Economic Evaluation of Sectoral Emission Reduction Objectives for Climate Change

Economic Evaluation of Emission Reduction of Greenhouse Gases in the Energy Supply Sector in the EU

Bottom-up Analysis

Final Report
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Preface

On its way to its current form this report has received significant input from a considerable number of experts. In particular, a panel of experts in Brussels discussed a draft version of the report on March 29, 2000 (see Annex 1 for a list of names), and made a number of specific and more general comments and suggestions. The authors would like to thank these people for their valuable inputs into this study. It was attempted to consider their suggestions wherever possible.

EXECUTIVE SUMMARY

The *Energy supply sector* comprises all centrally and decentrally produced steam and electricity, and refineries. Within the EU, the energy supply sector is an important source of carbon dioxide, accounting for almost 40% of total carbon dioxide emissions in 1990 and 31% of total greenhouse gas emissions. Including all emissions of greenhouse gases from this sector, 32% of the greenhouse gases are emitted by the energy supply sector.

Description of the sector
In 1995, in the EU15 about 2300 TWh of electricity has been produced and about 1066 TWh of steam. The steam and electricity are mainly supplied by conventional fossil fuel power plants, by nuclear plants, by combined heat and power plants (CHP), by steam boilers and by renewable energy sources, or by a combination of aforementioned types of plants. Emissions of CO_2 occur during the production of power with the use of fossil fuels.

Frozen technology reference level
The emission reduction potential for 2010 is calculated using an emission reference level based on frozen technology development. The reference level for 2010 is based on the projected total power and steam production from the Primes model [Primes, 1999]. It is assumed that in the frozen technology reference level no additional renewables and CHP units are installed in 2010 compared to 1995 and that for the 'conventional fossil fuelled plant' the emission factors are the same, i.e. assuming no fuel switch and efficiency improvements.

Emission reduction options
In this report options to reduce carbon dioxide emissions from the energy supply, option to reduce SF_6 from switch gears and options to reduce nitrous oxide emission from combustion from stationary combustion are discussed. There are various options to reduce CO_2 emissions in the energy supply sector. This can be done by increasing the share of lower or zero (CO_2) emission units like combined cycles, renewables, and combined heat and power plants (CHP). In principle extension of the share of nuclear energy leads also to a reduction of CO_2 emissions. In this study, however, it is assumed that there is no expansion of nuclear capacity in the EU towards 2010. A principal other way to reduce emissions is CO_2 removal; recovering of CO_2 from an (energy) conversion process and subsequently storage underground to avoid CO_2 entering the atmosphere.

In this study four 'basic' options are distinguished and discussed. In the first option all new capacity (to compensate for growth in production and to replace decommissioned capacity) will be efficient combined cycle power plants (NGCCs). The second option is implementation of renewables. In practice renewables may be an alternative for many other forms of power production. For computational reasons it is here defined as an option that is implemented in-

stead of efficient combined cycle power plants (NGCCs). The third option is implementation of CHP. For this option the same remark as made for renewables is valid. Also in this case the option is defined as an option that is implemented instead of NGCCs. When a CHP unit replaces a coal-fired steam boiler, it will be clear that in that case two options (options 1 and 3) are implemented at the same time, reducing in total CO_2 emissions of both options. The fourth distinguished option is the application of CO_2 removal.

Three options are described to reduce carbon dioxide emissions from refineries, i.e. reflux overhead vapour compression, recovery of power and use of improved catalysts. In addition, a set of options are categorized in the option miscellaneous.

Options to reduce nitrous oxide emissions from stationary combustion are limited to fluidized bed combustion. This type of combustion has a relatively high emission factor compared to other type of stationary combustion processes.

Finally, options to reduce SF_6 emissions from manufacture and use of gas insulated switch gears are identified.[1]

Table A and B give an overview of the investment costs, the yearly costs (sum of operation and maintenance costs and savings), average specific avoidance costs and potential for options applicable in the energy supply sector. The specific costs are calculated using a real interest rate of 4% and using the technical lifetime of the option, i.e. installation.

Table A. EU15-average costs and potential (Mt of CO_2) for emission reduction in the Energy supply sector (renewables only)

Pollutant	Measure Name	Emission reduction	Specific costs (euro/tCO2) at discount rate			
		Mt CO2 eq.	2%	4%	6%	Sector specific
CO2	Biomass 3b: heat only on solid biomass	25	-42	-42	-41	-41
	Biomass 1b: CHP on solid biomass	4	-38	-34	-30	-26
	Biomass 2: CHP anearobic digestion	4	-28	-23	-17	-11
	Subtotal: cost range < 0 euro / t CO2 eq.	**33**				
	Wind onshore	30	-6	3	13	24
	Small hydro	2	-5	10	27	46
	Large hydro	15	-4	11	29	48
	Biomass 3a: heat only on woody sources	64	15	15	16	17
	Subtotal: cost range 0 < 20 euro / t CO2 eq.	**111**				
	Biomass 1a: CHP on woody energy sources	29	17	20	24	28
	Subtotal: cost range 20 < 50 euro / t CO2 eq.	**29**				
	Geothermal electricity production	2	36	53	71	92
	Wind offshore	18	69	88	109	131
	Tidal	2	84	118	158	201
	Biomass 4a: ethanol	9	228	236	246	256
	Biomass 4b: biodiesel	24	287	299	312	326
	Solar photovoltaic	1	235	308	388	475
	Subtotal: cost range > 50 euro / t CO2 eq.	**56**				
	Total emission reduction options	**229**				

Note: For options Biomass 1a and 3a biomass costs of 3.2 €/GJ biomass were assumed, for options Biomass 1b and 3b 0 €/GJ biomass.

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[1] These options are not described in this report but in the report “Economic Evaluation of Emission Reductions of HFCs, PFCs and SF_6 in Europe”, J. Harnisch and C. Hendriks, Ecofys, March 2000.

Table B. EU15-average costs and potential (Mt of CO_2) for emission reduction in the Energy supply sector (except renewables see Table A)

Pollutant	Measure Name	Emission reduction	Specific costs (euro/tCO2) at discount rate			
		Mt CO2 eq.	2%	4%	6%	Sector specific
CO2	Refineries: Reflux overhead vapour recompression (distillation)	6	-66	-66	-65	-65
	Refineries: Power recovery (e.g. at fluid catalytic cracker)	1	-53	-51	-49	-42
	Refineries: Miscellaneous I (Low cost tranche)	6	-31	-29	-26	-17
	Replacement of capacity by natural gas-fired combined cycles	214	<0	<0	<0	<0
	New capacity by natural gas-fired combined cycles	286	<0	<0	<0	<0
	Subtotal: Cost range < 0 euro / t CO2 eq.	**513**				
	Refineries: Improved catalysts (catalytic reforming)	4	0	0	0	0
	CHP - Food, drink and tobacco	1	-3	12	28	46
	Subtotal: Cost range for 0 < 20 euro/t CO2 eq.	**5**				
	CHP - Refineries	6	6	25	44	65
	CHP - Residential - Small	5	5	27	49	74
	CHP - Non-ferrous metals	0.1	5	27	49	74
	CHP - Engineering goods	0.5	5	27	49	74
	CHP - Other industries	0.3	5	27	49	74
	CHP - Paper and pulp	3	5	27	49	74
	CHP - Tertiary - Large	1	5	27	49	74
	CHP - Textiles	0.1	5	27	49	74
	Subtotal: Cost range for 20 < 50 euro / t CO2 eq.	**17**				
	CO2 removal	50	46	50	54	59
	Refineries: Miscellaneous II (High cost tranche)	6	52	60	69	98
	CHP - Tertiary - Small	3	50	63	76	90
	CHP - Food, drink and tobacco (implemented in situation of overcapacity)	3	108	123	140	157
	CHP - Iron and Steel	1	113	131	150	171
	CHP - Chemicals	3	113	131	150	171
	CHP - Building materials	0.1	113	131	150	171
	CHP - Residential - Large	5	113	131	150	171
	CHP - Tertiary - Small (implemented in situation of overcapacity)	3	140	152	166	180
	CHP - Tertiary - Large (implemented in situation of overcapacity)	1	180	201	224	248
	CHP - Engineering goods (implemented in situation of overcapacity)	1	180	201	224	248
	CHP - Paper and pulp (implemented in situation of overcapacity)	3	180	201	224	248
	CHP - Textiles (implemented in situation of overcapacity)	1	180	201	224	248
	CHP - Residential - Small (implemented in situation of overcapacity)	5	180	201	224	248
	CHP - Non-ferrous metals (implemented in situation of overcapacity)	0.3	180	201	224	248
	CHP - Other industries (implemented in situation of overcapacity)	1	180	201	224	248
	CHP - Building materials (implemented in situation of overcapacity)	0.2	200	218	238	258
	CHP - Residential - Large (implemented in situation of overcapacity)	5	200	218	238	258
	CHP - Chemicals (implemented in situation of overcapacity)	7	200	218	238	258
	CHP - Iron and Steel (overcapacity)	2	200	218	238	258
	CHP - Tertiary - Medium	1	190	227	267	310
	CHP - Tertiary - Medium (implemented in situation of overcapacity)	1	361	398	438	481
	Subtotal: Cost range > 50 euro/t CO2 eq.	**101**				
Non CO2	Recovery of SF6 from gas insulated switchgears	1	3	3	3	3
	N2O Combustion processes Fluisidised bed after burner	1	2	3	3	4
	N2O Combustion processes Fluisidised bed reversed air staging	1	4	4	4	4
	Subtotal: Cost range 0 < 20 euro/t CO2 eq.	**3**				
	Cost range < 0 euro / t CO2 eq.	**513**				
	Cost range 0 < 20 euro / t CO2 eq.	**8**				
	Cost range 20 < 50 euro / t CO2 eq.	**17**				
	Cost range > 50 euro / t CO2 eq.	**101**				
	Total emission reduction potential	**639**				

In 2010 renewables may contribute with an emission reduction of about 229 Mt CO_2. In this figure it is assumed that renewables replace NGCCs. The potential is higher if renewables replace power production facilities with a higher CO_2 emission rate, e.g. coal-fired power plants.

Based on projected steam demand in 2010, the maximum technical potential of CHP units can cover about 90% of the required new capacity in the EU15, although this percentage may vary country by country. CHP and NGCCs may reduce about 564 Mt of CO_2. 500 Mt of CO_2 may be avoided by installing NGCCs thus replacing the 'average power plant' based on fossil-fuels. A further 64 Mt of CO_2 can be avoided by installing CHP units instead of NGCCs.

An adequate estimate of the potential of CO_2 removal is difficult to make. CO_2 removal is a technical feasible option, but still substantial research is required to understand better the impact, environmental consequences and risks of underground storage. In this study an EU-wide potential of 50 Mt of CO_2 is assumed, but the actual potential might be considerably higher.

The reduction potential for refineries is estimated at 23 Mt CO_2. The potential for emission reduction in stationary combustion is estimated at about 2 Mt CO_2. The total technical emission reduction potential in the energy supply sector is estimated at about 869 Mt of CO_2.

Summary of the Energy supply sector

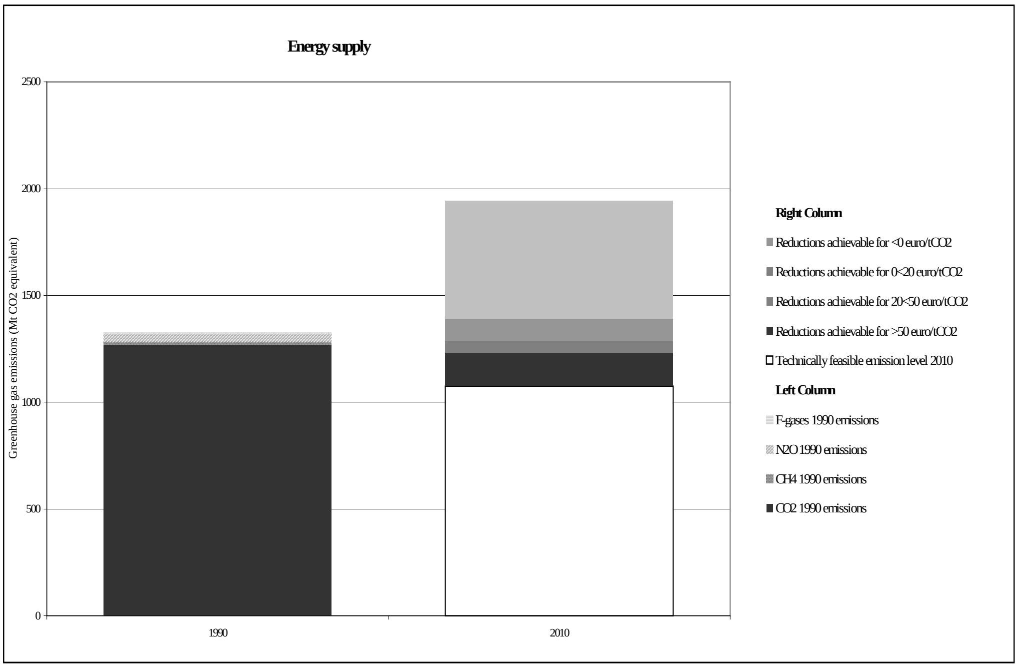
Table C summarises the frozen technology reference level (FTRL) in the energy supply sector and shows the position if all the measures in the table above were adopted.

Table C. Summary of emissions (Mt CO_2 equivalent)

	1990	**2010 FTRL**	**2010 with all measures**
Carbon dioxide	1268	1898	1032
Methane	12	12	12
Nitrous oxide	42	29	27
Fluorinated gases	4	4	3
Total	**1327**	**1943**	**1075**

Figure A shows the share in emission reduction in the energy supply sector categorised in four costs brackets.

Figure A. Energy supply sector: 1990 base year (left column, by gas) and 2010 frozen technology reference level (right column). Emission reduction potential is indicated for four costs brackets . The specific costs are calculated assuming a real interest rate of 4%.



CONTENTS

1. INTRODUCTION

The energy supply sector (steam and electricity production and refineries) is an important contributor to carbon dioxide emissions in the European Union. The main source of emission is carbon dioxide from fossil fuel combustion. Table 1.1 gives an overview of the greenhouse gas emissions energy supply sector.

Table 1.1. 1990 and 2010 frozen technology reference level in energy supply sector (in Mt CO_2 equivalent).

Energy supply sector		1990					2010				
		CO2	CH4	N2O	F-gases	Total	CO2	CH4	N2O	F-gases	Total
Austria	AUT	18	0	0	0	18	30	0	0	0	31
Belgium	BEL	31	0	2	0	33	80	0	2	0	82
Germany	DEU	445	3	8	1	458	468	3	5	1	478
Denmark	DNK	27	0	1	0	28	41	0	1	0	42
Spain	ESP	83	1	6	0	90	190	1	4	0	195
Finland	FIN	21	0	1	0	23	61	0	1	0	62
France	FRA	78	3	3	1	85	150	3	2	1	156
United Kingdom	GBR	265	2	4	1	272	358	2	3	1	364
Greece	GRC	38	0	2	0	40	73	0	1	0	75
Ireland	IRL	12	0	1	0	13	26	0	0	0	27
Italy	ITA	154	1	13	0	168	232	1	9	0	242
Netherlands	NLD	68	1	0	0	68	113	1	0	0	114
Portugal	PRT	19	0	0	0	20	52	0	0	0	52
Sweden	SWE	10	0	1	0	11	23	0	1	0	25
European Union	EU	1268	12	42	4	1327	1898	12	29	4	1943

Source: Primes (1999); UNFCCC (1999); sector study on fluorinated gases; this study.

Non-CO_2 greenhouse gases

In addition to CO_2 emission the other greenhouse gases methane, nitrous oxide and SF_6 are emitted in the energy supply sector. Nitrous oxide is released mainly during the combustion of coal. Emission of SF_6 is related to the use of gas in insulated switch gears. This report describes reduction options for CO_2 emissions and N_2O. Options to reduce SF_6 are covered by a separate report.[2] The results for non-CO_2 greenhouse gases are incorporated in the overview tables as presented in this report (e.g. Table).

[2] see http://europa.eu.int/comm/environment/enveco

2. OPTIONS TO REDUCE CO_2 EMISSIONS IN THE ENERGY SUPPLY SECTOR

2.1 INTRODUCTION

Currently steam and electricity is mainly supplied by conventional fossil fuel power plants, by nuclear plants, by combined heat and power plants, by steam boilers and by renewable energy sources, or by a combination of aforementioned types of plants. The energy supply sector comprises all energy production sites, including industrial boilers and industrial CHP. Emissions of CO_2 occur during the production of steam and electricity with the use of fossil fuels.

In principle CO_2 emission reduction in the energy supply sector can be obtained by applying more energy efficient power plants, by shifting to fuels with a lower carbon content, by applying more combined heat and power generation, and by applying more renewables. Another emerging technology is to reduce emissions by recovering CO_2 from energy production processes and storing it underground. In this chapter we discuss the possibilities to reduce power production related CO_2 emissions.

Fuel shift is nowadays a widely applied concept that reduces CO_2 emissions. For instance, a shift from coal to natural gas for power production might reduce emissions by about 50%. This reduction is partly obtained by the lower carbon content of natural gas and partly because of the higher overall efficiency of natural gas-fired power plants. Extension of the share of nuclear energy also leads to a reduction of CO_2 emissions. However, we assume that no additional capacity is in place in 2010.

During the last decades considerable improvement has been made in the energy efficiency performance of power plants. Nowadays new coal fired power plants can obtain (fuel to power) efficiencies of over 45%. After the large-scale introduction of gas turbines and combined cycles in the eighties, the efficiency of natural gas-fired power plant improved considerably. New combined cycles may reach efficiencies up to 60%. When new technologies are combined, for instance the integration of coal gasification and combined cycles, efficiencies of coal-fired power plants can be close to 50%.

Another way to improve the energy efficiency of power production is to make use of the heat generated, which is wasted in case only power is produced. Combined generation and utilisation of heat and power (CHP) is a technique that reduces primary energy consumption compared to separate generation of heat and power. The savings in primary energy by CHP gas turbine units can be about 30 per cent when CHP replaces a conventional power plant and about 15 per cent when CHP replaces natural gas-fired combined cycles. The savings obtained by condensing and back-pressure steam turbines are smaller.

Most of the heat generated by CHP units is used for the production of steam and hot water. In the future it may also be possible to use high-temperature heat from the flue gases directly as process heat for industrial applications; this technique would reduce the primary energy consumption further. This technique is successfully demonstrated by Shell at an oil refinery in Denmark, and is being implemented at Nerefco oil refinery in the Rijnmond area in the Netherlands.

The potential of future CHP depends on future demand of electricity and heat in mainly the industrial and residential and services sector. The aim of the European Commission is a doubling of the current share of CHP from 9% to 18% of the total gross electricity generation by the year 2010. This is estimated to equal to a CO_2 emission avoided in 2010 of 100 Mt if no growth of electricity consumption is assumed [EC, 1997].

In the analysis of the application of CHP three different groups are distinguished: (i) industrial CHP, (ii) CHP in the commerce and services, and (iii) use of CHP in the residential sector.

Renewable energy sources will play an increasing role in the energy supply in this century. Renewables do not cause direct (long-cycle) CO_2 emissions and are therefore effective means to reduce these emissions. Renewables that may play a substantial role reducing emissions towards 2010 are large and small scale hydro, biomass, wind energy, and thermal solar energy. On the longer run, solar energy is believed to play an important role in the energy supply. According the EU White Paper on renewables 675 TWhe of power and over 3 Exajoule of heat should be produced by renewable energy in 2010, reducing about 250 Mt of CO_2 in 2010 [EC, 1997a].

CO_2 removal is principally another way to reduce CO_2 emissions. The aforementioned options have in common that they reduce the use of (the carbon in) fossil fuels and subsequently the emissions of CO_2 to the atmosphere. CO_2 removal is an end-of-pipe method which recovers CO_2 before, during or after the energy production, mostly in a highly concentrated form. The recovered CO_2 may be compressed, transported and stored underground to avoid entering the atmosphere. In principle CO_2 removal can be applied to at any energy conversion process, and the potential to reduce emission of CO_2 is therefore high.

2.2 EMISSIONS IN EU-15

In 1995 the total CO_2 emissions from power and heat production in the EU15 amounts to 1142 Mt [PRIMES, 1999]. The CO_2 emission factors for power and heat production per Member State are given in Table 2.1. Table 2.2 gives the CO_2 emissions for each Member States for CHP and non-CHP related power and heat production.

Table 2.1. 1995 CO_2 emission factor for power and steam production [PRIMES, 1999].

1995 CO2-emission factor	AUT	BEL	DEU	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	NLD	PRT	SWE	EU
CHP (t/GWh-steam+electricity)	258	315	228	340	246	138	261	331	380	264	230	262	170	117	241
Non-CHP Electricity (t/GWhe)	160	273	581	740	493	251	55	543	950	705	561	661	655	3	395
Non-CHP (fossil-fuel based only) Electricity (t/GWhe)	811	686	910	786	1012	972	805	805	1029	736	691	727	906	527	838
Non-CHP steam (t/GWh-steam)	188	289	316	160	265	286	235	290	285	229	303	241	123	62	255
Non-CHP (fossil-fuel based only) Steam (t/GWh-steam)	330	314	324	246	314	312	310	291	318	329	313	250	336	351	307

Table 2.2. CO_2 emission in 1995 for power and heat production [PRIMES, 1999], and frozen technology level for 2010.

	AUT	BEL	DEU	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	NLD	PRT	SWE	EU
CO2-emission (Mt) - 1995	**16**	**28**	**370**	**33**	**96**	**26**	**48**	**176**	**41**	**13**	**155**	**66**	**23**	**8**	**1143**
of which by CHP	8	4	33	13	9	11	0	0	0	0	24	18	3	5	170
of which by Non-CHP Electricity (fossil fuel based only)	7	19	287	17	76	11	26	160	38	12	117	37	19	0	828
of which by Steam (fossil fuel based only)	1	5	49	3	12	5	21	16	3	1	14	11	0	3	145
CO2-emission (Mt) - 2010	**29**	**49**	**449**	**41**	**186**	**61**	**144**	**340**	**73**	**26**	**228**	**109**	**51**	**22**	**1807**
of which by CHP	8	4	33	13	9	11	10	33	0	0	24	18	3	5	170
of which by Non-CHP Electricity (fossil fuel based only)	18	38	355	23	162	37	105	281	69	24	184	72	47	7	1422
of which by Steam (fossil fuel based only)	4	7	60	6	15	13	30	26	3	2	20	18	2	10	215

2.3 METHODOLOGY

In this section the emission growth in the power and heat sector towards 2010 and the emission reduction potential and associated costs is determined in a three-step procedure.

1. Starting point are the 1990 CO_2 emissions from the Primes database (see bar A Figure 2.1). However, detailed emission figures were only available for 1995. Potentials for emission reduction options are therefore calculated compared to the 1995 situation.

2. 2010 emissions base line emissions are calculated following the power demand development from Primes. It is assumed that in the frozen technology reference level no additional renewables and CHP units will be installed in the period between 1995 and 2010, and that for the 'conventional fossil fuelled plant' the emission factor remains constant, i.e. assuming no fuel switch and efficiency improvement (see bar B Figure 2.1). The grey area indicates the emission reduction in the period from 1990 to 1995 compared to the frozen technology reference case.

3. Subsequently four different emission reduction options are defined and described, which are indicated by the following names: Substitution, More renewables, CHP and CO_2 removal. They are shortly introduced below.

In option 1 *Substitution* modern *natural gas* fired combined cycle power plants (NGCC) are installed. In the period towards 2010, a part of the production park will be decommissioned and replaced by new capacity (*replacement capacity)*. In addition also new capacity will be required because of extra demand projected for 2010 (*new capacity)*.[3] The option also includes early retirement of

[3] Assumed is installation of new natural gas-fired combined cycle power plants with an efficiency of 55% (average percentage of 55% assumed for a mix of large and small plants, including effects as not running on full load, start-ups and shut-down activities).). It should be noted that net efficiency is also depending on the position of the power plant (NGCC plant and CHP units) in relation to the consumer of the power. According to Cogen [2000], the losses on the European electricity system are around 7%.

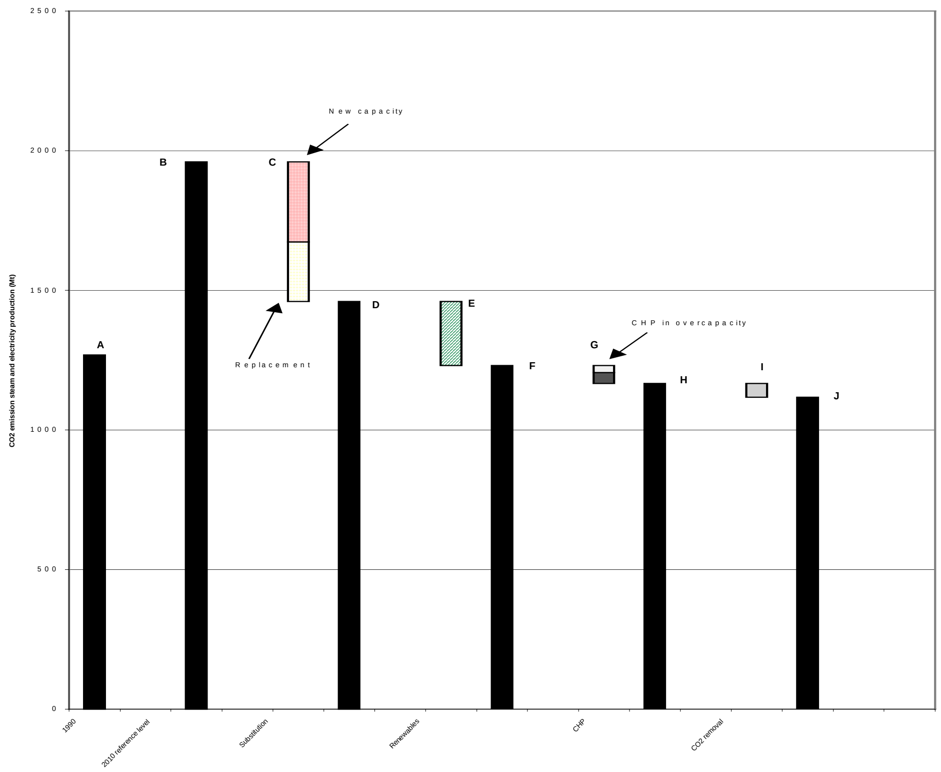
coal-fired power plants. This option reduces CO_2 emission because the share of natural gas (NG)-fuelled combined cycles will increase on the expense of the share of coal-fired plants. The emission reduction effect is enhanced by the fact that new modern plants do have higher energy conversion efficiencies. In Figure 2.1 the potential emission reduction is depicted of this option (bar C). After subtraction from the projected 2010 emissions the remaining emissions are (bar D).

The second option is to introduce *more renewables*. By enhancing the share of renewables emission reductions can be obtained. In principal renewable energy can replace many other forms of energy producing facilities. Depending on the type of renewables the emission reduction and reduction costs will vary. For sake of transparency, in this study it is assumed that all renewables replaces NGCCs.[4] The emission reduction potential and costs are therefore relative to the emissions and costs of such NGCC. In Figure 2.1 the emission reduction potential by renewables is depicted (bar E), as well as the resulting emission in 2010 after implementation of the total potential of renewables (bar F). In practise it might well be that a renewable replaces a coal fired power plant. In that case option 1 (Substitution) and option 2 (Renewables) are taken at the same time.

Option 3 is implementation of combined heat and power plants (*CHP*). Also in this case the reference is NGCCs; i.e. the emission reductions are calculated assuming CHP replaces NGCC capacity. It will be clear that often coal-fuelled steam boilers will be replaced by natural gas fuelled CHP units. In that case, both options (option 1 and option 3) are implemented at the same time. In Figure 2.1 the emission reduction potential by CHP is depicted (bar G), as well as the resulting emission in 2010 after implementation of the total potential of renewables (H). Option 4 is CO_2 removal; i.e. recovery and storage of carbon dioxide to avoid that CO_2 is emitted the atmosphere. Although this option is treated in this chapter about the power and steam production, CO_2 removal can practically be applied in any energy conversion process, and even in some processes where CO_2 is released as process emission (e.g. cement industry). In Figure 2.1 the emission reduction potential by CO_2 removal is depicted (bar I), as well as the resulting emission in 2010 after implementation of the potential of CO_2 removal (bar J).

[4] To determine the avoided CO_2 emissions by renewables and CHP a reference must be chosen. For example, does renewables or CHP replace the average fuel mix for electricity production, or does it replace a new combined cycle (i.e. a power plant containing a steam and gas turbine). In the latter case, the amount of CO_2 avoided is typically substantially less. The choice of the reference is to some extent arbitrary. In this study, we assume that renewable and CHP replaces NG-fired combined cycle plants with an efficiency of 55% (see footnote 3).

Figure 2.1. Methodology calculation emission reduction potential in power and heat sector. Letters in the figure refer to remarks in the text.



2.3.1 Substitution

2.3.1.1 Description

An effective means of reducing CO_2 emissions is to switch from a fuel with a high carbon content to a fuel with a lower carbon content, e.g. from coal to natural gas. At the same time capacity with higher efficiency can be installed. As both effects often occur at the same time we defined this as one option: *Substitution*. Implementation of such a measure depends on many factors, such as costs, political willingness, but also on the availability of natural gas. The availability of natural gas has increased throughout Europe. Recently, piped natural gas has arrived in Greece and Portugal, but still not everywhere where power plants are built natural gas is available. In principle, power plants can be also be converted or replaced before the end of their technical lifetime.[5]. The

[5] Existing power plants can be improved by replacement of key components such as the steam turbines and control equipment by modern ones. Examples of such system modifications are (i) *Topping*, where hot flue gases of a gas turbine, which is added to the system, is fed to the the existing boiler as combustion gas. (ii) A somewhat simpler system modification is the use of the heat to raise steam and to reheat boiler feed water. In these systems the existing boiler remains in place. (iii) Another possibility is *fuel powering*. (iv) The most drastic solution is *early retirement*, i.e. to take power plants out of operation before the end of lifetime. Depending on the plant reconstruction, the efficiency of the plant might improve by 2% to 6%-points.

option '*Substitution*' refers to (i) replacement of fossil-fuelled power plants (both early retirement of coal-fired plants and plants at the end of their lifetimes) by modern natural gas-fuelled combined cycles, and (ii) construction of new capacity. In the latter case, emission reduction is obtained, because in the frozen technology reference level it is assumed that for new capacity power plants are constructed with the average 1995 fossil fuel mix.

The replacement is calculated on basis of the average yearly replacement rate and the period to go towards 2010. The fraction of the production park replaced between 1995 and 2010 is estimated at 50%. A correction is made for those countries with limited availability of natural gas, based on information from Cadence [1999].

2.3.1.2 Potential and Costs

The emission reduction potential of the option 'Substitution' has been calculated using the assumptions in the former paragraph, and is estimated at 500 Mt of CO_2 avoided. Table 2.3 gives an overview of the emission reduction potential per country.

Table 2.3. CO_2 Emission reduction potential for the option 'Substitution'.

Emission reduction (Mt) by Subst.	**AUT**	**BEL**	**DEU**	**DNK**	**ESP**	**FIN**	**FRA**	**GBR**	**GRC**	**IRL**	**ITA**	**NLD**	**PRT**	**SWE**	**EU**
Replacement power plants	1.0	4.5	85.8	4.5	18.1	1.7	7.2	43.4	6.1	2.3	27.4	9.2	2.9	0.0	214
New capacity power plants	2.9	8.6	40.5	3.2	41.1	8.2	42.6	65.9	10.1	4.5	31.7	17.4	8.1	1.6	286

The costs of the option are based on the difference between the electricity production cost of the replaced stock and the electricity production costs of new combined cycles.[6] Currently power production from natural gas-fuelled combined cycles seems generally to be less expensive than the costs for coal-fired plants. According to [Shared Analysis, 1999] the cost difference is about 0.006 euro/kWh for plants running at 7500 hours per year. Because the prices of fuel are a relatively uncertain factor, it can not be said with certainty that this (small) cost difference will remain the same in the future. Furthermore, costs of early retirement of coal-fired power plants are generally low (or sometimes even negative) because they are replaced by modern plants with higher efficiency and less O&M costs. Therefore, we assume that the newly installed combined cycle is the cheapest option for power generation and that the cost differences between alternative power plants are very small.

Backfitting, refurbishment, reconstruction or early retirement of coal-fired power plants can also be cost-effective. Construction and equipment costs can be offset by the extra income due to improved efficiency. Worldwide the potential of this option might be large. The potential of this option in the EU, however, is not known. In this study we assume that instead of a technical lifetime of 40 years, coal-fired power plants are adapted or retired after 30 years.

[6] Alternatively, the costs can be based on the difference between the cheapest option and the production cost of the new NG-fired combined cycle.

2.3.2 Renewable energy sources

2.3.2.1 Description

Some energy flows on earth are induced by energy processes, which are eternal in human perspective. Solar nuclear fusion and gravitational forces are, notably in combination, the most important driving sources of such flows of renewable energy carriers (e.g. solar irradiation, winds, the short-cycle carbon cycle). The points at which these renewable energy carriers enter the (economic) energy system, by conversion into the secondary energy carriers electricity, heat and/or fuel, are generally regarded as renewable energy sources. Three categories of renewable energy sources can be identified and will be dealt with in this report[7]:

Recurring energy forces

Wind energy (onshore/offshore)
Hydropower (small scale <10 MW/ large scale >10 MW)
Solar energy

- solar photovoltaic energy (electricity)
- solar thermal power (parabolic trough, power tower, dish/Stirling)
- solar thermal heat (active and passive)

Wave energy
Tidal energy

Ambient- and geothermal energy

Ambient energy
Geothermal electric
Geothermal heat

Biomass energy

E.g. woody biomass (forest residues, industrial waste streams, energy crops such as willow, poplar), other energy crops (sugar beet, wheat, rapeseed, Miscanthus, et cetera), agricultural and industrial wastes, other wastes with a significant biomass fraction (e.g. MSW, Municipal solid waste), biogas from waste water treatment or landfill sites, et cetera.

Some renewable energy technologies (RET) are typical energy production units (e.g. large-scale hydropower, biomass to electricity production) and can usually be considered to be part of the energy supply sector, whereas others are more intertwined with energy demand (e.g. solar hot water boilers, domestic and industrial biomass combustion) or other activities (e.g. waste or waste water treatment).

[7] Often waste incineration (including fossil fuel based materials) is incorporated in the category biomass-energy. In this study waste incineration is treated as a mitigation option for landfill gas.

Ever since the first oil crisis, the importance of both energy conservation and diversifying energy sources has been recognised in the Member States (MS) of the European Union (EU). Later the issue of climate change became a relevant stimulus for the development of renewable energy policies and R,D&D programmes. The targets for the contribution of renewable energy for the year 2010 from the European Commission, as described in the White Paper 'Energy for the Future' (EC, 1997) are 675 TWh_e of electricity and 3.3 EJ_{th} of heat (excepting passive solar energy). This would altogether result in a mitigation of 250 Mt of CO_2 with respect to the pre-Kyoto reference scenario value for 2010. Table 2.4 lists the breakdown per renewable energy source for 1995 (statistics) and 2010 (target).

As for other emission sources, an estimate has been made to the technical potential of the reduction option. In this study this is defined as the capacity that could be implemented if economic, technological and institutional barriers and constraints are levelled out, taking into account both the time of such a process and the penetration rate of the specific RET technology (see Annex 2). This implies the implementation of a successful policy with respect to renewables: financial incentives, research and development, and elimination of institutional barriers.

Table 2.4: 1995 statistics and 2010 target for renewable energy sources in the White Paper for a Community Strategy and Action Plan (EC, 1997)

	1995		2010	
	Capacity	**Energy production**	**Capacity**	**Energy production**
1. Wind energy	2.5 GW	4 TWh_e	40 GW	80 TWh_e
2. Hydropower	92 GW	307 TWh_e	105 GW	355 TWh_e
2.1 Large (> 10 MW)	82.5 GW	270 TWh_e	91 GW	300 TWh_e
2.2 Small (< 10 MW)	9.5 GW	37 TWh_e	14 GW	55 TWh_e
3. Photovoltaics	0.03 GW_p	0.03 TWh_e	3 GW_p	3 TWh_e
4. Biomass	1.9 EJ_{LHV}	22.5 TWh_e 1.6 EJ_{th}	5.7 EJ_{LHV}	230 TWh_e 3.1 EJ_{th}
5. Geothermal				
5.1 Electric	0.5 GW	3.5 TWh_e	1 GW	7 TWh_e
5.2 Heat (incl. heat pumps)	1 GW_{th}	16.7 PJ_{th}	5 GW_{th}	42 PJ_{th}
6. Solar Thermal Collectors	6.5 million m^2	10.9 PJ_{th}	100 mill. m^2	170 PJ_{th}
7. Passive solar				1.5 EJ
8. Others			1 GW	

Annex 2 gives an extensive overview for all the sources on technical aspects, implementation constraints, technical potential and costs. Below a short description on the position of each of the sources considered in the EU.

Wind energy

Wind energy is a rapidly growing renewable energy source in Europe. The last years annual installed capacity increased with 30-40% to a level of over 8900

MW[8] at the end of 1999, compared to 473 MW in 1990. The technical potential for wind-energy in Europe is enormous, several hundreds of GW onshore; including offshore installations the potential may even be over 1 TW. In this study we assume an implementation potential of about 50 GW of which 16.5 GW offshore.

Hydro-energy

Hydropower is an important source of renewable energy in almost all European countries and is considered to be a mature technology. In the early 1990s the total installed capacity of hydropower in Europe was almost 110 GW, of which about 22 GW was capacity for pumped storage and about 88 GW 'real' hydropower. In turn about 9 GW consisted of small-scale (<10 MW) installations, and 79 GW of large-scale installations. At the end of 1997 a total of about 91 GW was installed (9.7 and 81.7 GW for small- and large scale respectively).

The target for 2010 according to the White Paper is 105 GW [EC, 1997]. The baseline scenario of PRIMES [EC, 1999] even project 110 GW of hydropower in Europe. Additional capacity is limited and restricted by environmental constraints. In this study we assume an implementation potential of 102 GW.

Solar photovoltaic energy (PV)

Photovoltaics (PV) is generally categorised as grid connected and autonomous PV. Although autonomous PV is an important application and already often cost effective, the potential in the EU-15 Member States is hard to determine. Currently the growth in the PV market comes from grid connected systems, and for this reason autonomous PV systems are treated here as a *pro memori* technology.

Grid connected PV can be divided into roof-integrated PV and larger PV-plants. The installed capacity of PV-plants is relatively low compared to roof-integrated PV. According to EPIA [1996] 12 MWp of PV-plants was installed in 1994 compared to 6 MWp of roof-integrated PV systems in 1994. In this study we assume an implementation potential in 2010 of 2 GWp.

Solar thermal power

By means of concentrating solar energy onto a focal point or line, enough heat can be produced to generate electricicity with turbines or other heat driven conversion engines. The following techniques are considered as most promising in the short term: parabolic troughs, power towers, and dish/Stirling systems. Solar thermal power has a large technical potential in the Mediterranean countries and could become cost-effective in the longer term. Significant efforts in research, development and demonstration have to be undertaken (notably the upscaling of some techniques), and in this study a breakthrough of this technologies is expected to occur after 2010. However, it is expected that even before 2010 some projects will be realised.

[8] EWEA internet site (http://www.ewea.org/stats.html) d.d. 26/1/2000

Solar thermal heat

Active solar thermal energy comprises solar heating systems which can be used in the domestic sector, the tertiary sector (solar hot water boilers) and in agriculture (e.g. drying of crops). According to EC [1997] 170 PJ_{th} heat is expected to be produced by active solar systems in Europe in 2010. That can be achieved by 100 million m^2 collector surface [EC, 1997], using an average collector surface of 5 m^2, that would mean roughly 20 million systems. In this study only glazed collectors are taken into account, as this type is expected to have the largest market penetration opportunities in the EU. In an accelerated implementation, total heat production could reach some 240 PJ in 2010.

Wave and Tidal energy

Wave energy and tidal energy are treated as different options, but now discussed together because of their limited expected contribution in 2010. In 1990 the use of wave and tidal energy in Europe was restricted to tidal energy in France, with a total capacity of approximately 240 MWe. No further projects are foreseen in the period up to 2010.

Geothermal energy

In 1995 a total of 1200 MWth and 640 MWe of geothermal energy has been installed in Europe [ATLAS, 1997]. This accounted for 13.5 PJ of heat and 3.5 TWh electricity production. For 2010 we assume an implementation potential of 1.9 GWth and 1.3 GWe.

Biomass energy

Various biomass resources are or could be converted to energy: woody biomass (forest residues, industrial waste streams, energy crops such as willow, poplar), other energy crops (sugar beet, wheat, rapeseed, Miscanthus, et cetera), agricultural and industrial wastes, other wastes with a significant biomass fraction (e.g. MSW, Municipal solid waste), biogas from waste water treatment or landfill sites, et cetera. For these biomass to energy conversions various technologies are available, e.g. incineration, co-firing, gasification, pyrolysis, anaerobic digestion, fermentation, extraction, et cetera.

Landfill gas recovery and utilisation as well as municipal solid waste incineration are discussed in the section on methane abatement of landfill gas and are not part of this section.

An estimate of the implementation potential of biomass to energy is therefore twofold: it requires an estimate of the biomass resources and of the specific technologies and conversions that will be applied. Given the variety of biomass resources, the competition between energetic utilisation and alternative uses of biomass (e.g. for food production or use in the manufacturing industry) and the various conversion technologies and conversion routes (electricity and/or heat production, fuel production: e.g. bio-ethanol, bio-diesel, biogas), the estimate

of the implementation potential will have a broad range. Furthermore, biomass statistics are no complete by far and/or uniform for all EU-15 member states and for all statistical references.
In this study we consider the following biomass to energy conversion routes:

1a. Incineration of forest residues and woody energy crops in CHP-units;
1b Incineration of other solid biomass in CHP-units;
2. Anaerobic digestion of liquid and/or digestible wastes;
3a. Incineration of forest residues and woody energy crops in heating boilers;
3b. Incineration of other solid biomass in heating boilers;
4a. Fermentation of sugarbeets and wheat for ETBE production;
4b. Extraction of biodiesel from rapeseed and sunflowers.

According to EC [1997] the energy content of the biomass used in 1995 in EU-15 was about 1.9 EJ. The White Paper mentions for 2010 a growth to about 5.7 EJ (including landfill gas and municipal solid waste (MSW) incineration). The electricity and heat production is respectively estimated to be 230 TWhe and 3.1 EJth. PRIMES [1999] projects 66 TWhe and 0.75 EJth respectively, whereas the Best Practice Policy scenario of TERES-II [1996] presents figures of 93 TWhe and 2.8 EJth (and 445 PJ of biofuels). These data are used for the 2010 implementation potential.

2.3.2.2 Overview renewables

Table 2.5 and Table 2.6 give the technical power and heat production potential in 2010 additional to the production in 1990. Table 2.7 gives a the 2010 projection for renewable energy sources in the White Paper for a Community Strategy and Action Plan (EC, 1997) and the results of this study.

Table 2.5. Power production potential of renewables in 2010 (TWhe.)

	Biomass	Wind onshore	Wind offshore	Geothermal	hydro large	Hydro small	Solar PV	Tidal	Total
AUT	3762	1875	0	0	38000	5314	81	0	49033
BEL	314	2500	1500	0	40	283	23	0	4660
DEU	8540	20000	6000	0	12800	5403	180	0	52922
DNK	2874	7500	6000	0	0	27	9	0	16410
ESP	5274	6250	2750	0	29000	4429	720	0	48423
FIN	6288	2500	4500	0	17357	1874	8	0	32527
FRA	11305	7500	1375	0	62600	9020	270	1128	93198
GBR	10671	5000	7000	0	5600	469	90	3752	32581
GRC	3594	2500	1375	0	8500	351	203	0	16523
IRL	601	3750	1750	0	800	117	5	0	7022
ITA	4724	10000	4125	9316	37400	9489	585	0	75638
LUX	6	50	0	0	30	82	1	0	169
NLD	1243	5000	6000	0	0	189	27	0	12458
PRT	1373	2500	2750	41	10800	703	230	0	18396
SWE	6307	5000	4500	0	89357	2929	16	0	108109
EU	66876	81925	49625	9357	312284	40678	2446	4880	**568070**

2.3.2.3 Costs and potential

In 2010 renewables may contribute with an emission reduction of about 229 Mt. In this figure it is assumed that renewables replace natural gas fired combined cycles. The potential may increase if one assumes that renewables replace other forms of fossil-fuel power plants. Specific costs range from below zero for some biomass options to over 300 euro per tonne of CO_2 avoided for PV. Table 2.8 gives an overview of technical emission reduction potentials per renewable for the EU and specific emission reduction costs.

Table 2.6. Heat production potential of renewables in 2010 (in PJth.)

	Biomass	Geothermal	Solar thermal	Total
AUT	111	0	8	120
BEL	12	0	5	18
DEU	503	3	61	567
DNK	60	0	4	64
ESP	204	0	25	229
FIN	80	0	7	87
FRA	494	9	26	529
GBR	120	0	32	152
GRC	59	0	14	73
IRL	25	0	2	27
ITA	453	6	29	487
LUX	1	0	0	1
NLD	66	0	6	72
PRT	103	0	7	110
SWE	217	1	12	230
EU	2508	20	237	**2765**

Table 2.7. Comparison of the 2010 targets for renewable energy sources in the White Paper for a Community Strategy and Action Plan (EC, 1997) and the results of this study.

	White Paper	This Study	
1. Wind energy	80 TWh_e	82 TWh_e	Onshore
		50 TWh_e	Offshore
2. Hydropower	355 TWh_e	353 TWh_e	
2.1 Large (> 10 MW)	300 TWh_e	312 TWh_e	
2.2 Small (< 10 MW)	55 TWh_e	41 TWh_e	
3. Photovoltaics	3 TWh_e	2 TWh_e	
4. Biomass	230 TWh_e	68 TWh_e	
	3.1 EJ_{th}	3.5 EJ_{th}	
5. Geothermal			
5.1 Electric	7 TWh_e	9 TWh_e	
5.2 Heat (incl. heat pumps)	42 PJ_{th}	20 PJ_{th}	(exc. heat pumps)
6. Solar Thermal Collectors	170 PJ_{th}	237 PJ_{th}	
7. Passive solar	1.5 EJ	PM	
8. Others			

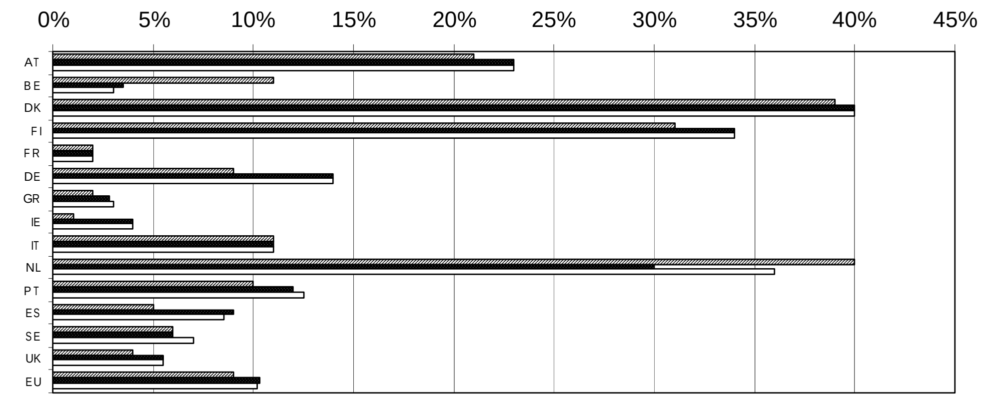
Table 2.8. Emission reduction potential in 2010 and average European specific emission reduction costs for renewable energy sources.

Name measure	Specific costs	Emission reduction
	euro/tCO2 eq.	Mt CO2
Biomass energy 3b: heat only on solid biomass	-42	25
Biomass energy 1b: CHP on solid biomass	-34	4
Biomass energy 2: CHP anearobic digestion	-23	4
Wind energy - onshore	3	30
Small hydropower (<10 MW)	10	2
Large hydropower (>10 MW)	11	15
Biomass energy 3a: heat only on solid biomass	15	64
Subtotal: cost range 0 < 20 euro / t CO2 eq.	0	111
Biomass energy 1a: CHP on solid biomass	20	29
Geothermal electricity production	53	2
Wind energy - offshore	88	18
Tidal energy	118	2
Biomass energy 4a: ethanol	236	9
Biomass energy 4b: biodiesel	299	24
Solar photovoltaic energy	308	1
Total		**340**

2.3.3 CHP in the industry, residential and services sector

2.3.3.1 Description

The actual realised penetration of CHP in 1990 is estimated at about 9% of total generated electricity. Currently there has been a very heterogeneous development of CHP in the Member States. This is valid for the policies applied and the implementation rate obtained. Countries as the Netherlands, Denmark and Finland have shares of CHP of over 30%, while the share of CHP in all other countries, except Austria, are close to or under 10%. European average amounts to 9 to 10%.



	EU	UK	SE	ES	PT	NL	IT	IE	GR	DE	FR	FI	DK	BE	AT
EC - 1997	9%	4%	6%	5%	10%	40%	11%	1%	2%	9%	2%	31%	39%	11%	21%
Cogen - 1997	10%	6%	6%	9%	12%	30%	11%	4%	3%	14%	2%	34%	40%	4%	23%
Cogen - 1999	10%	6%	7%	9%	13%	36%	11%	4%	3%	14%	2%	34%	40%	3%	23%

Figure 2.2. CHP as a share of national power production for 1997 (the shaded bars by [EC, 1997]; the black bars by the [Cogen,1997]). Cogen made recently an update, which is presented by the white bars [Cogen, 1999]. As every country collects data in a different way and definitions of CHP still may differ by country, the graph should be used as an indication only.

Steam and hot water (low-temperature heat demand) are used in practically all industrial sectors. In 1995 CHP units supplied about 45% of the low-temperature demand in the industry. According to the PRIMES model, the low-temperature heat demand will grow in the base scenario by 20% between 1995 and 2010, from 1070 TWh to 1300 TWh. In the residential sector, the steam demand for district heating increases by 30% by 2010 compared to 1995. In the commercial sector the increase in heat demand is about 75%. In the frozen technology reference level of this study we assume there will be no CHP additionally installed.

The abatement potential by CHP depends on the capacity that can be installed and on future development of the efficiency of both CHP technology and technology for separate generation of heat and power. It is obvious that with improved power generation technologies, the CO_2 abatement potential of CHP will diminish. Table 2.9 shows the comparison between an industrial CHP and separate generation of heat and power. The starting point of the comparison is that the current difference in power efficiency remains the same in future development. In that case, the potential savings of CHP will diminish.

Table 2.9. Comparison between CHP and separate generation of heat and power [Cogen, 1999]. Starting point is that the difference in power efficiency remains the same.

Separate Generation							
Power eff.	%	40	45	50	55	60	65
Heat eff.	%	90	90	90	90	90	90
Total eff.	%	61	63	65	68	70	73
CHP							
Ratio H/P		1.7	1.3	1.1	0.9	0.8	0.6
Power eff.	%	30	35	40	45	50	55
Heat eff.	%	50	47	44	41	38	35
Total eff.	%	80	82	84	86	88	90
Savings	%	23.4	23.1	22.4	21.5	20.4	19.0

2.3.3.2 Emission reduction potential

Potential heat demand. For the option, we calculated per country the maximum amount of heat that could be covered by CHP units. This estimation is separately done for industrial sectors, the residential sector and the services sector.

<u>Industry</u>: The reduction potential in the industry can be divided into two categories: (i) replacement of non-CHP units by CHP units and construction of additional CHP units to cover the growth in the heat demand, and (ii) retrofit of existing steam boiler/steam turbine installations by adding a separate gas turbines at the upfront side.

Little information is available on the existing penetration of steam boiler/steam turbine combination. In this study we assume a share of 50% (percentage based on heat coverage).

The maximum heat demand that can be covered by CHP, however, is not equal to the full steam demand. A full coverage (thus including peak load) would be disproportional expensive. On average the coverage degree is about 80%. The remaining steam demand is covered by steam boilers. Furthermore, the demand of steam will be lower than projected in the base line, because energy improvement options will be implemented to a larger extent than is currently assumed in the Primes baseline scenario (see chapter “Options to reduce CO_2 emissions by industrial energy efficiency improvement”). Based on the insights presented in that chapter, we assume a 10% lower heat demand than is assumed in the base case. Whether this percentage is adequate or not depends on the efforts to implement energy efficiency options. The remaining steam demand is considered as the maximum potential that can be covered by CHP-units.

The emission reduction potential of applying CHP depends on the type of CHP units that is implemented. In heavy industries, typically larger CHP units can be applied than in other industries. However, the share of energy use to generate steam in the total consumption of energy varies for the various industries. While the paper and pulp industry use more than 90% of their energy use for steam raising, this is only about 20% in Iron and Steel industry.

Table 2.10 gives an overview of the share of energy use for steam and hot water production in the industrial sectors in the Dutch case. As the applied technologies do not differ substantial across Europe, we assume in the calculations that this division can be applied to all Member States. The division is used to allocate the total steam demand over the industrial sectors.

Table 2.10. Share of fuel use in the production of hot water/steam and process heat, and the share of fuel use for hot water/steam production for each industrial sector in the Netherlands [ECN, 1999].

	hot water/steam	process	Share of total
	%	%	%
Iron and steel	18%	82%	8%
Non-ferrous metals	23%	77%	1%
Chemicals	69%	31%	42%
Building materials	4%	96%	6%
Paper and pulp	95%	5%	7%
Food, drink and tobacco	82%	18%	19%
Engineering goods	46%	54%	5%
Textiles	86%	14%	2%
Other industries	21%	79%	10%
Total	59%	41%	100%

Services and residential sector: Although CHP can be applied for all types of dwellings, in this study it is assumed that it is only applied to new dwellings and commercial sites. To be economical, the heat demand should satisfy a minimum demand. Therefore it is not likely that substantial amount of district heating can be applied in southern European countries. In this study, we divide the EU in three zones: Northern Europe (AUT, BEL, DEU, DNK, FIN, GBR, IRL, LUX, NLD, SWE), Central Europe (FRA), and Southern Europe (ESP, GRC, ITA, PRT). It is estimated that in Northern Europe about 50% of the heat demand for new dwellings can be covered in 2010 by district heating. This is 25% for Central Europe and 10% for Southern Europe.[9]

Potential CO_2 emission reduction. Besides steam, CHP units also produce electricity that would otherwise be produced elsewhere. As discussed earlier, we assume that CHP units will replace combined cycle-units with an energy

[9] A reviewer believes that 50% for Northern countries is a too high estimate.

conversion efficiency of 55% (fuel to electricity conversion efficiency). An overview of the conversion efficiency of the CHP-units is given in Table 2.14. Depending on the characteristic of the CHP unit, the amount of CO_2 emission avoided varies from 65 to 200 tonne of CO_2 per GW of heat produced.

Table 2.11 gives the emission reduction potential for new CHP in 2010 for option GT/CHP in the industrial sector and the reduction potential for services sector and residential sector. The total potential is about 64 Mt of CO_2. It should be noted that often gas-fired CHP units replace obsolete coal-fired units. The two measures combined (substitution and CHP) will result in an emission reduction of about 320 Mt of CO_2 in 2010. Table 2.12 gives the reduction potential for CHP units that can be retrofitted. Table 2.13 distinguishes the CHP potential replacing depreciated and non-depreciated plants, i.e. CHP installed in a situation of overcapacity. Overcapacity may occur when CHP units produce more power (to cover the heat demand) than there is power demand.

Table 2.11. Emission reduction potential of CHP in 2010 by EU-country for various sectors by new CHP (in Mt CO_2-avoided).

MtCO2 by CHP	AUT	BEL	DEU	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	NLD	PRT	SWE	EU
Iron and steel	0.03	0.20	0.61	0.01	0.17	0.13	0.40	0.40	0.01	0.01	0.25	0.12	0.01	0.14	2
Non-ferrous metals	0.00	0.02	0.10	0.00	0.04	0.01	0.08	0.05	0.03	0.02	0.03	0.02	0.00	0.02	0
Chemicals	0.04	0.55	2.66	0.06	0.99	0.19	1.29	1.01	0.07	0.13	0.92	1.19	0.05	0.24	9
Building materials	0.00	0.01	0.06	0.00	0.04	0.01	0.04	0.02	0.02	0.00	0.05	0.01	0.01	0.00	0
Paper and pulp	0.09	0.11	0.89	0.06	0.52	0.93	0.92	0.67	0.04	0.03	0.55	0.14	0.09	1.40	6
Food, drink and tobacco	0.02	0.11	0.75	0.15	0.38	0.08	0.90	0.59	0.04	0.10	0.35	0.40	0.03	0.15	4
Engineering goods	0.01	0.04	0.41	0.02	0.10	0.03	0.31	0.28	0.00	0.02	0.20	0.08	0.00	0.08	2
Textiles	0.00	0.02	0.10	0.01	0.11	0.01	0.09	0.10	0.01	0.01	0.21	0.02	0.02	0.02	1
Other industries	0.00	0.03	0.13	0.02	0.05	0.03	0.23	0.15	0.02	0.01	0.05	0.06	0.01	0.04	1
Refineries	0.01	0.31	1.52	0.39	0.40	0.12	0.86	0.76	0.26	0.02	0.51	1.22	0.06	0.00	6
Total industry	*0.22*	*1.41*	*7.23*	*0.71*	*2.80*	*1.53*	*5.11*	*4.03*	*0.49*	*0.35*	*3.11*	*3.27*	*0.26*	*2.09*	*33*
Commercial	0.34	0.13	3.37	0.68	0.18	0.54	1.40	1.08	0.14	0.11	0.08	1.61	0.07	1.14	11
Residential	0.51	0.33	7.15	1.11	0.15	1.68	2.39	2.31	0.34	0.18	0.38	1.74	0.05	1.92	20
Total	**1.1**	**1.9**	**17.7**	**2.5**	**3.1**	**3.7**	**8.9**	**7.4**	**1.0**	**0.6**	**3.6**	**6.6**	**0.4**	**5.2**	**64**

Table 2.12. Emission reduction potential of CHP in 2010 by EU-country for various sectors by retrofitted CHP (in Mt CO_2-avoided)

Emission reduction (Mt) by CHP	AUT	BEL	DEU	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	NLD	PRT	SWE	EU
Retrofit Steam boiler/turbine	0.3	0.1	1.5	0.1	0.3	0.9	0.5	1.1	0.0	0.0	1.5	0.7	0.3	0.2	7

Table 2.13. Emission reduction potential by CHP-units replacing depreciated plants and covering growth in demand in 2010 and emission reduction potential by CHP-units replacing non-depreciated plants (Mt CO_2 avoided).

Emission reduction (Mt) by CHP	AUT	BEL	DEU	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	NLD	PRT	SWE	EU
New+replacement power production	0.5	1.9	9.6	0.0	3.1	1.1	5.8	7.4	1.0	0.6	3.6	3.6	0.4	0.0	39
Overcapacity power production	0.6	0.0	8.1	2.5	0.0	2.6	3.1	0.0	0.0	0.0	0.0	3.1	0.0	5.2	25
Total	1.1	1.9	17.7	2.5	3.1	3.7	8.9	7.4	1.0	0.6	3.6	6.6	0.4	5.2	63.7

2.3.3.3 Costs

The profitability of CHP installations depends on many factors, the main ones being transition costs, investment costs, electricity price, buy-back tariffs, fuel prices and tariffs for wheeling. In the last decade, some main applications of CHP produced electricity at costs lower than conventional electricity production, including most applications in industry and part of the applications in the service sector (e.g. hospitals). Other applications however were not or hardly cost-effective, e.g. most new applications of district heating, small-scale applications for the service sector and the residential sector [De Beer et al.,1994]. Recently, the effect of liberalisation of energy markets on prices and tariffs has been signalled to form a threat to new capacity, including CHP. A study by ECN [1999] showed that profitability of investments in CHP has substantially decreased. The main cause is the fierce competition on the electricity market and the uncertainty whether prices will cover more than just marginal fuel costs in the near future. Investments and O&M costs seem to have risen substantially, contributing to the decrease in profitability of CHP.

Based on an extensive research, the Netherlands Energy Research Foundation ECN made an inventory of efficiencies and costs for various CHP units. The characteristics of the units differ according to their size and application. Table 2.14 gives an overview for typical investment and O&M costs for 7 different pre-defined types of CHP units. The cost figures (investment and O&M costs) are based on data obtained from the industry [ECN, 1999]. For each type of CHP-unit two cost calculations are presented, one based on replacement of depreciated plants (see Table 2.14), and one based on premature replacement. In that case a capacity penalty is introduced, i.e. the value of the power produced decreases (see Table 2.15). In some cases a CHP unit will not replace an NGCC but other installations. As an example shows Table 2.16 the specific CO_2 emission reduction costs for the same CHP units but compared with a coal-fired power plant with a fuel to power conversion efficiency of 40%.

From this analysis we conclude that only large-scale CHP units show nett negative costs from a social perspective.[10]

[10] Based on interest rate of 4% and lifetime of the power production units of 15 years.

Table 2.14. Cost figures and CO_2 emissions savings for various CHP units [ECN, 1999].

Capacity	MWe	100 - 250 MW	100 - 250 MW	25 - 100 MW	10 - 50 MW	1 - 10 MW	0.1 - 1 MW
Type		Combined cycle	Combined cycle - District heating	Combined cycle	Gas turbine	Gas turbine	Gas engine
efficiency							
power	%	44%	48%	42%	34%	32%	40%
heat	%	34%	36%	32%	48%	46%	45%
CHP ratio	-	0.77	0.75	0.76	1.41	1.44	1.13
Load	hrs/year	8000	4000	7500	7000	7000	4000
Costs							
Investment	Euro/kWe	500	680	750	800	1260	460
Fuel costs	Euro/kWhe	0.025	0.023	0.026	0.032	0.034	0.027
O&M costs (variable)	Euro/kWhe	0.003	0.0023	0.004	0.0038	0.0053	0.013
O&M costs (fixed)	Euro/kWe	9	7	14	14	36	0
Value heat	Euro/kWhth	0.012	-0.004	0.012	0.012	0.012	0.012
Value electricity	Euro/kWhe	0.03	0.03	0.03	0.03	0.03	0.03
Power production	MWhe/yr	8	4	8	7	7	4
Heat production	MWhth/yr	6	3	6	10	10	5
Saved CO2	tCO2/MWh-steam	0.11	0.15	0.08	0.06	0.04	0.10
Saved CO2	tCO2/yr	0.65	0.46	0.43	0.63	0.41	0.45
Specific investment	Euro/tCO2-saved/yr	767	1,484	1,748	1,272	3,075	1,032
Specifc Fuel costs	Euro/tCO2-saved	301	196	449	354	576	242
Specifc O&M costs (variable	Euro/tCO2-saved	37	20	70	42	91	117
Specifc O&M costs (fixed)	Euro/tCO2-saved	14	15	33	22	88	-
Specific benefits heat	Euro/tCO2-saved	113	- 28	158	187	292	120
Specific benefits power	Euro/tCO2-saved	368	262	524	334	512	269
Interest	%	4%	4%	4%	4%	4%	4%
Lifetime	years	15	15	15	15	15	15
deprecitation	Euro/tCO2-saved	69	133	157	114	277	93
yearly costs	Euro/tCO2-saved	352	232	552	418	755	359
yearly benefits	Euro/tCO2-saved	481	234	683	521	804	389
total costs	Euro/tCO2-saved	- 60	131	27	12	227	63

NB_1: in the 'Value heat' of the CC-DH (combined cycle - district heating) the costs of district heat network are taken into account (see for details Table 2.17).
NB_2: in some applications of CHP costs can be avoided for boiler or network upgrading.

Table 2.15. Specific Reduction Costs for the same CHP units as shown in Table 2.14, but without capacity costs for the production of power in the reference case taken into account.

		100 - 250 MW	100 - 250 MW	25 - 100 MW	10 - 50 MW	1 - 10 MW	0.1 - 1 MW
		Combined cycle	Combined cycle - District heating	Combined cycle	Gas turbine	Gas turbine	Gas engine
Value electricity	Euro/kWhe	0.020	0.020	0.020	0.020	0.020	0.020
total costs	Euro/tCO2-saved	66	218	201	123	398	152

Table 2.16. Specific Reduction Costs for the same CHP units as shown in Table 2.14, but compared to coal-fired power plant with an efficiency of 40%.

		100 - 250 MW	100 - 250 MW	25 - 100 MW	10 - 50 MW	1 - 10 MW	0.1 - 1 MW
		Combined cycle	Combined cycle - District heating	Combined cycle	Gas turbine	Gas turbine	Gas engine
total costs	Euro/tCO2-saved	-13	35	5	3	40	16

Table 2.17. Costs and saved fuel costs for typical district heating system [ECN, 1999].

Investement heat grid	Euro/kWth	829
O&M fixed	Euro/kWth/year	17
O&M variable	Euro/kWh_th	0.20
life time	years	25
Produced kWth	kWh/kW/yr	4000
Depreciation	Euro/kWth	54
O&M	Euro/kWth	17
Fixed costs	Euro/kWh_th	0.018
Variable costs	Euro/kWh_th	0.008
Saved fuel cost	Euro/kWh_th	0.022
Total costs	Euro/kWh_th	**0.004**

In the calculations, we assumed for each sector one or more typical installations as defined in Table 2.14. Large combined cycles (100-250 MWe) are typically installed in industries as Iron and Steel, and Chemical Industries. Small combined cycles are more common in industries as Non-ferrous Metals, Pulp and Paper and Food Industry. In the Food Industry also large gas turbines are assumed. In the remaining industry, mainly small gas turbines are assumed to be installed. Outside the industry, mainly gas engines are used in the commercial sector. For the residential sector, application of large combined cycles for district heating are assumed.

For the large scale industrial combined cycles, generation of low-pressure steam of 10 bars and 220 °C is assumed. Industrial application of CHP units requires flexibility in steam supply. Therefore, in many cases additional steam raising is needed in a separate boiler, which makes that the H/P ratio increases. In some cases, steam can be tapped from the power section. This makes that the power production is variable. For large scale heat distribution (DH) water is heated up to about 90 °C. For small scale CHP units, two different kinds of installations are assumed: gas engines and the gas turbines, of which the former is the one most often applied. From a technological point of view, there are only small differences. However, in operational management, differences may occur.

2.3.4 Carbon dioxide removal

2.3.4.1 Description

A principle other way to reduce emissions of carbon dioxide is to recover and store the CO_2 from energy conversion processes. In CO_2 removal the objective is not to reduce the use of (carbon-rich) fossil fuels, but to separate the carbon component (often in the form of CO_2) and to store it underground to prevent it entering the atmosphere. Besides underground storage research is directed towards storage in deep oceans.

CO_2 removal has been subject for research since the late eighties. Nowadays, the most intensively studied technology is the recovery from power plants and from natural gas winning activities, but also good recovery opportunities exist from industrial processes and, on the longer term, in the transport sector.

A commercial CO_2 removal project by Statoil is currently carried out in Norway, where yearly about 1 million tonnes of CO_2 is separated from CO_2-rich natural gas and stored in an aquifer nearby the offshore natural gas production site.[11]

In carbon dioxide removal generally three steps can be distinguished: recovery of CO_2, compression and transportation of the CO_2, and the storage of CO_2. These steps are shortly described.

Recovery of CO_2. Exhaust gases of industries and power plants contain CO_2 in concentrations normally in the range of 3% to 20%. There are various technologies to separate the CO_2 from this exhaust gas stream. The most commonly known is separation with an amine-based solution. Other ways are the use of low-temperature separation or the use of membranes, which have not found as wide an application.

Another way to separate CO_2 is to convert the fuel prior to combustion. In this way a carbon-poor or carbon-free (hydrogen) fuel can be produced. An example of this technology is the chemical conversion of coal to a mixture of hydrogen and CO_2, with subsequent separation of the CO_2. The hydrogen can then be used in, for instance, a combined cycle to generate electricity, to replace transport fuel or to feed fuel cells. A promising technology might be the use of fuel cells with integrated CO_2 recovery. However, it is not expected that fuel cells will become available on large scale before 2010.

A third method to recover CO_2 is to combust the fuel in a mixture of oxygen and (recycled) CO_2. In this way the CO_2 does not have to be separated, because it is released in nearly pure form. Disadvantage is that pure oxygen has to be

[11] Research on CO_2 removal is relatively new. A valuable information source are the proceedings of the bi-annual conferences (Greenhouse Gas Control Technologies conference) organised on this topic. The latest GHGT conference was held in Cairns, August 2000.

supplied. A promising route may be the development of a gas turbine that uses CO_2 as a working medium. It is expected however, that the development of such turbine will take some years and several hundred millions of euros of investment.

Compression and transport of CO_2. Once the CO_2 has been recovered it should be transported to a storage location. Because of the large volumes, pipeline transport is required. The use of large tanker might be economically attractive for long-distance transport over water. Transport of CO_2 can best be done at high pressure in the range of 80 to 140 bars. Compression of CO_2 to such pressures is feasible and technological proven. Pipeline transport of CO_2 is not an uncommon practice. Large amounts of this gas are nowadays transported over long distances in the United States, where over 600 kilometre of large-scale pipeline is in use for pumping carbon dioxide. The transported CO_2 is used in enhanced oil recovery projects.

Storage of CO_2. Alternatives to releasing CO_2 to the atmosphere must be found. Underground storage is a viable option. Suitable candidates are exhausted natural gas and oil fields. These sites are well-known, and most-probably a secure place to store CO_2. Another attractive option is to store CO_2 in not (yet) exhausted oil fields. Due to its properties, supercritical CO_2 can be used to recover additional oil from the reservoir. In this case, storage will generate extra income. This so-called Enhanced Oil Recovery (EOR) is a well-established technology within the petroleum industry. In some cases it might also be possible to recover some extra gas from natural gas fields.

Another emerging technology is to store CO_2 in unminable coal layers. These layers often contain large amount of natural gas. By injecting the CO_2 in these layers, some of this natural gas can be recovered. At the moment about 3 to 4% of the natural gas production in the United States is produced from coal layers. In Europe coal layers are typically much older. Therefore experiences from other location can not directly be implemented elsewhere.

CO_2 might also be stored in aquifers (water containing layers). These underground compartments are generally more widespread than hydrocarbon fields. A Joule II study concluded that “underground disposal is a perfectly feasible method of disposing of very large quantities of carbon dioxide” [Holloway, 1996].

2.3.4.2 Potential of CO_2 removal

To determine whether CO_2 removal is an option that can contribute significantly to the reduction of CO_2 emissions and to the development of a sustainable energy system, it is important to know how large the reserve of fossil fuels is and whether there is enough space to store CO_2 safely.

Nowadays the amount of carbon stored in fossil fuels is estimated at 5.000 to 10.000 GtC, which is about 800 to 1600 times the current use [OTA, 1991]. IIASA estimated that about 3.000 GtC can be recovered at costs below 20 euro per barrel of oil equivalent [Nakicenovic, 1992]. Climate restrictions may cause that only a limited part may be emitted to the atmosphere. To stabilise CO_2 concentrations in the atmosphere at 550 ppm (twice the pre-industrial concentration of CO_2), the cumulative emissions until 2100 may not exceed the 700 to 1100 GtC [IPCC, 1995}. The use of more fossil fuels will then only be possible using decarbonisation processes. It should be noted that CO_2 removal could also be used in combination with biomass use. This way, CO_2 will be removed from the atmosphere, thus lowering the CO_2 concentration.

The storage potential of CO_2 is probably large. Worldwide the storage potential in oil and gas fields is estimated at about 500-1800 GtC. In the European union and Norway the potential is estimated at about 40 GtC [Holloway, 1996]. The storage potential in aquifers depends very much on the requirement of a 'cap', i.e. a CO_2 impermeable layer above the reservoir. The potential in Europe is estimated at 220 GtC (=800 $GtCO_2$), but might be much higher [Holloway, 1996].

Nowadays large scale removal of CO_2 is only implemented in Norway, where CO_2 is separated from recovered natural gas and injected in an aquifer above the gas field. Concrete plans exist in the Netherlands to use about 1 Mt yearly recovered CO_2 from a hydrogen production facility as feedstock in greenhouses. To cope with the irregular demand pattern, a part of the CO_2 has to be stored temporarily in a buffer underground. From a technical point of view, CO_2 removal can at present be applied at many different energy conversion processes, although substantial improvements in efficiency and costs can still be made. The estimate of the potential is therefore not straightforward. In this study we assume that CO_2 removal is only applied at *new* power plants, because adapting existing plants is much less cost-effective and energy efficient. For new power plants, the choice of location and technology may be influenced by application of CO_2 recovery. Locations may be chosen close to empty natural gas fields or appropriate aquifers.

Regarding the current low implementation rate of CO_2 removal it is not realistic to assume that this technology may play a highly substantial role to reduce CO_2 emissions before 2010. Based on current experiences on application of this technology we estimated that a potential between 10 to 100 Mt of CO_2 is attainable before 2010. In this study we assume a potential of 50 Mt of CO_2 in the EU that can be recovered and stored in 2010.

2.3.4.3 Cost of CO_2 removal

Costs of CO_2 removal are distributed over costs for extra energy, and costs for equipment (recovery equipment, compressors, pipelines, injection wells). In some cases additional winning of hydrocarbons can generate income. In a limited number of cases the CO_2 can be sold to for instance greenhouses as a fertiliser. Table 2.18 gives an overview of typical costs and application of CO_2-removal technologies.

Table 2.18. Overview of typical costs and applications of CO_2-removal technology.

	Costs	**Technology**	**Industry**
	euro/tCO_2		
Recovery			
Pure CO_2 stream	Small		Ammonia production; Hydrogen production (feedstock)
Post-combustion	30-60	Amines, membranes	Power plants; Iron and Steel, Refineries, etc
Pre-combustion	15-35	Synthesis gas (followed by shift)	Hydrogen production, methanol production, power plants
Compression/transport			
Compression (80 bars)	6-8	4-stage compressor (capacity: 1-4 Mt)	
Transport (per 100 km)	3-7	Pipeline (underground); (capacity: 1-4 Mt CO_2)	
Storage			
Hydrocarbon fields / aquifer (onshore)	3-6	Income possible by enhanced oil/gas recovery	
Hydrocarbon fields / aquifers (offshore)	6-10	Income possible by enhanced oil/gas recovery	

2.3.4.4 Conclusion

CO_2 removal is a technical feasible option. Nevertheless substantial research is required to better understand the impact, environmental consequences and risks of underground storage. Improving recovery technology may substantially lower the costs of CO_2 removal.

The technology can be applied to power plants and a broad range of industries. Also in this way hydrogen can be produced carbon free and subsequently used for various applications, e.g. to feed into the natural gas pipelines, to produce electricity, or on the longer run, to be used as transport fuel. Total removal costs are typically in the range from 15 euro per tonne of CO_2 (for pure sources nearby a storage location) to 75 euro per tonne of CO_2 (including recovery, compression, transport and storage). An estimate of the potential is difficult to make. In this study an EU-wide potential of 50 Mt of CO_2 is assumed.

2.4 PETROLEUM REFINERIES

2.4.1 Description

The primary energy demand for all refineries in the EU is estimated to be 1600 PJ per year in 1990 (EU-12), or 3.4% of the EU total primary energy consumption [Worrell, 1994].

In 1990 in almost all EU Member States petroleum refining capacity was in place. The countries with the largest refining capacities are Italy, United Kingdom, France and Germany. Table 2.19 gives an overview of the primary distillation capacity in EU member states in 1990.

Table 2.19. Capacities of primary distillation in 1990 (source: [CEC, 1993], except when otherwise noted)

million tonnes of crude oil annual capacity															
AUT	BEL	DEU[1]	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	LUX	NLD	PRT	SWE	**EU**
0	35	78	9	62	10[2]	85	91	18	3	117	0	60	14	21[2]	**603[3]**

[1] FRG only; [2] data for 1996 [Swedish Petroleum Institute, 2000]; [3] including the capacity in Sweden and Finland.

The Specific Energy Consumption (SEC) of refineries is expressed in GJ of final energy per tonne of throughput (crude oil intake). See Table 2.20.

Table 2.20. SEC for petroleum refining (source: [Worrell et al.*, 1994], except when otherwise noted).*

GJ of final energy per tonne of throughput (crude oil intake)															
AUT	BEL	DEU[1]	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	LUX	NLD	PRT	SWE	**EU**
0	2.7	3.5	2.7	3.5	N/A	3.3	3.4	2.5	4.8	2.9	0	3.5	2.9	3.3	**3.3**

[1] FRG only; 2 data for 1996 [AF-Energikonsult, 1997].

2.4.2 Options to improve the energy efficiency

The following options to improve the energy efficiency of petroleum refineries will be described:

- Reflux overhead vapour recompression;
- Power recovery;
- Improved catalysts.

Furthermore, several other measures are taken together in one category called miscellaneous.

It should be noted that petroleum refineries vary from relatively simple – only a crude distillation unit and a vacuum unit – to very complex and highly integrated complexes. Over the past decades the complexity of refineries has constantly increased. This is the result of changes in the product mix towards a higher degree of processing, partly because of environmental requirements for transport fuels. A recent Concawe report shows that the largest changes have occurred before 1990. The share of simple refineries[12] decreased from 82% in 1974 to 11% in 1990. In 1997 the share of simple plants in total number of plants increased again to 13% [Concawe, 1999]. Since the largest changes occurred before the reference year of this study (1990), we do not account separately for this shift in structure. It is possible, however, that more changes will occur in the future, for instance in case transport fuel requirements tighten even more. Such changes and their influence on energy consumption have not been taken into account in this study.

Reflux overhead vapour recompression (distillation) – The energy efficiency of the crude distillation unit can be improved by pumping reflux from the overhead condenser to lower points in the column. In this way the heat transfer temperatures are higher and a higher fraction of the heat energy can be recovered by preheating the feed [Gary and Handwerk, 1994]. The savings amount to 0.15 GJ/tonne [WEC, 1995]. Investment costs of a crude distillation unit are $50 million for a 5 kt oil feed per day plant (1992 U.S. Gulf Coast [Gary and Handwerk, 1994]). According to Gary and Handwerk [1994] hydrocarbon plant costs at the Gulf Coast are the lowest of the U.S. Plants in New York, for instance, is 1.7 times as expensive, and in Chicago 1.3 times. We assume that in Europe costs are 1.5 times as high as the costs on the Gulf Coast. If we assume that the overhead vapour recompression pump costs 0.1% of the investment of a total crude distillation unit (equalling € 0.7 million for a 15 ktpd plant), the investment would equal 0.9/GJ saved annually.

Power recovery (e.g. in the hydrocracker) – Some processes in a refinery are carried out at elevated pressure, e.g. cracking processes. The subsequent fractionation of cracking products, takes place at a much lower pressure. Hence, after the completion of the cracking reaction the pressure needs to be reduced. The energy of the pressurised gas can be recovered by using a power recovery turbine. At the Total refinery in Vlissingen (the Netherlands) a power recovery turbine is installed at the hydrocracker. Annual electricity production is 32 TJ with investment costs of 376.000 [Caddet, 2000]. Annual throughput of this refinery is estimated at 5 million tonnes of crude oil. Thus, energy savings amount to 0.01 GJ/tonne and investments are 12/GJ saved annually for power recovery at hydrocrakers (of which 10 are in operation in Europe [Callau, 2000]). Power recovery systems, using different types of turbines are also possible at fluid catalytic crackers [OIT, 1990; Caddet, 2000]. At fluid catalytic crackers, a turbine power recovery train could save 0.05 GJ/tonne [OIT, 1990]. Investments are expected to be higher, because more equipment is needed. We estimate investment cost per GJ saved annually, however, to be the same (€ 12/GJ saved annually). In Europe, 44 fluid catalytic crackers are in operation [Callaud, 2000].

[12] Defined as non-conversion refineries, composed of crude oil distillation, reforming, treatment of distillate products, including desulphurisation and/or other quality improvement processes (i.e. isomerisation or specialty manufacturing) [Concawe, 1999]

Improved catalysts at catalytic reforming and cracking – Higher active and selective catalysts can increase the yield of processes based on catalytic conversions, e.g. in the catalytic reformer and the cracker. Savings of 0.5 GJ/tonne have been reported [WEC, 1995]. We assume that only smaller savings are possible up to 2010: 0.1 GJ/tonne. Costs will mainly be manifested as higher operation and maintenance costs: 5/GJ saved annually.

Miscellaneous – Other measures to improve the energy efficiency of refineries are [WEC, 1995]:
- Better process management (potential energy savings: 0.05 GJ/tonne)
- More efficient hydrogen production
- Intermediate reboilers and condensers (potential energy savings: 0.05 GJ/tonne)
- Air preheaters (potential energy savings: 0.1 GJ/tonne)
- Staged crude preheat (potential energy savings: 0.1 GJ/tonne)
- Application of mechanical vacuum pumps (potential energy savings: 0.3 GJ/tonne in the distillation section and 0.15 GJ/tonne in cracking)

Not all of the above options will be possible at all plants, and part has already been implemented. Therefore, we estimate the saving on fuel demand attainable through the above mentioned miscellaneous measures at a modest 0.3 GJ/tonne crude oil. Half of this saving can be achieved at costs of 15/GJ saved annually and the other half at 50 GJ/saved.

2.4.3 Summary table emission reduction options

The list of options given above and the results for refineries in the overall analysis should be seen as a first attempt to identify important efficiency options in the refineries, based on information available in literature. The various refineries in the EU may differ substantially from one to the other[13]. For more accurate estimates more detailed information is required on each type of refinery. This is an area for future research. Table 2.21 gives an overview of the average specific costs and potential. The costs are calculated using an real interest rate of 4% and using the technical lifetime of the option, i.e. installation.

Table 2.21. Average specific costs (euro/tCO_2) and emission reduction potential (Mt CO_2) for refineries in 2010 compared to frozen technology reference level.

Name measure	**subsector**	**Specific costs**	**Emission reduction**
		euro/tCO2 eq.	Mt CO2
Reflux overhead vapour recompression (distillation)	Refineries	-66	6
Power recovery (e.g. at fluid catalytic cracker)	Refineries	-51	1
Miscellaneous I (Low cost tranche)	Refineries	-29	6
Improved catalysts (catalytic reforming)	Refineries	0	4
Miscellaneous II (High costtranche)	Refineries	60	6
Total			**23**

[13] In addition, it should be noted that because of the shift in products of the refineries (i.e. to higher quality because of environmental regulations in the transport sector), emissions per tonne of product may go up.

3. OPTIONS TO REDUCE N_2O EMISSIONS FROM STATIONARY COMBUSTION

3.1 INTRODUCTION

Nitrous oxide in the atmosphere is largely of biogenic origin. In addition to the biogenic sources, several anthropogenic abiogenic sources can be distinguished. This includes industrial processes like adipic acid production, nitric acid production, and combustion processes. In this section the focus is on stationary combustion processes.

Emissions from the combustion of fossil fuels in stationary combustion processes are generally low, typically 1 to 2 ppmv for coal-fired plants and 1 ppmv or below for oil and gas fired plants. Combustion sources where emissions may not be low are flue gases from fluidised bed combustion (where the lower bed temperatures leads to higher emissions) flue gas cleaned by selective non-catalytic reduction (SNCR-NO_x abatement), and combustion of wood, waste and other biomass. The total estimated emission of N_2O in 1990 of the EU-15 is approximately 1.3 Mt N_2O.

With an emission of 0.14 Mt in 1990, fuel combustion (transport excluded) contributes to approximately 11% of total estimated nitrous oxide emissions from human activities. The mechanisms that cause the formation of N_2O during the combustion process are fairly well understood.

With an emission of 0.01 Mt in 1990, waste contributes to approximately 1% of total estimated nitrous oxide emissions in the EU. The main source within this category is emissions from wastewater treatment, where emissions arise from denitrification units in wastewater treatment plants. N_2O emissions from incineration of waste form a minor part of the emissions of this category. This study will not elaborate on this category.

3.2 EMISSIONS

3.2.1 Emission mechanisms

Nitrous oxide is produced directly from the combustion of fossil fuels, mainly as a by-product of the so-called “fuel-NO mechanism”, although a number of other mechanisms may contribute to its formation and destruction. The average emission factors for the fuel types as mentioned by AEA Technology (1998) are listed in Table 3.1. The mechanisms are fairly well understood, and it is possible to forecast, at least in a qualitative manner, N_2O emissions from different combustion sources and flue gas treatment techniques.

Table 3.1 Emission factors for stationary combustion by fuel type (AEA Technology, 1998).

Fuel	g N_2O/GJ
Coal (non fluidised bed)	1.4
Coal (brown and hard coal, fluidised bed)	10-70
Oil	0.6
Gas	0.1
Wood, other biomass and waste	4

N_2O emissions due to the fuel-NO mechanism are highest for combustion temperatures of about 730^{o}C. For combustion temperatures below 530 ^{o}C or above 930 ^{o}C almost zero or negligible amounts of N_2O are emitted. Emissions may also be affected by other factors, for example, increased pressure of the combustion gases or higher oxygen concentration, tends to increase the emissions.

Other mechanisms, which may affect emissions arising from combustion processes, are less well studied. They include:

- the destruction of N_2O on bound carbon atoms in graphite and coal char;
- the formation of NO_X from char bound nitrogen atoms;
- the formation of N_2O from NO and reduced sulphates;
- catalytic N_2O formation and destruction in fluidised bed combustion due to limestone ($CaCO_3$) which is added to capture the sulphur present in the coal and reduce SO_2 emissions.

N_2O may also be formed and destroyed where catalysts are used to abate NO emissions in flue gases.

In practice the characteristics of these mechanisms mean that emissions from the conventional combustion of fossil fuels in power stations, boilers etc. is very low (de Soete, 1993), as the flame temperature is high (well beyond 1000^{o}C). Situations where this is not the case are:

- **Fluidised bed combustion (FBC)**. Fluidised bed combustion is a “clean coal technology” with a higher efficiency than conventional pulverized fuel combustion and lower emissions of NO_x due to a lower combustion temperature. However the lower combustion temperature in the bed leads to higher N_2O emissions. Emissions decrease with increasing bed temperature, and increase to a certain degree with increasing oxygen concentration. Lower rank coals, brown coal and lignite, peat wood and oil shales, produce less N_2O than bituminous coal. Circulating fluidised beds have often been found to have higher emissions than bubbling fluidised beds, possibly due to longer residence time in the former.

- **Selective Non Catalytic Reduction (SNCR)**. In selective non catalytic reduction (SNCR) chemicals such as ammonia, urea, or cyanuric acid are injected into the flue gas to reduce NO_x. This leads to some emissions of N_2O, which are higher in the case of urea or cyanuric acid than in the case of ammonia. A more expensive, but more effective technique for reducing NO_x emissions in the flue gases is selective catalytic reduction (SCR), where ammonia is injected into the flue gas in the presence of a catalyst, commonly titanium oxide based, to reduce NO and NO_2 to nitrogen and water. Little experimental data is available, but SCR appears to have little effect on N_2O emissions (de Soete, 1993).

3.2.2 Emissions in EU-15

The breakdown of emissions in 1990 and time development of the emissions for the EU are shown in Table 3.2 and Table 3.3.

It needs to be mentioned that if the N_2O emissions were calculated from the emission factors in Table 3.1 and the energy input for combustion of fuels from the PRIMES-database, emissions will turn out to be much lower then given here. Incorporating a higher coal emission factor due to FBC will not solve this difference. It needs a FBC share of the coal use in the order of 15% instead of the 3% that Takeshita et al (1993) assume, to solve this difference.

Fluidised bed combustion is the source with the largest N_2O emissions in the fuel combustion category. If we want to estimate the influence of the emission reduction measures for this category, figures on the emissions due to this source are necessary. However, only figures on total fuel combustion emissions are available.

There is no country specific database available on installed fluidised bed combustion plants and their production or emissions. There may be data available for other countries in diffuse literature sources (Smith, 1999), but it is to time consuming to carry out a survey within the scheme of this project. Only for the Netherlands and Sweden some information is directly available for this study. Takeshita et al (1993) mention that 20% of the N_2O emissions of stationary combustion in Sweden were estimated as coming from fluidised bed combustion. De Jager et al (1996) mention that about 9% of the N_2O emissions of stationary combustion in the Netherlands comes from fluidised bed combustion.

Because of this lack of data, a country specific subdivision of emissions from fluidised bed combustion and from other sources will be derived. It is clear that this proposed subdivision needs further refinements and adjustments based on country specific data and is therefore open for discussion.

Table 3.2. Emissions of N_2O from stationary combustion expressed in kton N_2O [UNFCCC, 1999].

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**
Austria	1	1	1	1	1	1	1	1
Belgium	7	7	7	7	7	7	7	7
Denmark	1	1	1	1	1	1	1	1
Finland	4	0	0	0	0	6	6	0
France	9	10	11	10	9	9	10	9
Germany	26	25	23	22	22	24	21	20
Greece	7	6	6	6	6	6	7	7
Ireland	2	3	3	3	3	3	3	3
Italy	42	42	42	42	37	39	39	39
Luxembourg	0	0	0	0	0	0	0	0
Netherlands	0	0	0	0	0	0	0	0
Portugal	1	1	1	1	1	1	1	1
Spain	19	19	21	19	21	21	21	21
Sweden	4	3	3	5	4	3	6	5
United Kingdom	13	13	12	12	11	11	12	12
EU 15	**136**	**131**	**131**	**129**	**123**	**132**	**135**	**126**

Table 3.3. Emissions of N_2O from stationary combustion expressed in kton N_2O, subdivided over sectors in 1990 [UNFCCC, 1999].

1990	**Energy Industries**	**Industry**	**Commercial**	**Total Emissions**
Austria	0	0	1	1
Belgium	2	2	3	7
Denmark	1	0	0	1
Finland	1	1	1	4
France	2	3	4	9
Germany	14	6	6	26
Greece	3	2	2	7
Ireland	1	0	1	2
Italy*	20	10	12	42
Luxembourg	0	0	0	0
Netherlands	0	0	0	0
Portugal	0	0	1	1
Spain	10	5	3	19
Sweden	1	2	1	4
United Kingdom	7	4	2	13
EU 15	**62**	**35**	**37**	**136**

* figures seem high

For all EU Member States the subdivision will be derived in the following way:

- a fixed emission factor will be estimated for coal combustion based on the assumption: 3% of the coal use is assumed to be in fluidised bed combustion. The weighted emission factor is 3 g N_2O/GJcoal, assuming a FBC-emission factor of 50 g N_2O/GJcoal and the coal (non FBC) emission factor from AEA Technology (1998). Under this assumption 55% of the emissions due to coal combustion are from fluidised bed combustion. Takeshita et al (1993) estimated the contribution from FBC to the total emissions from coal use at about 60-70%.

- the emissions due to coal combustion now will be calculated in the following way:

$$\frac{Ecoal * EFcoal}{Ecoal * EFcoal + Eoil * EFoil + Egas * EFgas} * Emissions\_fuel\_combustion$$

  with E = energy input (in energy sector 1995) and EF = emission factor.

- For this calculation Primes-data, total energy use for combustion (of 1995, excl.transport) are used.

Table 3.4 Emissions of N_2O from stationary coal combustion and FBC expressed in percentages of total emissions from stationary combustion and in kton N_2O in 1990.

1990	**Emissions from FBC %**	**Emissions from coal combustion (incl. FBC) %**	**Emissions from FBC kton N_2O**	**Emissions from other coal combustion kton N_2O**	**Emissions from other fuel combustion kton N_2O**
Austria	39%	70%	0.4	0.3	0.3
Belgium	42%	76%	2.9	2.4	1.7
Denmark	48%	87%	0.5	0.4	0.1
Finland	46%	84%	1.8	1.6	0.6
France	35%	63%	3.1	2.6	3.3
Germany	48%	87%	12.5	10.2	3.3
Greece	47%	86%	3.3	2.7	1.0
Ireland	45%	82%	0.9	0.7	0.4
Italy	26%	47%	10.8	8.9	22.3
Luxembourg					
Netherlands	39%	72%	0.0	0.0	0.0
Portugal	40%	73%	0.4	0.3	0.3
Spain	44%	80%	8.3	6.8	3.9
Sweden	20%		0.8	0.0	3.2
United Kingdom	47%	86%	6.1	5.1	1.8
EU 15	**38%**	**68%**	**52**	**42**	**42**

3.3 EMISSION REDUCTION OPTIONS

3.3.1 Introduction to the measures

Options to reduce N_2O may be categorised as follows:

- reduced emissions from fluidised bed combustion;
- use of other NO_x abatement techniques as NSCR;
- reduction in fossil fuel consumption or change of fuel type (e.g. by applying energy efficiency improvement measures, shift to other fuel types, and increased use of renewables). A shift from coal to oil to gas would result in lower emissions of nitrous oxide in the energy provision sector as shown in Table 3.1. Also a shift to non-fossil energy sources will result in emission reductions. This category of options will not be incorporated in the calculations of this study.

3.3.2 Options to reduce emissions associated with fluidised bed combustion

3.3.2.1 Description

3.3.2.1.1 *Optimising operating conditions*

As indicated earlier, emissions decrease with increasing bed temperature, and increase to a certain degree with increasing oxygen concentration. Optimising conditions within FBC, e.g. by keeping the bed at higher temperature (of about 900 °C) can reduce N_2O emissions. Tests in two medium-sized pilot plants (72 MWth and 105 MWe) showed a decrease of N_2O emission between 30 and 60%, but a doubling of NO_x emissions (Boemer et al, 1993). The NO_x could be abated by using SCR. SNCR is not preferable in the viewpoint of N_2O emission reduction. SCR fitted on a fluidised bed plant is demonstrated in Japan and Sweden (Takeshita et al, 1993).

Use of afterburner

N_2O in the flue gas is decomposed by injecting extra gas in the flue gas downstream the boiler, which raise the temperature shortly to 950 °C. This is demonstrated on small-scale. For large-scale commercial plants this still has to be demonstrated. The N_2O emission reduction achieved is 90%. An amount of gas corresponding to 10% of the total energy input was required (Lyngfelt et al, 1996). There was no significant increase in NO_x emissions. It appears that this approach might offer the potential to reduce N_2O emissions without any concomitant increases of other pollutants.

Apply reversed air staging

It is possible to reduce N_2O emissions without affecting SO_2 by ensuring a good supply of oxygen in the bottom part of the chamber and less oxygen in the upperpart. This is done by introducing primary air only through the bottom zone of the combustion chamber, and introducing secondary air for final combustion after the cyclone (Lyngfelt et al, 1995). The results for the test plant (a 12 MWth circulating FBC) show that, reversed air staging can reduce N_2O emissions by about 75% (from about 100 ppmv to 25 ppmv at 6%) without any effect on emissions of other pollutants. More work is needed to establish whether the results would be valid in plants of other sizes.

Application of catalytic reduction of N_2O

The range of 30-150 ppmv is suitable for catalytic reduction. Currently, catalysts for nitrous oxide are in development and it is expected that they could reduce emissions with about 80%. It is unknown when this technology might become available.

Conversion to pressurised fluidised bed combustion

Instead of atmospheric fluidised bed, pressurised fluidised bed plants may be used. A small test plant showed an N_2O emission rate of below 20 ppmv, a reduction of about 80%; still higher than conventional coal-fired plants but lower than atmospheric fluidised combustion plants.

3.3.2.2 Current practice

Except catalytic reduction of N_2O, all options are demonstrated.

3.3.2.3 Implementation

These emission reduction options are assumed to be implemented only at new FBC plants. According to AEA Technology (1998) new coal fired plants which are introduced are assumed to be either conventional type stations or in the case of new thermal technologies, predominantly Integrated Gasification Combined Cycle Plants. A large build of fluidised bed combustion plants, which have significantly higher emisisons is not forecast. Due to normal replacement of plants with a lifetime of 30 years in the period 1995-2010 about 50% of the plants would be qualified to be replaced. Since a reduction in coal combustion of 30% in this period is forecast, the other 20% of the plants that reach the end of their lifetime are either replaced by conventional type stations and IGCC-plants or by FBC with abatement measures.

In the abatement case it is assumed that all FBC plants that will be replaced are FBC plants with a mix of abatement options resulting in an average abatement of 80% of the emissions of the replaced FBC plants.

3.3.2.4 Costs

AEA Technology (1998) gives cost data on the first three abatement options for FBC mentioned above.

Cost assumptions (AEA Technology, 1998) are shown in Table 3.5 :

Table 3.5 Cost assumptions for N_2O reduction options associated with Fluidised Bed Combustion (AEA Technology, 1998).

	optimised conditions	**after burner**	**reversed air staging**
Investment cost per tonne N_2O abated (Euros)	18000-19400	5400	-
Operating costs per tonne N_2O abated (Euros)	1160-1080	500	1200
Lifetime (years)	15	30	30

In the abatement case it is assumed that only the options 'after burner' and 'reversed air staging' will be applied.

3.3.2.5 Country specific implications

There is no country specific information publicly available on implemented reduction measures and policies for the implementation of measures.

3.4 FROZEN TECHNOLOGY REFERENCE CASE

The frozen technology reference level for emissions of N_2O from stationary fuel combustion are derived from the developments of fuel use according to the PRIMES-database:

- Energy use in the energy sector increases with about 11% over the period 1995-2010 and total energy use (excl. transport) decreases with about 30% in this period.
- Both for the energy sector and the total energy use the coal use decreases, with 20% respectively 25%. For liquid fuels a decrease with 6% and 53% applies and for gas fuels an increase of 84% and a decrease of 8% applies.
- The no abatement case assumes that no measures are introduced to reduce emissions over the period 1990 to 2010 and the initial distribution over the plant types per fuel is maintained.
- The abatement case shows the effect on emissions of reduction measures which are due to be implemented over the period 1990 - 2010. This consists of the abatement of emissions as described in section 3.3.2.3.

Table 3.6 Emissions of N_2O from stationary coal combustion and FBC expressed in kton N_2O in 2010 in the no abatement case.

2010	Emissions from fuel combustion kton N_2O	Emissions from FBC kton N_2O	Emissions from coal combustion (incl. FBC) kton N_2O	Total emissions from stationary combustion kton N_2O
Austria	0.6	0.2	0.2	1
Belgium	2.1	1.6	1.3	6
Denmark	0.4	0.3	0.3	1
Finland	0.7	1.3	1.0	3
France	3.1	1.6	1.3	6
Germany	2.8	7.8	6.4	17
Greece	1.1	2.2	1.7	5
Ireland	0.1	0.5	0.4	1
Italy	9.7	8.9	7.4	26
Luxembourg	0.0	0.0	0.0	0
Netherlands	0.0	0.0	0.0	0
Portugal	0.5	0.3	0.2	1
Spain	3.4	5.3	4.3	13
Sweden	2.5	0.5	0.0	3
United Kingdom	3.7	3.4	2.9	9
EU 15	**30.7**	**33.9**	**27.4**	**90**

Table 3.7 Emissions of N_2O from stationary coal combustion and FBC expressed in kton N_2O in 2010 in the abatement case.

2010 (abatement)	Emissions from FBC kton N_2O	Emissions from other coal com-bustion kton N_2O	Emissions from other fuel com-bustion kton N_2O	Total emissions from fuel com-bustion kton N_2O
Austria	0.2	0.2	0.2	0.6
Belgium	1.3	1.3	1.8	4.4
Denmark	0.3	0.2	0.1	0.6
Finland	1.1	1.0	0.3	2.4
France	1.4	1.3	3.0	5.7
Germany	6.5	6.4	3.0	15.9
Greece	1.8	3.6	0.7	4.3
Ireland	0.4	0.4	0.4	1.2
Italy	7.5	7.4	11.4	26.2
Luxembourg	0.0	0.0	0.0	0.0
Netherlands	0.0	0.0	0.0	0.0
Portugal	0.3	0.2	0.1	0.6
Spain	4.5	4.3	2.9	11.7
Sweden	0.4	0.0	2.6	2.6
United Kingdom	2.9	2.8	2.3	8.0
EU 15	28.5	55.4	28.8	84.2

3.5 AGGREGATION OF OPTIONS

Table 3.8 shows a summary of the costs of abatement of N_2O from fuel combustion.

Table 3.8 Summary of the costs of N_2O abatement from fuel combustion, in particular from Fluidised Bed Combustion.

	emission reduction kton	Capital cost kEuro	Operating cost kEuro
after burner	1.8	9720	900
reversed air staging	3.6	-	4320

3.6 SUMMARY TABLE EMISSION REDUCTION OPTIONS

Table 3.9 gives an overview of the average specific costs and potential. The costs are calculated using an real interest rate of 4% and using the technical lifetime of the option, i.e. installation.

Table 3.9. Average specific costs (Euro/tCO_2 avoided) and total potential (kt of CO_2) for fuel combustion emission reduction options in the EU15

Name measure	subsector	Specific costs	Emission reduction
		Euro/tCO2-eq.	ktCO2-eq.
Combusti processes Fluisidised bed after burner	Fuel combust	4.7	583
Combusti processes Fluisidised bed reversed air stag	Fuel combust	13.9	1167

4. FROZEN TECHNOLOGY REFERENCE LEVEL

To be consistent with the approach in other sectors, the 2010 steam and electricity demand of the industry, households sector and services sector are taken from the PRIMES model. In the 2010 frozen technology reference level emissions of CO_2 are calculated assuming that efficiencies of the plants remain on the same level and the fuel mix remains constant. Furthermore we assume that no additional CHP is built after 1995, i.e. we assume that only non-CHP units cover all additional steam demand in 2010. Table 4.1 shows the emission reference level in 2010. Table 4.2 shows the 1990 base year emissions and 2010 frozen technology reference level for the energy supply sector.

Table 4.1. CO_2 emission in 1995 for power and heat production and emissions in 2010 in the frozen technology reference level.

	AUT	BEL	DEU	DNK	ESP	FIN	FRA	GBR	GRC	IRL	ITA	NLD	PRT	SWE	EU
CO2-emission (kt) - 1995	**15594**	**28197**	**369569**	**32895**	**96388**	**26219**	**57418**	**209526**	**41452**	**13432**	**154903**	**66139**	**22511**	**8465**	**1142707**
of which by CHP	7723	3532	33248	12548	8657	10930	9767	33472	435	476	23500	18247	2637	4557	169730
of which by Other Electricity (fossil fuel-related)	7358	19173	287449	17047	75766	10775	26443	159590	38111	12104	116919	37019	19447	437	827638
of which by steam (fossil fuel-related)	513	5492	48872	3299	11965	4515	21208	16464	2907	852	14484	10873	426	3471	145339
CO2-emission (kt) - 2010	**29298**	**48507**	**448724**	**41096**	**185555**	**60847**	**144008**	**340101**	**72718**	**26477**	**227585**	**108817**	**50892**	**22417**	**1807041**
of which by CHP	7723	3532	33248	12548	8657	10930	9767	33472	435	476	23500	18247	2637	4557	169730
of which by Other Electricity (fossil fuel-related)	18001	37603	355276	23012	161680	36958	104721	280692	69455	24035	184411	72103	46735	7457	1422142
of which by steam (fossil fuel-related)	3573	7372	60199	5535	15218	12960	29520	25936	2829	1965	19673	18466	1519	10403	215169

Table 4.2. 1990 and 2010 frozen technology reference level in energy supply sector (in Mt CO_2 equivalent).

Energy supply sector		1990					2010				
		CO2	CH4	N2O	F-gases	Total	CO2	CH4	N2O	F-gases	Total
Austria	AUT	18	0	0	0	18	30	0	0	0	31
Belgium	BEL	31	0	2	0	33	80	0	2	0	82
Germany	DEU	445	3	8	1	458	468	3	5	1	478
Denmark	DNK	27	0	1	0	28	41	0	1	0	42
Spain	ESP	83	1	6	0	90	190	1	4	0	195
Finland	FIN	21	0	1	0	23	61	0	1	0	62
France	FRA	78	3	3	1	85	150	3	2	1	156
United Kingdom	GBR	265	2	4	1	272	358	2	3	1	364
Greece	GRC	38	0	2	0	40	73	0	1	0	75
Ireland	IRL	12	0	1	0	13	26	0	0	0	27
Italy	ITA	154	1	13	0	168	232	1	9	0	242
Netherlands	NLD	68	1	0	0	68	113	1	0	0	114
Portugal	PRT	19	0	0	0	20	52	0	0	0	52
Sweden	SWE	10	0	1	0	11	23	0	1	0	25
European Union	EU	1268	12	42	4	1327	1898	12	29	4	1943

5. CONCLUSIONS

In the frozen technology reference case greenhouse gase emissions in the energy supply sector grow from 1327 Mt in 1990 to 1943 Mt in 2010.

Four options are discussed to reduce CO_2 emissions from steam and electricity production: substitution (shift to lower carbon fuels and more efficient plants), use of more renewables, use of more combined heat and power, and CO_2 removal. When all new plants towards 2010 will be built as NGCCs this will reduce emissions by 500 Mt of CO_2.[14] Implementation of renewables (instead of a part of the NGCCs) will reduce an additional 229 Mt of CO_2. Practically all new power capacity required, i.e. capacity that is required to replace depreciated plants and to cover increasing demand, can be covered by CHP units, i.e. there is sufficient steam demand. In some countries implementation of the maximum technical potential for CHP units will result in an excess of electricity. In that case, existing power production units should be decommissioned prematurely. Implementation of CHP (instead of NGCCs) will abate an extra 64 Mt of CO_2 for the EU in 2010.

Implementation of all options in refineries may result in an emission reduction of 23 Mt CO_2. Implementation of options to reduce nitrous oxide emission in the stationary combustion may lower emissions by 2 Mt CO_2 equivalent.

Implementation of the option to recycle SF_6 from gas insulated switch gears may reduce emissions by about 1 Mt CO_2 equivalent.[15]

Table 5.1 and Table 5.2 give an overview of the investment costs, the yearly costs (sum of operation and maintenance costs and savings), average specific avoidance costs and potential for options applicable in the energy supply sector. The specific costs are calculated using a discount rate of 4% and using the lifetime of the option, i.e. installation. A graphical overview of the results is given in Figure 5.1.

[14] The emission reduction potential is calculated based on the structure of the energy supply sector in 1995. This year is chosen because there was no detailed data available on 1990. To arrive to the total emission reduction potential in 2010, the reduction in emission already obtained in 1995 should be accounted for. This was 91 Mt of CO_2.

[15] These options are not described in this report but in the report "Economic Evaluation of Emission Reductions of HFCs, PFCs and SF_6 in Europe", J. Harnisch and C. Hendriks, Ecofys, March 2000.

Table 5.1. EU15-average costs and potential (Mt of CO_2) for emission reduction in the energy supply sector (renewables only)

Pollutant	Measure Name	Sector	Emission reduction	Investment	Yearly costs	Lifetime	Specific abatement
			Mt CO2 eq.	euro/tCO2 eq.	euro/tCO2 eq.	year	euro/tCO2 eq.
	Biomass energy 3b: heat only on solid biomass	Renewables	25	47	-45	20	-42
	Biomass energy 1b: CHP on solid biomass	Renewables	4	284	-55	20	-34
	Biomass energy 2: CHP anearobic digestion	Renewables	4	421	-54	20	-23
	Subtotal: cost range < 0 euro / t CO2 eq.		**33**				
	Wind energy - onshore	Renewables	30	763	-65	15	3
	Small hydropower (<10 MW)	Renewables	2	1094	-45	40	10
	Large hydropower (>10 MW)	Renewables	15	1109	-45	40	11
	Biomass energy 3a: heat only on solid biomass	Renewables	64	47	12	20	15
CO2	**Subtotal: cost range 0 < 20 euro / t CO2 eq.**		**111**				
	Biomass energy 1a: CHP on solid biomass	Renewables	29	284	-1	20	20
	Subtotal: cost range 20 < 50 euro / t CO2 eq.		**29**				
	Geothermal electricity production	Renewables	2	1296	-30	25	53
	Wind energy - offshore	Renewables	18	1585	-55	15	88
	Tidal energy	Renewables	2	2477	-7	40	118
	Biomass energy 4a: ethanol	Renewables	9	700	185	20	236
	Biomass energy 4b: biodiesel	Renewables	24	960	229	20	299
	Solar photovoltaic energy	Renewables	1	5640	-54	25	308
	Subtotal: cost range > 50 euro / t CO2 eq.		**56**				
	Total emission reduction options		**229**				

Table 5.2. EU15-average costs and potential (Mt of CO_2) for emission reduction in the energy supply sector (except renewables see Table 5.1)

Pollutant	Measure Name	Sector	Emission reduction	Investment	Yearly costs	Lifetime	Specific abatement costs
			Mt CO2 eq.	euro/tCO2 eq.	euro/tCO2 eq.	year	euro/tCO2 eq.
	Refineries: Reflux overhead vapour recompression (distillation)	Energy supply	6	12	-67	15	-66
	Refineries: Power recovery (e.g. at fluid catalytic cracker)	Energy supply	1	160	-65	15	-51
	Refineries: Miscellaneous I (Low cost tranche)	Energy supply	6	200	-47	15	-29
	NGCC: Replacement of capacity by natural gas-fired combined cycle	Energy supply	214	0	0	25	<0
	NGCC: New capacity by natural gas-fired combined cycles	Energy supply	286	0	0	25	<0
	Subtotal: Cost range < 0 euro / t CO2 eq.	**Energy supply**	**513**				
	Refineries: Improved catalysts (catalytic reforming)	Energy supply	4	0	0	15	0
	CHP - Food, drink and tobacco	Energy supply	1	1272	-102	15	12
	Subtotal: Cost range for 0 < 20 euro/t CO2 eq.	**Energy supply**	**5**				
	CHP - Refineries	Energy supply	6	1500	-110	15	25
	CHP - Residential - Small	Energy supply	5	1748	-131	15	27
	CHP - Non-ferrous metals	Energy supply	0	1748	-131	15	27
	CHP - Engineering goods	Energy supply	0	1748	-131	15	27
	CHP - Other industries	Energy supply	0	1748	-131	15	27
	CHP - Paper and pulp	Energy supply	3	1748	-131	15	27
	CHP - Tertiary - Large	Energy supply	1	1748	-131	15	27
	CHP - Textiles	Energy supply	0	1748	-131	15	27
	Subtotal: Cost range for 20 < 50 euro / t CO2 eq.	**Energy supply**	**17**				
	CO2 removal and storage	Energy supply	50	325	21	15	50
	Refineries: Miscellaneous II (High cost tranche)	Energy supply	6	667	0	15	60
CO2	CHP - Tertiary - Small	Energy supply	3	1032	-30	15	63
	CHP - Food, drink and tobacco (implemented in situation of overcap	Energy supply	3	1272	9	15	123
	CHP - Iron and Steel	Energy supply	1	1484	-3	15	131
	CHP - Chemicals	Energy supply	3	1484	-3	15	131
	CHP - Building materials	Energy supply	0	1484	-3	15	131
	CHP - Residential - Large	Energy supply	5	1484	-3	15	131
	CHP - Tertiary - Small (implemented in situation of overcapacity)	Energy supply	3	1032	60	15	152
	CHP - Tertiary - Large (implemented in situation of overcapacity)	Energy supply	1	1748	44	15	201
	CHP - Engineering goods (implemented in situation of overcapacity)	Energy supply	1	1748	44	15	201
	CHP - Paper and pulp (implemented in situation of overcapacity)	Energy supply	3	1748	44	15	201
	CHP - Textiles (implemented in situation of overcapacity)	Energy supply	1	1748	44	15	201
	CHP - Residential - Small (implemented in situation of overcapacity)	Energy supply	5	1748	44	15	201
	CHP - Non-ferrous metals (implemented in situation of overcapacity)	Energy supply	0	1748	44	15	201
	CHP - Other industries (implemented in situation of overcapacity)	Energy supply	1	1748	44	15	201
	CHP - Building materials (implemented in situation of overcapacity)	Energy supply	0	1484	85	15	218
	CHP - Residential - Large (implemented in situation of overcapacity)	Energy supply	5	1484	85	15	218
	CHP - Chemicals (implemented in situation of overcapacity)	Energy supply	7	1484	85	15	218
	CHP - Iron and Steel (implemented in situation of overcapacity)	Energy supply	2	1484	85	15	218
	CHP - Tertiary - Medium	Energy supply	1	3075	-49	15	227
	CHP - Tertiary - Medium (implemented in situation of overcapacity)	Energy supply	1	3075	122	15	398
	Subtotal: Cost range > 50 euro/t CO2 eq.	**Energy supply**	**101**				
	SF6 Recovery from gas insulated switchgears	Energy supply	1	8.9	2.7	15	3
Non CO2	N2O Combustion processes Fluisidised bed after burner	Energy supply	1	257	24	30	3
	N2O Combustion processes Fluisidised bed reversed air staging	Energy supply	1	0	57	30	4
	Subtotal: Cost range 0 < 20 euro/t CO2 eq.						
	Cost range < 0 euro / t CO2 eq.		**513**				
	Cost range 0 < 20 euro / t CO2 eq.		**8**				
	Cost range 20 < 50 euro / t CO2 eq.		**17**				
	Cost range > 50 euro / t CO2 eq.		**101**				
	Total emission reduction potential		**639**				

Figure 5.1. 1990 emissions, 2010 frozen technology reference level and emission reduction potentials for four defined options in the production of steam and electricity. Also the reduction potential of refineries is included.

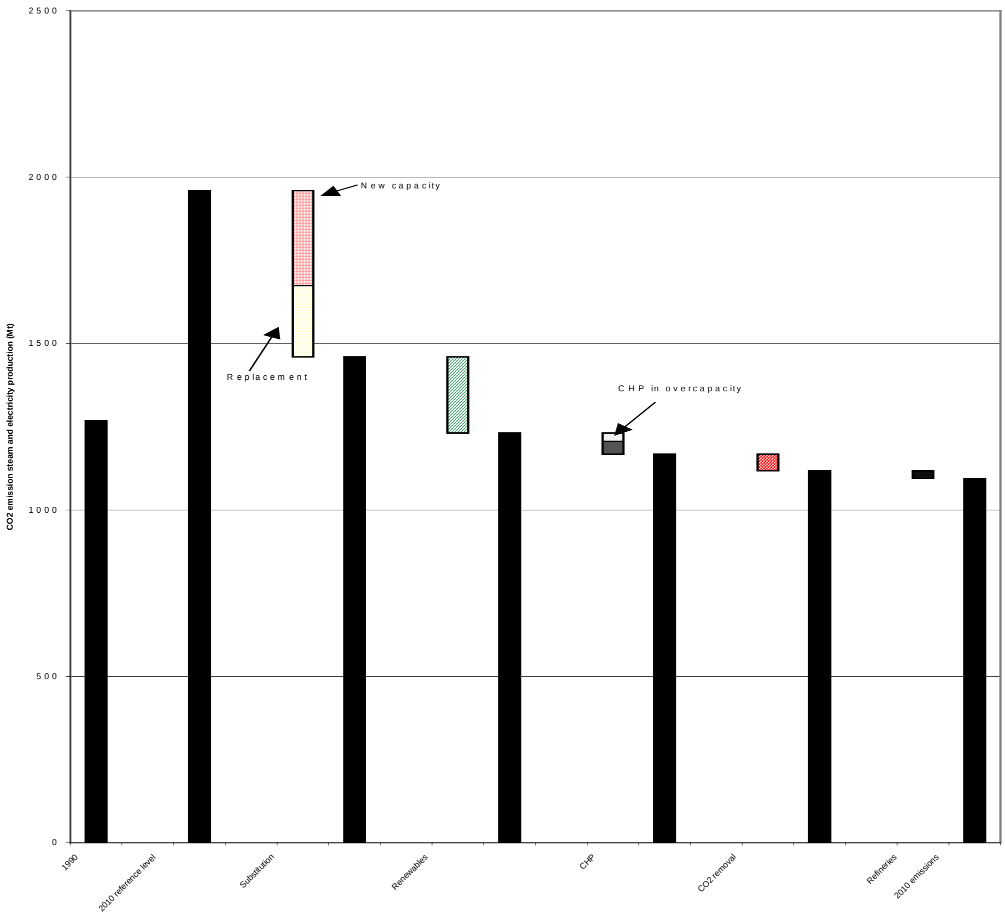
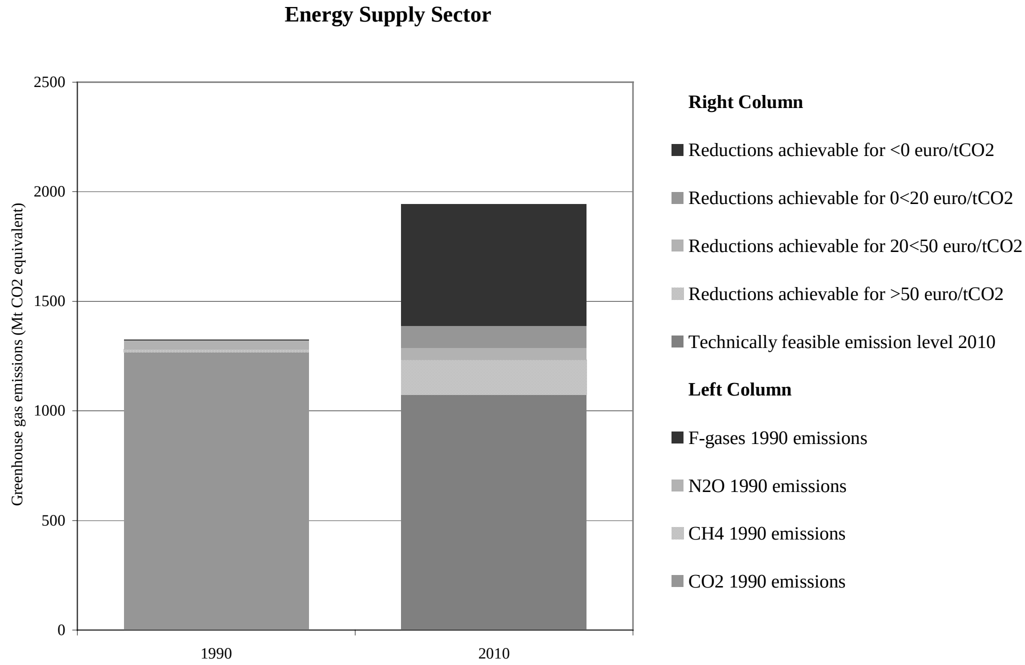


Figure 5.2 shows the share in emission reduction in the energy supply sector categorised in four costs brackets.

Figure 5.2. Energy supply sector: 1990 base year (left column, by gas) and 2010 frozen technology reference level (right column). Emission reduction potential is indicated for four costs brackets . The specific costs are calculated assuming a real interest rate of 4%.



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ANNEX 1. LIST OF PARTICIPANTS

Participants at Experts Workshop “Energy supply”
March 29, 1999, DG Environment, Brussels

Name	Organisation
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Mercedes Marin	COGEN Europe
Bo Nelson	Vattenfall
Nick Otter	ABB ALSTOM POWER
Beate Raabe	International Association of Oil and Gas Producers
Stephan Singer	WWF European Policy Office
Björn Sund	Norsk Hydro
Helmut Warsch	Siemens
Gerd Weber	German Coal Mining Association
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ANNEX 2: RENEWABLE ENERGY OPTIONS

CONTENTS

1 INTRODUCTION

Some energy flows on earth are induced by energy processes, which are eternal in human perspective. Solar nuclear fusion and gravitational forces are, notably in combination, the most important driving sources of such flows of renewable energy carriers (e.g. solar irradiation, winds, the carbon cycle). The points at which these renewable energy carriers enter the (economic) energy system, by conversion into the secondary energy carriers electricity, heat and/or fuel, are generally regarded as renewable energy sources. Three categories of renewable energy sources can be identified and will be dealt with in this report[16]:

Recurring energy forces

Wind energy (onshore/offshore)
Hydropower (small scale <10 MW/ large scale >10 MW)
Solar energy

- solar photovoltaic energy (electricity)
- solar thermal power (parabolic trough, power tower, dish/Stirling)
- solar thermal heat (active and passive)

Wave energy
Tidal energy

Ambient- and geothermal energy

Ambient energy
Geothermal electric
Geothermal heat

Biomass energy

e.g. woody biomass (forest residues, industrial waste streams, energy crops such as willow, poplar), other energy crops (sugar beet, wheat, rapeseed, Miscanthus, et cetera), agricultural and industrial wastes, other wastes with a significant biomass fraction (e.g. MSW, Municipal solid waste), biogas from waste water treatment or landfill sites, et cetera.

Some renewable energy technologies (RET) are typical energy production units (e.g. largescale hydropower, biomass to electricity production) and can usually be considered to be part of the energy supply sector, whereas others are more intertwined with energy demand (e.g. solar hot water boilers, domestic and industrial biomass combustion) or other activities (e.g. waste or waste water treatment).

Ever since the first oil crisis, the importance of both energy conservation and diversifying energy sources has been recognised in the Member States (MS) of the European Union (EU). Later the issue of climate change became a relevant stimulus for the development of renewable energy policies and R,D&D pro-

[16] Often waste incineration (including fossil fuel based materials) is incorporated in the category biomass-energy. In this study waste incineration is treated as a mitigation option for landfill gas.

grammes. The targets for the contribution of renewable energy for the year 2010 from the European Commission, as described in the White Paper 'Energy for the Future' (EC, 1997) are 675 TWh_e of electricity and 3.3 EJ_{th} of heat (excepting passive solar energy). This would altogether result in a mitigation of 250 Mt of CO_2 with respect to the pre-Kyoto reference scenario value for 2010. Table 2.4 lists the breakdown per renewable energy source for 1995 (statistics) and 2010 (target).

Table 3. 1995 statistics and 2010 targets for renewable energy sources in the White Paper for a Community Strategy and Action Plan [EC, 1997]

	1995		**2010**	
	Capacity	**Energy production**	**Capacity**	**Energy production**
1. Windenergy	2.5 GW	4 TWh_e	40 GW	80 TWh_e
2. Hydropower	92 GW	307 TWh_e	105 GW	355 TWh_e
2.1 Large (> 10 MW)	82.5 GW	270 TWh_e	91 GW	300 TWh_e
2.2 Small (< 10 MW)	9.5 GW	37 TWh_e	14 GW	55 TWh_e
3. Photovoltaics	0.03 GW_p	0.03 TWh_e	3 GW_p	3 TWh_e
4. Biomass	1.9 EJ_{LHV}	22.5 TWh_e 1.6 EJ_{th}	5.7 EJ_{LHV}	230 TWh_e 3.1 EJ_{th}
5. Geothermal				
5.1 Electric	0.5 GW	3.5 TWh_e	1 GW	7 TWh_e
5.2 Heat (incl. heat pumps)	1 GW_{th}	16.7 PJ_{th}	5 GW_{th}	42 PJ_{th}
6. Solar Thermal Collectors	6.5 millon m^2	10.9 PJ_{th}	100 mill. m^2	170 PJ_{th}
7. Passive solar				1.5 EJ
8. Others			1 GW	

2 METHODOLOGY

In the following sections the **implementation potential** of renewable energy technologies in Europe will be presented. The determination of this implementation potential is especially for RET not a straightforward activity. Generally, this potential is determined via the following steps:

- **Technical potential**
  The technical potential is determined by the physical possibilities for harvesting renewable energy, such as the supply of biomass residues, the space available for windturbines. The technical potential is time-dependent as technological improvements will increase the yield of renewables per hectare landuse for example. Moreover, competition between RET and other claims on landuse is in most cases more apparent than for conventional energy sources (e.g. agriculture, buildings, nature, recreation, etc.), and landuse claims develop in due course. Heat producing RET have to be fitted to local heat demand, which could decrease as a consequence of energy conservation measures.

- **Economic potential**
  The economic potential is that part of the technical potential which will be implemented by the market after a cost/benefit analysis if no further limitations exist. Economical barriers can be levelled out by financial incentives.
- **Market potential**
  The market potential in a certain year is that part of the economic potential which is not affected by market barriers or constraints, taking the penetration rate into account.
- **Market barriers and constraints**
  Numerous barriers exist that limit the economic potential in practice: the stage of technological development, capacity, quality and branching of energy infrastructures, competition with other claims on landuse, public acceptance, the lack of information and knowledge by market parties, uncertainties with respect to markets (e.g. the effects of the liberalisation of the energy markets on RET), and other transaction costs (e.g. financing RET, legislation). Some barriers can be leveled out by research and development, some barriers are institutional and need government initiatives (e.g. legislation, certification, education), some need new marketing concepts.
- **Penetration rate**
  The stage of the technological and market development of a certain RET restricts the penetration rate of this technology and therefore the medium-term market potential.

In this study the **implementation potential** is defined as that part of the technical potential which could be implemented if economic, technological and institutional barriers and constraints are levelled out, taking into account both the time of such a process and the penetration rate of the specific RET technology. This implies the implementation of a successful policy with respect to renewables: financial incentives, research and development, and elimination of institutional barriers.

As stated and illustrated before, the determination of the implementation potential for the year 2010 is not straightforward and the figures presented in this study should be considered as expert estimates and not as robust figures. Various literature references were used for delimiting the implementation potential:

- the European Renewable Energy Study [TERES-II, 1996], which describes the market penetration of RET under various scenarios;
- the ATLAS [1997] study, which presents a forecast of RET market penetration under current policies and trends;
- the Shared Analysis Project [EC, 1999], which describes a business as usual scenario and various CO_2-emission reduction scenarios; and
- various forecast and technical potential studies (per country and per technology).

The results of the Best Practice Policy scenario of the TERES-II study would come close to the implementation potential this study wants to determine. If we refer to this study, we refer to this scenario. However, both statistical information and scenario outcomes are superseded in many cases (e.g. scenario outcomes show lower production figures than already realised), which limits the applicability of the TERES study and the accompanying SAFIRE database. The ATLAS results are close to the market potential as defined above, and are therefore an underestimate of the potential which could be attained in an intensified renewable energy or climate policy. The same holds more or less for the outcome of the Shared Analysis Project and the accompanying macro-economic PRIMES model. In this study data on (market) potentials from TERES, ATLAS and PRIMES are therefore used as input, but are adjusted with RET specific studies or assumptions.

For each renewable energy source the following information will be provided:
- implementation potential in terms of capacity (MW electric or thermal, number of installations, et cetera.);
- associated energy production;
- investment costs, operation and maintenance costs and fuel costs per unit of capacity.

3 RENEWABLE ENERGY TECHNOLOGIES (RET)

3.1 Wind-energy

Wind energy is a rapidly growing renewable energy source in Europe. The last years annual installed capacity increased with 30-40% to a level of over 8900 MW[17] at the end of 1999, compared to 473 MW in 1990. The technical potential for wind-energy in Europe is enormous, several hundreds of GW onshore; including offshore installations even about 1 TW.

Implementation potential
The market for onshore wind energy technology is almost fully deployed. Further technological improvements will result in higher availabilities, higher installed capacities per turbine and higher production rates. The implementation potential is derived from the various references presented in the introduction (TERES-II, ATLAS, PRIMES), but adjusted according to new information and own estimates (a.o. EWEA). In 1999 2.5 GW of wind turbines were installed, reaching a total installed capacity of almost 9 GW. At this pace, total installed capacity would reach 35-40 GW in 2010. If the annual growth rate of 30-40% would be sustained, this would result in a total installed capacity of several hundreds of GW. In this study we assume an implementation potential of 50-55 GW, with a subdivision per country as presented in Table 4.

For offshore wind-energy we expect that several 100-200 MW demonstration projects will be realised in the coming years. After this stage, we assume a strong incentive for offshore wind energy and continuous technological improvements as a consequence of research and development. The implementation potential under these assumptions is estimated at 15 GW in 2010.

Table 1.2 presents the installed capacity for 1990 and the projections for 2010, as assumed in this study. In total we assume an implementation potential of about 33 respectively 16.5 GW for onshore and offshore wind energy. The European Wind Energy Association has set itself a target of 40 GW in 2010 and 100 GW in 2020. The 2010 figure is about 10 GW higher than the targets of the EC White Paper [EC, 1997].

Energy production
In 1990 most wind turbines were build at an axis height of 50 metres above ground level, and therefore generated different amounts of electricity due to different wind-speeds and different location specific conditions. Full load hours were differed per region and country. The expectations are that the development will be to build wind turbines at a specific height (from 50 to 100 metres axis height) and in certain places, so that an economic viable energy production is possible. This would mean a minimum specific energy production of 2500

[17] EWEA internet site (http://www.ewea.org/stats.html) d.d. 26/1/2000

kWh$_e$/kW per year for onshore wind turbines, independent of location mainly by adjusting the turbine axis height.

For offshore wind turbines in 2010 different full load hours depending on different wind speeds are still the case. For this study offshore Europe was divided into 3 zones with different full load hours for offshore (see Table 4).

Table 4. Installed capacity (MW) wind energy in 1990, assumed full load hours for 2010 and market penetration (MW) for wind energy in 2010 for EU15 countries.

	1990	2010				
	Installed	Implementation potential			Full load hours	
	capacity	Total	o.w. onshore	o.w. offshore	onshore	offshore
	MWe	MWe	MWe	MWe	h	h
AUT	0	750	750	0	2500	3000
BEL	2	1500	1000	500	2500	3000
DEU	60	10000	8000	2000	2500	3000
DNK	340	5000	3000	2000	2500	3000
ESP	10	3500	2500	1000	2500	2750
FIN	0	2500	1000	1500	2500	3000
FRA	2	3500	3000	500	2500	2750
GBR	8	4000	2000	2000	2500	3500
GRC	2	1500	1000	500	2500	2750
IRL	6	2000	1500	500	2500	3500
ITA	2	5500	4000	1500	2500	2750
LUX	0	20	20	0	2500	3000
NLD	40	4000	2000	2000	2500	3000
PRT	1	2000	1000	1000	2500	2750
SWE	5	3500	2000	1500	2500	3000
Total	**478**	**49270**	**32770**	**16500**		

Costs[18]

The wind energy industry is a global industry. Investment costs hardly vary per region. Cost data and forecasts were taken from Ecofys [1998b] and ECN [1999].

The investment costs for onshore wind turbines are now 1000 /kW, O&M costs are 15 /kW/year. The investment costs will decrease to 700 /kW in the year 2010. The investment costs for offshore wind parks are still very high in 2010, up to 2.5 times the investment costs for onshore wind parks (1750 /kW). The O&M costs are about two times as much as for onshore wind turbines (30 /kW/year). The technological lifetime of wind-turbines is assumed to be 15 year.

[18] All costs are expressed in 1990 euro's.

3.2 Hydro-energy

Hydropower is an important source of renewable energy in almost all European countries and is considered to be a mature technology. In the early 1990s the total installed capacity of hydropower in Europe was almost 110 GW, of which about 22 GW was capacity for pumped storage and about 88 GW 'real' hydropower. In turn about 9 GW consisted of small-scale (<10 MW) installations, and 79 GW of large-scale installations. At the end of 1997 a total of about 91 GW was installed (9.7 and 81.7 GW for small- and large scale respectively) [IEA Statistics; EurObserv'ER, 1999].

It should be noted that statistics on hydropower in Europe from various references show an inconsistent picture: the subdivision into pumped storage capacity and other capacities is often not clear, as is the subdivision into small- and large-scale (with threshold capacities for subdividing small- and large-scale hydropower ranging from 0.5 to 10 MW). National and international (a.o. Eurostat, IEA) statistics are therefore often in contradiction which each other.

Implementation Potential
The implementation potential of small-scale hydropower is almost 50 GW which has usually lower environmental impacts than large-scale hydropower, but these impacts should be taken into account and still regulatory obstacles have to be taken. The implementation of large-scale hydropower is restricted by environmental constraints as most feasible sites are already developed. However, upgrading of exitsing installations is also an important option.

[EC, 1997] assumes an increase of 4.5 GW (small) and 8.5 GW (large) respectively in 2010 with respect to 1995, reaching a total capacity of 105 GW. In this study increases of 3 and 11.5 GW are assumed respectively (see below).

Energy production
Not all literature references divide hydro into small- and large-scale installations. Actual full load hours vary for different installations from 2000 to 5500. In this study full load hours are used as presented Table 5. These full load hours were calculated from various statistical references. In practice, specific energy production will be very project specific, and the range of full load hours will therefore be significant. Capacity figures (MW) were calculated from energy production data in [ATLAS, 1997] using the assumptions above. The installed capacity and expected market penetrations in 2010 are given in Table 5.

Costs

Data on investment costs vary a lot for different countries. Costs were found in a range from 1000 /kW to 10,000 /kW [Ecofys, 1998b; ETSU, 1994; BUNR, 1999], depending on the type of installation. We therefore assume a mix of technologies and of small and large hydro, and use an average of 3000 Euro/kW investment costs for all European countries (this is high compared to the assumed 1000 /kW in the White Paper [EC, 1997]). Upgrading of existing plants has usually lowewr costs. O&M costs are estimated at 2% of the investment costs. Life-time of the installations varies from 25 to 40 years, depending on the size of the installation and the working conditions.

In this study a lifetime of 40 years is used for small and large scale installations and for all countries.

Table 5. Installed capacity hydro energy in the early 1990s and market penetration and full load hours for hydro energy in 2010 for EU 15 countries

	Early 1990s Installed capacity (GWe)			2010 Implementation potential (GWe)			Full load hours (h)	
	Total Hydro	Small Hydro	Large Hydro	Total Hydro	Small Hydro	Large Hydro	Small Hydro	Large Hydro
AUT	11.1	0.8	10.3	12.9	1.0	11.8	3800	3200
BEL	0.1	0.1	0.0	0.1	0.1	0.0	3000	3500
DEU	4.3	1.3	3.0	5.4	1.9	3.6	5000	3500
DNK	0.0	0.0	0.0	0.0	0.0	0.0	2500	
ESP	12.4	1.1	11.3	15.8	2.1	13.6	3500	3000
FIN	2.7	0.3	2.4	3.3	0.3	3.0	3500	4500
FRA	20.6	1.9	18.7	21.4	2.0	19.4	3500	3000
GBR	1.4	0.2	1.3	1.5	0.2	1.3	2500	3000
GRC	2.2	0.0	2.2	4.1	0.1	4.0	3300	3000
IRL	0.2	0.1	0.2	0.3	0.1	0.2	3250	3000
ITA	12.9	2.0	10.8	14.4	2.4	12.0	3700	3000
LUX	0.0	0.0	0.0	0.0	0.0	0.0	3000	3500
NLD	0.0	0.0	0.0	0.0	0.0	0.0	4500	
PRT	3.7	0.2	3.6	4.9	0.3	4.6	3000	3100
SWE	16.0	1.0	15.1	17.9	1.2	16.7	4500	4500
Total	**87.6**	**8.9**	**78.7**	**102.1**	**11.8**	**90.3**		

3.3 Solar Energy

3.3.1 Solar photovoltaic energy (PV)

Photovoltaics (PV) is a high technology with export potentials worldwide. Europe experiences great competition from Japan and the USA. Europe has a very motivated PV industry, that puts great effort in both domestic and export market. A growth of the PV market is necessary and expected in order to lower the costs for PV systems.

PV is generally categorised as grid connected and autonomous PV. Although autonomous PV is an important application and already often cost effective, the potential to reduce CO_2 is hard to determine as is the potential in the EU-15 Member States. Currently the growth in the PV market comes from grid connected systems, and for this reason autonomous PV systems are presented here as a *pro memori* technology.

Grid connected PV can be divided into roof-integrated PV and larger PV-plants. The installed capacity of PV-plants is relatively low compared to roof-integrated PV. According to EPIA [1996] 12 MWp of PV-plants was installed in 1994 compared to 6 MWp of roof-integrated PV systems in 1994. The growth in PV is expected in roof-integrated PV, according to EPIA [1996] 600 MWp in 2010. We therefore assume the growth in electricity from PV to the year 2010 is roof-integrated, grid connected PV.

Implementation potential

The technical potential for PV is hard to estimate as is the case for the implementation potential. By EPIA [1995] the installable building rooftop mounted PV potential in 2010 is estimated at over 600 GWp. The implementation potential will be much lower, as the costs of PV systems are still not competitive with other energy sources. According to ATLAS [1997] the EU-wide deployment of PV will be 1.2 - 2 GWp in 2010. Ecofys [1995] estimated an implementation of 2.2 GWp in a large-scale market deployment scheme (including autonomous systems and centralised PV-plants).

The EC [1999] suggests that the total installed capacity in the 500.000 PV roof campaign in Europe should be 1 GWp in 2010. The total share of PV in 2010 is supposed to be 3 GWp [EC, 1997] installed capacity and an electricity production of 3 TWh. In this study the approach of Ecofys [1995] is followed; rounded figures for grid connected PV systems are presented in Table 6.

Table 6. Irradiation and installed capacity (Wp) for EU-15 countries in 1990 and prognoses for 2010 (grid connected systems; adjusted from [Ecofys, 1995]; EPIA, 1996])

	Irradiation kWh/m2/yr	1990		2010	
		Installed capacity MWp	Energy production kWh/kWp	Implementation potential MWp	Energy production kWh/kWp
AUT	1200	1	960	75	1080
BEL	1000	0	800	25	900
DEU	1000	2	800	200	900
DNK	1000	0	800	10	900
ESP	1600	7	1280	500	1440
FIN	900	0	720	10	810
FRA	1200	0	960	250	1080
GBR	1000	0	800	100	900
GRC	1500	0	1200	150	1350
IRL	1000	0	800	5	900
ITA	1300	15	1040	500	1170
LUX	1000	0	800	1	900
NLD	1000	2	800	30	900
PRT	1700	0	1360	150	1530
SWE	900	0	720	20	810
Total		**28**		**2026**	

Electricity production

Differences between countries in electricity produced per Wp installed capacity are related to differences in irradiation. The productivity is a percentage of the irradiation that is converted into electricity. Aspects as irradiation angel and shade-effects are among others responsible for these losses. For 1990 system losses of 20% were assumed, for 2010 that is expected to decrease to 10%, due to technological development. Furthermore, an average of 100 kWh/Wp is assumed, and irradiation factors were accounted for.

Costs

Costs for PV differ slightly between EU-countries. The system costs depend on system size, location and technical specifications. An average investment cost in 2010 of 2500 /Wp including installation costs is expected [Ecofys, 1998b; ECN, 1999]. The O&M costs are 0,5% of investment costs for all countries. The technical lifetime is taken as 25 years.

A costs reduction of PV is expected, due to the following developments:

- Improvement of technology (higher efficiency)
- Higher production capacities
- Integration in roofs and facades, so costs for PV are integrated in building costs (reduction of balance of system (BOS) costs).

3.3.2 Solar thermal power

By means of concentrating solar energy onto a focal point or line, enough heat can be produced to generate electricicity with turbines or other heat driven conversion engines. The following techniques are considered as most promising in the short term:

- parabolic troughs,
- power towers, and
- dish/Stirling systems.

For Europe these technologies are mainly of interest for the Mediterranean countries, and in fact prototypes concentrating solar energy installations were in operation in France, Italy and Spain. At the moment, only in Spain these technologies are being demonstrated or used as research facilities.

Solar thermal power installations can often be combined with power production using fossil fuels (hybrid systems). Furthermore, power towers and to some extend parabolic troughs can store solar heat and are therefore less intermittent than for instance solar photovoltaics. Storage periods for power towers are expected to increase from 3 hours to 7 or even 13 hours.

Parabolic troughs are commercially available, but further improvements are expected to occur as markets develop and typical plant sizes increase from e.g. 30 to over 300 MW. Power tower technology has to be demonstrated for larger installation capacities (currently 0.5 - 10 MW, expected to increase to 200 MW) but is demonstrated technology. Solar dish/engines are in the demonstration phase. Typical installation capacities might increase from 5 to 50 kW. More key figures are given in the table below.

Production costs of solar thermal power are expected to decrease with 30% to 60% reaching electricity production costs that are coming close to the reference costs used in this report (0.03 /kWh): 0.04 - 0.06 /kWh (macro-economic cost calculation, 4% interest rate, depreciation periode 20 years).

Table 7. Key-figures of solar thermal power technologies [EPRI-USDOE, 1997]

		Parabolic trough			Power tower			Dish/engines		
		2000	2010	2030	2000	2010	2030	2000	2010	2030
Typical plant size	MW	30-80	320	320	10-30	200	200	0.025	0.0275	0.0275
Capacity factor	%	34	40-50	50	20-43	65	77	50	50	50
Investment costs	€/kW	2700	3000	2750	4400	2600	2500	5700	1700	1325
O&M costs	€/kW/yr	65	45	35	65	30	25	160	45	40

Note: For each technology specific configuration characteristics are different for different years

The realistic potential of solar thermal power in the Mediterranean countries is estimated to be 23 GW by 2020/2025 [IEA, 1997]. With an average capacity factor of 50% this could result in an electricity production potential of about 100 TWh. The market development in the Mediterranean region as well as the implementation potential in the period up to 2010 is hard to determine. Significant efforts in research, development and demonstration have to be undertaken, and in this study a breakthrough of this technologies is expected to occur after 2010. However, it is expected that even before 2010 some projects will be realised. In Spain initiatives exist for two 10 MW solar power towers (near Sevilla and Cordoba) and one 32 MW solar trough plant (Anadasol), whereas in Greece a license for a 52 MW solar trough plant on Crete is applied for. If realised, these plants would generate about 0.4 TWh electricity per year.

3.3.3 Solar thermal heat

Active solar heat comprises solar heating systems which can be used in the domestic sector, the tertiary sector (solar hot water boilers) and in agriculture (e.g. drying of crops). According to EC [1997] 170 PJ_{th} heat is aimed to be produced by active solar systems in Europe in 2010. That can be achieved by 100 million m^2 collector surface [EC, 1997], using an average collector surface of 5 m^2, that would mean roughly 20 million systems. In this study only glazed collectors are taken into account, as this type is expected to have the largest market penetration opportunities in the EU.

Implementation potential

The implementation potential is calculated by assuming different implementation percentages for the 1990 building stock (renovation) and the new building stock in the period 1990-2010 (see Table 9). The numbers of dwellings that could be installed with solar collectors are then multiplied by the typical collector surface in order to determine the potential in terms of square meters collector surface.

Heat production

The specific heat production (in kWh/m^2 of collector surface, per year) depends on the degree of insolation. The assumptions are presented in Table 8. The system characteristics differ strongly per country, notably typical collector surfaces per system. For some countries typical system characteristics in use are known [ESIF, 1995]. For the countries of which no typical data are available, data from comparable countries are taken, so for example Spain has comparable systems (and costs) as Portugal [Ecofys, 2000]. The assumptions are presented in Table 9.

Table 8. Average solar productivity (based on [European Solar Radiation Atlas, Koln, 1984; ESIF 1995])

Zone	Specific heat production (kWh/m^2 collector surface per year)
1) Ireland, Sweden, Denmark, Finland, The Netherlands, Luxembourg, Belgium	350
2) France and Austria	450
3) Spain, Portugal, Italy and Greece.	550

Table 9. Typical values for active solar thermal systems in EU 15 countries, predictions for 2010 [ESIF, 1995; Ecofys, 2000]

	Typical coll. surface	Specific heat prod.	Dwellings		1994		2010						
			1990	**2010**	Coll. surface	Heat prod.	Penetration level solar thermal		Coll. surface	Number	Heat prod.	Invest-ment costs	O&M costs
	m2	kWh/ m2/yr	(*1000)	(*1000)	1000 m2	TJ	'Old' 1990	'New' 1990-2010	1000 m2	(*1000)	TJ	per system	/yr per system
AUT	7	450	3050	3290	565	915	20%	50%	5111	730	8280	3115	0
BEL	5	350	3748	4044	17	21	20%	30%	4192	838	5282	2450	0
DEU	6	350	33856	38400	685	863	20%	30%	48806	8134	61496	3738	0
DNK	5	350	2353	2816	74	93	20%	30%	3048	610	3840	2706	0
ESP	4	550	11993	13457	118	234	20%	50%	12524	3131	24797	1200	0
FIN	10	350	2023	2645	3	4	20%	30%	5912	591	7449	3010	0
FRA	2.5	450	21302	25570	320	518	20%	50%	15985	6394	25896	1200	0
GBR	5	350	21818	24058	108	136	20%	30%	25179	5036	31725	2660	0
GRC	2.4	550	4690	5451	2000	3960	50%	75%	6998	2916	13856	644	0
IRL	5	350	1026	1194	1	1	20%	30%	1277	255	1610	2660	0
ITA	3	550	18071	19737	176	348	20%	75%	14592	4864	28893	1661	0
LUX	5	350	135	165	1	1	20%	30%	181	36	228	2450	0
NLD	2.8	350	5892	7256	49	62	20%	30%	4445	1588	5601	1483	0
PRT	4	550	2843	3217	200	396	20%	75%	3394	849	6721	1356	0
SWE	10	350	4044	4410	71	89	20%	30%	9186	919	11575	2997	0
Total			**136844**	**155711**	**4388**	**7643**			**160832**	**36891**	**237249**		

Costs

Because of the different systems in use and because of market imperfections, the investment costs (per system, including installation) vary from country to country. These investment costs are known for 1995 [ESIF, 1995; Ecofys, 2000]. The cost development for most countries is considered the same as known for the Netherlands, that is in 2010 70% of the 1995 costs. For Greece, France, Spain and Portugal the costs for 2010 are set to 80% of 1995; less development was expected because of the already low costs in these countries.

A percentage of 2% of the investment costs for solar systems is generally considered to give the annual O&M costs for the complete installation. In this study the extra O&M costs of a solar thermal installation compared to a conventional system are considered to be negligible for all European countries. Lifetime is 15 years, and is not expected to increase; research and development is mainly focussed on cost reduction and improvement of installation.

3.3.4 Passive solar energy

Passive solar energy is derived from the design of buildings in such a way, that an optimised use of sun-shine for heating and lighting of buildings is ensured. In countries with a colder climate, passive heating is an interesting option. For southern counties, isolation and cooling are much more important. The estimation of the potential of passive solar energy is not a straightforward calculation as many methodological obstacles are existing. The potential however can be large. The extra costs involved in the design of buildings are considered to be negligible and are integrated in building costs. No separate estimate for passive solar energy is given in this study.

3.4 Wave and Tidal energy

Wave energy and tidal energy are treated as different options, but now discussed together because of their limited expected contribution ins 2010. In 1990 the use of wave and tidal energy in Europe was restricted to tidal energy in France, with a total capacity of approximately 240 MWe.

Implementation potential

ATLAS [1997] predicts a capacity of 50 MW (0.45 TWh) of **wave energy** in the EU and the EFTA (European Free Trade Association) countries together in 2010. No breakdown per country is given. TERES-II [1996] expects no implementation of wave energy. Given the R,D&D that is still required for the various concepts of wave energy (shoreline and nearshore oscillating water column (OWC) devices, various devices for offshore application), we expect a negligible contribution in 2010.

The EU technical potential of **tidal stream energy** is about 12.5 GWe which could generate 48 TWh/year. The technical potential of **tidal barrages** across estuaries is even about 64 GW (105 TWh/year) [ATLAS, 1997]. Significant R,D&D efforts are required in order to start with the realisation of this potential. At the moment it is not expected that the current installed capacity of 240 MWe (tidal barrage in France) will increase.

3.5 Ambient energy

Cold and heat storage and heat pumps are discussed in the section on energy conservation in buildings.

3.6 Geothermal energy

In 1995 a total of 1200 MWth and 640 MWe of geothermal energy was installed in Europe [ATLAS, 1997]. This accounted for 13.5 PJ of heat and 3.5 TWh electricity production.

Implementation potential
The implementation potential is taken from ATLAS [1997], with some adaptations taken from the blue book on geothermal resources [EC, 1997a]. The ATLAS study expects an increase of 130 MWth and 640 MWe on thermal and electrical geothermal capacities respectively (see Table 10). Here a total of 1.9 GW_{th} and 1.3 GW_e is assumed as the implementation potential for 2010.

Energy production
Energy production figures are also taken from ATLAS [1997].

Table 10. Installed capacity of geothermal heat and electricity in 1990 and predictions for 2010 [ATLAS, 1997; EC, 1997a]

	1995				**2010**			
	Geothermal heat		Geothermal electric		Geothermal heat		Geothermal electric	
	MWth	GWh	MWe	GWh	MWth	GWh	MWe	GWh
AUT	41	56			45	62		
BEL	4	10			4.4	11		
DEU	323	330			681	696		
DNK	3	13			3.3	14.3		
ESP		40				44		
FIN								
FRA	456	2006			599	2633		
GBR	2	4.7			2.2	5.2		
GRC	23	38			25.3	42		
IRL								
ITA	308	1008	625.7	3417	504	1649	1266	9316
LUX								
NLD					10	55		
PRT (Azores)			8	40.5			8	40.5
SWE	47	266			52	293		
Total	**1207**	**3772**	**634**	**3458**	**1926**	**5505**	**1274**	**9357**

Costs
Costs for geothermal heat were taken from EnergieNed [1997], and were used for all European countries. Costs for geothermal electrical energy were taken from ETSU [1994]. This results in the costs for geothermal energy as showed in Table 11. A lifetime of 25 years was used, according to EnergieNed [1997].

Table 11. Costs of geothermal energy [EnergieNed, 1997; BUNR, 1999]

	Investment costs (€/kW)	O&M (€/kW/year)
Geothermal heat	500	30
Geothermal electrical	3500	140

3.7 Biomass energy

Various biomass resources are or could be converted to energy: woody biomass (forest residues, industrial waste streams, energy crops such as willow, poplar), other energy crops (sugar beet, wheat, rapeseed, Miscanthus, et cetera), agricultural and industrial wastes, other wastes with a significant biomass fraction (e.g. MSW, Municipal solid waste), biogas from waste water treatment or landfill sites, et cetera. For these biomass to energy conversions various technologies are available, e.g. incineration, co-firing, gasification, pyrolysis, anaerobic digestion, fermentation, extraction, et cetera.

Landfill gas recovery and utilisation as well as municipal solid waste incineration are discussed in the section on methane abatement of landfill gas and ar not part of this section.

An estimate of the implementation potential of biomass to energy is therefore twofold: it requires an estimate of the biomass resources and of the specific technologies and conversions that will be applied. Given the variety of biomass resources, the competition between energetic utilisation and alternative uses of biomass (e.g. for food production or use in the manufacturing industry) and the various conversion technologies and conversion routes (electricity and/or heat production, fuel production: e.g. bio-ethanol, bio-diesel, biogas), the estimate of the implementation potential will have a broad range. Furthermore, biomass statistics are by far complete and/or uniform for all EU-15 member states and for all statistical references.

According to EC [1997] the energy content of the biomass used in 1995 in EU-15 was about 1.9 EJ, which is expected to grow to about 5.7 EJ in 2010 (including landfill gas and municipal solid waste (MSW) incineration). The electricity and heat production is respectively estimated to be 230 TWhe and 3.1 EJth. PRIMES [1999] predicts figures of 66 TWhe and 0.75 EJth respectively, whereas the Best Practice Policy scenario of TERES-II [1996] presents figures of 93 TWhe and 2.8 EJth.

Implementation potential

The implementation potential is taken from the calculated energy production by the Best Practice Policy scenario in TERES-II [1996], expressed in GWhe electricity production, PJth heat production and PJ bio-fuel production (bio-diesel and bio-ethanol). The TERES-II [1996] study and the accompanying SAFIRE database present no installed capacity figures.

Electricity, heat and fuel production

Table 12, Table 13 and Table 14 show the TERES-II results, that will be used in this study. Note that landfill gas recovery and utilisation as well as municipal solid waste incineration are discussed in the section on methane abatement of landfill gas and ar not part of this section. We assume that all electricity is generated in combination with heat production (30%-el.; 40%-th.); the remainder of the heat production comes from normal heat boilers (80%-th).

Table 12: Electricity production from biomass resources in 2010 [TERES-II, 1996]

Electricity production (GWhe) - 2010								
	Forest residues	Agric. waste, liquid	Agric. waste, solid	Energy crops, wood	Indust. waste, solid	Indust. waste, liquid	Munic. Diges-tible	**Total (TWhe)**
AUT	0	0	3	1038	2628	92	1	**3.8**
BEL	0	0	0	32	264	12	6	**0.3**
DEU	0	0	25	7866	0	449	200	**8.5**
DNK	0	0	120	2583	106	19	46	**2.9**
ESP	110	0	0	4354	438	219	154	**5.3**
FIN	553	0	4	211	1787	3732	2	**6.3**
FRA	0	0	0	10285	568	341	110	**11.3**
GBR	475	0	332	7373	1529	482	480	**10.7**
GRC	2	0	0	3438	31	115	8	**3.6**
IRL	88	0	10	241	165	88	9	**0.6**
ITA	0	0	0	848	2889	313	673	**4.7**
LUX	0	0	0	2	2	1	1	**0.0**
NLD	521	0	0	526	0	89	106	**1.2**
PRT	1	0	1	175	876	300	20	**1.4**
SWE	2639	0	6	1762	1796	100	6	**6.3**
Total	**4388**	**0**	**501**	**40734**	**13079**	**6351**	**1823**	**66.9**

Table 13. Heat production from biomass resources in 2010 [TERES-II, 1996]

Heat production (PJth) - 2010								
	Forest residues	Agric. waste, liquid	Agric. waste, solid	Energy crops, wood	Indust. waste, solid	Indust. waste, liquid	Munic. Diges-tible	**Total (PJth)**
AUT	58	0	1	40	10	1	0	**111**
BEL	6	0	0	3	3	0	0	**12**
DEU	129	21	5	199	163	5	5	**527**
DNK	14	1	2	25	18	0	0	**60**
ESP	81	4	0	80	38	3	2	**209**
FIN	29	2	1	3	11	28	0	**74**
FRA	330	25	14	112	34	4	3	**521**
GBR	14	1	19	56	21	5	2	**120**
GRC	39	0	2	16	1	2	0	**60**
IRL	6	1	0	16	2	1	0	**27**
ITA	48	7	2	249	144	4	8	**461**
LUX	0	0	0	1	0	0	0	**1**
NLD	23	0	0	41	1	1	0	**65**
PRT	54	0	0	25	22	4	0	**104**
SWE	99	0	3	21	93	1	2	**219**
Total	**930**	**63**	**50**	**887**	**562**	**59**	**22**	**2573**

Table 14. Bio-fuel production from biomass resources in 2010 [TERES-II, 1996]

Fuel production (PJ) - 2010						
	Energy crops, ethanol	Energy crops, biodiesel			Energy crops, ethanol	Energy crops, biodiesel
AUT	4	8		GRC	5	4
BEL	0	4		IRL	2	1
DEU	58	31		ITA	19	48
DNK	3	5		LUX	0	0
ESP	13	36		NLD	6	14
FIN	5	2		PRT	3	6
FRA	43	70		SWE	8	4
GBR	50	23		**Total**	**235**	**179**

Costs

- Electricity and heat

We assume that forest residues, wood, solid agricultural and industrial biomass wastes are all incinerated in co-generation units. All liquid or digestible wastes are supposed to be treated in CHP anaerobic digesters. The remainder of the heat production as presented in the TERES-II study is assumed to be produced by heating boilers.

Biomass costs vary per type, per region and depend on any alternative uses and the market for biomass for energy conversion. The production costs of energy crops for instance depend highly on land costs and physical factors as climate, wheather and soil conditions.

The cost calculations for biomass are therefore highly uncertain. We assume biomass costs of 3.2 /GJ for forest residues and woody energy crops and 0 /GJ for all other biomass waste streams (e.g. wood industry wastes) in 2010. Currently some biomass residues have negative values.

Table 15. General data on biomass to energy conversion in 2010

	Heat and electricity production				**Fuel production**		
	Incineration *[Biomass 1a and 1b]*	Anaerobic digestion *[Biomass 2]*	Heat boiler *[Biomass 2a and 2b]*		Fermentation (ETBE) *[Biomass 4a]*	Extraction (biodiesel) *[Biomass 4b]*	
Investment costs	1400	3500	100	€/kW	a) 0.5 b) 0.8	0.5	€/liter/yr
O&M costs	50	50	5	€/kW/jr	a) 0.025 b) 0.04	0.13	€/liter
Benefits byproduct					a) 0.05 b) 0.12	0.15	€/liter
Load hours	7000	8000	8500	hours	7000	7000	hours
Lifetime	20	20	20	years	20	20	years
Efficiencies - electrical - thermal - fuel	 30% 40%	 15% 40%	 80%		 i) 58% ii) 61%	 49%	
Biomass costs Residues and wastes - forest residues *[a]* - other biomass *[b]* Energy crops - woody energy crops - sugar beet - wheat - rapeseed	 3.2 0 3.2	 0 3.2	 3.2 0 3.2	 €/GJ €/GJ €/GJ	 8 15	 12	 €/GJ €/GJ €/GJ
Lifecycle avoided CO_2 emissions per GJ of fuel					i) 42 ii) 70	95	kg CO2/GJ fuel

i) Fermentation of sugar beet
ii) Fermentation of wheat, with use of straw for energy production in CHP-unit

- Biofuels

Biodiesel and bio-ethanol are produced via extraction and fermentation respectively. Biodiesel or RME (rapeseed oil methyl ester) is currently used as a transport fuel (subsititute of diesel) or as a heating fuel. It is produced out of rapeseed or sunflowers. Bio-ethanol is produced out of sugar beets or wheat. In Europe the bio-ethanol is directly converted into ETBE (ethyl tertiary butyl ether), a transport fuel additive which substitutes MTBE (methyl tertiary butyl ether).

Compared to other conversion routes of biomass the overall cost-effectiveness of the complete biodiesel or bio-ETBE conversion routes is high in terms of Euro per tonne of CO_2 equivalents. This is a consequence of both relatively high costs of crop production and high direct and indirect emissions of greenhouse gases (notably CO_2 and N_2O), which results in small overall CO_2 equivalent. reductions per GJ of fuel [Ecofys, 1998a]. Some byproducts of the conversion route can be sold as fodder or could be used for energy production. These aspects are taken into account in the cost calculation. The assumptions are presented in Table 15.

In summary, this study considers the following conversion routes for biomass:

Biomass 1a: CHP with forest residues and woody energy crops
(biomass costs of 3.2 €/GJ)
Biomass 1b: CHP with other biomass (biomass waste streams)
(biomass costs of 0 €/GJ)
Biomass 2: CHP with anaerobic digestion
Biomass 3a: Heat production with forest residues and woody energy crops
(biomass costs of 3.2 €/GJ)
Biomass 3b: Heat production with other biomass (biomass waste streams)
(biomass costs of 0 €/GJ)
Biomass 4: Ethanol production (fermentation)
Biomass 5: Biodiesel production (extraction)

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ANNEX 3. EXAMPLE OF CALCULATION OF SPECIFIC COSTS

The calculation of the specific costs of energy supply options will be demonstrated by presenting an example: biomass incineration.

Key data biomass incineration (co-generation):

Investment costs:	1400 €/kW	Electrical efficiency:	30%
O&M costs:	50 €/kW	Thermal efficiency:	40%
Biomass costs:	3.2 €/GJ		
Load hours:	7000 h		
Lifetime:	20 year		

Key data reference technologies:

Boiler:	Thermal efficiency 80%
NGCC:	Electrical efficiency: 55%
	(see main text for the selection of reference technologies)
CO_2 emission factor natural gas:	56 kg CO_2/GJ
Costs natural gas:	2.5 €/GJ
Costs electricity:	0.03 €/kWh_e
Costs heat:	0.012 €/kWh_{th}
Biomassa input:	12 MJ/kWh_e

Calculation of avoided emissions:

For each kWh of electricity, additionally 40%/30%= 1.3 kWh of heat is produced (and assumed to be utilised).

1 GJ_e saves 1/0.55 = 1.8 GJ of natural gas

1.3 GJ_{th} saves 1/0.8 = 1.7 GJ of natural gas

Per GJ_e of electricity in total 3.5 GJ NG is saved, equal to 56*3.5 = 195 kg CO_2/GJ NG or to 0.70 kg CO_2/kWh_e.

Converted cost data (kWh_e):

Investment costs:	0.2 €/kWh_e	= 285 €/ton CO_2
O&M costs:	0.010 €/kWh_e	
Biomass costs:	0.038 €/kWh_e	
Benefits electricity:	0.03 €/kWh_e	
Benefits heat:	0.003 €/MJ_{th} = 0.016 €/kWh_e	
Nett annual costs:	0.048 - 0.046 = 0.002 €/kWh_e = 3 €/ton CO_2	

Annualised investment costs (4% discount rate, 20 year) = 21 €/ton CO_2

Net specific costs: 24 €/ton CO_2.

(Due to roundings figures in this example may differ from reported figures in the report).