Economic Evaluation of Sectoral Emission Reduction Objectives for Climate Change

Economic Evaluation of Methane Emission Reduction in the Extraction, Transport and Distribution of Fossil Fuels in the EU

Bottom-up Analysis

Final Report
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Chris Hendriks and David de Jager
Ecofys
P.O. Box 8408
NL-3503 RK Utrecht
The Netherlands

Contact: Chris Hendriks
c.hendriks@ecofys.nl

http://europa.eu.int/comm/environment/enveco

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Preface

On its way to its current form this report has received significant input from a considerable number of experts. In particular, a panel of experts in Brussels discussed a draft version of the report on March 29, 2000 (see Annex 5 for a list of names), and made a number of specific and more general comments and suggestions. The authors would like to thank these people for their valuable inputs into this study. It was attempted to consider their suggestions wherever possible.

EXECUTIVE SUMMARY

The fossil fuel extraction, transport and distribution sector comprises the exploration, transport and distribution of oil, natural gas and coal. Within the EU, the fossil fuel extraction, transport and distribution sector is an important source of methane, accounting for 20% of total methane emissions in 1990. This equals to about 2.3% of total greenhouse emissions in the EU in 1990. Between 1990 and 1995 (the latest year for which emissions data was available at the time of writing), emission from the fossil fuel extraction, transport and distribution sector fell by about 20%, due principally to decrease in production of hard coal.

In the oil and gas sector, methane emissions occur throughout system: during exploration, in production, at transport and distribution. From wellhead to end user, the gas moves through hundreds of valves, processing mechanisms, compressors, pipes, pressure-regulating stations and other equipment. Whenever the gas moves through valves and joints under high pressure, methane can escape to the atmosphere. In many cases, gas is vented to the atmosphere as part of normal operations. In coal mining, methane emissions occur along the entire supply chain from the mine up to the end-user. The vast majority of the emissions, however, come from gassy underground mines.
In summary there are two main sources of emissions of methane in the fossil fuel extraction, transport and distribution sector:

- Methane emissions from fugitive sources, including distribution pipelines of natural gas;
- Methane emissions from mining of hard coal.

Description of the sector

The total EU *oil* production amounted in 1990 to about 114 million tonnes. In 1998 the total production has increased to 159 million tonnes. The production of oil is estimated to grow until the year 2000 by 40%, compared to 1990. The *natural gas* production amounted in 1990 to about 5.6 EJ, gradually increasing to 7.5 EJ in 1998. Since 1971 world production of hard *coal* has grown at 2 to 2.5% per year until 1992 when production flattened out [IEA Statistics, UN]. Production in the European Union has declined sharply due to cheaper overseas coal. In 1998 the EU coal production amounted to about 5 EJ.

Table 1 gives an overview of the production of oil, natural gas and coal of the EU-15 Member States in 1990 and 1998.

Table 1. Production of oil, natural gas and coal in the EU [EC, 2000; BP-Amoco, 1999; Esso, 1999; Coal information 1995, 1996; EC, 1998]

	Oil production		**Natural gas production**		**Coal production**	
	1990	**1998**[1]	**1990**	**1998**[1]	**1990**	**1998**
	PJ[2]	PJ	PJ	PJ	PJ	PJ
Austria	50	38	46	*51*	-	14
Belgium	-	-	0.41	*0.01*	-	11
Denmark	251	544	117	285	-	-
Finland	-	-	-	-	-	86
France	126	80	101	*89*	327	147
Germany	151	121	599	636	5078	2568
Greece	35	20	6	*2*	297	348
Ireland	-	-	79	*80*	-	49
Italy	196	248	653	703	-	3
Netherlands	167	113	2282	2395	-	-
Spain	33	15	53	*7*	683	503
Sweden	0.12	-	-	-	-	-
United Kingdom	3836	5553	1717	3404	2363	1052
EU	**4845**	**6732**	**5654**	**7652**	**8749**	**4669**

[1] Numbers in *italic* refer to production rates in 1997.

Frozen technology reference case

The emission reduction potential for 2010 is calculated using an emission reference level based on frozen technology development. The frozen technology reference level is based on change in physical activity assuming no improvement in reducing greenhouse gas emissions from the activity. The activity levels (production and distribution of coal, oil and natural gas) of 1990 and for 2010 are taken from the Primes model [Primes, 1999]. Any application of emission reduction measures after 1990 is therefore not taken into account in the frozen technology reference level, but considered in the potential of the emission reduction options.

Summary of emission reduction options

Emission reduction options in the oil and gas sector minimise emissions from associated gas, process vents and flares, engines, turbines, compressors and pumps, system upsets, and transmission and distribution activities. In coal production emission reduction options are directly related to minimising methane emissions associated with mining activities. Table 2 gives an overview of the investment costs, the yearly costs (sum of operation and maintenance costs and savings), average specific mitigation costs and potential for options applicable in the fossil fuel extraction, transport and distribution sector. The specific costs are calculated using a real interest rate of 4% and using the lifetime of the option, i.e. equipment. The technical emission reduction potential of the identified options is estimated at 34 Mt of CO_2 equivalent. or about 55% of the total projected emissions in 2010.

Table 2. EU15-average costs and total potential (Mt CO_2) for emission reduction of methane options in the oil and gas and coal mining sectors (summary table).

Pollutant: CH4 Measure Name	Subsector	Emission reduction	Investment	Yearly costs	Lifetime	Specific abatement costs
		Mt CO2 eq.	euro/tCO2 eq.	euro/tCO2 eq.	year	euro/tCO2 eq.
Various improvements of compressors	Compressors	0.4	0 .. 0.3	-4.0	1	-4
Inspection and maintenance - power equipment	Energy requirements	0.1	0	-3.5	1	-4
Increased gas utilisation	Process vents/flares	0.1	30	-4.1	15	-1
Coal mining degasification (low and medium recovery rate)	Coal mining	6	30 .. 40	-5 .. -4	15	-1
Subtotal : Cost ranges for < 0 euro / t CO2		**6.5**				
Coal mining degasification (medium recovery rate)	Coal mining	2	47	-4	15	0.1
Coal mining abatement from ventilation air	Coal mining	0.6	18	-0.2	15	1
Reducing flaring/venting emissions related to associated gas	Associated gas	0.2	30 .. 60	-3 .. 1	15	1 .. 3
Utilisation of process vents and other options	Various oil and gas	0.2	60 .. 145	-4 .. 7	15 .. 20	2 .. 18
Subtotal : Cost range for 0 < 20 euro / t CO2		**3**				
Offshore flaring instead of venting of process vents	Process vents/flares	0.1	179	5	15	21.4
Replacement grey cast iron network low	Fugitive emissions	10	952	-8.6	50	36
Subtotal : Cost ranges for 20 < 50 euro / t CO2		**10**				
Various options: compressors, associated gas, system upsets	Various oil and gas	0.4	0 .. 900	10 .. 90	various	75 .. 90
Increasing the pipeline examination frequency	Fugitive emissions	4	0	77	1	77
Replacement grey cast iron network high	Fugitive emissions	10	1905	-9	50	80
Subtotal : Cost range for < 50 euro / t CO2		**14**				
Total emission reduction potential		**34**				

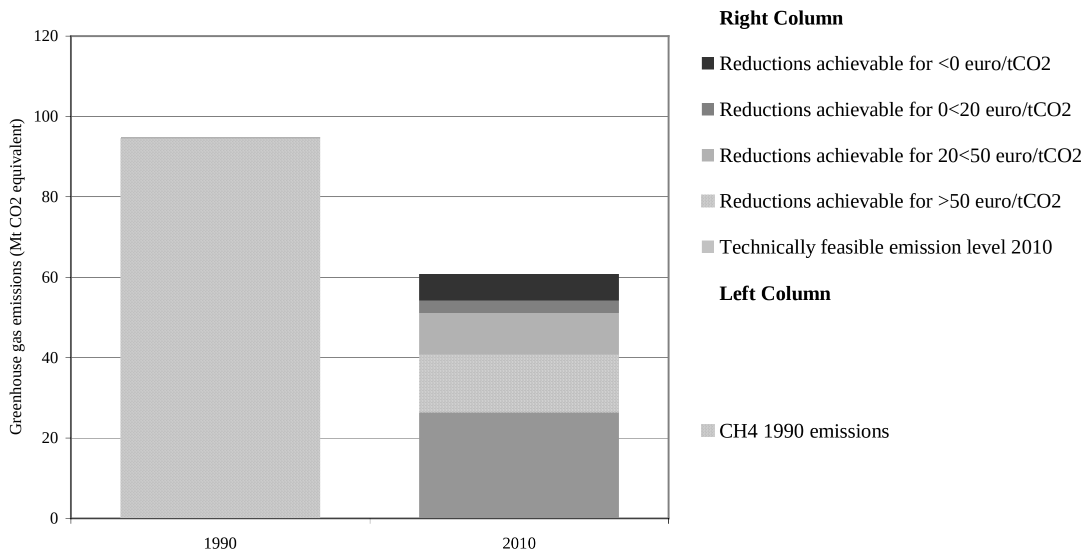
Note: Table 4.1 presents the complete list of options

Table 3. Summary of methane emissions (Mt CO_2 equivalent)

	1990	**2010 reference**	**2010 with measures**
Coal production	62	27	8
Oil and gas sector	33	34	19
Total	**95**	**61**	**27**

Figure 1. Fossil fuel extraction, transport and distribution sector: 1990 base year direct emissions (left), 2010 frozen technology reference level and reduction potentials per cost bracket (right)

Fossil fuel extraction, transport and distribution



Summary of emission levels and reduction potentials

Table 3 summarises the frozen technology reference level in the fossil fuel extraction, transport and distribution sector and shows the position if all the measures in the table above were adopted. Figure 1 shows the share in emission reduction categorised in four costs brackets.

Contents

1. INTRODUCTION

This report deals with the methane emissions related to fossil fuel extraction, transport and distribution, i.e. the oil and natural gas sector and the coal mining sector. Within these two sectors, emissions from methane form by far the largest contribution to the greenhouse gas emissions. Table 1.1 gives an overview of the methane emissions in these sectors per country for the base year 1990 and for the frozen technology reference level of 2010.

Table 1.1. 1990 and 2010 frozen technology reference level direct methane emissions in the fossil fuel extraction, transport and distribution sectors, in Mt of CO_2 equivalent.

Fossil fuel extraction, transport and distribution		1990			2010		
		Solid fuels	Oil and Gas	Total	Solid fuels	Oil and Gas	Total
Austria	AUT	0	0.1	0.1	0	0.1	0.1
Belgium	BEL	0.3	1	1	0.3	0.9	1
Germany	DEU	26	7	33	10	7	17
Denmark	DNK	0.1	0.2	0.3	0.1	0.2	0.3
Spain	ESP	13	2	14	10	2	12
Finland	FIN	0.02	0	0.02	0.02	0	0.02
France	FRA	4	2	7	0.3	2	3
United Kingdom	GBR	17	11	28	5	10	15
Greece	GRC	1	0	1	1	0	1
Ireland	IRL	0	0.2	0.2	0	0.2	0.2
Italy	ITA	0.1	6	6	0.03	6	6
Netherlands	NLD	0	4	4	0	4	4
Portugal	PRT	0.1	0.02	0.1	0.1	0.02	0.1
Sweden	SWE	0	0	0	0	0	0
European Union	EU	62	33	95	27	33	60

Source: Primes (1999); UNFCCC (1999); this study.

In the next two chapters the emissions in the frozen efficiency reference case are presented as well as the emission reduction options for both the oil and natural gas sector and the coal mining sector.

2. OPTIONS TO REDUCE METHANE FROM OIL AND NATURAL GAS PRODUCTION, TRANSPORT AND DISTRIBUTION

2.1 INTRODUCTION

The total EU oil production amounted in 1990 to about 114 million tonnes, from which 80% in the United Kingdom. In 1998 the total production has increased to 159 million tonnes. The relative share of the UK increased in the same period to 83%. The production of oil is estimated to grow until the year 2000 by 40%. After 2000 the production will steadily decrease to a level which is about 10% higher than the production in 1990 [Primes, 1999].

The natural gas production amounted in 1990 to about 134 Mtoe, gradually increasing to 183 Mtoe in 1998. Table 2.1 gives an overview of the production of oil and gas of the EU-15 member states in 1990 and 1998. The production of natural gas is estimated to grow steadily towards 2010, resulting in a 70% higher level compared to 1990 [Primes, 1999].

Table 2.1. Production of oil and natural gas in the EU [EC, 2000; BP-Amoco, 1999; Esso, 1999]

	Oil production		**Natural gas production**	
	1990	**1998**[1]	**1990**	**1998**[1]
	PJ[2]	PJ	PJ	PJ
Austria	50	38	46	*51*
Belgium	-	-	0.41	*0.01*
Denmark	251	544	117	285
France	126	80	101	*89*
Germany	151	121	599	636
Greece	35	20	6	*2*
Ireland	-	-	79	*80*
Italy	196	248	653	703
Netherlands	167	113	2282	2395
Spain	33	15	53	*7*
Sweden	0.12	-	-	-
United Kingdom	3836	5553	1717	3404
EU	**4845**	**6732**	**5654**	**7652**

[1] Numbers in *italic* refer to production rates in 1997 [2] 1 Mtoe = 41.9 PJ

2.1.1 Oil system

Oil production

If crude oil is produced, it is generally obtained as a mixture of oil, associated gas and formation water. When oil production has just started, most of the fluid produced is oil. In a later stage more and more water is produced. The oil is obtained from a well at pressures between 8 and 50 bars. In some cases an artificial lift has to be applied. This may be done by pumping liquid in the reservoir or by injecting compressed natural gas at a pressure of about 50 bars. Oil processing consists of separating the three components: water, oil and gas. The gas phase (associated gas and lift gas) is separated in a first separator, operating at pressures typically at 8 bars. There are three ways to process the gas:

- The gas may be compressed, e.g. to 50 bars; dried in a glycol dehydration unit or in a low temperature separator, and ultimately reused as lift gas or sold for ultilisation;
- The gas may be used to generate electricity, using gas-engines and generators;
- The gas may be flared or vented.

The liquid phase is treated in a second stage separator. Here the hydrocarbon mixture is separated from the formation water. In some cases, gas is used to improve this separation (gas flotation). The water mixture is re-injected in the oil reservoir or further treated and disposed of. The oil is stabilised (that means, the highly volatile components are removed upon heating) and stored before transport. The off-gas from the various unit-operations may be used, recompressed, flared or vented.

Oil transport

After being produced and treated, the oil is transported. The most widely applied methods for oil transport are pipeline transport and tanker ship transport. Minor amounts are transported by train or by tanker cars. In the EU pipeline transport is predominant.

Oil refinery

After transport the crude oil is transformed, mostly close to the products market, into its products ranging from fuels as gasoline and kerosene, to a broad spectre of chemicals as plastics, lubricants and surfactants.

2.1.2 Natural gas system

Production of associated gas

Associated gas is always formed as a side product of oil production. Associated gas is usually rich in the larger hydrocarbons. In some cases the gas is sold, used for on-site energy generation, or re-injected to enhance oil recovery. In other cases the associated gas has to be disposed of, which is usually done by flaring or venting.

Production of non-associated gas

Non-associated natural gas may be formed by decomposition of coal. It is generally methane rich. The raw gas is normally obtained as a mixture of gas, condensable hydrocarbons (condensate) and formation water. Composition of natural gas may vary widely.

Before it is distributed and used, the natural gas has to be treated. There are several reasons for doing this:

1. Water and condensate have to be removed to avoid hydrate formation and to safeguard transport and distribution pipelines;
2. H_2S has to be removed to avoid corrosion of pipelines and to mitigate emission of acidifying components at gas utilisation;
3. Carbon dioxide has sometimes to be removed to meet gas specifications (heating value).

Natural gas treatment may take place before and after transport. In most cases dehydration is performed on-site, in order to meet transport specifications, before it is gathered and transported over shorter distances. After transportation additional dehydration may take place to meet sales specifications. Condensate, and in some cases even oil, may be transported along with the natural gas. In these cases pigs are used to safeguard the flow of the condensate, and after transport (before distribution) the condensate is removed from the gas. Removal of CO_2 and H_2S may take place near the well, but in other cases it is performed at larger treatment plants. A detailed description of natural gas treatment unit operations is given in Annex 1 ("Natural gas treatment unit operations").

Natural gas transport

The most common way of natural gas transmission is transportation through pipes having diameters ranging from 36 to 142 cm. Transportation pressures typically are 80 to 100 bar. Along the pipeline compressor stations are present to overcome the pipelines pressure drop; compressor stations are located typically every 100 to 150 km.

An alternative for pipeline transport of natural gas is the shipping of liquefied natural gas (LNG). To liquefy the natural gas, it is cooled down to about –160 ^oC, and subsequently shipped in purpose-built insulated ships with capacities of 45,000 to 140,000 m^3. LNG production is not performed in the EU offshore industry. However, Belgium, France, Italy and Spain import LNG from Algeria, Lybia and the Gulf region.

Natural gas distribution

Although some larger companies may obtain their gas directly from the high pressure transportation grid, most local consumers (companies and households) receive their natural gas from a local gas distributing company. Such a gas distributing company obtains the natural gas from the transportation pipelines, reduces its pressure to 4 to 8 bars and subsequently delivers the gas to the consumers, through a network of small pipes.

In many cities around the world, natural gas is nowadays distributed through the old ‘town-gas’ distribution grid, generally consisting of cast-iron pipes, with hemp and lead-joints, and usually installed before 1955. Because of a difference in gas characteristics (natural gas is usually dry, where town gas is rather humid), special precautions have to be taken to prevent the hemp joints from drying out and starting to leak. This is done in different ways in the various countries. In the United Kingdom, for example, monoethylene glycol is added to swell the yarn within the joints of the grey cast iron mains; in the Netherlands the joints were prevented from starting to leak, by encapsulating them with sleeves. After the introduction of new materials as polyethylene (PE) and polyvinylchloride (PVC), most newer distribution grids are constructed of these types of materials, having fewer problems with leaky joints.

2.2 EMISSIONS

2.2.1 Emission mechanisms

Methane emissions occur throughout the oil and gas system: during exploration, in production, at transport and distribution. From wellhead to end user, the gas moves through hundreds of valves, processing mechanisms, compressors, pipes, pressure-regulating stations and other equipment. Whenever the gas moves through valves and joints under high pressure, methane can escape to the atmosphere. In many cases, gas is vented to the atmosphere as part of normal operations. For example, a major source of vented emissions are pneumatic devices, that operate valves using pressure in the system and bleed small amounts of gas when valves are opened and closed. Another example of venting is the common industry practice of shutting down a compressor and purging the gas in the compression chamber to the atmosphere.

This study breaks emission sources into a number of types of sources to which mitigation options can be applied [De Jager et al., 1997]:

1. Emissions in the exploration phase (due to drilling and well testing).
2. Emission related to unused associated gas (vented or flared).
3. Emission due to venting or flaring of off-gases from facilities in the treatment of both associated and non-associated gas.
4. Emissions from maintenance in natural gas production, transport and distribution.
5. Emissions related to energy requirements: exhaust emissions and emissions due to start-up and shut-down of engines and turbines.
6. Emissions from compressors, notably seal losses, but also emissions during start-up and shut-down.
7. Emissions from pneumatic devices, such as valves and actuators
8. Emissions related to system upsets.
9. Fugitive emissions from (leakages) from process equipment, transportation (pipelines and tanker shipments), storage facilities and from the distribution grid.

Here a description of each identified source of emission is given. A short description of the assumptions for the emission inventory per source-type is given in Annex 2 ("Emission inventory based on source-type definitions"). For each emission source-type an indication of the contribution to the total methane emissions of the EU-15 oil and gas system is given (1990, see section 2.2.2).

With regards to the difference between oil and gas production, the main difference is that in oil production amounts of associated gas may remain unused, and are therefore vented or flared. In non-associated gas production this is not the case, and therefore this source does not exist here. When it is decided to sell the associated gas for utilisation, the gas is treated similar to non-associated gas. Emissions therefore are comparable to emissions due to treatment, transport and distribution of non-associated gas. For this reason associated gas and non-associated gas are not distinguished in this chapter, and both types of gases are referred to as natural gas.

1. Emission during exploration

In the exploration phase methane emissions may occur as a result of blow-outs during exploration drillings, when wells are tested, and during the cleaning of wells. Various studies indicate however, that these emissions are negligible, when sufficient precaution measures are performed.

2. Emission related to unused associated gas

In the production of natural gas and oil, amounts of gas are produced, that can not be sold at the moment. This problem goes especially for the associated gas, that is linked to the oil production. Part of the associated gas may be used for on-site energy supply, but the remainder remains unused. This unused gas is sometimes re-injected in the oil reservoir to enhance the oil recovery, but in some cases it is flared or vented, resulting in methane emissions. This goes especially for offshore production. In 1996 the amount of associated gas vented or flared globally was reduced to about 4% [WEC, 1998]. Most of this gas is flared. Flare efficiencies (expressed in percentage combusted hydrocarbon) may vary from 0 to 99.9% depending on the meteorological conditions and operational aspects.

Methane emissions from re-injection are most likely very low, and emissions are limited to emissions due to compressor operations, to energy requirements and to some fugitive emissions. Little quantitative information is available about methane emissions due to re-injection. US-EPA [1993] estimates emissions to be about 0.3 Mg per 10^9 m^3 gas re-injected (about 0.00004%).

No (complete) statistical overview for the EU-15 is available with respect to the part of the associated gas flared, vented or re-injected and of the related emissions of carbon dioxide, methane and non-methane volatile compounds. Methane emissions related to unused associated gas may contribute to about 3% of total EU-15 methane emissions by the oil and gas system. The OGP [2000] considers this percentage too high, as practice in the EU is directed towards maximal utilisation or re-injection.

3. Flaring and venting of off-gases from gas treatment facilities

Gases from various operation activities are flared or vented:

- *Off-gases*: these emissions occur when methane is dissolved in various fluid phases, and subsequently released again, after pressure reduction.
- *Purge gas*: purge gas is normally applied in vent- and flare systems to prevent air from entering the system.
- *Blanket gas emissions of storage vessels*: when such storage vessels are filled with condensate liquid, the gas content of the vessel is replaced with the liquid, and removed through the atmospheric vent or flare system. Storage tanks are often blanketed with nitrogen, which results in reduced emissions [OGP, 2000].

- *Vessel breathing*: as a result of ambient temperature fluctuations the gas and the liquid phase in the vessel is continuously expanding and shrinking.
- *Passing valves emissions*: when as a result of fouling or wear, passing valves (pressure safety valves and block valves) do not close completely, certain amounts of natural gas leak through. These passing valves emissions ultimately end-up in the high-pressure flare or vent-system. The NAM estimated that these emissions amounts to about 50% of the purge gas and off-gas in the Netherlands [NAM, 1995].

Process emissions can be calculated as a sum of the off-gases from processes, the purge gas, blanket gases and passing-valve emissions. In this estimation it is of importance to what extent high-pressure streams are used on-site or recompressed, to what extent streams are flared instead of vented, how much purge gas is used and to what extent passing valve emissions are avoided. Table 2.2 gives an indication of the total emissions from process vents and flares, for poor, moderate and good operating practices. This indication is based on various detailed system studies [Tilkigcioglu and Winters, 1990; US-EPA, 1993; Oonk and Vosbeek, 1995; OLF, 1993].

Table 2.2. Methane emissions from process vents and flares

Operating practice	**Methane emission (Gg per 10^9 m^3 net gas production)**
poor	1.5 - 5
fair	0.5 - 2
good	0.01 - 0.2

poor: no recompression or reuse of high-pressure off-gases; venting of both high-pressure and low-pressure off-gas system; no control and repair of pressure-safety and other open-end valves;
fair: recompression and reuse of high-pressure off-gases; venting of low-pressure off-gases; incidental control and repair of pressure-safety and other open-end valves;
good: recompression and reuse or flaring of high-pressure off-gases; flaring of low-pressure off-gases; operational programmes for control and repair of prssure-safety and other open-end valves.

Emissions of gas treatment facilities may contribute to about 10% of total EU-15 methane emissions by the oil and gas system.

4. Emission related to maintenance of the natural gas system

In routine maintenance, amounts of methane may be released. This occurs, for example, when process-equipment or a pipeline is depressurised and flushed with air, before maintenance.

Examples of these maintenance activities include well workovers, orifice fitting replacement, maintenance blowdowns, maintenance of gathering pipelines, pipeline and compressor blowdowns. In most cases, these off-gases are vented, although in field production these gases are usually fed to a flare system.

Maintenance emissions are believed to contribute to about 2% of total EU-15 methane emissions by the oil and gas system. The OGP [2000] states that the maintenance activities mentioned above have been minimised.

5. Emission related to energy requirements

Emissions of methane related to the energy requirements of the oil and gas system are part of exhaust emissions, but also occur during start-up and shut-down of engines and turbines.

- *Exhaust emissions*: On-site a number of incineration processes are used for several purposes: reciprocating engines and turbines are used on location to supply the power to operate compressors and to generate electricity required on-site; heaters are used, e.g. in the regeneration of glycol. In many cases these incineration processes are natural gas-fired, and due to incomplete combustion they might be a significant source of methane.
- *Non-exhaust engine-emissions*: At shut-down of reciprocating engines, the engines are flushed with air for safety reasons. Before starting-up again, these engines are flushed several times with natural gas. Doing this, amounts of methane are released to the atmosphere. So both start-up as shut down is normally accompanied by emissions of methane.

These emissions are believed to contribute to about 2% of total EU-15 methane emissions by the oil and gas system.

6. Emission from compressors

Gas compression is an integral part of the gas transmission system, about every 100-150 km a compressor station is required. Compressor stations give rise to methane emissions for several reasons:

- *Seal losses*: the compressors axis has to revolve in the compressor casing. The connection between both parts can not be made gas-tight. As a result of this, the seals between the axis and the casing are always leaking to some extent. 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. Dry gas seals operating on nitrogen as buffer gas are being used to reduce these seal losses [OGP, 2000].
- *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 of compressors, the equipment is flushed with air, at start-up with natural gas. Normally this gas is vented, resulting in emissions of methane. In order to facilitate a quicker re-start after short-term shutdowns, compressors are usually not flushed but left filled with gas [OGP, 2000].

Emissions from compressor stations may contribute to about 3% of total EU-15 methane emissions by the oil and gas system.

7. Emission from pneumatic devices

Valves and actuators in the production and transmission system are sometimes natural gas-operated. This means that the hydraulic pressure of the natural gas is used to switch valves etc. The natural gas used is vented to the atmosphere.
Pneumatic devices occur all through the system, both at well-sites as along pipelines. In the United States natural gas operated devices are widely applied, whereas in north-western Europe, electricity or pressurised air is used to adjust these devices. Most remaining pneumatic devices will be taken out of service within the next few years [OGP, 2000].

Emissions from pneumatic in the EU-15 are therefore believed to be neglegible.

8. Emission during system upsets

At system upsets, the safety system of the production location comes into action. As a result of this, pressure relief valves may open, and the system is depressurised. The off-streams of a pressure safety valve are normally fed to the high pressure flare or vent-system.

Emissions during system upsets may contribute to about 3% of total EU-15 methane emissions by the oil and gas system.

9. Fugitive emissions

Chronic leaks occur throughout the natural gas system. Especially, joints, flanges and valves may leak to some extent. Most of these leaks are most likely limited to a few cc a day (10^{-6} m^3), but considering the amount of this type of connections, the total sum of the fugitive leaks may contribute significantly to the total emissions.

- *Exploitation and transport*: in exploitation and transport larger leakages are easily detected, since they will cause the formation of ice on the flanges outer surface. This ice is a result of a drop in temperature, due to the expansion of the gas from about 80 bar to atmospheric pressure.
  Smaller chronic leaks are hard to address, since they may occur throughout the system. An accompanying problem is that most flanges do not leak, and a greater part of the emissions comes from less than about 0,5% of all flanges [Countess and Browne, 1993].
- *Distribution*: fugitive emissions during distribution are much harder to assess. In some cases emissions can be estimated from differences between input and output of the system. But due to metering inaccuracies, this method is rather unreliable.
  A number of more detailed studies for methane emissions from the natural gas distribution system are performed, boiling all down to the same conclusion: most emissions come from the old grey cast-iron distribution grid, especially the part with the hemp-joints. Newer distribution grids are much less leaky.

According to an extensive survey in the UK, the leakage rate of PE pipelines is about 10% of the metallic pipelines. They also concluded that leakage is proportional to pressure, at least in the range 20 to 50 mbar [Rose, 1994]

Other possible fugitive emissions might occur during the following operations [Aarebrot, 2000]:

- Crude tanker loading at terminals and offshore installations and venting during tanker transport. Methane emissions are estimated to be about 50-60 tonne of methane during each loading operation [Aarebrot, 2000].
- Gas storage facilities.
- Facilities for liquefied natural gas (LNG) storage, peak shaving and local storages.

Fugitive emissions are the predominant emission source of the European oil and natural gas system with an estimated share of almost 75-80%. Most fugitive emissions are related to distribution (>90%).

2.2.2 Emission in EU-15

The Second Communication from the European Community [NC2-EC; 1998] reports a total emission of methane by the oil and gas system of 1561 Gg CH_4 for the year 1990. This estimate will be used for this study. Table 2.3 gives the development of the methane emissions from the oil and gas sector from 1990 to 1997 (taken from the UNFCCC database).

A subdivision to source-type is made by De Jager et al. [1997]. A short description can be found in Annex 2. The figure below presents a tentative breakdown of the 1990 emissions.

Table 2.3. Development of methane emissions in the oil and gas system in the EU-15. (in kt CO_2 equivalent). Figures in italic refer to the proceeding year.

Country	1990	1991	1992	1993	1994	1995	1996	1997
AUT	84	84	84	105	105	105	126	105
BEL	819	840	861	924	945	693	693	*693*
DEU	7014	7371	8169	9009	8568	7497	7749	7308
DNK	189	210	210	210	231	231	231	252
ESP	1554	1722	1827	1785	1953	2289	*2289*	*2289*
FIN	0	0	0	0	0	0	21	0
FRA	2205	2352	2247	2226	2037	2079	2142	1953
GBR	10500	10143	10101	9828	9807	9723	9429	9261
IRL	210	210	210	231	231	231	252	*252*
ITA	6384	6384	6384	6384	7329	7329	7329	7329
LUX	42	42	42	42	42	42	42	42
NLD	3759	3948	3423	3318	3528	3654	4032	4032
PRT	21	21	21	21	21	*21*	*21*	*21*
EU15	**32760**	**33306**	**33558**	**34062**	**34776**	**33873**	**34335**	**33516**

Source: UNFCCC (1999)

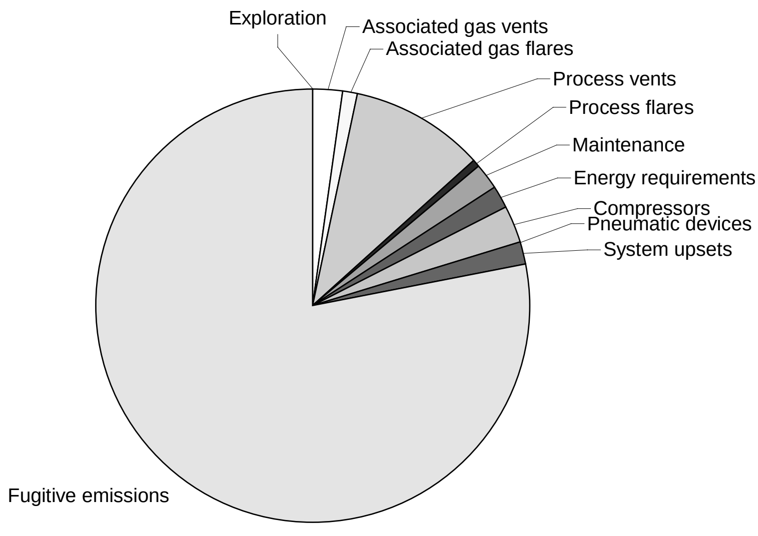


Figure 2-1: Tentative breakdown of the 1990 emissions by the EU-15 oil and gas system (adapted from [De Jager et al., 1997])

2.3 EMISSION REDUCTION OPTIONS

2.3.1 Introduction to the measures

The implementation of measures to reduce methane emissions from the oil and gas system can be applied as the following mitigation strategy:

1. Emission reduction by *prevention* (e.g. improved process efficiencies, reduction of leakages).
2. Emission reduction by *recovery* of off-gases and *re-injection* into the subsystem (e.g. oil reservoir, natural gas transport pipeline).
3. Emission reduction by *recovery* and *utilisation* of the otherwise emitted gases for energy production. This will also result in energy savings and avoidance of greenhouse gas emissions (notably carbon dioxide).
4. Emission reduction by *recovery* of methane and other volatile organic compounds, followed by *combustion* (e.g. in a flare) without utilisation of the energy content of these gases. By combustion the global warming potential of the off-gases will be reduced.

The costs of the measures depend highly on the local situation on the various sites (e.g. differences between on- and offshore production), so they may strongly differ from installation to installation. *Specific* investments (in euro per Mg (tonne) of methane mitigated) also depend on the throughputs of the installation: in installations with larger throughputs the costs per tonne of methane avoided will generally be smaller. Measures for installations with high emission characteristics generally have lower specific costs. Furthermore, investments may be smaller for new installations (notably for offshore production platforms) than for retrofit situations. It should be noticed, that the figures presented here are examples or mean values for a mix of installations.

2.3.2 Reduction of associated gas vented or flared

2.3.2.1 Description

In 1996 the amount of associated gas vented or flared worldwide was about 4% of world gross production, where for the EU-15 this figure is at least 1.4%, see the table below [WEC, 1998]. An exact breakdown into the vented respective flared fraction is not available at a central point, and therefore no exact statistical information can be derived on methane and carbon dioxide emissions.

It is estimated that a reduction of 50% of the emissions from venting can be achieved in the medium term through application of a combination of flaring and utilisation of associated gas, with the possibility of an 80% reduction in the long term [Baudino and Volski, 1991]. However, the scope of emission reduction is likely to be much lower in the EU where producers are already encouraged to utilise associated gas wherever possible, and to flare rather than vent where it is not conflicting with safety.

Table 2.4. Gross and net production of natural gas in the EU-15 (1996)

Country	**Natural gas production (10^9 m^3) - European Union 1996**				
	Gross production	**Re-injected**	**Flared/ Vented**	**Shrinkage**	**Net production**
Austria	1.5	-	-	-	1.5
Denmark	8.6	1.3	0.9	-	6.4
France	4.2	-	n.a.	1.1	3.1
Germany	25.9	3.3	n.a.	0.7	21.9
Greece	0.1	-	-	-	0.1
Ireland	2.7	-	-	-	2.7
Italy	19.6	0.6	n.a.	-	19
Netherlands	90	-	0.2	-	89.8
Spain	0.7	0.2	-	-	0.5
United Kingdom	98.3	2.9	2.5	3	89.9
EU-15	**251.6**	**8.3**	**3.6**	**4.8**	**234.9**
	100%	3.3%	1.4%	1.9%	93%

n.a.: not available

Shrinkage: due to the extraction of natural gas liquids part of the natural gas is removed

Source: WEC (1998)

Venting or flaring of associated gas produced during oil production can be reduced by recovery and utilisation of this gas. The following options may be applied:

- *Recovery and re-injection for enhanced oil recovery*: (Associated) gas can be re-injected in the field to help maintain the formation pressure. Injection can improve recovery of oil from less than 15% to more than 50%. About 11% of world gas production is estimated to be re-injected for this purpose. For the EU-15 this figure is 3% [WEC, 1998]. Re-injection is not applicable to all oil production reservoirs as a consequence of specific (geologic) circumstances. The decision to re-inject will be influenced by costs associated and the likely benefits in terms of improved yields.
- *Recovery and utilisation of associated gas for energy production*: (Associated) gas can be used for consumption on the platform, for domestic consumption by converting it to liquefied natural gas (LNG) or to electricity. Systems for the recovery of low pressure vent gases are commercially available. The availability of an infrastructure for gas transport and distribution to (nearby) consumers is necessary for domestic consumption to be cost-effective. In the EU many offshore installations have an existing infrastructure for the transportation and utilisation of associated gas, in the form of a pipeline to an onshore terminal.
  There has been recent interest in the production of LNG at some remote platforms in the North Sea, where gas pipelines are not technically or economically feasible. However, no cost data were available. The offshore use of associated gas to generate electricity for export has also been considered but there is no reported application at present. This option may

be more attractive than it has been in the past because new smaller gas turbines based generators are now readily available and because electricity cables may be easier to lay on sea beds than gas pipelines. There are no costs available from the literature for this option. Also fuel cells are considered as offshore power production units.

Increased utilisation of associated gas, that otherwise would be flared does not necessarily result in a decrease in methane emissions, since the emissions due to production, treatment and transport are in the same order of magnitude as the emissions from a flare. *Carbon dioxide* emissions wíll be reduced by this measure. The effect depends on the specific flare system replaced and the way in which the natural gas is treated and transported. Of course, when such a measure is taken, it should be evaluated on its whole contribution to sustainability, and utilisation has te be regarded as the preferred option.

If the associated gas is currently vented, the emission reduction will be over 99%.

- *Flaring instead of venting*: venting involves releasing the gas into the atmosphere, resulting in significant methane emissions. Emissions due to venting of associated gas can be reduced by application of flares. Since the associated gas is released in a more or less continuous way, the disadvantages of discontinuous flaring do not apply here (see below). The actual implementation potential of this option is limited by technical, environmental and safety constrains.

  When off-gases are flared instead of being vented, methane emissions are reduced by about 95 to 99.8%, depending on the flare efficiency. It should be noted that although flaring reduces emissions of methane, it increases emissions of carbon dioxide. Combustion of 1 kg methane will therefore result in avoidance of about 17 kg CO_2 equivalent (assuming a GWP value of 21). If no adequate infrastructure for associated gas is available and re-injection is not possible or to costly, flaring is preferred above venting.
- *Improvement of flare efficiencies:* it may also be possible to improve combustion efficiency in the flare by promoting turbulence. This would reduce methane emissions and emissions of other products of incomplete combustion (soot, carbon monoxide, etc.). Flare efficiencies of 95-99% are typical [Woodhill, 1994] with EU flare efficiencies likely to be at the upper end of this range, with limited scope for improvement.

At the offshore facilities in Europe (notably the North Sea), associated gas re-injection and flaring instead of venting is more or less common practice. However, no central statistical information source is available for exact figures.

2.3.2.2 Cost of option

The cost-effectiveness of utilisation of associated gas for energy purposes may vary signifantly as most measures will have very site-specific components. 67% of the associated gas emissions are estimated to be vented, 33% flared.

Furthermore, we assume that less than 10% of associated gas emissions are located onshore.

Option	Effect.	Share in subsector	Investment	O&M	Savings	Lifetime
	(%)	(%)	euro/Mg CH /yr	euro/Mg CH_4	euro/Mg CH_4	year
Flaring instead of venting (offshore)	98%	10%	15000	450	0	15
Flaring instead of venting (onshore)	98%	5%	600	18	0	15
Associated gas (vented) mix other options	90%	25%	1000	20	92	15
Associated gas (flared) mix other options	95%	15%	1200	40	92	15

Subsector is "Unused associated gas"

2.3.3 Process vents and flares

2.3.3.1 Description

Most off-gases from oil and gas production processes are collected and either vented to the atmosphere or flared. The main emission reduction options for process vents and flares are discussed in the following paragraphs. These options fall into two categories – reducing the volume of gas that comes off at the various stages of production, and reducing the percentage of methane from this gas which is emitted to the atmosphere.

There are six main options for reducing the amount of methane gas that must be vented or flared:

- Minimising strip gas in glycol dehydration
- Increasing the pressure of the condensate flash
- Recompressing process emissions
- Recovering and utilising process emissions as a fuel gas
- Reducing passing valves emissions
- Reducing purge gas streams

There are four options for reducing methane emissions from those gases which must be emitted from process vents and flares:

- Flaring instead of venting
- Improving flare efficiency
- Reducing pilot gas flow rates
- Improving pilot ignition systems

Minimising of strip gas in glycol dehydration

Natural gas is used as a strip-gas in the glycol regenerator. This means that it is added to the product gas, which has been dissolved in glycol, and it then comes off with the product gas when it is regenerated from the glycol. The use of strip gas improves the efficiency of the glycol regeneration process.

It is possible to minimise methane emissions from strip gas by changing the design and operation of this process. Options include reducing the amount of strip gas used (without compromising gas dryness or glycol quality), increasing the temperature at which the glycol is regenerated and using alternative stripping gases such as nirtogen or off-gases from the condensate separation process. These gases are normally vented, so use of these gases as stripping gas will not result in increased methane emissions. De Jager et al. [1997] suggest that these options could reduce total emissions for process vents and flares by as much as 20% world-wide, although the figure is likely to be lower for the EU where measures have already been taken to reduce emissions from gas processing. Also alternative drying schemes, such as "cild finger" or "Drizo" are available for the revamp of existing systems [Aarebrot, 2000].

Increasing the pressure of the condensate flash

Increase of the pressure of the condensate flash reduces the amount of methane that is desorbed from the condensate. Increase of this pressure may be important, as the feasibility of recompression or reuse of this gas improves, if this gas is released at higher pressures. The reduction potential, however, will generally be limited.

Recompressing process emissions

Process emissions that would otherwise be vented or flared can instead be compressed and recombined with the dried natural gas streams. In the Dutch onshore gas production, for example, this is done for most off-gases from glycol flashes and condensate flashes. Recompression of the off-gases from processes does not necessarily contribute to reduction of methane emissions, since the emissions from compression, treatment and transport are in the same order of magnitude as flare efficiencies. It would reduce carbon dioxide emissions as it improves overall use of resources.

Recompression is most feasible for higher pressures of process gas. It could reduce emissions from process vents and flares by as much as 75%.

Recovery and utilisation of process emissions as a fuel gas

Recovery and utilisation of process emissions as a fuel gas is an option if the quality of the gas is sufficiently high. Variations in quality over time may pose problems for gas turbines, therefore gas engines may be used as they are less sensitive to these changes. Both gas turbines and gas turbines engines are demonstrated technologies on- and offshore.

It is estimated that this option can reduce emissions from process vents and flares up to about 75%.

Reduction of passing valve emissions
Leaking valves are detected, using ultra-sonic equipment. Larger leaks may be indicated by the formation of ice on the outside of the low-pressure side of the valve; a result of adiabatic expansion of the gas.
Another option for detecting passing valve emissions might be the application of flow-meters in the vent-stacks. An increasing trend in continuous emissions is most likely a result of increasing passing valve emissions. Once a leaking valve is detected, repair (e.g. sealing) or replacement of the valves stops emission. It has been estimated that about 30% of vented emissions are as a result of passing valve emissions.

Implementation of an improved inspection and maintenance programme of the valves may significantly reduce passing valve emissions. The emission can, in theory, be reduced to a negligible amount.

Reduction of purge gas streams
Purge gas is normally applied in vent and flare systems to prevent air from entering the system. As the amount used is often unnecessarily high, reductions in methane emissions from this process can be achieved by reducing the amount of purge gas used. Reduced flows can be obtained by installing restriction orifices or flow meters. This option may reduce about 5% of the emissions of the subsector. A second option is to use an alternative purge gas, such as nitrogen. This is only applicable to process vents, where the energy content of the off-gas may become too low for them to be flared. Nitrogen is frequently used as a purge gas.

Flaring instead of venting
A flare requires a continuous minimum load. For this reason a certain amount of natural gas is continuously flared. Emission reduction of methane and other hydrocarbons by flaring results in extra carbon dioxide emissions and also in the emissions of e.g. nitrogen oxides. The overall environmental impact differs from case to case, and depends notably on the continuity or discontinuity of the off-streams that have to be vented or flared. For continuous off-streams, flaring is preferred. However, if off-streams are of a very discontinuous nature, venting might be preferred from an environmental point of view[1].

There are significant safety options to be considered, especially if this option is to be retrofitted on an offshore installation. The flare needs to be at a safe distance from the main part of the platform, and this may be an obstacle to implementation. However, the same holds for existing vent stacks which could ignite without compromising safety.

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[1] For example: In the United Kingdom's offshore oil and gas production, emissions of continuous venting (purging of vent systems, use of stripping gas in dehydration units and disposal of gas that is not considered to be economic to recover) and intermittent venting (depressurisation (blowdown) of pipelines, emergency shutdown) account to 70% and 30% of total offshore venting respectively [Woodhill Engineering, 1994].

When off-gases are flared instead of being vented, methane emissions are reduced by about 95 to 99.8%, depending on the flare efficiency. Nearly all offshore oil platforms and most offshore gas facilities in the EU have flare systems installed.

Improvement of flare efficiencies
Replacement of existing flares by state-of-the-art flares will result in a reduced methane emission, but as well in reduced emissions of other incompletely burnt components as CO, volatile organic components and soot. Flare efficiencies of 95-99% are typical [Woodhill, 1994] with EU flare efficiencies likely to be at the upper end of this range, with limited scope for improvement.

Reduced pilot gas flow rates
Pilot systems secure ignition of flared gases. The applied pilot gas flow rates are often higher than required, as operators want to be on the safe side. For the UK (offshore) it is believed that emissions from pilots could be reduced by 50% [Woodhill, 1994], with no costs. With respect to total emissions of process vents and flares this would result in about an emission reduction of 1%.

Improved pilot ignition systems
By applying flameout detection with spark re-ignition, the emissions of extinguished pilots (e.g. as a consequence of high wind) can be reduced. In the UK offshore industry this would result in an emission reduction of about 1% of emissions from this source-type [Woodhill, 1994].

2.3.3.2 *Cost of option*

The cost of the measures depend highly on the local situation on the process installations, so they may strongly differ from site to site (e.g. offshore versus onshore). In many cases space and weight constraints on offshore platforms will determine the applicability of the various options. The *specific* investment also depends on the throughput at the site: larger throughputs generally result in lower costs per tonne of methane avoided. Furthermore, investment will be smaller for new installations than for existing ones. The figures presented here are not valid for individual process installations, but are valid as an average value for all installations together.

On the basis of information provided in a number of interviews we make the following first estimate of the potentials and costs of methane emission reduction at offshore platforms:

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 Meuro of investment per platform (ranging from zero to 0.25 Meuro). For an average platform, having a methane emission of 800 tons per year, this means an investment of 600 euro per tonne of methane avoided per year (600 euro/(tonne CH_4/year)).

Increasing the recovery to 75% will generally require higher investments, for example 0.5 Meuro per platform (ranging from 0.25 to 1.0 Meuro), this means an investment of 1250 euro per tonne of methane avoided per year (1250 euro/(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 92 euro/tonne.

A further 10-15% can be reduced by replacement of vents by flares. Flaring of gas is always associated with costs which are not accompanied by profits. Onshore, and when new platforms are built offshore, flares may be installed at relatively low costs. Offshore retrofit of platforms will result in high costs. This is mainly due to the fact that both man-power and equipment have to be helicoptered in.

Investment costs of a flare are about 0.3 to 0.6 Meuro for offshore platforms in the Netherlands [De Jager and Blok, 1993]. For the UK investment costs are estimated at 1 (onshore) to 3 (offshore) Meuro; costs of retrofit of offshore platforms for flaring are estimated at 10 to 20 times higher [Woodhill, 1994]. The investment of this option is typically 3750 euro per tonne of methane avoided per year. 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.

Option	**Effect.**	**Share in subsector**	**Investment**	**O&M**	**Savings**	**Lifetime**
	(%)	(%)	euro/Mg CH /yr	euro/Mg CH_4	euro/Mg CH_4	year
Increased gas utilisation	25	100	625	6	92	15
Further increased utilisation	50	100	1250	13	92	15
Offshore flaring instead of venting	15	100	3750	112	0	15

Subsector is "Process vents and flares"

2.3.4 Energy requirements

2.3.4.1 Description

Energy is used in oil and gas production for compressors, pumps, and other auxiliary equipment, and for compressors used in gas transmission and distribution. This energy is usually supplied by burning some of the process gas in a reciprocating engine or a gas turbine. Emissions can be reduced by replacing reciprocating engines with gas turbines and by improving inspection and maintenance procedures for power generation equipment.

Use of gas turbines instead of gas engines
Replacement of reciprocating engines by gas turbines will reduce methane emissions because combustion is normally more complete in a turbine. However, gas turbines generally need a more constant fuel quality compared to gas-engines. So when gas turbines have to be applied in gas production, the possibility to use off-gases from processes for the on-site energy supply is reduced.
It is also possible that increased emissions of carbon dioxide due to lower efficiency of the gas turbine will negate any methane savings, but this will depend on the relative efficiencies of the turbine and the engine it replaces. US-EPA [1993] estimates that this option is applicable to 10% of emissions from the energy requirement sector, and reduces methane emissions by 90%. In the UK national transmission system, all compressors already use gas turbines rather than gas engines. In the rest of Europe, also the vast majority of drivers are turbines [OGP, 2000].

Improving maintenance of power generation equipment
Better design, monitoring and maintenance of engines and turbines can lead to emission savings of several percent [US-EPA, 1993] due to increased combustion efficiency and reduced fugitive emissions.

2.3.4.2 Cost of option

Option	**Effect.**	**Share in subsector**	**Investment**	**O&M**	**Savings**	**Lifetime**
	(%)	(%)	euro/Mg CH /yr	euro/Mg CH_4	euro/Mg CH_4	year
Use of gas turbines instead of reciprocating engines	90	5	3000	150	-	20
Inspection and Maintenance	70	20	-	18	92	1

Subsector is "Energy requirements"

2.3.5 Compressors

2.3.5.1 Description

Options related to the use of compressors relate to both the compression equipment and also the engines or gas turbines used to power these machines. There is therefore some overlap between the options considered here for compressors and those which apply more generally to energy requirement (Section 2.3.4).

Compressors are used throughout the process of natural gas production, and high-pressure transmission as a means of transporting and storing the fluid gas. The main sources of methane emissions are:

- Releases from valve actuators powered by methane

- Fugitive emissions from compressor seals, pipe flanges and valve stems
- Releases during the changeover from one compressor to another
- Releases from the depressurisation and venting of compressors and pipework during annual maintenance.

The main mitigation options are:

- Using hydraulically powered valve actuators
- Relocating of valves
- Minimising number of changeovers by on-line washing
- Recompression of gas during maintenance
- Reduced flushing of engines at start-up and shut-down
- Flaring of seal losses
- Improved sealing of compressors
- Electrical start-up
- Improving inspection and maintenance

Hydraulically powered valve actuators

Valve actuators are typically powered by natural gas, which is released during movement of the valve. They can be replaced by locally mounted hydraulic actuator systems, which are recharged using electric pumps. These can reduce methane emissions from this source to zero. For a new compressor station, the cost of hydraulic valve actuators is estimated to be less than natural gas powered actuators [Foster Wheeler Energy, 1996].

Relocating of valves

Relocating isolation and other valves as close to the compressor as safety criteria allow can reduce the volume of gas released during depressurising at changeover and for annual maintenance. For new plant it is assumed that there would be no additional costs for this design change.

Minimising number of changeovers by on-line washing

Compressor units are shut down and operations switched to the partner unit to equalise wear on machines, but also to allow for monthly turbine washes. In other industries, "on-line" washing, involving spraying deionised water into the compressor while online is frequently used for cleaning gas turbines. Adoption of this practice would require depressurisation for full cleaning only four times a year instead of 24, thus reducing releases associated with change over by over 80%.

Recompression of gas during maintenance

Emissions can be reduced through recompression of the emissions using a portable compressor unit, and re-routing them through the system. In this way on average about 20% of the emissions related to maintenance can be reduced.

Reduced flushing of engines at start-up and shutdown.
Investigations of gas-transporting companies indicate that flushing compressors or engines before start-up is not required [Coors, 1994]. Formation of an explosive mixture is prevented by the overpressure in the system. In this way on average about 5% of the emissions related to maintenance can be reduced.

Flaring of seal losses
Gas from compressor-seals is released in a controlled way, and it is well possible to feed these seal-gases to a low-pressure flare system.

Improved sealing of compressors
Seal-losses from oil-seals are much higher than seal-losses of gas-seals. So a change from compressors with oil-seals to compressors with gas-seals results in reduced emissions. US-EPA mention the replacement of wet seals by dry seals on centrifugal compressors (65-80% emission reduction); and early replacement of rings and rods on reciprocating compressors.

Electrical start-up
Electrical start-up instead of the use of a gas expander can be applied to new compressors and as a retrofit option. Costs for the use of this option in new installations are negligible. Application will reduce energy requirement emissions by 3%. The marginal costs are considerable for retrofitting. US-EPA estimates the investment at about 18000 euro per compressor, and additional annual O&M costs at 4500 euro [US-EPA, 1999]

Improving inspection and maintenance
Inspection and maintenance programmes to prevent leakage at compressor seals and valves can reduce emissions by up to 70%

2.3.5.2 *Cost of option*

No extra costs are ascribed to altering start-up procedures.

Investigations of gas-transporting companies indicate that recompression is economically attractive, when the amounts of gas recompressed are larger than 65,000 m^3 [Coors, 1994]. Onshore recompression is therefore often economically viable. Offshore it is harder to achieve, since all equipment has to be flown in per helicopter. This makes offshore recompression an expensive option (costs will roughly be about 10 times as high).

Option	**Effect.**	**Share in subsector**	**Investment**	**O&M**	**Savings**	**Lifetime**
	(%)	(%)	euro/Mg CH /yr	euro/Mg CH_4	euro/Mg CH_4	year
Altering start-up procedure during maintenance	100	5	-	-	92	1
Recompressing of gas during maintenance	75	20	-	-	92	1

No/reduced flushing at start-up	100	7	-	-	92	1
Electrical start-up (retrofit)	75	7	18000	360	92	20
Electrical start-up (new installations)	75	3	-	-	92	1
Improved sealing	60	10	6	0.1	92	25
Inspection and Maintenance	70	70	-	18	92	1

Subsector is "Compressors"

2.3.6 System upsets

2.3.6.1 Description

System upsets may be caused by pipe breakage or pressure surges which cause pressure relief valves to open. This is a rare occurrence, with a frequency much lower than the frequency of maintenance depressurisations and hence the emissions from this source are less than 2% of methane emissions from the oil and gas sector.

System upsets can be reduced by using automatic shut-off valves, which detect pressure surges. Implementing an adequate centralised administration system of the locations of pipes, and a system of checks in order to prevent accidental breakage during digging or construction work can also reduce system upsets. Such a system could reduce emissions from this source by 80%.

2.3.6.2 Cost of option

Option	**Effect.**	**Share in subsector**	**Investment**	**O&M**	**Savings**	**Lifetime**
	(%)	(%)	euro/Mg CH /yr	euro/Mg CH_4	euro/Mg CH_4	year
Inspection and Maintenance	80	90	-	2000	92	1

Subsector is "System upsets"

2.3.7 Transmission and distribution

2.3.7.1 Description

The downstream processes of transmission and distribution involve the storage and transport of natural gas from the production process to the consumer. These subsectors account for the majority of emissions from the oil and gas sector in the EU.

In the EU gas is primarily transported through networked pipeline systems. Opportunities to reduce methane emissions from the pipeline network arise through:

- Replacement of the grey cast iron networks
- Increasing the pipeline examination frequency
- Pressure management systems

- Recompression of gas during pipeline maintenance
- Gas conditioning
- Reducing of system upsets

Replacement of the grey-iron network

The length of grey-iron pipelines amounts to 140,000 km in the UK, 36,000 km in France, 13,000 km in the Netherlands, 11.500 km in Germany, and 2,500 km in Belgium [Rose, 1994; NC2-Germany, 1997; Bruchem, 1999]. At the moment, 99% of the Dutch households are connected to the NG grid. In the UK this percentage is 85%, in Belgium 59% and in France 54%. Grey cast iron networks date from when town gas was used, which was a wetter gas. The network includes hemp and lead joints which leak if they dry out. The change to natural gas therefore resulted in more leakage. Newer distribution networks are constructed of polyethylene (PE) or polyvinylchloride (PVC). Replacement of the grey cast-iron network by a modern pipeline system will reduce the emissions through leaks, that presently are at a level of about 5 tonne/km/year (varying from 2.5 to 11 tonne/km/year), by 95% [Rose, 1994; NC2-Germany, 1997].

Increasing the pipeline examination frequency

The alternative option is to improve inspection and maintenance programme to increase the frequency of leak detection and repair. This can be done by directly measuring gas concentrations along the network or by monitoring system pressures in possible risk areas. At present, in the Netherlands gas distribution pipelines are generally examined on average every four years, unless a leakage rate higher than 3 leaks per km was found during the last inspection. Increasing the frequency of survey helps identify leaks, particularly from welded steel, pipelines where corrosion is a problem, and there tends to be a relatively small number of large leaks. However, for jointed mains it has been shown increasing the frequency of surveys has been shown to have only limited benefits due to the very large number of small losses involved.

In the UK the Transco Leakage Survey Policy is now focused on risk prioritisation, i.e. identifying leakage which poses a significant risk first. This has resulted (since the introduction of the policy in 1995) in a significant reduction in the length of distribution main surveyed. Transco studies have established that much of the leakage from the grey cast iron network is comprised of a very high number of low flow leakages, many of which may not be detectable by a leakage survey. Costs for detecting such low flow leakages and carrying out subsequent repairs are not yet available.

It seems a reasonable estimate that in general emissions per km/year will be cut by 50% if the control frequency is doubled from every four to every two years, although this was not found in practice. Note that emission factors and control frequency practices differ from country to country.

Pressure Management Systems
Pending pipeline replacement, the introduction of pressure management systems (in the form of profile logging equipment or electronic clocks) to reduce the annual average pressure system in grey cast iron networks is one of the main tools to reduce pipeline emissions. Capital and installation costs vary across the network, as do benefits (reduced amounts of lost gas and fewer public reported escapes of gas). The UK and the Netherlands are two of the countries who apply this measure. There was no quantitative data available on reduced gas emissions and costs.

Gas Conditioning
Within the low pressure network, a widely utilised leakage reduction techniques to condition gas with monoethylene glycol (MEG) to swell the yarn within the joints of the grey cast iron mains. However, glycol may affect the new plastic lines, the control systems and domestic gas equipment. This technique has been utilised in the UK since the 1970s, but its benefits are decreasing as the amount of grey cast iron network decreases. The option has never been implemented in the Netherlands because of the aforementioned drawbacks.
Gas conditioning with distillate to treat rubber gasketed mechanical joints within the low pressure system is currently being considered in the UK, but the practicality and financial costs of the process have yet to be fully assessed**.**

Recompression During Pipeline Maintenance
Emissions during routine maintenance are caused when parts of pipeline or pieces of equipment are depressurised and flushed with air before maintenance begins. In most cases these off-gases are vented. Emissions can be reduced by recompression of the emissions using a portable compressor unit, and re-routing them through the system. It is estimated this can reduce the specific emissions by up to 80% and the emissions from all maintenance by 20%.
Recompressing of gas from venting compression stations is routinely carried out in several EU countries, like the UK and the Netherlands. There is no comprehensive overview of this measure of all EU countries.

System Upsets
System upsets may be caused by fracture of pipes or by pressure surges that cause pressure relief valves to open. This is a rare occurrence, with a frequency much lower than the frequency of maintenance depressurisations and hence the emissions from this source are estimated to be only 1.8% of methane emissions from the oil and gas sector.

System upsets can be reduced by using automatic shut-off valves, which detect pressure surges, although it is difficult to estimate the reduction in emissions which might occur from implementing this option. It has also been suggested that emissions could be reduced by implementing an adequate centralised administration system of the location of pipes, and a system of checks in order to prevent accidental breakage during digging or construction work. It has been suggested in studies carried out for countries such as the Netherlands that such a system could reduce emissions from this source by 80%, but the applicability and cost of this option are not known.

2.3.7.2 Cost of option

The cost of replacing pipelines vary considerably, ranging from 50 - 250 euro/m depending on the local situation and the pipe diameter. Transco [Bates, 1999] quoted 100 euro/m replacement costs. As most of the grey cast-iron network is in old cities we will stay on the high end of the cost range: 200 euro/m (40,000 euro/(tonne CH_4/year)). Cost savings are savings on the reduction of methane losses. The specific costs can be reduced by replacing the most vulnerable parts of the network only.

Option	**Effect.**	**Share in subsector**	**Investment**	**O&M**	**Savings**	**Lifetime**
	(%)	(%)	euro/Mg CH /yr	euro/Mg CH_4	euro/Mg CH_4	year
Replacement grey cast iron network	97	75	(20000) to 40000	0	180	50
Increasing the pipeline examination frequency	50	25	-	1800	180	1

Subsector is "Fugitive emissions"

2.3.8 Country specific implications

Within the EU, it is not expected that throughout the Member States significant differences exist occur in terms of costs and potential for emission reduction measures. The lion part of the production takes place in the United Kingdom and its supremacy is not to believe to diminish in the short term. The accessibility to international technology in the oil and gas industry is large, and therefore the prices are comparable throughout the Union. A large source of emissions is the distribution system of natural gas. The variability of the cost of replacement is rather determined by the accessibility of the grid then by country specific circumstances.

2.4 FROZEN TECHNOLOGY REFERENCE LEVEL

Table 2.5 shows the development in oil production in the EU countries from 1990 towards 2010. Today's oil production has increased by 40% compared to 1990 level. The projected production of oil in 2010 is about 25% lower, at about 10% higher level than the level in 1990. Emissions in the frozen technology reference case are proportional with the production.

Table 2.6 and Table 2.7 give the estimated primary production and consumption of natural gas in the EU-15 in 1990 and projected energy production consumption. EU-wide, the production of natural gas is predicted to grow with more than 40%. A large part of the growth already occurred in the period 1990-1995. The consumption is predicted to grow by 70%. A large part of the consumption is due to extra use for power production, which consumption more than double. Final natural gas energy demand is predicted to grow by 20%. Emissions arising from natural gas transport and distribution in the reference case are estimated to rise only with limited amount. New pipelines with relatively low leak rates will transport the bulk of the increased natural consumption to power plants. For fugitive emissions the increase in gas consumption by the non-power sector was assumed to represent new customers who require new distribution networks. Increasing the pressure of old distribution lines significantly was not considered feasible due to technical criteria of existing lines [Bruchem, 1999].

Table 2.5. Oil production and projection in the EU member states [Shared Analysis, 1999].

Primary Production Oil (PJ)	1990	1995	2000	2005	2010	% Change 1990-2010	% Change 1995-2010
AU	57.4	44.8	41.9	37.8	33.6	-42%	-25%
BE	2.0	0.2	0.0	0.0	0.0	-100%	-100%
DK	253.8	390.0	650.4	420.0	294.3	16%	-25%
FI	28.0	57.0	4.0	4.0	4.0	-86%	-93%
FR	142.4	166.6	105.7	95.3	84.8	-40%	-49%
GE	178.1	134.7	124.5	119.2	115.0	-35%	-15%
GR	34.9	19.2	0.0	0.0	0.0	-100%	-100%
IR	0.0	0.0	0.0	0.0	0.0		
IT	197.1	221.6	36.3	25.5	0.0	-100%	-100%
NL	168.7	147.4	153.8	141.2	128.7	-24%	-13%
PO	0.0	0.0	0.0	0.0	0.0	0%	0%
SP	33.3	32.6	27.0	28.0	28.3	-15%	-13%
SV	0.1	0.2	0.0	0.0	0.0	-100%	-100%
UK	3859.6	5553.8	5831.0	5496.7	4742.5	23%	-15%
EU	4955.5	6768.1	6932.2	6325.1	5385.8	9%	-20%

Table 2.6. Natural gas production and projection in the EU member states [Shared Analysis, 1999].

Primary Production Natural gas (PJ)	1990	1995	2000	2005	2010	% Change 1990-2010	% Change 1995-2010
AU	46.4	52.9	37.7	36.7	35.6	-23%	-33%
BE	0.4	0.0	0.0	0.0	0.0	-100%	-100%
DK	114.6	194.8	368.7	377.1	209.5	83%	8%
FI	0.0	0.0	0.0	0.0	0.0		
FR	101.4	117.0	46.1	23.0	0.0	-100%	-100%
GE	566.9	620.7	634.2	638.0	586.6	3%	-5%
GR	5.8	1.8	0.0	0.0	0.0	-100%	-100%
IR	79.3	91.9	32.3	0.0	0.0	-100%	-100%
IT	587.8	684.9	649.5	607.6	544.7	-7%	-20%
NL	2288.3	2533.1	2801.3	2723.5	2514.0	10%	-1%
PO	0.0	0.0	0.0	0.0	0.0		
SP	53.3	15.9	14.7	8.4	6.3	-88%	-60%
SV	0.0	0.0	0.0	0.0	0.0	0%	
UK	1714.5	2665.0	3980.5	4231.9	4106.2	139%	54%
EU	5558.9	6978.1	8565.0	8646.1	8002.9	44%	15%

Table 2.7. Natural gas consumption and projection for power production in the EU member states [Shared Analysis, 1999].

Primary Consumption of Natural gas (electricity and steam generation) (PJ)							
	1990	**1995**	**2000**	**2005**	**2010**	***% Change 1990-2010***	***% Change 1995-2010***
AU		114.7	138.7	138.3	151.7		32%
BE		110.6	194.9	203.9	269.4		144%
DK		58.8	114.0	123.6	115.3		96%
FI		99.8	107.3	116.2	115.0		15%
FR		189.2	308.1	308.0	386.7		104%
GE		699.9	702.8	705.5	955.0		36%
GR		0.6	55.7	72.3	123.3		20997%
IR		48.9	83.2	104.2	139.6		186%
IT		633.2	1190.5	1115.6	1350.5		113%
NL		501.2	519.5	607.2	672.9		34%
PO		0.0	48.6	122.8	166.4		
SP		112.1	183.2	283.0	414.8		270%
SV		14.4	46.1	72.2	78.1		441%
UK		638.6	1160.7	1368.9	1766.8		177%
EU		3222.0	4853.4	5341.9	6705.5		108%

Table 2.8. Natural gas consumption and projection (final energy demand) in the EU member states [Shared Analysis, 1999].

Primary Consumption of Natural gas (final energy demand) (PJ)							
	1990	**1995**	**2000**	**2005**	**2010**	***% Change 1990-2010***	***% Change 1995-2010***
AU		122.4	137.1	140.5	145.9		19%
BE		306.4	347.0	362.3	372.8		22%
DK		57.0	75.3	86.7	90.7		59%
FI		17.1	26.8	37.0	60.1		251%
FR		917.6	1001.0	1029.3	1049.8		14%
GE		1703.4	1845.4	1862.6	1833.6		8%
GR		0.0	5.5	33.3	52.1		
IR		23.0	31.0	35.4	39.9		74%
IT		1169.9	1270.1	1340.9	1373.9		17%
NL		791.0	907.9	964.3	987.3		25%
PO		0.0	19.5	34.5	47.6		
SP		188.6	315.4	404.7	473.5		151%
SV		11.9	14.0	14.8	16.6		39%
UK		1696.7	1939.2	2047.8	2053.6		21%
EU		7004.9	7935.1	8394.0	8597.4		23%

AU: Austria
BE: Belgium/Luxembourg
DK: Denmark
FI: Finland
FR: France
GE: Germany
GR: Greece
IR: Ireland
IT: Italy
NL: Netherlands
PO: Portugal
SP: Spain
SV: Sweden
UK: United Kingdom
EU: European Union

2.5 AGGREGATION OF OPTIONS

The set of options per source-type as described in the previous paragraphs will be used in the calculation of specific costs of emission reduction. In most cases, these are already aggregated sets of options. It should be noted that it is not easy to determine which option is the preferred one, as this often depends on many local parameters. By combining several options indicating the share of it in its total (experts guess) and by weighing the costs and average potential an cost figure was generated. Reduction in this way of the number of measures will also make it easier to interpretate the final results.

The options are listed in Table 4.1 in chapter 4. A more detailed list of measures is presented in Annex 3.

3. OPTIONS TO REDUCE METHANE EMISSIONS FROM COAL MINING

3.1 INTRODUCTION

Coal is produced over the world both from underground and surface mines. Underground mines produce only hard coal. The production of surface mines may include brown coal as well. Since 1971 world production of hard coal has grown at 2 to 2.5% per year until 1992 when production flattened out [IEA Statistics, UN]. Production in the European Union has declined sharply due to cheaper overseas coal. In 1998 worldwide coal production amounts to about 94 EJ. In the EU about 5 EJ was produced. The main producers are Germany 2.6 EJ and United Kingdom 1 EJ [BP-Amoco, 1999]. Table 3.1 gives an overview of total coal production in the EU from 1990 to 1998, and projected coal production in 2000, 2005 and 2010 [Shared Analysis, 1999].

The production capacity in the EU is decreasing because of high costs and relatively cheap import. In 1993, labour costs, the most significant component in the final cost of delivered coal amounts in Australia to 10 euro/tonne, in South Africa to 3 euro/tonne, while labour costs in United Kingdom amounts to 23 euro/tonne and in Germany to 90 euro/tonne [Coal information 1995, 1996].[2]

Table 3.1. Coal production and projection in the EU (PJ). Figures in italic taken from the proceeding year.

Country	1990	1995	1996	1997	1998	2000	2005	2010
AUT		14	*14*	*14*	*14*	17	11	11
BEL		11	*11*	*11*	*11*	0	0	0
FIN		86	*86*	*86*	*86*	72	74	72
FRA	327	214	214	176	147	177	109	26
DEU	5078	3113	2920	2799	2568	2717	2374	2088
GBR	2363	1353	1278	1236	1052	858	746	632
GRE	297	331	344	339	348	343	372	369
IRL		49	*49*	*49*	*49*	34	29	26
ITA		3	*3*	*3*	*3*	6	6	6
ESP	683	561	545	536	503	386	386	352
EU	**8749**	**5624**	**5352**	**5138**	**4669**	**4522**	**4021**	**3498**

Source: 1990-1998: BP-Amoco (1999), Coal Information 1995 (1996), EC (1998)
200-2010: Shared Analysis (1999)

[2] Some care should be taken while comparing the labour costs, because the publicly available data have been compiled on a different basis in different countries.

3.2 EMISSIONS

3.2.1 Emission mechanisms

The process of converting vegetation into coal also produces substantial quantities of methane. Estimates suggest that as much as 200 m^3 of methane per tonne of coal may be generated during this process [Smith, 1992]. Most of this methane is subsequently lost by migration through the surrounding strata. However, undisturbed coal seams may still contain up to 25 m^3 per tonne of coal, absorbed within the pore structure of the coal. This residual methane is emitted when the coal is mined and used.

Methane is present in coal as a result of two distinct processes:

- Biodegradation of plant matter in the initial stage of coal formation;
- Methane formation during coalification, after deep burial.

The amount of methane generated during coal mining is primarily a function of coal rank, depth, and mining methods. Coal rank represents the degree of coal formation and depends on the history of the coal seam; high rank coals such as (hard) bituminous coal contain more methane than low rank coals such as lignite. The methane in coal is held in place by the hydrostatic pressure of the pore fluids in the surrounding strata. For a given geological setting methane content tends therefore to increase with depth, thus emissions from surface mines are generally lower than those for underground mines.

Methane can be emitted from coal at various stages in the coal chain and its release is influenced by a number of geological and technical factors. Geological factors include the gas storage capacity of the coal and the nature of the coal itself. Technological factors which may affect methane release include the mining methods and the rate of extraction of the coal [Lama, 1991].

Methane is emitted when the coal is de-stressed and fractured as part of the mining operation, with further, but reducing, emissions occurring for some time after. The gas released comes not just from the seam being worked, but also from the adjoining strata and seams. The amount of methane released can be more than 100 m^3 per tonne of coal produced. The process of natural desorption can be speeded up by the drilling of boreholes and other gas drainage techniques. These holes may be sued to drain the methane off prior to, or during normal mining procedures.

Coal bed gas is normally over 90% methane. The remaining gas is made up of carbon dioxide, nitrogen, argon, and helium. The gas typically contains between 2 and 5% of ethane and higher hydrocarbons. Average pore size and volume vary with the rank and carbon content of the coal. The amount of methane absorbed generally increases with the rank of the coal.

Methane emissions occur along the entire supply chain from the mine up to the end-user. The majority of the emissions come from gassy underground mines and hence we will focus on this type of mine.

The following stages in the coal supply chain can be distinguished:

- Extraction of the coal
- Transport of coal in the mining district
- Coal washery/preparation plant and mine-side stockpiles
- Transport to end users.

The contribution of each of the stages and the absolute amounts of emissions depends on a number of factors, like the initial gas content, particle size, diffusivity, density of packing, movement of ventilation air and elapse time. Calculation to two different coal layers explored under two different scenarios showed that the percentage of gas released during mining and preparation vary from 86% to 96%. A minor part (4-14%) is released during transport and storage after the winning. Figure 3.1 gives the relative global contribution of the emissions from each stage of the coal supply chain. Open cast mining releases methane directly to the atmosphere but makes only a small contribution to the total. This is because the seams being exploited are generally close to the surface and therefore retain little of their original methane.

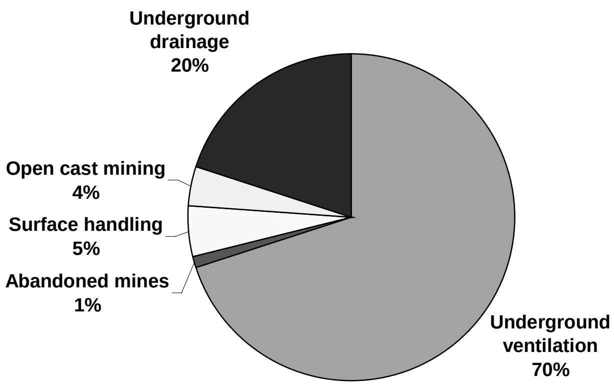


Figure 3.1. Sources of coal-related methane emissions [IEA GHG, 1998].

3.2.2 Emission in EU-15

In the past various studies are undertaken to determine the methane release factors from coal mines. Table 3.2 gives a compilation of the methane release factors for European countries. In this section a description is given on the methane emissions and utilisation in the European countries.

Table 3.2. Methane release factors for European Countries.

Coal type	**Methane release factor (m^3/t)[1]**	**Source**
Western Europe (all coal and lignite)	11.2	Barns and Edmonds, 1990
EC countries (brown coal)	0.015	Selzer and Zittel, 1990
Germany (hard coal)	25.7	Zimmermeyer, 1989
Germany (underground)	22.4	CIAB, 1992
Germany (brown coal and lignite)	0.015	CIAB, 1992
Poland (underground)	12.5	CIAB, 1992
United Kingdom (deep)	15.3	BCTSRE, 1992
United Kingdom (underground)	15.1	CIAB, 1992
United Kingdom (open cast)	0.5	BCTSRE, 1992

[1] Not always a clear distinction is made between methane released at the coal seam and methane released into the atmoshpere.

Germany

It has been calculated [Zimmermeyer, 1989] that a methane release factor of 25.7 m^3/t of saleable coal output can be assumed for hard coal from Germany (before unification). Methane emissions from the coal following mining were not considered. Emissions from surface mines producing only brown coal (lignite) was considered to be negligible. Multiplying the release factor by the production rate gave a total methane production of 1.2 Mt for 1989. Around 27-30% of this total is drained of which 69% (approximately 0.24 Mt of the total) was used for energy production. The remainder (around 0.96 Mt/yr for 1989) is released to the atmosphere. For 1990 these emissions were estimated at 0.97 Mt. The estimate of Boyer et al. [1990] using the extrapolation from US mines is significantly higher for surface mining (0.7 Mt). In 1993 the utilisation of coal bed methane is estimated at 23% [Williams et al., 1996].

The UBA [1999] gives an own estimate based on average emission factors for hard coal, brown coal and methane concentration in the mine gas. Table 3.3 gives an overview of the coal production in Germany from 1987 to 1996, and the associated mine gas production and methane utilisation. In 1996, UBA estimated an emission of 0.9 Mt of methane from hard coal and 0.013 Mt of methane from brown coal. The emission in 1990 from abandoned mines is estimated at 0.01 Mt methane. The share of methane utilised from mine gas increased from 1987 to 1996 from 20 to 32%, but stays constant in absolute terms at about 0.3 Mt per year. The increase in share is mainly due to the decrease of coal production from mines without methane utilisation equipment. The German Coal Mining Association (GCMA) estimated the methane production in 1990 at 1230 kt, from which 260 kt (21%) has been utilised. For 1998 GCMA estimated a total methane production of 630 kt with an utilisation of 204 kt (33%). According to the German Coal Mining Association, there are substantial regional differences on the applicability of utilisation of mine gas. In Saarland, about 70 to 80% of the mine gas is utilised, whereas in other parts in Germany, like the Ruhr area, this is much lower, mainly because the mines lie scattered over a large area [Weber, 1999].

Table 3.3. Coal production and methane emissions and utilisation of mine gas in Germany

Year	Hard Coal: Coal production (kt/year)	Hard Coal: CH4 emission (kt/year)	Brown Coal: Coal production (kt/year)	Brown Coal: CH4 emission (kt/year)	Share Methane utililised %
1987	76,300	1412	417,597	30	20%
1988	73,303	1356	418,936	30	22%
1989	71,428	1321	410,897	30	19%
1990	70,158	1298	356,850	26	18%
1991	66,481	1230	279,578	20	21%
1992	65,899	1219	241,812	17	24%
1993	58,283	1078	221,802	16	28%
1994	52,406	970	207,078	15	30%
1995	53,561	991	192,756	14	29%
1996	48,197	892	187,180	13	32%

Emission factor hard coal = 18.5 kg/tonne coal
Emission factor brown coal = 0.072 kg/tonne coal
Emission factor mine gas = 0.32 kg CH4/m3

Source: UBA (1999)

United Kingdom

In 1998, in the United Kingdom 180 mines were operational. Sixty-two of them are underground mines. Seven underground mines have an annual production rate of higher than 1 million tonnes. These mines are responsible for over 70% of total UK hard coal production. Estimates for methane released from coal mines in the UK, produced by British Coal, are based on direct measurements of gas flows from fan drifts and vent pipes [BCTSRE, 1992]. It is estimated that a methane release factor of 15.3 m^3/t can be assumed. Calculations based on this factor suggest that coal mining in the UK resulted in the release of 0.75 Mt of methane in 1990. This value is considerably less than the 1.6 Mt estimated by Boyer et al. [1990]. In 1990, about 13% of the coal bed methane has been utilised in the United Kingdom. In 1993 the utilisation of coal bed methane is estimated at about 20% [Williams et al., 1996].

According to RJB, producing more than 90% of British underground coal, they produced in the first six months of 1999 in total 114 kt of methane. That comprises of 86 kt at low concentration in the ventilation air and 28 kt from the methane drainage system. Out of this total 8.5 kt (7.5% of total methane; 30% of recovered methane) was vented to the atmosphere [Allen, 1999].

France

France is not a major coal producing country with annual production rate at less than 12 Mt coal. In 1990 and in 1993 there was no large-scale use of coal bed methane, although some local users in the Nord-Pas-de-Calais Basin are supplied with small quantities. According to the Second National Communication of France, the majority of the methane released by active and abandoned mines is captured and used for heating. In 1996, less than 20% of the methane due to coal mining has not been captured.

Table 3.4 shows the development of the methane emissions from coal mining in the EU-15. It should be noted that the emission figure for 1998 given by the UNFCCC is about twice as high as the emstimate given by the GCMA, 807 and 422 kt methane, respectively.

Table 3.4 Emissions of methane from coal mining in the European Union (in kt CO_2 equivalent). Figures in italic refer to proceeding year.

Country	1990	1991	1992	1993	1994	1995	1996	1997
BEL	294	189	63	0	0	21	21	21
DEU	25767	23541	22554	19320	17031	17577	15414	16947
DNK	63	84	84	105	126	126	126	126
ESP	12852	11844	12138	11928	11088	10920	10920	10920
FIN	21	0	0	0	0	21	21	21
FRA	4326	4032	4200	4368	4473	4431	3381	2877
GBR	17409	17787	17052	11046	7035	7749	7287	6867
GRC	924	945	987	987	1008	1029	1071	*1071*
ITA	105	105	105	105	63	63	63	63
PRT	63	63	63	63	42	*42*	*42*	*42*
EU15	**61761**	**58527**	**57183**	**47859**	**40824**	**41937**	**38304**	**38913**

Source: UNFCCC (1999)

3.3 EMISSION REDUCTION OPTIONS

3.3.1 Introduction

The use of methane drainage technology in underground mines is not new. Generally, it is practised when normal ventilation practices do not meet safety and statutory requirement. Technology of gas drainage using surface boreholes and drainage on a larger scale using longer boreholes drilled into the seam from underground is a more recent development.

Drainage of gas from coal seams either prior to or immediately before extraction of coal is called pre-drainage. Extraction of gas immediately after the extraction of coal from a seam where gas is drained from the mined out area is called post-drainage. Most commonly, drainage is carried out in advance. Drilling usually takes place from the current working face or from adjacent working areas. In some cases, however, it may be necessary to drive a separated heading specifically for drainage purposes. The particular technique selected, and the length and the spacing of the drainage holes, depends on local geological conditions. All systems require suction to be applied to the drainage holes.

Gas emitted from the coal seams and captured in drainage pipes can be used depending upon the methane content. Commonly uses are as a fuel, for boilers and furnaces, internal combustion engines, feedstock for the chemical industry and as a supply to household. Coal bed methane is already produced commercially, particularly in the USA. In most cases it is used purely as an alternative source of natural gas.

The ultimate use of the gas depends on a number of factors, such as the proximity of local industry, townships and availability of infrastructure such as gas and electricity grids. In addition to these geographical constraints, the quality (heating value and purity) of the mine gas is also an important factor. The heating value of the mine gases is dependent on the composition of the gas in the coal seam (presence of higher hydrocarbons can have very beneficial effects on the heating value), the method of gas drainage and leakage in the system.

Air sucked into the mine gas system is the most common dilutant. Carbon dioxide present in the mine gases comes from the seam gas itself. For the burning of captured gases, a certain minimum percentage of methane must exist to ensure that a flame can be maintained and the danger of explosion of air-methane gas is eliminated. Methane is explosive at concentrations of between 5 to 15% in atmospheric air. This range widens as the pressure is increased above atmospheric. This can have implications where it is necessary to compress the gas, such as prior to use in a gas turbine, and can therefore limit the range of end used. The lower limits for the methane content range from 24-40%, and vary from country to country. Legislation in the United Kingdom prohibits the utilisation of mine gas containing less than 40% methane, although this figure can be reduced to 30% under certain circumstances. In Germany the limit is lower, at 25%.

Requirements for use in other industries may narrow the limits. In gas turbines, the percentage of gas should be above 50%, chemical industry generally requires methane percentages over 60%, and the pipe line gas prior to upgrading usually about 75-80%.
If dilution is not a problem, mine gases have an advantage over natural gas as they rarely contain any measurable traces of sulphur, which is common in some natural gases.

3.3.2 Utilisation of mine methane

The utilisation of mine methane has a surprisingly long history. The earliest recorded example was at Salton Colliery in Northwest England as long ago as 1730. The gas was brought to the surface through a square wooden pipe and was used to heat specially constructed furnaces. In the 1940s mine gas was used to generate the mine's own electricity or to drive steam-powered winding engines and ventilation fans. At the moment mines generally have electric winders and fans and take their electricity from the public grid. Gas may have limited application, e.g. in providing hot water for showers and space heating for offices and other buildings. These residual uses are not sufficient to use all gas at mines, which practice methane drainage, so other options must be considered.

Worldwide 25% of the emitted methane is being captured. Despite of the available options, less than 40% of the captured methane by mine drainage schemes is currently used for fuel purposes. This is equivalent to about 10% of the total mining related emissions. In Europe about 50% is captured from which about 25% is utilised. The remainder is flared or vented to the atmosphere. Table 3.5 gives an overview of methane capture and utilisation in the most important coal producing countries. Table 3.6 gives a more detailed scheme of utilisation of captured mine gas in Germany.

Table 3.5. Methane captured and proportion utilised of mine gas in the main coal producing countries.

	Methane captured (% of total emitted)	Proportion Utilised (% of total emitted)
China	9	5
Former USSR	28	4
USA	30	19
Germany	63	25
Poland	49	14
United Kingdom	18	20
Others	30	14
World Average	**25**	**9.7**

Source: IEA (1998)

Table 3.6. Utilisation of mine gas in Germany in 1985.

Location	**Reden**	**Losenthal**	**Kamp-hausen**	**Ensdorf**	**Gottelborn**	**Waridt**
Captured (Mm^3)	59.2	33.4	6.2	2.4	21.7	58.9
Total (Mm^3)	182					
Use	Used by mines	Chem. Industry	Power plant	Mining Process	Other uses	Open Flared
	17.9%	18.4%	17.4%	3.8%	1.9%	40.5%

Source: Lidin (1990)

As mentioned earlier, the use of mine gases depends upon the quality of the gas. Some of the most common uses of mine gases discussed below are:

- Thermal use in boilers
- Firing of furnaces, kilns and ovens
- Use in turbines and internal combustion engines
- Enrichment of drained mine gas
- Utilisation off-site
- Flaring

Thermal use in boilers

This is the simplest and most common application of mine gases requiring low investment and imposes least conditions in use. In 1988, 30 mines were using this technology in the UK. In Germany, it were also about 30 mines. Another option is a boiler combined with a steam turbine. It would have advantages, as boilers are relatively tolerant of varying fuel quantities. However, the thermal efficiency would be comparatively low given the modest steam conditions, which would be necessary. This option is not therefore normally used.

Firing of Furnaces, Kilns and Ovens

The use of mine gas as a fuel in dryers is common. At the Gilson à la Croyère Works in Belgium, mine gas was preferred to town gas for firing certain ovens because it contained no measurable trace of sulphur. Mine gas was also utilised in coke ovens in the UK and elsewhere and is still utilised in some cases. Formerly the corresponding quantity of coke oven gas thereby released was sold as town gas. In these cases, investment in pipes for transmission of mine gas paid off, even when distances between collieries and coking plant were large. In the UK, mine gas has been utilised to fire kilns at a number of brickworks.

Use in turbines and internal combustion engines: Gas turbines

Gas turbines of varied capacity are available for use with mine gas as long as the methane content exceeds 40%. If available, natural gas can be added to upgrade the mine gas to the standards required. The size of the turbines typically varies from 1 MW to 20 MW. One example was the 1.3 MW Konigsberg KG 2/3 radial gas turbine, which was installed at Point of Ayr Colliery in the UK in 1978. The machine was a comparatively simple light-weight unit, originally designed for power generation on North Sea oil platforms, and its efficiency was only about 25%. However the overall efficiency was improved by using the waste heat from the exhaust to produce hot water.

A far more sophisticated system was installed at Harworth Colliery in the UK. This uses a combined cycle, based on two 4 MW gas turbines. The exhaust heat from these is fed to two waste-heat boilers, which supply steam to a single 10 MW steam turbine. In the event of a fall in the gas quality it is possible to fire it directly into the waste-heat boilers. The result is a very flexible system, although one with high capital costs. At Appin Colliery a 16.8 MW turbine was installed in 1988 and operated until 1995. The turbine generated 12 MWe.

Use in turbines and internal combustion engines: Spark-ignition reciprocating engine

Mine gas can be used in a spark ignition engine, either in a naturally-aspirated or turbo-charged form. A current example is the Appin coalmines in Australia with a production of 2 million tonnes of coking coal per year. The mines have installed in total ninety-four 1 MW engines. The engines run on drained gas (90% methane, 10% carbon dioxide) and about 20% of the generated mine ventilation air (0.4% methane). These have been operating since 1996. The plant consumes about 95,000 tonnes of methane annually. The engines used are modified Caterpillar diesel engines – there being no readily available gasoline engines of this size – and were based on a unit previously developed for use on landfill gas. Reasons for using spark-ignition engines instead of gas turbines include: modular (flexible) design based on unit developed for landfill gas utilisation; low fuel gas pressure and high flexibility in dealing with variable gas supply. The engines efficiency is about 35% and the availability about 90% [Ecoal, 1999].

Use in turbines and internal combustion engines: Dual-fuel compression-ignition engine

Mine gas can be used to fuel a compression-ignition engine, but a small amount of diesel oil has to be used as a 'pilot fuel' to initiate ignition. The thermal efficiency is marginally higher than for a spark-ignition engine (typically 36% compared with 34%), but this must be offset against the cost of the diesel fuel. The advantage is that it is generally possible to operate as a 'simple' diesel engine in the event of an interruption to the gas supply; the engine can switch rapidly from one fuel to another. This can be useful if a 'secure' electricity supply is required. Fixed internal combustion engines do not require high quality gas; the minimum requirements are about 30% methane. Due to their size, they can be easily reallocated. At Manton Colliery, UK, dual-fuel engines have been used with drained gas, with a total capacity of more than 4 MWe.

Ventilation air

Most mine gas is traditionally released to the atmosphere in the ventilation air used in the mine. The methane levels of the vented air must be below 5% for safety reasons – above 5% the mixture forms an explosive gas. The level is frequently as low as 0.5% to comply with relevant regulation and in all major coal producing countries methane in mine air is restricted to a maximum of 1-2%. Despite this low-level concentration, there may be opportunities to use ventilation air as combustion air in turbines or boilers. Depending on its concentration and the generator technology, ventilation air could supply between 7 and 15% of a generator's energy (or higher if methane concentrations are in excess of 0.5%).

Simply flaring is not viable, since the concentration of methane is too low to support combustion. The more recent technology of catalytic incineration could ease this by reducing the required operating temperature, although poisoning may be a problem. In either case, additional fuel would be required for start-up and to support combustion during periods when the concentration of methane was low. Such support fuel could, of course, come from an associated methane drainage system.

A few alternative technologies are developed to eliminate and even utilise methane in ventilation air. Natural Resources Canada describes a catalytic flow-reversal reactor that can eliminate methane as dilute as 0.1% (v/v) in air, with no external heat requirement. For air with methane concentrations above 0.3% heat can be recovered with efficiency between 40 and 90% depending on the inlet methane concentration. The technology is still in a developing stage. In 1998 a pilot unit of 22 kW operated successfully on mine gas of the Phalen mine. For 2000 a 1 MW project is planned. The designers expect the technology mature within 3 years [Sapoundjiev and Sejnoha, 1999]. Technology based on the same principle is also developed in Germany and Sweden [Grace, 1997]. A conversion rate of methane to power between 20 and 30% is claimed, depending on the concentration of methane in the air.

As an alternative system to incineration, biological oxidation could be considered. Bacterial systems (‘methanotrophs’) are known, which are capable of converting methane to carbon dioxide. These could be sued in an installation such as a soil bed filter which, although large, would be relatively cheap to install. There is, however, no practical operating experience of such a system.

Finally, the methane content of the ventilation air could be enhanced by one of the several adsorption-based techniques. Unfortunately, methane is not strongly absorbed on any of the substrates currently in use. The technique could, however, be considered as a means of obtaining the relatively small increase in concentration required for stable incineration.

Enrichment of the drained mine gas

The drained mine gases can be enriched by one or more of the following processes:

- By combining gases from different sources which can result in both stability of gas composition and quantity of gas available;
- Upgrading the gas;
- Use of better methods for control of leakages; separation low and high concentrated methane areas by for instance providing duplicate ranges, etc.

Upgrading of gas using methane technology is highly effective. However, the method requires fairly high amount of energy and is effective only when the initial composition contains only small amount of impurities that need to be removed. Carbon dioxide can be removed easily by cryogenic methods. Oxygen is very difficult to remove.

Flaring

Flaring combusts the gas and is a disposal rather than a utilisation method, reducing methane emissions by 95-99% depending on the flare efficiency. Flaring produces no economic benefit, which is why it has not been done in the past. There may also be legislative barriers to flaring, for example in the United Kingdom legislation is interpreted as prohibiting flaring of mine gas at present. According to RJB flaring is not performed because of safety reasons [Allen, 1999].

Utilisation off-site

Mine gas has been widely used by other industries; examples include brickworks, potteries, glassworks, and chemical industry. Depending on the heating value of mine gas, and the requirement to construct a dedicated pipeline, this option is only likely to be economic generally if the distance is less than about 10 km.

Utilisation off-site. Mine Gases as a Chemical Feedstock

Methane in drained mine gas can be used for the production of carbon black, hydrogen, ammonia, acetylene, nitric acid, methanol, formalin and chlorine derivatives. Important in its use is that the mine gas must be of high quality, > 90% of CH_4.

In Belgium, Sociète-Carbochimique de et à Terte used a methane cracking installation to produce hydrogen for synthesis of ammonia with a daily production of 70 tonnes. In Kyushu, Japan, mine gas with 70% of CH_4 was used for the production of ammonia and other substances.

Utilisation off-site: Auxiliary fuel

An interesting option would be to supply gas, as an auxiliary fuel, to a nearby coal-fired power utility; or even better to an oil- or gas-fired one. The amount of gas produced by a typical EU coal mine, compared to the size of a modern power plant, means that it would only serve as an auxiliary fuel. However, for this very reason, it would require only minimal modifications to the boiler.

Another option that have been proposed is upgrading to pipeline quality gas. Some authors have shown that this route can give satisfactory financial returns, but no mining company has actually gone this route to date.

3.3.3 Methods to recover mine gas

Four strategies can be distinguished to recover methane from coal mining:

- Enhanced gob well recovery
- Pre-mining degasification
- Ventilation air utilisation
- Integrated recovery

Enhanced Gob Well Recovery is an approach that seeks to improve and augment methane recovery techniques that are already in place at a mine so that recovery is more efficient. Gob areas consist of fractured rock and coal that have collapsed into mined-out areas. Since these areas are considerably more permeable than intact coal and rock, methane stored above and below the coal seam is released during the creation of this gob area. The proximity to the lower pressure of the mine results in the flow of significant quantities of methane into the mining workings. Much of this released methane is emitted to the atmosphere rather than being utilised. Enhanced Gob Well Recovery will improve the efficiency of existing recovery systems and expand the use of these techniques. Between 20% and 50% of the total methane emissions may be recovered with these techniques, depending upon the site-specific geologic conditions.

Table 3.7. Methane recovery and utilisation strategies..

	Enhanced Gob Well Recovery	Pre-mining Degasification	Ventilation Air Utilisation	Integrated Recovery (combined strategies)
Recovery techniques	➢ In-mine boreholes ➢ Vertical gob wells	➢ Vertical wells ➢ In-mine boreholes	➢ Fans	➢ All techniques
Support techniques	➢ In-mine drills and/or basic surface riggs ➢ Compressors, Pumps, and other facilities	➢ In-mine drills and/or advanced surface rigs ➢ Compressors, pumps and other facilities	➢ Surface fans and ducting	➢ All techniques ➢ Ability to optimise degasification using combined strategies
Gas quality	➢ Medium quality (11-29 MJ/m^3)	➢ High quality (32-37 MJ/m3)	➢ Low quality (<1-5% CH4)	➢ All qualities
Use options	➢ On-site power generation ➢ Gas distribution systems ➢ Industrial use	➢ Chemical feedstocks and those options listed for medium quality gas	➢ Combustion air for on-site/nearby turbines and boilers	➢ All uses
Availability	➢ Currently available	• Currently available	➢ Currently available	➢ Currently available
Capital requirements	➢ Low	➢ Medium/high	➢ Low	➢ Medium/high
Technical complexity	➢ Low	➢ Medium/high	➢ Low	➢ High
Methane reductions	➢ Up to 50%	➢ Up to 70%	➢ 10-90%	➢ 80-90%

Source: US/Japan WG on Methane (1992)

Pre-mining Degasification is a strategy that seeks to recover methane from targeted coal seams prior to active mining. During mining operations stored methane flows laterally and vertically towards the exposed working face, and eventually into the mine workings where it may create a severe safety hazard. The conventional method for removing mine gas vents methane into the atmosphere. Pre-mining degasification recovers this otherwise wasted resource before mining begins, thereby reducing the methane releases associated with future mining activities. The two primary techniques are in-mine horizontal boreholes and vertical wells drilled from the surface. Underground conditions determines whether this might be a viable option.

Ventilation Air Utilisation is a strategy that uses the considerable volume of mine gas that is currently vented into the atmosphere from all underground mines. Developing uses for ventilation air can significantly reduce methane emissions to the atmosphere from coal mining.

An Integrated Recovery system can take full advantage of all the available strategies for reducing methane emissions from coal mining. In many mines, using two or more methane recovery approaches (e.g. pre-mining degasification with horizontal boreholes and vertical gob wells) can optimise mine degasification, achieving the maximum improvement in mine safety and productivity and realise economics of scale as fixed costs are shared. Integrated systems of methane recovery and utilisation can take full advantage of all the available strategies for reducing methane emissions from coal mining.

3.3.4 Implementation of the options

All the major EU coal producers already have some recovery and utilisation of mine methane. In 1990 and 1993 the utilisation of mine gas in Germany is estimated at 21% and 23%, respectively [Williams, 1996]. UBA [1999] estimates an utilisation rate of 17% in 1990, increasing to 32% in 1996. In 1990 and 1993 the utilisation of mine gas in the United Kingdom is estimated at 13% and 20%, respectively [William, 1996]. Data from the Second National Communications indicates a utilisation rate of 11% in 1994. Recovery and utilisation in Spain are estimated to be lower at 5%. For France, the Second National Communication states that all production of coal is planned to finish by 2010.

Technically it might be possible to recover and utilise coal mine gas to a high degree. The economics to implement the options, however, depend on the local circumstances. An option cost-effective at one location could turn out to be expensive in another location, depending on local conditions as the density of mine sites (requirement of infrastructure), methane content of the coal and possibilities for utilisation. The following assumptions are therefore made about the potential for recovery and utilisation for each of these four countries. Assumptions about the measures already installed are based on the premises that lowest cost measures have been installed first.

- **UK and Germany** (see Table 3.8): a recovery and utilisation rate of at least 30% could be achieved in all mines, a 50% recovery and utilisation rate at mine equivalent to 70% of coal production, a 70% rate achieved at mines equivalent to 40% of the coal production, and a 90% rate achieved at mines equivalent to 20% of the coal production. To achieve it’s 1990 level of utilisation rate of 17%, Germany is assumed to have 30% recovery and utilisation at sites equivalent to 33% of production and 70% recovery and utilisation at mines equivalent to 10% of production. For the UK to achieve its 11% utilisation rate, it is assumed that there is a recovery and utilisation of 30% at mines equivalent to 37% of production.
- **Spain**: a recovery and utilisation rate of 30% could be achieved in 50% of the mines. To achieve its utilisation rate of 5%, it is assumed that there is a recovery and utilisation rate of 30% at mines equivalent to 17% of production.
- **France**: due to the planned closure of all mines no further additional recovery is assumed to be implemented.

The production of a site has to be at least 0.5 Mt coal per year. In the UK , in 1998, 63% of the underground mines does have a yearly capacity of more than 0.5 Mt. For Germany and Spain no site specific data could be obtained.

Table 3.8. Assumed methane utilisation scheme in 2010 in UK and Germany

Recovery/utilisation rate	Percentage production capacity
30%	30%
50%	30%
70%	20%
90%[1]	20%
Overall 56%	100%

1) 50% through drainage; 40% through use of ventilation air

3.3.5 Cost estimates

Cost estimates are made for a set of two options, which are defined as 'reference projects'. The production of the mine is assumed to be 2 million tonnes of coal per year. The reference projects are characterised in Table 3.9. These two reference projects serve as a representative case for the options mentioned above.

Cost and performance data of the two reference projects are calculated. In the first reference project recovered ventilation air and drained gases are used in a gas turbine. The cost-effectiveness of the measures is calculated for three levels of collection efficiency, 30%, 50% and 70%, and for two methane contents in the coal. In the second reference project, the methane is oxidised. The costs given are indicative. The actual choice and costs of the utilisation of the mine gas will depend very much on the local circumstances. The calculated costs are average costs for all mines and can not be attributed to individual mines.

Reference project 1: Degasification and power production.
Under this project, coal mines recover methane using vertical wells drilled five years in advance of mining, horizontal boreholes drilled one year in advance of mining, and gob wells. All this is fed to a gas turbine. The waste gases are used to raise steam and/or hot water. Depending on the size of the turbine input the installation might be extended with a steam turbine. The economics of this reference project is calculated for three levels of recovery 30%, 50%, and 70%, and for coal with two levels of methane content, 10 and 20 m^3 of methane per tonne of coal. This reference project is therefore divided in six subprojects.

An alternative scheme may be that the methane is sold to a pipeline. The possibilities for such a scheme depend on the availability of a nearby pipeline. Also the quality of the methane recovered is a more stringent requirement. The option to sell the methane to a pipeline is not considered as a reference project.

Reference project 2: Oxidation of the methane from ventilation air.
Under this reference project, coal mines eliminate methane in ventilation air using a catalytic oxidiser system. Assumed is a methane content of 0.5% in the ventilation air. The catalytic oxidiser is estimated to oxidise up to 98% of the methane that passes through the system. 75 percent of the heat will be recovered, from which 95% will be utilised. The heat may serve to produce power and heat. In this reference project, we assume the production of heat. This project can be implemented solely or in conjunction with reference project 1.

Table 3.9. Characterisation of Reference projects at coal mining. Assumed is a typical size of the coal mine of 2 Million tonnes per year.

	Methane content	Recovery rate	Output
Reference project 1a	10 m3/t coal	30%	Heat and Power
Reference project 1b	10 m3/t coal	50%	Heat and Power
Reference project 1c	10 m3/t coal	70%	Heat and Power
Reference project 1d	20 m3/t coal	30%	Heat and Power
Reference project 1e	20 m3/t coal	50%	Power
Reference project 1f	20 m3/t coal	70%	Power
Reference project 2	0.5% of air	All vent. air	Heat

Costs estimates can be divided into well costs, transport costs and transmission costs. Well costs are depending on the flow rate. Total methane recovery per well may vary widely. Various experiments in the United States have yielded for in-mine boreholes production rates of 800 to 2800 m^3 per day. For vertical gob wells typical production rates of 2800 m^3 per day were obtained, but could be as high as 10.000 m^3 per day per well. In our calculations we assume 1000 m^3 per well per day for the coal mines with 10 m^3 methane per tonne of coal and 2000 m^3 per well per day for the coal mines with 20 m^3 methane per tonne of coal.

The recovered mine gas is compressed and collected through a system of pipelines, and transported to a gas turbine. An average pipeline distance of 0.5 km is assumed per well. The gas turbine is connected to the grid. The production of heat and/or electricity may generate extra income or save purchase of energy.

The revenue or savings resulting from each project should be estimated using local information obtained from electricity/energy authorities. A brief description of how these values may be estimated is as follows:

- *On-site use*. The savings associated with the use of coal mine methane on-site can be estimated using the cost of the fuel displaced (excluding taxes).
- *Electricity sales*. There are a variety of methods by which the electricity price is determined. For example, the price could be set at the average marginal cost of generating electricity elsewhere in the system, or it could be set at the price given to the producers using conventional fuels.

- *Sale of gas*. The expected price of gas sold directly to consumers can be based on the price of alternative fuels. The price of gas sold to a pipeline company can be based on the price paid for other gas supplies on a comparable energy basis.

In our reference projects there are no revenues assumed from the heat, replacing other fuels.

Annex 4 gives an overview of the assumed required installation, costs and benefits. In Table 3.10 a summary is presented of the financial results for the two reference projects. As the costs of a project depends highly on the local conditions, a sensitivity analysis is presented in Table 3.11.

Table 3.10. Financial results for the two reference projects reducing methane emissions from coal mining.

Reference project nr.	1a	1b	1c	1d	1e	1f	2
Investment costs (kEuro)	2824	6061	10041	5952	16399	27289	3500
O&M costs (keuro/yr)	92	218	378	192	633	1103	293
Savings (kEuro/yr)	504	870	1260	1080	2400	3360	332
Yearly costs (kEuro/yr)	-158	-107	21	-353	-292	198	298
Investment costs (Euro/tCH4/yr)	654	842	996	689	1139	1354	375
O&M costs (Euro/tCH4)	21	30	38	22	44	55	31
Savings (Euro/tCH4)	117	121	125	125	167	167	36
Specific costs (Euro/tCH4)	-37	-15	2	-41	-20	10	32

NB: In the calculations is an interest rate of 4% assumed, a project lifetime of 15 years, and an electricity payback tariff of 0.03 euro/kWh.
Combustion of methane produces carbon dioxide. Assumed is that these emissions are balanced by the power (and heat) production that is replaced by this activity.

Table 3.11 Sensitivity analysis for the two reference projects (see Table 3.10) for 150% and 75% of the yearly investment and O&M costs, respectively.

Specific costs (Euro/tCH4)	3	38	66	1	53	98	66
Specific costs (Euro/tCH4)	-57	-41	-30	-62	-57	-34	15

3.3.6 Conclusion

Technologies for recovering methane in conjunction with coal mining have been well demonstrated and are currently in use throughout the world. Methane recovered using this way, can be used in a variety of ways to meet local energy needs, including on-site use as gas; on-site use to generate electricity, or sale for off-site use to residential commercial, or industrial customers. Besides the advantages of reduced emissions of greenhouse gases, increased use of degasification systems may improve safety by reducing methane levels in the mine. Techniques for recovering methane before mining can significantly reduce the amount of methane in the coal when mining occurs. Implementation of utilisation of ventilation air may reduce total methane emissions by 90% or more. This technology, however, should still be commercially proven.

3.4 FROZEN TECHNOLOGY REFERENCE CASE

To ensure consistency with the other EU projections which are forming the basis for examining trends in the future trends in coal production are taken from the ‘Shared Analysis’ study. Table 3.12 gives 1990 coal production and projections towards 2010. It is clear from this table that coal production is expected to decline substantially in the future, with EU production of only about 40% in 2010 compared to 1990.

Emissions arising from coal production, presented in Table 3.13, are taken from the second national communications. Emission in the 2010 frozen technology reference case are based on the assumption that emission factor remains constant, and that current ratio of deep mine to surface is maintained.

3.4.1 Existing Policies and Measures

Various countries announced action to reduce coal mine emission. Hereunder a summary is presented:

France: In 1996 estimates were that non-recovered mine gas emissions in France represented less than 20% of the total. Coal production is planned to end at 2005. *Projected emissions: 50 kt (2000), 29 kt (2005), 14 kt (2010).* No emission reduction measures were announced.

Germany: Reduction of subsidies for sale of hard coal. A decrease of production towards 2005 is foreseen. The use of pit gas for energy recovery has been increased from 70 to 78%. According to industry’s data, methane emission has reduced by 30%. More extensive methane reduction measures are now being studied; for example, the German Federal Environmental Agency is carrying out a study on avoidance of climate-relevant methane emissions in coal mining.
Expected effect: 580 kt (2000), 730 kt (2005), 730 kt (2010), 730 kt (2020)

United Kingdom: Utilisation waste gas from coal mines for energy. Type of action: Voluntary action. 9 kt (2000), 9 kt (2005), 9 kt (2010), 9 kt (2020). To be implemented by 2000.

Table 3.12. Development of solid fuel production under the Shared Analysis Scenario (PJ))

	1990	1995	2000	2005	2010	% Change 1990-2010	% Change 1995-2010
AU	27	13	17	13	11	-60%	-15%
BE	45	11	0	0	0		
DK	0	0	0	0	0		
FI	61	86	73	74	72	18%	-17%
FR	319	225	175	111	25	-92%	-89%
GE	5258	3302	2714	2362	2096	-60%	-37%
GR	297	331	352	371	370	25%	12%
IR	60	50	33	29	25	-59%	-50%
IT	14	4	4	4	4	-74%	-8%
NL	0	0	0	0	0		
PO	5	0	0	0	0		
SP	489	426	384	387	353	-28%	-17%
SV	11	13	13	13	13	13%	-4%
UK	2225	1297	857	744	631	-72%	-51%
EU	8813	5758	4623	4107	3599	-59%	-38%

Table 3.13. Emissions from solid fuels for the main countries following the 'Shared Analysis Scenario' (in Mt of CO_2 equivalent)

Country	1990	2010
DEU	25767	10713
ESP	12852	9171
FRA	4326	421
GBR	17409	15352

3.4.2 Aggregration of options

The options described above have been grouped in 'packages' of options as shown in Table 3.14. This is done to end up with a surveyable amount of options. The grouping is possible, because the cost-effectiveness of the options grouped is in a relatively narrow range.

Table 3.14. Overview of aggregrated options to reduce methane emissions from coal mining.

	Reduction potential			Investment	O&M	Savings	Lifetime
	Germany	United Kingdom	Spain				
proj 1a/1d	9%	9%	15%	654	21	117	15
proj 1b/1e	20%	20%	0%	842	30	121	15
proj 1c/1f	14%	14%	0%	996	38	125	15
proj 2	4%	4%	0%	375	31	36	15

4. CONCLUSIONS

In the frozen efficiency reference case greenhouse gas emissions decline from 95 Mt of CO_2 equivalent in 1990 to 61 Mt of CO_2 equivalent in 2010. The decline is mainly caused by projected decrease of coal production. Emission of methane is the most important emissions of greenhouse gases in this sector. The main source of methane in the oil and gas sector is the fugitive emissions. It is estimated that about 75% of the emissions stems from this source. The main emission source during winning of solid fuels is underground ventilation air from coal mining.

Emission reduction options in the oil and natural gas sector minimise emissions from associated gas, process vents and flares, engines, turbines, compressors and pumps, system upsets, and transmission and distribution activities. In coal production emission reduction options are directly related to minimising methane emissions associated with mining activities. The emission reduction options are identified and described. Table 4.1 gives an overview of the investment costs, the yearly costs (sum of operation and maintenance costs and savings), average specific mitigation costs and potential for options applicable in the fossil fuel extraction, transport and distribution sector. The specific costs are calculated using a real interest rate of 4% and using the lifetime of the option, i.e. equipment.

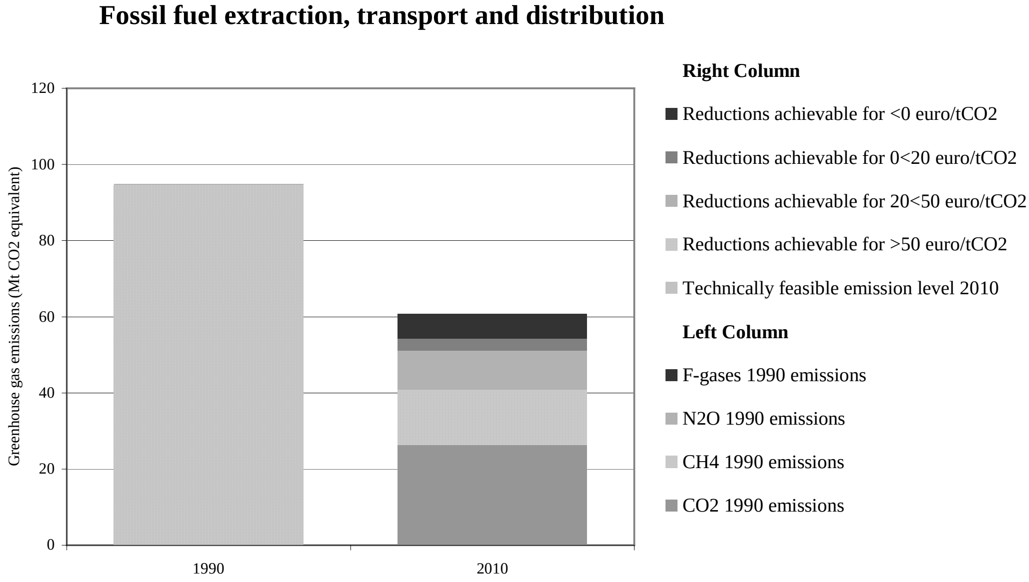
Table 4.1. EU15-average costs and total potential (Mt CO_2) for emission reduction options in the oil and gas sector.

Pollutant: CH4 Measure Name	Subsector	Emission reduction	Investment	Yearly costs	Lifetime	Specific abatement costs
		Mt CO2 eq.	euro/tCO2 eq.	euro/tCO2 eq.	year	euro/tCO2 eq.
Recompressing of gas during maintenance compressors	Compressors	0.07	0	-4	1	-4
Altering start-up procedure during maintenance compressors	Compressors	0.02	0	-4	1	-4
No/reduced flusing at start-up compressors	Compressors	0.03	0	-4	1	-4
Electrical start-up (new) compressors	Compressors	0.01	0	-4	1	-4
Improved sealing compressors	Compressors	0.03	0.3	-4	25	-4
Inspection and maintenance - compressors	Compressors	0.2	0	-4	1	-4
Inspection and maintenance - power equipment	Energy requirements	0.1	0	-4	1	-4
Coal mining degasification (low recovery rate)	Coal mining	2.9	31	-5	15	-2
Increased gas utilisation	Process vents/flares	0.1	30	-4	15	-1
Coal mining degasification (medium recovery rate)	Coal mining	3.0	40	-4	15	-1
Subtotal : Cost ranges for < 0 euro / t CO2		**6.5**				
Coal mining degasification (high recovery rate)	Coal mining	2.1	47	-4	15	0.1
Associated gas (vented) mix other options	Associated gas	0.1	48	-3	15	1
Coal mining abatement from ventilation air	Coal mining	0.6	18	-0.2	15	1
Further increased utilisation	Process vents/flares	0.2	60	-4	15	2
Associated gas (flared) mix other options	Associated gas	0.1	57	-2	15	3
Flaring instead of venting (onshore) of unused associated gas	Associated gas	0.02	29	1	15	3
Use of gas turbines instead of reciprocating engines	Energy requirements	0.02	143	7	20	18
Subtotal : Cost range for 0 < 20 euro / t CO2		**3**				
Offshore flaring instead of venting of process vents	Process vents/flares	0.1	179	5	15	21
Replacement grey cast iron network low	Fugitive emissions	10	952	-9	50	36
Subtotal : Cost ranges for 20 < 50 euro / t CO2		**10**				
Electrical start-up (retrofit) compressors	Compressors	0.02	857	13	20	76
Increasing the pipeline examination frequency	Fugitive emissions	4	0	77	1	77
Replacement grey cast iron network high	Fugitive emissions	10	1905	-9	50	80
Flaring instead of venting (offshore) of unused associated gas	Associated gas	0.04	714	21	15	86
Inspection and maintenance - system upsets	System upsets	0.33	0	91	1	91
Subtotal : Cost range for < 50 euro / t CO2		**14**				
Total emission reduction potential		**34**				

The technical potential is estimated at 34 Mt of CO_2 equivalent or about 55% of the total projected emissions in 2010.

Figure 4.1 shows the share in emission reduction by the residential and commercial sector in four costs brackets.

Figure 4.1. Fossil fuel extraction, transport and distribution sector: 1990 base year direct emissions (left), 2010 frozen technology reference level and reduction potentials per cost bracket (right)



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ANNEX 1: NATURAL GAS TREATMENT UNIT OPERATIONS

Figure A1-1 gives a schematic overview of gas treatment and transport in the Netherlands. Often applied unit operations in natural gas treatment are:

- *Inlet separators*

The natural gas is produced at high pressure and elevated temperature. In an 'inlet separator' (Figure A1-2) a water-condensate mixture is separated from the natural gas main-stream. The volatile fraction (consisting of a mixure of methane, aromatics, other hydrocarbons and water) is subsequently removed from the water-condensate mixture at a moderate pressure and ambient temperatures. Simultaneously the water is separated from the condensate. After this, the water is treated at atmospheric pressure, in order to remove the volatiles. Besides this, other impurities are removed, and finally the water is disposed of.
The condensate may be recompressed, and transported further with the natural gas. In other cases the condensate is stored, loaded into tanker-cars and transported to refineries.

- *Glycol dehydrators*

When the natural gas has to be transported along larger distances, the water vapour is removed in order to meet transport specifications. This is often done in a glycol dehydrator, which is depicted in Figure A1-3.
After the natural gas is obtained, water and condensate are separated and treated as described above (1-4). For a further reduction of the water content, the gas is treated in a glycol contactor (5). The glycol (usually triethyleneglycol) absorbs most of the water from the natural gas, along with amounts of hydrocarbons. Water and hydrocarbons are subsequently removed from the glycol in several different stages. Usually most of the hydrocarbons are removed in a first glycol flash (6). The remaining volatiles are separated by heating the glycol at a temperature of about 200 ^{o}C in the glycol regenerator (7). In some cases no glycol flash exists, and all volatiles are released in the regenerator.
In some cases, natural gas is fed as a strip gas, just below the stills-column in the regenerator. This is done to improve the efficiency of glycol regeneration, for example, when the well-pressure of the natural gas is relative low and larger amounts of water have to be removed in order to meet transport specifications. Another reason for application of strip-gas is to obtain a sufficient dry glycol at a reduced regenerator temperature. This may be done to inhibit the degradation of the glycol and to increase it's life-time.

- *Low temperature separator*

Condensate may be removed from the natural gas in a low-temperature separator, described in Figure A1-4. Due to adiabatic expansion of the gas, the gas is cooled to approximately -15^{o}C. When the gas-pressure is insufficient to obtain these low temperatures in this way, additional cooling is applied. To avoid formation of hydrates, mono- or diethyleneglycol is added to the gas. At this low temperature a condensate-glycol-water mixture is separated from the natural gas (5), and subsequently split in a condensate and a glycol-water mixture (6). After this the condensate is stabilised (7) and transported to refineries, while the glycol is regenerated and reused (8).

- *Silica-gel separation*

Recently the silica-gel adsorption process is developed as an alternative for the low-temperature separator. A simplified flow-scheme of this process is presented in Figure A1-5. First the condensate and water are separated, in about the same way as described in the glycol-dehydration process (1 to 3). Then the condensate is removed from the natural gas in a three-stage process. The gaseous condensate is adsorbed in a column, filled with silica (4a), and the resulting natural gas is sold. When a column is saturated, the column is regenerated, using a hot natural gas stream in which the condensate is desorbed (4b). Finally the column is cooled down (4c), simultaneously warming up the natural gas-stream used in the regeneration step. A furnace (5) is used to provide additional heating of the regeneration gas. Normally three or four columns are present and at each time, one column is used as an adsorber, another column is regenerated and the third column is cooled down.
The condensate-gas stream is subsequently cooled (6) and the condensate is separated (7), stabilised (8) and transported to refineries. The natural gas, used to regenerate the silica, is recycled to the adsorbed column.

- *Desulphurisation units*

When sour gas is produced, it has to be sweetened. The gas is treated with Sulfinol, in which the hydrogen sulphide is dissolved. After this, the hydrogen sulphide is removed again from the Sulfinol and finally transformed into elementary sulfur in a Claus/SCOT-unit.

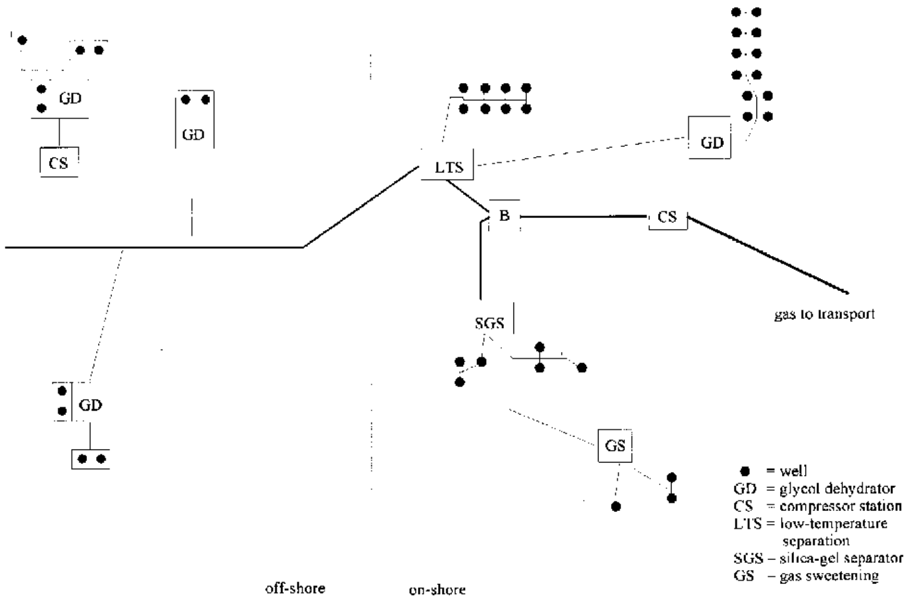

Figure A1-1: Schematic overview of gas treatment and transport (example for the situation in the Netherlands)

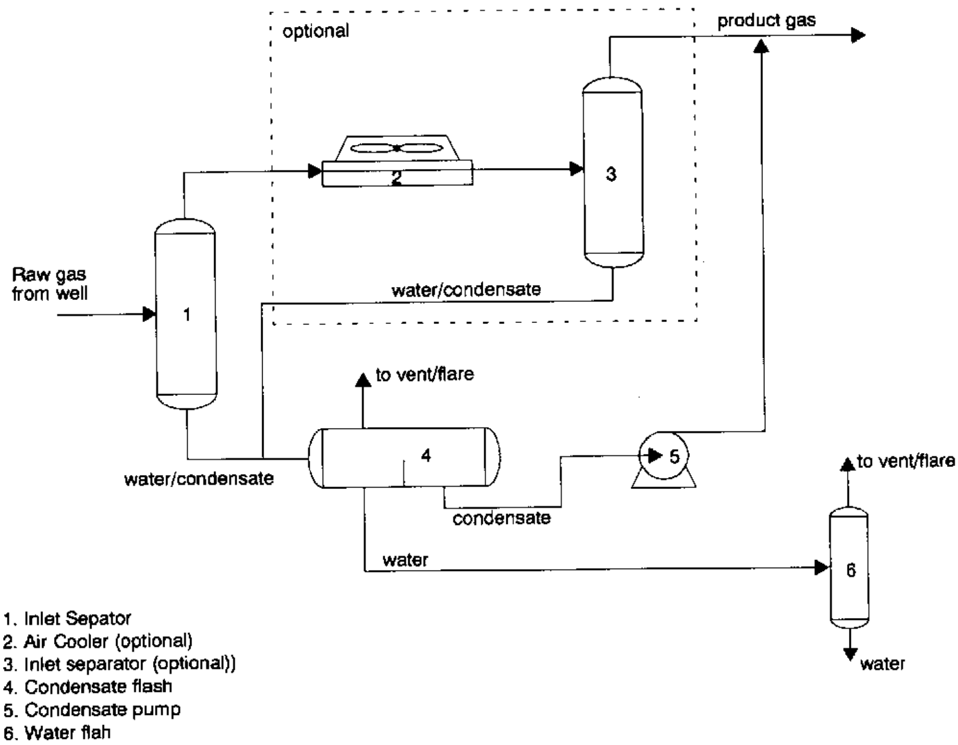

Figure A1-2: Inlet separation

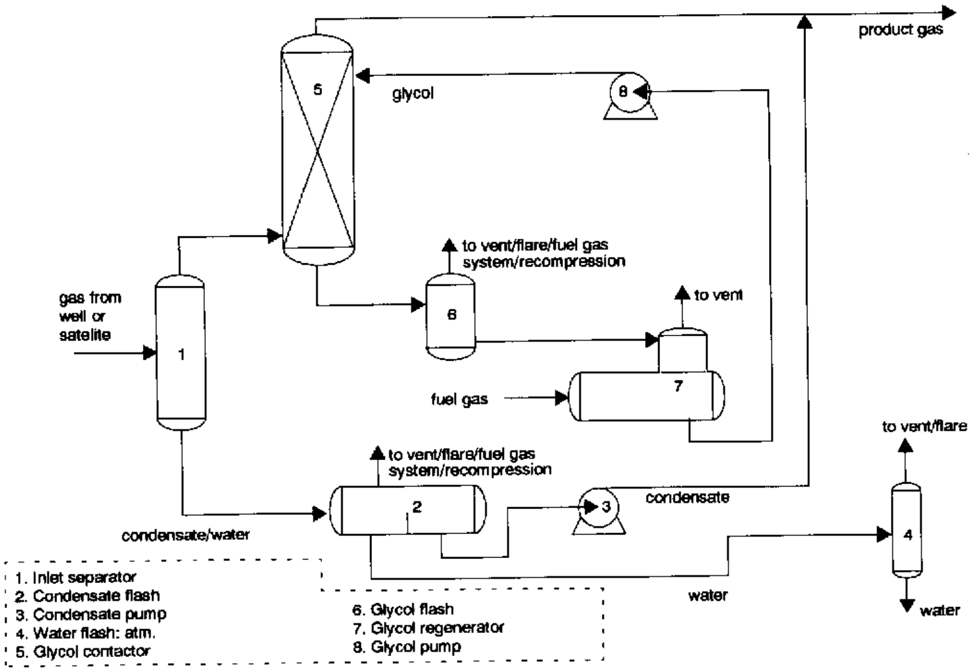

Figure A1-3: Glycol dehydration

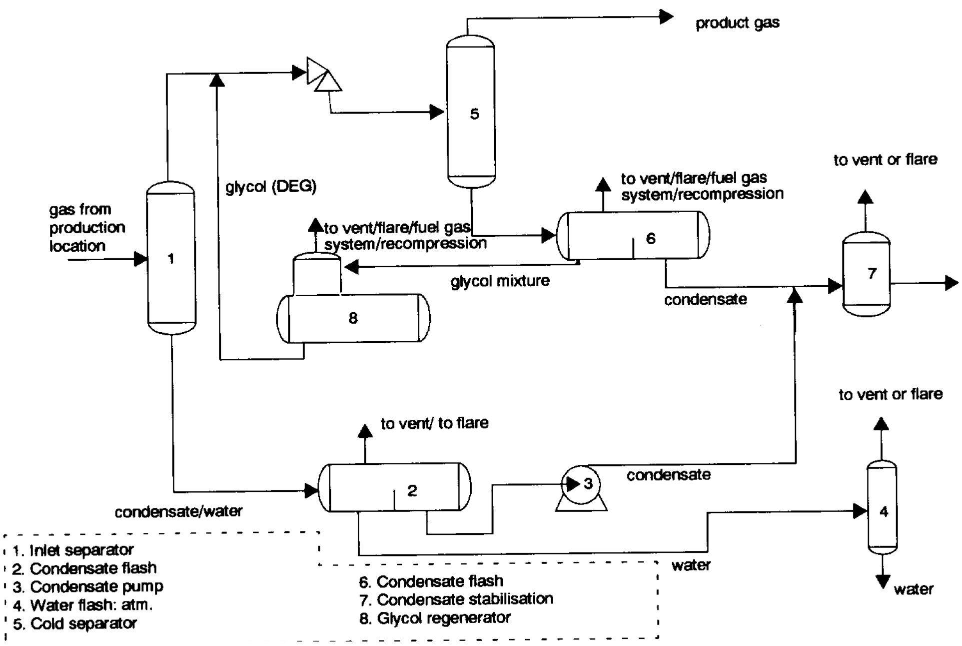

Figure A1-4: Low-temperature separation

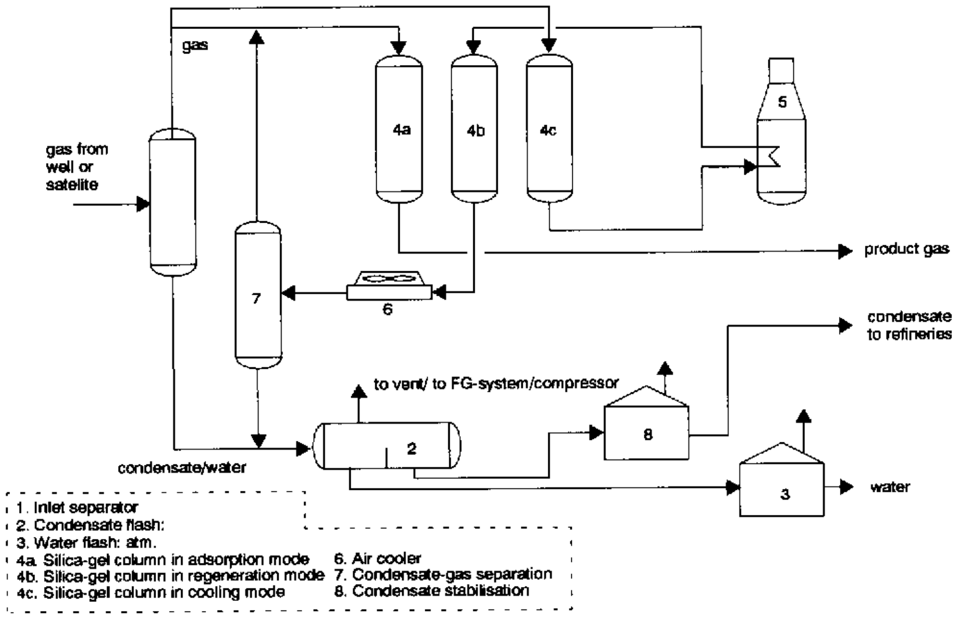

Figure A1-5: Silica-gel process

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ANNEX 2: EMISSION INVENTORY BASED ON SOURCE-TYPE DEFINITIONS

General

Totals of methane emissions are available for a number of countries. Only for a few countries a subdivision of these methane emissions in phases in the oil and gas system or per source-type is given. These available methane emission data were used in an estimate of global methane emissions by the oil and gas system [De Jager et al., 1997]. For countries with no emission data, an own estimate of emissions was used.

In case only total emissions are known, a subdivision of these emissions over the source-types was made, based on regional emission factors per source-type. For countries with no methane emission data at all, default regional methane emission factors per source-type were used. These estimates are based on oil and gas production and consumption statistics, and on emission factors per region and source-type by the IPCC [1995]. Note that in many national emission inventories also (sometimes adjusted) IPCC [1995] default emission factors are used for calculating total emissions.

Calculation of methane emissions per source-type

This section describes the method and assumptions that were used to estimate total methane emissions by the oil and natural gas system, for countries with no specific emission breakdown into source-types.

- *Associated gas vents and flares*

Methane emission estimates for countries with no emission data per source-type are based on the gross gas production per country, the share of vented and flared gas and on an estimate of the emission factor (kg CH_4/TJ gas vented or flared).
The gross gas production is derived from net gas production data[3] and production data from The Survey of Energy Resources[4]. The share of vented and flared gas is also derived from the latter source. The emission factor is derived from general estimates of Barns and Edmonds [1990]. They assume that about 20% of all vented/flared gases is released without being combusted in a flare.

3 IEA/OECD (1994a, 1994b, 1995)
4 WEC (1995)

- *Process gas vents and flares*

Methane emission estimates are based on the net gas production data per country[3] and on an estimate of the emission factor (kg CH_4/TJ of gas vented or flared).
The emission factor is derived from emission factors mentioned in the main chapter, from general estimates for fractions of methane emissions vented or flared of Barns and Edmonds [1990] and of country-specific data, when available.

- *Exploration, maintenance, energy requirements and compressors*

Methane emission estimates are based on the net gas production data per country[3] and on an estimate of the emission factor (kg CH_4/TJ of gas and/or oil production). The emission factors per region or country are derived from data available for specific countries or available general estimates.

- *Pneumatic devices and systems upsets*

Methane emission estimates are based on the net gas production and transport/consumption data per country and on an estimate of the emission factor for the production phase (kg CH_4/TJ of gas production) and the transport phase (kg CH_4/TJ of gas transport). The emission factors per region or country are derived from data available for specific countries or available general estimates.

- *Fugitive emissions*

Methane emission estimates are based on the net gas production data, the fraction of non-industrial consumption per country and on an estimate of the emission factor for the transport phase (kg CH_4/TJ of gas transport) and the distribution phase (kg CH_4/TJ of non-industrial gas consumption)[3]. The emission factors per region or country are derived from data available for specific countries or available general estimates. It is assumed that all industrial consumers are connected to a high-pressure network

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ANNEX 3: OVERVIEW OF CONTROL OPTIONS FOR METHANE EMISSION REDUCTION IN THE OIL AND NATURAL GAS SYSTEM

AEA [1998] fact sheets for the European Union, based on
De Jager et al. [1997], Woodhill [1994] and Foster Wheeler Energy [1996]

Source of CH4	**Control option**	**Emission reduction**	**Costs** (incremental costs; 1997)	**Lifetime (years)**
Leakage through control and relief valves	Installing a more leak tight component during routine replacement	20%	Inv: 2500 £/t/yr	15
Purge gas	Management practice. Some form of measurement system may be needed.	50%	-	-
Purge/blanket gas	Gas generator and associated infrastructure	50%	Inv: 3600 £/t/yr 10% of saved gas	15
Gas in dehydation and deaeration unit	Reducing or replacing strip gas by inert gas (available on-site). Only small modifications required	50%	Inv: 800 £/t/yr 10% of saved gas	15
Gas pressure as motive power	Replacing motive gas uses on existing platforms	50%	Inv: 25000 £/t/yr 10% of saved gas	15
Vents (onshore)	Flaring	50%	Inv: 550 £/t/yr	15
Vents (offshore)	Flaring	50%	20000 £/t/yr	15
Flares	Improved combustion efficiency	-	-	15
Pilot flame gas	Improved ignition system to reduce incidents of extinguishment	50%	No cost involved	15
Pilot flame gas	Improved igntion system	50%	Inv: 4000 £/t/yr	15
Compressor stations	Hydraulic fluid valve actuators	-	Inv: -42000 £/t/yr	10
Compressor	Hydraulic starter (new plant)	-	Inv: 18000 £/t/yr	10
Compressor	Design change (1)	-	-	10
Compressor	Design change (2)	-	-	10
Compressor	Reduce changeover releases (on-line washing)	-	Inv: 210 £/t/yr	10
Compressor	Reduce changeover releases (Improved on-line washing, with change to valve location)	-	Inv: 500 £/t/yr	10
Compressor	Portable compressor at changeover	80%	Inv: 1800 £/t/yr	10
Compressor	Gas turbine instead of reciprocating engines	90%	Inv: 900 £/t/yr	20
Pipeline maintenance	Recompression during maintenance	20%	O&M: 26 £/t/yr	-
System upset	Various I&M measures	80%	O&M: 1200 £/t	-
Distribution lines (grey iron)	Replacement by PVC	90%	Inv: 28000 £/t/yr	50
Distribution	Improved leak detection	25%	O&M: 1200 £/t	-
Distribution	Pressure management in pipe lines	?	Inv: 1850 £/t/yr	10
Distribution	Gas conditioning	?	O&M: 210 £/t	-
Distribution	Portable compressors	70%	Inv: 3000 £/t/yr	10

US-EPA [1999] fact sheets for the United States of America

Best Management Practice	Applicability and Emission Reductions (USA)	Costs
Replace high-bleed pneumatics with low-bleed pneumatics	Applicability: 50%-90% of pneumatic systems in the productioon and transmission sector Emission reduction: 50%-90%. For all sectors, applicability and emission reductions are higher for high-bleed devices	Capital: $750/device ($1500/device * 0.5 to reflect early replacement) Annual O&M: $150
Practice directed inspection and maintenance at compressor stations	Applicability: 100% of compressor stations in the transmission sector Emission reduction: 12%	Capital: $5000/station instr. $500/facility Annual O&M: $2065/station
Use static-seal compressor rod packing	Applicability: 100% of reciprocating compressors in the transmission sector Emission reduction: 6.0% of emissions from storage compressor stations; 8.7% of emissions from transmission compressor stations	Capital: $3000/compressor Annual O&M: none
Reduce glycol recirculation rates on dehydrators	Applicability: 100% of dehydrators in production, processing and transmission sector Emission reduction: 30%-60% of emissions from production and processing; 30% of emissions from transmission	Capital: $0 Annual O&M: $50/dehydrator
Install flash tank separators on glycol dehydrators	Applicability: 100% of glycol dehydrators without flash tanks in the production, processing and transmission sectors Emission reduction: For the production and processing sectors: 12%-63% of emissions from dehydrator vents and 63% of emissions from Kimray pumps For the transmission sector: 90% % of emissions from dehydrators with gas-assisted pumps; 30% of % of emissions from dehydrators without gas-assisted pumps	Capital: $8000/dehydrator Annual O&M: none

Best Management Practice	**Applicability and Emission Reductions (USA)**	**Costs**
Use fuel gas retrofits	Applicability: 100% of reciprocating compressors in the transmission sector Emission reduction: 36% of emissions from reciprocating compressors in the transmission sector; 21.3% of emissions from reciprocating compressors in gas processing plants	Capital: $1250/compressor Annual O&M: none
Change wet seals to dry seals on centrifugal compressors	Applicability: 100% of all centrifugal compressors in the processing and transmission sectors Emission reduction: 77.2% of emissions from storage compressors; 70.9% of emissions from transmission compressors; 65.9% of emissions from processing compressors	Capital: $240,000/compressor Annual O&M: -$63,000/compressor savings in material and relative to wet seals
Practice early replacement of rings and rods on reciprocating compressors	Applicability: 100% of reciprocating compressors in the transmission sector Emission reduction: 1.4% of emissions from storage compressor stations; 1.5% of emissions from transmission compressor stations	Capital: $100/compressor Annual O&M: $120
Practice directed inspection and maintenance at gate stations and surface facilities	Applicability: For transmission sector: 100% of transmission co. interconnect meter and regulator stations For distribution sector: 100% of high pressure stations; 50% of medium pressure stations; and 0% of low pressure stations Emission reduction: For transmission sector: 33% of emissions For distribution sector: 33% of emissions from high pressure stations; 25% of emissions from medium pressure stations	Capital: $5000/survey instrument $250/station Annual O&M: $295/station

Identified opportunities	Applicability and Emission Reductions (USA)	Costs
Practice directed inspection and maintenance at production sites	Applicability: 100% of non-associated gas wells; 100% of off-shore platforms; 100% of pipeline leaks in the production sector Emission reduction: 33% of emissions from non-associated gas wells; 33% from off-shore platforms; 60% of emissions from pipeline leaks	Capital: $200/well; $6,000/offshore platform, $100/mile of pipeline Annual O&M: $300/well; $2,000/offshore platform, $150/mile of pipeline
Use enhanced directed inspection and maintenance at production sites	Applicability: 100% of non-associated gas wells in the production sector Emission reduction: 50%	Capital: $500 Annual O&M: $700
Use electric starter	Applicability: 100% of compressor starts in the production sector Emission reduction: 75%	Capital: $20,000/compressor Annual O&M: $5,000/compressor
Use plunger lift well	Applicability: 20% of non-associated gas (Appalachia) and 20% of rest of U.S. onshore wells in the production sector Emission reduction:	Capital: $2,500/well Annual O&M: #100/well
Use surge vessel to capture blowdowns	Applicability: 100% of pipeline venting during routine maintenance and upsets in production, processing and transmission sector Emission reduction: 50%	Capital: $100,000/vessel or compressor station Annual O&M: $2,000/unit
Use portable evacuation compressors	Applicability: 100% of pipeline venting during routine maintenance and upsets in production and transmission sector Emission reduction: 80%	Capital: $1400/mile Annual O&M: $10/mile
Install instrument air systems	Applicability: 50%-90% of pneumatic systems in the production and transmission sector Emission reduction: 100%	Capital: $4200 Annual O&M: various (e.g. $750 for pneumatic device vents in the production sector)
Practice directed inspection and maintenance at processing sites	Applicability: 100% of processing plants Emission reduction: 33%	Capital: $1,000/plant Annual O&M: $2,000/plants
Use catalytic converters on engine exhaust	Applicability: 75% of engines and turbines in the transmission sector (including LNG storage)	Capital: $20,000/engine Annual O&M: $1,000/engine

Identified opportunities	**Applicability and Emission Reductions (USA)**	**Costs**
	Emission reduction: 75%	
Practice directed inspection and maintenance at LNG stations	Applicability: 100% of LNG stations in the transmission sector Emission reduction: 60%	Capital: $500/station Annual O&M: $2,065/station
Practice directed inspection and maintenance of transmission pipelines	Applicability: 100% of pipeline leaks in the transmission sector Emission reduction: 60%	Capital: $100 Annual O&M: $150
Use enhanced directed inspection and maintenance at compressor stations	Applicability: 100% of compressor stations in the transmission sector Emission reduction: 26.5% of emissions from storage compressors; 18.9% of emission from transmission compressor stations	Capital: $1,000/station Annual O&M: $6,000/station
Practice directed inspection and maintenance at storage wells	Applicability: 100% of storage wells in the transmission sector Emission reduction: 33%	Capital: $200/well Annual O&M: $200/well
Practice enhanced directed inspection and maintenance at storage wells	Applicability: 100% of storage wells in the transmission sector Emission reduction: 50%	Capital: $300/well Annual O&M: $400/well
Practice enhanced directed inspection and maintenance at gate stations and surface facilities	Applicability: 100% of gate stations and surface facilities in the distribution sector Emission reduction: 30%-80% of emissions (higher spressure stations have higher emission reductions)	Capital: $1,000/station Annual O&M: $1,000/station
Use electronic metering	Applicability: 100% of transmission co. interconnect M&R stations in the transmission sector; 100% of meter and regulator stations at city gates in the distribution sector Emission reduction: 95%	Capital: $15,000/station Annual O&M: $2,500/station
Replace pipeline	Applicability: 100% of cast iron and unprotected steel mains in the distribution sector Emission reduction: 95%	Capital: $1,000,000/mile Annual O&M: $50/mile
Replace services	Applicability: 100% of unprotected steel services in distribution sector Emission reduction: 95%	Capital: $250,000/service Annual O&M: $50/service

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ANNEX 4: COAL MINING

The cost calculations for reference 1 are based on the cost data given in Table A4.1. Table A4.2 gives for six variants an overview of costs for recovery and utilising coal bed methane.

Table A4.1. Cost data for coal mining (costs in 1998 euro's)

Well_costs_vertical	150000	Euro/well
Well_costs_gob	30000	Euro/well
Costs In_mine_boreholes	75000	Euro/well
Well_Production_vertical	1	Mm3/yr
Well_Production_gob	1	Mm3/yr
Production In_mine_boreholes	0.5	Mm3/yr
Ratio Vertical well	50%	
Ratio gob well	25%	
Ratio In-mine-borehole	25%	
Well_water_disposal_costs	3	Euro/m3
Well_water_production	6000	m3/Mm3 gas
Compressor	18	kWe/Mm3/yr
Compressor_costs	800	Euro/kW
Length Line Well_Generator	500	m
Line_costs	30	Euro/m3
O&M costs (excl. GT)	5%	
Power to grid connection	100	Euro/kW
Load	7200	hrs/yr
LHV gas	36	MJ/m3
Gas turbine_costs	1000	Euro/kW
Gas turbine_O&M	0.004	Euroct/kWh
STEG_costs	1200	Euro/kW
STEG_O&M	0.006	Euroct/kWh
Electricity payback tariff	0.03	Euro/kWh
Interest	4%	
Life_time	15	

Table A4.2. Cost estimates for reference 1 projects for coal mining.

		30%	50%	70%	30%	50%	70%
		low gas content			**high gas content**		
Production	Mtcoal/year	2	2	2	2	2	2
Methane content	m3/t	10	10	10	20	20	20
Methane production	Mm3/yr	20	20	20	40	40	40
Average production rate well	M3/yr	0.9	0.6	0.4	0.9	0.6	0.4
Number of vertical wells	well/yr	11	17	26	11	17	51
Number of gob wells	well/yr	6	9	13	6	9	13
Number of In-mine boreholes	boreholes/yr	6	9	13	6	9	13
Number of extra vertical wells	well/yr	0	6	14	0	6	40
Number of extra gob wells	well/yr	0	3	7	0	3	7
Number of extra In-mine boreholes	boreholes/yr	0	3	7	0	3	7
Number of extra well (total)	well/yr	0	11	29	0	11	54
Production of methane	Mm3/yr	6	10	14	12	20	28
Production of methane	kt/yr	4.3	7.2	10.1	8.6	14.4	20.2
Heat rate recovered gas	MJ/s	8	14	19	17	28	39
Lines from wellhead to generator	m	5714	8571	12857	5714	8571	25714
Gas turbine efficiency	%	28%	29%	30%	30%	40%	40%
Gas turbine output	MW	2	4	6	5	11	16
Gas turbine production	MWh	16800	29000	42000	36000	80000	112000
Gas turbine costs	Euro/kW	1000	1000	1000	1000	1200	1200
Well costs	Euro	0	1157143	2892857	0	1157143	5496429
Well water disposal costs	Euro	0	72000	144000	108000	252000	396000
Compressor costs	Euro	86400	144000	201600	172800	288000	403200
Line costs	Euro	171429	257143	385714	171429	257143	771429
Connection to grid	Euro	233333	402778	583333	500000	1111111	1555556
Total Investment (excl. GT)	Euro	491162	2033063	4207505	952229	3065397	8622613
O&M (excl. GT)	Euro/yr	24558	101653	210375	47611	153270	431131
Gas turbine costs	Euro	2333333	4027778	5833333	5000000	13333333	18666667
Gas turbine costs (O&M)	Euro/yr	67200	116000	168000	144000	480000	672000
Investment (total)	Euro	2824495	6060841	10040838	5952229	16398730	27289279
O&M (total)	Euro/yr	91758	217653	378375	191611	633270	1103131
Total benefits	Euro/yr	504000	870000	1260000	1080000	2400000	3360000
Yearly Costs	Euro/yr	-158204	-107228	21459	-353039	-291810	197558

ANNEX 5 LIST OF PARTICIPANTS

Participants at Experts Workshop "Fossil fuel extraction, transport and distribution" and "Energy supply". March 29, 1999, DG Environment, Brussels

Name	**Organisation**
Eivind Aarebrot	Statoil
Rob Bradley	Energy specialist Climate Network Europe
Marc Darras	Gaz de France, Normalisation Environnement Qualité
Jürgen Engelhard	Rheinbraun AG
Margot Loudon	Eurogas (European Union of the Natural Gas Industry)
Mercedes Marin	COGEN Europe
Bo Nelson	Vattenfall Policy analyst
Nick Otter	ABB ALSTOM POWER
Beate Raabe	International Association of Oil and Gas Producers
Stephan Singer	WWF European Policy Office
Björn Sund	Norsk Hydro Senior Vice President Corp. Research Technology
Helmut Warsch	Siemens
Gerd Weber	German Coal Mining Association
Arturos Zervos	European Wind Energy Association
Consultants	
Judith Bates	AEA Technology Environment
Kornelis Blok	Ecofys Energy and Environment
Pantelis Capros	NTUA - E3M – Lab
David de Jager	Ecofys Energy and Environment
Chris Hendriks	Ecofys Energy and Environment
Commission staff	
Timo Aaltonen	TREN.B.1 Sectorial Economy
Jaime Garcia	TREN.A.3 Environment
Marc Hayden	ECFIN.E.4 Environmental policy, transport and energy
Peter Horrocks	ENV.D.3 Air quality, urbain environement, noise, transport & energy
Marco Loprieno	ENV.A.2 Climate change
Aphrodite Mourelatou	European Environment Agency Energy and Environment project manager
Matti Vainio	ENV.B.2 Economic Analyses and Employment
Beatriz Yordi	DG TREN.D.1 Promotion des énergies et maîtrise de la demande