European Commission

Economic Evaluation of Quantitative Objectives for Climate Change

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FINAL REPORT

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Executive summary

1. Introduction

At the conference of the parties in Kyoto in December 1997, the EU agreed to reduce emissions of the six greenhouse gases (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride) by 8% of 1990 levels by 2010[1]. The target applies to emissions weighted by their (100 year) global warming potential.

The overall objective of the study was to conduct an economic evaluation of EU's Kyoto target. More specifically, the study aimed at:

- identifying the least-cost packages of specific policies and measures for meeting the Community's quantitative reduction for greenhouse gases under the Kyoto Protocol. This evaluation included an analysis of the relative role of carbon dioxide, methane and nitrous oxide emissions, and of the different sectors of the economy (i.e. power production, industry, tertiary-domestic, transport, waste sector and agriculture). It combined two methodologies for the assessment of potentials and costs of reduction: ECOFYS cost curve methodology for methane and nitrous oxide, and the PRIMES partial equilibrium approach for CO2. The results of the evaluation are summarised in section 2, 3 and 4 below.

- analysing the costs and emission reductions of an emission trading system towards meeting the goals in a cost-effective way. In particular, the analysis included an assessment of the costs of a ceiling on CO_2 trading. The study results came from the POLES model (a sectoral model of the world energy system to 2030) and are summarised in section 5 below.

2. Emission reduction potential and costs for methane and nitrous oxide in the EU

A least-cost multi-gas strategy requires that differences in greenhouse gas warming potential between different gases are taken into account when deciding which policies and measures are the most cost-effective. Methane's GWP is 21 times CO_2 equivalent when calculated over 100-year period. Major sources of methane emissions are agriculture, waste and fuel production, distribution and combustion. The GWP of nitrous oxide is 310 times CO_2 equivalent when calculated over a 100-

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[1] More precisely, Member States have the choice of a 1990 or 1995 baseline for HFCs, PFCs and SF6, and a limited allowance can be made for sinks in calculating the 8% reduction.

year period. Major sources of N_2O emission are agriculture, industrial processes and fuel combustion.

Within each sector, specific emission reduction measures were defined together with their associated costs and reduction potentials. Costs are direct costs, i.e. they only include investment costs, operation and maintenance costs, and costs savings (e.g. fuel costs savings in the energy sector). At this stage, costs were assumed to be the same throughout Europe.

On the basis of the above data collected for each specific measure, sector specific discount rate figures and evolution of energy prices to 2010, specific emission reduction costs expressed in ECU per ton CO_2-eq. avoided, were determined for each Member State and for each reduction option. For the sake of consistency with the analysis conducted for CO_2 with the PRIMES model, the same sector specific discount rate figures and energy prices were used for the calculation of methane reduction costs.

Reduction potentials and costs were estimated in comparison with a baseline scenario for CH_4 and N_2O emissions up to 2010. Baseline energy related methane and nitrous oxide emissions were calculated on the basis of the pre-Kyoto energy scenario. Non-energy related emissions were determined from the analyses made by the AEAT (non-energy related agricultural projections) and analyses described in the *Expert Group's work on EU common and Coordinated Policies and Measures* (landfill emissions).

Total human induced 1990 methane emissions in the EU were estimated at 24 Mt CH4 (500 Mt CO2-eq). Projected baseline emissions in 2010 were estimated at 19 Mt CH4 (400 Mt CO2-eq). The emission reduction potential by the identified measures were estimated at an additional 8 Mt CH4 (170 Mt CO2-eq).

Main sources with high potential reduction possibilities are landfills, natural gas distribution pipelines and livestock. The potential of measures may reduce methane emissions in 2010 by 51% compared to 1990. Eighty percent of this potential can be obtained by measures with an average cost below 50 ECU/ton CO2-eq.

Total human induced 1990 nitrous oxide emissions in the EU were estimated at 0.9 Mt N2O (280 Mt CO2-eq). Projected baseline emissions in 2010 were estimated at 1.0 Mt N2O (320 Mt CO2-eq). The emission reduction potential by the identified measures were estimated at an additional 0.35 Mt N2O (110 Mt CO2-eq).

Main sources with high potential reduction possibilities are industrial production of nitric acid and adipic acid and by improving fertiliser use. The potential of measures may reduce the nitrous oxide emissions by 26% in 2010 compared to 1990. More than eighty percent of the reduction potential can be obtained by measures with an average cost below 1 ECU/ton CO2-eq. An additional emission reduction of 10% can be obtained by measures with an average cost below 50 ECU/ton CO2-eq.

3. Contribution of non-CO2 greenhouse gases to the EU Kyoto target: evaluation of the reduction potential and costs

Until recently, studies and strategies for addressing climate change mitigation have principally been focused on reducing emissions of carbon dioxide, but the importance of other greenhouse gases and opportunities for their abatement have been increasingly recognised in the last couple of years. In particular, DGXI of the European Commission has lauched three studies considering non-CO_2 greenhouse gases and examining their reduction potential and costs. These studies are:

(1) Economic evaluation of quantitative objectives for climate change, COHERENCE (ongoing); in the framework of this study ECOFYS produced a report in June 1998 on Emission reduction potential and costs for methane and nitrous oxide in the EU-15;
(2) Reductions of the emissions of HFC's, PFC's and SF6 in the European Union, ECOFYS, June 1998;
(3) Options to reduce methane emissions, AEA Technology Environment, September 1998, and
Options to reduce nitrous oxide emissions, AEA Technology Environment, September 1998.

This part of the project aimed at summarising the major findings from the above studies as to the reduction potential and costs of non-CO_2 greenhouse gases emissions in 2010. It also addressed the uncertainties in emissions and costs estimates for some sources and mitigation options. The reduction potential of each gas was estimated in comparison with a business-as-usual scenario to 2010. It was provided both in ktonne of gas considered and in ktonne of CO_2-equivalent using the global warming potential of the gases (100 years). Costs of reduction options or of packages of reduction options were provided in ECU (1995) per tonne of CO2-equivalent abated.

Emissions of non-CO_2 greenhouse gases under a business-as-usual scenario were projected to increase by 1% in 2010 compared to 1990/1995 levels. This is the result of the combination of a downward trend for methane emissions (-8%) and upward trends for nitrous oxide and the three halogenated gases emissions (+8% and +41% respectively).

The examination of measures to reduce non-CO_2 greenhouse gases emissions showed that such measures could make a substantial contribution to the achievement of the EU's Kyoto target.

The implementation of all measures identified would lead to a reduction of 380 Mt CO_2 equivalent in 2010. This would bring total non-CO_2 emissions to 43% (370 Mt CO_2 equivalent) below 1990 levels by 2010.

The EU six gas basket of emissions in 1990 was estimated to be about 4227 Mt CO_2 and a reduction of 600 Mt of CO_2 would be required to meet the EU's Kyoto target. The identified reduction in non-CO_2 emissions is equivalent to 63% of total reduction needed, and would bring emissions of the six gas basket to 2.5% below 1990 levels by 2010.

Table: **Synthesis of reductions and costs of non-CO_2 mitigation options**

Agricultural measures

	Em. reductions in 2010 (Mt CO2 equ)	Costs (ECU/t CO2 equ)
CH4	34	< 0
	20	0-50
	7	> 50
N2O	24	
Total non-CO2	**85**	

Non agricultural measures

	Em. reductions in 2010 (Mt CO2 equ)	Costs (ECU/t CO2 equ)
CH4	27	< 0
	71	0-50
	31	> 50
N2O	9	< 0
	86	0-50
HFC's	0	< 0
	48	0-50
	12	> 50
PFC's	4	0-50
SF6	7	0-50
Total non-CO2	**295**	
of which	36	< 0
	216	0-50
	43	> 50
Measures in place	146	
Additional measures	149	

Reductions from agricultural measures have been estimated at 85 Mt CO_2 (see Table above), these measures are potentially the most difficult to implement and estimates of their applicability and impact have still high level of uncertainty (this is particularly true for nitrous oxide and for methane from enteric fermentation).

Reductions from non-agricultural measures have been estimated at 295 Mt CO_2 (see Table above), of which half corresponds to reductions resulting from the implementation of existing and planned measures directed at landfilling of waste and adipic acid manufacturing plants. The cost-effectiveness analysis showed that 252 Mt CO_2 can be reduced at a cost below 50 ECU/tonne CO_2. With only non-agricultural measures implemented, emissions of the six gas basket were projected to stabilise at 1990 levels by 2010.

4. Energy system implications of reducing CO2 emissions

This part of the study was designed to quantify energy system changes that are necessary for the EU to reach a series of CO_2 emission reduction targets for 2010 and to evaluate the adjustment costs by sector and member-state. The analysis was based on the use of the PRIMES Ver. 2 energy system model. The results were confined to the energy system and considered that the macroeconomic and sectoral patterns of growth remain unchanged.

The methodology behind the calculations carried on and the assumptions behind the baseline scenario are described in chapter 5 of the report. The results of the baseline projection show a continuous increase of the use of fossil fuels in Europe and hence an increase of CO2 emissions from energy conversion and use. Compared to 1990 emissions, CO2 emitted in the EU is shown to increase by about 8% in 2010.

Some key findings of the study are summarised below.

- "Carbon value" and associated emission reduction targets

  A range of CO_2 emission reduction scenarios was defined for a spectrum of marginal abatement cost levels defined between 1 Euro per ton of carbon up to 900 Euro per ton of Carbon. A marginal abatement cost was defined as the cost that was necessary to pay to avoid the emission in 2010 of the last ton of carbon for a given emission reduction target. Given an emission reduction target, the “carbon-value” was defined as the associated marginal abatement cost measured in Euro per ton of carbon avoided.

  The Table below gives the carbon values and associated emission reduction targets as provided by the PRIMES model. The upper part of the table shows the level of the carbon value for a range of emission reduction scenarios referring to the year 2010 and the associated emissions of CO2 in 2010. Then for each level of carbon value, the table shows the associated quantity of CO2 the emission of which is avoided in 2010 (bottom part of the table) and the percent reduction of emissions in 2010 compared to the level in 1990 (middle part of the table).

Table: Carbon values and associated emission reduction targets

			Carbon Value : Marginal Abatement Cost in Eur per ton of Carbon avoided																
		1990	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
CO2 Emissions (Mtn CO2)	AU	55.0	58.1	58.0	58.0	57.8	57.2	56.1	54.3	52.5	49.8	47.6	45.9	44.3	41.9	40.7	37.9	34.2	30.9
	BE	104.8	122.9	122.7	122.5	121.8	121.0	119.6	117.7	114.6	111.2	106.7	102.0	96.9	90.2	84.8	79.5	72.9	66.0
	DK	52.7	54.9	54.8	54.8	54.6	54.3	53.0	50.9	47.8	45.0	41.7	39.1	37.0	34.3	32.3	28.9	25.8	23.5
	FI	51.3	72.3	72.2	72.0	71.1	70.0	68.8	64.6	57.2	54.8	51.3	46.3	42.7	39.7	37.2	34.1	31.0	28.0
	FR	352.4	393.3	392.8	391.6	390.9	388.7	384.2	372.6	360.4	347.6	341.4	323.3	306.1	286.3	270.8	249.6	219.8	192.5
	GE	951.6	839.2	835.9	835.8	833.2	820.8	807.3	780.7	761.1	731.6	691.8	653.7	616.3	582.4	552.1	526.3	496.1	464.1
	GR	70.9	109.4	108.4	108.4	108.3	107.9	107.4	96.7	95.0	92.6	90.0	87.1	83.7	80.0	77.6	75.8	73.0	70.6
	IR	30.1	42.8	42.7	42.7	42.6	42.4	41.8	40.1	38.4	36.9	34.4	32.3	30.5	28.7	27.0	25.7	24.1	22.3
	IT	388.0	429.9	429.2	429.1	428.6	426.2	421.1	409.3	387.9	373.2	361.2	347.6	333.7	319.4	305.2	287.1	261.9	234.9
	NL	153.0	207.1	206.1	205.5	203.3	200.5	197.6	192.4	187.6	183.1	177.9	170.6	162.3	153.1	145.7	138.2	129.9	118.7
	PO	39.1	64.6	64.5	64.5	64.1	63.6	62.7	61.9	59.7	56.6	50.1	47.5	45.3	42.7	39.6	37.3	34.3	31.2
	SP	201.9	275.1	274.8	274.6	273.9	273.3	269.4	262.4	243.3	234.9	223.8	208.9	193.3	182.4	173.0	161.1	148.5	130.5
	SV	50.0	69.2	68.9	69.0	68.9	67.7	66.8	64.4	62.1	57.4	54.4	50.4	47.7	44.9	41.7	37.7	32.7	29.0
	UK	566.9	572.3	571.5	563.4	560.9	555.4	549.0	537.5	521.3	502.4	483.1	460.8	434.6	407.3	385.6	359.3	331.2	296.2
	EU14	3067.5	3311.1	3302.7	3291.9	3280.2	3248.9	3205.1	3105.5	2988.9	2877.1	2755.3	2615.6	2474.5	2333.2	2213.3	2078.5	1915.4	1738.4
			Emission Reduction Target : % Change of emissions in 2010 compared to 1990																
CO2 Change from 1990	AU		5.7	5.6	5.5	5.2	4.1	2.1	-1.1	-4.5	-9.4	-13.4	-16.4	-19.3	-23.7	-25.9	-31.1	-37.9	-43.7
	BE		17.4	17.2	17.0	16.3	15.5	14.2	12.3	9.4	6.2	1.9	-2.6	-7.5	-13.9	-19.1	-24.1	-30.4	-37.0
	DK		4.3	4.1	4.1	3.6	3.1	0.6	-3.4	-9.3	-14.6	-20.8	-25.7	-29.7	-34.9	-38.7	-45.1	-51.0	-55.4
	FI		40.8	40.6	40.2	38.5	36.4	34.1	25.8	11.5	6.7	-0.2	-9.9	-16.8	-22.7	-27.6	-33.7	-39.6	-45.4
	FR		11.6	11.4	11.1	10.9	10.3	9.0	5.7	2.3	-1.4	-3.1	-8.3	-13.2	-18.8	-23.2	-29.2	-37.6	-45.4
	GE		-11.8	-12.2	-12.2	-12.4	-13.7	-15.2	-18.0	-20.0	-23.1	-27.3	-31.3	-35.2	-38.8	-42.0	-44.7	-47.9	-51.2
	GR		54.3	52.9	52.9	52.7	52.1	51.4	36.3	34.0	30.7	26.9	22.8	18.1	12.9	9.4	7.0	3.0	-0.4
	IR		42.6	42.2	42.1	41.8	41.1	39.2	33.3	27.9	22.9	14.5	7.6	1.6	-4.4	-10.1	-14.6	-19.7	-25.9
	IT		10.8	10.6	10.6	10.5	9.9	8.5	5.5	0.0	-3.8	-6.9	-10.4	-14.0	-17.7	-21.3	-26.0	-32.5	-39.5
	NL		35.4	34.7	34.3	32.8	31.0	29.1	25.8	22.6	19.7	16.2	11.5	6.1	0.0	-4.7	-9.7	-15.1	-22.4
	PO		65.4	65.2	65.1	64.2	62.7	60.7	58.5	52.9	45.0	28.2	21.5	16.0	9.2	1.4	-4.5	-12.3	-20.1
	SP		36.3	36.1	36.0	35.7	35.4	33.5	30.0	20.5	16.4	10.9	3.5	-4.3	-9.7	-14.3	-20.2	-26.4	-35.3
	SV		38.4	37.9	38.1	37.9	35.4	33.7	28.8	24.2	14.8	8.8	0.8	-4.6	-10.1	-16.5	-24.5	-34.5	-42.0
	UK		0.9	0.8	-0.6	-1.1	-2.0	-3.2	-5.2	-8.0	-11.4	-14.8	-18.7	-23.3	-28.2	-32.0	-36.6	-41.6	-47.8
	EU14		7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
			CO2 emissions avoided in 2010																
CO2 Emissions (Mtn CO2)	AU		0.0	0.1	0.1	0.3	0.9	2.0	3.8	5.6	8.3	10.5	12.2	13.8	16.2	17.4	20.2	23.9	27.2
	BE		0.0	0.2	0.4	1.1	2.0	3.3	5.3	8.4	11.7	16.2	20.9	26.0	32.7	38.2	43.4	50.0	56.9
	DK		0.0	0.1	0.1	0.3	0.6	1.9	4.1	7.2	9.9	13.2	15.8	17.9	20.6	22.6	26.0	29.1	31.4
	FI		0.0	0.1	0.3	1.2	2.2	3.4	7.7	15.1	17.5	21.0	26.0	29.6	32.6	35.1	38.2	41.3	44.3
	FR		0.0	0.5	1.7	2.4	4.6	9.0	20.7	32.8	45.7	51.9	70.0	87.2	107.0	122.5	143.7	173.5	200.8
	GE		0.0	3.3	3.4	6.0	18.4	31.9	58.5	78.1	107.7	147.4	185.5	222.9	256.8	287.1	312.9	343.1	375.1
	GR		0.0	1.0	1.0	1.1	1.5	2.1	12.7	14.4	16.8	19.4	22.3	25.7	29.4	31.8	33.6	36.4	38.8
	IR		0.0	0.1	0.1	0.2	0.4	1.0	2.8	4.4	5.9	8.4	10.5	12.3	14.1	15.8	17.2	18.7	20.6
	IT		0.0	0.6	0.8	1.2	3.6	8.8	20.5	42.0	56.6	68.7	82.3	96.2	110.5	124.7	142.7	168.0	195.0
	NL		0.0	1.0	1.6	3.8	6.7	9.5	14.7	19.6	24.0	29.2	36.5	44.8	54.0	61.4	68.9	77.2	88.4
	PO		0.0	0.0	0.1	0.4	1.0	1.8	2.7	4.9	8.0	14.5	17.1	19.3	21.9	25.0	27.3	30.3	33.4
	SP		0.0	0.3	0.5	1.2	1.9	5.7	12.7	31.8	40.2	51.3	66.2	81.9	92.7	102.1	114.0	126.6	144.6
	SV		0.0	0.3	0.2	0.2	1.5	2.4	4.8	7.1	11.8	14.8	18.8	21.5	24.3	27.5	31.4	36.4	40.2
	UK		0.0	0.8	8.9	11.3	16.9	23.2	34.7	51.0	69.9	89.2	111.4	137.7	165.0	186.7	212.9	241.1	276.1
	EU14		0.0	8.4	19.2	30.9	62.2	106.0	205.6	322.2	434.0	555.8	695.5	836.5	977.8	1097.8	1232.6	1395.7	1572.7

The analysis with PRIMES permitted also the construction of marginal abatement cost curves for each Member State (referring to energy-related CO2 emissions only). Such a curve plots the tons of CO2 emissions avoided in 2010 against the carbon-value.

- Analysis of energy system changes

Energy system changes induced by emission constraints were analysed by decomposing the effects into four general categories: structural and behavioural changes, technology changes, fuel-mix changes in direct combustion energy uses of fossil fuels and supply-side effects from power and steam generation. The results generally showed that the contribution of each of the above four categories of change were different, as the emission constraint becomes bigger:

- In general, the contribution of structural and behavioural change becomes quite large, close to 20%, at relatively low levels of carbon values (20 Euro per ton of carbon, corresponding to about 4% increase of emissions in 2010 from 1990). As higher emission constraints are introduced the contribution of structural and behavioural changes stabilises between around 21%.

- The contribution of factors related to technology progress in the demand-side increases continuously with the level of the emission constraint. This contribution is of the same order of magnitude as that of the structural and behavioural change up to a carbon value of 110 Euro per ton of carbon, which corresponds to a decrease of emissions in 2010 from 1990 by 6.2%. As carbon values increase further the contribution of technology progress increases and at extremely high carbon values it accounts for nearly half of the overall emissions reduction.
- The role of changes in the fuel mix of fossil fuels directly used in end-use sectors is small for all values examined (of the order of 2 to 2.5%). It should be noticed that fuels used for steam generation are included in the power and steam sector, therefore fuel mix changes in this domain are included in the indirect effects from power and steam. The low contribution from changes in fossil fuel intensity of direct energy uses is due to the fact that natural gas is extensively used already in the baseline and high carbon-content fossil fuels are mostly used in specific processes.
- The role of supply-side effects is important. The power and steam generation system meters a large contribution to the emission reduction. At low levels of carbon-value, the effects from power and steam generation dominate, having a share ranging from 73 to 59%. However, the share of this sector in total emission reduction continuously decreases with successively increasing emission targets. In the range that is of interest for the Kyoto targets, the effects from power and steam system account for about 50% of the total. This share decreases up to 30% at high emission targets. Within that range, technology progress in the demand-side becomes significantly more important than the power and steam system.

- Sectoral costs of emission reductions

  The imposition of emission reduction targets results in an increase in total energy system cost, partly due to the associated marginal abatement cost. The way the imposition of the carbon-value affects different energy consumers depends on their ability to adapt to emission reduction targets through investment in new, more efficient technologies, structural shifts and changes in their choice of fuel mix. Average system costs were computed at a sectoral level and summarised in the table below.

Table: Analysis of CO2 Emission reduction by Sector

ANALYSIS OF ENERGY SYSTEM CHANGES TO REDUCE CO2 EMISSIONS IN 2010 FOR EUROPE - 14

Level of Carbon Value (in Eur'90/ton of Carbon)	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
% Emission change in 2010 from 1990	**7.7**	**7.3**	**6.9**	**5.9**	**4.5**	**1.2**	**-2.6**	**-6.2**	**-10.2**	**-14.7**	**-19.3**	**-23.9**	**-27.8**	**-32.2**	**-37.6**	**-43.3**
DECOMPOSITION OF CO2 EMISSIONS REDUCTION (Mtn of CO2 avoided in 2010)																
In the table below the changes in Electricity and Steam are included in Demand Sectors																
Industrial Sectors - Metals	-1	-1	-2	-5	-8	-15	-24	-30	-36	-45	-59	-73	-83	-92	-101	-110
Industrial Sectors - Chemicals	0	-1	-2	-4	-7	-12	-19	-26	-32	-39	-45	-52	-56	-60	-64	-69
Industrial Sectors - Materials	0	-1	-2	-5	-7	-13	-20	-27	-34	-42	-50	-57	-62	-68	-76	-83
Industrial Sectors - Others	-1	-3	-4	-8	-12	-24	-37	-49	-61	-76	-89	-101	-110	-119	-127	-135
Industrial Sectors - Total	-3	-7	-10	-22	-34	-64	-100	-132	-163	-201	-243	-282	-312	-340	-368	-397
Services	-2	-6	-8	-17	-31	-60	-90	-116	-145	-179	-211	-238	-257	-274	-288	-304
Agriculture	0	0	-1	-1	-2	-4	-5	-7	-8	-10	-12	-14	-15	-16	-17	-18
Households	-2	-5	-8	-15	-24	-48	-79	-107	-137	-173	-206	-246	-280	-317	-361	-388
Passenger Transports	-1	-1	-2	-4	-8	-15	-27	-42	-61	-80	-98	-118	-139	-167	-219	-299
Goods Transports	0	0	-1	-2	-5	-9	-15	-22	-32	-41	-52	-62	-73	-94	-116	-130
TOTAL SYSTEM - FINAL DEMAND	-8	-19	-31	-62	-104	-201	-316	-426	-546	-684	-822	-960	-1,077	-1,208	-1,369	-1,537
In the table below the changes in Electricity and Steam in demand are included in Power and Steam Sectors																
Electricity production	-7	-15	-22	-41	-64	-127	-193	-242	-287	-349	-403	-447	-483	-519	-561	-593
Steam production	1	-1	0	-3	-5	-6	-9	-17	-23	-31	-38	-45	-48	-50	-52	-55
Other Supply Sectors production	0	0	0	0	-1	-2	-2	-3	-4	-5	-7	-9	-11	-12	-14	-16
Statistical Difference (second order effects)	-1	0	0	0	-1	-3	-3	-4	-6	-6	-7	-9	-11	-12	-13	-20
In the table below the changes in Electricity and Steam are included in Power and Steam sector																
Total CO2 emissions reduction	-8	-19	-31	-62	-106	-206	-322	-434	-556	-696	-837	-978	-1,098	-1,233	-1,396	-1,573
In Final Energy Demand	-1	-3	-9	-17	-36	-69	-117	-170	-239	-308	-387	-474	-553	-648	-765	-897
In Electricity and Steam Generation	-7	-16	-22	-45	-69	-135	-203	-261	-313	-382	-442	-495	-534	-573	-617	-660
In Other Energy Conversion Sectors	0	0	0	0	-1	-2	-2	-3	-4	-5	-7	-9	-11	-12	-14	-16

Combined with figures obtained in the analysis of reduction potentials and costs for non-CO2 greenhouse gases (see section 3), the above figures should provide useful information for the determination of sectoral targets for the EU as well as on the least-cost allocation of reduction effort between the different greenhouse gases.

5. Kyoto Protocol and emission trading: potential cost savings and emission reductions

In the context of the current debate on principles, rules and modalities for an international emission trading, the present study attempts to provide elements of answer as to the cost-effectiveness and supplementarity issue of an international trading system.

Its general objective was in fact to explore the potential costs and emission reductions impact of different designs of emission trading on the achievement of the Kyoto targets. Five different emission trading schemes or scenarios were designed that reflect different possible constraints on emission trading: in terms of participants (e.g. restrict the trading to Annex B countries), in terms of quantities (e.g. put a ceiling on emission trading), in terms of both participants and quantities.

It was not the aim of the study to address the economic theory of emission trading, nor to discuss the implementation issues of an international trading system (transaction costs estimates, monitoring, etc.).

The study results are based on the POLES model. POLES is a sectoral model of the world energy system to 2030, describing the international energy markets and national or regional subsystems. The methodology adopted consisted in using the POLES model to simulate the impact of the emission trading scenarios by comparing the results to a reference scenario without trading.

The analysis considered CO_2 emissions only due to lack of a consistent analysis framework for the other greenhouse gases and sinks. The Kyoto targets specified for the basket of six greenhouse gases were thus applied to CO_2 emissions only.

All scenarios take into account the Kyoto targets of Annex B countries. The trading of "hot air" was not excluded, so that Russia and Ukraine can sell emission permits equivalent to the difference between their Kyoto targets and the level of their emissions in a Business as Usual scenario.

The results suggest the following conclusions if trading is restricted to Annex B.

- Even without constraints on emission trading, trading is supplemental (more than 50% of the required reductions in 2010 would be done domestically) except in Japan where permit acquisition contributes to around 70% of the required reduction[2]. In the EU, domestic actions would represent 75% of the reduction in 2010. Party's acquisitions are up to 20% of their CO_2 emissions in 1990, depending on the country (6% for the EU, 15% for the USA, 20% for Japan).

- The permit price would be equal to 66.5 $/tC (17 ECU/$tCO_2$). At Annex B level, the reduction effort is expected to decrease from around 0.2% of 2010 GDP without trading to around 0.09% of 2010 GDP with full trade.

- Reducing the traded volume to half would increase annual costs of total Annex B by 50% (or 10 billion $/year). On the other hand, global emissions would be 1% lower since part of the "hot air" can not be sold.

- The main result of the analysis of emission trading among Annex B countries seems to be that no ceiling on flexibility mechanisms (ET and JI) is needed to ensure that these are supplemental to domestic action. Furthermore, restrictions on trade would result in significant cost increases.

If trading would take place world wide, the main findings are the following.

- Without restriction on the use of flexibility mechanisms (ET, JI and CDM), trading would not necessarily be supplemental (less than 50% of the required reductions in 2010 would be done domestically). Acquisitions could make up to 90% of the reduction in 2010 (70% in the EU, 76% in the USA, 87% in Japan).

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[2] This result is in line with MITI's policy (The Ministry of International Trade and Industry of Japan) to reduce greenhouse gases emissions by 6% from 1990 levels by 2010: 2% reduction will come through national efforts while the remaining 4% reduction will come through emission trading with other nations.

Moreover, EU’s acquisitions would represent 16% of its CO_2 emissions in 1990, compared to 6% if trading is restricted to Annex B. USA shows however the highest share with acquisitions representing 30% of their CO_2 emissions in 1990.

- The permit price would be equal to 24 $/tC (6 ECU/t$CO_2$), namely three times lower than if trading is restricted to Annex B.

- World wide, the total costs of reduction are expected to be six times lower than without trading (2 times for the EU, 3 times for the USA, 5 times for Japan and 4 times for Annex B as a whole). The emission reduction effort would decrease from around 0.1% of 2010 GDP without trading to around 0.02% of 2010 GDP with full trade. At Annex B level, the decrease would be from 0.2% to 0.06% of the GDP in 2010.

- Reducing the traded volume to half would make the world wide trading supplemental. However, the price to pay is a doubling of the annual reduction costs (12 billion $1990/year). Global emissions would be 1% lower since part of the "hot air" can not be sold.

- The analysis of a world wide emission trading system points to the conclusion that a ceiling on the use of flexibility mechanisms would be needed to ensure that these are supplemental to domestic action. However, a cap on trade is expensive and does not solve the "hot air" issue. Moreover, the resulting restriction on "hot air" that can be sold has only a very limited impact on global emissions (1 percentage point lower).

Finally, as caveat, it should be stressed that the present analysis did not consider the possibility of banking and assumed perfect market for emission permits. Furthermore, Parties were assumed to minimise costs and to ignore ancillary benefits of domestic action. In reality, domestic action might then be more important than the model results suggest.

I. Introduction

At the conference of the parties in Kyoto in December 1997, the EU agreed to reduce emissions of the six greenhouse gases (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride) by 8% of 1990 levels by 2010[3]. The target applies to emissions weighted by their (100 year) global warming potential.

The overall objective of the study was to conduct an economic evaluation of EU's Kyoto target.

More specifically, the study aimed at:

- identifying the least-cost packages of specific policies and measures for meeting the Community's quantitative reduction for greenhouse gases under the Kyoto Protocol. This evaluation included an analysis of the relative role of carbon dioxide, methane and nitrous oxide emissions, and of the different sectors of the economy (i.e. power production, industry, tertiary-domestic, transport, waste sector and agriculture). It combined two methodologies for the assessment of potentials and costs of reduction: ECOFYS cost curve methodology for methane and nitrous oxide, and the PRIMES partial equilibrium approach for CO_2.

- analysing the costs and emission reductions of an emission trading system towards meeting the goals in a cost-effective way. In particular, the analysis included an assessment of the costs of a ceiling on CO_2 trading. The study results came from the POLES model (a sectoral model of the world energy system to 2030).

The results of the evaluation of emission reduction potential and costs for methane and nitrous oxide emissions in the EU and its Member States are described in chapter 2. A synthesis of key findings on reduction potentials and costs of non-CO_2 mitigation options based on three studies launched by DGXI (e.g. two studies on methane and nitrous oxide by Ecofys (see chapter 2) and AEAT, and one on onthe three halogenated gases by Ecofys) is provided in chapter 3. The least-cost solution to meet CO_2 reduction targets in the EU and its Member States and the energy and sector implications are described in chapter 5.

The above studies aim to provide useful input for the identification of greenhouse gas emission objectives by sector at Community level. The sectors are transport, energy (mainly power production), industry, domestic/tertiary, and agriculture. The

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[3] More precisely, Member States have the choice of a 1990 or 1995 baseline for HFCs, PFCs and SF6, and a limited allowance can be made for sinks in calculating the 8% reduction.

methodology for the identification of Community sectoral targets will thus combine the PRIMES approach for CO_2 and the Ecofys approach for the other greenhouse gases.

Finally, the economic analysis of emission trading schemes with the POLES model with the objective of evaluating of potential cost savings and emission reductions of emission trading under different assumptions is reported in chapter 4.

Emission Reduction Potential and Costs for Methane and Nitrous Oxide in the EU-15

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June 1998

Interim report

by order of the
DGXI, EC

M714

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SUMMARY

Within the activities to develop the Commission' Communication on a Post-Kyoto Climate Strategy analyses are made to identify the least-cost package of specific policies and measures for meeting the Community's proposed quantitative reduction for six greenhouse gases under the Kyoto Protocol for the period 2008-2012. These analyses will be used for the Commissions Post-Kyoto Climate Strategy for the June 1998 Environment Council.

In this study, for two of the greenhouse gases methane and nitrous oxide emission reduction measures are identified. For these measures, subsequently the emission reduction potential in the year 2010 is determined and a quantitative cost analysis is made for all EU-15 Member States. On basis of this inventory methane and nitrous oxide cost-supply curves are constructed.

In the study, the following steps are executed:
1. Preparation of the 1990 base year emission of CH_4 and N_2O
2. Preparation of the base-line emission development scenario for view year 2010
3. Identification of the emission reduction measures, their potential and specific costs.

In this study we use key-figures to estimate EU15-wide potentials and costs. In the next step country specific information on reduction measures and reduction costs will be incorporated.

BASE YEAR (1990) METHANE AND NITROUS OXIDE EMISSIONS

The emission data for the base year 1990 are taken from the estimates submitted by Member States to the Commission and published in the *Second Communications from the European Community under the UNFCC (draft, May 1998)*. In the case a further breakdown of the emission inventory is required, the CORINAIR'90 emission inventory database is used.

Figure 0.1 and Figure 0.2 give an overview of the 1990 methane and nitrous oxide emissions. The main methane sources are from landfills (waste) and livestock (agriculture). Main nitrous oxide sources are agriculture and production of nitric acid and adipic acid (industrial processes).

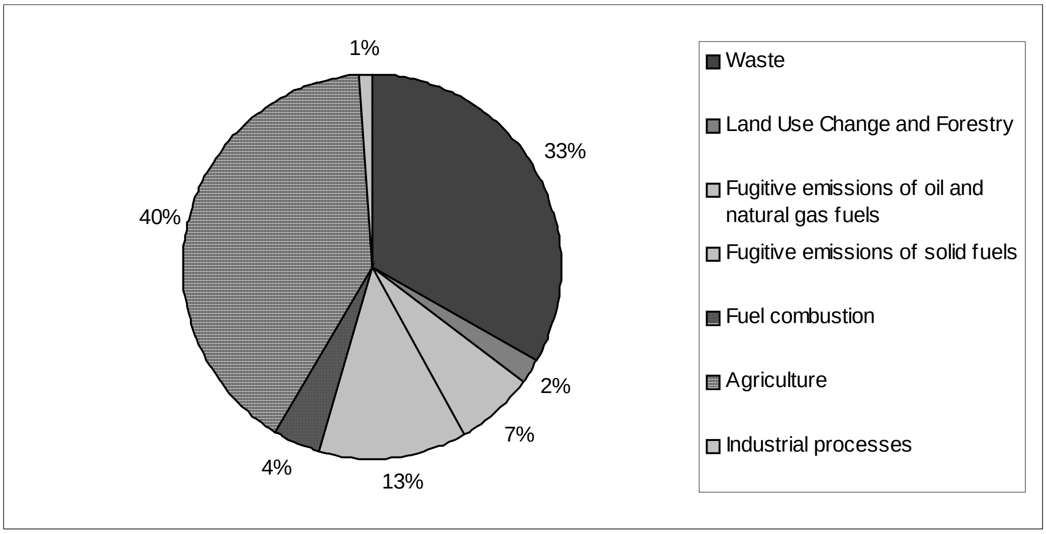

Figure 0.1. Breakdown of 1990 methane emissions in the EU-15. Total EU-15 methane emissions are estimated at 500 Mtonne CO_2-eq.

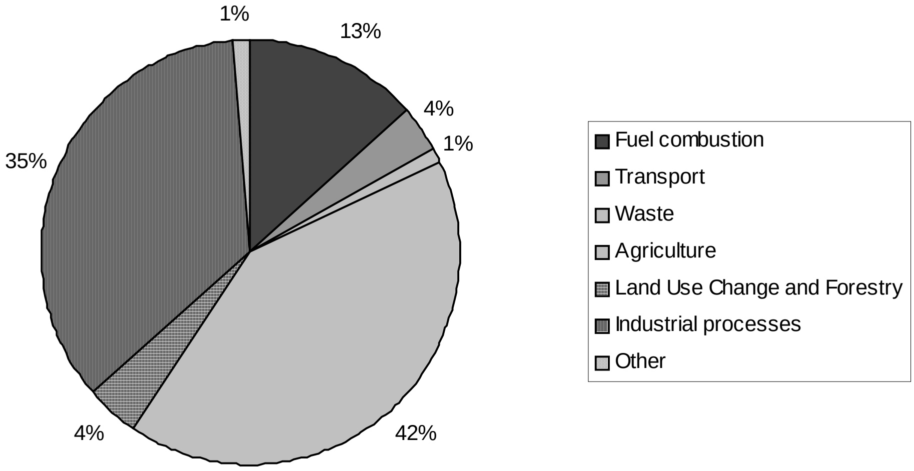

Figure 0.2. Breakdown of 1990 nitrous oxide emission in the EU-15. Total EU-15 nitrous oxide emissions are estimated at 315 Mtonne CO_2-eq.

BASE-LINE EMISSION VIEW YEAR 2010

Projections for the base-line emissions in 2010 relative to 1990 are calculated using the emission estimates from the Pre-Kyoto scenario (energy related projections), analyses made by AEA (non-energy related agricultural projections), and analyses as described in *the Expert Group's work on EU Common and Coordinated Policies and Measures* [Phylipsen *et al.*, 1997] (landfill emissions).

Projections are based on a Business-as-Usual scenario taking into account existing policies. Table 8.1 on page 55, shows the base line emissions for 2010.

The analysis shows that EU-15 methane emissions are to decrease with over 20% in 2010 compared to 1990 emissions. This is mainly obtained by reducing emissions from landfills and by lower emissions from solid fuels extraction. Emissions of nitrous oxide are projected to increase by 13%. The increase is mainly due to the expected increase of nitrous oxide emissions from car catalysts. In the base line no emission reduction measures are assumed for nitrous oxide from nitric acid and adipic acid production. It is, however, likely that emissions are considerably reduced from these processes by 2010. Implementation of current technical available measures will reduce total nitrous oxide emission in 2010 by 18% compared to the 1990 emissions. Furthermore, it should be noted that non-anthropogenic sources of methane and nitrous oxide have a significant contribution to total emissions, by over 28 and 32% of the total emissions respectively. However, the accuracy of the emission estimates, especially for the non-anthropogenic related emissions, is generally not very high.

EMISSION REDUCTION MEASURES, POTENTIAL AND COSTS

To reduce methane emission 22 different measures are identified. The total technical reduction potential in 2010 of the measures amounts to about 6 million tonne of CH_4, which is equivalent to 125 million tonne of CO_2.[1] This corresponds with a reduction of 34% compared to the 2010 base line emissions. 100 million tonne CO_2-eq. of this potential (27% reduction) can be reduced at costs below 50 ECU/tonne. Table 0.1 gives an overview of the potential and associated costs per sector.

For nitrous oxide 7 different measures are identified. The total technical reduction potential in 2010 of the measures amounts to about 0.36 million tonne N_2O, which is equivalent to 113 million tonne of CO_2. This corresponds with a reduction of 34% compared to the 2010 base line emissions. 94 million tonne CO_2-eq. (28% reduction) can be reduced at very low costs (below 1 ECU/tonne CO_2-eq). Approximately an additional 10 million tonne can be reduced at costs below 50 ECU/tonne. Table 0.2 gives an overview of the potential and associated costs per sector. Figure 0.3 and Figure 0.4 show the supply curve for the EU-15 as a whole for methane and nitrous oxide, respectively. In annex 3, from page 58 on, the supply curves for methane and nitrous oxide for the individual Member States are presented.

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[1] Global Warming Potential CH_4 = 21; GWP N_2O = 310 [IPCC, 1996]

Table 0.1 Estimates of reduction potential for methane and associated costs per sector in the EU-15.

Sector	**Reduction**		**Average cost**
	ktonnes CH_4	Mtonnes CO_2-eq.	ECU/tonne CO_2-eq.
Agriculture	1680 720	35 15	<0 0-50
Waste	690 875	14 18	<0 0-15
Energy	370 175	8 4	<0 0-50
Total	4700	100	<50

Table 0.2. Estimates of reduction potential for nitrous oxide and associated costs per sector in the EU-15.

Sector	**Reduction**		**Average cost**
	ktonnes N_2O	Mtonnes CO_2-eq.	ECU/tonne CO_2-eq.
Agriculture	8 27	2 8	<0 0-50
Waste	3	1	~0
Industrial Processes	290	91	0.2
Total	328	102	<50

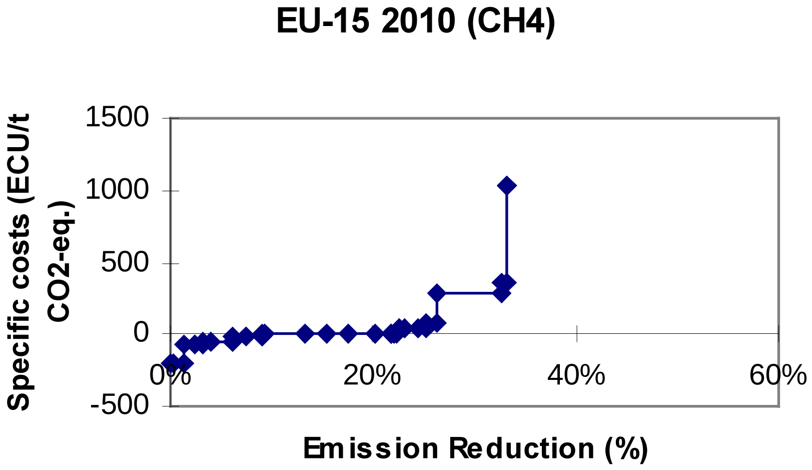

Figure 0.3. Supply curve for the EU-15 for methane emission reduction options in 2010.

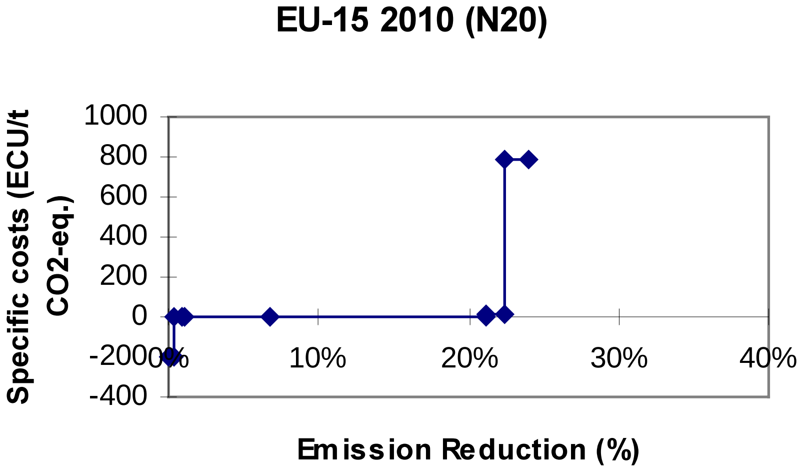

Figure 0.4. Supply curve for the EU-15 for nitrous oxide emission reduction options in 2010

CONTENTS

1. INTRODUCTION

1.1 BACKGROUND

The European Commission (EC) will forward to the June 1998 Environment Council a Communication outlining a strategy to allow Community implementation of the Kyoto protocol. That post-Kyoto strategy will start, among other issues, to identify cost-effective policies and measures for adoption at Member State and Community levels for meeting the Community's emission reduction target. The Community's and Member States joint target is a 8% reduction of emissions of six greenhouse gases in the period 2008-2012, compared to the 1990 level (or 1995 level for the three industrial gases HFCs, PFCs and SF_6).

The EC commissioned studies for the identification of cost-effective policies and measures to meet quantitative objectives for climate change. The objective of the studies is to provide a first evaluation as to which policies and measures might be cost-effective at EU level across three gases.

This report deals with two major greenhouse gases: methane (CH_4) and nitrous oxide (N_2O).

1.2 AIM OF THIS STUDY

The aim of this work is to assess technical control options and costs of controlling the greenhouse methane and gases nitrous oxide for the year 2000 and 2010 for the EU-15 countries.

Tasks

Within this study the following tasks are performed:

1. Provide an estimate of the development of the EU wide emissions of methane and nitrous oxide in the year 2010 compared to 1990 with existing (current) national and Community policies. This will be done by making use of the CORINAIR emission inventory and *the Second National Communications* of the EU Member States.
2. Collect the best existing estimates of the (capital and operating) costs and associated emission limitations / reductions in 2010 of options to control methane and nitrous oxide in the EU-15. The degree of reliability of the figures will be indicated; furthermore, it will be ensured that the cost estimates are comparable with cost estimates provided for the other 3 gases in a companion study.
3. Rank these options on the basis of their specific costs (cost per tonne CO_2 equivalent abated) in EU-wide cost-functions.

2. METHODOLOGY

To construct the CH_4 and N_2O cost-supply curves for the year 2010, three main steps are executed:

1. Preparation of the 1990 base year emission of CH_4 and N_2O
2. Preparation of the base-line emission development scenario for view year 2010
3. Preparation of emission reduction measures for CH_4 and N_2O

2.1 PREPARATION OF THE 1990 BASE YEAR EMISSION OF CH_4 AND N_2O

The 1990 emission of CH_4 and N_2O are taken from *the Second Communication from the European Community under the UN Framework Convention on Climate Change* (Draft May 1998). See Chapter 3 for a more detailed description.

2.2 PREPARATION OF THE EMISSION DEVELOPMENT SCENARIO FOR VIEW YEAR 2010

For the preparation of the 2010 emission scenario the emission projections of the *Pre-Kyoto scenario* for energy related activities. For the projections of the N_2O emissions in agriculture, nitric acid production and adipic acid production, the projections developed by AEA [Bates, 1997] are used. Projections on methane emissions from landfills are taken from ETSU [Meadows, 1997 in: Phylipsen *et al.*, 1997]. See Chapter 4 for a more detailed description.

2.3 PREPARATION OF EMISSION REDUCTION MEASURES FOR CH_4 AND N_2O

For each methane and nitrous oxide source specific emission-reduction measures can be defined. To judge the effectiveness of a measure as part of an emission reduction strategy, amongst others the following aspects are relevant.

- emission rate of the source before implementation of the measure
- share of the source in the emission in the sector
- reduction potential of the measure
- technical or theoretical maximum implementation degree of the measure in the view year
- costs and/or cost savings of the measure (investment costs, operation and maintenance costs, savings)
- lifetime or depreciation time of the measure

The main part of the measures described are from the following sources: [Jager, 1994], [Jager, 1996] [Bates, 1997] and [Gerbens, 1998]. Experts working in the field of research or the category concerned reviewed the measures described.

Per measure - if possible - data were collected regarding potential, efficiency, costs and/or cost savings, availability, applicability, barriers and other relevant information. When data are lacking, approximate estimates are made and implemented in the database. The underlying assumptions are described in the text. More detail can be found in the literature sources. The range of uncertainty in these data can vary widely. Especially cost figures often refer to different kind of costs. If possible, direct investment costs (for appliances and adaptations) and installation costs are identified. Often the emission reducing measure has additional beneficial side-effects (for instance sellings or avoided purchase of energy, Table 2.1 gives an overview of the assumed prices for natural gas and electricity). In some cases it is even applied for this reason. In those cases it is difficult to allocate the costs or cost savings to effect and side-effect of the measure properly.
In this study costs are assumed to be equal throughout Europe, independently in what country or region a measure is implemented. A follow-up study should identify cost differences in the various EU-15 countries. The results of such work could easily be implemented in the database constructed for this study.

2.3.1 Description of the cost calculation method

The costs expressed in this study refers to *direct* costs: the additional resources that are directly used up in complying with a measure. A change in direct costs will often show up as a change in the market price. For instance, increases in the costs of nitric acid production (because exhaust gases are treated) may be passed to the consumers of the nitric acid. Not taken into account are the indirect costs: the costs arising when a measure induces behavioural change. Costs savings induced by less environmental damage are also not taken into account.

The specific nett costs for each measure E (ECU/tonne avoided greenhouse gas) are determined as follows:

$$E_s = C_s - P_s$$

with E_s = specific nett costs of emission reduction of substance S (ECU/tonne avoided)
C_s = specific costs of emission reduction of substance S (ECU/tonne avoided)
P_s = specific cost savings of emission reduction of substance S (ECU/tonne avoided)

The specific costs C_s is calculated by dividing the yearly costs of the measure by the yearly emission reduction of substance S.

$$C_s = (\alpha * C_s^{inv} + C_s^{O\&M})/R_s$$

with C_s = specific costs of reduction of substance S (ECU/tonne avoided)
C_s^{inv} = yearly investment costs (ECU/year)
$C_s^{O\&M}$ = yearly operation and maintenance costs (ECU/year)
α = annuity factor: $r/(1-(1+r)^{-n})$
r = discount rate (in %/year); the discount rates of the different sectors are given in Table 2.2.
n = depreciation period (in years)
R_s = yearly avoided emission of substance S (tonne-avoided/year)

For sake of comparison the specific emission reduction costs are expressed in specific nett costs of GWP (global warming potential) reduction E_{GWP}. In this way, the costs to reduce the various greenhouse gases can directly be compared.

$$E_{GWP} = E_s / \beta_s$$

with E_{GWP} = specific nett costs global warming potential reduction (ECU/tonne-avoided CO_2-equivalent.)
β_s = global warming potential of substance S.

Table 2.1. Assumed natural gas and electricity prices for the calculations.

	Production		Consumption	
	ECU/GJ	ECU/tonne	ECU/GJ	ECU/tonne
Natural gas	2.1	80	(small consumers) 10.1 (large consumers) 3.4	(small consumers) 380 (large consumers) 130
Electricity	15.0		(small consumers) 36 (large consumers) 17	

Table 2.2. Discount rate in the different sectors

Sector	**Discount rate**[1]
Centralised electricity sector	8%
Large Co-generation installations	12%
Other industrial investments	15%
Tertiary sector	15%
Household sector	18-25%[2]

[1] For sake of comparability equal discount rates are used in the projects on control options for CO_2-emission and HFCs, PFCs and SF_6-emissions.

[2] Depending on the level of income: discount rate increase when income decrease (for instance 18% for individual housing and 25% for collective housing in urban areas)

3. EMISSIONS OF BASE YEAR 1990

In this study emission data for base year 1990 are taken from the estimates submitted by Member States and published in *the Second Communication from the European Community under the UN Framework Convention on Climate Change* (Draft May 1998). These emission inventories are composed following the IPCC emission inventory guidelines [IPCC, 1996]. The *Second National Communication* provides emission figures data of 7 main sectors. In some cases a further breakdown of the emission inventory is required. This breakdown is made using the more detailed CORINAIR'90 emission inventory database, which provides emission data for 11 sectors and for over 250 subsectors [EEA, 1998]. The breakdown was composed using the proposed solution by the IPCC Guidelines for allocating emission of the CORNAIR emission inventory to the IPCC emission inventory [IPCC, 1996].
In the case the *Second National Communication* does not report emissions, emissions estimates are taken from the CORINAIR'90 database. Table 8.1 shows the 1990 national estimates of CH_4 and N_2O emissions by sector in the EU-15 Member States.

3.1 METHANE

3.1.1 Global Warming Potential

Methane has been recognised as an important greenhouse gas because of a high warming potential. The GWP over 100 year is 21 times CO_2 equivalent when calculated over 100-year period. [IPCC, 1996]. Methane is currently responsible for 17-19% of the total radiative forcing.

3.1.2 Sources of Methane

Methane is formed in the Earth's interior and at the Earth's surface. The first major type of formation is a thermogenic process in buried carbon. The second is a biological process performed by anaerobic bacteria at or near the Earth's surface, for instance in wetlands and the intestinal tracts of some animal types. Global methane concentration in 1990 was about 1680 ppbv, 140% greater than the pre-industrial concentration of 700 ppbv. Current (1994) global methane concentration growth rate is about 8 ppbv/year [IPCC, 1996].

The total estimated EU-15 emission of methane in 1990 is approximately 24 Mtonne CH_4. A breakdown to sectors is given in
Figure 3.1. Here we give a short discussion for the main emission sources of methane in the EU-15.

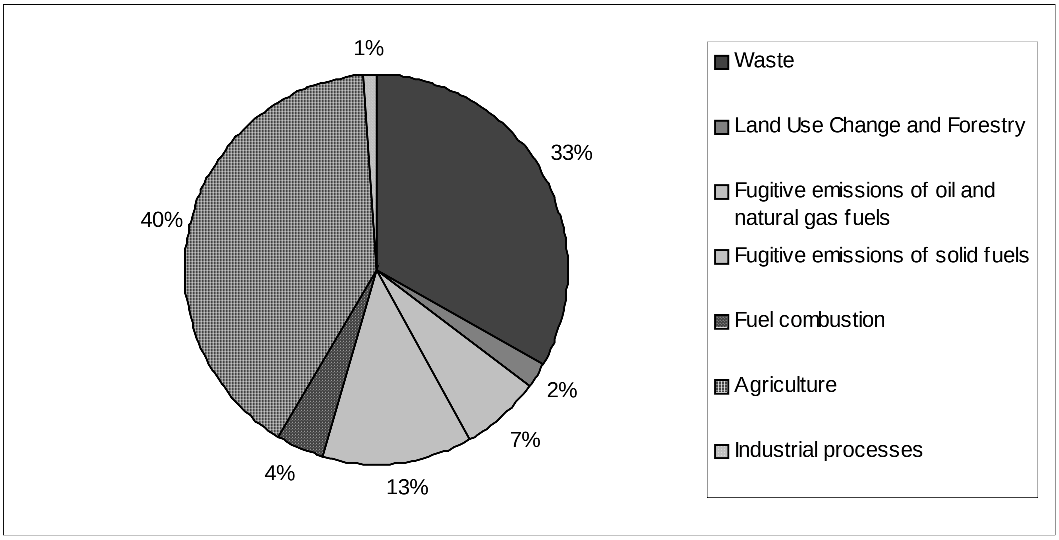

Figure 3.1: Breakdown of methane emissions for 1990 in EU-15. Total EU-15 methane emissions are estimated at 24 Mtonne CH4.

3.1.2.1 *Methane emissions from Waste*

With an emission of 7.9 Mtonne in 1990, waste contributes to approximately 34% of total estimated methane emissions. The main contributors are emissions from landfill (83%) and waste water treatment (9%).

The emissions from the landfills come from open and closed landfills that contain municipal or equivalent solid waste. The methane emissions from waste originate from degradable organic fractions of solid waste, which decompose by aerobic and anaerobic bacteria, the latter being responsible for methane formation.

3.1.2.2 *Methane emissions from Land use Change & Forestry*

With an emission of 0.6 Mtonne in 1990, land use change and forestry contribute to approximately 2% of total estimated methane emissions. The emissions are due to human activities in changing the way land is used (e.g. clearing of forest for agricultural use, including open burning of cleared biomass), or affecting the amount of biomass in existing biomass stocks.

3.1.2.3 *Methane emissions from Fugitive Emissions of Oil and Natural Gas Fuels*

With an emission of 1.6 Mtonne in 1990, fugitive emissions from oil and natural gas fuels contribute to approximately 7% of total estimated methane emissions. The main source of emissions is the distribution and transport of natural gas. Less important, in terms of emissions, is the production phase of natural gas and oil.

3.1.2.4 Methane emissions from Fugitive emissions of solid fuels

With an emission of 2.9 Mtonne in 1990, fugitive emissions from solid fuels contribute to approximately 13% of total estimated methane emissions. The main contribution is from the coal industry. Here, trapped methane in the coal bed and surrounding strata may be emitted into the atmosphere.

3.1.2.5 Methane emissions from Fuel combustion

With an emission of 0.9 Mtonne in 1990, fuel combustion contributes to approximately 4% of total estimated methane emissions. Methane is produced in small quantities from fuel combustion due to incomplete combustion of hydrocarbons in fuel. Small installations have typically much larger emission rates than large efficient combustion facilities.

3.1.2.6 Methane emissions from Agriculture

With an emission of 9.5 Mtonne in 1990, agriculture contributes to approximately 40% of total estimated methane emissions. The main contributors are the emissions from enteric fermentation (74%) and manure management (21%). Relatively small contributions come from fertilised agriculture.

Methane from enteric fermentation is produced as a by-product of the digestive process of herbivores, in particular ruminants. Methane from manure management is mainly produced from the decomposition of fractions under anaerobic conditions.

3.1.2.7 Methane emissions from Industrial processes

With an emission of 0.02 Mtonne in 1990, industrial processes contribute to less than 1% of total estimated methane emissions. Methane is released in small quantities from various processes, like aluminium production, ferro-alloy production, coke production, steel production and ammonia production.

3.2 NITROUS OXIDE

3.2.1 Global Warming Potential

Nitrous oxide has been recognised as an important greenhouse gas because of a high warming potential. The GWP is 310 times CO_2 equivalent when calculated over 100-year period. [IPCC, 1996]. Nitrous oxide is currently responsible for 4-6% of the total radiative forcing.

3.2.2 Sources of Nitrous oxide

Nitrous oxide is like CO_2 and CH_4 one of the natural components of the Earth's atmosphere. It is a greenhouse gas and it plays an important role in the chemistry of the stratosphere. As a result of human activities, its concentration has been increasing since the beginning of the century. Estimates from ice core measurements suggest that the pre-industrial atmospheric concentration of N_2O was about 275 ppbv. By 1994, this had increased by about 15% to a level of 312 ppbv. Current (1993) global nitrous oxide growth rate is about 0.8 ppbv/year [IPCC, 1996].

Nitrous oxide in the atmosphere is largely of biogenic origin. Bacteria in soils and oceans release N_2O during nitrification and denitrification processes. *Human activities* tend to enhance biogenic production of N_2O. Agriculture, land use change, deforestation and nitrogen fixing processes all stimulate bacterial production of N_2O. In addition, several anthropogenic abiogenic sources can be distinguished. This includes industrial process like adipic acid production, nitric acid production, and combustion processes. An emerging source of N_2O emissions is the three-way catalysts in cars.

The total estimated emission of N_2O in 1990 of the EU-15 is approximately 0.92 Mtonne N_2O. A breakdown to sectors is given in
Figure 3.2. Here we give a short discussion for the main emission sources of nitrous oxide in the EU-15.

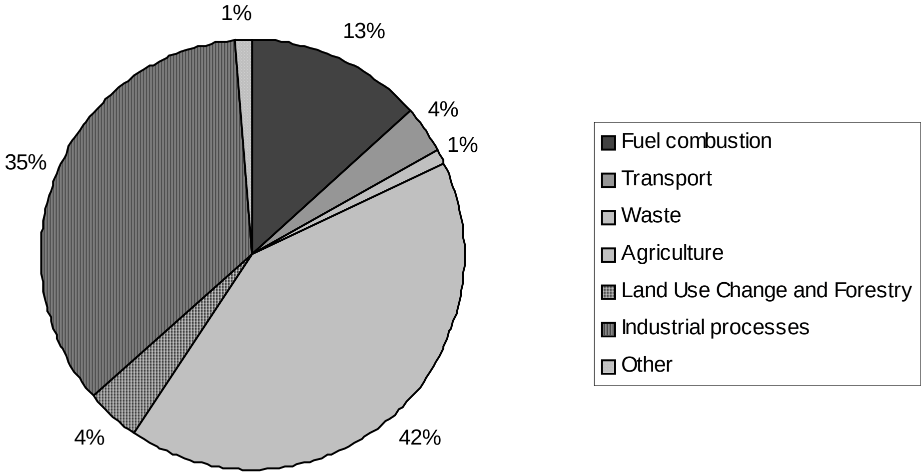

Figure 3.2. Breakdown of nitrous oxide emissions for 1990. Total EU-15 nitrous oxide emissions are estimated at 1.0 Mtonne N2O.

3.2.2.1 Nitrous oxide emissions from Fuel combustion

With an emission of 0.13 Mtonne in 1990, fuel combustion (transport excluded) contributes to approximately 13% of total estimated nitrous oxide emissions. The mechanisms that cause the formation of N_2O during the combustion process are fairly well understood. N_2O is formed almost exclusively in combustion processes at temperatures between the 800 and 1200 K, reaching its maximum at 1100 K.

3.2.2.2 Nitrous oxide emissions from Transport

With an emission of 0.04 Mtonne in 1990, transport contributes to approximately 4% of total estimated nitrous oxide emissions. These emissions are mainly related to the use of catalysts. Emissions from vehicles equipped with catalyst are considerably higher than vehicles without catalyst. Aged catalyst (e.g. after use of 15,000 km) may emit five times as much N_2O as new catalyst.

3.2.2.3 Nitrous oxide emissions from Waste

With an emission of 0.01 Mtonne in 1990, waste contributes to approximately 1% of total estimated nitrous oxide emissions. The main source within this category is emissions from waste water treatment, where emissions arise from denitrification units in waste water treatment plants. N_2O emissions from incineration of waste form a minor part of the emissions of this category.

3.2.2.4 Nitrous oxide emissions from Agriculture

With an emission of 0.42 Mtonne in 1990, fugitive emissions from agriculture contribute to approximately 42% of total estimated nitrous oxide emissions. Nitrous oxide is produced from agricultural soils mainly by the microbial processes of nitrification and denitrification. There is a strong relationship between mineral nitrogen levels in soil and emissions of N_2O, which applies whether the nitrogen originates from fertiliser or manure application, mineralisation in the soil or atmospheric deposition. A minor, but not insignificant part of the agricultural N_2O emission (7%) is from manure management. N_2O is formed during storage of manure.

3.2.2.5 Nitrous oxide emissions from Land use change and Forestry

With an emission of 0.04 Mtonne in 1990, land use change and forestry emissions contribute to approximately 4% of total estimated nitrous oxide emissions. The emissions are due to human activities in changing the way land is used (e.g. clearing of forest for agricultural use, including open burning of cleared biomass), or affecting the amount of biomass in existing biomass stocks.

3.2.2.6 Nitrous oxide emissions from Industrial processes

With an emission of 0.35 Mtonne in 1990, industrial processes contribute to approximately 35% of total estimated nitrous oxide emissions. More than 99% of the estimated non-combustial N_2O emissions from industrial processes originates from the production of adipic acid (73%) and nitric acid production (26%). Production of other chemicals is responsible for about 1% of the N_2O emissions.

3.2.2.7 Nitrous oxide emissions from Other sources

With an emission of 0.01 Mtonne in 1990, other sources contribute to approximately 1% of total estimated nitrous oxide emissions. The emissions are from solvent use, are related with oil and natural gas recovery and from not further identified sources.

4. EMISSION PROJECTIONS FOR THE YEAR 2010

4.1 INTRODUCTION

Projections for the base-line emissions in 2010 relative to 1990 were calculated using the emission estimates from the Pre-Kyoto scenario (energy related projections), analyses made by AEA (non-energy related agricultural projections), and analyses as described in *the Expert Group's work on EU Common and Co-ordinated Policies and Measures* [Phylipsen et al., 1997] (landfill emissions).

4.1.1 Energy related emission projections for 2010

On the basis of the Pre-Kyoto scenario the emissions for the energy-related methane and nitrous emissions were calculated for year 2010.

4.1.2 Non-energy related emission projections for 2010

4.1.2.1 Agriculture

For non-energy related agricultural base-line emissions for 2010, the BaU scenario as developed by AEA [Bates, 1997] was used. The background trends in crop areas and livestock numbers were based on projections developed by the European Commission (European Commission, 1997). The EC trends estimated up until 2005 were projected forwards until 2020, using a power trend-line which calculated the least squares fit through the points using the equation $y = cx^b$. The projections are qualified in Table 4.1.

Table 4.1. Estimated background trends (relative to 1994)

	2000	2010
Cereals (yield)	8.6%	22.4%
Other crop (yield)	10.7%	17.6%
Non-dairy cattle	-6.5%	0.1%
Dairy cattle	-10.0%	-27.2%
Poultry	15.0%	30.4%
Sheep	-3.9%	-2.0%
Pigs	5.4%	12.8%
Other livestock	5.5%	13.7%

Concerning the crop area related emissions, on top of these background trends, a number of assumptions were made about future agricultural practices [see for details: AEA, 1997]. The estimated change in agricultural N_2O base-line emission in 2010 compared to 1994 is a decrease in emissions of 2%. The relative change in emissions compared to 1990 was not estimated by AEA. Here we assume a decrease of 2% in 2010 compared to 1990.

Concerning the animal related methane emissions, the base-line projected emission development was kept proportional to the change in number of livestock in the case of animal related methane emissions.

4.1.2.2 Industrial processes

For non-energy industrial process related N_2O emissions (virtually all related to adipic acid and nitric acid production) the following assumptions were made.
Adipic acid production: the principal use of adipic acid is the production of the synthetic fibre nylon 6,6, which is mainly used in carpet production. As no estimates of future adipic acid production were available, estimates were based on projected trends in the synthetic fibres market. AEA assumes that the production of adipic acid regains by 2000 the level of 1990 and will grow 1% per year in the years from 2000 to 2010. The overall production of adipic acid in 2010 will therefore be 10.5% higher than in 1990.
Nitric acid production: The main use for nitric acid is in fertiliser manufacture. According to AEA [Bates, 1997], the projected growth in fertiliser consumption is very small. Therefore no growth of nitric acid production is projected.

4.1.2.3 Landfill

Table 4.2 shows the estimated projected change in methane emissions from landfills when existing policies are implemented. Projections provided by the Member States are in bold type, the remaining projections were calculated using the IPCC methodology, scaled for projected population.

Table 4.2. Projected change in methane emissions from landfills including existing policies. Projections provided by the Member States are in bold type. The remaining projections were calculated using the IPCC methodology, scaled for projected population [Meadows, 1997].

	Methane	
	1990	2010
AT	100%	76%
BE	100%	162%
DK	100%	85%
FI	100%	54%
FR	100%	**84%**
DE	100%	**17%**
GR	100%	70%
IE	100%	**103%**
IT	100%	52%
LU	100%	125%
NL	100%	**28%**
PT	100%	164%
ES	100%	125%
SE	100%	**76%**
GB	100%	**67%**
EU	100	*58%*

With existing measures, base-line projected methane emissions will decrease to around 5.3 Mtonne by 2010. This decrease is due to some Member States adopting measures to reduce the mass of degradable waste entering landfills and/or to collect and burn landfill methane from new landfills.

4.2 SUMMARY PROJECTED BASE LINE EMISSION 2010

Based on the assumptions described in this chapter, Table 4.3 gives the estimated percentage growth for the base line scenario of emission for methane and nitrous oxide for the year 2010 compared to 1990.

Emission figures in absolute numbers (expressed in ktonne methane and in ktonne nitrous oxide) can be found in *Appendix 1: Methane and nitrous oxide emission estimates*. Table 8.1 in the annex shows the emission of CH_4 and N_2O for base year 1990, the base line emissions for view year 2010 and the emissions in 2010 after implementing of the identified measures. Table 8.2 and Table 8.3 show Member States estimates and projection of methane and nitrous oxide emissions according to the Second National Communications. Difference in projections for the year 2010 between the base line estimates and the Member States estimated may be caused by extra intervention for reducing emissions in the Member States' projections compared to the policies assumed in the base line projections.

Table 4.3. Emission growth projections for 2010 base-line scenario

1. Prod/Distr. fossil fuels
1a Solid fuels
1b liquid fuels
1c gaseous fuels
2. Power Generation
3. Other energy industries
4. Industry (energy related)
5. Nitric acid production
6. Adipic acid production
7. Transport
8. Tertiary/Domestic
9. Landfill
10. Agriculture

	CH4											
	1a	1b	1c	2	3	4	5	6	7	8	9	10
AT	47%	67%	136%	190%	353%	97%	NA	NA	116%	96%	76%	93%
BE	0%	100%	100%	270%	336%	105%	NA	NA	143%	80%	162%	78%
DK	100%	59%	215%	417%	407%	77%	NA	NA	130%	93%	85%	90%
FI	100%	100%	100%	150%	1133%	33%	NA	NA	109%	99%	54%	93%
FR	3%	3%	166%	54%	405%	97%	NA	NA	125%	103%	84%	90%
DE	21%	9%	155%	118%	550%	65%	NA	NA	116%	46%	17%	90%
GR	110%	0%	359%	180%	140%	148%	NA	NA	189%	101%	70%	93%
IE	0%	100%	100%	100%	100%	18%	NA	NA	130%	75%	103%	93%
IT	5%	95%	96%	196%	335%	123%	NA	NA	166%	115%	52%	94%
LU	100%	100%	100%	100%	100%	31%	NA	NA	140%	66%	125%	87%
NL	100%	72%	153%	291%	231%	85%	NA	NA	143%	155%	28%	87%
PT	0%	100%	100%	83%	148%	110%	NA	NA	210%	101%	164%	94%
ES	55%	125%	441%	141%	314%	85%	NA	NA	169%	98%	125%	99%
SE	100%	100%	100%	300%	443%	141%	NA	NA	113%	98%	76%	89%
GB	23%	113%	111%	159%	332%	97%	NA	NA	133%	48%	67%	94%
EU	28%	97%	138%	74%	282%	92%	NA	NA	135%	84%	58%	91%

	N2O											
	1a	1b	1c	2	3	4	5	6	7	8	9	10
AT	NA	NA	NA	139%	100%	89%	100%	111%	460%	100%	NA	96%
BE	NA	NA	NA	121%	124%	128%	100%	111%	451%	118%	NA	94%
DK	NA	NA	NA	163%	257%	83%	100%	111%	400%	97%	NA	100%
FI	NA	NA	NA	132%	100%	13%	100%	111%	429%	100%	NA	99%
FR	NA	NA	NA	87%	194%	105%	100%	111%	442%	107%	NA	99%
DE	NA	NA	NA	86%	198%	78%	100%	111%	545%	103%	NA	98%
GR	NA	NA	NA	126%	120%	121%	100%	111%	790%	113%	NA	102%
IE	NA	NA	NA	140%	100%	100%	100%	111%	521%	100%	NA	87%
IT	NA	NA	NA	113%	111%	100%	100%	111%	462%	89%	NA	100%
LU	NA	NA	NA	100%	100%	20%	100%	111%	518%	100%	NA	100%
NL	NA	NA	NA	54%	244%	82%	100%	111%	492%	156%	NA	95%
PT	NA	NA	NA	106%	120%	88%	100%	111%	675%	121%	NA	105%
ES	NA	NA	NA	129%	102%	130%	100%	111%	525%	128%	NA	100%
SE	NA	NA	NA	379%	154%	142%	100%	111%	594%	94%	NA	99%
GB	NA	NA	NA	54%	256%	89%	100%	111%	593%	77%	NA	95%
EU	NA	NA	NA	108%	136%	101%	100%	111%	517%	103%	NA	98%

5. EMISSION REDUCTION MEASURES

In this section methane and nitrous oxide emission reduction measures are described for the main emission sources in EU-15. A summary of the collected data for methane emission reduction measure can be found in Table 5.6 and for nitrous oxide emission reduction measures in Table 5.7.

5.1 METHANE EMISSION REDUCTION MEASURES

5.1.1 Coal Mining Industry

In the coal industry, methane trapped in the coal bed and surrounding strata can be emitted into the atmosphere by:

- emissions of ventilation air from mines into the atmosphere; for underground mines, ventilation air generally contains up to 1% of methane;
- post mining activities, such as breaking, crushing, and drying.

Emissions from the second mentioned source may form a small, but not negligible part of the total emissions. In general, specific emissions from underground mining are assumed to be one order of magnitude higher than those of surface mining [Smith and Sloss, 1992]. The Corinair'90 database give for the EU-15 for both open cast mining as well as underground mining an emission of about 1.5 Mtonne of methane.

1A. Utilisation of recovered methane

In general, if the gas content of the minable coal seam is less than 6 m^3/t, recovery of the methane is impractical. Deeper seams (more than 300 meters) of high rank coal hold the most promise for coalbed methane recovery. Shallow deposits of any rank coal, due to low gas content, offer little or no potential for commercially viable coalbed methane recovery projects.

Methane emissions from underground coal mines can be reduced before, during, and after mining: or by a combination of all three. The information on this subject is derived from EPA [1992]. Lama [1991] gives similar results.

Before mining, emissions can be mitigated by pre-mining degasification. Boreholes are drilled into the coal bed (from the surface or elsewhere in the mine) from half a year to several years before the coal is mined. Through these wells a proportion of up to 70% of the methane can be extracted and utilised in the form of high quality fuel gas (> 32 MJ/m^3).

During mining, the ventilation air can be used as combustion air. A constraint for using this option is the local applicability of combustion air. This depends on the methane content of the extracted air, type of fuel, and type of combustion equipment. The emission can be reduced by this method up to 90%.

After mining, emissions can be reduced by recovering methane from areas of fractured coal and rock that is created after the coal is mined out. The quality of the fuel gas is lower (10 - 20 MJ/m^3), but its applicability is still quite good.
A combination of the three options, indicated as *integrated recovery* can give an emission reduction of 80 - 90%.
Under ideal conditions, as much as 60 to 70% of the methane emissions at a specific mine can be recovered and utilised. Under less favourable conditions, recovery efficiency may drop to 30 to 40%. Shallow underground mines and surface mines offer little potential for coalbed methane recovery [Thakur, 1995]. At present there are no emission reduction measures known or available for the methane emission from open cast mining and post mining activities.
The main coal producers in the EU-15 are Germany and the UK. The 1993 Germany produced 64 Mtonne of black coal and 222 Mtonne of braun coal. The UK produced 68 Mtonne of black coal. The technical overall coalbed methane recovery potential for Germany and the UK is estimated at 35-45% [Thakur, 1995].

Costs: Wide experience has been gained within various countries with both pre- and post-mining degasification. The required technologies are commercially available. The application of mine ventilation air was yet not practised at 1990. From cost data in [EPA, 1992] it can be seen that the investment costs of recovering methane by pre- and post-mining degasification may range from 600 to 3000 ECU/(tonne CH_4/year). This is substantially more if the gas has to be upgraded and fed to an existing nearby natural gas pipeline. [OECD, 1994] estimated for such a facility 10,000 ECU/(tonne CH_4/year), including well-head compressors, the main compressors, gas collection piping, enrichment facilities and a typical 15 km pipeline to the main transmission pipeline. Depending on the location and the use of the recovered gas, the investment costs varies from 600 to 10,000 ECU/(tonne CH_4/year).
Here we assume an average investment of 5,000 ECU/(tonne CH_4/year). O&M costs are estimated at 5% of the investment cost. Assumed is a lifetime of the installation of 15 years. Cost savings may be obtained from the savings of the methane for combustion or to sell it. Assumed is the avoided production cost of 80 ECU/tonne CH_4 (2.1 ECU/GJ). It should be noted that, especially the use of the *integrated recovery* technique could give additional cost savings due to the reduction of mine ventilation costs.

5.1.2 Oil and Natural Gas Industry

The main sources of methane within the oil and natural gas industry are the distribution grids. Emissions during winning contribute relatively little (approx. 10%, mainly offshore) to the total oil and natural gas related emissions, although this may vary from country to country.

In the oil and natural gas industry various processes can be identified which cause emissions of methane, like unused associated gas, process vents and flares, maintenance, energy requirements, compressors and fugitives emissions. The main process sources of methane emissions are the fugitive emissions from process equipment, transportation lines and from the distribution grid, and the compressors.

In this section we describe the measures applicable for the offshore oil and gas recovery and for the distribution of natural gas.

5.1.2.1 Emission Reduction Measures Oil and Gas Industry: offshore

In offshore situations the natural gas is received on the platforms at a pressure of 100 - 200 bar typically. During the measuring and treatment process on the platform methane is emitted on a number of places.

- Desorption of methane from this condensate stream measurement system is the main source of methane on many platforms.
- Methane is dissolved in the water recovered from the condensate stream. This will be emitted after pressure reduction.
- Methane will be absorbed by the glycol that is used for drying the mainstream of natural gas. In the stripper this methane will be desorbed. The same is valid for the amine in H_2S and CO_2 removal unit. However, CO_2 removal is not common at North Sea platforms.
- Also the purge streams in venting systems form an important source of methane on part of the platforms. These streams have to have a minimum rate in order to avoid the inflow of air and the formation of an inflammable mixture in the piping system.
- Incidental sources, like blow-down of equipment during shutdowns, leakages and well testing are estimated to play a less important role.

The following measures can be taken to reduce methane emissions.

2A/2B. Increased utilisation of natural gas at offshore platforms

The most attractive option to reduce venting at offshore platforms is to increase the utilisation of natural gas.

- Increasing the pressure to which the condensate is expanded during the condensate measurement procedure will reduce desorption of methane from the condensate stream. This measure requires replacement of part of the existing measuring equipment; depending on the exact configuration of the gas treatment equipment on the platform high-pressure vessels should be installed. In general not only the methane emission reduction, but also the costs will increase with increasing pressure. A possible problem is that the way of measuring is fixed by contract.
- Another option is to use the gas presently vented for power generation at the platforms. A potential problem is the varying composition of the gas streams that can possibly lead to engine trips. However, this option is cheap and on

some platforms already available. However, the applicability may be limited by the energy demand on the platform and the quality of the gas streams.

- A third option is to decrease the absorption of methane by absorption liquids and hence the amount of methane that will desorb and is vented at present. A cheap way to decrease the absorption of methane is to decrease the circulation rate of the absorber liquids to a more critical level (at present often a higher circulation rate than necessary is applied).
  Another, more expensive, way is to move to absorbers with lower methane absorption (compared to the absorptivity of the agent to be removed).
- A last possibility is the compression of the methane gas that is recovered from the condensate expansion and feeding it back to the mainstream. Probably this is the most expensive option.

The costs of the measures depend highly on the local situation on the platforms, so they may strongly differ from platform to platform. In many cases space and weight constraints will determine the applicability of various options. The *specific* investments also depend on the throughput of the platforms: on platforms with larger throughputs the costs per tonne of methane avoided will in general be smaller. Furthermore, investments will be smaller for new platforms than for existing platforms. Anyway, the figures presented here are not valid for individual platforms, but for all platforms together.

Costs: On the basis of information provided in a number of interviews we make the following first estimate of the potentials and costs:
A first reduction step of about 25% will in general be rather cheap (improved process control and small system adaptations), requiring e.g. 0.12 MECU of investment per platform (ranging from zero to 0.25 MECU). For an average platform, having a methane emission of 800 tons per year, this means an investment of 600 ECU per tonne of methane reduction per year.
Increasing the recovery to 75% will generally require higher investments, for example 0.5 MECU per platform (ranging from 0.25 to 1.0 MECU (1200 ECU/(tonne CH_4/year)). As the equipment mainly replaces existing equipment the annual operation and maintenance costs are taken to be zero and 1% of the investment, respectively. Annual cost savings are calculated using a natural gas production price of 80 ECU/tonne.
Taking into account that many platforms only have a limited time to go before production will be stopped, the average lifetime is taken to be 15 years.

2C. Replace venting by flaring

Remaining natural gas emissions from offshore platforms can be reduced to a large extent by replacing the vents by flares. In Norway flaring is already obligatory [NOIA, 1991].
There are some problems associated with flaring. First, the flare causes a potential hazard as it can ignite uncontrolled natural gas emissions from the platform. Second, in case of excessive blow-off, the flare will cause a strong radiation level at the platform. Locating the flares at a sufficient distance from the platform can reduce both problems. Furthermore, an open flare will attract birds. Finally, a

flare may require a higher purge stream in the network, which may limit the net reduction of greenhouse gases.
Sometimes a solution can be found in using closed flaring systems, which can be shut off in the case of an accidental gas emission from other sources. We assume that flaring can reduce 50% of the emissions after the previous measures have been taken.

Costs: The estimated investment required for such a system is 0.25 - 0.5 MECU (3600 ECU/(tonne CH_4/year)). The annual operation and maintenance costs are taken as 3% of the investment. The average life-time is estimated at 15 years.

2D. Reduction at compressors
Gas compression is an integral part of natural gas transmissions system, about every 100-150 km a compressor is required. Compressor stations give rise to methane emissions for several reasons:

- *Seal losses*

The compressor axis has to resolve in the compressor casting. The connection between both parts can not be made gas-tight. Older compressors are sealed with oil-seals. More modern compressors are equipped with gas-seals. Seal losses of a compressor are defined by the manufacturer, and are about 1.5-5 m^3/h for gas-seals, which boils down to about 1 to 2.5 Mg of methane per compressor per year. Oil seals may be 5-10 times as high. Seal losses may be disposed off in a controlled way through an atmospheric vent or flare system, but in many cases they are vented separately from the rest of the emissions of the site.

- *Passing-valves emissions*

Open-end valves, block-valves and pressure safety valves may contribute significantly to the emissions of a compressor station, especially when the valves are poorly controlled and maintained.

- *Start-up / shut down*

During start up and shut down methane emissions may occur as well. At shut down the equipment is flushed with air, at start up with natural gas. Normally this gas is vented, resulting in emissions of methane. A compressor is typically start up and shut down 12 to 24 times per year; the amount of methane released depends upon the type of compressor, and might be as high as 650 kg per compressor per start-up.

Several measures, ranging from maintenance improvement to compressor efficiency improvement may be taken. This option is a set of measures, which may reduce emissions as high as 90%. For Europe a reduction of 60% is estimated. The measures considered are:
Leak reduction: by using low-bleed devices, emission reduction of over 50% seem realistic.

Reducing flushing of engines at start up and shut down: Emission may be reduced by diminishing flushing procedures during start up and shut down.
Increased efficiency of compressors. An efficiency improvement of 10%-points will reduce the energy consumption and at the same time reducing methane and carbon dioxide emissions (by 0.2 and 2.9 g/m^3 of natural gas throughput, respectively)
Flaring of seal losses. Feeding the seal-gases to a low-pressure flare system.
Reducing passing valve emissions. Leaking open-end valves contribute significantly to emissions from compressor stations. Control and repair or replacement of old valves reduces these emissions.

Costs:
The investment for these set of measures amount to 120 ECU/(tonne CH_4/year). O&M costs amount to 19 ECU/(tonne CH_4). The average lifetime is estimated at 20 years. The cost savings obtained by less losses, and higher efficiencies of machineries, amount to 140 ECU/(tonne CH_4). Most of the measures may be cost-effective. This counts certainly for the maintenance programmes.

5.1.2.2 *Emission Reduction Measures Oil and Natural Gas Industry: natural gas distribution*

The larger part of the emissions from oil and natural gas industry is caused by leaks from the grey cast-iron network that was originally designed for coal-derived town gas. The other emissions are from leaks in the other networks (steel, plastic, etc.) Most emissions are coming from small leaks: large leaks, e.g. due to accidents, in general are repaired in a short-term and therefore only contribute marginally to the emissions.

2E. Replacement of the grey cast-iron network
Replacement of the grey cast-iron network by a modern pipeline system (e.g. polyethylene) will reduce the emissions through leaks, that presently are at a level of about 5 tonne/km/year, with 97%.

Costs: The cost of replacing pipelines vary considerably, ranging from 50 - 250 ECU/m depending on the local situation and the pipe diameter. As most of the grey cast-iron network is in old cities we will stay on the high end of the cost range: 200 ECU/m (40,000 ECU/(tonne CH_4/year)). Cost savings are savings on the reduction of methane losses (production price natural gas of 80 ECU/tonne). Only replacing the most vulnerable parts of the network can reduce the specific costs.

2F. Increasing the pipeline examination frequency

At present gas distribution pipelines in general are examined on average every four years (Dutch situation). It seems a reasonable estimate that the present total emission of 0.14 tonne/km/year will be cut by 50% if the control frequency is doubled, although this was not found in practice.

Costs: Surface leak inspection requires one person to inspect 400 km per year. Assuming annual cost of 50,000 ECU per person-year (including measuring equipment and consumables) it can be estimated that inspection costs are 120 ECU per km annually (assuming inspection once in four years). Doubling the examining frequency will lead to double these costs. These costs are accounted for as operation and maintenance cost (1700 ECU/tonne CH_4). Cost savings are savings on the reduction of methane losses (production price natural gas of 80 ECU/tonne).

5.1.3 Emission Reduction Measures at Waste Treatment and Disposal

5.1.3.1 Emission Reduction Measures Waste Treatment and Disposal: Landfill

In landfills aerobic and anaerobic bacteria decompose the degradable organic fraction of solid waste. In the anaerobic phase, the main product of this decomposition, apart from water, is landfill gas, which is composed mainly of methane (56 to 65%) and carbon dioxide (31 to 41%). The composition of landfill gas varies with time. The methane production increases after about two months and generally reaches its maximum within two years. By then an equilibrium is achieved and landfill gas composition varies little. In the next 20 years most of the methane is produced and emissions tend to decrease. The degradable organic material is more and more depleted and aerobic conditions occur, thus prohibiting methanogenesis [EPA, 1992; IPCC, 1990; Van Amstel, 1993]. The generation and emission of methane by landfills is determined by several site-specific factors, of which the most important are: the depth of waste, site management, age of fill and the presence and operation of gas collection systems. Determing physical factors are: fraction of degradable organic material, moisture content, temperature, oxygen content, presence of biological inhibiting/promoting compound, and pH. The geometry of many shallow sites do not encourage conditions which are conductive to methane-rich gas formation, and the wide variability in climatic conditions in Europe means that landfilled waste degradation behaviour and rates are very variable.

The reduction of emissions of landfills can be done either by stimulation of methanogenesis combined with the use of the produced methane for energy production, or by preventing methanogenesis.
The following options can be distinguished:
1. collecting and burning landfill gas;

2. optimising biological methane oxidation in the cover soils of landfills
3. reducing the mass of degradable organic waste landfilled.

The first measure is a short-term option; the second and the third measure are long-term options. Reducing landfill appears the most effective single option for reducing landfill methane emissions. This option, however, needs major changes to waste management practice in many Member States. Waste reduction should also be considered as part of an integrated waste management strategy that might have environmental benefits in addition to methane reduction.
Collecting landfill gas and optimising oxidation of methane appear the most practical and easily adopted measure.

Table 5.1 gives an overview of the production of waste and its fate [Statistical Compendium Eurostat, 1995].

Table 5.1. Production of waste (in ktonne) and its fate in the EU-15.

	Total (kt)	% incineration	% landfill	% recycling
AT	2506	12%	68%	16%
BE	3082	23%	50%	0%
DK	2430	54%	30%	7%
FI	3100	2%	77%	19%
FR	20320	37%	47%	4%
DE	27958	17%	77%	0%
GR	3000	0%	100%	0%
IE	1100	0%	100%	0%
IT	20033	6%	90%	0%
LU	170	69%	30%	0%
NL	7430	34%	43%	4%
PT	2538	0%	32%	0%
ES	12546	5%	75%	0%
SE	3200	41%	44%	13%
GB	20000	13%	70%	0%
EU	129413	18%	68%	2%

Several strategies can be followed to reduce methane emissions to the atmosphere by landfills. These strategies can be subdivided in: *(i)* strategies stimulating methane production, combined with isolation and use of the generated gas (methane recovery), *(ii)* strategies inhibiting methane production (aerobic landfill management and/or reduced landfilling), (*iii*) strategies reducing methane formation by reducing disposal of degradable organic waste.

(*i*) Methane recovery

When (part of) the landfill is capped by an impermeable layer, gas-emissions can be prevented. The generated waste gas, however, has to be removed to protect the capping for rupture. The waste gas is collected in recovery wells inside the landfill and withdrawn by a pump unit. Recovery efficiencies of up to 100% are possible, with methane concentrations varying from 30 to 70%. The overall recovery of the methane will be less, because generated methane during the phase the landfill site is built-up is generally not recovered. Depending on the construction of such a site, 30-70% of the methane is recovered. In our calculations we assume 50%.

The recovered waste gas can either be used for energy-production (measure 3A to 3C) or burned in a flare (measure 3D):

3A) Electricity generation
3B) Heat generation
3A/B) Co-generation: Combined generation of electricity and heat
3C) Upgrading of landfill gas to natural gas quality
3D) Flaring

The gas could also be used as chemical feedstock. This option is not further explored.

The technology for landfill gas collection and combustion, either for energy recovery or in flares, is well understood and demonstrated in many Member States. An additional advantage (not accounted for) is the increased methane oxidation of the left gas, because there is a lower gas flux into the cover soil.

The gas recovery system consists of vertical wells made of perforated or slotted plastic (e.g. HDPE) pipes and filled with gravel or other permeable materials. The wells are sealed with concrete or other impermeable materials as bentonite or clay and connected to a collection system. Other components are siphons.

By means of a compressor or fan a negative pressure is maintained in the collection system. The gas is withdrawn from the landfill and delivered, after cleaning, to the one above mentioned utilisation systems.

Note: The distinct measures all need an impermeable layer of soil or other material in order to prevent emissions of landfill gas and infiltration of water and oxygen. The layer also prohibits the emission of odorous gases and prevents the spread of substances in the neighbouring soils. Such layers are in some Member States obligatory for soil-protection. The costs of such layers is not taken into account in the cost estimates of the hereunder described measures.

3A. Methane recovery: Electricity Generation

Engines are powered by the recovered gas to produce electricity. Three types of engines have been used in Europe with success: spark ignition; dual fuel and gas turbines. Gas compressors are required for the latter two options. If the gas is not being used, the gas can be flared.

Costs: Investment costs are highly dependent on site specific parameters and associated system capacities. Furthermore, it depends on whether or not a cover sheet is already used for soil protection reasons. If there is no obligation to cover the waste for soil protection, the costs of the cover sheet should be allocated to the methane recovery costs.
As revenues can be obtained by selling the produced electricity, yearly costs can be lowered and in some cases a net benefit ('negative costs') is attainable. De Jager and Blok [1993] calculated the costs without cover sheet for two different system sizes, with a recovery rate of: 500 m^3/h and 800 m^3/h, respectively.
The average investment for these systems amounts to 2000 ECU/(m^3/h) recovered gas (excluding cover sheet) or 300 ECU/(m^3/h) recovered gas (with cover sheet). The O&M: is estimated at 100 ECU/(m^3/h). The cost savings of the produced electricity amount to 425 ECU/(m^3/h), using a pay-back tariff of 13.5 ECU/GJ.

3B. Methane recovery: Heat Generation

This option can be used in the case where a customer is located near to the site. The gas burners, for example in industrial boilers and brick kilns, need to be adapted for the lower energy content of the landfill gas compared to natural gas. The applicability of this measure is limited because a consumer for landfill gas is hardly ever located near the landfill location.

3C. Methane recovery: Upgrading of landfill to natural gas quality

For a situation where the natural gas network is widespread, for instance like in the Netherlands, upgrading of the gas may be attractive.. To achieve a high quality gas the following substances have to be removed: apart from water, also sulphur (e.g. apparent as H_2S), halogenic and higher hydrocarbons (HCs) and carbon dioxide for gas enrichment. This requires special devices, among with a compressor to accomplish the right processing pressure. Final gas pressure has to be higher than the 3 bar pressure in the distribution network. Gas quality (Wobbe-index, gas composition) and pressure are measured before delivery to the distribution network. Gas is flared if delivery restrictions can not be met.

Costs: In contrast with the case of gas utilisation for electricity generation, no general cost figures are available for upgrading of waste gas to natural gas quality as site-specific factors are dominating the height of the costs. De Jager and Blok estimated the investment costs for small scale upgrading systems (approx. 250 m^3/h; without cover sheet) at 2500 ECU/(m^3/h). With cover sheet the investment costs amount to 3500 ECU/(m^3/h), O&M at 375 ECU/(m^3/h). The cost savings for the recovery of natural gas is assumed to be 80 ECU/tonne.

3D. Methane recovery: Flaring

Flaring is the combustion of recovered landfill gas without utilisation of the energy released during combustion. If a landfill is covered with an impermeable layer, waste gas might build up underneath this capping and damages can occur. In such cases flaring is the simplest way of gas removal. Several flaring systems are available: e.g. open or enclosed flame combustors. In the open burner, gas is

burned in a flame burner with no method of control. Therefore, the efficiency is probably not as high as in the enclosed burner where landfill gas and air flows can be controlled and optimal combustion conditions can be reached.
Both systems contain a pump unit, an ignition unit, gas flow regulation and are able to burn over 98% of all hydrocarbons in the waste gas.

Costs: Enclosed flame combustors are more expensive than open flame combustors; investment costs are further determined by gas recovery capacities. In general investment costs vary from 12,000 to 60,000 ECU for a gas recovery capacity of 200 m^3/hr. Including an elementary piping grid we will assume investment costs of 500 ECU/(m^3/y) and a lifetime of 20 years.

(ii) Aerobic landfill management

In an aerobic landfill the ratio of CH_4 to CO_2 production is shifted towards CO_2 production, as a consequence of the improved oxidation in the landfill. Methanogenic bacteria are impeded to function and as a consequence aerobic bacteria are able to convert organic wastes into carbon dioxide and water. Instead of being fermented, the waste is composted.
In order to sustain aerobic conditions in a landfill, a specific design is necessary. The following techniques are available:
Semi-aerobic landfilling: landfilling air can diffuse through the landfill as it is supplied through the leachate collection pipes located at the bottom of the landfill. Compared to anaerobic landfills a methane production reduction of 53% can be achieved. These systems are widely used in Japan and East Asia.
Re-circulatory semi-aerobic landfilling: This system is an improved version of the former one. The rate of decomposition and purification of leachate is enhanced, by recirculating the leachate to the landfill. Compared to anaerobic landfills a methane production reduction of 78% can be achieved. This system is currently developed and not yet available, but is expected to be commercially available around 1995
Aerobic landfilling: Air is forced into the landfill by means of an air blower. Compared to anaerobic landfills a methane production reduction of 87% can be achieved.

Costs: An aerobic landfill management requires special measurements such as leachate collection pipes and air-feed pipes at the bottom of the landfill. This measure is therefore hard to apply to existing landfill sites lacking them. No costs could be obtained for new landfill site.

(iii) Reduced landfilling of organic waste

Methane is an end-product of waste degradation in landfills. Reducing the mass of degradable waste landfilled will reduce methane emissions. There are many waste management practices to reduce the amount of waste disposed or to reduce the degradable portion of the waste disposed of. The EU waste hierarchy prioritises these option.

The reduction of disposed waste can be reached either by separate collection and processing of organic waste fractions; by separation of these fractions at the waste handling facilities followed by separate processing or by incineration of the waste without separation of the organic fraction.
The processing of the organic waste can be composting or fermentation under anaerobic conditions.

3E. Composting

In composting facilities organic waste is converted under aerobic circumstances into carbon dioxide, water and mainly compost, which can be applied as fertiliser. To achieve an aerobic environment, enough oxygen should be supplied to the waste. In extensive systems the waste is just regularly turned; in intensive systems forced ventilation is applied. Because of uncontrolled emissions of odorous gases and leachate the use of extensive systems is not believed to be an environmental sound alternative. Per tonne of organic waste about 0.48 tonne of compost is produced. De Jager and Blok [1993] assume the production of 45 kg methane per tonne of unprocessed organic waste. The emissions of methane during composting are considered to be negligibly low. Extra fossil carbon dioxide emissions of composting organic wastes are related to the energy-use of the facility (30 kWh_e for which approximate 20 kg CO_2 per tonne of processed organic waste is emitted.

Costs: The costs are composed of the investment costs for the composing facility (4500 ECU/(tonne CH_4/year)), and operation costs mainly due to the salaries of personnel and maintenance costs (1000 ECU/(tonne CH_4/year)) [De Jager and Blok, 1993]. Cost savings come from the selling of compost (here neglected) and the avoided costs for landfilling of the organic fraction (500 ECU/(tonne CH_4)).

3F. Fermentation under anaerobic conditions

In fermentation facilities organic waste is converted under anaerobic circumstances into biogas, water and compost. In fact the same processes are active as in a landfill layer; all be it in a more intensified and controlled manner. The biogas consists mainly of methane (about 55%(vol.)) and carbon dioxide (about 45%(vol.)). As oxygen inhibits methane production, fermentation of organic wastes will be applied in closed reactor vessels.
The biogas produced by a fermentation facility can be used for the production of heat and electricity, which is used for maintaining the total fermentation process. A possible surplus of energy, in the form of (*i*) purified biogas or (*ii*) electricity, can be delivered to the gas or electricity net and refunds can be obtained. By using biogas as an energy source, emissions of CO_2 can be avoided.
As with composting organic waste per tonne of organic waste about 0.48 tonne of compost is produced after fermentation. De Jager and Blok [1993] assume the production of 45 kg methane per tonne of unprocessed organic waste. The emissions of methane during fermentation are considered to be negligibly low.

Costs: The costs are composed of the investment costs for the composing facility (5000 ECU/(tonne CH_4/year)), and operation costs mainly due to the salaries of personnel and maintenance costs (1500 ECU/(tonne CH_4/year)) [De Jager and Blok, 1993]. Cost savings come from the selling of compost (here neglected) and the avoided costs for landfilling of the organic fraction (500 ECU/(tonne CH_4)). Extra income due to the generated biogas used for energy supply are estimated at 100 ECU/(tonne CH_4).

3G. Waste Incineration

In waste incineration plants municipal solid waste is burned and the energy released is being used for heat and/or electricity production.

We estimated the contribution of waste incineration to electricity and heat production, and calculated the CO_2 emissions avoided by the incineration and energy production of the renewable fraction of the waste stream. It should be noticed that CO_2 emissions released during incineration of substances containing fossil carbon (in the form of plastics) are not taken into account.

Costs: The costs are composed of the investment costs for the incinerator (50,000 ECU/(tonne CH_4/year)), and operation costs mainly due to the salaries of personnel and maintenance costs (10,000 ECU/(tonne CH_4/year)) [De Jager and Blok, 1993]. Cost savings come from the selling of compost (here neglected) and the avoided costs for landfilling of the organic fraction (2000 ECU/(tonne CH_4)).

5.1.4 Emission Reduction Measures at Agriculture

5.1.4.1 Emission Reduction Measures by reducing enteric fermentation

Methanogenesis in the rumen

In ruminants (cattle, sheep and goats) methane is produced in the rumen as part of the digestion process. Micro-organisms decompose the animal feed (mainly consisting of cellulosic carbohydrates) into products that can be digested and used by the animal, mainly volatile fatty acids (VFAs, as acetic acid, propionic acid and butyric acid). The population of these micro-organisms is highly influenced by the composition of the animal diet. Part of the products of these fermentative bacteria are hydrogen, formate and carbon dioxide that are believed to be consumed by methane producing bacteria. Between 4% to 10% of the energy present in the feed is lost by methanogenesis and is not available for digestion. The methane is emitted by the animal through eructation and exhalation.

Methane emissions by animals are dependent on animal type, animal age, function (e.g. beef or milk cattle) and production level; and on the type, amount, and digestibility of the animal feed.

Emission reduction strategies

In principle methane emissions by animals and more specific by ruminants can be reduced in several ways:

- Reduction of livestock
- Increase of feed conversion efficiency by adjusting animal diets
- Increase of animal production by adding chemical compounds
- Other options as methane removal in stables

These options are described in further detail in the following sections. In these sections specific measures will be defined.

4A. Livestock Reduction

An effective measure in reducing animal methane emissions is a reduction in animal numbers. As cattle causes the greatest emissions, volume reductions are especially effective for this animal type. Table 5.2 presents the yearly average methane emission per type of animal.

Table 5.2. Yearly methane production per animal (kg CH_4/year) [Crutzen *et al*, 1986; Stolwijk *et al*, 1992].

Diary Cows	Heifers	Steers	Young Cattle	Horses	Sheep	Goats	Pigs
94	65	65	51	18	8	5	1.5

In this study, livestock reduction as a measure on its own is not taken into account. A determination of the cost-effectiveness of this measure is hard to make. Livestock reduction is normally taken into account as a part of the measures which improve feed digestion. Very often, the productivity per animal increases. To obtain a constant level of production less animals are required.

Improved feed conversion efficiency

A ruminant can lose a significant part of the gross feed energy intake to the production of methane, producing 0.02-0.03 kg of methane per kg dry matter intake. By decreasing this loss, dietary energy is made available for growth and lactation. As a result, livestock producers will benefit economically from higher calving rates, better calf growth, faster heifer maturation, higher milk rates, and healthier animals.

Some measures can be taken to improve animal efficiency by decreasing energy losses through methanogenesis. For ruminants, one of the valuable properties of methanogenic bacteria is the removal of hydrogen, formed by other fermentative bacteria. When methanogenic bacteria are inhibited, this function should be taken over by other agents in the rumen ecosystem.

Methanogenic bacteria are inhibited by ammonia and by the volatile fatty acid (VFA) propionate. By sustaining a sufficient level of ammonia, which improves digestibility, and shifting the rumen VFA-composition towards more propionate and less acetate, methane production can be reduced and animal feed efficiency (and production) can be improved.

By the US/Japan Working Group on Methane [1992] several measures are described based on nutrition improvement through mechanical or chemical feed processing or through strategic supplementation. To the first category complies: alkali/ammonia treatment of low digestibility straws, chopping of low digestibility straws and treating/wrapping of rice straw. Strategic supplementation can be done with molasses/urea multinutrient blocks (MUB), molasses/urea blocks with bypass protein (BPF), by defaunation, through targeted mineral/protein supplements or by bioengineering of rumen microbes.

4B. Increased level of feed intake

An increase in level of feed intake changes rumen VFA-content in such a way that less acetate and more propionate is formed, with lower methane emissions as a consequence. However, the biggest contribution to methane emission reduction is accomplished through livestock reduction, when production levels of meat, milk or draft per region are presumed to remain on the same level. Application of the measure may reduce methane emissions with 8% (dairy animals), 10% (non-dairy animals) and 50-55% of (non-dairy farming animals) [Gerbens, 1998].

Costs: For Western Europe and other regions in the world, the cost-effectiveness of this measure is estimated by Gerbens [1998]. They assume that by the year 2000, practically all farmers will apply this measure.

In the cost analysis the cost savings of overall feed reduction and the costs of less beef production (diary) or less milk production (non-diary) due to livestock reduction are accounted for. Assumed is an extra feed intake by mature animals of 1 kg dry matter per day (kg DM/day); young animals of 0.7 kg DM/day. The methane reduction is 10% per 20% VFA-diet decrease. The specific methane emission reduction costs are estimated at -1000 ECU/tonne CH_4.

4C. Replacing roughage with concentrates

As roughage contains a high degree of structural carbohydrates (fibres), replacement of part of the roughage in the animal diet with concentrates will generally improve propionate generation and decrease methane production. Remarkably is that currently more roughage is being used than some years ago as a consequence of the European milk-quotas. Per milk producing cow more grassland is available and therefore more roughage per cow. This tendency is probably hard to bend. When replacing roughage by concentrates, the methane emission per animal remains on the same level or increases slightly, but decreases per unit of product. Methane emission reduction is therefore only obtained combined with livestock reduction. Additional CH_4 emission reduction is accomplished through a VFA-shift. Application of the measure may reduce methane emissions with 6% (dairy animals), 8% (non-dairy animals) and 50-55% of (non-dairy farming animals) [Gerbens, 1998].

Costs: For Western Europe and other regions in the world, the costs-effectiveness of this measure is estimated by Gerbens [1998]. The cost-effectiveness depending on the possibility to sell the extra milk/beef production of high quality feed requires intensive agronomic practices that result in increased emission of the greenhouse gases CO_2 and N_2O due to increased energy use and use of nitrogen-fertilisers. The cost savings of feed reduction and the costs of (increased) concentrate feeding and less beef production (diary) or less milk production (non-dairy) due to livestock reduction are accounted for.

Assumed is an extra concentrate intake by mature animals of 1 kg DM/day; replaced roughage by mature animals of 0.5 kg DM/day. Extra concentrate intake by young animals of 0.7 kg DM/day, and replaced roughage by young animals of 0.35 kg DM/day. The methane reduction is 10% per 20% VFA-diet decrease. Assumed applicable only for stall-fed and pasture/range animals. The CH_4 emission reduction costs are estimated at -4300 ECU/tonne CH_4.

4D1. Changing composition of concentrates: non-structural carbohydrates

If the composition of the currently added concentrates is changed towards one with less fibres, substantial reduction of methane emissions is possible. Alternatives are starch and sugars, which could be produced by cultivation of maize and mangel-wurzel. With this option the 'surplus' of grassland can be used for the production of concentrates. By replacing 25% of structural carbohydrates with non-structural carbohydrates a CH_4 emission reduction of almost 20% is predicted. However, by replacing grassland with maize cultivation, an unwanted increase of nitrate concentration in groundwater will occur.

By adding unsaturated fatty acids to the animal diet also more propionate is formed and also part of the degradation of the fibres will take place in the intestines. Adding 10% of fat to the diet of dairy cows, results in a decrease of methane production with 20% to 25%. Application of the measure may reduce methane emissions with 13% (dairy animals), and 8% (non-dairy animals) [Gerbens, 1998].

Costs: For Western Europe and other regions in the world, the cost-effectiveness of this measure is estimated Gerbens [1998].
The cost savings of feed reduction and the costs of increased non-structural carbohydrates concentrate feeding and less beef production (diary) or less milk production (non-diary) due to livestock reduction are accounted for. Assumed is a replaced structural carbohydrate concentrate of 25% and an average concentrate feed of 40% of GE. CH_4 emission reduction per kg concentrate due to VFA-shift of 20%. The costs of structural carbohydrates concentrate and non-structural carbohydrate concentrates are assumed to be equal. Furthermore it was assumed that only structural carbohydrates are used up to 1990. The CH_4 emission reduction costs are estimated at -320 ECU/tonne CH_4.

4D2. Changing the composition of concentrates: lipids
The addition of large amounts (up to 10%) of lipids to the diet of dairy cows with a high production potential satisfies the animals' considerable energy requirements. They bring about a decrease in methane production associated with a drop in the molecular percentage of acetic and butyric acid, and an increase in propionic acid. By adding unsaturated fatty acid part of the degradation of the fibres will take place in the intestines. Usually feed already consists of 2% 'natural' fat, and the addition of extra fat (e.g. coco, destruction fat) has been suggested up to a maximum of 5%, adding up to a total maximum of 7% dietary fat. The maximum amount of this fat is limited by possible impairment of the fermentation processes in the forestomaches. Application of the measure may reduce methane emissions with 7% (dairy animals), and 4% (non-dairy animals) [Gerbens, 1998].

Costs: For Western Europe and other regions in the world, the cost-effectiveness of this measure is estimated by Gerbens [1998].
The cost savings of roughage and 'low fat' (4%) concentrate reduction and the costs of increased 'high fat' (7%) concentrate feeding and less beef production (diary) or less milk production (non-diary) due to livestock reduction are accounted for. Assumed is a replaced low fat concentrate of 100% and an average concentrate feed of 40% of GE. CH_4 emission reduction per kg concentrate due to VFA-shift amounts to 2% per kg concentrate replaced.
The CH_4 emission reduction costs are estimated at -1430 ECU/tonne CH_4.

4E. Alkali/ammonia/urea treatment of low quality roughages
A variety of chemicals has been tested for treatment of low quality roughages such as straw and other crop by-products to improve their digestibility. To date,

treatment with sodium hydroxide and ammonium hydroxide have been found to be the most beneficial and cost effective methods available. Alkali treatment of straw results in a decreased ratio of acetate propionate. Substantial methane emission reduction is possible in combination with livestock reduction.

Urea treatment (which shortens the right expression "urea-generated ammonia treatment") is the treatment best adapted to the small farmer's conditions, both at the individual small scale treatment and at the collective large scale treatment.
The urea treatment is the result of two processes which occur simultaneously within the mass of forage to be treated: ureolysis which turns urea into ammonia, and the subsequently generated effect of the ammonia on the cell walls of the forage. Urea treatment can be accomplished with 5.3 kg of urea per 100 kg DM.

Urea treatment improves the nutritional status of animals and their performances. An average improvement of 200 g/d of the average daily growth of growing cattle, and increase of 1.0 to 2.5 kg of milk per day and a better efficiency of draught are observed. Application of the measure may reduce methane emissions with 52.5 % for non-dairy farming animals [Gerbens, 1998].

Costs: For Western Europe and other regions in the world, the cost-effectiveness of this measure is estimated by Gerbens [1998].
Assuming that 5 kg straw is used to feed 1 cow per day, about 95 g of NaOH and 65 g of urea per cow per day are required. Contracted cost of treatment with only NaOH (3%) are around 40 ECU per tonne of straw, and 1 kg of urea costs 0.12 ECU. So for centralised processing of straw the costs are estimated at 0.0021 ECU/kg DM straw (transportation costs not included).
The indirect energy consumption, as a result of centralised processing of the low quality roughages and transportation of the feed to the farm are not addressed. Also the saved indirect energy consumption, due to less feed consumption, is not taken into account. Assumed is an increase of digestible energy intake of 50%, and no CH_4 emission reduction due to VFA-shift. The CH_4 emission reduction costs are estimated at -700 ECU/tonne CH_4.

4F. Chopping of low quality crop by-products

Physical modifications of straws and other crop-by-products, such as chopping and milling, can improve feed intake and animal performance, by mechanically isolating the carbohydrate in the feed from the lignin. Although digestibility may in fact be reduced by grinding, increased feed intake more than compensates, so that total digestible energy intake improves. Application of the measure may reduce methane emissions with 50-55 % for non-dairy farming animals.

Costs: For Western Europe and other regions in the world, the cost-effectiveness of this measure is estimated by Gerbens [1998].
The primary costs consists of the grinding equipment and the labour necessary to operate it. The capital costs are estimated at 5-10 ECU/animal per year. On farm-

labour costs for operating the grinding equipment for mechanical feed processing are variable, but low.
Assumed that the measure is applicable for stall-fed and pasture/range non dairy animals with average feed digestibility of less than 60%. The extra energy input only consist of an increase of the average digestible energy intake to 60%, and no extra energy gain is presumed through extra feed input.
Assumed is an increase of digestible energy intake of 10%,and no CH_4 emission reduction due to VFA-shift.. The CH_4 emission reduction costs are estimated at 5500 ECU/tonne CH_4.

Improved animal productivity

By adding production enhancing agents to animal feed, or by injecting animals with these agents, animal productivity can be improved. With increasing animal productivity, methane emissions per agricultural product (milk, beef) can be decreased.

4G. Antibiotics

Currently several antibiotics, ionophores, and halogenated compounds are being used for growth stimulation, some of which have a direct effect on methanogenesis in the rumen as well. For instance Flavomycin, Monensin (applicable for young beef cattle), Avoparcin (applicable for young dairy cattle), and Selenomycin have all been shown to induce a shift in the pattern of rumen fermentation in favour of propionate.

Monesin and Avoparcin are applied to young animals, which reach their final slaughter weight with less feed input, and consequently have less energy losses to methane. Therefore methane emissions are only reduced by VFA-shift and not, like most measures described before, in combination with livestock reduction. Methane emission reduction can be significant: methane emission reductions of 4% to 31% per cow are registered with commonly used agents. A beneficial side-effect of production enhancing agents is a decrease in nitrogen-excretion per product (about 10% to 15%), reported for beef cattle. Another side-effect is that methane production in manure can be impeded (e.g. in the case of Monensin). This side-effect is beneficial, but can impede methane production in manure digesters.
Reductions up to 90% can be reached with specific halogenated methane inhibitors (e.g. chloroform, carbon tetrachloride, and methylene chloride). Associated with this inhibition is an unwanted accumulation of hydrogen gas. These compounds are unsuitable as feed additives because of their volatile character or change in feed palatability. Also loss of methane inhibition in time can happen due to an adaptation of rumen microbial populations.

Costs: It is assumed that Monensin is already used in 75% of the EU-15. No use of Avoparcin is assumed, because it is prohibited in the EU per April 1997.
As the costs of the agents are low compared to the saving on animal feed and the extra productivity, this option has net negative costs. The feed intake depressions

are in general about 1% to 5%, depending on base diet (roughage or grain quality). Related to the increase in rate of gain, these percentages are about 7% to 14%.

Beef cattle: In a specific field experiment with beef cattle the extra costs of the use of a production enhancing agent (Monensin) was about 4 ECU per steer, but as a consequence of savings on feeding costs and especially of extra beef production, the nett cost savings were about 32 ECU. From the conservative assumption of 5% methane reduction per steer and a methane emission per steer from 65 kg CH_4/year, an indication of cost-effectiveness can be derived of about -10,000 ECU per tonne of CH_4, per animal, per year.

4H. Bovine somatotropin (bST)

Another class of production enhancing agents are hormones as bovine somatotropin (bST) and anabolic steroids. These hormones are currently prohibited in the EU and not expected to be used in a short term as the opposition of consumers to these agents is huge.

4I. Improved genetic characteristics

Apart from adding agents that stimulate growth and milk-production, also other strategies that might be applicable for the EU herd can be found in literature, such as improved production through improved genetic characteristics. It is estimated that by the use of high productive cows around the year 2000 10% less feed is required per litre milk produced compared to 15 year earlier. Consequently 10% less CH_4 will be produced. Another method that holds dramatically improvement of the productivity of domestic livestock is genetic manipulation: the transfer of genetic material form one specie to another. This can be realised in two ways: manipulation of rumen bacteria, and by manipulation of the genes of the animal self. At this moment considerable research is required before transgenic manipulation is used commercially in food producing animals. Furthermore, ethical aspects and public acceptance are very important topics to be dealt with.

5.1.4.2 Emission Reduction Measures at Animal Manure

Manure production per animal type

Table 5.3 shows the manure production and estimated methane emissions per animal type. Table 5.4 gives an overview of the number of animals in the EU-15 in 1990. The main contribution comes from both pigs and cattle. In this section some methane reducing measures will be described. Most attention is given to manure from these two animal types. Some measures however, will be applicable to other animal types. The measures should be coherent with the aim of reducing emissions of nutrients and acidifying substances to the environment. Measures can be directed at preventing manure fermentation or at stimulation of controlled fermentation in combination with combustion of methane (manure digesters).

Table 5.3. Manure and Methane production per animal

	Prod of Manure (ton/(animal/yr)	Prod. of CH4 (ton/(animal/yr)
Cattle	18.6	6
Pigs	1.4	1
Sheep and Goats	1.0	4

Table 5.4. Livestock in the EU-15 in 1990

	Cattle (in thousand)	Pigs (in thousand)	Sheep and Goats (in thousand)	Horses (in thousand)
AT	2562	3773	323	48
BE	3146	6426	145	18
DK	2241	9282	111	34
FI	1363	1348	65	44
FR	21446	12013	12233	322
DE	20265	34048	4476	93
GR	624	996	13994	45
IE	6028	1069	6001	20
IT	8234	8837	12145	220
LU	215	70	8	0
NL	4830	13788	1947	70
PT	1341	2531	6424	26
ES	5127	16002	27700	241
SE	1718	2264	406	53
GB	11843	7380	30260	145
EU	90983	119827	116238	1379

Emission reduction strategies

If manure is kept under anaerobic conditions and with temperatures higher than about 15 °C, methanogenic bacteria will produce methane. Little is known about the actual methane production in current farm management systems. When manure is stored for several months during winter in the cellar of a stable, the emissions of pig manure amounts to 4.8 to 7.2 kg CH_4 per tonne of manure and the emission of cattle manure amounts to about 3.6 kg CH_4 per tonne of manure. These emissions decrease to one sixth when the manure is stored in silos outside the stable.

The following reduction strategies can be followed:

- Reduction of livestock
- Prevention of fermentation during stabling
- Controlled fermentation of manure
- Side-effects of measures aimed at reducing methane emissions caused by enteric fermentation

The measure of reducing livestock is already discussed in the section on enteric fermentation processes and will not be considered in this section.

4J. Prevention of fermentation during stabling of livestock

The way manure is handled and stored in stables determines the extent of methane production and emission. Higher temperatures and longer storage periods favour growth of methanogenic bacteria. Cattle is generally kept in stables with cow cubicles. If the floor is made of concrete, the manure is usually mechanically removed to a manure storage outside the stable. In stables with a grid floor the manure falls into a manure cellar where it is kept for some months (depending on cellar capacity). During manure storage significant methane emissions might occur, especially in heated pig stables.

By complete regular emptying of the manure cellar or stable floor, methanogenesis can effectively be retarded. Depending on stable design, this can be done with a so-called 'manure slide', which frequently moves the manure to a storage pit outside the stable.

Also rinsing of the manure is an option currently applied. Cleansed water from the collected manure is being used as rinsing water, so manure volume and dry matter content will not be influenced.

Although it is expected that methane emission reductions will be significant, no data are available. For our calculations we will assume a reduction-factor of at most 10%.

Costs: The investment costs of a manure slide and storage system are about 100 to 500 ECU per animal (pigs). A manure rinsing system needs an investment of about 70 to 350 ECU per animal (pigs). The range in these figures depends on animal characteristics (e.g. sows, meat pigs), manure storage system (e.g. silo) and farm size. With an assumed emission reduction of at most 10%, the reduction costs are at least about 5,000 to 50,000 ECU/tonne CH_4 (lifetime 20 years).

However, as this measure also limits ammonia emissions, and is increasingly applied for this reason, these costs are not ascribed to the methane reduction measure.

Controlled fermentation of manure

When manure is anaerobically digested in special reactors, methane is generated and can be used for heat and/or electricity production. Depending on the temperature in the reactor, three alternative methods can be distinguished: thermophilic (40-70 °C), mesophilic (35-40 °C) and psychrophilic (15 °C) digestion. thermophilic digestion is mainly applied in Denmark. The high temperature is needed for the destruction of pathogenic micro-organism. Because of the lack of information, this option is not further considered in this analysis.
The energetic value of produced biogas from manure is about 0.45 MJ per tonne processed [Jager, Blok, M802]. Anaerobic digestion can take place in large centralised processing plants or on small scale on farm level. Recently, a processing plant in the Netherlands went bankruptcy, because the system was felt inflexible and too expensive by the farmers. In the light of these experiences, we therefore assume the potential for this option zero.
Another option is fermentation of animal manure in combination with agri-organic material. This option is currently operational in Denmark.

4K. Mesophilic digestion on farms

Mesophilic digestion occurs at temperatures of 35-40 °C.

Costs: Investment costs for a mesophilic digester for use on farms are about 380 ECU per m^3 of digester-volume. We will assume that the generated biogas is used in a central heating system (which also sustains the mesophilic temperature in the digester) with rather high O&M costs of 10%/year of investment costs. The (average) lifetime is taken at 15 years. The net energy production per m^3 of digester-volume is about 5 GJ/year. The cost savings are calculated assuming a consumer price of natural gas of 250 ECU/GJ.

4L. Psychrophilic farm scale digestion

Psychrophilic fermentation occurs at temperatures above 15 °C; below this temperature methanogenesis is inhibited. In a psychrophilic digester no heat is generally added to the slurry, except when temperature declines below this value. Compared to a mesophilic digester, methane production and gross energy-production is lower in a psychrophilic digester: about 0.4 GJ/year per m^3 of digester-volume. As manure silos can easily be adapted to psychrophilic digesters, by thermal isolation and capping of the silo, this measure is a promising, yet currently not profitable, option.

Costs: Investment costs vary from about 40 to 50 ECU per m^3 of digester-volume, dependent of the isolation material used. For the cost estimation we used the same assumptions as in measure 4K.

Cost savings by using less fertilisers due to the better fertilising characteristics of the digested manure are not taken into account in the calculations of measure 4K and 4L.

4M Combined manure agri-organic fermentation

Manure is anaerobic fermented in combination with agri-organic by-products. The technology of biogas production by anaerobic digestion of organic material is used in several parts of the world, especially in Denmark. Here we assume an installation able to handle annually 100.000 tonne, composed of 75% animal manure and 25% agri-organic by-products. The biogas production is about 35 m^3 (730 MJ) per m^3 digested material, which is equal to 23 m^3 natural gas equivalents. The internal energy use is about 70 MJ/m^3, which is taken from the produced biogas. The remaining part (660 MJ) is sold for a price of 80 ECU/tonne.
The total investment amounts to 45 ECU/(m^3/year) (including costs for land). O&M costs (including personnel) amount to 1.8 ECU/(m^3/year). Saved costs for processing agri-organic amounts to 40 ECU/tonne, which equals 30 ECU/tonne processed material.

The emission reduction factor of manure digestion is not known exactly. In literature methane reductions up to 50% to 70% are mentioned. However, methane reductions are highly dependent on conditions in stable and storage before digestion. We will assume a reduction factor of 35% and 50% for large-scale and farm-scale digestion respectively.

5.2 NITROUS OXIDE EMISSION REDUCTION MEASURES

5.2.1 Emission Reduction Measures at Chemical Industry

5.2.1.1 Chemical Industry: Nitric Acid Production

Nitric acid is a raw material mainly used as a feedstock for fertiliser production, but also in the production of adipic acid and explosives. Nitric acid is produced widely in the EU-15.

Most commercial manufacture of nitric acid is based on the oxidation of ammonia. Three main production steps can be distinguished: (1) catalytic oxidation of ammonia to nitrogen monoxide, (2) oxidation of the nitrogen monoxide to nitrogen dioxide, and (3) absorption of the formed nitrogen dioxide in water to produce medium concentrated nitric acid.

The N_2O is formed in the first step. A part of the ammonia is converted to nitrogen (mainly), and nitrous oxide. The N_2O and nitrogen pass through the other stages of the process and are released in the flue gases along with the unreacted NO and NO_2.

Three options exist for reducing N_2O emissions:

- Optimising the nitric acid production process
    - ♦ Temperature, pressure, reaction time, type of catalytic converter
- Reducing N_2O emissions using end-of-pipe technologies
    - ♦ Catalytic reduction of N_2O to N_2 and O_x
    - ♦ Thermal dissociation of off-gas (e.g. using methane)
    - ♦ Biofiltration of off-gas using denitrifying bacteria
    - ♦ Photo-catalytic conversion
- Reducing demand of nitric acid (by reducing the use of fertiliser)

1A. Optimising the nitric acid production process
Optimisation of process parameters with respect to minimal nitrous oxide formation is an option that is hard to quantify. Most likely, this would effect production efficiency, nitric oxide emissions and/or production costs. The potential and side-effects of this option need still to be determined. An estimate of the reduction costs and potential can yet not be made.

1B. Catalytic reduction to N_2 and O_2
Concentrations of nitrous oxide in flue gases of nitric acid plants are generally in the range of 300 to 1700 ppmv. This range is generally more suitable for

catalytic conversion than for thermal dissociation as the latter requires additional energy input. Catalytic decomposition of nitrous oxide requires elevated temperatures (about 450 °C). For the process conditions of nitric acid production this would require additional energy input or the development of catalysts working at lower temperatures. This techniques reduces over 80% of the N_2O emission.

Costs: For a nitric acid production plant with a capacity of 1000 tonne per year, the total initial investment amounts to 2.5 MECU [Jager, 1996]. The investment for the catalysts amounts to 0.5 MECU. The catalysts have to be replaced approximately every three year. Assuming a total life-time of the installation to be 15 years, the net-present-value of current and future investment in the catalyst amounts to 1.7 MECU (assumed 5% interest). The total investment is therefore 3.7 MECU.
The specific investment amounts then to 370 ECU/(tonne N_2O avoided per year). The O&M costs amounts (4% of the investment) amounts to 12 ECU/tonne N_2O.

1C Thermal dissociation of off-gases
Because of the low off-gas concentrations of nitrous oxide from nitric acid production, thermal dissociation (afterburning) by injection of fuel (e.g. natural gas, methane) is generally not considered to be a feasible option. However, in some cases off-gases could be mixed with high temperature off-gases of other nearby industrial processes, which would result in a net nitrous oxide destruction. Reduction potential and costs are again site-specific and not quantified in this study.

1D Biofiltration of off-gases using denitrifying bacteria and Photo-catalytic conversion
Oonk [1995] discusses these two options. Neither reduction potential nor costs are known yet, nor the applicability to off-gases of the nitric acid production. Further research is required which makes these two technologies, if applicable at all, mid- to long-term options.

5.2.1.2 Chemical Industry: Adipic Acid production

Adipic acid is a raw material used mainly in the manufacture of 6,6 nylon that is used, for instance, in industrial carpets; some adipic acid is also used in the manufacure of some low temperature lubricants. The starting point for the acid is cyclohexane, which is used to produce 'KA' (a mixture of cyclohexanon and cyclohexanone), which is then oxidised with nitric acid to produce adipic acid. N_2O is a side product of this final oxidation step.

In the EU-15, adipic acid is produced in 4 countries: Germany, France, Italy and the UK.

The five main producers of adipic acid world-wide, members of the inter-industry group, have already agreed to reduce their N_2O emissions by 90-99%. In the United Kingdom, owners of adipic acid plants are committed to minimise N_2O emissions; it is one of the substances subject to regulation according to BATNEEC rules (Best Available Technology Not Exceeding Excessive Costs). Also in France regulation is in place to reduce N_2O emissions from adipic acid production to virtually zero; for nitric acid production plants best available technology standards are set.

Three options exist for reducing N_2O emissions:

- Optimising the adipic acid production process
  - ♦ Re-use of N_2O emissions
- Reducing N_2O emissions using end-of-pipe technologies
  - ♦ Catalytic reduction of N_2O to N_2 and O_2
  - ♦ Thermal dissociation of off-gas (e.g. using methane)
- Reducing demand of adipic acid (not considered here)

1E. Optimising the adipic acid production process

A way to optimise the production process of adipic acid is to re-use N_2O-rich off-gas as an oxidant to produce phenol from benzene in a single step. This technology is to be installed in a new 135 million tonne plant of Soluda in the United States, and will be ready to start-up in 2000. The company says that the new technology *saves* 20% of the cost of making adipic acid. The France company Alsachemie have plans to re-use N_2O for nitric acid production. The company, responsible for 90% of France N_2O emissions has developed a bolt-on technology that produces nitric acid by burning N_2O at high temperatures in the presence of steam. This approach captures the N_2O from the adipic acid production while avoiding the N_2O generated by conventional nitric acid processes [Chemical Week, Feb. 1998]. As the driving force is cost reduction of the production process rather than environmental considerations, these options are not considered as an emission reduction measures, but as part of the autonomous development.

1F. Catalytic reduction to N_2 and O_2

A catalyst bed is used to decompose the N_2O into N_2 and O_2. The reaction is strongly exothermic and the heat produced must thus be removed; if there is a suitable demand on the production site, then it may be recovered and used to produce steam. Potential problems includes the need to recharge the catalyst once in the two or three years, and the complex design to generate useful steam from the process. Assumed is an abatement efficiency of 95%.

Costs: The estimated costs of the catalytic reduction process are based on costs of the 154 ktonne/year-installation of BASF in Germany. This installation is planned to be operational in 1999. In normal operation, 95 to 97% of the N_2O emission will be avoided [Schön, 1995].

The specific investment for the plant with a capacity of 154 ktonne and an annual emission of 51 ktonne per year amounts to 230 ECU/(tonne N_2O avoided per year). The catalyst makes about 15-20% of these costs. As the catalysts has to be replaced by about 4 times in during the life time of the installation of 15 years, the total investment is estimated at 400 ECU/(tonne N_2O avoided per year).

The yearly operation and maintenance costs are estimated at 4% of the initial investment costs (9 ECU/tN_2O).

1G. Combustion of off-gas

The N_2O in the off-gas is combusted in the presence of methane. The N_2O acts as an oxygen source and is reduced to nitrogen and water, giving non-negligible quantities of NO and some residual N_2O. The combustion process can be used to raise steam, if a demand exists on site. The Japanese company Asahi has developed a thermal recovery process that is expected to remove about 90% of the N_2O emissions. DuPont says it has developed a technology without increasing operating costs. The system will burn N_2O with oxygen and waste ammonia and hydrocarbon off-gas from other processes. DuPont expects even without the availability of the hydrocarbon-rich waste gases to create an operational saving [Chemical Week, Feb. 1998].

5.2.2 Emission Reduction Measures at Agriculture

The principal environmental parameters affecting N_2O emissions from agricultural soils are the availability of a nitrogen source, moisture and temperature, with nitrogen availability being the most important.
Therefore, there are two major lines to influence N_2O emissions from agriculture: (1) to influence the land use; (2) to apply measures reducing N_2O emissions by influencing land use management practices.

As the type of land use influences the N_2O emissions, various measures that lead to a shift in land use may result in a significant change in N_2O emission. Within the European Union, agricultural policy is driven by the Common Agriculture Policy (CAP). A land use shift may be the consequence of a change in the way subsidies are given, e.g. by change of crop specific to homogenous payment.

2A. Price support, Set aside and Marginal Land Subsidy
Price support for agriculture produce is assumed to be phased out over ten years, from 2000 to 2010. The removal of price support would encourage farmers to carefully re-examine their inputs in order to maximise profitability through improved fertiliser use efficiency. This would drive increases in efficiency at all levels of nutrient management, and so contribute to reducing nitrogen surpluses.
Removing price support may lead to the abandonment of 20% of the EU-15 agricultural area. The EC should pay for appropriate non-agricultural or very extensive agricultural management, helping to preserve the rural community while returning the area to sustainable land use.
The impacts on the N_2O emissions by these measures in 2010 is estimated at 20 ktonne N_2O. [Bates, 1997]. This figure represents a reduction of about 3.5% of the total projected N_2O emissions in 2010.

Costs: The savings to the EC would be 7287 MECU in 2010. These savings would be reduced by claims under the Marginal Land Subsidy, which would be phased in over the same period. The subsidy would be used to support sustainable, not necessarily agricultural, management practices on the marginal land. This is estimated at 2506 MECU in 2010. The difference of the savings and costs (4781 MECU) for the EC is assumed to be the net costs for the farmers in the same period. The specific costs are therefore 240,000 ECU/tonne N_2O avoided [Bates, 1997].
Most probably, N_2O emission reduction would not be the main driving force to phase out the price support. In this study we do not allocate the cost to N_2O emission reduction and assume therefore the costs of the measure to be zero.

2B. Fertiliser limits

The rationale behind the nitrogen application limits is to reduce the total amount of nitrogen in the system by replacing inorganic fertiliser with organic nitrogen from manure. In agricultural systems, nitrogen quantities are boosted by the addition of nitrogen to the system (manure is not regarded as a nitrogen addition, as it represents nitrogen that is already within the agricultural system). Nitrogen application limits would be introduced for inorganic fertilisers, with no limits imposed on the use of organic sources of nitrogen. The nitrogen limits would target arable and grassland systems only because these sectors are the largest nitrogen users, and their application rates are forecast to increase in the future. It was found that a 50 kg/ha limit achieved a 15% reduction. The substitution of inorganic fertilisers with manure would constitute a more efficient use of manure, which are currently disposed of as waste products.

The impacts on the N_2O emissions by this measures in 2010 is estimated at 70 ktonne N_2O. [Bates, 1997]. This figure represents a reduction of about 10% of the total projected N_2O emissions in 2010.

Costs: Assumed is that the use of manure instead of inorganic fertiliser will not affect the crop yield of the land. The difference between the cost of additional manure and the savings from reduced fertiliser will represent the net cost to the farmer. The price of manure-N from the most abundantly available manure processed as slurry amounts to about 7 ECU/kg manure-N). The price of fertiliser N is approximately 1.5 ECU/kg-N. In case large amounts of manure will be processed, expected is a significantly lower price for the manure-N than estimated here.

The estimated total manure-N required in 2010 amounts to 3700 ktonne-N. The total costs can then be calculated to be 17,000 MECU. The specific costs are therefore 243,000 ECU/tonne N_2O avoided [Bates, 1997].

2C. Fertiliser timing

Restriction on the timing of fertiliser and manure application would be introduced to minimise N_2O emissions from the indirect sources resulting from leaching, as well as direct denitrification processes in wetter winter soils with anaerobic sites.

Under the seasonal restrictions, applications of slurry, poultry manure and inorganic fertiliser would be banned from September to February, with applications of other types of manure permitted until October. These dates are based on leaching risk assessments which demonstrated that most leaching occurs when quickly-available nitrogen sources are applied over time period beginning immediately after harvest until early spring, when crops begin to take up nitrogen and soil through-flow decreases.

The impacts on the N_2O emissions by this measures in 2010 is estimated at 31 ktonne N_2O. [Bates, 1997]. This figure represents a reduction of about 4.5% of the total projected N_2O emissions in 2010.

Costs: The seasonal restriction on N application will have few cost implication for inorganic fertiliser, but may have an impact on manure storage times. Farmers in the EU-15 have on average five month' manure storage capacity. The additional 20% storage capacity is estimated at 87 Mtonne. The average annual storage cost per tonne is about 2.2 ECU, giving a total costs of 190 MECU. The specific costs are therefore 6,000 ECU/tonne N_2O avoided [Bates, 1997].

2D Improved fertiliser use efficiency

There are numerous measures to improve the use of fertilisers by farmers which most of them can be applied in the near future. Some of these options are: optimisation of the recommended fertilisation level; fertiliser spreader maintenance, application of a fertiliser free zone, optimisation of the fertiliser distribution geometry; row application, fertiliser need analysis, alternative fertiliser types, optimisation of fertiliser quality, application of catch crops and coating of fertilisers. A description of these measures can be found in [De Jager et al, 1996]. The application and potential of each measure may differ significantly from country to country. The total package of measures may reduce total agricultural related emissions by 2.5%.

Costs: Practically all of the measures are cost neutral or cost negative. The average specific costs for fertiliser improvement are estimated at -60,000 ECU/tonne N_2O avoided (i.e. benefits).

5.2.3 Emission Reduction Measures at Waste Treatment

3A. Sewage treatment

Most sewage treatment are optimised for N removal. Whether N disappears as N_2O or N_2 is not considered. Optimising the N removal process to N_2 production rather than N_2O production could reduce N_2O emissions significantly.

Table 5.5 Optimal process conditions in sewage water treatment for minimal nitrous oxide formation

Process parameters	Nitrification	Denitrification
Oxygen concentration	> 2 mg/l	< 0.5 mg/l
pH	neutral	Neutral
Organic content	low	BOD/N >4
Age of sludge	high	High

A study by BKH [1994] showed for the Netherlands room for 50% reduction by applying this option. Process conditions with minimal nitrous oxide formation are given in Table 5.5.

It is expected that these process adaptations may reduce nitrous oxide formation with one-third during nitrification and with two-third during denitrification, given an overall reduction of about 40%. It should be noticed the uncertainty in the estimates in reduction potentials are significant.

As a consequence of the improvement of nitrogen removal, total nitrogen loading of surface waters from sewage treatment plants will decrease significantly.

Another option to reduce N_2O emissions from sewage treatment plants would be a reduction in N removal. However, this would imply an increased input of N to surface water, which may be an unwanted side-effect.

Costs: There are no cost figures known for this option. Expected is that the measure can be applied against low or zero costs.

5.2.4 Emission Reduction Measures Transport

The most important factor responsible for the increase in emissions by the transport sector (mobile combustion) is the introduction of three-way catalytic converters for abatement of NO_x, CO and VOC. With respect to the situation without a catalyst, emissions of nitrous oxide increase by a factor of 4 to 5. Due to ageing of the catalyst, the production of nitrous oxide can increase up to a factor of 10 to 16. Apart from the effects of ageing, also catalyst type, size and temperature, engine output power, and the equivalence ratio of the flammable mixture determine the emission of nitrous oxide. These parameters are therefore highly dependent on actual driving cycle characteristics.

4A Improved catalyst performance

N_2O is produced as a result of an incomplete catalytic reduction of NO, and NO_x to NO. It is possible that in the longer term it might be possible to develop a new catalytic converter that also will prevent N_2O formation. It is likely that this would require a significant R&D effort.

N_2O emissions increase with age. Increased rate of replacement of catalytic converters in order to reduce N_2O emission is very costly (it might range from 15,000 to 80,000 ECU/tonne N_2O, and is therefore not considered as a realistic measure to reduce N_2O emissions.

Another opportunity may give the development and implementation of low-NO_x combustion engines. This may give the opportunity to avoid the use of catalysts, thus avoiding substantial N_2O emissions.

4B. Fuel switch, energy saving, reducing transport demand and other

Emission of N_2O reduces by measures as reduction of automobility, fuel-switch, fuel efficiency improvement, and decrease in urban driving and traffic jams. However, it is not very likely that these options will be implemented as part of a nitrous oxide abatement policy; with respect to the emission of greenhouse gases the reduction of carbon dioxide will prevail.

5.2.5 Emission Reduction Measures Stationary combustion processes

Emissions from the combustion of fossil fuels in stationary combustion processes are generally low, typically 1 to 2 ppmv [IEA, 1993] for coal-fired plant and 1 ppmv or below for oil and gas fired plant. 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. 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; and reduction in fossil fuel consumption (e.g. by applying energy efficiency improvement measures, energy saving measures, and increase use of renewables).

Fluidised bed combustion

Fluidised bed combustion is an energy conversion technology with on average a higher efficiency than conventional pulverised fuel combustion, lower NO_x emissions due to a lower combustion temperature, and low emission of SO_2 due to the addition of limestone to the bed. The lower combustion temperature between 800 and 900 ° C leads to higher N_2O emissions: typically in the range from 30-150 ppmv. Circulating fluidised bed have often been found to have higher emissions than bubbling fluidised beds, possibly due to longer residence time in the former.

Options to reduce N_2O emissions are in short discussed below:

5A. Fluidised bed combustion

There a number of potential available measures to reduce nitrous oxide emissions from fluidised bed combustion.

Optimising operating conditions: tests in two medium-sized pilot plants showed a decrease of N_2O emission between 30 and 60%, but an doubling of NO_x emissions. The NO_x could be abated by using SCR. SNCR is not preferable in view point of N_2O emission reduction. SCR fitted on a fluidised bed plant is demonstrated in Japan and Sweden. No cost estimates are available for this measure.

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. No cost estimates are available for this measure.

Catalytic reduction of N_2O: The range of 30-150 ppmv is suitable for catalytic reduction. Currently, catalyst for nitrous oxide are in development and it is expected that they could reduce emissions with about 80%. This is unknown when this technology might become available.

Pressurised fluidised bed combustion: Instead of atmospheric fluidised bed, pressurised fluidised bed plants may be used. Small test plant showed an N_2O emission rate of below 20 ppmv; still higher than conventional coal-fired plants but lower than atmospheric fluidised combustion plants.

5B. Selective Non-Catalytic Reduction

SNCR for the reduction of NO_x emissions require higher temperatures; typically between 900-1200 °C, which is the optimal temperature for N_2O formation. An alternative NO_x abatement system may be Selective Catalytic Reduction. The specific cost of NO_x abatement of SCR is about double the cost of SNCR. SCR decreases NO_x emissions typically by over 80%. As these abatement system are intentionally meant for NO_x abatement, it is not likely these options will be implemented as part of a nitrous oxide abatement policy.

5C. Stationary combustion processes

A shift from coal to oil to gas would result in lower emissions of nitrous oxide in the energy provision sector. Also a shift to non-fossil energy sources will result in emission reductions. However, it is not very likely that these options will be implemented as part of a nitrous oxide abatement policy; with respect to the emission of greenhouse gases the reduction of carbon dioxide will prevail.

5.3 OVERVIEW MEASURES

Table 5.6. Summary of data of methane emission reduction measures.

Sector	ID	Measure	1	2	3	4	5	6	7	8	9
Solid fuels	1A	Recovering at coal mining	100%	80%	5000	150	80	15	925	141.000	130,4
Oil and NG fuels	2A	Increased gas utilization	100%	25%	600	6	80	15	29	9.858	0,3
Oil and NG fuels	2B	Further increased gas utilization	100%	50%	1200	12	80	15	137	19.715	2,7
Oil and NG fuels	2C	Offshore flaring	100%	13%	3600	100	0	15	716	4.929	3,5
Oil and NG fuels	2D	Natural gas compressors	100%	60%	120	19	140	20	-102	246.211	-25,1
Oil and NG fuels	2E	Replace grey cast-iron network	75%	97%	40000	0	80	50	5.926	1.140.036	6755,3
Oil and NG fuels	2F	Double leak control frequency	25%	50%	0	1700	80	not rel.	1.620	195.883	317,3
Waste	3A	CH4 recovery + elect. generation	35%	50%	480	25	145	20	-43	687.965	-29,8
Waste	3C	Upgrading landfill gas to NG quality	15%	50%	650	100	190	20	14	294.842	4,1
Waste	3D	Flaring recoverd landfill gas	25%	49%	80	0,35	0	20	13	481.575	6,3
Waste	3E	Reduced landfilling by composting	2%	100%	0	900	620	20	280	82.556	23,1
Waste	3F	Reduced landfilling by fermentation	0%	100%	0	1350	715	20	635	15.725	10,0
Waste	3G	Reduced landfilling by incineration	3%	100%	0	9500	2050	20	7.450	98.281	732,2
Agriculture	4B	Improved level of feed intake dairy	100%	7%	0	-898,263	0	not rel.	-898	156.007	-140,1
Agriculture	4B	Improved level of feed intake dairy	100%	9%	0	-898,263	0	not rel.	-898	353.524	-317,6
Agriculture	4B	Improved level of feed intake dairy	100%	40%	0	-898,263	0	not rel.	-898	19.811	-17,8
Agriculture	4C	Replacing roughage with concentrates	100%	3%	0	-4300	0	not rel.	-4.300	69.025	-296,8
Agriculture	4C	Replacing roughage with concentrates	100%	4%	0	-4300	0	not rel.	-4.300	164.513	-707,4
Agriculture	4C	Replacing roughage with concentrates	100%	26%	0	-4300	0	not rel.	-4.300	12.728	-54,7
Agriculture	4D1	Non-structural carbohydrates	100%	11%	0	-265,024	0	not rel.	-265	241.575	-64,0
Agriculture	4D1	Non-structural carbohydrates	100%	6%	0	-265,024	0	not rel.	-265	259.663	-68,8
Agriculture	4D1	Non-structural carbohydrates	100%	0%	0	-265,024	0	not rel.	-265	0	0,0
Agriculture	4D2	High fat diet	100%	7%	0	-1385,67	0	not rel.	-1.386	157.504	-218,2
Agriculture	4D2	High fat diet	100%	4%	0	-1385,67	0	not rel.	-1.386	165.464	-229,3
Agriculture	4D2	High fat diet	100%	0%	0	-1385,67	0	not rel.	-1.386	0	0,0
Agriculture	4E	Alkali/NH3/urea	100%	0%	0	-240,968	0	not rel.	-241	0	0,0
Agriculture	4E	Alkali/NH3/urea	100%	0%	0	-240,968	0	not rel.	-241	0	0,0
Agriculture	4E	Alkali/NH3/urea	100%	9%	0	-240,968	0	not rel.	-241	4.484	-1,1
Agriculture	4F	Chopping of low quality crop (diary)	100%	0%	0	21664	0	not rel.	21.664	0	0,0
Agriculture	4F	Chopping of low quality crop (non-diary)	100%	0%	0	21664	0	not rel.	21.664	0	0,0
Agriculture	4F	Chopping of low quality crop (other)	100%	13%	0	21664	0	not rel.	21.664	6.614	143,3
Agriculture	4J	Complete emptying of stable cellar	40%	60%	0	0	0	20	0	370.821	0,0
Agriculture	4K	Farm scale (mesophilic)	15%	50%	3800	380	310	15	720	115.882	83,4
Agriculture	4L	Farm scale (psychropilic)	30%	50%	3900	390	260	15	797	231.763	184,7
Agriculture	4M	Combined agri-org. and manure digestion	15%	35%	2400	95	570	20	-92	81.117	-7,4

Total abated CH4 (kton)	5.829	
Total net costs (MECU)		6219
Average specific costs (ECU/ton CH4)		1067
Average specific costs (ECU/ton CO2-eq.)		51

1 Share in sector (%)
2 Emission reduction (%)
3 Investment (ECU/(ton/yr)
4 O&M (ECU/ton)
5 Savings (ECU/ton)
6 Average lifetime (years)
7 Specific costs (ECU/ton)
8 Abs. em. red. in 2010 (ton)
9 Total EU-15 costs (MECU)

Potential and Costs for measures with positive costs only		
Total abated CH4 (kton)	3.209	
Total net costs (MECU)		8397
Average specific costs (ECU/ton CH4)		2616
Average specific costs (ECU/ton CO2-eq.)		125

Table 5.7. Summary of data of nitrous oxide emission reduction measures

Sector	ID	Measure	1	2	3	4	5	6	7	8	9
Industrial process	1B	Nitric acid production (catalytic destr.)	100%	80%	370	12	0	15	75	82,585	6.2
Industrial process	1F	Adipic acid production (cat. destr.)	100%	90%	400	9	0	15	77	210,009	16.3
Agriculture	2A	Price support, set aside and Marginal Lan	100%	4%	0	0	0	no rel.	0	11,673	0.0
Agriculture	2B	Fertiliser limits	100%	10%	0	243000	0	no rel.	243,000	33,351	8104.2
Agriculture	2C	Fertiliser timing	100%	5%	0	6000	0	no rel.	6,000	15,008	90.0
Agriculture	2D	Improved use fertiliser	100%	3%	0	0	60000	no rel.	-60,000	8,338	-500.3
Waste	3A	Sewage treatment	100%	40%	0	0	0	no rel.	0	2,560	0.0

Total abated N2O (kton)	364	
Total net costs (MECU)		7716
Average specific costs (ECU/ton N2O)		21227
Average specific costs (ECU/ton CO2-eq.)		68

1 Share in sector (%)
2 Emission reduction (%)
3 Investment (ECU/(ton/yr)
4 O&M (ECU/ton)
5 Savings (ECU/ton)
6 Average lifetime (years)
7 Specific costs (ECU/ton)
8 Abs. em. red. in 2010 (ton)
9 Total EU-15 costs (MECU)

Potential and Costs for measures with positive costs only		
Total abated N2O (kton)	355	
Total net costs (MECU)		8217
Average specific costs (ECU/ton N2O)		23134
Average specific costs (ECU/ton CO2-eq.)		75

6. CONCLUSION

On basis of data collected for specific methane and nitrous oxide reducing measures, sector specific discount rate figures and energy prices, specific emission reduction costs expressed in ECU/tonne CO_2-eq. were determined. Subsequently cost curves were constructed. This has been done for each Member State and for the EU-15 as a whole.

Total human induced 1990 methane emissions in the EU-15 are estimated at 24 Mtonne CH_4 (500 Mtonne CO_2-eq.). Projected base line emissions in 2010 are estimated at 19 Mtonne CH_4 (400 Mtonne CO_2–eq.). The emission reduction potential by the identified measures are estimated at an additional 8 Mtonne CH_4 (170 Mtonne CO_2-eq.).

Main sources with high potential reduction possibilities are landfills, natural gas distribution lines and livestock. The potential of the measures may reduce the methane emission in 2010 by 56% compared to 1990. Eighty percent of this potential can be obtained by measures with an average cost-effectiveness below 50 ECU/tonne CO_2-eq.

Total human induced 1990 nitrous oxide emissions in the EU-15 are estimated at 0.9 Mtonne N_2O (280 Mtonne CO_2-eq.). Projected base line emissions in 2010 are estimated at 1.0 Mtonne N_2O (320 Mtonne CO_2-eq.). The emission reduction potential by the identified measures are estimated at an additional 0.35 Mtonne N_2O (110 Mtonne CO_2-eq.).

Main sources with high potential reduction possibilities are industrial production of nitric acid and adipic acid and by improving fertiliser use. The potential of the measures may reduce by 26% the nitrous oxide emission in 2010 compared to 1990. More than 80% of the reduction potential can be obtained by measures with an average cost-effectiveness below 1 ECU/tonne CO_2-eq. An additional emission reduction of 10% can be obtained by measures with an average cost-effectiveness below 50 ECU/tonne CO_2-eq.

Member State specific graphs and cost-curves are presented in appendix 8.2 and 8.3:

- cost-curves for methane and nitrous oxide emission reduction measures for the EU-15 Member States.
- cost breakdowns for methane emission reduction measures per sector per Member State.

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8. APPENDICES

8.1 APPENDIX 1: METHANE AND NITROUS OXIDE EMISSION ESTIMATES AND PROJECTIONS

Table 8.1. Emission of CH4 and N2O for base year 1990, base line emissions for view year 2010 and emissions in 2010 after implementing identified measures.

	Member State estimates for 1990		Base line projection (Ecofys) for 2010		Emissions after implementing measures for 2010	
	CH4 kton	N2O kton	CH4 kton	N2O kton	CH4 kton	N2O kton
AT	587	12	383	8	281	8
BE	635	31	643	34	412	23
DK	423	35	391	38	234	37
FI	245	17	113	19	82	13
FR	3025	182	2518	178	1674	90
DE	5682	226	3163	274	1945	182
GR	438	13	403	18	336	17
IE	812	27	755	24	535	20
IT	2423	166	2032	156	1485	122
LU	25	0	23	0	15	0
NL	1289	64	926	78	482	61
PT	843	14	272	14	189	11
ES	2208	95	2273	104	1467	87
SE	324	9	284	25	207	23
GB	4449	119	3161	131	2041	46
EU	23408	1009	17338	1102	11386	738

Table 8.2. Member States estimates and projection of methane emissions according to the Second National Communications (draft May 1998).

	CH4 (kton) 1990	CH4 (kton) 2000	CH4 (kton) 2010	CH4 (kton) 1990	CH4 (kton) 2000	CH4 (kton) 2010
AT	587	600	np	100%	102%	np
BE	634	537	np	100%	85%	np
DK	421	409	362	100%	97%	86%
FI	246	226	191	100%	92%	78%
FR	3017	2820	2350	100%	93%	78%
DE	5682	3892	2759	100%	68%	49%
GR	443	np	np	100%	np	np
IE	811	837	839	100%	103%	103%
IT	2329	2455	1856	100%	105%	80%
LU	24	22	22	200%	93%	93%
NL	1290	971	710	300%	75%	55%
PT	806	714	716	100%	89%	89%
ES	2181	2356	2399	100%	108%	110%
SE	324	284	262	100%	88%	81%
GB	4409	3361	2804	100%	76%	64%
EU	23204	19485	15270	100%	84%	66%

np = emissions not projected

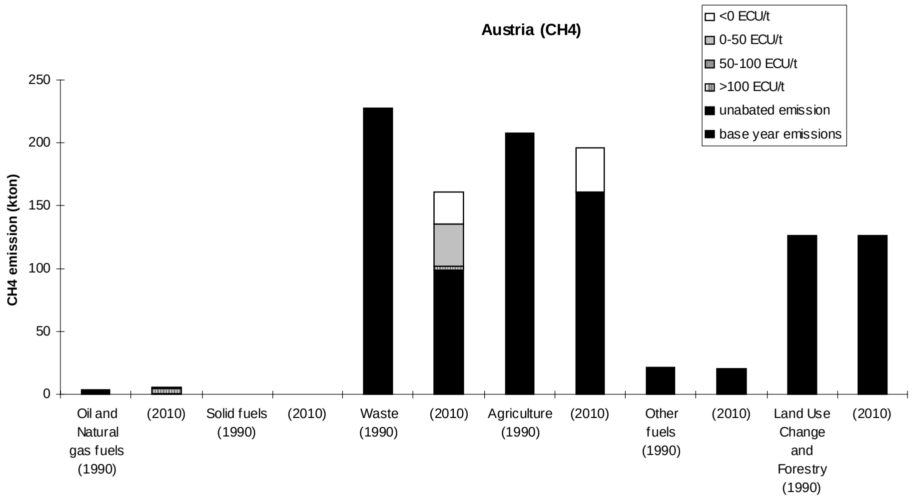
Table 8.3. Member States estimates and projection of nitrous oxide emissions according to the Second National Communications (draft May 1998).

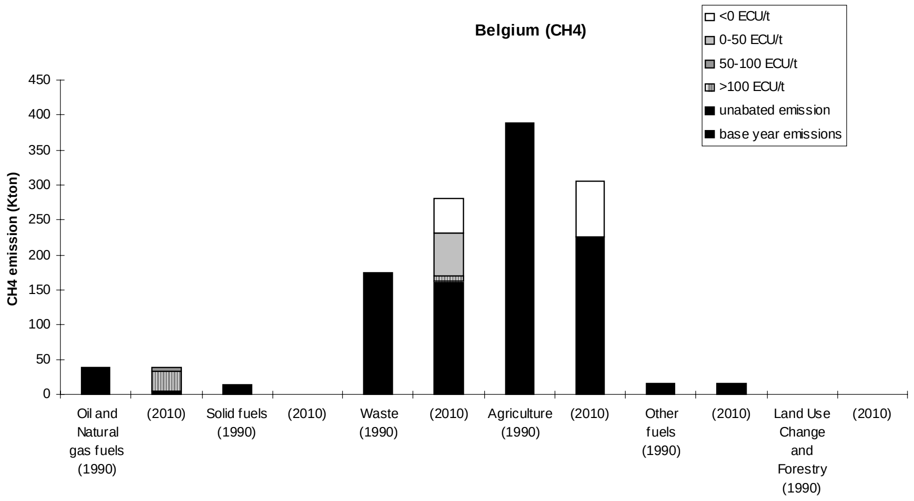
	N2O (kton)	N2O (kton)	N2O (kton)	N2O (kton)	N2O (kton)	N2O (kton)
	1990	2000	2010	1990	2000	2010
AT	12	np	np	100%	np	np
BE	31	34	np	100%	109%	np
DK	34	28	28	100%	82%	82%
FI	18	20	24	100%	108%	131%
FR	182	95	107	100%	52%	59%
DE	226	162	157	100%	72%	69%
GR	17	np	np	100%	np	np
IE	29	26	26	100%	88%	88%
IT	165	161	157	100%	98%	95%
LU	1	1	1	100%	140%	137%
NL	64	74	68	100%	116%	107%
PT	14	14	15	100%	100%	107%
ES	94	94	94	100%	100%	100%
SE	9	11	13	100%	114%	138%
GB	203	133	142	100%	66%	70%
EU	1098	852	831	100%	78%	76%

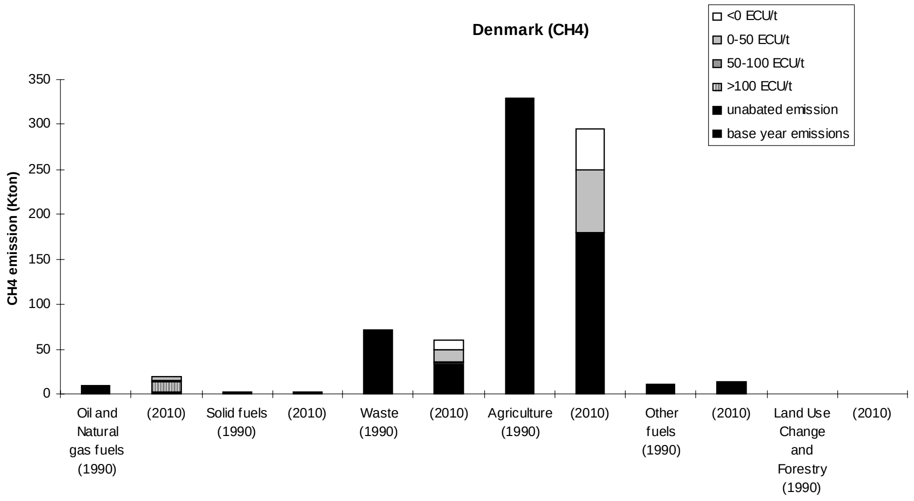
np = emissions not projected

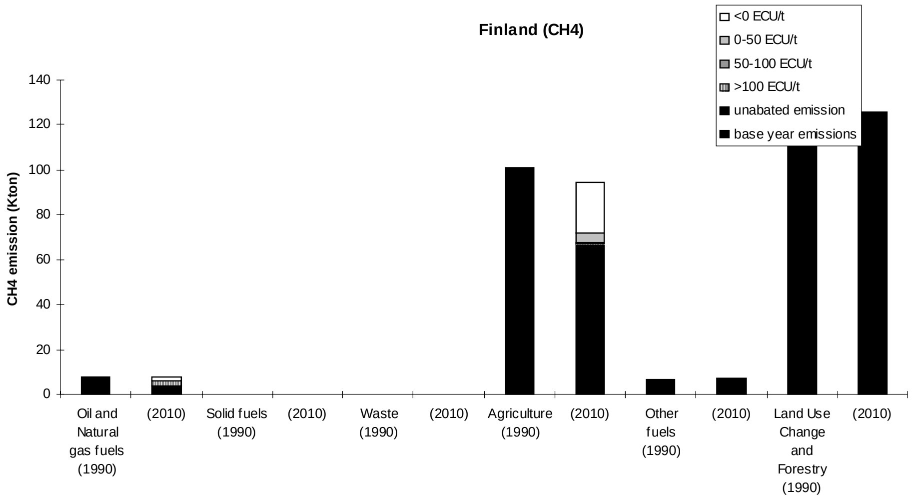
8.2 APPENDIX 2: EMISSIONS AND COST WINDOWS FOR ESTIMATES AND PROJECTIONS

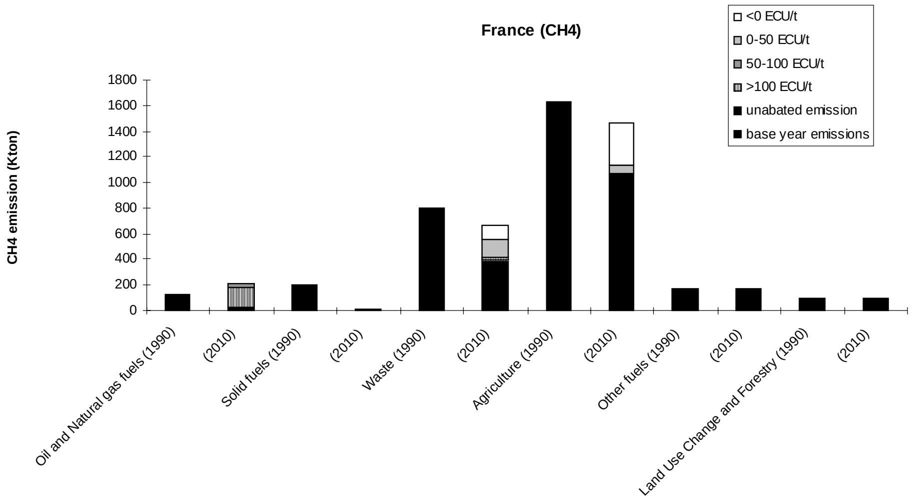
8.3 APPENDIX 3: COST CURVES METHANE AND NITROUS OXIDE FOR MEMBER STATES AND EU-15

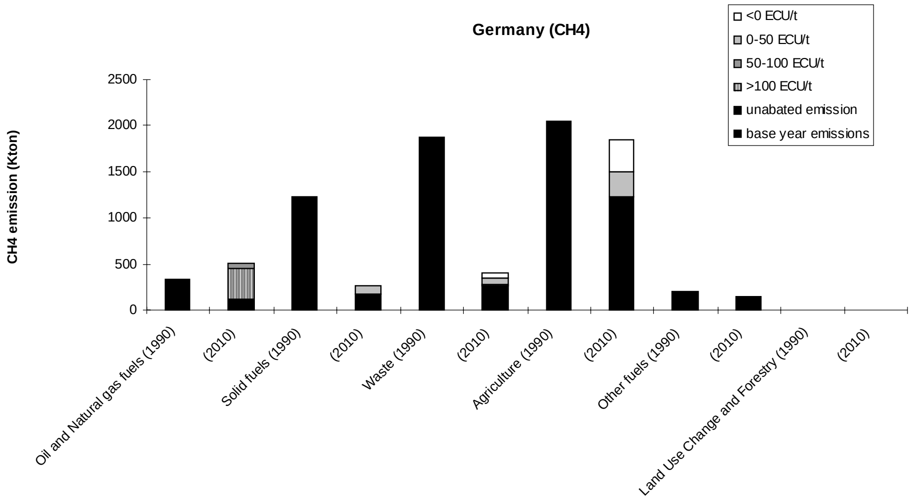

Austria (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
250
200
150
100
50
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

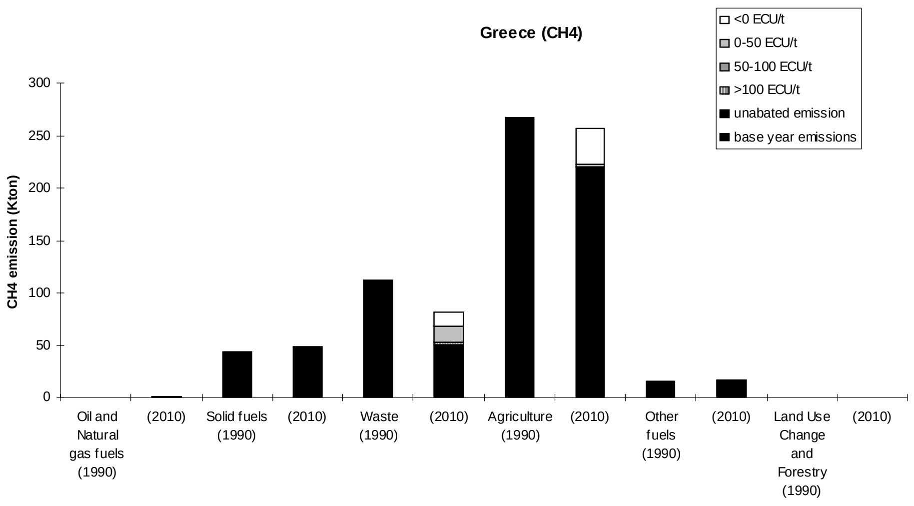

Belgium (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
450
400
350
300
250
200
150
100
50
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

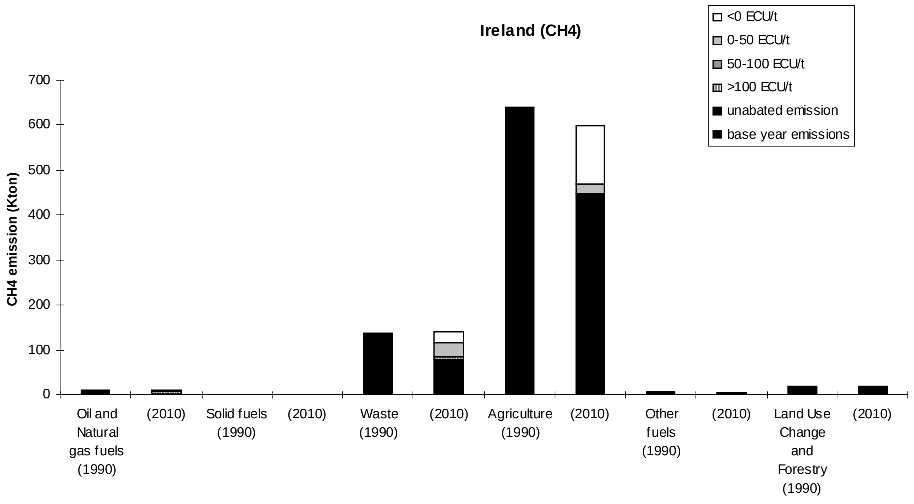

Denmark (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
350
300
250
200
150
100
50
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

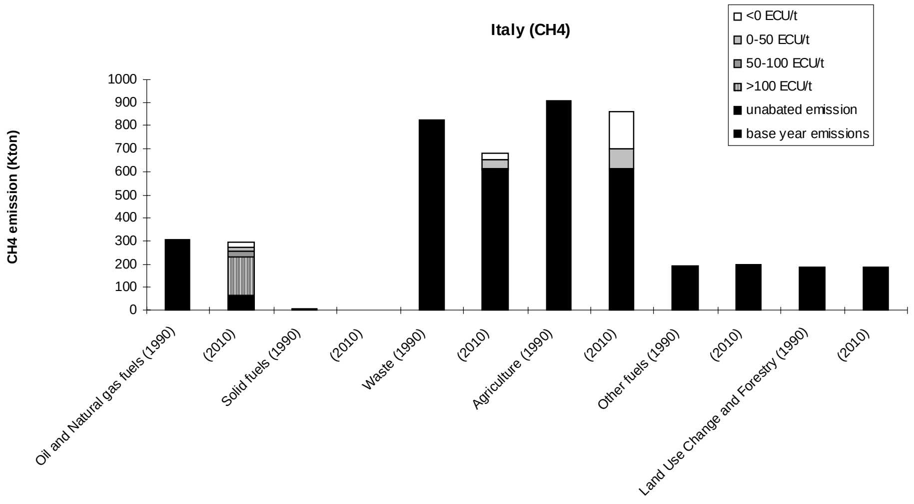

Finland (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
0
20
40
60
80
100
120
140
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

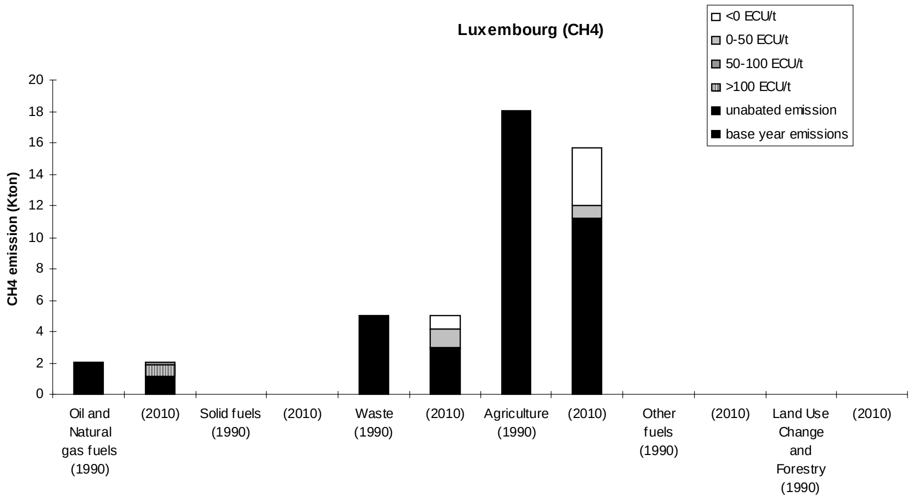

France (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
0
200
400
600
800
1000
1200
1400
1600
1800
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

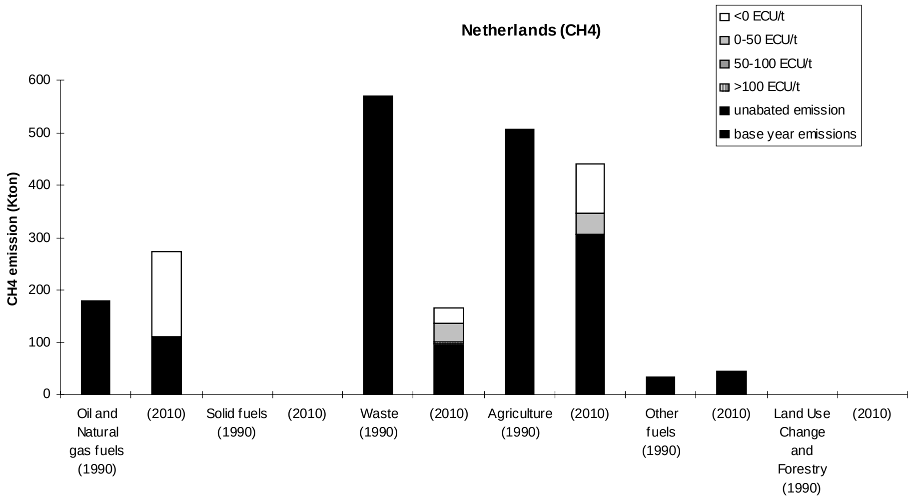

Germany (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
0
500
1000
1500
2000
2500
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

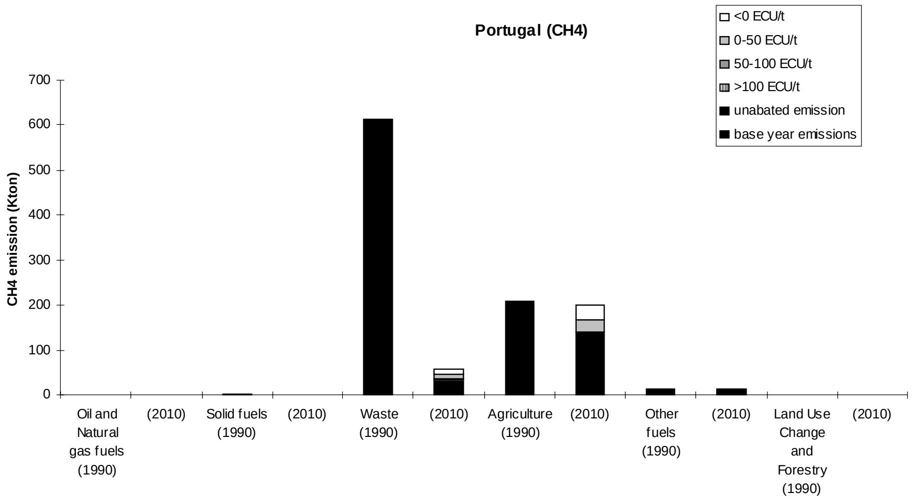

Greece (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
300
250
200
150
100
50
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

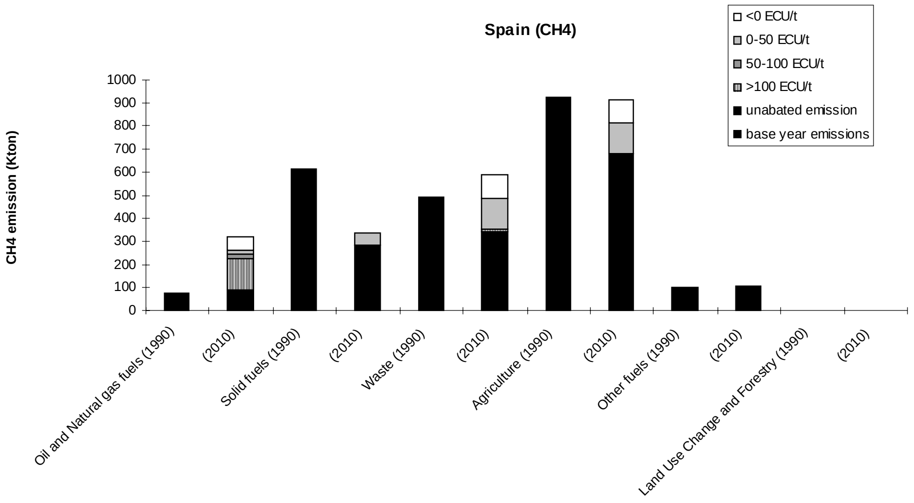

Ireland (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
700
600
500
400
300
200
100
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

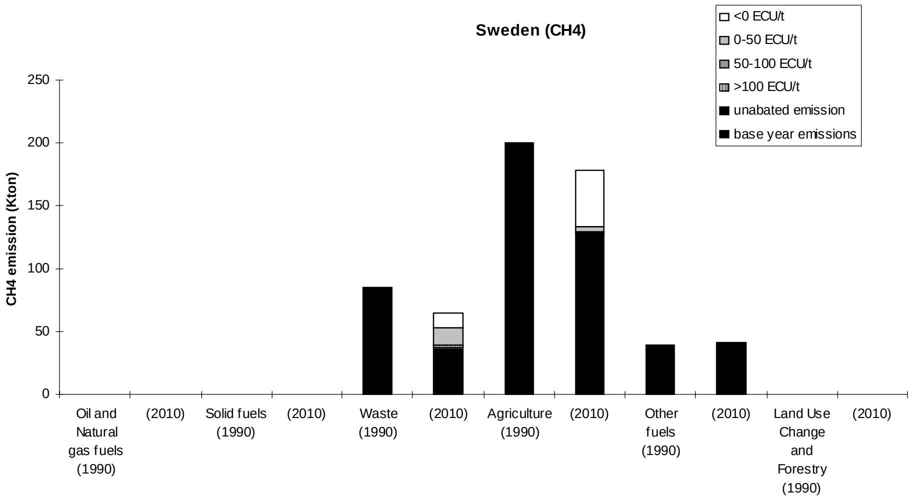

Italy (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
1000
900
800
700
600
500
400
300
200
100
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

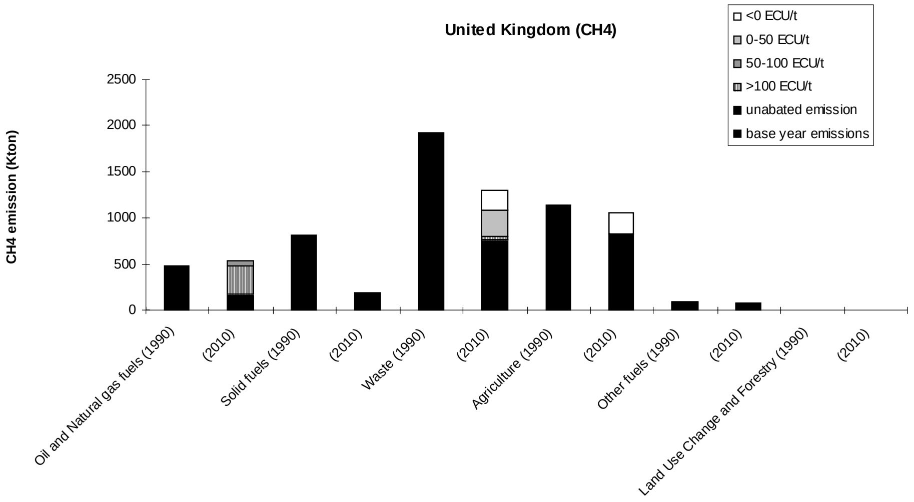

Luxembourg (CH4)
CH4 emission (Kton)
0
2
4
6
8
10
12
14
16
18
20
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
□ <0 ECU/t
▨ 0-50 ECU/t
▨ 50-100 ECU/t
▨ >100 ECU/t
■ unabated emission
■ base year emissions

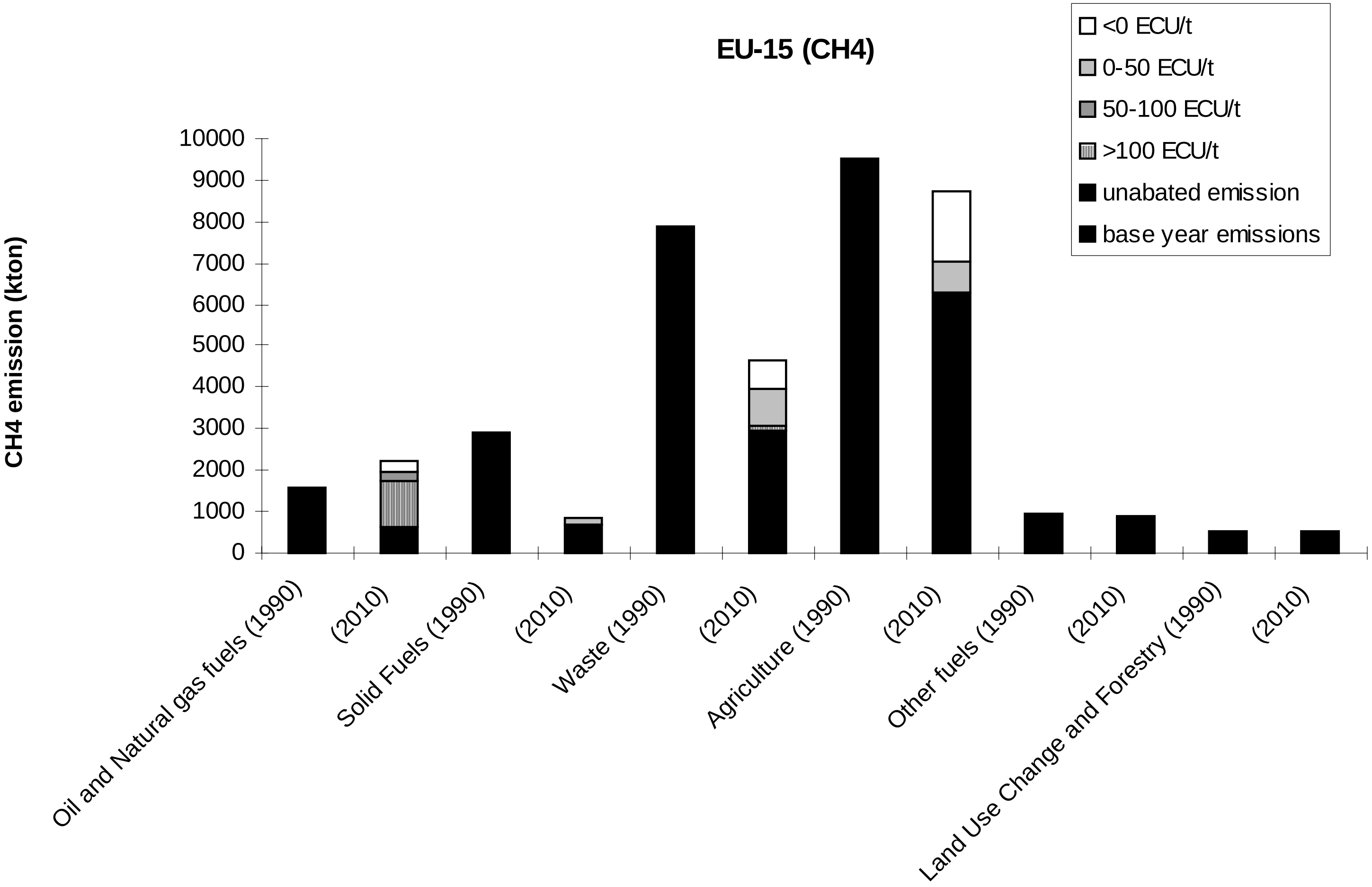

Netherlands (CH4)
CH4 emission (Kton)
0
100
200
300
400
500
600
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
□ <0 ECU/t
▨ 0-50 ECU/t
▨ 50-100 ECU/t
▨ >100 ECU/t
■ unabated emission
■ base year emissions

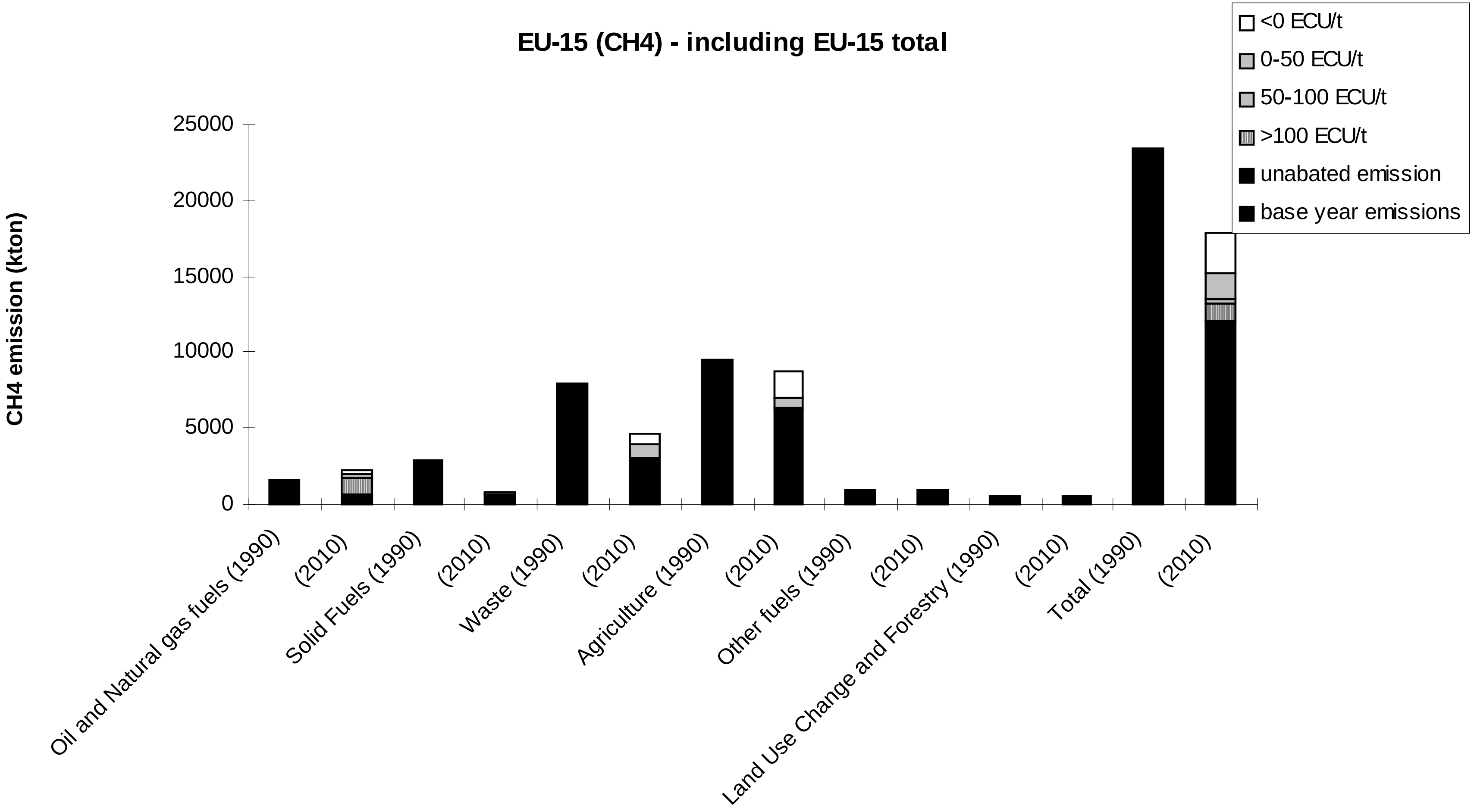

Portugal (CH4)
CH4 emission (Kton)
0
100
200
300
400
500
600
700
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
□ <0 ECU/t
▨ 0-50 ECU/t
▨ 50-100 ECU/t
▨ >100 ECU/t
■ unabated emission
■ base year emissions

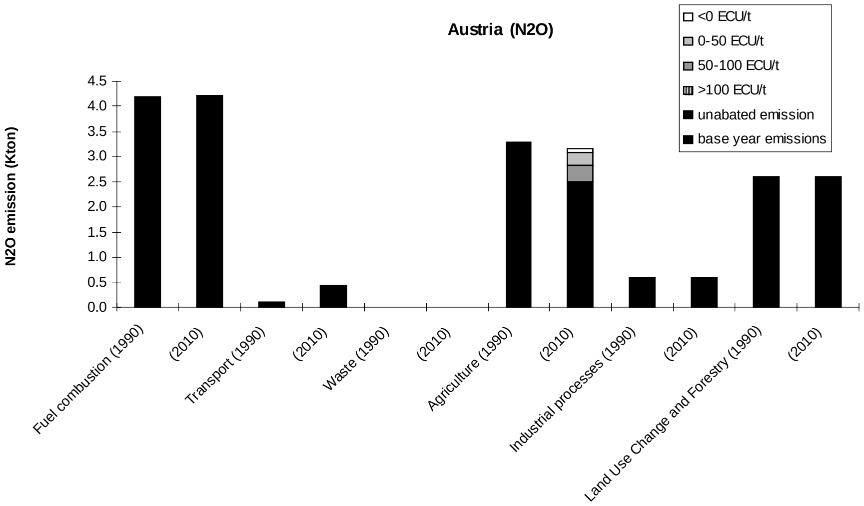

Spain (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
1000
900
800
700
600
500
400
300
200
100
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

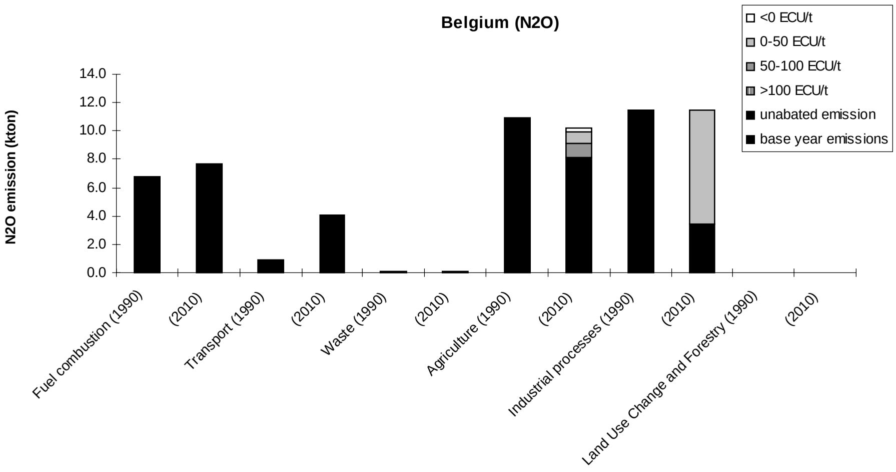

Sweden (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
250
200
150
100
50
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

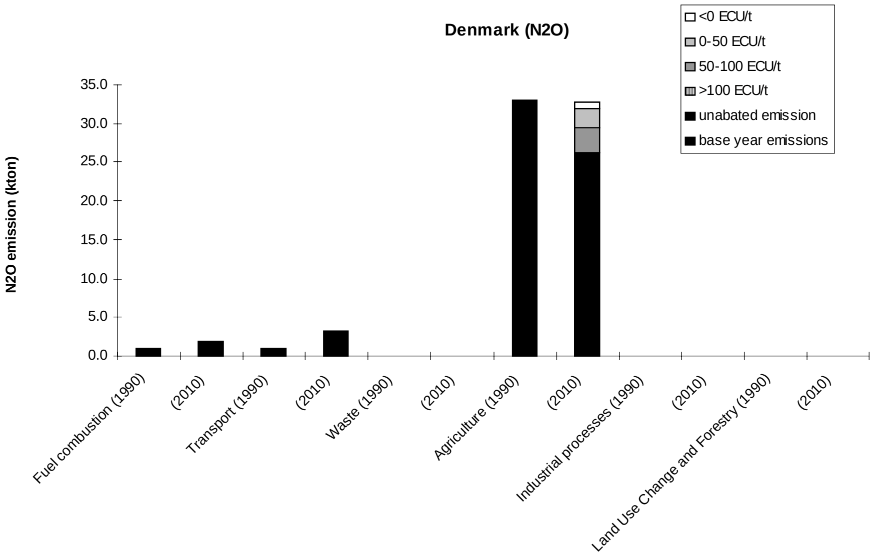

United Kingdom (CH4)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
CH4 emission (Kton)
2500
2000
1500
1000
500
0
Oil and Natural gas fuels (1990)
(2010)
Solid fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

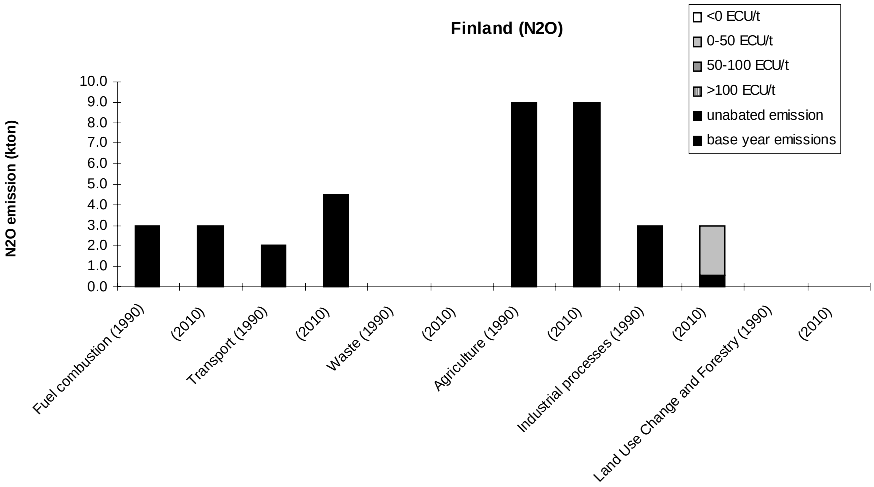

EU-15 (CH4)
CH4 emission (kton)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
Oil and Natural gas fuels (1990)
(2010)
Solid Fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

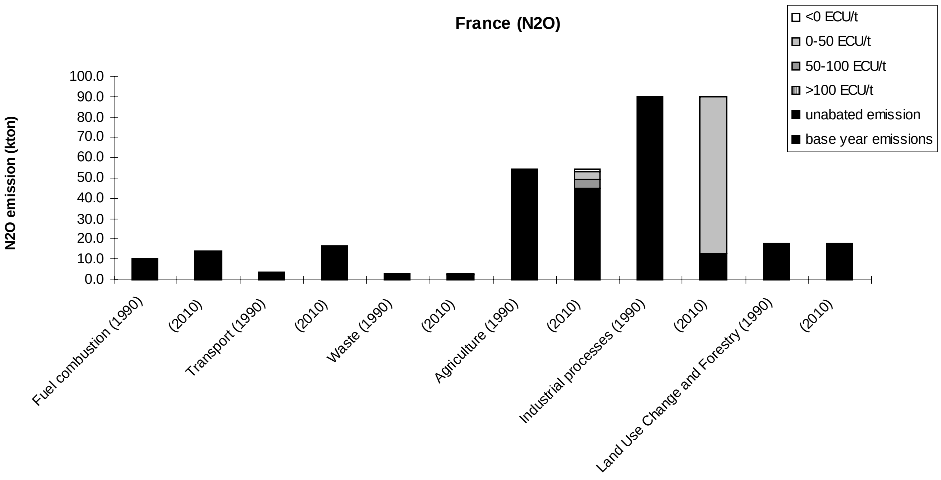

EU-15 (CH4) - including EU-15 total
CH4 emission (kton)
25000
20000
15000
10000
5000
0
Oil and Natural gas fuels (1990)
(2010)
Solid Fuels (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Other fuels (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
Total (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

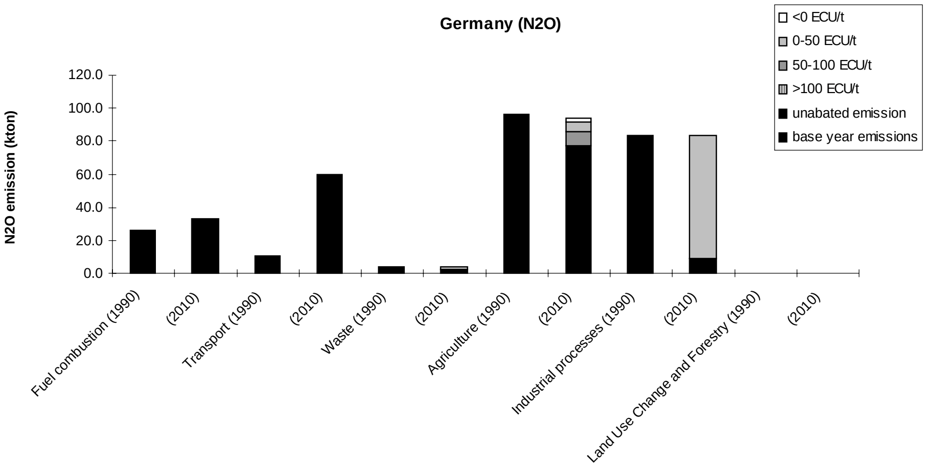

Austria (N2O)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
N2O emission (Kton)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

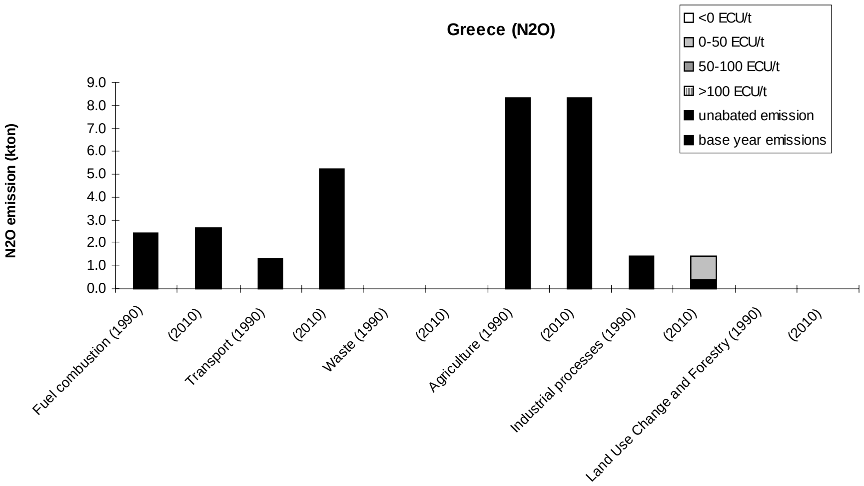

Belgium (N2O)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
N2O emission (kton)
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

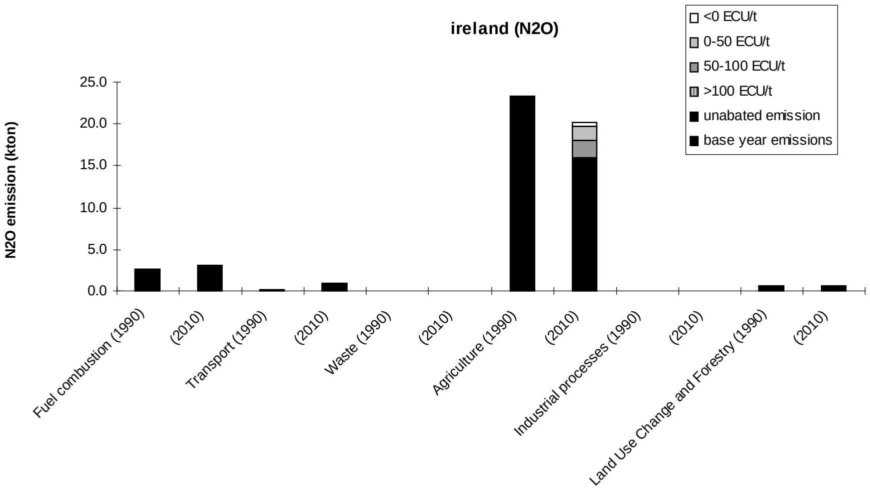

Denmark (N2O)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions
N2O emission (kton)
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)

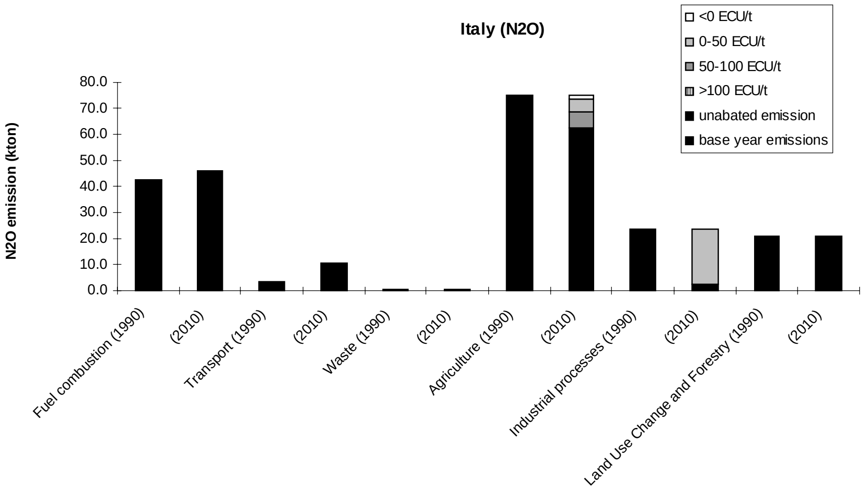

Finland (N2O)
N2O emission (kton)
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

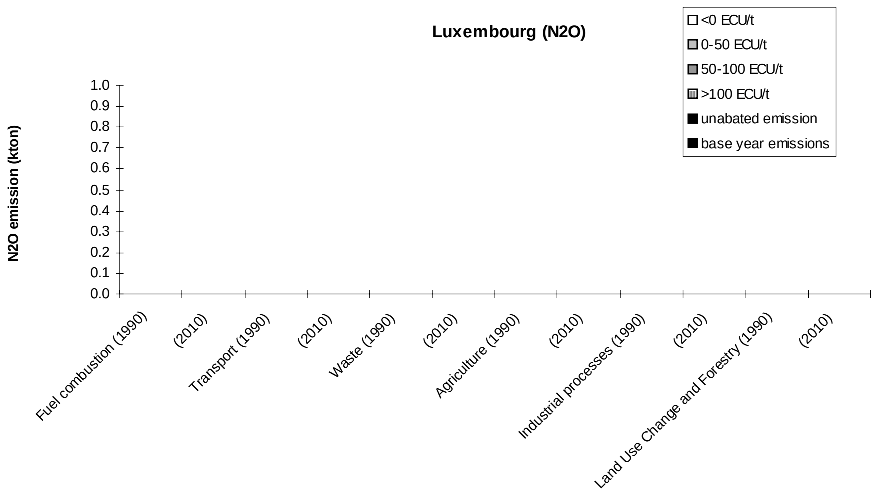

France (N2O)
N2O emission (kton)
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

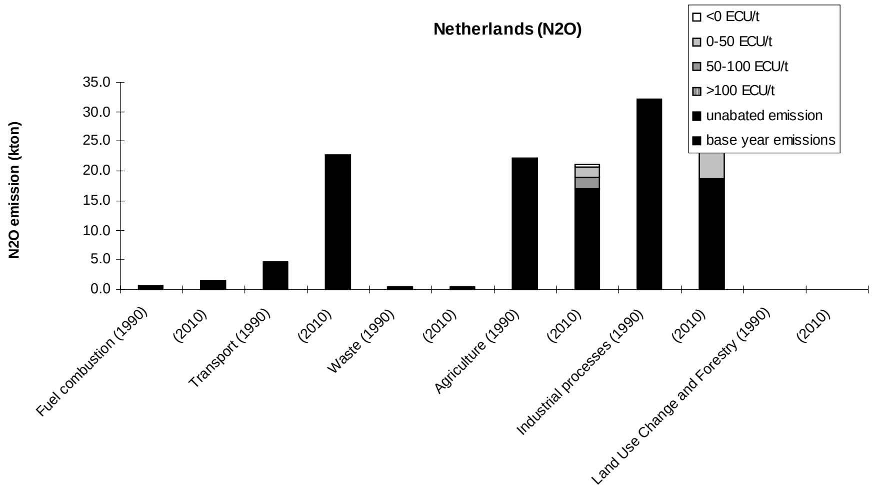

Germany (N2O)
N2O emission (kton)
120.0
100.0
80.0
60.0
40.0
20.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

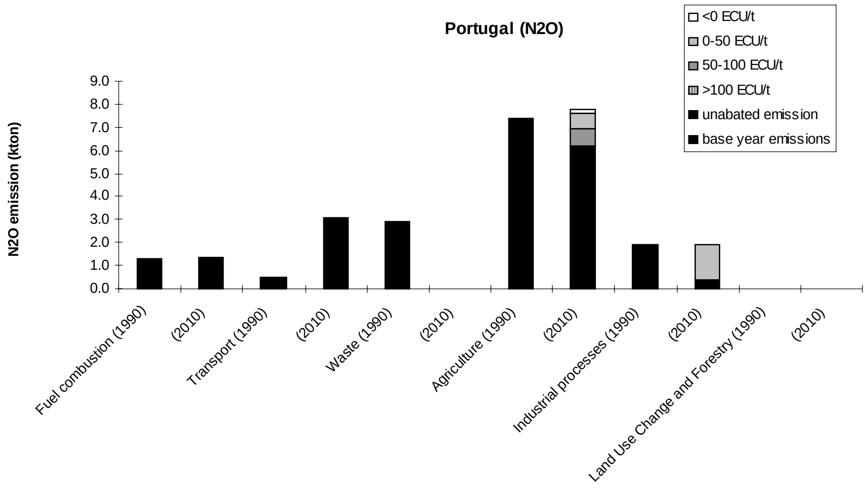

Greece (N2O)
N2O emission (kton)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

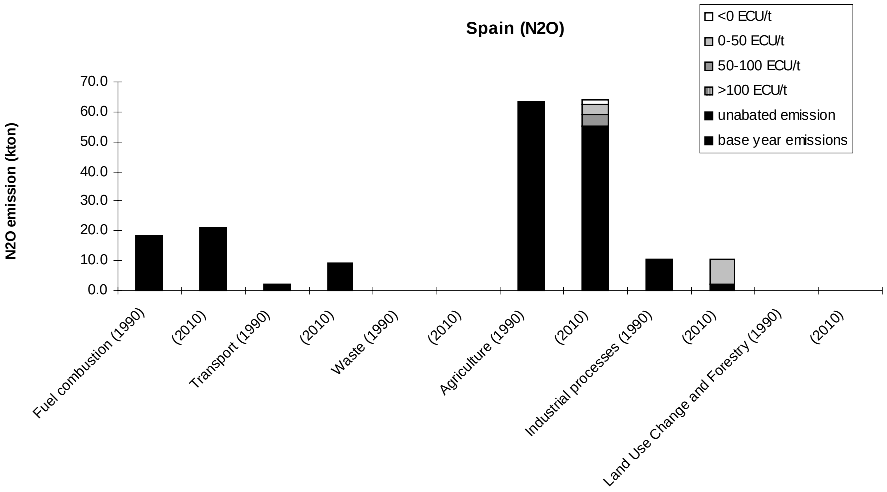

ireland (N2O)
N2O emission (kton)
25.0
20.0
15.0
10.0
5.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

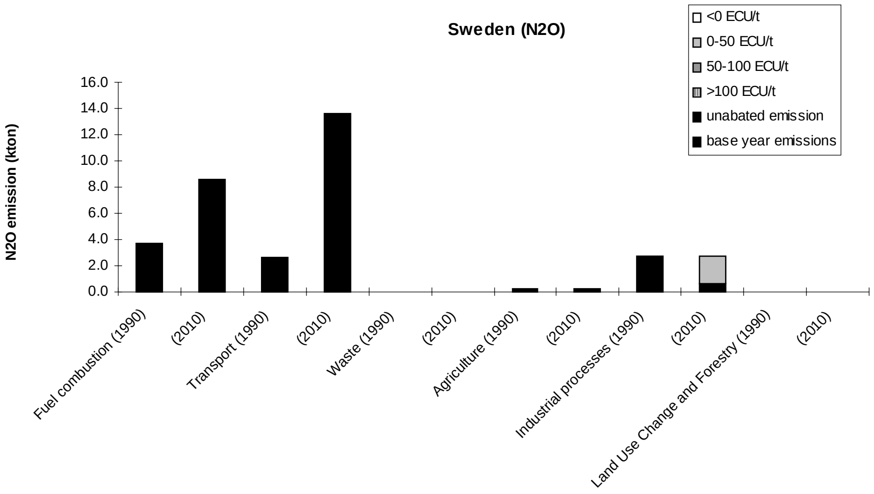

Italy (N2O)
N2O emission (kton)
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

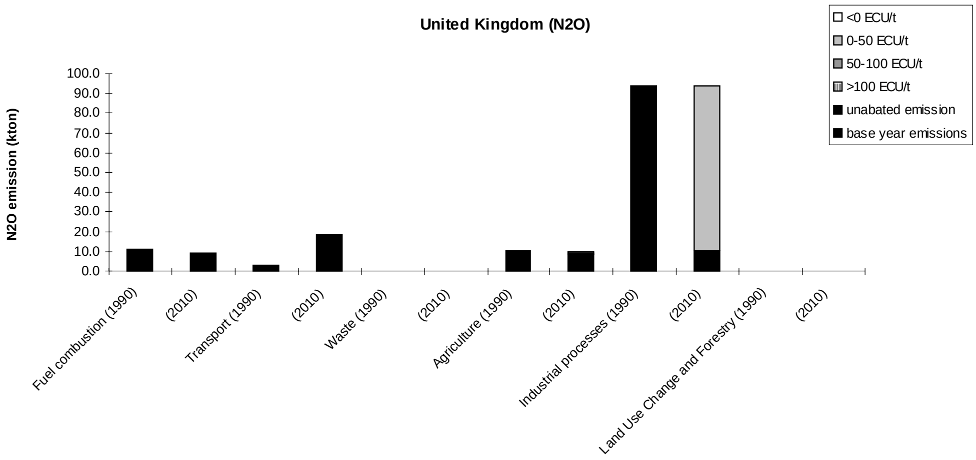

Luxembourg (N2O)
N2O emission (kton)
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

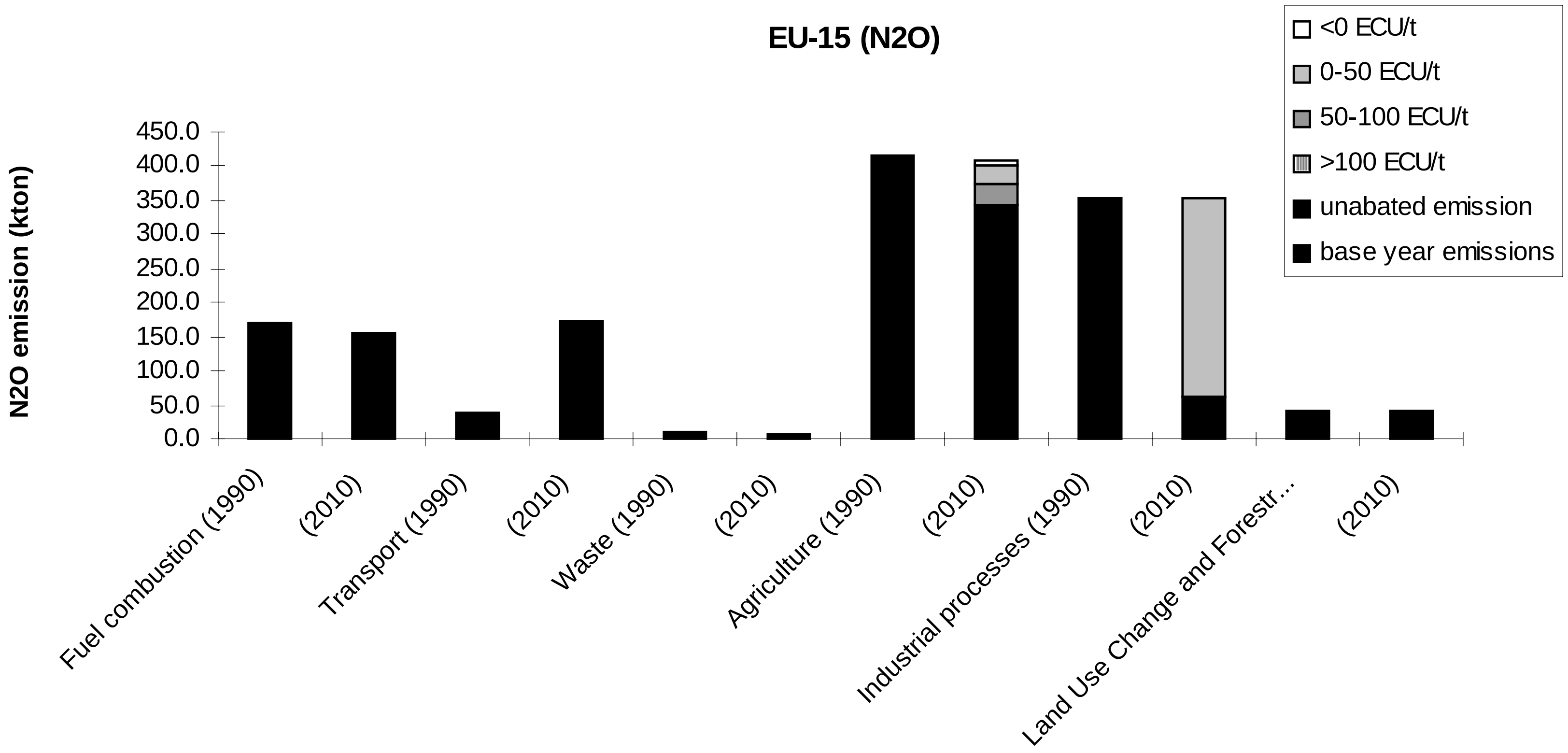

Netherlands (N2O)
N2O emission (kton)
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

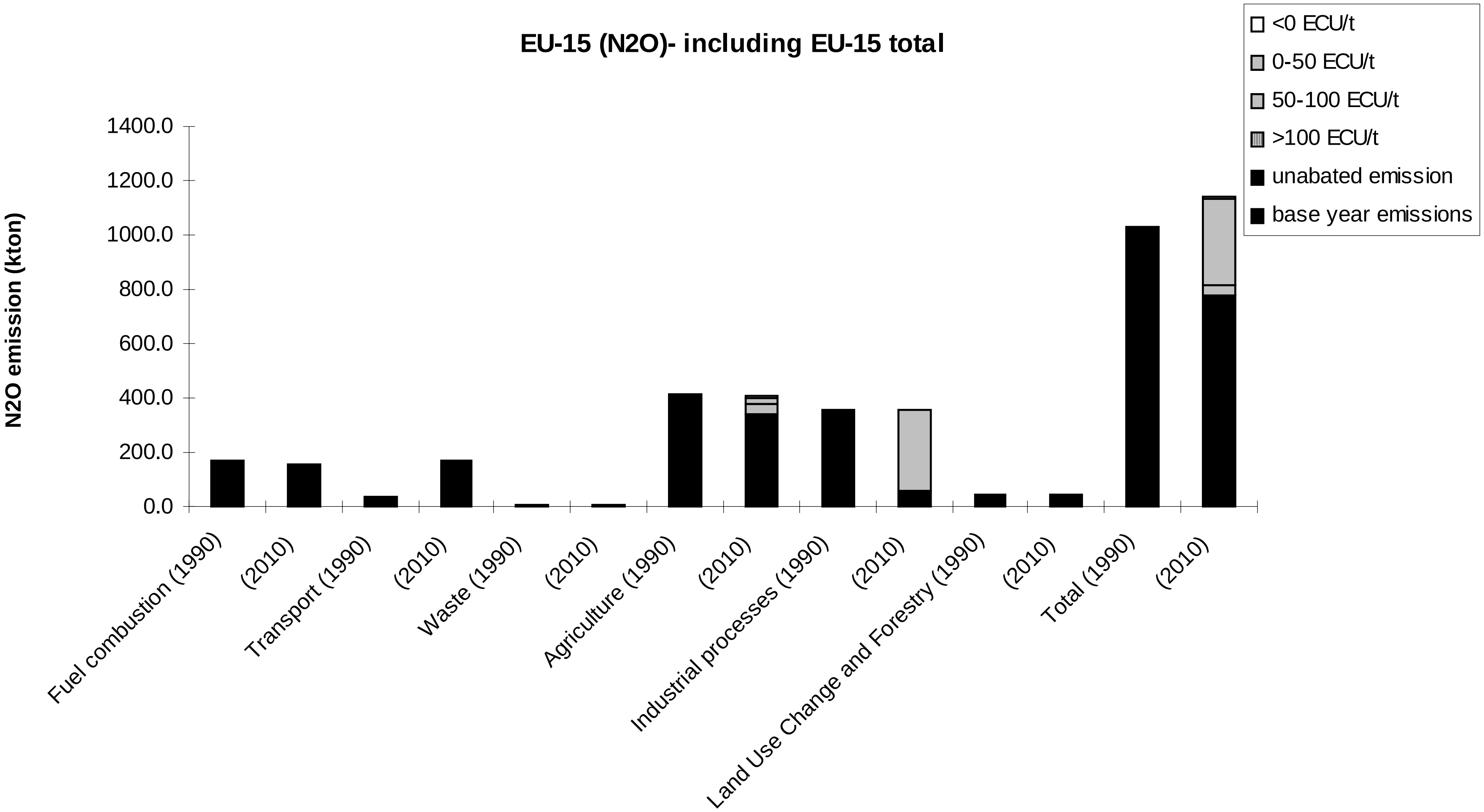

Portugal (N2O)
N2O emission (kton)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

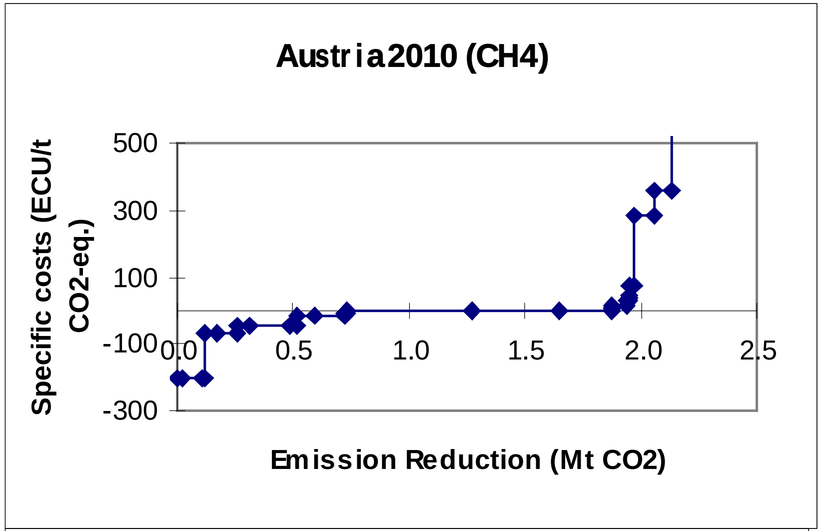

Spain (N2O)
N2O emission (kton)
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
☐ <0 ECU/t
▨ 0-50 ECU/t
▨ 50-100 ECU/t
▨ >100 ECU/t
■ unabated emission
■ base year emissions

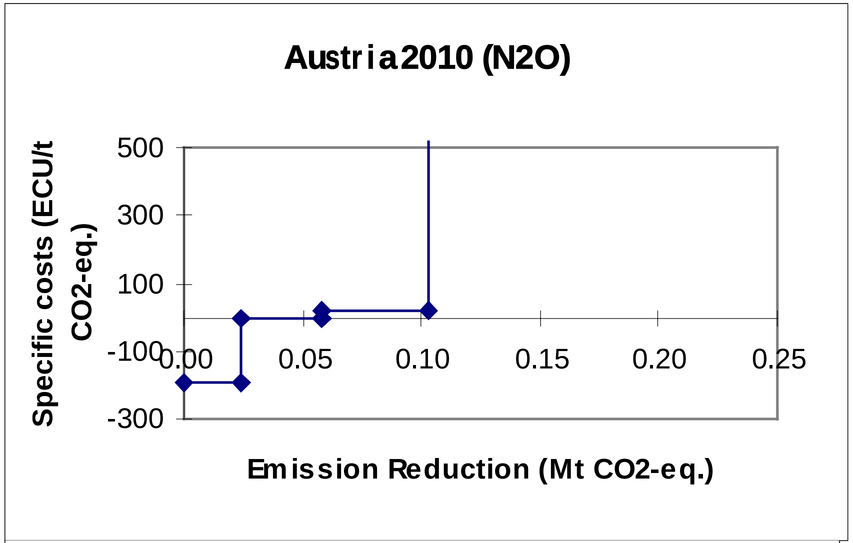

Sweden (N2O)
N2O emission (kton)
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
☐ <0 ECU/t
▨ 0-50 ECU/t
▨ 50-100 ECU/t
▨ >100 ECU/t
■ unabated emission
■ base year emissions

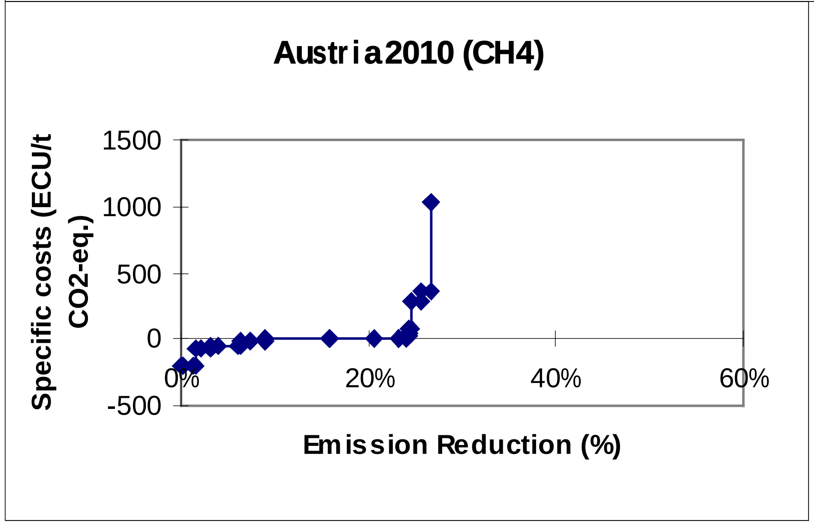

United Kingdom (N2O)
N2O emission (kton)
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
☐ <0 ECU/t
▨ 0-50 ECU/t
▨ 50-100 ECU/t
▨ >100 ECU/t
■ unabated emission
■ base year emissions

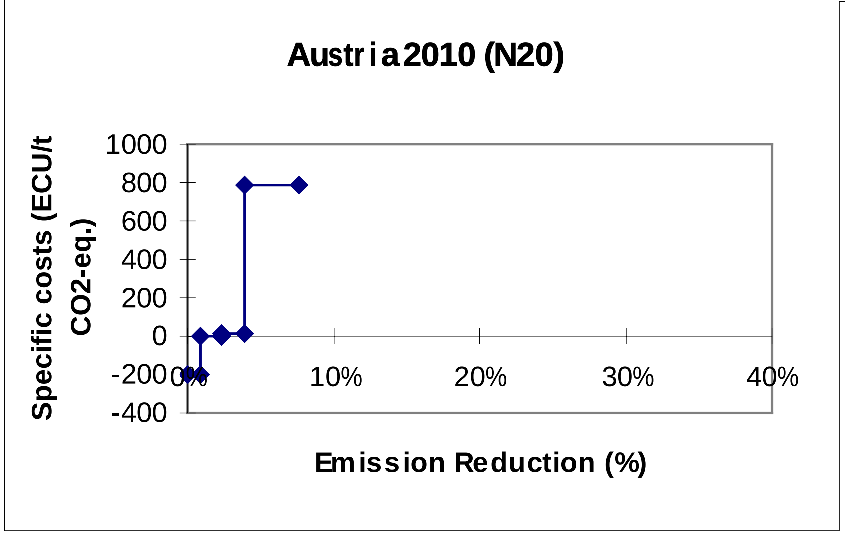

EU-15 (N2O)
N2O emission (kton)
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestr...
(2010)
□ <0 ECU/t
▨ 0-50 ECU/t
▨ 50-100 ECU/t
▥ >100 ECU/t
■ unabated emission
■ base year emissions

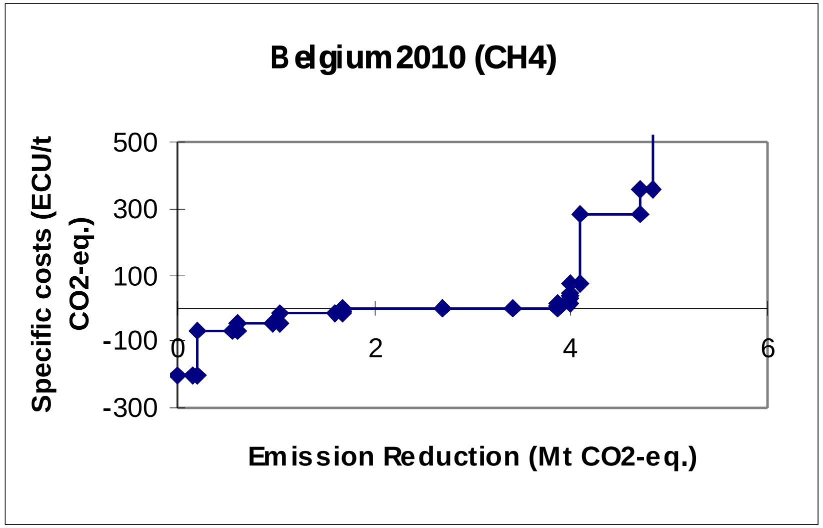

EU-15 (N2O)- including EU-15 total
N2O emission (kton)
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
Fuel combustion (1990)
(2010)
Transport (1990)
(2010)
Waste (1990)
(2010)
Agriculture (1990)
(2010)
Industrial processes (1990)
(2010)
Land Use Change and Forestry (1990)
(2010)
Total (1990)
(2010)
<0 ECU/t
0-50 ECU/t
50-100 ECU/t
>100 ECU/t
unabated emission
base year emissions

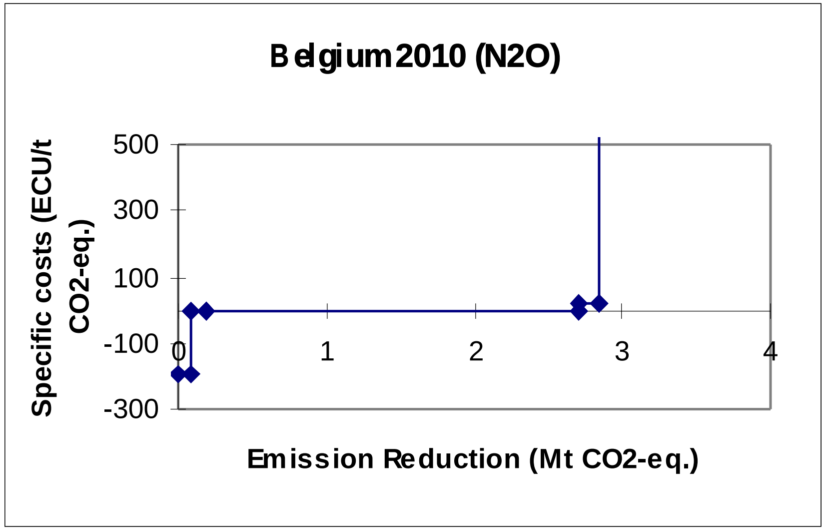

Austria 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.5
1.0
1.5
2.0
2.5
Emission Reduction (Mt CO2)

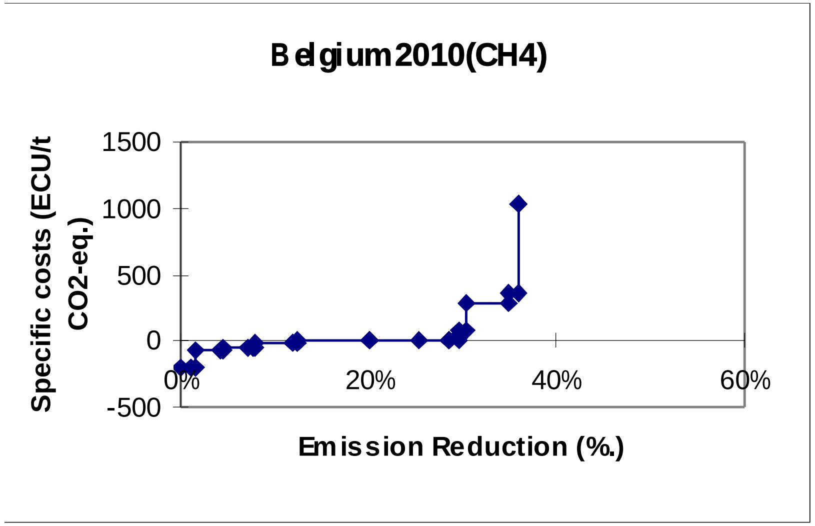

Austria 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.00
0.05
0.10
0.15
0.20
0.25
Emission Reduction (Mt CO2-eq.)

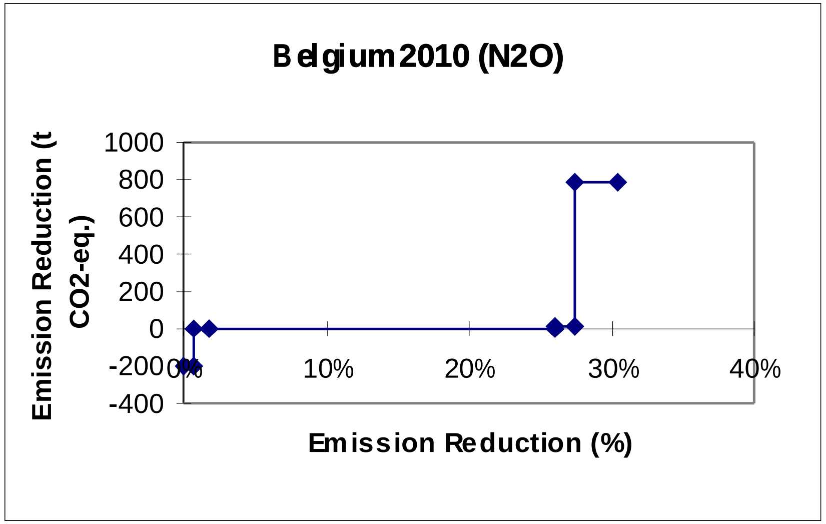

Austria 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

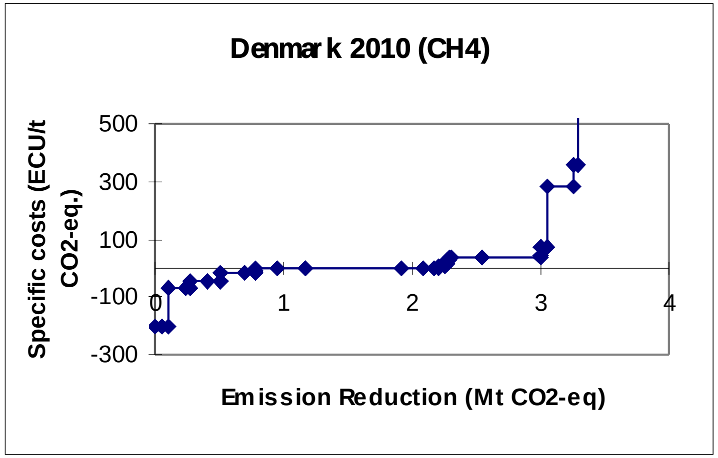

Austria 2010 (N20)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

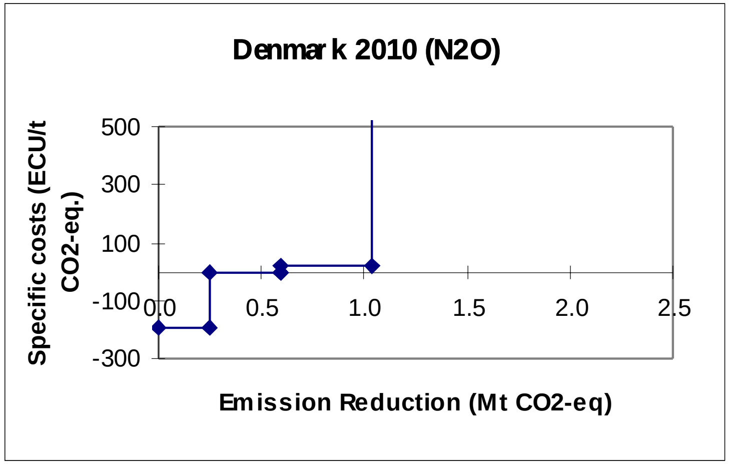

Belgium 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
2
4
6
Emission Reduction (Mt CO2-eq.)

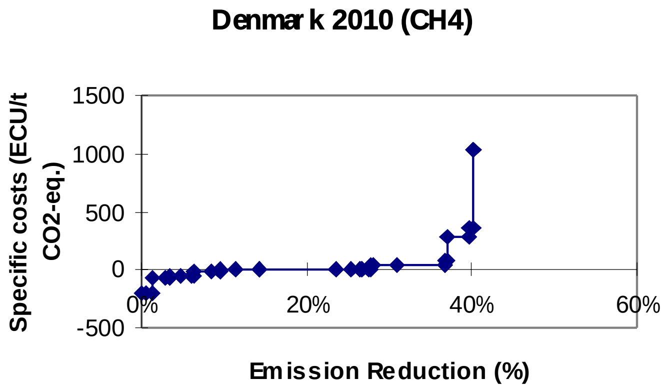

Belgium 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
1
2
3
4
Emission Reduction (Mt CO2-eq.)

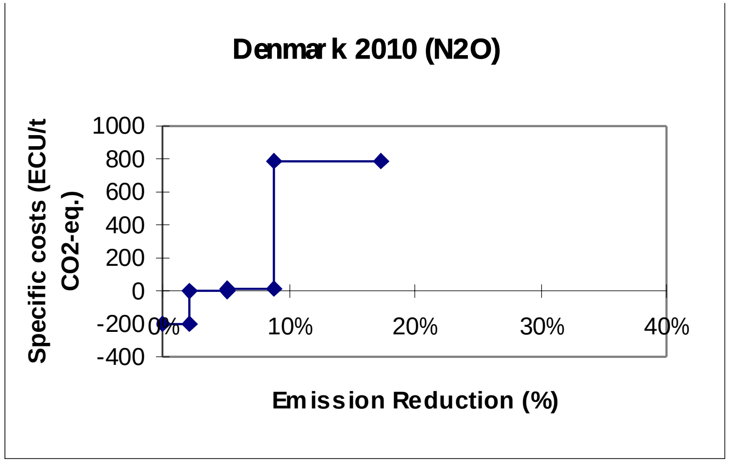

Belgium 2010(CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%.)

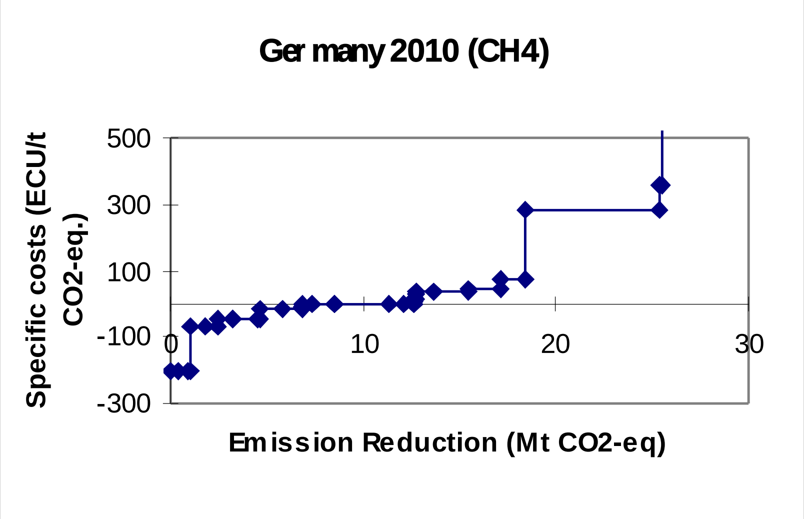

Belgium 2010 (N2O)
Emission Reduction (t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

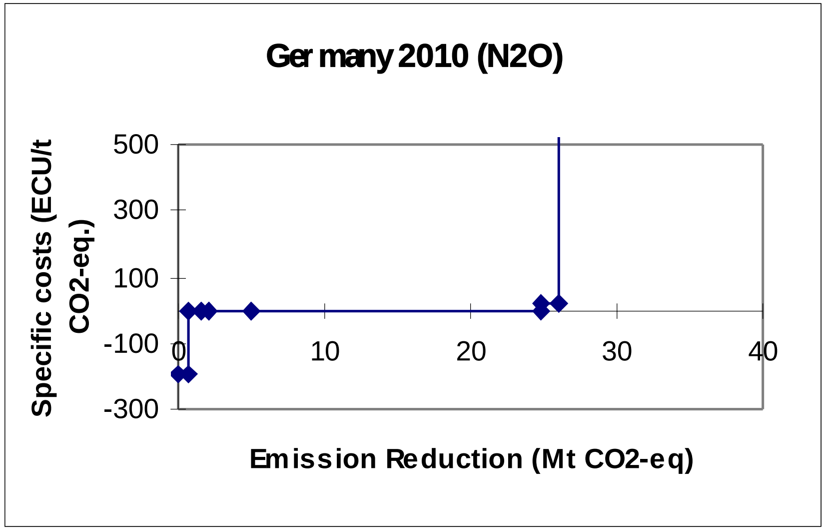

Denmar k 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
1
2
3
4
Em ission Reduction (Mt CO2-eq)

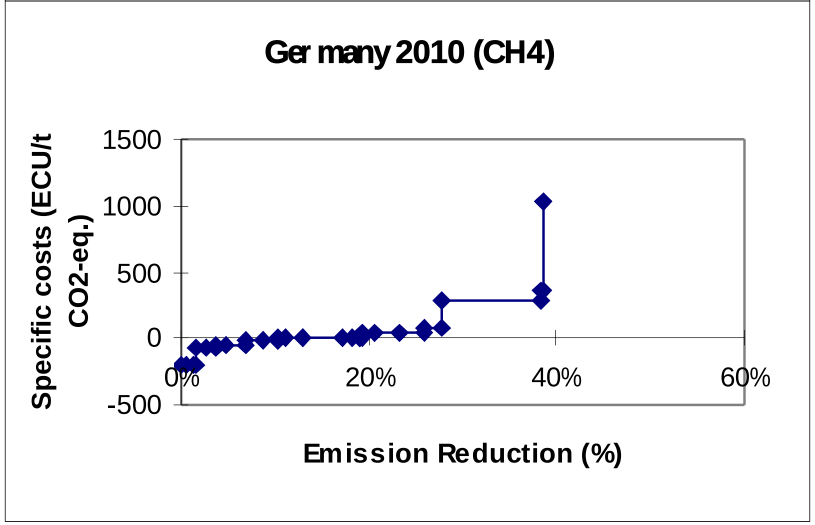

Denmar k 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.5
1.0
1.5
2.0
2.5
Em ission Reduction (Mt CO2-eq)

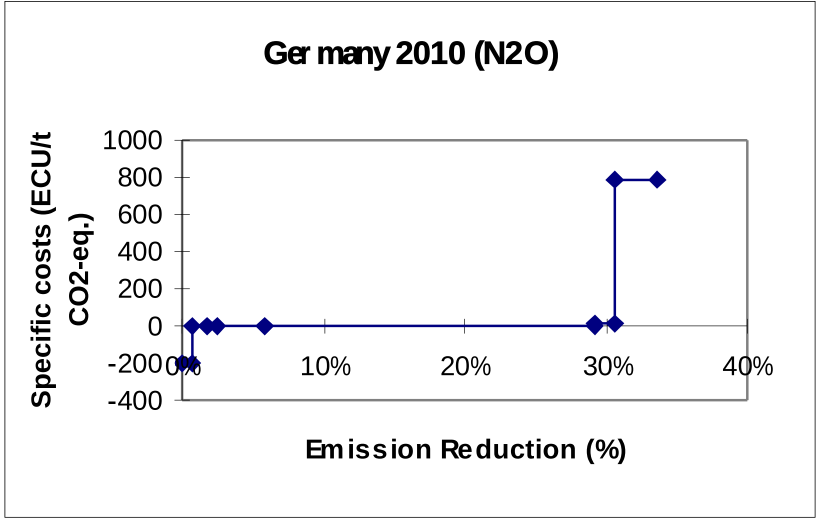

Denmar k 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Em ission Reduction (%)

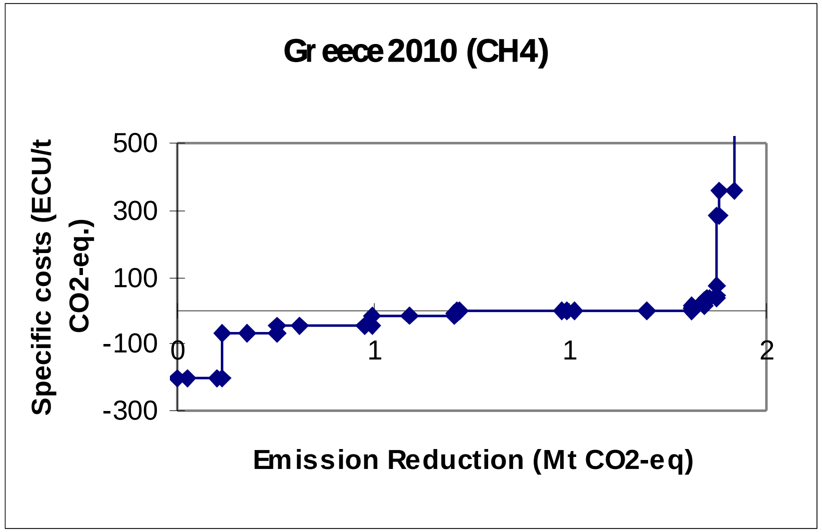

Denmar k 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Em ission Reduction (%)

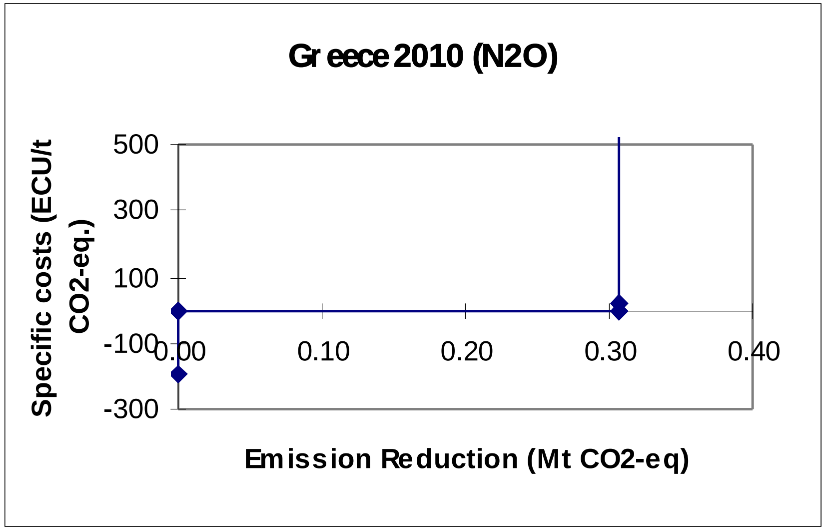

Ger many 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
10
20
30
Emission Reduction (Mt CO2-eq)

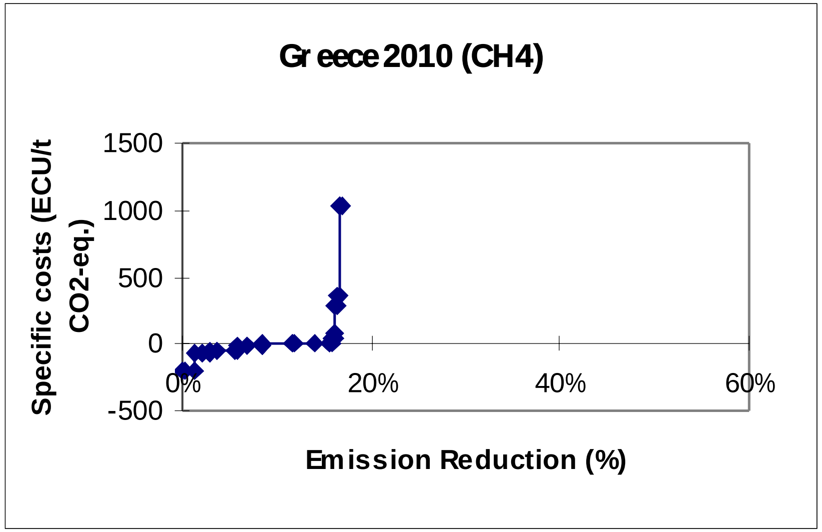

Ger many 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
10
20
30
40
Emission Reduction (Mt CO2-eq)

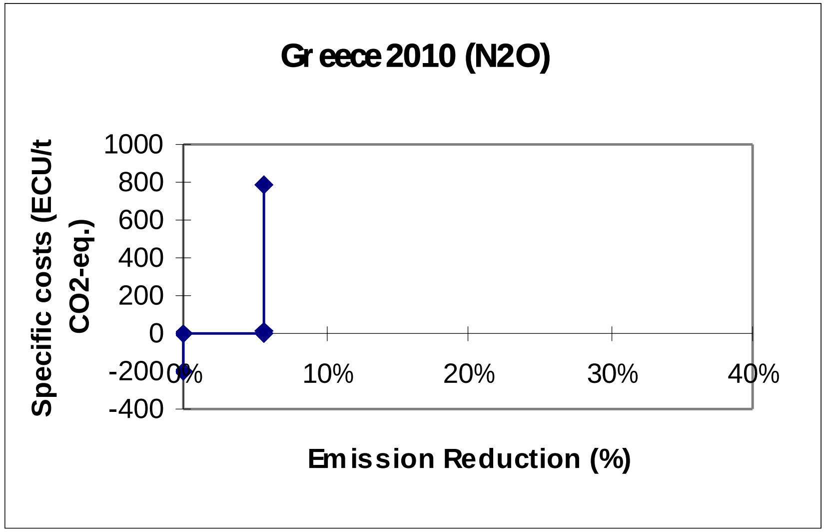

Ger many 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

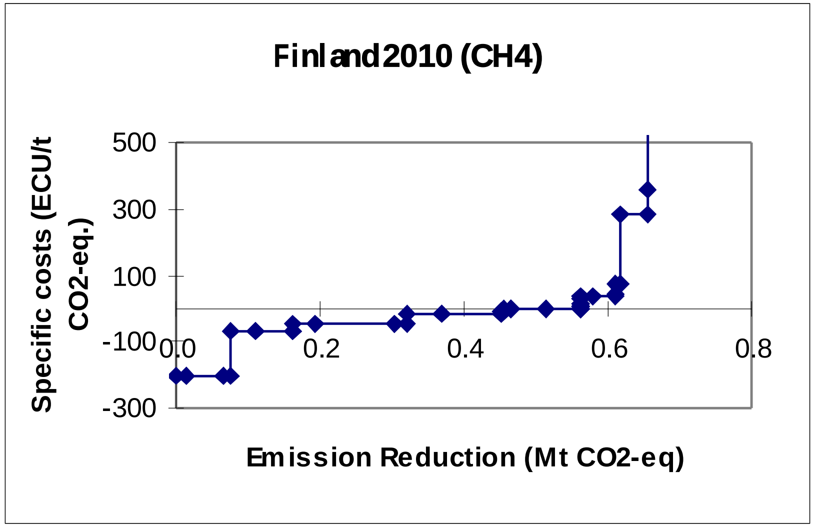

Ger many 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

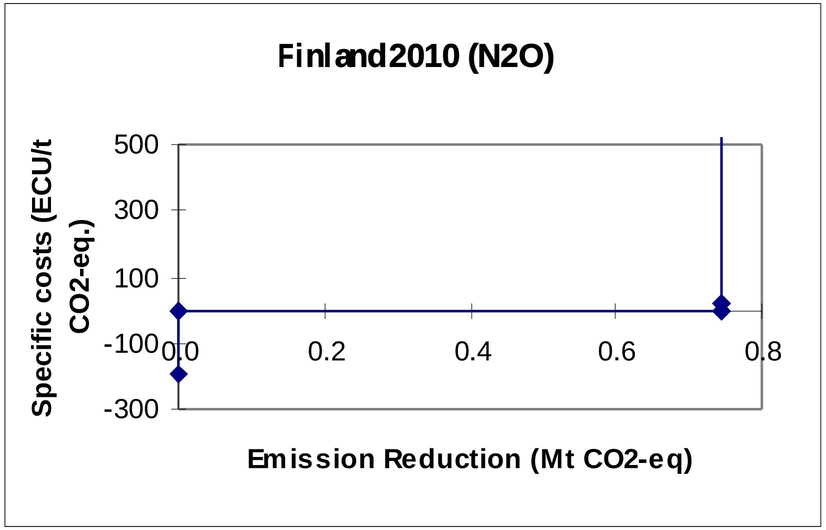

Greece 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
1
1
2
Emission Reduction (Mt CO2-eq)

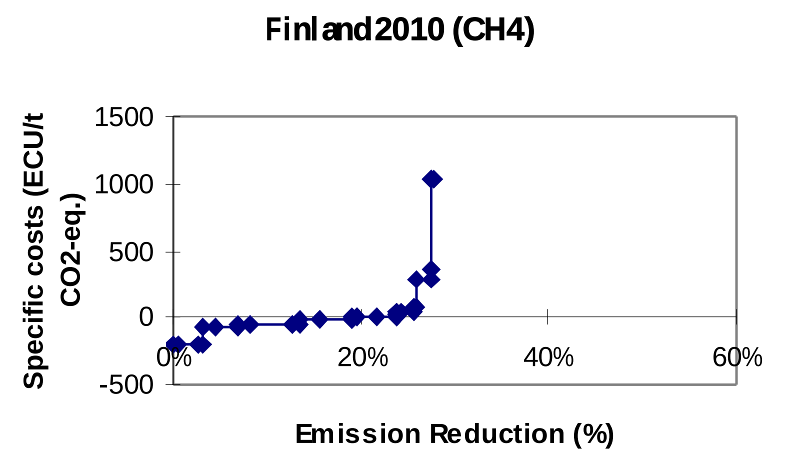

Greece 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.00
0.10
0.20
0.30
0.40
Emission Reduction (Mt CO2-eq)

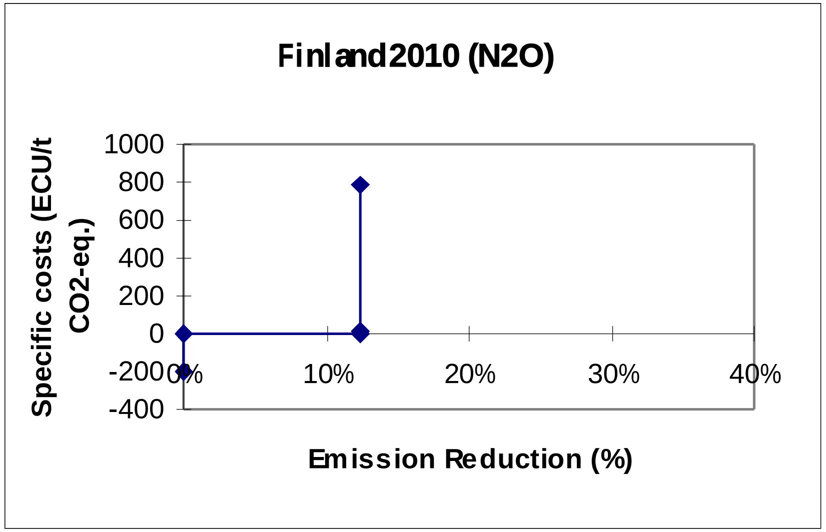

Greece 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

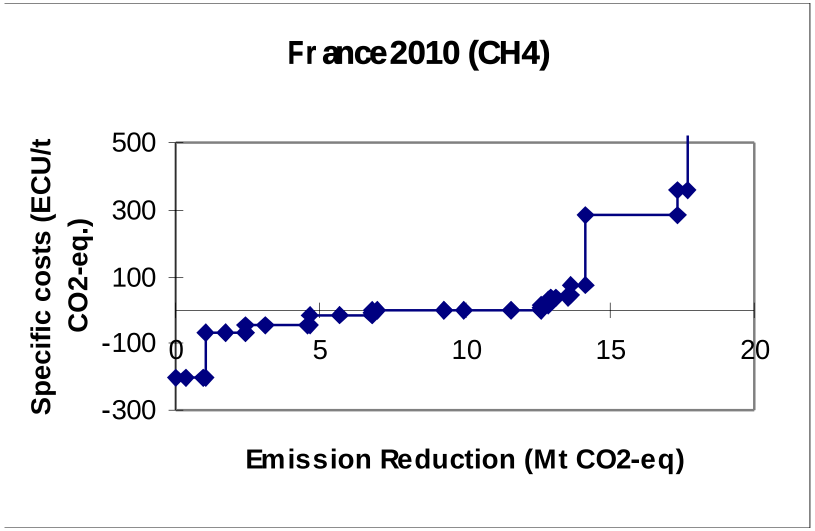

Greece 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

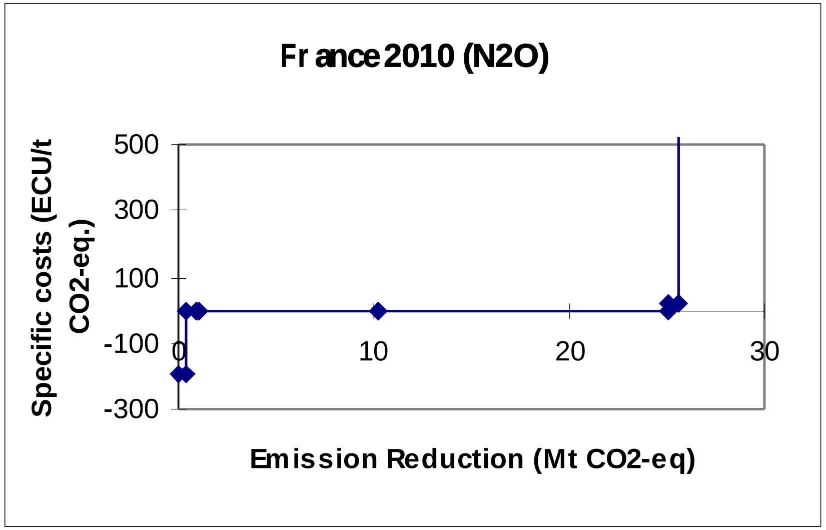

Finland2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.2
0.4
0.6
0.8
Emission Reduction (Mt CO2-eq)

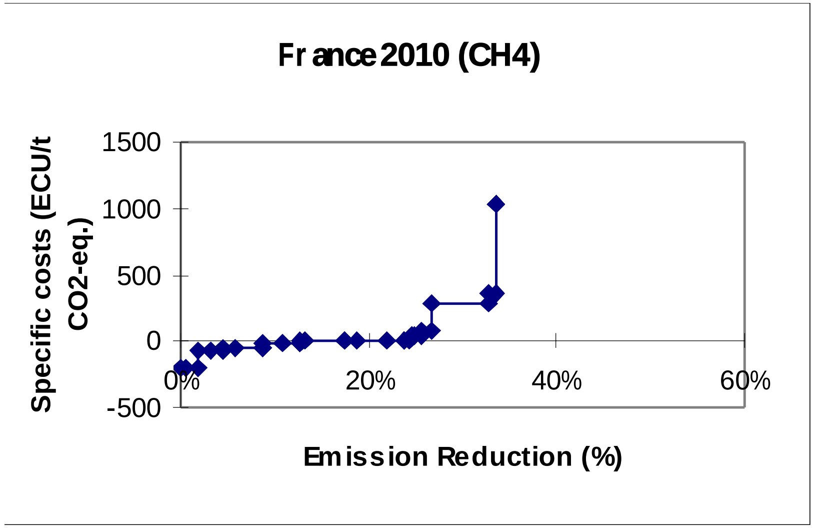

Finland2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.2
0.4
0.6
0.8
Emission Reduction (Mt CO2-eq)

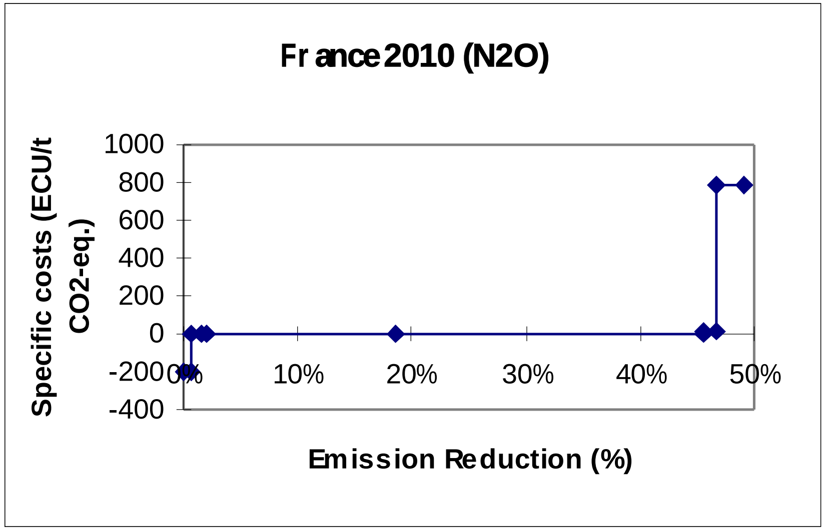

Finland2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

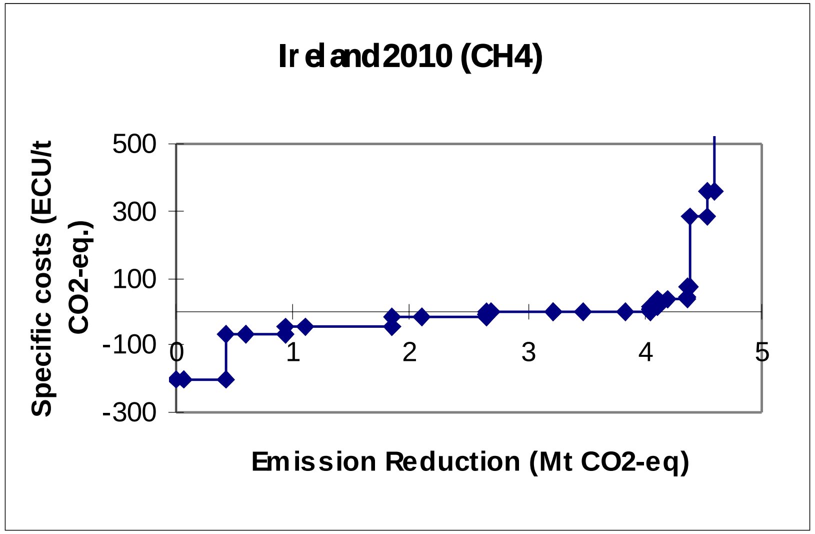

Finland2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

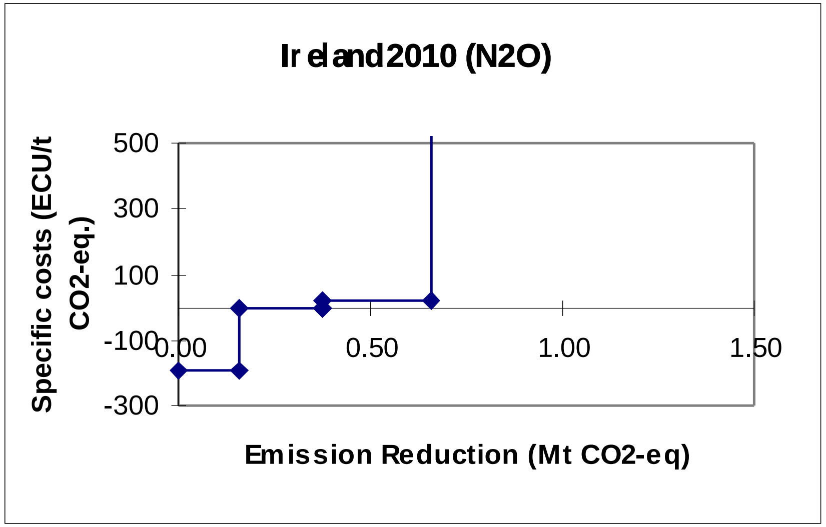

France 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
5
10
15
20
Emission Reduction (Mt CO2-eq)

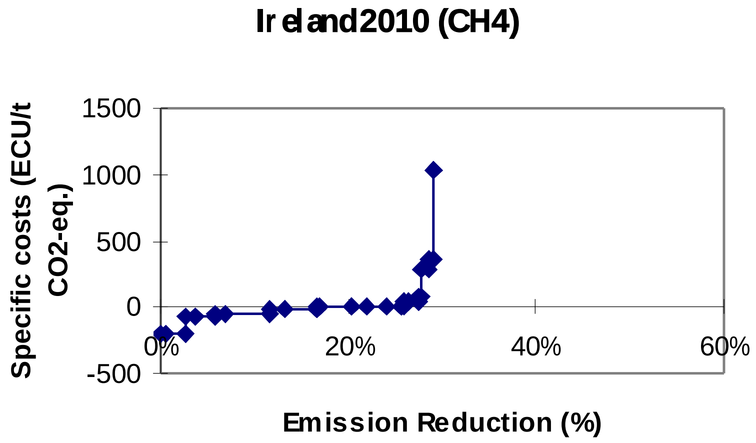

France 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
10
20
30
Emission Reduction (Mt CO2-eq)

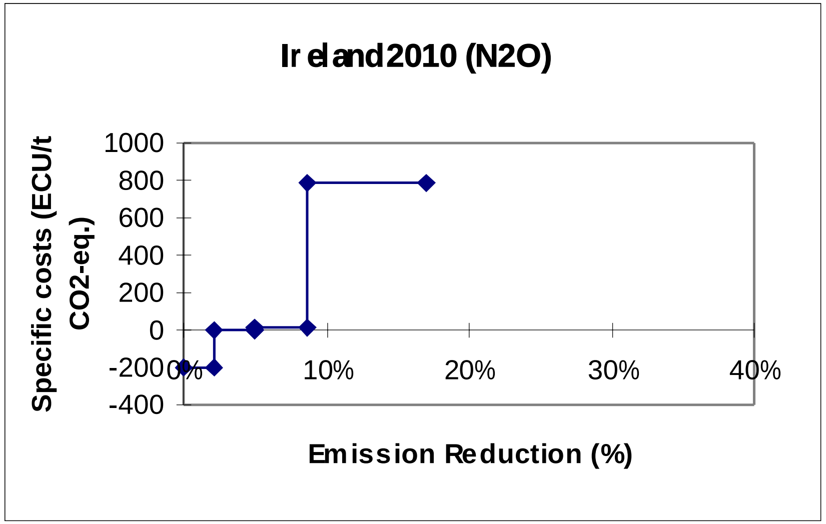

France 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

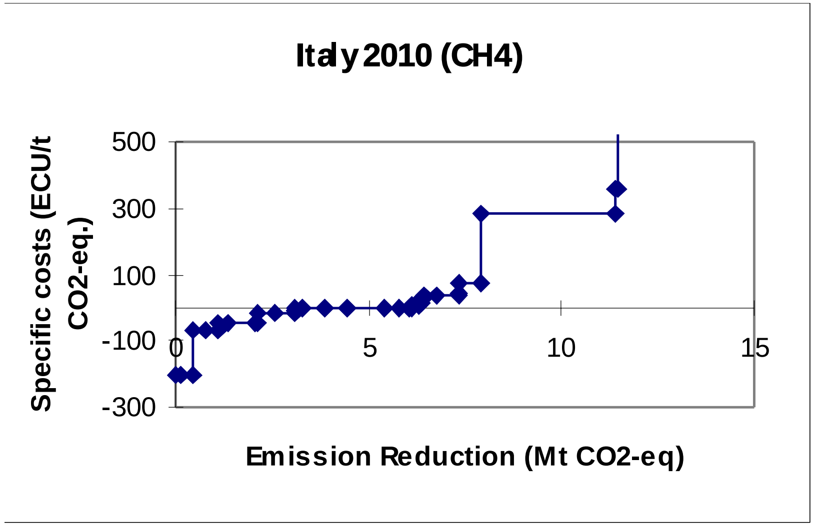

France 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
50%
Emission Reduction (%)

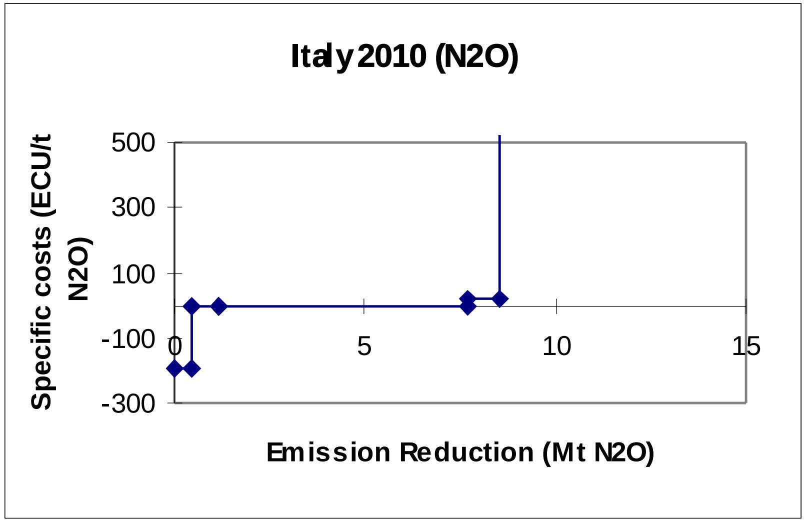

Ireland2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
1
2
3
4
5
Emission Reduction (Mt CO2-eq)

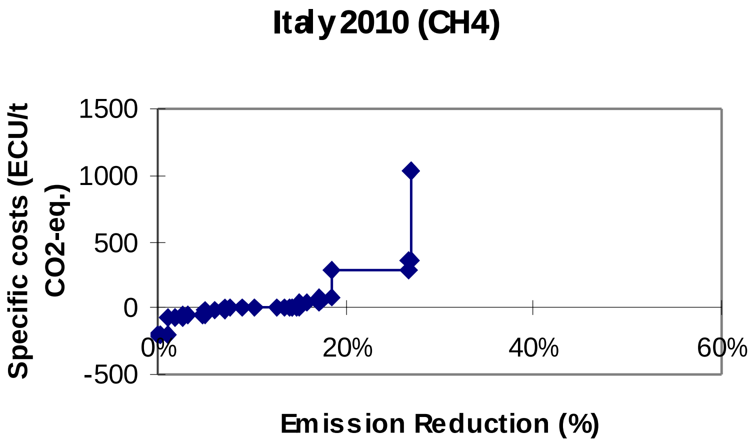

Ireland2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.00
0.50
1.00
1.50
Emission Reduction (Mt CO2-eq)

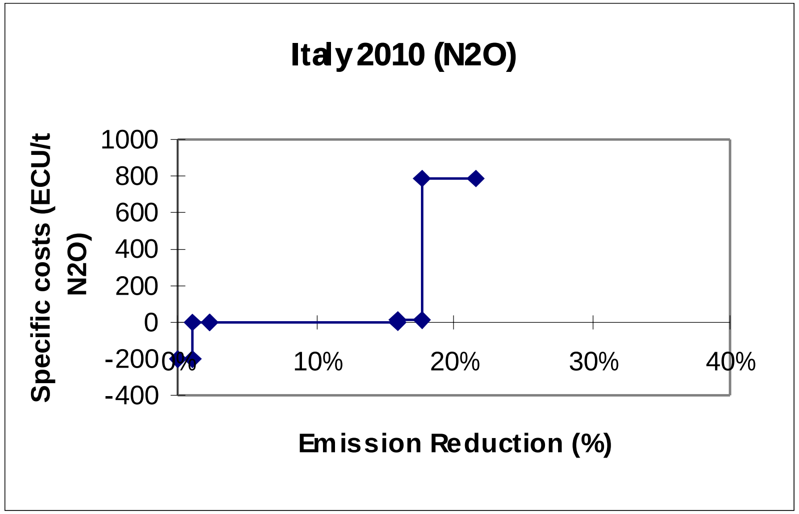

Ireland2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

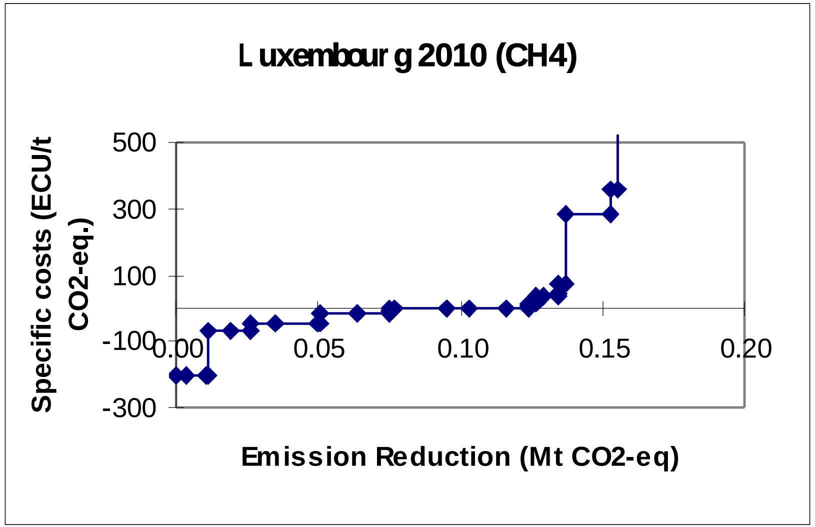

Ireland2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

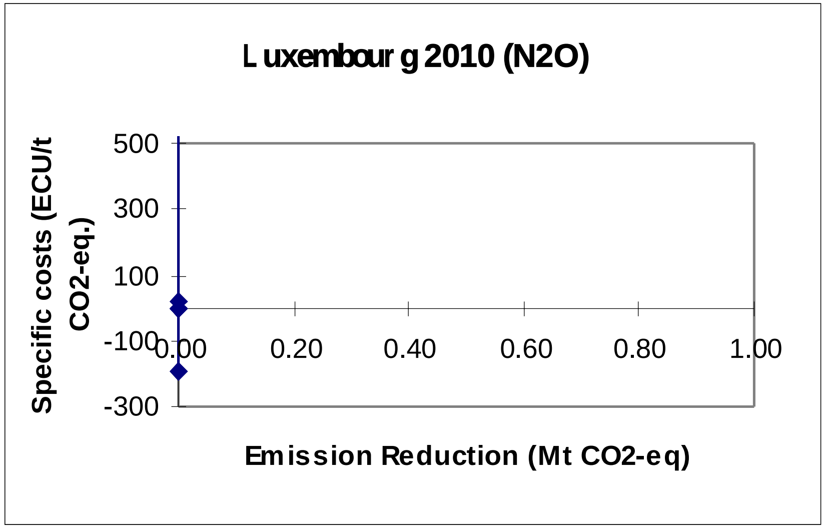

Italy 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
5
10
15
Emission Reduction (Mt CO2-eq)

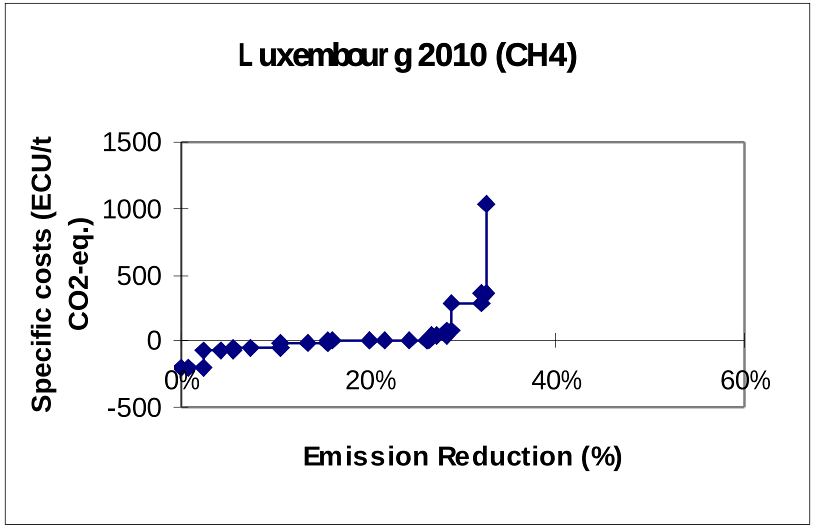

Italy 2010 (N2O)
Specific costs (ECU/t N2O)
500
300
100
-100
-300
0
5
10
15
Emission Reduction (Mt N2O)

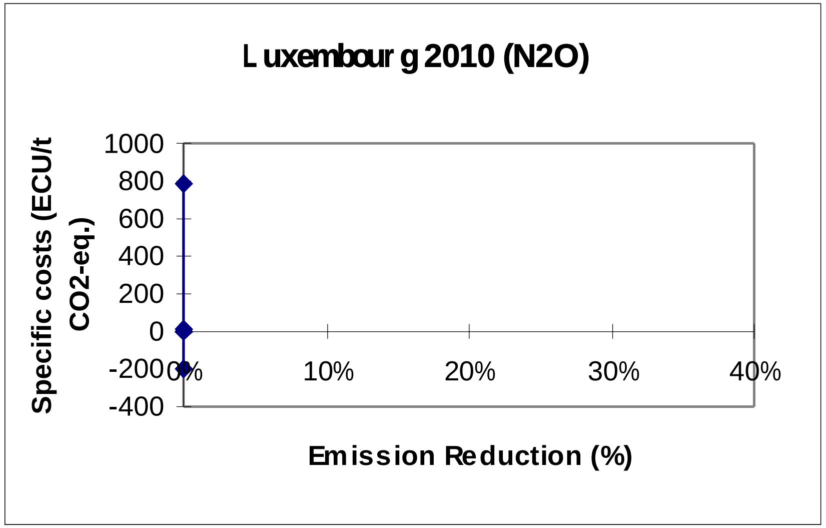

Italy 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

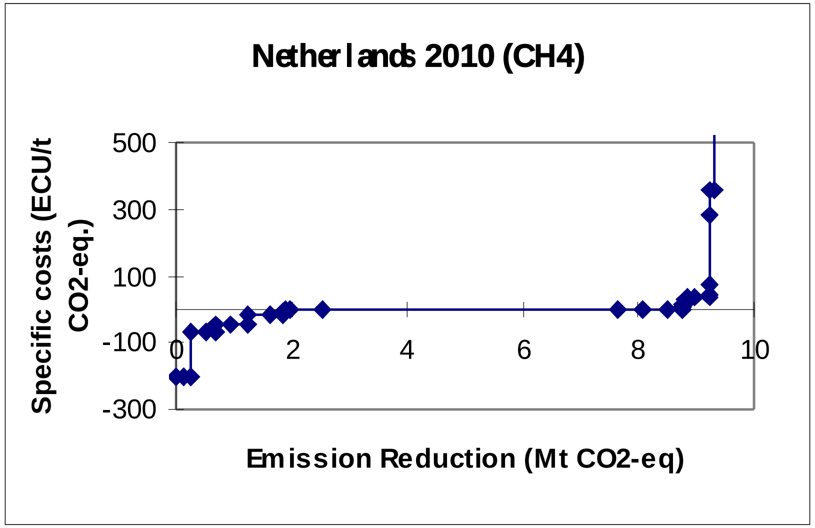

Italy 2010 (N2O)
Specific costs (ECU/t N2O)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

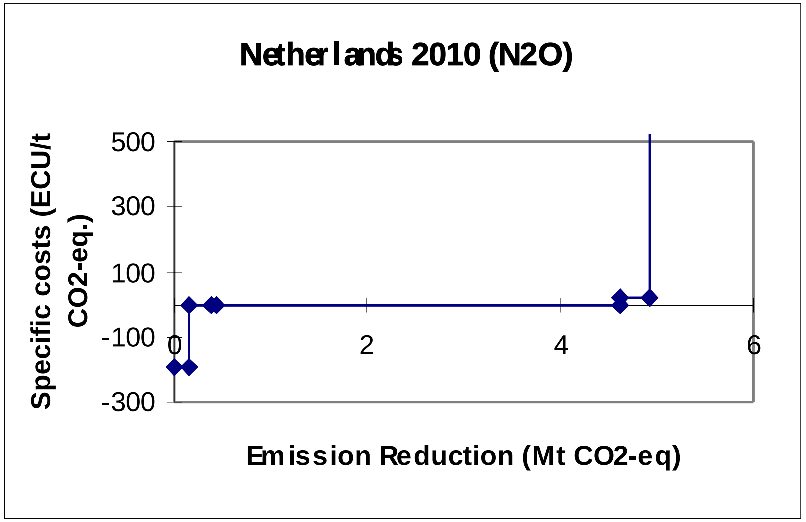

Luxembourg 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.00
0.05
0.10
0.15
0.20
Emission Reduction (Mt CO2-eq)

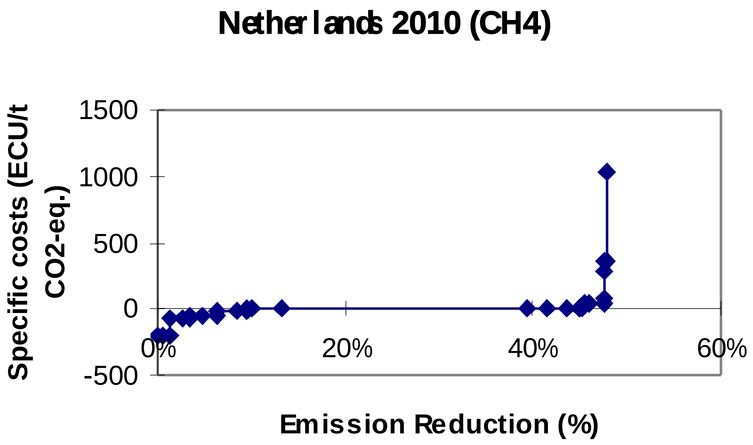

Luxembourg 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.00
0.20
0.40
0.60
0.80
1.00
Emission Reduction (Mt CO2-eq)

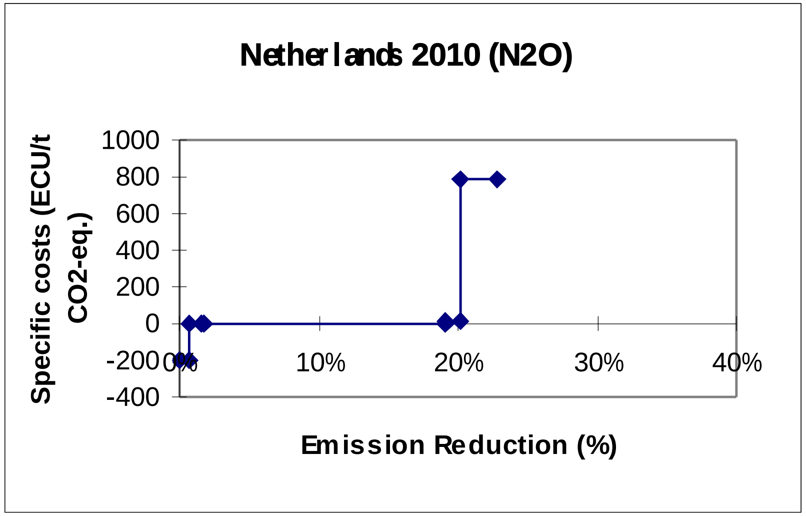

Luxembourg 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

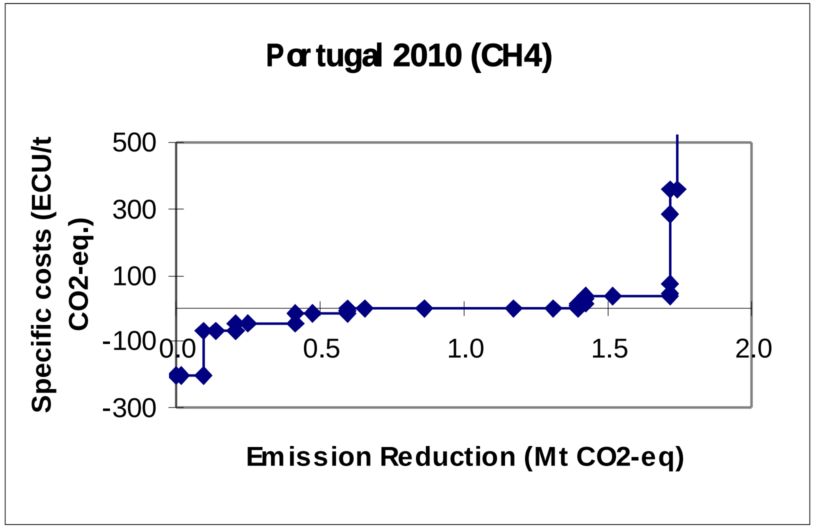

Luxembourg 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

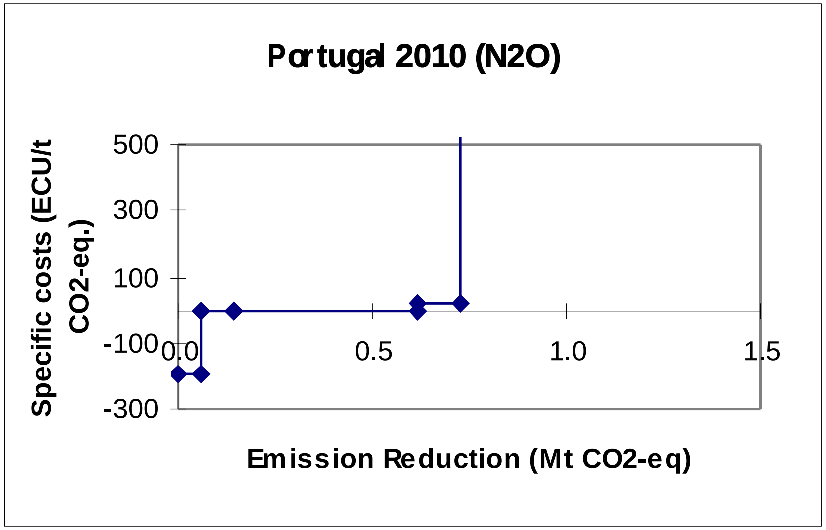

Netherlands 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
2
4
6
8
10
Emission Reduction (Mt CO2-eq)

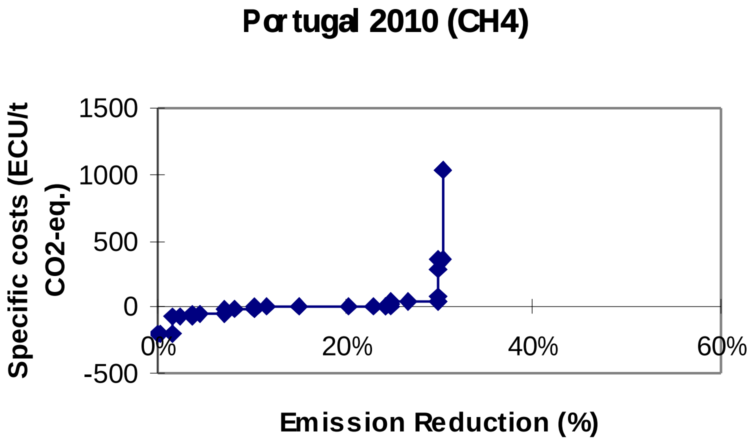

Netherlands 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
2
4
6
Emission Reduction (Mt CO2-eq)

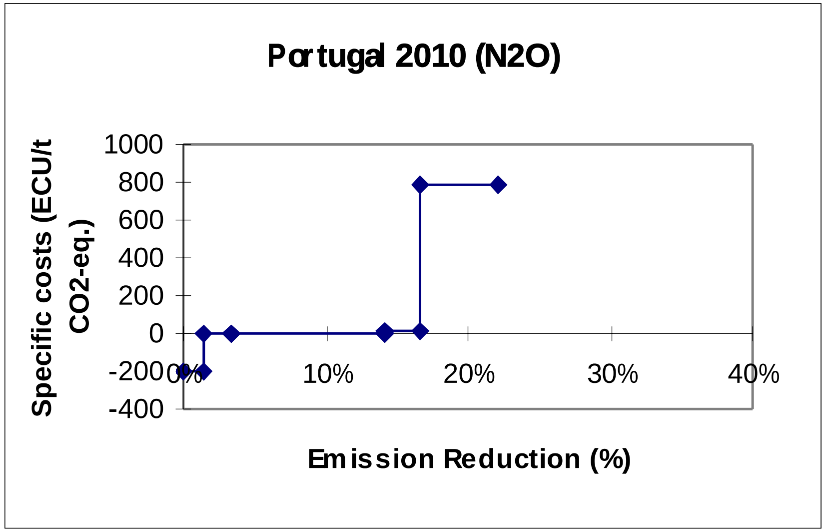

Netherlands 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

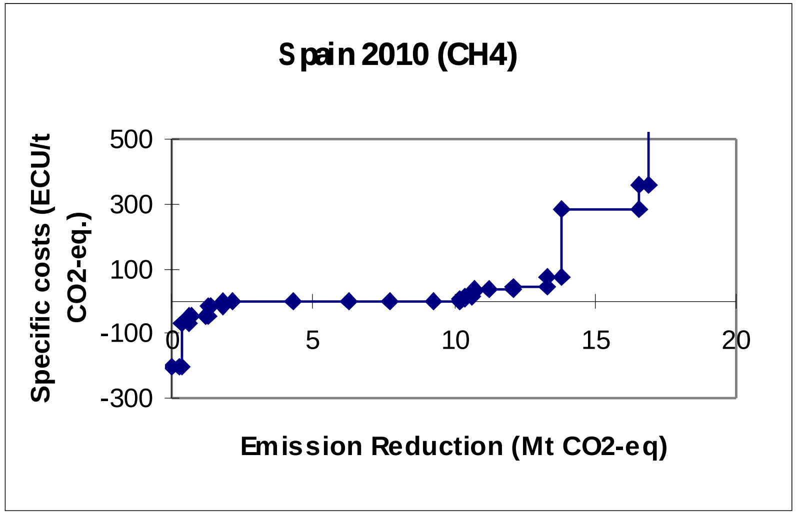

Netherlands 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

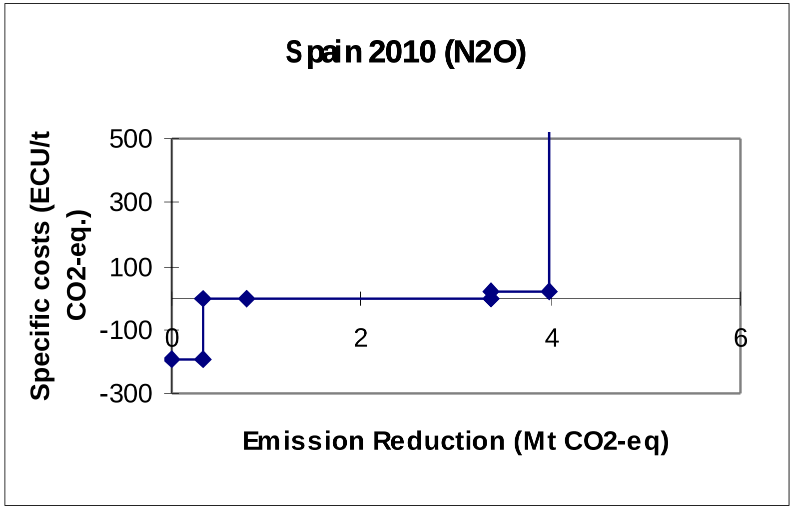

Portugal 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.5
1.0
1.5
2.0
Emission Reduction (Mt CO2-eq)

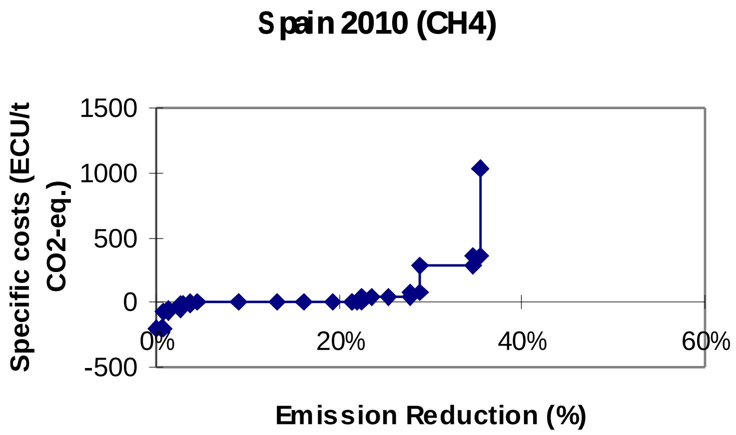

Portugal 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.5
1.0
1.5
Emission Reduction (Mt CO2-eq)

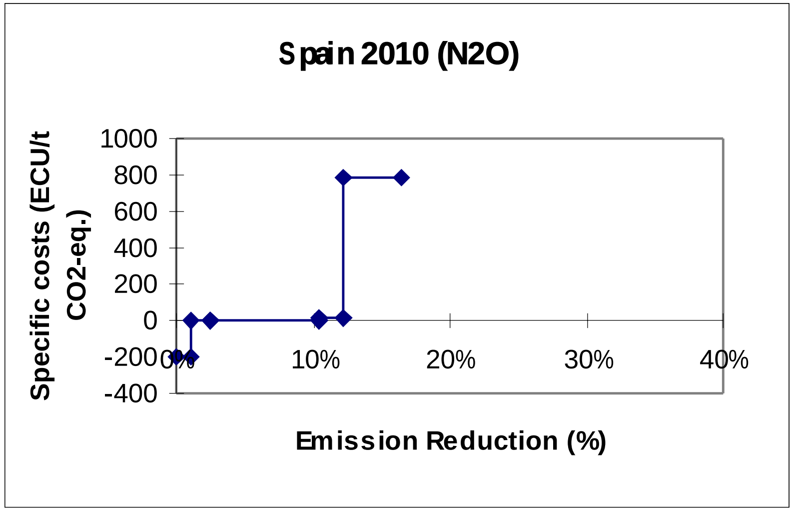

Portugal 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

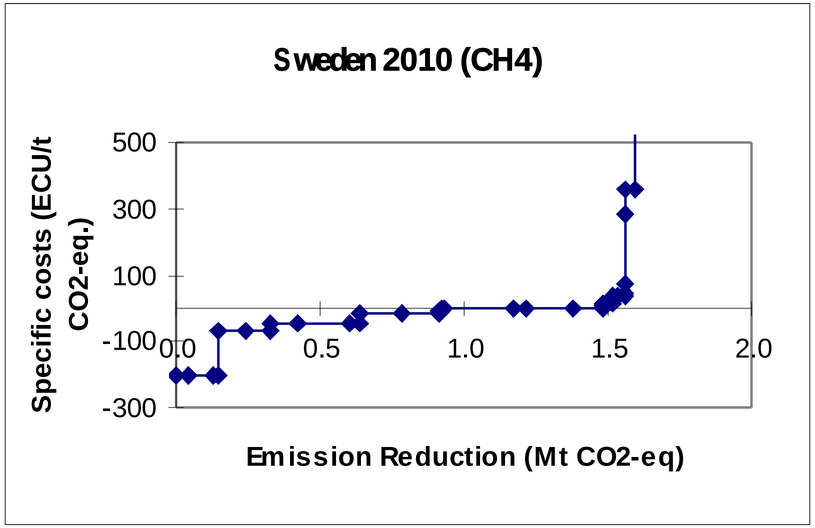

Portugal 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

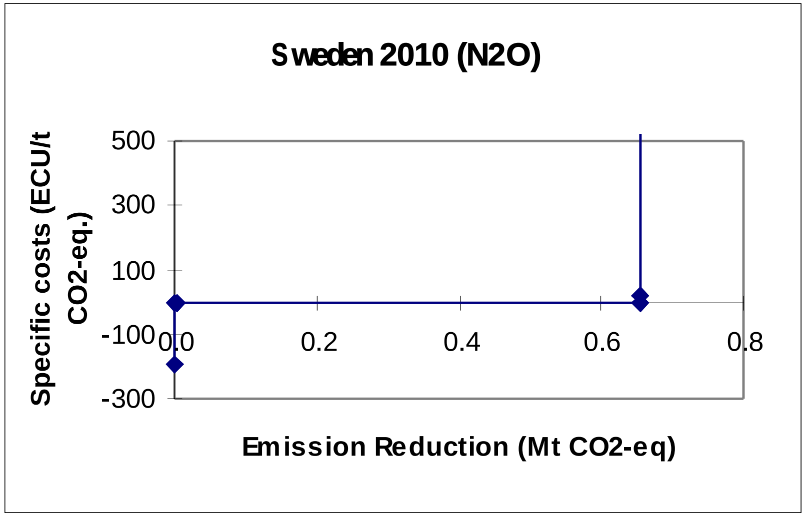

Spain 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
5
10
15
20
Emission Reduction (Mt CO2-eq)

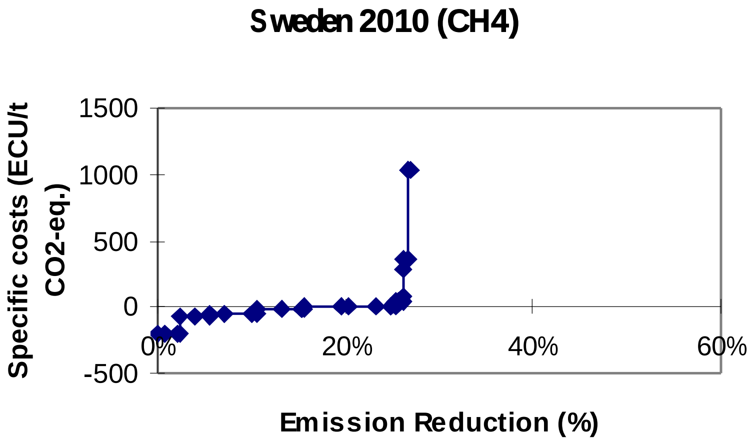

Spain 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
2
4
6
Emission Reduction (Mt CO2-eq)

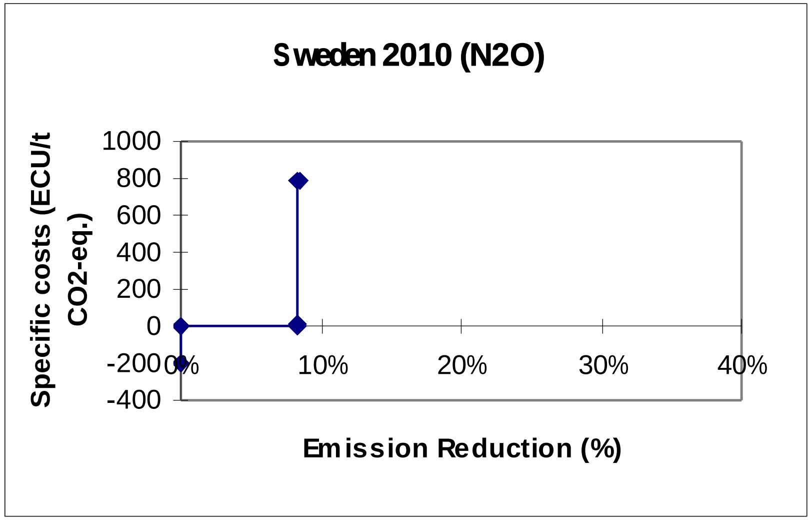

Spain 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

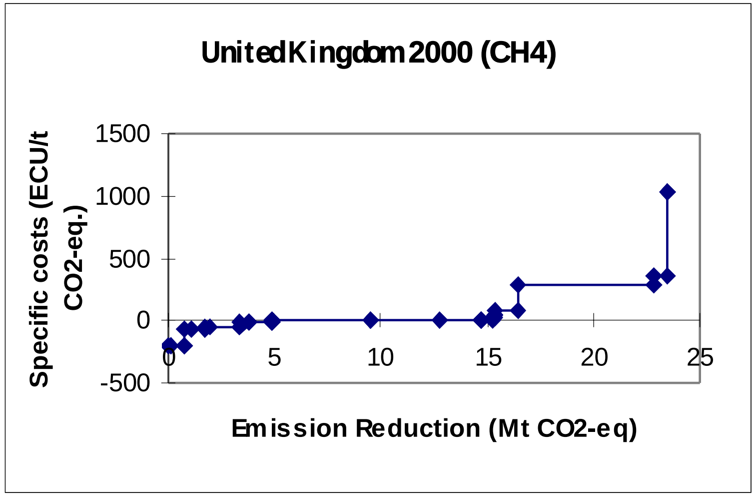

Spain 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

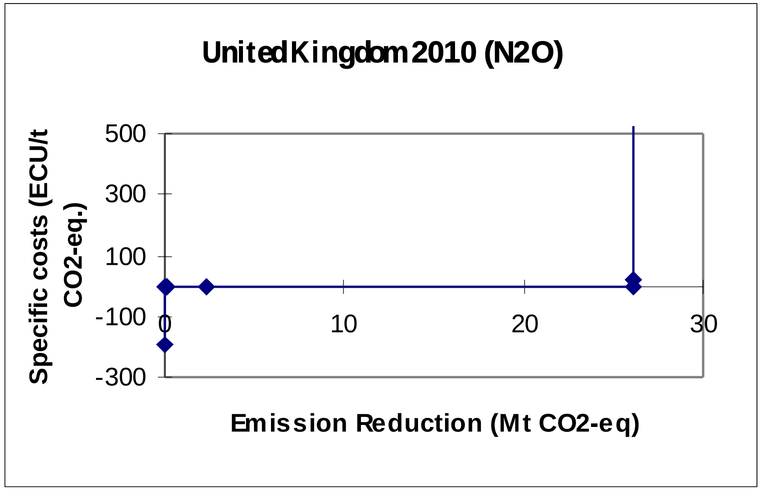

Sweden 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.5
1.0
1.5
2.0
Emission Reduction (Mt CO2-eq)

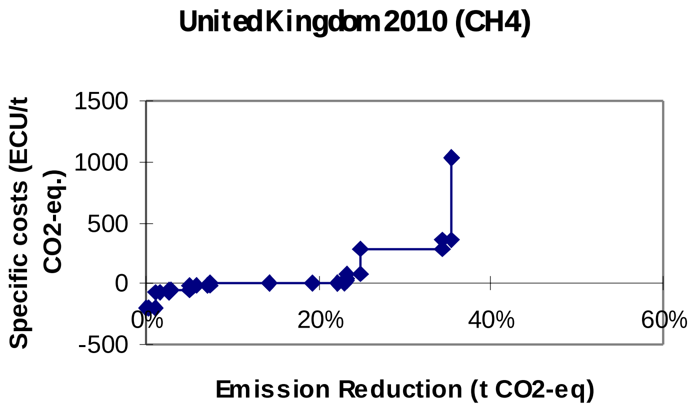

Sweden 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0.0
0.2
0.4
0.6
0.8
Emission Reduction (Mt CO2-eq)

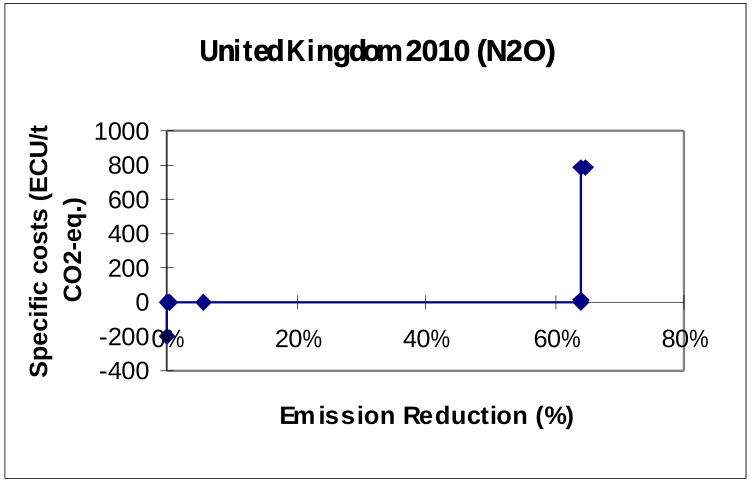

Sweden 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (%)

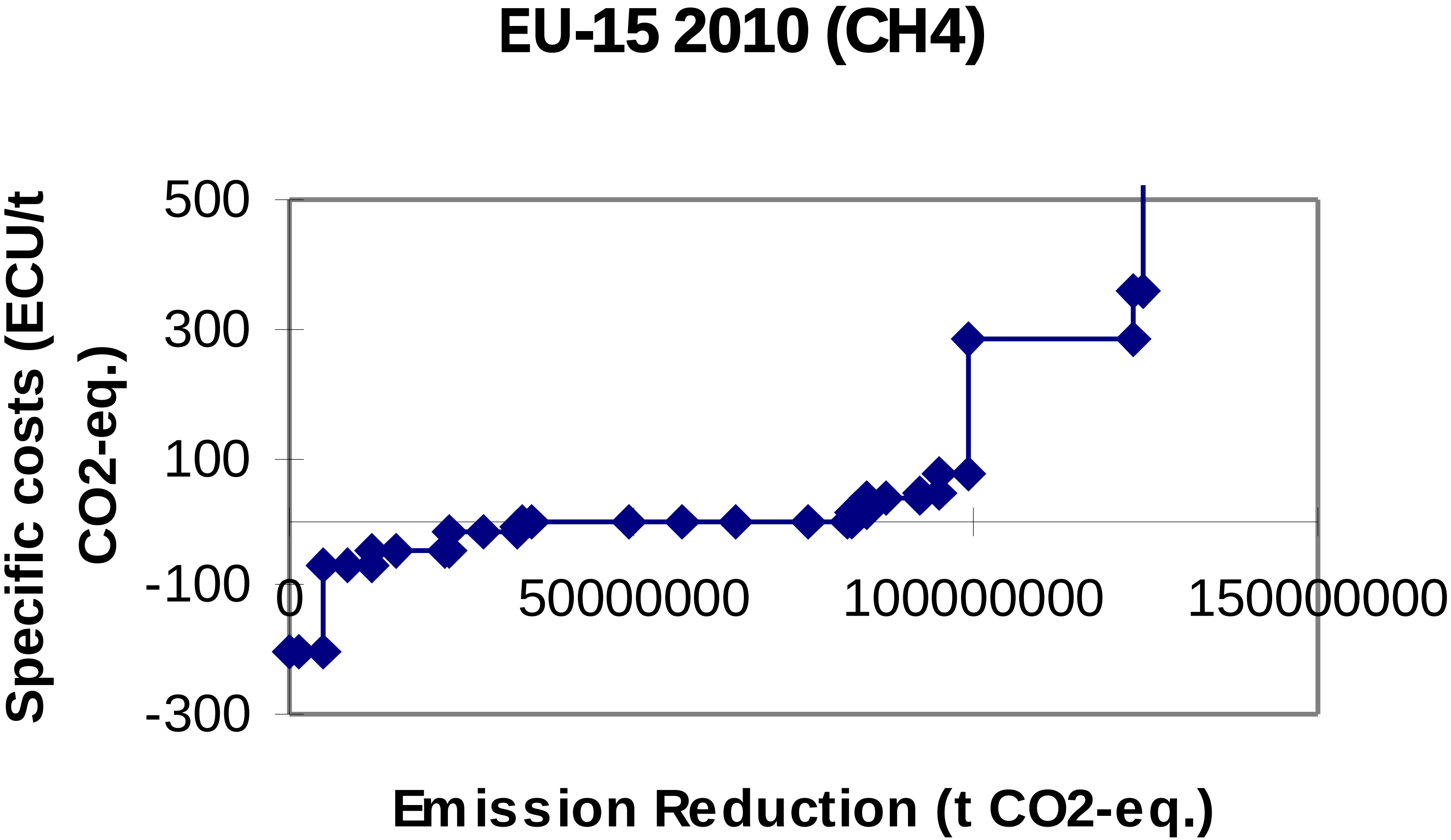

Sweden 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
Emission Reduction (%)

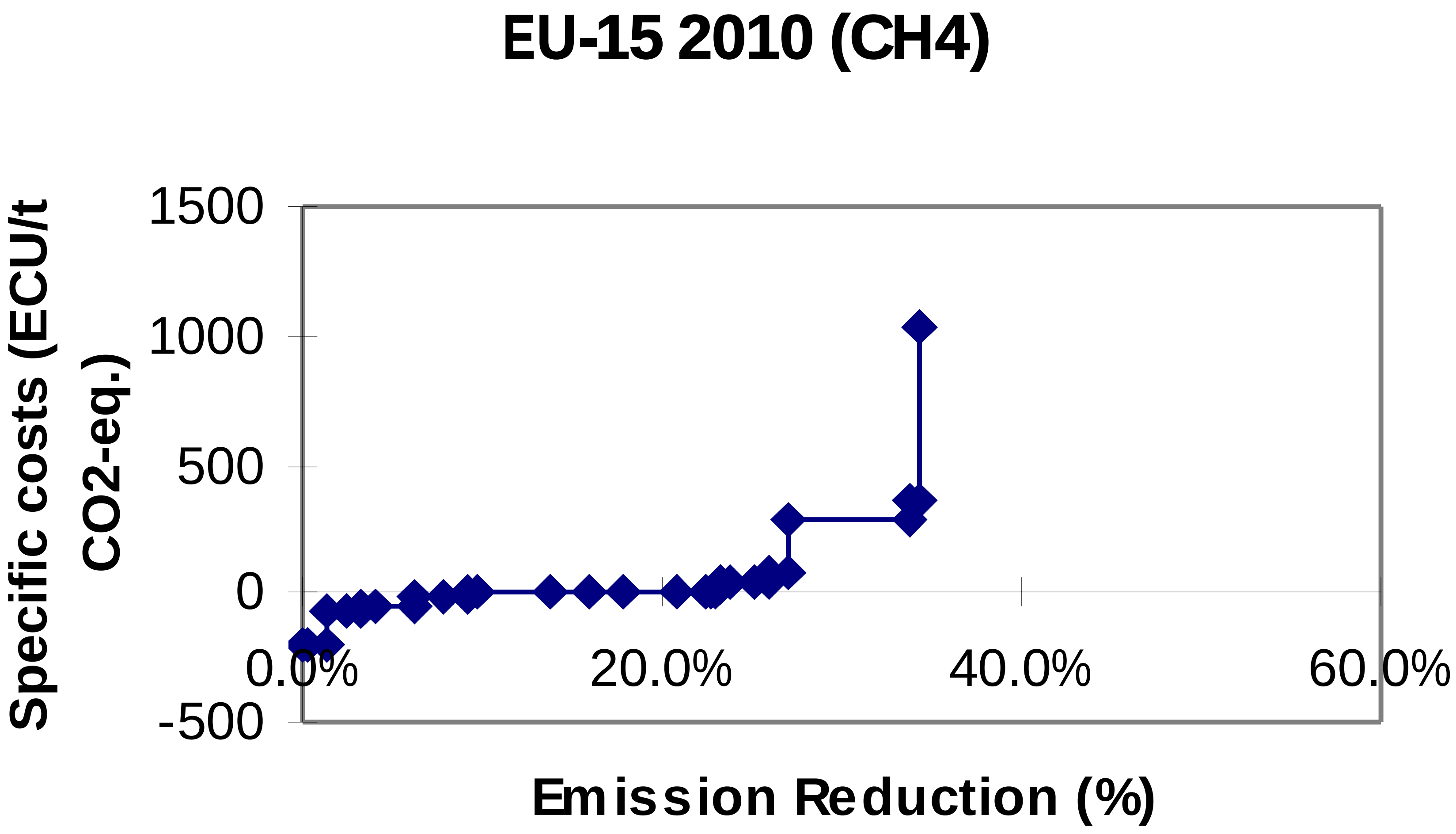

United Kingdom 2000 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0
5
10
15
20
25
Emission Reduction (Mt CO2-eq)

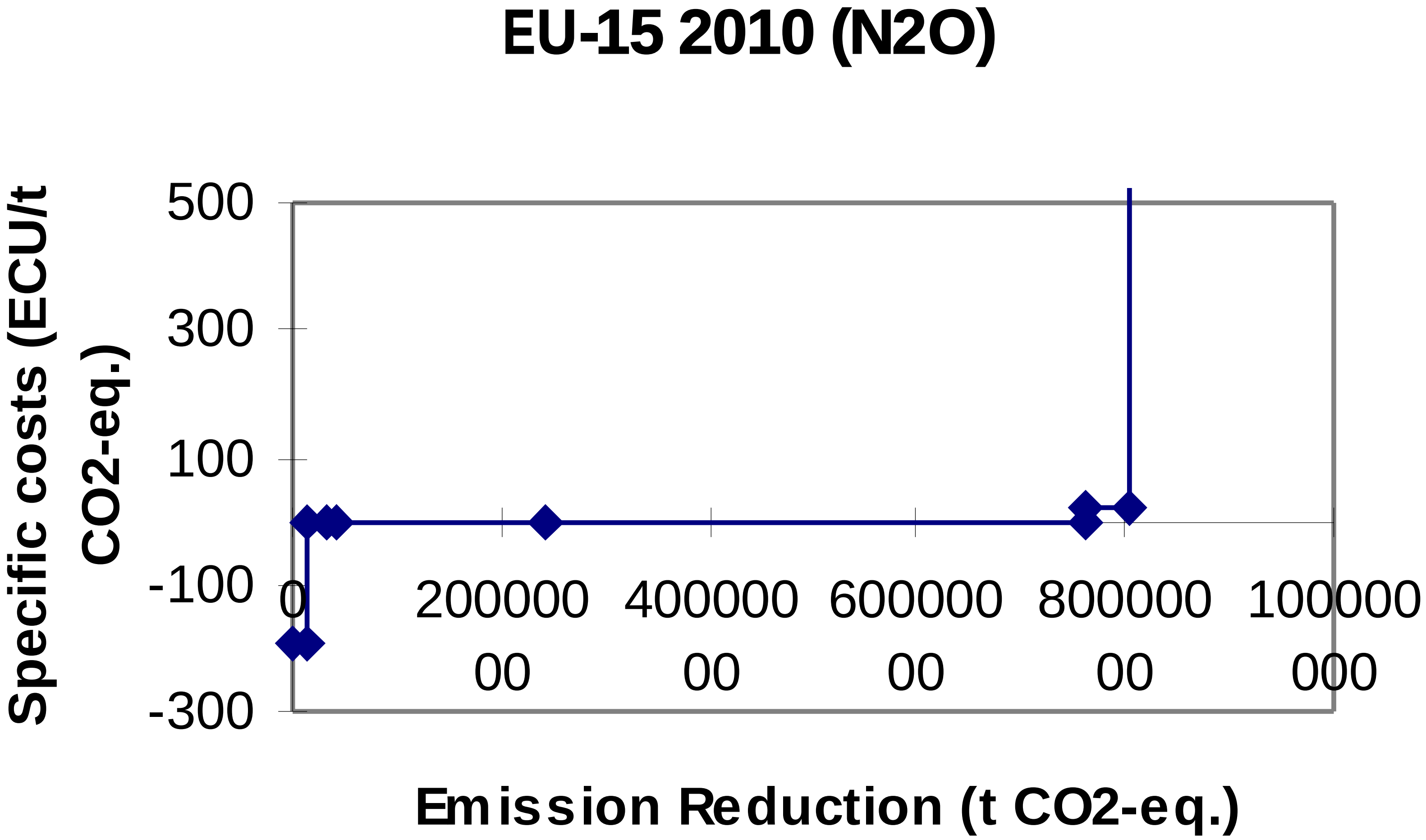

United Kingdom 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
10
20
30
Emission Reduction (Mt CO2-eq)


United Kingdom 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0%
20%
40%
60%
Emission Reduction (t CO2-eq)

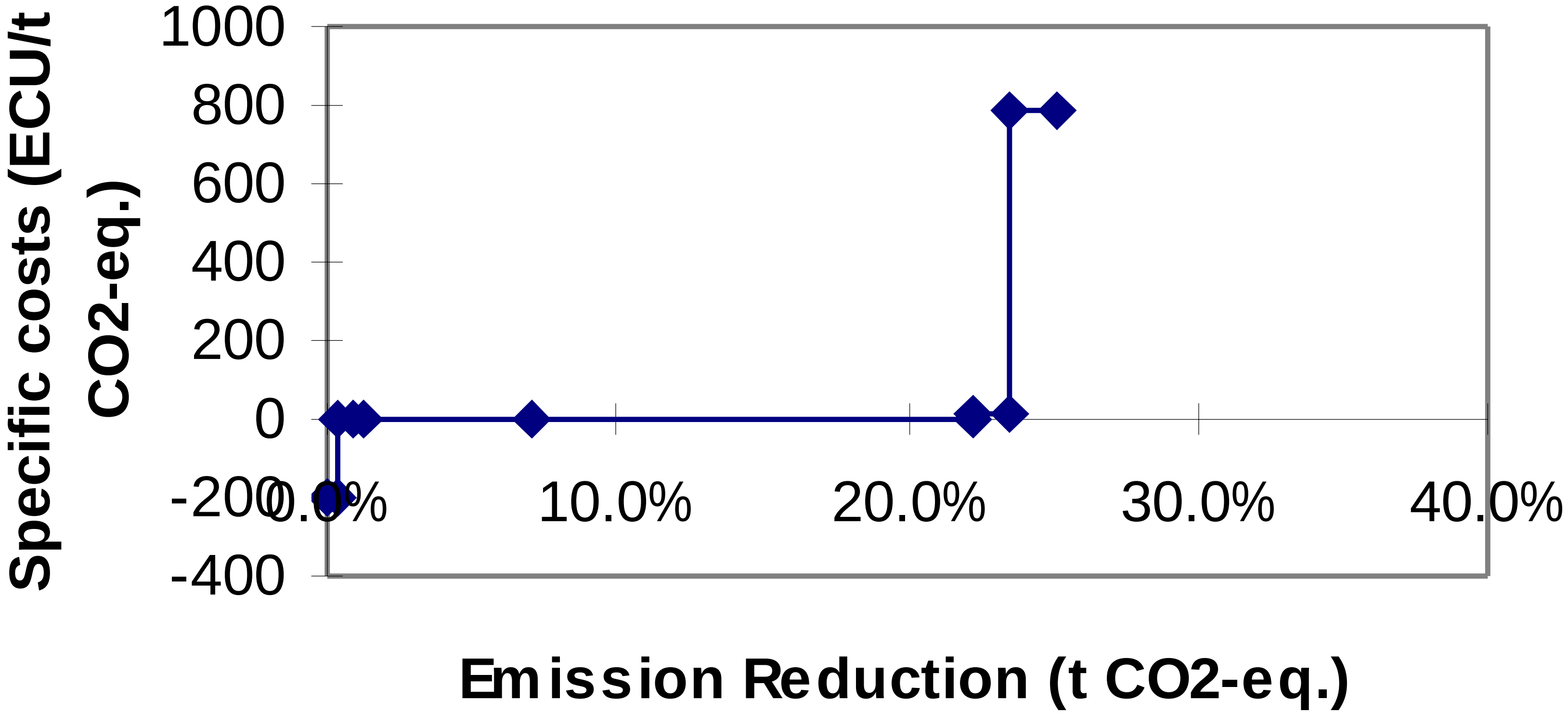

United Kingdom 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
1000
800
600
400
200
0
-200
-400
0%
20%
40%
60%
80%
Emission Reduction (%)


EU-15 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
50000000
100000000
150000000
Emission Reduction (t CO2-eq.)


EU-15 2010 (CH4)
Specific costs (ECU/t CO2-eq.)
1500
1000
500
0
-500
0.0%
20.0%
40.0%
60.0%
Emission Reduction (%)


EU-15 2010 (N2O)
Specific costs (ECU/t CO2-eq.)
500
300
100
-100
-300
0
20000000
40000000
60000000
80000000
100000000
Emission Reduction (t CO2-eq.)

EU-15 2010 (N20)



Contribution of non-CO_2 greenhouse gases to the EU Kyoto target: Evaluation of the reduction potential and costs

Synthesis

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1. Background

At the conference of the parties in Kyoto in December 1997, the EU agreed to reduce emissions of the six greenhouse gases (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride) by 8% of 1990 levels by 2010[1]. The target applies to emissions weighted by their (100 year) global warming potential.

Until recently, studies and strategies for addressing climate change mitigation have principally been focused on reducing emissions of carbon dioxide, but the importance of other greenhouse gases and opportunities for their abatement have been increasingly recognised in the last couple of years. In particular, DGXI of the European Commission has lauched three studies considering non-CO_2 greenhouse gases and examining their reduction potential and costs. These studies are:

(1) Economic evaluation of quantitative objectives for climate change, COHERENCE (ongoing); in the framework of this study ECOFYS produced a report in June 1998 on Emission reduction potential and costs for methane and nitrous oxide in the EU-15;
(2) Reductions of the emissions of HFC's, PFC's and SF6 in the European Union, ECOFYS, June 1998;
(3) Options to reduce methane emissions, AEA Technology Environment, September 1998, and

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[1] More precisely, Member States have the choice of a 1990 or 1995 baseline for HFCs, PFCs and SF6, and a limited allowance can be made for sinks in calculating the 8% reduction.

Options to reduce nitrous oxide emissions, AEA Technology Environment, September 1998.

This paper summarises the major findings from the above studies as to the reduction potential and costs of non-CO_2 greenhouse gases emissions in 2010. It also addresses the uncertainties in emissions and costs estimates for some sources and mitigation options. The reduction potential of each gas is estimated in comparison with a business-as-usual scenario to 2010. It is provided both in ktonne of gas considered and in ktonne of CO_2-equivalent using the global warming potential of the gases (100 years). Costs of reduction options or of packages of reduction options are provided in ECU (1995) per tonne of CO2-equivalent abated.

2. Emissions in 1990/1995

Emissions of the six greenhouse gases in the EU are shown in Table 1. Emissions of the three main greenhouse gases in 1990 are those estimated by the Member States and reported in the EU Second Communication to the FCCC. Emissions of the three halogenated gases in 1995 (the reference year for these gases) are those reported and discussed by the Member States at Expert Group meetings [1].

Table 1: Anthropogenic emissions of CO_2, CH_4, N_2O, HFC's, PFC's and SF6 in the EU in 1990/1995

GHG	Emissions in 1990 (Mt)	GWP (100 years)	Emissions in 1990/1995 (*) (Mt CO2-equiv)
CO2	3365	1	3365
CH4	23	21	489
N2O	1	310	315
HFC's		[1000-3000]	37
PFC's		6500; 9200	7
SF6		23900	14
Basket of six			4227
EU Kyoto target in 2010		(% of 1990) (kt CO2 equ.)	-8% 3889

(*) 1995 for halogenated gases.

After allowing for the global warming potential of the gases (100 years), it is clear that non-CO_2 greenhouse gases are significant contributors to greenhouse gases emissions. Methane and nitrous oxide emissions in 1990 are equivalent to 24% of CO_2 emissions. Emissions of halogenated gases in 1995 are equivalent to slightly less than 2% of CO_2 emissions in 1990.

The main sources of anthropogenic emissions of non-CO_2 greenhouse gases in 1990/1995 are shown in Table 2. It should be noted that the uncertainty in emissions estimates for some sources is significant [2]. This is particularly the case for landfill gas emissions, for N_2O emissions from agricultural soils and for halogenated gases emissions.

The achievement of the EU Kyoto target means that total EU emissions of the six gases in 2010 should not exceed 3889 Mt CO_2-equivalent.

3. Emissions in 2010 under a Business as Usual scenario

To allow the calculation of achievable emission reductions in 2010, business-as-usual projections are calculated for each gas and each of the main sectors.

Emissions under a business-as-usual scenario were estimated in the above studies using similar assumptions regarding background trends in activity indicators (e.g. fuel production and consumption, crop areas, livestock numbers, waste production, industrial production) and management practices (e.g. manure management, reduction in fertiliser use, lower leakage rates from new gas pipelines) [3]. These assumptions are described and discussed in the study reports.

However, business-as-usual projections have been made using sometimes different approaches as to the inclusion or not of the effect of existing policies and measures to reduce greenhouse gases emissions [4]. There is no single approach for dealing with this issue, so the general approach adopted in this paper is not to take into account specific policies and measures which the EU and Member States may have already put in place to reduce emissions. These reductions will be included in the reduction potential of the corresponding measure. Consequently, emission projections may differ from those reported in the above studies and by the Member States because the latter include the effect of some measures already implemented and/or planned [5] [6].

Non-CO_2 greenhouse gases emissions under a business-as-usual scenario are shown by sector in Table 2.

Table 2: Non-CO_2 greenhouse gases in the EU under a business-as-usual scenario (kt/year)

GHG	Sources	1990/1995 (*)	2010 (**)	2010 incr/decr (%)	2010 (in Mt CO2-equ.)
CH4	**Total**	**23309**	**21469**	**-8%**	**451**
	Agriculture	**9946**	**9248**	**-7%**	
	enteric fermentation	7054	6463	-8%	
	animal manures	2022	1928	-5%	
	other	870	857	-2%	
	Waste	**7991**	**8499**	**6%**	
	landfill	6641	7043	6%	
	waste water	1350	1456	8%	
	Energy	**5350**	**3697**	**-31%**	
	coal production	2936	822	-72%	
	oil and gas sectors	1561	2139	37%	
	fuel combustion	853	736	-14%	
	Other	**22**	**25**	**12%**	
N2O	**Total**	**1015**	**1093**	**8%**	**339**
	Agriculture	**417**	**377**	**-9%**	
	Waste	**11**	**11**	**0%**	
	Energy (combustion)	**175**	**268**	**53%**	
	Transport	41	146	256%	
	Other	134	122	-9%	
	Industrial processes	**357**	**381**	**7%**	
	Other	**55**	**55**	**0%**	
Halogenated gases		**58**	**82**	**41%**	**82**
	HFC's	**37**	**65**	**76%**	
	PFC's	**7**	**5**	**-29%**	
	SF6	**14**	**12**	**-14%**	
Basket of non-CO2 gases					**872**

(*) 1990 and in kt for CH4 and N2O; 1995 and in Mt CO2-equ. for HFC, PFC and SF6
(**) in kt for CH4 and N2O; in Mt CO2-equ. for HFC, PFC and SF6

By 2010, methane emissions would fall by 1.8 Mt to 8% below 1990 levels due predominantly to a dramatic decline in emissions from coal mining as coal production falls. There is also a significant reduction in livestock related emissions as cattle numbers are predicted to fall. These reductions are partially offset by increased emissions from landfills due to large volumes of waste produced and hence disposed to landfill and a small rise in emissions from the oil and gas sector due essentially to increased gas consumption levels.

By 2010, nitrous oxide emissions are projected to increase by 8% (78 kt) from 1990. This is mainly due to an increase in emissions (of 93 kt) from road transport, due to the increased penetration of catalytic converters. There is also an increase (of 24 kt) in emissions from production processes which is partially offset by a fall (of 40 kt) in agricultural emissions. The business-as-usual projections do not include reductions of around 240 kt (in 2010) resulting from abatement plans installed or due to be installed at the main adipic acid EU production plants.

Finally, emissions of the three halogenated gases are projected to increase by 41% in 2010 compared to 1990 levels due essentially to a significant increase in HFC's emissions (78%); PFC's and SF_6 emissions are projected to decrease by 29% and 14% respectively over the same period due to a decrease in aluminium production and in the use of high-voltage switches in the EU.

Table 3 summarises the emission projections under a business-as-usual scenario for the basket of six gases. Overall, emissions are projected to increase by 6% in 2010 compared to 1990 levels.

The above projections should be regarded with caution; uncertainty in emission estimates for some sources is significant, a new baseline energy scenario is under development, forecasts for the three industrial gases are hampered by inconsistencies, lack of data for some countries and several source categories. For these reasons, Table 3 only gives an order of magnitude of the challenge.

Table 3: Business-as-usual projections for the basket of six gases (in Mt CO_2 equivalent)

	1990 1995 for halog.	2010 BAU (*)	2010 % of 1990
CO2	3365	3617	8%
CH4	489	451	-8%
N2O	315	339	8%
HFC's	37	65	76%
PFC's	7	5	-29%
SF6	14	12	-14%
Basket of six	4227	4489	6%
Kyoto target		3889	
Reduction needed		600	

(*) CO2 emission projections are calculated on the basis of the pre-Kyoto scenario which assumes an 8% increase in (energy-related) CO2 emissions by 2010 compared to 1990. Other CO2 emissions are assumed to remain constant.

The emission reduction required compared to business-as-usual (as defined in Table 3) is estimated to be about 600 Mt CO_2 equivalent for the six gases. Because this overall challenge excludes the effect of current policies equivalent to around 140 Mt of CO_2 [7], it is comparable to that under the pre-Kyoto communication (COM(97)481 final) where around 500 Mt of additional emission reduction was estimated to be necessary to meet the EU Kyoto target.

4. Emission reduction measures, potential and costs in 2010

Measures have been identified to reduce non-CO_2 emissions in all of the main sectors, together with estimates of the achievable reductions in 2010 compared to the business-as-usual scenario and mitigation costs.

In general, similar mitigation options have been considered in the above studies (see list in annex). The major difference concerns mitigation options for methane in the agricultural sector. On the basis of a recent study by the Agricultural University of Wageningen (Gerbens, 1998), further measures have been considered in the Ecofys study; these measures aim at improving feed conversion efficiency by adjusting animal diets. Another difference, which has however a lower impact on emission reductions, concerns mitigation options for N_2O in the energy sector. The AEAT study has estimated the impact on N_2O emissions of several CO_2 reduction measures such as the introduction of energy efficiency measures and renewables in the energy supply sector, and inter-modal shift in the transport sector.

Although different assumptions have sometimes been made as to the applicability of individual measures, overall both studies have estimated comparable achievable reductions for methane and nitrous oxide emissions provided the same mitigation options are considered.

The reduction costs of the different measures or packages of measures have been estimated on the basis of direct (private) resource costs (i.e. investment costs, operation and maintenance costs, and potential cost savings).

Large cost ranges for some measures and small differences in costing methodology and approach [8] have led to sometimes big differences in cost estimates between the two studies. Nevertheless, a number of measures have been identified in the same cost ranges. Three cost categories are thus considered in this analysis that correspond to different cost ranges, and mitigation options are ranked according to these cost categories. The "low cost" category corresponds to measures identified as having "negative costs"[2] (or as being "cost-positive" according to AEAT study). The "medium cost" category encompasses measures with a marginal reduction cost ranging from 0 to 50 ECU per tonne CO_2 equivalent abated. Finally, the "high cost" category characterises the measures which fall above the limit of 50 ECU per tonne CO_2 equivalent abated.

The potential reductions and costs of non-CO_2 mitigation measures are summarised below.

For methane, the set of options is estimated to offer total reductions of 9 Mt (or 189 Mt CO_2 equivalent) in 2010 and would bring methane emissions down to 53% of 1990 levels. In other words, methane emissions could be reduced by 47% in 2010 compared to 1990 levels. The largest reductions (Table 4.1) arise from measures directed at landfilling of waste (4.7 Mt), although significant reductions are also available in the agricultural sector (2.9 Mt) and in the oil and gas sector (1.3 Mt).

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[2] Cost savings more than offset the cost of the measure.

Total reductions include methane reductions from landfills as resulting from the implementation of Member States' current and planned measures (i.e. utilisation or flaring of landfill gas and diversion of organic waste from landfill). These measures are estimated to deliver reductions of 3.2 Mt by 2010. Their implementation is also suggested under the proposed Landfill Directive.

Reductions in enteric fermentation emissions have been estimated on the basis of a single and recent study (1998). Further studies are maybe required to confirm the estimated reduction potential of around 1.6 Mt, which represent more than 50% of reductions estimated in the agricultural sector.

A number of mitigation options were also identified in the energy sector (some recovery of mine methane, various measures in the oil and gas sectors), their potential reductions in 2010 have been estimated at around 1.5 Mt

80% of total estimated reductions (7.2 Mt) could be reduced at a cost below 50 ECU/tonne CO_2 equivalent.

With all measures implemented, nitrous oxide emissions could be reduced by 385 kt (or 119 Mt CO_2 equivalent) in 2010. This would bring emissions 30% below 1990 levels. The largest reductions (Table 4.2) arise from measures directed at adipic and nitric acid production. Reductions of 237 kt result from the installation of abatement equipment at the main adipic acid manufacturing plants in the EU; further reductions of 39 kt are possible by abating emissions at the remaining adipic acid plants and at nitric acid plants.

The "package of options" identified for the agricultural sector offer the second greatest savings, with a reduction potential of 79 kt [9]. Measures identified in the other sector would contribute to less than 8% of total reductions.

Table 4.1: Reductions and costs of CH_4 mitigation options

Sources	Reduction in 2010		Cost range	red. 2010/1990
	(kt)	(Mt CO2-equ.)	(ECU/t CO2-equ.)	(%) (*)
Total	**8999**	**189**		**-47%**
(BaU)				(-8%)
low cost measures	2883	61	< 0	-20%
medium cost measures	4337	91	0-50	-39%
high cost measures	1779	37	> 50	-47%
Agriculture	2874	60		
enteric fermentation	1600	34	< 0	
	83	2	> 50	
animal manures	969	20	0-50	
	222	5	> 50	
Waste				
landfill	4655	98		
	1110	23	< 0	
	2867	60	0-50	
	678	14	> 50	
Energy				
coal production	140	3	< 50	
oil and gas sectors	1330	28		
	173	4	< 0	
	361	8	0-50	
	796	17	> 50	

(*) cumulative, i.e. percentage reduction accounts for lower cost measures.

Table 4.2: Reductions and costs of N_2O mitigation options

Sources	Reduction in 2010		Cost range	red. 2010/1990
	(kt)	(Mt CO2-equ.)	(ECU/t CO2-equ.)	(%) (*)
Total	**385**	**119**		**-30%**
(BaU)				(8%)
low cost measures	3	1	< 0	7%
medium cost measures	277	86	0-50	-20%
agriculture	79	24		
by-product of CO2 red.	26	8		
Agriculture	79	24		
Waste	3	1	< 0	
Energy (combustion)				
Transport	10	3	(**)	
Other	16	5	(**)	
Industrial processes				
adipic acid production	261	81	0-50	
nitric acid production	16	5	0-50	

(*) cumulative, i.e. percentage reduction accounts for lower cost measures.
(**) costs not estimated; by-product of CO2 reduction policies

The preliminary estimate of potential reductions of halogenated gases emissions reported in the Ecofys study, suggests that emission reductions of 72 Mt CO_2 equivalent would be feasible in 2010 and would bring total emissions of the three gases 82% below 1990 levels. The largest reductions (Table 4.3) arise from measures aimed at HFC reduction (61 Mt CO_2 equivalent).

More than 80% of total estimated reductions have a cost below 50 ECU/tonne CO_2.

Table 4.3: Reductions and costs of mitigation options for the three halogenated gases

Sources	Red. in 2010 (Mt CO2-equ.)	Cost range (ECU/t CO2-equ.)	red. 2010/1990 (%) (*)
Total halogenated gases	**72**		**-82%**
(BaU)			(41%)
low cost measures	0	< 0	41%
medium cost measures	59	0-50	-61%
high cost measures	12	> 50	-82%
HCF's			
HCFC-22 production	9	0-50	
refrigeration	9	0-50	
	12	> 50	
Other (foam, solvents)	30	0-50	
PFC's			
aluminium production	4	0-50	
SF6			
package of measures	7	0-50	

(*) cumulative, i.e. percentage reduction accounts for lower cost measures.

5. Conclusions

Emissions of non-CO_2 greenhouse gases under a business-as-usual scenario are projected to increase by 1% in 2010 compared to 1990/1995 levels. This is the result of the combination of a downward trend for methane emissions (-8%) and upward trends for nitrous oxide and the three halogenated gases emissions (+8% and +41% respectively).

This examination of measures to reduce non-CO_2 greenhouse gases emissions shows that such measures could make a substantial contribution to the achievement of the EU's Kyoto target.

The implementation of all measures identified would lead to a reduction of 380 Mt CO_2 equivalent in 2010. This would bring total non-CO_2 emissions to 43% (370 Mt CO_2 equivalent) below 1990 levels by 2010.

The EU six gas basket of emissions in 1990 is estimated to be about 4227 Mt CO_2 and a reduction of 600 Mt of CO_2 would be required to meet the EU's Kyoto target.

The identified reduction in non-CO_2 emissions is equivalent to 63% of total reduction needed, and would bring emissions of the six gas basket to 2.5% below 1990 levels by 2010.

Reductions from agricultural measures have been estimated at 85 Mt CO_2 (Table 5), these measures are potentially the most difficult to implement and estimates of their applicability and impact have still high level of uncertainty (this is particularly true for nitrous oxide and for methane from enteric fermentation).

Reductions from non-agricultural measures have been estimated at 295 Mt CO_2 (Table 5), of which half corresponds to reductions resulting from the implementation of existing and planned measures directed at landfilling of waste and adipic acid manufacturing plants. The cost-effectiveness analysis shows that 252 Mt CO_2 can be reduced at a cost below 50 ECU/tonne CO_2. With only non-agricultural measures implemented, emissions of the six gas basket are projected to stabilise at 1990 levels by 2010.

A comparison of figures provided in the two studies on CH_4 and N_2O and in this paper as provided in annex.

Table 5: Synthesis of reductions and costs of non-CO_2 mitigation options

Agricultural measures

	Em. reductions in 2010 (Mt CO2 equ)	Costs (ECU/t CO2 equ)
CH4	34	< 0
	20	0-50
	7	> 50
N2O	24	
Total non-CO2	**85**	

Non agricultural measures

	Em. reductions in 2010 (Mt CO2 equ)	Costs (ECU/t CO2 equ)
CH4	27	< 0
	71	0-50
	31	> 50
N2O	9	< 0
	86	0-50
HFC's	0	< 0
	48	0-50
	12	> 50
PFC's	4	0-50
SF6	7	0-50
Total non-CO2	**295**	
of which	36	< 0
	216	0-50
	43	> 50
Measures in place	146	
Additional measures	149	

6. Comments

[1] Expert Group on Climate Change, "Community target - adjustments for extra gases and sinks resulting from Kyoto protocol", fax from DETR dated 19 February 1998; and

Expert Group on Climate Change, Comments to the letter "Burden sharing: data on greenhouse gas emissions and removal by sinks", fax from DETR dated 19 January 1998.

[2] In the AEAT nitrous oxide report, emissions from the agricultural sector were modelled using the revised IPCC methodology (IPCC, 1997) and for the EU were found to be 20% higher than those reported by Member States in their second national communications. This is believed to be due to the fact that not all Member States had yet adopted the revised IPCC methodology. In any case, N_2O emission estimates from agricultural soils have still very high levels of uncertainty.

[3] The only major difference between the studies concerns methane emissions from gas pipeline leakages. Although both studies based their calculation on the pre-Kyoto energy scenario (DGXVII, July 1997), AEAT assumes an overall better improvement of gas pipeline systems due to significantly lower leakage rates from new polyethylene gas distibution pipes, based on UK figures. Overall, methane emissions from oil and gas sectors are estimated to increase by only 10% between 1990 and 2010 in the AEAT study, compared to 37% in the Ecofys study. Gas consumption in the EU would increase by 98% over the same period. The above difference in BAU emission trend has little impact on the calculation of the reduction potential which is based on mitigation options independent of the leakage rate of new gas pipelines. In this paper, the Ecofys BAU emission trend was chosen.

[4] The AEAT business-as-usual projections of nitrous oxide emissions take into account the abatement measures taken at the main adipic acid manufacturing plants, while the Ecofys business-as-usual projections of nitrous oxide emissions do not. On the contrary, the Ecofys business-as-usual projections of methane emissions from landfills take into account the abatement measures taken or planned by the Member States (according to the *Expert Group's work on EU*

common and coordinated measures (landfill emissions)), while the AEAT business-as-usual projections do not.

[5] Business-as-usual projections of methane emissions are similar to the ones reported in the AEAT report (a decrease by 9% in 2010 below 1990 levels), the difference comes from the oil and gas sector where emissions are predicted to increase less (see [3]); they are however far different from Ecofys' projections (a decrease by 26% in 2010 below 1990 levels) because the latter include the effect of existing and planned policies and measures to reduce emissions from landfills. If these measures were taken into account in the BaU projections reported here, methane emissions would have fallen by 22% in 2010 below 1990 levels.

Business-as-usual projections of nitrous oxide emissions are similar to the ones reported in the Ecofys report (an increase by 9% in 2010 above1990 levels), the small difference comes from the agricultural sector where emissions are predicted to decrease less; they are however far different from AEAT projections (a decrease by 15% in 2010 below 1990 levels) because these include the effect of existing measures to reduce emissions from adipic acid manufacturing plants (industrial processes). If these measures were taken into account in the BaU projections reported here, nitrous oxide emissions would have fallen by 16% in 2010 below 1990 levels.

[6] Emissions in 1990 provided in the above studies are not always in close agreement with emissions provided by the Member States and reported the EU Second Communication. This is believed to be due to the fact that Member States, Ecofys and AEAT have not used the same methodology for estimating emissions. In order to ensure consistency with national estimates, emission projections have been scaled by the difference in the 1990 emission estimates.

[7] According to AEAT and Ecofys' studies, current Member States policies would allow to reduce methane emissions from landfills by around 73 Mt of CO_2 and nitrous oxide emissions from adipic acid production by 73 Mt of CO_2.

[8] Both studies have used a bottom-up costing approach to estimate the cost-effectiveness of the various measures: only direct resource costs are taken into account, namely investment, operation and maintenance, energy costs and cost savings. The assessment does not include any positive or negative macroeconomic impacts that might occur if certain mainly economic

instruments are used to implement the technical measures, nor any estimate of social resource costs or secondary environmental benefits. Costs are calculated as the ratio between the yearly costs of the measure and the resulting yearly emission reduction. The calculation of the yearly costs differ however slightly in the two studies; in the AEAT study, a levelised cost/discounting method is used with a discounting rate of 8%; in the Ecofys study the total cost stream is only annualised over the lifetime of the equipment, the annuity factor is calculated with a discounting rate of 15%. Differences in methodology are however small compared to differences in costs associated with some mitigation options.

[9] The reduction potential is derived from AEAT's reduction estimate of 114 kt which has been scaled by the difference in the N_2O emission estimates' methodology for the agricultural sector.

Annex

Comparison between figures provided in the studies and in the synthesis paper: CH4 and N2O

METHANE

	1990	2010 BAU		2010 without agr. measures		2010 with all measures included		reduction 201 without agr.	eduction 201 all measures	eduction 2010 from agr.
	Mt CO2	Mt CO2	% of 199	Mt CO2	% of 199	Mt CO2	% of 199	Mt CO2	Mt CO2	Mt CO2
Ecofys (Coheren report)	492	364	-26%	290	-41%	239	-51%	74	125	50
AEAT (*)	490	443	-10%	314	-36%	294	-40%	129	149	20
Synthesis	489	451	-8%	322	-34%	262	-46%	129	189	60
		(1) (2)		(3)						(4)

NITROUS OXIDE

	1990	2010 BAU		2010 without agr. measures		2010 with all measures included		reduction 201 without agr.	eduction 201 all measures	eduction 2010 from agr.
	Mt CO2	Mt CO2	% of 199	Mt CO2	% of 199	Mt CO2	% of 199	Mt CO2	Mt CO2	Mt CO2
Ecofys (Coheren report)	313	342	9%	250	-20%	229	-27%	92	113	21
AEAT	377	322	-15%	302	-20%	266	-29%	20	56	36
Synthesis	315	339	8%	244	-23%	220	-30%	95	119	24
	(5)		(6)				(7)	(6)		

(*) Figures for 2010 have been revised from the September report.

EU's Kyoto target

	Basket of six 1990/1995 Mt CO2	Basket of six 2010 BAU Mt CO2	Mt CO2	Reduction needed in 2010
Ecofys (Coheren report)	4228	4405		515
AEAT	4290	4464		517
Synthesis	4227	4489		600
	(8)	(8)		

Contribution of GHG to EU's Kyoto target

	Reduction needed in 2010	CH4 non-agr.	CH4 agr.	N2O non-agr.	N2O agr.	HFC's	PFC's	SF6	balance CO2 (*)
Ecofys (Coheren report)	515	74	50	92	21	60	4	7	206
AEAT	517	129	20	20	36				240
Synthesis	600	129	60	95	24	60	4	7	221
						(9)	(9)	(9)	(10)

(*) Assuming a 8% increase in CO2 emissions in 2010 compared to 1990 levels in the business-as-usual scenario, and assuming that all measures identified for non-CO2 GHG are implemented including the most expensive ones.

Explanation of major differences

(1): Ecofys' BAU scenario includes existing and planned measures to reduce CH4 from landfills. The reduction potential in 2010 is therefore lower than in AEAT study.

AEAT study and the paper do not incorporate in the BAU scenario CH4 abatement measures in place.

(2): AEAT's BAU assumes significant reductions from new gas distribution pipes based on UK figures (leakage rate from new pipes is calculated as a percentage of leakage rate of old distribution pipelines in the UK; the same percentage is applied in all MS despite the fact that MS other than UK have average leakage rates of existing distribution network far lower than in the UK). However, the AEAT methodology has the advantage to distinguish between transmission system and distribution system for the additional gas, the latter being the key source of methane emissions.
The Ecofys approach is more global in the sense that methane emissions are estimated on the basis of total gas throughput (or inland consumption) and an average "target" leakage rate for the overall gas network of at most 0.5% in 2010 (the average leakage rates in the MS ranged from 0.5% to 2% in 1990). One may however argue that it is too approximative as it does not account for the characteristics of the national gas networks (e.g. operating pressure, length of transmission network versus length of distribution network, length according to the material of the pipes etc).

(3): The level of emissions is lower in Ecofys' study because it assumes higher reductions from measures in the gas sector (compressors and replacement of old grey cast iron pipes)

(4): Agricultural measures are different in Ecofys and AEAT syudies. The reduction potential is higher in the synthesis paper because it sums up the effect of measures in both studies.

(5): In the AEAT study, agricultural emissions for 1990 and future years have been calculated using the revised IPCC methodology; for the EU they were found to be 20% higher than those reported in the EU second communication and used by Ecofys and in the synthesis paper.

(6): AEAT' s BAU scenario includes existing N2O abatement plans at the main adipic acid manufacturing plants; so BAU emissions are lower than in the two other analyses.
The reduction potential in 2010 is therefore lower than in the other two analyses. Ecofys' study and the paper do not incorporate in the BAU scenario N2O abatement measures in place.

(7): Emission projections with all measures included are lower in the paper than in the other two studies because it sums up the effect of measures considered in the two studies (no measure in the waste water sector in AEAT's study (reduction of 1 Mt CO2); no measure in the energy sector in Ecofys'study (reduction of 8 Mt CO2)).

(8): CO2 and halogenated gases emissions as in Table 3 of the paper.

(9): Reduction potential taken from Table 4.3 of the paper.

(10): CO2 contribution to the EU's Kyoto target if all measures identified for non-CO2 greenhouse gases are implemented irrespective of their cost and political applicability.
If only abatement measures with a cost lower than 50 ECU/t CO2 were implemented, CO2 contribution would be higher by 20 to 30% (270 to 300 Mt).
In the "AEAT" row, the CO2 balance was estimated using Ecofys' figures for the three halogenated gases.

Non-CO2 mitigation options considered in the studies

	Options	Comments
CH4		
Agriculture		
Enteric fermentation	Improved feed conversion efficiency	Ecofys: 6 different measures considered
		AEAT: not included
	Improved animal productivity	Ecofys: described but not included
		AEAT: 1 measure considered (propionate precursors)
Animal manure		
	Manure management	several measures considered in both studies with similar overall reduction potential
Landfill		
	Improved landfill gas recovery	measures include direct use, power generation, flaring
	Improved capping of landfill	
	Reduction of waste to landfill	measures include paper recycling, composting, incineration, anaerobic digestion
		Ecofys and AEAT: similar overall reduction potential (of which 67% is in the BaU of Ecofys' study)
Energy		
Coal production	Recovery and utilisation of mine gas	Ecofys: single package of measures
		AEAT: 5 alternative measures
		similar overall reduction potential
Oil and gas sectors	Increased gas utilisation offshore	
	Natural gas compressors	Ecofys: package of measures
		AEAT: 2 different measures
	Offshore flaring	
	Inspection and maintenance	Ecofys: not considered explicitly
	Replacement of grey cast-iron pipes	Ecofys red. potential is twice the AEAT red. potential
	Doubling the frequency of leak controls	

N2O		
Agriculture	Price support, subsidies for marginal land Fertiliser use limits Fertiliser timing limits	Ecofys: provides an estimate of the reduction potential of a fourth measure (or rather a package of measures) aimed at improving the efficiency of fertiliser use
Waste	N removal during sewage treatment	AEAT: not included (small reduction potential)
Energy		
Transport	Intermodal shift	Ecofys: not included AEAT: by-product of CO2 reduction strategy
Other combustion	Energy efficienct, renewables	Ecofys: not included AEAT: by-product of CO2 reduction strategy
Industrial processes		
Adipid acid production	End of pipe technology	AEAT: reductions of 237 kt included in the BaU scenario
Nitric acid production	Catalytic destruction, NSCR	
HFC's		
HCFC-22 production	Incineration	
Refrigeration	Leakage reduction, alternatives	
Other (foam, solvents)	Process optimisation, alternatives	
PFC's		
Aluminium production	Process modifications	
SF6	Package of measures (high voltage switches, etc.)	

Kyoto protocol and emission trading: potential cost savings and emission reductions

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1. Introduction

The Kyoto protocol to the UN-FCCC provides for the use of so-called flexible mechanisms to meet the agreed greenhouse gases reduction commitments. These include international emission trading, Joint Implementation (JI) and the Clean Development Mechanism (CDM). The major advantage of these mechanisms is that they should allow to meet the Kyoto commitments at lower costs. In the case of international emission trading, each Party can buy or sell emission reductions corresponding to the difference between the national marginal cost of reduction and a unified marginal cost which is equivalent to the permit price.

The principles, rules and modalities for use of these mechanisms are however still under discussion, they have to be further defined at COP4 in November 1998. Among the principles governing an international trading system, environmental effectiveness and supplementarity are key issues. Environmental effectiveness includes the assurance that real emissions reductions are delivered at lower cost. Supplementarity means that domestic actions should provide the main means of meeting the commitments. As to the latter issue, the EU believes that a concrete ceiling on the use of flexible mechanisms has to be defined to safeguard domestic policies and measures. In practice, a ceiling would limit the acquisition of emission pemits.

2. Objective and methodology

The present study deals, at least partly, with the above issues. Its general objective was in fact to explore the potential cost and emission reduction impact of international emission trading on the achievement of the Kyoto targets. A secondary objective consisted in estimating, for Annex B countries, the cost of meeting the Kyoto targets in the absence of emission trading.

It was not the aim of the study to address the economic theory of emission trading, nor to discuss the design parameters and implementation issues of an international trading system (transaction costs estimates, monitoring, etc.).

The study results are based on the POLES model. POLES[1] is a sectoral model of the world energy system to 2030, describing the international energy markets and national or regional subsystems; it has been designed, among others, to simulate and analyse CO_2 emission reductions strategies in an international perspective. In this respect, it is a relevant and useful analytical tool for the economic evaluation of international CO_2 emission trading.

The analysis considered CO_2 emissions only due to lack of a consistent analysis framework for the other greenhouse gases and sinks. The Kyoto targets specified for the basket of six greenhouse gases were thus applied to CO_2 emissions only. In fact, the focus on CO_2 emissions is in line with the step by step approach proposed by the EU.

3. The scenarios

Five different emission trading schemes or scenarios were designed that reflect different possible constraints on emission trading: in terms of participants (e.g. restrict the trading to Annex B countries), in terms of quantities (e.g. put a ceiling on emission trading), in terms of both participants and quantities.

All emission trading scenarios take into account the Kyoto targets of Annex B countries. The trading of "hot air" was not excluded, so that Russia and Ukraine can sell emission permits equivalent to the difference between their Kyoto targets and the level of their emissions in a Business as Usual scenario. As a result, the world wide level of CO_2 emissions in 2010 is equal to the sum of the Kyoto commitments for Annex B countries (overall reduction of 5.2%) and the Business as Usual emission levels for non-Annex B countries.

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[1] POLES was developed under the EC-JOULE programmes of DGXII. A detailed description of POLES 2.2 can be found in "POLES 2.2, Joule II Programme, Science Research Development, EC, December 1996 (Ref. EUR 17356 EN).

The emission trading scenarios are briefly described below.

- **Full trade world wide (Annex B and others)**

  International emission trading can be considered at different geographical scale. The larger the scale, the lower will be the permit price and the total cost of the Kyoto reduction commitments. This scenario assumes the establishment of emission trading among all countries of the world, without any ceilings on the use of flexibility instruments.

- **Full trade across Annex B only**

  This scenarios is similar to the previous one but trading is restricted to Annex B countries.

- **Trade in two zones within Annex B**

  This scenario implies a further constraint on the number of participants to the trading. Trading is restricted to Annex B countries, but within Annex B, trading is organised in two zones: within EU and across Annex B excluding EU. This implies that EU countries may not acquire from or transfer to non-EU Annex B countries emission reduction units.

- **Half trade among Annex B**

  This scenario assumes a ceiling on emission trading among Annex B countries: the traded volumes resulting from the full trade scenario are reduced to half.

- **Half trade world wide**

  This scenario also retains the assumption of halving the trade volumes but among all countries of the world.

Two reference scenarios were retained for the present analysis:

- the POLES Business as Usual (BAU) scenario[2] without constraints on greenhouse gases emissions, and
- the "no trading" scenario where the Kyoto targets are achieved by Annex B countries but with no emission trading allowed. Thus, the additional reductions from Russia and Ukraine mean that total Annex B reductions are higher in this scenario than if trading had been allowed (i.e. overall reduction around 10%). The CO_2 emissions of non-Annex B countries in 2010 are equal to the emission levels of the BAU scenario.

According to the BAU scenario, CO_2 emissions are expected to increase in 2010 compared to 1990 levels by 15.5% in the EU, by 13% in Annex B countries, and by 51% world wide. CO_2 emissions in the countries of the Former Soviet Union which are in Annex B[3] would decline by about 25% between 1990 and 2010 compared to the stabilisation target agreed at Kyoto. This situation gives rise to so called "hot air".

To address the potential cost of meeting the Kyoto targets if trading had not been permitted, the methodology adopted consisted in using the POLES model to simulate the impact of the "no trading" scenario by comparing the results to the BAU scenario.

To explore the cost and emission reduction implications of emission trading, the methodology adopted consisted in using the POLES model to simulate the impact of the emission trading scenarios by comparing the results to the "no trading" scenario.

In the geographic disaggregation of the POLES model, the world is divided into fourteen main regions[4], some of them being further divided into sub-regions i.e. countries or group of countries. As some Annex B countries, put together in POLES sub-regions, may have different quantified emission limitation or reduction commitments under the Kyoto Protocol[5], the Kyoto reduction commitments for POLES sub-regions are determined on the basis of individual countries' commitments and their respective contribution to the 1990 CO_2 emissions of the sub-region.

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[2] The POLES BAU scenario was revised in March 1998 mainly as to the energy forecasts in FSU (Former Soviet Union) which are closer to the IEA energy forecasts.

[3] The BAU scenario includes energy price increases in the framework of the overall price reform in Russia and Ukraine.

[4] North Americ (United States, Canada); Central America; South America; EC (15); Rest of Western Europe; Central Europe (4 adhesion countries, Rest of Central Europe); Former Soviet Union; North Africa; Middle-East; Africa South of Sahara; South Asia; South East Asia; Continental Asia; Pacific OECD (Japan, other Pacific OECD).

[5] e.g. Australia+New Zeeland; Poland+Hungary+Czech Republic+Slovekia; Romania+Bulgaria+Slovenia+Croatia.

On the other hand, the Former Soviet Union (FSU) region gathers together Annex B and non-Annex B countries. In this case, the Kyoto commitment is only applied to a percentage of FSU emissions determined on the basis of 1994 CO_2 emissions of Annex B countries, namely Russia, Ukraine, Latvia, Lithuania and Estonia[6].

4. The results

The POLES model provides the elements for an economic evaluation of the Kyoto emission limitation scenario and of various forms of CO_2 emission trading. These elements include the emissions before and after trade in each country/region and the volumes traded, the marginal abatement costs and the abatement costs in each country/region with and without trade, the permit prices, and the total expenditures for each country/region in absolute figures and in percentage of GDP in 2010.

The above elements are gathered in Tables 1 to 6 which are annexed to this report. Table 1 shows the results of the "no trading" scenario, Tables 2 to 6 show the results of the five emission trading scenarios.

The main results of the study are presented below.

- **"No trading" scenario**

  The overall effect of the Kyoto targets is a world wide reduction of CO_2 emissions in 2010 by 10% (20% in Annex B countries) compared to the BAU scenario.

  In Annex B, CO_2 emissions are 10% below the level of 1990. This is a higher reduction compared to the Kyoto commitment of reducing overall emissions by 5.2%. This results from the fact that, in this scenario, Russia and Ukraine can not trade the difference between their baseline emissions and their Kyoto targets. The size of this 'hot air' is not negligible, it is estimated to be slightly less than one fourth of the overall reduction in the other Annex B countries.

  The total and marginal costs of meeting the Kyoto commitments without trading vary widely from one country to another. The total costs of reduction are the highest in Japan, the United States and Australia/New Zealand (0.3%, 0.35% and 0.2% of GDP in 2010, respectively), they are of the order of 0.1% of GDP in

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[6] These five countries represent approximately 75% of total FSU emissions of CO2.

Canada and the European Union, and zero or close to zero in the other Annex B countries. However, the marginal costs of reduction are comparable in Canada, the EU, Australia/New Zealand and the USA (in the range of 90 to 110 $/tC), but far higher in Japan (245 $/tC).

For Annex B as a whole, the average cost of reduction is estimated at 0.2% of the GDP in 2010.

- **Full trade world wide**

Emission trading takes place both between Annex B and non-Annex B countries, and among Annex B countries. The overall result is that total Annex B is a net buyer of emission permits and non-Annex B a seller of permits.

If trading would take place world wide (CDM), it would not necessarily be supplemental. The trade between Annex B and non-Annex B represents more than 50% of total Annex B reductions required in 2010 (i.e. domestic action is thus less than 50%). Furthermore, as emission trading also takes place within Annex B, acquisitions of emission permits by individual Annex B countries could make up to 90% of the required emission reduction in 2010 (70% for the EU, 87% for Japan and 76% for the USA). Within Annex B, the sellers are Central European countries and Russia/Ukraine which contribute respectively to 3% and 97% of the trade.

The potential cost savings of a world wide emission trading are significant: 84% at the world level, 75% for Annex B, and 56% for the EU. Part of Annex B cost savings results from the revenues of sales of hot air by Russia and Ukraine: they represent slightly more than 10% of the estimated potential cost savings.

At the world level, the total reduction effort was estimated at 0.02% of the world GDP in 2010, compared to 0.1% in the "no trading" scenario. For Annex B, it was estimated at 0.06% of the Annex B GDP in 2010, compared to 0.2% in the "no trading" scenario. For the EU, it is reduced by half, from 0.1% of the EU GDP in 2010 to 0.05%.

The permit price of a world wide free emission trading was estimated at 24 $/tC.

- **Full trade across Annex B only**

  If emission trading is restricted to Annex B, trading is supplemental: more than 50% of total Annex B reduction in 2010 is expected to be done domestically. The acquisitions represent 25% of required reduction in 2010 for the EU, 37% for the USA and 68% for Japan. About 30% of total Annex B acquisitions are hot air. Again, the sellers of permits are Central European countries and Russia/Ukraine. They contribute respectively to 9% and 91% of this trade. Compared to CO_2 emission levels in 1990, party's acquisitions are up to 20%.

  Restricting the scope of emission trading results in lower cost savings. Nevertheless, potential cost savings are still significant, they were estimated at 58% in total Annex B (they were estimated at 75% with a world wide emission trading).

  Cost savings in total Annex B result from contrasting situations in Annex B countries: small costs savings for Canada and Australia/new Zealand (i.e. decrease of the total reduction cost by less than 6% compared to the "no trading" scenario), moderate cost savings for the EU and the USA (cost decrease around 15%), significant cost savings for Japan (cost decrease around 50%), and net revenues for Central Europe and the FSU.

  The permit price was estimated at 66.5 $/tC, i.e. almost three times higher than if trading would take place world wide.

  The total reduction effort of Annex B was estimated at 0.09% of the Annex B GDP in 2010, compared to 0.2% of GDP without emission trading. Again, cost savings include the revenues of sales of hot air by Russia and Ukraine; they represent 45% of the total cost savings.

- **Trade in two zones within Annex B**

  As this scenario involves a restriction on the number of participants to emission trading across Annex B (no trade is assumed between EU and non-EU countries), its results are compared to the results of the "full trade" scenario across Annex B only.

From the definition of the scenario, the total cost of reduction and the corresponding marginal cost of reduction for the EU are the same as in the "no trading" scenario. Similarly, the EU's Kyoto reduction commitment in 2010 is achieved exclusively through domestic action.

The exclusion of EU from trading allows the rest of Annex B to acquire more emission permits compared to full trading across Annex B. However, trading still remains supplemental in all Annex B countries except Japan.

Emission trading restricted to non-EU Annex B countries would result in higher cost savings than without restriction on trading (four times higher for Canada, 9% higher for Japan, 72% higher for Australia/New Zealand and 35% higher for the USA), and in lower revenues for Central Europe (29% lower) and Russia/Ukraine (13% lower). The permit price was estimated at 58.5 $/tC, this is 12% lower than in the full trade scenario.

- **Half trade among Annex B countries**

The objective of this scenario is to evaluate the impact of concrete ceilings on the amount a Party can acquire through trading so to ensure that trading is supplemental to domestic actions. The ceiling on trade is defined as follows: the emission permits an Annex B country can acquire from another Annex B country is limited to half the trade that would take place without restrictions on trading (i.e. in the "full trade" scenario across Annex B only).

The results of this scenario are compared to the results of the "full trade" scenario across Annex B only.

The first impact of the restriction on trade - that is in fact the objective of the constraint - is to increase the contribution of domestic action. Party's acquisitions represent less than 20% of their required reductions in 2010 with the exception of Japan where they still represent 35% (in the "full trade" scenario, party' s acquisitions were ranging from 20% to 70%).

Global CO_2 emissions would be 1% lower (2% lower in Annex B) since part of the "hot air" can not be sold.

Reducing the traded volume to half would increase annual costs of total Annex B by 50% (or 10 billion $1990/year).

On the other hand, the estimation of annual costs increases in each Annex B country is not straightforward. Whereas the model provides the impact of restrictions on trading on the costs of reduction realised domestically, it cannot deal with the impact on expenditures on permit acquisitions because there is no proper market clearing price for emission permits when ceilings are imposed on the exchanges.

Nevertheless, it could be assumed that emission trading will take place at a price somewhere between the highest (160 $/tC) and the lowest (30 $/tC) marginal costs of reduction within Annex B. Under the assumption that the permit price is in the range from 80 to 100 $/tC, halving the trade would increase the total costs of reduction by 40 to 50% in Japan and by 10 to 20% in the other buyer countries.

- **Half trade world wide**

The results of this scenario are compared to the results of the "full trade" scenario world wide.

With the specified restrictions on trading, trading becomes supplemental (more than 50% of the reductions required in 2010 would be done domestically). Global CO_2 emissions would be 1% lower (7% lower in Annex B) since part of the "hot air" can not be sold.

If trading would take place world wide, reducing the traded volumes to half would mean that annual costs are twice as high (or 12 billion $1990/year) at the world level.

Using similar assumptions as to the value of the permit price under limited trade, as the ones described in the "half trade" scenario among Annex B only, the total reduction costs of the buyer countries would be two to three times higher than without restrictions on trading[7].

5. Conclusion

The main findings of the previous comparison exercise between the different emission trading schemes are briefly summarised in Tables 7 to 10. Tables 7 to 8 show the impact on emissions and costs if emission trading is limited to Annex B countries. Tables 9 to 10 depict the results for emission trading among all countries of the world.

The results suggest the following conclusions if trading is restricted to Annex B.

- Even without constraints on emission trading, trading is supplemental (more than 50% of the required reductions in 2010 would be done domestically) except in Japan where permit acquisition contributes to around 70% of the required reduction[8]. In the EU, domestic actions would represent 75% of the reduction in 2010. Party's acquisitions are up to 20% of their CO_2 emissions in 1990, depending on the country (6% for the EU, 15% for the USA, 20% for Japan).

- The permit price would be equal to 66.5 \$/tC (17 ECU/tCO_2). At Annex B level, the reduction effort is expected to decrease from around 0.2% of 2010 GDP without trading to around 0.09% of 2010 GDP with full trade.

- Reducing the traded volume to half would increase annual costs of total Annex B by 50% (or 10 billion \$/year). On the other hand, global emissions would be 1% lower since part of the "hot air" can not be sold.

- The main result of the analysis of emission trading among Annex B countries seems to be that no ceiling on flexibility mechanisms (ET and JI) is needed to ensure that these are supplemental to domestic action. Furthermore, restrictions on trade would result in significant cost increases.

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[7] the permit price was assumed to be in the range 60 to 80 \$/tC.

[8] This result is in line with MITI's policy (The Ministry of International Trade and Industry of Japan) to reduce greenhouse gases emissions by 6% from 1990 levels by 2010: 2% reduction will come through national efforts while the remaining 4% reduction will come through emission trading with other nations.

If trading would take place world wide, the main findings are the following.

- Without restriction on the use of flexibility mechanisms (ET, JI and CDM), trading would not necessarily be supplemental (less than 50% of the required reductions in 2010 would be done domestically). Acquisitions could make up to 90% of the reduction in 2010 (70% in the EU, 76% in the USA, 87% in Japan). Moreover, EU's acquisitions would represent 16% of its CO_2 emissions in 1990, compared to 6% if trading is restricted to Annex B. USA shows however the highest share with acquisitions representing 30% of their CO_2 emissions in 1990.

- The permit price would be equal to 24 $/tC (6 ECU/$tCO_2$), namely three times lower than if trading is restricted to Annex B.

- World wide, the total costs of reduction are expected to be six times lower than without trading (2 times for the EU, 3 times for the USA, 5 times for Japan and 4 times for Annex B as a whole). The emission reduction effort would decrease from around 0.1% of 2010 GDP without trading to around 0.02% of 2010 GDP with full trade. At Annex B level, the decrease would be from 0.2% to 0.06% of the GDP in 2010.

- Reducing the traded volume to half would make the world wide trading supplemental. However, the price to pay is a doubling of the annual reduction costs (12 billion $1990/year). Global emissions would be 1% lower since part of the "hot air" can not be sold.

- The analysis of a world wide emission trading system points to the conclusion that a ceiling on the use of flexibility mechanisms would be needed to ensure that these are supplemental to domestic action. However, a cap on trade is expensive and does not solve the "hot air" issue. Moreover, the resulting restriction on "hot air" that can be sold has only a very limited impact on global emissions (1 percentage point lower).

Finally, as caveat, it should be stressed that the present analysis did not consider the possibility of banking and assumed perfect market for emission permits. Furthermore, Parties were assumed to minimise costs and to ignore ancillary benefits of domestic action. In reality, domestic action might then be more important than the model results suggest.

Table 1:	**"No trading"**					**Permit Price: n.a.**						
Regions	Emissions (in Mt of C)					Cost of reduction (value)				Cost of reduction (as % of GDP 2010)		
	1990	2010 BAU	2010 Kyoto Protocol	2010 scenario	2010 net em. trade +(buys) -(sells)	net value of trade mil $1990	marginal cost $1990/tC	cost of lomestic red mil $1990	total cost of red. mil $1990 (2)	GDP 2010 bil $1990	cost of lomestic red (% of GDP)	total cost of red. (% of GDP)
Canada	125	143	117	117	0	n.a.	100	1168	1168	803	0.145	0.145
Visegrad 4 (1)	180	175	168	168	0	n.a.	18	37	37	615	0.006	0.006
European Union	**946**	**1093**	**870**	**870**	**0**	**n.a.**	**102**	**10423**	**10423**	**8451**	**0.123**	**0.123**
Russia, Ukraine, Baltics	804	587	804	587	0	n.a.	n.a.	0	0	1967	0.000	0.000
Japan	319	398	300	300	0	n.a.	245	11432	11432	3679	0.311	0.311
Rest of Cent. Europe in A	73	68	68	68	0	n.a.	2	1	1	248	0.000	0.000
Australia, New Zealand	83	119	89	89	0	n.a.	90	1263	1263	604	0.209	0.209
United States	1411	1870	1312	1312	0	n.a.	115	30211	30211	8521	0.355	0.355
Total Annex B	3941	4454	3729	3512	0	n.a.	n.a.	54535	54535	24889	0.219	0.219
Rest of the World	2111	4711	4711	4711	0	n.a.	n.a.	0	0	26501	0.000	0.000
World	6052	9164	8440	8223	0	n.a.	n.a.	54535	54535	52249	0.104	0.104

(1): Poland, Hungary, Slovakia, Tch. Rep.
(2): i.e. incl. emission permits
n.a. : not applicable

Source: ECOSYM

Table 2:	**Full trade worldwide**					**Permit Price: 24 $/tC**						
Regions	Emissions (in Mt of C)					Cost of reduction (value)				Cost of reduction (as % of GDP 2010)		
	1990	2010 BAU	2010 Kyoto Protocol	2010 scenario	2010 net em. trade +(buys) -(sells)	net value of trade mil $1990	marginal cost $1990/tC	cost of lomestic red mil $1990	total cost of red. mil $1990	GDP 2010 bil $1990	cost of lomestic red (% of GDP)	total cost of red. (% of GDP)
Canada	125	143	117	138	20	490	24	70	560	803	0.009	0.070
Visegrad 4 (1)	180	175	168	166	-2	-58	24	115	57	615	0.019	0.009
European Union	**946**	**1093**	**870**	**1025**	**155**	**3722**	**24**	**822**	**4544**	**8451**	**0.010**	**0.054**
Russia, Ukraine, Baltics	804	587	804	542	-262	-6286	24	480	-5805	1967	0.024	-0.295
Japan	319	398	300	386	85	2047	24	144	2191	3679	0.004	0.060
Rest of Cent. Europe in A	73	68	68	63	-5	-110	24	57	-53	248	0.023	-0.021
Australia, New Zealand	83	119	89	110	21	504	24	108	612	604	0.018	0.101
United States	1411	1870	1312	1737	424	10186	24	1702	11887	8521	0.020	0.140
Total Annex B	3941	4454	3729	4166	437	10495	24	3498	13993	24889	0.014	0.056
Rest of the World	2111	4711	4711	4273	-438	-10495	24	5076	-5419	26501	0.019	-0.020
World	6052	9164	8440	8439	0	0	24	8574	8574	52249	0.016	0.016

(1): Poland, Hungary, Slovakia, Tch. Rep.
(2): i.e. incl. emission permits
n.a. : not applicable

Source: ECOSYM

Table 3:	**Full trade across Annex B only**					**Permit Price: 66.5 $/tC**						
Regions	Emissions (in Mt of C)					Cost of reduction (value)				Cost of reduction (as % of GDP 2010)		
	1990	2010 BAU	2010 Kyoto Protocol	2010 scenario	2010 net em. trade +(buys) -(sells)	net value of trade mil $1990	marginal cost $1990/tC	cost of lomestic red mil $1990	total cost of red. mil $1990	GDP 2010 bil $1990	cost of lomestic red (% of GDP)	total cost of red. (% of GDP)
Canada	125	143	117	125	8	512	66.5	631	1143	803	0.078	0.142
Visegrad 4 (1)	180	175	168	149	-19	-1263	66.5	859	-404	615	0.140	-0.066
European Union	**946**	**1093**	**870**	**925**	**55**	**3664**	**66.5**	**5146**	**8810**	**8451**	**0.061**	**0.104**
Russia, Ukraine, Baltics	804	587	804	490	-315	-20934	66.5	2830	-18104	1967	0.144	-0.920
Japan	319	398	300	367	67	4436	66.5	970	5405	3679	0.026	0.147
Rest of Cent. Europe in A	73	68	68	57	-11	-712	66.5	338	-373	248	0.136	-0.150
Australia, New Zealand	83	119	89	96	6	419	66.5	763	1182	604	0.126	0.196
United States	1411	1870	1312	1521	209	13872	66.5	11184	25056	8521	0.131	0.294
Total Annex B	3941	4454	3729	3729	0	0	66.5	22721	22715	24889	0.091	0.091
Rest of the World	2111	4711	4711	4711	n.a.	n.a.	n.a.	0	0	26501	0.000	0.000
World	6052	9164	8440	8439	n.a.	n.a.	n.a.	22721	22721	52249	0.043	0.043

(1): Poland, Hungary, Slovakia, Tch. Rep.
(2): i.e. incl. emission permits
n.a. : not applicable

Source: ECOSYM

Table 4:	**Trade in two zones within Annex B**					**Permit Price: 58.5 $/tC**						
Regions	Emissions (in Mt of C)					Cost of reduction (value)				Cost of reduction (as % of GDP 2010)		
	1990	2010 BAU	2010 Kyoto Protocol	2010 scenario	2010 net em. trade +(buys) -(sells)	net value of trade mil $1990	marginal cost $1990/tC	cost of domestic red mil $1990	total cost of red. mil $1990	GDP 2010 bil $1990	cost of domestic red (% of GDP)	total cost of red. (% of GDP)
Canada	125	143	117	127	10	559	58.5	513	1071	803	0.064	0.133
Visegrad 4 (1)	180	175	168	152	-16	-936	58.5	671	-265	615	0.109	-0.043
European Union	**946**	**1093**	**870**	**870**	**n.a.**	**n.a.**	**102**	**10423**	**10423**	**8451**	**0.123**	**0.123**
Russia, Ukraine, Baltics	804	587	804	499	-306	-17889	58.5	2264	-15625	1967	0.115	-0.794
Japan	319	398	300	370	70	4095	58.5	769	4864	3679	0.021	0.132
Rest of Cent. Europe in A	73	68	68	59	-9	-538	58.5	249	-290	248	0.100	-0.117
Australia, New Zealand	83	119	89	98	9	521	58.5	603	1124	604	0.100	0.186
United States	1411	1870	1312	1555	243	14192	58.5	9061	23253	8521	0.106	0.273
Total Annex B	3941	4454	3729	3729	0	0	n.a.	24552	24555	24889	0.099	0.099
Rest of the World	2111	4711	4711	4710	n.a.	n.a.	n.a.	0	0	26501	0	0
World	6052	9164	8440	8439	n.a.	n.a.	n.a.	24552	24552	52249	0.047	0.047

(1): Poland, Hungary, Slovakia, Tch. Rep.
(2): i.e. incl. emission permits
n.a. : not applicable

Source: ECOSYM

Table 5:	**Half trade among Annex B countries**					**Permit Price: not determined (3)**						
Regions	Emissions (in Mt of C)					Cost of reduction (value)				Cost of reduction (as % of GDP 2010)		
	1990	2010 BAU	2010 Kyoto Protocol	2010 scenario	2010 net em. trade +(buys) -(sells)	net value of trade mil $1990	marginal cost $1990/tC	cost of lomestic red mil $1990	total cost of red. mil $1990	GDP 2010 bil $1990	cost of lomestic red (% of GDP)	total cost of red. (% of GDP)
Canada	125	143	117	121	4		84	907		803	0.113	
Visegrad 4 (1)	180	175	168	159	-10		42	350		615	0.057	
European Union	**946**	**1093**	**870**	**898**	**28**		**84**	**7203**		**8451**	**0.085**	
Russia, Ukraine, Baltics	804	587	804	587	-157		n.a.	n.a.		1967	n.a.	
Japan	319	398	300	334	33		159	4715		3679	0.128	
Rest of Cent. Europe in A	73	68	68	62	-5		29	79		248	0.032	
Australia, New Zealand	83	119	89	93	3		78	987		604	0.163	
United States	1411	1870	1312	1417	104		91	19374		8521	0.227	
Total Annex B	3941	4454	3729	3669	0	0		33613	33613	24889	0.135	0.135
Rest of the World	2111	4711	4711	4710	0	0	n.a.	0	0	26501	0	0
World	6052	9164	8440	8380	0	0		33613	33613	52249	0.064	0.064

(1): Poland, Hungary, Slovakia, Tch. Rep.

(2): i.e. incl. emission permits

n.a. : not applicable

(3): their is no market clearing price for emission permits when ceilings are imposed on the exchanges.

Source: ECOSYM

Table 6:	**Half trade worldwide**					**Permit Price: not determined (3).**						
Regions	Emissions (in Mt of C)					Cost of reduction (value)				Cost of reduction (as % of GDP 2010)		
	1990	2010 BAU	2010 Kyoto Protocol	2010 scenario	2010 net em. trade +(buys) -(sells)	net value of trade mil $1990	marginal cost $1990/tC	cost of omestic red mil $1990	total cost of red. mil $1990	GDP 2010 bil $1990	cost of omestic red (% of GDP)	total cost of red. (% of GDP)
Canada	125	143	117	127	10		56	476		803	0.059	
Visegrad 4 (1)	180	175	168	167	-1		21	87		615	0.014	
European Union	**946**	**1093**	**870**	**948**	**78**		**55**	**3793**		**8451**	**0.045**	
Russia, Ukraine, Baltics	804	587	804	587	-131		n.a.	n.a.		1967	n.a.	
Japan	319	398	300	343	43		131	3281		3679	0.089	
Rest of Cent. Europe in	73	68	68	65	-2		12	18		248	0.007	
Australia, New Zealand	83	119	89	100	11		54	512		604	0.085	
United States	1411	1870	1312	1525	212		66	10934		8521	0.128	
Total Annex B	3941	4454	3729	3861	219			19102		24889	0.077	
Rest of the World	2111	4711	4711	4492	-219		11	1244		26501	0.005	
World	6052	9164	8440	8353	0	0		20346	20346	52249	0.039	0.039

(1): Poland, Hungary, Slovakia, Tch. Rep.
(2): i.e. incl. emission permits
n.a. : not applicable
(3): their is no market clearing price for emission permits when ceilings are imposed on the exchanges.

Source: ECOSYM

Table 7: **Emissions and acquisitions with trading among Annex B**

	Emissions (Mton C)					Acquisitions (Mton C) +(buys) -(sells)		Acquisitions (+) as % of required reduction		Trade as % of 1990 emissions	
	1990	2010 BAU	2010 Kyoto Protocol	2010 Full trade	2010 Half trade	2010 Full trade	2010 Half trade	2010 Full trade	2010 Half trade	2010 Full trade	2010 Half trade
Canada	125	143	117	125	121	8	4	29%	15%	6%	3%
Visegrad 4 (1)	180	175	168	149	159	-19	-10			11%	5%
European Union	**946**	**1093**	**870**	**925**	**898**	**55**	28	**25%**	**12%**	**6%**	**3%**
Russia, Ukraine, Baltics	804	587	804	490	587	-315	-157			39%	20%
Japan	319	398	300	367	334	67	33	68%	34%	21%	10%
Rest of Cent. Europe in A	73	68	68	57	62	-11	-5			15%	7%
Australia, New Zealand	83	119	89	96	93	6	3	21%	11%	8%	4%
United States	1411	1870	1312	1521	1417	209	104	37%	19%	15%	7%
Total Annex B	3941	4454	3729	3729	3669	0	0				
in % of 1990		113	95	95	93						
Rest of the World	2111	4711	4711	4711	4710						
World	6052	9164	8440	8439	8380						
in % of 1990		151	139	139	138						

(1): Poland, Hungary, Slovakia, Tch. Rep.

Table 9: **Emissions and acquisitions with worldwide emission trading**

	Emissions (Mton C)					Acquisitions (Mton C) +(buys) -(sells)		Acquisitions (+) as % of required reduction		Trade as % of 1990 emissions	
	1990	2010 BAU	2010 Kyoto Protocol	2010 Full trade	2010 Half trade	2010 Full trade	2010 Half trade	2010 Full trade	2010 Half trade	2010 Full trade	2010 Half trade
Canada	125	143	117	138	127	20	10	78%	39%	16%	8%
Visegrad 4 (1)	180	175	168	166	167	-2	-1			1%	1%
European Union	**946**	**1093**	**870**	**1025**	**948**	**155**	**78**	**70%**	**35%**	**16%**	**8%**
Russia, Ukraine, Baltics	804	587	804	542	587	-262	-131			33%	16%
Japan	319	398	300	386	343	85	43	87%	44%	27%	13%
Rest of Cent. Europe in A	73	68	68	63	65	-5	-2			6%	3%
Australia, New Zealand	83	119	89	110	100	21	11	70%	35%	25%	13%
United States	1411	1870	1312	1737	1525	424	212	76%	38%	30%	15%
Total Annex B	3941	4454	3729	4166	3861	437	219	60%	30%	11%	6%
in % of 1990		113	95	106	98						
Rest of the World	2111	4711	4711	4273	4492	-438	-219				
World	6052	9164	8440	8439	8353	0	0				
in % of 1990		151	139	139	138						

(1): Poland, Hungary, Slovakia, Tch. Rep.

Table 8: **Costs of emission reduction in 2010 with trading among Annex B**

	Costs of reduction (in mil $1990)					Costs of reduction as % of GDP 2010			
	Costs of domestic reduction			Expenditures c acquisitions	Total costs of red.	Costs of domestic reduction			Total expenditures
	No trade	Full trade	Half trade	Full trade	Full trade	No trade	Full trade	Half trade	Full trade
Canada	1168	631	907	512	1143	0.145	0.078	0.113	0.142
Visegrad 4 (1)	37	859	350	-1263	-404	0.006	0.140	0.057	-0.066
European Union	**10423**	**5146**	**7203**	**3664**	**8810**	**0.123**	**0.061**	**0.085**	**0.104**
Russia, Ukraine, Baltics	0	2830	0	-20934	-18104	0.000	0.144	n.a.	-0.920
Japan	11432	970	4715	4436	5405	0.311	0.026	0.128	0.147
Rest of Cent. Europe in A	1	338	79	-712	-373	0.000	0.136	0.032	-0.150
Australia, New Zealand	1263	763	987	419	1182	0.209	0.126	0.163	0.196
United States	30211	11184	19374	13872	25056	0.355	0.131	0.227	0.294
Total Annex B	54535	22721	33613		22721	0.219	0.091	0.135	0.091
Cost savings in %		58%	38%		58%				
Permit price in $1990/tC					66.5				

(1): Poland, Hungary, Slovakia, Tch. Rep.

Table 10: **Costs of emission reduction in 2010 with worldwide emission trading**

	Costs of reduction (in mil $1990)					Costs of reduction as % of GDP 2010			
	Costs of domestic reduction			Expenditures o acquisitions	Total expenditures	Costs of domestic reduction			Total expenditures
	No trade	Full trade	Half trade	Full trade	Full trade	No trade	Full trade	Half trade	Full trade
Canada	1168	70	476	490	560	0.145	0.009	0.059	0.070
Visegrad 4 (1)	37	115	87	-58	57	0.006	0.019	0.014	0.009
European Union	**10423**	**822**	**3793**	**3722**	4544	**0.123**	**0.010**	**0.045**	**0.054**
Russia, Ukraine, Baltics	0	480	n.a.	-6286	-5805	0.000	0.024	n.a.	-0.295
Japan	11432	144	3281	2047	2191	0.311	0.004	0.089	0.060
Rest of Cent. Europe in A	1	57	18	-110	-53	0.000	0.023	0.007	-0.021
Australia, New Zealand	1263	108	512	504	612	0.209	0.018	0.085	0.101
United States	30211	1702	10934	10186	11887	0.355	0.020	0.128	0.140
Total Annex B	54535	3498	19102	10495	13993	0.219	0.014	0.077	0.056
Cost savings in %		94%	65%		74%				
Rest of the World	0	5076	1244	-10495	-5419	0	0.019	0.005	-0.020
World	54535	8574	20346		8574	0.104	0.016	0.039	0.016
Cost savings in %		84%	63%		84%				
Permit price in $1990/tC					24				

(1): Poland, Hungary, Slovakia, Tch. Rep.

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Energy System Implications of Reducing CO_2 Emissions

Analysis for EU Sectors and Member-States by using the PRIMES Ver. 2 Energy System Model

Final Report from ICCS/NTUA

By: Prof. P. Capros and Dr. L. Mantzos

Athens, 10/12/99

Table of Contents

1. Introduction

The present report presents quantified analysis of energy system changes that are necessary for the EU to reach a series of CO_2 emission reduction targets for 2010 and evaluates the adjustment costs by sector and member-state. The analysis is based on the use of the PRIMES Ver. 2 energy system model (see Appendix). The results are confined to the energy system and consider that the macroeconomic and sectoral patterns of growth remain unchanged.

The study was carried out after the Kyoto protocol on climate change and analyses how the energy system might adjust in the period 2000 to 2010 to help the EU meeting the emission reduction target. The purpose of this study is to provide analytical information for a variety of emission reduction targets aiming at establishing an information basis to support policy design. The study does not recommend concrete policies and measures, but supports the design of such a policy. In that sense, the report provides energy system indicators that show which changes are cost-effective as long as the CO_2 emission reduction target for 2010 becomes higher. It also provides enough sensitivity analysis information to support discussion about sharing the burden of emission reduction among sectors and member-states.

2. Methodology

The calculations carried out within the present study followed the steps explained below:

1) The analysis started from a baseline scenario projecting the EU energy system from 1995 to 2010. The baseline scenario, also constructed by using the PRIMES model, reflects current policies and trends without including specific effort to reduce CO_2 emissions. The definition of the baseline scenario has been a result of shared analysis activity, which is on going under the auspices of DG XVII of the European Commission. The version of the baseline scenario is that delivered on February 5, 1999.

2) Starting from that baseline, the model ran to compute the least cost solution corresponding to a given level of CO_2 emissions in 2010, which is constrained to be lower than the level of the baseline in 2010. A large range of such emission levels were defined, all of them being towards reducing emissions from baseline. An emission reduction level is imposed as an exogenous global emission constraint applied to the whole energy system of a member-state, letting the sector without any specific constraint (except those that have already been imposed in the baseline scenario). The model determines the allocation of effort by sector within each member-state that is necessary to meet the global constraint.

3) The analysis exploits the differences between the results of each model run corresponding to lower emissions and the results of the baseline. These differences span the whole energy system, showing changes that are necessary to reach the lower emission level. Such changes may concern behaviour in using energy,

structural changes in energy uses and processes, possible accelerated adoption of new technologies, changes in the fuel mix, etc. The exploration of the series of least cost solutions, varying according to the magnitude of the emission reduction level, provides a rich set of information revealing the priority of changes that are recommendable by sector and country, and their nature. This information can further support design of concrete policies and measures.

4) The model provides simultaneous estimations of the marginal and average costs of these changes, by sector and member-state. Following a least cost methodology, the marginal costs plotted against the varying levels of emission reduction, in other terms the model-based marginal abatement cost curves, can be used as a basis for defining the sharing of the emission reduction effort by country and furthermore by sector.

5) The PRIMES model simulates the overall market equilibrium of the energy sector. It computes the prices of energy products that lead to balancing demanded and supplied quantities of each energy product in a period of time (usually a five-year period). Since the PRIMES model is formulated as a complementary mathematical problem (dual to a mathematical programming problem), the imposition of a global constraint is mathematically strictly equivalent to the inclusion of a shadow variable which appropriately affects all economic costs, exactly as the global constraint would do. Appendix-A shows that the two approaches are equivalent. Let us call the value of the shadow variable “carbon-value” of the global emission reduction constraint. Obviously, there will be a single carbon value associated to a given emission reduction level for a given member-state. To facilitate the analysis, we prefer to present the results in terms of carbon value, which was set to vary from a small level of 1 Eur/ton-of-carbon up to 900 Eur/ton-of-carbon. The comparison of the obtained emissions with the level of baseline scenario (per member-state) shows the magnitude of abated emissions that is dual to the level of the carbon-value. The adjustment of the energy demand and supply system, as computed by the model, is therefore exactly identical to the results from imposing the associated emission reduction level as a global constraint to the system of a member-state.

3. The Baseline Scenario

The baseline scenario includes current trends and all policies in place except those that aim at reducing CO2 emissions in the perspective of reaching the Kyoto targets. The scenario includes:

- the dynamic trends of technology progress that improves the efficiency of the energy system,
- the restructuring of markets effected through the liberalisation of electricity and gas market in Europe and
- the observed sectoral pattern of economic growth that shifts away from traditional energy intensive sectors and operates through high value added activities.

Energy prices are assumed to gradually increase from their presently low-level following a smooth ascending path. Table 1 shows the main assumptions for the energy prices at the border of the EU. Oil prices are assumed to recover by 2005 at their 1995 level and then grow smoothly. Natural gas prices increase at lower rates in the first half of the period but then grow slightly faster than oil. Coal prices remain practically stable in real terms.

Energy taxation policies are assumed to remain unchanged from the current situation in the EU member-states.

Table 1: Baseline Assumptions on Energy Prices

Average Border Prices at the EU in Eur'90 per toe				
	1995	**1998**	**2005**	**2010**
Crude Oil	81.7	58.6	81.2	86.2
Natural Gas	65.7	58.6	72.7	79.7
Coal	51.7	50.9	50.4	51.1

Average % change per year			
	1998-95	**2005-98**	**2010-05**
Crude Oil	-10.5	4.8	1.2
Natural Gas	-3.8	3.1	1.9
Coal	-0.5	-0.1	0.3

Table 2 summarises the macro-economic assumptions in the baseline scenario. Economic growth of the EU is projected to be significant (about 2.5% per year). The sectoral pattern of this growth is projected to change smoothly over time. The share of manufacturing in GDP decreases, while that of the tertiary sector increases. Within the manufacturing sector, the contribution of energy intensive sectors further reduces. Population is increasing very slowly.

Table 2: Macroeconomic Assumptions for the EU in the baseline scenario

	1995	**2000**	**2010**	**1995**	**2010**	**2000-95**	**2010-00**
	M Eur'90			% Structure of GDP		% change per year	
Gross domestic product	5672.0	6456.9	8191.4			2.6	2.4
Income - Private consumption	3308.8	3702.3	4636.5			2.3	2.3
Decomposition of Gross Domestic Product	K Eur'90						
Manufacturing	*1,502,841*	*1,673,161*	*2,064,748*	*28.1*	*26.7*	*2.2*	*2.1*
- Energy Intensive Manuf.	338,108	373,496	455,475	6.3	5.9	2.0	2.0
- Metals	48,855	51,341	54,157	0.9	0.7	1.0	0.5
- Chemicals	123,224	137,739	176,931	2.3	2.3	2.3	2.5
- Paper	102,697	114,951	142,799	1.9	1.8	2.3	2.2
- Building Materials	63,332	69,465	81,589	1.2	1.1	1.9	1.6
- Non Energy Intensive Manuf.	1,164,732	1,299,665	1,609,272	*21.8*	*20.8*	*2.2*	*2.2*
- Food	169,961	191,335	231,488	3.2	3.0	2.4	1.9
- Textiles	82,291	84,452	92,961	1.5	1.2	0.5	1.0
- Engineering	495,535	572,732	748,740	9.3	9.7	2.9	2.7
- Others	112,501	121,997	136,262	2.1	1.8	1.6	1.1
- Construction	304,444	329,149	399,822	5.7	5.2	1.6	2.0
Services	*3,433,811*	*3,978,889*	*5,165,089*	*64.3*	*66.9*	*3.0*	*2.6*
- market services	1,981,302	2,339,987	3,196,503	37.1	41.4	3.4	3.2
- non market	775,080	876,756	1,052,711	14.5	13.6	2.5	1.8
- trade and transports	677,429	762,147	915,875	12.7	11.9	2.4	1.9
Agriculture	*154,692*	*162,808*	*183,048*	2.9	2.4	1.0	1.2
Energy Sector	*252,254*	*270,017*	*312,710*	4.7	4.0	1.4	1.5
TOTAL	*5,343,598*	*6,084,874*	*7,725,595*	*100.0*	*100.0*	*2.6*	*2.4*
	000 persons						
Population	371,693	376,526	383,057			0.3	0.2

Energy policies not directly related to Kyoto objectives are assumed to continue within the baseline scenario:

- The liberalisation of electricity and gas markets starts operating in the beginning of the new century and is assumed to fully develop in the second half of the first decade.

- The restructuring is enabled by mature gas-based power generation technologies that are efficient, involve low capital costs and are flexible regarding plant sizes, cogeneration and independent power production.

- Energy policies that aim at promoting renewable energy (wind, small hydro, biomass and waste) are assumed to continue, involving subsidisation of capital cost and preferential electricity selling prices.

- On-going infrastructure projects in some member-states concerning the introduction of natural gas are assumed to gain full maturity in the first half of the first decade of the projection period.

- Finally, stringent regulation for acid rain pollutants is also assumed to continue, in particular for large combustion plants.

The results of the baseline projection show a continuous increase of the use of fossil fuels in Europe and hence an increase of CO2 emissions from energy conversion and use. Compared to 1990 emissions, CO2 emitted in the EU is shown to increase by about 8% in 2010.

The rise of emissions is unequally distributed among the sectors of the energy system (see Table 3). Energy use for transport of passengers and goods represents by far the highest increase of CO2 emissions due to high rates of growth of activity in this sector. The tertiary sector also develops significantly, because of high economic activity. Energy use in industry and households grow at lower rates reflecting restructuring trends in industry and saturation of energy uses in households. Despite relatively high growth of electricity demand, the power and steam generation sector succeeds to keep CO2 emissions roughly at the level of 1990.

Table 3: CO2 Emissions by Sector in the Baseline Scenario

EU-14	**1990**	**1995**	**2000**	**2005**	**2010**
TOTAL Energy CO2 Emissions	*3068*	*3029*	*3139*	*3272*	*3301*
(Eurostat conventions)					
industry	424	381	384	383	380
tertiary	190	200	215	219	218
households	450	430	454	451	449
transports	735	800	868	935	993
electricity-steam production	1211	1160	1160	1228	1208
energy branch	57	59	57	56	52
CO2 emission index (1990 = 100)	**1990**	**1995**	**2000**	**2005**	**2010**
TOTAL	*100.0*	*98.8*	*102.3*	*106.7*	*107.6*
industry	100.0	89.9	90.4	90.3	89.6
tertiary	100.0	105.0	113.4	115.3	114.9
households	100.0	95.5	100.8	100.2	99.8
transports	100.0	108.8	118.2	127.2	135.2
electricity-steam production	100.0	95.8	95.7	101.4	99.7
energy branch	100.0	103.6	100.2	97.9	91.0

The baseline scenario projects a change of trends that were in the past improving the carbon intensity in Europe. Carbon intensity does not improve significantly and remains rather stable over the projection period (see Table 4). This is mainly due to the stagnation of nuclear energy development. Carbon intensity slightly improves in the second half of the projection period, as a result of the rapid penetration of natural gas in power generation and some new developments in the domain of renewable energy.

Table 4: Energy and Carbon Intensity in the Baseline Scenario

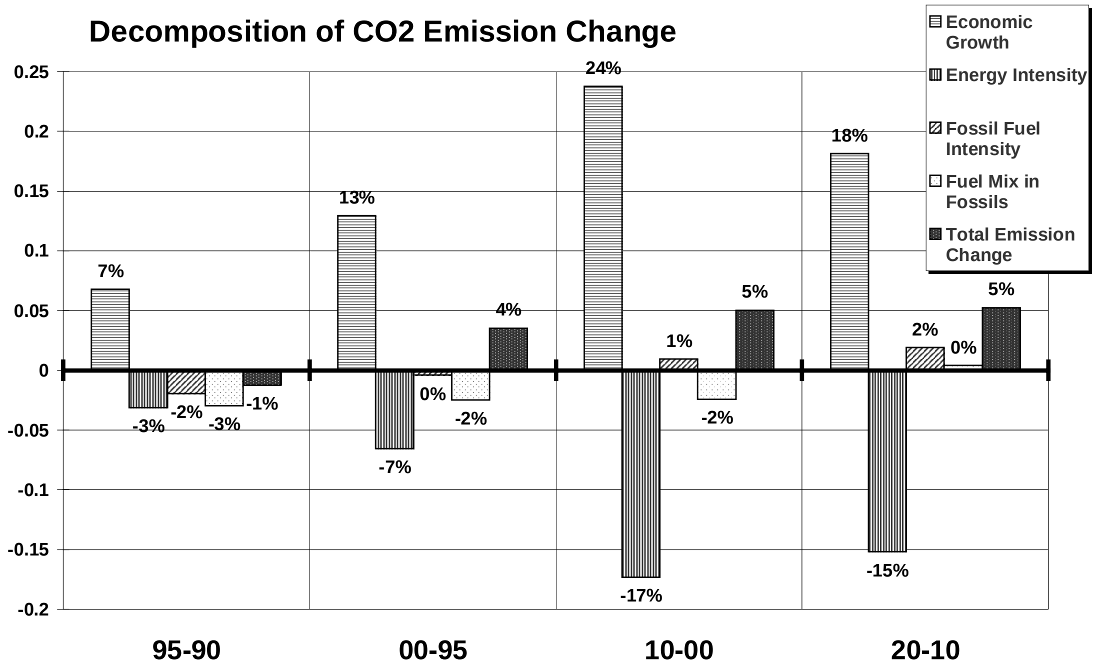
European Union	**1990**	**1995**	**2000**	**2005**	**2010**
Gross Inl Cons / GDP (toe/MEURO90)	247.8	240.2	224.9	207.6	189.2
Carbon Intensity (tn of CO2/toe)	2.3	2.2	2.2	2.2	2.1
Annual % rates of change		**1995-90**	**2000-95**	**2005-00**	**2010-05**
Energy Intensity		-0.6	-1.3	-1.6	-1.8
Carbon Intensity		-1.0	-0.6	0.0	-0.3

Table 4 shows that the baseline scenario projects a significant improvement of the energy intensity ratio. This can be interpreted as a result of the combined effects from economic restructuring and energy technology progress both in demand and supply sides.

Given the stagnation of carbon intensity, CO2 emissions do not grow at the rate of economic growth because of the improvement of energy intensity. Emissions would be higher in the baseline if the projected evolution of energy intensity proved to be slower than expected.

Figure 1 shows the role of energy intensity improvement in moderating the rise of CO2 emissions in the baseline projection for Europe. Similar role is played by the fuel mix within the fossil fuels, also contributing to moderate the rise of emissions, since natural gas is strongly penetrating in power generation. The intensity of primary energy consumption in fossil fuels contributes to the rise of emissions, a result that goes opposite to past trends. Similar trends prevail in the next decade beyond 2010.

Figure 1: Factors that contribute to the change of emissions in the baseline



The rise of CO2 emissions from the European energy system is also unequally distributed among the member-states. Four member-states succeed to reduce or almost stabilise emissions in 2010 compared to 1990. In the baseline scenario this is the result of restructuring of the economy and/or the energy system due to factors other than climate change concerns. Three member-states increase emissions significantly but at rather moderate growth rates. In seven member-states, CO2 emissions strongly tend to increase and become in 2010 35 to 60% higher than 1990.

Table 5: CO2 Emissions per Member-State in the Baseline Scenario

(in Mtn CO2 per year)	1990	1995	2000	2005	2010	*Index 2010-1990*
Austria	55.0	56.7	57.1	57.8	57.6	*104.8*
Belgium	104.8	111.0	118.4	120.3	122.9	*117.3*
Denmark	52.7	59.9	59.8	57.7	53.9	*102.3*
Finland	51.3	56.0	64.4	69.0	72.5	*141.1*
France	352.4	345.7	371.8	390.3	399.1	*113.2*
Germany	951.6	847.9	837.8	858.0	836.6	*87.9*
Greece	70.9	77.9	89.7	100.9	108.7	*153.3*
Ireland	30.1	31.9	38.4	41.6	42.7	*142.2*
Italy	388.0	402.8	417.4	435.6	431.5	*111.2*
Netherlands	153.0	170.7	184.4	191.7	206.3	*134.8*
Portugal	39.1	48.0	51.9	58.8	64.7	*165.7*
Spain	201.9	236.1	253.1	270.9	276.4	*136.9*
Sweden	50.0	53.5	58.0	63.5	66.8	*133.7*
United Kingdom	566.9	531.3	536.2	555.9	561.3	*99.0*

4. “Carbon-value” and Emission Reduction Targets

As mentioned before, the range of CO2 emission reduction scenarios is defined for a spectrum of marginal abatement cost levels defined between 1 Eur per ton of carbon up to 900 Eur per ton of Carbon. A marginal abatement cost is defined as the cost that is necessary to pay to avoid the emission in 2010 of the last ton of carbon (one ton of carbon represents 12 over 44 parts of one ton of CO2 emitted in the atmosphere) for a given emission reduction target. As also mentioned there is a strict duality between marginal abatement cost values and the quantity of tons of carbon of which the emission is avoided in 2010. Evidently the starting point for measuring the avoidance of CO2 emissions in 2010 is the level of emissions projected within the baseline scenario.

Given an emission reduction target we call “carbon-value” the associated marginal abatement cost measured in Eur per ton of carbon avoided.

Table 6 shows the main results of the analysis by using the PRIMES model. The upper part of the table shows the level of the carbon value for a range of emission reduction scenarios referring to the year 2010 and the associated emissions of CO2 in 2010. Then for each level of carbon value, the table shows the associated quantity of CO2 the emission of which is avoided in 2010 (bottom part of the table) and the percent reduction of emissions in 2010 compared to the level in 1990 (middle part of the table). The table shows this information for each member-state and the sum for the European Union (except Luxembourg).

The information in Table 6 can be used in two ways. If one knows the quantity of CO2 the emission of which must be avoided in 2010, he can start from the bottom line of the table and then read the corresponding column to determine the allocation of emission reduction effort by member-state, according to least cost. For example, the EU target of –6.2% emission reduction from 1990 (or avoidance of 434 Mtons of CO2 in 2010), corresponds to a carbon-value of 110 Eur per ton of Carbon (or 30 Eur per ton of CO2).

At that level of carbon-value, the least cost allocation to the member-states is shown in the column that corresponds to 110.

Table 6: Carbon values and associated emission reduction targets

			Carbon Value : Marginal Abatement Cost in Eur per ton of Carbon avoided																
		1990	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
CO2 Emissions (Mtn CO2)	AU	55.0	58.1	58.0	58.0	57.8	57.2	56.1	54.3	52.5	49.8	47.6	45.9	44.3	41.9	40.7	37.9	34.2	30.9
	BE	104.8	122.9	122.7	122.5	121.8	121.0	119.6	117.7	114.6	111.2	106.7	102.0	96.9	90.2	84.8	79.5	72.9	66.0
	DK	52.7	54.9	54.8	54.8	54.6	54.3	53.0	50.9	47.8	45.0	41.7	39.1	37.0	34.3	32.3	28.9	25.8	23.5
	FI	51.3	72.3	72.2	72.0	71.1	70.0	68.8	64.6	57.2	54.8	51.3	46.3	42.7	39.7	37.2	34.1	31.0	28.0
	FR	352.4	393.3	392.8	391.6	390.9	388.7	384.2	372.6	360.4	347.6	341.4	323.3	306.1	286.3	270.8	249.6	219.8	192.5
	GE	951.6	839.2	835.9	835.8	833.2	820.8	807.3	780.7	761.1	731.6	691.8	653.7	616.3	582.4	552.1	526.3	496.1	464.1
	GR	70.9	109.4	108.4	108.4	108.3	107.9	107.4	96.7	95.0	92.6	90.0	87.1	83.7	80.0	77.6	75.8	73.0	70.6
	IR	30.1	42.8	42.7	42.7	42.6	42.4	41.8	40.1	38.4	36.9	34.4	32.3	30.5	28.7	27.0	25.7	24.1	22.3
	IT	388.0	429.9	429.2	429.1	428.6	426.2	421.1	409.3	387.9	373.2	361.2	347.6	333.7	319.4	305.2	287.1	261.9	234.9
	NL	153.0	207.1	206.1	205.5	203.3	200.5	197.6	192.4	187.6	183.1	177.9	170.6	162.3	153.1	145.7	138.2	129.9	118.7
	PO	39.1	64.6	64.5	64.5	64.1	63.6	62.7	61.9	59.7	56.6	50.1	47.5	45.3	42.7	39.6	37.3	34.3	31.2
	SP	201.9	275.1	274.8	274.6	273.9	273.3	269.4	262.4	243.3	234.9	223.8	208.9	193.3	182.4	173.0	161.1	148.5	130.5
	SV	50.0	69.2	68.9	69.0	68.9	67.7	66.8	64.4	62.1	57.4	54.4	50.4	47.7	44.9	41.7	37.7	32.7	29.0
	UK	566.9	572.3	571.5	563.4	560.9	555.4	549.0	537.5	521.3	502.4	483.1	460.8	434.6	407.3	385.6	359.3	331.2	296.2
	EU14	3067.5	3311.1	3302.7	3291.9	3280.2	3248.9	3205.1	3105.5	2988.9	2877.1	2755.3	2615.6	2474.5	2333.2	2213.3	2078.5	1915.4	1738.4
			Emission Reduction Target : % Change of emissions in 2010 compared to 1990																
CO2 Change from 1990	AU		5.7	5.6	5.5	5.2	4.1	2.1	-1.1	-4.5	-9.4	-13.4	-16.4	-19.3	-23.7	-25.9	-31.1	-37.9	-43.7
	BE		17.4	17.2	17.0	16.3	15.5	14.2	12.3	9.4	6.2	1.9	-2.6	-7.5	-13.9	-19.1	-24.1	-30.4	-37.0
	DK		4.3	4.1	4.1	3.6	3.1	0.6	-3.4	-9.3	-14.6	-20.8	-25.7	-29.7	-34.9	-38.7	-45.1	-51.0	-55.4
	FI		40.8	40.6	40.2	38.5	36.4	34.1	25.8	11.5	6.7	-0.2	-9.9	-16.8	-22.7	-27.6	-33.7	-39.6	-45.4
	FR		11.6	11.4	11.1	10.9	10.3	9.0	5.7	2.3	-1.4	-3.1	-8.3	-13.2	-18.8	-23.2	-29.2	-37.6	-45.4
	GE		-11.8	-12.2	-12.2	-12.4	-13.7	-15.2	-18.0	-20.0	-23.1	-27.3	-31.3	-35.2	-38.8	-42.0	-44.7	-47.9	-51.2
	GR		54.3	52.9	52.9	52.7	52.1	51.4	36.3	34.0	30.7	26.9	22.8	18.1	12.9	9.4	7.0	3.0	-0.4
	IR		42.6	42.2	42.1	41.8	41.1	39.2	33.3	27.9	22.9	14.5	7.6	1.6	-4.4	-10.1	-14.6	-19.7	-25.9
	IT		10.8	10.6	10.6	10.5	9.9	8.5	5.5	0.0	-3.8	-6.9	-10.4	-14.0	-17.7	-21.3	-26.0	-32.5	-39.5
	NL		35.4	34.7	34.3	32.8	31.0	29.1	25.8	22.6	19.7	16.2	11.5	6.1	0.0	-4.7	-9.7	-15.1	-22.4
	PO		65.4	65.2	65.1	64.2	62.7	60.7	58.5	52.9	45.0	28.2	21.5	16.0	9.2	1.4	-4.5	-12.3	-20.1
	SP		36.3	36.1	36.0	35.7	35.4	33.5	30.0	20.5	16.4	10.9	3.5	-4.3	-9.7	-14.3	-20.2	-26.4	-35.3
	SV		38.4	37.9	38.1	37.9	35.4	33.7	28.8	24.2	14.8	8.8	0.8	-4.6	-10.1	-16.5	-24.5	-34.5	-42.0
	UK		0.9	0.8	-0.6	-1.1	-2.0	-3.2	-5.2	-8.0	-11.4	-14.8	-18.7	-23.3	-28.2	-32.0	-36.6	-41.6	-47.8
	EU14		7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
			CO2 emissions avoided in 2010																
CO2 Emissions (Mtn CO2)	AU		0.0	0.1	0.1	0.3	0.9	2.0	3.8	5.6	8.3	10.5	12.2	13.8	16.2	17.4	20.2	23.9	27.2
	BE		0.0	0.2	0.4	1.1	2.0	3.3	5.3	8.4	11.7	16.2	20.9	26.0	32.7	38.2	43.4	50.0	56.9
	DK		0.0	0.1	0.1	0.3	0.6	1.9	4.1	7.2	9.9	13.2	15.8	17.9	20.6	22.6	26.0	29.1	31.4
	FI		0.0	0.1	0.3	1.2	2.2	3.4	7.7	15.1	17.5	21.0	26.0	29.6	32.6	35.1	38.2	41.3	44.3
	FR		0.0	0.5	1.7	2.4	4.6	9.0	20.7	32.8	45.7	51.9	70.0	87.2	107.0	122.5	143.7	173.5	200.8
	GE		0.0	3.3	3.4	6.0	18.4	31.9	58.5	78.1	107.7	147.4	185.5	222.9	256.8	287.1	312.9	343.1	375.1
	GR		0.0	1.0	1.0	1.1	1.5	2.1	12.7	14.4	16.8	19.4	22.3	25.7	29.4	31.8	33.6	36.4	38.8
	IR		0.0	0.1	0.1	0.2	0.4	1.0	2.8	4.4	5.9	8.4	10.5	12.3	14.1	15.8	17.2	18.7	20.6
	IT		0.0	0.6	0.8	1.2	3.6	8.8	20.5	42.0	56.6	68.7	82.3	96.2	110.5	124.7	142.7	168.0	195.0
	NL		0.0	1.0	1.6	3.8	6.7	9.5	14.7	19.6	24.0	29.2	36.5	44.8	54.0	61.4	68.9	77.2	88.4
	PO		0.0	0.0	0.1	0.4	1.0	1.8	2.7	4.9	8.0	14.5	17.1	19.3	21.9	25.0	27.3	30.3	33.4
	SP		0.0	0.3	0.5	1.2	1.9	5.7	12.7	31.8	40.2	51.3	66.2	81.9	92.7	102.1	114.0	126.6	144.6
	SV		0.0	0.3	0.2	0.2	1.5	2.4	4.8	7.1	11.8	14.8	18.8	21.5	24.3	27.5	31.4	36.4	40.2
	UK		0.0	0.8	8.9	11.3	16.9	23.2	34.7	51.0	69.9	89.2	111.4	137.7	165.0	186.7	212.9	241.1	276.1
	EU14		0.0	8.4	19.2	30.9	62.2	106.0	205.6	322.2	434.0	555.8	695.5	836.5	977.8	1097.8	1232.6	1395.7	1572.7

If one starts from given emission reduction targets separately for each member-state, then the marginal abatement costs (carbon values) will differ across the member-states. One would then pick up one column for each member-state and determine the EU marginal abatement cost as a weighted average over the member-states.

The emission reduction targets set within the Kyoto protocol refer to the basket of all greenhouse gases (GHG) and not only to energy-related CO2 emissions. An overall least cost solution should take into account the marginal abatement costs of non-CO2 emissions and the shadow costs of other flexibility mechanisms defined at Kyoto (emission trading, joint implementation and clean development mechanism). This report does not cover this overall analysis and only deals with energy-related CO2 emissions.

The analysis with PRIMES permitted the construction of marginal abatement cost curves for each member-state (referring to energy-related CO2 emissions only). Such a curve plots the tons of CO2 emissions avoided in 2010 against the carbon-value.

The results show that the shapes and the slopes of the curves differ across the member-states. All shapes are concave and non-linear showing high increase of marginal costs for successively higher emission reduction targets. There is no curve showing negative costs, since the partial equilibrium model PRIMES did not allow for negative or zero-cost options (if such options existed they would have been taken-up in the baseline scenario). Consider also that the external costs (i.e. benefits from avoiding the damages caused by pollution) are not included in the analysis. The curves show, however, that proportionally lower marginal abatement costs (still positive) are associated with low emission reduction targets. This relation changes as one moves towards higher emission reduction targets.

Figures below show the marginal abatement cost curves for the EU member-states and the EU as a whole (referring to the least cost allocation of effort among the member-states). If one follows least-cost allocation of the target, he may start from the EU curve and determine the carbon-value that corresponds to a given quantity of emissions to avoid in 2010. Then he considers the member-state curves to determine which quantities of emissions each member-state should avoid in 2010 for the carbon-value level determined before at the level of the EU. This corresponds to a least-cost allocation of effort.

One cannot vertically compare the marginal abatement cost curves across the member-states, since the x-axis (quantities) is not normalised. These graphs can be exploited horizontally: which quantity to abate per member-state for a given carbon-value.

Table 7 shows normalised slopes (indicators of the gradient of the curve) of marginal abatement cost curves for the member-states. A higher absolute value of a slope shows more effectiveness than a lower absolute value.

The slopes are generally decreasing (in absolute terms) as the carbon-value increases, showing increasing difficulty of reducing emissions. Several of the slopes show a maximum value at low carbon-value levels, a result that reveals interesting and cheap opportunities to reduce emissions. Generally, the absolute values of the slopes are significantly high in the range corresponding to the beginning of the spectrum of emission reduction targets. In particular, the slopes decrease rapidly after the carbon-value range of 40 to 110 Eur/ton of carbon. Coincidentally, this corresponds to the order of magnitude of the carbon value associated with the emission target set at the Kyoto protocol for the European Union (the exact value depends upon the degree of use of non-CO2 GHG and other flexibility instruments). This result suggests that the agreed emission target for the EU is roughly consistent with the adjustment possibilities of the European energy system.

Table 7: Slopes of the Marginal Abatement Cost Curves

Carbon-Value in Eur per ton of Carbon avoided	AU	BE	DK	FI	FR	GE	GR	IR	IT	NL	PO	SP	SV	UK	EU14
	Normalised Slopes of the Marginal Abatement Cost Curves														
1	-102	-180	-162	-95	-130	-392	-913	-231	-151	-480	-73	-106	-376	-141	-253
2	-107	-169	-50	-278	-293	-17	-25	-96	-35	-301	-88	-70	154	-1408	-327
5	-90	-191	-136	-414	-58	-101	-27	-65	-35	-359	-174	-85	-46	-144	-118
10	-202	-139	-111	-294	-113	-297	-77	-105	-110	-272	-181	-49	-358	-193	-189
20	-195	-107	-233	-167	-113	-160	-48	-132	-119	-139	-125	-139	-126	-111	-132
40	-151	-80	-195	-294	-148	-159	-488	-205	-137	-124	-65	-128	-176	-101	-150
70	-107	-84	-188	-340	-103	-78	-51	-128	-166	-79	-113	-232	-112	-94	-117
110	-115	-68	-126	-85	-82	-88	-54	-87	-85	-54	-120	-76	-170	-83	-84
160	-76	-73	-119	-98	-31	-95	-49	-118	-56	-50	-203	-81	-86	-67	-74
220	-48	-64	-79	-115	-77	-76	-44	-80	-53	-58	-67	-90	-96	-65	-70
290	-39	-59	-54	-71	-63	-64	-44	-60	-46	-57	-48	-81	-56	-66	-61
370	-52	-68	-62	-52	-63	-51	-42	-52	-42	-56	-51	-49	-50	-60	-53
460	-23	-49	-41	-38	-44	-40	-25	-45	-37	-39	-52	-38	-51	-42	-40
560	-49	-43	-61	-43	-54	-31	-16	-32	-42	-37	-36	-43	-58	-46	-41
700	-46	-38	-40	-30	-54	-26	-18	-25	-42	-29	-33	-33	-51	-35	-35
900	-28	-28	-21	-21	-35	-19	-11	-22	-31	-27	-24	-33	-27	-31	-27

Table 7 shows significant differences of the slopes across the member-states, especially for the range of low carbon-values. At high carbon-values the differences tend to smooth out. Within the range of low carbon-values, the slopes of some member-sates show a fluctuation which partly reveals limitations of the model and partly should be attributed to the strong non-linearity and effects from economies of scale mechanism that are present in the model.

Figure 2: Marginal Abatement Cost Curves (EU)

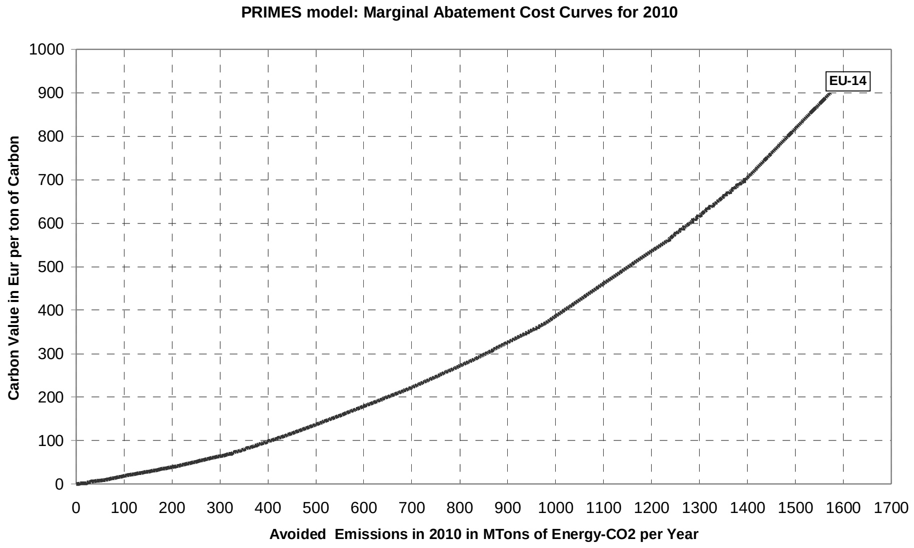


Figure 3: Marginal Abatement Cost Curves (BE, NL, SP, IT, FR, UK, GE)

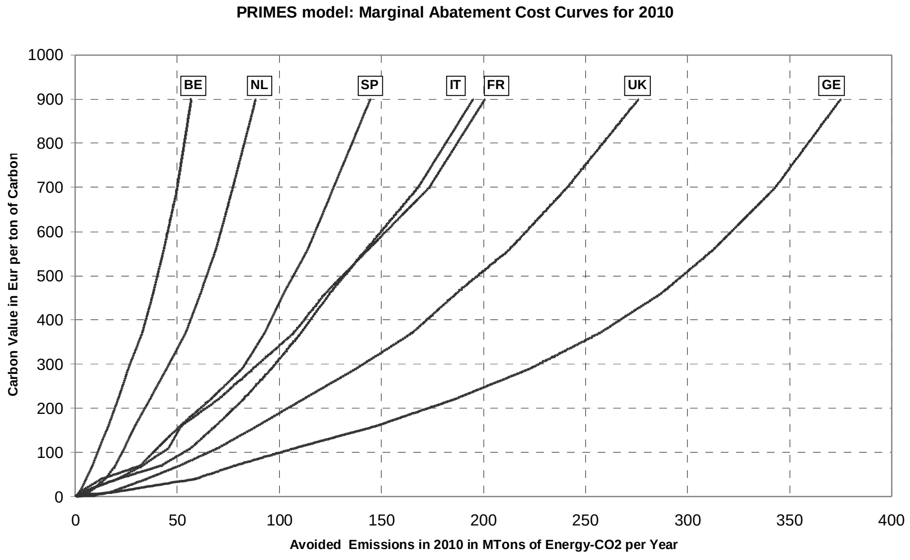
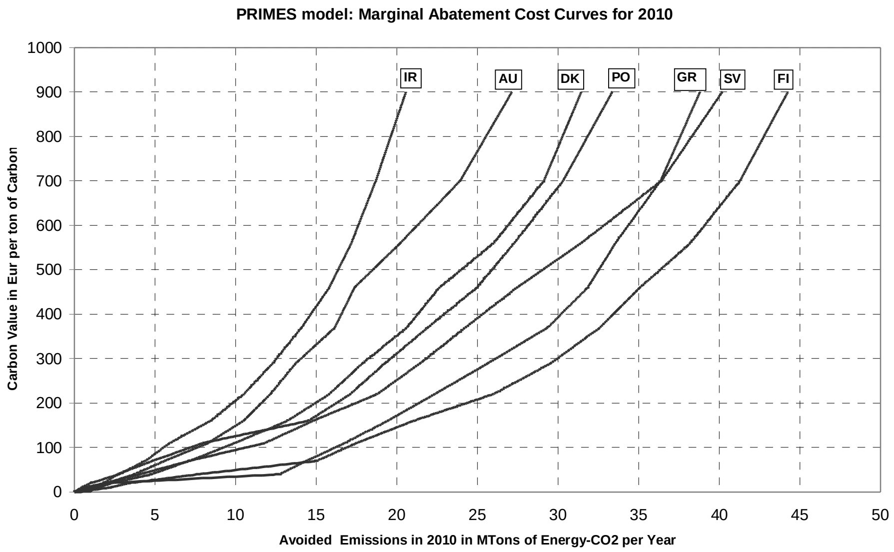


Figure 4: Marginal Abatement Cost Curves (IR, AU, DK, PO, GR, SV, FI)



5. Analysis of Changes in the Energy System

For each level of carbon-value and for each member-state there is a full PRIMES model run and a corresponding energy balance sheet. The differences of each emission constrained energy balance from that of the baseline scenario indicate the changes in the energy system that are necessary to meet the emission constraint (associated to the level of the carbon-value).

The detailed report from the PRIMES model includes 10 industrial sectors (and a large number of processes and energy uses), 4 tertiary sectors, 4 types of households, and 4 transport means (separately for passenger and goods transports). The changes of the energy system induced by the emission constraint spread over the whole energy system. All structures, technologies and fuel mix choices change, to a smaller or greater degree, as a consequence of the imposition of the emission target. This is related to the nature of the PRIMES model, since the model is non-linear and combines behavioural functions with cost optimisation at the decentralised level of each energy agent[1].

Consequently, the analysis of energy system changes induced by emission constraints is cumbersome involving high level of detail. To simplify the presentation of energy system changes, we have used a meta-model[2] that formally decomposes the effects into four general categories:

1) Structural and Behavioural Changes

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[1] Linear programming models can isolate a single (or almost) system change associated to a small variation of the emission reduction constraint. This is not possible with PRIMES.

[2] The meta-model uses the detailed definition of the energy system as in PRIMES and operates on the outputs of PRIMES decomposing the differences of an emission-constrained scenario from the results of baseline.

2) Technology Changes

3) Fuel-mix changes in direct combustion energy uses of fossil fuels

4) Supply-side effects from power and steam generation

The category referring to structural and behavioural changes includes several types of effects, the nature of which differs by sector. For the industrial sectors, this category includes changes in industrial processes, changes that might favour recycling of materials, production factor changes that generally increase the productivity of energy and allow for higher value added production, etc. For the tertiary and household sectors, this category includes behavioural changes in favour of more rational use of energy (e.g. voluntary limitation of the average heating temperature, more attention to switching-off of lighting, etc.), higher insulation of buildings and limitation of the degree of comfort in the houses and buildings. For the transport sectors, this category includes reduction of mobility, speed limitations, purchase of smaller cars, and shifts in the transport modes.

The category referring to technology changes (in the demand-side only) includes all types of energy technology efficiency gains that are associated to both the improvement of the average technology used by the consumers and the mix of energy uses that might differ in terms of technology-related efficiency. As a response to the emission constraint, the consumer may accelerate the adoption of more efficient technologies along the schedule of normal replacement of his equipment, or he may even prematurely scrap equipment and replace it with equipment incorporating more efficient technology. The suppliers of advanced technologies (equipment manufacturers, maintenance and technical support operators) anticipate higher demand for the advanced technologies and make them more attractive and more acceptable by the market. This technology supply-side effect[3] contributes to the acceleration of adoption of new technologies by consumers. Of course, both the availability of technologies and the technology adoption mechanism take into account the limited time available for system adjustment given that the emission target horizon is set to 2010. In fact it is assume that significant changes in technology choices can start operating in 2005, when energy users are assumed to anticipate fully the emission constraint for 2010.

The category referring to fuel mix changes in direct energy combustion uses concerns the fuel mix within the bulk of fossil fuels used in end-uses by consumers. It does not include changes in power and steam generation and excludes the effects (positive or negative) from shifting in favour of electricity or steam.

The category referring to supply-side effects includes all structural changes in power and steam generation excluding the effects from changes in electricity and steam consumption. The latter are included in the structure/behaviour and the technology change categories depending on their origin. In general, the analysis considers the average emission from power and steam generation and accounts for its change in the final demand sectors. Roughly the effects in the supply-side category concern the effects induced by the changes in the average emission factor in power and steam generation.

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[3] A technology-supply mechanism is present in the PRIMES model only in the demand-side (not in power and steam generation). The mechanism acts similarly to learning-by-doing allowing for increasing returns.

The results generally show that the contribution of each of the above four categories of change is different, as the emission constraint becomes bigger:

- In general, the contribution of structural and behavioural change becomes quite large, close to 20%, at relatively low levels of carbon values (20 Eur per ton of carbon, corresponding to about 4% increase of emissions in 2010 from 1990). As higher emission constraints are introduced the contribution of structural and behavioural changes stabilises between around 21%.

- The contribution of factors related to technology progress in the demand-side increases continuously with the level of the emission constraint. This contribution is of the same order of magnitude as that of the structural and behavioural change up to a carbon value of 110 Eur per ton of carbon, which corresponds to a decrease of emissions in 2010 from 1990 by 6.2%. As carbon values increase further the contribution of technology progress increases and at extremely high carbon values it accounts for nearly half of the overall emissions reduction.

- The role of changes in the fuel mix of fossil fuels directly used in end-use sectors is small for all values examined (of the order of 2 to 2.5%). It should be noticed that fuels used for steam generation are included in the power and steam sector, therefore fuel mix changes in this domain are included in the indirect effects from power and steam. The low contribution from changes in fossil fuel intensity of direct energy uses is due to the fact that natural gas is extensively used already in the baseline and high carbon-content fossil fuels are mostly used in specific processes.

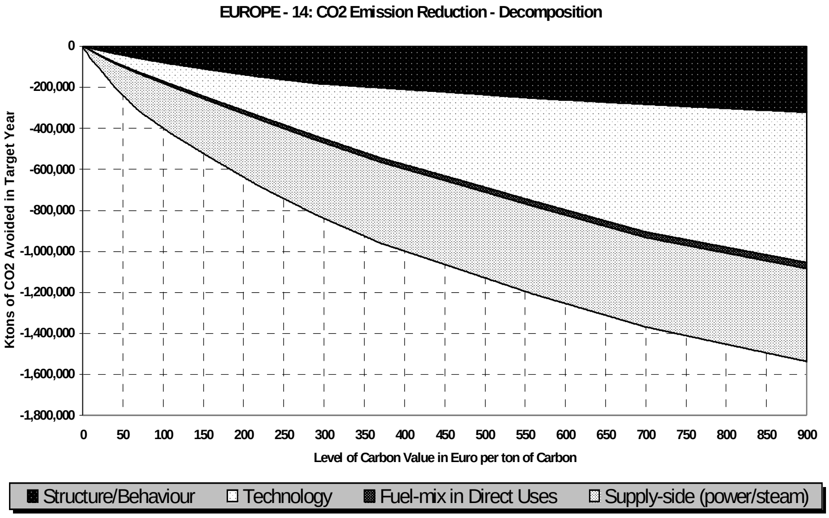
- The role of supply-side effects is important. The power and steam generation system meters a large contribution to the emission reduction. At low levels of carbon-value, the effects from power and steam generation dominate, having a share ranging from 73 to 59%. However, the share of this sector in total emission reduction continuously decreases with successively increasing emission targets. In the range that is of interest for the Kyoto targets, the effects from power and steam system account for about 50% of the total. This share decreases up to 30% at high emission targets. Within that range, technology progress in the demand-side becomes significantly more important than the power and steam system.

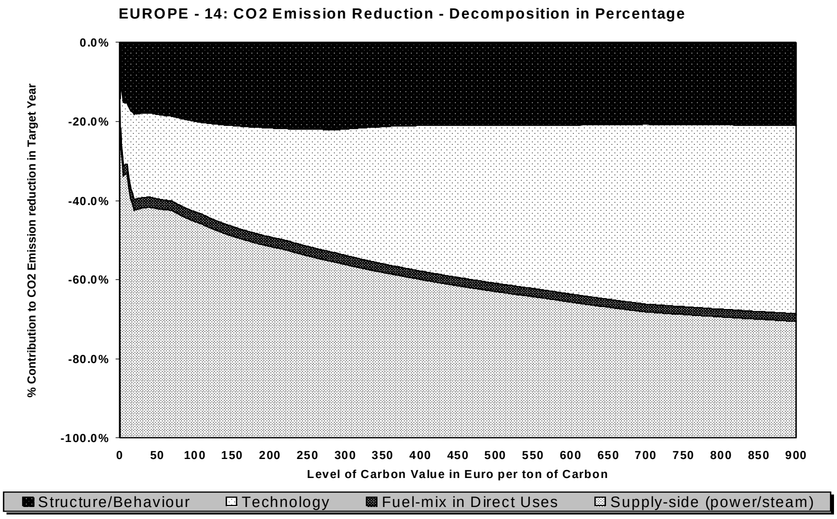
Table 8: Decomposition of energy system changes in four categories

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Total CO2 Emissions reduction in 2010 in Mtons of CO2		-7.7	-18.9	-30.7	-61.7	-104.1	-201.3	-316.4	-426.3	-546.1	-683.5	-821.8	-959.6	-1076.7	-1208.3	-1368.8	-1537.0
Structural change and behavioural effects		-1.1	-1.7	-4.7	-9.4	-18.9	-35.9	-59.0	-86.3	-115.7	-149.2	-181.2	-202.6	-225.1	-253.4	-283.4	-322.2
Technological improvement		-0.8	-2.4	-4.9	-9.6	-22.4	-42.9	-67.9	-99.0	-141.9	-192.5	-257.1	-341.9	-418.1	-501.6	-622.5	-732.4
Change of fuel mix		-0.2	-0.3	-0.7	-1.5	-2.8	-5.1	-7.5	-10.5	-13.1	-16.3	-19.4	-20.4	-22.6	-24.7	-26.9	-29.6
Change of emission factor of electricity and steam (supply effect)		-5.6	-14.6	-20.4	-41.2	-59.9	-117.5	-181.9	-230.5	-275.5	-325.5	-364.1	-394.8	-410.9	-428.5	-435.9	-452.9
% Decomposition																	
Structural change and behavioural effects		14.3	9.0	15.2	15.3	18.2	17.8	18.7	20.2	21.2	21.8	22.0	21.1	20.9	21.0	20.7	21.0
Technological improvement		10.9	12.7	16.1	15.6	21.6	21.3	21.5	23.2	26.0	28.2	31.3	35.6	38.8	41.5	45.5	47.7
Change of fuel mix		2.1	1.5	2.4	2.4	2.7	2.6	2.4	2.5	2.4	2.4	2.4	2.1	2.1	2.0	2.0	1.9
Change of emission factor of electricity and steam (supply effect)		72.7	76.9	66.3	66.7	57.6	58.3	57.5	54.1	50.4	47.6	44.3	41.1	38.2	35.5	31.8	29.5
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

The results shown in Table 8 are decomposed in three vertical sections. The first section corresponds to small emission reduction targets. For such targets, priority should be given to the power and steam generation system. The role of structural and behavioural changes and of technology progress in demand-side is also important in this section. The second section, corresponding to medium level of emission reduction targets, is also dominated by changes in power and steam generation but the role of structural and behavioural changes and of technology progress in demand-side is now more significant. The third section corresponds to high emission targets. In this section the power and steam generation sector seems saturated and its emission reduction effort that is additional to that of the previous section seems to be limited. The demand-side system has to make a significant additional effort. For high levels of emissions reduction constraints technology progress becomes the dominant potential contributor.

Figure 5: Decomposition of CO2 Emission Reduction into 4 categories





The graphics in the figure above further illustrate the analysis.

The changes in the power and steam generation system can be also decomposed in categories. For this purpose, we define the following categories:

1) Change of demand for electricity and steam.

2) Change of non-fossil fuel intensity defined as the share of non-fossil energy forms in power and steam generation (this concerns the zero CO2 emission fuels, including renewables, biomass, waste and nuclear energy).

3) Change of carbon intensity at fossil fuels defined through the fuel mix among the fossil fuels used in power and steam generation.

4) Technological improvement of fossil fuel plants (including the effects of cogeneration).

Of course, the effect from the changing electricity and steam demand is included in the decomposition of the demand-side effects. Since the latter included the indirect effects from power and steam generation, they represent the decomposition for the whole energy system.

Table 9: Decomposition of changes in power and steam generation

Carbon-Value (Eur per ton of Carbon)	0	1	2	5	10	20	40	70	110	160	220	290	370	460	560	700	900
Emission reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Power and Steam CO2 emissions reduction in 2010 in Mtons of CO2		-6.3	-15.8	-22.4	-44.8	-69.1	-133.5	-201.9	-258.9	-310.5	-379.4	-440.7	-493.0	-531.1	-568.6	-613.2	-647.9
Demand-side effects		-0.7	-1.5	-2.3	-4.3	-10.0	-18.1	-22.9	-32.1	-39.7	-58.9	-82.2	-104.0	-126.1	-146.7	-184.0	-203.4
Production from non-fossils		-0.9	-1.8	-3.4	-5.9	-13.0	-27.4	-56.3	-80.7	-104.4	-139.7	-174.8	-206.4	-231.3	-256.4	-285.3	-299.7
Fuel mix among fossils		-4.8	-10.3	-15.4	-33.8	-45.6	-78.9	-115.9	-134.4	-148.4	-155.0	-140.9	-133.0	-121.0	-108.5	-89.6	-79.3
Technological improvement of fossil fuel plants		0.2	-2.2	-1.4	-0.8	-0.4	-9.1	-6.7	-11.6	-18.0	-25.7	-42.8	-49.5	-52.6	-57.0	-54.3	-65.5
% Decomposition																	
Demand-side effects		11.5	9.2	10.3	9.6	14.5	13.5	11.4	12.4	12.8	15.5	18.6	21.1	23.7	25.8	30.0	31.4
Production from non-fossils		14.6	11.7	15.2	13.2	18.8	20.5	27.9	31.2	33.6	36.8	39.7	41.9	43.6	45.1	46.5	46.3
Fuel mix among fossils		76.4	65.0	68.5	75.4	66.1	59.1	57.4	51.9	47.8	40.9	32.0	27.0	22.8	19.1	14.6	12.2
Technological improvement of fossil fuel plants		-2.4	14.1	6.0	1.8	0.6	6.8	3.3	4.5	5.8	6.8	9.7	10.0	9.9	10.0	8.9	10.1
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

The changes of demand for electricity and steam explain a significant part of emission reduction in the power and steam generation sector. In percentage terms this part is significantly high (about 28%) at high levels of emission targets. This part is of the range of 10 to 15% even at small emission targets revealing the existence of cheap opportunities for electricity and steam savings in the demand-side.

The change of fuel mix in plants that use fossil fuels is clearly the cheapest solution for power and steam generation. This effect accounts for about 70% in the area of small emission targets. The corresponding possibilities are however exhausted as one imposes higher emission constraints. The share of this effect decreases significantly, from about 50% in the zone of middle emission targets down to less than 15% in the zone of high targets.

On the contrary, the contribution of the shift of production in favour of non-fossil fuels continuously increases in share. This ranges from 15% at small target-levels up to 45% at high target-levels. Table 10 shows the contribution of each non-fossil energy form. Clearly the role of large hydro and nuclear energy is kept constant in percentage terms, being of the order of 20% and 60%, respectively. This is due to the fact that both technologies have very long lead times and investment[4] cannot be committed within the horizon of the target (2010). The role of small renewables and zero-emission fuels (biomass and waste) increases significantly with the level of the emission target. Together they represent a share of 20% at high levels of target.

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[4] There is no new investment in nuclear energy in any emission-constrained scenario compared to baseline.

Table 10: Decomposition within the contribution of non-fossil fuels in electricity production

Carbon-Value (Eur per ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emission reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Emission reduction in 2010 from non fossil power generation (Mtons of CO2)	0.0	-0.9	-1.8	-3.4	-5.9	-13.0	-27.4	-56.3	-80.7	-104.4	-139.7	-174.8	-206.4	-231.3	-256.4	-285.3	-299.7
Large hydro	0	-0.2	-0.4	-0.8	-1.4	-3.0	-6.2	-12.3	-17.4	-21.9	-28.7	-35.6	-41.8	-46.3	-50.4	-55.6	-58.1
Small renewables	0	-0.1	-0.1	-0.2	-0.3	-0.8	-2.0	-4.4	-6.8	-9.4	-13.8	-18.0	-22.0	-24.5	-27.3	-30.1	-32.3
Biomass and waste	0	0.0	-0.1	-0.1	-0.3	-0.6	-1.3	-3.7	-6.4	-9.0	-13.4	-17.7	-21.4	-24.9	-28.3	-31.2	-32.8
Nuclear energy	0	-0.6	-1.2	-2.3	-3.9	-8.7	-18.0	-35.9	-50.2	-64.1	-83.9	-103.6	-121.2	-135.7	-150.4	-168.4	-176.6
% Decomposition of the effect of producing from non-fossil fuels																	
Large hydro	0	23.2	23.2	23.1	23.0	22.8	22.5	21.9	21.6	21.0	20.6	20.4	20.2	20.0	19.6	19.5	19.4
Small renewables	0	5.6	5.6	5.7	5.8	6.2	7.2	7.9	8.4	9.0	9.9	10.3	10.7	10.6	10.6	10.5	10.8
Biomass and waste	0	4.2	4.3	4.3	4.4	4.4	4.7	6.5	7.9	8.6	9.6	10.1	10.4	10.8	11.1	10.9	10.9
Nuclear energy	0	67.0	66.9	66.9	66.8	66.6	65.6	63.7	62.2	61.4	60.0	59.2	58.7	58.7	58.7	59.0	58.9
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

The effects from technological improvement of fossil fuel plants are rather limited for small and medium emission reduction targets. They become more significant for high emission targets, reaching a share of 10% at the maximum reduction case. This result can be explained through three considerations:

(1) demand for electricity and steam decreases with higher levels of emission reduction targets, leaving little room for new power generation investment and economies of scale (hence premature replacement becomes more and more expensive);

(2) steam savings in the demand-side seem to be more cost-effective than the massive development of cogeneration, since cogeneration is not the most efficient way (in terms of CO2) for producing electricity and still uses fossil fuels;

(3) advanced technologies like the fuel cells and advanced fuel cycles like methanol and hydrogen cannot develop fast within the limited time frame related to the horizon of the Kyoto target.

In summary, the response of the power and steam generation sector is dominated by fuel mix changes within fossil fuel uses for the range of small to medium emission targets and by a combination of demand-side savings and accelerated use of non-fossil fuels at high emission target levels.

The figures below further illustrate the analysis for the power and steam sector.

Figure 6: Decomposition of changes in power and steam generation sector

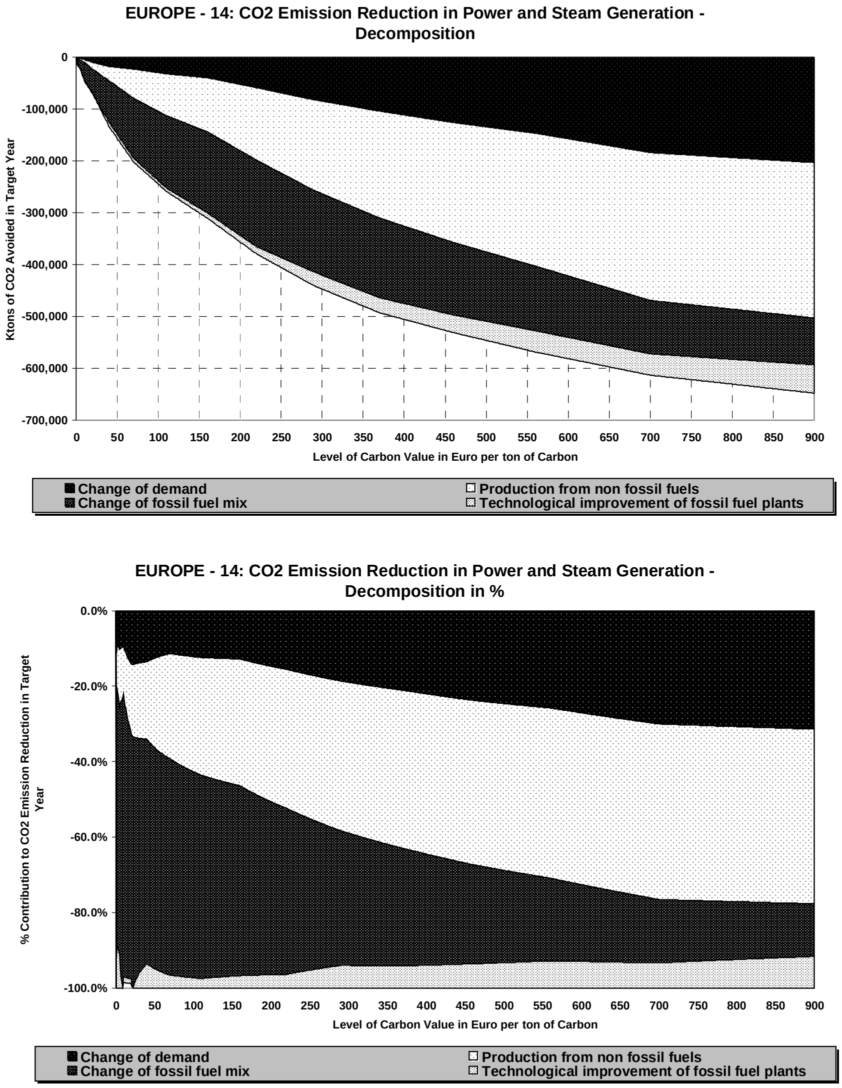
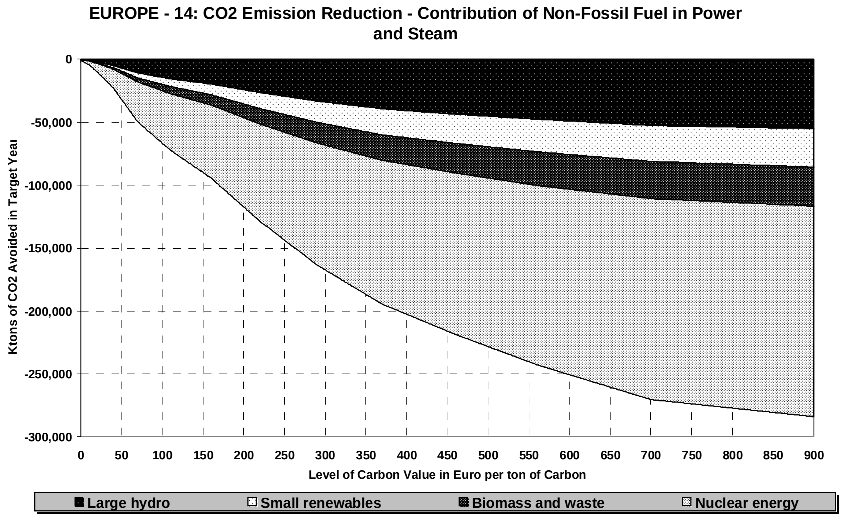
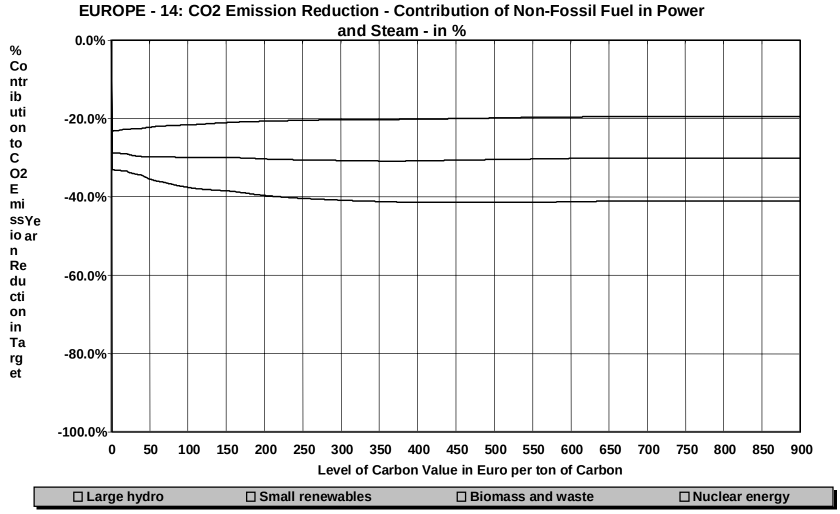


Figure 7: Decomposition of changes due to the use of non-fossil fuels in power sector





The role of other energy conversion sectors[5] is insignificant contributing by less than 0.3% to total emission reduction.

6. Further Details about Energy System Changes

This chapter provides more details regarding the energy system changes and is organised by sector. Table 11 summarises the CO2 emission avoided by each sector. Table 12 provides the same information in percentage terms.

Table 11: Analysis of CO2 Emission reduction by Sector

ANALYSIS OF ENERGY SYSTEM CHANGES TO REDUCE CO2 EMISSIONS IN 2010 FOR EUROPE - 14

Level of Carbon Value (in Eur'90/ton of Carbon)	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
% Emission change in 2010 from 1990	**7.7**	**7.3**	**6.9**	**5.9**	**4.5**	**1.2**	**-2.6**	**-6.2**	**-10.2**	**-14.7**	**-19.3**	**-23.9**	**-27.8**	**-32.2**	**-37.6**	**-43.3**
DECOMPOSITION OF CO2 EMISSIONS REDUCTION (Mtn of CO2 avoided in 2010)																
In the table below the changes in Electricity and Steam are included in Demand Sectors																
Industrial Sectors - Metals	-1	-1	-2	-5	-8	-15	-24	-30	-36	-45	-59	-73	-83	-92	-101	-110
Industrial Sectors - Chemicals	0	-1	-2	-4	-7	-12	-19	-26	-32	-39	-45	-52	-56	-60	-64	-69
Industrial Sectors - Materials	0	-1	-2	-5	-7	-13	-20	-27	-34	-42	-50	-57	-62	-68	-76	-83
Industrial Sectors - Others	-1	-3	-4	-8	-12	-24	-37	-49	-61	-76	-89	-101	-110	-119	-127	-135
Industrial Sectors - Total	-3	-7	-10	-22	-34	-64	-100	-132	-163	-201	-243	-282	-312	-340	-368	-397
Services	-2	-6	-8	-17	-31	-60	-90	-116	-145	-179	-211	-238	-257	-274	-288	-304
Agriculture	0	0	-1	-1	-2	-4	-5	-7	-8	-10	-12	-14	-15	-16	-17	-18
Households	-2	-5	-8	-15	-24	-48	-79	-107	-137	-173	-206	-246	-280	-317	-361	-388
Passenger Transports	-1	-1	-2	-4	-8	-15	-27	-42	-61	-80	-98	-118	-139	-167	-219	-299
Goods Transports	0	0	-1	-2	-5	-9	-15	-22	-32	-41	-52	-62	-73	-94	-116	-130
TOTAL SYSTEM - FINAL DEMAND	-8	-19	-31	-62	-104	-201	-316	-426	-546	-684	-822	-960	-1,077	-1,208	-1,369	-1,537
In the table below the changes in Electricity and Steam in demand are included in Power and Steam Sectors																
Electricity production	-7	-15	-22	-41	-64	-127	-193	-242	-287	-349	-403	-447	-483	-519	-561	-593
Steam production	1	-1	0	-3	-5	-6	-9	-17	-23	-31	-38	-45	-48	-50	-52	-55
Other Supply Sectors production	0	0	0	0	-1	-2	-2	-3	-4	-5	-7	-9	-11	-12	-14	-16
Statistical Difference (second order effects)	-1	0	0	0	-1	-3	-3	-4	-6	-6	-7	-9	-11	-12	-13	-20
In the table below the changes in Electricity and Steam are included in Power and Steam sector																
Total CO2 emissions reduction	-8	-19	-31	-62	-106	-206	-322	-434	-556	-696	-837	-978	-1,098	-1,233	-1,396	-1,573
In Final Energy Demand	-1	-3	-9	-17	-36	-69	-117	-170	-239	-308	-387	-474	-553	-648	-765	-897
In Electricity and Steam Generation	-7	-16	-22	-45	-69	-135	-203	-261	-313	-382	-442	-495	-534	-573	-617	-660
In Other Energy Conversion Sectors	0	0	0	0	-1	-2	-2	-3	-4	-5	-7	-9	-11	-12	-14	-16

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[5] Power and steam generation in the oil refinery sector is included in power and steam generation.

Table 12: Percent Analysis by Sector

% ANALYSIS OF ENERGY SYSTEM CHANGES TO REDUCE CO2 EMISSIONS IN 2010 FOR EUROPE - 14

Level of Carbon Value (in Eur'90/ton of Carbon)	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
% Emission change in 2010 from 1990	**7.7**	**7.3**	**6.9**	**5.9**	**4.5**	**1.2**	**-2.6**	**-6.2**	**-10.2**	**-14.7**	**-19.3**	**-23.9**	**-27.8**	**-32.2**	**-37.6**	**-43.3**
DECOMPOSITION OF CO2 EMISSIONS REDUCTION (Mtn of CO2 avoided in 2010)																
In the table below the changes in Electricity and Steam are included in Demand Sectors																
Industrial Sectors - Metals	7.5	6.9	7.9	7.6	7.5	7.3	7.3	6.9	6.6	6.4	7.1	7.4	7.6	7.5	7.2	7.0
Industrial Sectors - Chemicals	4.9	6.9	6.3	7.2	6.5	6.1	6.0	6.0	5.7	5.6	5.4	5.3	5.1	4.9	4.6	4.4
Industrial Sectors - Materials	5.8	7.5	6.8	7.2	6.5	6.3	6.3	6.3	6.1	6.0	6.0	5.8	5.7	5.5	5.4	5.3
Industrial Sectors - Others	11.7	13.8	12.6	13.1	11.6	11.5	11.5	11.4	10.9	10.9	10.6	10.3	10.0	9.7	9.1	8.6
Industrial Sectors - Total	29.9	35.1	33.6	35.1	32.1	31.3	31.1	30.5	29.3	28.9	29.1	28.8	28.5	27.6	26.4	25.2
Services	25.2	28.8	27.4	27.3	29.2	29.4	28.0	26.7	26.1	25.7	25.2	24.3	23.4	22.2	20.7	19.4
Agriculture	1.5	0.4	2.5	1.8	1.8	1.9	1.6	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.2	1.2
Households	27.2	26.3	25.5	24.8	23.1	23.5	24.6	24.6	24.7	24.8	24.6	25.2	25.5	25.7	25.9	24.7
Passenger Transports	6.0	5.5	7.1	6.9	7.4	7.5	8.4	9.8	11.0	11.5	11.7	12.0	12.7	13.5	15.7	19.0
Goods Transports	2.7	2.5	3.3	3.3	4.7	4.4	4.6	5.1	5.7	5.9	6.2	6.4	6.7	7.6	8.3	8.3
TOTAL SYSTEM - FINAL DEMAND	92.4	98.6	99.4	99.1	98.2	98.0	98.2	98.2	98.3	98.3	98.2	98.1	98.1	98.0	98.1	97.7
In the table below the changes in Electricity and Steam in demand are included in Power and Steam Sectors																
Electricity production	81.2	78.5	71.3	66.6	60.4	61.8	59.9	55.7	51.7	50.1	48.1	45.8	44.0	42.1	40.2	37.7
Steam production	-6.3	3.9	1.2	5.5	4.8	3.1	2.7	4.0	4.2	4.4	4.6	4.6	4.4	4.1	3.7	3.5
Other Supply Sectors production	0.4	0.5	0.6	0.6	0.7	0.8	0.7	0.7	0.7	0.8	0.9	0.9	1.0	1.0	1.0	1.0
Statistical Difference (second order effects)	7.3	0.9	0.0	0.2	1.1	1.3	1.1	1.0	1.0	0.9	0.9	0.9	1.0	1.0	0.9	1.3
In the table below the changes in Electricity and Steam are included in Power and Steam sector																
Total CO2 emissions reduction	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
In Final Energy Demand	17.9	16.6	27.5	27.7	33.8	33.7	36.2	39.2	43.0	44.3	46.2	48.4	50.4	52.6	54.8	57.0
In Electricity and Steam Generation	81.8	82.9	71.8	71.6	65.4	65.5	63.0	60.0	56.3	54.9	52.9	50.6	48.7	46.5	44.2	42.0
In Other Energy Conversion Sectors	0.4	0.5	0.6	0.6	0.7	0.8	0.7	0.7	0.7	0.8	0.9	0.9	1.0	1.0	1.0	1.0

Table 13: Further sectoral information on CO2 emission reduction

Level of Carbon Value (in Eur'90/ton of Carbon)	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
% Emission change in 2010 from 1990	**7.7**	**7.3**	**6.9**	**5.9**	**4.5**	**1.2**	**-2.6**	**-6.2**	**-10.2**	**-14.7**	**-19.3**	**-23.9**	**-27.8**	**-32.2**	**-37.6**	**-43.3**
Percentage Change of Sectoral Emissions in 2010 compared to baseline scenario																
In the table below the changes in Electricity and Steam are included in Power and Steam sector																
Industry	-0.09	-0.24	-0.57	-1.10	-2.16	-4.01	-6.27	-8.43	-10.67	-13.71	-19.01	-24.07	-28.40	-32.41	-37.08	-40.85
Tertiary	-0.20	-0.41	-1.02	-2.16	-4.59	-9.16	-15.13	-20.37	-28.54	-35.06	-41.64	-47.06	-51.69	-55.32	-58.80	-62.01
Households	-0.06	-0.10	-0.40	-0.83	-1.66	-3.27	-5.81	-8.77	-12.41	-16.30	-20.10	-26.24	-31.21	-36.61	-41.23	-45.45
Transports	-0.05	-0.09	-0.23	-0.47	-1.02	-1.95	-3.41	-5.48	-8.11	-10.72	-13.42	-16.28	-19.36	-24.15	-31.27	-40.53
In Final Energy Demand	-0.07	-0.16	-0.42	-0.85	-1.76	-3.40	-5.72	-8.34	-11.72	-15.10	-18.95	-23.21	-27.10	-31.75	-37.48	-43.96
In Electricity and Steam Generation	-0.56	-1.31	-1.82	-3.66	-5.69	-11.05	-16.66	-21.37	-25.65	-31.33	-36.30	-40.62	-43.83	-46.99	-50.64	-54.14
Elasticities: Percent change of sectoral emissions over percent change of energy demand/production in the sector																
Note: high value of the elasticity signifies high responsiveness of the sector																
In the table below the changes in Electricity and Steam are included in Power and Steam sector																
Industry	1.81	2.98	2.38	2.33	2.37	2.36	2.22	2.09	1.99	1.85	1.83	1.79	1.71	1.68	1.67	1.63
Tertiary	2.29	1.49	1.50	1.57	1.41	1.42	1.60	1.60	1.66	1.59	1.53	1.48	1.45	1.44	1.43	1.41
Households	1.05	1.10	1.77	1.84	1.91	1.93	1.82	1.79	1.74	1.66	1.58	1.54	1.50	1.45	1.34	1.35
Transports	0.98	0.97	1.00	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.00
In Final Energy Demand	1.31	1.33	1.39	1.41	1.36	1.36	1.40	1.39	1.38	1.34	1.31	1.29	1.27	1.26	1.24	1.25
In Electricity and Steam Generation	8.89	10.05	9.89	10.78	6.52	7.04	8.50	7.57	7.32	5.66	4.49	3.85	3.39	3.08	2.56	2.47

6.1 Industrial Sectors

6.1.1 Overview

The industrial sector consumes energy as input to processes that produce goods that are directly available to consumers, such as cars and computers, as well as a wide range of basic materials, such as cement and steel, that are used to produce goods for final consumption.

Although energy and the associated technological equipment is an important factor of production, it is not large in terms of annual manufacturing expenditures, ranging from about 20% of total production costs for energy intensive industries to less than 2% for non energy intensive ones. As a result, energy related technological breakthroughs (in terms of improved equipment efficiency) tend to have a rather small impact in small to medium levels of emission reduction targets (as discussed later in detail). In the contrary, the mix of energy uses that might differ in terms of technology-related efficiency plays a much more significant role concerning emissions reduction.

Restructuring of industrial processes (e.g. increase of electric arc processing instead of integrated steelworks in the iron and steal sector) may play an important role in reducing CO2 emissions, since it has an important impact in industrial efficiency. The same stands for changes that generally increase the productivity of energy and allow for higher value added production, for example increase of the contribution of low energy chemicals to sectoral value added.

Changes in fossil fuel mix of direct energy uses do not have an important role in emissions reduction. This is due to the fact that natural gas is extensively used already in the baseline and high carbon-content fossil fuels are mostly used in specific processes.

Supply-side effects are very important in industrial sectors. Their contribution is dominant in small to medium emission reduction targets declining only in high emission reduction targets where they still account for almost half of the overall sectoral emissions reduction.

Table 14: Decomposition of energy system changes in industrial sectors

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand)	26.6	26.6	26.6	26.6	26.6	26.7	26.8	26.9	27.1	27.5	27.7	27.8	28.1	28.2	28.7	29.6	30.7
Sectoral as % of Overall CO2 Emissions reduction in 2010		32.3	35.6	33.8	35.5	32.7	31.9	31.7	31.1	29.8	29.4	29.6	29.4	29.0	28.2	26.9	25.8
Total Industry CO2 Emissions reduction in 2010 in Mtons of CO2		-2.5	-6.7	-10.4	-21.9	-34.0	-64.3	-100.2	-132.5	-162.7	-201.1	-243.4	-282.0	-312.4	-340.2	-367.8	-396.6
% Decomposition																	
Structural change and behavioural effects		12.9	7.2	12.5	11.9	14.7	14.0	14.3	14.3	14.9	14.9	15.4	15.1	15.1	15.4	16.0	16.9
Technological improvement		5.0	3.1	7.7	7.1	8.7	8.7	9.7	11.5	12.5	15.3	19.5	23.7	27.5	29.7	31.6	32.5
Energy saving in heat uses		*0.1*	*0.8*	*2.2*	*1.9*	*2.4*	*2.7*	*3.1*	*4.0*	*4.7*	*5.6*	*5.9*	*6.6*	*7.8*	*8.7*	*9.3*	*9.8*
Specific Industrial processes		*2.0*	*1.7*	*3.3*	*3.0*	*3.6*	*3.6*	*3.8*	*4.3*	*4.3*	*5.0*	*7.8*	*10.9*	*13.1*	*14.3*	*15.7*	*16.3*
Electrical Equipment		*2.8*	*0.6*	*2.2*	*2.3*	*2.6*	*2.4*	*2.8*	*3.2*	*3.5*	*4.8*	*5.7*	*6.2*	*6.6*	*6.7*	*6.5*	*6.4*
Change of fuel mix		3.1	2.1	3.4	3.2	3.7	3.4	3.2	3.0	2.8	2.6	2.5	2.1	2.0	1.8	1.7	1.6
Change of emission factor of electricity and steam (supply effect)		79.0	87.6	76.4	77.8	72.9	73.9	72.7	71.3	69.8	67.2	62.7	59.2	55.5	53.1	50.7	48.9
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

In the results shown in Table 14 technological improvement effects are further decomposed in three types of equipment technologies: those that refer to low enthalpy heat uses, those that refer to specific industrial processes and electrical equipment.

For small emission reduction targets, priority is given to the power and steam generation system, the contribution of which ranges around 75% of sectoral emissions reduction. A part of the reduction is due to lower electricity and steam consumption in carbon value scenarios. A larger part of the reduction results from sharply lower carbon intensity of electricity and steam production. The role of supply side effects decreases as higher emission reduction targets are set, but still remains the most important of all. Structural and behavioural changes are important for low carbon values. Their contribution increases, as higher emission targets are set, stabilising though at about 15% for a large range of medium to high carbon values. Technology progress is of small significance for small emission reduction targets. Its role becomes of great importance at higher levels of carbon value reaching 32.5% of overall emissions reduction. Specific process technologies improvement is the most important, followed by low enthalpy heat uses technologies. Electric equipment technologies improvement, cross cutting technologies such as motor drives, lighting equipment, air compressors etc., contributes to a smaller extend in emissions reduction. This is due to the fact that these technologies achieve high efficiencies in the baseline scenario and their improvement potential is limited. Changes in the fossil fuel mix of direct energy uses are not important, their contribution to sectoral emissions reduction ranges from 3% at low carbon value scenarios to 1.5% at high carbon value scenarios.

Industrial sector contribution is very important for small emission reduction targets raging between 32 to 35% when the market share of industry in terms of final energy demand is stable around 27%. As higher emission reduction targets are set the sectoral potential exhibits saturation effects and inefficiencies prevail. As a result the sectoral contribution in emissions reduction decreases reaching 25% at very high carbon values scenarios while the market share of industry increases up to 30%.

Changes of final energy demand for the different carbon value scenarios are given in Table 15. It must be mentioned here that fuels consumption in industrial sectors does not include consumption of industrial boilers and industrial co-generators of steam and electricity. The later are included in the power and steam generation system.

Table 15: Final energy demand in industrial sectors

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Final energy demand in industry in 2010 (Mtoe)	278	278	278	278	277	276	274	271	267	264	258	250	241	232	225	217	209
% change from baseline		0.0	-0.1	-0.2	-0.5	-0.9	-1.7	-2.8	-4.0	-5.3	-7.4	-10.4	-13.4	-16.6	-19.2	-22.2	-25.0
Fuel shares in final demand (%)																	
solid fuels	9.0	8.9	8.9	8.8	8.7	8.5	8.1	7.7	7.4	7.2	6.9	6.2	5.7	5.3	4.9	4.5	4.0
liquid fuels	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.7	12.6	12.6	12.6	12.6	12.7	12.7	12.7	12.6	12.5
liquified petroleum gas	1.5	*1.5*	*1.5*	*1.5*	*1.5*	*1.5*	*1.6*	*1.6*	*1.6*	*1.6*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*	*1.7*
diesel oil	4.4	*4.4*	*4.4*	*4.4*	*4.4*	*4.5*	*4.5*	*4.6*	*4.7*	*4.7*	*4.8*	*4.9*	*5.0*	*5.1*	*5.1*	*5.1*	*5.2*
residual fuel oil	4.1	*4.1*	*4.1*	*4.1*	*4.1*	*4.0*	*4.0*	*3.9*	*3.9*	*3.8*	*3.7*	*3.7*	*3.6*	*3.6*	*3.5*	*3.5*	*3.4*
other petroleum products	2.6	*2.6*	*2.6*	*2.6*	*2.6*	*2.6*	*2.5*	*2.5*	*2.5*	*2.4*	*2.4*	*2.4*	*2.4*	*2.4*	*2.4*	*2.3*	*2.3*
natural gas	24.7	24.7	24.7	24.7	24.8	24.9	24.9	25.0	25.0	25.0	24.9	24.6	24.1	23.7	23.3	22.7	22.2
steam	22.5	22.5	22.5	22.5	22.6	22.6	22.7	22.9	23.0	23.1	23.3	23.7	24.1	24.3	24.5	24.8	25.0
electricity	31.2	31.2	31.3	31.3	31.3	31.4	31.6	31.7	31.9	32.1	32.3	32.8	33.4	34.0	34.6	35.4	36.3

Consumption of solid fuels, which are mainly used in iron and steel, drops sharply and has the greatest percentage change from baseline for all scenarios. This reduction is mainly due to the observed structural shift from integrated steelworks to electric arc processing and secondarily to improvement of equipment efficiency. The share of liquid fuels in industrial energy demand is stable for all emission reduction targets at around 12.5%. However, the substitution in favour of liquefied petroleum gas and, mainly, diesel oil is significant. Demand for natural gas is also stable, in terms of percentage to total demand, for small to medium carbon value scenarios. As high emission reduction targets are set the share of natural gas decreases by up to 2.5% from baseline, being substituted by electricity and steam. The later continuously gain market shares, especially electricity, as emission reduction targets are set. The high efficiency of electric equipment technologies and the continuous improvement of carbon intensity of the power and steam generation system lead to this result.

6.1.2 Metals Production

6.1.2.1 Introduction

The production of metals is one of the most energy intensive industrial activities and includes sectors that produce iron and steel and a variety of sectors that produce non-ferrous metals such as primary aluminium, secondary aluminium, copper, zinc, lead and non-ferrous alloys.

The production of iron and steel (as modelled in PRIMES) falls into two sub-sectors. Integrated production units transform iron ore into pig iron then converting into steel which is further casted and rolled into primary products in a variety of shapes. Electric steelworks produce primary steel products from scrap steel, usually in an electric arc furnace. In both sub-sectors the production of steel products involves thermal energy uses that are in PRIMES grouped in energy uses such as rolling of steel, sinter making, process furnaces and foundries. Coal is used in integrated production units. Oil, gas and electricity are used in thermal energy uses that produce steel products. Motor drives are widely used in the sector.

Primary aluminium production involves treating bauxite and then decomposing dissolved alumina into a crude molten metal through electrolysis. Electricity consumption in electrolysis represents over 80% of energy use in the sector. Thermal processing in the sector uses all kinds of fuel and electricity. Secondary aluminium production processes scrapped aluminium products to refine and thermally convert into primary aluminium. This process is almost 6.5 times less energy intensive than primary aluminium production. In the PRIMES modelling primary and secondary aluminium are represented as two distinct sectors.

The production of other non-ferrous metals uses specific processes. The production of zinc involves thermal transformation of ores into oxides, which are reduced by carbon in an electric furnace or refined through an electrolytic process. The second method is currently dominating production of zinc. The main production method for lead involves thermal conversion of ore into oxide and reduction in a furnace. Recycling of waste material is widely practised in the sector allowing for lower overall energy intensity. Copper is produced from ore, which is mechanically processed and then thermally reduced in a furnace. The production of non-ferrous alloys also involves thermal processing in furnaces.

6.1.2.2 Sector Evolution in the Baseline Projection

In the baseline the projection for the iron and steel sector shows a significant restructuring favouring electric steelworks which would deliver 47% of production in 2010 instead of 32% in 1995. Since integrated iron and steel production is very energy-intensive, in fact 2.9 times higher than electric steelworks, the overall energy intensity of the sector greatly improves over time (-0.80% per year). However, the baseline projects little technology improvement over time, showing that energy intensity measured at the level of each individual process would progress at a rate of about –0.05% per year for both sub-sectors. The drivers for sectoral restructuring are economic (competitiveness of the EU industry, specialisation of European industry in specialty steels, etc.) rather than related to energy or environment.

Industrial restructuring of the aluminium production sector is also projected in the baseline. Economic competitiveness of the sector drives this change, leading to high concentration of primary aluminium producers in a few European regions. In the baseline the restructuring involves a significant decline of primary aluminium production and an increase of secondary aluminium. The latter would represent 78% of total aluminium production in the EU, against 58% in 1995. Such a change implicitly assumes higher imports of primary aluminium into the EU, since it cannot be only attributed to higher recycling of aluminium. Recycling, although assumed greatly developing in the baseline, has limitations, as for example for some technological uses of aluminium, like the cars for which high quality is required. The restructuring of the sector explains the spectacular drop of the overall energy intensity of the sector in the baseline (-2.7% per year in the 1995-2010 period). Technology progress of the specific industrial process is shown to be very limited in the baseline projection.

In the same period, technology progress of the specific processes of producing the other non-ferrous products is also very low. Energy intensity ratios in these sectors are projected to remain stable or improve slightly.

6.1.2.3 Sector Adjustment for Different Emission Targets

Imposing CO2 emission reduction targets at the level of the overall energy system leads the iron and steel sector to shift more aggressively into electric arc processing and progressively abandon integrated processing along with more stringent emission targets.

As mentioned, the model displays equilibrium responses of the system to emission reduction targets, therefore the results for a sector reflect the emission reduction costs in the sector relative to the costs of other sectors in the energy demand and supply system.

For emission targets ranging from small to medium values (corresponding to carbon values up to about 220 Eur per ton of Carbon, or a target of about –19% from 1990) the reaction of the iron and steel sector is practically limited in process restructuring. In this range, the electricity production sector has a higher contribution than demand sectors in reducing emissions. The shift of iron and steel sector reduces energy demand[6], since electric arc is much less energy intensive than integrated processing, and helps to improve carbon intensity, since the average emission factor of electricity becomes lower than that of coal (used in integrated processing) in the emission reduction cases.

At higher levels of emission reduction target, the potential gains from shifting into electric arc, directly or indirectly via the improvement of carbon intensity in the power sector, become more and more limited. Within this range, more efficient technologies would be adopted for both integrated processing and electric steelworks.

The results show for these cases a significant improvement of energy intensity measured as specific energy consumption per process. A close look to the results shows that this is mainly achieved through premature scrapping of iron and steel production capacities.

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[6] The sector's energy intensity in average improves up to 10% from baseline just because of the restructuring in favour of electric arc.

Evidently this involves high costs and uncertainty for the industry, explaining the inertia of the sector, regarding technology improvement, in the range of small to medium levels of emission reduction targets. It should be noticed that capital turnover rates are particularly slow in the iron and steel sector and that the sector has rather recently undergone a considerable investment program for renovation and restructuring.

In the case of integrated steelworks, specific energy consumption improves up to 35% (compared to baseline projection for 2010), involving adoption of more efficient technologies from a menu that includes the following:

- ✓ Direct smelting and direct reduction that allow for a decrease of the use of coke in blast furnaces and reduces the need for ore preparation (sinter making). This technology may lead to an improvement up to 30% of energy intensity.

- ✓ Casting and rolling operations improve in energy terms by adopting hot connection techniques and mainly near-net-shape casting that replace continuous slab casting and hot rolling, leading to savings that may reach 25 % of energy needs. The electric steelwork sub-sector also benefits from these techniques.

- ✓ Several techniques, among others scrap pre-heating, contribute in making the electric arc processes more efficient. The results show a net improvement from baseline of the order of 20%.

Improvement of energy efficiency is also obtained in the iron and steel sector in domains other than process technologies. They can be classified in three domains: energy savings from better housekeeping; improvement of the efficiency of crosscutting technologies, such as motor drives; improvement of product (steel) quality allowing for higher value added per ton of steel.

Good housekeeping measures in highly energy-intensive industries are generally limited in scope. The improvement of crosscutting technologies is discussed in a separate section for the industry as a whole. The model involves the possibility of obtaining in an endogenous manner higher value added in a sector from lower production in physical units. This is represented in the model via behavioural functions involving elasticities. The approach followed does not provide engineering evidence for example on saving of materials or higher quality materials that may enable higher value added from lower volume of materials.

Within a large range of emission targets, the material-improvement effect is rather limited: the ratio value added per ton of steel improves by 5% at a level of 260 Eur per ton of Carbon. The improvement becomes more significant when the emission reduction target becomes higher, reaching a maximum improvement of about 9%.

Regarding the aluminium production sector, the restructuring in favour of secondary and recycled aluminium, as shown in the baseline scenario, has been mentioned above. In the emission constrained cases, the important restructuring occurring in the baseline restricts the adjustment possibilities of the sector. Achieving higher aluminium recycling rates would be difficult, since both institutional and technological factors reduce the potential for recycling. This potential is therefore limited in emission constrained cases, leading to a rate of 78% that slightly increases from baseline, roughly remaining stable over the range of emission reduction targets.

The sector of non-ferrous metal is highly depending on electricity, as briefly discussed before. Energy uses are principally confined in a few very specific processes and technologies. In case of small of medium levels of emission reduction targets, the non-ferrous sector reacts very little, in terms of technological and structural changes in the sector. In this range, emission reduction mainly comes from the power generation side.

At the middle of the range of emission reduction targets, the average energy intensity of non-ferrous metals improves by 3% compared to baseline. This is mainly due to the penetration of improved crosscutting technologies (motor drives, etc.).

At high levels of emission reduction, the results show substantial technological changes leading to improving specific energy consumption of the non-ferrous production processes.

In primary aluminium production the improvement of specific energy consumption reaches 35% from baseline. This is mainly effected by the introduction of:

- ✓ Advanced electrolysis technologies based on improved Hall-Heroult cell efficiency
- ✓ Advanced melting and holding furnaces that reduce energy needs through heat recuperators and regenerators, combined with the use of oxygen-assisted combustion.

Specific energy consumption in the production processes of other non-ferrous metals (including secondary aluminium production) improves by 14% and concerns furnaces, kilns and electrolysis plants adopting a variety of improved technologies.

The overall energy intensity of the sector of non-ferrous metals improves by 23%, compared to baseline, in case of highly constrained emission reduction cases. The contribution from improving the non-ferrous materials and obtaining higher value added per ton of material is much smaller that in other industrial sectors. The improvement of the corresponding ratio reaches an upper bound of 5% at highly emission-constrained cases.

Table 16: Decomposition of energy system changes in metals production

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand in Industry	20.7	20.7	20.7	20.6	20.6	20.5	20.3	20.2	20.1	19.9	19.8	19.1	18.2	17.6	17.1	16.7	16.3
Sectoral CO2 Emissions reduction in 2010 in Mtons of CO2		-0.6	-1.3	-2.4	-4.7	-7.9	-15.1	-23.6	-29.9	-36.4	-44.8	-59.0	-72.7	-83.2	-92.4	-100.9	-109.5
as % of total industry emission reduction		25.0	19.6	23.5	21.5	23.2	23.5	23.5	22.5	22.4	22.3	24.2	25.8	26.6	27.2	27.4	27.6
% Decomposition																	
Structural change and behavioural effects		25.2	22.1	33.7	34.6	40.7	38.7	38.7	39.1	40.0	40.1	39.2	35.7	34.4	34.4	35.2	36.4
Technological improvement		2.3	2.6	2.9	2.9	3.2	2.9	3.0	4.0	4.8	6.8	14.6	24.3	28.5	30.4	31.2	30.8
Energy saving in heat uses		*-1.3*	*-0.7*	*-1.1*	*-1.2*	*-1.3*	*-1.1*	*-0.9*	*-0.4*	*0.9*	*1.8*	*2.3*	*2.8*	*3.1*	*3.3*	*3.4*	*3.9*
Specific Industrial processes		*3.1*	*3.2*	*4.0*	*4.0*	*4.5*	*3.9*	*3.8*	*4.3*	*3.8*	*4.7*	*11.9*	*21.0*	*24.7*	*26.4*	*27.0*	*26.2*
Electrical Equipment		*0.4*	*0.1*	*0.0*	*0.1*	*0.0*	*0.0*	*0.1*	*0.1*	*0.1*	*0.2*	*0.4*	*0.5*	*0.7*	*0.8*	*0.8*	*0.8*
Change of fuel mix		7.6	6.4	8.6	8.7	9.4	8.5	8.1	7.7	7.2	6.6	6.2	4.5	4.3	3.9	3.5	3.3
Change of emission factor of electricity and steam (supply effect)		64.9	68.9	54.7	53.7	46.7	49.9	50.1	49.2	48.1	46.5	40.0	35.5	32.8	31.3	30.1	29.5
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

As can be seen in Table 16 energy supply-side effects (from power and steam generation) play a dominant role in the reduction of sectoral emissions in a range of small levels of emission reduction. However, as emission reduction targets become higher the contribution from supply-side decreases dropping to about 30%. At this level, structural changes (including recycling and production of improved metals) start playing a bigger role along with effects from adopting improved technologies. At high emission reduction targets, results show a substantial technological improvement in the specific metal-processing technologies, such as blast furnaces and electric arcs for iron and steel production. The same stands for electrolysis and furnace processing in non-ferrous metals. Thus, the contribution of technology progress reaches 30% at high emission reduction targets. The changes of fuel mix at the level of direct combustion (since fuel mix changes at the level of boilers is included in the supply-side effects) is of some importance, contributing by 8% to 4% depending on the level of the target.

Table 17 provides more details regarding iron and steel production. Energy intensity (expressed in toe of energy consumed per ton of output) for integrated steelworks is almost three times that of electric arc processing. The shift towards electric arc from around 50% to 75%, as higher emission reduction targets are set, also exerts a beneficial effect on energy productivity, allowing for higher value added per ton of steel. The above changes, i.e. the shift towards less energy intensive production and the improvement of productivity, explain the importance of structural and behavioural changes in the sector.

Table 17: Indicators for Iron and Steel production

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Value added to physical production ratio (index, 100 for baseline)	100.0	100.0	100.1	100.2	100.3	100.6	101.2	102.1	103.2	104.3	105.4	106.4	107.2	107.8	108.2	108.6	109.0
Energy intensity (toe per tn of output)																	
integrated steelworks	0.424	0.424	0.424	0.424	0.423	0.423	0.423	0.422	0.421	0.419	0.417	0.397	0.365	0.343	0.328	0.316	0.308
electric arc	0.169	0.169	0.169	0.169	0.169	0.169	0.169	0.169	0.169	0.168	0.165	0.162	0.157	0.152	0.147	0.144	0.142
Production shares of electric arc (%)	46.7	46.7	46.8	47.1	47.5	48.3	49.6	51.0	51.7	52.6	54.0	57.8	60.3	63.0	66.2	70.4	75.3
Energy intensity of specific process technologies (toe per tn of output)																	
integrated steelworks	0.382	0.382	0.382	0.381	0.381	0.380	0.379	0.378	0.377	0.377	0.376	0.358	0.327	0.307	0.293	0.282	0.275
electric arc	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.135	0.133	0.130	0.126	0.122	0.118	0.115	0.113

In non-ferrous metals, the production of primary aluminium is the major consumer of energy having energy intensity seven times bigger than in other non-ferrous metals processes (see Table 18). No significant structural changes are observed in the sector, since aluminium recycling potential is almost exhausted in the baseline scenario, as mentioned. Non-ferrous metal products are not substitutable to each other, so the share of aluminium production is stable at around 20%. At high emission reduction targets a significant technology breakthrough is observed for electrolysis in primary aluminium production. The efficiency of electrolysis increases more than 30% compared to baseline scenario. Energy consumption in the specific energy use accounts for more than 75% of total consumption in primary aluminium production and, therefore, the effect of this technology progress is very strong and the overall energy intensity increases at about 35%. Technology progress in other non-ferrous metals production is less impressive and originates from improvement of efficiency in crosscutting and thermal processing.

Table 18: Indicators for Non-ferrous metals production

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Value added to physical production ratio (index, 100 for baseline)	100.0	100.0	100.0	100.1	100.2	100.3	100.6	101.0	101.5	102.1	102.8	103.4	104.0	104.5	104.9	105.4	105.9
Energy intensity (toe per tn of output)																	
primary aluminium	1.487	1.487	1.485	1.487	1.487	1.487	1.488	1.486	1.484	1.483	1.481	1.478	1.466	1.430	1.366	1.250	1.103
other non-ferrous metals	0.235	0.235	0.235	0.235	0.235	0.234	0.234	0.233	0.233	0.232	0.230	0.228	0.224	0.220	0.216	0.214	0.207
Production shares of aluminium (%)	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.1	20.1	20.2	20.3	20.4
of which secondary aluminium	*77.7*	*77.8*	*77.7*	*77.8*	*77.8*	*77.9*	*78.0*	*78.2*	*78.3*	*78.4*	*78.4*	*78.3*	*78.3*	*78.5*	*78.3*	*77.1*	*75.5*
Energy intensity of specific process technologies (toe per tn of output)																	
primary aluminium	1.164	1.164	1.162	1.164	1.164	1.165	1.165	1.165	1.165	1.166	1.165	1.164	1.155	1.128	1.076	0.980	0.871
other non-ferrous metals	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.024	0.024	0.024

The changes described above lead to significant improvement of carbon intensity in the sector of metals production. Energy demand as percentage of total demand in industry decreases from around 21% in the baseline scenario to less than 17% for high emission reduction targets. At the same time, the sector's contribution in total CO2 emission reduction in industry increases from around 20% for small emission reduction targets to more than 27% in high carbon value scenarios.

6.1.3 Chemical Sector

6.1.3.1 Introduction

Chemical industry produces a large variety of products (over a thousand). The PRIMES model groups these products into four producing sectors, namely fertilisers, petrochemicals, inorganic chemicals and low energy chemical products. In energy use terms, the first three sectors are energy intensive. Petrochemicals mostly use energy (fossil fuels) as raw material and produce low carbon emissions per unit of production.

A large variety of energy using processes is present in the chemical industry. Some processes, as those used to produce some inorganic substances, are based on electrolysis or other electricity uses to compress and liquefy gases. Other processes, as in the petrochemical industry, require high temperature and pressure to effect the chemical combination or separation required. Generally in energy-intensive chemical industry, heat and pressure are used to separate and combine chemical building blocks into saleable products, either for final consumers or to other manufacturers. Often electricity competes thermal processing in the production of energy-intensive chemical products. For example mechanical treatment, using electricity, may substitute for steam-based processing in the production of chemical products.

The sector producing low-energy chemical products includes pharmaceuticals, cosmetics and other products addressed to final consumers. They generally require small amount of energy for their production.

6.1.3.2 Sector Evolution in the Baseline Projection

In the baseline scenario, the overall energy intensity of chemicals improves by 23% in 2010 compared to 1995. This is partly due to structural changes at the level of the sector, since the growth of low-energy chemical products is significantly higher than that of energy-intensive products. The share of the former reaches 60% in 2010, compared to 53% in 1995.

At the level of each sub-sector, the baseline scenario projects relatively moderate technological progress in terms of specific energy consumption. The production of fertilisers improves in specific energy terms by only 2% over the period 1995-2010. Higher improvements are projected for petrochemicals (7.5%), inorganic chemicals (4%) and low-energy chemical products (2.2%).

Chemical industries account for about 17.5% of industrial demand in EU-14 for 2010 (without including use of fuel as raw material in petrochemicals).

6.1.3.3 Sector Adjustment for Different Emission Targets

The baseline economic restructuring of the sector, in favour of low-energy products, leaves little room for further restructuring in the emission reduction constrained cases. The economic structure of the sector changes very little as a consequence of the emission limitations.

There is a big range of technology possibilities that may be applied for the processing of chemical products. Also, lead times for capital replacement are lower than in the case of other energy-intensive sectors, such as the metal industry.

The results show that technology change effects are significant in the chemical industry for the whole range of emission reduction targets:

- ✓ In case of small emission reduction targets, the energy intensity of the sector improves by 2% from baseline, and the specific energy requirements by production process also improve by about 1.5 to 2%.
- ✓ In case of medium level of emission targets, the energy intensity improvement reaches 6% and approaches 25% at highly constrained cases. At the level of specific processes, this rate ranges from more than 25% in petrochemical and inorganic chemicals, down to 12% in low-energy chemicals (16.5% in fertilisers).
- ✓ These improvements are effected through the penetration of improved technologies mainly in reaction and separation processes. The role of electrical-technologies is significant, allowing both for direct energy savings and for indirect carbon savings via the adjusted power and steam generation system.

In petrochemicals, the improvement of specific energy consumption is facilitated by the introduction of advanced distillation control techniques, which reduce specific energy consumption by about 15%. In inorganic chemicals the use of advanced electrolysis equipment and improved electric compression technologies contribute to reduce energy requirements up to 25%.

Key factor for the improvement of specific energy consumption in all energy-intensive processes in the sector is the introduction of pinch analytical techniques which optimise heat recovery in thermal processes and provide energy savings of up to 30%.

The penetration of industrial heat pumps is also very promising. They allow for economies in the use of heat and cooling and greatly save electricity. The results show that the share of heat pumps in the chemical industry increase from a small percentage in the baseline (in 2010), into 15% in small and medium levels of emission reduction reaching 80% in highly constrained cases.

In addition, the share of electrical-mechanical processing (replacing steam processing techniques) increases with successively higher emission targets approaching 75% in high target cases.

Direct energy savings combined with substitution effects from higher electricity penetration, highly reduces the demand of the sector for heat and steam, therefore limiting the role of cogeneration in the high emission reduction cases.

When introducing emission reduction targets the share of the sector's energy demand remains stable at about 17.5% (see Table 19). On the other hand, the sector's contribution in reducing total industry's CO2 emissions ranges from 20% at small emission reduction targets to 17.5% at high emission reduction targets. In other words, for small emission reduction targets the sector is highly reacting achieving higher emission reduction performance compared to other industrial sectors. At higher emission reduction targets other industrial sectors react as well.

Table 19: Decomposition of energy system changes in chemical industries

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand in Industry	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.2	17.2	17.2	17.2	17.4	17.4	17.4	17.5	17.5	17.4
Sectoral CO2 Emissions reduction in 2010 in Mtons of CO2		-0.4	-1.3	-1.9	-4.5	-6.9	-12.5	-19.2	-26.0	-31.9	-38.7	-45.3	-51.6	-56.4	-60.2	-64.2	-69.0
as % of total industry emission reduction		16.4	19.7	18.7	20.5	20.2	19.4	19.2	19.7	19.6	19.2	18.6	18.3	18.1	17.7	17.4	17.4
% Decomposition																	
Structural change and behavioural effects		19.9	4.6	10.6	10.1	11.8	10.7	10.8	9.7	10.4	9.5	9.2	9.5	9.5	10.2	11.6	13.4
Technological improvement		7.1	4.0	11.2	8.7	10.9	11.8	13.3	14.7	14.7	16.1	18.4	20.4	24.8	26.2	27.6	28.5
Energy saving in heat uses		*0.9*	*0.5*	*1.0*	*0.8*	*1.0*	*1.1*	*1.3*	*1.4*	*1.4*	*1.6*	*1.5*	*1.7*	*1.9*	*2.0*	*2.1*	*2.1*
Specific Industrial processes		*5.5*	*4.0*	*9.1*	*7.1*	*9.0*	*9.8*	*10.9*	*12.1*	*12.1*	*13.3*	*15.8*	*17.6*	*21.5*	*22.8*	*24.1*	*25.0*
Electrical Equipment		*0.8*	*-0.5*	*1.0*	*0.8*	*0.9*	*0.9*	*1.1*	*1.2*	*1.2*	*1.2*	*1.1*	*1.1*	*1.4*	*1.4*	*1.4*	*1.4*
Change of fuel mix		0.6	-0.1	0.5	0.4	0.5	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.1	0.2	0.1	0.2
Change of emission factor of electricity and steam (supply effect)		72.3	91.5	77.7	80.7	76.8	77.0	75.6	75.2	74.6	74.1	72.2	69.9	65.6	63.4	60.7	58.0
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Changes in the power and steam generation sector principally contribute to reduce direct and indirect emissions from chemical industry. The role of supply side effects is more important in low and medium levels of emission target, accounting from 90 to 75%,. Technology progress, contributing around 10% for small emission reduction targets, covers the gap created from limited further contribution from the supply side in the case of medium to high emission constraints. Technology improvement mainly concerns specific process technologies and electrical-techniques, as mentioned before, since consumption in specific processes accounts for around 90% of total energy consumption in the sector. The contribution of crosscutting and low enthalpy heat uses technologies is rather limited and, mainly, emerges through the introduction of heat pumps in low enthalpy heat uses. The contribution of technology increases from 13% to almost 29% at very high emission reduction targets. Contribution of behavioural and structural changes seems stable for the whole range of cases varying around 10%. Only at very high emission reduction targets this share increases to 13%. The change of fuel mix in direct energy uses does not affect overall sectoral emission reduction, contributing less than 0.5% for the range of emission reduction targets examined.

As can be seen in Table 20, the improvement of sectoral productivity in chemicals is limited reaching 2.5% for high carbon value scenarios. In addition, no significant structural changes are observed related to the different production activities of the sector.

Table 20: Indicators for chemical industries

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Value added to physical production ratio (index, 100 for baseline)	100.0	100.0	100.0	100.0	100.0	100.1	100.2	100.3	100.4	100.6	100.8	101.0	101.2	101.5	101.7	102.1	102.6
Energy intensity (toe per tn of output)																	
fertilisers	0.593	0.593	0.593	0.592	0.591	0.589	0.586	0.582	0.576	0.572	0.565	0.557	0.547	0.531	0.523	0.512	0.499
petrochemical industry	0.156	0.156	0.156	0.156	0.156	0.155	0.154	0.153	0.151	0.150	0.147	0.144	0.140	0.135	0.131	0.127	0.122
including use of energy as raw material	*0.887*	*0.887*	*0.887*	*0.887*	*0.887*	*0.887*	*0.886*	*0.886*	*0.885*	*0.885*	*0.883*	*0.882*	*0.880*	*0.876*	*0.874*	*0.871*	*0.869*
inorganic chemicals	0.564	0.564	0.564	0.563	0.563	0.561	0.558	0.554	0.549	0.545	0.537	0.519	0.505	0.483	0.472	0.462	0.450
low energy chemicals	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.034	0.034	0.034	0.033	0.033	0.032	0.032	0.031	0.031

In low energy chemicals no significant improvement of energy intensity is observed for small to medium emission reduction targets since the role of energy in this production activity is very limited. However, at highly constrained cases, a certain improvement of equipment efficiency occurs driven by technology progress in crosscutting technologies and the penetration of heat pumps.

6.1.4 Production of Non-Metallic Materials

6.1.4.1 Introduction

This section covers the production of building materials and paper. The sector of building materials includes the production of cement, glass, bricks, ceramics, etc. The sector of paper includes the production of pulp and paper.

Cement is produced in special kilns that reduce raw material through fossil fuels that keep up the high temperature required for the process. In general, pyro-processing assuring a chemical reaction constitutes the basic processing for building materials. Melting silica sand produces glass. Bricks and ceramics is just clay until fired. All sub-sectors are very energy-intensive.

The cement production involves production of clinker in kilns burning a mixture of products (limestone and metal oxides), which is then blended with other constituents. Two main technology processes are known: the wet and the dry one. The dry-type is more energy efficient and currently dominates cement production in the EU.

The main products of the glass industry include container glass, flat glass and other glass products (e.g. fibres). The basic processing for glass production involves burning of silica and additives at high temperature. The major energy-intensive processes of the industry involve glass tank furnaces and annealing of glass in ovens after forming. Use of recycled glass allows for significant energy savings in basic processing. This possibility is however limited only for some of the types of glass products.

The production of bricks, tiles and ceramics is made from quarried clay and other materials that are formed dried and subsequently baked at thigh temperatures in kilns and furnaces. The process involves mechanical treatment, low enthalpy heat uses, high temperature furnaces and product finishing.

The manufacturing of paper requires that a fiber source (e.g. from wood) is chipped, digested, bleached and then formed as a slurry (pulping) from which paper is produced. Large amounts of steam (for thermal processing) and electricity (for mechanical processing) are necessary to debark and chip the wood, digest the wood, bleach the pulp and dry the paper product. Use of waste paper, instead of wood, reduces energy requirements avoiding the initial processing which is energy-intensive.

Sectoral restructuring in this sector mainly concerns bigger use of waste glass and paper.

6.1.4.2 Sector Evolution in the Baseline Projection

In the baseline scenario, specific energy consumption of cement production drops by 5% in 2010 (0.067 toe/ton) compared to 1995. Consumption for clinker (kilns) represents more than 80% of total energy consumption in the cement sector.

The average specific energy consumption in glass industry of the EU was 0.2 toe/ton in basic processing and 0.15 toe/ton for recycled glass. The latter represented about 50% of total glass processing in the EU. The baseline scenario projects an improvement of about 6% by 2010 and a higher share of glass recycling, reaching 60% by 2010. The average energy intensity of the sector improves by 10% in 2010.

Regarding the production of bricks, tiles, ceramics and other building materials (except cement), the baseline scenario projects improvement of average energy intensity ranging from 8.5 to 2.5% in 2010, compared to 1995.

Specific energy consumption in pulp and paper is for basic processing almost double than in case of paper recycling. The baseline scenario projects an improvement of energy needs of specific processes ranging from 5 to 8% by 2010 (compared to 1995) and higher recycling of paper (from 65% of paper production in1995 in the EU to almost 70% by 2010). The combined effect of these changes lead to improved average energy intensity of paper and pulp by 10% in 2010.

6.1.4.3 Sector Adjustment for Different Emission Targets

The cement industry is highly capital intensive and uses equipment having a long lead-time for construction and replacement. Because of high competition, the European cement industry is very efficient in energy terms and yet improving in the baseline scenario.

Given also that energy use is mainly related to kiln technology, for which technology progress prospects are evolving slowly, the emission reduction possibilities of the cement sector are rather limited. In case of small and medium emission reduction targets, the results show inertia for the cement industry to adjust, in particular regarding the adoption of improved technologies. The overall energy intensity of the cement industry improves by less than 1.5% from baseline.

At highly emission constrained cases, the cement industry undergoes premature replacement of capital equipment enabling an improvement of average specific energy consumption by 17% from baseline (26% in production of clinker). Advanced kiln technologies are adopted involving improved furnace design and waste/heat recovery. In addition, advanced electrical-technologies for mixing, grinding and milling also allow for efficiency gains.

The potential for further increase of glass recycling in 2010 (compared to the level projected in the baseline scenario) is rather limited because of technical limitations, the diversity of glass products and the lack of scrap material (practically only bottles are recycled). However, depending on the structure of the glass industry, some countries may experience higher recycling rates (e.g. 80% in the Netherlands).

In case of small emission reduction targets, the adjustment of the glass industry is rather limited, in particular regarding basic processing. This is explained by the capital intensiveness of the sector. Specific energy consumption improves by only 1.5% for basic processing and 2% for recycled glass, compared to baseline.

However at higher emission reduction targets, technology change enables high performance of the glass industry improving specific energy consumption by up to 30% from baseline. The average gain at the level of specific glass furnaces is even higher, reaching 35% from baseline.

The technologies that contribute to this significant improvement include:

- ✓ Use of advanced burners in oxy-fuel process glass furnaces which can decrease energy needs by up to 30%

- ✓ Use of dual batch/cullet preheaters that use the oxy-gas furnaces waste heat to preheat cullet and batch before feeding into the furnace, leading to lower energy requirements by up to 30%.

The results also show a significant shift towards electric glass furnaces, instead of fossil fuel fired ones (from 16% in baseline to more than 20% in emission constrained cases). This improves the overall specific energy consumption of glass production.

The production of bricks, ceramics and other building materials (except cement) also shows adjustment inertia at small emission reduction targets. The improvement of average specific energy consumption remains limited at about 2% from baseline.

In case of high emission targets, technology change involves replacement of tunnel kilns with roller kilns that lead to lower specific energy consumption by about 25% compared to baseline. In roller kilns the clay is prepared dry with appropriate additives to maintain the forming and baking characteristics. The process reduces heating time and uses shorter firing curves. The role of electrical-technologies for mechanical processing involved in mixing and milling is important, also leading to significant saving of electricity.

The fact that paper recycling highly develops in the baseline scenario limits further deployment in the emission-constrained cases. The share of recycled paper increases slowly with the level of emission targets.

Specific energy consumption of paper and pulp does not improve significantly in case of small and medium emission targets (reduced by only 2 to 4% compared to baseline). At higher emission targets, the improvement of specific energy consumption is significant (lower by 14 to 17% from baseline), but smaller than in other energy-intensive sectors.

The main changes regard heat and electricity savings enabled by heat management techniques and electrical-technologies respectively. The role of the latter is important, allowing for significant savings in mechanical treatment and refining. Heat management techniques include:

- ✓ Impulse drying that reduces energy requirements of evaporating drying by removing more water in the pressing section leading to high heat savings (theoretically up to one third). The results show an average gain of more than 20% in paper drying.
- ✓ Advanced techniques in pulping involving better management of steam input lead to specific energy savings of about 35% in highly constrained cases.
- ✓ Sensors in paper refining allow for better process management, avoidance of reprocessing and greater use of recycled fiber, leading to specific energy savings of about 35% in highly constrained cases.

Table 21: Decomposition of energy system changes in materials production

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand in Industry	25.3	25.3	25.3	25.3	25.3	25.4	25.5	25.5	25.6	25.7	25.8	26.0	26.4	26.7	26.9	26.7	26.7
Sectoral CO2 Emissions reduction in 2010 in Mtons of CO2		-0.5	-1.4	-2.1	-4.5	-6.9	-13.0	-20.3	-27.3	-33.8	-42.0	-50.2	-56.9	-62.5	-68.2	-75.8	-83.1
as % of total industry emission reduction		19.5	21.3	20.2	20.6	20.3	20.3	20.3	20.6	20.8	20.9	20.6	20.2	20.0	20.0	20.6	21.0
% Decomposition																	
Structural change and behavioural effects		11.0	6.0	8.4	7.4	9.0	8.9	9.8	10.8	12.1	12.6	12.8	12.6	12.7	12.6	12.1	12.1
Technological improvement		3.7	3.2	7.6	7.0	8.7	8.8	9.7	11.1	12.0	14.8	18.6	21.1	24.6	27.6	32.6	35.7
Energy saving in heat uses		*0.8*	*0.6*	*1.9*	*1.9*	*2.5*	*2.6*	*3.0*	*3.6*	*4.1*	*4.9*	*5.6*	*6.4*	*7.6*	*8.1*	*8.6*	*8.8*
Specific Industrial processes		*1.8*	*1.5*	*3.4*	*3.1*	*3.8*	*3.7*	*4.0*	*4.5*	*5.1*	*6.6*	*9.6*	*11.1*	*13.0*	*15.4*	*19.9*	*22.5*
Electrical Equipment		*1.1*	*1.1*	*2.3*	*2.1*	*2.5*	*2.5*	*2.6*	*2.9*	*2.8*	*3.2*	*3.4*	*3.6*	*4.0*	*4.1*	*4.2*	*4.4*
Change of fuel mix		4.1	2.8	4.7	4.2	5.0	4.6	4.3	4.2	4.0	3.7	3.2	3.1	2.9	2.8	2.6	2.4
Change of emission factor of electricity and steam (supply effect)		81.2	88.1	79.3	81.4	77.4	77.6	76.2	73.9	71.9	69.0	65.4	63.2	59.8	57.0	52.7	49.8
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 21 shows that the sector’s adjustment through technology change takes place mainly at highly emission constrained cases and concerns both specific processes and heat uses. The role of supply-side effects (from electricity and steam generation) remains continuously important. The contribution of fuel-mix changes in direct energy uses (except boilers) is limited.

Table 22: Indicators for building materials production

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Value added to physical production ratio (index, 100 for baseline)	100.0	100.0	100.0	100.1	100.2	100.4	100.7	101.3	102.0	102.7	103.6	104.4	105.1	105.8	106.4	106.9	107.5
Energy intensity (toe per tn of output)																	
cement production	0.067	0.067	0.067	0.067	0.067	0.067	0.066	0.066	0.066	0.066	0.065	0.064	0.063	0.062	0.062	0.060	0.057
ceramics production	0.043	0.043	0.043	0.043	0.043	0.043	0.043	0.043	0.043	0.043	0.042	0.041	0.041	0.040	0.039	0.037	0.035
glass basic processing	0.194	0.194	0.194	0.194	0.194	0.194	0.193	0.193	0.192	0.191	0.188	0.185	0.184	0.178	0.170	0.154	0.148
recycled glass processing	0.143	0.143	0.143	0.142	0.142	0.142	0.142	0.141	0.140	0.139	0.138	0.135	0.132	0.129	0.125	0.116	0.112
other building materials	0.105	0.105	0.105	0.105	0.105	0.104	0.104	0.104	0.103	0.103	0.101	0.099	0.097	0.094	0.090	0.085	0.082
Production share of recycled glass processing over glass prod. (%)	58.8	58.8	58.8	58.8	58.8	58.9	59.0	59.2	59.5	59.7	59.4	58.8	58.8	58.9	59.3	59.8	61.9

Table 23: Indicators for paper and pulp production

Carbon Value (in Eur'90/ton of	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Value added to physical ratio (index, 100 for	100,0	100,0	100,0	100,1	100,1	100,2	100,3	100,6	100,9	101,3	101,7	102,0	102,4	102,8	103,2	103,7	104,5
Energy intensity (toe per tn of																	
paper production (incl.	0,372	0,372	0,372	0,371	0,371	0,371	0,369	0,368	0,365	0,364	0,360	0,356	0,352	0,346	0,340	0,334	0,325
recycled paper	0,218	0,218	0,218	0,218	0,218	0,217	0,216	0,215	0,213	0,212	0,209	0,206	0,203	0,198	0,195	0,191	0,187
Production shares of recycled processing (%)	71,5	71,6	71,7	71,9	72.1	72.2	72,5	72,8	72,9	73,1	73,3	73,5	73,8	74,0	74,1	74,2	74,6
Energy intensity of specific technologies (toe per tn of																	
paper production (incl.	0,071	0,071	0,071	0,071	0,071	0,070	0,070	0,070	0,070	0,069	0,068	0,068	0,067	0,065	0,063	0,061	0,058
recycled paper	0,045	0,045	0,045	0,045	0,045	0,045	0,045	0,045	0,045	0,044	0,044	0,043	0,043	0,041	0,040	0,039	0,038

6.1.5 Other Industrial Sectors

6.1.5.1 Introduction

The other industrial sectors produce equipment goods (for transports, for households, machinery, etc.), food, beverages and tobacco, textiles and other goods (e.g. wood products, rubber, construction, etc.).

These sectors generally are low energy-intensive. The energy uses in specific product processing are very limited, mainly including coating and foundries in the equipment goods industry and some other sectors. Use of steam is significant in food processing, while low enthalpy heat uses (e.g. for drying and separation) are present in many sectors. Most of the technologies are crosscutting, including motor drives, compressors, heating and cooling, etc.

6.1.5.2 Sector Evolution in the Baseline Projection

Energy intensity ratios are computed against value added measured in monetary terms (and not against an indicator of physical production as in the other industrial sectors, mentioned before). The baseline scenario projects rather moderate improvement of energy intensity over time. The improvement in 2010 compared to 1995 ranges from 2% to 3.7% depending on the sector.

6.1.5.3 Sector Adjustment for Different Emission Targets

Within the range of small emission targets, the low-energy industrial sectors undergo rather little adjustment. Energy intensity improvement ranges between 2% and 4% (compared to baseline) and mainly comes from savings in heat uses.

The changes are more significant at high emission reduction targets that enable technologies to penetrate.

Energy intensity of food, beverages and tobacco improves by up to 15% and concern both steam processing (14% more efficient) and cooling (10% more efficient).

The equipment goods industry shows a better performance improving energy requirements by 25%, achieved mainly in foundries and low-enthalpy heat uses. The results for this sector also show a shift in favour of electrical-mechanical processing (which improve by 12% from baseline) that allow both for direct energy savings and indirect carbon savings. The use of heat pumps is generally highly favoured (up to 93% penetration in highly constrained cases) also allowing for direct and indirect gains (up to 80% efficiency improvement in some processes).

In the textile industry, efficiency in process heating increases by up to 13.5% from baseline. In drying processes, the results show a shift in favour of electrical technologies combined with an extensive use of heat pumps that lead to a efficiency gains of up to 60%.

Table 24 shows the increasing role of technology along with higher emission targets. This mainly enables savings in both the heat and electric uses. The role of structural effects is limited (only 6%). Changes in fuel-mix, in direct energy uses (except boilers), are also very limited.

Although these sectors are low energy intensive, their contribution in reducing emissions within total industry is very significant (35 to 40%). This of course is due to the fact that the energy-intensive sectors represent a small fraction of industrial GDP of the EU.

Table 25 shows that the effect from total factor productivity is limited to maximum 3% in this sector.

Table 24: Decomposition of energy system changes in other industrial sectors

Carbon Value (in Eur'90/ton of Carbon)	0	1	2	5	10	20	40	70	110	160	220	290	370	460	560	700	900
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand in Industry	36.7	36.7	36.7	36.7	36.8	36.8	36.9	37.1	37.1	37.2	37.2	37.6	38.0	38.3	38.5	39.1	39.6
Sectoral CO2 Emissions reduction in 2010 in Mtons of CO2		-1.0	-2.6	-3.9	-8.2	-12.3	-23.7	-37.1	-49.3	-60.5	-75.6	-89.0	-100.8	-110.3	-119.4	-127.0	-134.9
as % of total industry emission reduction		39.1	39.3	37.5	37.4	36.2	36.8	37.0	37.2	37.2	37.6	36.5	35.7	35.3	35.1	34.5	34.0
% Decomposition																	
Structural change and behavioural effects		3.0	1.7	2.3	2.4	3.0	2.9	3.1	3.4	3.9	4.0	4.2	4.4	4.7	4.9	5.4	6.0
Technological improvement		6.5	3.0	9.0	8.7	10.9	10.8	12.2	14.5	16.2	20.4	23.8	26.4	29.7	31.9	33.3	33.9
Energy saving in heat uses		*0.4*	*1.8*	*4.9*	*4.2*	*5.6*	*6.1*	*6.6*	*8.1*	*9.1*	*10.2*	*10.8*	*12.1*	*14.6*	*16.5*	*18.2*	*19.2*
Specific Industrial processes		*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Electrical Equipment		*6.1*	*1.2*	*4.2*	*4.6*	*5.3*	*4.7*	*5.6*	*6.4*	*7.1*	*10.2*	*12.9*	*14.4*	*15.2*	*15.4*	*15.1*	*14.6*
Change of fuel mix		0.7	0.5	1.0	0.9	1.1	1.0	0.9	0.9	0.9	0.8	0.7	0.7	0.6	0.6	0.6	0.6
Change of emission factor of electricity and steam (supply effect)		89.7	94.8	87.7	88.0	85.0	85.4	83.7	81.1	79.1	74.9	71.3	68.5	64.9	62.5	60.7	59.6
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 25: Indicators for other industrial sectors

Carbon Value (in Eur'90/ton of	0	1	2	5	10	20	40	70	110	160	220	290	370	460	560	700	900
Overall Productivity Gains ratio -Index,100 baseline																	
food, drink,	100,0	100,0	100,0	100,0	100,0	100,1	100,2	100,3	100,5	100,7	100,9	101,1	101,3	101,6	101,8	102,2	102,6
engineerin	100,0	100,0	100,0	100,0	100,1	100,1	100,3	100,5	100,7	101,0	101,3	101,6	102,0	102,3	102,7	103,1	103,6
textile	100,0	100,0	100,0	100,0	100,0	100,1	100,1	100,2	100,3	100,5	100,6	100,7	100,9	101,1	101,2	101,4	101,7
other	100,0	100,0	100,0	100,0	100,1	100,1	100,2	100,4	100,6	100,8	101,1	101,4	101,7	102,1	102,4	103,0	103,7
Energy intensity (toe per Unit)																	
food, drink,	0,126	0,126	0,126	0,126	0,126	0,126	0,125	0,124	0,123	0,123	0,121	0,119	0,118	0,115	0,113	0,111	0,110
Engineering	0,044	0,044	0,044	0,044	0,044	0,044	0,044	0,044	0,043	0,043	0,042	0,041	0,040	0,038	0,037	0,037	0,036
textile	0,092	0,092	0,092	0,092	0,092	0,091	0,091	0,090	0,089	0,089	0,087	0,086	0,085	0,082	0,081	0,080	0,078
other	0,257	0,257	0,257	0,257	0,256	0,256	0,255	0,254	0,251	0,249	0,244	0,239	0,234	0,228	0,222	0,217	0,213

6.2 Crosscutting Technologies in Industry

Energy-using technologies that are not product or process specific are widely used in industry. They include equipment types such as motor drives, air compressors, lighting, space heating and some standardised furnaces. The discussion below attempts to summarise the findings per equipment category in order to show the scope for improving industrial standards.

6.2.1 Heat Pumps

Industrial heat pumps play a considerable role in medium to high emission constrained cases. Their penetration is spectacular leading to high improvement of energy efficiency in low enthalpy heat uses, in drying/separation and in particular in chemical industry and in food processing. The heat-pump technology also has a significant room for improvement. This is shown in the results in cases of highly constrained cases involving high adoption rates for advanced heat pump technologies.

6.2.2 Standardised Industrial Furnaces

The results show that technologically advanced industrial furnaces are increasingly adopted as emission reduction targets become more stringent. The average efficiency gains range from 8% to 25%, depending on the level of emission constraint. The progress is effected both for furnaces using fossil fuels and electric furnaces.

6.2.3 Industrial Motor Drives and Compressors

This category includes a wide range of equipment types. The model does not classify their use by size and does not make consideration of application differences related to quality, reserve and other technical characteristics.

The overall improvement of motor drives, in terms of specific efficiency, is of the order of 8%. The potential is bigger, being around 20%. Compressors improve in average by 10% (potential 22%).

6.2.4 Industrial Lighting

Industrial lighting is generally highly optimised in the baseline scenario. The room for further improvement is high, estimated at maximum 70% in terms of specific energy consumption. The results show an average efficiency gain of 50% occurring at highly constrained emission cases.

6.2.5 Space Heating

The analysis for industrial space heating is made in aggregate terms, even though explicated by sector. The energy saving gains go together with other low enthalpy heat uses and are enabled by using more efficient technologies and heat pumps. The results show an overall gain of 25% in highly constrained cases, compared to baseline scenario in 2010.

6.3 Tertiary Sector

6.3.1.1 Introduction

The tertiary sector includes energy consumption in buildings (not used as dwellings), public places and agriculture. Buildings are further classified in commercial buildings, trade facilities and shops and public buildings (schools, offices, hospitals,etc.).

Energy uses in buildings include lighting, specific electricity for electric appliances, space heating, cooling, water heating and cooking. Agriculture also uses energy for motor drive and additional heating of greenhouses.

6.3.1.2 Sector Evolution in the Baseline Projection

In 1995, the tertiary sector represented 13% of total final energy demand of the EU. The energy intensity, expressed per unit of value added generated in the sector, was 33.6 toe/MEur'90 and is quite small compared with other sectors.

The dynamics, as projected in the baseline scenario, show high growth of both economic activity and energy demand in the tertiary sector. Its share in total energy demand increases to 15% in 2010 and electricity demand grows at high rates both in specific electricity uses (appliances) and in heating and cooling energy uses. The share of electricity in the tertiary sectors rises from 27% in 1995 to 32% in 2010. The share of natural gas remains stable (at about 32%), while liquids lose share dropping to 29% in 2010 (from 29% in 1995). The use of solid fuels approaches zero in 2010.

The baseline projection shows a technology progress path that differs by type of energy use. The average energy efficiency of equipment used in thermal energy uses improves slowly. The efficiency for space heating improves by 6.7% over the 1995-2010 period and that of water heating by 5.8%. Efficiency of electricity using equipment improves at much higher rates. The average efficiency of lighting is projected to improve by 29% and that of cooling by almost 10%.

The overall energy intensity of the sector decreases substantially by 14%, a rate that represents an improvement of –1% per year over the period 1995 to 2010.

The baseline scenario projects higher energy demand in commercial offices (more than 2% per year) than in public buildings and uses (less than 1.5% per year).

6.3.1.3 Sector Adjustment for Different Emission Targets

The imposition of emission reduction constraints at the level of the whole economy also implies adjustment of energy consumption in the tertiary sector.

The tertiary sector has a rather large room of manoeuvre by adapting behavioural aspects of energy consumption. For example, in case of emission constraints, tertiary consumers can alter the way of using energy consuming equipment, can vary their standard of comfort and apply power management for lighting and electric appliances.

The improvement of the thermal integrity of buildings is of utmost importance for such an adjustment. Since it is expensive to improve insulation and glazing in existing buildings, it is expected that the improvement of thermal integrity evolve together with the rhythm of new constructions of offices.

Regarding the technology of energy using equipment, there is also a large potential for energy efficiency gains. This is particularly true for electricity using appliances.

The combined effects from the above possibilities are reflected in the results for the tertiary sector showing relatively high responsiveness to emission reduction constraints.

In case of small emission reduction targets, the tertiary sector achieves the overall energy intensity by 7% from baseline (in 2010). About 2 percent points of this improvement are due to behavioural factors. The improvement of thermal integrity contributes in average terms by 0.8%. The rest is due to technology progress resulting from the accelerated adoption of improved technologies and efficiency gains enabled by the use of more efficient fuels (electricity and natural gas). The average efficiency in space heating improves by 3.5% from baseline. The gains in other thermal uses range from 2 to 2.5%. The improvement in specific electricity uses is more spectacular, reaching 36% from baseline. Lighting is largely contributing since advanced lighting technologies are massively adopted in the tertiary sector, as a result of small emission reduction targets.

At medium levels of emission target, technology progress accelerates resulting in higher efficiency gains of energy uses. The average efficiency of equipment improves by 16.5% in space heating, 6.5% in cooling, 7.5% in water heating and 40.5% in specific electricity uses. The improvement of electric equipment seems saturated since it stops increasing at higher emission reduction targets.

At medium levels of emission target, the average thermal integrity of buildings improves by 3.5% from baseline, but the contribution from behavioural adjustment seems limited and saturated (only 2.5%). The combined effects from technology, insulation and behavioural adjustment lead to an improvement of the overall energy intensity of the tertiary sector of about 20% in 2010 compared to baseline.

In case of highly constrained emission reduction, the tertiary sector can improve the overall energy intensity by up to 78% from baseline. The contribution from improving thermal integrity reaches 10% and that of behavioural adjustment another 10%. The rest is due to high improvement of the average technology used in the tertiary sector. Electrical technologies are massively adopted even in thermal energy uses. Those electrical technologies are generally based on advanced heat pump systems, allowing for high efficiency gains in both heating and cooling. The share of electricity in the sector increases to reach almost 55% in highly constrained cases. The penetration of advanced electrical equipment is facilitated by general premature replacement of equipment in these cases. The average efficiency gains are spectacular, approaching 46% in space heating, 52% in cooling, 20 in water heating and cooking. The average efficiency of electric equipment used in specific electricity uses improves by more than 60% and this mainly concerns electric appliances and not lighting, since improvement of the latter is saturated at medium levels of emission target.

Table 26: Decomposition of energy system changes in the tertiary sector

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand)	15.0	15.0	15.0	15.0	14.9	14.7	14.4	14.2	14.0	13.6	13.2	12.8	12.5	12.3	12.4	12.7	13.0
Sectoral as % of Overall CO2 Emissions reduction in 2010		28.9	29.6	30.1	29.3	31.6	32.0	30.1	28.7	28.1	27.6	27.1	26.2	25.3	24.0	22.3	21.0
Total Tertiary CO2 Emissions reduction in 2010 in Mtons of CO2		-2.2	-5.6	-9.2	-18.1	-32.9	-64.3	-95.1	-122.5	-153.3	-188.8	-222.5	-251.1	-272.3	-290.2	-305.4	-322.6
% Decomposition																	
Structural change and behavioural effects		9.7	4.3	12.6	13.1	12.7	13.7	15.1	17.3	17.3	18.2	18.7	19.1	19.4	19.7	20.2	20.5
Technological improvement		12.7	23.4	23.9	24.0	37.3	35.5	31.7	31.4	34.1	35.6	38.0	40.3	41.6	42.1	42.3	42.8
Space heating and cooling		*10.4*	*13.9*	*7.6*	*8.1*	*11.5*	*13.3*	*14.9*	*17.3*	*21.0*	*22.7*	*23.9*	*25.0*	*25.2*	*26.0*	*26.6*	*26.5*
Other heat uses (water heating, cooking, etc.)		*0.1*	*3.1*	*2.7*	*2.7*	*3.8*	*3.8*	*4.2*	*4.1*	*4.5*	*4.8*	*5.0*	*5.0*	*5.0*	*4.9*	*4.9*	*4.9*
Electric uses		*2.3*	*6.4*	*13.6*	*13.2*	*22.0*	*18.5*	*12.6*	*9.9*	*8.5*	*8.1*	*9.2*	*10.4*	*11.3*	*11.1*	*10.7*	*11.4*
Change of fuel mix		-0.6	-1.0	-0.6	-0.4	-0.4	-0.4	-0.9	-0.8	-1.0	-1.0	-0.9	-1.3	-1.2	-1.2	-1.2	-1.3
Change of emission factor of electricity and steam (supply effect)		78.2	73.3	64.1	63.3	50.4	51.2	54.0	52.2	49.7	47.1	44.2	41.9	40.2	39.4	38.8	38.0
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 27: Indicators for the Tertiary Sector

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Final energy demand in tertiary in 2010 (Mtoe)	158	158	157	157	155	153	147	143	138	131	123	115	107	102	97	93	88
% change from baseline		-0.1	-0.3	-0.7	-1.4	-3.3	-6.4	-9.4	-12.7	-17.2	-22.0	-27.2	-31.8	-35.5	-38.5	-41.0	-43.9
Fuel shares in final demand (%)																	
solid fuels	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
liquid fuels	24.8	24.8	24.8	24.7	24.6	24.5	24.2	23.3	22.6	21.6	20.9	20.1	19.6	19.0	18.4	17.8	17.2
liquified petroleum gas	1.2	*1.2*	*1.2*	*1.2*	*1.2*	*1.2*	*1.1*	*1.1*	*1.1*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*
diesel oil and other liquids	23.6	*23.6*	*23.6*	*23.6*	*23.4*	*23.3*	*23.0*	*22.1*	*21.5*	*20.5*	*19.9*	*19.1*	*18.6*	*18.0*	*17.4*	*16.8*	*16.3*
natural gas	26.5	26.5	26.4	26.4	26.3	26.1	25.6	24.7	24.1	22.5	21.6	20.7	19.9	19.1	18.5	17.7	17.1
solar energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
biomass	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.1	1.1	1.1	1.1	1.2
geothermal heat	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
steam	5.7	5.8	5.8	5.8	5.8	5.9	6.1	6.4	6.6	6.9	7.3	7.8	8.2	8.6	9.0	9.3	9.7
electricity	41.9	41.9	41.9	42.0	42.2	42.3	42.9	44.4	45.4	47.6	48.8	49.9	50.7	51.6	52.5	53.6	54.2

6.4 Household Sector

6.4.1.1 Introduction

Energy is used in households to provide a variety of services such as lighting, space heating, air conditioning, water heating, cooking and use of electric appliances.

The households sector represented in 1995 27.5% of total final energy demand. More than 90% of energy is used for space heating and air conditioning.

The PRIMES model distinguishes among five categories of households defined according to their pattern of energy use. These are defined as follows:

- Central Boiler Houses: they have full heating comfort and they use a central heating system based on a boiler that may burn oil or natural gas.

- Electric Heating Houses: they also have full heating comfort and they use electricity-base heating systems centrally controlled.
- Individual Gas Heating Houses: they have either full or partial heating comfort and they use individual gas appliances, connected to the gas grid.
- District Heating Houses: they have full heating comfort and are connected to a district heating network.
- Non-full Heating Houses: they are partially heated through individual appliances (electric or stoves) that individually heat some of the rooms of the house.

All types of household may use electric appliances (refrigerators, freezers, TV, washing machines, drying machines, dishwashers and other). They also use energy for water heating, cooking, cooling and lighting.

6.4.1.2 Sector Evolution in the Baseline Projection

The baseline scenario projects increasing energy use per capita in the houses (7.8% increase in the period 1995 to 2010). Energy intensity expressed as final energy demand in houses divided by the volume of overall consumption of households drops by 21% over the same period, representing an improvement of 1.5% per year. This is mainly due to the fact that most of the energy uses in houses are rather saturated in the member-states of the European Union, in particular the heating energy uses. Technology progress as projected in the baseline also contributes to this improvement of energy intensity.

The relative shares of energy uses remain stable, despite the high increase of demand for services associated to some energy uses, like electric appliances and cooling. In final energy demand terms, the increasing demand for the associated services is partly offset by technological improvement of the corresponding equipment, in particular regarding electric appliances.

The baseline scenario projects significant efficiency gains in space heating as a consequence of adopting more advanced technologies an shifting in favour of electric equipment (mostly heat pumps) that gain an additional market share of 4% and enable efficiency gains. Natural gas also increases its share, to the detriment of diesel and solids. These developments, occurring in the baseline, are in favour of limiting the growth of CO2 emissions from energy use in houses. The overall gains in space heating reaches 4% by 2010, in comparison to 1995.

More efficient equipment also enables gains in water heating (17% in 2010 from 1990), cooking (4%) and air conditioning (2%).

The adoption of more efficient technologies for electric appliances of all kinds is an important mechanism highlighted in the baseline scenario. Specific energy consumption of refrigerators improves in average by 28% in 2010 (compared to 1990). This rate is as high as 39% for washing machines, 18% for drying, 18% for TV sets and 5% for small electric appliances. The average efficiency of lighting also improves in the baseline. This change over time is due to the availability of low cost and more energy-efficient electric technologies as a result of market competition among manufacturers and the

European policy that imposes high standards and labels on energy consumption of appliances. It is also facilitated from the fact that households generally change frequently their electric appliances, as a result of income growth and the aggressive policy of manufacturers introducing appliances that provide highly improved services to the consumers.

6.4.1.3 Sector Adjustment for Different Emission Targets

In emission constrained cases, households have high adjustment possibilities primarily through their behaviour. They can adjust the thermostat, reduce their comfort standards, switch off appliances and lighting when leaving and generally using energy in amore rational way. The improvement of thermal integrity of their houses and the replacement of old boilers and heating equipment operates more slowly, depending on the rate of stock turnover which is low for houses and heating equipment.

However, as far as equipment replacement is concerned, the reaction of households to emission constraints is rather inert. The example of light bulbs is characteristic of such an inertia. Statistical studies have shown that the implicit subjective discount rates used by households in making such decisions are very high. They often indicate that the households prefer not bearing any additional purchase cost, even if the savings in operational costs are high. To mimic such behaviour the model uses relatively high discount rates for representing the capital choice decisions of households.

In case of small emission targets, the reaction of households is limited in good housekeeping behaviour, explaining an overall gain of about 2% from baseline. The shift in favour of more efficient fuels such as electricity and gas is rather small in this range of emission targets and has a small contribution to efficiency gains. The choice of technology for equipment purchasing is not significantly altered from baseline.

Technology improvement becomes obvious at medium to high emission reduction targets. However, the behavioural response of the consumers still explains largely the emission reduction. The efficiency gains in average equipment technology are ranging from 2% to 12%. In total, medium levels of emission targets induce an improvement of 8% of energy intensity in the households sector, compared to baseline. Higher efficiency of thermal integrity of houses contributes by 1-2 percent points.

Highly constrained cases induce greater reaction of households, leading to an overall efficient gain that can be as high as 50% better than in the baseline. The improvement of insulation and glazing contributes by 8.5 percent points. The behavioural adjustments, including lowering comfort standards, contribute by 5 percent points. The rest comes from premature replacement of equipment and the purchase of advanced technology appliances.

In these highly constrained cases, the improvement of specific energy consumption can reach in average 26% for space heating, 6% for cooking, 55% for air conditioning and about 30% for water heating. A significant shift in heating uses in favour of electricity is observed leading to an additional market share of electricity of 6%, compared to baseline in 2010.

Premature replacement also leads to high efficiency gains in the use of electric appliances. This of courses acts on top of high efficiency standards achieved in the baseline scenario. The additional gain is 20% for washing machines and dryers, 55% for dishwashers, 25% for refrigerators and 5% for television sets. At high emission constraints, lighting devices are massively replaced by advanced techniques leading to a reduction of electricity use by 450%.

Table 28: Decomposition of energy system changes in the Households sector

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand)	25.5	25.5	25.5	25.6	25.6	25.7	25.8	25.8	25.8	25.9	26.0	26.1	25.8	25.7	25.5	25.3	26.1
Sectoral as % of Overall CO2 Emissions reduction in 2010		29.4	26.7	25.7	25.1	23.5	24.0	25.0	25.0	25.2	25.3	25.0	25.7	26.0	26.2	26.4	25.3
Households CO2 Emissions reduction in 2010 in Mtons of CO2		-2.3	-5.1	-7.9	-15.5	-24.4	-48.2	-79.2	-106.7	-137.4	-172.7	-205.7	-246.3	-279.6	-317.2	-360.9	-388.4
% Decomposition																	
Structural change and behavioural effects		15.6	10.6	14.1	14.7	17.6	16.9	17.7	20.2	22.2	23.4	24.5	24.0	24.2	23.9	23.5	24.1
Technological improvement		6.7	5.8	7.1	6.7	8.1	8.4	11.5	12.7	15.1	17.1	19.1	24.5	28.0	31.9	37.5	37.5
Space heating		*2.5*	*1.5*	*2.7*	*2.5*	*2.9*	*3.1*	*4.1*	*5.0*	*6.4*	*8.2*	*10.2*	*16.0*	*19.1*	*22.4*	*22.5*	*22.4*
Other heat uses (water heating, cooking, air conditioning)		*2.7*	*3.0*	*3.5*	*3.7*	*4.8*	*4.8*	*6.5*	*6.8*	*7.4*	*7.6*	*7.4*	*6.7*	*6.6*	*6.2*	*5.7*	*5.3*
Electric appliances		*1.4*	*1.4*	*1.0*	*0.5*	*0.4*	*0.5*	*0.8*	*0.9*	*1.2*	*1.3*	*1.5*	*1.8*	*2.2*	*3.3*	*9.4*	*9.7*
Change of fuel mix		4.4	3.8	5.7	5.6	6.9	6.6	6.4	7.0	7.2	7.4	7.4	7.1	6.9	6.7	6.6	6.9
Change of emission factor of electricity and steam (supply effect)		73.3	79.7	73.1	73.0	67.3	68.1	64.4	60.1	55.5	52.2	49.0	44.4	40.9	37.5	32.5	31.5
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 29: Indicators for the Households Sector

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Final energy demand in households in 2010 (Mtoe)	268	268	268	267	267	265	263	259	255	249	241	234	222	212	200	186	177
% change from baseline		-0.1	-0.1	-0.2	-0.5	-0.9	-1.7	-3.2	-4.9	-7.2	-9.8	-12.7	-17.1	-20.8	-25.2	-30.7	-33.7
Energy per capita (toe per capita)	0.699	0.699	0.698	0.698	0.696	0.693	0.687	0.677	0.665	0.649	0.630	0.610	0.580	0.554	0.523	0.484	0.463
Fuel shares in final demand (%)																	
solid fuels	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
liquid fuels	25.4	25.4	25.4	25.3	25.2	25.0	24.5	24.0	23.3	22.6	21.8	21.1	20.2	19.3	18.3	17.8	16.7
liquified petroleum gas	3.0	*3.0*	*3.0*	*3.0*	*3.0*	*3.0*	*2.9*	*2.9*	*2.8*	*2.7*	*2.6*	*2.6*	*2.5*	*2.4*	*2.3*	*2.2*	*2.0*
diesel oil and other liquids	22.4	*22.4*	*22.4*	*22.3*	*22.2*	*22.0*	*21.6*	*21.1*	*20.5*	*19.8*	*19.2*	*18.6*	*17.7*	*16.9*	*16.1*	*15.6*	*14.7*
natural gas	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.7	37.6	37.5	37.5	37.0	36.6	36.4	37.1	36.7
solar energy	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5
biomass	7.4	7.4	7.4	7.5	7.5	7.6	7.8	8.1	8.5	8.9	9.4	9.7	10.3	10.9	11.5	12.6	13.3
steam	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.9	4.9	4.9	5.0	5.0	5.2	5.5	5.6
electricity	23.9	23.9	23.9	24.0	24.0	24.1	24.3	24.6	24.9	25.3	25.7	26.0	26.9	27.5	27.8	26.3	26.9

6.5 Transport Sectors

6.5.1.1 Introduction

The transport sector was the largest energy consumer in 1995 at the European Union, representing about 31% of total final energy demand.

The model splits demand by purposes making a distinction between transportation of passengers and transportation of goods. The former represented 69% of total energy consumption in transports. This is mainly consumed by cars and motorcycles (51%), followed by aviation (12%). Consumption by passenger trains and inland navigation[7] represents a small fraction. In terms of mobility activity in passenger transports, cars and motorcycles carried out more than 80% in the EU while public road transports undertook only 9%. In average each citizen of the EU travelled for 12300 km per year (in 1995). Road transports based on trucks dominated freight transports in the EU (29% of total energy in transports, 70% of ton-kilometres transported in the EU). Train transports follow in importance for freight transports (18%), while inland navigation represented 12% of freight transports). Energy demand by trains and navigation generally represent a small fraction of total energy demand in the sector.

6.5.1.2 Sector Evolution in the Baseline Projection

The baseline scenario extrapolates past trends showing high growth of mobility and freight transport. However, because of technology progress and structural changes in transport modes, energy demand grows at lower rates.

The rates of growth follow those of GDP and income. In 2010, passenger mobility is 28% higher than 1995 (reaching 15200 km per capita). Structural shifts in transport modes are explained by the natural trend in favour of using faster transport modes. Passenger cars lose share (-2.5%), followed by public road transports (-1.5%). On the contrary the share of trains increases (+1.5%) and aviation gains in terms of mobility (+2.5%). The technology of vehicles slightly improves in the baseline, showed through an improvement by more than 1% of specific energy consumption of the average vehicle by 2010 compared to 1995. The technology progress of cars and buses is higher (2-3%). This small improvement is an aggregate result of two factors: the technology of the average car does improve substantially, but the average consumer tends to buy bigger cars having additional comfort standards than need more energy. Train transportation undergoes a more significant progress in the baseline, reaching 32% of average efficiency gain in 2010 compared to 1995. This is attributed to improved technologies, but mainly to high penetration of electric trains, which increase in share to 98% in 2010 from 76% in 1995. Technology progress is also projected for aviation. Specific energy consumption of the average airplane increases by 33% as a result of introducing more efficient engines and an accelerated replacement of the ageing stock of aircraft. However, aviation remains the most energy intensive transport mean (about 3 times above average in passenger transports). The combination of the above changes leads to an increase of energy demand for passenger transports by 27% in 2010 from 1995.

Freight transport grows by 32% over the 2010-1995 period. Trucks lose market share (-4%) favouring trains (+3%) and navigation (+1%). The average vehicle is more efficient in 2010 by 7.7% compared to 1995. This comes mainly from technology progress in train transport (the efficiency indicator improves by 25%), as a result of structural shift in favour of electric trains and the adoption of improved technologies.

Liquid fuels dominate the fuel mix of transport activity. The demand of kerosene grows as a result of growth in aviation. The share of electricity increases mainly because of high penetration of electric trains. Gasoline slightly loses market share (1.4%) which

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[7] Consumption of bunkers (ships doing international trips) is excluded from the analysis because according to Eurostat conventions it does not account in national CO2 emissions.

shifted to diesel oil (+2.5%). The introduction of new fuels (bio-fuels, natural gas, etc.) is very limited in the limited timeframe of the projection.

6.5.1.3 Sector Adjustment for Different Emission Targets

Emission constraints influence the behaviour of consumers in many ways. At high constraints they may reduce their mobility, change their driving habits, use more public transports and purchase smaller and more efficient cars. Similarly freight transport companies may better optimise the use of transport modes and choice of technology. The cost of fuels in total transport costs represents a substantial component. However, most of the cost represents taxes imposed for non-environmental reasons. If emission constraints were effected through carbon taxation, one would need very high carbon taxes to signal a price difference to the consumer. This is an important feature of transport economics and heavily influences the results obtained.

At small levels of emission targets the implications for the sector of transports are rather limited. Mobility and the volume of freight transport remain almost stable as in baseline. The shares of the different transport models also remain quite stable. The specific efficiency of the average vehicle improves slightly, only at 1.5% from baseline. This is mainly achieved in the aviation sector where efficiency of the average aircraft improves by 5%. Train transports also undergo some efficiency gains (3%). Passenger cars are not really affected at this low level of emission constraint. In freight transport average efficiency improves by 1.7% as a result of improving train technologies (7%).

Energy intensity improvement is higher at medium levels of emission reduction targets. Passenger transports gain 8.2% in average efficiency and goods transport gain 10%. Mobility of passengers and the volume of freight are less affected. Some small but significant changes occur in terms of structural shifts among transport modes. Aviation and cars lose share (-0.4%) in favour of trains and public transports (0.7%). The average vehicle technology improves by 7%, mainly driven by improving efficiency of aircrafts (26%) followed by trains (15%). The improvement of the average car is lower (1 to 3%). In freight transport the effects come from a shift in favour of train transport (1.5% higher share) and efficiency gains of the average technology (6.7%). Trains are mainly improving (25%).

The results show that high emission constraints are necessary to enable a significant technology progress at the level of the average car. The range of possible improvement is big: from 7% to 44% gains in average (in terms of specific energy requirements of the average car for a given travelling pattern) from baseline. The maximum gain corresponds also to changes in driving habits and the massive replacement of cars with more efficient car technologies. Vehicles used for public road transports can also improve at a spectacular rate: the gains range from 25% to 45% from baseline. The average efficiency of trains becomes better by 50% from baseline, but this level remains stable even at higher emission constraints. Aviation undergoes very significant energy efficiency gains in case of stringent emission constraints. The energy requirements of an average aircraft can drop very significantly, reaching efficiency gains that approach 100% in highly constrained cases. The improvement of passenger transportation technologies is asymmetric, often leading to paradoxical (but understandable) results regarding the shares of transport modes. For example, at high emission reduction cases, the share of cars increases again as a result of the reduction of the relative cost of travelling by car due to high energy-efficiency gains. The technology of freight transports also improves mainly for trucks, then for trains.

At high emission reduction targets, the results show a significant drop of mobility and freight volume (reduction up to 5% and 1.2% respectively from baseline). The combination of the above changes, lead to a reduction of energy intensity by 70% for passenger transports and 65% for goods transport, when emissions are highly constrained.

Given the limited timeframe of the emission target (10 years corresponding to the average turnover of stock of cars, and less than half of time-life of aircrafts and trains) new vehicle technologies (e.g. fuel cells) do not emerge in the market at noticeable rates. Their stock in 2010 approaches only 1% in highly constrained cases.

Table 30: Decomposition of Energy System Changes in the Transport Sector

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Sectoral demand in 2010 (% of Final Energy Demand)	32.8	32.8	32.9	32.9	32.9	32.9	33.0	33.1	33.1	33.0	33.1	33.3	33.6	33.8	33.4	32.4	30.2
Sectoral as % of Overall CO2 Emissions reduction in 2010		9.4	8.1	10.5	10.2	12.3	12.2	13.2	15.2	17.0	17.7	18.3	18.8	19.7	21.6	24.4	27.9
Total Transports CO2 Emissions reduction in 2010 in Mtons of CO2		-0.7	-1.5	-3.2	-6.3	-12.8	-24.5	-41.8	-64.6	-92.7	-120.8	-150.2	-180.2	-212.5	-260.7	-334.6	-429.4
% Decomposition																	
Structural change and behavioural effects		29.2	28.0	33.9	34.6	42.2	40.3	38.9	38.3	37.0	36.8	34.5	29.5	27.1	26.1	23.3	22.2
Technological improvement		38.5	38.0	42.2	42.4	41.2	42.3	45.2	49.1	52.6	53.7	57.1	62.9	66.3	68.1	72.3	74.5
Train transports		*6.2*	*7.7*	*5.4*	*5.0*	*7.0*	*6.1*	*5.7*	*6.3*	*6.1*	*6.3*	*6.4*	*5.8*	*5.4*	*4.5*	*3.3*	*2.4*
Aviation / Navigation		*26.7*	*25.2*	*29.9*	*30.2*	*28.9*	*29.2*	*31.1*	*32.6*	*33.4*	*31.6*	*29.6*	*27.9*	*25.6*	*22.4*	*17.4*	*13.6*
Road transports		*5.7*	*5.2*	*6.9*	*7.2*	*5.3*	*7.0*	*8.4*	*10.2*	*13.1*	*15.8*	*21.1*	*29.2*	*35.2*	*41.2*	*51.6*	*58.5*
Change of fuel mix		0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
Change of emission factor of electricity and steam (supply effect)		32.1	33.8	23.8	22.8	16.4	17.2	15.7	12.4	10.3	9.3	8.2	7.4	6.5	5.6	4.2	3.2
Total effect		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 31: Indicators for the Transports Sector

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Final energy demand in transports in 2010 (Mtoe)	344	344	344	344	343	341	338	333	326	317	308	299	289	278	262	237	205
% change from baseline		0.0	-0.1	-0.2	-0.5	-1.0	-1.9	-3.4	-5.4	-8.0	-10.6	-13.3	-16.1	-19.2	-23.8	-31.0	-40.3
Energy per capita (toe per capita)	0.699	0.699	0.698	0.698	0.696	0.693	0.687	0.677	0.665	0.649	0.630	0.610	0.580	0.554	0.523	0.484	0.463
Fuel shares in final demand (%)																	
liquid fuels	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.2	97.3	97.3
liquified petroleum gas	0.8	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*	*0.8*	*0.7*
gasoline	42.4	*42.4*	*42.4*	*42.5*	*42.6*	*42.8*	*43.2*	*43.7*	*44.5*	*45.3*	*46.2*	*47.0*	*47.8*	*48.3*	*49.3*	*51.1*	*52.1*
kerosene	15.0	*14.9*	*14.9*	*14.9*	*14.8*	*14.6*	*14.3*	*13.8*	*13.0*	*12.1*	*11.3*	*10.7*	*10.1*	*9.5*	*9.1*	*7.6*	*5.5*
diesel oil and other liquids	39.1	*39.2*	*39.2*	*39.1*	*39.1*	*39.1*	*39.0*	*39.0*	*39.0*	*39.1*	*39.0*	*38.8*	*38.7*	*38.7*	*38.1*	*37.8*	*39.0*
natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
methanol	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
ethanol	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
liquified hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
electricity	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.4	2.6	2.4	2.3

Table 32: Indicators for Passenger transports

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Travel per person (km per capita) in 2010	15201	15200	15199	15196	15191	15180	15159	15127	15085	15033	14971	14900	14819	14731	14635	14505	14326
% change from baseline		0.0	0.0	0.0	-0.1	-0.1	-0.3	-0.5	-0.8	-1.1	-1.5	-2.0	-2.5	-3.1	-3.7	-4.6	-5.8
Vehicles efficiency indicator (toe/Mpkm)	41.3	41.2	41.2	41.2	41.1	41.0	40.7	40.2	39.5	38.6	37.7	36.8	35.9	34.9	33.5	30.6	26.0
% change from baseline		0.0	-0.1	-0.2	-0.4	-0.7	-1.4	-2.6	-4.4	-6.5	-8.7	-10.7	-12.9	-15.5	-18.9	-25.9	-37.1
Split of activity by transport mode (%)																	
road transports	84.8	84.8	84.8	84.8	84.8	84.8	84.8	84.8	84.7	84.4	84.0	83.8	83.6	83.5	83.7	86.7	89.9
of which private cars	*75.4*	*75.4*	*75.4*	*75.4*	*75.5*	*75.5*	*75.5*	*75.5*	*75.4*	*75.1*	*74.8*	*74.5*	*74.2*	*73.9*	*73.7*	*78.1*	*82.4*
train transports	7.6	7.6	7.6	7.6	7.6	7.6	7.7	7.8	8.0	8.4	9.0	9.3	9.7	9.9	10.0	8.1	6.5
aviation/navigation	7.6	7.6	7.6	7.6	7.6	7.5	7.5	7.4	7.3	7.2	7.0	6.9	6.7	6.5	6.3	5.2	3.7

Table 33: Indicators for Goods Transports

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Activity per unit of GDP (tkm/000 EURO90)	257	257	256	256	256	256	255	253	251	249	246	243	240	237	234	231	227
% change from baseline		0.0	0.0	-0.1	-0.2	-0.4	-0.8	-1.3	-2.1	-2.9	-4.0	-5.1	-6.3	-7.5	-8.7	-10.1	-11.6
Vehicles efficiency indicator (toe/Mtkm)	49.4	49.4	49.4	49.3	49.3	48.9	48.6	48.1	47.3	46.3	45.4	44.2	43.0	41.8	38.8	35.7	33.7
% change from baseline		0.0	-0.1	-0.2	-0.3	-1.0	-1.7	-2.8	-4.3	-6.3	-8.2	-10.7	-13.0	-15.4	-21.5	-27.8	-31.7
Split of activity by transport mode (%)																	
road transports	64.8	64.8	64.8	64.7	64.7	64.2	63.9	63.4	62.8	62.3	62.1	62.6	64.8	66.6	66.5	66.3	66.3
train transports	21.5	21.5	21.5	21.5	21.6	22.0	22.3	22.7	23.1	23.6	23.6	23.5	22.0	21.0	20.7	20.7	21.0
aviation/navigation	13.7	13.7	13.7	13.7	13.8	13.8	13.8	14.0	14.1	14.2	14.3	13.9	13.1	12.4	12.8	13.0	12.7

6.6 Power and Steam Generation

6.6.1.1 Introduction

Electricity and steam generation system is one of the main energy consumers and carbon emitters in the EU representing 26.7% of CO2 emissions in 1995. Current energy policies influence the evolution of the electricity system. The baseline projection includes the effects from the liberalisation of electricity and gas markets, the promotion of renewable energy and stringent regulations for acid rain pollutants. In addition, technology trends, such as the maturity of gas-based power generation technologies and the effects from infrastructure projects concerning the introduction or expansion of supply of natural gas, facilitate the shift in favour of gas-based generation as projected the baseline.

6.6.1.2 Sector Evolution in the Baseline Projection

Final energy demand for electricity increases in the baseline scenario by 31.5% in 2010 compared to 1995. Demand for steam also increases by 20% in the same period. To meet increased demand, and replace decommissioning of old plants, electricity and steam suppliers invest by building more than 280 GW of electric and/or cogeneration capacity and 150GW of boilers, according to the baseline results (up to 2010). The bulk of these investment is made in natural gas combined cycle plants (GTCC) leading to a significant increase of their share in total capacity from 4.3% in 1995 (24.5 GW) to 30% in 2010 (214GW).

On the contrary, conventional thermal power technologies (monovalent coal, lignite and gas-fired plants, polyvalents with or without coal) decline. Their share drops to from 48.8% in 1995 to 24% in 2010 in total capacity. Nuclear capacities increase slightly from 132GW in 1995 to 134GW in 2010 because of commitment of plants that are under construction. The share of nuclear, however, decreases from 23% in 1995 to 18.7% in 2010. Investment in new technologies such as clean coal plants, fuel cells and supercritical combustion plants are very limited. Their capacity accounts for 9GW in 2010 (1.2% of installed capacities). Gas turbine steam injections plants penetrate significantly in the system. Their capacity (including traditional peak devices) increases from 21.8GW in 1995 to 45.8GW in 2010 and their market share from 3.8% in 1995 to 6.4% in 2010. Biomass and waste combustion plants do not achieve high penetration in the baseline scenario. Capacities of renewable energy forms increase by 26.8GW. The bulk of new investments are made in wind turbines the capacity of which increases from 1.9GW in 1995 to 24.3GW in 2010. Only 4GW are invested in hydropower (106.8GW in 1995) and 0.4GW in geothermal plans (0.7GW in 1995). The share of renewables capacity remains stable at around 19%. An important part of investment in thermal plans concerns cogeneration. Cogeneration capacity reaches 150GW in 2010 from 64.2GW in 1995. The share of cogeneration plants in total capacity increases from 11.3% in 1995 to more than 21% in 2010.

The new structure of electricity and steam production plant-mix in combination with increased demand, lead to important changes of fuel mix and plant operation. In 1995 45% of electricity production was generated from conventional thermal plants, followed by nuclear (35%) hydro and other renewables (12.5%), GTCC (5.5%), biomass-waste (1%) and peak devices (0.5%). The picture changes completely in 2010. GTCC plants are now the main electricity producers, accounting for 33.2% of production, followed by nuclear (29.5%) and conventional thermal plants (19.5%). New technologies (mainly clean coal, secondarily supercritical combustion plants) produce 2.3% of electricity in 2010. The penetration of gas turbine steam injections plants is significant for cogeneration, in particular in industry. Increased use of biomass-waste plants and renewables capacities lead to an increase of biomass’ share to 1.9% and stabilisation of renewables’ share at 12.7%.. Electricity production from cogeneration plants increases substantially reaching 15% in 2010 from 6.5% in 1995.

The changes for steam generation are along the same lines. The share of boilers decreases from 15% in 1995 to 55% in 2010, and that of thermal CHP plants from 22% to 17%. Gas-based CHP plants cover the larger part of this change (21% in 2010 from 2% in 1995) followed by new technologies (4% in 2010) and gas turbine steam injections plants (2.2% in 2010).

Total energy used as input fuel increases by 13% in 2010 compared to 1995. The use of solid fuels declines substantially, while the use of gas is highly developed in the baseline.

Efficiency of electricity and steam production improves significantly in the period 1995-2010 by 21% and 23% respectively. Carbon intensity also improves by 23% from 0.342 tnCO2 per MWh of output to 0.278 tnCO2 per MWh of output.

It is obvious from the above that the baseline scenario projects an optimistic evolution regarding CO2 emissions from power and steam generation. All changes are in favour of lowering CO2 emissions per unit of electricity and steam production.

6.6.1.3 Sector Adjustment for Different Emission Targets

Despite the evolution of the sector that is favourable for CO2 emission reduction, the possibility of the system for further reducing emissions is high. The structural changes that are necessary considerably vary. They range from simple changes in fuel mix (e.g. in polyvalent plants) up to considerable reorientation of investment choices and the premature under-utilisation of conventional plants.

In all emission-constrained cases, the demand side measures lead to a decrease of demand for electricity and steam. The substitution effects in favour of electricity in the demand side are always lower than the direct electricity-saving effects. The power and steam system faces lowered demand. This influence the investment decisions and the possibilities for deploying new smaller-scale technologies particularly used by smaller generators. The model represents this mechanism through varying economies of scale by size of generator and type of plant.

In case of small emission reduction targets, measures in demand side combined with fuel-mix changes lead to a small decrease of demand for electricity and steam by up to 1.6% and 1% compared to the baseline for 2010. Total installed electric capacity remains stable as in the baseline, implying a small decrease of the average load factor (by less than 1%.) The overall structure regarding the mix of plant types also remains unchanged. Investments in cogeneration plants are slightly lowered (133.5MW compared to 151MW in the baseline) but production of steam from cogeneration increases. This is possible by relying more on plants that allow for higher steam to electricity ratio. This increases from 1.2 in the baseline up to 1.32.

The main effect of small levels of emission reduction targets lies in the use of GTCC platns. Their use increases significantly. Their share in production increases from 33.2% in the baseline up to 36.8%. Conventional thermal plants are less used, having a share dropping to 16% from 19.5% in the baseline. Electricity production from wind energy increases from 2.2% in the baseline up to 3%. Electricity production from CHP plants decreases to 13.5% from 15.1% in the baseline. The increase of the steam/electricity output ratio of cogeneration plants counterbalances the decrease of CHP capacities. Bigger use of GTCC-CHP supports this change. Total fuel input for electricity and steam production decreases by up to 4% compared to the baseline. The energy forms that are affected the most are coal (-30%), lignite (-25%) and liquids (-17.5%). In the contrary, input of natural gas increases by 11.5% and of biomass by 13%.

Efficiencies of electricity and steam production remain almost stable for low emission reduction targets while the shifts observed in the utilisation of capacities lead to an improvement of carbon intensity by up to 11.5% compared to the baseline.

In summary, small emission reduction targets induce changes in the fuel mix and the operational-mix of plants. Technologies and major sector’s choices are not noticeably affected. The gains in terms of CO2 are significant and cheap. This explains that the power and steam generation sector is the first in reacting to emission constraints, even at small reduction targets.

The imposition of medium emission reduction targets leads to important changes in electricity and steam generation sector. The nature of the changes is different from the previous analysis.

Within the middle range of emission reduction targets, demand for electricity and steam decrease by 3.7% compared to baseline. Despite this drop, producers of electricity and steam undertake large investments, implying over-capacity. Up to more than 25GW of additional electric and cogeneration capacities and 20GW of boiler capacities are created compared to baseline. Generators invest in more carbon-efficient technologies and under-utilise the conventional plants.

Along these lines, they massively invest in wind turbines, the capacity of which reaches up to 45GW compared to 24.5GW in the baseline and secondarily to supercritical combustion plans (10.8GW installed of 34MW in the baseline) which also use biomass and waste. In addition, they choose to make retrofitting of nuclear plants (the potential is however very limited) gaining some extra capacity of 1.5GW compared to baseline. The capacity of GTCC plants remains stable (as in the baseline). The use of biomass-waste fired plants is also expanded.

In system operation, the generators expand the utilisation of GTCC plants, increasing their share in electricity production up to a level of 37%. The share of nuclear also increases up to 31% as does that of biomass–waste (reaching 43% -1.9% in the baseline) and wind energy (reaching 4.1% - 2.2% in the baseline). Again, conventional thermal plants loose share dropping to 9.5%.

In steam production except of a very small increase of gas turbine steam injection plants, no significant change is observed. The increase of steam to electricity ratio in cogeneration plants (reaching 1.38) reduces the need for additional cogeneration plants.

In terms of fuel inputs, the consumption of coal decreases to 25% of that in baseline, followed by liquids (-40% compared to baseline) and lignite (-30% compared to baseline). Consumption of natural gas increases by up to 18% compared to baseline and that of biomass/waste by up to 65%. Total fuel input for electricity and steam production decreases by up to 8%. Increased use of biomass, wind and nuclear energy in combination with the decrease of demand implies a higher share of non-fossil fuels in production reaching 50% for electricity (from 44.3% in baseline) and 20.5% for steam (from 15.7% in the baseline). Carbon intensity improvement reaches 30% (or 0.213 tnCO2 per MWh produced) and the average efficiency of electricity production improves by about 1.5% compare to baseline.

A mix of actions describes the reaction of generators in the middle range of emission reduction targets. They use more gas-based technologies (under-utilising conventional thermal plants), they retrofit nuclear plants, they use biomass and waste and they invest in wind energy. These actions do not constitute a big change of the power system, indicating that high emission reduction potential exists with rather realistic arrangements in the power system. Over-investment is the most noticeable effect.

High emission reduction targets induce a significant decrease of demand for electricity and steam reaches as a consequence of demand-side measures. The drop of demand reaches 22.5% and 20% compared to baseline. Despite this significant decrease of demand, electricity and steam suppliers still massively invest to change the power system and meet the emission reduction targets. Consequently the average load factor of power plants drops to less than 37% (from 48% in the baseline) while that of combined electricity/steam capacities drops from 51.5% in the baseline down to 40%.

Highly constrained cases induce big changes in the technology choice of generators.

For example, GTCC plants are not so attractive, any more, and loose market shares, in terms of capacity, dropping down to less than 20% for very high emission reduction targets (70 GW less than in baseline). The gap is, mainly, covered by vast investment in fuel cells (reaching up to 35GW or 5% of the market from almost zero at medium emission reduction targets). Capacity of biomass-waste fired plants, also, increases reaching up to 12.5 GW, also facilitated by increased capacity of supercritical combustion plants reaching 20GW which almost double from case of medium emission reduction targets. Retrofitting of nuclear plants is more intense resulting in an additional capacity of 3.5 GW compared to baseline. Investment in wind turbine increase involving the installation of 15 additional GW from lower target cases. The share of wind turbines to total capacity reaches 7.5%. Small additional investments for large hydro (+25GW from baseline) are also observed for very high emission reductions, a level at which solar plants also emerge reaching an installed capacity of up to 3.5GW. Capacity of cogeneration plants increases in high emission reduction targets (+12GW from baseline) while that of boilers decreases by up to 30GW. The above change in combination with the decrease of steam demand results in a reduction of steam to electricity ratio from CHP down to 0.92 enabling however high share for cogenerated steam.

Changes in installed capacities in combination with decrease of demand for electricity and steam result in significant changes in the utilisation of plants.

The contribution of nuclear energy, the production of which remains rather stable at the levels of baseline, reaches 37.5% becoming the major electricity producer at high emission reduction targets. Production from GTCC drops down to less than 18% of total electricity (33% in the baseline) while production from conventional thermal plants diminishes into less than 4%. Production from fuel cells reaches 8.5% from 0% in the baseline, from supercritical combustion plants 3.5% (1% in the baseline) and from clean coal technologies 3% (1.4% in the baseline).

Biomass and waste gain market share reaching 7% of the total electricity production (from 2% in the baseline). Renewables also improve their position in electricity production. Hydropower that contributed around 10.5% in other cases gets a share of 12.5% in highly constrained cases. In absolute values however their production decreases by up to 18TWh because of demand load effects. On the contrary, production from wind energy increases continuously reaching a market share of 6%.

The contribution of cogeneration plants increases from 15% in the baseline up to 18.2% of total electricity production, being, however, more than 30 TWh less than in baseline. In steam production, fuel cells gain up to 6% of the market and boilers gain up to 5% from baseline (reaching 60.5% of production). The contribution from conventional thermal cogeneration plants (-5% from baseline) and GTCC CHP plants (-4% from baseline) declines.

In total, fuel input for electricity and steam generation decreases by up to 26.5%. Consumption of coal diminishes to less than 8% of that in the baseline, as does that of liquids which drop to 18% of baseline consumption. Consumption of lignite decreases by up to 40% compared to baseline. In the case of high emission targets consumption of natural gas also decreases (by up to 20% compared to baseline) instead of increasing in lower emission reduction targets. Only consumption of biomass and waste increases in high emission reduction targets by up to 90% from baseline.

The observed shift towards the use of non-fossils in combination with the significant decrease of demand results in an increase of their share in production up to 64% for electricity and 25% for steam. Consequently, carbon intensity improvement reaches 74% compared to baseline (0.16 tnCO2/Wh produced compared to 0.218 tnCO2/Wh produced).

Technology shifts in favour of non-fossil energy forms describes the reaction of generators in case of high emission reduction constraints.

6.6.1.4 Analysis by Technology Type

6.6.1.4.1 Conventional Thermal Plants

Monovalent coal, lignite and gas-fired plants, as well as polyvalents with or without coal are included in this category. The corresponding capacity decreases in the baseline scenario by more than 60% (or 105 GW) in 2010 compared to 1995. This is due to the decommissioning of old plants and the preference on other more carbon-efficient plant technologies. Their capacity in 2010 as shown in the baseline (about 172 GW) remains stable independently of the emission constrained case. Small changes are rather due to altering decisions about retrofitting in the context of emission constrained cases.

In electricity production terms, the contribution of conventional thermal plant technologies continuously decreases with increasing level of emission target. The share of electricity produced by conventional thermal plants drops from 19.5% in the baseline (2010) to about 4% in highly constrained cases (being 10% in the middle range of targets). Similarly the use of conventional thermal technologies in steam production from cogeneration is progressively abandoned at high emission reduction targets (being for steam about 17% in the baseline).

The capacity of conventional thermal plants remains stable as mentioned but they are progressively used more for reserve margin, rather than for generation. Their average load factor drops from 60% in baseline down to 15% at high emission targets.

6.6.1.4.2 Natural Gas Combined Cycle (GTCC) Plants

The baseline scenario that 215 GW of GTCC technology would be in operation in 2010. Investment in 2010 is projected to be very high in the 2010-1995 period (about 190 GW) representing the highest share in capacity expansion of the EU among all technologies. In 2010, the baseline projects that 33% of electricity and 21% of steam would be generated from GTCC plants at an average load factor of 75%.

The imposition of a wide range of small to medium levels of emission targets does not alter the baseline schedule of constructing and using natural gas combined cycle plants (GTCC). Even though demand for electricity and steam decreases as a result of emission constraints imposed on the system as a whole, the capacity of GTCC plants remains stable and even increases by 5 GW from baseline. In addition, the GTCC plants are more used for base load production approaching 82% in terms of average load factor. Their share in electricity production reaches 38% (for steam 23%).

In general, the results show that emission constraints make utilities using and building more GTCC plants, leaving old conventional plants under-utilised.

This picture changes at highly constrained cases. GTCC plants are not enough to meet the stringent constraints. The producers shift towards more efficient technology mix in terms of carbon emissions, and adopt a mix of fuel cells, supercritical (or ultra-supercritical plants) plants and renewables.

This change combined with the drop of electricity and steam demand, as a result of savings in the demand-side, imply a decrease of GTCC capacity from baseline. At highly constrained cases, the bulk of GTCC plants accounts for 137 GW (77 GW less than in baseline). They are also use for load following at an average load factor of 55%. Their production represents only 17% in total generation. However, they are still used intensively for steam generation through cogeneration (their share drops only slightly from baseline).

6.6.1.4.3 Nuclear Technology Plants

The timeframe of ten years is very limited for observing big changes in decisions related to nuclear plants. Decisions for new plants need 2-3 years and the construction needs another 7-8 years. Therefore, the model does not consider new investment in nuclear plants during the 2001 to 2010 period, except decisions undertaken before and retrofitting of existing plants. Also decisions about closing and decommissioning plants, that have been taken in some countries, can be altered in view of emission constraints. However, the intensity of use of nuclear plants might be changed, not so much in terms of load factor, but as a percentage of total generation (if demand drops as a result of demand-side measures).

The baseline scenario shows that 134 GW of nuclear plants in 2010, representing 18.7% of total capacity (23% in 1995) produce 30% of electricity (35% in 1995). New constructions in this period are only for 10 GW.

The retrofitting possibilities that are undertaken in emission constrained cases are about 3.5 GW of additional capacity.

The average load factor of nuclear plants remains almost stable, varying from 90 to 85%, across all emission constrained cases. The contribution of nuclear energy in electricity production continuously increases at successively higher emission reduction targets, ranging from 30% up to 37%. In absolute terms, nuclear energy remains stable (varying from 891 TWh to 877 TWh). The rise of its share is due to the reduction of electricity demand because of demand-side measures.

6.6.1.4.4 New thermal Technologies

This category includes clean-coal technologies, super (and ultra) critical plants, fuel cells and small gas machines (mainly gas turbine steam injection).

Capacity of clean-coal plants increase in the baseline from 500 MW in1995 to 5.5 GW in 2010. This represents a small fraction in the system of the EU. Most of the capacity provides cogeneration possibilities. The imposition of emission reduction constraints has direct adverse effects on clean-coal technologies, since despite their higher efficiency these plants use coal. In a range of small to medium levels of emission constraints, clean coal drops to 1.7 GW in 2010. At high emission constraints, lignite plants that are still used to cover national objectives about using indigenous resources are converted into clean-coal technologies. Consequently, clean-coal capacity reaches 10.9 GW in highly emission reduction cases. They are generally used in base load.

Capacity of supercritical plants reach in the baseline 3.4 GW in 2010 (2 GW being cogeneration plants). Small and medium level emission targets do not affect this technology. At high emission targets, supercritical technology becomes attractive and the capacity ranges from 10 to 20 GW. This development can be mainly explained by the fact that biomass and waste can be also used in supercritical plants. These fuels are not supposed to emit CO2. The use of supercritical plants ranges from base load to load following.

Fuel cells (cogeneration) technology emerges at high emission reduction targets. The capacity of fuel cells reaches as much as 36 GW in some constrained cases. To some extend fuel cells are substituting GTCC plants. However, their contribution is limited in the timeframe of 10 years analysed.

The role of small gas machines is important in the baseline scenario. The corresponding capacity increases to 21 GW in 2010 in the baseline. They are used as peak devices but mainly as flexible cogeneration units of independent power producers, in particular related to industry. Small gas machines have lower efficiency rates than GTCC. Emission constraints generally have negative effects on the development of small gas machines, especially in case of high emission reduction targets.

6.6.1.4.5 Biomass and Waste

The use of biomass and waste is limited from the supply side. The scenarios generally do not assume high deployment of energy crops and new biomass, because of the limited timeframe of the analysis. The available resources are then rather small mainly coming from waste.

The share of electricity generated by using biomass and waste ranges between 7% and 12% in all cases studied. The corresponding capacity ranges from 4 to 13 GW, in total.

6.6.1.4.6 Renewables

This category as described here excludes biomass and waste, but includes large hydropower.

The EU system has already exploited the large possibilities for hydroelectric generation. The additional possibilities for large-scale hydro plants are limited both in the baseline and in all scenarios studied. Considerable possibilities exist for wind and solar power.

The construction of small hydroelectric plants mainly explains the increase of total hydro capacity from 106.8 GW in 1990 to 110.8 GW in 2010, according to the baseline scenario. In emission constrained cases, additional constructions of hydropower also concern small-scale plants (2.5 GW of additional capacity).

Wind energy deploys significantly in the baseline scenario. Capacity increases from 2 GW in 1995 to 24 GW in 2010. Electricity production from wind energy also increases reaching 67 TWh in 2010.

The emission constraints greatly favour further development of wind energy. The total installed capacity of wind power ranges from 32 to 56 GW in 2010 depending on the level of emission constraint. In particular, the cases of medium to high emission reduction targets are ver favourable for wind energy (representing 4 to 6% of electricity production).

Solar energy is not significantly exploited within a wide range of emission reduction targets. It emerges at highly constrained cases, reaching a maximum of 3.5 GW.

6.6.1.5 Tables for the Power and Steam Generation Sector

Table 34: Effects on Power Sector – Demand and Operation

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Electricity demand in 2010 (Twh)	2668	2665	2664	2662	2658	2643	2624	2612	2589	2570	2516	2447	2380	2315	2253	2133	2074
% change from baseline		-0.1	-0.1	-0.2	-0.4	-0.9	-1.6	-2.1	-3.0	-3.7	-5.7	-8.3	-10.8	-13.2	-15.5	-20.0	-22.3
Steam demand in 2010 (Twh)	1207	1206	1207	1205	1204	1201	1196	1187	1176	1163	1144	1122	1098	1066	1039	1009	974
% change from baseline		-0.1	0.0	-0.1	-0.3	-0.5	-0.9	-1.6	-2.5	-3.6	-5.2	-7.0	-9.0	-11.7	-13.9	-16.4	-19.3
Carbon intensity (tn CO2/MWh)	0.278	0.277	0.275	0.273	0.268	0.264	0.250	0.235	0.224	0.213	0.200	0.190	0.181	0.176	0.170	0.165	0.160
Load factors																	
for gross electric capacities	0.48	0.48	0.48	0.48	0.48	0.48	0.47	0.47	0.46	0.45	0.44	0.42	0.41	0.40	0.39	0.38	0.36
for electric/steam capacities	0.51	0.51	0.51	0.51	0.51	0.50	0.50	0.49	0.48	0.47	0.46	0.46	0.45	0.44	0.43	0.42	0.41
CHP indicators																	
steam/electricity ratio from CHP	1.20	1.21	1.21	1.21	1.23	1.27	1.32	1.27	1.28	1.38	1.36	1.29	1.20	1.19	1.11	1.09	0.92
% of electricity from chp	15.1	15.1	15.1	15.0	14.8	14.3	13.6	14.0	13.9	12.9	13.0	13.8	14.9	14.7	15.7	15.8	18.2
% of steam from chp	44.4	44.4	44.4	44.4	44.4	44.2	43.6	43.2	43.1	43.2	42.7	42.7	42.6	41.9	41.3	40.0	39.3

Table 35: Effects on Power Sector – Capacities

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Total Installed capacity (GWe) in 2010	716	715	714	715	714	711	715	723	727	741	743	742	743	739	737	724	735
% change from baseline		-0.1	-0.2	-0.2	-0.3	-0.7	-0.1	1.0	1.6	3.5	3.7	3.6	3.8	3.3	2.9	1.1	2.7
CHP capacity (GWe) in 2010	151	150	147	146	143	136	133	131	131	125	127	137	146	147	150	149	163
% change from baseline		-0.8	-2.8	-3.5	-5.1	-10.3	-11.7	-13.3	-13.0	-17.3	-15.6	-9.0	-3.6	-2.8	-0.9	-1.4	7.8
Split of capacity by plant type (%)																	
nuclear plants	18.7	18.7	18.8	18.7	18.8	18.8	18.7	18.6	18.5	18.3	18.3	18.3	18.3	18.5	18.6	19.0	18.7
conventional thermal	24.1	24.1	24.1	24.1	24.2	24.7	24.7	24.5	24.0	24.0	24.2	23.7	23.4	23.7	23.6	24.4	24.5
GTCC	29.9	29.9	29.8	29.8	30.0	29.4	29.7	30.4	30.1	28.7	27.0	26.0	24.5	23.3	21.5	19.8	18.6
new combustion technologies	1.2	1.3	1.3	1.3	0.9	0.8	0.5	0.6	0.9	1.7	2.1	3.3	4.2	4.9	6.5	7.0	9.1
peak devices	3.5	3.5	3.4	3.3	3.3	3.2	2.9	2.6	2.6	3.0	2.6	2.8	2.8	2.8	3.1	3.1	2.7
gas turbine steam injection	2.9	2.9	3.0	3.0	2.9	3.0	2.7	1.9	1.8	2.1	2.4	2.2	2.5	2.4	2.0	1.9	1.9
biomass-waste	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	1.0	1.1	1.4	1.4	1.5	1.5	1.7	1.4	1.4
hydroelectric	15.5	15.5	15.5	15.5	15.5	15.6	15.5	15.3	15.3	15.0	15.0	15.0	15.0	15.1	15.2	15.6	15.4
wind turbines	3.4	3.4	3.4	3.5	3.5	3.8	4.5	5.1	5.6	6.0	6.9	7.2	7.5	7.6	7.6	7.2	7.0
other renewables	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Boilers capacity (GWth) in 2010	228	229	233	233	236	244	245	247	246	248	243	232	226	218	215	208	198
% change from baseline		0.4	2.2	2.4	3.5	7.3	7.7	8.3	8.0	8.8	7.0	2.0	-0.7	-4.1	-5.4	-8.6	-13.2

Table 36: Effects on Power Sector – Plant mix

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Electricity production in 2010 (Twh)	3018	3015	3013	3012	3006	2989	2965	2951	2923	2901	2839	2760	2682	2610	2538	2404	2334
% change from baseline		-0.1	-0.2	-0.2	-0.4	-1.0	-1.8	-2.2	-3.1	-3.9	-5.9	-8.6	-11.1	-13.5	-15.9	-20.4	-22.7
of which from CHP	456	455	456	453	444	427	405	413	406	374	369	380	399	384	398	380	426
% change from baseline		-0.2	-0.2	-0.8	-2.6	-6.3	-11.3	-9.6	-11.1	-18.1	-19.2	-16.6	-12.7	-15.8	-12.8	-16.7	-6.7
Ratio of non-fossil fuels to electricity production (%)	44.1	44.1	44.1	44.2	44.3	44.6	45.4	47.0	48.4	49.9	52.2	54.4	56.5	58.2	60.0	62.1	63.3
Split of electricity production by plant type (%)																	
nuclear plants	29.5	29.5	29.5	29.6	29.6	29.7	29.8	29.9	30.2	30.7	31.4	32.3	33.2	34.2	35.3	36.9	37.6
conventional thermal plants	19.5	19.3	18.8	18.6	18.3	18.0	15.9	13.3	11.4	9.5	8.5	6.7	5.5	4.8	4.0	3.7	3.6
GTCC	33.2	33.4	33.7	33.9	34.7	35.0	36.8	37.8	37.8	37.0	35.0	32.4	30.3	28.0	24.8	22.0	16.9
new combustion technologies	2.2	2.2	2.3	2.2	1.6	1.3	0.9	0.9	1.4	2.4	3.0	5.1	6.3	7.6	10.0	11.0	15.1
peak devices	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
gas turbine steam injection	0.5	0.5	0.5	0.6	0.6	0.7	0.7	0.6	0.6	0.8	1.0	0.9	1.0	0.9	0.8	0.7	0.6
biomass-waste	1.9	1.9	1.9	1.9	1.9	2.0	2.1	3.1	3.8	4.3	4.9	5.5	5.8	6.2	6.6	6.8	6.9
hydroelectric	10.3	10.3	10.3	10.3	10.3	10.2	10.3	10.4	10.5	10.5	10.8	11.2	11.6	11.8	11.9	12.3	12.5
wind turbines	2.2	2.2	2.2	2.3	2.3	2.5	3.0	3.4	3.8	4.1	4.8	5.2	5.7	5.8	5.9	5.7	5.8
other renewables	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.5

Table 37: Effects on Power Sector – Steam production

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Steam production in 2010 (Twh)	1237	1236	1237	1235	1234	1231	1225	1216	1205	1192	1172	1149	1124	1091	1064	1033	998
% change from baseline		-0.1	0.0	-0.1	-0.3	-0.5	-0.9	-1.7	-2.6	-3.6	-5.3	-7.1	-9.1	-11.8	-13.9	-16.5	-19.3
Ratio of non-fossil fuels to electricity production (%)	14.8	15.0	15.0	15.2	15.7	16.6	17.4	18.4	19.6	20.5	21.3	21.6	22.0	22.7	23.3	24.0	24.6
Split of steam production by plant type (%)																	
conventional thermal plants	16.9	16.9	16.9	16.7	16.5	17.2	17.0	16.1	15.5	16.2	15.1	13.5	12.5	12.6	12.4	12.6	11.8
GTCC	21.2	21.3	21.1	21.0	21.2	20.7	22.1	23.4	23.6	21.9	21.6	22.9	22.7	21.8	20.3	19.0	17.1
new combustion technologies	3.9	3.8	3.9	3.9	3.9	3.3	1.4	1.0	1.2	1.3	1.5	2.2	3.0	3.4	5.0	5.0	7.5
gas turbine steam injection	2.1	2.1	2.3	2.4	2.6	2.8	2.7	2.3	2.4	3.2	3.9	3.5	3.8	3.6	3.0	2.9	2.4
biomass-waste	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.5	0.4
boilers	55.6	55.6	55.6	55.6	55.6	55.8	56.4	56.8	56.9	56.8	57.3	57.3	57.4	58.1	58.7	60.0	60.7

Table 38: Effects on Power Sector – Fuel Mix

Carbon Value (in Eur'90/ton of Carbon)	**0**	**1**	**2**	**5**	**10**	**20**	**40**	**70**	**110**	**160**	**220**	**290**	**370**	**460**	**560**	**700**	**900**
Emissions Reduction Target as % from 1990 (EU)	7.9	7.7	7.3	6.9	5.9	4.5	1.2	-2.6	-6.2	-10.2	-14.7	-19.3	-23.9	-27.8	-32.2	-37.6	-43.3
Fuel input for electricity and steam generation (Mtoe)	644	643	641	640	637	632	618	610	600	592	577	558	541	527	512	490	473
% change from baseline		-0.2	-0.4	-0.6	-1.1	-1.9	-4.0	-5.4	-6.8	-8.0	-10.4	-13.3	-16.0	-18.2	-20.5	-23.9	-26.5
Split by type of energy form (%)																	
Domestically Produced Coal	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.3
Imported Coal	12.7	12.5	12.0	11.7	11.2	10.3	9.0	6.3	4.4	2.7	1.1	0.6	0.2	0.2	0.1	0.0	0.0
Lignite and Peat	7.2	7.1	7.2	7.2	6.6	6.6	5.7	5.7	5.7	5.6	5.3	5.4	5.5	5.6	5.7	6.0	6.2
Fuel Oil and other oil products except diesel and refinery gas	7.6	7.6	7.5	7.5	7.3	7.2	6.4	5.7	4.8	4.8	3.6	2.7	1.6	1.5	1.4	1.2	1.1
Diesel Oil	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0
Natural Gas	26.1	26.3	26.7	26.9	27.8	28.3	30.3	32.0	33.2	33.5	34.4	33.7	32.9	31.2	29.2	27.2	28.3
Byproducts (derived and refinery gas)	5.3	5.3	5.3	5.3	5.4	5.4	5.5	5.6	5.7	5.8	5.9	6.1	6.2	6.3	6.5	6.8	4.0
Nuclear Energy (in thermal units)	35.0	35.1	35.2	35.2	35.4	35.6	36.1	36.7	37.2	38.1	39.1	40.4	41.7	43.0	44.3	45.8	47.0
Biomass-Waste	4.4	4.4	4.5	4.5	4.6	4.8	5.1	6.3	7.2	7.9	8.7	9.3	9.8	10.2	10.7	10.9	11.2
Hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Methanol	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

7. Sectoral Costs of Emission Reduction

The imposition of emission reduction targets results in an increase in total energy system cost, partly due to the associated marginal abatement cost, for which the term “carbon-value” is used here. In other words, the “carbon-value” is defined as the cost incurred in avoiding the last tonne of CO2 that is necessary in order to meet the reduction target in 2010. The way that the imposition of the carbon-value affects different energy consumers depends on their ability to adapt to emission reduction targets through investment in new, more efficient technologies, structural shifts and changes in their choice of fuel mix.

The additional energy system costs are defined as the integral below the marginal abatement cost curves of reducing CO2 emissions in 2010.

The additional system cost in the case of small emission reduction targets, reaches up to 2640 MEur’90, representing less than 0.05% of EU GDP in 2010(gross domestic product). The corresponding cost in cases of medium emission reduction targets increases up to 10600 MEur’90 (0.2% of GDP) while for stringent emission constraints it can reach up to 128800 MEur’90 (1.6% of GDP).

Average system costs are computed at a sectoral level. They are computed by the model and defined as accounting costs. They are estimated on an annual basis and are decomposed into capital costs (annuity paid for old and new capital), non-energy production costs (materials, labour, etc.), operation and maintenance costs for energy equipment and fuel purchase costs. These costs are defined as average costs since they are the result of the division of the total cost by the volume of production, or by any other indicator denoting the volume of activity or income. Obviously, the imposition of an emission reduction target leads to the change in the overall average cost and its components. Non fuel costs may also change, perhaps due to higher capital costs or to any additional investment needed in the sector in order to meet the target. Fuel costs may change because a likely shift towards less carbon-intensive but probably higher cost fuels. The carbon value is an additional cost. The way a sector is affected by this cost depends on the way the emission reduction policy is implemented. In case of a carbon tax or pollution permits, the carbon value is really paid by consumers. In case of higher standards or voluntary agreements, carbon values are not reflected in any actual payments of the sectors.

One of the most interesting results of the analysis presented here is that of the relatively modest cost of meeting the carbon constraints considered, once payments for carbon emissions have been allowed for. Overall fuel costs, excluding charges for carbon emissions (the carbon value), may, of course decline because of the reduction in overall energy use that result from its increased cost. The average fuel cost might increase, even if carbon values are excluded, as a result of purchasing more expensive energy forms, such as electricity and gas.

The major reason for the limited overall cost of the imposition of a carbon constraint is related to the developments of the costs of new technologies, as these are allowed to occur by PRIMES. These developments are especially evident in the cases of very high emission reduction targets when advanced technologies make significant inroads.

Advanced technologies are, almost by definition, significantly more costly to adopt initially, in terms of capital spending. However, once the carbon value exceeds a certain level and the adoption of these technologies becomes marginally cost effective their market penetration develops a strong momentum leading to the decline in the additional capital charges involved in the use of the new technology. In other words, the more a new technology is used the greater the reduction in its costs. There are many examples of this process with energy technologies, including the many fold reductions in the cost per unit of photovoltaics and wind turbines that have occurred over the past decade as the use of these energy forms has entered a number of niche market applications. The PRIMES model introduces such learning-by-experience mechanisms in the demand-side technologies. Cost gains induced from massive use of a technology reflects increasing returns to scale in the supply-side (the manufacturers and technicians) of this technology.

The rather limited costs of severe carbon constraints originate from this process of the continued reduction in the cost of advanced technologies as these are increasingly adopted.

In industrial sectors the increase in the average cost of sectoral production ranges from up to 1.5% (in other industrial sectors) to 20% (in metals production) for high emission reduction targets. This wide range of average cost increase is explained by the different contribution of energy in the different industrial sectors. Energy intensive sectors are affected more. The contribution of non-energy costs, in percentage terms, to average production cost excluding carbon-value in industry remains rather stable in case of small to medium emission reduction targets. However, it increases considerably as more stringent emission reduction targets are imposed. In this case, the increased market penetration of advanced technologies, achieved through a technology-supply mechanism as described earlier, in combination with their high efficiency, leads to a decrease in the costs of energy related equipment and related fuel bill because of higher efficiency. For example, in metals production and in chemical industries the average production cost (excluding carbon-value cost) decreases in the case of high emission reduction targets by up to 2% and 1.3% respectively, when compared to baseline.

The average cost of energy service in the tertiary sector increases by up to 18.5%, compared to baseline, due to the introduction of emission reduction targets. The share of energy related equipment and fuel costs in the average cost of the energy service, excluding carbon-value cost, increases from 18% in the baseline to more than 22% in the case of high emission reduction targets. This result reflects the effort of energy consumers to reduce emissions by improving overall sectoral efficiency through the purchase of advanced equipment technologies and the shift from carbon-intensive fuels towards less carbon-intensive ones. Consequently, the average cost of the energy service, excluding carbon-value cost, increases by up to 2% compared to baseline in high emission reduction targets. However, for medium emission reduction targets the average cost decreases by up to 1%.

The average cost of delivering one unit of energy service to households increases as a consequence of emission reduction targets. The costs increase continuously almost at a rate proportional to the carbon value, reaching 25% increase from baseline in case of highly constrained emissions. A similar result is obtained for passenger (up to 24% higher costs) and goods transports (up to 15% higher costs). In all these sectors, the results show that the additional costs from carbon emissions are largely offset from cost gains effected by technology progress.

The power and steam generation sector also bears additional costs when emission reduction targets are imposed. Depending on the way policy is implemented they may bear costs directly proportional to carbon emissions, as explained before. The sector also bears costs of adjustment needed to meet the emission reduction target. The adjustment costs relate to eventually higher capital expenditures (more expensive plant technology), the costs induced from stranded capital and investment in over-capacity, eventually higher fuel purchase costs, etc.

The results show that in all emission reduction cases, the power and steam generation sector bears additional costs independently of charges related to carbon emissions. At highly constrained cases, the additional non-carbon costs are at maximum 19% higher than in baseline. When charges from carbon emissions are included, average generation costs increase at maximum by 112%. In the middle range of emission reduction targets, costs increase by 25 to 35%.

The investment expenditures for power and steam generation also rise (ranging from 10% in the middle range of emission reduction targets, up to 26% in highly constrained cases).

These results are reflected on electricity tariffs that increase from 30 to 100 % if including the effects of charges related to carbon emissions.

The total bill paid by the average EU household for all kinds of energy services increases in a range of 5% to 27% (respectively for a reduction close to Kyoto commitment and for a very high emission reduction target). This represents a range from 100 Eur to 500 Eur per household and per year.

8. Implications on non-CO2 Objectives of Energy Policy

The introduction of emission reduction targets leads to a significant decrease of energy needs. Import dependency remains rather stable, at the same level as in baseline (57%). It even slightly decreases, as emission constraints become higher (from 53.5% to 43%). In highly constrained cases, EU requirements for imported fossil fuels considerably drop: 50% for natural gas, 40% for crude oil, 85% for solid fuels. Given indigenous fossil-fuel production possibilities of the EU, potentially the European Union would become an exporter. Hence, there are no adverse effects on energy independence from CO2 emission reduction.

The imposition of emission reduction targets would also affect the on going process aiming at market liberalisation of electricity. The cases of small to medium emission reduction targets would have adverse effects on market liberalisation in the sense that independent producers will see their position threatened in competitiveness terms. This is a result of the reduced volume of electricity and steam generation reducing the scope of small generators in obtaining gains from economies of scale. Also in this range of emission targets there is larger opportunity for large-scale GTCC plants for which large utilities have higher possibilities for economies of scale. At highly emission constrained cases, there is greater opportunity for renewables, cogeneration and fuel cells. These technologies enable higher decentralisation of the generation system allowing smaller-scale generators to survive and even increase their market share. In fact, the results show that at such high emission reduction targets, small producers may gain a market share as high as 21.5% whereas in the middle range of emission targets they lose market share compared to baseline.

The decrease of demand for energy, the fuel mix shifts towards gas and the changes in power and steam generation in favour of non-fossil fuels, contribute to considerable reductions of the emission of acid rain pollutants, such as SO2 and NOx. In the power sector only, SO2 emissions drop range from 17% up to 70% and those of NOx range from 13% to 55%. An emission reduction close to Kyoto commitment would induce a decrease of emissions from power generation by 37% for SO2 and 26% for NOx.

9. Appendix-A: Equivalency between Global Emission Constraints and the Carbon-value.

The PRIMES energy system model formulates energy market equilibrium according to the mixed-complementarity methodology, which roughly corresponds to the Kuhn-Tucker conditions of a mathematical programming problem.

To illustrate the general structure of how PRIMES formulates energy market equilibrium, consider a system involving a single supplier of an energy form, a single consumer of that energy form and a primary energy form used by the supplier. The supplier determines the optimal supplied quantities S by maximising his profits, calculated as a difference between revenues from selling to the consumer and his production costs, which involve fuel (cost of purchasing the primary energy form), variable and capital costs. The consumer determines the optimal demanded quantities D by minimising his cost that involve cost of purchasing from the supplier, variable and capital costs. Supply and demand balancing at the market level determines the price of the energy form used by the consumer. A cost-supply function determines the cost of the primary energy form.

In mathematical terms, the text of this simple model consists of 5 simultaneous generalised equations and is as follows:

***(1)	Cost-supply curve of a primary energy form:***

$$p_F = f(S,\ldots)$$

***(2)	Behaviour of the Supplier:***

$$\left|\begin{array}{ll} Max & \pi = p \cdot S - \left[\left((p_F + e_S \cdot \lambda)\, {}^{1}\!/_{n_S} + v_S \right) \cdot S + c_S \cdot K_S \right] \\ s.t. & S \le K_S \\ & S \in \Phi_S \\ & \end{array}\right.$$

(3) Behaviour of the Demander:

$$\left|\begin{array}{ll} Min & z=\left(\left(p+e_D\cdot\lambda\right)\frac{1}{n_D}+v_D\right)\cdot D+c_D\cdot K_D \\ s.t. & D\le K_D \\ & D\in\Phi_D \end{array}\right.$$

(4) Market Equilibrium:

$$S=D$$

(5) Global emission constraint:

$$e_S\cdot S+e_D\cdot D\le E$$

The unknown variables are demand (D), supply (S), prices (p and p_F), capital (K_S and K_D) and the shadow variable λ (carbon-value) associated to the global emission constraint (5). The set of given exogenous parameters include efficiency rates (n_S and n_D), unit cost coefficients (v_S, v_D for variable cost and c_S, c_D for capital cost) and emission factors (e_S, e_D) related to the use of fuels in supply and demand, respectively. The mappings Φ_S, Φ_D define the sets of feasible solutions in supply and demand, and the function $f(\ldots)$ determines the unit cost of the primary energy resource as a function of the quantities used by the supplier.

The system (1) to (5) is expressed in complementarity-problem terms. Notice that the shadow value λ associated with the global constraint (5), appropriately affects the cost of using fuels that are involved in the emission constraint: see the objective functions of equations (2) and (3). The emission constraint becomes binding when the exogenous allowed level E is higher than the emissions that would have been obtained if the shadow value λ was set equal to zero. That would correspond to the emissions of the baseline scenario.

In an emission constrained case, E should be set at a level below that of the baseline, to make the constraint binding. This would induce a non-zero value for the shadow variable λ implying changes in the behaviour of the supplier and demander, equations (2) and (3), further leading to an emissions equal to E. The same result can be obtained by varying λ in an exogenous manner up to a level that also leads to emissions equal to E.

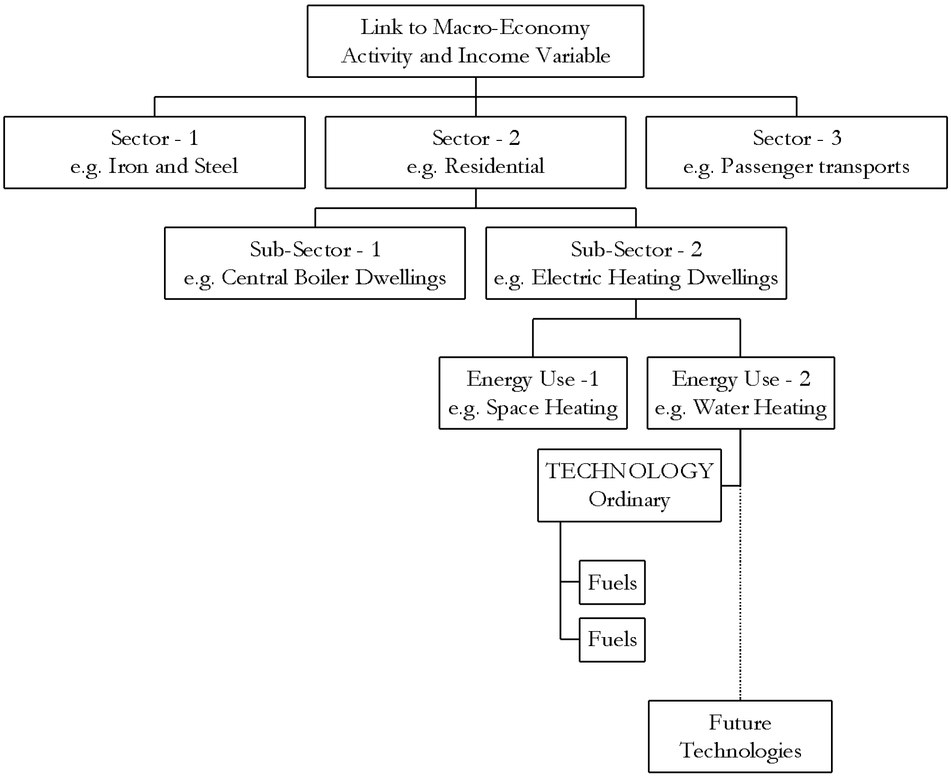
Therefore, there is a strict duality between the carbon-value λ and the exogenous emission constraint E.

10. Appendix-B: The Data Structure of the Demand-side of PRIMES V.2

10.1 General Structure of the Demand-Side Sub-Models

The demand-side sub-models of PRIMES V.2 have a uniform structure. Each sub-model represents a sector that is further decomposed into sub-sectors and then into energy uses. A technology operates at the level of an energy use and utilises energy forms (fuels). The following graphic illustrates the hierarchical decomposition of the demand-side models.

Decomposition Structure of the Demand-side Models



The data that are necessary to calibrate the model for a base year (1995) and a country (all EU member-states) can be divided in the following categories:

1. Macro-economic data that correspond to demographics national accounts, sectoral activity and income variables. These data usually apply to sectors.

2. Structure of energy consumption along the above-described tree in the base year and structure of activity variables (production, dwellings, passenger-kilometres, etc.). Some indicators regarding specific energy consumption are also needed for calibration.

3. Technical-economic data for technologies and sub-sectors (e.g. capital cost, unit efficiency, variable cost, lifetime, etc.).

The basic source of data for energy consumption by sector and fuel is Eurostat (detailed energy balance sheets). By using additional information (surveys of cogeneration operation and capacities and surveys on boilers), we modify the balance sheets in order to represent explicitly the production of steam.

According to PRIMES definitions, steam includes industrial steam and distributed heat (at small or large scale). In the balance sheets, Eurostat reports on steam production in the transformation input/output only if the producers sells that steam. If the steam, irrespectively of the way it is produced (e.g. a boiler or a CHP plant), is used for self-consumption only, Eurostat accounts for only the fuels used to produce that steam and includes these fuels in final energy consumption. Our modification consists in introducing that steam (for self-consumption) in the final energy consumption tables of the balance sheets and inserting the fuels used to produce that steam in the table of transformation input and output. This is necessary for the model to calibrate to a base year that properly accounts for the existing cogeneration activities (even if they are used for self-generation of steam).

The fuel types are as follows:

1. Solid fuels except lignite and peat
2. Lignite and Peat
3. Residual Fuel Oil
4. Diesel Oil
5. Liquefied Petroleum Gas
6. Kerosene
7. Gasoline
8. Naphtha
9. Other oil products
10. Bio-fuels
11. Natural and derived gas
12. Thermal Solar (active)
13. Geothermal low enthalpy
14. Steam (industrial and distributed heat)
15. Electricity
16. Biomass and Waste
17. Hydrogen

Data on fuel purchase prices, with and without taxes, are needed for large customers and small customers.

10.2 Industrial Sector

The industrial sector consists of nine sectors. For each sector different sub-sectors are defined. At the level of each sub-sector a number of different energy uses are represented. A technology at the level of an energy use may consume different types of fuels (one of which is steam generated from the power and steam sub-model of PRIMES, so only steam distribution and use costs are accounted for in the demand-side, together with a price for steam).

The structure for the industrial sector is given below:

SECTORS	SUB-SECTORS	ENERGY USES
Iron and Steel		
	Iron and Steel integrated	
		Air compressors
		Low enthalpy heat
		Lighting
		Motor drives
		Rolled steel
		Sinter making
		Steam and high enthalpy heat
		Blast furnace
		Process furnaces
	Electric arc	
		Air compressors
		Low enthalpy heat
		Lighting
		Motor drives
		Electric arc
		Electric process
		Rolled steel
		Foundries
		Sinter making
		Steam and high enthalpy heat
		Process furnaces
Non ferrous metals production		
	Primary aluminium production	
		Air compressors
		Lighting
		Motor drives
		Electric furnace
		Electrolysis
		Process furnaces
	Secondary aluminium production	
		Air compressors
		Lighting
		Motor drives
		Electric furnace
		Electrolysis
		Process furnaces
	Copper production	
		Air compressors
		Lighting
		Motor drives
		Electric furnace
		Electric kilns
		Low enthalpy heat
		Steam and high enthalpy heat
		Process furnaces
	Zinc production	
		Air compressors
		Lighting

		Motor drives
		Electric furnace
		Electrolysis
		Process furnaces
	Lead production	
		Air compressors
		Lighting
		Motor drives
		Electric furnace
		Process furnaces
	Other non ferrous metals production	
		Air compressors
		Lighting
		Motor drives
		Electric furnace
		Low enthalpy heat
		Foundries
		Process furnaces
Chemicals production		
	Fertilizers	
		Air compressors
		Low enthalpy heat
		Lighting
		Motor drives
		Electric processes
		Steam and high enthalpy heat
		Thermal processes
	Petrochemical	
		Air compressors
		Low enthalpy heat
		Lighting
		Motor drives
		Electric processes
		Steam and high enthalpy heat
		Thermal processes
		Energy use as raw material
	Inorganic chemicals	
		Air compressors
		Low enthalpy heat
		Lighting
		Motor drives
		Electric processes
		Steam and high enthalpy heat
		Thermal processes
	Low enthalpy chemicals	
		Air compressors
		Low enthalpy heat
		Lighting
		Motor drives
		Electric processes
		Steam and high enthalpy heat
		Thermal processes

Building materials production		
	Cement dry	
		Air compressors
		Lighting
		Motor drives
		Low enthalpy heat
		Cement kilns
		Drying and separation
	Ceramics and bricks	
		Air compressors
		Lighting
		Motor drives
		Electric kilns
		Low enthalpy heat
		Tunnel kilns
		Drying and separation
	Glass basic production	
		Air compressors
		Lighting
		Motor drives
		Glass annealing electric
		Glass tanks electric
		Low enthalpy heat
		Glass annealing thermal
		Glass tanks thermal
	Glass recycled production	
		Air compressors
		Lighting
		Motor drives
		Glass annealing electric
		Glass tanks electric
		Low enthalpy heat
		Glass annealing thermal
		Glass tanks thermal
	Other building materials production	
		Air compressors
		Lighting
		Motor drives
		Low enthalpy heat
		Material kilns
		Drying and separation
Paper and pulp production		
	Chemical paper	
		Lighting
		Motor drives
		Pulping electric
		Refining electric
		Steam and high enthalpy heat
		Low enthalpy heat
		Pulping steam
		Drying and separation
		Refining steam

	Mechanical pulp and paper	
		Lighting
		Motor drives
		Pulping electric
		Refining electric
		Steam and high enthalpy heat
		Low enthalpy heat
		Pulping steam
		Drying and separation
		Refining steam
Food, Drink and Tobacco production		
	Food, Drink and Tobacco goods	
		Air compressors
		Cooling and refrigeration
		Lighting
		Motor drives
		Drying and separation electric
		Steam and high enthalpy heat
		Low enthalpy heat
		Space heating
		Drying and separation thermal
		Specific heat
		Direct heat
Engineering		
	Engineering goods	
		Air compressors
		Lighting
		Motor drives
		Drying and separation electric
		Machinery
		Coating electric
		Foundries electric
		Steam and high enthalpy heat
		Low enthalpy heat
		Space heating
		Drying and separation thermal
		Coating thermal
		Foundries thermal
		Direct heat
Textiles production		
	Textiles goods	
		Air compressors
		Cooling and refrigeration
		Lighting
		Motor drives
		Drying and separation electric
		Machinery
		Steam and high enthalpy heat
		Low enthalpy heat
		Space heating
		Drying and separation thermal
		Direct heat

Other industrial sectors		
	Other industrial sectors goods	
		Air compressors
		Lighting
		Motor drives
		Drying and separation electric
		Machinery
		Steam and high enthalpy heat
		Low enthalpy heat
		Space heating
		Drying and separation thermal
		Specific heat
		Direct heat

Macroeconomic Data (for each sector, not sub-sector):

Value added for the industrial sectors in Million ECU90

Production Data (for each sub-sector):

Index of industrial production – in physical units or an aggregator proxy

Energy Consumption structure:

Fuel consumption (steam is a fuel) per sector, sub-sector and energy use (in toe) for the base year (1995).

Specific energy consumption data:

Energy consumption per unit of physical production (preferably at the level of sub-sector). It may be computed if all above data are available.

Useful energy indicator (in toe) at the level of each energy use.

It requires assumption on average energy efficiency of the energy use in a sub-sector.

Technical economic data for ordinary technology for each energy use

Capital purchase cost (ECU'90/toe-year) for a unit capacity of an energy use.

Variable and fixed costs (ECU'90/toe) of an energy use

Efficiency rate per fuel type and energy use.

Capital utilisation factor (average yearly load factor in %) of an energy use.

Lifetime in years.

Statistical data for technology for each energy use:

Average age in years in the base year (1990).

Degree of overcapacity in the base year (%)

Technical-Economic data for sub-sectors.

Non energy related capital investment cost per unit of production

Non energy and non-capital related operating costs per unit of production

Price of production of each sub-sector.

10.3 Tertiary Sector

The tertiary sector comprises of 4 sectors. At the level of the sub-sectors, the model structure defines groups of energy uses, which are further subdivided in energy uses defined according to the pattern of technology. The structure is as follows:

SECTORS	SUB-SECTORS	ENERGY USES
Agriculture		
	Lighting	
		Lighting
	Space heating	
		Electric
		Gas connected
		Boiler
		District heating
		Solids
		Greenhouses
	Electrical uses	
		Electrical uses
	Pumping	
		Pumping
	Motor energy	
		Motor energy
Offices and Services		
	Lighting	
		Lighting
	Space heating	
		Electric
		Gas connected
		Boiler
		District heating
		Solids
		Greenhouses
	Air conditioning	
		Electric
		Gas connected
		District heating
	Electrical uses	
		Electrical uses
	Water heating	
		Water heating
Trade		
	Lighting	
		Lighting
	Space heating	
		Electric
		Gas connected
		Boiler
		District heating
		Solids
		Greenhouses

	Air conditioning	
		Electric
		Gas connected
		District heating
	Steam uses	
		Steam uses
	Electrical uses	
		Electrical uses
	Water heating	
		Water heating
Public services		
	Lighting	
		Lighting
	Space heating	
		Electric
		Gas connected
		Boiler
		District heating
		Solids
		Greenhouses
	Air conditioning	
		Electric
		Gas connected
		District heating
	Steam uses	
		Steam uses
	Electrical uses	
		Electrical uses
	Water heating	
		Water heating

Macroeconomic Data (for each sector, not sub-sector):

Value added for the tertiary sectors in Million ECU90

Employment per tertiary sector

Structural Data (for each sub-sector):

Index of surface per employee

Energy Consumption structure:

Fuel consumption (steam is a fuel) per sector, sub-sector and energy use (in toe) for the base year (1995).

Useful energy indicator (in toe) at the level of each energy use.

It requires assumption on average energy efficiency of the energy use in a sub-sector.

Average Thermal integrity of buildings in each tertiary sector

Technical economic data for ordinary technology for each energy use

Capital purchase cost (ECU’90/toe-year) for a unit capacity of an energy use.

Variable and fixed costs (ECU’90/toe) of an energy use

Efficiency rate per fuel type and energy use.

Capital utilisation factor (average yearly load factor in %) of an energy use.

Lifetime in years.

Statistical data for technology for each energy use:

Average age in years in the base year (1990).
Degree of overcapacity in the base year (%)
Technical-Economic data for sub-sectors.
Non energy related capital investment cost per unit of production of a tertiary sector
Non energy and non capital related operating costs per unit of production of a tertiary sector

10.4 Residential Sector

The residential sector distinguishes five categories of dwelling. These are defined according to the main technology used for space heating. They may use secondary heating as well. At the level of the sub-sectors, the model structure defines the categories of dwellings, which are further subdivided in energy uses. The electric appliances for non heating and cooling are considered as a special sub-sector, which is independent of the type of dwelling. The structure is as follows:

SECTORS	SUB-SECTORS	ENERGY USES
Dwellings		
	Central boiler households that may also use gas connected to the central boiler (flats)	
		Space heating
		Cooking
		Water heating
		Air conditioning
	Households with mainly electric heating equipment (non partially heated)	
		Space heating
		Cooking
		Water heating
		Air conditioning
	Households with direct gas equipment for heating (direct gas for flats and gas for individual houses)	
		Space heating
		Cooking
		Water heating
		Air conditioning
	Households connected to district heating	
		Space heating
		Cooking
		Water heating
		Air conditioning
	Partially heated dwellings and agricultural households	
		Space heating
		Cooking
		Water heating
		Air conditioning
Electric appliances		
		Washing machines
		Dish washers
		Dryers

		Lighting
		Refrigerators
		Television sets

Macroeconomic Data:
  - Population
  - Number of households

Structural Data (for each sub-sector):
  - Index of surface per dwelling category
  - Number of households per dwelling category
  - Number of electric appliances (per type) per household

Energy Consumption structure:
  - Fuel consumption (steam is a fuel) per sector, sub-sector and energy use (in toe) for the base year (1995).
  - Useful energy indicator (in toe) at the level of each energy use.
  - It requires assumption on average energy efficiency of the energy use in a sub-sector.
  - Average use per year of an electric appliance per household
  - Average Thermal integrity of buildings in each category of dwelling
  - Technical economic data for ordinary technology for each energy use
  - Capital purchase cost (ECU'90/toe-year) for a unit capacity of an energy use.
  - Variable and fixed costs (ECU'90/toe) of an energy use

Efficiency rate per fuel type and energy use.
  - Capital utilisation factor (average yearly load factor in %) of an energy use.
  - Lifetime in years.
  - Statistical data for technology for each energy use:
  - Average age in years in the base year (1990).

  - Degree of overcapacity in the base year (%)

10.5 Transport Sector

The transport sector distinguishes passenger transport and goods transport as separate sectors. They are further subdivided in sub-sectors according to the transport mean (road, air, etc.). At the level of the sub-sectors, the model structure defines several technology types (car technology types, for example), which correspond to the level of energy use. The structure is as follows:

SECTORS	SUB-SECTORS	ENERGY USES
Passenger transports		
	Busses	
		Internal combustion engine
		Electric motor
		Fuel cell
		Gas turbine
	Motorcycles	
		Internal combustion engine

		Electric motor
	Private cars	
		Internal combustion engine
		Electric motor
		Fuel cell
		Gas turbine
	Passenger trains	
		Internal combustion engine
		Electric motor
		Fuel cell
	Air transports	
		Gas turbine
	Navigation passengers	
		Internal combustion engine
Goods transports		
	Trucks	
		Internal combustion engine
		Electric motor
		Fuel cell
		Gas turbine
	Trains	
		Internal combustion engine
		Electric motor
		Fuel cell
	Navigation	
		Internal combustion engine

Macroeconomic Data:
  Gross Domestic Product in ECU’90 for the base year
  Volume of Imports and Exports
Structural Data (for each sub-sector):
  Passenger-kilometres and ton-kilometres per type of transport mean
Energy Consumption structure:
  Fuel consumption per transport mean and transport technology (in toe) for the base year (1995).
  Useful energy indicator (in toe) at the level of each transport technology.
  It requires assumption on average energy efficiency of the energy use in a sub-sector.
  Average use per year of a vehicle per type (kilometres per vehicle per year)
  Average number of passengers per vehicle type
  Technical economic data for ordinary technology for each energy use
  Capital purchase cost (ECU’90/toe-year) for a unit capacity of a transport technology.
  Variable and fixed costs (ECU’90/toe)
  Efficiency rate per fuel type and technology.
  Capital utilisation factor (average yearly load factor in %) of a technology.
  Lifetime in years.
Statistical data for technology for each energy use:
  Stock of vehicles per technology and transport mean
  Average age in years in the base year (1990).
  Degree of overcapacity in the base year (%)

11. Appendix-C: The Power and Steam Generation Sub-Model of PRIMES

11.1 Introduction

The aim of the electricity and steam sub-model of PRIMES is to simulate the behaviour of agents that use fuels and other energy forms to produce, transmit and distribute electricity, industrial steam and district heating. This behaviour concerns the choice of equipment and the fuel mix to satisfy demand, the setting of selling prices and the purchase of fuels from the energy markets.

The model design is adapted to the very nature of the energy forms produced in this sub-model, related to the impossibility to use storage, the high degree of capital intensive equipment and the importance of technology choice for energy strategy.

The emergence of heat and power cogeneration possibilities and the prospects for increasing decentralisation of production led to the adoption of a unified modelling for power and steam production. On the contrary, the previous version of PRIMES has considered a separation between centralised electricity and the independent production of steam and electricity, the latter being modelled within the demand sub-models of PRIMES. That design has put more emphasis on the self-supply character of cogeneration, since such a situation has prevailed in the market for a long period of time. The emergence of efficient smaller scale technologies and the opening of the markets to competition created new prospects for cogeneration and independent production. The modelling needs then to tightly integrate producers of different nature, regarding for example economies of scale and market opportunities, into a single framework that will mimic the operation of the market.

The new version of PRIMES puts emphasis on the different nature of producers that will operate in the market and the interaction between electricity and steam markets, as enabled by cogeneration. For example, it is necessary to distinguish producers according to their scale, but also according to the captive markets they might address. A utility can exploit high economies of scale, but can hardly benefit from the market of steam, as steam cannot be self-consumed. On the contrary, an industrial independent producer will operate at smaller plant size, loosing competitiveness as far as the economies of scale are concerned, but obtaining benefits from a high base load demand for steam that he can supply. A company operating at the level of local authorities, may obtain benefits from niche markets (renewables, district heating), but it will face a highly fluctuating demand for heat and electricity.

The representation of different technologies that are now available or will be available in the future is a major focus of the model, as it is intended to also serve for strategic analyses on technology assessment. To support such analyses, the model uses a large list of alternative technologies and differentiates their technical-economic characteristics according to the plant size, the fuel types, the cogeneration techniques, the country and the type of producer. A model extension is also designed aiming at representing a non-linear cycle of the penetration of new technologies, for which learning through experience (and other industrial economic features) relates penetration with the technology performance.

The differences between the producer types play an important role in their ability to obtain interesting natural gas supply contracts. This issue seems to become very important in the future, as natural gas is emerging as the key fuel because of technology progress and environmental constraints. Again, a unified modelling approach is necessary to analyse the differentiated effects of natural gas for producers that differ as described above.

Both the market allocation from the producer perspective and the effects of natural gas supply conditions need a consideration of the time pattern of demand, production and fuel supply. In addition, the corresponding loads have to be considered in chronological terms, as serious limitations would arise if using load duration monotone curves, because of the need to analyse the synchronisation of the time patterns of electricity consumption, steam consumption and fuel supply (such as natural gas).

The consideration of intermittent energy sources, such as the renewables, also requires a representation of chronological curves, as the random availability of the source over time can be approximated. Nevertheless, the correct modelling of intermittent production also requires a representation of geographical characteristics of production and transmission and a modelling of congestion over the electricity networks. Obviously, such features are necessary to adequately represent the market for steam and heat.

Such features have not been yet introduced in PRIMES, as the model mainly aims to serve for integrated strategic analyses. The algebraic coding of the electricity and steam sub-model of PRIMES is enough generic and abstract, to provide a consistent framework for model expansion in the future, along the geographical or network congestion research lines.

The development of independent power and/or steam producers and their market forces heavily depend on the prevailing institutional regime in the market. In the past, market regulation, cross-subsidisation and the importance of returns to scale in power production has deprived small independent producers to enter the market. Exceptions have arisen in specific cases in which the scale of self-consumption or the existence of by-product fuels has permitted the survival of independent producers. The expectations for the future are different. New technologies allow for competitive production at a smaller scale, while the institutional regime in the market is increasingly opening to competition.

To represent these market dynamics, the model design preferred the representation of representative companies operating under a market competitive regime. For example, the exchanges of electricity and steam between the companies are performed under marginal cost pricing in the model. This choice has a limitation, as it cannot represent transitory phenomena of oligopolistic nature that might prevail in the market. However, a full competitive regime has been preferred as PRIMES puts emphasis on strategic analysis. Constraints regarding for example the degree of opening of the market can be introduced in the model through parameters regulating market allocation to producers.

In addition, constraints that would increase the inertia of the market are introduced in the form of contracts. These apply to both the exchanges between the companies and the provisions of fuels.

11.2 Model Overview

11.2.1 Background of Model Design

11.2.1.1 Literature on Power Modelling

There exists an important literature on electrical power economics and modelling. The different approaches have used a big variety of advanced mathematical techniques, including optimisation, probabilistic simulation and dynamic systems. Because of the complexity of electricity systems, the mathematical models have been specialised by focusing on some of the features of the system. With reference to their scope, the models can be classified in the following categories:

- Models emphasising on the operation and dispatching of the electricity system; load flow and probabilistic techniques are commonly used.
- Models emphasising on reliability issues especially regarding the transmission network; stability analysis techniques are often used.
- Models emphasising on capacity expansion and plant selection; they usually follow dynamic programming and mixed-integer optimisation, as they represent discrete candidate plants.
- Models emphasising on the strategic economic issues and the interactions between the electricity system and the rest of energy systems and markets; a variety of economic modelling techniques are used.

PRIMES' focus is mainly along the lines of this last category. However, given the importance of the sector, the model design gave importance to a minimum standard representation of the engineering aspects of the electricity system. In this sense it borrows elements from the engineering-oriented power economics modelling. In addition, it was aimed to design a model framework that would be easily expandable to construct sufficiently detailed model version that would be used specifically for the analysis of the electricity sector.

11.2.1.2 Decisions Represented in the Model

Decision-making by electric utilities (or steam producers) may be considered in three different, yet interrelated, problems:

i. **The strategic capacity expansion problem** which concerns the choice of new plants for construction, so as to meet future demand at a least long-run generation cost;
ii. **The operational plant selection and utilisation problem** which concerns the choice of existing plants to be committed in the system, so as to meet load at a least operation cost;
iii. **The cost evaluation and pricing policy** that has to be in conformity both with the long-term financial objectives of the company and with the aim to influence demand load.

In the electricity and steam sub-model of PRIMES, the representation of the above decision problems is in accordance with the optimal pattern of supply behaviour in a competitive equilibrium market. In particular, we formulate long run marginal cost principles for capacity expansion and short run marginal costing for dispatching and plant commitment. However, for price setting we formulate Ramsey pricing, which is close to average cost pricing, and we interpret this choice as representative of both the regulated monopoly and the monopolistic competition market regimes.

11.2.1.3 Engineering Features

The model puts emphasis on the following features that are dominant in electricity economics and engineering:

a. Demand fluctuates over time in a year.
b. The optimality depends on exchanges between producing companies, via interconnections.

A fundamental characteristic of electric or steam producers is that they cannot inventory their product in order to meet fluctuations in demand. Thus, an important feature to be captured in modelling is the implications of changing time-related patterns of demand on plant capacity selection and utilisation.

At the level of the electricity and steam sub-model, demand for electricity and steam is considered as exogenously given, varying widely between different times of the day and between different seasons. The representation of demand is based on the definition of a chronological load curve, which depicts the load (e.g. in GW) as a function of time in a year. Within an iteration of the overall PRIMES model, the demand sub-models provide estimates of demand (as a function of time in a year). They use the same representation of time as the electricity and steam sub-model. Changes in the demand-side, for example, induced by prices or other factors, influence the electricity and steam sub-model. The latter may, for example, change prices that may further affect demand.

The closed-loop interaction performing at the level of the overall PRIMES model represents the link between demand and supply of electricity and stream in an endogenous manner. This link is fully defined over time of a year, since all the sub-models are synchronised at the same representation of time. This synchronisation concerns not only electricity and steam, but also fuels that are inputs to power and steam production, such as natural gas for which the time pattern is important for their pricing. Of course, the synchronisation concerns both prices and quantities. As we will explain below, the synchronisation over time in a year includes also the supply of intermittent power sources, such as the renewables.

Other models adopt a representation through a load duration curve, which is simply a reordering of the loads in a monotone non-increasing way. The synchronisation feature as operates in the PRIMES model does not comply with a load duration curve.

The second important feature is associated to transmission and distribution of electricity and steam, which operate over networks (cables and pipelines). As explained in a previous section, PRIMES adopts a network representation but dissociates this from any geographical characterisation. In fact, nodes and arcs in PRIMES are virtual, without involving any physical characteristic other than losses and capacities. The adoption of a network representation endows the model with abstraction sufficient to expand the model so as to represent geographical or production characteristics in a more realistic way.

The interconnections between electricity companies are important, as electricity cannot be stored. Traditionally, interconnections between countries served to reduce the costs of system reliability for each country. They have also served to the establishment of contracts, concerning exchanges between countries that have reflected differences in the economics or capacities. The contracts have been always defined over time (time pattern), besides their contacted quantity. To this respect, the synchronisation feature of the model is useful to also represent contracts, which in fact are formulated as obligations for load exchanges.

As the electricity market is being increasingly liberalised in Europe, the interconnections also serve to support market operations, covering commercial transactions between a country, but also among companies within a country. In other terms, the development of the network physically defines upper bounds to the possibilities for market-related transactions of electricity. At a more technical level, congestion over the network also limits market development. Market competition regimes, such as the single buyer or third party access, following the jargon adopted in the EU, can be also represented through different topologies of the connections in a network. For example, a consumer may be allowed to connect to a utility in another country, to reflect a situation in a third party access regime.

In brief, the representation of the network in PRIMES is an abstraction that serves to support the representation of engineering information about transmissions, but also serves to formulate the possibilities for commercial transactions. The algebraic coding of the model, regarding the network, is general enough to allow for an expansion of the model either towards engineering representation of the network and/or a generalise formulation of commercial agreements.

11.2.1.4 The Temporal Framework

The model horizon is composed of a set of periods of equal length. The length of the periods may be one or several years. Activity variables related to generation, trade and sales are generally treated as time series, except some of the parameters that are assumed invariant with time.

During a year, the conditions under which the electricity or steam system works may vary from day to day. The model therefore considers a set of typical days in a year. Each typical day is characterised by a different set of operating conditions for the system.

Also, the operating conditions under may exhibit significant variations during a single day. This is taken into account by decomposing the day in a set of time segments, each time segment leading to different operating conditions.

Regarding the dynamics of the decision making, the model is flexible. Two anticipation regimes, activated through an optional switch, are formulated in the model:

- The myopic time-forward anticipation, in which the decision-maker has information only about the past and the present time-period, while the model is solved dynamically along time-steps in a time-forward manner.
- The perfect foresight over finite horizon, in which the decision-maker has full and correct information about the future, over a finite horizon, and the model runs simultaneously (intertemporally) the set of time periods from present up to the horizon.

The building of equipment in the electricity and steam system requires several years. This has important implications for planning and plant type choice. The model considers the financial costs associated to the construction period but ignores the fact that the plant types differ in construction time, which may influence plant selection in particularly uncertain circumstances. Furthermore, under the myopic anticipation regime, the model considers that the plants can be constructed and immediately used within the 5-years runtime period of the model. In this sense, the model operates as if the current 5-years period is perfectly known by the decision-maker.

11.2.1.5 The Spatial Framework

The model considers the electricity system of the member states of the European Union. To represent the interconnections between countries, the model considers links to Switzerland and the rest-of-the-world. However, their electricity systems are not represented. Regarding steam, the model considers that connections exist only within each country, separately.

11.2.1.6 The Mathematical Form of the Model

The model is designed to follow the general problem of optimisation of flows over a network.

Assume that the network of interconnections can be described as a set of nodes $n \in \{1,...,N\}$ and a set of oriented arcs $tr = (n,m) \in \{N \times N\}$ defined on the Cartesian product of the set of nodes. The exact definition of the set of arcs determines the topology of the network that of course influences the solution. The flows (by fraction of time) over the arcs are unknown and denoted by x_{tr} while the capacities of some of the arcs are also unknown, denoted by K_{tr}. Then the problem consists of determining the values of the unknown variables so as to optimise the total cost of the network flows under feasibility of the network flows:

$$\begin{array}{lll}
Min & \sum\limits_{tr} c_{tr} \cdot x_{tr} + \sum\limits_{tr} k_{tr} \cdot K_{tr} & \\
s.t. & \sum\limits_{tr\ inputs\ to\ n} x_{tr} = Eff_{tr} \cdot \sum\limits_{tr\, outputs\ from\ n} x_{tr} & \forall n \\
 & x_{tr} \leq K_{tr} & \forall tr \\
 & \sum\limits_{some\, of\ tr} x_{tr} \geq \text{Demand} & \\
 & \sum\limits_{some\, of\ tr} x_{tr} \leq \text{Resources} & \\
 & \text{L} \leq \sum\limits_{some\, of\ tr} x_{tr} \leq U &
\end{array}$$

The first constraint is the equilibrium on the nodes of the network and may involve an efficiency rate. The second constraint limits the flows by capacity, some of which may be expandable. The third constraint expresses the obligation to satisfy demand, while the fourth constraint may limit some of the flows to the available resources. Finally other constraints may restrict aggregations of the flows, as for example environmental regulation, cogeneration technical constraints, reserve margins, and so on. The objective function involves cost parameters.

If all parameters are linear and the unknown variables continuous, the problem corresponds to linear programming. This is the standard version of the model. By applying Kuhn-Tucker conditions, the problem can be transformed into a complementarity formulation, involving a system of equalities and inequalities to solve for the original unknown variables and the dual variables of the constraints.

In particular, in PRIMES, the network is separately defined for electricity and steam. The flows over the two independent networks are interrelated only at the level of the constraints that concern cogeneration of heat and power. Also, the unknown variables are defined as functions of time segments through which load and plant commitment is handled.

11.2.2 Model Design Principles

The electricity and steam sub-model of PRIMES is designed to be very general so as to provide a framework for studies specifically for the sector and not only for being a component of the overall model PRIMES. When building a model implementation, the user defines the content of the sets and gives numerical values to the exogenous parameters, at a level of detail that depends on the content of the sets. This definition can vary widely, so as to give rise to different types of electricity and team models. A variety of market situations can be represented. When building the model implementation that is used as a component of PRIMES, the user has to consider time needed for running the electricity sub-model and the size. Usually, the component has to be more aggregated and simpler than other model implementations intended to support specific sectoral studies.

In the following, we present first the general model design principles, putting emphasis on the variety of possibilities of the model. Then, we present the current model implementation constructed to be a component of the overall PRIMES model.

The physical elements of the electricity and steam system that we consider are the production plants and the transmission and distribution networks.

11.2.2.1 The Production Technologies

Combustion of fossil fuels, or by transforming mechanical, chemical or nuclear energy, can perform production of electricity and/or steam. Regarding the output energy form, the plants are subdivided in three categories:

- Plants that produce only electricity
- Plants that can cogenerate electricity and steam
- Plants that can produce only steam (boilers).

For the combustion plants the distinction between electricity plants and cogeneration ones is necessary for the economic analysis of generation, as in engineering terms the distinction is not always clear. Combustion plants are also called thermal, a term that often includes nuclear plants and fuel cells, although the latter use a chemical process. Non thermal plants produce only electricity and are, in the model, subdivided in two categories, according to the possibility of dispatching:

- Hydroelectric lakes, also termed reservoir plants; they are constrained by energy rather than power, as depending on the inflow of water in the reservoir.
- Plants that depend on the availability of a randomly intermittent energy resource like wind, sun or maritime waves. Electricity produced by such plants is not dispatchable.

The model considers pumping as an exogenous shift made on the total demand load, implying of course higher production from base load plants and higher availability of hydro-power in peak hours.

11.2.2.2 Deterministic and Continuous Variables

The model generally follows a deterministic approach in the representation of the technical characteristics of the plants. More detailed engineering models of power systems treat some technical parameters of the plants as random variables. Usually, this is the case of the technical availability of thermal plants (for commitment), the availability of the energy resource in intermittent plants and the water inflow to lakes. These models consider probability distributions associated with these random variables and apply convolution techniques to aggregate the distributions and estimate system reliability and economic optimality.

In such models, the probabilistic approach combines with a discrete treatment of the power plants, and some times even the blocks of each plant. This is necessary because of the discrepancy of the technical parameters of each plant, fuel type or location. Also, the discrete approach reflects the non-linearity of the costs associated with the start-up, the operation and even the construction costs of the plants.

For PRIMES we consider that both the probabilistic modelling and the discrete treatment of plants are out of the scope of the model, mainly because of the great complexity that it would imply. If we included such features, the mathematical problem of PRIMES would be that of dynamic, non-linear, stochastic and mixed-integer programming, a problem that is extremely difficult to solve, especially when the capacity expansion problem is the main focus.

Therefore, PRIMES adopts deterministic approximations of the above random variables and considers the plant activity or capacity variables as continuous and not discrete. Also the model ignores non-linearity associated to start-up, block operation or location-specific costs of the plants.

However, PRIMES does consider that cost and performance of the plants can vary with the size of the plant. This relationship is artificially introduced in the model through the representation of a number of discrete sizes that are related to the cost and performance parameters, although the plant capacity variables are continuous. Of course, without introducing integer variables, it is also impossible to control that, for example, a minimum capacity is required to accumulate before producing from a plant-type, or that a plant with high start-up flexibility may be more preferable for peak load than a less flexible plant. The model, in fact, ignores such kinds of issues that normally heavily influence plant selection, in reality.

Regarding plant commitment availability, the model considers a single deterministic parameter, which expresses the percentage of time in a year in which the plant is available. There is no time pattern associated to maintenance schedules, nor to statistics of plant failure. However, if kept in deterministic terms, such technical information can be easily introduced in the model. Also, the annual availability rate is constant and does not depend on the rate of use of the plant, since such a dependency would introduce a non-linear relationship.

Similarly the parameters on the operation costs do not depend on the shape of plant use in a typical data, as this would also require non-linearity. Such non-linear relationships, are however introduced in the mixed-complementarity formulation of the model, as it is will be explained below.

The random system reliability issue (often termed loss of load probability) is not represented, as mentioned above. Instead, a single reserve margin ratio is used as a constraint implying the building of capacity higher than peak load. As the plant selection depends on the ratio between capital and variable costs, it is expected that only peak devices will be adopted to fulfil the reserve margin requirement. This approach, of course, cannot address situations of over-capacity with base-load or renewable plants. The reserve margin ratio is exogenous and differs by country, to reflect the prevailing practice in terms of system reliability. The back-up issue, which is relevant for companies, even small producers, is also approximated through the reserve margin ratio, which then applies to a company.

The random availability of intermittent energy resources is approximated by means of an exogenous time-pattern of resource availability. Of course, this approach neglects situations in which additional back-up capacity is required to cope with probabilistic situations in which non-availability events occur jointly. Finally, the random availability of water in reservoir plants is also approximated through a deterministic annual inflow parameter.

11.2.2.3 Producers, Companies and Market Relationships

Self-production of electricity or steam technically differs from the production of utilities because a self-producers traditionally does not consider trading of production surplus. Along the rapid development of trade in the electricity market, the self-production changes in character, as trading through interconnections alters the economics of the plants. The term “independent producers”, which is now widely used to characterise self-production among other cases, does not make reference to the purpose of production, but to the scale of the company, in comparison to large utility companies. Because of this market evolution, PRIMES considers independent production only.

The economics of independent production usually are justified in situation when one or more of the following conditions hold:

- The producer is also a consumer of his output, the consumption costs less in terms of transmission and distribution, and there is sufficient development of a market for trading excess supply.
- The producer has access to a free or cheap energy source (waste, by-products, and specific locations for renewables).
- The liberalisation of the market and privatisation of utilities leads to smaller scale companies that are necessary to cope with the eventual diseconomies of scale of large utilities.

The design of the model is oriented to cover the first two situations. Differences in return to scale, related to the average size of plants that a producer is allowed to handle, are compared against eventual gains in transmission and distribution, while market allocation constraints may limit or favour the development of independent production. Similarly, among the variety of fuels considered, the model explicitly represents cheap or free resources to which some of the producers can only access. In this sense, the companies (producers), represented in the model differ in purpose: a utility makes business by selling electricity or steam, an industrial company is mainly addressing his own demand but can profit from market development, etc.

However, the model is not designed to represent adequately the development of multiple utilities in the same country or the case of independent producers, which transform from self-producers to small utilities. In compliance with the long-run orientation of the model, the design considers that these cases will be transitory, and that the in the long term competition can be adequately approximated by means of the "representative firm" assumption. The different representative firms (producers) reflect then differences in purpose, in size or market opportunities.

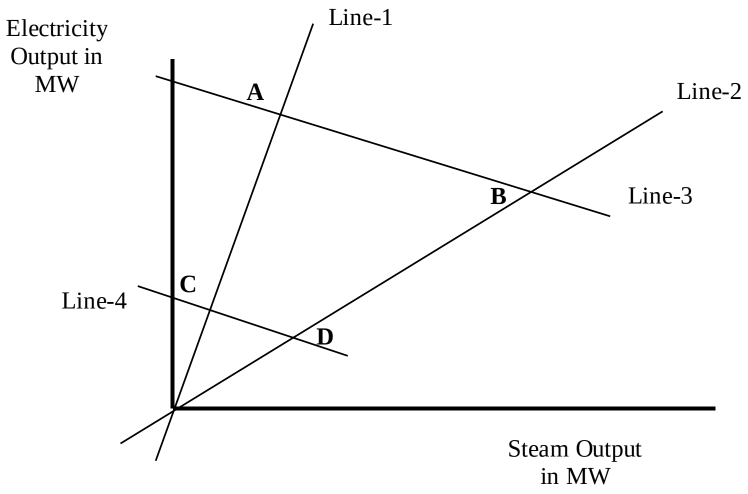
11.2.2.4 Cogeneration Technologies

The cogeneration technologies constitute a valid substitute of the traditional heat producing technologies, as for example the boilers. Their importance and their rapid emergence in the market justify their inclusion in the set of power technologies.

Cogeneration can be obtained through changes in the circuit of steam in thermal power plants. If it is intended to obtain big quantity of steam, then the change of the circuit is important, consisting in conducting steam to demand, instead of recycling through the cooling system of the plant. This kind of technology, usually termed "back pressure" technique, has significant negative implications for the electric efficiency rates of the plant and can achieve high steam to electricity ratios. If the quantity of steam, required to conduct to demand, is rather small, then steam can be just extracted at some point of the steam circuit. In this case, called "steam extraction", the steam to electricity ratio is mall, but also the implications on the electric efficiency ratios are also small. Finally, gas turbines, internal combustion engines and fuel cells can also obtain cogeneration.

All the above mentioned techniques of cogeneration are represented in PRIMES. To unify the modelling of cogeneration and simplify, the model considers that the feasible combination of electricity and heat output from a thermal plant are constrained within a surface delimited by four lines, as in the scheme.

Figure 8: Feasible Domain of Cogeneration per unit of nominal Electric Power



The feasible domain of cogeneration is the area ABCD. Line 1 denotes the maximum electric power and minimum steam combinations. Line 2 denotes the minimum electric power and maximum steam combinations. Line 3 is an iso-fuel line (equal electric efficiency of the plant), per unit of maximum use of nominal electric power. Finally, line 4 is also an iso-fuel line, defined for the minimum electric output necessary to obtain a steam output. Of course, depending on the cogeneration techniques, the slope and the exact position of these lines can change, but the basic shape of the feasible domain for electric and steam output combinations remain the same. The above lines are introduced in the model as linear constraints, specifically calibrated for each cogeneration technique and type of plant. Line 4 (the minimum power) is incompatible with the continuous character of the activity variables, as assumed in the model. Therefore, this constraint is ignored.

11.2.2.5 Technical-Economic Characterisation of Plants

Power technologies are characterised by the type of fuel they can use, their efficiency in generating heat and/or power, their cogeneration technique (if applicable), their availability, their investment costs and their operating costs. In the linear optimisation version of the model, the corresponding parameters are constant. In the mixed complementarity version of the model, some of the parameters can be expressed as functions of endogenous variables, which obviously makes the model non-linear. The non-linearity functions are as follows:

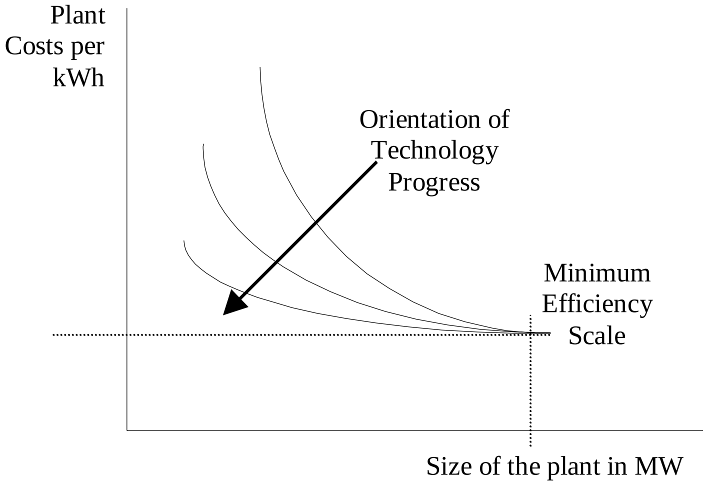
- The availability rate is a decreasing function of the rate of use (output) of the plant in a year.
- The operation cost is a function of the dispersion of plant use across the time segments (to reflect start-up costs).
- The capital cost is a function of the accumulated stock of the technology (learning by experience or economies of scale in the producers of equipment). Similarly, the thermal efficiency rate is a function of the accumulated stock.

The model put emphasis on the representation of plant efficiency and performance as a function of plant size. Given the limitation from the assumption about continuity of the plant-related variables, the plant size is associated to the nature of the power and steam production companies. It is assumed, for example, that utilities can invest in large size plants and benefit from economies of scale, while industrial power and steam producers can invest only in small size plants.

The relationship of plant performance as a function of plant size is considered as varying with the type of technology and time. Through this assumption, the model attempts to capture a technology progress that would bridge the gap between the plant sizes, in terms of performances and costs. Such an example has been recently observed with the developments in gas turbine technologies and the combined cycle plants.

The following scheme illustrates how a certain type of technology progress reduces differences of plant performance across plant sizes.

Figure 9: Relationship between pant performance and size



11.2.2.6 Old and New Power and Heat Generation Plants

These are plants that use the aforementioned technologies to generate power and/or heat. We distinguish the old plants existing in the base year and the potential plants, i.e., those that might be built through investment.

The model does not consider investment in old plants but treats endogenous retrofitting of these plants. The extension of their lifetime may be judged as economical when scrapping is to be undertaken. Retrofitting involves capital costs and fixed costs that rapidly increase over time.

The technical-economic characteristics of the new power and steam plants are fixed over time. Future generations of plant technologies are represented as different technologies. Once a new plant is built remains as candidate for commitment in operation over its lifetime. New reservoir plants are not considered in the model, however all intermittent plants are fully endogenous.

11.2.2.7 The Grids and Pipelines

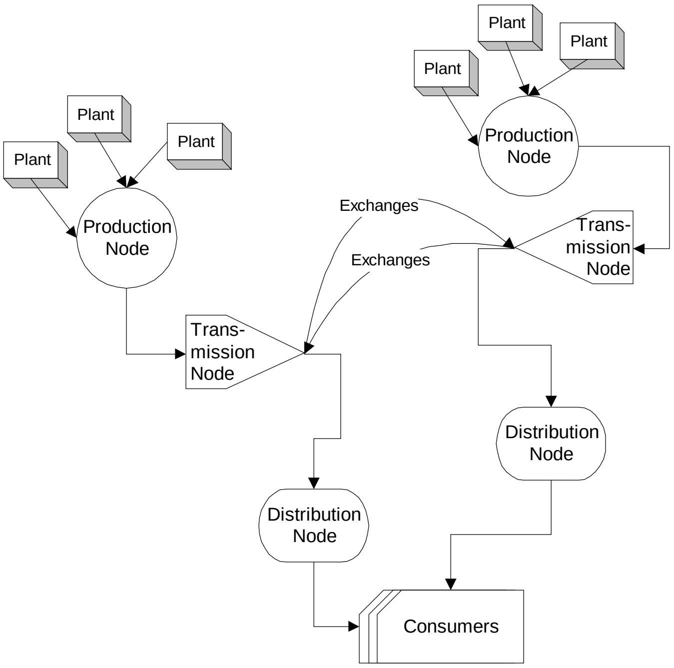
A transmission grid is a set of electric equipment that allows transporting electricity at high voltage. A distribution grid is a set of low voltage lines that connect the individual customers to the transmission grid. A distribution grid has a single owner. Steam pipelines and district heating distribution networks serve to connect producers and consumers for distances that are normally short. There is no interconnected network for steam.

The model neglects geographical characteristics of both electricity and steam networks. It considers a typical and simple network that has different topology for electricity and steam. The two networks are related only at a node representing cogeneration plants. The grids are characterised by two technical parameters: the connection capacity and the rate of losses (efficiency). The connection capacity is limited only is the case of transmission links, letting distribution links to have unlimited capacities.

The network comprises five types of nodes: plants, production nodes, transmission nodes, distribution nodes and consumers. The arcs link plants to production nodes, production nodes to distribution nodes, distribution nodes to consumers and transmission nodes to other transmission nodes, so as to allow trading between companies.

The following scheme illustrates the definition of the network.

Figure 10: A typical power or steam network as represented in PRIMES



11.2.2.8 The Polluting Emissions and Abatement

The model considers a set of polluting emissions. This set includes atmospheric emissions only. The pollutants are generated from combustion of fossil fuels and their emission is generally proportional to the quantity of fuel used. The emission factors are exogenous.

Installing emission abatement technologies may reduce the emission of the pollutants. The model assumes the simplification that these technologies operate for a single fuel type and can reduce only one pollutant. Hence one needs to set up separate abatement data for each fuel, plant and pollutant.

Because of the complexity of abatement technologies and their applicability to the various types of plants, the model adopts an implicit technology approach. It considers that the abatement is a service provided by an external supplier to the plant, which just pays a fee proportional to the achieved abatement. Given that the abatement technology exhibits decreasing returns to scale, the model represents the abatement service as a stepwise function in which abatement costs per unit increase non-linearly with the abatement level (in % of the corresponding fuel use).

11.2.3 The Actors in the Electricity and Steam Market

We shall consider three types of agents on the electricity market: the regulated companies, the independent generators and the consumers.

11.2.3.1 The Consumers

The consumers consume electricity and steam: government, private firms and households are consumers. They are aggregated in consumption sectors and are linked to the rest of the PRIMES model.

In all the models considered, the consumption sectors are price takers that maximise their utility. Their behaviour is represented by their electricity and steam demand curve, which is fixed for a given iteration of the overall PRIMES model. The electricity and steam sub-model sets the consumer electricity price which also include distribution costs, excises and taxes (including the VAT when it is not deductible).

11.2.3.2 The Regulated Companies

The model considers several companies that are acting as suppliers of electricity and steam in the market. These companies are defined along the principle that their main aim is to sell electricity and steam to consumers, without having any self-demand (other than losses) to satisfy. Each company may own power plants, transmission and distribution grids. A company may have an exclusive right to serve some demand sectors. Because of their market power, these companies are subject to regulation.

Companies seek to achieve maximal profit under regulatory control. It is assumed that they follow the Ramsey-Boiteux regulated monopoly scheme. Given that they have to satisfy demand, this scheme implies that the regulated companies seek to minimise their long-term cost and tariff their output at average long run cost, on which a fixed mark-up may apply. They may perform the following actions.

- generate power
- transport electricity on transmission grids and maintain transmission grids
- distribute electricity on the distribution grids and maintain distribution grids.

If a company only owns a share of a power plant, it may use up to a part of the total capacity of the plant. This part is proportional to the company's share in the ownership of the plant. The company may use its capacity independently of the actions of the other owners of the equipment.

The companies may also engage themselves in transactions with other economic agents.

These transactions are:

- sell and/or buy electricity from other companies
- sell and/or buy transportation services
- serve consumers

The companies determine the price and the quantities in the aforementioned transactions by exploiting their possible market power, subject to the regulatory constraints. They earn revenues from selling electricity and services. They pay the costs of the equipment that they own and their purchases from the other companies.

Several types of companies that are frequently met in practice are detailed below:

- The regulated generating companies are companies that own an important part of the power plant capacity in a country. They can be assimilated to those that have a dominant position in the common market. Because of that reason, the sales of these companies are subject to regulation.
- The manager of transmission grid owns and develops the transmission grid. It offers the grid for rent to the operator of the transmission infrastructure. Because the development of the grid has a character of natural monopoly, the manager of the transmission grid is regulated.
- The operator of the transmission grid dispatches the generation plants. It rents the transmission grid from the owner of the infrastructure. It provides the transmission services. Because the dispatching of the generation plants has a character of natural monopoly, it is regulated.
- The manager of the distribution grid owns and develops the distribution infrastructure. It offers the distribution grid to the distributor. Because the

development of the distribution grid has a character of natural monopoly, the manager of the distribution grid is regulated.
- The distributor delivers power to the customer. In order to do so it rents the distribution grid from the owner and insures that adequate supplies are available. The distributor may or may not be regulated.
- The utilities own the transmission grid, the distribution grids and the power plants in a region. The utilities have a character of natural monopoly and are therefore operated under regulatory control.

11.2.3.3 The independent generators

The independent generators are entities that produce and sell electricity and/or steam to the grid. They may be industrial firms that produce at least part of their needs in electricity or steam by the way of power technologies. They may also be firms developed at the level of local authorities or large tertiary sectors that also produce at least part of their needs in electricity or steam and may also distribute heat through district heating networks. They cannot be entities whose main goal is to produce electricity or steam for sale to the grid. It is assumed that these entities are not regulated.

In the general model design there is no reference to a country, as actor in the market of electricity or steam. In economic terms, the model does not consider that a company, grid or other item has an ownership relation with a country. However, in order to support regulatory policy analysis and country-specific reporting (like the energy balance sheets), the model considers the countries. A country is conceived as an institution related to a subset of the nodes of the network. A formal association is entered in the data of the model. This association allows for a representation of regulations, including:

- reserve margin constraint at the level of the country, to represent policy considerations regarding country independence
- upper and lower limits in the consumption of fuels by country, to represent special policy conditions in the provision of fuels in a country
- non fossil fuel obligations or obligations to use a certain percentage of renewable energy
- environmental regulations, as for example upper limits on certain total emissions in a country.

11.2.4 Relationships between Actors and the System Components

As mentioned, the physical components of the electricity system, their organisation and the actors on the market are represented as a network i.e. a set of nodes connected by arcs. A node represents a set of generation plants, a transmission grid, a distribution grid or a consumption sector. The arcs represent transmission capacities of flows between the nodes or exchanges among the actors.

Arcs represent the interconnections between two nodes. They should therefore not be considered as electric lines or sets of electric lines or steam pipelines, but as interfaces, or set of interfaces, between equipment. Also the arcs have no ownership.

The transportation of energy between two nodes requires a transportation capacity and it involves costs and losses. It is also limited by capacity. We consider one way arcs only. Therefore one or two arcs may connect two nodes. The latter case may only occur between two transmission grids. Since the arcs are directed, one may distinguish their origin and their end. One may also consider their origin node and their destination node.

The ownership relationships are presented below:

Transmission grids have a single owner. They are characterised by a transportation capacity, transportation cost

One or several nodes of the electric system represent the power plants in a country. Power plants may have several owners. At this stage, plants are characterised by the fuels they can use, their efficiency, their availability, their operating and investment costs. A power plant is connected to one and only one transmission grid.

Distribution grids have a single owner. A distribution grid is characterised by transportation capacity, transportation costs and transportation losses. Losses are due to the electric line resistance. A distribution grid is connected to one and only one transmission grid. At least one consumption sector is connected to a distribution grid.

One or several nodes of the electric system represent the consumption sectors in a country. These nodes have no ownership. A consumption sector is connected to one and only one distribution grid.

The companies are defined over the network through the ownership relationship. Except consumers, all other nodes are attributed to companies that may own plants, transmission grids and distribution nodes. The exact topology of the network and the definition of the companies as partitions of the network, determine their nature, according to the classifications given above.

A utility for example has no links to self-consumption and gives no priority to one of the consumers. The utility may have privileges in supplying exclusively a consumer, or even exclusively own a distribution system. An independent generator is also defined through the ownership of a number of nodes of the network. But the independent generator is constrained to give priority to supply self-consumption and normally has limited direct access to the consumers, while being able to transmit excess supply to utilities.

Consumers may be linked to several utilities or independent generators to allocate their needs to different suppliers. Wheeling, that is transmission through an intermediate grid, is possible, depending of course on the topology of the network. In this sense, the so-called third party access can be fully reflected in the topology of the model.

11.2.5 The Commercial Transactions

Several markets can be identified in the electricity and steam system. We first distinguish the market for power and the market for transportation services. In both markets we represent in a different way the transactions ruled by long term contractual agreements and the transactions that take place on the spot market, that is to say, where conditions for the sale of goods or services are arranged as a function of the current circumstances. Some transactions involve both transportation services and power.

The different types of contracts are further divided in new and existing contracts. An existing contract has already been settled and its clauses are fixed. A new contract has not been singed yet and some of its clauses may be negotiated. Such a representation allows a maximum flexibility in specifying the conditions that will prevail on the market in the future.

The physical movements of electricity, which cause costs and transmission and distribution losses, occur mainly through the nodes and not the arcs, which are only connection capacities. For this reason possibly unusual modelling options have been adopted for the representation of the commercial operations. The electricity delivery operations i.e. operations whereby the ownership of electricity changes are supposed to take place at the connection between two elements of the electricity system. Hence, we consider that the power deliveries take place on the arcs, that is to say, after losses and costs on the arc are incurred.

The transportation services are offered on a transmission or a distribution grid, between two connections of the grid. One can therefore represent a transit operation as flows on two adjacent arcs. We assume that the transportation services begin at the end of an arc and end at the end of another arc.

11.2.5.1 The Combined Transactions: Power Purchase Contracts

The power purchase contract is an agreement whereby a company commits to deliver power to another company at a specified arc. The power purchase contract may specify a power plant that will generate the power and power and a route for the deliveries.

The contract specifies

- a price for the electricity or steam
- the average amount of electricity or steam sold per year, typical day and time segment,
- a possible flexibility on these quantities
- the delivery arc or a set of delivery arcs; if a set of delivery arcs is specified, the buyer may choose the distribution of the deliveries among the delivery point to its best interests
- (possibly) the plant that will produce the power
- (possible) the route or the set of routes to be taken by the deliveries. A contract path is specified as a set of arcs. The contract paths connect

transmission grids owned by the seller, or power plants whose the seller owns a share, to a transmission or distribution grid owned by the buyer. The seller may only commit to Transport electricity on grids that he owns. Therefore, the contract paths should only cross nodes that the seller owns.

11.2.5.2 The Electricity Market

The contractual arrangements on the electricity market: exchange usually take the form of contracts, which may be considered as a special case of power purchase contract wherein neither a power plant nor a route is specified. Exchange contracts are not considered explicitly in the model design.

Besides the power purchase contracts, a spot market may take place at the different arcs. In such a market, power is assigned immediately on the arc where the transaction occurs i.e. it is a short term market. This kind of exchanges is taken into account in the model design.

The contractual arrangements on the transport market, as for example the transit contracts, can be considered as agreements whereby a company sells transportation services to another company. The contractual clauses may specify a route or a set of routes used for computing the charges of the transportation services. Such arrangements are explicitly represented when defining the content of the sets of a model implementation.

The sales to the consumption sectors may be constrained by regulations established in compensation of exclusive rights granted on some parts of the consumption sectors, or because of the dominant position of the seller. For example, the sales to consumption sector may be confined within requirement contracts, which are contracts whereby a company commits to deliver power to a consumption sector. Unlike the other types of contracts, the amount of electricity to deliver is determined by the consumption of the sector instead of being fixed (with a possible flexibility) by the contractual clauses.

The contract specifies

- the share of the electricity consumption of the sector that the company must serve
- tariffs for the electricity
- the arc where the power has to be delivered

Short-term agreements (on the spot) may be concluded for power purchase between companies and consumption sectors

The companies perform also commercial transactions regarding the purchase of fuels from the market. The model design represents two types of fuel purchase transactions:

- the fuel contracts for which a yearly quantity, a duration, a degree of flexibility and a rate indicating dispersion of fuel load over time segments are determined;
- fuel purchases in the spot market, in which there are no quantity constraints at the level of the electricity and steam sub-model.

11.3 Model Implementation for PRIMES

In the following we present the model version as implemented to be a component of the overall PRIMES model, version 2.

11.3.1 The Network and the Companies

The network includes plants, production nodes, transmission nodes, distribution nodes and consumers. The set of nodes (except consumers) is partitioned in three types of companies:

- a utility aiming at producing electricity and/or steam, transmit and distribute electricity and transmit steam to other companies (not distribute steam); the utility can exchange electricity with other companies through links of the transmission nodes;
- an industrial company aiming at producing electricity and/or steam, mainly to supply his own demand (for several industrial sectors); it can supply the excess power to the utility company, but it cannot distribute or exchange steam for purposes other than supplying its own needs (this assumption is made to reflect the special quality of industrial steam);
- a tertiary company aiming at producing electricity and/or steam; regarding electricity, the aim is to act as independent generator and sell electricity through the utility’s grid or to directly supply tertiary electricity needs; for steam, the tertiary company acts as a utility for district heating, collecting production from the utility company and distributing district heating to the consumers (except industrial consumers); no steam connections among countries are allowed.

All companies own production plants. It is not possible to share a plant among companies. There is no ownership of transmission and distribution grids, but the receiving company pays transport services at variable costs, which are also paid implicitly through the marginal cost (dual variable) of the corresponding capacity constraint. There exists one type of company per country. This assumption is equivalent to an assumption about the existence of a representative firm per company category. The consumers are not connected to utilities or other companies outside their country of origin. They can be indirectly supplied from other countries through the transmission nodes linking the countries, via the corresponding utilities.

The companies can agree electricity or steam exchange contracts among each other and with the consumers. The contracts involve a quantity, a time pattern over typical days of a year, a duration, a flexibility degree and a route (sequence of nodes) that is used to fulfil the contract along the topology of the network.

Network connections are characterised through their: transmission capacity, transmission efficiency (through which losses are determined at the level of distribution and transmission nodes) and their operation cost (applying only to links between companies). The following schemes present the network as implemented in this version of the sub-model.

Figure 11: The Electricity Network in PRIMES Version 2

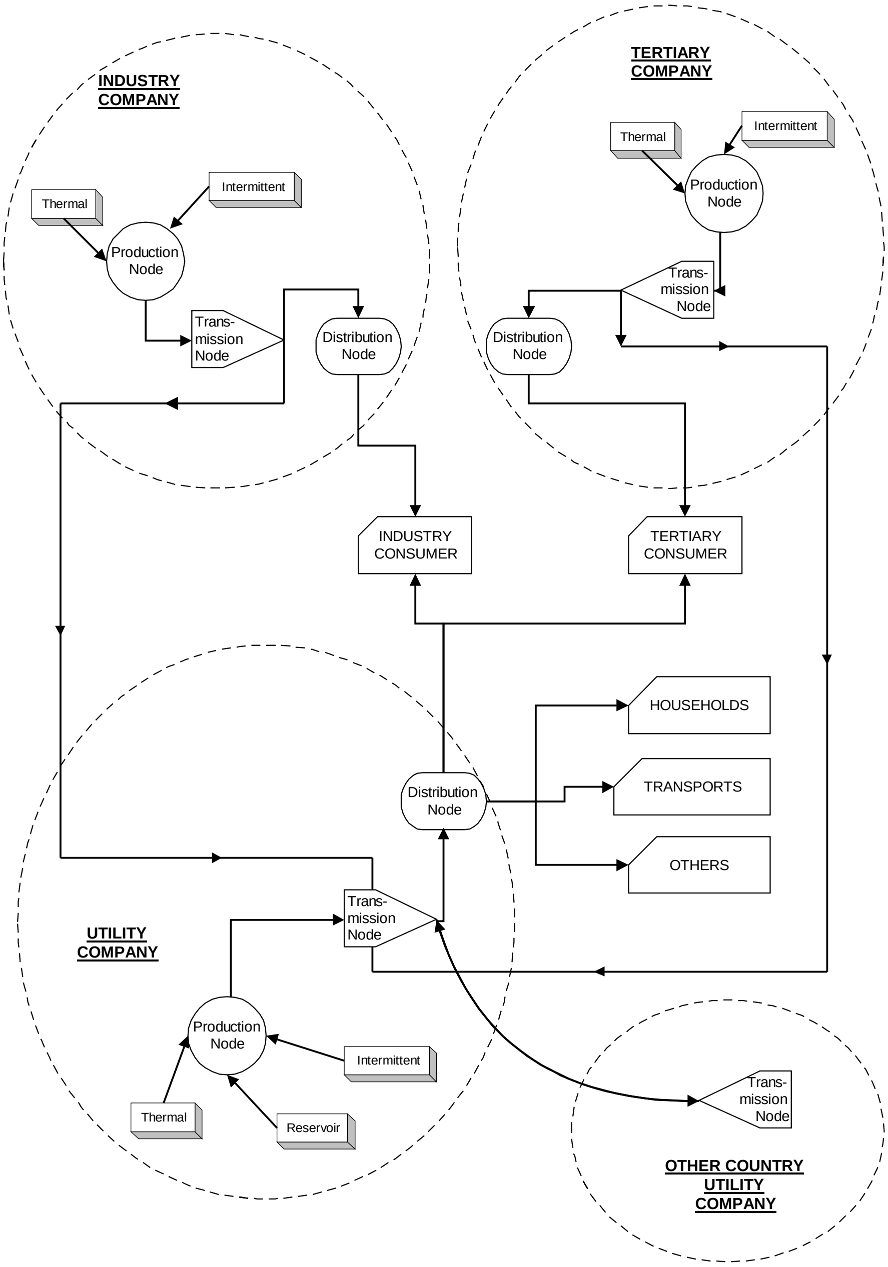
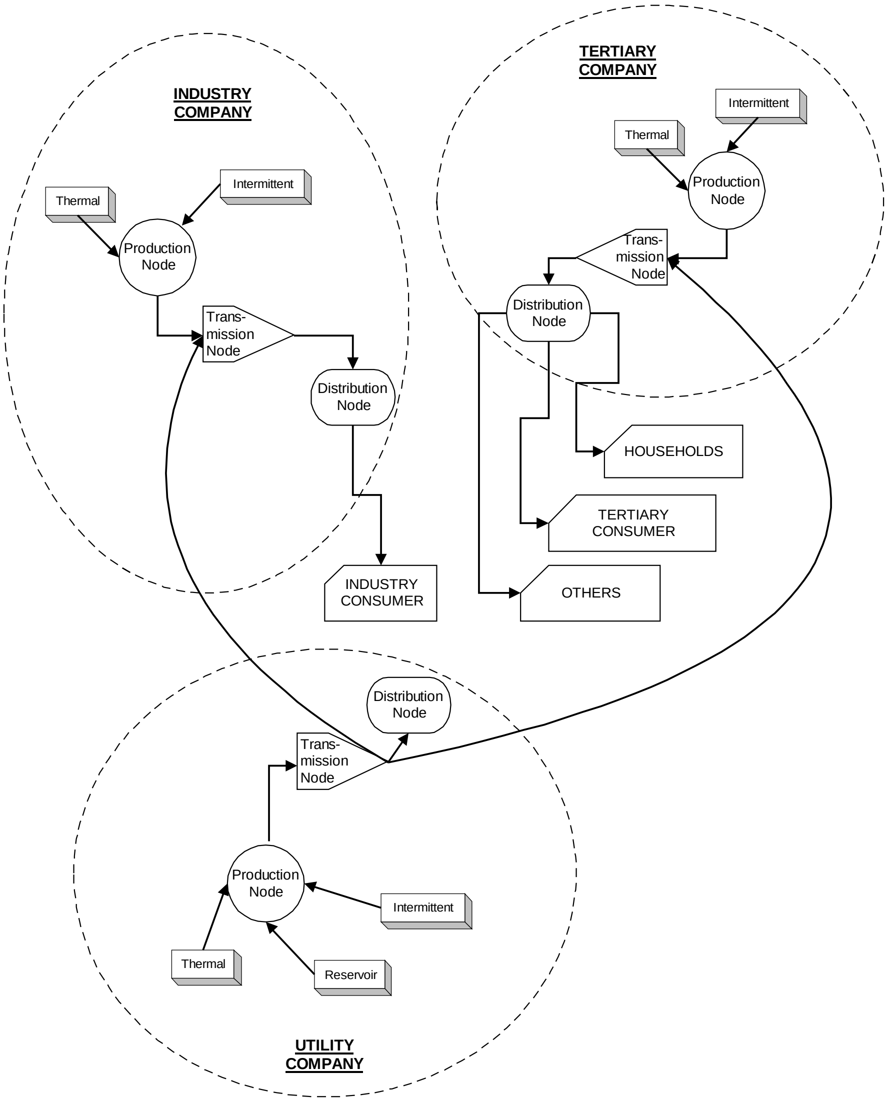


Figure 12: The Steam Network in PRIMES Version 2



11.4 The Production Technologies

11.4.1 Plant Categories

The model considers the following plant categories:

- existing thermal plants of which the capacities are known in the base year
- new thermal plants that are candidate for investment
- existing hydroelectric reservoir plants of which the capacities are known in the base year
- existing intermittent renewable energy plants of which the capacities are known in the base year
- new intermittent renewable energy plants that are candidate for investment.

The variety of different plant types is incrementally specified in the model, by combining the elements from the following sets:

1. Generic plant technologies (7 existing thermal plant types, 27 types for new thermal plants, 1 reservoir type, 4 existing intermittent and 10 new intermittent)
2. Type of fuel combustion (if applicable), including multiple fuel capability (13 types)
3. Size of the plant (three sizes considered), 3 types.
4. Cogeneration technique (if applicable), 9 types.
5. Company type, 3 types
6. Country of origin, 15 countries.

The technical-economic characteristics of the plants differ across the above items. Regarding new plants, technology progress is represented as technological generations that are considered as different plant types.

In total, the model considers:

- 148 different plant types per country for the existing thermal plants
- 678 different plant types per country for the new thermal plants
- 3 different plant types per country for the existing reservoir plants
- 30 different plant types per country for the existing intermittent plants
- 60 different plant types per country for the new intermittent plants

11.4.2 Technical-Economic Characteristics of Plants

The model considers the following information to characterise a plant technology:

- Capital cost, including overnight cost (ECU’90/kW) and financial charges during construction.
- Variable cost (per kWh produced) and annual fixed costs (per kW). The fixed costs increase over time, as the plant becomes older.
- Thermal efficiency rate and multiple fuel capability, if applicable. Rate of electricity auto-consumption per plant.

- Plant availability rate and rate of utilisation for intermittent plants.
- Time-related characteristics of a plant, like technical lifetime and economic lifetime (used for capital amortisation).
- Technical parameters for the feasible combinations of electricity and steam output, if applicable.
- An old plant (in the category of existing plants) can be retrofitted at the moment of decommissioning (which is exogenous). The retrofitting extends the lifetime of the plant and involves capital and fixed cost payments.
- Intermittent plants are linked to renewable resources for which the time pattern of supply is given.
- Reservoir plants can operate at the limits of energy available from inflow water (exogenous) in the lakes, during each year.
- To reflect future technologies, it is assumed that new plant technologies will become available at different points in time (exogenous parameter).

The model considers several atmospheric pollutants and links them to the combustion of fuels through fixed emission factors. Emission can be abated per plant and fuel used. The costs and possibilities of abatement are represented by cost-supply curves specific to each plant-type, involving five abatement levels.

11.4.3 Fuel Types and Purchases from the Market

The model considers 10 fuel types and an association to 13 fuels that can be purchased in the market. Fuels are characterised by their purchase prices, taxes and availability limits.

Fuels can also be supplied through fuel contracts, which are specified per company. A contract involves a quantity, degree of flexibility and a price. Time of use limits on fuels is generally represented through constraints that restrict the dispersion of fuel use over time segments.

11.4.4 Company and Country Regulation

The companies can be constrained by policy, through three types of restrictions:

- upper emission limit, per pollutant
- obligation to use a certain percentage of non fossil fuels, or renewables, in the company's energy balance
- fuel obligations, expressed as lower bounds to fuel consumption per company
- upper bounds on investment in new plants
- capacity reserve margins.

The same constraints can apply at the country level, to reflect national policies.

Finally the model includes the possibility of having different discount rates per company and country.

12. Appendix-D: Detailed Results (separate volume)

Based on PRIMES model ver. 2 per EU Member State

13. List of Tables and Figures

13.1 List of Tables

13.2 List of Figures