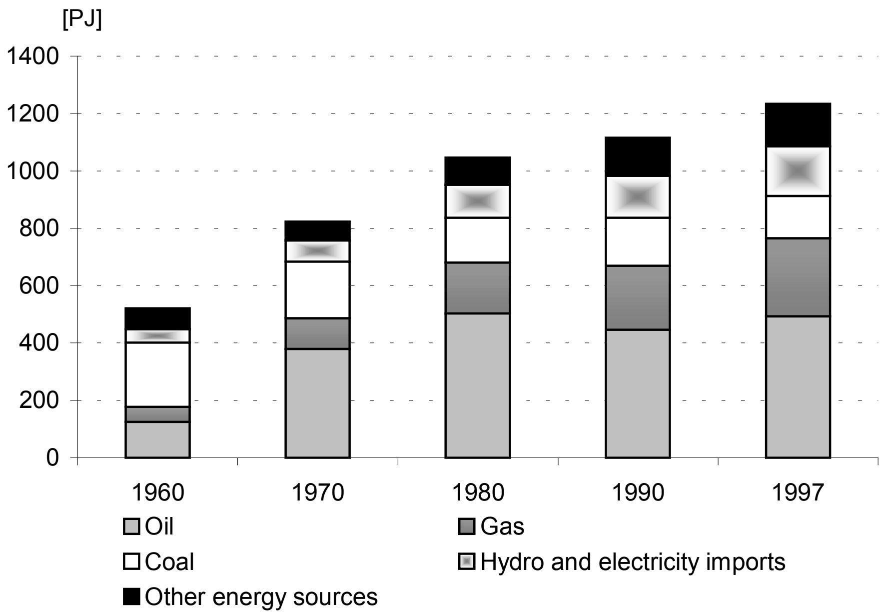

Figure A.1 *Total primary energy consumption*
Source WIFO, 1998.

Table A.1 *Basic energy indicators*

		1990	1995	1996	1997
Population	[Million]	8	8	8	8
GDP	[Billion Euro 1990]	126	139	141	144
Gross inland primary consumption	[Mtoe]	26	26	28	28
Total electricity production	[TWh]	51	57	55	57
CO_2 emissions	[Mt of CO_2]	55	57	60	60
Total EU primary consumption	[Mtoe]	1,314	1,363	1,411	1,407
Share of primary consumption in EU	[%]	2	2	2	2
Gross inland/GDP	[toe/1990 Euro]	204.14	189.68	197.51	196.60
Gross inland/Capita	[toe/inhabitant]	3.32	3.26	3.45	3.51
Electricity generated/Capita	[MWh/inhabitant]	6.58	7.03	6.80	7.03
CO_2 emissions/Capita	[t/inhabitant]	7.12	7.04	7.38	7.36

Source: Annual Energy Review 1999.

A.2.2 Electricity sector

The Austrian electricity sector is tied very closely to the state. In 1947, the Second Law on Nationalisation (2. Verstaatlichungsgesetz) was passed, which assigned electricity supply to state-owned utilities. Generation (mainly hydro) and transmission were mainly concentrated at the ‘Verbund’ company, which is in majority owned by the federal state. During the last decades, the nine provinces (Länder) strengthened the generation capacities of their regional utilities (with a larger portion of thermal generation). Today the Verbund controls 50% of electricity generation.

Austrian electricity production is characterised by the combination of hydro power and thermal power plants. In 1996, hydro accounted for 64% of the gross electricity production (54,8 TWh). The remaining power is produced from fossil fuels, mainly gas (18%) and coal (11%). Austria has no nuclear power plants.

Table A.2 *Electricity sector information for Austria*

		1990	1995	1996	1997
Total electricity production	[TWh]	50.83	56.58	54.83	56.84
Production of RES-E	[TWh]	32.91	38.47	35.57	37.29
Total installed capacity in electricity	[GW_e]	16.69	17.44	17.52	17.86
Installed capacity of RES-E	[GW_e]	10.95	11.31	11.38	11.55
Electricity prices to industrial consumers	[1990Euro/toe]	598.2	561.2	579.5	656.3
Electricity prices to domestic consumers	[1990Euro/toe]	1,425.4	1,326.8	1,383.7	1,373.8
Production of RES-E/Total E production	[%]	65	68	65	66
Installed capacity of RES-E/Total inst capacity	[%]	66	65	65	65

Source: 1999 Annual Energy Review.

The organisational structure of the sector is as follows:
- Verbund AG, under federal control, operates most of the large hydro plants, some thermal generation and most of the transmission system;
- nine utilities of the provinces (Länder), under regional control, they operate most of the thermal power plants and some hydro;
- municipal utilities (Stadtwerke), the larger ones operate CHP stations in district heating systems.

To give an overview Table A.3 shows the development of the Austrian electricity supply from 1970 to 1995.

Table A.3 *Balance of Austrian electricity supply from 1970 to 1995*

	1970	1980	1990	1993	1994	1995
River and threshold river power plants	13.091	19.011	21.413	24.283	23.522	24.793
Storage power plants	6.205	8.004	8.683	11.051	10.721	10.962
Hydropower supply of electric utilities	*19,295*	*27,015*	*30,096*	*35,.334*	*34,243*	*35,754*
Hardcoal	304	24	3,982	2,192	2,419	3,286
Browncoal	1,890	2,473	2,278	1,026	904	1,459
Fuel oil	1,132	4,249	1,264	1,390	1,489	1,064
Natural gas	2,878	2,580	5,872	5,097	5,896	6,284
Others	17	15	32	25	29	17
Thermal power supply of electric utilities	*6,220*	*9,342*	*13,428*	*9,730*	*10,738*	*12,111*
Supply of hydropower	194	226	447	684	701	710
Supply of thermal power	108	110	78	138	145	224
Supply of own generation utilities	*302*	*337*	*525*	*822*	*847*	*934*
National supply	*25,818*	*36,693*	*44,048*	*45,886*	*45,827*	*48,799*
Supply from railroad authority (OEBB)	7	2	3	3	3	3
Physical Electricity exports	1,303	3,156	6,742	8,005	8,167	7,232
Total of supply	27,128	39,851	50,793	53,893	53,998	56,034

Source: VEOe.

A.2.3 Gas sector

As a first step to liberalising the Austrian gas market, the Austrian government has proposed to open the gas market on the first of August 2000 to consumers with a demand bigger than 25 million m3 of gas per year.

A.3 Liberalisation process

Austria is progressing in liberalising its electricity and gas markets. The Austrian Chancellor Schüssel announced on 28 March 2000 that starting from 1 October 2001 every electricity consumer will be free to choose his electricity supplier. The Austrian government is heading for a first step of liberalisation on the gas market on 1 August 2000 when the market is planned to be opened for big customers with a gas demand larger that 25 million m^3.

As a reaction to Directive 96/92/EG, a new federal Law on the Organisation of the Electricity Industry was passed in August 1998[1]. With this legislation, system access is established on the basis of a single buyer system without obligation to purchase electricity contracted by eligible customers (Art. 18 (3) Directive 96/92/EG).[2]

Eligible customers are defined as follows:

- Final customers
  - with a consumption above 40 GWh/a (from 19 February 1999),
  - with a consumption above 20 GWh/a (from 19 February 2000),

1 'Elektrizitätswirtschafts- und -organisationsgesetz (ElWOG)' (Electricity Industry and Organisation Act), BGBl I 143/1998 of 18.08.1998

2 With regard to the federal system of legislation in Austria, the ElWOG itself establishes a legal framework for the liberalisation process. The provinces (Länder) are obliged to pass individual legislation under this framework until August 1999. Nevertheless, binding regulations for the liberalisation are set by the federal act.

  - with a consumption above 9 GWh/a (from 19 February 2003).
- Distribution system operators
  - which also operate transmission systems (from 19 February 1999),
  - with electricity sales above 40 GWh/a (from 19 February 2002),
  - with a consumption above 9 GWh/a (from 19 February 2003).

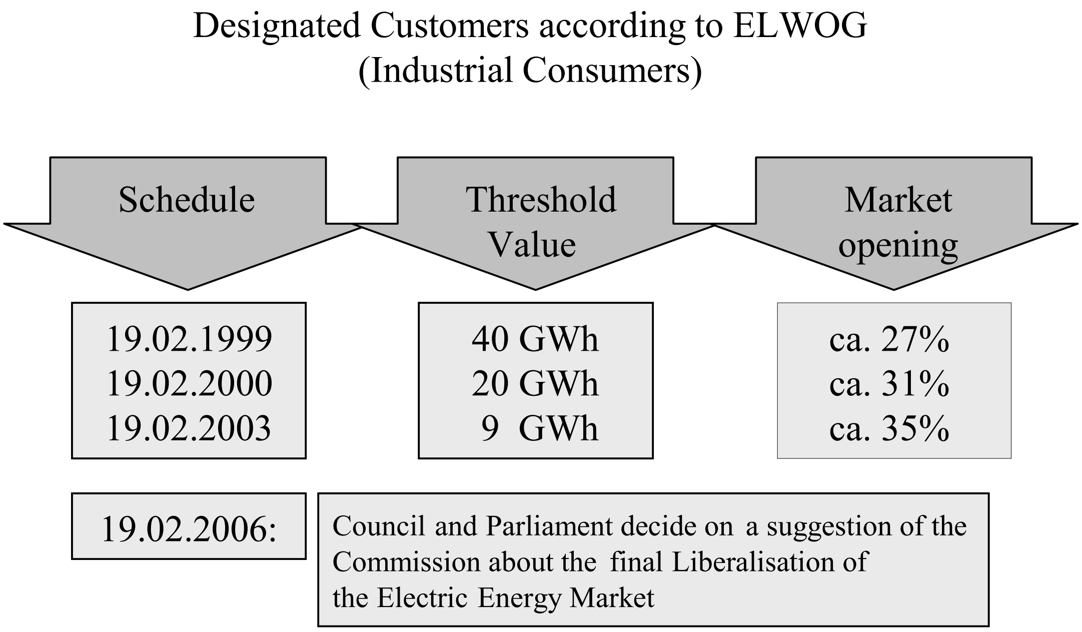

Figure A.2 *Schedule for opening the electricity market in Austria*

The tariffs for the utilisation of the system have been set by a federal decree, which was issued in February 1999. In a further decree, four power plants and one contract for delivery of coal have been recognised as ‘stranded costs’. Subject to the consent of the European Commission, a maximum of 8702 million ATS (632 million Euro) will be charged on eligible customers in the period until 2009.

In Austria the national law which is applicable for this matter is the so-called ‘Elektrizitätswirtschafts- und Organisationsgesetz’ further on referenced as ELWOG. As of July 1998 the ELWOG was passed by the parliament. It contains the following regulations:
- The main goal is to reduce prices, a secondary goal is to increase the market penetration of renewables.
- With respect to unbundling the law requires only an organisational but no legal separation of the generation, transmission and distribution divisions of a vertically integrated utility. A separate financial balancing of the different divisions is required.
- The major Austrian generator Verbund stays with 51% in public ownership.
- The designated customers which have access to the grid are industrial consumers and utilities which have an own transmission grid. The other distribution utilities will be introduced as designated customers step by step until 2004. The model for the access will be the so-called ‘Regulated Third Party Access’, further on referenced as RTPA. This model foresees a publicly announced regulation of the transmission tariffs by the government.
- Electricity from hydropower facilities will have priority access to the transmission grid but must be offered at market prices. This means that access for a power producer can be denied if there is enough hydro capacity. The payment for the hydro energy will be only depending on the market price and not on the costs for generation of the producer.

- A higher price for renewables might be fixed by the regional governments after consulting all affected parties (utilities, independent producers, the chamber of commerce, and the trade unions).

As the ELWOG has not fixed the decisions, the discussion on stranded investments is prolonged. Stranded investments are those investments which cannot be covered by revenues from electricity sales on the future liberalised market. Austrian hydropower plants were not built for electricity supply reasons only but also to create jobs, to reduce emissions from alternative plants, to reduce import dependence or to improve the Danube for international boat traffic. The high investment costs especially of the latest hydropower plants were economic only, when these social benefits were taken into account. Now there is an intensive discussion on who shall pay for these social benefits in future.

A.4 Renewable energy activities and policies

A.4.1 Renewable energy status

Table A.4 describes the amount of renewable energy production in Austria 1997 and its share in total primary energy consumption. Renewable energy sources cover about 20% of Austria's total energy supply (hydro 11%, biomass 10%). Thus, after Norway and Sweden, Austria has the third largest share of renewable-based energy supply in all IEA countries. About 65% of the technical potential is exploited. A further increase of the market share is restricted by the high investment costs, stringent environmental regulations and the resistance of the public opinion against big projects. From 11300 MW hydro power plants approximately 700 MW are small (<5 MW) hydro power plants. There is a potential for further 300 MW of small hydro.

The biomass energy production capacities can be divided into wood heating systems and biomass based local heat distribution systems with the following installed capacities:

- Wood heating systems, 1998: 2484 MW.
- Biomass based local district heating systems, 1997: 490 MW.

In terms of electricity production from biomass there are some research projects, including the co-firing of biomass to thermal power plants and combined heat and power plants. Solar thermal energy for warm water supply has reached already a remarkable value. There have been many local private initiatives to build solar collector building systems with a total solar collector capacity in 1998 of 1.87 million square metres, most of them in warm water supply for households or swimming basins.

Table A.4 *Renewable energy*

Renewable energy	Energy [PJ]	Share in total primary energy consumption [%]
Hydro power	129	10.7
Wood	81	6.4
Wood residues	22	1.8
Sewage gas, biogas, wind, pv, etc.	4	0.4
(Waste)	12	0.9
Total biomass (excl. waste)	107	8.5
Total biomass (incl. waste)	119	9.5

Source: EVA, 1999.

A.4.2 Renewable energy policy

The new Law on the Organisation of the Electricity Industry from August 1998 (ElWOG) sets a new framework for renewable electricity (in this context, 'renewable electricity' does not include hydro and waste):

- Feed-in Regulation:
  The distribution system operators are obliged to buy renewable electricity offered by independent power producers and to pay minimum feed-in tariffs, which will be defined by the governments of the nine Länder until August 1999. Extra costs from this regulation will be recovered by a surplus on the tariffs for the utilisation of the system (ElWOG, § 47).
- Minimum quota:
  The distribution system operators are obliged to raise the share of renewable energy sources in their production portfolio. A renewable minimum quota of 3 % of the electricity sold to final customers has to be fulfilled by each distribution system operator until 2005 (ElWOG, § 31). It can be expected that the minimum quota will be raised in the years following 2005. Though, it is not clear if there will be any sanctions if the minimum quota is not met by the system operators.
- Improved system access:
  Producers of electricity from renewable energy sources are allowed to deliver electricity to any customer in Austria or abroad. This includes customers, which are not regarded as eligible for system access with 'conventional' electricity (ElWOG, § 39). The tariffs for the utilisation of the system for delivery of renewable electricity are the same as for 'conventional' power.

There are divers subsidies for biomass utilisation, solar thermal collectors, photovoltaics, and wind energy. Investment subsidies and private initiatives in the field of solar thermal collector installation has been particularly successful in Austria. The state specific feed-in tariffs for photovoltaics and wind energy have not created a substantial market yet.

With regard to the large share of large hydro to the total electricity production a clear distinction has to be made between this kind of renewable power and smaller, decentralised renewable power. Large hydro plants were built in the past by the federal Verbund or the regional electricity companies, sometimes with only little regard to economic data. Thus, some of the large hydro plants now have to be regarded as 'stranded investment' in the liberalised electricity market. It can be assumed that, besides the reimbursement of these 'stranded investments' no additional support for the operation of large hydro plants is necessary. For other renewable electricity, feed-in tariffs are fixed by the provinces (Länder).

Table A.5 *Feed-in tariffs in 1998*

		Min [ATS/kWh]	Max [ATS/kWh]	Min [€/kWh]	Max [€/kWh]
Wind and Photovoltaic	Summer	0.40	0.55	0.029	0.040
	Winter	0.61	1.08	0.044	0.078
Biomass	Summer	0.38	0.55	0.028	0.040
	Winter	0.59	0.90	0.043	0.065

The tariffs vary for different renewable technologies and are dependent of the season (winter/summer) and of the time (day/night and weekend). Under the framework of the so-called 'three-year agreement', a voluntary agreement between the electricity industry and the federal government, Austrian utilities have paid an extra bonus in addition to the regular feed-in tariffs to independent producers of renewable electricity. For wind and photovoltaic, the bonus was 100 %, for biomass a bonus of 20 % of the regular feed-in tariffs was paid. These extra payments were applicable for new renewable power plants constructed until the end of 1996 (for some projects this limit has been extended until early 1998) and were paid during the first three years of operation of these plants.

In addition to these schemes, some investment subsidy programmes for renewable energy are in place. The federal programme covers 30 % of the eligible costs of wind, hydropower, landfill gas, biomass and biogas facilities. Some of the Länder have set up additional programmes.

In May 1998, the federal government implemented a new subsidisation scheme. Potential investors in wind turbines were invited to submit their offers. Contracts for subsidisation were awarded to the most cost-effective projects.

So far, 52 wind power projects have been put to operation with a total capacity of 20.3 MW, starting from only 10 kW in 1993. In 1997 32.2 GWh electricity were produced and 20 units with a total capacity of 8.5 MW were added. Under favourable market conditions 40 to 200 MW of wind power might be achieved till 2005, then producing 60-300 GWh per year. As long as the situation is not clear concerning the tariffs for selling wind energy in the liberalised market, a future development can not be foreseen.

The development of photovoltaics for electricity generation in Austria is similar progressive as the use of wind energy. Figure A.3 shows the exponential growth of photovoltaics installed capacity in the years 1988 to 1994. In 1997 the capacity reached 2140 kW at growth rates of 400 kW annually. It is estimated that under proper conditions (increased supply tariffs, investment subsidies and support programs) about 50 MW could be achieved by 2008. The use of photovoltaics can be economic in remote areas like mountain huts, where expensive transmission lines can be saved.

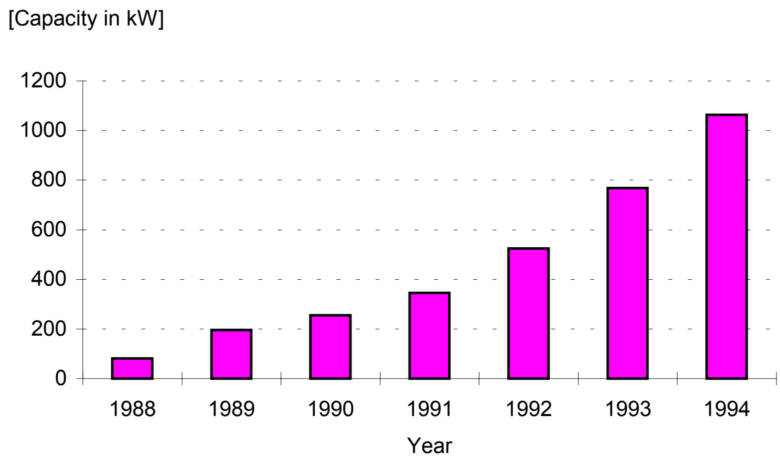

Figure A.3 *Development of photovoltaïcs in Austria*

Up to now the producers of small hydro plants, wind generators or photovoltaics systems had privileged tariffs for their energy supply. The crucial criteria for a further development of these renewables will be the political will to subsidise these energy sources with a higher price than the market allows.

A.4.3 Renewable energy potentials and costs

Table A.6 *Technical potential for renewables [TWh]*

Wind speed [m/s]	*7.5*	*6.5*	*5.5*	*4.5*
Wind: onshore	0	2.2	4.4	0
Water depth [m]	*10*	*20*	*30*	*40*
Wind: offshore	0	0	0	0
Large hydro	14.8			
Small hydro	0			
	50% of building integrated solar potential			
Photovoltaics	7.6			
Solar heating	15.2			
Solar thermal electricity	0			
Biomass electricity	*10% solids substitution*			
Fuel switch	0.4			
Biomass CHP				
(complementary to fuel switch)[%]	*fuel eff.: 65*	electricity: 33	heat: 67	
Wood (residues)	2.7	0.9	1.8	
Biogas	4.5	1.5	3.0	
Crops	3.1	1.0	2.1	

Source: Bräuer and Kühn (2000) RECert-report on market volume and market value of Tradable Green Certificates (forthcoming).

Table A.7 *Estimates for cost developments for renewables [€cents/kWh]*

	2000 low	2000 high	2005 low	2008 high	2010 low	2010 high
Wind: onshore						
7.5 m/s	2.5	4.5	2.0	4.0	1.8	3.5
6.5 m/s	3.5	7.0	3.0	5.5	2.5	5.0
5.5 m/s	5.5	9.5	3.5	7.0	3.0	6.0
4.5 m/s	8.0	15.0	5.0	11.0	4.0	9.0
Wind: offshore						
10m	3.3	6.0	2.7	5.3	2.3	4.7
20m	4.7	9.3	4.0	7.3	3.3	6.7
30m	7.3	12.7	4.7	9.3	4.0	8.0
40m	10.7	20.0	6.7	14.7	5.3	12.0
Large hydro	3	6	3	8	3	8
Small hydro	5	17	5	17	5	17
Photovoltaics						
North	60	90	48	72	38.4	57.6
Central (FR, AT)	50	75	40	60	32	48
South (GR, IT, PO, SP)	40	60	32	48	25.6	38.4
Solar heating (EU-north)	15	25	12	20	10	15
Biomass electricity						
Fuel switch	5.5	5.5	5.5	5.5	5.5	5.5
Wood	2	20	2	20	2	20
Biogas	6.5	100	6.5	100	6.5	100
Crops						
Biomass heat						
Wood	1	4	1	4	1	4
Biogas	6	8	6	8	6	8
Crops	2	6	2	6	2	6

Source: Bäuer and Kühn (2000) RECert-report on market volume and market value of Tradable Green Certificates (forthcoming).

A.5 Tradable green certificates

Austria is an active member of RECS. VÖE is about to issue a feasibility study with respect to the requirements of stock-markets from a TGC-system. Political decisions will be taken according to the outcome of that feasibility study. However, only little discussion on tradable certificates for renewable electricity has taken place in Austria so far.

A.6 Cross-cutting GHG emissions sector

In the Kyoto Protocol to the Framework Convention 38 industrialised and transition countries plus the European Community have committed to limit or reduce emissions of a set of six greenhouse gases (GHG). The European Community and its Member States have the obligation to reduce GHG emissions by 8% in the target period 2008 to 2012 compared to the emissions level in 1990. Besides the main greenhouse gas carbon dioxide (CO_2), the Protocol covers also methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6). The EU distributed the reduction obligation through the so-called EU-Burden-Sharing in conjunction with Article 4 of the Protocol among the Member States. Austria agreed on a target of -13%.

Furthermore, Austria announced a national target for CO_2. Emissions should be reduced by 2005 by 20%, compared to 1988 levels.

According to an IEA-report (1998), the implemented policies and measures will not be sufficient to meet either of the two reduction targets, despite comparatively low per-capita CO_2 emissions for Austria.

Table A.8 *GHG emissions*

		1990	1995	1996	1997
Total EU-15 emissions	[Mt CO_2]	3,336	3,259	n.a.	n.a.
Country emissions	[Mt CO_2]	62	62	64	66
Share of Austria's emissions / Total EU	[%]	2	2	n.a.	n.a.
Emissions per capita		8.03	7.75	7.94	8.18

Source: UNFCCC Emission summary for CO_2 in Austria.

B. BELGIUM

B.1 Energy sector

B.1.1 General overview

With a population of 10 million people (in 1997), Belgium has a GDP of 9 billion BEF (225 billion Euro) in 1998. The Belgian economy is particularly open, exporting as much as 73% of its GDP, and importing some 68%. As Belgium has almost no traditional domestic energy resources (nuclear power represents 94% of its total indigenous energy production), a similar percentage is found for its energy needs, which rely for about three-quarters on imports.

Belgium has been successful in phasing out the exploitation of its high-cost and uncompetitive coal, its previous energy resource, without major social problems. To enhance its energy supplies, Belgium has developed a nuclear electricity sector based on a high level of technology. In 1998, a year with a total primary energy supply of 57 Mtoe and a part of nuclear energy in it of 18%, nuclear power has been 55% of the electricity production.

Belgium has no production of natural gas, but has actively promoted natural gas imports the last years, 33% gas for electricity production in 1998. Belgium imports now mostly from the Netherlands, Algeria, Norway and to a less extent Germany, while the role of the UK will grow in the near future. Mainly because Belgium imports its gas - 13860 Mtoe in 1998, about 25% of the primary energy supply - the country occupies a key strategic position at the heart of the European gas grid. Belgium plays today an important role as a transit country for natural gas, which contributes to the security and diversification of supplies in Europe.

The rapid conversion of the Belgian power sector to gas consumption (conversion of existing units and substitution to gas in polyvalent units) has been one of the key factors to achieve stability of CO_2 emissions at the 2000 horizon. Unlike most countries, this conversion is quite finished in Belgium. This also means that there will be no bullish development of gas demand anymore.

The fundamental factor affecting the evolution of Belgium's energy policy is the Special Law of Institutional Reform that turned the country into a federal state in 1988. In the development of energy policies, significant delegation of responsibilities has been fully ascribed to the three regional governments.

Competencies of the regions:
- Distribution of gas, electricity and heat,
- Valuation of 'terrils',
- Energy efficiency and renewable energy policy,
- Utilisation of mine gas and gas 'fatals' (blast furnaces and cokes production).

Competencies of the federal authority:
- Electrical equipment,
- Nuclear power,
- Storage infrastructure,
- Transport and production of energy,
- Tariffs, fiscal regulations and commercial practice.

Often, the Federal Government's role in energy matters is limited to one of co-operation and harmonisation as is the case for the Cellule CONCERE/ENOVER (Concertation Etats-Regions pour l'Energie; in charge of the co-operation) and the Control Committee for Electricity and Gas (CCEG, see below).

As an example of federalism, each region designs its own energy efficiency programmes according to its specific interests and financial and technical capabilities. Accordingly, these policies vary greatly depending on the regions. However, many participants acknowledge that the Cellule plays a positive role in fulfilling the delicate mission of harmonising the respective positions of the three regions. Still, the IEA (1997 and 1998) has recommended that the role of the Cellule should be strengthened in the interests of all parties.

B.1.2 Electricity sector

In 1997, the consumption of electricity has been 78.4 TWh, that is 7703 kWh per capita. Government responsibility for the national equipment programme for the total electricity sector, for nuclear power, and for pricing policy, rests at the federal level with the Minister of Economic Affairs. The price regulation is one based on the rate of return principle. This government regulation is enforced through the Control Committee for Electricity and Gas (CCEG), which is responsible for recommending the tariffs to the government. The existence of this separate body, a Committee composed of representatives from the electricity industry, various consumer groups and the Government itself, may be one of the reasons why Belgian consumers have not spoken out publicly against quite high electricity prices.

Municipalities used to have a legal monopoly over the distribution of electricity in their area for most customers. Today, a great deal of the distribution is represented by the 'mixed sector' in which municipalities join forces with Electrabel via the mixed intermunicipal companies to organise distribution management and investment activities.

B.1.3 Gas sector

Even without own gas production, the Belgian gas sector is situated in the middle of the European gas industry. This industry has started to undergo fundamental changes as traditional monopoly structures are now open to competition. Triggered by the EU directive on gas market opening (the EU gas directive focuses on gas transmission) adopted in May 1998, governments are reviewing the regulatory framework of their gas industry.

The energy Department of the Ministry of Economics Affairs is responsible for the gas sector in Belgium. The same committee, the CCEG, administers the price regulation decided by the Ministry. This Committee is also composed of representatives from the gas industry, various consumer groups and the Government itself. This means that, although the Government still has a golden share in Distrigaz, it has no longer large influence on the gas industry. Once more, the existence of this Committee is one of the reasons why Belgian consumers have not spoken out publicly against rather high gas prices. (Gas distribution appears to have been more profitable than average in Belgium).

Like most countries the Belgian gas industry typically consists of a transmission and a distribution sector. Local distribution companies (LDCs) buy the gas from one transmission company based on long-term supply contracts. Transmission companies also sell to large end users, but they are few in Belgium. For the regulation of distribution, the municipalities often are the owner of the grid: they confer exclusive agreements to the LDCs which pay fees to them. For the regulation of price, the CCEG used to fix prices in all parts of the gas chain (thus, with approbation of the Government too). The approach to pricing looked like a relatively pure cost-plus approach (with no direct reference to the prices of alternative fuels). The tariff system used, to some extent, to favour certain socially disadvantaged groups, and large industrial users (which may have benefited from an implicit cross-subsidisation).

The main tax on gas is an energy tax, one based on fiscal neutrality between fuels, introduced in 1993. In addition, there are some small indirect taxes such as a withholding tax on income earned by gas distribution companies, the fees these companies have to pay to the municipalities, and, sometimes, additional local taxes.

B.1.4 Heat sector

Like other countries, Belgium has tried to map the (mostly environmental) benefits of Combined Heat and Power (CHP or co-generation). Both the possibility for local power production and the reduction of carbon dioxide emissions are an important driver behind the future potential of this approach to power generation. Therefore, the development of CHP receives priority in the framework of the Belgian National Programme for Reducing CO_2 Emissions. Moreover, CHP is also part of the National Programme for Electrical Energy Production and Transport 1995-2005.

However, Belgium will not achieve the target of 1000 MW of CHP (mainly industrial co-generation) by 2005 without a wide range of regulatory, fiscal and financial measures. Some regulatory measures, tax advantages and direct grants to promote CHP have already been adopted, but the development of CHP is hampered by barriers such as pricing policy for surplus electricity produced by autoproducers. Additional measures should be taken.

Since 1 January 1989, CHP has been under the responsibility of the regions. In Flanders, subsidies for ecological investments have also be allocated to CHP investments, with a maximum of 21% of the investment; in the Walloon region, the industry and tertiary sector can benefit from fiscal abatement for investments in energy efficiency. In a report in 1997, the IEA wanted Belgium to promptly establish an independent national body to promote CHP in co-operation with the regional governments.

Belgium is one of 16 contracting parties in the IEA project: Implementing Agreement on Heat Pumping Technologies, a project that found that the use of industrial heat pumps could reduce global energy consumption for process heating by 2 to 5 per cent. In 1998, still a very small part of the electricity production comes from heat pumps, namely 1.3%. Total renewable energy production, mainly hydro and wind, is only 1.8%, while 55% is nuclear and 42% is conventional production.

B.2 Liberalisation process

B.2.1 Recent situation and current legislation

The electricity and gas industries have traditionally been highly concentrated and integrated, in many cases preventing competition from working to benefit consumers. Electrabel, born after restructuring of three private utilities, used to supply most electricity (about 92% in 1997). Distrigaz used to have a de facto monopoly for natural gas supplies, and still does after its privatisation in 1994. Furthermore, these two industries were highly integrated as a financial holding company, Tractabel, had substantial interests in both Electrabel and Distrigaz. Electrabel, through the mixed intermunicipal companies, controlled the distribution of natural gas and electricity to consumers, thus giving it a monopolistic position with possible market distortions. In the gas market, the situation has been similar, again preventing competition as it was extremely difficult for other companies to enter gas distribution. Therefore, structural reforms, consistent with policies at the EU level, were needed in Belgium to create competitive, efficient and more flexible electricity and gas markets. Today, the situation is one marked by transition.

For example, the long duration of the agreements between Electrabel and the mixed intermunicipal companies for electricity distribution still impedes competition by preventing other electricity producers from selling electricity. The same agreements also prevent any other distributor from offering its services to the municipalities.

Electricity

Belgium has chosen the modality of licensing for generation of electricity while no dispute resolution has been taken into account. Expeditious dispute resolution is often seen as prerequisite to establish confidence of market participants in the liberalisation process. The Chambre d'Appel only deals with transmission, not with disputes on generation contracts, which may make it difficult to challenge the conditions in the license, and the outcome of awarding contracts.

Market opening will be 35% in 2000 and 100% in 2007. Eligible consumers until 2007 are the large consumers linked to the transmission grid and the distribution companies, for the amount of electricity consumed by their customers larger than 40 GWh.

Belgium, unlike most other member states, has chosen for negotiated third party access (nTPA), a system with which the parties are asked to engage into commercial negotiations for access to the grid. A new regulator, the Electricity Regulation Commission (ERC) is responsible for the liberalised market. Of course, the system is regulated for non-eligible consumers until 2007, under the existing CCEG. The ERC supervises the Transmission System Operator that manages the network and deals only with transmission issues, mainly access to transport network and technical regulations. This new dispute resolution may decide of maximum prices for eligible consumers.

The distribution system used to involve about 600 municipal companies, which have a monopoly regarding customers requiring less than 1 MW in supply. Municipalities have organised themselves in intermunicipal organisations, which consist of two types. The public intermunicipal companies (PI) are fully owned by public authorities, whereas the mixed intermunicipal companies (MI) are partly (ca. 50%) owned by Electrabel. End 1995 Electrabel started to intensify its grip on the distribution sector by adapting its MI contracts. The major changes it wanted to make were the extension of the contracts to 30 years and making the municipalities shareholders in Electrabel (ca. 5%). However the European Commission (EC) did not approve these extensions. The European Commission found that the dominant position of Electrabel, both in production and distribution markets, violated the competition rules of the EC Treaty. In April 1997 Electrabel and the EC came to a compromise. The EC accepted a term of 15 years in stead of 30 years. Therefore, the following changes (among others) of the statutes of the mixed intermunicipal electricity distribution companies in all three regions were agreed:

- Exclusive supply of electricity by Electrabel will cease completely in 2011. Thereafter, all distribution companies will be free to choose their supplier.
- From 2006, the mixed intermunicipal companies will have the right to obtain 25% of its total requirements for electricity supply from third parties (and this will be the baseload supply, while Electrabel will continue to supply the balance, including peakload supplies).

Consequently, to ask free access to the electricity market for distribution companies in the short term (before 2006), is rather a pressure position, which will not lead to much change in practice.

Gas

As known, the gas directive intends to create a competitive market in natural gas by introducing minimum rules governing transmission, storage, and distribution of natural gas. That the directive does not address the production of gas is not of much significance for Belgium that has no natural gas production at all. Therefore, it focuses on access by third parties (at least, the 'eligible customers') to network facilities in order to enable them to buy gas from the suppliers of their choice. The definition of eligibility appears to be governed by higher threshold levels of gas consumption and achieves therefore lower percentage shares of market opening when compared with other countries: 45% in 2000, increased in 2003, and finally up to 60% in 2006. For the gas sector too, third party access will be negotiated (nTPA).

Table B.1 summarises the liberalisation objectives for the electricity and gas markets.

Table B.1 *Scheme for liberalising the Belgian energy market*

Type of customer	Year of free status	Electricity or Gas demand in 1995 [%]
Electricity (nTPA)		
annual use > 40 GWh	2000	35
all consumers	2007	100
Gas (nTPA)		
annual use > 25 mln m^3	2000	45
annual use > 15 mln m^3	2003	?
annual use > 5 mln m^3	2006	?
all consumers	2010	100
Renewables		
TGC In Flanders	2001	--

B.2.2 Perspectives on the future state of liberalisation

Different regions in Belgium approach liberalisation from a different perspective. This may give problems with regard to reciprocity. The Flemish Government champions to open up the market for small and medium scale companies so they have access to cheaper electricity. Flanders looks to its foreign neighbours. If they will have a competitive advantage because of electricity market liberalisation, Flanders will enforce a faster opening of the market. In the interregional consultation, i.e. on the federal base, this proposal was blocked, but Flanders promises to create this opening in their own region.

For the gas sector, it is not certain that the market opening will remain fixed at about 60% in 2006. Some market forces may pressurise the situation. For instance, within 5 to 8 years, the interconnector between Bacton and Zeebrugge, capable for 20 million cubic meters of gas per year, will be released from the 11 million cubic meters that are now fixed in long-term contracts. The position of Distrigaz may also appear less dominant in the future European landscape as Distrigaz has no access to domestic production and its storage capacity is very limited. This creates opportunities for potential market entrants. The development of the spot trading at Zeebrugge will surely stimulate some large Belgian consumers and distributors to purchase their gas based on short-term supplies. However, there are also some forces working against full-liberalised markets, such as the lack of very large industrial consumers compared to the other major European markets, or the different calorific values of the different gas imports.

Even when implementing the EU directive and even when achieving more than its minimum requirements, changes seem to be more evolutionary than revolutionary. Moreover, there is little chance of Electrabel, a much larger company than Distrigaz, challenging Distrigaz's hegemony in the gas market given that both companies are Tractabel affiliates. Instead, there is plenty of scope for the two companies to combine their flexibility resources and exploit potential arbitrage between gas and electricity. There is therefore a very important role to play for the Control Committee for Electricity and Gas (CCEG) to ensure that the cross-shareholdings in the electricity and gas sectors do not distort competition in the energy markets. This will happen through consistent control of transparency of costs and prices through unbundling of accounts and through guaranteed third party access.

In order to close this section, Table B.2 below provides an overview of the main, probable elements of the future state of liberalisation in Belgium.

Table B.2 *Energy market liberalisation in Belgium*

Issue	Electricity regulation	Gas regulation
Access to grid	Negotiated TPA	Negotiated TPA
Degree of vertical integration	? unbundling	? unbundling
Time schedule	Complete market opening in 2007, in two phases. But, Flanders may decide on accelerated liberalisation at least for small-sized companies.	60% market opening in 2007, in three phases. But, there are some market forces will pressurise the situation to accelerate liberalisation or achieve a higher percentage.
Degree of government intervention	Tariffs for supply to captive customers are set by the CCEG and need approval from the government. The ERC is responsible for the liberalised market by supervising transmission. The ERC may decide of maximum prices for eligible consumers.	
Degree of openness to imports from and exports to other countries.	Open to imports, although imports from less liberalised countries could in principle be limited through the reciprocity clause in the EU directive.	

B.3 Renewable energy activities and policies

B.3.1 Renewable energy status

Specific for the electricity sector, the commission AMPERE was formed to analyse the possibility to match the production of Belgian electricity with a sustainable economic development in Belgium. The Commission will report in October 2000. Figure B.1 describes the start position.

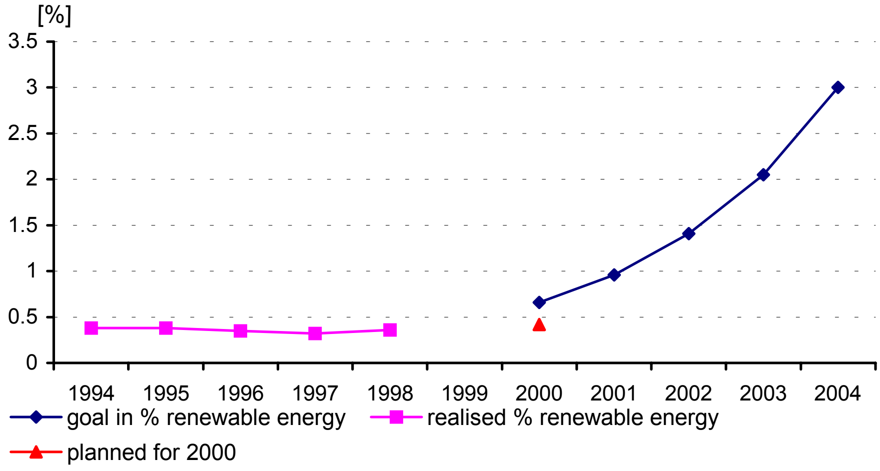

Figure B.1 *Renewable energy in Belgium*

B.3.2 Renewable energy policy

As said above, the regional governments of Flanders, Wallonia and Brussels-Capital are responsible for renewable energy policy, although certain aspects such as tariff-setting are still under federal authority. The federal energy R&D funds that exist are still mostly allocated to the development of nuclear resources. Some additional funds are allocated to solar heating and cooling, thermal and PV technologies, and biomass, but these are very small. Moreover, the Belgian national programme for reducing CO_2 emission states that promotion of renewables should be done within the current system of regulation. At the same time, both the Flemisch and Walloon governments primarily concentrate their R&D activities on energy conservation technologies. With reference to this, the IEA (1998) wished Belgium would avoid providing large energy-intensive industries with energy conservation subsidies as these subsidies tend to provide funding for improvements that would be undertaken anyway.

As regard to the heat sector, the IEA (1997) wanted Belgium to establish an independent national body to promote Combined Heat and Power (CHP), in co-operation with the regional governments. This body would work at providing adequate conditions, i.e. fair selection of projects, electricity tariffs and cost of back-up power, to support the development of CHP over the long term.

There are indications that Belgium intends to develop, over the long term, renewable energy sources for electricity production on a competitive basis. An obvious example is the decision in 2000 of the Flemish Government to install a system of Tradable Green Certificates to stimulate the production of renewable energy.

The Flemish government has put forward some targets for the period from 1996 till 2000:
- 100% extra renewables (electricity and heat) in 2000, compared to 1996.
- 3% share of renewables in the primary use of energy against 2010.
- 5% share of renewables in the primary use of energy against 2020.

The recently installed government has agreed to speed up this progress: 3% share of renewables in the primary use of energy against 2004 and 5% in 2010. In order to achieve these targets, the Flemish government has taken the option of imposing a minimum quota of renewables on suppliers of electricity, using a system of renewable energy certificates. The system is based on the draft version of the law regulating the Flemish electricity market.

B.4 Tradable green certificates

B.4.1 Green Power Certificates in Flanders

During a ‘pilot phase’, the department of Natural Resources and Energy of the Flemish Community (ANRE) will issue TGCs (or Green Power Certificates as they are called in Belgium) for the production of renewable electricity in blocks of 1000 kWh. Once the pilot phase is over, the Flemish regulator, created by the new electricity law, will deal with this. The certificates issued in the pilot phase are valid (subject to the expiration date) once the final phase has started (foreseen 1 January 2001).

The Flemish regulator will only issue certificates for renewable electricity produced in the Flemish Community or in offshore installations (falling under the jurisdiction of Belgium). Certificates will only be regarded as data in a database: physical certificates will be printed, but the latter will not be considered as physical evidence of ownership of a TGC. A minimum of renewable electricity production per year is required in order to obtain certificates. Photovoltaïc solar panels have a minimum of 2000 kWh, wind energy 300,000 kWh per installation, and other renewables 40,000 kWh. To make sure that the information the producer submits is genuine, the producer’s installation will be verified by an officially recognised verification organisation. This certification is at the expense of and on initiative of the producer of renewable electricity.

For the issuance of certificates, all renewable energy sources will be recognised by the Flemish government, in order to create a market as large as possible for certificates. Renewable electricity is then defined by all forms of electricity produced by means of renewable energy sources, other than fossil or nuclear energy sources, that can be used in a sustainable manner. Certificates will only be issued for renewable electricity which has already been produced, i.e. no borrowing, but regardless of the fact that the producer uses the electricity for his own benefit or puts it on the distribution grid. Certificates will be issued for already existing production installations or new ones, regardless of the fact whether the producers have received state aid (or could benefit of a higher feed-in tariff). However, this information will be marked on the relevant certificate.

B.4.2 Obligation

The legal basis of the Green Power Certificates in the Flemish Community lays in the new draft electricity law regulating the Flemish electricity market, as in essence approved by the Flemish government on 8 June 1999. The law imposes the obligation on anyone who has obtained a licence for the delivery of electricity through the distribution grid, to deliver a certain percentage of renewable electricity (which will increase annually) on the total of his electricity deliveries. The distributor can meet with his obligation by handing in on a yearly basis (before 31 December of each year) a certain amount of certificates. These certificates have to be handed in to the Flemish Regulator (ANRE in the pilot phase). Green Power Certificates can only be produced for meeting the renewable energy obligation during the year of production and five years thereafter. This makes banking of these certificates possible.

If one cannot meet with his obligations, a fine will be imposed. This fine will increase gradually from 49.58 Euro in 2001 to 123.95 Euro in 2004 per missing certificate, and will be used for the Renewable Energy Fund (see later on). This administrative fine may not exceed, per calendar year, 3% of the turnover that the relevant holder of a supply licence has generated on the Flemish electricity market in the previous financial year.

For the acceptance of Green Power Certificates by the Flemish Community, the following renewable energy sources will be accepted for meeting with the renewable energy obligation: solar energy, wind-energy, hydropower, biomass, biogas, geothermie, and tidal energy and tidal wave energy. Electricity from burning of waste will not be accepted for meeting with the obligation.

In an initial stage, only certificates will be accepted, representing a production on Flemish territory or on the offshore installations mentioned above. When on an international level, an international TGC or Green Power Certificates market has been established, Green Power Certificates from other (local) governments will be accepted too (Art. 18 of the Decree). Certificates that mention state aid will only be accepted under certain conditions. Accordingly, the Flemish government is disposed to trade internationally once such a trade is commenced. However, the minimum-norm will be increased accordingly, so the minimum norm will consist of two parts: a percentage for 'Flemish' certificates and another percentage for 'foreign' certificates. The latter percentage will have to be linked to the emission reduction targets as agreed upon in the Kyoto protocol.

For the acceptance of Green Power Certificates by other governments, these local governments are free to state which kind of certificates they will accept in order to let the companies, on which a norm for renewables is imposed, meet with the local requirements. This way, the Flemish certificates are ready for international trade once such a trade is commenced.

Green Power Certificates are consumed when they are redeemed by one of the three following means:
- Submission to the authorities for meeting the obligation.
- Annulment of the certificate by the owner of the certificate (to be asked to the Trade Registrar).
- Expiry of the period of validity (this period may differ from country to country, but each country is free to make the validity of the certificate a criterion for the fulfilment of the renewable energy obligation).

In the decree on the generation and distribution of electricity, as approved in principle by the Flemish government on 8 June 1999, Art. 17. is the part concerning Green Power Certificates, and says the following:
- Every network operator and every holder of a supply licence shall, as of 2001, be required to present to the regulatory authority, annually before 31 December, as many certificates as required.
- The number of certificates required to be submitted by a network operator or holder of a supply licence for a given year shall be fixed using the following equation $C = G \times (Ev - Ewkk - Eg)$ where C = the number of Green Power Certificates to be submitted in the year n, expressed in MWh (1000 kWh); Ev = the total quantity of electricity sold to end users in the year n-1 (in MWh); Ewkk = the electricity (in MWh) generated in year n-1 by means of a qualitative co-generation facility; Eg = the electricity (in MWh) generated in the year n-1 by means of a facility for the generation of sustainable electricity; G = the minimum percentage to be attained in the year n. This percentage is fixed at 0.77% for the year 2001 and will rise annually by a coefficient of 1.163 until the year 2010. As of 2011 the coefficient will be 1.05.

The percentage that serves as a basis for the obligation, is laid down in the draft electricity law and coincides with the Flemish targets regarding the use of renewables, see Table B.3.

In the Flemish draft electricity law, besides the Green Power Certificates system, other measures have been integrated in order to promote renewables. If more renewable energy is being produced than the minimum norm, the obligation for year *n* will be increased based on the actual percentage of produced renewable electricity in year *n-1*. Notice that no minimum norm is to be met by the suppliers of electricity during the pilot phase. Table B.3 shows the minimum norms.

Table B.3 *RE obligations*

		1996	2000	2001	2002	2003	2004
	[%]	(0.33)	0.66	0.96	1.41	2.05	3
Estimate of distribution deliveries	[GWh]			28997	29519	30050	30591
Minimum norm of renewable energy to be produced	[GWh]			278	416	616	918

B.4.3 Other modalities

As the market for Green Power Certificates is free, anyone can buy and sell certificates. Those who buy the certificates without having to meet any obligation (e.g. private persons), will decrease the amount of certificates being on the market for those having to meet the minimum norm. This will force the market to produce more renewable electricity or to pay the penalty, thus contributing to the Renewable Energy Fund, a fund established for the promotion of renewables.

As registration of the certificates is an absolute prerequisite to avoid fraud entering the system, all transactions, ownership and data on the Green Power Certificates have to be registered in a Central Registration Database. This database will keep track of the actual ownership of the relevant certificates and will be administered by ANRE in the pilot phase. In the final phase, the Flemish government will appoint different certified Trade Registrars, who will keep track of the different certificates transactions with the help of the database administered by the Flemish regulator acting as the Central Registration Office. That means that the Trade Registrars will transfer their data to the Central Registration Office on a regular basis. All disputes concerning the attribution and acceptance of Green Power Certificates shall be settled by the Flemish regulatory authority.

Other than the normal means of communication, a public website will be created where suppliers of Green Power Certificates can publish the amount and type of certificates for sale. This website, as well as the database on certificates available for sale, will be managed by the Central Registration Office.

The grid operators will have to perform all tasks necessary for the distribution of renewable electricity for free, except for the connection to the grid. The producers of renewable electricity are eligible for a limited amount of electricity. End consumers of renewable electricity are completely eligible, so they have free access to the market to buy their renewable electricity. Only the delivery of renewable electricity and electricity from co-generation is allowed via a direct line.

B.5 Cross-cutting GHG emissions sector

The recognition of a great dependence between the environmental goals of Kyoto (Belgium ratified on April 29 1998) and on policy towards renewable energy can be found within the mission of the Commission AMPERE.

In 1995, Belgium accounted for 1.1% of total IEA energy-related CO_2 emissions and emissions per capita (with 11.5 tonnes) slightly below the IEA average. Energy-related CO_2 emissions decreased by 21% from 1973 to 1990, then increased by 7% until 1995. The decrease was mainly due to the switch from coal to nuclear electricity production. Belgium's Kyoto target is a 7.5% reduction in GHG emissions.

As said earlier, CHP seems to open a world of opportunities for promoting both energy efficiency and achieving reductions in CO_2 emissions. The development of CHP has received priority in the National Programme for Electrical Energy Production and Transport 1995-2005, and in the framework of the Belgian National Programme for Reducing CO_2 Emissions. In June 1991, the Council of Ministers adopted a target for CO_2 aimed at a 5% reduction between 1990 and 2000. This target refers to total emissions and not energy specific emissions. To achieve this target, both the regional governments and the Council of Ministers approved the National Programme for Reducing CO_2 Emissions in 1994. As said above, in the development of energy policies, significant delegation of responsibilities has been fully ascribed to the three regional governments. A report of the IEA (published in 1997) recommended that the transferred responsibilities needed to be more harmonised, especially those concerning climate change. The IEA states that considerable gains could be realised by implementing common, harmonised programmes and measures decided in a spirit of close co-operation among the regional executives. This is particularly true in the field of energy efficiency programmes, as for example to stimulate energy efficiency in the transport sector. While these programmes are held central in Belgium's National Programme for Reducing CO_2 emissions, they are still implemented on a non-organised, non-harmonised base at the regional level, and the monitoring and assessment of regional energy efficiency policies are not sufficiently well developed. This is of course less true for the other important part of the climate change programme adopted at the federal level, as it rests on the adoption of the future European carbon/energy tax. Since the emissions were almost 110 million tonnes in 1990, the target becomes 104 million tonnes in 2000. However, the Federal Government said in 1997 that this target would only be achieved or surpassed if the carbon/energy tax proposed by the EU was implemented soon. Within a couple of years, the Belgian electricity production sector has switched from environmental pollutants such as coal towards natural gas, with 33% gas input in 1998. It has benefited the reduction of CO_2 emissions.

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C. DENMARK

C.1 Introduction

The EU countries differ very much with respect to fuel input and technology used within the electricity sectors. The Danish electricity sector is characterised by no hydro, no nuclear power, a relatively large share of wind, a large share of CHP produced electricity and heavy use of coal. In a very rough sense these characteristics reflect past Danish energy policy with respect to the power producing sector. In the past, the Danish electricity sector has been closely related to the Norwegian and Swedish hydro based electricity sectors. The Danish power production has matched the weather dependent Norwegian and Swedish power production.

With respect to the use of economic instruments to regulate the energy sector, Denmark agreed on a tradable emission quota system (with a fairly low maximum price) within the electricity sector in 1999 and also in 1999 a domestic green certificate market was agreed on. The green certificate market should be initiated by 1 January 2002.

This country report draws on information from a Danish country report under the Joule program 'Renewable energy projects in Denmark: An overview of subsidies, taxation, ownership and finance' by Peter Helby, 1998, from the country report on the Danish electricity sector from the Altener project, and from P.E. Morthorst, 2000, The development of a green certificate market. Citations are made from all three sources.

C.2 Energy sector

C.2.1 General overview

The following is a brief description of the Danish primary energy production, net import of energy, the Danish electricity production by fuel and the Danish energy consumption by sector. In combination these tables give a brief overview of the Danish energy sector as it looked by the end of the century. The current organisational structure is described in the end of the section.

Table C.1 shows that Danish primary production of oil and natural gas has increased considerably in the past 15 years. The Danish wind power production has increased by more than a factor ten, but does not count much in the total energy production. Wind power production is however underestimated in this table if the focus is on the usable energy in energy consumption.

The increased primary energy production is reflected in a considerable decrease in energy imports. In 1998 Denmark is a net exporter of oil, natural gas and electricity and the import of coal has diminished. While the developments over the period 1985-1998 in net imports for coal, oil and natural gas can be interpreted as 'true' developments, this is not the case with respect to electricity. The net import or export of electricity reflects the hydro power situation in Norway and Sweden. In wet years in Norway and Sweden, as in 1990, Denmark is a net importer of hydro produced electricity from these countries - and in dry years (1998), net exporter. On average Denmark has a *small* electricity export.

Table C.1 *Trends in primary energy production in Denmark [Mtoe]*

	1985	1990	1995	1998
Solids	0	0	0	0
Oil	2.92	6.06	9.31	11.64
Natural gas	0.97	2.74	4.65	6.76
Nuclear	0	0	0	0
Wind	0.01	0.05	0.10	0.23
Geothermal	0	0	0	0
Other	0.96	1.09	1.40	1.46
Total	4.85	9.94	15.46	20.01

Source: Energy in Europe, Annual Energy Review 1997. European Commission. And www.ens.dk.

Table C.2 *Danish net energy import [Mtoe]*

	1985	1990	1995	1998
Solids	7.70	6.23	7.65	4.68
Oil	8.19	3.16	1.83	-0.78
Natural gas	-0.40	-0.93	-1.49	-2.46
Electricity	0.04	0.61	-0.07	-0.36
Total	15.53	9.08	7.92	1.08

Source: Energy in Europe, Annual Energy Review 1997. European Commission. And www.ens.dk.

Table C.3 shows Danish electricity generation in 1998 by source. More than two-third of the electricity production is coal based. Oil and orimulsion counts for 12 per cent and natural gas for 13 per cent. These figures indicate that fuel conversion within the power producing sector is a policy with a large emission reduction potential. Wind and biofuel based power production was in 1998 6.8 and 1.3 per cent respectively. In 1999 new policies were implemented to reach a goal of 20 per cent share of renewables (Danish sources) in Danish electricity consumption (almost equal to Danish electricity production) by 2003. This is a very ambitious goal, more than doubling the share of renewables over 5 years.

Table C.4 shows electricity consumption by sector in 1998.

Table C.3 *Total electricity generation by energy source, 1998 in Denmark [TWh]*

	[TWh]	[%]
Geothermal power		0,0
Wind power	2,7	6,8
Other [1]	3,4	8,7
Biofuel	0,5	1,3
Natural gas	5,0	12,8
Oil	1,4	3,6
Coal	26,0	66,7
Nuclear power		0,0
Hydropower	0,0	0,1
Net exports (neg. value)	-4,3	
Total production	39,0	100

[1] In Denmark orimulsion.

Table C.4 *Gross energy consumption by sector in Denmark [PJ]*

	1980	1988	1990	1996	1997	1998
Adjusted consumption[1]						
Total gross energy consumption	*815*	*815*	*819*	*837*	*846*	*839*
Extraction and refinery	18	28	29	40	41	40
No energy purpose	16	15	13	13	13	12
Transport	146	167	173	190	194	198
Production sectors	231	223	228	233	237	233
Trade and service sectors	127	125	128	124	123	121
Households	276	257	249	236	239	235
Non-adjusted consumption						
Total gross energy consumption	*828*	*787*	*751*	*945*	*877*	*855*

[1] Adjusted for variations in climate and deducted fuel used for net export of electricity.

The new Danish energy reform (1999) to some extent restructures the organisation of the Danish energy producing sector. The following is a description of the organisation as it was.

By tradition the Danish energy utilities have been owned by consumers. More than 100 local utilities (1999), most in the western part of the country, distributed power, gas and heat. Municipalities and consumer co-operatives owned the distribution utilities, and the distribution utilities owned the generating companies. The generating companies owned and collaborated in Elkraft (in the East) and Elsam (in the West). These two organisations had the task of co-ordinating supply and demand and balance them with political and environmental goals. They also had the responsibility of managing the two transmission grids. (There are two transmission grids separated by the Great Belt). In the Elkraft region distribution was dominated by two large utilities, NESA and SEAS. In the Elsam region there were about 100 small local distribution companies (Altener project).

C.2.2 Main policies

The main underlying trends in Danish energy related policies in the last four decades have been 1) to adjust the Danish energy consumption, energy production and the Danish energy consumer prices in response to the oil price fluctuations in the 1970s and ´80s and 2) to adjust to greater environmental concern.

The oil price crises in the seventies gave political priority to:
- Extraction of own oil and gas resources in the North Sea.
- Substitute oil for coal within the electricity producing sector.
- Substitute oil for natural gas, district heating (combined heat and power plants), and electricity in private households and within the industry sector.
- Support energy savings.

When oil prices fell in 1986 this led to increased energy taxes to neutralise the price decreases. The aim of the energy taxes was to neutralise the effects of the energy price fall on private consumption, to keep energy demand low and to maintain the efforts to reduce energy demand.

The increased importance of environmental and especially climate related issues has given political priority:
- To substitute coal for natural gas and renewables within the electricity producing sector.
- To support investments in wind mills.
- To support the erection of combined heat and power plants.
- To support industrial combined heat and power production (auto producers).
- To introduce emission taxes on SO_2 and CO_2 emissions (from 1992 and onwards).

For reasons of international competitiveness Danish industry was exempted from energy taxes. The industry is not exempted from SO_2 and CO_2 taxes, but the tax burden is differentiated by arguments related to international competitiveness.

C.3 Liberalisation process

The Danish liberalisation of the electricity and gas sectors was initiated by the EU liberalisation initiatives in the early 1990s and later directives on these sectors. The Danish liberalisation of the electricity sector is much influenced by, and closely linked to, the Norwegian and Swedish restructuring of their electricity sectors. This is due to close dependencies between the Nordic power systems and due to the traditional electricity trade pattern. The Danish electricity market will be fully liberalised before 2003, and the western part of Denmark (Jutland and Funen) has already become part of the Nordic power exchange, NordPool.

The Energy Law of June 1996 (L486) implemented the minimum requirements for the opening of the electricity market in accordance with the EU-directive.

On March 3, 1999 a political agreement was reached between the main political parties in the Danish Parliament on the contents of a new Danish Electricity Act. This Act will provide a fast schedule for liberalisation:

- Full market opening for consumers of more than 10 GWh/y before 1 April 2000.
- Full market opening for consumers of more than 1 GWh/y before 1 January 2001.
- Full market opening for all consumers before 1 January 2003.

The agreement also deals with unbundling. There will be four sorts of companies, at least till 2003:

- Production and trading companies. These companies will be ordinary commercial companies that will produce and sell electricity (wholesale). These companies will not be able to own more than 15% of the other kind of companies. There will be some price regulations to protect the heat consumers of district heating systems.
- Grid companies. These companies will be responsible for the management of the grid. Elected consumers must have the controlling influence in these companies. There will be no possibility for high yields for the owners. Grid companies will be responsible for promoting energy savings and energy efficiency. They will safeguard technical security of supply and will provide information services to enhance the transparency of market conditions and prices for consumers. The grid must be open to everybody at payment of non-discriminatory tariffs, as a public infrastructure.
- Supply obligation companies. These companies must offer electricity to all consumers in a certain area against ‘reasonable conditions’. These companies are to ensure that all consumers are offered a standard package of energy services. Price-regulated profits for owners of these companies are allowed. Consumer representatives must form at least 1/3 of the voting rights. It can be expected that consumers of supply obligation companies might more and more be served by the commercial production and trading companies as the number of free consumers will grow in the next three years. Therefore these companies are typically companies that play a role in the transition period. However, also after that period, these companies will have a role in securing that all civilians will be able to use electricity.
- System-responsible companies. These companies will have the overall responsibility for the security of supply, co-ordination of the overall system and for the implementation of special demonstration and development programs. There will be no possibility for high yields of the owners of these companies. It is the intention that shares will gradually be transferred to the Danish State.

A new Energy Supervisory Board will be set up that will supervise the setting of the grid tariffs and will keep an eye on the quality of grid and system services. It will also take care that price structures are not discouraging energy savings (e.g. by high fixed subscription prices) and will enhance efficiency. The new price regulations have to be subject to provisions in the Open Administration Act.' (Altener).

C.3.1 Specific subsidies

In Denmark there are no subsidies to lower energy consumption prices to a level below production costs - on the contrary. Energy taxes on private energy consumption and, since 1992, CO_2 taxes on industrial and private energy consumption have contributed to high energy prices and thereby to reduce energy demand and CO_2 emissions.

The liberalisation of the electricity market is expected to lower Danish energy prices because of increased competition.

There have been no direct price *subsidies* to compensate for Transition Costs to Competition (TCC). But other kinds of public regulation shelter for example wind mill owners and CHP production from the effects of free competition. Public regulation secures these technologies a minimum price for electricity

Subsidies as an economic instrument has been used to support for example investments in new wind mills and energy savings in private households and within Danish industry.

C.4 Renewable energy activities and policies

The following table shows the weight of renewables in Danish gross energy consumption in the past, and the targets for the next 30 years as expressed in the official Energy 21 plan.

Table C.5 *Gross domestic energy consumption in Denmark*

	CO_2 emissions [Mton]	Gross energy consumption [PJ]	Fossil fuel share [%]	Bio-energy share [%]	Wind, solar and hydro share [%]	Waste share [%]
1972	61	825	98	0.7	0.01	1.0
1985	61	792	95	2.9	0.04	1.7
1990	61	816	94	3.6	0.30	1.8
1995	59	827	92	4.1	0.56	2.9
'Energy 21 plan'						
2000	53	803	90	7	1	3
2005	49	788	88	8	2	3
2010	45	754	84	9	4	3
2020	34	668	75	14	9	3
2030	27	594	67	16	15	2

Source: Helby, 1998.

Wind power is (1996) produced on some 4000 turbines. Around 85% is in private ownership. The remaining 15% is utility owned.

Straw and wood is used in some 3-400,000 individual wood stoves, 75,000 boilers for wood and 7000 boilers for straw. Two thirds of these bio-fuels are used in small installations for single buildings. In district heating systems straw and wood is used by around 140 plants. Central power stations now work under a mandate to include straw and wood in their fuel mix. This will nearly double the use of these fuels in 2000.

Bio-gas is produced in around 20 large plants and a similar number of individual farm plants. Around 100 bio-gas plants are working in association with waste water treatment. Bio-gas is mostly used for CHP. Bio-gas is regarded as an emerging technology with large potential. Only 5-10% of the resources are used at present.

Garbage is roughly 50% recycled, 25% incinerated and 25% deposited. Beginning 1997, it is illegal to deposit waste that is fit for incineration. The energy produced by incineration must be used for electric power, district heating or similar purposes. 95% percent of incineration will be CHP by 2000.

Solar power is mostly used for direct heat production. Denmark has (1996) some 18,000 solar thermal installations, with a collector area of 170,000 m^2. Grid connected PV is not significant in Denmark. There are only some 10 facilities with grid connection, and none of them are large.

Hydropower is regarded only a marginal renewable resource in Denmark, due to the geography of the country and to conflicts with nature preservation interests. Production is gradually falling. A total of some 50 plants are working, mostly private micro- or mini-hydro plants. Yet, hydropower is a significant element of Danish power consumption, due to trade with Norway and Sweden. Scandinavian hydropower is important for the long term implementation of renewables in Denmark, because of its flexibility qualities. The combination with Scandinavian hydropower makes it possible to plan for a high penetration of wind power in the Danish power system, without excessive costs for reserve capacity' (Helby, 1998).

The historical development of renewable energy use is showed in detail in Table C.6.

Table C.6 *Renewable energy use, Denmark [TJ]*

	1972	1985	1990	1995	1996
Solar energy		58	105	219	259
Wind power		185	2197	4238	4381
Hydro power	76	107	101	109	68
Geothermic			48	47	32
Straw	725	9892	12481	13051	13723
Wood Chips			1724	2336	2745
Firewood	2406	7706	7019	9191	9768
Wood pellets			1575	2376	2702
Wood waste	2562	5339	4913	4954	5046
Bio-gas	154	294	752	1752	1990
Fish oil			744	243	65
Waste Combustion	8400	13770	15006	24088	25394

Source: Helby, 1998. Official statistics (http://www.ens.dk).

As shown by Table C.7 approximately 40 per cent of the total Danish capacity for electricity production is covered by CHP plants. This fact makes electricity production an integrate part of Danish heat production - and ownership, regulation, planning, etc. are either the same or very interdependent. Renewables as such are not treated differently dependent on whether it is used for electricity, heat or gas production. Renewable bio-gas is mostly used as input in the CHP production. Therefore most of the descriptions of the electricity, heat and gas sectors are covered by the preceding section on the energy sector as such, and therefore the following sections are very brief.

Table C.7 *Installed capacity on 31 Dec. 1997, [MW] Denmark*

Total installed capacity	11546
Hydropower	10
Nuclear power	0
Other thermal power	10461
- condensing power[1]	5569
- CHP, district heating	4403
- CHP, industry	200
- gas turbines, etc.	289
Other renewable power	1075
- wind power	1075
- geothermal power	0

[1] Includes the German share of Enstedværket (300 MW).

C.4.1 Renewable energy policy

The instruments used to promote renewables in Danish energy consumption are political mandates to private parties (for example utilities), price guarantees, tax refunds, investment subsidies and voluntary agreements. Often it is very difficult to get a clear picture of the amount of direct and indirect economic support to renewables implied by the different rules. One of the reasons behind the Danish decision to use green certificates to promote renewables is that the price subsidies to renewables become transparent (as the subsidies are equal to the prices of the certificates). Moreover, via the market price subsidies are adjusted to exactly what is needed to reach the public targets.

In the past, policies towards utilities and district heat companies have to a large extent relied on political mandates. For example, mandates to electric power utilities to use certain amounts of biomass and to buy electricity from wind mils and CHP plants at high prices, mandates to natural gas utilities to promote solar heating and mandates to district heating companies to convert to bio-mass. One of the characteristics of mandates is that they (at first hand) are neutral to the public budgets.

Past policies towards private consumers have relied on mandates and economic incentives. In relevant geographic areas consumers are mandated to connect to district heating - to secure a maximum level of profitability to the investments. Economic incentives to invest in renewables have been given through tax refunds, price guaranties and other economic instruments. Investment subsidies have been given to solar panels.

The following description pays special attention to wind power, but is to a certain extent applicable for all renewable technologies.

In its previous policy the Danish Government has used a number of different instruments to promote and regulate the development of wind power:

1. *Power purchase agreements.* Utility companies are obliged to buy all power produced by wind turbines, at a rate equal to 85% of the consumer price of electricity in the given distribution area. On average this buy-back rate is approximately 0.32 DKK per kWh, corresponding to 4.3 Euro cents.
2. *Production subsidy.* To promote the development of wind power a general production subsidy is given to all power produced by wind turbines (and most other renewable technologies). The subsidy amounts to 0.17 DKK per kWh or about 2.3 Euro cents.

3. *Carbon tax*. A general carbon tax is levied on all forms of energy in Denmark. For renewables it affects the price in the same way as the production subsidy. This means that the producers of wind power are refunded the environmental tax, which amounts to 0.10 DKK per kWh, corresponding to some 1.3 Euro cents.
4. *Tax credits*. Different forms of ownership have different tax arrangements. The formation of a *co-operative* is a traditional way of owning a wind farm in Denmark. Each member can own up to 30 shares (corresponding to 30 MWh per year) and pays 60% tax of gross income above a certain bottom limit. For *personally owned* turbines (e.g. owned by a farmer) a marginal tax of about 59% is paid of net income (after deducting interest on loans, operation/maintenance costs and depreciation).

Thus, the Danish system has consisted of long-term agreements on (almost) fixed feed-in tariffs, where about half of the tariff has been in the form of governmental subsidies. These feed-in tariffs have been fixed at fairly high levels, making it highly profitable to establish new wind turbines in Denmark. (Morthorst, 2000).

C.4.2 Renewable energy potentials

Wind conditions in Denmark are very good for wind based power production. Provided that the wind mills are not placed in sheltered terrain all locations have in general high wind resources. The very long coastal line and the opportunity of placing the wind mills at open sea makes the Danish wind resources very high. Denmark has no major rivers and no potentials for hydro power.

As a country with a large agricultural sector Denmark has potentials for growing energy crops and supplying bio-mass to the power and heat producing sectors. For quite a number of years the agricultural sector has supplied the energy producing sectors with relatively low priced straw. Prices have been low because the straw in many cases had no alternative use (a waste product). The use of straw in power and heat production has been a moderate success because the production processes using straw are difficult to control.

Denmark has low temperatures and few sun hours compared to most of the other EU countries. This means that Denmark is far from the optimal location with respect to photovoltaïcs and other solar technologies.

The geographic differences within Europe with respect to wind, hydro and solar conditions and the availability of low priced bio-mass will be reflected in geographic differences in costs of wind, hydro, solar and bio-mass based power production.

C.5 Tradable green certificates

The new Danish electricity reform introduces an obligation by Danish consumers to distinguish between the production methods of electricity and to buy a minimum percentage (of their total electricity consumption) of renewable electricity.

At least the following arguments have favoured the idea of a green certificates market:

- The increased profitability of the wind mils combined with unchanged and inflexible economic regulation made a reform desirable.
- In 1998 more than 100 million Euro was paid out of the public budget only to subsidise wind turbines. Taking into account the rapid development of turbine capacity this amount was expected to increase substantially in coming years if the electricity reform was not carried through (Morthorst, 2000).
- A green certificate system makes the economic support to renewables explicit. The price of the certificates is (in theory) equal to the extra cost of renewable electricity production

compared to conventional electricity production. The level of the economic support is flexible and based on supply and demand on a market for renewable electricity.
- A political wish to continuous support of renewable energy.
- The Kyoto commitment.

The main characteristics of the Danish proposal for a green certificate market are the following:
- All consumers of electricity in Denmark are obliged to buy a certain share of electricity generated by renewable energy technologies. A major part of this will be covered by the electricity distribution companies, which will buy the green electricity on behalf of their consumers. Large companies (or other consumers) trading directly with power suppliers will have to cover an equivalent share of their consumption with green electricity.
- All renewable energy technologies, including wind power, biomass and biogas plants, photovoltaïcs, geothermal and small hydro plants, will be certified for producing green electricity. Per unit of electricity produced (per MWh) they will get a green certificate, which can be sold to distribution companies or other electricity consumers with the obligation to cover a certain share of their electricity consumption with green power.

The demand for green certificates will thus be given by distribution companies and other consumers, which have to cover their share on an annual basis. The Danish energy authorities will determine this share, presumably for a number of years in advance. At the end of each year a volume of green certificates corresponding to the quota will be withdrawn from the market by the authorities. According to the Danish electricity reform agreement a share of 20% of total electricity consumption has to be covered by the end of 2003 (for all renewable technologies).

C.6 Cross-cutting GHG emissions sector

Following the Bruntland report, the Danish government in 1990 presented a plan for sustainable development of the energy sector, which included a national commitment to reduce CO_2 emissions by 20% in 2005 compared to the 1988 level. In 1996, a new comprehensive energy plan, ‘Energy 21’ was presented. It reaffirmed the 20% goal for 2005, included stronger policy measures to reach this goal, and outlined long-term goals. For renewables, the long term goal (until 2030) is a yearly conversion of 1% of energy production from fossil fuels to renewable energy sources, with the goal of reaching 35% percent in 2030.

The unilateral Danish 20% CO_2 reduction commitment refers to 1988, which was approximately an average year in Denmark, and it refers only to the domestic use of energy. 1990, which is the reference year in the Kyoto protocol, was for Denmark an extreme year, with large import of excess hydropower from Norway and Sweden, and thus unusually low CO_2 emissions. The difference in base year (if not corrected for net import) is so significant, that Denmark appears as one of the worst ‘sinners’ in terms of growing CO_2 emissions if calculations are based on 1990 emission levels. But at the same time the Danish government can maintain that it is successfully pursuing its goal of 20% CO_2 reduction (Helby, 1998).

The EU commitment in the Kyoto Protocol is to reduce emissions in the period 2008-2012 by 8% as compared to the 1990 emission level. Within the EU bubble Denmark has agreed to reduce emissions by 21% as compared to an import adjusted 1990 emission level.

As part of the new electricity reform tradable CO_2 emission quotas has been introduced in the electricity producing sector. If the CO_2 quotas are violated a penalty of 40 DKK (approximately 5.5 Euro) must be paid.

D. FINLAND

D.1 Introduction

Finland is located in the northern part of Europe. The country is large and sparsely populated. The total area is 338,145 km^2 and population amounts to 5.1 million, i.e. 15 people per square kilometre. About two thirds of the Finns live in urban areas and only a minor part in Arctic areas. More than three-quarter of the country is covered by forests, approximately 10% by lakes and less than 10% is farmland.

Partly due to its cold climate but primarily due to the concentration on very energy-intensive industries Finland is among those countries that have the highest per capita energy consumption. Table D.1 below summarises the main indicators for Finland.

Table D.1 *Basic indicators for Finland*

		1990[1]	1995	1998
Population	[Million]	5.0	5.1	5.2
GDP	[Bil. Euro 1990]	106	142	217
Gross Inland Primary Consumption	[Mtoe]	28.8	29.7	33.3
Total Electricity Production	[MWh]	54.4	63.9	70.1
CO_2 emissions	[Mt of CO_2]	54.0	57.5	66.3
Total EU Primary Consumption	[Mtoe]	1330.7	1375.7	1449.6
Share in EU (GIPC/TEUPC×100)	[%]	2.2	2.2	2.3
Gross Inland/GDP	[%]	27	21	15
Gross Inland/Capita	[toe]	6	6	6
Electricity Generated/Capita	[kWh]	10906	12509	13594
CO_2 emissions/Capita	[t CO_2]	11	11	13

Source: NRD 3.0.1. - data base.

[1] Finland has been independent since 1917. In 1995 Finland became a member of EU.

In the early 90s Finland experienced a severe economic recession. From a low of 3% in 1989 unemployment rose to approximately 20% in 1993 and industrial production decreased correspondingly. In recent years the economy has recovered - 1997 was a veritable boom year for the Finnish economy where GDP increased by almost 6%.

D.2 Energy sector

D.2.1 General overview

The development of total final energy consumption by sectors in Finland is shown in Figure D.1. Industry accounts for approximately 50% of total energy consumption, while transport accounts for a little more than 17% and approximately 33% is related to the residential/ commercial sector.

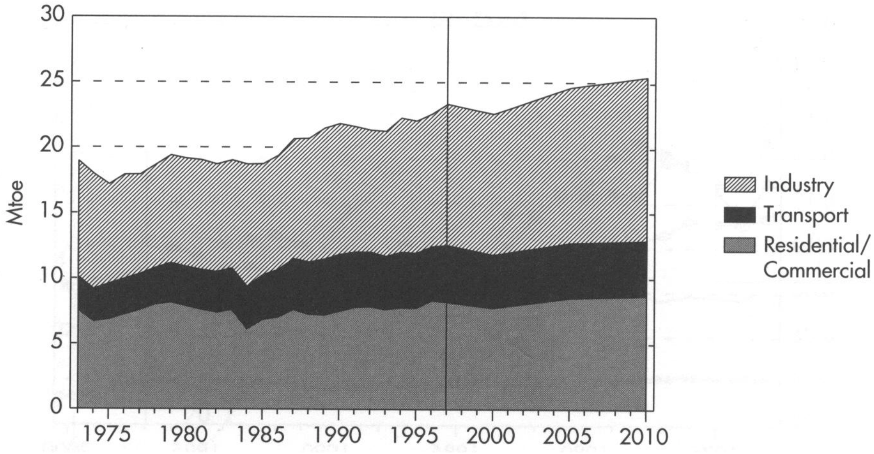

Figure D.1 *Development of energy consumption in Finland*

Source: IEA energy balances.

Total primary energy supply (TPES) in Finland is shown in Figure D.2. Oil accounts for approximately one-third of TPES, renewables of approximately 20%, while coal and nuclear account for approximately 15%, respectively. Most of the renewable energy comes from combustible renewables (biomass) and wastes, i.e. mainly black liquor, wood combustion and wood wastes.

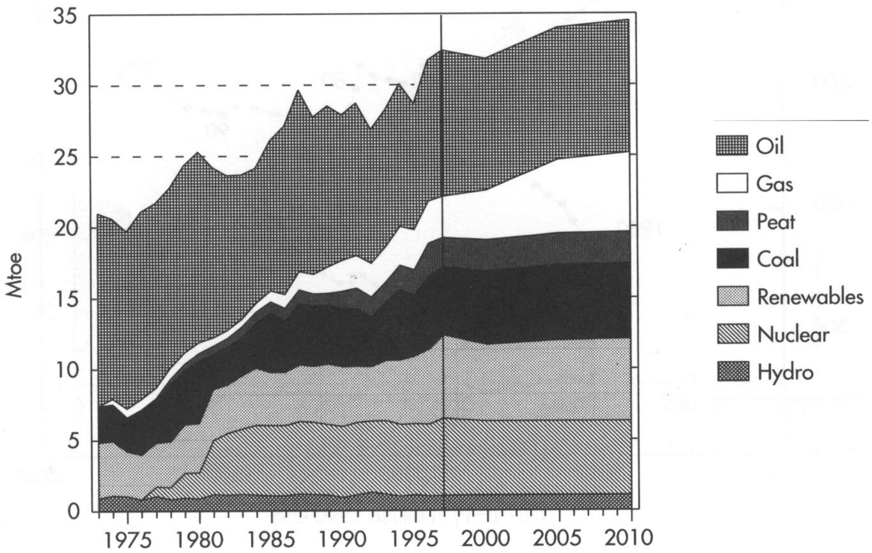

Figure D.2 *The development of Finland's total primary energy supply by fuel*

The main objectives of the Finnish Governments energy strategy are:
- Developing the structure of energy production towards reduced emissions of CO_2.
- Promoting the competitive energy market
- Ensuring diversified and economically advantageous energy supply
- Ensuring security of supply
- Ensuring continued economic growth
- Promoting efficient energy use and energy conservation
- Maintaining the high standard of energy technology

D.2.2 Electricity sector

In 1997 the Finnish electricity supply industry produced 69.2 TWh of electricity. Approximately 35% was produced in CHP-plants, 18% came from hydropower, 30% from nuclear and the rest (approx. 17%) from fossil fuel-fired conventional plants. How electricity production is split into fuel use, is shown in Figure D.3.

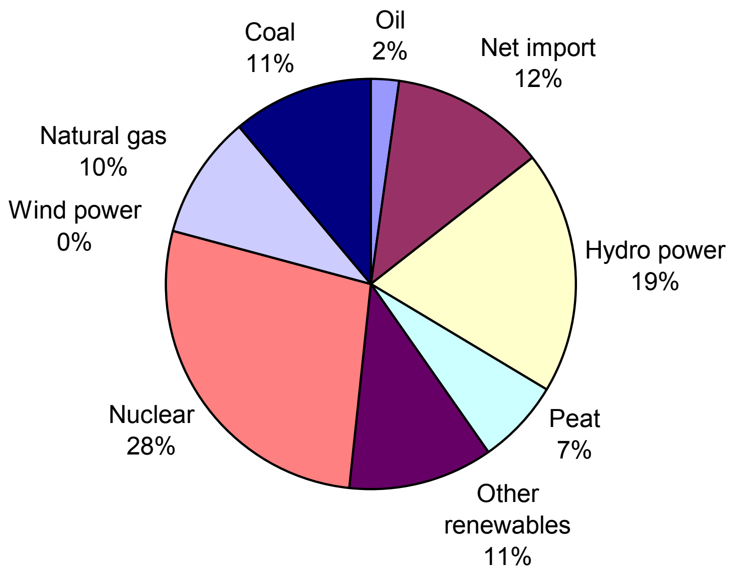

Figure D.3 *Electricity production in Finland split into the use of fuels*

Approximately 400 power plants are operating in Finland, owned by some 120 power producers. The two largest companies are Imatran Voima Oy (IVO) and Pohjolan Voima Oy (PVO). Both operated as vertically integrated power companies until 1997, where their transmission assets were merged into the new national transmission company Fingrid. IVO generates approximately 40% of all electricity sold in Finland, while PVO generates approximately 20%. About 20% is generated by independent industrial power producers and the residual 20% is generated by a number of other companies, among these municipal CHP-companies. More than 30% of electricity production in Finland is produced by CHP-plants.

Some 115 distribution companies operate in Finland, mainly owned by municipalities. The main market participants in Finland are the following:

- The national grid (Fingrid) and its licensed operators,
- Regional network operators,
- Local distribution network operators,
- Electricity generators and retailers,
- The electricity exchange, where Finland is a part of NordPool.

The present energy tax system consists of duties on traffic fuels and heating fuels, and on electricity. The fuel duty is divided into a basic duty and an additional duty. The basic duty is differentiated in order to promote environmental protection and, therefore, lower tax rates are applied to unleaded and reformulated petrol, as well as desulphurised diesel oil. The additional, environmentally-based duty (the so-called CO_2 tax, introduced on 1 January 1990) is determined on the basis of the carbon content of the fuel. Since September 1998, the rate of the additional duty is FIM 102 per tonne of carbon dioxide (app. 17 Euro/t) for liquid fuels and coal.

Since 1997, no taxes on fuels for electricity production have been applied. Instead, there is an output tax on electricity, which falls into two classes: a lower rate (2.5 cents/kWh or app. 0.4 Euro cents/kWh) for industry and greenhouse cultivation and a higher rate (4.1 cents/kWh or app. 0.7 Euro cents/kWh) for households and the service sector. To improve the competitiveness of renewable energy sources, taxes on electricity produced by wind, wood and wood-based fuels are refundable. Additionally, small-scaled hydropower and small-scaled peat-based power production are included in this refund scheme.

D.2.3 Gas sector

Finland has no indigenous natural gas reserves. All gas is imported from Russia through one single pipeline. One company in Finland (Gasum Oy) is responsible for import and transportation of gas. Gas consumption in Finland started in 1974 and is now used widespread in the southern part of the country. In 1997 3.4 million cubic metres of natural gas was consumed. Most of it is used in industry (51%) and in heat and power generation (47%) and only a small part in households (2%).

The natural gas industry in Finland has so far been almost unregulated, except for safety regulations. The EU directive opening up the gas market will also apply for Finland. However, since the country is not interconnected to the European grid, provisions on opening up the Finnish gas market to other gas suppliers do not have to be implemented.

Interconnection to the European natural gas network is seen as a vital priority in Finland and a number of different proposals are being evaluated.

D.2.4 Heat sector

In total approximately 20% of energy consumption is used for space heating purposes. There is widespread use of combined heat and power systems throughout the country for heating purposes in communities and industrial processes. Approximately 53% of CHP produced power came from district heating plants and 47% from industry.

Approximately 27 TWh heat is produced by district heating plants, slightly more than 75% is co-generated. 50% of the building stock is connected to the district heating network, the rest is mainly supplied by individual furnaces.

D.3 Liberalisation process

Energy pricing and markets in Finland have been gradually deregulated since the 1980s. In the early 80s oil and coal imports were subject to import licences. Recently - as the last area - licences for electricity imports were removed, and thus energy imports are no longer controlled by the Government. In general, energy prices are determined by the market and the Government does not interfere in price setting or mechanisms.

Transmission prices of electricity are, however, kept under surveillance by a new electricity market regulator due to the monopoly nature of that business. Pricing for the network services has to be reasonable and fair, but without recourse to regulations, for instance on permissible rates of return.

The Finnish Electricity Act has been substantially revised, with the main aim of a further liberalisation of power transmission at all voltages, i.e. local distribution lines included. Any producer can sell electricity to any end-user or retailer throughout the country. Differentiation of operations and increased transparency of electricity prices and costs support that goal. The Act entered into force at the beginning of June 1995.

Finland has no statutory scheme for the planning of national electricity capacity. Permits are no longer required even for the very largest plants. Only nuclear and hydro power need licences under the particular legislation. Free competition is thus a fact in electricity generation. For land use, environmental protection and similar reasons, appropriate permits or licences are, of course, required.

D.3.1 Phasing of the electricity liberalisation

The country began the process of liberalising its energy market with the Electricity Market Act of 1995, and continued until by January 1997 all consumers were free to select their electricity supplier. The initial requirement for even domestic consumers to install hourly meters is now relaxed, and the supply industry is moving towards the use of load profiling systems, such as those used in the Norway and Sweden. The following shows the individual steps taken in Finland towards a free electricity market:

- *1st June 1995* Electricity Market Act entered into force. In August 1995 a new Electricity Market Authority began its work.
- *1st November 1995* all end-users buying over 500 kW have been able to freely select their electricity suppliers.
- In *August 1996* Finnish electricity exchange EL-EX began its work. Fingrid Plc bought EL-EX in *January 1998.*
- *1st January 1997* all electricity users has been able to freely select their electricity suppliers, hourly kWh-metering was required.
- *1st September 1997* Fingrid Plc began its work and there is in Finland only one grid company instead of previous two.
- During *1998* Norwegian-Swedish electricity exchange NordPool began its activities also in Finland.
- *1st September 1998* hourly kWh-metering is not required any more for households and 1st November 1998 for other small customers whose main fuse is 3×63 A or lower.

By now Finland is a full-blooded member of the Scandinavian NordPool exchange.

D.4 Renewable energy activities and policies

D.4.1 Renewable energy status

Very little is used of small-scale renewable energy in Finland. Wind power at the moment meets a small fraction (around 0.03%) of the country's electricity demand and the installed wind capacity in the country was 23 MW at the end of 1998. There is no opposition movement to wind power developments. The wind industry in the country is in its early stages, and uses imported equipment. Small hydro (50 kW - 10 MW) schemes produce around 900 GWh annually, which accounts for 1% of the country's energy needs. A number of small photovoltaic installations are established especially for summer cottages, but have no importance in the total energy supply.

Large hydro schemes account for around 804 MW of the country's capacity, and large thermal plants burn wood waste and other biomass for both electricity and process heat in the pulp and paper industry.

Biomass figures largely in the Finnish energy picture. CHP plants burn wood waste, peat, and agricultural biomass. The country burned wood to meet an estimated 17% of its energy needs in 1997 (the highest national level of wood use in the industrialised world). The country has a well developed industry centred on this.

Peat forms one of the main fuel streams, accounting for 25% of all district heating and 7% of the country's electricity but for the purposes of this report, peat is regarded as a non-renewable resource.

The main contributors to the electricity supply in Finland are biomass and hydro. In 1997 their share of electricity supply were 18% from hydro and 12% from combustible renewables, mainly CHP-biomass. Biomass includes industrial wood residues (wood chips, bark and sawdust), black liquor and firewood. Black liquor is a waste product from the paper and pulp industry.

Wind power has favourable conditions on the coast of Finland, but only a minor part of this potential is utilised. Figure D.4 below shows the development of wind power capacity and electricity production in Finland.

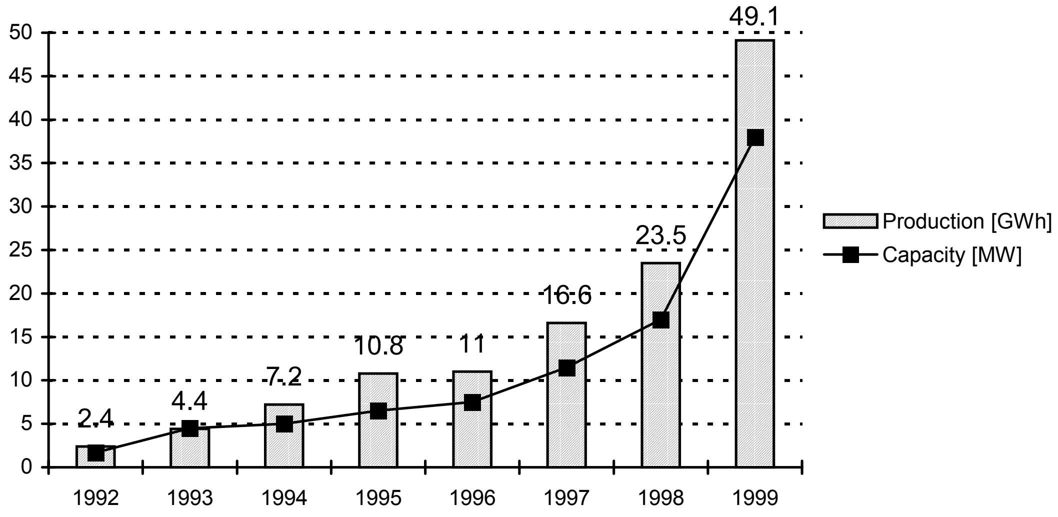

Figure D.4 *Wind power capacity and electricity production in Finland*

Approximately 35,000 small photovoltaic systems are in operation in Finland, mainly supplying recreational houses. In addition to this 3 grid-connected systems are established. In total these systems account for no more than 2-3 MW of photovoltaic capacity and thus have no major influence on the electricity supply.

Finally, approximately 200 small-scale hydro power plants exist in Finland, ranging in capacity up to 10 MW and amounting to electricity production by a little more than 1%.

D.4.2 Renewable energy policy

The Finnish government adopted in 1995 a decision on energy policy which includes increased use of bioenergy of 25% by 2005. A promotion programme for wind energy in 1993 set a target of 100 MW installed capacity by 2005.

The Ministry of Trade and Industry (which is the electricity industry regulator) supports wind generator investments with subsidies of 30-40%, but there is no guarantee of this as applications are considered on a case-by-case basis and the outcome of each application depends on the availability of annually budgeted amounts. The fund is paid for by an annual electricity tax on producers of FIM 0.041/kWh (app. 0.7 Euro cents/kWh). The producers generally pass this charge on to their customers. Wind power producers get a tax refund at the end of each year. Bioenergy producers also receive tax relief at a rate of FIM 0.02/kWh (app. 0.3 Euro cents/kWh). However, there are no investment aids for bioenergy plants. For hydro, there is no support at all.

Regulation of the electricity supply industry in Finland is the responsibility of the Ministry of Trade and Industry. The Ministry has recently commissioned studies on electricity production from renewables from the company VTT and the Finnish Association of Nature Conservation. Partly as a result of these the Ministry has announced that it will take no position to the green electricity market, which it sees as a market initiative in which the ministry has no role.

The green electricity market is taking its first steps in Finland. The market is a totally voluntary initiative on the part of utilities, consumers and the Nature Conservation Society. The Nature Conservation Society announced a national accreditation standard for Green Energy in July 1998. The standard covers electricity and heat production from renewable sources. The Society took two years to prepare the standard and is now working on harmonising its accreditation criteria with the Norwegian Nature Conservation Society's energy 'ecolabel' and the Swedish Nature Conservation Society's 'Bra miljöval' 'ecolabel for electricity' which has been in operation since November 1995.

Utilities can request accreditation, which they are awarded after the Society has checked that they fulfil the criteria. In general, wind, old hydro, biomass and PV are accredited, (within set boundary conditions). New hydro is specifically excluded from the scheme as is the use of peat and any form of energy from waste. The Society plans to label energy efficiency measures in future, and has designed stringent conditions for this.

Some consumers are willing to pay a higher tariff for Green Electricity (typically FIM 0.05/kWh or app. 0.8 Euro cents/kWh) and ten to fifteen utilities, to date, have applied for and been awarded the green label. The Nature Conservation Society charges for the accreditation service and will audit each utility every third year after accreditation, charging again for this service.

In addition to the Nature Conservation Society label, various utilities have announced their own labels for wind electricity and bio electricity. These 'flavours' of electricity also attract a premium - also of around FIM 0.05/kWh (app. 0.8 Euro cents/kWh). Around ten utilities now offer wind electricity. Individual customers for wind electricity are counted in hundreds, but it is likely that their number will increase.

D.5 Cross-cutting GHG emissions sector

The aim of the UN Framework Convention on Climate Change is to stabilise greenhouse concentrations. In the Kyoto Protocol, the industrialised countries pledged to reduce emissions of six greenhouse gases by at least five per cent from the levels of 1990 in the period between 2008 and 2012. Finland is expected to bring its emissions in the same period down to 1990 levels. Subsequently CO_2 emissions are to be reduced. The Finnish Government intend to reach this goal through the use of a number of different measures, including increased energy-efficiency, increased use of renewables and natural gas, energy and CO_2 taxation, promoting the energy market and keeping the nuclear option open. In areas, such as combined heat and power production and the use of bioenergy, Finland has already met the targets set by the EU for the year 2010.

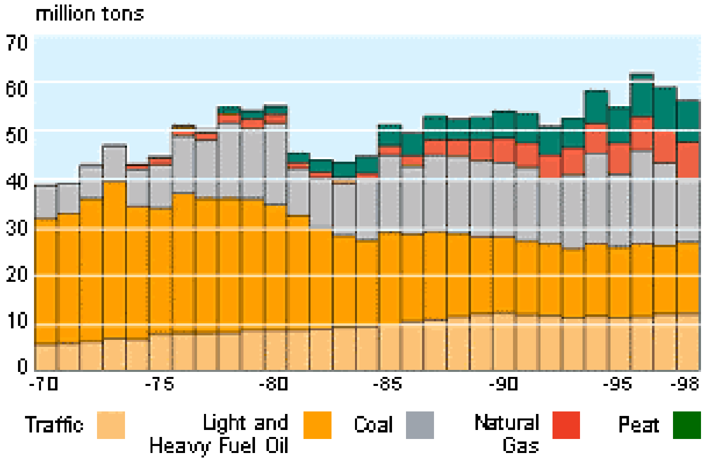

Figure D.5 *The development of CO_2 emissions in Finland*

The development of CO_2 emissions in Finland is shown in Figure D.5. A slow but gradual increase in emissions has occurred since the early 80s. As shown coal, natural gas and peat have increasingly substituted for oil. Finally, there has been a fairly rapid increase in CO_2 emissions from traffic.

E. FRANCE

E.1 Introduction

Much of the information in this report is gained and excerpted from IEA - International Energy Agency (1998): Renewable Energy Policy in IEA Countries. Volume II: Country Reports. OECD, Paris. (= Energy and Environment. Policy Analysis Series). In addition, Poppe/ Cauret (1996) and Schaeffer et al. (1999) was used for describing the general electricity framework. All other references are directly indicated in the respective passage.

E.2 Energy Sector

E.2.1 General overview

In France, primary energy consumption has been dominated by nuclear power (34% in 1999) and oil (39%) for more than a decade. In 1999, gas contributed 14%, coal 6%, hydro 2%, biomass and waste 4%, and geothermal, solar, wind power, etc. accounted for less than 0.1% of primary energy consumption. The emphasis on nuclear power is a result of the extremely limited indigenous reserves of fossil fuels and concerns about security of supply. The CO_2 emissions per capita are with approximately 6 tons per inhabitant below EU average (about 8 t/inhabitant). Check Table E.1 for further basic data.

Table E.1 *Basic energy indicators for France*

		1990	1995	1996	1997	1998	1999
Population	[Million]	57	58	58	59	n.a.[1]	n.a.
GDP (Bil. Euro 1990)		940	987	1,001	1,023	n.a.	n.a.
Gross Inland Primary Consumption	[Mtoe]	219	235	248	243	248	250
Total Electricity Production	[TWh]	420	495	512	504	n.a	n.a.
CO_2 emissions	[Mt of CO_2]	352	345	363	358	n.a.	n.a.
Total EU Primary Consumption	[Mtoe]	1,314	1,363	1,411	1,407	n.a.	n.a.
Share in EU	[GIPC/TEUPC]	17%	17%	18%	17%	n.a.	n.a.
Gross Inland PC/GDP	[toe/1990 Euro]	233.21	237.57	248.04	237.14	n.a.	n.a.
Gross Inland PC/Capita	[toe/inhabitant]	3.86	4.03	4.25	4.14	n.a.	n.a.
Electricity Generated/Capita	[MWh/inhabitant]	7.40	8.51	8.78	8.59	n.a.	n.a.
CO_2 emissions/Capita	[t/inhabitant]	6.21	5.94	6.22	6.11	n.a.	n.a.

[1] n.a.: not available.

Sources: AER (2000) for 1990-1997 data; Direction (2000) for 1998 and 1999 data.

The French energy sector is ruled by the philosophy of the 'Service Public' saying that providing the French population with energy is a task of the public sector. Accordingly, the electricity sector as well as the gas sector have each been controlled by one big state-owned monopolist and efforts to liberalise the markets have been progressing very slowly.

Following the two oil crises, France started a national programmes to increase its level of energy independence. It did this in two main ways:

- A strong push on the nuclear power front, resulting in over-capacity and over-production of electricity, i.e. beyond national demand.
- Energy Efficiency measures, which resulted in a 22% drop in energy intensity between 1973 and 1997.

E.2.2 Electricity sector

In France, the majority of electricity has been generated by non-fossil sources for about two decades. In 1999, for example, 75% of electricity was produced in nuclear power plants and 15% in hydropower plants (Direction 2000). As ca. 90% of the French electricity plants cause very low CO_2 emissions, there are few incentives to promote growth in new renewable electricity from a greenhouse gas perspective. The contributions from non-hydro renewable energy sources to electricity supply are expected to remain insignificant in the medium term. This is reflected in the small renewable R&D budget. However, other environmental considerations, notably regarding waste disposal have increased interest in electricity generation or heat production from waste, while employment and agricultural considerations provide an impetus for the development of biomass.

Table E.2 *Basic electricity indicators for France*

		1990	1995	1996	1997	1998	1999
Total Electricity Production	[TWh]	420.08	494.62	512.30	503.61	n.a.	n.a.
Production of RES-E	[TWh]	57.91	78.01	70.76	67.99	70.5	81.4
Total Installed Capacity in Electricity	[GW_e]	103.41	107.61	109.45	112.70	n.a.	n.a.
Installed Capacity of RES-E	[GW_e]	24.99	25.23	25.32	25.34	n.a.	n.a.
Electricity prices to industrial consumers	[1990Euro/toe]	516.5	452.5	428.1	415.3	n.a.	n.a.
Electricity prices to domestic consumers	[1990Euro/toe]	1,374.3	1,253.5	1,238.8	1,141.6	n.a.	n.a.
Production of RES-E/Total E Production	[%]	1	16	14	14	n.a.	n.a.
Installed Capacity of RES-E/Total Inst Capacity	[%]	24	23	23	22	n.a.	n.a.

Source: AER (2000).

Electricité de France (EdF) was founded by the French Government after World War II, in 1946. Since its creation the company has benefited from a quasi-monopoly of generation, transmission and distribution of electricity in France. EdF is the epitome of the state power monopoly. Centrally planned and controlled, it has a huge workforce and displays little transparency in its accounting systems. EdF owns more than 90% of the installed electricity generation capacity and the grid systems in France. The rise of nuclear power came about largely as a result of EdF's response to the oil shock of the 1970s -a shock felt more keenly in France than in other countries as it simultaneously lost control of its oil interests in Algeria which was further exacerbated by the decline of the French coal industry.

Table E.3 *Electricity supply in France between 1997 and 1999 [TWh]*

	1997	1998	1999
Combustible Fuels	37.1	51.9	45.0
Nuclear	375.9	368.5	374.4
Hydro/Other	67.6	65.4	74.2
Domestic Production	480.7	485.8	493.5
+ Imports	3.8	4.2	4.8
- Exports	69.6	66.1	71.1
Total Consumption	414.9	423.9	427.3

Source: IEA Monthly Electricity Survey, January 2000.

France is one of Europe's largest exporters of electric power. The equivalent of around 18% of the French electricity consumption is exported (see Table E.3). Its main customers are Switzerland followed by the UK, Italy, Benelux and Germany. It is reported that most of this power is sold at a rate which is less than half the average EdF tariff and that it does not cover the cost of generation. Electricity prices in France have been based on the price-equalisation principle which is a social tool for equity and for homogeneous national development. It means that pricing is geographically uniform over the country for the same use at the same time. However, this induces financial transfers from one area to another, since cost disparities of distribution or generation depending on location are not reflected.

So far the Ministry of Industry, through the General Directorate of Energy and Raw Materials (DGEMP) and more specifically the Directorate of Gas, Electricity and Coal (DIGEC), has been directly in charge of the French power sector, as a regulatory authority.

E.2.3 Gas sector

Similar as in the electricity sector the French gas sector is dominated by one big state-owned company - Gaz de France (GdF). One question that now arises is whether or not France can transpose the gas directive, which sets August 2000 as a start-date for competition, any easier than the electricity directive. The French government has indicated it intends to execute the first slice of competition on time, to avoid embarrassing its presidency of the EU from August. However, according to the draft law, Paris envisages opening 20% of the gas market for competition from August 2000, while some of its partners have established fully open markets already.

Recuperation of landfill gas for greenhouse gas mitigation purposes is expected to increase energy production from landfill gas, which has not been developed to a great extent until now.

A policy similar to the EOLE tender for wind installations was announced in February 1998 for 10 MW biogas electricity plants.

Table E.4 *Renewable heat supply in France and its overseas territories [ktoe]*

	1998	1999[1]
Geothermal	117	117
Solar	17	18
Waste	767	767
Solid Biomass	9,249	9,213
Biogas	118	118
Biofuels	261	278
Total	10,529	10,511

[1]preliminary figures.
Source: http://www.industrie.gouv.fr/energie/renou/textes/se_bilan2.html.

E.2.4 Heat sector

Solid biomass (mainly wood) contributed an estimated 8.8 Mtoe to France's total energy supply in 1996. The majority of this, 7.1 Mtoe, was used for heating purposes in the residential sector. Thus, the use of wood for heating is widespread in France, with more than 3 million households using wood to fulfil their main heating requirements, and a further 4 million applying wood heating occasionally. An extra 1.5 million homes are estimated to infrequently use wood for heating purposes. District heat production from waste incineration is increasing, and was reported as 47,500 TJ in 1996.

Solar collectors installed provide 17 ktoe of heat (largely for hot water in residential buildings and for swimming pools), and 4,000 solar water heaters were installed in 1996. Geothermal energy is exploited via 41 low enthalpy geothermal heat plants around Paris and 15 in the Aquitaine region, estimated to supply around 121 ktoe heat in 1996.

There are solar thermal and biomass initiatives to offset the demand for fossil fuels in generating primary heat. Promotion of wood energy for heating (of apartment blocks) was being strengthened via a Wood Energy Plan, initiated by the Ministry for Industry. The total budget for the plan was 215 million FF and the plan ran between 1995 and 1998. The plan aimed to create 500 additional jobs by 2000 and should also result in fossil fuel savings of 60 ktoe. In support of this plan, France's 1997 budget lowered the VAT rate of 5.5% on wood used for home heating. Subsidies are allocated on a case-by-case basis. In the framework of a government programme of early 1996, 20,000 solar water heaters were to be installed in French departments by 2000.

The most recent figures (Table E.4) indicate that the programmes have not been very successful. Only the use of solid biomass (wood) for heating purpose seems to have increased since 1996. Yet, the IEA figures given in the text and the figures given in Table E.4 might not be comparable anyhow.

E.3 Liberalisation process[3]

Over the years, subsequent French governments did all in their power to keep the effects of the European Directives to a minimum for their companies, Electricité de France (EdF) and Gaz de France. Together with Belgium, Italy and Luxembourg the country was soon among the latecomers on the deregulation front. In December of 1998, the French government put forward a first draft for the national implementation of the Single Electricity Market Directive. Market opening was certainly to be oriented to the minimum stipulations of the Directive and the state was under no circumstances willing to let go of the entrepreneurial reins. In contrast, the government allowed the monolith to further expand its already extensive foreign activities in the run-up to deregulation. EdF is by far the largest European electricity utility (sales of more than 450 TWh) and has already in the past been the largest electricity exporter with an export surplus of 65 TWh in 1997.

In the course of 1999, many EU member states (the UK, Spain, the Netherlands, Germany, etc.) were expressing their frustration at the deadlock over France's delay with electricity sector liberalisation. 20% of France's market was opened from February 29, 1999 on, with eligibility confined to 100 GWh customers, but only as Community Law became the immediately applicable legislation. Five companies were said to receive their power supply from elsewhere. EdF published a transitional tariff for grid access on its website, which 100 GWh consumers could use to shop around for their power.

On 1 February 2000, France finally transposed the EU electricity directive, almost exactly one year after the official deadline. The news came at the Council of Ministers in Brussels on 2 December, 1999 when French energy minister Christian Pierret expressed the 'firm determination' of his government to table new proposals before the Assemblee nationale on 18 January. Pierret's announcement came just one week after the European Commission had launched infringement proceedings against France and Luxembourg for failure to transpose the electricity directive. The Commission wrote letters of formal notice -the first stage in the procedure- on 24 November. The offending member states have two weeks from receipt of the letter to reply with detailed information before the Commission decides whether to proceed to the next stage. The Commission was concerned with certain details of the draft law, particularly the independence of the grid operator.

The French 'Act for the transformation and development of the public electricity supply' does not go further than the minimum requirements of the EU directive. Because of the delay in transposition, France has to meet both the 1999 minimum market opening (customers consuming more than 40 GWh/y or 26.48%) and the 2000 minimum (more than 20 GWh/y or 30%) at the same time. In theory this throws open to competition 115 TWh of industrial consumption. France has a total net consumption of about 390 TWh. French estimates showed that the 40

[3] Sources: 'Frankreich öffnet Strommarkt minimal', Stromthemen 1/2000 and 3/2000; 'France: Minimum Competition by February', EU Energy Policy, 16.12.1999, http://www.uk.ftenergy.com/news.asp.

GWh threshold would create 400 eligible customers. As it is, the market opened immediately to 20 GWh, releasing around 800 customers. The third threshold (9 GWh/y or 33%), coming into force by 2003, will enable some 2,500 customers to shop around.

The law creates a single regulatory entity for both power and gas, the Commission de Regulation. The Commission is to be independent and should have 6 members. Setting grid tariffs will be the job of the ministry on advice from the regulator. The Commission monitors the legality of all activities concerning grid access and electricity use.

It may be surprising that the French law opts for regulated third party access (rTPA), and not for a single buyer model, since France was strongly pushing the latter during the lengthy negotiations on the Single Market Directives.

In early February 2000 the French Parliament passed a law that enables about 800 industrial consumers to buy electricity from other generators than the EdF. The law implements the EU Electricity Market Directive with a one year delay and at the lowest possible level (only 30 per cent of the electricity market have been opened for competition) (cf. Section 1.3).

The law makes the first move towards unbundling the electricity supply industry in France, by setting out conditions under which EdF can operate the high voltage transmission grid. EdF will, however, maintain its monopoly on this activity and more or less continue to be an integrated company. The law proposes a new regulator for the sector which is responsible for administering the authorisation of all new generating capacity, including that based on renewable sources. The law also proposes the set-up of a ‘Public Service’ fund that would cover the cost of connecting isolated users (especially in rural areas), favourable tariffs for renewable electricity projects etc. This fund will be financed by a levy on all electricity producers. Electricity consumers eligible for picking their supplier are forced to complete three-year contracts. Trade is restricted to few players, an electricity exchange is not intended.

E.4 Renewable energy activities and policies

Renewable energy policy is formulated by the Ministry of Industry and implemented through the Agence de l’Environnement et de la Maîtrise de L’Energie (ADEME). Reported use of non-hydro renewable energy and wastes in France amounted to 4.4% (11.2 Mtoe) of total primary energy supply in 1999 -due mainly to the contribution of solid biomass (particularly wood), by far the largest non-hydro renewable source (Direction 2000). Almost all of the biomass used is exploited for residential heating. Moreover, it should be mentioned here that France gives a high priority to the development of biofuels, largely for agricultural reasons. Municipal and industrial wastes are being applied to generate growing quantities of electricity and heat. Only small amounts of geothermal heat, solar energy and, increasingly, wind have bee utilised so far. Hydropower accounted for ca. 15% of total electricity production, equivalent to an additional 2% of total energy supply.

E.4.1 Renewable energy status

The capacity of hydropower plants has been stable at 20.5 GW since the early 1990s. Weather variations lead to considerable variations in generation from year to year (77.3 TWh in 1994, and 65.2 TWh in 1996). Large hydro dominates both renewable electricity and total hydro output, with small hydro (>8 MW) contributing approximately 10% of total hydro.

Wind capacity is small, but has been expanding over the last few years, and should continue to do so due to the commissioning of the plants under the EOLE programme -a government support scheme to be described below. Capacity was 900 kW in 1992, 3.4 MW in 1995 and around 13 MW at the end of 1997; generation stood at 0.009 TWh in 1996. Only a small percentage of total biomass exploitation (8.8 Mtoe) was used to generate 0.714 TWh of electricity in 1996. Both municipal and industrial wastes are used, in approximately equal amounts, for electricity generation estimated at 1.4 TWh in 1996.

Photovoltaics have been employed in remote areas, but is not widespread. National estimates for the capacity of installed PV systems were 2.5 MW in 1996, when generation was estimated at 0.002 TWh. Electricity production from geothermal energy is being explored via a joint German/French/UK geothermal project on hot dry rocks underway at Soultz in Alsace. France is one of two IEA countries with installed tidal power. A large scale tidal installation (210 MW) delivers approximately 550 GWh/y. No expansion of tidal power is planned.

Table E.5 gives the newest figures published by the Ministry for Economic Affairs, Finance and Industry in May 2000. No new capacities have been installed in 1999. According to the European Wind Energy Association (AWEA), the installed wind capacity remains at 21 MW.

Table E.5 *Renewable electricity supply in France and it overseas territories [GWh]*

	1998	1999[1]
Hydro	67,473	78,311
Wind	49	51
Solar	7	7
Waste	1,385	1,385
Biofuels	1,500	1,485
Biogas	145	145
Total	70,560	81,385

[1] preliminary figures.

Source: http://www.industrie.gouv.fr/energie/renou/textes/se_bilan2.html.

E.4.2 Renewable energy policy

France has a substantial population that are not connected to the main electricity grid. The higher cost of electricity supply to these areas would in theory make renewable electricity supply an economically attractive option, particularly as these sites have significant solar and wind resources. However, EdF is legally obliged to supply low-voltage electricity at equal rates to consumers wherever they are located in metropolitan France or in overseas departments and whatever the cost to EdF. The resulting sale of some electricity at prices lower than its production cost effectively removes a niche market for (independent) renewable electricity production, and is therefore at odds with the proclaimed aim to promote renewables where they are competitive.

Under current legislation EdF must purchase all power produced by IPPs from renewable energy sources (purchase obligation), but EdF is free to negotiate the contract with each IPP. The price EdF pays for 'green' generation is usually based on some measure of avoided cost. Independent small hydro producers benefit from a purchase price guaranteed for 15 years. As a result of this, renewable energy has made more headway in the island of Corsica and French overseas territories than in France in general.

Since 1996, France has a programme for the promotion of wind power (EOLE 2005) launched by the Ministry for Industry. The target is to achieve 250-500 MW installed wind power capacity by 2005. In order to do this the government (in co-operation with EdF and ADEME) has set up a system of competitive bidding for 15 year contracts with EdF. It is run in a similar fashion to the UK's NFFO. There are several criteria which projects must pass in order to be considered for a contract. These include carrying out an Environmental Impact Assessment (EIA), receiving local support, etc. Projects have to be between 1.5 and 8 MW capacity -the legal limit for independent power producers. Successful bids are chosen on cost grounds. Projects totalling

77.5 MW of capacity had submitted successful bids by the end of 1997, and in theory these turbines should have been installed by the turn of the century, as developers are given at three-year period in which to construct winning bids. The first call for proposals resulted in the selection of a first band of 4 projects with a total capacity of 13 MW at an average purchase price of 0.337 FF/kWh. The second band, selected in October 1997, brought about a further capacity of 64.5 MW. EOLE aims to drive costs down to a competitive 0.25 FF/kWh by 2005. A further round of bidding for 100 MW (of which 25 MW is to be in France's overseas territories and departments) was initiated in early 1998, and another series of bids was to be held before 2005. The new climate action plan of the French government is aiming to achieve an installed wind power capacity of 3,000 MW by 2010.

The EOLE programme is the largest programme available for promoting renewable electricity. A similar policy to encourage installation of 10 MW of biomass electricity capacity was announced in February 1998.

Financial support is currently not available for grid-connected PV systems. However, from 1993 until the introduction of the Amortisation of Electrification Costs scheme (FACE), such systems benefited from a subsidy equivalent to 25% of the capital cost: 10% from ADEME and 15% by EdF. This subsidy was not high enough for many PV systems to be built. The FACE fund is a source of finance for investments in renewables and demand-side management in rural areas. The annual budget for FACE is 100 million FF. The majority of funds are spent on PV systems in rural areas, and aim to reduce either grid extensions or grid strengthening, via reducing peak demand or increasing stand-alone generation capacity. However, without further incentives for solar electricity, it is unlikely to take off in the medium term, except in remote districts and in overseas departments.

In 1996, national government expenditure on renewable energy sources accounted for 1% of the total energy R&D budget. This was the lowest reported proportion of any OECD country's energy R&D budget that is spent on renewable energy. The majority of the money was spent on biomass, PV and geothermal.

Nevertheless, government supports renewable energy in several ways, including direct funding of local and regional projects, joint EdF/ADEME agreements, financial incentives (such as favourable tax treatment for renewable energy investments, reduced VAT on renewable energy equipment, and premium buy-back rates for successful projects under national tender programmes)4 and information/education programmes.

At a very recent press conference, the Union of Renewable Energies said that France will remain among the least dynamic countries for this industry, if authorities do not give incentives to the renewables sector in France. In no sub-sector (solar, wind, biomass, wood, geothermal, small hydro-power generation) has France showed any sign of development. The Union is calling for incentive measures such as a higher feed-in tariffs - 0.40-0.50 FF[5].

E.4.3 Renewable energy potentials

The majority of the large hydro potential is already exploited. An additional 4 TWh/y mostly from small hydro projects has been identified. Limits on the development of small hydro sites are generally due to flow requirements under water use regulations.

A significant contribution from geothermal to electricity supply is not expected for at least 10 years. There are no plans for noteworthy short-term expansion of geothermal energy use. De-

[4] Also a tax on municipal waste was introduced in 1993 to encourage energy recuperation from waste. It was fixed at 30FF/ton in 1996, and was planned to be raised to 35FF/t in 1997 and 40FF/t in 1998.

[5] Source: *europe environment*, n° 565 of April 4, 2000, 16.

velopment of energy from wastes is set to increase as legislation prohibits landfill of household wastes after 2002.

Table E.6 *Technical potential for renewables in France, [TWh]*

Wind speed [m/s]	*7.5*	*6.5*	*5.5*	*4.5*
Wind: onshore	0	2	8	0
Water depth [m]	*10*	*20*	*30*	*40*
Wind: offshore	102	130	135	110
Large hydro	0			
Small hydro	0			
	50% of building integrated solar potential			
Photovoltaics	58.75			
Solar heating	117.5			
Solar thermal electricity	0			
Biomass electricity	*10% solids substitution*			
Fuel switch	2.1			
Biomass CHP				
(complementary to fuel switch)	*fuel eff.: 65%*	*electricity: 33%*	*heat: 67%*	
Wood (residues)	12.7	4.2	8.5	
Biogas	38.4	12.8	25.6	
Crops	35.7	11.9	23.8	

Source: Bräuer/ Kühn (2000).

E.5 Cross-cutting GHG emissions sector

France has a special role in international climate policy. The high share of nuclear and hydro power in electricity generation has led to comparatively low energy-related CO_2 emissions per capita. In 1995, per-capita emissions were only 56% of the OECD average (IEA 1997). Hence, the transport sector has a greater share in national CO_2 emissions than in any other EU Member State, about 38% in 1995, whereas the electricity sector accounted for about 9% only (IEA 1997).

In the Kyoto Protocol to the Framework Convention 38 industrialised and transition countries plus the European Community have committed to limit or reduce emissions of a set of six greenhouse gases (GHG). The European Community and its Member States have the obligation to reduce GHG emissions by 8% in the target period 2008 to 2012 compared to the emissions level in 1990. Besides the main greenhouse gas carbon dioxide (CO_2), the Protocol covers also methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6). The EU distributed the reduction obligation through the so-called EU-Burden-Sharing Agreement in conjunction with Article 4 of the Protocol among the Member States. France agreed on a stabilisation of their emissions.

Until 1991, hardly any climate policy had been implemented. Due to the on-going international negotiation process, meanwhile, the French government has implemented a bunch of climate policy instruments. On 19 January 2000, the French government adopted a new national climate change strategy with a new energy tax as its centrepiece. The plan comprises 100 actions aimed at enabling France to stabilise greenhouse gas emissions at 1990 levels by 2008-12, addressing transport, industry, construction, land-use planning, forestry and other sectors. The tax is likely to start next year at Euro 23-30 (FF 150-200) per tonne of carbon, raising around 760 million Euro. The price could rise to about 76 Euro per tonne by 2010. Following recent experience with a similar UK energy tax plan, the French government plans to exempt energy-intensive industries, but only in exchange for voluntary commitments to reduce emissions. The strategy also allows for future development of market-based mechanisms such as emissions trading between businesses.

Among the plan's many other elements is an objective to stabilise greenhouse gas emissions from transport by 2020. It also confirms a previous objective of reducing a tax differential between petrol and diesel that has long made diesel relatively cheap in France compared with other EU countries. State support for renewable energy is to be stepped up, while energy efficiency standards for buildings are to be tightened. In addition, efforts are to be made to achieve a better balance between different freight transport modes. Meanwhile, reinforced co-operation between central and regional governments is promised during forthcoming negotiations on regional plans (French Government 2000).

Table E.7 *GHG emissions in France*

		1990	1995	1996	1997
Total EU-15 emissions	[Mt CO_2]	3,336	3,259	n.a.	n.a.
Country Emissions	[Mt CO_2]	396	396	409	402
Share of Country Emissions/ Total EU	[%]	12	12	n.a.	n.a.
Emissions per capita		6.97	6.81	7.00	6.86

France has experienced only a slight increase in CO_2 emissions since 1990 by about 2%. Due to the expansion of nuclear power, CO_2 emissions had already been reduced before 1990 by 26.5%, compared to 1980 levels (Michaelowa, 1998).

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F. GERMANY

F.1 Introduction

This report focuses on some highlights and the most recent developments, as comprehensive information on German energy policies and energy industries has already been published in many reports.

F.2 Energy sector

F.2.1 General overview

In 1999, the German gross primary energy consumption reached about 340 million tonnes of oil equivalents (Mtoe). This makes the German energy market the fifth largest world-wide, ranked behind the USA, China, Russia, and Japan. The per capita consumption has been maintained at around 4.2 toe during the last 5 years, 3 times higher than world average. On the other hand, energy consumption per 1,000 Euro GDP has ranged at 224 to 244 kgoe in the same period - half of world average, so that energy is used comparatively efficiently (see Table F.1).

Table F.1 *Basic energy indicators for Germany*

		1990	1995	1996	1997	1998	1999
Population	[million]	79	82	82	82	82	82
GDP	[billion Euro 1990]	1,297	1,405	1,423	1,455	1,495	1,516
Gross Inland Primary Consumption	[Mtoe]	354	336	348	344	345	339
Total Electricity Production	[TWh]	549	536	555	551	553	554
CO_2 emissions	[Mt of CO_2]	947	864	872	830	886	859
Total EU Primary Consumption	[Mtoe]	1,314	1,363	1,411	1,407	n.a.	n.a.
Share in EU (GIPC/TEUPC)	[%]	27	25	25	24	n.a.	n.a.
Gross Inland/GDP	[toe/1990 Euro]	272.86	239.19	244.32	236.15	230.77	223.61
Gross Inland/Capita	[toe/inhabitant]	4.46	4.12	4.25	4.18	4.20	4.13
Electricity Generated/Capita	[MWh/inhabitant]	6.91	6.57	6.78	6.71	6.74	6.76
CO_2 emissions/Capita	[t/inhabitant]	11.94	10.58	10.64	10.10	10.79	10.48

Source: AER 1999 for 1990-1997 data; different sources for 1998 and 1999 data.

The primary energy mix of 1999 in Germany was still dominated by mineral oil (39.4%). While the use of natural gas (21.3%), nuclear energy (13.1%), hydro power and wind energy (0.6%) was growing, the use of hard coal (13.4%) and lignite (10.3%) decreased. Including biomass and solid waste, renewable sources of energy contributed ca. 2% to primary energy consumption in Germany. Finally, CO_2 emissions have been reduced by as much as 15.3% since 1990 (Schiffer 2000).

Responsibility for energy policy in Germany is shared between the federal government and the 16 Länder, with regulatory and operational responsibilities at the local and municipal level. The main responsibility, however, remains with the Federal Ministry of Economic Affairs.

The Act for the Revision of the German Energy Industry Legislation was passed by the German Parliament on November 28, 1997 after lengthy and controversial discussions. It came into force on April 29, 1998. In contrast to the rest of Europe, both the gas and electricity markets were 100% opened in one step, at least legally. The fundamental regulation of the Act is that

§§103 and 103a of the Anti-Trust Act, which exempts some industry sectors from the general ban on cartels, were no longer applicable for the electricity and gas supply (Art. 2). The Energy Industry Law (Art. 1) replaced the Law for the Promotion of the Energy Industry from 1935. This framework had favoured regional monopoly structures in production, transmission and distribution.

On the first of January, 2000, the second stage of the German Ecological Tax Reform started. The general objective of this reform is to relieve pressure from the cost factor employment and in return to increase cost pressure on energy. Yet, the taxable bases and the tax rates differ, and the law knows many exceptions. The basic elements of the eco-tax reform include an increase of the tax on mineral oil and the initiation of a general electricity tax (2 Pf/kWh in 1999 plus additional 0.5 Pf/kWh at the beginning of 2000, 2001, 2002 and 2003, respectively).

F.2.2 Electricity sector

On the 29th of April, 1998, the new 'Energiewirtschaftsgesetz (EnWG)' (Energy Industry Law) came into effect. The main elements from a European perspective under this new law are:

- The full market opening in one, not in three steps:
  The traditionally closed supply areas have ceased to exist. There has been no step-by-step liberalisation, as visualised in the EU Directive 96/92/EC concerning common rules for the internal market in electricity. The electricity market has instead officially opened to all customers at once. §6 in EnWG obliges the operators of the electric grid to allow the transmission to all customers. It establishes a universal access to the grid rule, since all reasons for the refusal of full access are listed and the burden of proof is imposed on the network owner.
- The model of negotiated, not regulated third party access (TPA):
  In contrast to other member states, Germany does not have a regulatory authority. No grid access rules and tariffs were worked out in the new Energy Industry Law. This is left to the industry itself. Only in case of failure of the industry-led grid access scheme does the government plan to take the initiative.
- The transition period for municipal utilities until 2002:
  The municipal electric utilities are given the permission to make use of the Single Buyer option in their supply areas for a transition period until 2002 (or even 2005). A respective paragraph has been included in the new Law.
- Separation of accounting, but no legal unbundling required:
  No changes in network ownership or operation

Table F.2 *Basic electricity sector indicators for Germany*

		1990	1995	1996	1997	1998	1999
Total Electricity Production	[TWh]	548.62	536.15	555.24	551.47	553.4	554
Production of RES-E	[TWh]	18.56	25.92	27.08	23.93	25.28	28.70
Total Installed Capacity in Electricity	[GW]	121.17	115.28	114.90	113.96	111,00	111.00
Installed Capacity of RES-E	[GW]	8.76	9.95	10.49	10.79	8.27	n.a.
Electricity prices to industrial consumers	[1990Euro/toe]	835.3	694.2	619.1	584.7	n.a.	n.a.
Electricity prices to domestic consumers	[1990Euro/toe]	1,500	1,412	1,297	1,309	n.a.	n.a.
Production of RES-E/Total El-Production	[%]	3.4	4.8	4.9	4.3	4.6	5.2
Installed Capacity of RES-E/Total Installed Capacity	[%]	7.2	8.6	9.1	9.5	7.5	n.a.

Source: AER 1999 for 1990-1997 data; different sources for 1998 and 1999 data.

When liberalisation began, there were about 1,000 electricity utilities in Germany, of which about 500 had generation assets of their own. On the national level, there were the eight companies shown in Table F.3. These eight supra-regional utility companies dominated the market. They were, and are still interconnected through capital links and are joint members of the Association 'Deutsche Verbundgesellschaft e.V.'. In addition, there were about 80 regional utilities and approximately 900 local, mostly horizontally integrated utilities in mid-1998. With the exception of PreussenElektra AG and Bayernwerk AG, the big utilities were also directly supplying industrial and standard rate customers. HEW, for instance, used to mainly sell electricity to households and small businesses. With a share of more than 80% in public supply, the eight large interconnected utilities have been the main producers of electricity in Germany, even after liberalisation. A share of about 80% in the high voltage grid guarantees them a crucial position in electricity transmission as well. Further influence has been secured through an immense number of interest acquisitions in regional and municipal utility companies. Over-capacity was and is a problem in the German power market.

Table F.3 *The largest electric utilities in Germany and their electricity sold from 1997 to 1999 [TWh]*

	1997	1998	1999
1. RWE Energie AG, Essen	132	138	136
2. PreussenElektra AG, Hanover	105	106	110
3. Bayernwerk AG, Munic	63	73	78
4. Energie Baden-Württemberg AG (EnBW), Karlsruhe	49	51	55
5. Vereinigte Energiewerke AG (VEAG), Berlin	47	47	49
6. Vereinigte Elektrizitätswerke Westfalen AG (VEW), Dortmund	33	35	41
7. Hamburgische Electricitäts-Werke AG (HEW), Hamburg	14	17	21
9. Berliner Kraft- und Licht AG (Bewag), Berlin	13	13	13
Total	470	494	517

Source: http://www.vdew.de/ak_wo_1.htm.

In the first two years of electricity market opening, grid access rules and tariffs have turned out to be the major obstacle for competition to really start. The scheme worked out gave the established electric utilities some more time to get prepared. Under the pressure to find a consensus between each other and to prevent regulation by the government, as foreseen in the bill, the electricity industry and their big industry customers agreed on a 'Verbändevereinbarung (VVD)' (Voluntary Agreement of Associations). It fixed the criteria for how to determine the grid access rules and charges literally in the last minute. The VVD I between the 'Bundesverband der Deutschen Industrie e.V. (BDI)' (Association of German Industry), the 'Verband der Industriellen Energie- und Kraftwirtschaft (VIK)' (Association of the Industrial Energy and Power Sector) and the 'Vereinigung Deutscher Elektrizitätswerke (VDEW)' (Association of German Electric Utilities) was ultimately signed at end of May 1998 to be in force until September 30, 1999. Although technically the agreement was not strictly binding for the members of the associations, but a recommendation only, it provided the baseline for the calculation of transmission as well as distribution charges.

The first Association Agreement of May 1998 has been heavily criticised from all sides because of its lack of transparency and practicability, high charges and the distance dependency of the tariffs. It has been a major obstacle for (fair) competition. The second Verbändevereinbarung (VVD II) was agreed on in December 1999. Under the pressure of the Federal (Cartel) Office for Fair Trading and other actors in the market, grid access rules and tariff structures have been simplified a lot. Transaction and negotiations costs should therefore decrease. Additional associations representing smaller companies were sitting on the negotiation table as well this time. The most controversial question between the different parties is how to standardise load profiles and charges for typical households. Nevertheless, the second Verbändevereinbarung seems to guarantee the necessary level playing field.

F.2.3 Gas sector

The liberalization of the gas markets has begun its final spurt. The regulations of the EU Gas Directive must be adopted to national law by August 10, 2000. The market opening is hoped to make a simple and transparent access to the gas grid possible for all competitors.

The 1998 revision of the German Energy Legislation included a regulatory reform of the German gas market. Like in the electricity sector, closed supply areas ceased to exist; the market was fully opened. But two years later, the negotiations for an association agreement on discrimination-free access to the gas pipelines were still on-going. Like in the electricity sector, associations have volunteered to regulate the access to the gas grid, so that government intervention would not become necessary. In July 2000, an agreement between the top associations and the Federal Ministry of Economic Affairs was reached about the conditions for pricing and grid access. In order to calculate the compensation, a distance-dependent point-to-point model was made for the interregional district gas supply. In the regional supply as well as at the end distribution level, compensation is independent of distance. A so-called post mark system was created for fixed regions. Regulations for private customers could not be worked out. It is therefore still undecided if and when private households will also profit from competition in the gas market. For competition to really start, the adoption of a non-discriminatory association agreement is regarded even more important than on the electricity market.

The structure of the German gas sector is in many respects similar to the structure of the electricity sector. The public gas utility sector comprises about 750 companies. One can distinguish between 730 local and regional utilities and 18 long-distance transportation companies or between the generation importing level, the transportation and distribution level and the consumer level. About 97% of the gas supply of the public sector is derived from natural gas. In 1998, about 80% of the 960 TWh total natural gas supply in Germany was imported from 5 foreign sources (Russia, the Netherlands, Norway, Denmark, and the U.K.). Mainly 10 companies are active in the domestic gas production, but 76% of total production remains with three companies: Shell, ESSO (Exxon) and Mobil Gas and Oil. Thus, the suppliers are mostly connected to the mineral oil, coal, steel, and electricity industries.

In only a few years, natural gas has become a corner-stone in German energy supply. Gas (21%) is the second most important energy source after mineral oil. In power production, natural gas is gaining in importance. The share of gas in total electricity generation, in particular the use in gas and steam turbine power plants, is expected to grow. In 1998, it was about 12% or about 8% of the total gas sales to end customers was to the electricity sector. Other markets for gas are regarded as saturated.

On the whole, the liberalization of the gas market is not comparable to that of the power market. Natural Gas is a growing market that has no over-capacities, unlike the power market. The buyers can therefore only expect limited price benefits. The German gas industry is assuming a (30%) rise in gas prices, since the oil prices have also risen.[6] The profit margin of gas distributor businesses will probably be under a tremendous pressure. After the circa 750 German gas suppliers have already cut 30,000 jobs in the last few years, another cut of around 10,000 jobs is planned for the gas industry.

F.2.4 Heat sector

In Germany, about 250 companies supply their customers with district heat. About 320,000 buildings are connected to the heat grid. District heat is provided for about 12% of the in total 37 million apartments; in the former East Germany this share amounts to 28%. 78% of the total heat fed into the grid is generated in combined heat and power (CHP) plants.

According to a poll by the VIK, the Association of the Industrial Energy and Power Sector, 9% of the combined heat and power (CHP) plants has been completely shut down since the electricity market opening in April 1998, while another 6% was shut down partially. An additional 18% is said to have a threatened existence. So, in 1999 about 2,000 MW of industrial CHP have

[6] The gas suppliers are tied to the prices of the subsidy market through long-term delivery contracts.

been put out of operation. The price of CHP electricity offered by utilities went down by 30% between the beginning of 1998 and January 2000 (WWF / Cogen 2000).

On March 25, the Bundestag (German Parliament) ratified a new law, the Law on the Protection of Electricity Generation from CHP plants. The law obliges grid operators to purchase the produced electricity from CHP plants, and remunerate 9 Pf/kWh in the first year of its effectiveness, and 0.5 Pf/kWh less in each subsequent year. The additional funds have to be raised in the electricity sector by an increased fee on grid use. The five-year subsidy program includes plants that burn coal, gas, oil, or waste, on the condition that the installed CHP capacity amounts to at least 25% of the total power production capacity of the respective public utility. Additional restrictions apply, so that only about 60 municipal plants would fall under this program, but the formulations give room for different interpretations. The law came into effect in May 2000.

The support mechanism is very similar to the mechanism under the German Electricity Feed-in Law and the Renewable Energies Law. Like the former EFL, the system is restricted to certain ‘public’ utilities, and not open to all CHP units. It is a law that only focuses on somehow coping with stranded investments (economic difficulties because of liberalisation). Environmental criteria have definitely not played a role in the design of the support scheme, although climate protection and energy savings are mentioned in §1 of the CHP law as the main purposes.

Table F.4 *Electricity generation in CHP plants in Germany in 1997*

	MW_{el}	TWh_{el}
Public CHP plants	11,250	26,420
Co-generation (engines)	420	1,890
Biogas co-generation	230	1,130
Co-generation (gas turbines)	1,070	1,190
Industrial CHP	10,110	41,150
	2,480	11,350
Co-generation (engines)	140	500
Gas turbines	1,320	7,850
Sum	21,370	67,570

Source: AGFW, VDEW, FG BHKW and VIK

Other measures that have been taken to promote electricity from CHP plants include an eco-tax break for units with a monthly efficiency over 70%.

The federal government is about to set a target of doubling CHP electricity production in Germany by 2010. For reaching this objective, the introduction of a system of tradable green certificates combined with an obligation on energy companies is under discussion at the moment. Parties and interest groups that have pointed to the inefficiency and ineffectiveness of such a scheme for the promotion of renewable sources of electricity now emphasise exactly these advantages of that policy-instrument.

F.3 Liberalisation process

The German electricity industry has been tremendously restructured since the full market opening in April 1998. Most of the developments that we have seen in the sector were predicted or expected -they are a logical outcome of the new commercial pressure. Yet, it is the speed that is surprising to most experts.

In the course of the last two years, the German electricity market has become one of the most competitive in Europe. The EU Internal Electricity Market Directive 96/92/EC has not only been translated into national legislation in time, but the national liberalisation efforts have also gone far beyond the liberalisation targets required by the Directive. As a consequence, there has been a great deal of strategic alliance, take-over and merger activity in the sector, including foreign firms. Electricity purchasing pools, strategic alliances, and asset sales are particularly popular among municipal utilities. Regional utilities have been merging quite a lot. The supra-regional utilities have increased their shares in or taken over regional and municipal utilities, and have also started to merge with each other. It was predicted that 3 supra-regional utilities and about 200 regional suppliers would survive in the medium-run; for the time being, it rather looks like we will end up with four blocks:

- E.ON (VEBA-VIAG merger, i.e. PreussenElektra and Bayernwerk merger), and
- RWE / VEW (the companies have also merged).
- VEAG, the supra-regional company in the area of Eastern Germany, is completely owned by a consortium of the large utilities listed. They are now obliged to sell all their shares.
- A 25.1% share of EnBW was sold to EdF and
- A 25.1% share of HEW was sold to Vattenfall.

The cartel office seems to prefer a solution with 4 major companies. They urge the supra-regional utilities to get rid of their capital links (e.g., PreussenElektra has a share in HEW, Bayernwerk has a share in VEW), and to sell VEAG to a foreign competitor (e.g., Vattenfall or Southern Energy, both companies are already in the German market).

In some price categories, electricity prices have fallen up to 40% in the last 2 years. For a long time, there were only price cuts and competition for industrial and bundle customers. But in the summer of 1999, supply companies opened competition in the residential sector, nation-wide, and not only on paper. Marketing efforts of some utilities have been immense, yet, the average switching rates are still rather low (1%), which is partly due to the pending implementation of the association agreement on grid access rules and tariffs. Of course, the competitive market has also brought new business opportunities, branches and companies or market players, especially in the fields of power trading and energy services.

F.4 Renewable energy activities and policies

F.4.1 Renewable energy status

In 1998, around 7 Mtoe was contributed by renewable energies to primary energy consumption. 45% of this was used in the heat market; the rest was used for electricity generation. The pattern of renewable energy use is markedly different to many other EU Member States: in many countries renewables' importance in primary energy consumption is higher than that in electricity generation reflecting the importance of the direct use of biomass. In Germany, although biomass constitutes the majority of renewable energy used, it is mainly used to produce electricity and heat.

The German federal government as well as the state and district governments have put in place a number of measures for promoting renewable sources of energy. Responsibility for the development of renewable energies indeed rests with a number of different institutions at the national and regional levels; full co-ordination has yet to be achieved. Yet, the Federal Ministry of Economic Affairs is responsible for the Electricity Feed Law (EFL)/Renewable Energies Law (REL) - the primary stimulation instrument for renewably generated electricity on the national level. Currently, the EFL supports about 2.5% of total renewable electricity generation in Germany. Many other policy types are implemented, including economic incentives (e.g. investment subsidies, low-interest loans), improved information flows and R&D programmes.

One of the reasons for Germany's promotion of renewable energy is its national and international CO_2 commitments. Chancellor Schröder just recently repeated the April 1995 declaration of former Chancellor Kohl to reduce national CO_2 emissions relative to 1990 by 25% by the year 2005. Also, the 'principle of sustainable development' was added as a societal aim to the

German constitutional law (Grundgesetz - Art. 20a GG) in 1994. A commitment has also been made to environmental protection in the Energy Industry Act of April 1998 where it is mentioned as one of three public goals in energy policy. Germany has definitely still a long way to go before it can pronounce the attainment of these environmental ends.

Table F.5 *Contribution of RES to energy supply in Germany in 1997 [GWh]*

		Electricity[1]	Heat[1]	Primary Energy[2]
Hydro Power		18,900		18,900
Wind Energy		4,050		4,050
Photovoltaics		32		32
Solid Biomass		179	13,410	17,327
Biogas, Landfill Gas, Sewage Gas, Rape-seed oil		700	500	1,339
Solar Thermal			650	831
Geothermal			111	142
Total	[GWh]	23,861	14,671	42,621
Share of Total	[%]	4.7	1	1.1
Waste, sewage sludge		2,113	5,050	8,571
Share of Total	[%]	5.1	1.4	1.3

1 Possible generation with the 1997 installed capacity in a climatologic normal year; total net electricity production (509 TWh/a).
2 Wirkungsgradmethode.
Source: BMU (1999: 2).

With respect to the contribution of renewable energy sources, there remains a large domestic potential for their increased use. The German Ministry for the Environment estimates that 10,000 MW of wind power could be installed in Germany within less than 10 years from now. That would equal a share of 3.5% of German electricity production, given stable consumption levels. The potential of hydropower is almost exhausted. Possible sites would make new plants very expensive and planning permission problems would occur for environmental reasons. Experts estimate that biomass could contribute up to 2.1 Mtoe within the next 5 years from its estimated technical potential of almost 29 Mtoe/year.

F.4.2 Renewable electricity

In particular the Electricity Feed Law (EFL - StrEG)[7], but also preferential planning guidelines, lower interest rates granted by the German Ausgleichsbank for part of the loans, and other support programmes in various German states, have brought Germany into the world-wide number one position in wind energy capacity. In 1998, some 1,000 new wind turbines with an overall electric power of some 800 MW were set up. So the total capacity installed almost reached 3,000 MW at the end of 1998; for comparison, in 1990, wind capacity was at 2 MW in Germany. In 1999, more than 1,500 additional MW of wind power had been installed - a new record. At the end of the year, the total wind capacities reached 4,440 MW.

However, despite this immense upswing, wind power plants still only accounted for about 1% of total electricity generation in Germany in 1998. As 1998 was also a rather good hydropower year, the share of renewable sources of energy in electricity consumption equalled about 5,2%. But only somewhat more than 1% was met by non-hydro renewable energy sources, which is quite below the EU-15 average. In 1990, before the 'famous' German Electricity Feed Law was introduced, the share of renewables was already at 4% (Table F.7).

7 Law on feeding electricity from renewable energy sources into the public grid (Electricity Feed Law (EFL) – Stromeinspeisungsgesetz (StrEG)) of 07/12/1990, Bundesgesetzblatt 1990, I, S. 2633, latest revision through Art. 3 of the Law on New Regulation of the Energy Sector Law of 24/04/1998.

Other renewable sources of energy have not had a boom comparable to that of wind energy. The installed capacities of hydropower, sewage and landfill gas have only changed slightly throughout the nineties. Nevertheless, the share of electricity produced from biomass has also started to grow. In 1998, the installed capacity was about 410 MW (1992: 230 MW), only 62 MW (1992: 40 MW) of which belonged to public electric utilities. Although the portion of photovoltaic energy in total electricity production is still below 0.01%, this technology has grown in recent years, among both public utilities and independent power producers. Photovoltaic installations seem to play a special role in Germany. They are equally popular in public, the electricity industry and government. The solar industry was successful in convincing the government to fix a feed-in tariff of 99 German Pfennig (about 50 EuroCents) per kWh in the newest EFL amendment. This policy is in addition to several investment subsidies and R&D programmes which exist in the solar energy field at state and federal levels.

Table F.6 *Share of renewable sources of energy in electricity consumption in Germany [%]*

	1998	1997	1996	1994	1992
Hydro	3.6	3.4	3.4	3.9	3.6
Wind	0.9	0.6	0.4	0.2	0.06
Waste	0.5	0.5	0.5	0.5	0.5
Biomass	0.2	0.2	0.2	0.1	0.07
PV	0.003	0.002	0.001	0.0009	0.0003
Total [%]	5.2	4.7	4.5	4.7	4.3
Total [million kWh]	25,279	21,733	21,090	21,082	18,784

Source: VDEW 1999.

End of 1998, the installed renewable capacity in Germany arrived at about 8,300 MW, about 7.5% of total generation capacity of 111,000 MW. It should be mentioned that public electric utilities own the big majority of hydro power and waste incineration plants, whereas independent power producers clearly have higher market assets, particularly in wind power plants, but also in biomass and PV installations. This is very much a result of the regulatory framework for the promotion of renewable sources. Under the EFL, the established utilities have been excluded from support until very recently (1st of April 2000).

The Electricity Feed Law has been based on a rather broad consensus in the political arena, but has been heavily criticised by the German electricity industry, e.g. as being discriminatory and as distorting competition among them. Especially the electric utilities located in the northern part of Germany have brought several actions against the EFL to Courts, as they were affected disproportionately by the regulation.[8] Under the EFL, the big majority of new renewable generation units has been built in the North. In Schleswig-Holstein, for example, the most northern state of Germany, the share of wind energy in total electricity consumption has risen to around 15% from almost zero in the past 10 years. The top three states concerning solar and wind generation capacities, in both cases contribute more than 50% to the overall capacity in Germany. In the field of wind energy, the regional differences are due to geographical or meteorological differences; in the field of PV, federal state policies and size of population have had the highest influence.

F.4.3 Renewable heat

In 1997, circa 13,400 GWh of heat were produced through the use of solid biomass, and about 500 GWh were produced using biogas, sewage and landfill gas. Solar collectors produced around 500 GWh_th in 1997. In addition, a surface of circa 0.5 million square meters of synthetic absorbers captured around 150 GWh of heat. The geothermal power has mainly been used in demonstration units. About 110 GWh of heat were produced in 1997 (cf. Table F.5).

[8] So far, the lawsuits have not been successful, one is still pending at the European Court of Justice.

The available surface area for solar collectors in Germany is estimated to be over 1.6 million square meters. The federal ‘Solarthermie 2000’ programme runs from 1993 to 2002 and aims for 10,000 square meters of installed solar collector surface for the provision of hot water in small- and large-scale systems at a cost of between 0.1-0.15 Euro per kWh_th. The programme was launched by the Federal Ministry for Research and Technology as part of its large-scale demonstration unit programme for the development of low-temperature heat from active systems, especially in East Germany. The technical potential of such systems is estimated at 130 ktoe/year by 2000 and up to 50 Mtoe/year in the longer run.

F.4.4 Renewable energy policy

The German Ministry for the Environment’s indicative target, brought up in several programmes, is to at least double the share of renewable energies in the electricity supply from 5 to 10% by 2010, and to reach a minimum renewables share of 50% in 2050 (cf. e.g. Umwelt No. 2/1999, 45). With the passing of the Renewable Energies Law, the 3rd amendment of the EFL, in March 2000, the 2010 target was legally laid down for the first time.

The Electricity Feed Law for renewable sources of energy was introduced in December 1990 and came into effect on January 1, 1991. Its second, revised version came into force on April 29, 1998 when the German electricity market opened to all customers. The law regulates the purchasing of electricity generated in the territory of the Federal Republic of Germany from specified renewable sources (hydropower, wind and solar energy, sewage and landfill gas as well as biomass). Excluded from the EFL were installations using sources, other than wind or solar energy, that have an installed capacity of more than 5 MW.

The EFL obliged the grid companies to buy the electricity and pay fixed feed-in tariffs to the eligible electricity producers. For hydropower, sewage and landfill gas plants that generate up to 5 MW, the tariff was set at 65% of the average utility electricity rates for consumers. For biomass as well as hydro, sewage and landfill gas installations under 500 kW the feed-in tariff is 80%, and for wind and solar power 90% of the average utility electricity rates for consumers. The tariffs were fixed by the regulatory authority for a one-year period based on the value of the average utility revenue per kWh sold. This value is to be drawn from an official statistic and has to be the value for the last but one calendar year. Table F.7 shows the feed-in tariffs subdivided into the three technology categories and consecutive years. The categories and percentages for sell-back rates have slightly changed from EFL amendment to EFL amendment.

Table F.7 *Feed-in tariffs (in Pf/kWh and Euro cents/kWh[1]) for electricity from renewable energy sources paid each year up to the 2nd amendment of the German EFL*

	1991	1992	1993	1994	1995	1996	1997	1998	1999	March 2000
Wind/Solar	8.49	8.45	8.47	8.66	8.84	8.80	8.77	8.59	8.45	8.23
Biomass/Hydro, sewage and landfill gas (< 499 kW)	7.08	7.05	7.06	7.21	7.85	7.82	7.80	7.63	7.51	7.32
Hydro, sewage and landfill gas (500 - 4999 kW)	6.13	6.10	6.12	6.25	6.38	6.36	6.33	6.20	6.10	5.95

[1] Values are given in terms of the respective year. The exchange rate of 1,95583 DM/EURO is used throughout.
Source: IWR (1999a)

Installations in which the Federal Republic of Germany, a federal state, a public electric utility or their subsidiaries hold shares of more than 25% were not qualified for the output subsidies under the EFL. Moreover, the EFL neither provided for a time limitation nor for a gradual reduction of the payments to eligible generators.

Under the EFL amendment of 1998, some important changes had been made, mainly driven by the financial burden issue. §4 StrEG introduces a cap of five percent. If the amount of electricity which must be supported under the EFL surpasses five per cent of the total kWhs delivered by an electric utility in one calendar year, the higher level network company is required to reimburse the costs of supporting additional renewable generation until it also reaches the five percent ceiling in its grid area. This basically means that for a share of RES-E above five percent, a utility has no (purchase) obligation any more. Since at least two network levels are usually affected, the regulation has also been called the double-threshold-rule.

The following is a summary of crucial parameters in the EFL amendment that was in effect until the end of March 2000:
- The feed-in tariffs were not financed from public budgets, but from revenues of utilities or grid companies. This has led to competitive distortions between electric utilities.
- The guaranteed premium rates only applied to the non-utility sector, i.e. utilities were generally not eligible.
- The double 5% ceiling rule was equal to an absolute upper limit for eligible renewables exploitation in Germany.
- The feed-in tariffs were based on average utility revenues from electricity sales to consumers. With presently sharply falling electricity prices, the feed-in payments would have shortly been lowered as well.
- The EFL guaranteed different levels of output premium rates depending on the source of renewable energy, thus, it (indirectly) included technology bands.

In October 1999, the supra-regional utility PreussenElektra announced that it expected to exceed the 5% ceiling in its grid area that year. According to the EFL effective at that time, the PreussenElektra Grid company was not obliged to support electricity generated from additional renewable energy plants from beginning of 2000 on. To avoid a halt of the dynamic development, especially in the wind energy sector, the government had been working on another amendment of the EFL for some time already. From October on, however, the follow-up version of the then existing EFL amendment was intensively discussed, not at all in public, but behind closed doors between politicians, the renewables industry and their associations, and other NGOs. Declared goals of the third revision were to quickly re-establish a reliable framework for investors, to get rid of regional distortions in competition caused by the financing mechanism, and, on the whole, to make the EFL more market-conform.

The Renewable Energies Law (REL) was passed by the German parliament on February 25, 2000 and came into effect on 1st of April, 2000. The REL continues with the practice of guaranteed grid access (purchase obligation on grid companies) and legally fixed feed-in tariffs. Yet, the cap was removed, output subsidies are no longer linked with market prices, but fixed on an even higher level. Biomass plants up to 20 MW_{el} and geothermal power are included. Equal sharing of costs between all suppliers. The new ‘Renewable Energy Law’ states that the electricity from renewable energy must be transported and charged to the final customer. Thus, the REL may be interpreted not so much as a feed-in tariff system, but more as an obligation for final customers to buy electricity at a fixed cost.

From the broad range of federal and state policies and programmes promoting or affecting renewable electricity development, only those regulations are referred to in the following that have been put in place by the new federal government since its inauguration. They comprise:
- the Directive for the promotion of PV installations (300 MW) by a 100,000-roofs solar electricity-programme of 1 January 1999,
- the Law for the introduction of an Ecological Tax Reform of 1 April 1999 (see above),
- the Directive for the promotion of measures for renewable energy sources (200-million-DM market incentive programme) of 1 September 1999.

The 100,000-roofs solar electricity programme aims at promoting the establishment of 100,000 photovoltaic installations with a maximum power production of 3 kW, i.e. a total production of

300 MW, between 1999 and 2004. The programme offers a special zero-interest loan with a repayment period of 10 years and up to 2 starting years without credit repayment. Private persons, small and medium-sized companies can apply.

A key uncertainty in the eco-tax reform is whether renewably-generated electricity will be exempt from the electricity levy from 2001 on, the third stage of the reform. Currently, renewably generated electricity is taxed like conventionally generated power. The public budget for the market incentive programme, however, is recycled of the revenue from the taxation of renewable energies. The support volume was set at DM 200 million per year until 2002. Priority funding shall go to solar thermal installations, installations for the recovery of energy from biogas/biomass, small hydroelectric power stations, individual wind farms and geothermal power plants. The average funding rate is estimated to be 20%.

Key concerns now dominating the renewables industry in Germany are the pending EU Directive on grid access of renewable energy sources, grid access rules and tariffs for RES-E in Germany, and the details of the third phase of the eco-tax reform.

F.5 Tradable green certificates

On the federal political level, the discussion on introducing a system for renewable energy certificate trade has not yet started. German market players seem to be prepared for getting involved in a test phase of international certificate trade on a voluntary basis, even though the German government has not made any effort toward that direction. There is a voluntary market in Germany and accreditation infrastructure is available as well. The potential market players accept the Basic Commitments of RECS. They work on finding an issuing and executive body for the test phase.

F.6 Cross-cutting GHG emissions sector

Germany signed and ratified the Framework Convention on Climate Change and is also a signatory of the Kyoto Protocol with ratification expected for the year 2002. The Federal Government introduced already a national climate protection strategy two years before the signing of the Framework Convention in Rio de Janeiro 1992. Meanwhile, several revisions of this strategy have been undertaken. Currently, the Federal Ministry for the Environment is preparing the fifth report of the CO_2-Reduction Interministerial Working Group ('Interministerielle Arbeitsgruppe', IMA). Publication is expected for July 2000.

In its climate protection programme, the Federal Government is relying on instruments under administrative law as well as economic instruments. These are accompanied by information measures, counselling and training. All levels of the energy supply industry in the fields of private households and institutions, industry, transport and the power sector are involved in the overall concept.

Germany agreed on a target of -21% within Kyoto. Furthermore, the Federal Government aims to reduce CO_2 emissions by the year 2005 by 25% compared to 1990 levels. This national target was confirmed by Chancellor Schröder as well as by the Minister for the Environment Trittin during CoP 5 in Bonn last year.

Since 1990, the Federal Government has been implementing a bunch of measures within the framework of its climate protection strategy. It is doing with a broad range of tools including regulatory measures, economic instruments (mainly taxes) and other supporting measures (such as research, education and training, provision of information and advising). The Government relies mainly on three instruments. The first two are the above mentioned Ecological Tax Reform and the Electricity Feed Law. Furthermore, so-called voluntary agreements play a major role in German climate policy, especially:

- German industry's declaration on climate protection (updated version from 27 March 1996)
- The German automobile industry's commitment of 1995 to reduce fuel consumption

The German industry's voluntary commitment on climate protection consists of an overarching declaration of the Federation of German Industries and individual declarations issued by 19 industry associations. German industry has stated its willingness to make special efforts to reduce its CO_2 emissions by 20% in 2005, based on 1990 levels. 12 associations also made a commitment regarding absolute reduction of emissions. The voluntary commitment covers over 71% of industrial final energy consumption, over 99% of the public power supply and parts of the residential and institutional sectors (BMU 1997, 119). Compliance is monitored by the Rheinisch-Westfälisches Institut für Wirtschaftsforschung (RWI). Currently, the agreement is in a renegotiation process in order to expand its scope (including further associations and greenhouse gases), tighten the targets and change the target period to 2008/2012 (BMU 1999). This seems to be necessary since effectiveness and economic efficiency of the current agreement is doubtful (Brockmann 2000).

In spring 1995, the German automobile industry made a voluntary commitment to reduce the average fuel consumption of new vehicles, beginning in 2005, by 25% on average, in comparison with relevant average fuel consumption in 1990 (BMU 1997, 149). Meanwhile, this declaration was replaced by the voluntary commitment made by the European Automobile Manufactures Association (ACEA) in August 1998. Under the commitment CO_2 emissions from new passenger cars made by ACEA's members will be cut by 25% from 1995 levels to an average of 140 g/km by 2008 (EWWE 1998).

Table F.8 *GHG emissions in Germany*

		1990	1995	1996	1997	1998	1999
Total EU-15 emissions	[Mt CO_2]	3,336	3,259	n.a.	n.a.	n.a.	n.a.
Germany emissions	[Mt CO_2]	1,015	904	919	894	886	859
Share of emissions in total EU	[%]	30	28	n.a.	n.a.	n.a.	n.a.
Emissions per capita		12.78	11.08	11.22	10.87	n.a.	n.a.
Emissions per sector	[Mt CO_2]						
Power Sector		439	380	382	366	339	325
Industry		170	127	122	124	148	145
Tertiary-Domestic		219	197	222	205	188	173
Transport		159	173	172	173	186	191

Source: DIW (2000), UNFCCC (2000), Schiffer (2000).

Between 1990 and 1999 energy-related CO_2 emissions in Germany fell by about 16%. In relation to GDP CO_2 emissions have fallen by 25% within this period. The energy-related emissions per capita decreased from 12.8 tCO_2 in 1990 to 10.5 tCO_2 in 1999, still 2.5 times higher than the world average (DIW 2000). The reasons for these trends are extremely varied. On the one hand, the economic reconstruction and reduced use of CO_2 intensive lignite in the new Länder have played a significant role in the improvement in Germanys emissions balance. On the other hand, the link between economic growth and CO_2 emissions continued to be severed in the old Länder. However, the trend was overlaid by population migratory movements within Germany, by immigration and by an increased utilisation of the production capacity in the old Länder. Projections made by Prognos/EWI (1999, 25) show that the existing policies and measures will not be sufficient to achieve the 25% reduction target in 2005. For 2005, they calculate a reduction of 14% compared to 1990 levels.

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G. GREECE

G.1 Energy sector

G.1.1 General overview

The energy sector in Greece is characterised by dependence on traditional fuels. Electricity consumption per capita in Greece is one of the lowest in the EU (only Portugal consumes less electricity per capita - 1997 figures). There has been a rapid increase in the use of natural gas in the last five years, due to pipeline developments within the country.

G.1.2 Electricity sector

The national electricity network of Greece and four of its main power plants were constructed after the Second World War with the help of US investments in the framework of the Marshall Plan. The construction was carried out by an American firm, Ebasco, and in 1950 the high voltage network and the power plants were transferred to the Public Power Corporation (PPC). Since that time the PPC has operated the state monopoly in the electricity sector. The PPC is responsible for the production, transmission and distribution of electricity and meets 97.5% of the total electricity demand. Its total production capacity is 9150 MW.

There is no direct interconnection with grids from other EU-countries, since Greece does not border any other EU-Member State directly. The Greek grid is connected to Albania, Bulgaria and Yugoslavia (Macedonia). A special feature of the Greek system is the existence of the many islands with many autonomous grids.

Until 1985 PPC had the exclusive right for generation, transmission and distribution of electricity. The Electricity Law of 1985 allowed some autoproduction. Feed-back tariffs from PPC were set at a very low level. In 1994 a new Electricity Law was issued. In this law Independent Producers and Autoproducers were allowed, but were not allowed to construct plants above 50 MW. All electricity that was not used for autoconsumption has to be delivered to PPC under regulated tariffs. Costs for grid extension or reinforcement of power lines have to be carried by the IPPs.

G.2 Liberalisation process

Currently the Greek government is reconsidering the regulation for the electricity sector, following the European Directive. The proposed legislation foresees a first step of deregulation of the electricity market for 19 February 2001. Consumers on the mainland with an electricity consumption over 100 GWh/year, i.e. 23% of the market, are the first to be liberalised. Furthermore the new legislation foresees unbundling of the activities of the Public Power Corporation (PPC) and access to the grid for licensed electricity generators and traders.

G.3 Renewable energy activities and policies

About 28% of the PPC's capacity installed (2764 MW) and 9.5% of its net generation (3933 GWh) comes from large hydro-power stations. Small hydro (40 MW) and wind (25 MW) account for another 0.4% (170 GWh). Some of the small hydro and wind electricity is generated by IPPs.

The 'island' character (Greece does not want to rely on its connections with Albania, Yugoslavia and Albania) has resulted in a low priority for intermittent resources such as new renewables. This is even more the case at islands. The expectation is that new advanced control systems will allow more renewables to penetrate. This will be especially the case at islands were wind is among the lowest costs options. Most of the wind capacity has been installed on islands.

Since 1994 feed-in tariffs for renewables have been set at between 25% and 45% of the selling tariff. In 1998 the Economic Development Law provided for investment subsidies for renewables between 45% and 55%, reduced loan interests, tax credits and increased depreciation rates. In addition within the 2nd Framework Support Program (1994-1999) (a program funded by the EU, national funds and private funds) 190 MEuro were earmarked for investments in renewables. About one third of this budget will be devoted to wind.

H. IRELAND

H.1 Energy sector

H.1.1 General overview

In the Republic of Ireland, national energy requirements are measured in terms of an index known as the Total Primary Energy Requirement (TPER). Table H.1 shows how the TPER has varied over the period 1980-98 and forecasts trends to 2010.

Table H.1 *TPER for Ireland, broken down by fuel type [Mtoe] 1980-2010*

	1980	1985	1990	1995	*1998*	2000	2005	2010
Coal	0.73	1.05	2.16	1.92	*2.05*	1.97	1.89	1.83
Peat	1.17	1.45	1.36	1.21	*0.98*	0.95	0.83	0.61
Oil	5.61	3.89	4.29	5.45	*7.05*	7.39	8.23	9.25
Natural gas	0.46	1.59	1.45	1.92	*2.35*	3.16	4.23	5.18
Renewable energy	0.07	0.06	0.17	0.20	*0.26*	0.29	0.43	0.48
Total	8.05	8.04	9.42	10.70	*12.68*	13.76	15.61	17.34

Source: Green Paper on Sustainable Energy, Department of Public Enterprise, September 1999.

National consumption of energy is measured using the Total Final Consumption (TFC) index. Table H.2 shows the variation in this index between 1980 and 1998, with forecasts up to 2010.

Table H.2 *Past and projected TFC by sector [Mtoe] 1980 -2010*

Year	1980	1985	1990	1995	1998	*2000*	*2005*	*2010*
Industry	1.96	1.68	1.72	1.78	2.06	*2.38*	*2.69*	*2.98*
Residential	1.94	2.09	2.19	2.20	2.30	*2.55*	*2.73*	*3.19*
Transport	1.73	1.72	2.03	2.46	3.36	*3.64*	*4.29*	*4.86*
Agriculture	0.00	0.00	0.25	0.29	0.30	*0.30*	*0.33*	*0.37*
Tertiary	0.60	0.68	1.01	1.23	1.34	*1.59*	*1.89*	*2.14*
Total	6.23	6.17	7.20	7.95	9.46	*10.47*	*11.92*	*13.54*

Source: Green Paper on Sustainable Energy, Department of Public Enterprise, September 1999.

The main policies covering the energy sector in Ireland are the Electricity Regulation Act of 1999 and the Green Paper on Sustainable Energy (published in September 1999).

H.1.2 Electricity sector

The current electricity liberalisation proposals (Electricity Regulation Bill, 1998, published December '98) now provide for green electricity producers to supply electricity directly to electricity customers via Third Party Access to the network from February 2000. All electricity customers will be entitled to purchase electricity which is produced using a renewable or alternative form of energy as its primary source. The costs for using the public national grid (use of system charges) will have to be paid for by the supplier. There are regulations concerning transparency and quality for the calculation of grid-use prices.

Demand for electricity has increased considerably over the last two decades, and by 48% in the period between 1990 and 1998. Growth is predicted to continue to increase up to 2010 (see Table H.3).

Table H.3 *Growth in electricity demand by sector 1980 - 2010 [TWh]*

Year	1980	1985	1990	1995	*1998*	2000	2005	2010
Industry	3.30	3.67	4.62	5.86	*7.09*	7.92	9.77	11.67
Residential	3.59	3.97	4.14	4.95	*5.64*	6.28	7.74	9.27
Transport	0.00	0.01	0.02	0.02	*0.02*	0.02	0.02	0.02
Agriculture	0.00	0.00	0.43	0.50	*0.58*	0.65	0.80	0.95
Tertiary	1.79	2.20	2.80	3.59	*4.43*	4.94	6.10	7.30
Total	8.69	9.85	11.99	14.93	*17.77*	19.81	24.44	29.22

Source: Wind energy developments in Ireland. Corinna Moehrlen, Eamon McKeogh, Brian Ó Gallachóir, IEA Expert Meeting, NREL, Colorado, USA. April 2000.

H.2 Liberalisation process

Ireland had a one year derogation on its obligation to liberalise its electricity market so the EU Directive was finally implemented in February of the year 2000. This was carried out with the publication of the Electricity Regulation Act 1999 and the design of the market liberalisation framework gives priority to low carbon or renewable power generation. As a result of this, 28% of all electricity is supplied within the liberalised market. Large customers (above 4 GWh) can choose their supplier, and all renewable electricity customers can choose their own supplier. Green electricity suppliers therefore have access to both commercial and domestic customers while 'brown' electricity suppliers do not.

In 1998, the Irish government published a consultation paper on the legislative proposals it was making in order to transpose the Council Directive 96/92/EC of 19 December 1996, (concerning common rules for the internal market in electricity) into Irish law. The Directive was implemented in Ireland by 19 February 2000.

In transposing the Directive, the legislative proposals give effect to a new regime for the functioning of the electricity industry in Ireland. Up to now, the industry has been governed by the Electricity (Supply) Acts, 1927 to 1988 with the Electricity Supply Board (ESB) being a vertically integrated electricity utility, combining practically all commercial-scale electricity generation with the functions of transmission, distribution and retail supply.

Under the Electricity Acts, ESB has also been the regulatory body for the industry, with the power to grant permits to other operators.

The requirement of the Directive to enable certain classes of electricity customer to choose their supplier means that Ireland must establish an independent regulatory regime, and that an independent role must be given to the function of dispatch of generating stations and the operation and planning of the transmission system.

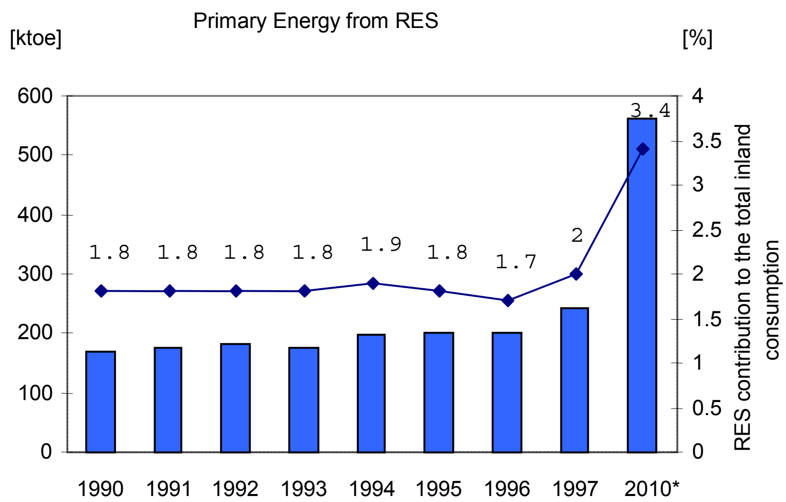
The new arrangements proposed include:
- The establishment of an independent Regulatory Authority,
- Separating the operation of the transmission system from ESB and placing it in a public limited company in State ownership,
- Licensing the distribution system operation within ESB,
- Licensing for ESB's generating stations and independent power producers,
- Licensing of independent power suppliers to supply customers who will be eligible to choose their supplier, and
- Establishing a licensed Public Electricity Supplier within ESB to serve all other electricity consumers.

A system must also be established to enable eligible customers and suppliers to conclude contracts for electricity and explicit provision must be made for the identification and treatment of public service obligations which up to now have been dealt with by ESB under their current break-even mandate.

H.3 Renewable energy activities and policies

H.3.1 Renewable energy status

The development of renewable energy in Ireland has not yet reached a level at which it can be considered to be a significant source of energy supply. In 1997, renewable energy contributed 2% to the National Energy Balance with 243 ktoe supplied.



	1990	1991	1992	1993	1994	1995	1996	1997	2010*
Primary Energy	169	175	182	177	198	200	202	243	562
RES Contribution	1.8	1.8	1.8	1.8	1.9	1.8	1.7	2	3.4

Figure H.1 *Primary energy from RES in Ireland*
Data from DPE Ireland
(*): business as usual result for 2010. Revised targets for 2010 not yet set.

The largest portion of renewable energy comes from industrial and traditional biomass, followed by large scale hydro power (200 MW_e capacity). Annual investment in the renewable energy sector is increasing all the time, with an expected investment amount of over IR£ 160 million (200 mil. Euro) during the next two years (1999 and 2000). This substantial economic activity will support over 60 companies in the sector.

In 1997 electricity generation from renewables accounted for 817 GWh, with a total capacity installed of 295 MW. The major contribution in the electricity sector comes from hydropower plants. Looking at the prospects for wind energy in the medium term, this sector will exceed the output level obtained by the hydropower stations by 2005. Electricity generation using biomass and municipal solid waste now accounts for 12 MW of installed capacity with this figure expected increase to 49 MW by 2005.

We examine the breakdown by technology below[9].

[9] This section was prepared by Brian Ó Gallachóir of the Sustainable Energy Group of University College, Cork.

Biomass
The main biomass element arises from heat produced from burning wood in households (1,735 TJ) and the combustion of wood, wood waste and other wastes in industry (2,834 TJ). In the period 1996 - 1997, 5 landfill gas projects were commissioned under AER I, with a combined installed capacity of 12 MW.

Two large boardmills, Louisiana Pacific and Mesonite were commissioned in 1996 which should increase the 1997 figure for heat production. Some of the existing board mills and sawmills changed from using trees to using timber boards and beams which has reduce their biomass resource (bark, sawdust, etc.) and load (heat for kiln drying). This should decrease the 1997 figure. As full data for 1997 is not yet available, it is not possible to say which had the biggest effect.

Hydro Energy
The 5 large scale (>10 MW) hydro plants in Ireland with a combined installed capacity of 200 MW are all owned by ESB and a vast majority of electricity from hydro power plants is produced by ESB, with 200 MW of large scale power plants. The Turlough Hill (292 MW) pumped storage station is not included here.

ESB also own 4 small scale stations with a combined capacity of 20 MW. Independent power producers own an additional 37 small scale plants providing 9MW.

Wind Energy
By March 2000 a total of 67.5 MW of Wind Power has been installed in Eire. An additional 80 MW is anticipated by the end of 2000. This will bring the total AER capacity to 147 MW. The main reason for the shortfall with respect to the targets is the lack of cohesion between planning policy and energy policy.

In 1992 a 6.45 MW wind farm was commissioned at Bellacorrick, Co. Mayo. There was no further commissioned wind farms in operation until 1997 when a further 6 windfarms were connected to the network, 4 as a result of AER I (Barnesmore - 15 MW, Cark - 15 MW, Tullymurray - 4.95 MW, Arigna - 1.2 MW) and 2 THERMIE funded projects (Kilronan - 5 MW and Cronalaght - 3 MW). In 1998, two remaining AER I projects were commissioned (Drumlough Hill - 5 MW and Crockahenny - 5 MW) bringing the total installed capacity to 60.6 MW. The annual electricity production from current installed wind energy can be estimated at 186 GWh (with 35% capacity factor).

Table H.4 *Renewable energy and electricity generating capacity [MW]*

Year	1990	1995	2000	2005	2010
Total Gen Cap	3932	4159	[1]4379	[1]5340	[1]6751
Renewables	225	236.5	[2]433	583	743
% RE share	5.7	5.7	10	11	11

[1] based on ESB (Gerry Duggan) fax to Dept. 15/7/98.
[2] based on ESB (Gerry Duggan) fax to Dept. 15/7/98.

Table H.4 above is based on the current installed capacity from renewables of 303 MW and assumes that the AER II 30 MW Waste to Energy plant and the original AER III 100 MW targets will be met which is by no means certain, given the planning difficulties these projects will face and the short time-scale.

Table H.5 gives the corresponding production figures.

Table H.5 *Renewable energy and electricity produced [GWh]*

Year	1990	1995	2000	2005	2010
Elec. generated	13,895	17,182	[10] 20,826	[10] 26,424	[10] 33,602
Renewables	690	808	1621	2152	2665
% RE share	5.0	4.7	7.8	8.1	7.9

1. Renewables figures for 2000 based on 777 GWh from hydro, 486 GWh from wind (150 MW with 37% capacity factor) and 105 GWh from landfill gas (15W and 80% load factor) and 253 GWh from the waste to energy plants (34 MW and 85% efficiency).
2. Renewables figures for 2005 based on 822 GWh from hydro (additional 9 MW installed) 972 GWh from wind (300 MW with 37% capacity factor), 105 GWh from landfill gas (15 MW and 80% load factor) and 253 GWh from waste to energy plants (34 MW and 85% efficiency).
3. Renewables figures for 2010 based on 848 GWh from hydro (additional 5 MW installed) 1459 GWh from wind (450 MW with 37% capacity factor), 105 GWh from landfill gas (15 MW and 80% load factor) and 253 GWh from waste to energy plants (34 MW and 85% efficiency).

H.3.2 Renewable energy policy

Ireland's targets and policy for renewable energy development are outlined in the policy document 'Renewable Energy : A Strategy for the Future' published in 1996 (now under review). It sets a target of 10% electricity generating capacity from renewables by 2000. Among the elements of this strategy are -

- Targets to install 100 MW new generating capacity from renewable energy sources by the end of 1999 and a further 310 MW by the year 2010 through the Alternative Energy Requirement (AER).
- A commitment to allow renewable energy generators third party access to the electricity distribution grid for the sale of green electricity
- Provision to support the development of a pilot-scale wave energy plant
- Guarantee of access to the network for renewable energy projects supported under the EU THERMIE programme
- Commitment to develop a scheme for small-scale renewable energy objects aimed at energy self-sufficiency

Renewable energies are seen as a means of meeting Ireland's climate change agreements. Priority focuses on the development of renewable technologies that have been proven to be both technically and economically feasible.

The Department of Public Enterprise has recently announced its intention to publish a Green Paper on Sustainable Energy in line with progress to date, the Kyoto Protocol and the European Union White Paper. The Green Paper will explore the options available for meeting Ireland's energy requirements over the next 10 - 15 years in an environmentally and economically sustainable way having regard to forecast economic growth and security of supply requirements.

Other regulatory structures affecting renewable energy development include the Department for the Environment and Local Government and their local & regional authorities who have a significant role relating to planning and environment protection issues.

A Renewable Energy Strategy Group has been established which includes representatives of planning authorities, the ESB, the Irish Energy Centre/Renewable Energy Information Office and relevant Government Departments, to recommend measures to redress the many constraints in the deployment of renewable energy. The Strategy Group reports to the Minister. The initial focus is wind energy. An integrated resource planning approach is being applied to the wind energy resource, electricity network and land use. The objective is to produce an action plan to ensure target delivery set in the green paper on sustainable energy and the Kyoto protocols.

[10] *Energy Demand and Associated Emissions in Ireland,* Gerry Duggan, ESBI Strategic Consultancy Group.

One green electricity suppler, Eirtricity is offering green electricity to commercial customers at a price that is 10% below what they are currently paying. The other green supplier is e.co, but they have not yet announced price levels.

The ‘Alternative Energy Requirement’ (AER) is the current principal support instrument for the introduction of renewable energies into the Irish electricity system. It is comparable to the British NFFO, in that it centres around a competitive bidding system and guarantees the successful developers a 15 year power purchase agreement with the Irish utility, ESB at the amount of their bids (in p/kWh) which is index linked. In addition, the developers of projects under this scheme are eligible for capital subsidies if necessary. Four AER rounds have been held since 1994.

In the wake of AER 1 (1994) contracts were signed, providing for the completion of systems with a total of 111 MW (renewable energy based projects included 73 MW wind, 12 MW biomass and 4 MW hydro) by the end of 1997. Of these projects a total of 75 MW installed generating capacity were completed. The feed-in tariffs offered under AER I were fixed in advance amounting to 6.1 - 6.6 p/kWh and 2.4 - 2.5 p/kWh for day hours (0800 to 2100, Monday to Friday) and night & weekend hours respectively - averaging 4 p/kWh (Euro 0.051/kWh).

AER 2, with a total output of about 30 MW, focused on biomass and waste-to-energy projects and was based on a competitive bidding system with a cap of 3.6 p/kWh (Euro 0.046/kWh). The successful developer bid in at 3.2 p/kWh (Euro 0.041/kWh). The project must be completed by the end of 1999 and will receive a grant of 9.3 MEuro.

AER 3 followed in 1997 the target being 100 MW (90 MW from wind, 7 from biomass and 3 from hydro) to be commissioned by late 1999. The technologies were treated separately in the competition with an additional small wind (< 5MW) category and pilot wave energy plant included. The cap price was 3.9 p/kWh (Euro 0.050/kWh) and 5 p/kWh (Euro 0.064/kWh) for the wave energy plant. Capital grants of 80 thousand Euro per MW installed (1.24 MEuro for the wave plant) were offered. Contracts were awarded in 1998 for projects amounting to 160 MW (101 MW large wind, 36.5 MW small wind, 4.4 MW hydro, 14 MW waste to energy and 3 MW landfill gas). The successful bid prices ranged from 2.21 p/kWh (Euro 0.028/kWh) to 3.9 p/kWh (Euro 0.050/kWh). The maximum size of wind farms has been fixed at 15 MW, and no developer got contracts totalling more than 20 MW.

In addition, the Irish government guarantees that all projects receiving funding under the EU THERMIE programme, have access to the electricity grid, via a THERMIE power purchase agreement based on AER prices.

A number of other support measures for renewable energy projects have been set up, including:

- The Alternative Energy Requirement - (Electricity Market) (Public Service Obligation)
- Third Party Access - (Electricity Market)
  From February 2000, all electricity customers will be entitled to purchase electricity which is produced using a renewable or alternative form of energy (Art. 27, Electricity Regulation Bill 1998). Details for access to the transmission and distribution system and charges for same, have not been published yet.
- The Renewable Energy Feasibility Study Grant Scheme
  The Irish Energy Centre, through its Renewable Energy Information Office, operated a Renewable Energy Feasibility Study Grant Scheme in 1998 to stimulate renewable energy projects.
- Corporate tax relief for equity investment
  The 1998 Finance Act provided a tax incentive for companies who wish to invest in renewable energy projects. Company profits invested in wind, hydro, biomass and solar projects are not subjected to tax under certain restrictions.
- The Interreg energy challenge

Interreg Energy Challenge provides support for energy efficiency and/or renewable energy projects in Northern Ireland and the Border regions of the Republic of Ireland. Financial assistance is available for either a feasibility study or, where the technical and financial viability of a proposal has been established, for project implementation. The programme is run to the end of 1999.

Ireland currently has no TGC system although it has been discussed in recent months.

H.4 Cross-cutting GHG emissions sector

Within the EU burden sharing agreement to meet the Kyoto protocol, Ireland is allowed to increase its Greenhouse Gas emissions up to 13% on 1990 levels within the period 2008 -2012. This will correspond to a reduction level of the equivalent of 7 million tonnes of CO_2 within the commitment period. As Ireland's economy has grown rapidly over the last few years, it has seen a corresponding growth in CO_2 emissions. It is currently undertaking a review of actions to be undertaken and has recently announced a National Abatement Strategy for Greenhouse Gases. The key measures in this strategy involved the reduction of energy consumption, improved building standards, 'fuel-switching' to natural gas and renewables. (The government estimates that natural gas will account for 56% of the fuel mix in 2010). The government is also considering systems of carbon taxation and tradable emissions permits.

Ireland's greenhouse gas emissions for the period from 1990 up to 2010 (forecast) are shown in Table H.6.

Table H.6 *Ireland's Greenhouse Gas Emissions 1990 -2010*

	Emissions (calculated on a GWP 100 basis and expressed in Mton CO_2 eq.)						
Year	Carbon Dioxide CO_2	Methane CH_4	Nitrous Oxide N_20	Other HFCs, PFCs, SF_6	Forestry Sinks CO_2	Total	Limit breach
1990	30.719	17.038	9.105	0.046	0.000	56.907	0.000
1995	34.116	17.099	8.110	0.256	1.070	58.511	-6.032
1998	*39.107*	*16.398*	*7.981*	*0.685*	*1.651*	*62.519*	*-2.024*
2000	41.439	17.425	8.227	0.971	2.420	65.642	1.099
2005	45.581	17.516	7.728	1.125	3.420	68.481	3.938
2010	49.350	17.594	7.638	1.279	4.530	71.331	6.788

Source: Green Paper on Sustainable Energy, Department of Public Enterprise, Sept 1999.

Energy-related CO_2 emissions are projected to rise by 18.2 million tonnes between 1990 and 2010 and it is projected that (under a 'business as usual' scenario) Ireland will exceed its Kyoto target by 6.8 million tonnes of CO_2 equivalent by 2010.

Greenhouse gas emissions by sector are shown in Table H.7.

Table H.7 *Ireland's Energy Related CO_2 Emissions 1990 - 2010 (Million tonnes of CO_2 equivalent)*

	1990	1995	*1998*	2000	2005	2010	Increase on 1990 by 2010 [%]
Transport	4.885	6.198	*8.673*	9.412	11.070	12.564	157.19
Tertiary	4.840	5.882	*6.494*	7.103	7.990	8.511	75.86
Residential	10.293	10.361	*10.891*	11.105	11.267	12.267	19.18
Industry	7.973	8.654	*9.966*	10.727	11.790	12.471	56.42
Agriculture	1.048	1.195	*1.238*	1.235	1.346	1.430	36.42
Total	29.038	32.390	*37.262*	39.581	43.464	47.242	62.69

Source : Green Paper on Sustainable Energy, Department of Public Enterprise, Sept 1999.

I. ITALY

I.1 Introduction

Italy has the world's fifth largest economy. It has a population of about 57,5 million people, and a Gross Domestic Product of 1200 billion dollars. Since World War II, the Italian economy has changed from one based on agriculture into a ranking industrial economy, with approximately the same total and per capita output as France and the UK. This basically capitalistic economy is still divided into a developed industrial north, dominated by private companies, and a less developed agricultural south, with large public enterprises and more than 20% unemployment. Most raw materials needed by industry and over 75% of energy requirements must be imported. In the second half of 1992, Rome became unsettled by the prospect of not qualifying to participate in EU plans for economic and monetary union later in the decade; thus, it finally began to address its huge fiscal imbalances. Subsequently, the government has adopted fairly stringent budgets, abandoned its inflationary wage indexation system, and started to scale back its generous social welfare programs, including pension and health care benefits. In December 1998, Italy adopted a budget compliant with the requirements of the European Monetary Union (EMU); representatives of government, labor, and employers agreed to an update of the 1993 'social pact,' which has been widely credited with having brought Italy's inflation into conformity with EMU requirements. In 1999, Italy must adjust to the loss of an independent monetary policy, which it has used quite liberally in the past to help cope with external shocks. Italy also must work to stimulate employment, promote wage flexibility, and tackle the informal economy. (Source, CIA World Factbook)

I.2 Energy sector

I.2.1 General overview

Italy has a long tradition of state-led entrepreneurship and nationalisations, particularly in the energy sector. Ente Nazionale Idrocarburi (ENI) is, along with its main subsidiaries, Agip (hydrocarbons exploration and production) and Snam (gas supplies and distribution), the state-held oil and gas conglomerate. It is the sixth oil company in the world. ENI has also a substantial refining capacity of about 860 000 barrels a day, and is the fourth refining company in the world. Ente Nazionale per l'Energia Elettrica (ENEL) is the state-owned electricity company. Until recently both companies practically had monopolies in their sectors.

Although Italy has some own natural gas and oil reserves, it still is heavily dependent on imports. As of 1998, Italy was estimated to be less than 20% self sufficient in terms of energy. Historically, Italy has been heavily dependent on oil, also for its power production. The share of different energy carriers in 1998 was: oil (54.0%), natural gas (28.2%) and coal (5.7%). The remainder comes mainly from hydropower, geothermal energy and electricity imports. Italy's main strategy to reach its environmental targets is a shift to the use of natural gas. The division of the energy consumption is as follows: by the industrial sector (44.0%), transportation (25.7%), the residential sector (23.3%) and the commercial sector (6.6%).

EU membership has initiated important changes in Italy's energy sector, requiring privatisation of Italy's dominant energy monopolies and partial liberalisation of its markets. Hence, Italy's energy sector has been undergoing considerable restructuring in recent years. ENI and ENEL had to be privatised. Both ENEL and ENI became joint stock companies in 1992. The Italian government sold off shares of ENI between 1995 and 1998, and now holds 35% of the company. Privatisation of ENEL is underway.

Shifting to natural gas is among Italy's main strategy to meet domestic, European, and broader international requirements for a cleaner environment. As with oil, North Africa is a large exporter of natural gas to Italy. Algeria is the single largest supplier, and a new agreement with Libya makes the region an even more important supply source. There have been concerns that this reliance on North African sources has potentially negative implications for Italian security.

Because of its energy dependency there is also a shift to coal in Italy, although to a much smaller extent than the shift to gas. Coal consumption in Italy is dominated by power generation, which is increasing, and coke production for steel, which is decreasing. Coal has played a small role in the Italian energy sector, and Italy produces almost no coal domestically. The power sector is expected to increase its coal consumption in coming years, as ENI works to decrease reliance on imported oil. Clean coal technology will figure prominently in this increased coal usage, as EU environmental stipulations, Kyoto targets, and Italian public opinion demand that Italy's energy sector become increasingly clean.

The increased coal usage will be supplied by a combination of increased domestic production and increased imports. Coal mines on the island of Sardinia, previously closed by ENI, are scheduled to be re-opened. Imports are also predicted to double in coming years. Main exporters to Italy are the United States, Australia, and South Africa.

I.2.2 Electricity sector

In the after-War years electrification in Italy went on in a heterogeneous and diversified way. In the early 1960s there were between 1000 and 2000 electrical companies, some privately owned, some owned by municipalities. In late 1962 Enel, the National Body for Electric Power, was established by law and started to nationalise about 1250 electricity companies. In the 1960s and 1970s Enel put great effort in establishing a nation-wide transmission network, an activity that goes on into the 1980s and 1990s. Another focus of attention was the construction of many new power plants, including thermal, hydro and geothermal plants. After the oil crisis of 1973 it was also decided to build several nuclear plants. However, after a referendum in 1987 the four nuclear plants were closed down and the fifth, which was under construction, was converted to a thermal power plant.

Until the beginning of 1999, ENEL, the Italian state electricity utility, together with local municipally-owned utilities, were the only bodies allowed to transmit and sell energy. Prices were set by the government and since 1997 by the regulator (*Autorità per l'energia elettrica e il gas*) which has been established in 1996, based on an energy restructuring law of 1995. One of the missions of the regulator was to prepare the rules for more competition and the enhancement of efficiency. Until March 1999 independent power production was only allowed for self-supply and for some sale to ENEL under strict price control. Enel owns 100% of transmission and 93% of distribution in Italy. ENEL is also the country's only cross-border trader (Italy imports about 15% of its electricity, mostly from France and Switzerland). ENEL has had a monopoly in Italy's electricity sector since the industry was nationalised in the early 1960s. This has changed with the new energy law of 1998 and the subsequent Legal Degree of 1999 (see later).

Apart from ENEL, there are many autoproducers. About 25% of the total electricity consumption is produced by autoproducers. Import accounts for about 20% and about 165 Municipal utilities and IPPs produce another 4% of the electricity.

Table I.1 *Production of Italian electricity in 1998 [TWh]*

Total gross production	Produced by ENEL	Imports	Auto-production	Municipalities and IPPs
300	190	41	57	12

Electricity for pump storage and other auxiliary systems used 21 TWh, which gives a net production of 279 TWh in 1998.

I.2.3 Gas sector

Natural gas consumption in Italy in 1998 was 61.9 billion cubic meters (bcm). This represents 2158 PJ, which corresponds to 28.6% of the primary energy input of Italy in 1998. Most of the natural gas comes from import (Russia and Algeria, and for a far lesser extend from the Netherlands and Abu Dhabi). The following table gives the figures.

Table I.2 *Natural gas in Italy (bcm)*

Domestic production	From stock	Import from Algeria	Import from Russia	Import from the Netherlands	Import from Abu Dhabi	Total consumption
18.9	1	22.8	16.7	3	0.2	61.9

The main player of the gas sector is ENI and its subsidiaries Agip (production of natural gas and other hydrocarbon minerals) and Snam (import, trade and sales). ENI sold 55.7 billion cubic metres in 1998 (89%). The most important other player at the gas market in Italy is Edison Gas Italy, which has a small production capacity in Italy (2.1 bcm in 1998) and imports gas from Abu Dhabi (LNG). Edison sells mainly to large industrial consumers.

Part of ENEL's consumption of natural gas for power plants is directly imported by ENEL from Algeria (4 bcm). In total 15.6 bcm is used in Italian natural gas power plants.

Local distribution companies buy natural gas from Snam (99%) and Edison (1%) and distribute it to households and small industry. The main local distributor is Italgas (27% of the distribution market), another subsidiary of ENI. Other industrial users and power producers buy directly from Snam.

Natural gas consumption is growing fast. Consumption in 1998 was more than 8% higher than in 1997. It is expected to reach the 70 bcm level in 2000. The rising demand comes from new IPPs (electricity market), the continuous expansion of the distribution grid, especially in Central and Southern Italy and the increased use of gas for space heating in the domestic and service sector. 75% of the gas sales take place in North Italy. A moderate increase in demand is expected from industrial consumers for economic and/or environmental reasons. ENI intends to meet this growing demand by starting to import gas from Norway and expanding its imports from the Netherlands and Russia.

The primary distribution network in Italy is about 28 700 kilometres long and the secondary network about 370 000 km. Most citizens and industry in the North have access to natural gas (75% of the gas sales take place in the North), but there is still room for expansion in the Centre and the South of Italy.

Gas prices in Italy are set by the Regulator, and are dependent on the price of gasoil. There are different prices for cooking/hot water, individual heating systems, collective heating systems and the industry.

I.3 Liberalisation process

As a country with a strong tradition in state-owned national monopolies in the energy sector, Italy has not been among the frontrunners of liberalisation. The legislation needed for the electricity sector came only at the date of the deadline, i.e. 19 February 1999. The necessary legislation for the liberalisation of the gas market will probably be issued at 1 August 2000, the deadline. Italy is one of the Member States that will not completely liberalise its electricity market (only up to 40% by 2002) and is expected to keep to the minimum of the market opening according to the Gas Directive.

The partial liberalisation of the Italian electricity market is backed by a Law of 24 April 1998 in which the Parliament delegated to the government the task to issue a legal decree within a year to deal with the European Electricity Directive of 1998. The Law of 1998 contained some basic guidelines. A Legal Decree was approved by the Council of Ministers at 10 November 1998 and discussed in the Parliament in early 1999. At 19 February 1999 (at the day of the European deadline) the Legal Decree was approved by the Parliament. The official final version was issued at 16 March 1999 and is known as Legal Decree 79/99. It was published in the State Journal on 31 March 1999 and entered into force at 1 April 1999.

The Legal Decree 79/99 provided the following regulations:
- The unbundling of ENEL into at least four different enterprises:
  - Distribution and sale to captive customers
  - Production
  - Transmission
  - Sale to eligible customers.
- The transfer of the four nuclear reactors to the Italian State.
- The establishment of an independent Transmission System Operator (TSO): Gestore della Reti Trasmissione Nazionale (GRTN). The ownership of the transmission and distribution grid is transferred directly to the State (the Treasury with the Ministry of Trade and Industry as the official responsible authority). The ownership of the small percentage of the distribution grid that was not part of Enel, remains with these owners, who will also remain responsible for the operation of those parts of the grid.
- The establishment per 1 January 2000 of a Market Operator (Gestore del Mercato), as a subsidiary of GRTN, which will establish a non-obligatory Electricity Exchange (Pool) per 1 January 2001. The trading rules are currently in the process of being established. General criteria are transparency, efficiency and the enhancement of competition. The rules should be approved by the Regulator.
- Electricity distribution concessions will be issued by the Ministry of Trade and Industry at 31 March 2001 for a period of 30 years.
- Liberalisation of the market of consumers with a consumption of over 30GWh/y + the companies providing electricity to captive customers (33% of the market) per 1 February 1999, of consumers with a consumption of over 20 GWh/y per 1 January 2000 (35% of the market) and of consumers with an annual consumption of more than 9 GWh (40% of the market) per 1 January 2002.
- Dependent on new developments and the state of liberalisation in other countries, the Ministry might ask the Regulator to set new standards for a larger market opening in the future.
- Liberalisation of the production, import and export of electricity.
- Guaranteed supply of electricity at regulated tariffs for captive customers by an appointed organisation which act as a Single Buyer. GRTN should set up this organisation, should contain at least 51% of the shares and other enterprises cannot have more than 10%. The Enel-group ‘Enel-Distribuzione’ seems to be a good candidate for this (and is currently supplying electricity to the captive customers)
- The possibility of eligible customers to purchase their electricity from the Single Buyer at regulated tariffs for 2 years, with the possibility of extending this for another two years.
- The disallowance of a production/import market share larger than 50% per 1 January 2003 (with a minimum capacity of 15 000 MW for Enel).
- Regulated access to the grid for third parties.
- Delegation of tariff setting (grid, connection and captive customers) to the regulator.
- Priority dispatch to renewables, CHP and indigenous sources.
- A 2% obligation for the production of new renewable energy sources by 2002. Further details will be provided by the Regulator.

The Gas Directive has not yet been translated yet into final legislation in Italy. In May 1998 the Parliament delegated the task of proposing a legal decree on the gas market liberalisation within a year.

I.4 Renewable energy activities and policies

I.4.1 Renewable energy status

The 1998 share of renewable energy in the primary energy mix of Italy is 7.2%, which corresponds to 545 PJ (Total energy consumption 1998 = 7542 PJ). Most of this energy (90% on primary energy basis) is produced in the form of renewable electricity (47 TWh with an overall gross electricity consumption of 300 TWh), which is mainly provided by hydropower (6 GWh comes from pump storage plants). The remainder is produced and consumed as heat in the agricultural sector and in the industrial sector, mainly produced by agricultural and industrial organic residues and geothermal heat (314 MWth installed). Table I.3 gives some more details on renewable electricity production.

Table I.3 *Production of renewable electricity in Italy 1998*

Source	Number of plants	Installed capacity [MW]	Share of installed capacity [TC =72513 MW]	Production [GWh]	Share of E-consumption
Hydro < 1 MW	1149	406	0.01	1718	0.01
Hydro 1-10 MW	519	1803	0.02	6603	0.02
Hydro > 10 MW	284	14028	0.19	32893	0.12
Geothermal	30	579	0.01	4213	0.02
Wind	39	164	0.0	232	0.02
PV (>50 kW)	7	6	0.0	6	0.0
Waste and biomass	143	445	0.01	1228	0.0
Total	2171	17431	0.24	46893	0.19

Source: ENEL Statistical data on electricity in Italy 1998.

What can be seen, is that Italy is one of the largest producers of renewable energy in Europe. Even without large hydro, still a share of 7% of electricity is produced by renewable energy sources. Compared to other countries, Italy is behind in wind power development, waste and biomass use and solar thermal heating. It is a frontrunner however in small-scale hydro (3% of the electricity consumption) and especially in production of electricity from geothermal energy sources. More than half of the EU's total production capacity of this renewable source is installed in Italy.

Targets for 'Biomass and biogas' are ambitious, but it is not known what regulations are put forward to stimulate these (apart from the use of biogas for renewable electricity production).

In principle Italy has a large renewable energy potential. It has mountains for further hydropower development, coastal areas for wind turbines (although the wind regime is not as good as in the Atlantic countries of Europe), geothermal layers for further expansion of geothermal electricity production and a good solar irradiation (1100 kWh/kW for PV). Especially in the areas where it has good potential, but it is still lacking behind (waste, biomass, wind and solar thermal energy) it has the potential to grow significantly, as is shown by the Italian White Paper targets.

I.4.2 Renewable energy policy

In the Italian White Paper on Renewable Energy of 1999 an official target was stated for the first Kyoto budget period of increasing the total consumption of renewable energy to 855 PJ/yr, which is a 55% increase with regard to 1998. This target includes 78 TWh/yr electricity production, which means an increase of 30 TWh.

Table I.4 *Targets for renewable energy*

Source	1997		2002		2006		2008-2010	
	[MW]	[PJp]	[MW]	[PJp]	[MW]	[PJp]	[MW]	[PJp]
Hydro > 10 MW	13942	309	14200	312	14500	318	15000	329
Hydro < 10 MW	2187	75	2300	87	2600	98	3000	113
Geoth.	559	36	620	42	700	47	800	54
Wind	119	1	700	13	1500	28	2500	46
PV	16	0	25	0	50	1	300	3
Biomass and Biogas (el)	192	5	500	28	900	50	2300	127
Waste (el)	89	2	350	16	600	28	800	37
Biofuels		3		12		23		39
Biomass and biogas (them)		45		59		67		73
Solar Thermal		0		2		5		9
Geoth. Thermal		9		10		13		17
Waste (them)		4		5		7		8
Total		489		586		685		855

The largest contribution in the growth of renewables is expected from biomass and biogas, followed by wind, waste and small hydro plants.

To start-off a renewables market in the electricity sector, the government has introduced a tradable percentage obligation (with green certificates) for producers of electricity that deliver their electricity to the grid. These producers have to cover 2% of their electricity production by green certificates from electricity produced by new renewable energy sources in 2002. Since about 200 TWh is supplied to grid, this means an extra amount of renewable electricity of about 4 TWh, corresponding to about 41 PJ primary energy. This is about 40% of the renewable energy target for 2002, 60% of the renewable electricity target for 2002 and corresponds to the sum of the targets for renewable electricity excluding hydro and waste (which however, are included in the green certificate scheme). The 2 TWh target is considered to be a first step to reach the 2008-2012 targets.

In the heat sector solar water heaters will get a tax reduction and the VAT is fixed at 10%. Furthermore the government is considering to ease the financing rules and to let Third Parties participate in the heat sector.

A program to promote PV is the 10 000 roofs program, which will provide an extra 30 MW by 2005.

Furthermore the Italian government tries to establish several voluntary agreements with industrial sectors on renewable energy programs. This is e.g. the case in the biofuel sector in which Italy plays, after France, an important role with about 8% share in the biodiesel production. Italy uses, like France, a tendering system for the production of biofuels. The current quota is 125 000 ton/year (Observer, 1999). Public transport in municipalities with over 100 000 inhabitants will be used as an introductory market for biofuels. Biofuels will also be mixed with gas oil for domestic heating and marine applications. How this will be financed is not clear yet.

There are no additional industry initiatives yet. The Green Certificate System can be used for Green Electricity Demand, but as for now, no green electricity products are very widespread yet at the Italian market. The Italian government tends to issue also certificates for sources that are not eligible for the obligation, to facilitate a voluntary market. It is considering to give tax rebates for consumption of green electricity.

As yet no special barriers have been turned up in Italy. It is realised that for integration of renewable energy at the local level, the support of local planning authorities is necessary. Therefore the White Paper foresees the construction of Regional and local White Papers and Renewable Energy Action Plans (Barra (ENEA), 1999).

I.5 Tradable green certificates

The tradable green certificate system has been well summarised in the RECS Country Report, which is downloadable from the RECS-Homepage. It can compressed to the following points:
- The Italian TGC system is only for renewable electricity, not for heat, gas or other energy carriers.
- Demand comes from the obligation for producers and importers, stated in the Legal Degree 79/99, of 2% new renewable energy electricity production supplied to the grid by 2002, which corresponds by about 4 TWh.
- The Reference Year for the calculation is the year before the Compliance Year (i.e. 2001 for the first obligation in 2002).
- The Reference Amount will be the total non-renewable production + import per producer/importer.
- The obligation for later years will be set in the coming years, and will depend on policies of reaching the Kyoto target.
- Certificates for the obligatory market will only be issued for new plants (i.e. after 1 April 1999) with a production of more than 50 MWh/year, and only for the first 8 years. Existing waste and biomass plants that expand their biomass or waste use after 1 April 1999 will get certificates for the obligatory market for the additional (new) part.
- The size of certificates for the obligatory market will be 100 MWh/certificate.
- Certificates will also be issued for other renewable energy plants (existing + older than 8 years), but cannot be used for the obligation. However they can be used for voluntary demand.
- Voluntary demand might be developed in the future. The regulator is considering to set special tariffs for voluntary demand from captive customers. The government is considering to give tax cuts for green tariffs.
- The TGC system will be operational from 1 January 2001.
- Imported new renewable electricity will also get green certificates. These certificates can be used for the obligation, but are not tradable; also, the country of production should have a comparable system of support for renewable energy (the rules for this ‘reciprocity’ are not defined yet).
- GRTN will issue and redeem the certificates.
- Redemption takes place at the end of the year of compliance. The owner of the certificate at that moment will be the one from whom the certificate is redeemed.
- The registration of certificates has not been settled yet.
- GRTN might issue ‘uncovered’ certificates, to ‘stabilise the market’ or to provide flexibility to obliged actors in meeting their targets. The price of these certificates will be fixed according to a complicated calculation method. This method uses the pre-TGC-system, fixed-feed-in premiums as a basis and calculates the weighted price average on the basis of the production statistics of the year before. It is expected that this average price will be around 5.5 Eurocent/kWh. This will serve as an upper market price of certificates. GRTN has to re-

buy this amount of certificates from the market within 3 years. This regulation is (also) a form of 'borrowing'.

- Certificate information will include:
  - Identification number,
  - Generator,
  - Production site,
  - Production unit,
  - Date of start of production by production unit,
  - Year of production,
  - Number of kWhs (can be different than 100 MWh for the voluntary market),
  - Date of Issuing,
  - Name of Issuer (i.e. GRTN),
  - Related government support,
  - Period of validity (i.e. the year of production).
- The related CO_2-value will not be mentioned explicitly on the certificate.
- There is no additional support for renewable electricity production that is eligible for the obligatory market.

I.6 Cross-cutting GHG emissions sector

Italy has a Kyoto-commitment target within the EU of a reduction of 6.5% of CO_2-equivalents. In the reference year 1990 Italy emitted 421 Mton of CO_2 and 555 Mton of CO_2-equivalents. Therefore the 6.5% target corresponds with a reduction with regard to 1990 of 36 Mton.

On 19 November 1998 a 'delibera del Cipe' was issued on Climate Change. In this delibera Italy presented a baseline scenario in which the average emission in the First Budget period is expected to be 622 Mton, a growth of 67 Mton compared to 1990. Therefore there is a need to find measures that reduce in the order of 100 Mton (113 Mton maximum). The delibera indicated the measures in Table I.5.

Table I.5 *Options for GHG emission reduction*

Measure	Reduction 2002 [Mton]	Reduction 2006 [Mton]	Reduction 2008-2012 [Mton]
Improvement of the efficiency of thermal power plants	4/5	10/12	20/23
Reduction of the energy consumption in the transport sector	4/6	9/11	18/21
Renewable energy	4/5	7/9	18/20
Reduction of energy consumption in industry, services and household sector	6/7	12/14	24/29
Reduction of the emission in non-energy sectors	2	7/9	15/19
Forestry	0	0	1
Total	20/25	45/55	93/112

The Italian regulator gives the emission data/kWh for all EU countries in 1996. For Italy 522 g/kWh is given.

J. LUXEMBOURG

J.1 Energy sector

J.1.1 General overview

The reliance on energy imports is a major feature of the Luxembourg energy sector. Almost 100% of the energy consumption is satisfied through imported energy. The degree of self-sufficiency in energy supply, measured as the ratio of Total Domestic Production and Gross Consumption was 0.7% for the year 1996[11].

A second characteristic concerns the fuel-source distribution of the Luxembourg gross inland consumption. In 1996, the oil share over total consumption represented 53.2%, more than 12 percentage points above the EU average. The figure for natural gas was only 17.9%, slightly below the EU average. A look at Table J.1 reveals Luxembourg's energy dependency.

Table J.1 *Percentage distribution of Gross Inland Consumption by Fuel type [%]*

1996	Solids	Oil	Natural Gas	Other[1]
European Union	16.7	41.5	21.4	20.4
Luxembourg	14.4	53.2	17.9	13.5

Source: Annual Energy Review. Energy in Europe. European Commission.
[1] Hydro and Wind energy, net electricity imports, and other sources, such as nuclear power are included.

Table J.2 shows the electricity distribution by fuel type. No nuclear energy is generated, and the generation of hydro and wind is high above EU average (by more than 50 percentage points). This leads to a saving in thermal generation of almost 20 percentage points with respect to the EU average.

Table J.2 *Share of Electricity Generated by source [%]*

1996	Nuclear	Hydro & Wind	Thermal
European Union	35.3	13.0	51.7
Luxembourg	0	67.1	32.9

Source: Annual Energy Review. Energy in Europe. European Commission.

Finally, it is worth pointing out the predominance of natural gas in the generation of electricity (83.3%) followed, to a lesser extent, by geothermal and biomass (16.7). The table below shows a comparison of these percentages with those pertaining to the EU.

Table J.3 *Thermal Electricity Generation by Fuel-type [%]*

1996	Solids	Oil	Natural Gas	Geothermal & Biomass
European Union	60.0	15.2	20.3	4.5
Luxembourg	0	0	83.3	16.7

Source: Annual Energy Review. Energy in Europe. European Commission.

[11] Source: Annual Energy Review. Energy in Europe. European Commission.

J.1.2 Electricity sector

Main players in the electricity sector in Luxembourg are:

- SOTEL, supplier to and owned by ARBED (iron and steel industry),
- CEGEDEL, owned by the state (41%) and private companies,
- LUXENERGIE S.A, set up in 1990 by Ministry of Energy (25%), CEGEDEL (26%), Four private firms (49%).

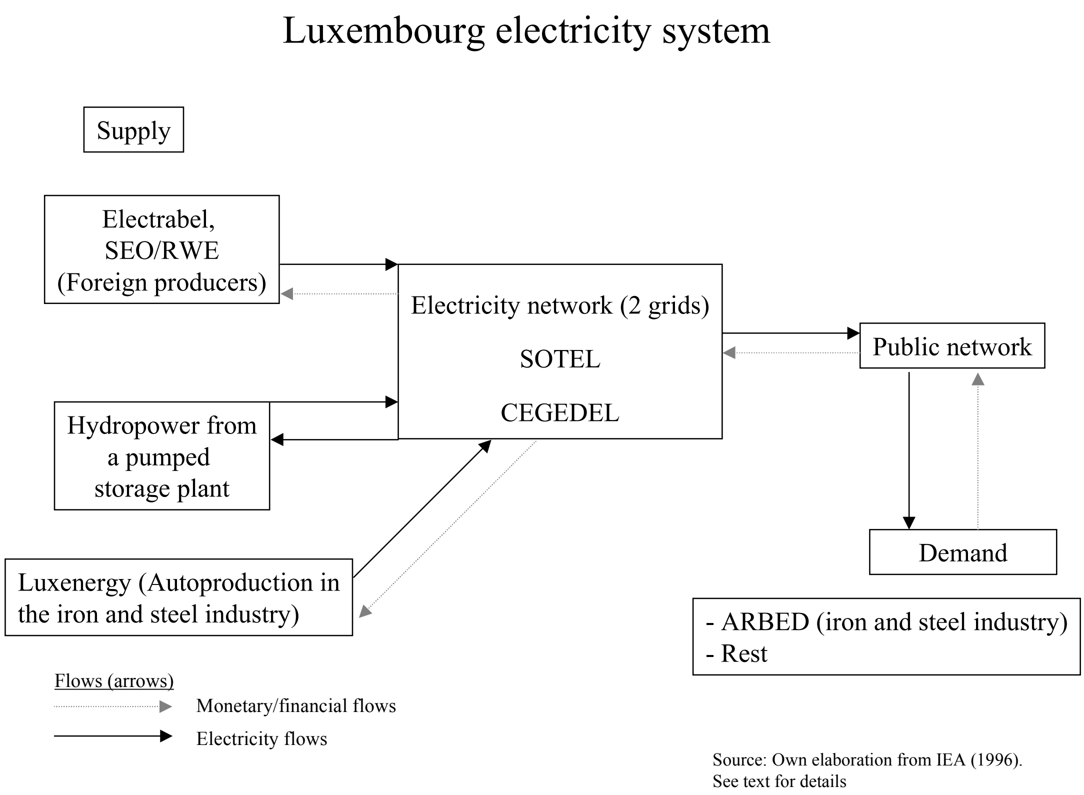


Figure J.1 *Structure of the electricity sector*

The production system has a decentralised structure (a variety of utilities in the electricity sector) while electricity supply is publicly owned. The production system is based on an authorisation procedure. 97% of electricity is imported, while the rest is provided by hydropower from a pumped storage plant (0.01 Mtoe in 1992) and autoproduction in the iron and steel industry.

Two separate grids coexist in Luxembourg. One is operated by SOTEL. The other by CEGEDEL. Luxembourg imports its electricity through both distribution networks. SOTEL imports electricity from Belgium under a contract with ELECTRABEL (until 2005) while CEGEDEL supplies the public network with electricity under a contract with SEO/RWE (contract in vigour until 31 December 2000).

Third party access to the electricity network is restricted due to fears that foreign suppliers take over the market (restricted third party access to transmission and distribution systems). Market opening after liberalisation is considered to be around 45%, while eligible customers will be those utilities producing more than 100 GWh. No dispatch priority for indigenous fuels is considered.

J.2 Renewable energy activities and policies

The system is based on two promotion mechanisms: feed-in tariffs and investment subsidies. The legal basis for feed-in tariffs for electricity produced from renewable sources of energy is provided by the Grand Ducal Regulation of 30 May 1994. There are two types of feed-in rates for producers, depending on their size:

- Producers of up to 500 kW - In 1997 the rate to be paid by the utility for electricity delivered from wind and photovoltaic systems totals LUF 4.03/kWh (Euro 0.100/kWh). This figure is made up of a (non-indexed) feed-in tariff of LUF 1/kWh (Euro 0.025/kWh) and an index-linked levy of currently LUF 3.03/kWh (Euro 0.075/kWh)(Offerman, 1997). There are only a few biomass schemes for power production and the figures are between the above mentioned amounts. Nonetheless, they would still be eligible for the above mentioned feed-in tariffs (including index-linking).
- Generators in the category covering the range 501-1500 kW are paid a price of LUF 2.30/kWh (Euro 0.058/kWh) during the day and LUF 1.20/kWh (Euro 0.030/kWh) during night hours. In addition to that, they receive a bonus of LUF 4,500/kW (Euro 0.112/kW) for average peak load deliveries during the three principal annual peak load periods recorded for the Luxembourg grid.

Government subsidies are granted for the first five wind power schemes in the amount of LUF 3000/kWh (Euro 0.075/kWh), up to a maximum of LUF 6000000 (Euro 149245). Private homes setting up photovoltaic systems receive 25% of the investment costs, up to a maximum of LUF 60000 (Euro 1492). Other projects, i.e. projects not concerning private households (e.g. PV systems for camp sites, sports centres), receive 25% of the investment cost, up to a maximum of LUF 1500000 (Euro 37311).

K. NETHERLANDS

K.1 Energy sector

K.1.1 Electricity sector

The electric utilities in the Netherlands used to be owned by local authorities at the municipal and provincial level. They were vertically and often horizontally integrated. During the years, several utilities started to co-operate on the production side and in the late 1980s some 15 vertically integrated electricity utilities existed. These companies were owned either by the local authorities of the larger cities or by the regional authorities of the provinces. They delivered electricity either directly to the end users, or to local distribution (integrated supply and network) companies that were owned by the local authorities. In the late 1980s there were about 70 of these local distribution companies, which were often horizontally integrated companies, delivering electricity as well as gas and water to the end users. The utilities that produced electricity collaborated on the national level in the Dutch Electricity Generation Board (Sep). Sep was responsible for the national transmission grid and co-ordinated the planning for the construction of new power plants for which it published bi-annual reports containing a 20-year electricity demand forecast and a 10-year power plant construction plan, which had to be approved by the national government. In the late 1980s several developments, such as a continuing number of mergers between the distribution companies and discussions on the conditions for and the degree to which outsiders could get access to the grid, lead to the restructuring of the electricity sector by the Electricity Law of 1989. Until mid-1998 the situation in the electricity sector was based on this law.

The most important aspects of the 1989 Electricity Law are:

- The separation between supply and production companies in the electricity sector.
- The obligation for the supply companies to accept electricity from IPPs against the supply company's avoided costs.
- The introduction of a tariff structure that allows for price differences between the production companies and between the supply companies.
- The possibility of horizontal shopping, i.e. the freedom of large end users to purchase their electricity from another supply company, as well as the freedom of supply companies to purchase their electricity from other production companies than their regional production company.
- The allowance to supply companies to produce electricity by renewables and small scale CHP. The law stated that supply companies could bring into operation plants below 25 MW without consulting the production companies and plants up to 100 MW in consultation with the Sep.

There are four central electricity production companies: UNA in the north-west, EPON in the north and the east, EPZ in the south and EZH in the south-western part of the Netherlands. Together, they supply about 60% of Dutch electricity consumption. Some 30% is produced by decentral production units, most of which is produced with CHP plants. Another 12% is imported. Total production capacity in the Netherlands is more than 20 thousand MW in 1998. Due to the ongoing liberalisation, electricity import is expected to grow, while the production with CHP is expected to decrease in the years to come.

The four central electricity producers co-operated in the Sep, which was responsible for the transmission grid, the import and export of electricity, and the co-ordination of the production planning of the production companies. The Sep operates as an electricity pool until the end of

2000 (based on an agreement between Sep and EnergieNed). The production companies are obliged to sell the electricity from the power plants first to the Sep against standardised fees that reflect the production costs. The Sep levels the costs of the different production plants and sells back the electricity to the production companies at one national basis tariff (LBT) which includes the coverage of Sep's own costs (e.g. maintenance of the transmission grid). The production companies sell the electricity to the distribution companies at a slightly higher tariff, reflecting their distribution costs. These tariffs, the regional basis tariffs (RBTs), might be different between the production companies, but because of the competitive pressure, these differences have turned out to be minor during the last decade. Finally the distribution companies sell the electricity to the end users at a tariff that reflects the distribution costs.

Attempts to transform the Sep into one national electricity production company that would be strong enough for the European market have failed in 1998. As a result, three of the four central production companies were taken over by international companies. UNA is now part of Reliant from the United States, EZH was taken over by PreussenElektra from Germany. Belgiums Electrabel, together with ING bank, will take over EPON. Energy supplier Essent owns the majority of the shares in EPZ.

K.1.2 Gas sector

The Dutch gas market is dominated by the producer NAM (equally owned by Shell and Exxon) and the transmitter Gasunie. Natural gas used in the Netherlands mainly comes from domestic fields. The share of the large Groningen field becomes smaller on the account of the small fields (mainly off-shore). Groningen is used as a balance field for peak production. The Dutch gas market in 1999 amounted to 75.4 bcm. Domestic demand was 40.4 bcm, 7% less than in 1998. The remainder of 35 bcm was exported. About 46% of the domestic production is destined for export and a little bit of gas is imported from Norway (2 bcm per year for power production) and the UK. In 1999 exports went to Germany (56%), Belgium, France, Italy and Switzerland.

Gasunie has a de facto monopoly on transportation of natural gas. Gasunie is owned by the NAM (50%), EBN (40%) and the Dutch state (10%). Gasunie purchases most of its natural gas from domestic producers like NAM, EBN, Amoco, Occidental and Elf. Since July 1995 domestic producers are no longer obliged to sell to Gasunie; however most keep doing so due to the attractive terms offered by Gasunie. The gas infrastructure in the Netherlands is dense and highly developed.

The distribution (integrated supply and network) companies, united in EnergieNed, handle all contractual negotiations between the suppliers/distributors and Gasunie. The contracts have a duration time of 3-10 years. There is no unbundling of gas tariffs in the Netherlands. All prices are based on market value, i.e. linked to the price of competing fuels.

With the availability of cheap gas from the UK, a number of new companies, for example Elstra and Entrade, have entered the Dutch market. Typically, these companies are joint ventures between distributors and/or large users. This emerging competition and the new Gas Act have pressed Gasunie to revise its tariff system (currently only applying to the large industrial gas users (> 10 mln cubic meters) and to services for third parties). Main difference between the new and the old system is that the load curve of the customer will be used to determine the price per m3 of natural gas (hence not the annual consumption). In addition, customers who are located further away from the main gas fields, will pay more: a distance related component is introduced. As a result gas prices for base load gas decline and prices for users with a high peak load will increase. This could have been expected as competition is mainly coming from 'low swing' UK gas. Whereas Gasunie (the Groningen field) has much 'high swing' gas.

K.1.3 Heat sector

To circumvent the requirement of the 1989 electricity law that supply companies cannot construct power plants with a capacity larger than 100 MW, the supply companies have set up many joint ventures with industrial firms for the construction of small and large scale CHP-plants (up to about 400 MW). Decentralised electricity generation capacity (mainly CHP) has grown from a little over 2000 MW in 1989 to 3000 MW in 1993 and 7000 MW in 1997 (27% of the total generating capacity in the Netherlands). Decentralised electricity generators produced approximately 26,000 GWh in 1997.

The exponential growth of decentralised CHP in the early 1990s led to a temporary moratorium on new CHP-plants in 1994, because it was feared that the total capital costs of the national electricity system would become far too high. Since then the tariff contracts between the supply and production companies have been adapted to accommodate for this problem. Another result of the growth of decentralised CHP is that almost all construction plans for central power plants have been cancelled, because of over capacity in production. Currently the production companies are also collaborating with large industrial firms to construct CHP plants, since it is the only way to extent their production capacity.

In general, heat is supplied and distributed by the same companies as electricity and gas.

K.1.4 Horizontally integrated energy distribution and supply

The Dutch energy sector is in a process of restructuring, driven by the new Electricity Law of 1998 and the continuing process of mergers and privatisation. In the last decades many mergers among the distribution companies have taken place. In 1998 there were 23 electricity supplying companies. These mergers have continued since then. There are large differences regarding the size of the supply companies. Some of them are small and still attached to one town or region, but most of them cover large regions, sometimes as large as the regions of the production companies. Most of these companies are horizontally integrated, although still mono-gas utilities exist. All the energy supply and distribution utilities co-operate in their branch organisation EnergieNed.

Mergers in the supply sector have resulted in a more concentrated industrial structure. In terms of number of connections, three supplying companies Essent, NUON and ENECO cover 85% of the electricity market, 76% of the gas market and 79% of the heat market. Essent resulted from a merger of the Pnem/Mega-group with Edon, Nuon from a merger of Nuon with ENW, Gamog, and EWR. Nuon and Essent are the largest suppliers of both electricity and gas. Eneco announced to merge with six smaller supply companies (Energie Delfland, Nutsbedrijf Amstelland, energiebedrijf Zuid-Kennemerland, Gasbedrijf Midden Kennemerland, Gasbedrijf Noord-Oost Friesland en Nutsbedrijven Weert).

The energy sector unbundled their electricity supplying activities from their network activities. Network companies operate in strictly separated geographical areas according to licences. Table K.1 gives an overview of the network companies and their relation with supply companies. In general, the supply companies are horizontally integrated, i.e. they supply electricity as well as natural gas, heat, and sometimes also water and cable-tv services. Distribution (i.e. network activities) of natural gas is still part of the supply companies.

Table K.1 *Unbundled network owners (electricity) and energy suppliers*

Province	Network owner	Supplier
Groningen	NV EDON Netwerk	NV EDON
Friesland	NV FRIGEM Netwerk	NV FRIGEM
	NV Continuon Netbeheer	NV Continuon Energielevering i.o.
Drenthe	RENDO Netbeheer BV	NV RENDO
	NV EDON Netwerk	NV EDON
Overijssel	Netbeheerder Centraal Overijssel BV	*Centraal Overijsselse Nutsbedrijven NV*
	NV EDON Netwerk	NV EDON
Flevoland	NV Continuon Netbeheer	NV Continuon Energielevering i.o.
Gelderland	NV Continuon Netbeheer	NV Continuon Energielevering i.o.
Noord-Holland	Noord West Net	Energie Noord West NV
	Regev Netbeheer BV i.o.	NV NUON Gooi- en Vechtstreek
	BV Netbeheer Zuid-Kennemerland	NV Energiehandel Zuid-Kennemerland
Zuid-Holland	EdelNet Delfland BV	Energie Delfland NV
	Netbeheer Midden-Holland BV	Energiebedrijf Midden-Holland NV
	EWR Netbeheer BV	EWR NV
	Westland Energie Infrastructuur BV	NV Nutsbedrijf Westland
	ENECO NetBeheer BV	NV ENECO
	ONS Netbeheer BV	NV ONS Energie
	BV Transportnet Zuid-Holland	
Utrecht	Elektriciteitsnetbeheer Utrecht BV	NV Regionale Energiemaatschappij Utrecht
Zeeland	DELTA Netwerkbedrijf BV	NV DELTA Nutsbedrijven
Noord-Brabant	ENET Eindhoven BV	NV Nutsbedrijf Regio Eindhoven PNEM
	PNEM Netwerk BV	Energieverkoop BV
Limburg	InfraMosane NV	EnerMosane NV
	MEGA Limburg Netwerk BV	MEGA Limburg Commerciële Zaken BV
	MEGA Limburg Netwerk BV (Heerlen)	Nutsbedrijf Heerlen COZ BV
	Netbeheer Nutsbedrijven Weert NV	Nutsbedrijven Weert NV

K.2 Liberalisation process

In order to implement directive no. 96/92 of the EU concerning the internal market for electricity and because of changing ideas with regard to the role of the market in electricity supply, a new Electricity Law was passed in Parliament in June 1998 (consequently, officially the law is now called the Electricity Law 1998). The Dutch Gas Act was implemented in August 2000. Heat is not officially subject to liberalisation.

The Dutch electricity and gas market is liberalised in phases as regards the eligibility of consumers to choose their suppliers. Table K.2 shows which customers will be free in the choice of their supplier at which date. The main discussion now focuses on an accelerated liberalisation. The minister of economic affairs would like to open-up the market for small customers (both electricity and gas) in 2004 instead of in 2007. Consumers of electricity and gas from renewable sources will already be free to choose their supplier as of 1 January 2001. However as indicated by the minister, this date highly depends on a well functioning green certificate system.

Table K.2 *Scheme for liberalising the energy market*

Type of customer	Year of free status	Number of customers	Electricity demand in 1995 [%]
Electricity			
annual use > 2 MW	1998	650	33
annual use < 2 MW			
connection > 3.8 Ampère	2002	54350	29
connection < 3.8 Ampère	2004	6720000	38
Gas			
annual use > 10 mln m^3	1999	150	46
annual use > 170000 m^3	2002	16000	16
all consumers	2004	6458000	38
Renewables	*2001(?)*		

Electricity

Access to both the high-voltage grid and the distribution networks is regulated on the basis of regulated Third Party Access (rTPA). Entry should be free and non-discriminatory. Network owners are therefore obliged to publish tariffs and the technical requirements for use of the network. In addition, network administration should be vested in a separate company, although this company can be part of a holding which also includes production and/or supply of electricity (legal unbundling). However, the creation of a separate company for network management should ensure that this is independent from other activities of network owners such as the supply of electricity. With regard to the transmission grid a new organisation, called TenneT, has emerged from the Sep.

A special bureau (Dienst Toezicht en Uitvoering Electriciteitswet, DTe) is set-up, which will supervise and regulate the implementation of the new Electricity Law. Network tariffs (for the transmission of electricity) will be allowed to rise in line with the consumer price index, minus an efficiency deduction. Moreover, network owners will only be allowed to make a modest profit, given that network management is a monopoly activity with low risks on investments. DTe is a specific chamber within the Dutch competition authority, NMa (the equivalent of the German Bundes Kartellamt or the British Monopolies and Merger Commission).

Household consumers and small businesses will only be free to choose their suppliers in 2007. Therefore, the Dutch Minister of Economic Affairs will supervise the tariffs set by the distribution companies for captive consumers until then. The tariff is composed of a network tariff, regulated as specified above, and a supply tariff. Distribution companies are allowed to set a supply price which is lower (but not higher) than the supply tariff, which will be based on market prices for electricity and changed periodically. The supply tariff is subject to a yearly efficiency deduction, which will be fixed for three to five years.

Gas

The Dutch history as a large producer and exporter of natural gas (and fund provider for the government) is reflected in the Gas Act. Access to the large diameter pipelines is regulated on the basis of negotiated Third Party Access (nTPA). Therefore, the network owner Gasunie has developed its so-called Commodity Services System (CSS), on the basis of which third parties may negotiate conditions and tariffs for gas transmission. In practice however, the tariff structure of CSS is fixed and hardly open for negotiation. CSS is approved by the Ministry of Economic Affairs. Gasunie will not have to separate its network and trading activities into different companies. However, it will separate these activities internally by creating Chinese Walls within the company. The NMa will supervise the implementation of the Gas Act, i.e. not a special body as in the case of electricity.

With regard to captive customers of natural gas, provisions will be the same as for electricity. However, the traditional distribution companies are not obliged to unbundle their network and supply activities for natural gas. Since most of these companies are also involved in supplying electricity, they might very well choose to separate their local networks from their commercial activities.

Table K.3 below provides an overview of the main elements of energy market liberalisation in the Netherlands

Table K.3 *Energy market liberalisation in the Netherlands*

Issue	Electricity regulation	Gas regulation
Access to grid	Regulated TPA	Negotiated TPA
Degree of vertical integration	Legal unbundling	Administrative unbundling
Time schedule	Complete market opening in 2004	Complete market opening in 2004
Degree of government intervention	Tariffs for supply to captive customers with annual efficiency reduction are set by DTe and need approval from the government	Transmission tariff of Gasunie approved by government
Reciprocity	Imports from less liberalised countries are limited through the reciprocity clause in the EU directive	Reciprocity will probably not be applied, because of minor imports

K.3 Renewable energy activities and policies

K.3.1 Renewable energy status

The national discussion on renewable energy has resulted in a more or less consistent definition for renewable energy in the Netherlands. However, there is still some controversy about including import of renewable sources (e.g. electricity from Norwegian large hydropower plants) in the definition. Renewable energy is all energy in the form of electricity, heat or fuel that is generated by (local) renewable energy sources, after correction for use of energy for its generation. In the ‘Progress Report on Renewable Energy (1999) the fraction of waste (as a rule of thumb 50% of the total volume is regarded organic) and industrial heat pumps are no longer considered as renewable but as energy conservation. Table K.4 shows the amount of renewables in the Netherlands. Avoided primary energy in PJ is calculated according to figures for reference technologies in 2000.

Table K.4 *Avoided primary energy [PJ] by renewable energy*

Renewable resource	1990	1995	1998	1999[1]
Hydro power	0.7	0.7	0.9	0.7
Wind energy	0.5	2.6	5.3	5.3
Solar - PV	0	0.01	0.03	0.05
Solar - thermic	0.1	0.2	0.3	0.4
Heat pumps	-	0.1	0.2	0.2
Heat/cold storage	0.01	0.1	0.3	0.5
Bio energy	17.5	18.7	26.4	28.1
burning waste	6.4	5.6	11.4	12.1
biomass burning	8.2	8.2	9.8	10.6
biomass fermentation	2.9	4.9	5.2	5.4
Total	19	22	33	35
% of total energy supply	0.7	0.8	1.1	1.2

[1] Preliminary figures.
Source: Ecofys and KEMA, 1999.

If non-electricity options are included (such as domestic fired wood) then the percentile contribution of renewables to the domestic energy consumption is about 1%.

Table K.5 *Energy production (or savings) by renewable sources in 1999*

Renewable resource	Capacity	Electricity [GWh]	Heat [TJsec]	Gas [mln m^3]
Hydro power	37.5 MW	90	-	-
Wind energy	409 MW	645	-	-
Solar - PV	9.6[1] MW	5.6	-	-
Solar - thermic	[2]	-	111	7.2
Heat pumps	44 MW_{th}	pm	pm	6.2
Heat/cold storage	179 MW_{th}	36	pm	5.8
Bio energy		1408	13534	55
burning waste	424 MW	924	3997	-
biomass burning	66 MW	198	8350	-
biomass fermentation	[3]	286	1187	55
Total		2185	13645	74

[1] Stand alone and grid connected.
[2] Total surface of collectors is 258200 m^2
[3] Extraction is 5013 TJprim/yr
Source Ecofys and KEMA, 1999.

K.3.2 Renewable energy policy

In the coming years the government budget for renewables will be raised by more than a third of the current level. Direct subsidies will be phased out, market stimulation will be promoted by indirect means, e.g. by fiscal measures. The budget for PV will almost be tripled in the coming years, while biomass and wind energy will see their stimulation budget doubled. The budgets consists of contributions to R&D-programs as well as programs aimed at a better acceptance of renewables in society and at enhancing the knowledge on the different indirect stimulation measures.

Table K.6 *Government direct budgets for renewables*

	1996	1997	1998	1999	2000
Wind	8.6	16.6	16.6	16.6	16.6
PV	12.3	33.1	34.1	34.3	34.3
Waste and biomass	7.5	15.5	15.5	15.5	15.5
Thermal solar energy	6.6	8.6	8.6	8.6	8.6
Solar boilers (subsidy)	6.6	6.6	0.6	0.6	0.6
Heat pumps (subsidy)	3.6	0.6	0.6	0.6	0.6
Heat pumps	5.3	8.3	8.3	8.3	8.3
Renewable Energy Project Bureau	0.6	5.6	5.6	5.6	5.6
ECN financing committed to renewables	10.6	10.6	10.6	10.6	10.6
TNO financing earmarked for renewables	1.5	1.5	1.5	1.5	1.5
Economy-Ecology-Technology Program	10.6	10.6	10.6	10.6	10.6
Total	70.8	114.6	109.6	109.8	109.8

Table K.7 gives an overview of the current energy related policy goals of the Dutch government.

Table K.7 *Energy related policy goals in the Netherlands*

Subject	Goal	Year
Renewables	3% of electricity	2000
	5% of energy consumption	2010
	10% of energy consumption (≈17% of electricity)	2020
Energy efficiency improvement	1.7% per yr	till 2000
	33%	2020
Greenhouse gases (Kyoto)	-6%	2010

Regulating Energy Tax

Since 1997 domestic consumers pay a Regulating Energy Tax (REB) on their electricity and natural gas consumption. Table K.8 shows that the REB has increased substantially; starting from 2001 the REB will also apply to the first 800 m^3 or kWh used (however, compensated by a rebate on taxes per connection). The aim of this tax is to stimulate energy conservation. The tax is paid by the consumers to the energy suppliers, which have to transfer it to the treasury. An exception is made for electricity and gas generated with renewable sources, i.e. customers buying renewable electricity or gas do not pay REB (nil tariff). This increases the profitability of renewables. Currently the nil tariff applies to all renewables, except waste incineration. Producers of renewable energy receive part of the proceeds of the REB.

Table K.8 *Regulating energy tax REB per user category [€cents/m^3 or per kWh]*

	1998	1999	2000	2001
Natural gas [m^3]				
0-800	0	0	0	11.65
800-5000	4.32	7.25	9.45	11.65
5000-170000	4.32	4.74	5.19	5.65
170000-1 mln	0	0.32	0.70	1.08
> 1 mln	0	0	0	0
Electricity [kWh]				
0-800	0	0	0	5.50
800-10000	1.34	2.25	3.72	5.50
10000-50000	1.34	1.47	1.61	1.75
50000-10 mln	0	0.10	0.22	0.34
> 10 mln	0	0	0	0

Accelerated Depreciation of Environmental Investments (VAMIL)
The VAMIL scheme allows investors in environmental technologies (defined explicitly by a VAMIL-list) to offset their investments against taxable profits, resulting in an interesting benefit for the investor. All renewable technologies are included in the VAMIL-list.

Energy Investment Deduction (EIA)
Since January 1997 investments in technologies that are explicitly defined on a qualifying list (including renewable energy technologies) may be deduced from taxable profit at a rate varying from 40% to 52% of the total investment (with a maximum of D*f* 50 million (= approximately Euro 22.5 million) per investment).

Green Funds
A green fund is a fund that invests money in environmental beneficial projects, which includes renewable energy. Private persons investing in a green fund are exempted from tax on the interest income from that fund. Under the current tax system in the Netherlands this comes down to return on investments criteria that can be about 50% lower than for other investments.

Capital subsidies for private investors in wind turbines
During the last years inspectors of the treasury have not allowed private persons such as farmers to make use of the VAMIL regulation, because investments in renewable technologies (i.e. wind turbines) were not considered as belonging to the core business of farmers. Since March 1998 a capital subsidy of 20% on the investment costs of wind turbines is available for these cases. The budget for 1998 is D*f* 12.5 million (allowing for a subsidy of about 30 MW wind turbines).

Export subsidies
In the framework of the environment and economic independence programme ‘MILIEV’ a 60% contribution can be granted towards the total transaction costs of market stimulation programmes and transactions involving Dutch technology products.

Energy Performance Standard for new buildings
A requirement for each new building project is to calculate the so-called Energy Performance Coefficient (EPC), which is an indicator for the energy quality of the new building. The Energy Performance Standard (EPN) gives the maximum value of the EPC for dwellings. In 1998 the EPN has gone from the 1997 level of 1.4 to 1.2 and will go to 1.0 in the year 2000. The standards have become so tight that renewable energy technologies will be cost effective in meeting the standards, except for solar PV, which is still too expensive. For existing buildings an Energy Performance Advice (EPA) can be given.

The Environmental Action Plan 1991-2000

The Environmental Action Plan (MAP) started in 1990 as a co-ordinated action of the government and the supply sector to promote energy efficiency and renewables. All energy companies in the Netherlands are committed within the framework of the Environmental Action Plan for the energy distribution and supply companies (MAP 2000) to renewable energy targets. The current goals of the MAP are the reduction of 17,7 Mton CO_2 and 0,4 billion acid equivalents (NO_x and SO_2) with regard to the 1990 situation. Since 1991 many measures have been taken, including the promotion of CHP, insulation, high-efficiency boilers as well as the stimulation of renewables.

By the end of 2000 at least 3.2% of the electricity distributed should come from renewable sources. This equals about 1,700 million kWh. In order to reach this target, energy companies have the opportunity to raise a so-called 'MAP levy' (which, on average, is 1.8%, of the energy bill) on conventional energy sold to their customers. The revenues from this MAP levy should be used for renewable energy and energy saving. The renewable energy target of 3.2% is divided among the energy companies. To give all energy companies the possibility to reach their targets (also those companies that operate in less windy regions), a system of Green Labels (green certificates) has been introduced in 1997. The total costs of the MAP has been in the order of Euro 225 million/year during the last years. Wind energy is supported by the MAP-funds at a level of about Euro 30 million/year.

Realisation of the MAP targets stands apart from the amount of green energy sold to individual energy users. This is called the additionality principle (or 'on-top-of' principle): money paid by green energy clients will only be used for additional renewable energy projects. The projects should not be counted for the MAP targets, as these should be financed by the money received from the MAP levy.

Because of the liberalisation in the energy sector, the MAP-levy will be abolished after 2000. This will be compensated by an increase in EIA and VAMIL for companies and additional premiums for the purchase of energy-efficient appliances by households.

Green Electricity Demand

Since 1995 a number of suppliers offer customers the choice to buy green electricity. The surplus price for the customers varies per supplier, but on average it is 0.07 D*f* (0.031 Euro) per kWh. The suppliers guarantee that the money raised by selling green electricity will be invested in the construction of green production capacity. An independent organisation (like the WWF) ensures that suppliers do not sell more green electricity than they have produced or bought. The total amount of green electricity sold has risen from 32,5 million kWh in 1996 to 350 million kWh in 1999. There were about 140000 customers (on a total of about 6.5 million connections) for green electricity in January 2000. Information on green electricity can be found on www.greenprices.com.

Since 1998, households that buy green electricity are exempted from the Regulatory Energy Tax (REB) which lowers the net consumer price of green electricity (above a level of consumption of 800 kWh/year). On average the net surcharge for green electricity is D*f* 0.02/kWh. With the increase of the REB, green electricity will become more attractive to the customer.

K.4 Tradable green certificates

K.4.1 Background

The largest contribution to reach the goal of 20% renewable energy consumption in 2020 is expected to come from renewable electricity. However, the cost of generating electricity from renewable sources is expected to be considerably higher than the production costs of power generation from conventional fuels (Third Energy Paper, 1995). Following the Environmental Action Plan 2000 (MAP 2000), published in 1997 by the Dutch energy utilities, renewable energy sources will be stimulated by a system of tradable green certificates.

In the new Dutch Electricity Law of 1998 and the proposed Gas Act of 2000, the possibility for the government to implement a system of green certificates is incorporated. The Electricity Act gives the Minister of Economic Affairs power to set a minimum share of the renewable energy for all electricity transmitted through the grids. This mandated share of renewable energy applies to final delivery. The Minister will announce the minimum share for a five-year period. However, until the year 2000, the voluntary approach of the utilities according to MAP 2000, i.e. the Green Label system, will be applied (Ministry of Economic Affairs, 1997).

K.4.2 Green Labels

In January 1998, the Dutch energy supplying companies, united in EnergieNed, have voluntarily introduced the Green Label system to establish a market for renewable electricity. The certificate system should achieve a target of 1.7 billion kWh electricity produced by renewable energy sources in 2000. The first binding target is set for (the end of) 2000, up till then the suppliers have the chance to get acquainted with the Green Labels. It is expected that trading will really develop in the year 2000 when companies have to meet their individual targets.

Each company is allotted a minimum target (quota) for electricity from renewable sources, based on past sales volumes (in 1995). In order to meet its quota, a supplier has to hand over Green Labels. These Green Labels are created by producers of renewable electricity, who receive one Green Label for every 10,000 kWh electricity produced from renewable sources. Suppliers and customers generating their own electricity from renewable sources can also receive Green Labels in return. If their renewable autogeneration exceeds their obligatory targets, they can capitalise the difference by selling their Labels. This will encourage further introduction of autogeneration of renewable electricity by private individuals, offices and firms (Ministry of Economic Affairs, 1997). Although the Green Label system is expressed in terms of electricity (kWh), Green Labels have also been issued for renewable gas (landfill gas). This gas has been converted to kWh by using the CO_2 content.

Green Labels and the MAP-levy

For the physical supply of electricity (both from conventional and renewable sources) in the Netherlands, producers receive feedback payments. The feedback tariff is based on the costs of conventionally produced electricity (about 8 ct/kWh). Production costs of renewable electricity are usually higher. Up till the introduction of Green Labels fiscal rebates and premium feed-in tariffs made up the difference. Subsidies were based on the exploitation costs of the project and funded by a small levy on the electricity price (the MAP-levy). The Green Labels system replaced the existing subsidy on feedback tariffs that producers of electricity from renewable sources receive from suppliers. The costs for the Green Labels are paid from the same sources as the costs for the former feed-in tariffs: either by the MAP-levy or by the selling of green electricity.

Green Labels and Green Electricity

There was no specific agreement on whether or not green electricity can also be counted in the target of 1.7 billion kWh. In practice, some suppliers used the Green Labels acquired in the production of the green electricity they sell, to meet their target, while others did not include these labels (which therefore increased demand for Green Labels). However, it is agreed that suppliers do not include the demand for green electricity in their target for Green Labels.

Green Labels and the Regulating Energy Tax
Table K.8 shows that the REB has increased substantially. A higher REB implies a lower price for Green Labels. Note that the REB is an instrument to encourage energy savings, but not primarily to encourage the use of energy from renewable sources.

Renewables in the Dutch Green Label system are those renewables that receive a rebate from the regulating energy tax (REB), which are hydro, wind, solar, biomass and gas from landfills. A difficulty here is the identification of renewable based electricity imported from other countries. Up till now, it is agreed that the import of electricity from Norway (produced with hydro energy) is not included in the Green Labels. Furthermore, at present, Green Labels are valid only in the year in which they have been created. At the end of 1999, Labels were artificially settled between distributors. However, settlement is without monetary payments, emphasising the experimental phase of the system. The limited validity of the Green Labels might hinder the development of the Green Label market; when labels retain their value they can be more easily traded, and investing in renewable energy is less hazardous (see van der Tak, 1998 for a discussion).

Experiences with the Green Label system
With the introduction of Green Labels, separation between the physically supplied electricity and the renewable part is established. Green Labels can be traded nation-wide. Energy supplying companies no longer depend on the possibilities of producing renewable energy in their own region. This is especially favourable for the penetration of wind-energy, for which the costs are lowest near the coast line.

Producers of renewable electricity receive Green Labels only when they also receive a rebate of the REB, which is granted by the Dutch fiscal administration. This will help assure that a Green Label does indeed represent 10,000 kWh of green electricity. There is a sanction for those suppliers who fail to meet their targets. They are obliged to buy Green Labels from other suppliers who have more Green Labels available than required. The price will be fixed by an independent third party (see van der Tak, 1998, for an analysis of the consequences of this system).

The Green Labels were launched in January 1998, although the first binding target is set for 2000. The first two years were trial years in which the Green Label market can be developed. For these two years it is recorded how many Green Labels are created and how many Labels are owned by supplying companies which, combined with their targets, give an idea about supply and demand. Every month, a nation-wide registration office registers the new producers of renewable energy that have entered the market, their actual production and production capacity, which Green Labels have been created by whom (including their serial number) and which Green Labels have been bought, including the duration of the contract. This information is partly available on the Green Label website which has been set-up by the association of Dutch utilities EnergieNed (www.groenlabelned.nl; in Dutch and not updated). Labels can also be bought and sold on this website.

The latest figures with respect to the Green Label system can be found on www.kema.nl. According to the information on the website, 96759 Labels were created (i.e. produced) in 1998, 89819 of those were sold (mostly under long-term contracts) and 6940 were still for sale at the end of 1998. A total deficit of 80181 (170000-89819) Labels still remained. Figure K.1 shows the market shares of the different types of renewables in the Green Labels created.

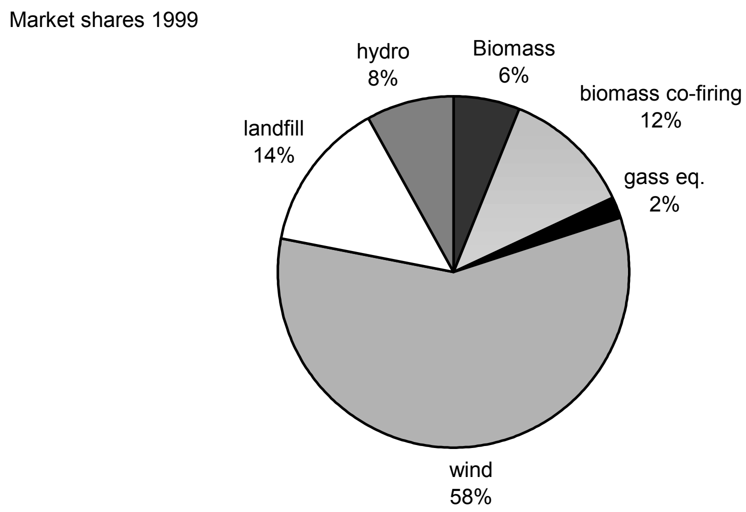


Figure K.1 *Market shares of RE in Green Labels (source: www.kema.nl)*

Figure K.2 shows the difference between individual firms' targets and the number of Labels they hold at the end of 1998. There are 19 firms participating in the Green Label system. Most of the firms still have to acquire Labels.

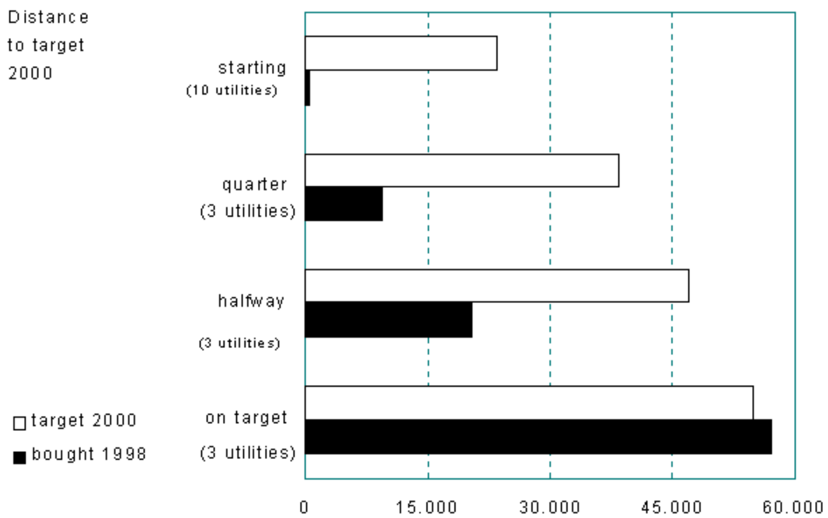


Figure K.2 *Distance to target (source: www.kema.nl)*

K.4.3 Governmental green certificate system

In the Electricity Law of 1998 and the proposed Gas Act of 2000, the possibility for the government to implement a system of green certificates is incorporated. In the Energy Report, published in 1999, the Minister of Economic Affairs elaborate on how to implement such a green certificate system. If possible, the new system should be introduced in January 2001 in order to be able to open-up the market for renewable energy. It is however not likely that such a TGC system will be operational on that date.

It would in principle be possible to transform the current Green Label system of the energy sector, which expires at the end of 2000, into a governmental system. However, there are some difficulties and differences. First, the Minister has no intention to set an obligation for a minimum share of renewables in energy consumption. The idea is that voluntary demand will be enough to ensure a market for green certificates. Second, EnergieNed will stop with the Green Label system because the labels are not recognised by the Dutch fiscal administration as a prove for renewable energy supply. Now, only the REB proves that renewable energy is supplied. If Green Labels would be recognised, the system could easily be transformed and used as the new green certificate system. Third, the current Green Label system is criticised by independent producers of green energy, who think that they are discriminated by the system. Finally, the Ministry still has no idea how to deal with international trade in green certificates.

K.5 Cross-cutting GHG emissions sector

In 1999 the Dutch government issued the first part of an enforcement paper regarding its Climate Change policy. This first part only deals with GHG measures that will be taken domestically. A second part of the paper, concerning measures to be taken abroad (Kyoto mechanisms) was published in March 2000.

According to the Kyoto protocol, the Netherlands has to reduce its GHG emission by 6% in 2008-2012 compared with 1990. This means that in addition to existing policy measures about 50 Mton of CO_2 equivalents (20% of expected emission in 2010) should be reduced annually. The Dutch government decided to get half of this reduction, i.e. 25 Mton, abroad using flexible instruments.

K.5.1 Domestic GHG reductions

The domestic reduction of 25 Mton should be realised with two packages of policy measures. Policy measures in the first package, the base package, are quite certain. A second, reserve package of policy measures will be prepared if the results of the base package are disappointing. The base package will be evaluated in 2002 and 2005. A final package of new initiatives will account for further emission reductions after 2008-2012.

The base package consists of a division of emission reductions over target groups (i.e. industries). An overview is given in Table K.9.

Table K.9 *Division of emissions and reduction efforts over industries [Mton]*

Industry	Expected emissions in 2010 with existing policies	Reduction effort in 2010
Industrial incl. refineries	89	10
Energy utilities	61	8
Agriculture	28	2
Transport	40	3
Households	23	2.3
Trade, services and government	12	1
Others	6	-
Total	≈256	≈25

In the industrial sector and refineries, a reduction of 2.3 Mton should be reached by energy savings. PFC and HFC reductions (in particular in the aluminium and chemical industry) should amount to the other 7.7 Mton. As from 2008, coal fired electricity production units should reduce their GHG emission towards the level of gas fired units. It should result in a reduction of 6 Mton/yr. Renewable energy should account for another 2 Mton, therefore an additional policy goal of 5% RE in 2010 is included (the final goal is 10% RE in 2020). The reductions in the agricultural sector should entirely be achieved by energy savings, using residual heat and CO_2 fertilisation in greenhouses.

The reserve package consists of increasing REB, increasing taxes on transportation fuels, storage of CO_2 from large industrial sources in e.g. aquifers and reduction of NO_2 emissions by the chemical industry.

For the long term, new initiatives such as technical development of climate neutral energy carriers will be supported. Instrumental development of tradable emission and reduction rights are also included in this package. It shows that the Dutch government does not rely on domestic Carbon Emissions Trading for reaching the Kyoto target.

K.5.2 GHG reductions with Kyoto Mechanisms

The main goal for the Dutch government of using the Kyoto mechanisms is cost efficiency, i.e. to reach emission reductions at lower costs that would be possible with domestic measures. In 1997, the Dutch government initiated a test project program for Activities Implemented Jointly. Based on this test program, further actions will be taken in JI and CDM. Budgets for Kyoto mechanisms are shown in Table K.10.

Table K.10 *Budgets for flexible mechanisms*

Project type	Period	Budget [D*f*]
Test project program for AIJ		
• in Central and Eastern Europe	1997-2000	36 million
• in developing countries	1996-1999	48 million
JI		
• *Min. of Economic Affairs (CO_2 reduction plan, directed at Annex I countries)*		100 million
• *Min. of Development Cooperation (non-ODA)*	as from 1999	75 million/yr
CDM		
• Min. of Development Cooperation (ODA)	2001	200 million
	2002	300 million
Emissions trading (experimental)	?	

Joint Implementation
In Central and Eastern Europe, 57 projects have been started in 1998 and 1999 in the test project program. Co-operation with other countries was not easy. Bilateral agreements on the division of resulting emission reduction between the countries have proved to be difficult. Up till now, the Netherlands has reached agreement with Rumania, Bulgaria, Russia and Poland on the division of emission reduction units (ERUs) and the baseline for the projects. Meanwhile, the Ministry has announced a European tendering procedure (ERUPT, Emission Reduction Unit Purchasing Tender) for the purchase of ERUs in Central and Eastern Europe. The first tender starts in June 2000 and amounts to D*f* 50 million.

In the test phase, the Joint Implementation Registration Centre (JIRC) of the Dutch government accounted for the validation and certification of the projects. JIRC ceased to exist and new certifying organisations should emerge.

The Netherlands also participates in the Prototype Carbon Fund of the World Bank. The WB expects that the price of one tone CO_2 eq will be 5-10 US$.

Clean Development Mechanism
In developing countries, carbon emission reductions should go together with sustainable (economic) development. For developing countries, about 20 projects in 13 countries have been started in the test project program at the end of 1999. Projects only get support from the Dutch government for the incremental costs, which varies between 5 and 30% of the total project. Selling emission reductions established by CDM projects, Certified Emission Reductions (CERs), ensures additional revenues for a project.

International Emissions Trading
International trading of CO_2 credits is not tied to particular project as is the case with JI and CDM. The Dutch government would like to gain experience with the purchase of credits from other governments. Moreover they would like to support a pilot of emissions trading between private companies. However, Dutch policy with respect to emissions trading will highly depend on the policy of the EU and agreements reached during CoP 6.

L. PORTUGAL

L.1 Energy Sector

L.1.1 General Overview

Portugals degree of self-sufficiency in the energy sector is relatively low, compared to the EU average. The ratio of total domestic production over gross consumption was 20.35% for the year 1996 (compared to a 53.26% for the EU as a whole), although the increase in this ratio for the years 1990-1996 for Portugal was one of the highest (increase of 5.6% per year on average).

The second characteristic concerns the fuel-source distribution of Portugal gross inland consumption. In 1996, the oil share over total consumption represented 62.9%, over 21 percentage points above the EU average, while the same figure for natural gas was only 0%, 21 percentage points bellow the EU average. The energy dependency problem of Portugal becomes clear from Table L.1, which shows the shares by fuel-type of the gross inland consumption in Portugal and in the European Union as a whole.

Table L.1 *Percentage Distribution of Gross Inland Consumption by Fuel type [%]*

1996	Solids	Oil	Natural Gas	Other[1]
European Union	16.7	41.5	21.4	20.4
Portugal	17	62.9	0	20.1

[1] Hydro and Wind energy, net electricity imports, and other sources, such as nuclear power are included.
Source: Annual Energy Review. Energy in Europe. European Commission.

Another differentiated characteristic comes from the electricity sector, where hydro and wind generation is more than 10 per cent over the EU average. This advantage provides a relative saving of more than 7 per cent of thermal generation of electricity with respect to the EU average. Table L.2 shows the electricity distribution by fuel type. No nuclear energy is generated, and the generation of hydro and wind is high above EU average (by more than 50 per cent). However this is not enough to compensate the no-nuclear generation of electricity and, therefore, the thermal share is more than 5 per cent above the EU average.

Table L.2 *Share of electricity generated by source [%]*

1996	Nuclear	Hydro & Wind	Thermal
European Union	35.3	13.0	51.7
Portugal	0	43.1	56.9

Source: Annual Energy Review. Energy in Europe. European Commission.

Finally, the fourth characteristic explains the main reason for the deficit in the use of natural gas mentioned before. Portugal barely uses 0.7% of natural gas in the thermal generation of electricity, almost 20 per cent below the EU average. This is compensated by a similar increase in oil (15 per cent) and solids (5 per cent). Table L.3 shows the shares by fuel type of the thermal generation of electricity.

Table L.3 *Thermal electricity generation by fuel-type [%]*

1996	Solids	Oil	Natural Gas	Geothermal & Biomass
European Union	60.0	15.2	20.3	4.5
Portugal	64.3	30.4	0.7	4.5

Source: Annual Energy Review. Energy in Europe. European Commission.

L.1.2 Electricity sector

The EdP (Electricidade de Portugal) Group, created in 1975, has been the core player, with both, vertical and horizontal links in the Portuguese electricity market. EdP had a monopoly of generation, transport, distribution and public supply of electricity until 1991. In that year EdP was changed into a government owned joint stock company and new legislation was passed concerning generation trade, transmission and distribution. After 1991 it no longer had a monopoly in generation but retained the monopoly in transmission and distribution and had an obligation to supply. Steps were taken to increase competition in generation and private investment into the market and to promote co-generation, use of national resources and independent power production. The aim was, also, to promote open access to the grid through agreement among the parties concerned. A public service concession would take responsibility for the management of transmission and trade.

However, the real restructuring of the electricity supply industry came in 1994 and involved unbundling of EdP according to business areas. The new structure is made up of the following:

- A holding company EdP (20% privatised).
- A production company (CPPE[12]) which runs 43 power stations.
- A grid company (REN[13]) which owns and operates the 220 and 400Kv-transmission grid and is engaged in interconnections with Spain. REN keeps responsibility or co-ordination and dispatch to ensure security and reliability of supply.
- Four regional distribution companies (EN, CENEL, SLE, LTE)[14]. These have access to the above mentioned interconnections (subject to capacity limitations).
- Ten service companies.

In 1997 30% of EdP shares were put on the market and in 1998 the government decided to further privatise a 15% of the company.

The system is under the control of the ‘surveillance authorities’ which are:

- the planning entity,
- the regulatory entity (three members, appointed by the Ministry for Industry and Finance).

These entities regulate the two-tier electricity market, namely, the centralised and closely regulated part (PES)[15] and the independent part (IES)[16]. It plays an important role in, both, controlling the prices charged by the grid to the distributors and the prices charged by distributors to customers and, on the other hand, in preparing and reviewing capacity expansion plans (they monitor both price and quantity, see below).

Two types of licenses for generation and distribution can be awarded, leading to two electricity market segments:

- PES (public electricity system), which represents the non-competitive market segment. Tendering is necessary for those who wish to be part of the public electricity supply.
- IES, which represents the competitive market segment. A non-binding procedure has been envisaged for those that intend to produce or distribute competitively for their own use or for third parties. This system is based on authorisation.

[12] Companhia Portuguesa de Produçao de Electricidade.
[13] Rede Eléctrica Nacional
[14] Divided into geographical areas: North, Central, South and the Lisbon area.
[15] Public Electricity System
[16] Independent Electricity System

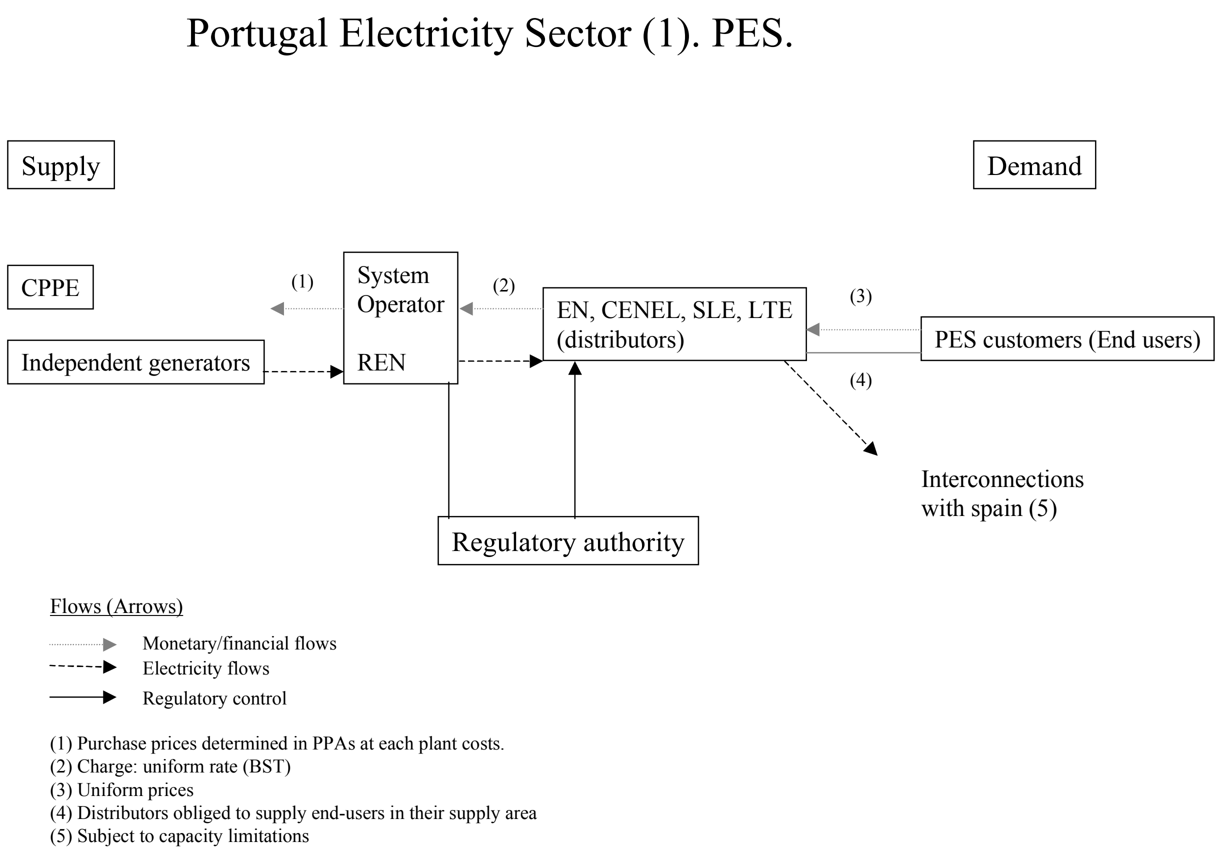


Figure L.1 *Structure of the Electric System PES*

A more detailed explanation of both systems, highlighting the interactions between them is provided in Figure L.2.

Prices and PPAs

Generators and distributors are connected contractually to one another and to the grid. Based on PPAs (power purchase agreement) for each power plant between CPPE (and independent generators) and REN the former are committed to sell electricity exclusively to REN at each plant's costs. REN, on the other hand, sells the electricity to its distributors at a uniform rate (the bulk supply tariff, BST). The system operator, situated within REN has an obligation to guarantee an adequate amount of service reliability to end-users in the PES. He is free to contract for reserve capacities from all entities in the power market. Finally, at the other extreme of the spectrum, the consumers buy the electricity from the distributors who are obliged to supply end-users in their supply area.

The role of the surveillance authorities in capacity expansion plans

Generating capacity expansion has two dimensions: one of central control and another of a competitive bidding process. The planning entity handles capacity expansion by preparing expansion_plans that are later reviewed by the regulatory body and approved by government. The characteristics of new power plants to be built (capacity, fuels used, technical characteristics and timetable for tendering) are, therefore, established by expansion plans. New capacity expansion is monitored is based on a tendering process monitored by the regulatory entity. According to IEA (1996, p.52) the bidding process for new capacity in the PES brings about some additional competition, but only in plant construction, not in operation.

The role of the surveillance authorities in electricity prices and charges
The regulatory entity controls transmission and distribution charges (based on rate of return) and end-user prices for consumers (based on a price cap which takes account of the consumer price index). That is, the regulatory entity controls price links two and three, but not pricing at generation level (price link one), as RENs purchase prices are determined in the PPAs.

Portugal Electricity Sector (2).
PES and IES.

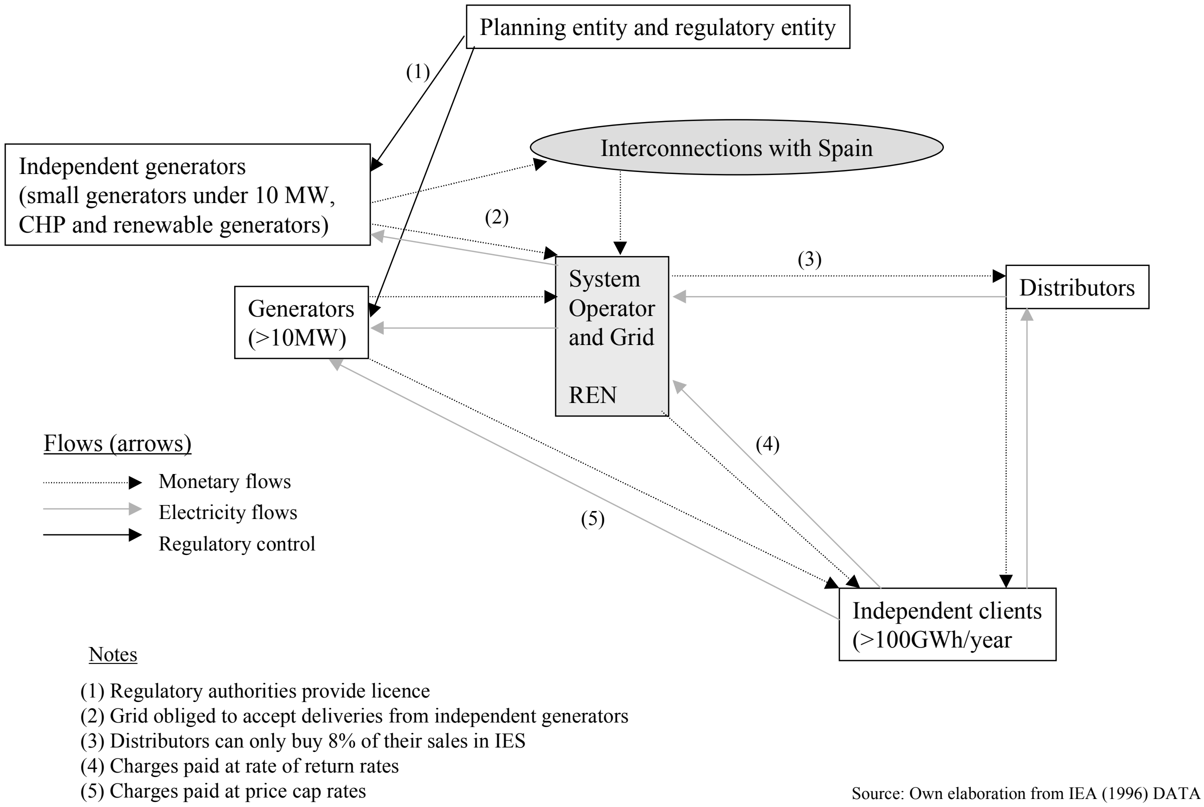


Figure L.2 *Structure of the Electricity System (IES)*

A few additional distinctions between the players are relevant in order to understand the functioning of the IES. These are:

- Independent generators, including:
  - Small generators under 10 MW.
  - CHP facilities.
  - Renewable energy generators.
- Generators above 10 MW.
- Independent clients demanding more than 100 GWh/year.

The explanation below will start with the generation, moving down the value chain to the final consumer. In the IES, independent generators (Small generators under 10 MW, CHP facilities and renewable energy generators) have access to the grid, which is obliged to accept their deliveries. They also have access to interconnections with Spain, and are free to construct their own direct transmission lines

Generators above 10 MW are dispatched through the central dispatch in, both the IES and PES. Direct supply contracts with end-users will be financial arrangements, free from government intervention.

Distributors are allowed to buy 8% of their sales in the IES. The owners of the transmission and distribution grid are required to sell electricity to independent consumers at the charges set for the public system (based on the rate of return and the price cap, respectively). However, consumers have their access to the EIS restricted: their size has to be over 100 GWh per year. According to IEA (1999) the IES would start to include competitive retail sales since 1999. Before that date, it only supplied the wholesale market only (through REN).

The system does in principle allow spot market exchanges between PES and IES: Independent generators with spare capacity will be able to sell power to REN at marginal system cost from the outset. PES generators will be able to sell power to independent consumers as back-up supplies.

In order to operate in the IES, generators need an authorisation that specifies the characteristics of the power plant to be built (location, capacity, fuel used and data on environmental requirements in force).

L.2 Renewable energy activities and policies

Renewable energy policy in Portugal is based on the following legislation:

- Decree-Law 189/88 (5/27/88). Obliged the grid to buy renewable electricity generated by small independent power producers (up to 10 MW) at favourable prices (IEA 1996).
- Decree-Law 313/95 (Independent Power Producers & Autoproducers Law)(11/24/95).
- Electricity Act 54/1997 (special regime)(3/14/97).

Feed-in tariffs

Private power generators profit from, both quantity and price guarantees. On the one hand, as mentioned above, EdP is obliged by law to purchase electricity produced by private power generators without limits in the plant's installed capacity. On the other hand, the Portuguese State guarantees the producer a revenue equal to 90% of the income received by applying the prices in the start-up year. The revenue is guaranteed during the payback period or during the first 8 years of exploitation (Cerveny et al 1998, p.16).

For grid power connections of up to 10 MVA, the monthly feed-in tariff is fixed on the basis of the high voltage tariff paid by clients supplied by the same grid and follows, in general, the principles of the two-part tariff:

1) The power feed-in tariff is a function of the medium voltage level price and of the energy delivered in the peak and day hours
2) And the energy feed-in tariff is that paid by the end-user in the medium voltage level (op. cit.).

Investment subsidies and other measures

Other incentives include subsidies for construction costs. The financial support framework provides incentives of up to 40% of capital investment in renewable projects. There are also direct capital investment grants and loans, fiscal incentives for the final use of renewable energy equipment and R&D measures

Loans and grants covering investment costs

Reimbursable zero-interest loans of up to 40% of capital investment costs are available for renewable energy projects that qualify as public infrastructure (public grid-connected projects with total investment costs above a certain ceiling). Also, in the framework of the SIURE programme[17], renewable energy projects are eligible for grants of up to 40% of the total investment cost. A reduced VAT rate applies to purchases of renewable energy equipment.

[17] SIURE is the national system for supporting energy projects outside the domestic sector, including renewables.

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M. SPAIN

M.1 Energy sector

M.1.1 General overview

The Spanish energy sector reveals four main characteristics clearly differentiated from the European Union average: (1) higher weight of imported primary energy from abroad, (2) lower primary energy consumption of natural gas, (3) greater share of electricity generated through hydro and wind power and, (4) a higher use of solid sources and lower use of natural gas in the thermal production.

The weight of imports over primary energy consumption in Spain is close to 70%, while the EU average only represents 50%[18].

The second characteristic concerns the fuel-source distribution of the Spanish gross inland consumption. In 1996, the oil share over total consumption represented 53.8%, over 12 per cent above the EU average, while the same figure for natural gas was only 8.6%, more than 12 percentage points below the EU average. The energy dependency problem in Spain becomes clear in Table M.1, which shows the shares by fuel-type of the gross inland consumption in Spain and in the European Union as a whole.

Table M.1 *Percentage distribution of gross inland consumption by fuel type [%]*

1996	Solids	Oil	Natural Gas	Other[1]
European Union	16.7	41.5	21.4	20.4
Spain	16.3	53.8	8.6	21.3

[1] Hydro and Wind energy, net electricity imports, and other sources, such as nuclear power are included.
Source: Annual Energy Review. Energy in Europe. European Commission.

Another differentiated characteristic comes from the electricity sector, where hydro and wind generation is more than 10 percentage points over the EU average. This advantage provides a relative saving of more than 7 percentage points of thermal generation of electricity with respect to the EU average. Table M.2 shows the electricity distribution by fuel type.

Table M.2 *Share of Electricity Generated by source [%]*

1996	Nuclear	Hydro & Wind	Thermal
European Union	35.3	13.0	51.7
Spain	32.4	23.5	44.1

Source: Annual Energy Review. Energy in Europe. European Commission.

Finally, the fourth characteristic explains the main reason for the deficit in the use of natural gas mentioned before. Spain barely uses 6.4% of natural gas in the thermal generation of electricity, 14 percentage points below the EU average. This is compensated by a similar increase in solid fuels. Table M.3 shows the shares by fuel type of the thermal generation of electricity.

[18] COM (97) 599, 'Energy for the future: Renewable Energy Sources - White Paper for a Community Strategy and Action Plan'

Table M.3 *Thermal Electricity Generation by Fuel-type [%]*

1996	Solids	Oil	Natural Gas	Geothermal & Biomass
European Union	60.0	15.2	20.3	4.5
Spain	74.8	15.5	6.4	3.2

Source: Annual Energy Review. Energy in Europe. European Commission.

The efforts in the development of hydro and wind power, and in the nuclear moratorium are satisfactory from an environmental point of view, but they may suppose a serious problem in the energy sector liberalisation process. This problem may be aggravated by the fact that the gross inland consumption in Spain grows at a rate of 0.7 percentage points above the EU average, and that the increase in electricity generation and demand is, respectively, 0.4 and 1.0 percentage points[19] greater than the mentioned average. The last data from 1997 confirms the relevance of these growth differences in the gross inland consumption, the period 1990-97 reveals a 0.7 percentage point increase over the 1990-96 period[20].

Spain exceeds the EU average in 0.9 percentage points in gross inland consumption/capita; 0.7 percentage points in the gross inland consumption/GDP; 0.6 percentage points in electricity generated/capita and 1.7 percentage points in the annual CO_2/capita emission index. The forecasted long stagnation of the Spanish population growth rate (0.2% vis-à-vis the 0.4% EU average) will surely enhance the above mentioned disparities among the indicators. However, in 1996 the CO_2/capita emissions in Spain barely represented 70% of the EU average figure.

The evolution in gross inland consumption and in the industry sector are summarised by the indexes of Tables A.13.4 and A.13.5. It can be shown that the stronger dependence in oil imports of Spain, compared with that of the EU has been increased in the 1990-96 period. It can also be shown that the deceleration rate in the use of solid fuels is proceeding at a lower pace in Spain (1.6 percentage points below), and, likewise, that the growth rate of natural gas is greater in Spain than in the average EU countries.

Table M.4 *Growth rate in Gross Inland Consumption by Fuel-type [%]*

1990-96	Total	Solids	Oil	Natural Gas
European Union	1.3	- 4.0	1.3	5.4
Spain	2.0	- 2.4	2.9	9.7

Source: Annual Energy Review. Energy in Europe. European Commission.

Moreover, in connection with energy consumption in the Industry sector, Table M.5 shows that total consumption has increased in Spain in the 1990-96 period, while it has mildly decreased in the EU. This has been partly due to the 0.7 points of reduction in energy intensity in the EU. It is, however, very plausible, that in the future Spain proceeds following a similar energy intensity path.

Table M.5 *Final energy consumption growth rate in the industrial sector [%]*

1990-96	Total Consumption	Industrial Production	Energy Intensity
European Union	- 0.2	0.5	- 0.7
Spain	0.6	0.3	0.3

Source: Annual Energy Review. Energy in Europe. European Commission.

[19] The three indexes are annual averages and comprise the period 1990-96. From this point on, all average annual data refers to this period.
[20] International Energy Agency (IEA).

M.1.2 Electricity sector

The electricity sector in Spain is regulated by the law 54/1997 and its several additional dispositions. This law provided a structure in compliance with EU directives and with competitive markets. In this 'new' structure (see Figure M.1), 'Red Electrica de España (REE)', that had been in charge of the technical aspects of operation, as well as of the administrative procedures of the market (supply and demand), was left only with the technical responsibility of the System Operator. 'La Compañía Operadora del Mercado Español de Electricidad (OMEL)', a new company, was created to act as the market administrator, therefore becoming responsible for all the financial transactions associated with the production, transport & distribution of electricity. A relevant independent public body in the sector is 'La Comisión Nacional del Sistema Eléctrico (CNSE)'. Created under the law 40/1994, and further validated by law 54/1997, the essential mission of the CNSE is to look out for compliance with effective competition, transparency and objectivity in the functioning of the electricity system.

Finally, another important development of this law, and relevant for InTraCert, was the obligation to clearly separate the supply side of the market (producers) from the demand side (distributors). By doing so, it not only made access to the market more competitive, but it also facilitated supervision, and made governmental measures such as subsidies to production, fixed premiums and feed-in tariffs more effective.

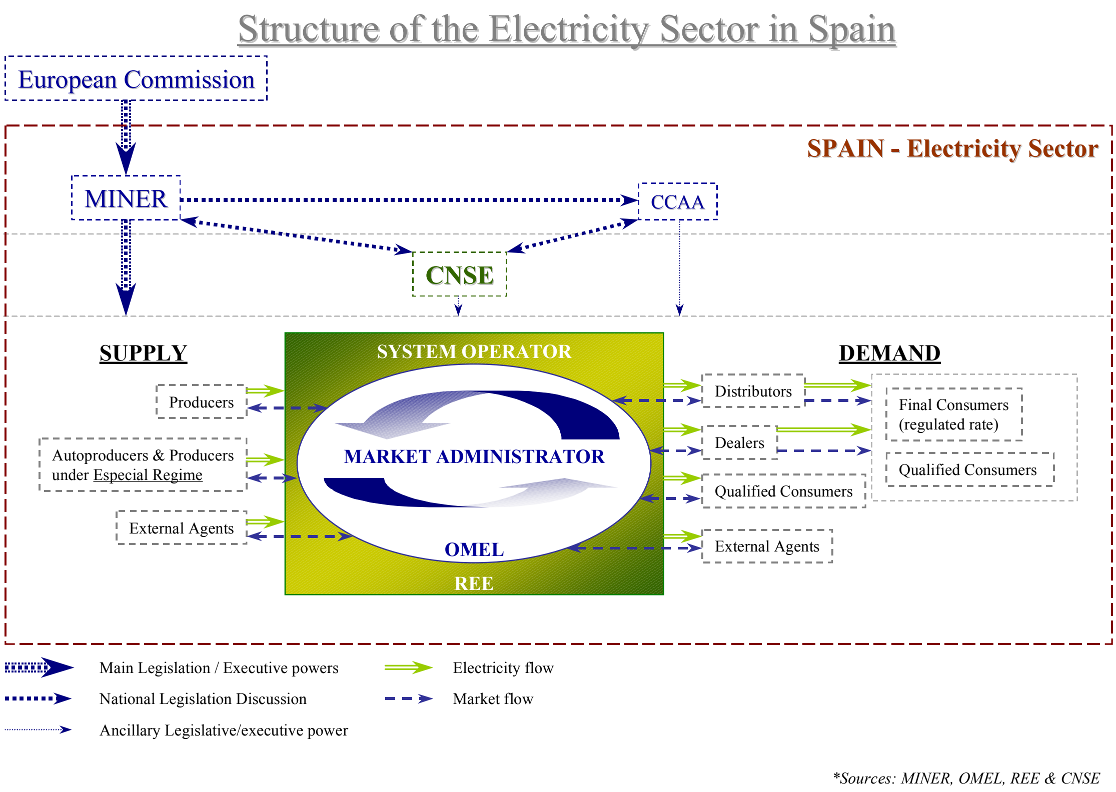

Figure M.1 *Structure of the Electricity Sector*

Figure M.1 graphically represents the structure and functioning of the electric system in Spain. First of all, the main legislative and executive powers regulating the system are pointed out (European Commission, Ministry of Industry and Energy (MINER) and the Autonomous Communities (CCAA)). Second, the actors involved directly in the process of generation, distribution and final consumption of electricity are described. In order to do so, the market is divided into supply side (producers, auto-producers under especial regime and external agents), administrators (CNSE, REE & OMEL), and demand side (distributors, dealers, qualified consumers and external agents). Final consumers, as well as some qualified consumer are the last actors in the electricity supply chain, and subject to regulated electricity rates.

The greater increase in electricity generation in Spain, for the period 1990-96, compared to the EU average, is revealed in Table M.6. The major increases in hydro and wind electricity generation are significant in Spain (7.7%), compared with the EU average (2.2%). Nuclear power has been kept under control by Spanish authorities, so that, for the mentioned period, it has only grown by 0.6%, while the EU average presents an increase of 2.8%.

Table M.6 *Increase in electricity generation for the period 1990-96 [%]*

Period 1990-96	Total	Nuclear	Hydro & Wind	Thermal
European Union	1.9	2.8	2.2	1.2
Spain	2.3	0.6	7.7	1.2

Source: Annual Energy Review. Energy in Europe. European Commission.

Thermal power generation structure by type of source presented in Table M.7 shows a decrease in the use of solid fuels, mainly coal, and its substitution by natural gas. In the case of Spain, it is noticeable the large increase in biomass (34.8%) compared to the EU average (7.8%). Furthermore, while the EU average shows a decrease in the use of oil as an input to thermal power generation, in the case of Spain there is an increase of 3.8% for the same period.

Table M.7 *Increase in Thermal Power Generation by type of Fuel [%]*

Period 1990-96	Total	Solids	Oil	Natural Gas	Geothermal	Biomass
European Union	0.3	- 1.6	- 0.4	6.8	3.9	7.8
Spain	1.0	- 0.8	3.8	15.1	0.0	34.8

Source: Annual Energy Review. Energy in Europe. European Commission.

M.1.3 Gas sector

Among biodegradable wastes, three different groups are worth to mention: farm wastes, industrial wastes and the organic part of RSU (urban solid wastes). The development of biogas facilities faces economic and financial barriers. The spills, which define profitability thresholds, are 100,000 tons/day for industrial and farm wastes and 225 tons/day for RSU. Apart from this quantitative restriction, there is a technological constraint that relates to the technical difficulties of this type of facilities: maintenance requirements are well above knowledge of the agents involved in the sectors generating the wastes.

The promotion of biogas facilities is a measure adopted in the framework of the European regulations relating to methane emissions reduction (COM (96) 557, November 15th 1996). Concerning farm wastes, the pertinent regulation is the Wastes Law 10/1988 that envisages the arbitration and management of the treatment by the public administration as a function of the volume of exceeding wastes of each farm. For RSU, the new law determines specific objectives and terms for the burning of urban landfill gases. Other set of measures are on the way as well, such as the implementation of biodegradable spills and waste management plans on the part of CCAA (notably, preliminary plans and demonstration projects) and investment support by the public authorities. Consumption of biogas reached 83,000 Toe (2.3% of total biomass consumed) by the end of 1998.

M.1.4 Heat sector

CHP in Spain has focused, mainly, on the refining and food industries and on the provision of electricity. It has been envisaged lately that CHP contributed to water desalinisation and purification. Energy could also be provided to large hospitals. The regulatory framework is defined by the Law 40/1994 (relating to the reorganisation of the electricity sector) and the already mentioned 2366/1994 and 2818/1998 (electricity production) Decrees.

Electricity generated through CHP is rewarded in three ways:
- Financial payment from the market operator for producing electricity, including a power guarantee and complementary services.
- Compensation for the transition costs to competition (TCCs) according to the concepts of 'general' and 'specific' allocation. This retribution will eventually end when the objective of market liberalisation is reached (in seven years time).
- Implicit subsidy. Granted for three reasons: consumption of national coal, technological incentive or electricity of 'special' regime.

The objective to be covered by CHP facilities by the end of this year is 2800 MW. In 1999 the energy produced (16,000 GWh) has increased by a 22% in relation to 1998. This figure represents 2/3 of energy produced by special regime sources.

M.2 Liberalisation process

M.2.1 Introduction

The energy sector is undergoing a transformation process leading, eventually, to an improvement in its competitiveness level, both, in terms of prices and quality. In this context, the Government signed a Protocol with the electricity utility companies in 1996 with the aim to increase competition in the sector and to reduce costs of the production inputs. This Protocol follows the instructions contained in the European Union Directive 96/62/CE.

The introduction of competition in the energy market has been carried out through the separation of the property, transport and service infrastructure, which, previously, had a monopoly structure. Nowadays, market forces play an increasing role in the distribution of electricity and gas by freeing the access to the electricity grid (after payment of a toll). This has improved the operation and control of the market.

A significant increase of the contribution of natural gas to the primary energy balance is envisaged. This will be achieved through the progressive penetration of this source, reaching 12% of electricity generation by the year 2000. The recent commissioning of the Algeria-Europe gas pipeline contributes to this objective.

In the oil sector, the medium term goal is to achieve greater deregulation and competition in the market. This is quite advanced thanks to the Law for reorganisation of the sector and the associated detailed regulations.

In the coal sector, negotiations between the Ministry of Industry and Energy and the various social agents involved have concluded with an agreement, the so-called 'Coal Mining and Mining Communities Alternative Development Plan'. This Plan, which covers the period ranging from 1998 to 2005 aims to achieve a competitive production with costs approaching international market levels. However, social and regional problems and concerns derived from its application are taken into account, much in line with the European Union policies for the coal sector.

The main measure taken in the energy sector is the Energy Conservation and Efficiency Plan, which basic object is to increase the efficiency of the energy system. Four programs were approved in order to implement such Plan (the Saving, Substitution, Cogeneration and Renewable Energies Programs). They aimed at stimulating end-use energy substitution and saving while encouraging certain highly efficient alternatives for production, even though these alternatives faced difficulties to gain market share. This Plan covers the period ranging from 1991 to 2000.

Plans for the transport sector are based on the encouragement of less pollution intensive (public) means of transport, especially in urban and metropolitan areas. Tax exemptions for railway diesel fuel were approved. This made railway transport more attractive in relation to road transport and, furthermore, led to an increase in support of diesel compared to electric traction. Finally, an energy certification system for buildings was established. It was based on the administrative and technical requirements set for buildings, especially concerning energy saving, thermal insulation and air conditioning.

M.2.2 Electricity liberalisation

Using the 1994 Electricity Law (LOSEN[21]) as a starting point, the public administration and the Spanish electricity firm went through a negotiation process in 1996 that culminated in the signing up of the ‘Protocol for the Setting up of a New Regulation of the National Electricity System’. This Protocol included a package of liberalisation and competition measures that served as a reference for the later elaboration of the New Electricity Sector Law.

In 1997, the basic regulations that made possible the implementation of the New Electricity System were approved. These were the 1997 Electricity Law and the 1997 Decrees[22] on fees, transport cost liquidation, distribution and trade, points of measure of consumption of electricity and functioning of the production market.

The liberalisation process is not a mere transformation of the electricity system, but implies the setting up of a new framework with different rules of the game concerning electricity production activities, transport, distribution and commercialisation. This leads to a whole new system.

The main elements in which the liberalisation process of the new electricity system is based could be summarised as follows (UNESA 1997, p.15):
1). Freedom of construction of new electricity generating plants. In the new electricity system any firm may install new electricity facilities (with the preferred features), having only to comply with the general restrictions established by Spanish regulation for setting up any other industrial facility.

2). Competition between electricity generators in an electricity market based upon a system of competitive bids of electricity. The functioning of the electricity production facilities is the result of supply and demand forces daily interacting in the market. Electricity plants communicate the quantity and price conditions at which they wish to sell their electricity. This is different from conditions under the previous system in which the daily functioning of electricity plants was determined by REE[23] according to the criteria of energy policy set by the Ministry of Industry and Energy. Those in charge of units with production capacity over 50 MW of power have an obligation to present selling offers of electricity in the production market, while this is not compulsory for those with less than 50 MW. These later units include both, auto-producers (with surplus electricity) and agents from foreign electricity systems taking or delivering electricity from/to the Spanish system.

Generators, distributors and ‘qualified consumers[24]’ may demand energy in the market through buy offers. Also, physical bilateral contracts between generators and external agents on one hand, and ‘qualified consumers’ on the other, are possible. These supplying contracts are mutually agreed between both parties and do not need to go through the competitive bid production market.

[21] LOSEN=Ley de Ordenación del Sistema Eléctrico Nacional.
[22] Decrees number 2016, 2017, 2018 and 2019.
[23] REE=Red Eléctrica Española.
[24] In the new system, ‘qualified consumers’ are those clients that have the possibility to choose supplier and do so. The rest obtains the electricity on the basis of fees approved by the public administration.

3). Freedom of the consumers to choose the electricity supplier that best fits their interests after negotiation of the conditions and price of kWh. The application of this right takes place progressively. For the moment, only consumers with an annual consumption over 9 million kWh (since 1/1/2000) may do so[25]. It is envisaged that in 2007 all consumers will be able to choose the supplier they prefer.

4). Freedom of electricity trade. Supply of electricity through contracts with qualified consumers is a liberalised activity. However, agents are not allowed to simultaneously undertake regulated activities (transport or distribution) if they are undertaking unregulated activities (generation or trade) and vice versa. Both activities have to be done by different firms, although they may belong to the same corporate holding.

5). Freedom of access to electricity distribution grid and transport network. The new system is based on the maintenance of a single transport and distribution network in each territory while at the same time recognising the right of every agent to freely access the system at a reasonable, non-discriminating, price.

6). Freedom to buy or sell electricity to firms and consumers belonging to other European Member States. All producers, distributors, trade firms and qualified consumers are authorised to buy or sell electricity directly to or from any Member State[26].

Concerning fees, prices and costs in the new electricity system, it is worth mentioning that two types of prices coexist. On the one hand, those freely set up in the production market and on the other, those fixed by the government through regulated tariffs. ‘Qualified consumers’ pay either one of these two prices: (1) the price freely agreed with the supplier or (2) the price stemming from the competitive system and, also, ‘an access to the market’ fee set up by the public administration that covers several cost items[27]. ‘Non-qualified consumers’ pay the electricity according to the fees fixed by the administration, which cover several cost items as well[28].

On the other hand, the 54/1997 law fixes the financial quantities to be perceived by electricity firms for the period 1998-2007 as ‘transition to competition costs’. All consumers pay these.

M.3 Renewable energy activities and policies

M.3.1 Renewable energy status

Renewable Energy policy in Spain has been recently summarised in the new ‘Plan de Fomento de las Energías Renovables’ (RE promotion Plan)[29]. It has been jointly developed by the central, autonomic and local administrations to promote the deployment of RE. In order to implement it, the necessary economic and fiscal measures to overcome the technical and marginal cost barriers have been identified. Table M.8 summarises this measures grouped in three main blocks: fiscal, structural and barrier removal.

[25] The first stage of the liberalisation process in this context took place in 1/1/1998. Since that date, large consumers (consumption over 15 million kWh) could in fact choose their supplier.
[26] The authorisation may be denied if reciprocity is not respected, that is, if the Member State in question does not recognise their respective agents the same ability to make contracts.
[27] These include the costs of using the transport and distribution networks, the so-called ‘permanent costs of the system’ and the ‘diversification and safety of provision costs’.
[28] Including electricity production costs, tolls for transport and distribution of electricity, commercialisation costs and ‘permanent costs of the system’ and ‘diversification and safety of provision costs’.
[29] IDAE & MINER (1999). Plan de Fomento de las Energías Renovables en España.

Table M.8 *Incentives and Measures for the promotion of RE*

Type of Measure	Description
Fiscal	Company Tax deductions for investments in RE projects
	Company Tax deductions for research in RE
	Fiscal Incentives for SME's investing in RES use
	Fiscal exemption for biofuels
Structural	Harmonisation of requirements for environmental impact projects
	Wind utilisation levy in favour of Municipalities
	Authorisation and concession for the private use of the hydraulic resources
	Promotion of solar panel integration in buildings
	Connection to the low-tension electric network for Photovoltaic plants
	Simplification of the procedure to access Especial Regime conditions in the electricity network
	Redistribution of premiums in the electric sector for plants under the Especial Regime using specified technologies
Barrier removal	Incentives to investments in technological innovation in RE
	Public Funds to promote the new RE Plan
	Finance Instruments creation to adapt projects to the new RE Plan
	Risk guarantee costs discounts for SME's by reciprocal guarantee companies

Source: IDAE & MINER (1999)

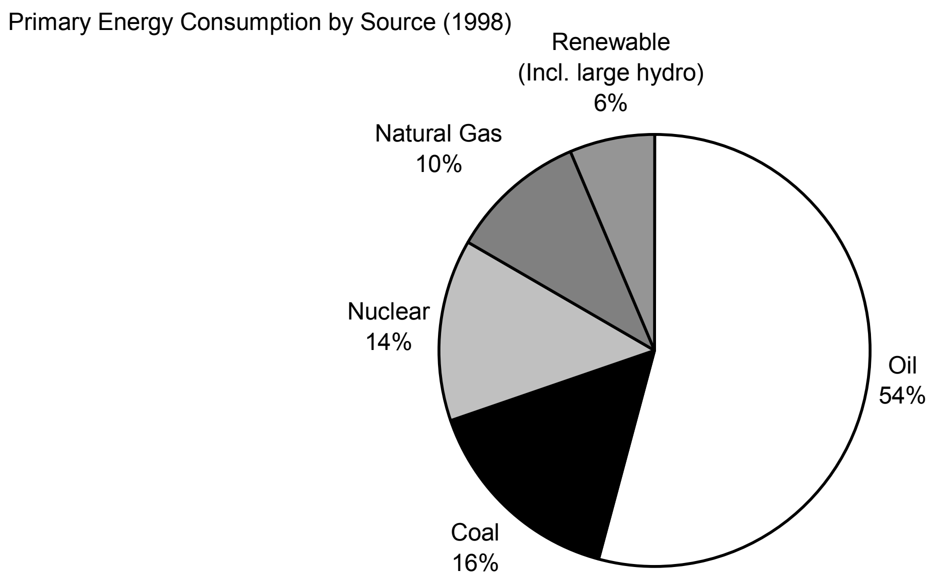

Figure M.2 *Primary energy consumption by source (Source: IDEA & MINER 1999)*

The Plan is based on the 1998 energy situation, where the RE contribution to primary energy consumption was 6.3% (hydro plants > 10 MW included), or 4% (excluding large hydro).

Depending on the use given to the energy produced, RE may be divided into two big blocks: electricity production and thermal production. Electricity production accounts for 51.1% of the energy produced from RES, while thermal production accounts for 48.9%.

Table M.9 *Electric and Thermal energy production with RE in Spain (1998)*

Production	Type	[MW]	[GWh/year]	[ktoe]
Electricity	Hydro > 10MW	16220.9	30753.4	2644.8
	Hydro < 10MW	1509.7	5607.0	482.2
	Biomass	188.8	1139.1	168.6
	Solid Waste	94.1	585.8	247.0
	Wind	834.1	1437.0	123.6
	Solar Photovoltaic	8.7	15.3	1.3
Total Electricity		18856.3	39537.6	3667.5
Thermal	Biomass			3476.2
	Solar thermal			26.3
	Geothermal			3.4
Total Thermal				3505.9
TOTAL				7173.4

Source: IDAE. Consultative Commission on energy saving & efficiency.

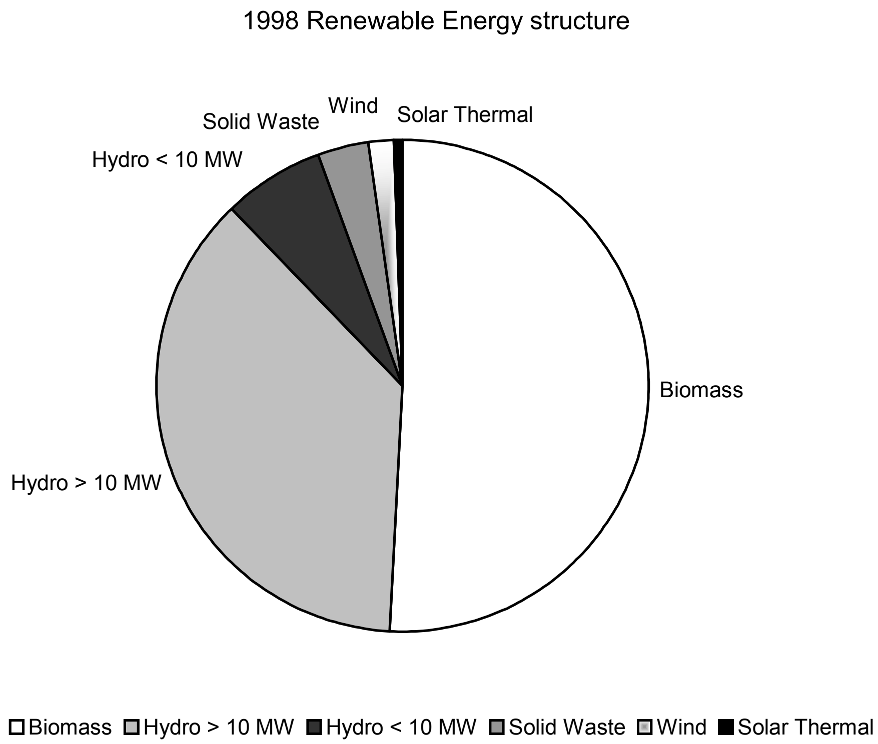

Figure M.3 *RE structure (Source: IDEA & MINER 1999)*

In 1998, 7.173 ktoe of RE were produced in Spain. Figure M.3 presents the structure of this production by type of renewable source. It is observed that biomass (50.8%) and hydro (43.6%) are the technologies quantitatively more important, representing the rest of RE forms a contribution of 5.6% to total production of RE.

The electric sector in Spain is responsible for 90% of SO_2 & NO_x emissions from big combustion plants. Furthermore, it produces 25% of total CO_2 emissions and it is responsible for most of the radioactive residues. In this context, the sixteenth transitory disposition of the law 54/1997, regulating the electricity sector in Spain, establishes a National Plan for the promotion of renewable energy. The main objective of this plan is similar to the one proposed by the 'White Book' of the EC; that is, in the year 2010 the renewable energy sources must cover, at least, 12% of total energy demand. This means, in the case of Spain, that the actual share of RE in primary energy consumption (6.3%) must double during the indicated period.

The share of RE in total generation of electricity in Spain is 4.5% (see Figure M.4). However, if large hydro is included this share goes up to 20%. The quantitatively most important sources are coal (32.5%) and nuclear power (30.2%). In the case of coal, the subsidies to mining due to the severe structural problems faced by the coal sector, with its socio-economic implications (job losses...) are greatly responsible for this situation.

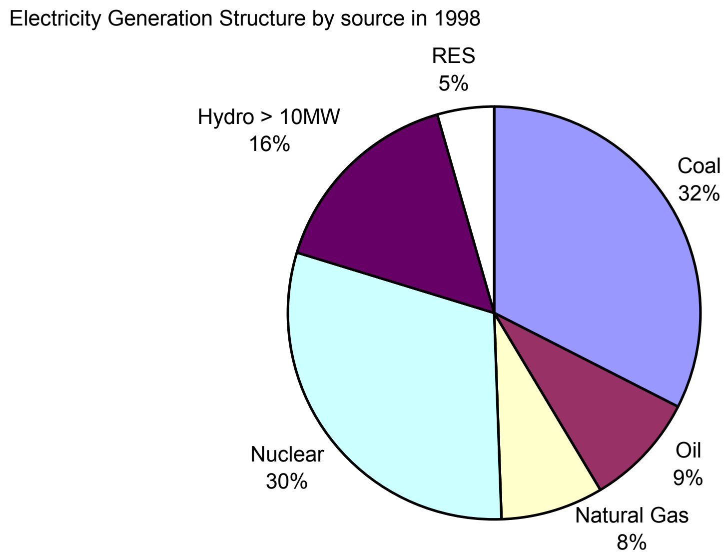

Figure M.4 *Electricity generation by source (Source: IDAE & MINER 1999*)

As pointed out before, in the case of the Spanish electricity system, the promotion of RE is organised through a system of premiums. As shown in Table M.10, these premiums are dependent on the technology used and on the installed capacity provided by it[30]. This system has proven its ability to successfully promote renewable energy in the electricity sector. In this sense, these premiums, which are indirectly paid by all consumers, locate Spanish residents among the 'greenest' of the EU.

[30] The premiums are regulated by the RD 2818/1998

Table M.10 *Fixed Premium value under the Especial Regime*

1998		Premium (10^{-2} €/kWh)	Total Price[1] (10^{-2} €/kWh)
CHP	< 10 MW (10 years)	1.92	5.38
	> 10 MW y < 25 MW (CTC)	1.92/0.96	5.38/4.42
Primary Biomass		3.05	6.51
Secondary Biomass		2.82	6.29
Wind		3.16	6.62
Hydro	< 10 MW	3.27	6.73
	> 10 MW y < 50 MW	3.27/0.00	6.73/3.46
Solar Photovoltaic	< 5 kW	36.06	39.67
	> 5 kW	18.03	21.64

[1] Average Market Price (3.4610^{-2} Euro/kWh) + Premium.
Source: MINER

Regarding the structure of the price paid by electricity produced under the Especial Regime, the average premium price paid was 1.6 Eurocents kW/h in 1999, while the competitive market price for electricity was 3.7 Euro cents kW/h. Furthermore, the transition costs paid to distributors accounted for 0.6 Euro cents kW/h. Figure M.5 shows the average price structure for energy produced under the Especial Regime, which includes the above mentioned sources.

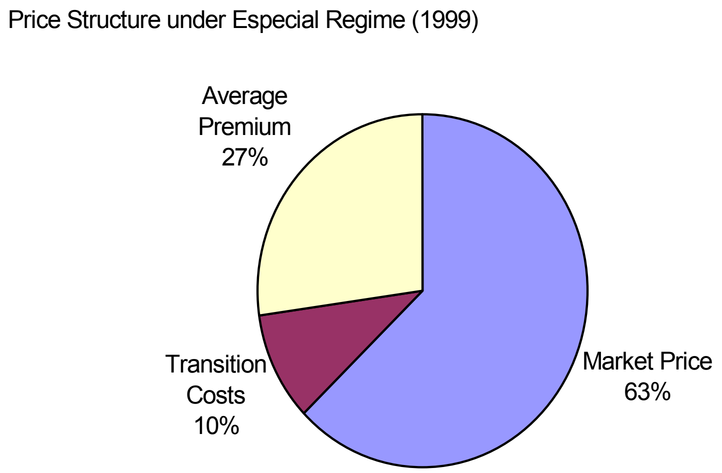

Figure M.5 *Price structure under especial regime (Source: CNSE 1999)*

Table M.11 presents the price paid to Producer under the Especial Regime during the first semester of 1999. Furthermore, it shoes the energy produced in MWh (10^3 kWh), and the hours of full power generation.

Table M.11 *Electricity generation by source under Especial Regime (1st semester 1999)*

Source type	Energy [MWh]	Full Power generation (h)	Price (10^{-2} Euro/kWh)
CHP			
Coal	56.477	142 (19%)	4.5
Fuel-oil	1,816.603	393 (53%)	5.9
Natural gas	5,250.156	382 (51%)	5.5
Refinery Gas	559.098	350 (47%)	4.7
Siderurgical Gas	19.673	234 (31%)	3.0
Gas-oil	259.192	254 (34%)	7.6
Propane	7.606	186 (25%)	7.7
Residual Heat	54.524	230 (31%)	6.1
Renewable			
Solar	0.779	116 (16%)	19.1
Wind	1,152.559	221 (30%)	6.7
Hydro < =10MW	1,371.905	315 (42%)	6.7
Hydro >10MW	696.211	247 (33%)	6.9
Biomass	21.646	111 (15%)	5.9
Biogas	26.367	379 (51%)	6.1
Residues			
Residual Gas	14.926	493 (66%)	6.1
Farm Residues	35.731	427 (57%)	6.7
Oil residues	13.769	544 (73%)	5.9
Urban solid waste	283.246	471 (63%)	5.9
Industrial Residues	269.995	371 (50%)	5.0
Purines (Natural Gas)	14.871	203 (27%)	6.3
TOTAL	11,840.335	331 (45%)[1]	5.9[1]

Source: CNSE (1999)
[1] Average values

M.3.2 Renewable energy policy

The promotion policies of renewable energy in Spain are based on the European Council Decision of Sept. 3rd 1993, and the Altener Project. The Autonomous Communities, or regions, are in charge of distributing the financial support and the determination of the corresponding specific requirements.

In general, the CCAA regulations apply subsidies to investment projects in RE, and also to energy saving schemes and environmental improvement practices. The subsidies may be applied to all RE (solar, thermal and photovoltaic, wind, biomass[31] and hydro with an installed capacity up to 10 MW[32]), to energy saving projects through a more rational and adequate use of energy and environmental improvements by switching fuel sources.

The law 40/1994 of 30 December regulates the procedures to promote the free access to the electricity production under Especial Regime[33]. The Real Decree (RD) 2366/1994, of 9 December, modified by the RD 2818/98, establishes the requirements to produce electricity under the especial regime and the inscription in the corresponding registry. Two procedures can be identified:

a) Tendering procedures. Authorisation issued to competing projects on the basis of their technical quality, socio-economic impact, and geographic & environmental concerns.

[31] The Autonomous Community of Cataluña has been the only one that has regulated the use of forestry Biomass for the production of energy. This has been done through the Decrees 75/83 & 75/86.
[32] The Autonomous Community of Navarra puts an upper limit of 5000 kW of installed capacity to receive subsidies.
[33] The Especial Regime contemplates the generating systems that operate using CHP, RE & Solid wastes and residues.

b) Authorisations issued to projects without a tendering procedure.

The wind power plants are forced to minimum energy efficiency levels, depending on the Wind objectives for RE Plans (of the CCAA and the National Energy Plan), the wind-turbine efficiency, the wind characteristics of the terrain and the existence of other wind power plants in the zone.

Each wind power plant ought to have two plans: (1) Preventive maintenance, (2) Stock administration. These plans are to be submitted to the Ministry of Industry and Energy, for their approval and the monitoring of compliance. Furthermore, there is the obligation that the maintenance of the plant has to be under the responsibility of a recognised firm.

Concerning solar energy, the Canary Islands and ‘Andalucía’ have been the only CCAA that have disposed subsidies for thermal installations (Domestic Heating...).

N. SWEDEN

N.1 Electricity sector

Sweden is a country with a very high electricity intensity; the specific consumption of electricity was 17,700 kWh per capita in 1996 (whereas the EU average ranks at about 8,800 kWh per capita). The main reasons for the high demand are the relatively cold climate and a widespread use of electrified comfort heating, and the relatively high proportion of energy-intensive industry.

Table N.1 *Basic energy indicators for Sweden*

		1997	1998
Population	[Million]	8.9	8.9
GDP (Bil. Euro 1990)		553	590
Gross Inland Primary Consumption	[Mtoe]	51.6	52.7
Total Electricity Production	[TWh]	149.5	157.4
CO_2 emissions	[Mt of CO_2]	61.6	61.2
Total EU Primary Consumption	[Mtoe]	1417.9	1449.6
Share in EU (GIPC/TEUPC×100)	[%]	3.6	3.6
Gross Inland/GDP	[%]	9	9
Gross Inland/Capita	[toe]	6	6
Electricity Generated/Capita	[kWh]	16878	17757
CO_2 emissions/Capita	[t CO_2]	7	7

Source: NRD 3.0.1. - database.

The Swedish electricity production is characterised by the combination of nuclear power and hydro power plants. In 1998 the production by nuclear power accounted for 46% (71 TWh) of total electricity production (see Table N.2). Hydropower production amounted to 74 TWh or 48% of total electricity production. The remaining share of only 6% is produced by CHP generation, condensing plants (mainly oil-fired), gas turbines or wind power.

Table N.2 *Total electricity generation in 1998 by energy source, 1998 TWh*

	[TWh]	[%]
Wind power	0.3	0.2
Biofuel	3.3	2.1
Natural gas	0.6	0.4
Oil	3.0	1.9
Coal	3.0	1.9
Nuclear power	70.5	45.6
Hydropower	73.7	47.8
Net exports	10.8	

Source: NordEl Statistics 1998.

There is a large number of electricity producers and distributors but they differ considerably in size. Power plants can be owned by the State, by local authorities, by industry or by commercial utilities. In 1997, seven large power companies together produced 92% of total electricity output and the two largest producers, Vattenfall and Sydkraft, accounted for 70% of the total production.

Concerning the (liberalised) generation, no specific license or tendering procedure is needed, but environmental and planning legislation apply. The transmission system operator, the national grid company Svenska Kraftnät (a state public entity created in 1992) is protected by the Swedish constitution which contains rules that protect its independence and prohibits government intervention in its decision-making. The distribution system operators are responsible in a given area and in order to be allowed to build and manage an electricity network they have to apply for a concession either for a service area or line operation from the State Energy Authority.

In June 1997 the Swedish parliament (Riksdagen) adopted new energy policy guidelines, with an objective to safeguard the availability of electricity and energy from renewable energy sources on terms that are competitive with respect to the deregulated electricity market.

According to the decision, phasing out of nuclear power should also be started, allowing the Government to decide when a permit to run a nuclear reactor for energy production will be discontinued. This law became effective in January 1998. One nuclear reactor has been taken out of service in July 1998 and another one is scheduled to be closed down in July 2001.

A comprehensive energy policy programme was started with the aim of facilitating the transition in the supply and utilisation of electricity and other forms of energy.

In 1992, the Swedish State Power Board (Vattenfall) was divided into a new state agency, Svenska Kraftnät, with responsibility for the central grid, and a state-owned power production company, Vattenfall. Thereby, the first step was taken to liberalise the Swedish power market. Sweden passed a new Electricity Act on January 1st 1996.

The Swedish electricity market reform in 1996 demanded full organisational separation of the grid on the one hand and sales and production services on the other. The reform included a separation of the high-voltage transmission system from the state power company Vattenfall. Now the national grid is administered by a new state company, Svenska Kraftnät. For the regulation of the high-voltage grid, Svenska Kraftnät relies heavily on operators working on a contractual basis, especially on Vattenfall. The low voltage grid is regulated by NUTEK (an extra ministerial authority).

This market reform replaced a former planned-economy system which consisted of decentralised regional monopolies, supplemented by state-company engagement (especially on the production side). The reform opened up common carriage and third-party access for all domestic networks (national, regional and local). The main part of the electricity systems remains under public control. The pricing of grid access is based on point tariffs, coupled to a geographical differentiation, which are related to regional generation deficit or surplus (implying that producers face relatively high tariffs for electricity input in the north of Sweden and low tariffs in the south).

The Swedish property laws for power companies are open for private investors. The major power companies are still mainly owned by the Swedish state or municipalities, but even foreign companies have been able to buy up Swedish companies.

Sweden, which is supplied equally by hydropower and nuclear power, was relatively easy to integrate with the Norwegian system applying the Norwegian institutions. From 1996 Nord Pool became a common non-mandatory power exchange for Sweden and Norway, and the two countries have almost harmonised their trading rules. Nord Pool is the first bi-national power exchange in the world. Swedish used the Norwegian Bourse as a stepping-stone towards a common Nordic system.

Since the 1996 electricity reform, all customers are allowed to choose their suppliers. But in fact especially small customers and private households were hindered to take advantage of this free market access for the reason of high transaction costs. In order to increase the possibilities for smaller consumers to buy electricity on the free market, a price ceiling was introduced in 1997 for the metering equipment required for buying electricity from other suppliers than the local utility.

N.2 Renewable energy activities and policies

Renewable energy sources covered 39% of Swedens energy supply in 1996 (including Combustible Renewables & Wastes). After Norway, Sweden has the second largest share of renewable-based energy supply in all IEA countries.

Renewable Electricity Production (RES-E) in Sweden is clearly dominated by large hydro plants. Hydropower facilities have a total capacity of 16.2 GW, equivalent to 48% of the total generation capacity in Sweden. In total RES-E counted for 77.3 TWh in 1998 or 50.1% of the total electricity production (see Table N.2).

In June 1997 Sweden made a political decision (The Energy Policy bill 1997) to increase RES-E by 1.5 TWh per year over a five year period. Focus is mainly on Bioenergy CHP, which shall stand for an increase of 0.75 TWh. Wind energy and small-scale hydro shall stand for respectively 0.5 TWh and 0.25 TWh per year. On the heat side of buildings and in district heating, additional use of biofuels shall replace electric power used at present.

Sweden uses both direct investment subsidies and support for procurement programmes for RES-E. The June 1997 Energy Policy bill provides investment support as follows:

- Investment grants administrated by the National Energy Administration are available for *biofuel-fired CHP plants*. The total appropriation for grants is SEK 450 million (M€ 54)[34] for the period between 1997 and 2002. It is expected to achieve an increase of at least 0.75 TWh on the annual electricity generated by biofuel-based CHP plants. The support to CHP production with biofuels is paid at a rate of:
  - SEK 4.000 (€ 482) per kW_e of installed electrical capacity to investments in *new* plants for CHP production with biofuels.
  - 25% of the investment cost for retrofitting of existing heating plants to CHP production with biofuels. The subsidy may not exceed SEK 4.000/kWe of installed electrical output.
  - 25% of the investment cost for conversion of fossil-fuelled CHP plants to CHP production with biofuels. The subsidy may not exceed SEK 4.000/kWe of installed electrical output.

  The actual use of biofuels on an annual basis in both new and retrofitted or converted plants must amount to at least 85% of the total fuel consumption during a period of 5 years.
- Support to investments in *wind power plants* was originally given at 25% of the investment cost, which was later changed to 35%. To qualify for support, the plant has to have an output of at least 60 kW_e.

Furthermore, wind power production receives a production subsidy (environmental bonus) equal to the excise tax on electricity - see Table N.4.

[34] 1€ = 8.3 SEK (April 00).

Also small-scale hydropower is considered investment grant appropriations in the Energy Policy bill from June 1997. The appropriation amounts to SEK 150 million (M€ 18) for a five-year period as from 1 July 1997:

- Investment subsidies (15%) can be granted to all new *small scale hydropower plants* of 100 - 1.500 kW_e.

This measure is expected to be capable of yielding 0.25 TWh of new electricity generation capacity.

Under a transitional regime, regional utilities are still obliged to purchase electricity deliveries from small renewable sources (< 1.5 MW) during a period of five years. The small generators have to conclude contracts with the grid operator. The price paid under the transitional regime is equivalent to the average household tariff, minus the costs for administration and the profit surplus. In 1996, the average price paid to wind power producers was SEK 0.25 - 0.28/kWh (€ 0.030 - 0.034/kWh). This feed-in tariff is supplemented by an environmental bonus from the state budget in the order of SEK 0.11/kWh (€ 0.013/kWh). Small generators are exempted from system charges; but they have to pay a one-off connection charge and annual metering costs to the grid operators.

In January 1998 a seven year programme was initiated. The main purpose is to reduce the costs of using renewable sources of energy and both technical and market development will be supported simultaneously. Furthermore, energy research, development and demonstration will be given additional resources. The measures will be directed especially towards an increased use of biofuels and also towards technology related to wind power, hydroelectric power and heat storage. Over the next seven years a total of SEK 5,280 million (€ 636 million) will be invested in this program, whereas more than 70% of the amount will be invested in energy research and energy technology support promoting long-term development of commercial electricity production from renewable sources.

In response to consumer pressure, green pricing schemes for electricity are being developed. The ELVIRA fund is operated by the largest utility, Vattenfall. The consumers pay into this fund and the sum is spent on renewable energy. Another green pricing scheme is being developed by the Gothenburg utility. The Swedish Society for Nature Conservation proposed to introduce an eco-labelling system for electricity in 1995. Suppliers would have to meet certain criteria (defined by Swedish Society for Nature Conservation) in order to obtain a licence to use the Good Environmental Choice logo. Consumer power could then even influence technical development towards more environmentally friendly products.

Through guarantees from the European Investment Fund one Swedish bank (SwedBank) offers soft loans to green investments by small and medium size enterprises.

In addition biofuels and other renewable sources are (almost) exempted from energy related taxes on heat production (RES-H).

Table N.3 *Fossil fuel taxes 1996*

	Unit	Tax rate	Exemption for biofuels	Exemption for manufacturing industry	Exemption for electricity production
CO_2 tax	SEK/Tonne [€/tonne]	360 (43,4)	yes	75% tax reduction (from July 1997: 50%)	yes
Sulphur tax	SEK/Tonne [€/tonne]	30 (3.6)	yes	no	no
NO_x tax	SEK/Tonne [€/tonne]	40 (4.8)	exemption only for boilers with less than 40 GWh yearly output (1997: 25 GWh)		

Source: Joule project, Swedish country report.

As seen in the table, renewable energy has a competitive advantage due to exempt from taxes - especially in the non-industry sector. The Swedish CO_2 tax is lower for the manufacturing industry than for other sectors. Therefore, it is more beneficial to use biofuels in district heating than in industrial CHP.

Power production (RES-E) on renewable sources has not had the same kind of tax exemptions. Compared with the heat production, there is no CO_2 tax on the fuels for power generation. Instead there is a tax on power itself when delivered to consumers. This has been criticised, since it might be a market barrier for RES-E as these are unable to gain any economic advantage from being CO_2-free.

However, special arrangement has been made for wind power. The end-user tax on electricity is refunded to these producers as an environmental bonus. This has meant gradual increased competitive advantages for wind power, as this end-user tax has been gradually increasing in the last years. In addition, special taxes have been introduced on large scale hydro and nuclear power, which also improve the advantages for new RES-E.

Table N.4 *Environmental bonus to wind power 1996*

	Unit	1996	1997	1998
Environmental bonus for wind power	SEK/MWh	113	138	152
	[€/MWh]	(13.6)	(16.6)	(18.3)
Tax on oldest large scale hydro	SEK/MWh	40		
	[€/MWh]	(4.8)		
Tax on nuclear power	SEK/MWh	22		
	[€/MWh]	(2.7)		

Source: Joule project, Swedish country report.

N.2.1 Market barriers for RES-E

A barrier such as thin grid connections to places with large renewable resources is counteracted by letting the owner of the grid pay for the reinforcement of the existing grid. The RES-E producer shall, like all other power producers, pay the costs of connecting to the nearest technically suitable point of the grid.

Even though Sweden seems to have large renewable energy resources some market barriers may prevent an optimal use of these resources. Several factors have worked against an increased implementation of renewables in Sweden:

1. There has been little need for extra power generation from renewables, since there is excess capacity on the Swedish power market.
2. The cost of RES-E looks prohibitive, since the power prices are low in Sweden and since even households have a considerable use of electricity - compared with other EU member states.
3. Compared with other EU member states, Sweden has a stricter nature conservation regulation that is a barrier for windmills and small-scale hydro.
4. Since nuclear and hydropower (more than 90% of the electricity supply) have been the dominating technologies on the power market, climate arguments for RES have not been effective.
5. There is only CO_2 tax on the fuels for heat production, not on fuels for power generation. Therefore, it might be a market barrier for RES-E as these are unable to gain any economic advantage from being CO_2-free.

N.3 Tradable green certificates

There is currently no discussion about a minimum quota system or about introducing 'green electricity certificates', whereas the Swedish Power Association (Kraftverksföreningen) proposed an international trade system in *Climate Certificates*. The definition of certificates is based on the abatement of greenhouse gases as defined in the Kyoto protocol. This system focuses on GHG emissions, not on renewable power. The intention is to create an open European market for these certificates, with principals and methods of certification governed by an EU directive.

The main idea of the proposal is as follows:

- *Full-value certificates for carbon dioxide-free electricity.*
  Electricity producers with 'no' GHG emissions (e.g. wind power plants) would be allowed to issue climate certificates. 1 kWh of electricity produced without emissions would entitle the producer to issue a climate certificate for 1 kWh.
- *Low CO_2 emissions would entitle to certificates in proportion*.
  Utilities with electricity from power stations having low emissions (e.g. modern natural gas-fired plants) would be entitled to issue certificates in proportion to how much lower their emissions are in comparison with those of conventional coal-fired power stations. The number of certificates would be reduced by an individual coefficient, related directly to the quantity of GHG emissions from the respective plant.
- *Initially, certificates would be traded within the European Union*.
  Certificates would be traded and noted on markets in the various member states but could also be traded across the borders.
- *Certificate trading could become global in the future*.
- *The EU would establish criteria for monitoring the certificates*.
  In accordance with overall EU directives, authorised exchanges would act as certification bodies, checking that certificates have been properly issued in accordance with a corresponding volume of electricity production.
- *Electricity and certificates would be traded separately*.
  Electricity and certificates could be purchased from different suppliers. Both could then be bundled to produce a single product, 'climate-certified electricity'.
- *Climate certificates could be traded between different forms of energy and different markets.*
  To encourage optimisation between different forms of energy it should be possible to issue corresponding, freely exchangeable, climate certificates for other emission-free forms of energy (e.g. bio motor fuels and other biofuels).

While electricity is sold via an electricity exchange or as previously contracted, there would be a minimum quote for the certificates and they would be offered for sale on an authorised trading floor. Electricity and certificates are purchased from an electricity supplier (or some other party). The supplier bundles the two products and creates a new one (which is 'climate-certified'). Then, the climate-certified electricity is sold on to the end-user. The end-user would be able to evaluate and prioritise climate consideration through the selection of electricity products.

Another possibility suggested is to incorporate the cost of the certificates in the normal price of electricity by legislating that all electricity suppliers must purchase certificates corresponding to a fixed quota of their electricity sales (regardless of their actual demand for it).

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O. UNITED KINGDOM

O.1 Introduction

This report describes the current status of the RE sector in the UK, with particular emphasis on the background to the development of the use of Tradable Green Certificates. The report also links this to the emissions of Greenhouse Gases and examines links with the Emissions Trading Scheme currently under development by the UK Confederation of British Industry Advisory Committee on Business and the Environment.

O.2 Energy sector

O.2.1 General overview

The UK has seen a shift in energy use over the last decade or so, mainly away from coal and towards the use of gas (see Table O.1).

Table O.1 *Inland Energy Consumption in the UK [Mtoe]*

	1970	1998
Primary electricity (mainly nuclear)	7.4	25.2
Coal	99.0	41.3
Gas	11.3	85.3
Oil	94.8	74.8
Total	212.5	228.9

Use by sector has also varied, with a rise in 90% of energy use in transport, 25% in domestic energy use and 17% for the service sector between 1970 and 1998. In the same period, consumption by industry has fallen by 44% (see Table O.2).

Table O.2 *Energy Consumption by Sector in 1998 [Mtoe]*

	Industry	Domestic	Transport	Services	Total
Coal & manufactured fuels	4.0	2.2	-	0.3	6.5
Gas	15.2	30.6	-	10.1	55.9
Oil	6.2	3.5	52.9	3.2	65.8
Electricity	9.1	9.4	0.6	7.9	27.1
Total	35.0	46.0	53.6	21.7	156.3

The UK does not have a single Energy Policy document. However, there are several policies concerning energy which can be taken together to form the overall UK approach to energy. The most important policies are the Electricity Act of 1989 and the Gas Act of 1986 which kicked off the process of the liberalisation of the UK's energy market. Recently, the government has carried out consultation on the restructuring of trading arrangements for the electricity market, and has just proposed the final form of the trading arrangements.

On 17th April 2000 it announced a set of subsidies to the coal industry that have been named 'the bail-out for coal'. These will total some £10 million, subject to approval by the European Commission, and are said to be aimed at securing employment within the sector.

O.2.2 Electricity sector

Historical Background

Prior to 1989, the UK electricity supply industry (ESI) was nationally owned and centrally planned and operated. The industry in England and Wales was divided into regional electricity boards, each of which was responsible for generation, transmission and distribution within its own area.

In 1989 the Electricity Act denationalised the ESI and gave regulatory powers to the Secretary of State for Energy. At that stage, the industry was divided into Generation companies and into 12 Regional Electricity Companies (RECs) which were formed around the old electricity supply boards.

Regulation and Legal framework

In 1999, the UK government, after much consultation, published its proposals for New Electricity Trading Arrangements. Although this paper is still theoretically under consideration, it seems that the key features of the new arrangements will be:

1. A forwards market, which will allow generators to establish bilateral contracts with either suppliers or (large) final consumers for the delivery of physical electricity.
2. A short-term power exchange which will operate between 24 hours and 4 hours ahead of time.
3. A balancing mechanism which will operate between 3.5 -4 hours ahead of real time. This will be managed by the National Grid Company.
4. A settlement process to deal with the financial settlement of balancing mechanism trades.
5. It is expected that a derivatives market will develop to allow market participants to manage market risks.

The implementation of these arrangements, to replace the UK pool system, is currently underway.

The government is currently carrying out consultation on the future of gas trading arrangements and has just released a document (February 2000) on further developments in this process.

Current Organisational and Institutional Structure

The UK electricity industry is currently divided into the following sections:

- Generators (companies that produce electricity)
- The National Grid Company (the company that owns and operates the high voltage electricity grid system)
- Distributors[35] (companies that own and operate low voltage electricity distribution networks)
- Suppliers (companies that buy electricity from generators and sell it to consumers)

There are also several certified metering and data collection companies, which collect data on electricity consumption (usually from electricity meters) for suppliers.

O.2.3 Gas sector

The gas sector is divided into:

- Supply (the companies that supply the gas - there were some 60 industrial and commercial supply companies and 26 domestic supply companies in 1998).
- Transportation (now legally separate from companies supplying gas).

[35] At the moment, the twelve large Public Electricity Suppliers (PESs) own the distribution networks in their own areas of operation. This is likely to end shortly.

- Storage (the UK uses natural features, such as the Hornsea salt caves in Yorkshire, together with five liquefied natural gas storage facilities located strategically around the national transmission system).

Since the introduction of natural gas into the UK in the 1970s, consumption has grown rapidly (see Table O.3). Since 1991, however, the main growth has been in the use of natural gas for electricity generation.

Table O.3 *Natural Gas Consumption in the UK [TWh]*

	1970	1980	1990	1998
Electricity Generators	1.8	4.0	6.5	257.9
Energy Industries	1.2	19.1	39.2	75.0
Industry	20.8	177.5	164.4	191.8
Domestic	18.4	246.8	300.4	355.9
Services	3.4	60.4	86.3	117.9
Total	45.6	507.8	597.0	998.5

In the same period, production of natural gas varied as shown in Table O.4.

Table O.4 *Production of Natural Gas in the UK [Mtoe]*

	1970	1980	1990	1998
Production	10.5	34.8	45.5	90.2

Natural gas is used increasingly in the UK for the generation of electricity. However, the government has recognised that the 'dash for gas' as it is known may threaten the diversity of the UK's energy resource base. Eighteen months ago the government therefore stated that:

> *'new natural gas-fired generation would normally be inconsistent with the governments energy policy concerns relating to diversity and security of supply'*

It lifted this 'moratorium on gas' on 17th April 2000.

The government is also aware that it is likely to be increasingly difficult to continue the recent improvements in the environmental performance of the power sector once the options for gas are exhausted.

The other significant feature in the UK energy market is the increased number of supply companies that offer both gas and electricity (often at significant price savings) to domestic consumers.

At present, the UK has no policy of support for Renewable Gas production - other than landfill gas used for the production of electricity.

O.2.4 Heat sector

The UK heat sector is not as developed as other EU states and the CHP sector accounts for most directly supplied heat. Around 50% of the CHP installations in the UK are small schemes with an electrical capacity of less than 100 kW_e. However, schemes larger than 10 MW_e account for almost 80% of the total CHP installed electrical capacity. In 1998, CHP capacity was 3929 MW_e, producing 21 104 GWh of electricity and 56 769 GWh of heat energy. The government is expected to announce a target of at least 100 000 MW_e of CHP by 2010 as part of its commitment to Climate Change.

There is currently no separate policy on renewable heat.

O.3 Liberalisation process

The UK has an overall view that energy markets should be completely liberalised. The market was opened in segments, starting with larger consumers, and liberalisation of the domestic market was finally completed in 1999. However, the market is regulated, and the regulatory office for gas (Ofgas) and Electricity (OFFER) were merged in June 1999 to form a single regulatory body Ofgem (the Office of Gas and Electricity Markets). In November 1999 the Government announced a Utilities Bill which is to provide a new framework for the regulation of gas and electricity markets.

The key piece of legislation which set the UK ESI on the path to liberalisation was the Electricity Act of 1989 which denationalised the industry and gave regulatory powers to the Secretary of State for Energy. Since that time the industry has undergone huge change, and is still evolving.

The government White Paper on Energy Source for Power Generation, published in October 1998, acknowledged that while the transition to a market-governed industry is to continue, there is a role for government in three specific areas:
1. Providing the legal framework for competitive energy markets that is consistent with sustainable economic development, safety and environmental protection.
2. Providing for regulation in the interest of the consumer.
3. Monitoring the wider public interest to ensure that energy is developed sustainably and that RE, CHP and energy efficiency are taken into account. The wider public interest is also taken to include security and diversity of supply.

The UK electricity market was liberalised in phases, with larger consumers (with consumption capacity over 100kW) able to select their supplier first. However, since early in 1998 all consumers have, in theory, been able to select their electricity supplier and domestic consumers are able to change suppliers by giving 28 days notice to their current supplier. In practice, the industry was not completely ready for liberalisation on this scale, and the smaller scale market also opened in phases until it reached its current state of full liberalisation.

One of the government's main priorities is to address the issue of fuel poverty, particularly amongst the elderly, those with low incomes and the chronically sick. This has formed the basis of the 'Social Action Plan' it is developing with Ofgem (the regulatory body).

The liberalisation of the UK gas market was completed on 23rd May 1998. Competition in the domestic supply market has led to some 5 million consumers (around 25% of the domestic market) switching supplier since competition was allowed (September 1999 figures). As many utilities now supply both electricity and gas, the government established a single regulatory body (Ofgem, see above) to oversee both markets in 1999.

O.4 Renewable energy activities and policies

O.4.1 Renewable energy status

Current total electricity generating capacity in the UK is around 73000 MW, and the capacity in 2010 is predicted to be around 83000 MW, so the target of 10% electricity production from RE represents a generating capacity of 8300 MW. This includes large hydro and energy generated from waste streams.

Hydro capacity not included in the Non-Fossil Fuel Obligation (NFFO) in the UK is currently around 1200 MW in Scotland and 100 MW in England and Wales.

NFFO projects and their equivalent in Scotland and Northern Ireland (already commissioned) have a total capacity of 522 MW. In total the current RE generating capacity in the UK is therefore 1822 MW. Further NFFO projects are due to be commissioned in the next few years, and they should take the total to something around 3300 MW. This means that the UK needs an additional 5000 MW RE generating capacity in order to reach its 10% target, i.e. 500 MW per year for the next ten years.

Until 1999, Renewable energy was supported in the UK by a market mechanism known as the Non-Fossil Fuel Obligation (NFFO). The previous Government's renewable energy policy was to award five NFFO Orders. The NFFO obliged the then 'Regional Electricity Companies' (RECs, since abolished) to buy a certain amount of renewable electricity at a premium price. NFFO contracts were awarded as a result of competitive bidding within a technology band on a pre-arranged date. This meant that wind projects competed against other wind projects but not against, for example, waste to energy projects. The cheapest bids per kWh within each technology band were awarded contracts, and these were announced as an 'Order' by the Secretary of State (for example, NFFO1).

The NFFO contracts are still honoured, so generators are still paid their (premium) bid price per kWh. Under previous arrangements, the Non-Fossil Purchasing Agency (NFPA), a wholly owned accounting body of the RECs, reimbursed the difference between the premium price and the pool selling price to the RECs[36]. The difference was paid for by a Fossil Fuel Levy on electricity, paid for by electricity consumers. Renewable energy projects received around £137 million in 1997-8 from the fossil fuel levy (FFL) (see Table O.5), with £116 going to the NFFO in England and Wales. Although the recently announced 'Response to the RE Consultation' document stated that NFFO contracts would be honoured under the new arrangements, it is not currently clear how this will be done.

Table O.5 *The Fossil Fuel Levy [£m]*

Year	Total raised	Amount for Nuclear generation	Amount for RE	Total levy for RE [%]
1990-1	1175	1175	0	0
1991-2	1324	1311	13	1
1992-3	1348	1322	26	2
1993-4	1234	1166	68	5.5
1994-5	1205	1109	96	8
1995-6	1105	1010	95	8.6
1996-7	844	732.5	111.5	13.2
Apr 96- Oct 96	633	570	63	10
Nov 96 - Mar 97	211	162.5	48.5	23
1997-8	279	142.3	136.7	49

The NFFO had mixed success. It certainly reduced prices for RE generation in the UK (see Table O.6).

[36] Provided the electricity is non-pooled.

Table O.6 *NFFO Prices*

Technology Band	NFFO1 cost-justification	NFFO2 Strike Price [p/kWh]	NFFO3 Average Price [p/kWh]	NFFO4 Average Price [p/kWh]	NFFO5 Average Price [p/kWh]
Wind	10.0	11.0	4.43	3.56	2.88
Wind sub-band	-	-	5.29	4.57	4.18
Hydro	7.5	6.0	4.46	4.25	4.08
Landfill Gas	6.4	5.7	3.76	3.01	2.73
M&IW (mass burn)	6.0	6.55	3.89	-	-
M&IW (fluidised bed)	-	-	-	2.75	2.43
Sewage Gas	6.0	5.9	-	-	-
EC&A&FW (gasification)	-	-	8.65	5.51	-
EC&A&FW (residual)	-	5.9	5.07	-	-
EC&A&FW (AD)	6.0	-	-	-	-
M&I W with CHP	-	-	-	3.23	2.63
AVERAGE	7.0	7.2	4.35	3.46	2.71

However, it also resulted in lower levels of deployment than expected (see Table O.7).

O.4.2 Renewable energy policy

As stated above, the UK government has recently announced (February 2000) in its ‘Response to the RE Consultation’ that it will have an obligation on suppliers to meet 10% of electricity supply from RE, if possible by 2010, using a system of Tradable Green Certificates (TGCs).

The key elements of the policy announcement are:
- progress is to be made towards a target of generating 10% of electricity from renewable sources by 2010,
- this can be undertaken through the purchase of TGCs,
- 5% is to be reached by 2003; 10% by 2010,
- the intention is to place an equal obligation on all suppliers,
- it is possible to ‘buy-out’ of the obligation by making a payment to OFGEM,
- buy-out payment receipts are to be discussed but possibly recycled to suppliers that meet the obligation,
- large-hydro over 10MW may be excluded,
- NFFO1 and 2 generation will be eligible for the obligation (as their contracts have expired),
- dual-fuel plants are eligible for renewable portion, as is CHP fuelled by RE,
- a green certificate is equivalent to a unit (as yet unspecified) of electricity,
- non-domestic consumers will be exempt from the Climate Change Levy (CCL) when a TGC is attached to the physical unit,
- it is expected that spot, forward and derivatives markets of TGCs will develop,
- evidence of compliance will be monitored by the regulator, OFGEM (or an agent),
- the period of obligation is expected to apply until 2025.

The ‘Response’ paper has not set out further details on these points but the DTI has commissioned several pieces of work to examine the options for TGC trade. The options considered are:
1. Trade within the UK only.
2. National and trans-national trade where sales of TGCs transfer only the CO_2 credit to the country of redemption, leaving the renewable energy deployment credit with the country of production.

3. National and trans-national trade where sales of TGCs transfer both the CO_2 and renewable energy deployment credits to the country of redemption.

In addition to UK government initiatives to support RE, there have been moves within the RE sector to develop Non-NFFO means of support for RE. Chief among these is the development of the 'Green Electricity' sector, which has seen initiatives in the areas of Green Tariffs and Green Funds. There have also been some attempts at community/cooperative ownership of RE generation schemes.

Within the UK, some utilities and so-called 'ethical' banks are also offering the public the opportunity to contribute to funds set up to provide equity investment in new RE generation projects. The utilities offer their customers the chance to make a contribution as they pay their electricity bill. An example of this is the 'Ecopower' fund set up by the utility Eastern. Ethical banks offer the opportunity to invest in RE via share offers. Triodos Bank, for instance, has set up the Wind Fund as a RE equity investment vehicle.

There is one example, in the UK, of a RE generation scheme owned by a cooperative. The cooperative, initiated by the Wind Company (the UK arm of the Swedish company Vindkompaniet) now has around 1100 members, owns two turbines at one site, and is negotiating the purchase of further turbines on a 'turn-key' basis at other sites. Their example has been followed to some extent by Fenland Green Power Investments ltd, which is currently building three wind-clusters in the Cambridgeshire Fens. The company is offering up to 14% of the equity investment in these schemes to local people. It is expected that there will be a minimum investment of £250, which is roughly equivalent to an annual household electricity bill. Other initiatives to promote community ownership of RE schemes are also underway (such as the RENUE scheme in Wandsworth in London, and the Dyfi Eco Valley Initiative), and have received financial support from UK bodies such as the Millennium Commission.

In 1997 MORI, the UK National Market Research Body, were commissioned by the Parliamentary Renewable and Sustainable Energy Group (PRASEG) to carry out an investigation into the sustainability of RE within the liberalised market. The survey showed that 94% of respondents were interested in the possibility of buying 'Green' electricity, and that around 21% of respondents were willing to pay more for their electricity if it came from an environmentally friendly source. There are now several utilities (e.g. Green Electron, The Renewable Energy Company, WRE) offering Green Electricity to their consumers, and many larger utilities are considering this option as a way of widening the portfolio of 'products' they offer their customers.

The government financed the development of a green electricity accreditation scheme known as 'Future Energy'. In April 2000, Future Energy report that they have accredited some 15 green electricity products for the voluntary market (see Table O.8). In addition there are other, very successful, green electricity products that do not wish to be accredited under the scheme.

Table O.7 *NFFO Deployment*

	Projects Contracted		Projects Generating		Projects Terminated		Projects still to be commissioned		Completion Rates [%]	
	Number	[MW]	Number	[MW]	Number	[MW]	Number	[MW]	Number	[MW]
NFFO1	75	152.12	61	144.53	14	7.58	0	0	81	93
NFFO2	122	472.23	82	173.73	40	298.49	0	0	67	37
NFFO3	141	626.91	58	191.40	2	1.9	83	460.99	40	26
NFFO4	195	842.72	10	18.46	0	0	187	828.96	4	2
NFFO5	261	1177.00	0	0	0	0	0	0	0	0
TOTAL	794	3270.98	211	528.14	56	307.97	270	1289.95	38	32

Table O.8 *Current RE electricity offerings (for the voluntary market) accredited under the Future Energy scheme*

Name of Supplier	Name of Accredited Renewable Energy Offering	Type of Renewable Energy Offering	Renewable Energy Technologies Currently Included	Regional/ National offering	Target Customers
Eastern Energy	Eco-Power	Fund	Solar / Wind / Biomass	Eastern Region	Domestic
London Electricity	N/A	Supply	Energy from Waste	National	Non - Domestic
Npower	EverGreen	Fund	All renewable sources	National	Domestic
Northern Ireland Electricity	Eco-energy	Fund / Supply	All renewable sources	N.Ireland only	All Customers
PowerGen	Green Supply	Supply	All renewable sources	National	Non-Domestic
PowerGen	GreenPlan	Supply	All renewable sources	National	Domestic
SEEBOARD plc	Go Green - Green Fund	Fund	All renewable sources	SEEBOARD Region	Domestic
Scottish and Southern Energy	ACORN	Supply	All renewable sources	Southern Electric Region	Domestic
Scottish and Southern Energy	RSPB Energy	Supply / Fund	Hydro / Wind/ Landfill Gas/ Sewage Gas/ Energy from Waste	National	Domestic
ScottishPower MANWEB	N/A	Fund	Hydro / Wind	ScottishPower &MANWEB Regions	All Customers
ScottishPower MANWEB	Green Energy	Supply	Hydro / Wind	ScottishPower &MANWEB Regions	Non-Domestic
SWALEC	Green Energy	Supply/Fund	Hydro/Tidal/ PV/ Landfill gas	SWALEC Region	Domestic
SWEB	Green Electron	Supply	Hydro/Wind/ Landfill Gas	England & Wales	All Customers
Unit Energy ltd	Unit[e]	Supply	Wind/Hydro	England & Wales	All Customers
Yorkshire Electricity	Green Electricity	Supply	Wind/Biomass	National	All Customers

The key barrier to the deployment of RE in the UK (and especially wind power) has been the planning process. Although the government issued guidelines to local planning departments stressing that they should balance local concerns with national environmental priorities, this has so far had little impact.

The UK has significant RE resources. The UK's Department of Trade and Industry published figures in March 1999 showing the 'Accessible' RE resources available in 2010 and 2025 under various discount rates. A summary of the data is given in Table O.9 below. (Note that in the UK, RE policy focuses almost exclusively on electricity production.)

Table O.9 Summary of Accessible RE resources

Cost of electricity [p/kWh]	Accessible Resource in 2010 [TWh] 8% discount rate	15% discount rate
3.0	124	2
3.5	187	15
4.0	213	94
Cost of electricity [p/kWh]	Accessible Resource in 2025 [TWh] 8% discount rate	15% discount rate
3.0	163	4
3.5	212	44
4.0	250	134

The DTI figures are calculated from theoretical potentials (derived from Wind maps, insolation maps, hydro surveys etc) examined using the Markal model developed by the IEA. The DTI used a set of scenarios to examine the RE resource available under different financial climates. A summary of the possible ways to reach the UK's 10% RE target under 3 example scenarios is shown in Table O.10.

Table O.10 *Possible Technology Contributions in 2010 [%]*

Scenario	'Trends continued'	'High Wind'	'Constrained Wind'
Existing Capacity	20	20	20
Hydro	1	1	1
Onshore Wind	21	26	13
Offshore Wind	13	18	8
Energy Crops	5	3	16
Landfill Gas	16	13	17
Waste Incineration	16	13	17
Other Biomass	5	3	5
Other	3	3	3

As stated above, the UK government recently announced that it is adopting a target of 10% of electricity supply from RE sources, if possible by 2010. Target levels for the years up to 2010 have not yet been set, but there has been discussion of a level of 5% in 2003 with a ramp up from that over the intervening years to 10% in 2010. It is likely that a system of TGCs will be used to enable the market to meet the targets as efficiently as possible. The target will be accompanied by an obligation on suppliers (i.e. that they should obtain a set fraction of their supply from RE sources). As the supply of RE-produced electricity is likely to be less than the (artificial) demand created by the RE obligation, this may well mean that the domestic market for Green Electricity in the UK will disappear, at least in the short term.

The practical details of the system are currently under exploration and we have no further data on them at this time. At the current time it seems likely that there will be no further support for RE from the government, apart from that which occurs as a 'side-effect' of other policies (such as the proposed Carbon Emissions Trading System - see later).

There is also discussion that TGCs could, in theory, be used by voluntary 'Green Power' suppliers to demonstrate proof of generation to their 'green' consumers, i.e. TGCs can be used to show that both imposed and voluntary demand targets are met.

Clearly, accreditation and auditing must be set up to ensure that each TGC is used only once, i.e. either to meet the obligation or to meet extra demand from 'green' consumers. This ensures that no double counting of RE generation takes place but also that all suppliers are affected equally by the obligation.
As it has been proposed that responsibility for the TGC lies with the regulator, OFGEM, it seems possible that the 'Future Energy' certification/ brand may well become redundant, or at least must tailor itself to fit with the proposed obligatory system. Of course, OFGEM may well decide to subcontract the task of auditing and verifying the obligation, in which case the Energy Savings Trust (which currently administers the 'Future Energy' accreditation scheme) would be a possible (but by no means the only) candidate for the job.

Under the current rules set out by the UK Customs and Excise office, businesses buying renewable electricity will qualify for an exemption on their Climate Change Levy[37] payments, while still remaining eligible for reduced National Insurance Contributions. This means that there is an indirect means of price support for business-purchased RE electricity (as any premium paid to the supplier can be offset to some extent by the CCL rebate). At the moment it seems that this applies equally to both 'voluntary' Green Electricity purchases and to those that fall within the proposed RE Obligation system. This means that electricity supply companies can support their purchase of Re electricity by passing on or selling their TGCs to business consumers, which can then claim the CCL rebate. Domestic consumers, however, (who do not pay the CCL) will not be eligible for this support.

In addition to this, it is currently proposed that large businesses should be allowed to negotiate an exemption of 80% of CCL payments in return for a pledge to reduce their emissions by energy efficiency measures. If they were also allowed to qualify for this by pledging to buy additional renewable electricity (as is under discussion), it would be an important boost to the voluntary green market, but would probably further 'squeeze out' domestic consumers.

O.5 Cross-cutting GHG emissions sector

Under the Kyoto Agreement the UK Government is committed to a binding emissions reduction target on a basket of six greenhouse gases of 12.5 per cent by 2012. In addition to this, the UK government also has a domestic target of a 20 per cent reduction in CO_2 by 2010. While this may require relatively little additional effort, given changes that have already taken place since the baseline date of 1990, further 'Kyoto' targets will be much more demanding. The government published its 'National Climate Change Programme' in 2000.

The government's Utilities Reform Bill has a major emphasis on improvement of energy efficiency on the UK. In particular, it will allow the statutory definition of 'Energy Efficiency Standards of Performance' (EESOPs) for energy suppliers.

[37] The government has recently proposed a Climate Change Levy on energy use by business. This will be accompanied by a lower rate of National Insurance Contribution, so in theory businesses will be encouraged to save energy but their taxation burden will not be increased.

The government announced in its budget of March 1999 that it plans to introduce a Climate Change Levy (CCL) on the supply of energy to business with effect from April 2001. After consultation with industry, the more recent 'pre-budget announcement' (Nov 1999) stated that large users of energy would be able to negotiate an 80% reduction in their CCL by pledging to voluntarily reducing their greenhouse emissions. It is not currently clear whether they are allowed to do this solely by energy efficiency measures or whether they can pledge to use 'Green' electricity (i.e. RE electricity that is additional to that covered by the obligation on suppliers) [38] in order to qualify. It would clearly benefit sustainable energy if this were possible. In addition, the 'pre-budget announcement' stated that renewable generation would be exempt from it which makes RE more attractive (on a cost basis). However, under the current rules proposed by HM Customs and Excise, rebates on the CCL will only be considered if trade in TGCs is matched with trade in physical electricity.

The Confederation of British Industry has an Advisory Committee on Business and the Environment (ACBE) which is working closely with government departments to develop an effective Emissions Trading Scheme for the UK. One of the key questions addressed by the group is the interaction between emissions trading systems, and Energy Efficiency and RE support measures. It has been proposed that an emissions trading scheme should be in place by 2001, although delays to this now seem likely.

CO_2 emissions have fallen in the UK over the last decade or so, largely because of the switch from coal to gas in the UK power industry (see Table O.11 below). Emissions by resource and technology are given in Table O.12 below.

Table O.11 *UK CO_2 emissions by sector (millions of tonnes of carbon)*

	1970	1980	1990	1998
Power stations	547	58	54	40
Industrial combustion	66	43	38	38
Domestic	26	23	22	24
Transport	22	26	35	36
Other sectors	11	14	11	11
Total	182	164	160	149

Table O.12 *Life Cycle Emissions from Conventional Electricity Generation in the UK [g/kWh]*

	CO_2	SO_2	NO_x
Coal - best practice	955	11.8	4.3
Coal - FGD & low NO_x	987	1.5	2.9
Oil- best practice	818	14.2	4.0
Gas-CCGT	446	0.0	0.5
Diesel embedded	772	1.6	12.3
Average Mix 1993	654	7.8	2.5

[38] Combined Departments of UK Government, Scottish Executive, the NI Department of Enterprise, Trade and Investment and the National Assembly of Wales, 1999, Consultation on Energy Efficiency Measures Under the Climate Change Levy Package, Dec.