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GREENHOUSE GAS EMISSIONS FROM FOSSIL FUEL FIRED POWER GENERATION SYSTEMS

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The Energy Technology Observatory (ETO) at the Institute for Advanced Materials of the DG-JRC focuses on technology aspects of power generation and conversion at large. In line with the mission statement of the JRC it provides objective and independent support to the EU policy-maker on power generation issues with emphasis on environment and sustainable growth aspects. Its work is carried out in close relationship with all stakeholders and with other Institutes of DG-JRC.

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EXECUTIVE SUMMARY

While high emissions of greenhouse gases (GHG) are a recognised threat to the stability of the earth's climate, global anthropogenic GHG emissions continue to rise. The prudent response to climate change is to adopt a portfolio of actions aimed at mitigation, adaptation, and research. The present document aims at **identifying effective technical measures for mitigation of GHG emissions** in the EU, particularly in view of complying with the Kyoto Protocol commitments.

Based on a review of the distribution and sources of GHG emissions, it appears that by far the largest contribution to the greenhouse effect stems from emissions of carbon dioxide CO_2. In turn, 75% of the global CO_2 emissions result from the combustion of fossil fuels for the transformation and use of energy. This indicates that **fossil fuel combustion is the largest single contributor to the greenhouse effect**.

Within the EU power generation and transport each account for approximately one third of CO_2 emissions from fossil fuel combustion, whereas the remaining third mainly comes from industry and domestic heating. Because flue gas streams from thermal power plants are large and few in number, whereas emission sources in the other sectors are many, small and dispersed, **technological measures to reduce emissions from power generation have the greatest impact,** both in terms of their efficiency and of the volume of the reduction potential.

CO_2 emissions from power generation are influenced by two factors, namely the carbon content of the fuel and the overall conversion efficiency. **Technological measures to reduce emissions primarily aim at increasing the thermal efficiency, a still insufficiently exploited route**. Substantial efficiency increases can be realised through the use of clean combustion technologies, and combined cycle operation. Optimum

exploitation of these approaches is expected to lead to efficiencies of up to 65% (more than a 50% relative increase from the current average thermal power generation efficiency in the EU), and concomitant CO_2 reductions in the range 40-50% from current levels. Further overall efficiency increases are possible by new advanced cycles, and by cogeneration.

Based on recent projections showing rather low penetration rates of zero carbon content fuels (nuclear and renewable energy sources), CO_2 emission abatement in the near future will increasingly rely on measures that reduce energy intensity and specific energy consumption, i.e. increase efficiency. **Beyond 2010 electricity and steam generation are projected to contribute most to the increase in CO_2 emissions from all sources, highlighting the extreme importance of measures to increase thermal efficiency to counter this effect.**

To meet the EU's Kyoto target, an annual total reduction of 650 Mt $CO_{2\text{-eq.}}$/yr is required, of which 400 Mt CO_2/yr from energy-related sectors. Based on several emission abatement studies, this corresponds to an economical cost of around 100 $€_{90}$/tC, or 27 $€_{90}$/tCO_2 (in current value 37 €/tCO_2). Cost evaluation of emission reduction options from different sources reveals that for this level of abatements cost **more than 60% of all CO_2 emission reduction is achieved in the power generation sector**.

In order to quantify CO_2 emission reduction costs for a number of thermal power generation technologies, a spreadsheet programme has been developed that allows calculation of the levelised electricity generation and the specific CO_2 reduction costs. In combination with quantitative assessments of the emission reduction potential offered by different technology options, a marginal cost abatement curve for the energy supply sector in the EU has been established and compared to projections from other studies.

GREENHOUSE GAS EMISSIONS FROM FOSSIL FUEL FIRED POWER GENERATION SYSTEMS

Issue

Global warming is a recognised threat to the stability of the earth's climate. The only way to control global warming is to control the concentration of greenhouse gases in the atmosphere. There are but two ways to do this: (1) substitute high-carbon fuels with low or no-carbon fuels; (2) produce and use energy more efficiently.

At the conference of the parties (CoP) in Kyoto in December 1997, the EU agreed to reduce emissions of six greenhouse gases by 8% of 1990 levels by 2010. This constitutes a specific challenge for EU ***energy policy*** as some 80% of the EU's total greenhouse gas emissions originate from energy use.

This document outlines first the dependence of greenhouse gas emissions from the power generation sector on fossil fuel mix and on efficiency, and subsequently discusses emission abatement potentials and the associated costs.

1. Distribution of GHG emissions and their sources

The major "Kyoto" greenhouse gases are CO_2, CH_4, and N_2O which emanate from both energy and non-energy sources. Also included are hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride, which have relatively high global warming potentials but are emitted in small volumes and are for the most part not energy-related. The "greenhouse effect" of the different gases is expressed as CO_2 equivalent, based on a similar global warming (GW) potential over a 100-year period.

Table 1: Global warming potentials [1]

Gas	global warming potential for various time horizons		
	20 years	100 years	500 years
CO_2	1	1	1
CH_4	56	21	6.5
N_2O	280	310	170
HFC-23	9100	11700	9800
HFC-32	2100	650	200
SF_6	16300	23900	34900

Based on the amount of gas emitted and the GWP, the contribution of different greenhouse gases to global warming for the EU in 1990 is shown in Fig. 1. Although there is agreement between different sources on the share of individual GHGs, the value of the total emissions ranges from 3938 Mt CO_2-eq. [28, p. 64] over 4292 Mt CO_2-eq. [33, vol. 11, p. 16] to 4334 Mt CO_2-eq. [30].

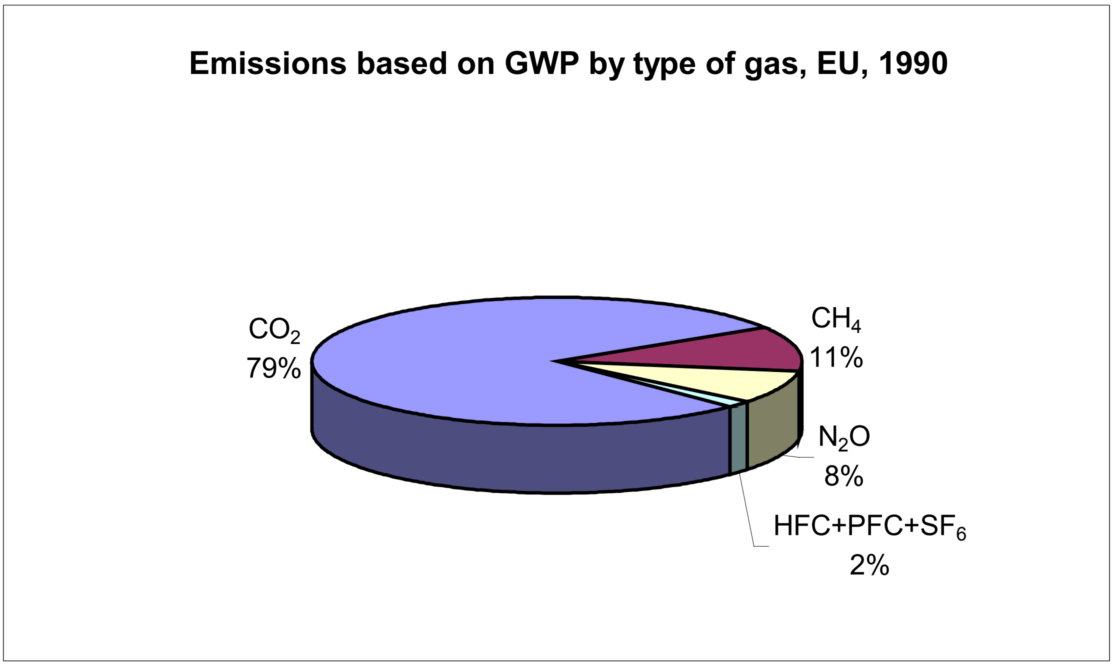

Fig. 1 [30]

In a similar way fig. 2 represents the situation of the US in 1998 (total 1.8 Gt C, typical for industrialised regions in the world).

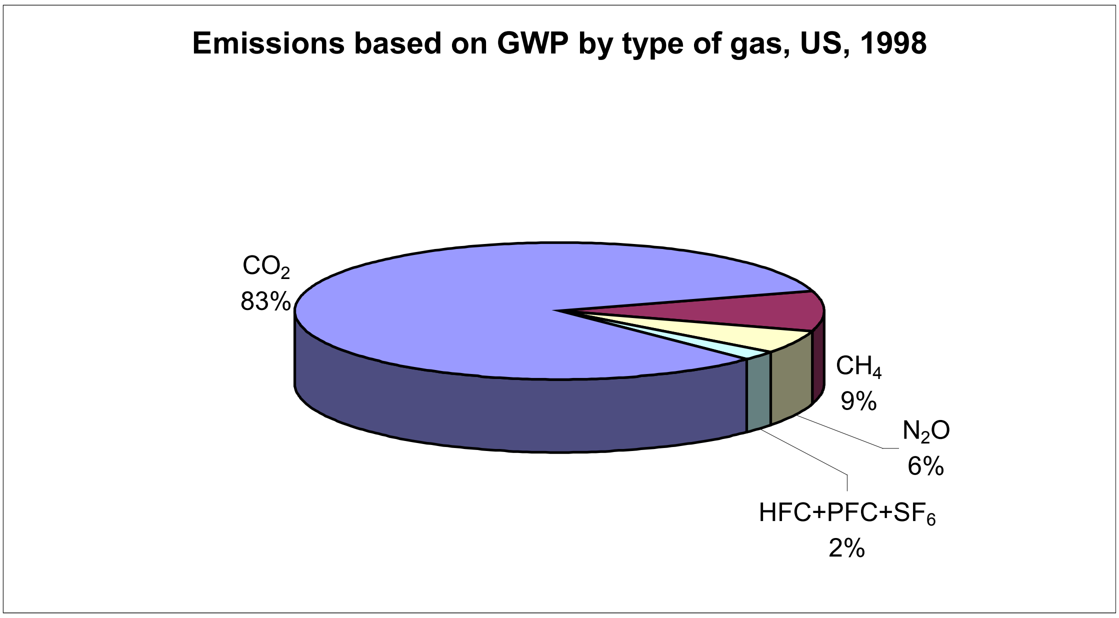

Fig. 2 [2, p. 310]

From these figures it appears clearly that ***by far the largest contribution to the greenhouse effect stems from emissions of*** CO_2. Among the other greenhouse gases, the emissions of methane and nitrous oxide in recent years have remained stable or tend to decrease [2, table 12.1]. Moreover, in compliance to the Montreal Protocol, halogenated gases (HFC, PFC, SF_6) are being phased out because of their role in destroying the ozone layer.

The two major anthropogenic (human activity induced) sources of CO_2 emissions world-wide are the combustion of fossil fuels and land-use changes, mainly deforestation. Currently, approximately 75% of global CO_2 emissions result from fossil fuel combustion for the transformation and use of energy, although the share varies by region [3, p. 155]. Therefore, the ***energy sector*** has to be considered as the central point of any emission reduction strategy.

In the following attention is focused on emissions from the energy sector with particular emphasis on ***fossil fuel combustion for energy-related activities.***

2. Emissions stemming from energy generation

The origins of CO_2 emissions from fossil fuel combustion in the EU are shown in Fig. 3 (total 3047 Mt CO_2). ***Power generation*** and ***transport*** each account for around one third of CO_2 emissions from fossil fuel combustion, although their dependence on fuel type is clearly different with the latter virtually exclusively relying on oil. Because emission sources in transport, industry and heating are many, dispersed and small, whereas the flue gas streams of power plants are few in number and large, technological solutions to reduce emissions from power generation have a greater impact than in the other sectors.

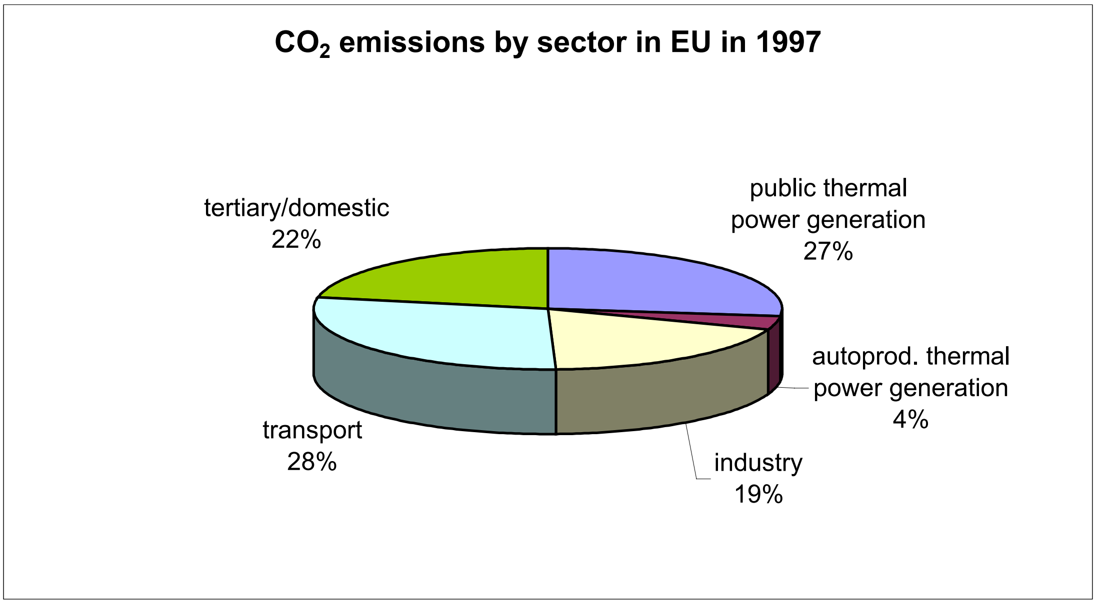

Fig. 3 [25, p. 77]

The energy consumption by fuel type for ***power generation*** is shown in figures 4 to 6. Figures 4 and 5 present the share of the different fuel types in terms of "primary" energy units Mtoe (megaton oil equivalent), Quad (Quadrillion Btu = 10^{15} British thermal unit), or Joule. A similar share of fuel types emerges from their proportion in the annual power production, expressed in TWh. (The ratio of primary energy consumption to power production is the (dimensionless) average gross specific fuel consumption, whereas the inverse is the average power generation efficiency).

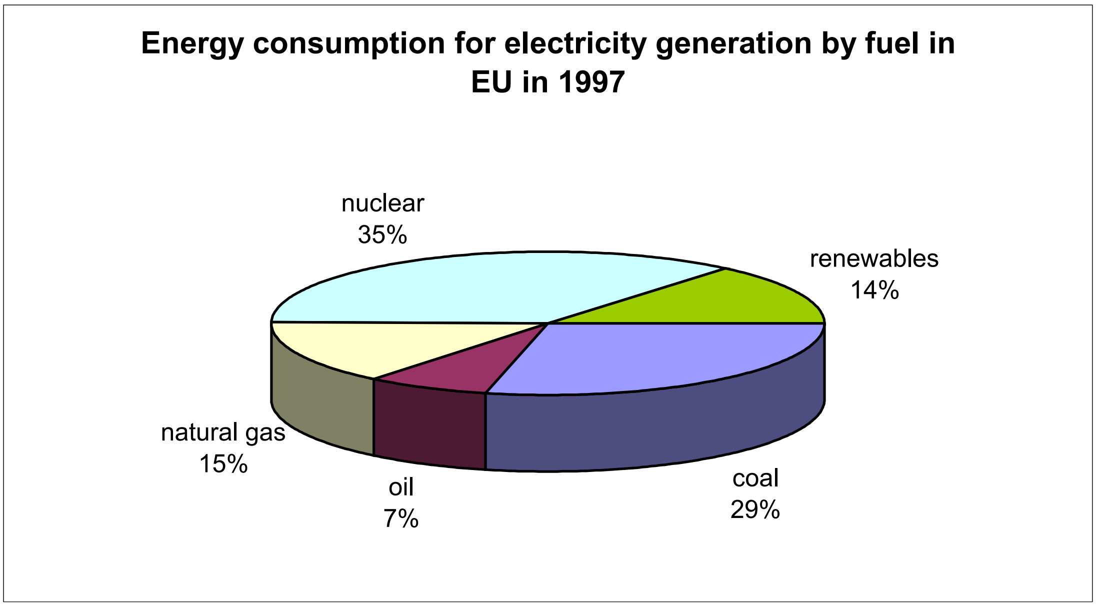

Fig. 4, derived from [25, p. 76], [4, table A-9]: total 510 Mtoe = 21.3 EJ (note that renewables include hydropower). Different data are presented in [5], see annex C.

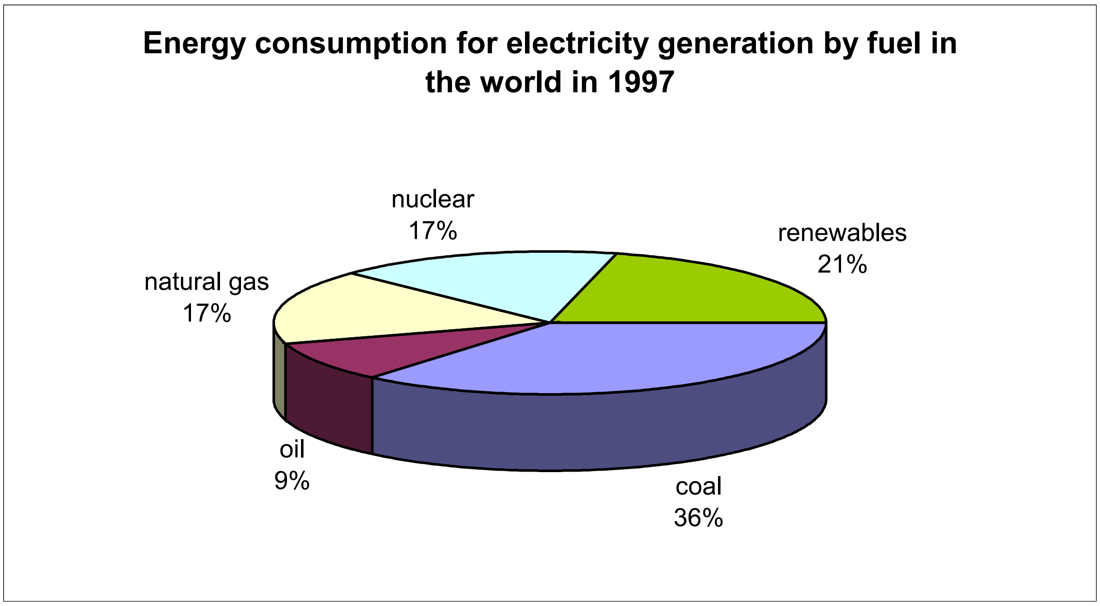

Fig. 5 [3, p.115], total 144 Quad = 151.2 EJ

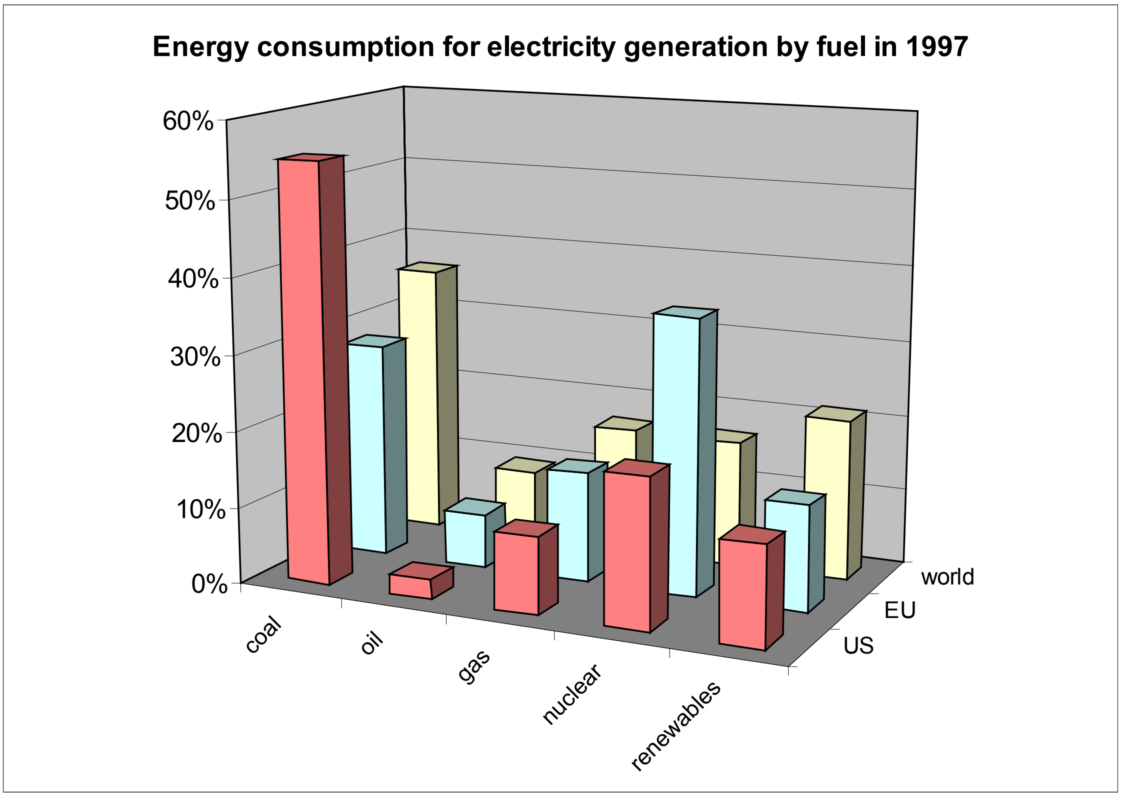

Fig. 6: EU [25, p. 76], world [3, p.115], US [2, p. 119]

Figure 6 shows major differences in energy vectors for power generation between different world regions. As can be derived from the following table, these differences are clearly expected to lead to different amounts of CO_2 emissions.

Table 2: GHG-emissions per kWh electrical energy generated by actual best available technology for each energy vector

Generation technology	source	g CO_2/kWh_e	ref.
coal	combustion	900	49
gas	combustion	400	49
nuclear	uranium enrichment	4	49
		8 (in EU), 46 (in US)	6
wind	construction	10-30	49
		10	6
photovoltaic	construction	100-200	49
hydro		18	6

Note: The emission figures in the third column indicate the emission per unit of electrical energy generated. The carbon content of the fuel is expressed in kgC/GJ or $kgCO_2/GJ$, and is related to the above value by the generating efficiency (see table 3).

Because CO_2 emission levels from non-fossil fuel energy vectors are low, and do not stem from the energy generation or conversion process itself, but rather from construction, the following section focuses on ***emissions from fossil fuel fired power plants***.

3. Emissions from fossil fuel fired power plants

3.1 relative contribution of generation technology and fuel type

The emission of CO_2 from fossil fuel fired power generation depends on
- the amount of electric power generation by fossil fuels (see figure 4),
- the fuel-mix used through its carbon-content, and
- the thermal efficiency of the fossil fuel combustion plants.

Emission figures per type of fossil fuel for the EU power generating sector have not been found. The situation for the US in 1997 is shown in Fig. 7 (total 2410 Mt CO_2): approximately 75% of all CO_2 emissions in US power generation stem from coal-fired plant, whereas gas-fired installations contribute around 15 %. Based on the different fuel-mix (considerably less coal and more natural gas, see fig. 6), these figures for the EU are about 53% for coal, 27% for gas, and 21% for oil-fired power plant.

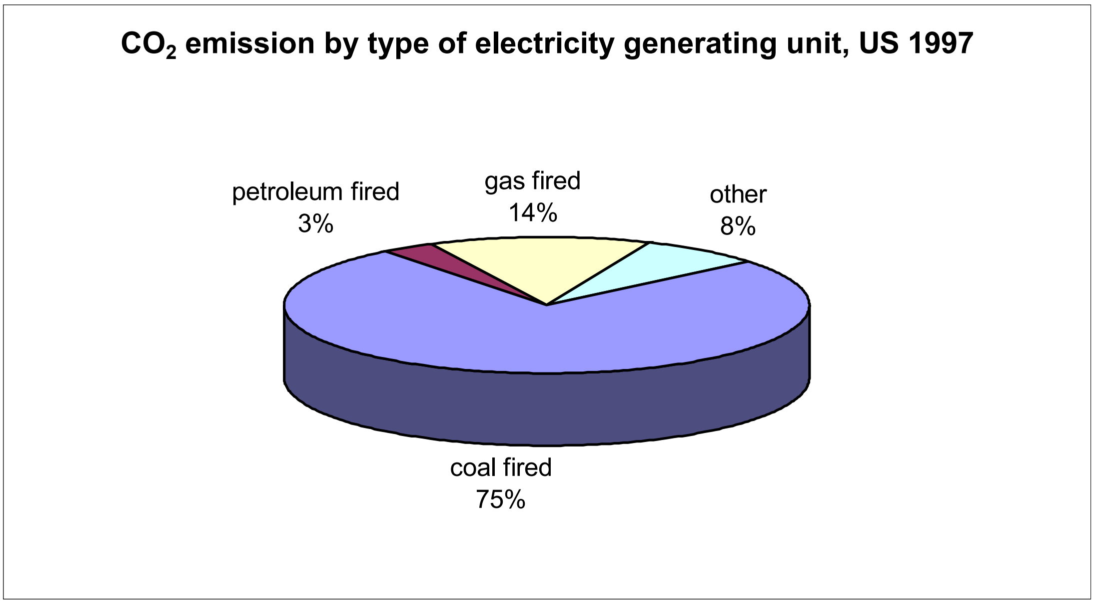

Fig. 7 [2, p. 322]

In the following, the two factors relevant for thermal power generation from fossil fuel combustion, namely fuel-mix and thermal efficiency are discussed.

3.2 Fuel mix: effect of carbon content

Natural gas has the lowest CO_2 emissions per unit of energy of all fossil fuels at about 14 kg C/GJ, compared to oil with about 20 kg C/GJ and coal with about 25 kg C/GJ (see table 3). From an emission point of view, the use of natural gas for power generation is hence clearly advantageous. Moreover, the lower carbon containing fuels can, in general, be converted with higher efficiency than coal [7], resulting in a knock-on effect of substituting higher-C by lower-C fuels on the amount of CO_2 emission (see also table 2).

Table 3: GHG emissions from a number of fuels

Fuel	CO_2 (gC/MJ)	CO_2 (gCO_2-eq./MJ)	CH_4 (gCH_4/GJ)	N_2O (gN_2O/GJ)
Coal	25.1 [1], 25.8 [8], 23.7 [9]	117 [1], 120 [8], 110 [9], 106 [49]	5.5 [1]	2 [1]
Hard coal		92 [10], 91 [11, 12]		
coke	27.5 [8]	128.3 [8]		
lignite	28.5 [14]	102 [12], 101 [13]		
Oil	20.8 [1], 21.1 [8], 20 [14]	97 [1], 98.5 [8], 76 [49], 75 [11], 78 [12]	8 [1]	2 [1]
Natural gas	14.3 [1], 16.8 [8], 14.2 [9], 15.3 [14]	67 [1], 78 [8], 66 [9], 57 [49], 61 [11], 56 [12, 13], 57 [10]	3 [1]	1 [1]
LPG	17.2 [8]	80 [8], 67 [11], 73 [12], 74 [13]		
diesel	20.2 [8]	94 [8]		
kerosene	19.6 [8]	91 [8]		
petroleum	19.0 [9]	89 [9]		
Peat	29.7 [1]	139 [1], 106 [13]	4.5 [1]	2 [1]
Wood	31.1 [1]	145 [1]	40 [1]	2 [1]

Numbers between square parenthesis indicate the references. Note that the values for CO_2 are expressed in different units: 1 g C corresponds to 44/12=3.667 g CO_2 through the molecular weigh ratio).

3.3 Thermal Efficiency

As a result of technological progress there has been a constant improvement in the efficiency of power generation technologies (see Fig. 8). This improvement should continue or even increase, since there is still insufficiently exploited theoretical potential. As discussed later, the penetration of clean and efficient natural gas, coal and lignite combustion technologies could improve electricity generating efficiency by 5-10%, resulting in a reduction in fuel costs and a 15-30% reduction in greenhouse gas emissions [15].

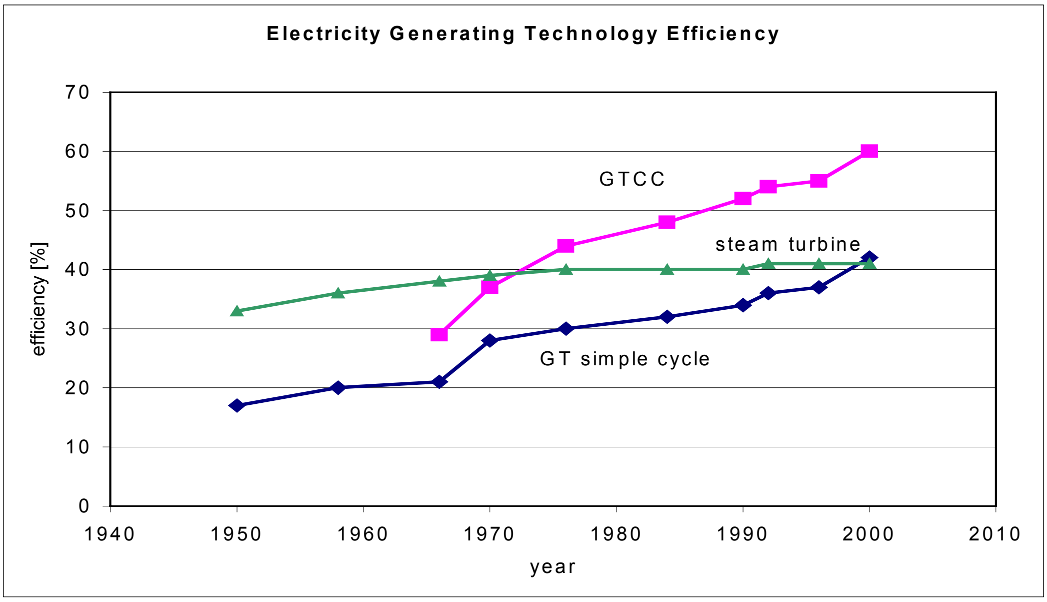

Fig. 8 [9].

The relationship between efficiency and CO_2 release for different power generation systems is shown in figure 9 (no CO_2 recovery is assumed). The vertical position of the curves corresponding to different energy vectors reflects their carbon content (see table 3). From the slope of the tangent to the curves, the reduction in CO_2 release per efficiency increment can be estimated. As a rule-of-thumb an efficiency increase from 40 to 41% for a gas-fired power plant reduces emissions of CO_2 by 2.5%. (For a 500 MW plant with a load factor of 85%, this translates into a decrease of CO_2 emissions of 37000 ton/year*).

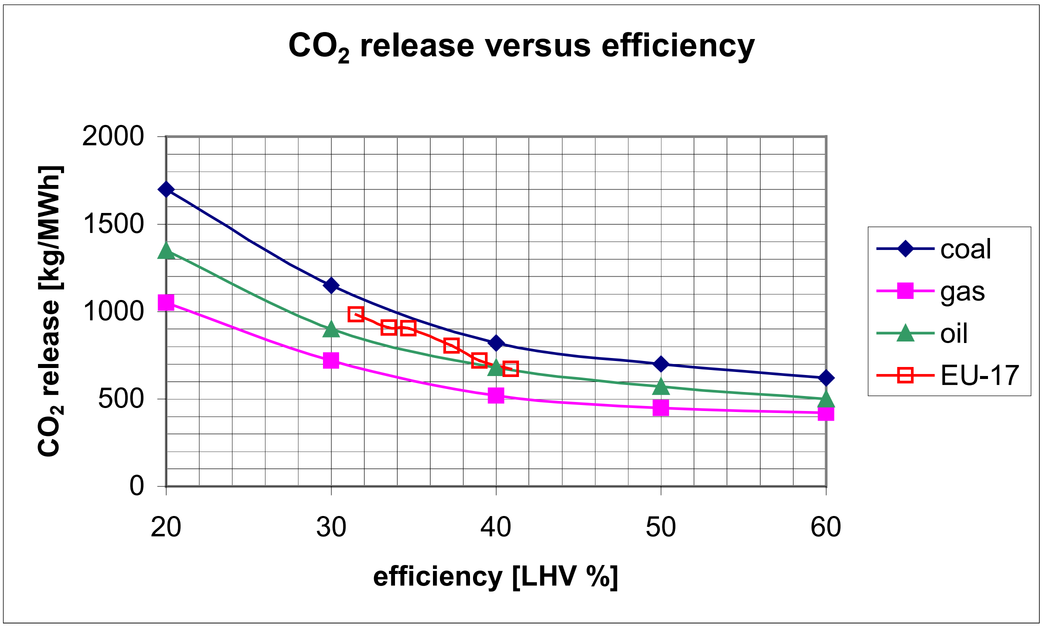

Fig. 9 [1], [16]

The open symbols in Fig. 9 represent the trend obtained from the evolution of the overall

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* 500 MW x (0.85 x 365 x 24 h/yr) x 400 kg/MWh x 2.5% = 3.7 10^7 kg/yr

CO_2 emissions and average efficiency of thermal power generation in the EU-17 (EU-15 + Norway and Switzerland) over the time period 1970-1996 (measured data) and projections for 2000 and 2010 (last two points) [16]. These data clearly demonstrate the merit of the increase in thermal power generation efficiency for CO_2 emission reduction.

3.3.1 Coal-fired plants

Today coal is used to generate about 36 percent of the world's electricity (fig. 5), a percentage that is not likely to change significantly during the next 15 to 20 years [3, p. 115]. In industrialised nations, a typical coal-burning power plant converts about 33 to 38 percent of the energy potential of coal into electricity. The rest is lost primarily as waste heat. In some plants, however, especially the older power plants of developing countries, Eastern Europe, and the former Soviet Union, electricity generating efficiencies are even lower, in some cases, below 30 percent. The corresponding penalty on CO_2 emissions is clear from Fig. 9.

Increasing a power plant's coal-to-electricity efficiency means that less fuel is needed to generate the same amount of electricity. Research and development over the last two decades has produced a new array of coal-burning technologies that boost efficiency – and as a result, sharply reduce emissions of carbon dioxide (fig. 9). The currently available coal combustion technologies, as well as future developments are listed in the following tables compiled from a number of sources.

In an integrated gasification combined cycle (IGCC) system, coal is converted into a combustible gas (typically a mixture of carbon monoxide and hydrogen, called syngas). The gas is burned in the combustor of a gas turbine to produce one source of electricity. Exhaust gases from the gas turbine remain hot enough to boil water for a conventional steam cycle.

Table 4.1: Current Coal Technology Status

	Efficiency (%)	greenhouse gas emissions (g CO_2/kWh)	ref.
Pulverised coal combustion (subcritical) + FGD (flue gas desulphurisation)	39-41	-	17
	40	830	1
	34	946	18
	38	862	18
	-	780	19
	37.5	860	19
	35	990	20
supercritical	42	-	17
	43.5	852	49
	44	-	28, p. 164
Atmospheric fluidised bed combustion	39	-	17
Pressurised fluidised bed combustion (PFBC)	44	-	17
	44	-	28, p. 164
Integrated gasification combined cycle (IGCC)	42	740	1
	43	-	17
	43	862	49
	46	-	28, p. 164
	47	691	19

Table 4.2: Short-term time frame (2000-2010)

	Efficiency (%)	greenhouse gas emissions ($g\ CO_2/kWh$)	ref.
Low emission boiler systems	42	728	20
(ultra-)supercritical	45-46 48 48.5	- - 764	17 28 p. 164 49
Pressurised fluidised bed combustion (PFBC)	45 45	- 708	28 p. 164 20
Integrated gasification combined cycle (IGCC)	49 45 47 48 -	- 679 693 772 690	28 p. 164 20 18 49 19
Indirectly fired cycle (IFC)	45	592	20

Table 4.3: Longer-term time frame (post 2010)

	Efficiency (%)	greenhouse gas emissions ($g\ CO_2/kWh$)	ref.
Low emission boiler systems	42	728	20
(ultra-)supercritical	51 50	- -	28 p. 164 17
Pressurised fluidised bed combustion (PFBC)	47 50	- 621	28 p. 164 20
Integrated gasification combined cycle (IGCC)	50 52	- 592	28 p. 164 20
Indirectly fired cycle (IFC)	48	582	20

Gasification technologies represent the next generation of solid feedstock based energy production systems. Gasification breaks down virtually any carbon-based feedstock in its basic constituents. This enables the use of different fossil feedstocks (coal, biomass, agricultural, forestry, municipal and refinery wastes), the separation of pollutants and greenhouse gases, and the production of clean gas for efficient electricity generation and of chemicals and clean liquid fuels. Experience with the Puertollano IGCC has shown that second generation IGCC plants must have an investment cost of less than 1400$/kW and a net efficiency of more than 48% to be competitive with other clean coal technologies. However, IGCC plants will always have a clear advantage from the points of view of fuel flexibility, future efficiency potential and synergy with other processes [17].

Apart from their high efficiency (the highest among coal technologies) gasification-based power systems offer another important advantage in greenhouse gas control. Unlike conventional coal-burning technologies, which release carbon dioxide in a diluted, high-volume mixture with nitrogen from the combustion air, gasification systems produce a concentrated carbon dioxide gas stream that may prove much easier to capture for subsequent sequestration.

In the future, the hydrogen gas from the coal gasification system might also be used in an advanced, high-temperature fuel cell. A fuel cell generates electricity electrochemically without using combustion from either hydrogen or methanol. Since neither of these is a naturally available fuel, they have to be manufactured. At present, hydrogen is produced from oil or gas, or from water using electricity. These processes create CO_2 and have a certain efficiency which must be included in the total efficiency of the fuel cell. To avoid CO_2 emissions, hydrogen must be produced from biomass or from water using solar energy.

New fuel cell technologies are being developed that operate hot enough to produce exhaust gas streams with sufficient heat energy to power a gas turbine, conventional steam cycle, or both. A hybrid system – combining coal gasification, high-temperature fuel cells, and high-efficiency gas turbine cycles – could boost coal-fired power plant efficiencies to nearly 60 percent, cutting carbon dioxide releases to around half of the amount produced today by a conventional coal-burning power plant [20].

The potential efficiency increases for coal-fired power plant are summarised in the next figure, which also indicates the major technological hurdles that have to be overcome.

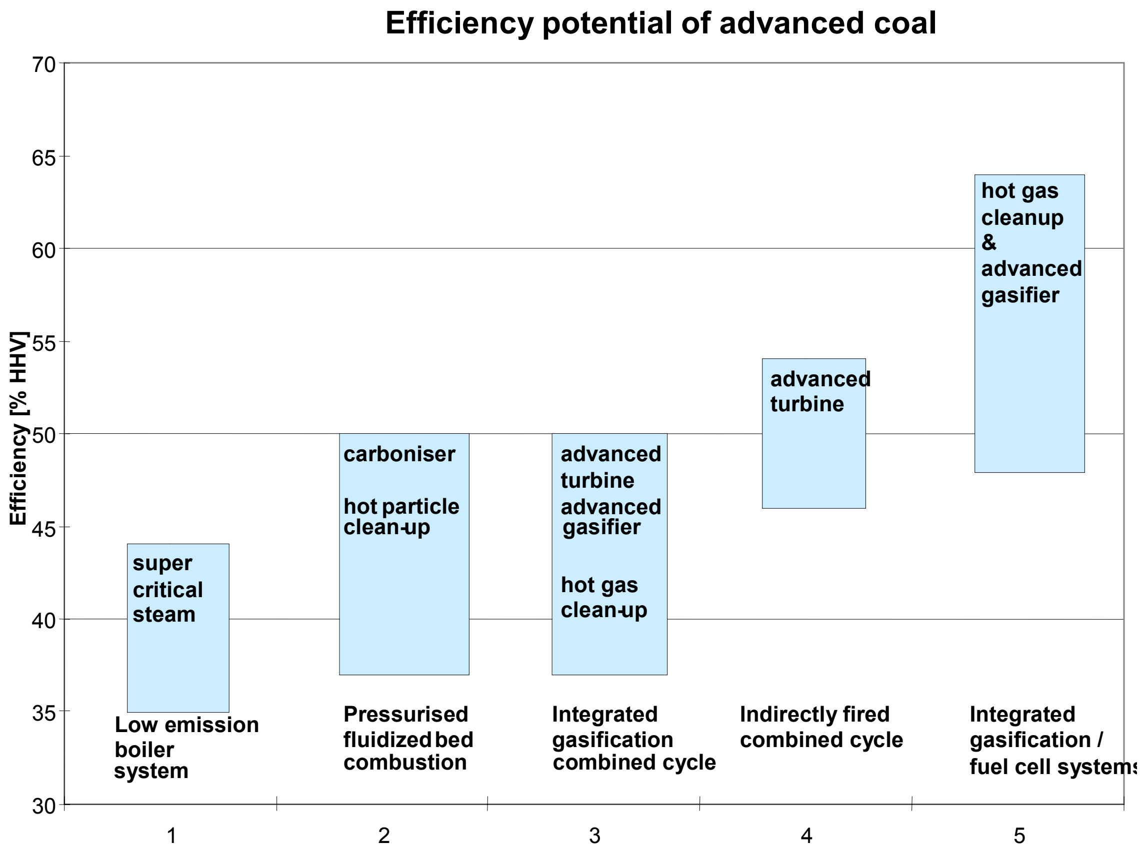

Fig. 10 [21]

3.3.2 Natural Gas Power Plants

When gas turbines were introduced more than 40 years ago, fuel-to-electricity efficiencies were low, typically less than 20 percent for simple cycle systems (see Fig. 8). Today, manufacturers have achieved dramatic advanced in gas turbine efficiency: a simple cycle gas turbine can operate at efficiencies of up to 40 percent, while the addition of a steam turbine in combined cycle can boost natural gas-powered turbine plant efficiencies into the mid-50 percent range. The efficiency of a gas turbine depends on the operating mode, with full operation giving the highest efficiency, and with efficiency deteriorating rapidly with decreasing power output.

Increased use of natural gas is important to greenhouse gas reduction because natural gas emits about half the amount of carbon dioxide than coal for the same energy produced (see table 2). Also, the emission of other pollutants is lower than from coal-fired plant of the same capacity (see annex 1). Moreover, as shown in the following tables, there are new technologies that enhance natural gas-to-electricity efficiencies, further reducing greenhouse gas emissions.

A further development is the so-called Humid Air Turbine (HAT), mostly coupled to an IGCC. The mass flow of the syngas entering the power turbine, and hence the turbine power output, is increased by water injection which evaporates into steam. Also steam from the waste heat boiler can be injected upstream in the gas flow path or in the combustor. Efficiency increases of 3 % points compared to a standard IGCC can be obtained [17].

Table 5.1: Current Gas Turbine Technology Status

	Efficiency (%)	greenhouse gas emissions (g CO_2/kWh)	ref.
Gas turbine open cycle	30-40 (size dep.)	-	45
	32	557	18
	43	418	18
	32	547	19
	43	413	19
Natural gas combined cycle (NGCC) Gas turbine combined cycle (GTCC)	55	-	28, p. 164
	55	370	49
	55	-	17
	49	367	18
	51-55 (size dep.)	-	45
	55	300	19
	54	334	18
	55	370	20
	54	328	19
	49	414	19
	52	400	1

Table 5.2: Short-term time frame (2000-2010)

	Efficiency (%)	greenhouse gas emissions (g CO_2/kWh)	ref.
Natural gas combined cycle (NGCC) Gas turbine combined cycle (GTCC)	60	-	28, p. 164
	60	340	49
	62	-	17
	60	365	20
Advanced hybrid fuel cells	70	306	20
	66	-	28, p. 164
	70	-	45
	64	282	18

Table 5.3: Longer-term time frame (beyond 2010)

	Efficiency (%)	greenhouse gas emissions (g CO_2/kWh)	ref.
Natural gas combined cycle (NGCC)	62	-	28, p. 164
Gas turbine combined cycle (GTCC)	65	344	20
Advanced hybrid fuel cells	70	306	20
	71	-	28, p. 164

3.3.3 Comparison coal and gas

The following figure shows typical power plant efficiencies as a function of the power unit size. As a general rule efficiency increases with increasing unit size. Advanced gas turbines operating in closed cycle currently offer the highest efficiencies, and the lowest emissions. Besides these advantages, natural gas fired power plants have shorter construction times, lower investment and lower operating costs. Cost considerations for different power generation technologies are detailed in section 6.2 and in Annex B.

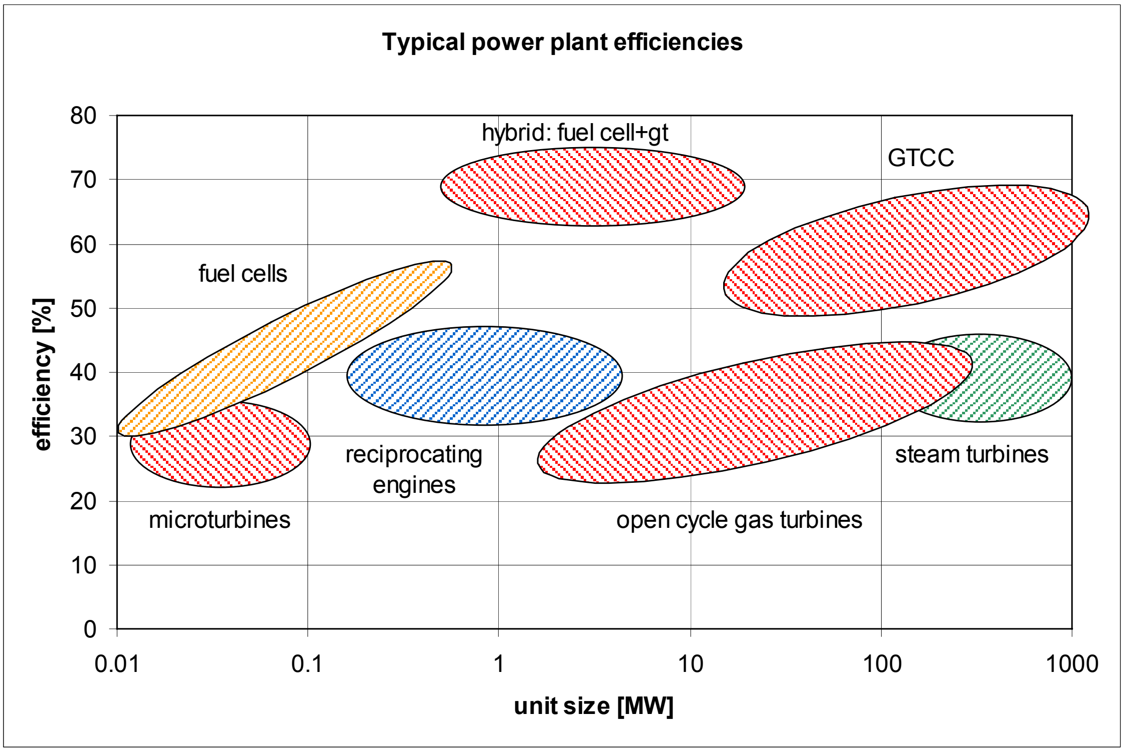

Fig. 11 [45]

It should be noted that, with the exception of some fuel cell based systems, all of the smaller scale power generation technologies yield *less* energy efficient solutions than central generation in large GTCCs. However, smaller scale generators are much better matched to combined-heat and power (CHP) and cogeneration applications. Such schemes are significantly more energy efficient, typically giving fuel utilisations of the order of 80-90% (almost independent of the energy conversion system) as well as being economically advantageous. Such high overall fuel utilisations can make a significant contribution towards reducing CO_2 emissions; it is estimated that the largest single contribution to Europe's CO_2 emissions reduction will come from more widespread use of CHP [22]. This is discussed further in section 3.4.

Figure 12 is a plot like Figure 9, but the power generation technologies currently in use are superimposed on the curves corresponding to coal and gas. In a similar way, Figure 13 compiles the data from tables 4.1 to 5.3 and compares them to the trend curves in Fig. 9. The main message from these figures is that substantial efficiency improvements in fossil fuel fired power generation are possible in the coming decades (*up by more than 50% from the current average value of 39.4% in the EU* [25, p. 76]). Because of the time needed for significant market penetration the impact of the efficiency increases in advanced coal- and gas-fired plant is only expected to show up from around 2010. However, already in the short term up to the Kyoto target date of 2010, improvements to existing installations ("retrofitting") will bring about substantial gains in the efficiency of energy use and reductions in pollution. For example, based on the EU coal-fired power generation capacity of 180 GW (1995 [33]) and a load factor of 80 %, an efficiency increase from 38 to 40 %, corresponding to a decrease in specific CO_2 emissions of 60 g/kWh (see fig. 13), would result in a decrease of CO_2 emissions of 76 Mt CO_2/year*.

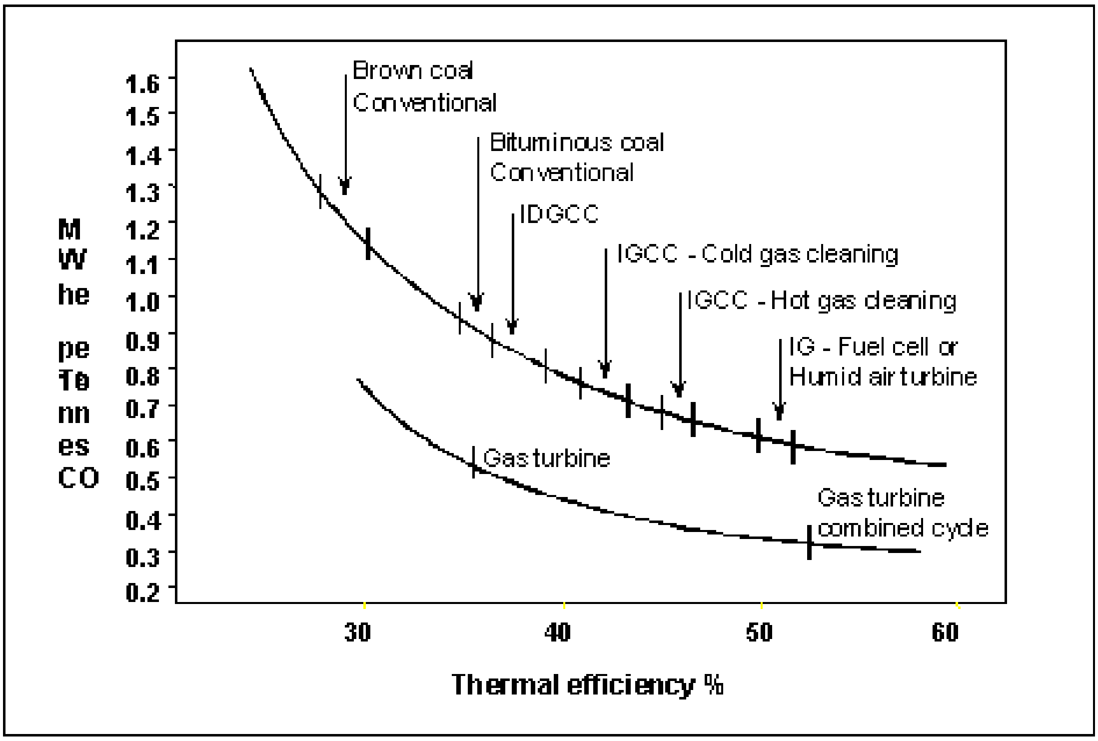

Fig. 12 [11]

* 180.10^3 MW x (0.8 x 365 x 24 h/yr) x 60 kg/MWh = $7.6.10^{10}$ kg/yr = 76 Mt/yr

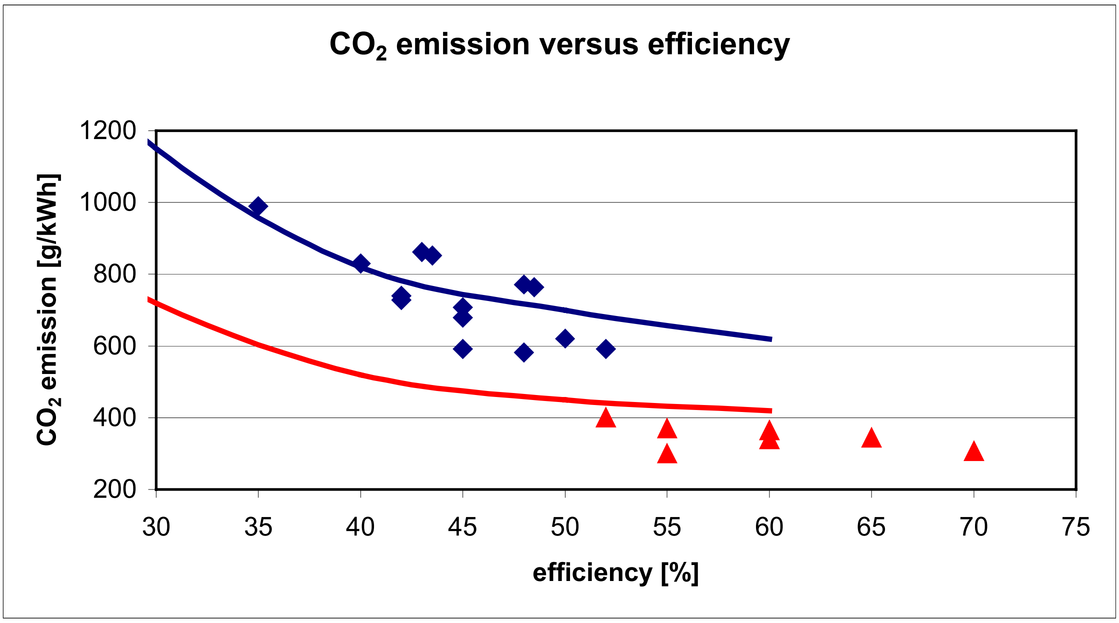

Fig. 13: comparison between trend curves in Fig. 9 and data from tables 4 and 5. The upper curve and diamonds correspond to coal-fired and the lower curve and triangles to gas-fired plant.

The dependence of the thermal efficiency on the power plant size (fig. 11) does not translate into a large dependence of the specific CO_2 emissions on the plant size. This is shown in Figure 14.

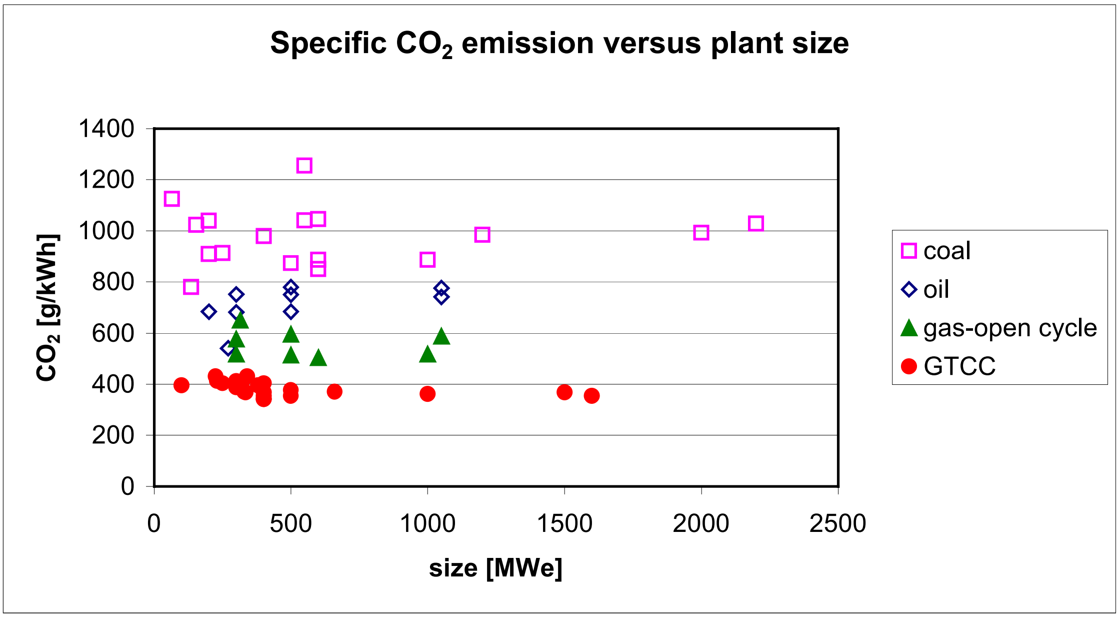

Fig. 14 [13]

Finally, Fig. 15 ranks the different power generation technologies in terms of their current specific CO_2 emissions. The two lines in the figure refer to the maximum and minimum values quoted in literature. For comparison purposes, emissions from non-fossil power generation are also presented.

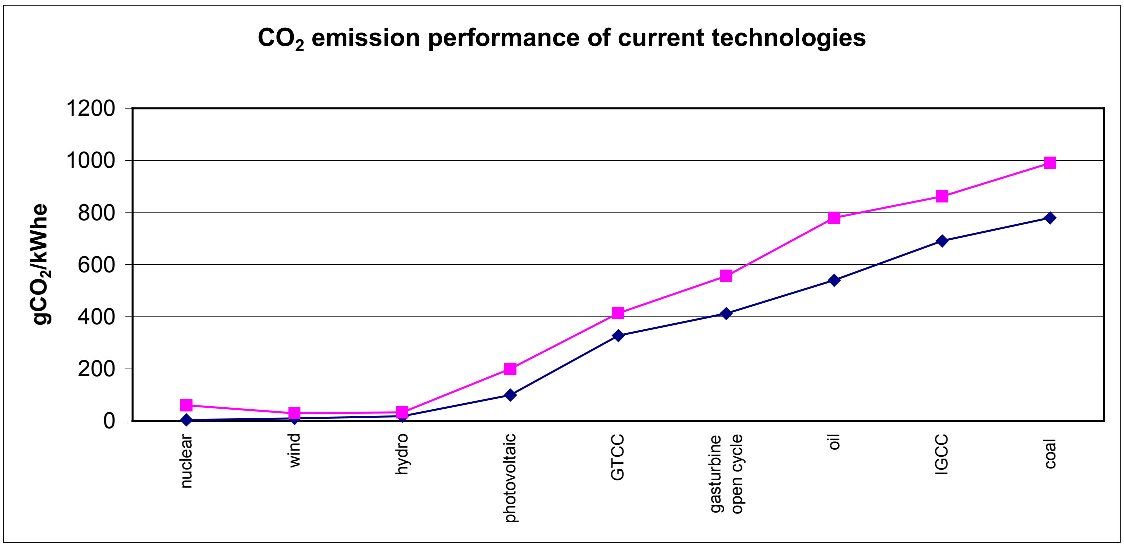

Fig. 15

3.4 Combined heat and power (CHP)

CHP involves the simultaneous production of thermal and electric energy from the same primary fuel source. For a given application, this is achieved through one of a number of different electricity generation technologies in which heat is diverted part-way through the electricity production process and used to satisfy thermal requirements (steam or hot water supply, process heating and cooling). From a thermodynamic perspective, CHP offers a clear efficiency advantage. Another advantage of CHP lies in the development of decentralised forms of electricity generation providing high efficiency and avoiding transmission losses.
The efficiency gains represented by CHP may be significant, but vary depending upon the technology and fuel source employed and displaced by CHP systems. An efficient CHP plant can convert more than 80% of the energy content of the fuel into useful energy* (see figure 16).

* Note that overall efficiencies (defined as fuel to electricity efficiency multiplied by the ratio of produced heat and power to produced power) exceeding 100% can be achieved by CHP.

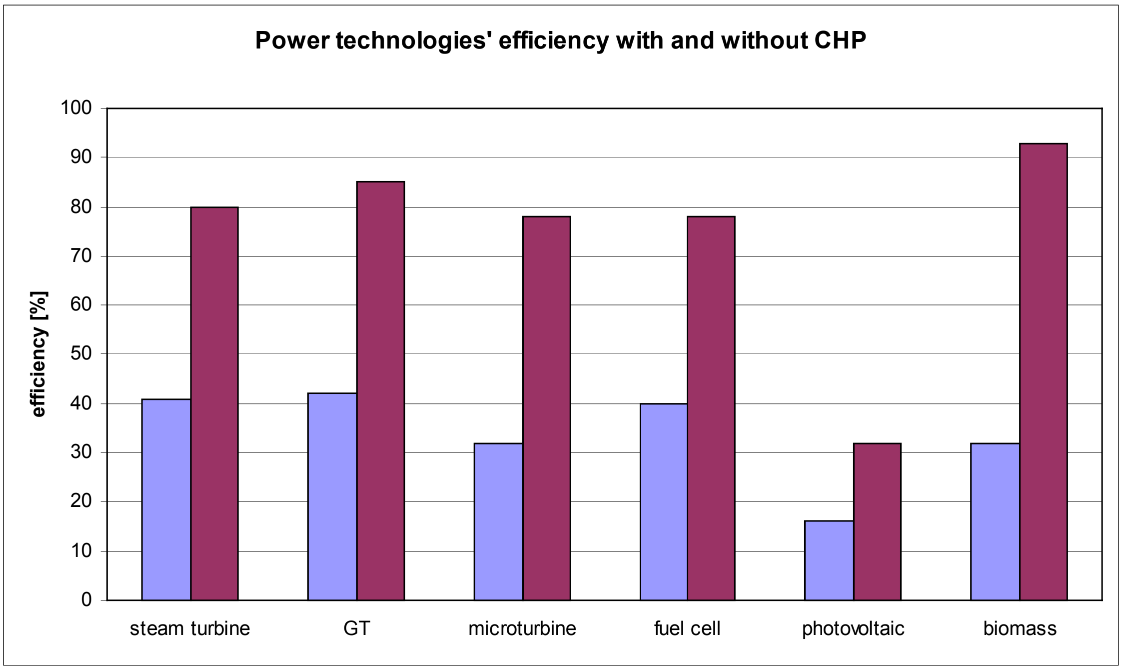

Fig. 16 [9, 10]

In line with the dependence of specific emissions on efficiency (see Fig. 9), the high energy conversion rates associated with CHP lead to substantially lower CO_2 emissions, particularly for gas-fired power generation. (Figs. 17, 18). The efficiency and emission data in these figures are "typical" values from a number of literature sources, as well as derived from the IAM emission reduction cost spreadsheet described in section 6.

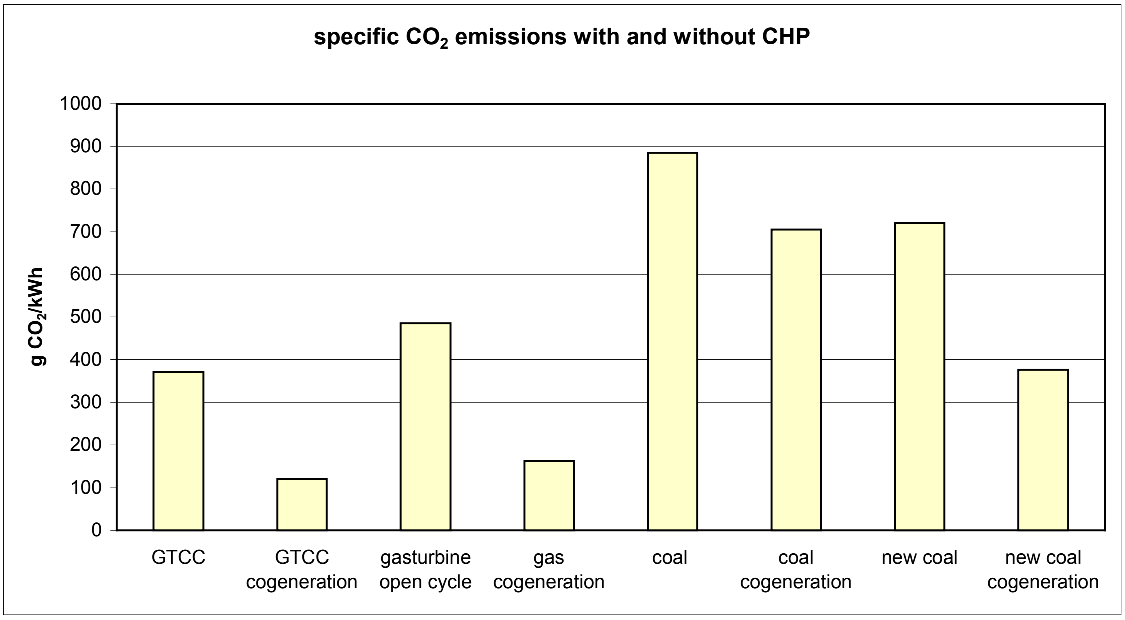

Fig. 17

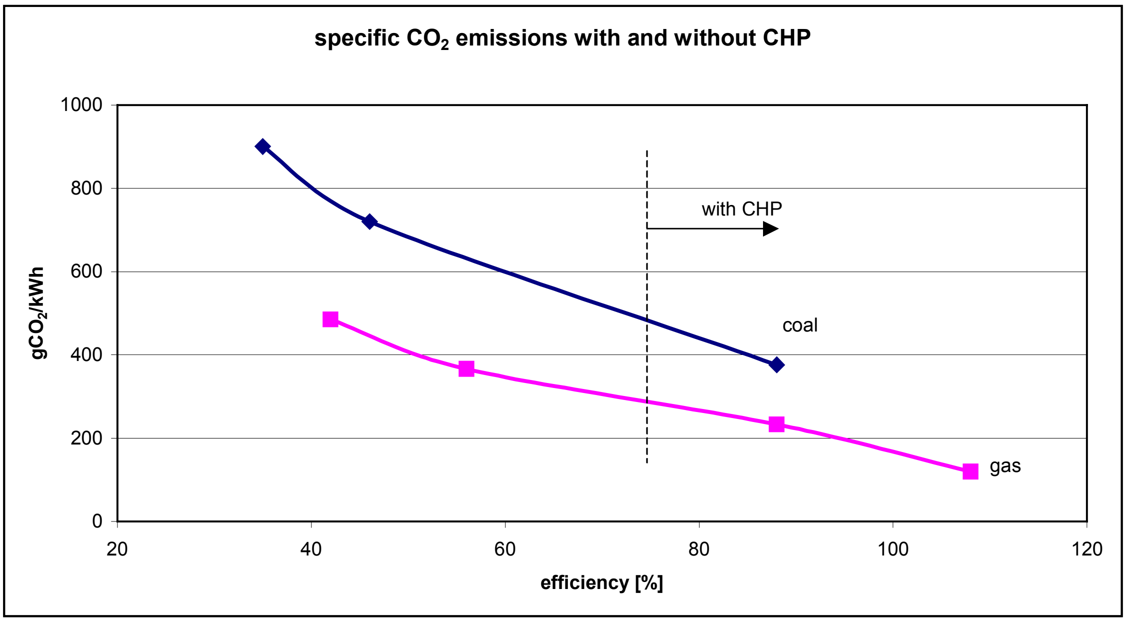

Fig. 18

In 1997 the EU set a target for the future evolution of CHP [23]: a doubling of electricity produced by cogeneration by the year 2010, based on the reference of 9% in 1995. In achieving this target, CO_2 emissions in the EU are claimed to decrease by 65 Mt CO_2/yr. This will be discussed further in section 5.2.

Finally, a word of warning on CO_2 emission from CHP is in place. CHP is only a good choice for reducing CO_2 emission where there is a real and proportionate heat load. Without this, and in any case to the extent that generated heat is not used, such a plant can have higher CO_2 emissions than one which is optimised for electricity generation. Related to this, many plants which are or could be called CHP plants, are often in fact not in CHP mode when in operation (so no CO_2 savings are arising). Therefore, great care is required in evaluating the contribution from emission reduction from CHP plants.

4. Evolution trend of CO_2 emissions from fossil-fuel fired power plants

In 1997, 63 percent of the world's total carbon dioxide emissions from human activities came from the developed countries [3, table A10]. The United States is the largest single source, accounting for 24 percent of the total, whereas the EU contributes 15 percent (for 6% of the total world population). If current trends continue, the developing countries will account for more than half of total global carbon dioxide emissions by 2035. The projected future increases in CO_2 emissions are the result of both economic growth and population growth, despite projected declines in the energy intensity of economic activity and the carbon intensity of energy supply [3, p. 158]. China, which is currently the second largest source, is expected to displace the United States as the largest emitter by 2015.

Realising the dominant contribution of fossil fuel combustion to the total amount of CO_2 emissions, and of the role of thermal power generation, the projected evolution of CO_2 emissions is closely related to that of power generation, via the thermal efficiency and the carbon content of the fuel used.

4.1 changes in energy consumption for power generation

The projected changes in energy consumption for power generation are shown in the figures below, both for the EU and the world. For the world, they are based on the "reference case" scenario from [3], whereas for the EU the PRIMES model has been used. Both scenarios ***do not reflect*** the potential effects of the Kyoto Protocol or other possible climate change policy measures.

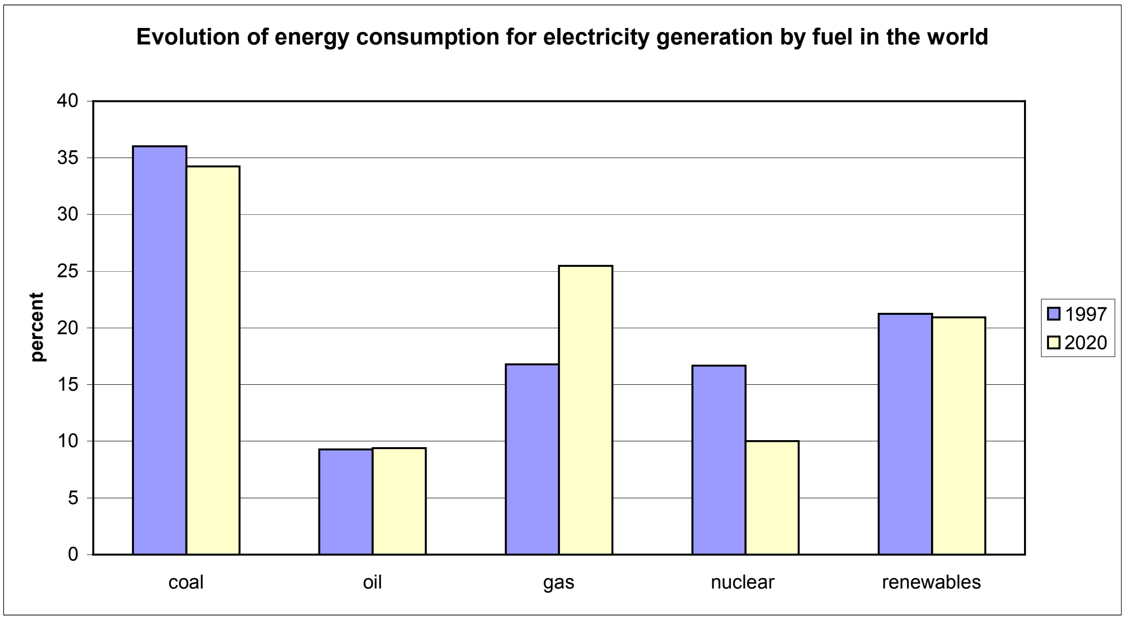

Fig. 19 [3, p. 115], total 224.3 Quad (an increase of 56% compared to 1997, see fig. 5)

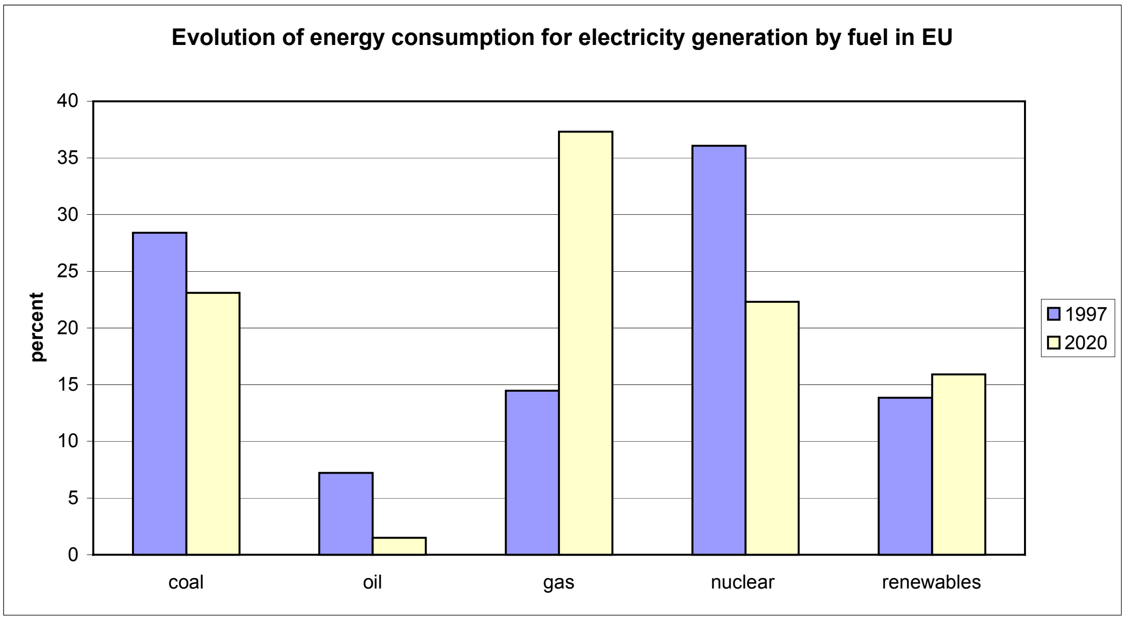

Fig. 20 [28, p. 176], total 754 Mtoe, an increase of 48 % compared to 1997, see fig. 4

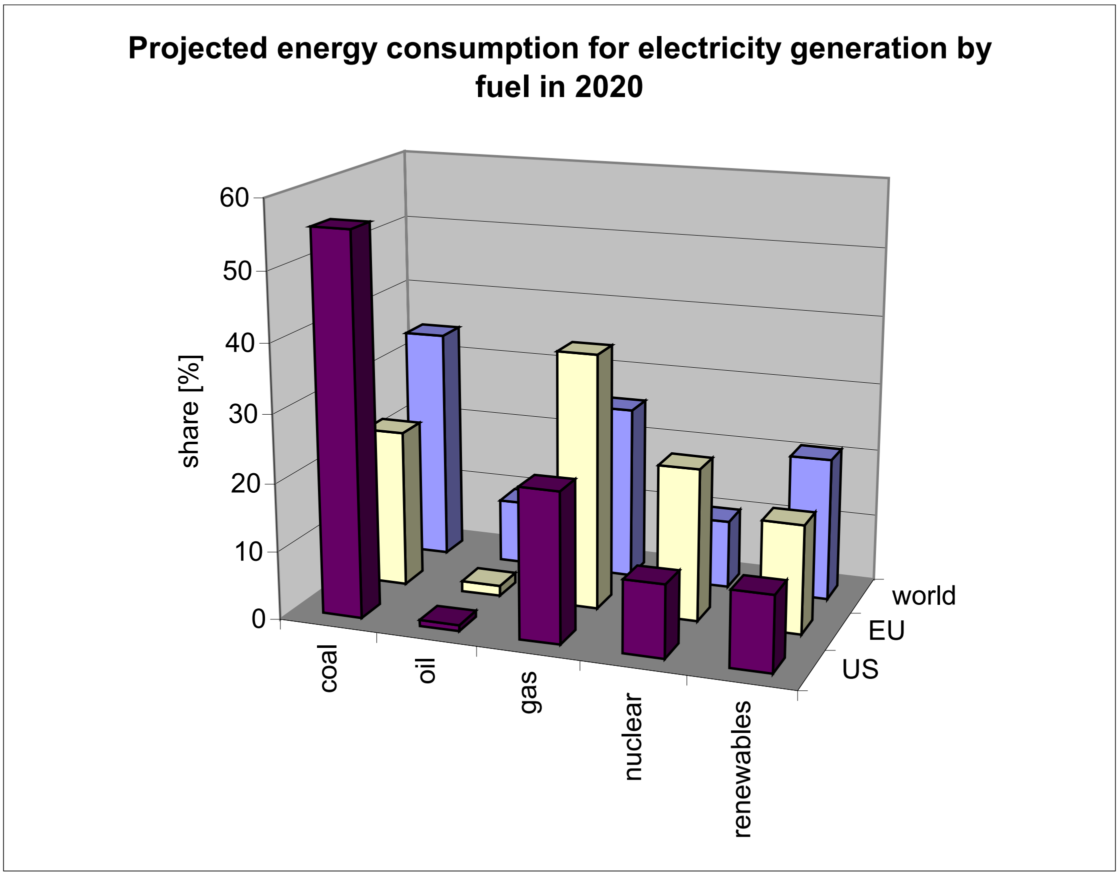

Fig. 21: world [3, p. 115], US [2, p. 119], EU [28, p. 176]

The changes in energy consumption for power generation ***by fossil fuels*** between 1997 and 2020 for the world and the EU are shown in figures 22 and 23. They are derived from figures 6 and 21 by considering only the contribution of thermal power generation.

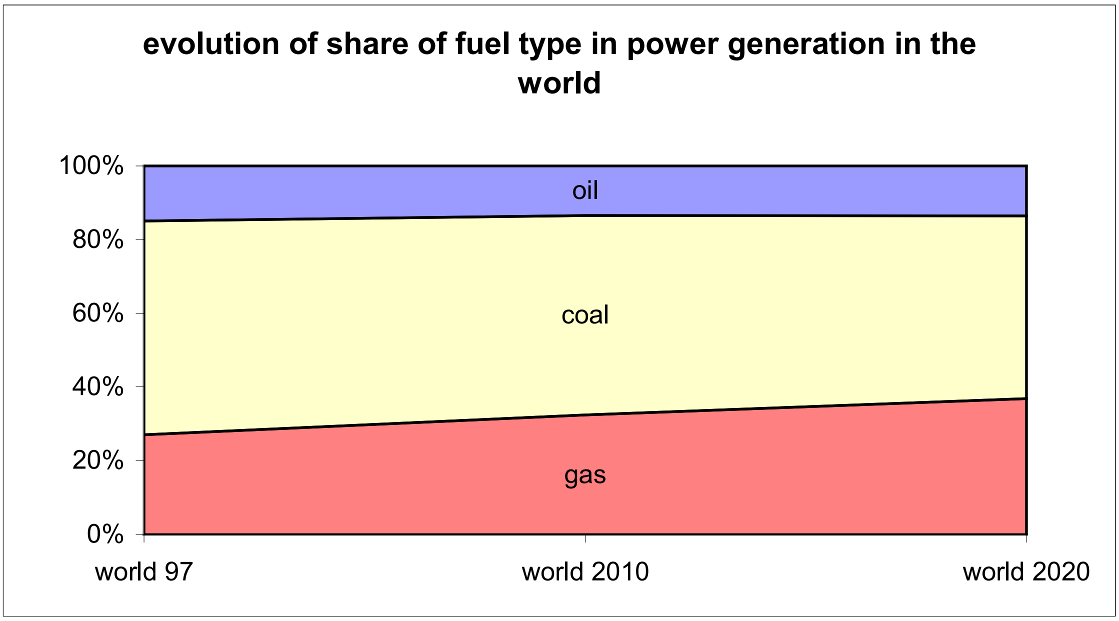

Fig. 22 [3, p. 115]

The use of natural gas to generate electricity is projected to be one of the most rapidly growing segments of the global energy market. World wide, natural gas is expected to grow from 27 percent of fossil fuel consumed for electricity generation in 1997 to 37 percent in 2020 [3, p. 115]. Although coal is projected to remain the dominant fuel for power plants, projections of ample natural gas supplies and relatively low prices have made it the preferred fuel for many power producers around the world. Also, the relative modularity of gas turbines, giving power companies the capability to add more power generating capacity in smaller increments to match more closely growth in demand, gives turbine technology distinct advantages in the marketplace. In the industrialised countries, with the notable exceptions of Japan and France, the projected trend is away from nuclear power and toward natural gas. In the developing world, coal still shows the greatest increase between 1997 and 2020, but natural gas use for power generation is expected to increase by three times [3, p. 115].

Despite the projected slowdown in electricity demand growth, total power capacity requirements for the EU are projected to increase by some 300 GW in the 1995-2020 period. If plant retirements are also taken into account, the EU will require close to 600 GW of new capacity construction in the 1995-2020 period. Traditional coal and lignite plants will be massively retired in this period, and they will not be replaced by technologies that use the same fuel for economy reasons. Less than half of the solid fuel capacity that will be retired will be replaced by more efficient and clean coal plants, the remainder (and also the phased out nuclear plants) will be replaced by gas turbine combined cycle plants and by small gas turbine plants [28, p. 173]. Because of the projected rise in gas prices in the longer term, the cost advantage of GTCC diminishes, and in the latter part of the projection period clean coal technologies become more prominent. However, results are extremely sensitive to assumptions made on nuclear, clean coal, and gas relative to coal prices.

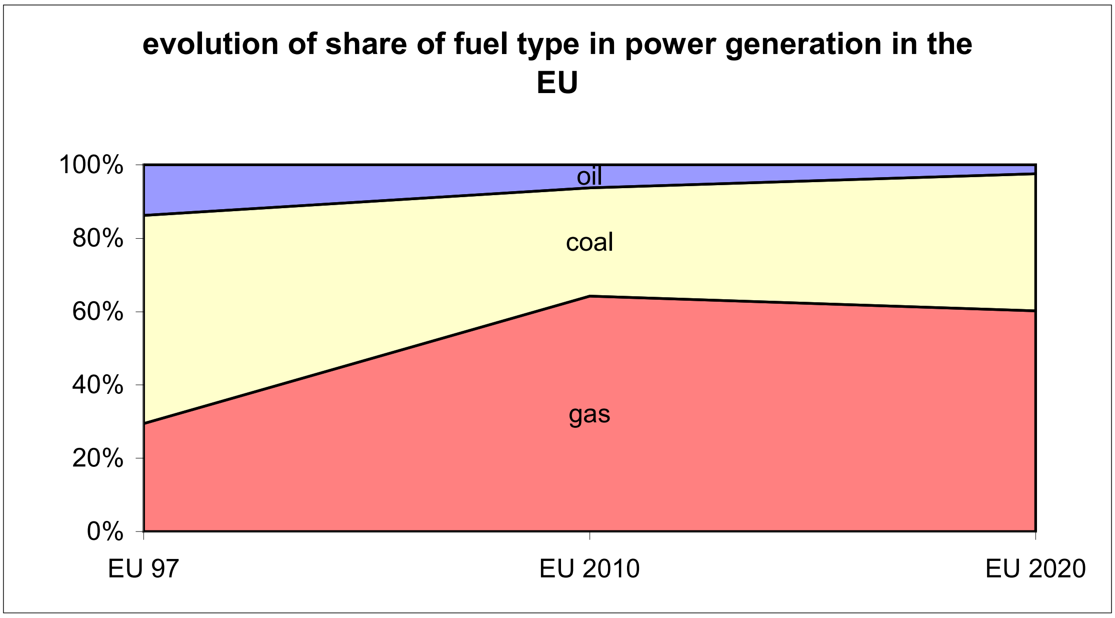

Fig. 23 [28, p. 176]

The increased use of natural gas for electric power generation translates into a relative increase of the use of gas turbine technology. The projected evolution for the EU is shown in figure 24.

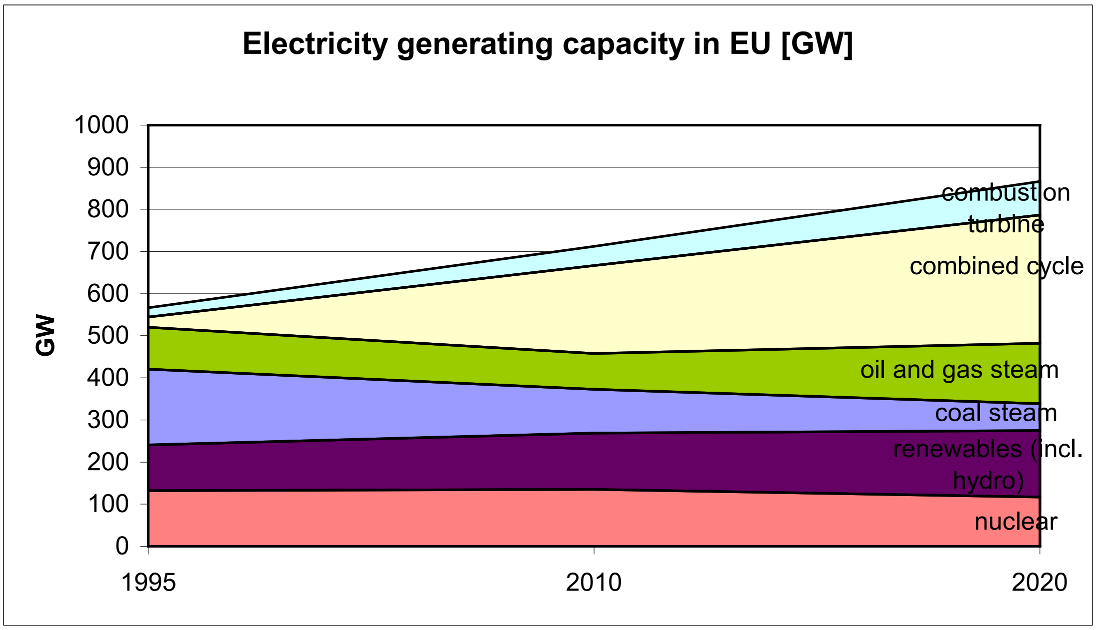

Fig. 24 [33, p. 57], [28, p. 173]

4.2 changes in emissions

Energy-related GHG emissions are likely to grow more slowly than energy consumption in general and energy sector requirements in particular because of the possibility of switching fuels and energy sources. At world level, energy-related CO_2 emissions are projected to increase from 6 Gt C in 1990 to 7-12 Gt C by 2020 (depending on the scenario, 10 Gt C for the reference scenario) and to 6-19 Gt C by 2050 (reference 13 Gt C), of which the energy sector accounts for 2.3-4.1 Gt C (reference 3.3 Gt C) by 2020 and 1.6-6.4 Gt C (reference 3.8 Gt C) by 2050 [24]. The share of power generation, the single largest source, to total greenhouse gas emissions hence remains stable at 30%.

Notwithstanding the economic growth the CO_2 emissions in the EU have stabilised between 1990 and 1997, [25, p. 71]. This is the result of three main factors: the continuous improvement of technologies reducing specific energy consumption, the increasing contribution of non-fossil fuels, mainly nuclear together with some wind energy and biomass, and greater penetration of natural gas both for power generation and in final markets substituting solid fuels and oil products. In future, the contribution of the last two factors is expected to change. The potential for new nuclear power is very limited and the load factor of existing units is already so high that it will be difficult to increase the nuclear contribution. The contribution of renewable energy sources is increasing very slowly from the current level of 6% even though the EU proposes a goal of a 12% share of renewables by the year 2010 [29]. The substitution limits for natural gas will be progressively reached. This means that, ***to reduce CO_2 emissions in the near future, measures that reduce the energy intensity and specific energy consumption (i.e. increase efficiency) will become increasingly more important.***

The past and projected trends in emissions ***from power generation*** in the EU are shown in Figure 25, where information from different sources is assembled. Whereas the relative behaviour is quite similar between those different sources, they provide different absolute emission values, even for the past and from the same organisation. For the future, similar assumptions (”scenarios”) are used in the projections shown. These scenarios are based on “business as usual (BAU)” and do not include any specific actions or mechanisms to achieve the EU commitment towards the Kyoto Protocol.

The projected rise in generation demand and the increase in fossil fuel use by the sector induce a rise of CO_2 emissions in the future. Compared to other sectors, like transportation, the increase of CO_2 emissions in the first decade is modest, due to the penetration of natural gas and the efficiency gains obtained from GTCC and co-generation. Notwithstanding this, the figure indicates that the problem of CO_2 emissions is unlikely to diminish over the outlook period, at least under circumstances close to the baseline assumptions. These emissions are clearly determined by the growth in the production of electricity, the carbon intensity of the input fuels, and the generation efficiency. The latter is expected to improve substantially in the period to 2020 (see tables 4 and 5), and can hence contribute to slowing down the increase of CO_2 emissions.

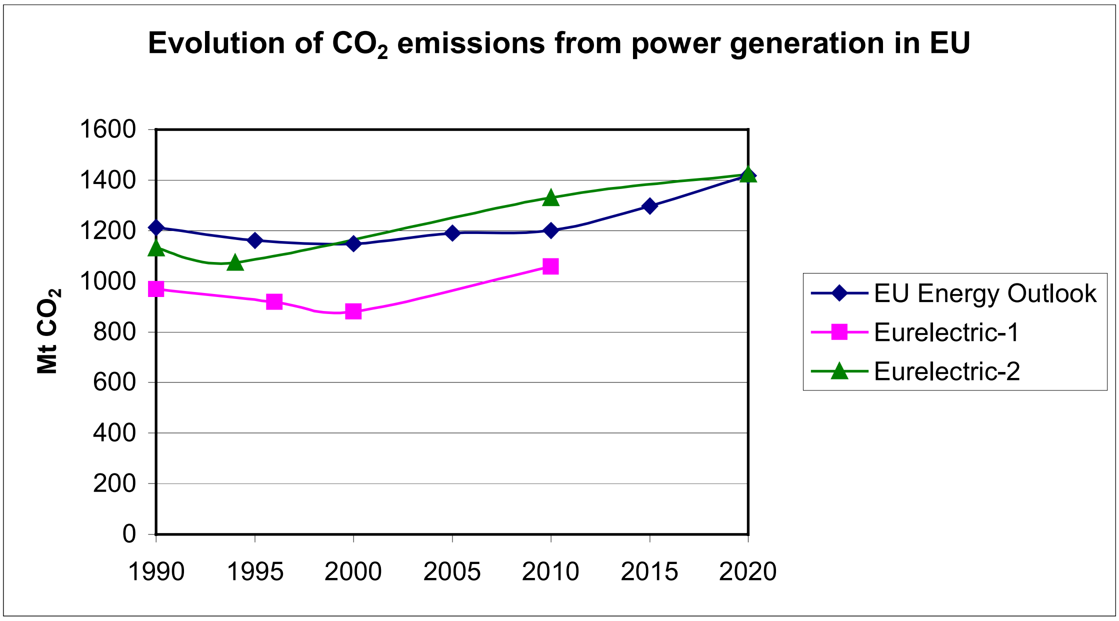

Fig. 25 [28, p. 181], [4], [16]

The following graph illustrates the CO_2 emission from power and heat production in the EU by the year 2020 according to a pre-Kyoto scenario [15]. A net increase in CO_2 emissions of 200 Mt CO_2 on an annual basis is observed (see also fig. 25), which is mainly caused by economic growth. The corresponding emission increase is partly compensated by two major contributions, enhanced efficiency and fuel switching, each contributing an annual reduction of about 300 Mt CO_2 per year by that date.

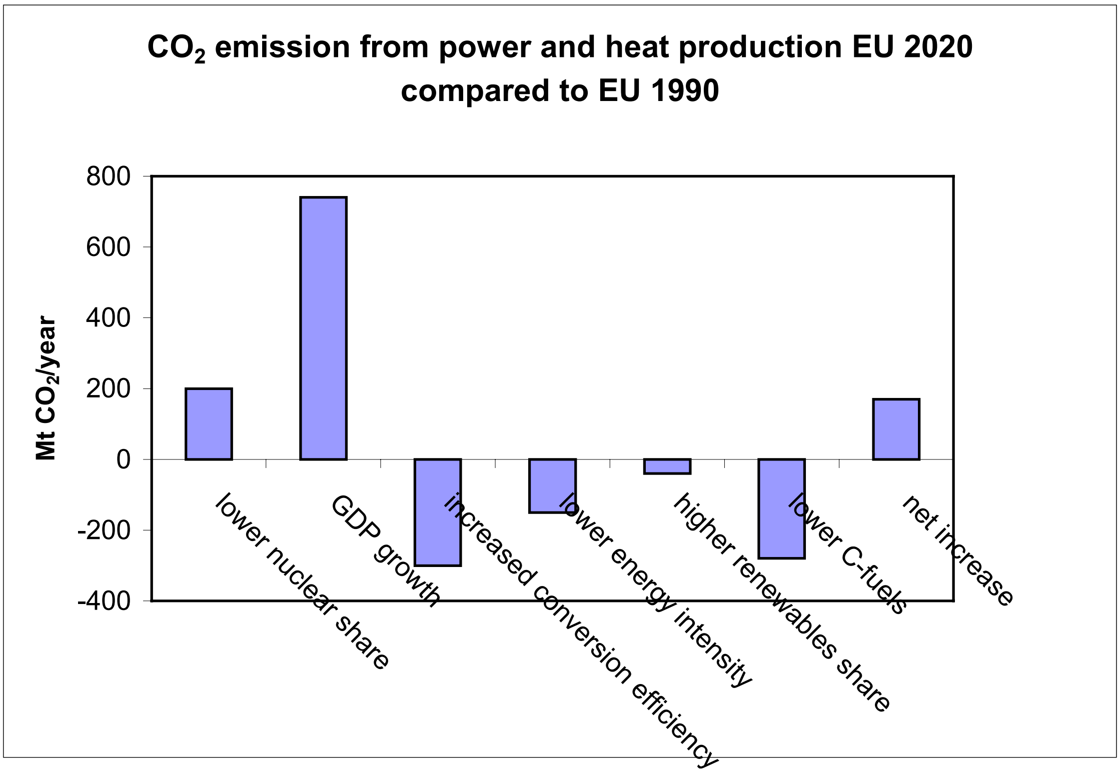

Fig. 26 [15]

From the two preceding figures it can be deduced that CO_2 emissions from energy generation in the EU will have to be reduced by additional measures compared to the baseline scenario if the Kyoto target is to be met. In the power generation sector, CO_2 emissions can be reduced by a number of measures, affecting supply and demand of electricity. Fig. 27 sketches the different possibilities.

Although efficiency improvements affect both conversion technology and end use, attention here is only paid to the supply-side, i.e. increasing the efficiency of the conversion process.

Supply-side approaches to reduce emissions include [24]

- more efficient conversion of fossil fuels (1% efficiency increase = 2.5% reduction CO_2 emissions, fig. 9),
- switching to low carbon fuels (substitution of coal by natural gas: up to 50% reduction, see Table 2 and fig. 14),
- decarburisation of flue gases and fuels (up to 85% reduction),
- CO_2 storage,
- switching to nuclear energy (virtual elimination),
- switching to renewable energy sources (virtual elimination).

Each of these options has its unique characteristics that determine cost-effectiveness, as well as social and political acceptability. Both costs and environmental impacts should be evaluated on the basis of full life-cycle analysis (see section 6).

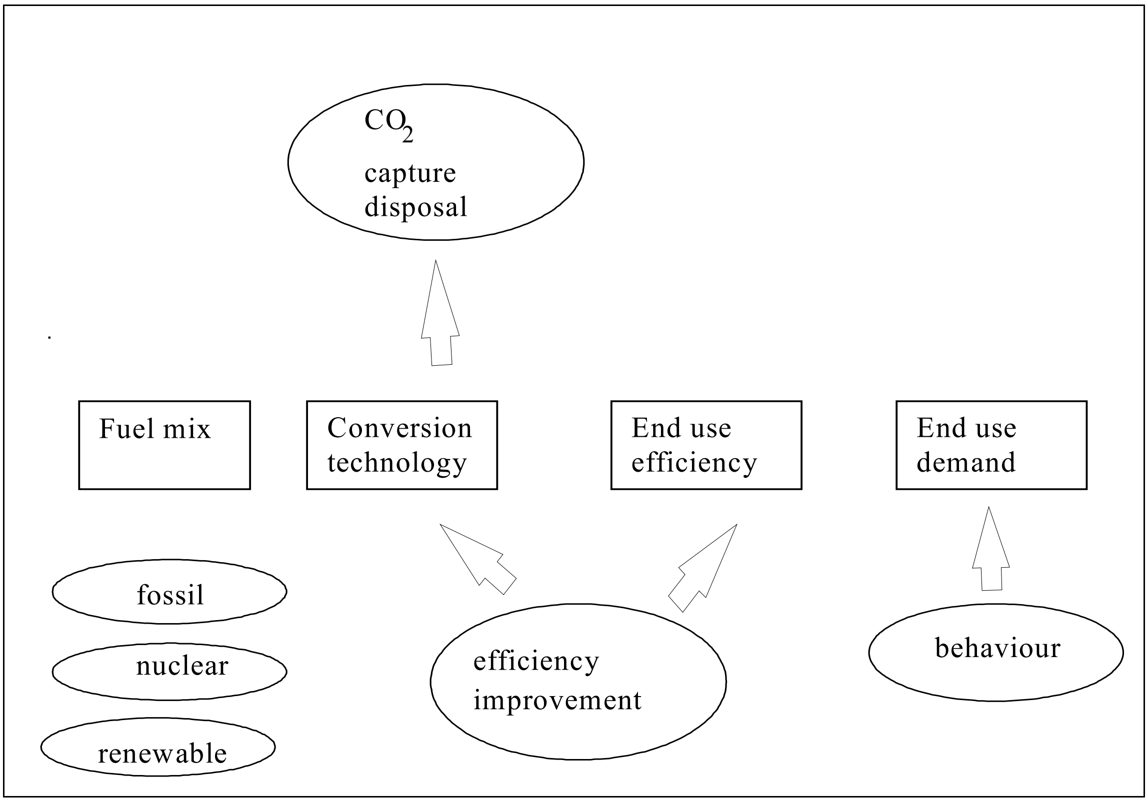

Fig. 27: Schematic illustration of CO_2 mitigation possibilities

5. Mitigation of CO_2 Emissions

5.1 Overall mitigation possibilities and potential

An overview of the potential contributions of CO_2 emission reduction options *from all sectors* is shown in figure 28 [26]. This graph indicates ***cumulative*** world CO_2 emission reductions, expressed as C-equivalents, in the period 1990-2100 compared to a BAU (business as usual) scenario which would result in a cumulative emission of 1600 Gt C. The figure shows that for a net total expected reduction of about 1000 Gt C the largest contribution originates from substitution of higher-C by lower-C fuel (in energy generation, transport, heating and industry), and that the emission reduction potential of efficiency improvement (supply and demand combined) is approximately equal to that of renewable energy. The total reduction falls within the range 800-1100 Gt C required from the BAU scenario to achieve CO_2 stabilisation at 450 ppm by 2100.

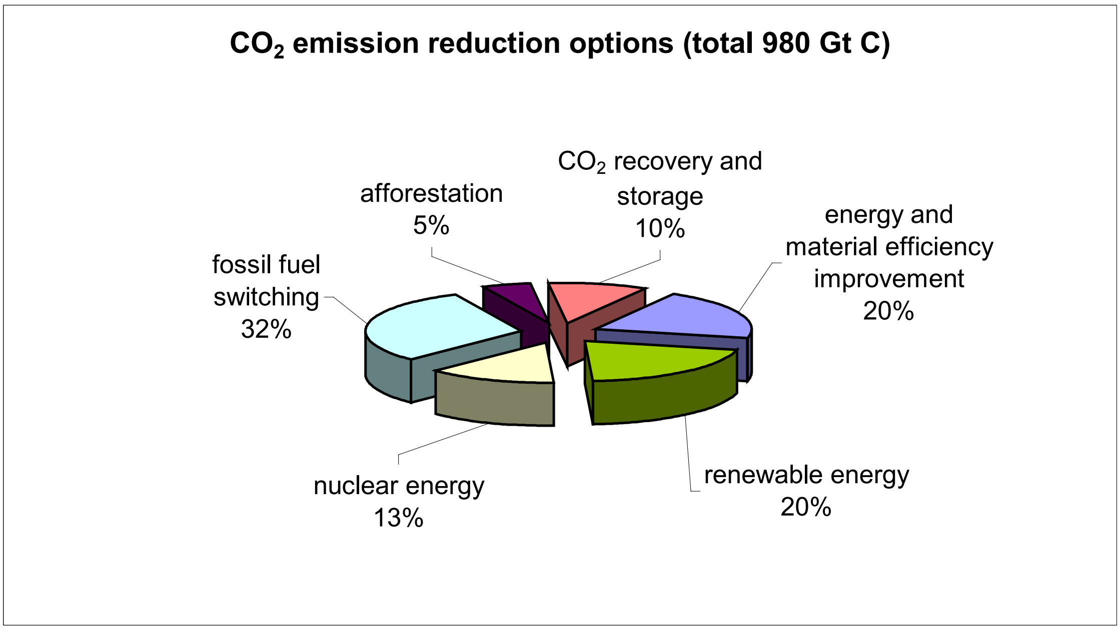

Fig. 28 [26]

Table 6 indicates the optimum mix of abatement options per world region for a predetermined annual emission reduction target from all sectors of 2.4 Gt C (8800 Mt CO_2) by 2100 [27].

The table and Fig. 29 show that half of the emission reduction target is achieved by forestry. The remaining half is achieved for 50% by efficiency enhancement. This projection is far larger than the previous one (compare Figs. 28 and 29). The contribution from fossil fuel switching on the other hand is much less. These differences highlight the possible variation in the results from different scenarios and clearly indicate that caution has to be exercised in comparing and rating contributions to emission reduction from fuel switching and efficiency increases.

Table 6: Level of emission abatement options per region (Mt C)

Option	OECD	Eastern Europe	Rest of the World	Total
Energy efficiency improvement	250	250	100	600
Fuel switch	50	50	50	150
Removal and disposal	100	50	0	150
Nuclear energy	50	50	0	100
Renewable energy	50	50	100	200
Forestry	250	250	700	1200
Total	750	700	950	2400

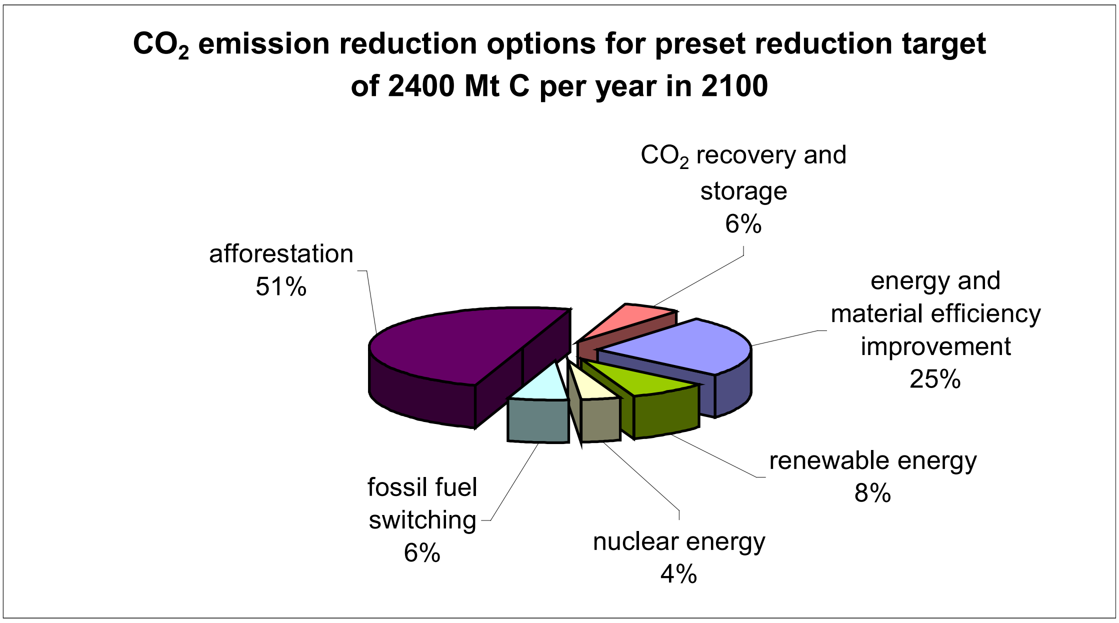

Fig. 29: emission abatement potential from last column of Table 6

5.2 Emission reduction potential in the European Union

The baseline scenario adopted in the European Energy outlook to 2020 [28] does not include any new policies which specifically address the climate change issue. According to this scenario, it is unlikely that the EU will meet its Kyoto commitment of a CO_2 reduction of 8 % compared to 1990. Additional policies and measures (PAMs) are hence required to reach the Kyoto emission limits. The potential reductions in GHG emissions quoted by different sources are listed in table 7.

From the table it appears that in all scenarios a major part of the emission reduction potential stems from the energy sector. The major reduction factors agree with those causing the "negative" emission contribution in Fig. 26, although the absolute value and ranking may differ. The differences may originate partly from the different time horizon (2010 compared to 2020), but this can not explain the largely different figures for the contribution to emission reduction from renewables. In fact, an even more optimistic value of CO_2 emission reduction by 402 million tonnes/year by 2010 is quoted in [29] corresponding to doubling of the 1997 share of renewables for gross EU energy consumption (see section 7).

Table 7: Annual GHG emission reduction potential in EU [Mt CO_2-eq./yr]

Sector/measures [reference]	[30]	[31]	[33, vol. 11]	[32]	[34]	[35]
CO_2						
• Transport	*150*	*100-200*		*105-140*		
• Tertiary and households (energy efficiency and insulation)	140	400		100		
• Industry (direct energy uses)	50	100		?		
Power demand	*190*	*500*		*100*		
• CHP (industry and district heating)	57	150		65		
• Renewables in power generation (see note 2)	110	200		249		
• Fuel switching + efficiency in power generation	115	200		85-129		
Power supply	*282*	*550*		*399-443*		
EU total CO_2	**622**	**1150-1250**		**604-683**		
CH4						
• Agriculture	54		33		61	29
• Waste (landfill gas recovery, flaring)	83		67		129	73
• Energy (reduction gas leakage)	15		31			10
EU total CH4	152		131		190	
N_2O						
• Agriculture	24				24	7
• Industry (BAT in nitric acid production)	86				95	65
• Energy (combustion)	8					
EU total N_2O	118		68		119	
Halogenated gases						
• HFC	34				60	25
• PFC	4				4	4
• SF6	7				7	7
EU total halogenated gases	45				71	
EU total non-CO_2 GHGs	**315**				**380**	
EU total greenhouse gases	**937**					

Note 1: the figures quoted are potential reductions, not least cost reductions

Note 2: In [32] a contribution of 330 Mt CO_2/yr is quoted from renewables, based on a target of doubling the share of RES in the gross EU consumption from its 1997 value. (This in turn is derived from the value quoted in the White Paper [29], which states a potential reduction of 402 Mt CO_2/yr. The difference is caused by the different time frame considered, and by changes in penetration pattern of RES). The value of 330 Mt CO_2/yr comprises 204 Mt CO_2/yr from biomass. Since the latter is not exclusively used for electricity generation, a value of 123 Mt CO_2/yr is used here, leading to a total contribution of renewables to power generation of 330-204+123 = 249 Mt CO_2/yr.*

* According to [29], an additional 32 Mtoe renewables are used for power generation until 2010. This amounts to 1.33×10^9 GJ, leading to a CO_2 reduction of 1.33×10^9 GJ x 92 kg CO_2/GJ = 123 Mt CO_2 (see table 3).

Table 8 summarises the emission reduction required for meeting the Kyoto limits (reductions required *on an annual basis* by 2010).

Table 8: GHG emission target and required reductions by 2010 [Mt CO_2-eq./yr]

	1990 level	Kyoto goal	Required reduction (ref. 1990)	2010 baseline	absolute reduction	% reduction (ref. 1990)
Total GHGs from all sectors [30]	4334	3988	346	4637 (+ 7%)	649	15.0
Total GHGs from all sectors [28, p. 64]	3938	3623	315	4170 (+ 6%)	547	13.9
Non-CO_2 GHGs	870	800	70	881 (+ 1.3%)	81	9.3
CO_2 emissions (energy-related) [28]	3079	2833	246	3298 (+ 7%)	465	15.1
power and steam generation	1212	1115[#]	97	1219 (+ 0.6%)	104	8.6
Ratio power generation to total	0.280-0.308			0.263-0.292	0.160-0.190	

[#] *For simplicity, an 8% reduction is assumed for both CO_2 and non-CO_2 GHGs alike.*

Given the emission reduction potential of the non-energy related GHGs, estimated at 18% or 160 Mt CO_2-eq. [33, p. 11] (larger than the required 8% reduction of 70 Mt CO_2-eq., but less than the maximum potential of 315 Mt CO_2-eq. quoted in table 7), an *energy contribution* (industry, power generation, transport, …) representing a CO_2 reduction of 6% of the corresponding 1990 CO_2 level (180 Mt), or amounting to around 400 Mt absolute reduction from the baseline projection is required in 2010. Approximately half of that reduction can be achieved through improved efficiency in power generation, the other half resulting from intensified use of less carbon-intensive fuels and renewables (see fig. 26 and table 7). Beyond 2010 electricity and steam generation are projected to contribute most to the increase in CO_2 emissions from all sources [33, p. 9, 59], *highlighting the extreme importance of increase in thermal efficiency* to counter this effect.

6. Emission Abatement Costs

6.1 Abatement cost curves

Every mitigation measure has a cost penalty. This is expressed in the so-called marginal abatement cost or "carbon value", which is defined as the cost to avoid the last ton of carbon (not CO_2) for a given emission reduction target. It must be borne in mind that *mitigation costs are always calculated based on the difference between some reference scenario and a different scenario* with lower emissions.

Figure 30 shows the carbon value for given *energy-related* emission reductions per year in 2010 and 2020, based on a business as usual scenario. To meet the EU's Kyoto target, a reduction of 400 Mt CO_2 is required on an annual basis (see 5.2). The graph shows that this corresponds to an abatement cost of around 100 Ecu_{90}/tC (or 27 Ecu_{90}/tCO_2). The figure also shows that the abatement cost increases non-linearly at higher emission reduction levels.

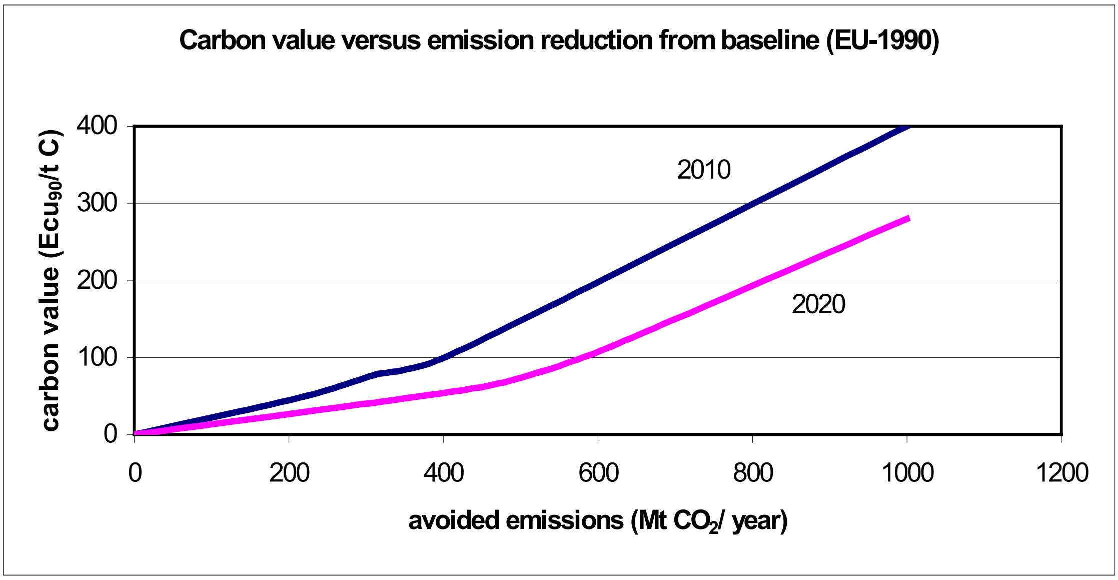

Fig. 30 [33, p. 70]

The graph below represents the percentage change in total energy-related CO_2 emissions and those from thermal power generation in the EU as a function of the abatement costs, assuming unchanged macro-economic and sectoral growth patterns from 1990 [34].

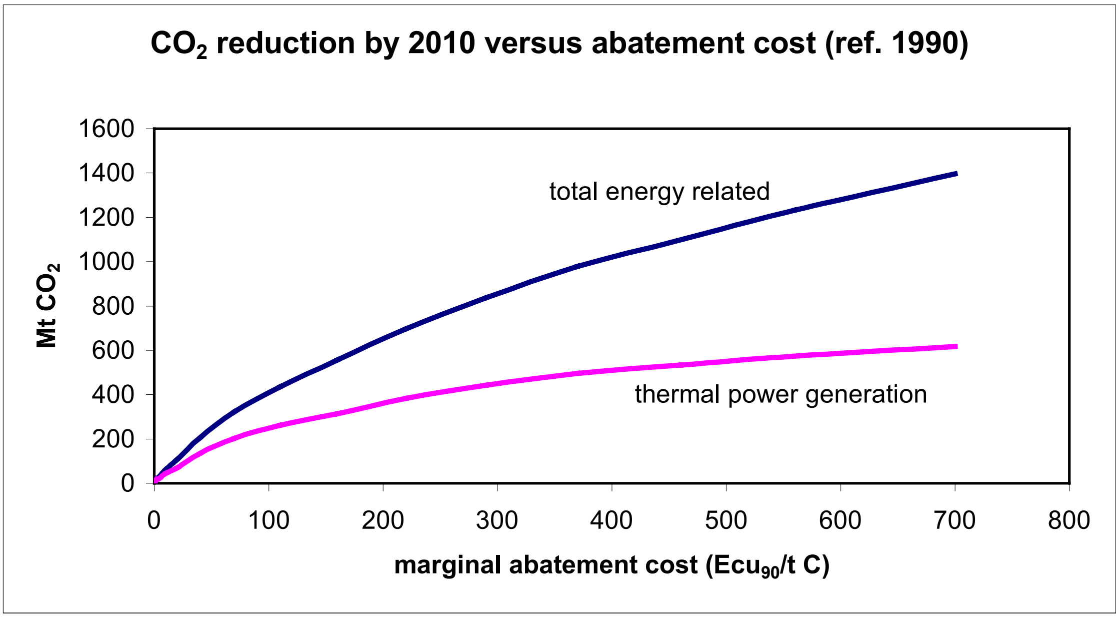

Fig. 31 [34]

The figure emphasises the role of power generation to emission reduction: for abatement costs in the range deemed necessary to reach the Kyoto target, ***more than 60%*** of CO_2 emission reduction is achieved in the ***power generation sector***. However, because of the faster increase in abatement cost with increase in emission reduction volume, the emission reduction potential levels off. This occurs relatively earlier for the power generation sector, causing earlier "diminishing returns".

The overriding importance of the power generation sector in reducing CO_2 emissions in the time period up to 2010 is illustrated by the projected reduction in emissions according to two scenarios which lead to meeting the Kyoto commitments by 2010 [35]. The results (reductions from baseline projection, non-CO_2 GHGs not included) are summarised in the following table:

Table 9: Share of power generation sector in CO_2 emission reduction

	scenario 1	scenario 2
Marginal abatement cost ($Euro_{97}$/t CO_2)	17.4	62.5
Total reduction in EU (Mt CO_2)	254	499
Electricity and steam generation (Mt CO_2)	170	293
Ratio (%)	68	58

The figures below illustrate that the substantial share of emission reductions in power generation (supply) decreases in favour of demand side reductions with increasing marginal abatement cost. Although decreasing in absolute value, the emission reduction in the power generation sector in both scenarios is achieved half by improved efficiency and increase in non-fossil fuels, and for the other half through changes in the fuel mix [35].

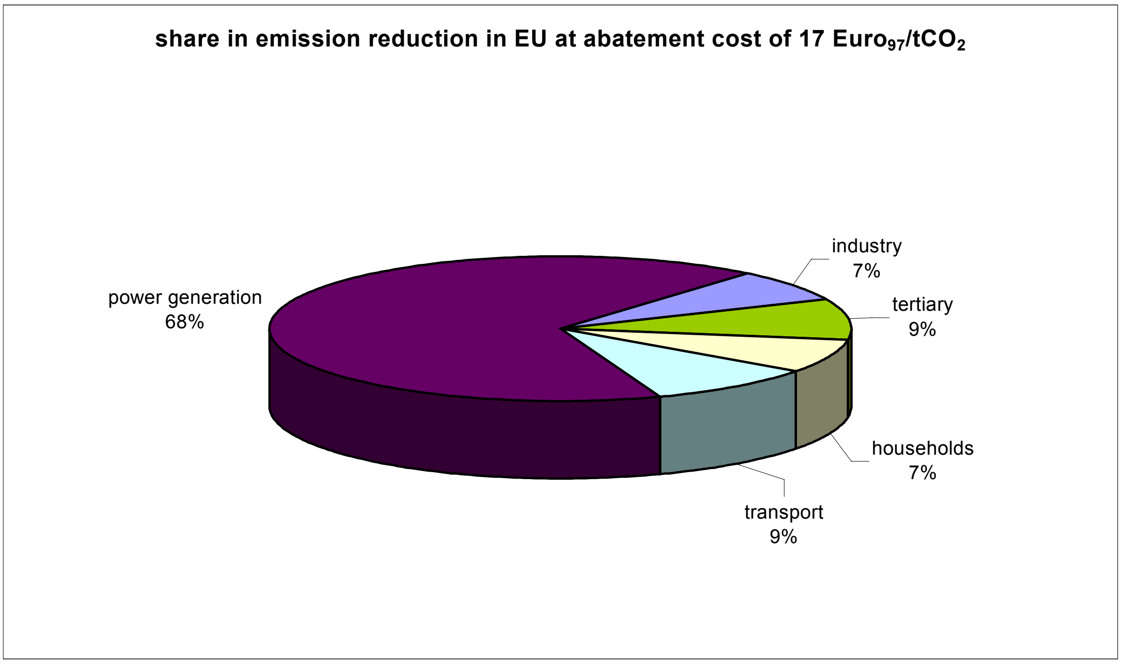

Fig. 32 Contributions of energy supply and demand sectors in emission reduction (scenario 1 of table 9)

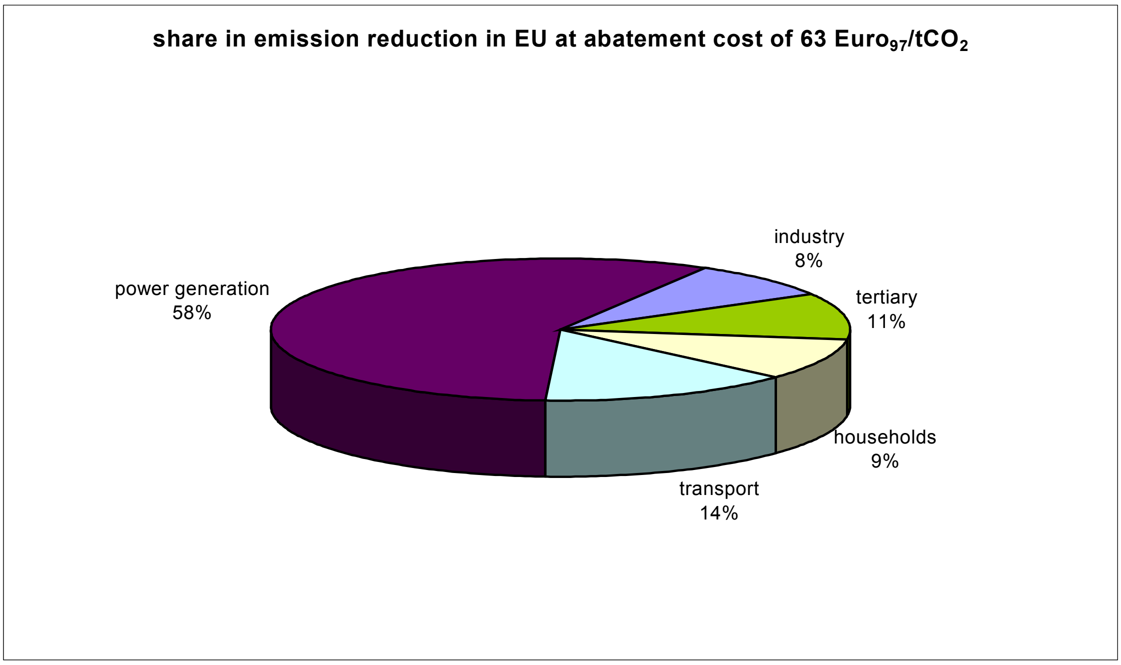

Fig. 33 Contributions of energy supply and demand sectors in emission reduction (scenario 2 of table 9)

6.2 Cost analysis and specific emission reduction costs in power generation

A critical issue in the evaluation of abatement costs is the reference with respect to which the emission reduction is realised. Indeed, emission reduction costs are obtained from the cost difference between the reference and an alternative power generation option, divided by the difference in the generated amount of CO_2. In the framework of this study, which focuses on the relationship between CO_2 emissions and the efficiency of thermal power generation technologies, a spreadsheet has been developed to quickly evaluate carbon emission reduction costs by substituting one technology for another.

The analysis is based on direct costs and includes capital costs (investment, depreciation), operating costs (fixed and variable), and fuel costs. The results are the "levelised" (or "discounted average") electricity generation cost and the specific CO_2 reduction cost. Required input information on capital, operating and fuel costs is listed in annex B. Indirect costs, such as e.g. costs associated with the gas distribution infrastructure when substituting gas for coal, are not included. "Downstream" costs, such as associated to transmission and distribution, as well as "intangible" social costs are not considered (see annex B).

Typical levelised electricity generating costs for different new power plant types (400 MWe) operating at 70% load factor, and power generation-CHP plant (100 MWe) operating at 50% are shown in the following figure. Also included are data for nuclear (1200 MWe) and wind (1.5 MWe, load factor 25%). The figure also indicates the breakdown in capital cost, operation and maintenance costs, and fuel costs.

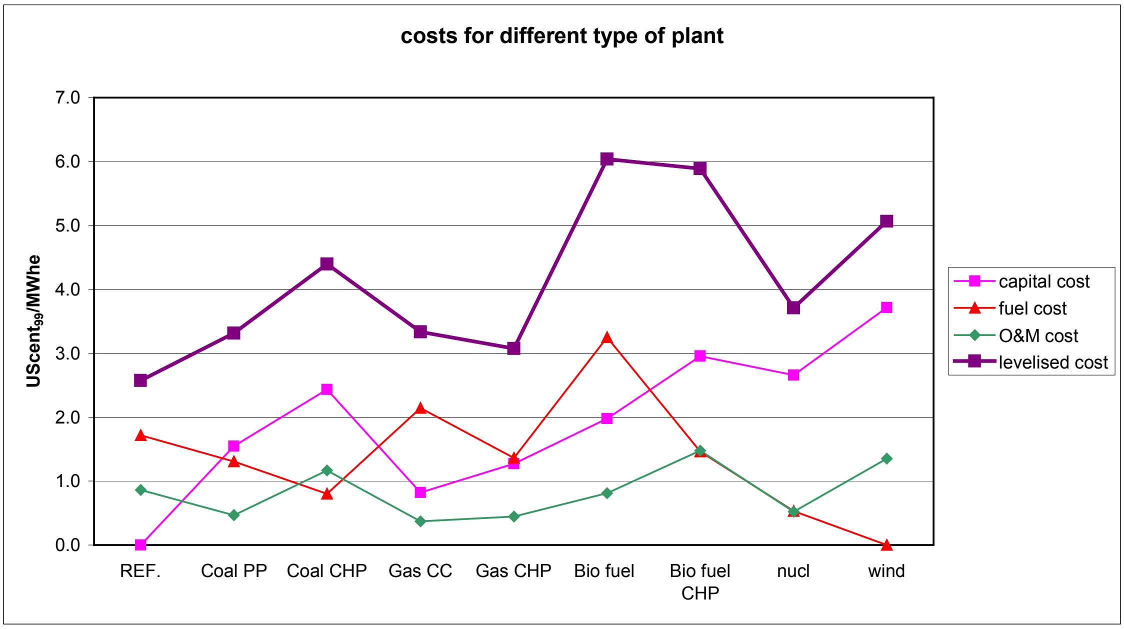

Fig. 34

Among the fossil-fired plant, those using biofuel are clearly the most expensive, whereas gas-fired plant produce the cheapest electricity. The electricity cost for the existing coal plant, in spite of its lower efficiency and higher fixed O&M costs, is lowest because this plant does not carry any capital cost.

Marginal costs only consider the part of the total cost that varies with production. Marginal costs for the same types of plant are shown in Fig. 35. On the basis of marginal costs, the CHP-plants are the cheapest, with the coal-fired CHP plant even having negative marginal costs. Also, gas-fired plant is no longer advantageous with respect to coal-fired plant.

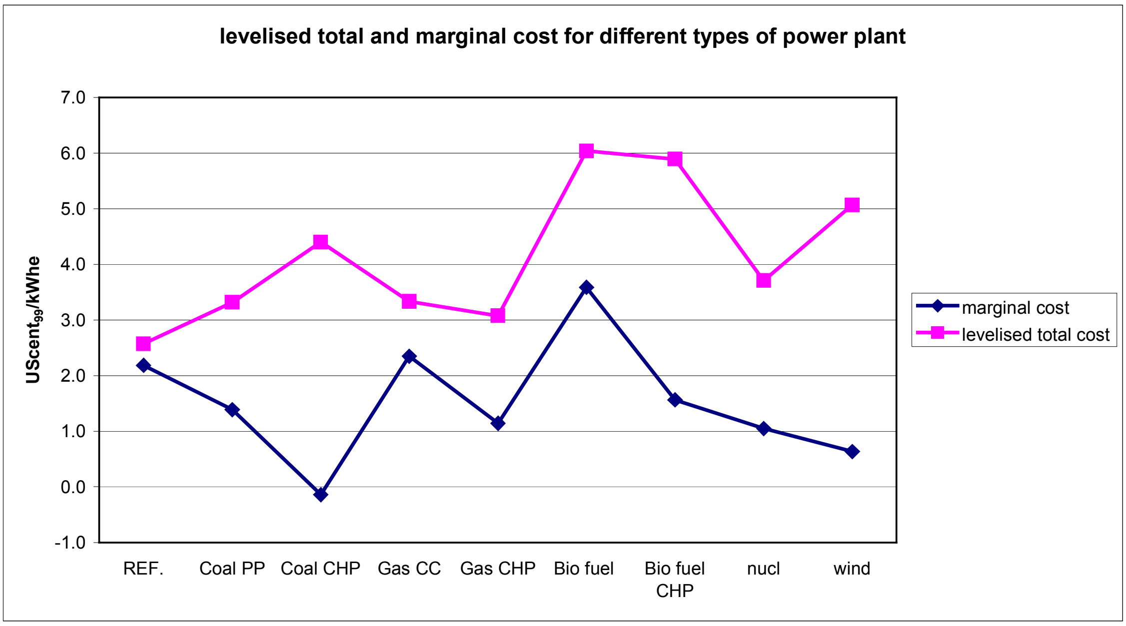

Fig. 35

The specific CO_2-reduction costs are shown in the following figure, where it is assumed that the reference is a coal-fired plant with an efficiency of 35% and a specific emission of 900 gCO_2/kWh (see tables 2-4).

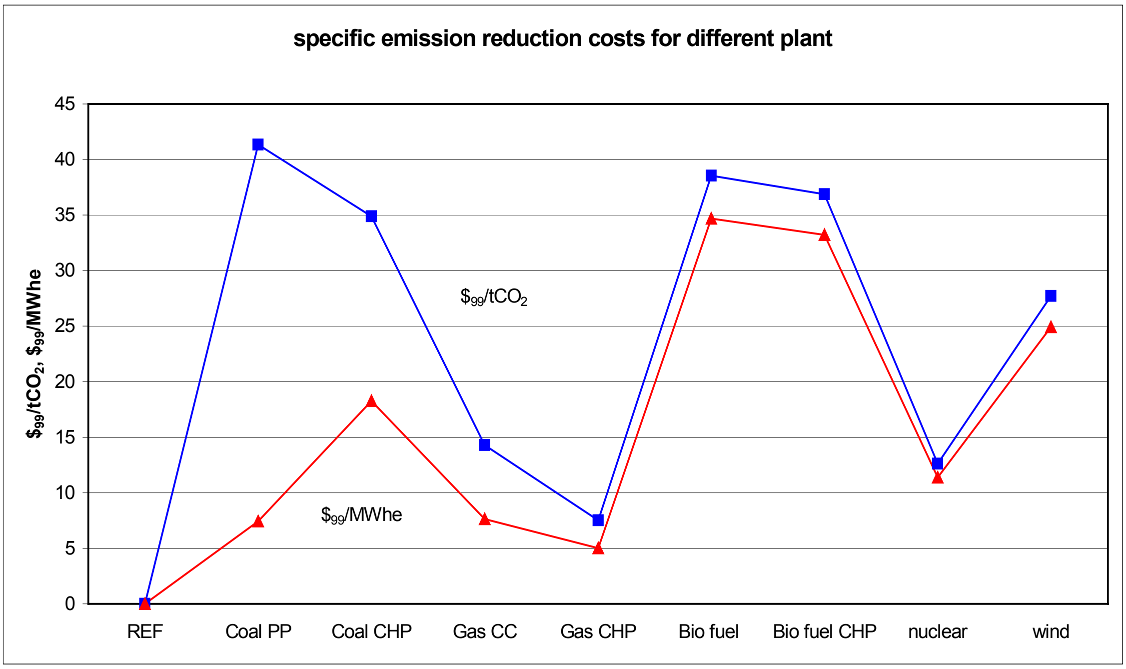

Fig. 36

6.3 CO_2 removal and storage costs

If natural gas and/or renewable resources turn out to be more expensive than expected, or if carbon reductions beyond the Kyoto protocol targets are required, technologies that remove and store carbon produced by fossil plants may be needed. This may be achieved either by separating carbon from the fuel prior to combustion, or by capturing CO_2 from the flue gases, and subsequently disposing of them.

At present, the removal and storage of CO_2 from fossil fuel power station stack gases is feasible, but reduces the conversion efficiency and significantly increases the production cost of electricity, as shown in Table 10.

Table 10: Efficiency and cost penalties associated with CO_2 capture and disposal

Cycle	carbon captured (%)	efficiency without capture (%)	efficien cy with capture (%)	% incr. in electricity costs	abatement cost (\$/tC)	abatement cost (\$/tCO_2)	Ref.
Steam	87	40	30	80	150		36
Steam PF	85	-	28.8	48	126		36
Steam PF	80	46	33	73		47	37
Steam PF+FGD	90	40	29			35 ($\$_{92}$)	38
usc pulverised	100	47	40.2				36
Coal plant				50		35-50	39
IGCC	79	-	35.5	26	58		37
IGCC	83	46	32.2				36
IGCC	85	44	37	30-40	80		36
IGCC	90	42	28			87 ($\$_{92}$)	36
NGCC	82	52	45	50	210		36
NGCC	83	-	42	51	198		40
NGCC	84	54	44.3				36
NGCC	92	56	47	46		32	36
NGCC	85	52	42			55 ($\$_{92}$)	36
NGCC						55 post -, 27-37 pre-combustion	41
Natural gas plant				60			36

Although the specific abatement costs per ton of carbon avoided are higher for natural gas than for coal, this translates into lower incremental cost per kWh of electricity because of the lower specific carbon content of natural gas (see table 3). The following table presents a comparison of pre-and post-combustion decarbonisation of natural gas for a GTCC [42]:

Table 11: efficiency, costs, and emissions from GTCC equipped with sequestration [42]

	post-combustion flue gas scrubbing	pre-combustion synthesis gas clean-up
Efficiency penalty	8-10%points	8-10%points
Cost of CO_2 capture and storage	1.5-2.0 UScent/kWh	1.0 - 1.5 UScent/kWh
Avoidance cost	50-60 \$/tCO_2	30-40 \$/tCO_2
Resulting specific emissions	60 g CO_2/kWh	60 g CO_2/kWh

The effect of carbon removal technologies on the emission of other pollutants is shown in Annex A.

7. Reduction potential and cost in the EU energy supply sector, excl. sequestration

In the preceding sections the available technologies (section 5.2), overall abatement-cost curves for the EU (section 6.1), and the specific cost for CO_2-emission reduction from the EU power generating sector (section 6.2) have been presented. However, in order to arrive at a comprehensive picture, also the *quantitative* reduction potential of the different technology options has to be assessed. Because of technology progress, this assessment is clearly related to a time frame. For the current analysis, the period to 2010, linked to meeting the Kyoto target, is considered.

When considering emission reductions from fossil fired thermal power plant, the obvious options are substitution (from old to new coal, to new gas, and from oil to gas*), carbon sequestration and storage, or enhanced use of renewable energy sources (RES). For all of these, the specific emission reduction cost for each option can be calculated as indicated in 6.2, based on literature values of relevant costs (annex B), and of specific CO_2-emissions (tables 2, 4, 5). Carbon sequestration technologies are not expected to contribute to carbon emission reductions in the time frame of the Kyoto protocol. If their economics can be improved significantly and long-term storage proves viable, they could provide an additional reduction option in the post-2015 time period [18, p. 69].

Quite different projections are available for the emission reduction potential in the EU (see table 7). The major difference stems from the contribution from renewable energy sources (see note 2 to table 7), and is highlighted in Fig. 37.

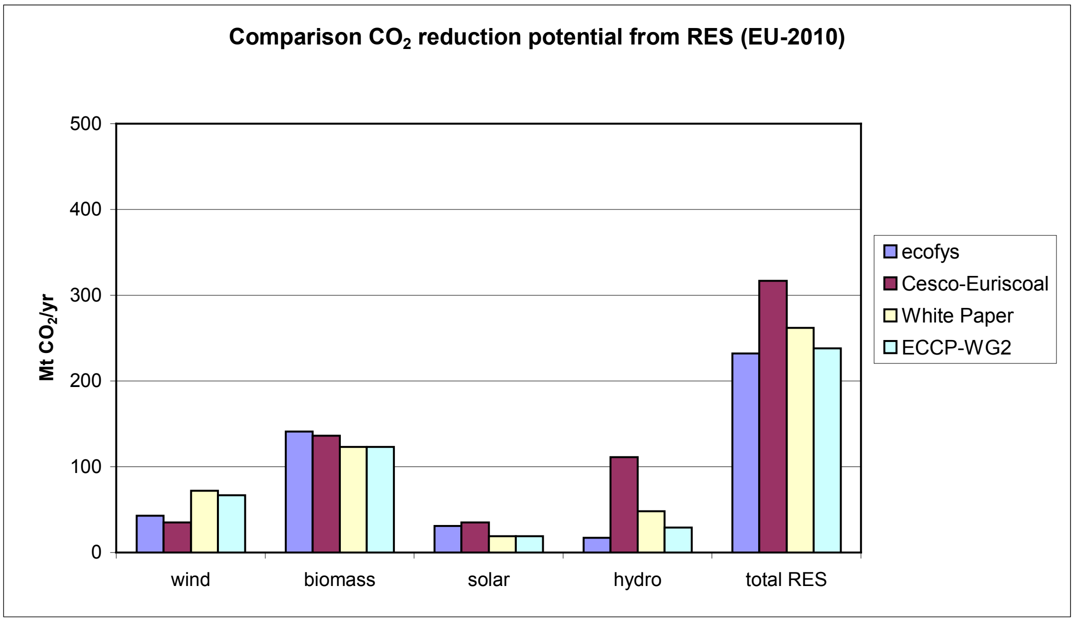

Fig. 37 [32, 29, 43]

* Some studies also consider the option of replacing relatively older gas-fired power plant by new gas plant. Based on the higher efficiency of gas-fired compared to coal-fired plant (see tables 4.1 and 5.1), this is probably a less realistic option.

The first bar in the graph refers to results from a study where the emission reduction potential is evaluated against a reference case of replacing NGCC [43], which obviously leads to an underestimation of the reduction potential. Other projections result from the White Paper [29] (third bar), and from a recent analysis performed within the context of ECCP-WG2, which is represented in the last bar. The second bar represents absolute values derived from the relative share quoted in [39, see table 10 below].

The different projections for emission reduction from renewables shown in Fig. 37 lead to differences in the total achievable reduction potential, as shown in Fig. 38 [30, 31, 32, 43].

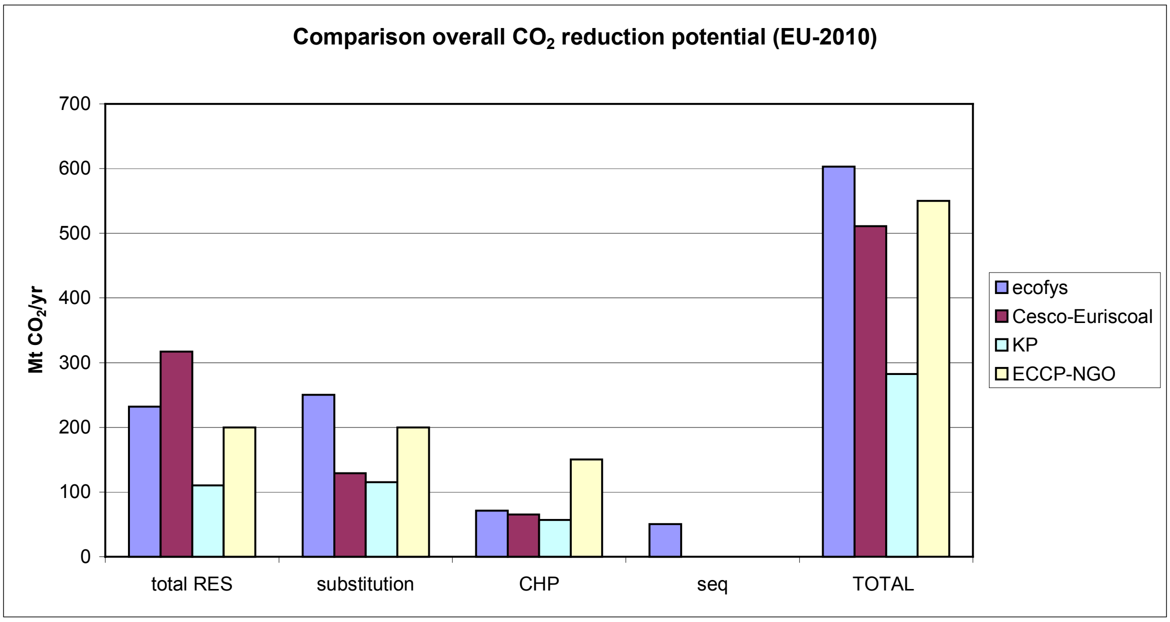

Fig. 38 [30, 31, 32, 43]

Except one result, there is a rather good agreement for the total emission reduction potential from the energy supply sector when carbon sequestration and storage is not considered. This value is about 500 Mt CO_2/yr. Comparison with table 8 and section 5.2 reveals that this achievable potential would allow the EU to reach its Kyoto commitments. An indication of the share of these substitutions, together with those of the options of sequestration and storage, and of renewables is given in [39]. The relative share and associated emission reduction cost from [39] are reported in the second and third column of the table below.

Table 12: Reduction potential and associated cost (relative potential and cost from [39]

	Reduction potential [%]	cost [$\$_{99}/tCO_2$]	volume [$MtCO_2/yr$]
coal to gas	3	11	35
coal to coal	3	14	35
oil to gas	3	23	35
late coal	9	43	102
sequestration and storage	53	48	591
reforestation	1	55	11
biofuel	11	64	125
hydro	10	82	111
wind	3	91	35
solar	3	105	35
total	*100*	*58.5*	*1115*

The potential of 524 Mt CO_2/yr from the energy supply sector ([32], and table 7], which does not include sequestration, represents 47% of the total (second column in table 10), indicating that the total potential amounts to 1115 Mt CO_2/yr (last column of table 10). From this, about 18% or 200 Mt/yr corresponds to the reduction stemming from renewables (excluding hydro), and another 18% or 200 Mt/yr from changes in the fuel mix and efficiency gains through substitution. These figures agree excellently with those from [31] listed in Table 7, and represented by the last bar in Fig. 38. Also, an average CO_2-emission reduction cost for the full realisation of the 524 Mt/yr potential of 58 $\$_{99}/tCO_2$ is obtained. When sequestration is also considered, the 1115 Mt/yr potential can be achieved at an average cost of 53 $\$_{99}/tCO_2$.

Based on these numbers, the following abatement cost curve for energy supply in the EU (excl. sequestration) is obtained.

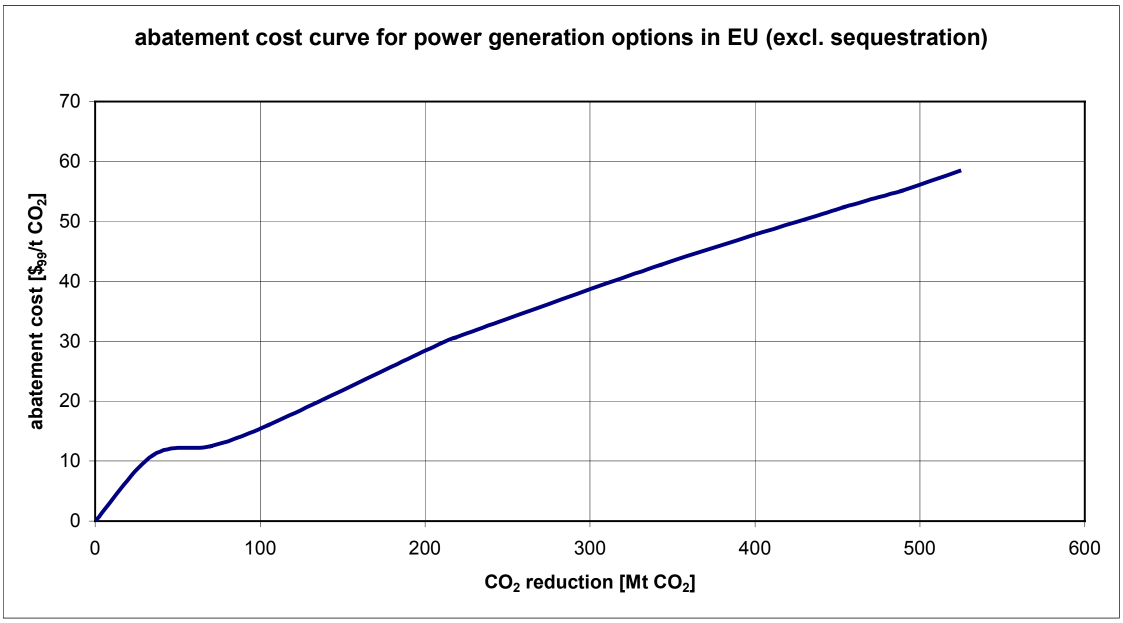

Fig. 39

From Fig. 30, the carbon value corresponding to the Kyoto emission reduction target is 27 Ecu_{90}/t CO_2, which amounts to approximately 33 $\$_{99}/tCO_2$ (based on a depreciation of 3% per year). When introducing this value on the ordinate of Fig. 39, an emission reduction of the energy supply sector of around 240 $MtCO_2$/yr is obtained, which agrees nicely with the 60% (=240/400) for the share of that sector in the total reduction (see Figs. 32 and 33). The figure also confirms that more than 100 Mt CO_2/yr emission reduction from fuel mix changes and efficiency gains can be achieved at an abatement cost of less than 20 $\$_{99}/tCO_2$ [39].

Finally, a word of warning is in place. As already mentioned, emission reduction potential and the associated cost are directly linked to the considered scenario, its time frame, and to the situation and/or technology taken as reference. In fact, it has been found that GHG mitigation cost estimates show a large dependence on the factors summarised in the table below [44].

Table 13: Critical factors in GHG cost estimation models

• definition of costs and benefits
• depiction of technological change dynamics
• definition of baselines
• assumptions on what policies are or will be put in place
• flexibility of consumer and producer response to raising energy prices

For the particular case of technological progress, it is to be expected that if technological change accelerates, the cost of GHG mitigation decreases. In the graph of Fig.39 this implies a downward shift of the curve*. In addition, for advanced technology scenarios, there are large benefits of delaying the onset of emission reduction measures, because this delay gives the new technologies more time to penetrate. In fact, delaying the onset of emission control measures is even claimed to achieve both a more stringent target and a lower cost [44].

* This is also evidenced by the fact that when sequestration is included, the average emission reduction cost decreases from 58 to 53 $\$_{99}/tCO_2$.

Annex A: Pollutants from power generation

Table A1: Annual (tonnes) and *specific (g/kWh)* emissions from typical 2000 MW fossil fuel power stations

	Coal-fired conventional (no FGD)	Pulverised fuel + FGD	IGCC	Oil-fired conventional (no FGD)	GTCC	Ref.
Airborne particles (tonnes)	7 000			3 000	negligible	11
PM (g/kWh)		*2.0*		*0.7*	*0.2*	9
Sulphur dioxide (tonnes)	150 000			170 000	negligible	11
g/kWh	*4.0*	*0.5*		*9.0*	*0.3*	9
		0.6				1
Nitrogen oxides (tonnes)	45 000			32 000	10 000	11
NO_x (g/kWh)		*2.1*	*0.25*		*0.3*	1
		2.6			*0.3*	20
		2.5		*2.0*	*1.5*	9
Nitrous oxide N_2O *(g/kWh)*		*0.06*			*0.02*	1
Carbon monoxide (tonnes)	2 500			3 600	270	11
Hydrocarbons (tonnes)	750			260	180	11
Carbon dioxide (tonnes)	11 000 000			9 000 000	6 000 000	11
CO_2 g/kWh (80% load)	*788*			*644*	*428*	11
CO_2 g/kWh		*780-990*	*740-862*		*370-400*	1
Hydrochloric acid (tonnes)	5 000 - 20 000			negligible	negligible	11
Bottom ash and fly ash (tonnes)	840 000			negligible	negligible	11

Yearly emissions from the most advanced types of power generating technologies with carbon removal are compared to the reference case of a state-of-the-art steam power plant without CO_2 capture in the following table [36].

Table A2: Annual principal emissions to air from 400 MW power plants (kt/y) [36]

	NGCC	IGCC	Ultrasupercritical PF
Fuel/ CO_2 storage	natural gas/gas field	coal/ocean	coal (no capture)
CO_2	288	504	2784
SO_2	0.0003	0.92	1.6
NO_x	0.8	4.6	3.5
N_2O	0.02	0.14	0.12
CO	0.009	1.1	0.9
CH_4	0.76	0.54	0.43
VOCs	0.34	0.04	0.07
PAHs	na	0.80	0.6
dust	na	0.02	0.2

The corresponding greenhouse gas equivalents and abatement costs are listed in Table A3. For sulphur dioxide a GWP (100 year) of minus 50 has been used [36].

Table A3: Annual equivalent emissions from 400 MW power plants

Greenhouse gas	steam (no capture)	IGCC	NGCC
CO_2 kt/yr	2784	504	288
CH_4 kt/yr	11	13	19
N_20 kt/yr	38	45	8
VOCs kt/yr	1	0.4	4
SO_2 kt/yr	-80	-46	-0.02
Total CO_2 equivalent kt/yr	2754	516	319
Total CO_2 equivalent g/kWh	775	135	75
Cost $/t C avoided	-	166	48

The last but one row of the table lists the greenhouse gas emission equivalent on a full cycle basis per unit of electricity produced (compare to tables 4 and 5), whereas the last row indicates the emission abatement costs (compare to table 10).

Annex B: Cost Considerations

B.1 Fixed costs

These include capital (i.e. investment and depreciation) costs, as well as fixed operating and maintenance costs. These cost categories are expressed in specific terms, i.e. cost per kWe or MWe, resp. cost per kWe per annum.

B.1.1 Investment costs

Typical specific investment costs are shown in the following figure.

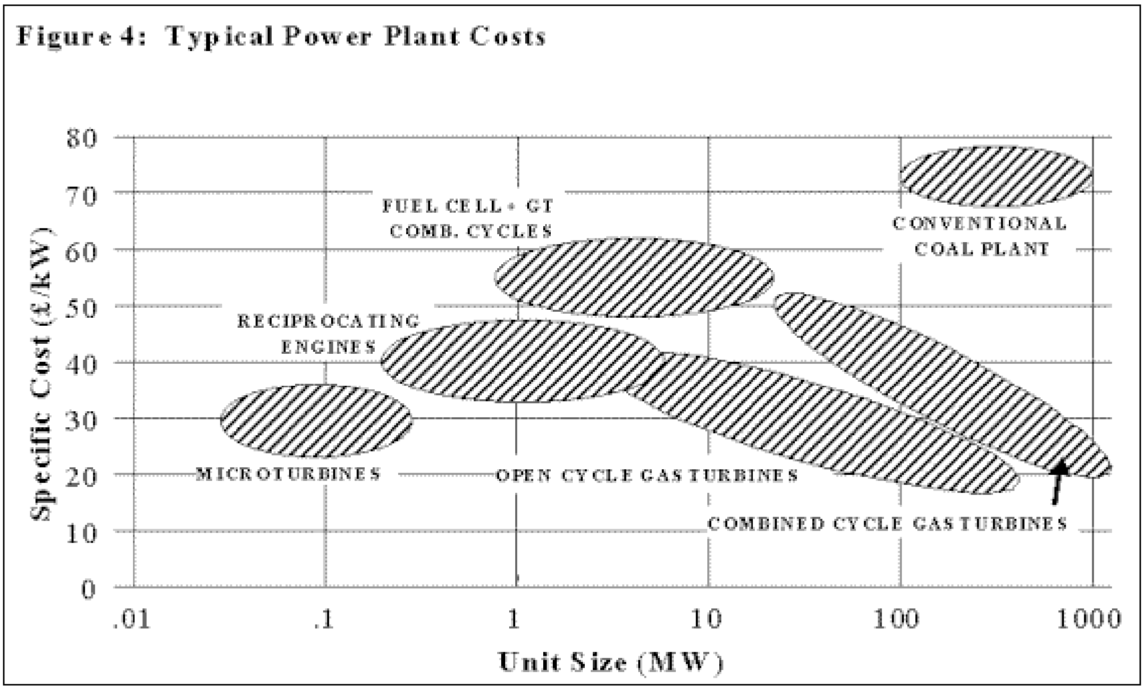

Fig. B1 [45] - *Note that the specific cost are a factor 10 too low as evidenced from the table below originating from the same paper!*

Power Generation Plant Assumptions [45]		
Plant Type	Typical Unit Size (MW)	Specific Cost ([sterling]/kW)
Large Coal Plant	500	900
Large CCGT	500	300
Mid-Size CCGT	70	500
Mid-Size OCGT	50	300
Small OCGT	5	400
Fuel Cell plus gas turbine	3	650
Reciprocating Engine	1	500
Microturbine	0.05	350

Other sources indicate the following typical investment costs:

investment cost (€$_{90}$/kW)					
year	1995	2000	2010	2020	ref.
PF + FGD		1000			17
GTCC	559		550	528	28 p. 164
IGCC	1661	- 1480	1552	1333	28 p. 164 17
FBC	1249		1179	1040	28 p. 164
PFBC	2200	- 2200	1370		28 p. 164 17
Supercritical	1336		1262	1114	28 p. 164
Fuel cells	1828		1128	820	28 p. 164
investment cost ($$_{96}$/kW)					
PF + FGD	1058	- 1079			1 19
GT simple cycle		325			19
GTCC		750 400			19
IGCC		1563 1206			19

The values quoted in the above table (for 2010) are shown in the following figure. The first bar refers to costs expressed in $$_{96}$/kW [19], whereas the second [46] and the third [28] bar indicate costs in Ecu$_{90}$/kW.

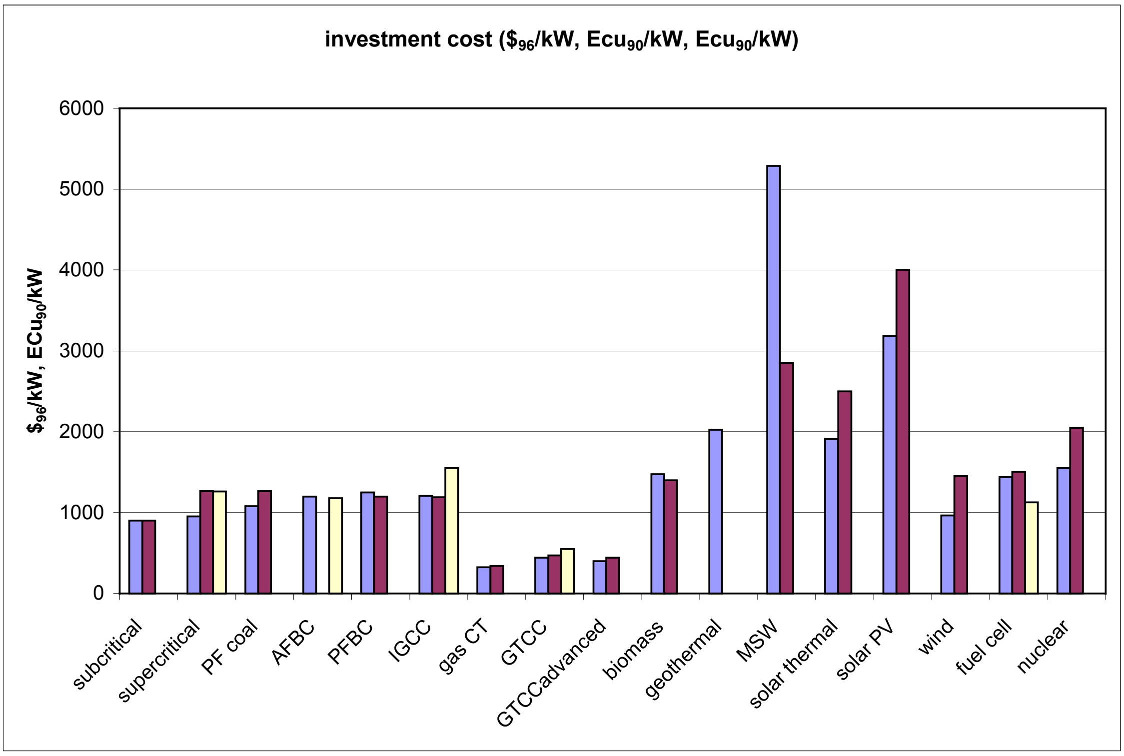

Fig. B2

The evolution of investment costs for a number of power generation technologies with time is shown in the following figure [9]:

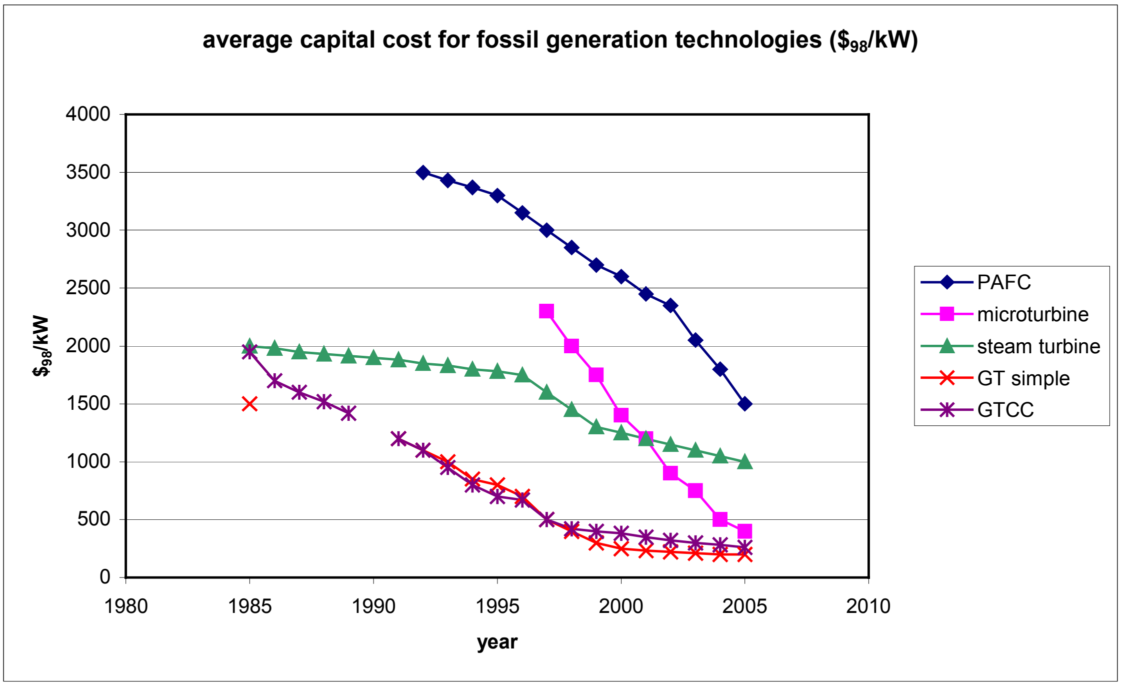

Fig. B3 [9] *(PAFC = phosporic acid electrolyte fuel cell)*

B.1.2 Fixed operating and maintenance costs

These are composed of costs for operating personnel, overhead charges, … and are given in the following figure. They are expressed in cost per kW per annum. The first bar refers to costs expressed in $\$_{96}$/kW,a [19], whereas the second [46] bar indicates costs in Ecu_{90}/kW,a.

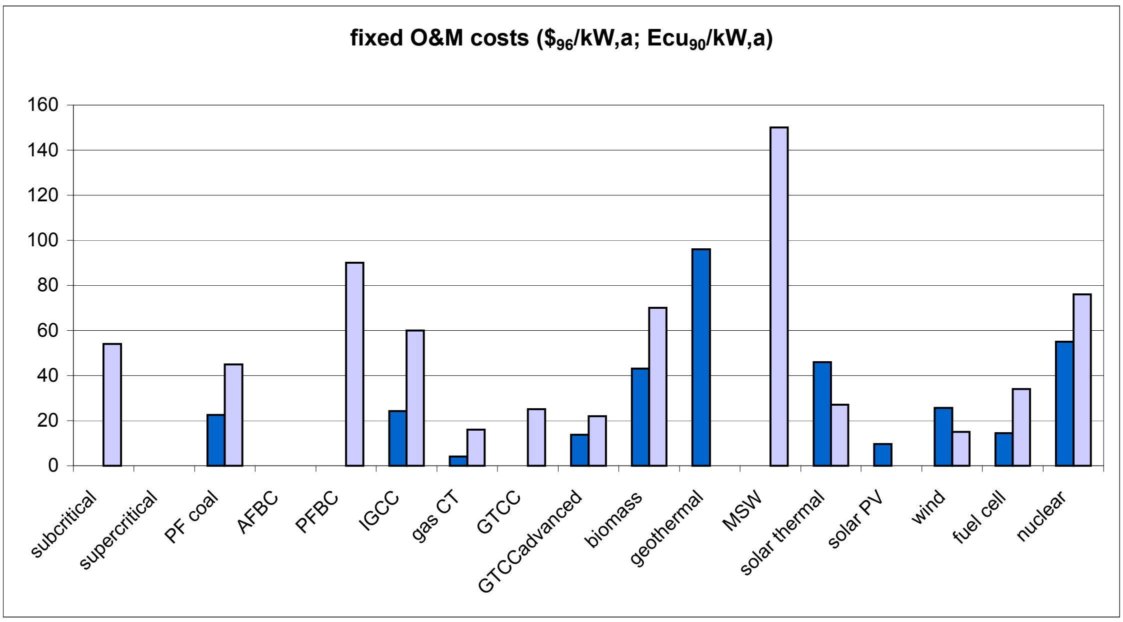

Fig. B4

B.2 Variable costs

These include variable operating and maintenance costs, consumables, etc., and are expressed in cost per kWh_e or MWh_e. Although fuel costs also depend on the operating time or load factor of the power plant, and are expressed in the same units, they are usually treated separately. Typical variable costs (excluding fuel costs) are included in the following figure, where the first bar refers to costs in $\$_{96}$/MWh [19] and the second to costs in Ecu_{90}/MWh [46].

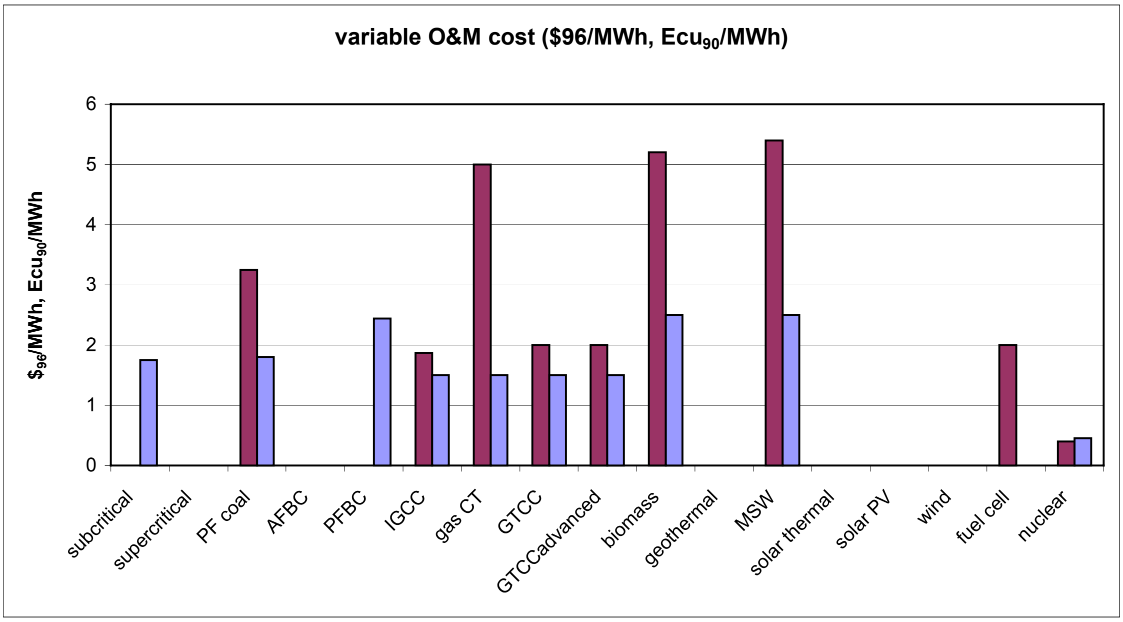

Fig. B5

Fuel costs

These may change considerably in time, and care therefore has to be taken in analysing the results. Fuel prices are either expressed in cost per energy unit (GJ, heating value) or costs per produced electricity (kWh_e). Sometimes they are also quoted in cost per unit of thermal energy, kWh_{th}.

B.3 Levelised electricity cost for new plants

This cost is the sum of fixed capital and O&M costs, of variable O&M costs, and of fuel costs. For CHP plant, the income from heat sales has to be deduced from this sum. This is either done straightforwardly, or indirectly by considering the total efficiency (including the generated heat) instead of the fuel-to-electricity efficiency only when calculating the fuel costs. Typical levelised electricity costs are indicated in the following table:

COE (cost of electricity) from new plants

Type	$cent/kWh	€cent/kWh	Cost ref. year/operating year	Ref.
Photovoltaics	40	40-80		48
Solar/thermal	12	10-25		48
Biomass	9			[47]
Waste combustion		2-14		48
biofuels		2-15		48
biofuels	6.0		1999/1999	IAM
Wind	7	6.2		47
		4-8		48
	5.1		1999/1999	IAM
Small-scale hydro		2-10		48
Fuel cells 5500h		4.6	1990/2030	28, p.165
Existing coal 7500h		3.2	1990/2010	28, p.165
PF+FGD		3.1		17
PF+FGD		2.6		49
	2.4		1999/1999	IAM
New coal	5.5			1, 20
	5	7		47
	4.4		1999/1999	IAM
Supercritical 7500h		3.1	1990/2020	28, p.165
PFBC		5.6		17
PFBC 7500h		3.0	1990/2020	28, p.165
IGCC	6			1
		4		17
IGCC 7500h		3.4	1990/2020	28, p.165
New gas	3	3.9		47
GTCC 7500h		2.6	1990/2010	28, p.165
GTCC 7500h		2.9	1990/2020	28, p.165
GTCC 5500h		3.3	1990/2030	28, p.165
	3			1
	2.9			20
		0.6		49
	3.3		1999/1999	IAM
Nuclear 7500h		3.6	1990/2010	28, p.165
	3.7		1999/1999	IAM

The reference IAM in the last column refers to the in-house developed cost evaluation spreadsheet.

The table below lists levelised electricity costs (c/kWh) including CO_2 removal and storage [36]

Fuel Cycle	u/sc PF	u/sc PF	IGCC	NGCC
Carbon store	none	managed forest	gas field	gas field
Fuel	bituminous coal	bituminous coal	bituminous coal	natural gas
Fuel cost	1.54	1.54	1.94	3.57
capital charges	3.45	3.93	4.43	2.46
Operating cost	0.67	2.19	0.87	0.53
Total	5.7	7.7	7.2	6.6

B.4 External costs

Every industrial or economic activity has an impact on people and the environment. Usually, this impact is negative, and is not quantified in conventional accounting practices (referred to as "private" cost assessments). Such impacts are hence represented as "external costs" or "externalities". As shown in Figure C6, private costs are only part of the total costs to society of an industrial activity.

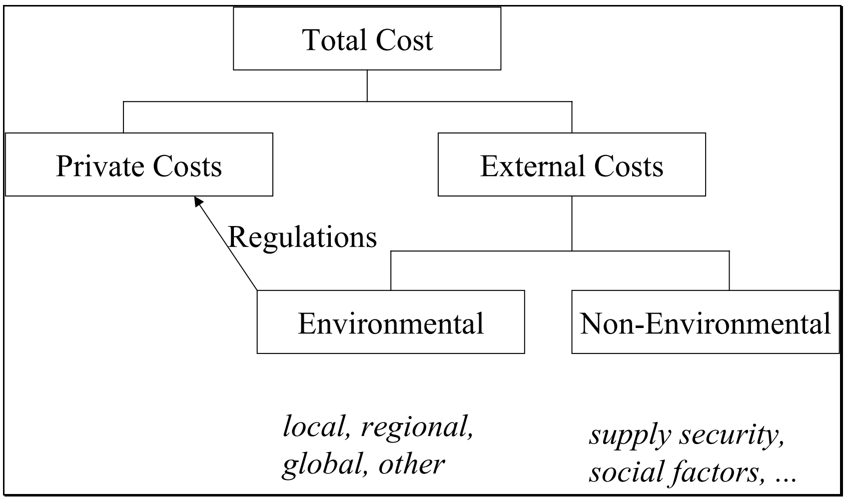

Fig. B6 [36]

The figure shows that the distinction between private (or internal) and external costs is not fixed. Environmental costs may be moved to become part of the private costs by the imposition of environmental and health regulations. Nowadays in the power generation industry there is an accumulation of knowledge on the costs and benefits of environmental externalities, which is increasingly being used as an aid to developing energy policy. Previous work in this field has concentrated on local (occupational health) and regional impacts ("acid rain").

Apart from the environmental costs, there are also non-environmental externalities. These depend upon the perceived views and values of a particular society. They are an important part of energy policy decisions (e.g. energy security).

The following table summarises the results of external (environmental) cost calculations for two power generation types, with and without carbon sequestration [36, 49]. The uncertainty on the external costs is very high, in some cases in the order of the figures itself. The external costs for the considered power generation system have to be added to the total private costs (as determined from section 6.2 and Annex B). For plant without sequestration, the external costs may amount up to a considerable share of the private cost (levelised electricity cost). For the plant with sequestration, the external costs are an order of magnitude smaller than the private costs.

External costs of electricity generation [Ecu/MWh$_e$]

Impact category	Coal with flue gas cleaning	Usc PF (seq. forest)	GTCC	GTCC (seq. gas field)
LOCAL	0.36	1.1 to 2.3	0.08	0.04 to 0.08
Accidents	0.36	1.7	0.08	0.06
Occupational health		0.02		0.002
REGIONAL	17.81	1.6 to 3.2	6.02	0.7 to 1.3
Public health	*17.77*	*2.1*	*3.01*	*1.0*
SO_2-emissions	5.16		0.01	
NO_x-emissions	9.31		2.74	
TSP-emissions	2.44		0.00	
Ozone	0.86		0.26	
Materials, buildings	*0.04*	*0.25*		*0.0*
GLOBAL				
Greenhouse gases		*-3.5 to 1.5*		*0.02 to 1.2*
Generation	6.81		2.86	
Fuel supply	0.55		0.17	
Ecosystems	0.29	-0.96	0.08	0.07
OTHER IMPACTS				
transport	0.43		-	
noise	0.2		0.03	
TOTAL EXTERNAL COSTS	26.4	3.1	6.3	1.1
range	5.3 to 132.2	-0.8 to 7.0	1.3 to 31.6	0.76 to 2.58
PRIVATE COSTS	~ 25	77	~ 30	66

Note: The damage values are those recommended by the EC: VSL (Value of a Statistical Life) 3.1 MEcu; value of acidifying emissions about 12 mECU/kg SO_2 and NO_x; value of the CO_2-emissions 7.4 mECU/kg CO_2 (range between 18 and 46 mEcu/kg CO_2, depending on the adopted discount rate).

Annex C

When investigating literature on GHG emissions, conflicting information or incomplete data are quite often found. This annex lists two typical examples, one for "factual" information, and another for "forecasts". The variation in the latter is clearly larger than in the former. Care has therefore to be taken when evaluating the information, and its reliability has to be weighed against a number of factors.

The relative contribution of different types of fuel used for electricity generation in the EU is shown in the following figure. Fuel shares from [5] (first bar) clearly deviate from those provided by the other two sources [4, 25].

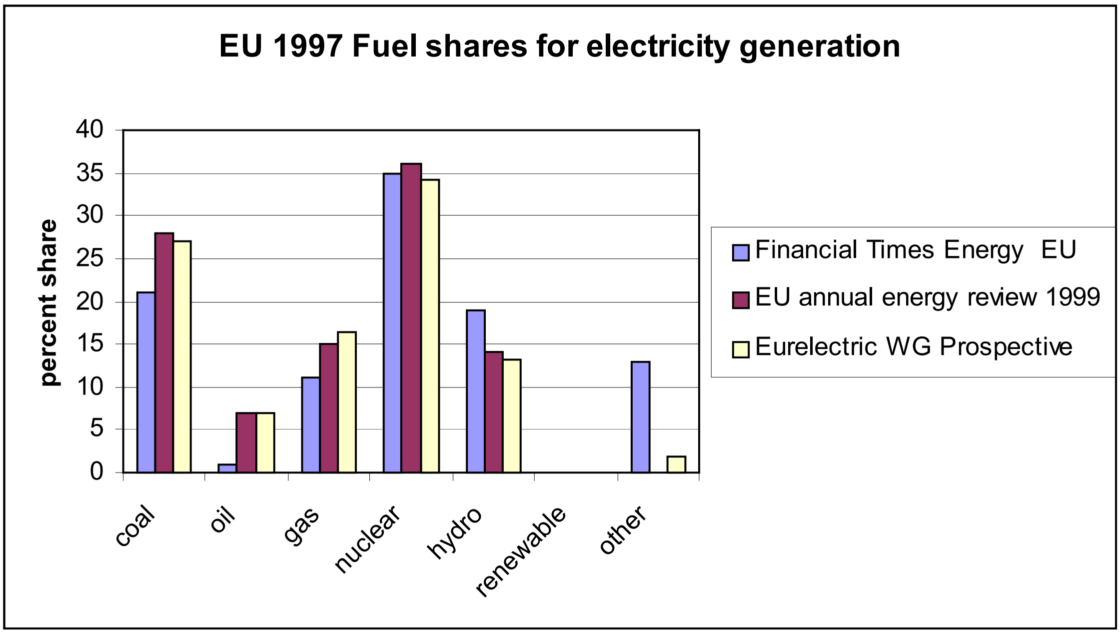

Fig. C1 [4, 5, 25]

The figure below shows the projected fuel shares for energy generation in the EU for 2020. As can be observed, different scenarios, although based on similar assumptions, give rise to quite different forecasts.

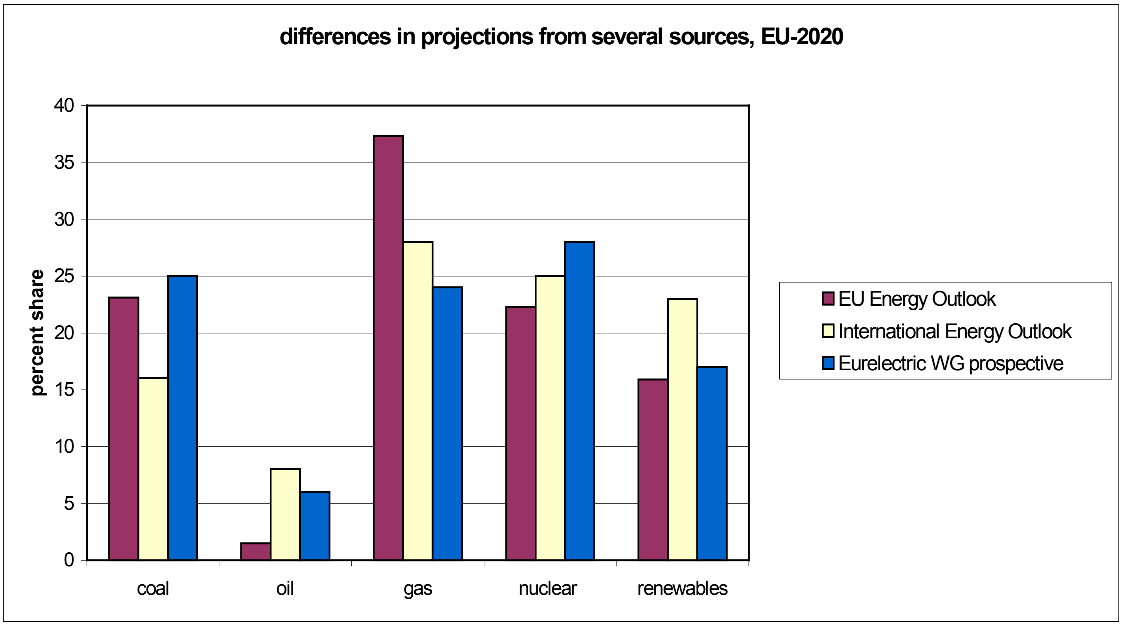
differences in projections from several sources, EU-2020
percent share
40
35
30
25
20
15
10
5
0
coal
oil
gas
nuclear
renewables
EU Energy Outlook
International Energy Outlook
Eurelectric WG prospective

Fig. C2 [3], [4], [28]

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