

FULL FUEL CHAINS AND THE BASKET OF GREENHOUSE GASES

Integrated analysis of options to reduce greenhouse gas
emissions related to energy use in the Netherlands

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Preface

This project is a result of the EMS project (Energy and Material Scenarios to reduce emissions of CO₂ and other greenhouse gases). At ECN this project is registered under number 7007.

Abstract

The assessment of long-term energy strategies with respect to the reduction of global warming is dominated by the linkage of these strategies with emissions of CO₂. The three major reasons for this limitation are : 1) CO₂ has the largest contribution to climate change; 2) the uncertainties in current and future emissions of non-CO₂ greenhouse gases are large and they may affect the accuracy of energy technology analysis; 3) the uncertainties in the comparative assessment of the impact of emissions of different greenhouse gases on climate change are large.

This study presents an integrated analysis on the cost-effectiveness of energy options for the medium to long term in the Netherlands, including non-CO₂ greenhouse gas emissions from the energy system, emissions of greenhouse gases which occur upstream in the energy chain both at production and at transport of fuels, and additional energy inputs to manufacture technologies (for renewables). The analysis was carried out using an integrated optimization model of the energy system (MARKAL) in a scenario for the time period 2000-2040. The warming impacts of emissions of different greenhouse gases were compared using the Global Warming Potential (GWP) concept. The uncertainties in emissions in the total fuel cycle and the uncertainties in GWPs were addressed and incorporated in the analysis. The cost-effectiveness was analyzed by applying various penalties to the CO₂ equivalent emissions of greenhouse gases. It was observed that the effectiveness of several energy technologies is modestly sensitive for assumptions with respect to emissions of non-CO₂ greenhouse gases. This sensitivity was mainly induced by the levels of both methane and upstream CO₂ emissions in the fuel cycles of natural gas and coal. Including these emissions increases the cost-effectiveness of renewable technologies and decreases the cost-effectiveness of CO₂ removal technologies. Together upstream CO₂ emissions and non-CO₂ greenhouse gas emissions account to 10-15% of total energy-related greenhouse gas emissions. Methane emission reduction options appear to be relatively attractive, while indirect upstream emissions of CO₂ appear difficult to abate.

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1. INTRODUCTION

In most OECD countries the main source of emissions of (GHGs) greenhouse gases is the energy sector. Regarding the contribution to global warming, CO₂ is usually the most important GHG from this sector. The CO₂ emissions from energy use are well known since they can be calculated relatively simple from energy statistics [1].

National or regional studies in OECD countries [2-6] which evaluate the energy technology strategies on the reduction of GHG emissions, usually focus on emissions from the energy sector. Such analysis is often limited to CO₂ emissions.

The main reason that the larger part of the studies only considers national emissions is the practical fact that these system boundaries are most commonly used e.g. for statistics on energy use as well as for international negotiations on reduction of GHG emissions. Moreover, in most GHG reduction studies, the national perspective is also taken to explore the most optimal sets of technology. However, a global perspective in view of emissions is more appropriate for strategic studies, since climate change is a global issue. Hence, if the system boundaries are taken at the borders of the country under consideration, this implies that upstream emissions of GHGs which occur outside the system boundaries to supply fuels to the considered country, the so-called indirect emissions, are not being considered. These indirect emissions can be very significant. Consequently, strategies that are effective from a national point of view may not be equally effective in a global perspective.

Limiting the strategic emission reduction analysis to CO₂, in other words neglecting emissions of other GHGs (non-CO₂ gases) entails a similar incomplete picture of the emission reduction issue. Thus, reduction strategies that seem optimal from the perspective of CO₂ reduction, are not necessarily so from the perspective of the reduction of the total group of GHGs.

This study to assess the cost-effectiveness of GHG emission reduction strategies for the Netherlands energy system, includes energy related emissions of all GHGs and all upstream GHG emissions in an integrated analysis. The incorporation of these emissions provides the possibility to give answers to a number of questions:

- How important are the energy related emissions of GHGs in comparison with the emissions of CO₂ from direct combustion?
- How important are the upstream emissions of GHGs? How will they develop over time without policy towards abatement of GHG emissions?
- What are the main sources of energy-related non-CO₂ GHGs?
- Is it difficult to abate energy-related emissions of non-CO₂ GHGs?
- What are the most effective energy strategies for the integrated reduction of GHGs?
- Is the most cost-effective energy strategy for emission reduction different now the non-CO₂ GHGs and the indirect CO₂ emission are included?
- How sensitive are the results for scientific uncertainties?

A detailed description of the general methodology and the specific methodology that has been applied to account for indirect GHG emissions and non-CO₂ GHG emissions is given in chapter 2. In chapter 3 the indirect emissions of fuel use have been characterized. chapters 4 to 7 pertain the points of departure for the model input for the energy related emissions and reduction options for respectively methane, nitrous oxide, carbon monoxide and halocarbons. In chapter 8 the model results will be presented and discussed in detail. In chapter 9, finally, a set of conclusions will be drawn.

2. APPLIED METHODOLOGY

2.1 Modelling tool and scenario

The applied model is a generalized bottom-up dynamic optimization model of the energy system. MARKAL (MARKet ALlocation) is a widely used model, which is constructed according to the concept of a Reference Energy System, allowing to model various kinds of detailed energy system networks [7,8]. These networks consist of existing and innovative energy technologies that is able to cope with exogenous demands given for energy services. In most applications an economically efficient solution is obtained by minimizing the net present value of the energy system's cost throughout the planning horizon. This implies cost-optimal energy strategies from a national point of view, not considering the behaviour of the individual actors in the energy system. Among others, the model allows for modelling of a time division in useful demands, intermittent energy production, constraints on (rates of) penetration of new technologies, resource depletion and emission reduction targets for various pollutants.

MARKAL configures an optimal mix of technologies to satisfy the specified useful energy demands. For this, it uses detailed compilations of data which characterize available and prospective energy technologies, and it incorporates projections and assumptions about the costs and availability of fuels. The model includes user-specified data of the energy system: fuel prices, investment costs, availability, efficiencies of different energy technologies, emission coefficients and emission abatement techniques.

The Netherlands' MARKAL model contains more than 200 technologies. The main commonly used groups of technological options for CO₂ reduction are present, see table 2.1. These technologies have been described in detail in [2,6,9]. A selection of the technical CO₂ abatement options is listed in annex A.

The model optimises the energy system for a specified period, simultaneously in periods of 5 years each. This dynamic simultaneous optimization assumes perfect foresight, reflecting the activities of policy makers as they are supposed to 'know the future'. Dynamic modelling is of vital importance for testing structural changes in the energy system under environmental constraints. Several new energy technologies are projected to become available at fixed moments in the future. This reflects the impact of ongoing energy and environmental R&D. Therefore, the model enables testing of such new technologies in a future energy system under various constraints ('technology assessment').

Table 2.1 *Groups of options for CO₂ emission reduction and examples of technologies included in Netherlands' MARKAL*

Groups of options	Examples of technologies
Savings on end-use	insulation options gas fired heat pumps compact fluorescent light-bulbs Stirling engine car process changes industry
Savings in conversion	combined heat and power fuel cells
Fossil fuel substitution	additional gas fuelled plants natural gas vehicles
CO ₂ removal, mainly coal-based	at methanol production from coal at coal power plants at combined cycle gas turbines at nitrogen fertilizer plants at H ₂ production from coal part of H ₂ use options
H ₂ from natural gas with CO ₂ removal	through steam reforming
Renewables	wind turbines solar PV energy crops H ₂ import from Sahara

Energy demands for energy services were taken from an existing scenario, that was used in various studies [2,6,9]. The scenario can be qualified as a Dynamics As Usual scenario (DAU) and covers the time period between 2000 and 2040. In this scenario gross domestic product (GDP) growth decreases gradually from a level of 2.2%/year in the period between 2000 to 2010 to 1.7%/year between 2020 and 2030. The current sectoral structure with a strong emphasis on the petrochemical industry will maintain; the decrease in energy intensity which can be attributed to structural changes is only 0.15%/year. On top of this, energy intensity of industry decreases with 0.90%/year as a result of autonomous efficiency improvements. In model runs, non-autonomous efficiency improvements also take place.

The population is projected to increase from 15 million inhabitants in 1990 to 16 million in 2000 and 17.1 million in 2030 [2]; after 2030 the population size is expected to decrease. The number of houses increases from 5.9 million in 1990 to 8.0 million in 2030. An increase of 25% in passenger kilometres is expected between 1990 and 2030, with a decreasing number of persons per vehicle the number of cars is expected to grow with 50%. Freight transport will almost double between 1990 and 2030.

The energy price paths which have been used (see table 2.2) are taken from [9]. It has been assumed that for the long term oil prices are assessed by the long term supply curves. The gas price is assumed to remain linked to the oil price.

Table 2.2 Price paths in the scenario [*Dfl₉₀/GJ*]

	2000	2010	2020	2030	2040
Oil	10.30	12.95	15.85	18.45	21.00
Coal	4.25	5.20	5.95	6.55	7.15
Natural gas	9.33	11.50	13.85	16.45	19.00

At the moment the best which could be said about nuclear energy in the Netherlands, is that the chance of nuclear energy is fifty-fifty. For this study, nuclear energy has not been considered as an option.

2.2 System boundaries and greenhouse gas emission accounting

CO₂ emissions from fossil fuels are usually calculated using national energy statistics, hereafter referred to as the national CO₂ accounting method (see figure 2.1). Such calculations basically consist of a multiplication of the consumption of fuels and the emission factors of the fuels. The national CO₂ accounting method has been adjusted and refined, e.g to account for non-energy use of fossil fuels [1,10] and a process is underway to generalize the method [11].

From the point of view of CO₂ emission inventories and international negotiations to reduce CO₂ emissions, the national CO₂ accounting method has benefits:

- The methodology is simple to use.
- Emission accounting is easy.
- Double-counting of emissions is largely avoided.
- Emissions coincide with the emissions that can be (more or less) controlled by the country under consideration.

However, a main disadvantage of the national CO₂ accounting method occurs, when CO₂ emission strategies are studied with respect to their (cost)-effectiveness. Hence, a reduction strategy which seems most effective on a national scale is not necessarily equally effective on a global scale. It has to be noted that the only reason to reduce CO₂ emissions is to decrease climate change, and climate change is a global scale problem. Consequently, the effectiveness of national strategies to reduce CO₂ emissions also needs to be examined on a global scale.

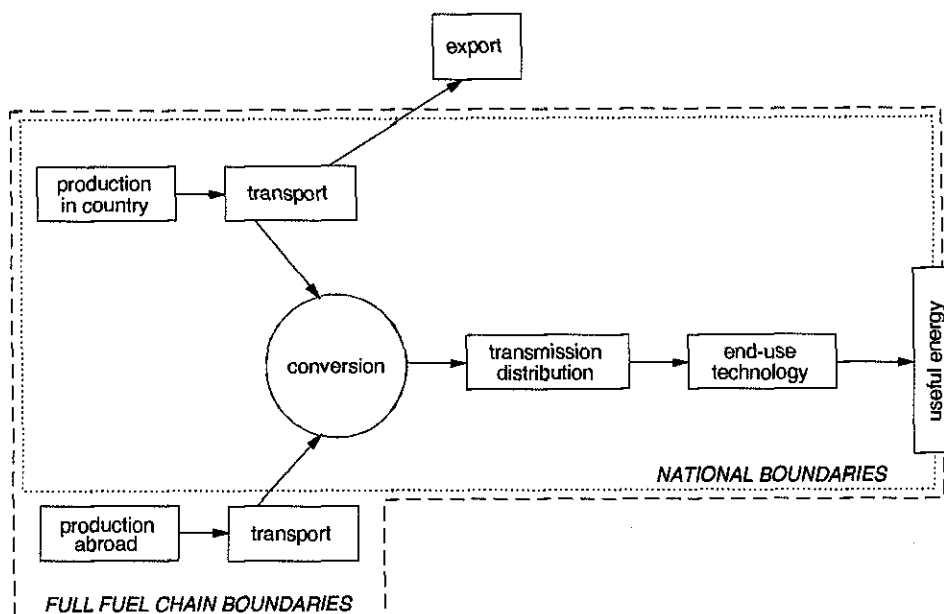


Figure 2.1 Schedule of energy system with two different system boundaries

In this study a different emission accounting method is used. The full chain GHG approach was applied to study the cost-effectiveness of GHG emission reduction strategies. All emissions which are directly or indirectly linked to final energy use in the Netherlands were considered. The indirect emissions included upstream emissions required to supply energy to the Netherlands (see figure 2.1), downstream emissions needed to deal with environmental impacts of energy use, and, if of significant importance, emissions which occur from building energy technologies. Thus, not only the emissions within the Netherlands' borders are considered, but also the emissions outside the Netherlands and those which are linked to energy use in the Netherlands are included. As a result, the most effective GHG reduction strategies from a global point of view can be assessed.

For imported fuels and domestic mining of fuels, the energy requirements to produce, refine and transport the fuels were considered. For export of fuels and feedstocks, the indirect emissions were not subtracted from the national emissions. Hence, the emissions occurring through import and conversion of primary fuels into refined energy carriers as well as products, which will later be exported can be attributed to the Netherlands, since the export appears to be an economically profitable activity.

It has to be noted that the emission estimates of CO₂ from indirect emissions are less reliable than the emission figures for direct emissions. An estimate for the uncertainty range for the total direct CO₂ emissions from the Netherlands is $\pm 1\%$, the corresponding uncertainty range for the total indirect emissions is $\pm 10\%$.

2.3 Accounting for non-CO₂ greenhouse gases: the GWP concept

To account for the effect of emissions of GHGs other than CO₂ in the evaluation of energy options to reduce GHG emissions, one need:

1. the emission factor of the processes involved;
2. the relative effect of the emission of the gas on climate.

Emission figures of the different GHGs for energy-related processes have been studied in detail in chapters 4 to 7 of this report. Methane, nitrous oxide, carbon monoxide and halocarbons are the gases that were considered. The emissions of GHGs which are not clearly linked to activities in the energy sector, e.g. methane emissions from animals, biogenic N₂O emissions from growing flowers and halocarbon emissions from fire extinguishers, were not considered in this study. As a result, the calculated annual emission totals for the non-CO₂ GHGs did not correspond to the total national emissions. Furthermore, emissions which are of insignificant magnitude were not taken into account.

Emission figures for emissions of non-CO₂ GHGs are less reliable than the emissions of CO₂ from the energy sector. CO₂ emissions simply depend on the quantities of fuel and the C/H ratio of the fuel. As fossil fuels have a clear economic value, the amounts used can be traced reasonably well, and thus, CO₂ emissions can be calculated fairly precise. On the contrary, emissions of other GHGs are either due to small losses or depending on combustion conditions or being of a biogenic kind. Consequently, such emissions are less well-known and less well accounted and thus have a large uncertainty range. Indicative reliability factors for GHG emissions are listed in table 2.3. These are a compilation of values widely used in literature. It has been noted that the reliability of emission figures for individual sources may be better or worse. N₂O emissions are least well-known.

Table 2.3 *Indicative reliability factor for total national emission figures of GHGs. This figure is the factor the medium emission estimate to multiply with and to divide through to calculate the uncertainty range*

	CO ₂	CH ₄	N ₂ O	CO	Halocarbons
Indicative range factor	1.01	1.3	2.5	2.0	1.3

The way to properly express the relative effect of emissions of individual GHGs on climate is still being debated, e.g. [12-15]. Hence, climate change is the process which is induced by increasing atmospheric concentrations of different gases, caused by increased anthropogenic emissions. These gases have different radiative forcing and different atmospheric behaviour.

The relative impact of the emission of individual GHGs on climate change depends mainly on three characteristics:

- the relative radiative force;
- the atmospheric lifetime;

- the chemical breakdown route of the gas and the extent to which it gives rise to other GHGs.

In considering the policy options for dealing with GHG emissions, it appeared to be necessary to have a means to describe the relative abilities of emissions of the different GHGs to affect radiative forcing and hence climate [12]. A Global Warming Potential (GWP) concept, which contains the three above listed characteristics has been developed. The GWP is a relative measure in that it expresses the warming effect compared to that of a reference gas. The GWP of a well-mixed gas was defined by [12] as the time-integrated change in the radiative forcing due to the instantaneous release of 1 kg of a trace gas expressed relative to that from the release of 1 kg of CO₂. Multiplication of the emission of a GHG with its GWP gives the CO₂ equivalent emission the GHG. Naturally, the GWP of CO₂ is equal to 1 by definition. The GWP due to indirect effects is quite often separately quantified. As it is derived from the globally - and annually - averaged net radiative fluxes it is a global measure. The GWP can be calculated for different time horizons, taking into account the change with time of the gas concentration.

The GWP index has a number of limitations. Major *scientific* uncertainties exist in the parametrization of the properties that are part of the GWP definition. These include the radiative transfer within the atmosphere, atmospheric residence times of gases, chemical processes and sink processes. Main uncertainties stem from the indirect effects, since both details of the chemical processes are not well-known and transformations involve spatial as well as temporal variations of gases [13]. For gases that are short-lived and not well-mixed (e.g. nitrogen oxides) the GWP concept is meaningless. The net temporarily effect of e.g. NO_x emissions on tropospheric ozone depends on both the chemical composition of the atmosphere and climatic circumstances at that time. Moreover, NO_x can either have a net warming effect or a net cooling effect, under different weather conditions and other trace gas concentrations [14].

Conventional uncertainty arises from the currently arbitrary assignment of an integration time period. If the time horizon is chosen to be infinite, all future temperature increases are weighted equally. This is in contrast with a short time horizon (e.g. 20 years), when the impacts on warming occurring 20 years after the emission of the gas are no longer considered. The choice for a time horizon is a political one. A GWP based on a relative short time horizon can be adopted if the view is taken that short term effects of climate change are most important (e.g. in order to save ecosystems that can only adapt slowly). On the contrary, a GWP based on a longer time horizon is appropriate if the long term effects of climate change are considered most important [14]. IPCC has confidence that GWPs calculated over time horizons of 20, 100 and 500 years provide a practical range for policy applications. In this study a 100-year time horizon for emissions has been considered to provide a balanced representation of the various time horizons for climate response. Carbon cycle models also indicate that this time period broadly represents the time scale over which a significant fraction of CO₂ is removed from the atmosphere.

Methodological uncertainties are related to the choice of a specific emission scenario and the choice between an analytical or a model-based approach to the estimation of GWPs. The analytical approaches, such as [12-14], have the advantage of being transparent. The model-based approach, e.g. [15] is more capable to deal with the many non-linear relationships within the atmosphere over long time periods.

Various attempts have been made to calculate GWPs. The most frequently known GWPs are those of the scientific assessments of the Intergovernmental Panel on Climate Change (IPCC) in 1990 [12] and 1992 [13]. IPCC has calculated GWPs for three different time horizons (20, 100 and 500 years). The GWPs of IPCC'90 and IPCC'92 for a limited set of GHGs are given in table 2.4.

Table 2.4 *Global warming potentials of selected greenhouse gases, mass to mass base, according to IPCC'90 [12] and IPCC'92 [13]. GWPs are dimensionless*

Greenhouse gases	IPCC 1990			IPCC 1992		
	Time horizon [years]			Time horizon [years]		
	20	100	500	20	100	500
CO ₂	1	1	1	1	1	1
CH ₄ dir.	26	6	2	35	11	4
CH ₄ chem.	37	15	7	N.Q.	N.Q.	N.Q.
N ₂ O	270	290	190	260	270	270
CO	7	3	2	N.Q.	N.Q.	N.Q.
CFC-12	7100	7300	4500	7100	7100	4100
HCFC-22	4100	1500	510	4200	1600	540
HFC-134a	3200	1200	420	3100	1200	400
HFC-152a	510	140	47	530	150	49
NO _x	30	8	3	N.Q.	N.Q.	N.Q.

N.Q. Not Quantified

The GWP of some of the gases represented in table 4.2 varies considerably with the time horizon taken into account. This is in particular the case for short-lived gases, such as methane and the HFCs. In comparison with the '90 scientific assessment, IPCC'92 refrained from quantifying indirect GWPs, since these were considered to be too uncertain.

It has been attempted to calculate the possible range in GWPs which are due to scientific uncertainties at a fixed time horizon of 100 years [14]. The range of the numerical values of the relevant properties of GHGs has been compiled from literature. From the lower and the upper values of these ranges the largest possible range in GWPs has been calculated. For most of the GHGs the high estimate GWP is more than twice the low estimate GWP (see table 2.5).

Table 2.5 Global warming potentials of selected greenhouse gas emissions, low and high estimates, mass to mass base according to [14]

Gas	Low estimate	High estimate
CO ₂	1	1
CH ₄ dir.	5.5	19.2
CH ₄ chem.	5.0	30.7
N ₂ O	124	331
CO	2.3	9.1
CFC-12	3385	7881
HCFC-22	669	2253
HFC-134a	508	1709
HFC-152a	51	207
NO _x	N.Q.	N.Q.

N.Q. Not Quantified

The climate effects of methane have probably been overestimated [16], largely due to the neglect of the height dependence of certain atmospheric processes, such as formation of tropospheric ozone and stratospheric H₂O. Based on the most recent knowledge of chemical processes, the indirect GWP of CH₄ should amount to 10.2 for a 100-year time horizon and 23 for a 20-year time horizon [16].

Although the uncertainty of the GWPs of indirect effects of GHGs is large, it is still preferable to include these effects in effectiveness studies of GHG abatement. For this study the GWPs of IPCC'92 and the GWPs of IPCC'90 were applied for, respectively, the direct effects and the indirect effects. These values are most widely known. For both effects a 100-year time horizon was taken. Those gases, which concentration may either enhance global warming or decrease global warming, e.g. NO_x, have not been taken into account at all.

In a sensitivity analysis (see section 8.6) the scientific uncertainties will be addressed for the calculation of GWPs. The low and high GWPs in table 2.5 have been applied.

Another possible sensitivity analysis would have been to consider 20 and 500 year time horizons for the calculation of the GWP (see the value in table 2.4).

2.4 Modelling indirect emissions and the full basket of greenhouse gases

As far as emissions of GHGs are energy-related, they are included in this analysis. Compared to earlier studies with the Netherlands MARKAL model, this implied an extension of the model with an accounting framework for the emissions of methane, nitrous oxide, carbon monoxide and several halocarbons. In addition, a system is added that accounts for the CO₂ equivalent emissions of all GHGs. This contains the GWP values of the GHGs.

In LP models such as MARKAL, emissions of GHGs can be forced to decline in two ways (see figure 3.1). The first possibility is by putting a constraint on the CO₂ equivalent emissions. The model calculates the most cost-effective way to achieve this target; the level of the marginal reduction cost is a key result. The second possibility is to penalize the emissions of GHGs. In the latter case the model chooses those technologies which have specific cost not exceeding the penalty (or marginal cost). In this way a lower CO₂ equivalent emission level is obtained.

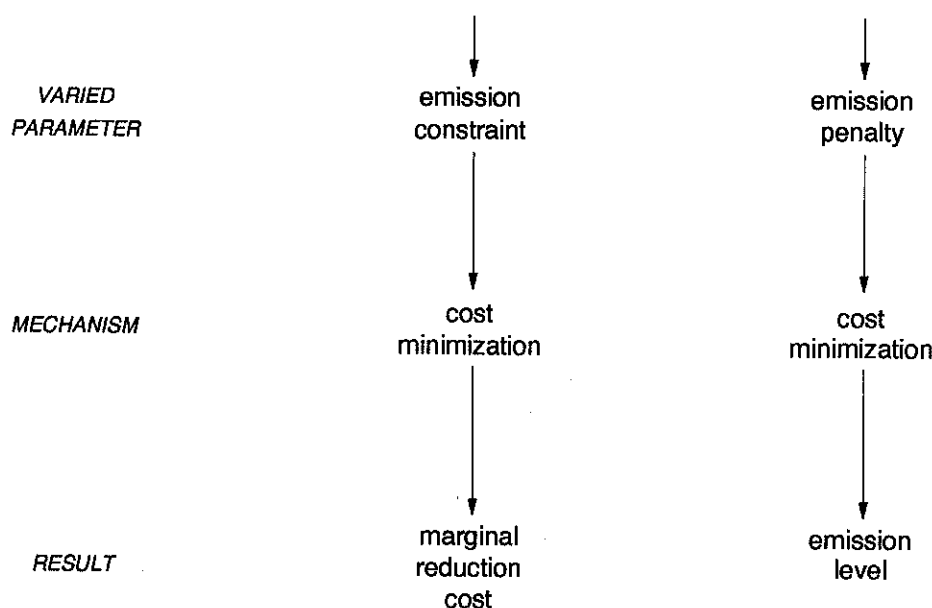


Figure 2.2 *Two main possibilities to assess cost-effective greenhouse gas reduction strategies in LP models, such as MARKAL*

An advantage of the use of a penalty is the avoidance of a whimsical marginal CO₂ reduction cost path. In both approaches the model searches for the most cost-effective way to reduce GHG emissions. Implicitly, a trade-off takes place to exchange technologies either at the supply side or at the demand side of the energy system and to reduce emissions of either CO₂ or of other gases. The model simultaneously considers all options for GHG reduction, to find out which combination of options is most cost-effective. The difference in annualized costs between a reduction case and the unconstrained case reflects the total annual cost for emission reduction.

A comparison between cost-effective reduction strategies which only considers direct CO₂ emissions, and strategies which consider both GHGs and indirect emissions is part of this study. Consequently, the reduction of emissions by applying a penalty is most appropriate. With the CO₂ constraint method no common points remain to make a comparison, since CO₂ emission reduction targets and CO₂ equivalent emission reduction targets can not directly be compared. For an approach with a CO₂ penalty, at least the marginal reduction cost levels offer fixed points for the comparison.

3. INDIRECT CO₂ EMISSIONS

3.1 Direct versus indirect emissions

The amount of CO₂ released from combustion of a fuel delivering a certain amount of thermal energy depends on the C/H-ratio of the fuel. Natural gas, with a low C/H ratio (CH₄) releases less CO₂ than coal (CH_{0,8}) or oil (CH_{2,2}) in delivering the same amount of thermal energy. The emission factors as given in table 3.1 were used in this study for the 'direct' emissions of CO₂.

Table 3.1 CO₂ emission factors direct combustion, lower heating value

Direct combustion	Emission factor [kg CO ₂ /GJ]
Hard coal	94
Oil products	73
Natural gas	56.1
Uranium	0
Renewables	0

In this chapter the upstream 'indirect' CO₂ emissions will be estimated, using concepts of full fuel cycle analysis. Indirect emissions from fossil fuels include CO₂ emissions before their actual usage for final energy purposes, such as emissions from mining, transport and refining of fuels. Currently, some important indirect emissions are from gas-flaring at oil fields, overseas transport of coal and oil, and energy use in oil refineries. Indirect emissions from uranium and renewables include e.g. uranium-extraction and -enrichment, and fuel-inputs for agricultural energy crops.

Consistent with the system boundaries as they have been applied in earlier studies, the following indirect emissions have already been accounted for in the model, as far as these took place in the Netherlands in the same year:

- CO₂ emissions associated with energy inputs for producing gasoline, diesel and LPG in oil refineries;
- CO₂ emissions associated with energy inputs for agricultural operations and industrial processing of energy crops.

For refined oil products and bio-ethanol the above mentioned emissions are 5 and 20 kg/GJ respectively in a base case situation without CO₂ constraints. In the case of national CO₂-reduction targets, these indirect emissions would tend to decrease, as a result of energy conservation, fuel substitution etc.

In the next paragraphs indirect emissions will be estimated for the main fossil fuels, for uranium and for building and decommissioning of energy conversion facilities.

Naturally, the upstream and downstream emissions of other GHGs than CO₂ are also considered in this study. The technical characterization of these emissions will be presented in chapters 3-7.

3.2 Coal

Australia, South Africa and the United States are expected to be the most important coal exporting countries for the Netherlands in the time period considered in this study (2000-2040). Energy is needed upstream in the energy chain to mine the coal as well as to transport it to the Netherlands. The upstream emissions are not fixed amounts. They depend on various parameters involved. The main upstream processes from which emissions occur, include:

- Energy use for *mining, coal washing and transport to port*: the emissions in mining operations depend on mining depth and mining methods, emissions from coal washing depend on the coal rank and the emissions from transport depend on the distance between the mine and the nearest bulk carrier port, and the available transport infrastructure. Average global energy requirements for mining, washing and transport of coal to the nearest port have been estimated equivalent to 2% of the CO₂ coefficient of coal: 1.9 kg/GJ [17].
- *Overseas transport and delivery at power station*. Energy use for overseas transport depends on various parameters. The most important parameters include the size of the bulk carrier and the route the carrier will take (through Suez Canal or not), the number of ship return loads, the average speed of the carrier and technical developments in ship efficiency. It has to be noted that these parameters are often strongly interlinked; e.g. medium size bulk carriers (65,000 ton) have normally a speed of approximately 16 knots and are able to go through the Suez Canal, while larger vessels (170,000 ton) have a higher speed, but are not able to go through the Suez Canal and thus increasing the distance between Australia and the Netherlands. For bulk carrier transport to the Netherlands an average transport distance of 8000 nautic miles has been assumed [17]. Depending on the above mentioned parameters, the calculated energy use for transport may range between 3% and 6% of the energy content of the transported coal. To calculate the related CO₂ emissions the direct and indirect emissions for the ship's diesel oil use (83 kg CO₂/GJ) have been taken. Energy requirements for transport of coal within the Netherlands are small.
- *Inorganic and biogenic oxidation in coal piles, and swirling*. CO₂ emissions through oxidation losses are very uncertain. For average operation of coal power stations they have been estimated at 2% of the coal's direct CO₂ emissions [17]: 1.9 kg/GJ. Swirling of coal piles was considered to be negligible.

The resulting total indirect emission from upstream activities for delivered coal have been estimated to amount to 6.0 kg CO₂/GJ. It has to be noted that these emissions may be substantially higher or lower in specific coal chains. Moreover, it has to be realized that methane is also emitted upstream the energy chain; however, these emissions will be discussed in section 5.3.

CO₂ emissions also occur downstream the energy chain to reduce the environmental load of coal use.

- Lime/limestone FGD processes: the mineral CO₂ emission factor from FGD (Flue Gas Desulphurization, gypsum process) was calculated according to the formula in [10]. For conventional pulverized coal power stations and industrial coal boilers and furnaces, with an average sulphur content of 0.8% the indirect CO₂ emissions amount to 0.4 kg/GJ. The reduction in electric efficiency was accounted for in the efficiency of the pulverized coal power stations.

3.3 Oil

Energy is required for different processes involved in oil production, oil transport and oil refining. Just as coal, a large share of oil is traded on a global scale. The Middle East is currently the main supplier of oil and will remain when the oil reserves are considered. Currently, the Netherlands also receives significant amounts of oil from North Sea production fields.

The indirect emissions from refining oil, which occur within the Netherlands, have already been accounted for [2].

The following estimates for energy use for upstream emissions which occur outside the Netherlands have been made:

- a. At oil production a mixture of oil and gas (associated gas) is recovered. The average share of associated gas is 10% [39]. The associated gas can not always be utilized. In offshore production, at small 'stripper' gas fields and areas with little industrial activity, this is most frequently the case. Three options are available to get rid of the methane: venting, *flaring* and reinjection in the oil field. Figures for venting are rarely available. Currently, a shift occurs from venting and flaring to oil field reinjection. In 1980 the gas flared amounted to 164 billion m³, equivalent to 4.5% of the energy content of oil production. With the high energy prices in the early 80's the flare rate decreased to 3.0% of production. The 1988 average flare rate was 2.3% of oil production [40]. Average flaring rates between the year 2000 and 2040 was assumed to amount to 2.0% of production. The emissions in flaring, pre-production, processing, etc. have been estimated equivalent to 2% of the CO₂ coefficient of oil: 1.5 kg/GJ [17].
- b. *Overseas transport* and delivery at refinery: for bulk carrier transport to the Netherlands over an average typical transport distance of 6000 km these emissions have been estimated to be equivalent to 1.5% of the oil: 1.1 kg/GJ [17].
- c. *Upstream emissions* that have been estimated according to a and b for the approximately 5% *own consumption in refineries* amount to: $(0.02 + 0.015) \times 0.05 \times 73 = 0.1$ kg/GJ.

The resulting indirect emission for oil products was 2.7 kg CO₂/GJ.

3.4 Natural gas

The Netherlands is currently one of the main suppliers of natural gas for the Western European market. However, it seems likely that national gas reserves are not sufficient to meet the domestic demands for natural gas which are expected for the period between 2000 and 2040. Then the Netherlands will become a net importer of natural gas. Russia is one of the main candidates to export natural gas to the Netherlands. Indirect emissions for natural gas production have been considered both for domestic gas production and for the import of gas from Russian natural gas fields.

Upstream energy use from natural gas produced in the Netherlands was not considered in combination with fixed indirect CO₂ emission factors (kg CO₂/GJ), but with energy losses in the gas production system. For the Netherlands' gas production, indirect emissions stem from energy use for exploration, production, processing, compression, storage and transport of natural gas. At gas production two processes account for the main energy consumption: processing and compression. The current energy consumption for processing and compression is 0.2% of throughput [18]. However, this figure will change in the future. The demand for natural gas varies from day to day and from hour to hour. In the Netherlands the large Groningen gas field is used to intercept these fluctuations. Since the production of the other gas fields will decrease in the future and the capacity of the Groningen field will decrease as a result of the decreasing pressure, it will become increasingly difficult to meet the peak demand. Storage of natural gas in depleted gas fields is an expedient to deal with the capacity problems. In summer such fields will be filled and in winter they will be emptied. In 2015 the energy requirements to process the natural gas and to compress the natural gas in summer with gas-fired compressors will amount to an energy loss of approximately 2.3% [18,19]. Energy losses amount to 1.0% with the use of electric compressors for compression. Both gas-fired and electric compressors have been allowed in this study. Energy use for transport of natural gas by Gasunie, the Dutch company for trade and transport of natural gas, is approximately 0.2% of throughput [19].

In addition, CO₂ emissions may originate from smaller gas fields which contain significantly higher CO₂ percentages (e.g. 5% in the Coevorden field, and 25% in 'K15F8' in the North sea basin). The average CO₂ content by volume in natural gas in the Netherlands is 1% (0.6 kg/GJ) [17]. This value is already included in the emission coefficient. In case of national GHG reduction targets, separation at the well head and re-injection has been assumed to be cost-effective [20].

Considering the large natural gas reserves in Russia, it could well be possible that most of the Netherlands' gas imports between the year 2000 and 2040 will be supplied by Russia. This implies that this natural gas needs to be transported over a distance of approximately 6000 km. Transport of natural gas over such a distance requires a significant amount of energy for compression. Several sources [21-23] have reported the energy use for gas transport through pipeline systems to amount to slightly more than 0.1% for each 100 km transport distance. Such a figure is also consistent with the energy use for gas transport in the Netherlands. As a result, the energy losses natural gas transport from Russia will be 6.0% of delivered energy

content. Additionally, it has been assumed that energy requirements for production and processing of natural gas in Russia will amount to almost 1% of gas production. Consequently, the total energy losses will be equivalent to 7% of the delivered gas.

3.5 Uranium

Important steps which require energy in the nuclear fuel chain are uranium ore mining, extraction of uranium from the ore and the enrichment process. Indirect CO₂-emissions in uranium-extraction and -enrichment have been estimated 3 kg per GJ heat generated in a light water reactor [17]. Key characteristics to calculate this figure included the assumed uranium ore concentration of 0.17%, an enrichment process based on the ultracentrifuge and no re-processing of nuclear reactor waste. If the gas diffusion process had been assumed for enrichment, energy requirements would have been substantially higher.

It has to be noted that nuclear power has not been allowed as an option in this study. The possible role of nuclear power in CO₂ constrained energy systems has been taken into account in [2].

3.6 Emissions from building and decommissioning of facilities

Energy and material requirements in the building stage of energy conversion facilities, also result in CO₂ emissions. In comparison with the direct and indirect emissions during operation of the facility (directly through fuel combustion, indirectly through fuel pre-processing) these building emissions are considered 'historical' emissions. From today's point of view there are of course no possibilities to reduce historical emissions.

In the decommissioning stage, after service life of the facilities, some of the materials may be recycled (e.g. aluminium, steel) and part of the facilities may be reduced (e.g. concrete foundations for windturbines). In this analysis such recycling options have not been considered.

On the other hand operations in the nuclear fuel cycle after power station service life (dismantling of nuclear power stations, maintenance of long term nuclear waste disposal sites) would require certain amounts of energy, thus increasing CO₂ emissions. To name one example: the energy requirements for water supply to basins for the long term storage of uranium-mill tailings, in order to reduce ²²²Rn emissions, in arid regions [17]. These future emissions have neither been considered.

The energy requirements for building renewable energy facilities are often expressed in terms of 'energy pay back time' (see table 3.2) using simple coefficients [24]. The energy pay back time is often longer for renewables than for conventional power plants. In this study the difference in energy pay-back time, as compared to conventional power stations, is translated in increased investment costs. This assumes that additional renewable ca-

capacity needs to be installed to generate energy to build the renewable technologies.

Table 3.2 *Energy pay-back times for selected energy facilities [17]*

Energy facilities	Energy pay back time [year]	Lifetime technology [year]	Investment increase [%]
Conventional power	0.5	25	-
Wind power	2	20	7
Solar PV (thin layer)	2	20	7
Solar hydrogen import	3	30	7
Wood power	0.5	25	-

Energy and material requirements to produce energy demand technologies (e.g. boilers, heat pumps) or which decrease energy demand (e.g. insulation) have not been considered. Recently a model has been developed which allows for modelling of the energy impacts of material inputs for product manufacturing [25]. This dynamic optimization approach considered the time-lags between production, the release of materials after the use in products and options for recycling of materials. As such this methodology integrated energy system analysis and life cycle analysis. Energy and material requirements in passenger car manufacturing have been included in calculations for the integrated energy/material systems model in [26]. The CO₂ emissions connected with the construction of a car represent about 15% of the passenger car life cycle CO₂ emission.

4. METHANE (CH₄)

4.1 Energy related CH₄ emissions

Total methane emissions from the Netherlands territory in 1991 have been estimated to amount to 1227 kton CH₄ [27]. Natural emissions from wetlands and inland and coastal waters are 121 kton per year [27]. The anthropogenic emissions are mainly from animals and landfills (see table 4.1). With present environmental policy, the anthropogenic emissions are expected to decrease substantially. This is mainly because landfilling will be reduced and as a side effect of the Dutch government's policy to reduce animal manure surpluses.

Table 4.1 *Anthropogenic methane emission from the Netherlands, best estimates, 1991 and 2000 [27] [kton/year]*

Emission source	1991 [kton/year]	2000 [kton/year]
Gas production	60	52
Gas transport	7	6
Gas distribution	84	72
Oil production	17	0
Combustion	23	26
Animals	424	371
Animal manure	109	77
Landfills	377	257
Sewage treatment	3	3
Water production	2	2
Total	1106	866

The national borders are not the system boundaries for GHG emissions of this energy system study. All emissions which are linked to energy consumption in the Netherlands have been accounted (see chapter 1). Consequently, emissions of GHGs 'upstream' in the energy system were also considered. Currently, these 'foreign' emissions are from coal mining and oil production; these emissions were estimated to amount to approximately 150 kton CH₄ in 1991. Since the Netherlands will presumably import quantities of natural gas between 2000 and 2040, emissions of CH₄ 'upstream', linked to production and transport of natural gas abroad, also need to be considered.

Since methane is an energy carrier, all sources of methane can be defined as 'energy related sources'; the anthropogenic emissions in 1991 listed in table 4.1 have an energy content of 60 PJ. However, in this study only those sources from which methane can practically be recovered and utilized are referred to as 'energy related sources'.

In the next sections the following sources of methane emissions will be regarded. They are also schematically shown in figure 4.1.

- natural gas production, transport and distribution
- coal mining
- oil production
- selected combustion processes.

Methane emissions from landfills will not be addressed. These emissions will strongly decrease in the next decades. Landfill gas recovery already occurs at profitable locations. Usage of methane from animal manure is already an option in the model. Three different biogas options were modelled [2].

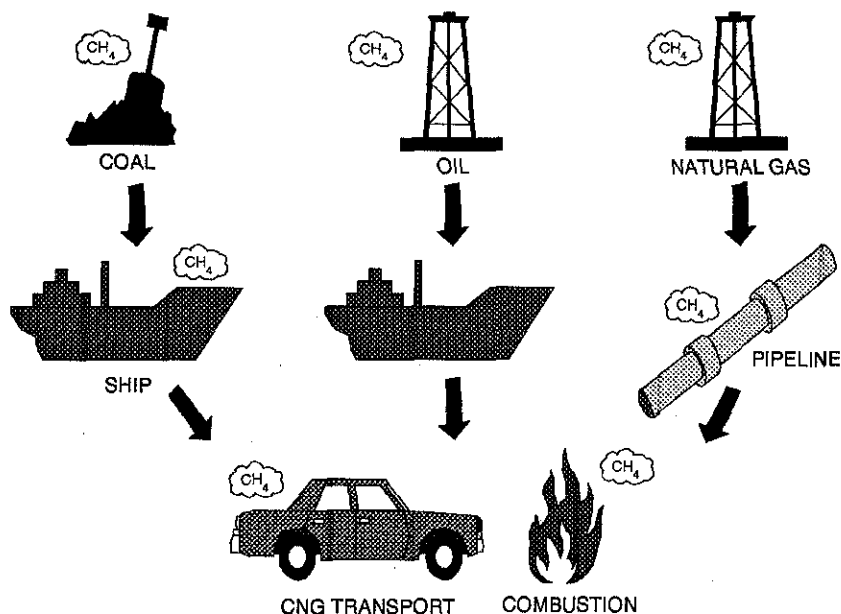


Figure 4.1 Energy related methane sources

4.2 Natural gas production, transport and distribution

4.2.1 Natural gas production

Methane emissions from natural gas production occur at exploration, at production testing, at production and at gas processing (separation of water and condensate from the natural gas). Average emissions of methane related to gas production in the Netherlands were estimated between 0.09-0.16 vol% of throughput [28]. Taking 0.12 vol% as a medium estimate, results in an emission factor of 22 gCH₄/GJ. Approximately 80% of these emissions takes place at offshore gas production platforms [29], although these gas fields produce only 25% of the total gas production. The reason for this difference is that excess natural gas is flared at onshore gas production sites, whereas excess natural gas is often vented at offshore gas production platforms. Consequently, the CH₄ emission factor for offshore gas production is higher than the average emission: $0.8 \times 100/25 \times 22 = 70 \text{ gCH}_4/\text{GJ}$. The emission factor for land based production is lower than the average emission: $0.2 \times 100/75 \times 22 = 6 \text{ gCH}_4/\text{GJ}$. Considering the shares of the Netherlands' reserves of natural gas which are based offshore

and onshore [30], offshore gas production will remain approximately 25% of the total natural gas production in the first part of the next century.

For this study options to reduce CH₄ emissions from offshore production were considered. According to [29], the most attractive option to reduce venting at offshore platforms is to increase the utilization of natural gas. This can be achieved by e.g. power generation at the platforms or by compressing methane gas that is recovered from the condensate expansion and feeding it back to the mainstream. Specific costs of such measures will depend on the local situation in the platforms and the throughput of the platforms. [29] provides estimates on measures for cost reduction. These are not valid for individual platforms, but only for all platforms together. A first reduction stage for an average platform with a throughput of 360 million m³ per year, requires an investment of roughly 0.25 million Dfl to reduce emissions with 25%. A higher methane recovery (75%) may be possible at an investment between 0.5 and 2.0 million Dfl per platform [29]. For this second reduction stage a high cost figure was taken. Lifetimes of such investments are expected to cover 15 years on average.

4.2.2 Import of natural gas

Before the end of the planning horizon of this energy system study (the year 2040), the Netherlands' reserves of natural gas will presumably have decreased to such a level that the Netherlands will have shifted from being a net exporter of natural gas to a net importer of natural gas. Currently the Netherlands, Norway and the UK are the main producers of natural gas for the Western European gas market. Russia and Algeria also produce gas for this market. To meet future demands on the long term, natural gas will be supplied to the Western European market by Russian and Norwegian producers and possibly by Algeria or the Middle East [9]. Here import of natural gas from Russia has been considered.

It has frequently been suggested that large amounts of natural gas are emitted from the natural gas supply systems in Eastern Europe and the Commonwealth of Independent States. These large emissions would be caused by notoriously inferior and troublesome supply systems [31] and unfavourable freezing/melting cycles in production fields. Unfortunately, information about these natural gas emissions is very scanty. Estimates range between 2% and 10% [32]. [33] even cites incredible emission figures in the range between 30% and 50% of production. In many cases these are economic loss figures, but not necessarily physical methane emissions to the atmosphere. A significant part of the methane losses consists of fuel to drive compressors, non-reported industrial gas consumption or differences between 'planned' and 'actual' production figures at the well head [34]. Regarding the overview of emission estimates in [32] and taking into account the global budgets of methane emissions from fossil sources, in our own opinion it is most likely that current CH₄ emissions from Russia are between 2% and 5% of production. As a result of increasing awareness of environmental problems such as methane leakage, the higher technical standards for supply systems and the transfer of Western technology [33], future emissions are expected to become significantly lower. For this study an average leakage rate of 2% was assumed for production and transport of

Russian natural gas in the period 2000-2040. Technically, the emissions of methane from transport can be reduced to 0.60% of throughput¹. In order to test the cost-effectiveness, it was assumed that natural gas with this lower methane emission will be available at a net additional price² of 0.015 Dfl/m³. This natural gas will origin from Russia and implies production and transportation with improved technologies in Russia.

4.2.3 Transport of natural gas

Gasunie, the Dutch company for trade and transport of natural gas, operates the high pressure (40 to 65 bar) natural gas transport system. It delivers the gas to utilities, power plants, large industries and neighbouring countries. The annual transported quantity amounts to approximately 75 billion m³. Methane emissions occur in this phase due to adjustments and servicing of the piping system and compressor stations. In transport systems with low technical standards (not present in the Netherlands) leakages from pipelines can also be caused by either corrosion or material and construction defects or incidents [28]. The estimate for methane emissions in 1989 amounted to 0.015% of throughput [28]. Options to reduce these emissions have not been considered in this study.

4.2.4 Distribution of natural gas

Emissions of natural gas from the distribution system in the Netherlands were estimated to be 0.6% of throughput [27,28]. 75% of these emissions is caused by leaks from the 11,200 km [29] grey cast-iron network that was originally designed for coal-derived town gas. When the grey cast-iron networks were constructed, mainly lead-yarn joints were used. Since the town gas was damp, the lead-yarn rope expanded in the joints and subsequently closed the joint. With the introduction of dry natural gas in the grey cast-iron networks in the late 60's and early 70's, emissions were initially high. Although the gas utilities have used various technologies to improve the tightness of the grey cast-iron networks, their leakage rate is still relatively high. The other 25% of methane emissions from natural gas distribution take place in the main part of the network. This consists of 85,000 km of distribution pipelines and approximately 42,000 km of service pipelines [29] which are largely made of steel, PVC and PE.

Assuming that grey cast-iron pipelines in the Netherlands have the same throughput as the average network, the leakage rate of the grey cast-iron

¹ High technical standards emission factors which currently occur in the Netherlands were assumed. For natural gas transport over an average distance of 200 kilometre in the Netherlands, emissions amount to 0.015% of throughput [1]. Assuming a linear relation between transport distance and CH₄ emission, transport emissions for a distance of 6000 kilometre, will be 30 times higher than in the Netherlands: 0.45%. With production emissions (0.15%) almost at the same level as in the Netherlands, total emissions will amount to 0.60%.

² Additional costs were estimated to amount to 5-10% of the projected natural gas price. This is 2 ct/m³. Benefits from saving 1.4% of natural gas throughput will amount to 0.5 ct/m³ throughput. Net costs will be 1.5 ct/m³.

pipelines would be 3.9% of throughput³. A recent study of British Gas gave an average leakage rate for the United Kingdom in the distribution system of 0.95% [35]. The same study indicated 2.0% leakage from the grey cast-iron system [36]. Emissions from the Dutch grey cast-iron may be relatively high due to its sinking soil which may have caused additional leaks. Considering this UK leakage figure and the fact that part of the old grey cast-iron system will be replaced by the year 2000, a leakage rate for Dutch grey cast-iron networks of 3.5% of throughput was taken for our study. For the remainder of the distribution system a leakage rate of 0.2% has been applied.

Replacement of the grey cast-iron network by a modern pipeline system will reduce emissions to a level of approximately 0.2%. The cost of replacing pipelines varies between Dfl 100 and Dfl 500 per meter pipeline [29]. [29] assumes the cost to be at the high end of the range (400 Dfl/m), since most of the grey cast-iron system is used in old cities. Such investments are assumed to have a lifetime of 50 years.

A mixture of 90% natural gas and 10% hydrogen (ratio of energy content) can also be distributed in the existing distribution network [2]. In these networks methane emissions are assumed to be 10% lower in comparison with pipelines with distributing only natural gas.

4.3 Coal mining

Coal is imported in the Netherlands for use in power plants and specific industrial use. Coal contains quantities of methane. The methane remains stored in the coal until the pressure on the coal is reduced, which can occur through coal mining. During coal mining methane is not only released from the mined coal but also from the adjoining coal. The amount of CH₄ generated during coal mining is primarily a function of coal rank and depth of the mined coal, as well as other factors such as moisture. High coal ranks contain more CH₄ than low coal ranks. Depth is important because it affects the pressure and temperature of the coal seam, which in turn determines how much CH₄ is generated during coal formation. Deeper coal seams will hold larger amounts of CH₄. The amount of released methane also depends on mining technology. The more coal seams are distorted and depressurized, the more methane is released. Some methane emissions occur after the coal mining. These post-mining emissions may occur over a long time frame. [11] suggested to calculate CH₄ emissions from coal mining systems as follows:

$$\text{CH}_4 \text{ emissions (tons)} = \text{CH}_4 \text{ emission factor} \times \text{coal production} \times \text{CH}_4 \text{ density}$$

For underground mining the proposed range for emission factors (excluding post-mining emissions), is currently 10-25 m³/ton coal mined and 0.3-2.0 m³/ton coal mined for surface mining [37]. Emission factors are

³ Average distribution emission are 0.6% of throughput. 75% of total emissions are from the grey cast-iron system. The grey cast-iron network is 11,200/96,000 = 11.7% of the total distribution network. Leakage rate of grey cast-iron is then: $0.75 \times 1/0.117 \times 0.6 = 3.9\%$. Leakage rate of the rest of the system is: $0.25 \times 1/(1-0.117) \times 0.6 = 0.2\%$.

recommended for post-mining emissions between 0.9 and 4.0 m³/ton coal for underground mined coal and between 0.0 and 0.2 m³/ton for surface mined coal.

In 1990 the coal which was used in the Netherlands mainly originated from Australia, the United States and others (Colombia, Poland, Germany). In Australia most coal is mined at the surface. In the Eastern part of the U.S. a large part of the coal is mined underground. It has been assumed that half of the coal which was consumed in the Netherlands was underground mined and the other half was surface mined. Taking 17 m³/ton coal and 1.1 m³/ton coal as the respective methane emission factors, the current methane emission associated with coal use in the Netherlands amounts to 124 kton methane.

In the first part of next century, Australia, the United States and South Africa are expected to be the main coal exporting countries. Without explicit policy to reduce CH₄ emissions from coal mining, it may be expected that roughly half of the coal production will be coal which is mined underground. Eventually, it is possible to rely completely on coal which is surface mined. If this would become an international strategy, the supply of surface mined coal would be constrained and the price of surface mined coal would increase. In order to test cost-effectiveness, it has been assumed that coal from surface mines will be 0.1 Dfl/GJ more expensive than the reference coal price path than the reference coal price path. The reference coal consists of 50% surface mining coal and 50% underground mining coal. The applied emission factors in the model calculation are 0.025 kg/GJ⁴ for surface mining and 0.210 kg/GJ⁴ for 50% surface mining coal and 50% underground mining coal.

In some underground mines advanced methane recovery systems may be used to supplement the existing ventilation systems and ensure mine safety. Such recovery may be able to produce a high methane concentration product, ranging from 35% to 95% methane which can be utilised. About 5% of methane from underground mining is currently being utilized [38]. The cost to recover methane from the ventilation air are largely site specific. This option has not been considered in the Netherlands' MARKAL model.

4.4 Oil production

Oil systems and resultant emissions vary greatly from system to system and country to country. Emissions from these systems can be distinguished from several components: pre-production, production and central processing, venting and flaring during processing and transmission [11]. Emission factors for these components are rarely available. Venting was considered to be the most important sources for methane from oil production. Flaring rates have decreased considerable in recent years [40] (see also section 3.3). Venting rates and other methane emissions from oil production are

⁴ Calculated as follows: $1.1 / 29.31 \times 0.67 = 0.025$ kg/GJ for surface mining, with 29.31 as lower heating value per ton of hard coal (GJ/ton) and 0.67 as density of natural gas (kg/m³). For reference coal: $0.5 \times (1.1 + 17) / 29.31 \times 0.67 = 0.210$ kg/GJ.

expected to decrease further as well. Taking 0.4% of the energy content of the current production as current natural gas emissions, results in a total emission figure of 10 Mton. This figure is consistent with emission figures of [12] and [34]. However, methane emissions from oil production (including venting, pre-production emissions and processing emissions) are expected to decrease further to an average amount to 0.2% of production in the period between 2000 and 2040, due to higher technical standards.

4.5 Combustion emissions

Emissions of methane from fuel combustion are small. At many places these occur due to incomplete combustion and ignition losses. In most cases these losses are insignificant. The exhaust gases of some pieces of equipment, such as power plants, contain even less methane than the inlet air. Thus, these installations are small sinks of atmospheric methane. The largest contributions appear to be from the combustion of fuel wood. Road transport is currently a relatively minor source.

For wood stoves relatively high emission figures have been reported [49]. For this study, an emission figure of 0.074 kg/GJ fuel wood was taken. If a catalyst is installed in the smokestack (see section 7.3), it is possible to reduce these emissions largely.

CH₄ emissions from CNG cars are substantial; they amount to 0.91 g/km for CNG cars without catalyst and 0.15 g/km for CNG cars with catalyst [47]. Expressed per unit energy consumption, these emissions are 0.412 kg/GJ and 0.068 kg/GJ respectively. The methane emission factor for CNG trucks and buses amounts to 0.28 kg/GJ [47].

5. NITROUS OXIDE (N₂O)

5.1 Energy related emissions of N₂O

In general, the emission figures for N₂O have the largest uncertainty range. For several of the sources that will be listed here, high and low estimates vary with a factor of 4. The sources of nitrous oxide can be divided into biogenic and fossil sources (see table 5.1). The main biogenic processes in which N₂O is formed, are denitrification and nitrification in the soil, in sediments and in surface water. Currently, fossil fuel combustion seems to be only a minor source of nitrous oxide. Projections of future emissions indicate total emissions from the Netherlands to remain stable. However, a shift is expected in emissions from biogenic sources to fossil fuel sources [42]. Emissions from transportation are expected to increase due to the rapid penetration of 3-way catalysts for gasoline cars, which give high N₂O emissions. However, the emission estimate for the year 2000 [42] was considered to be too high. Probably this figure was calculated with the highest emission factor estimates for catalyst cars. The supply of nitrogen to agricultural areas largely drives nitrous oxide production from soils. The supply will probably decrease as a result of the manure application policy. Consequently, biogenic emissions of N₂O will decrease [42].

Table 5.1 *Nitrous oxide emissions from the Netherlands, medium estimates, 1988-1990 and 2000 [42]*

Sources	1988-1990	2000
Fossil sources	6.6	16.5
transportation	4.2	14.1
other fossil	2.4	2.4
Biogenic sources	33.9	22.6
grassland and arable land	23.0	14.0
natural	0.4	0.1
inland and coastal waters	6.3	3.8
waste water treatment	3.8	4.7
Total	40.5	39.1

For this study N₂O emissions from transport and biogenic nitrous oxide emissions which are linked to the production of energy crops have also been taken into account. Since emissions from other fossil sources are very much diluted over the remainder of the energy system, these have not been considered in this analysis.

5.2 Nitrous oxide from transportation

Three-way catalysts in passenger cars aim to decrease emissions of nitrogen oxides (NO_x), carbon monoxide and volatile organic compounds (VOCs). However, due to the reducing conditions in catalysts, emissions of

N_2O are being increased in comparison with the gasoline cars without 3-way catalysts (part of the NO_x is chemically reduced to N_2O). Figure 5.1 illustrates uncertainties in average emission factors for N_2O emissions from passenger cars with catalysts; at low speed emissions are substantially higher than at higher speed.

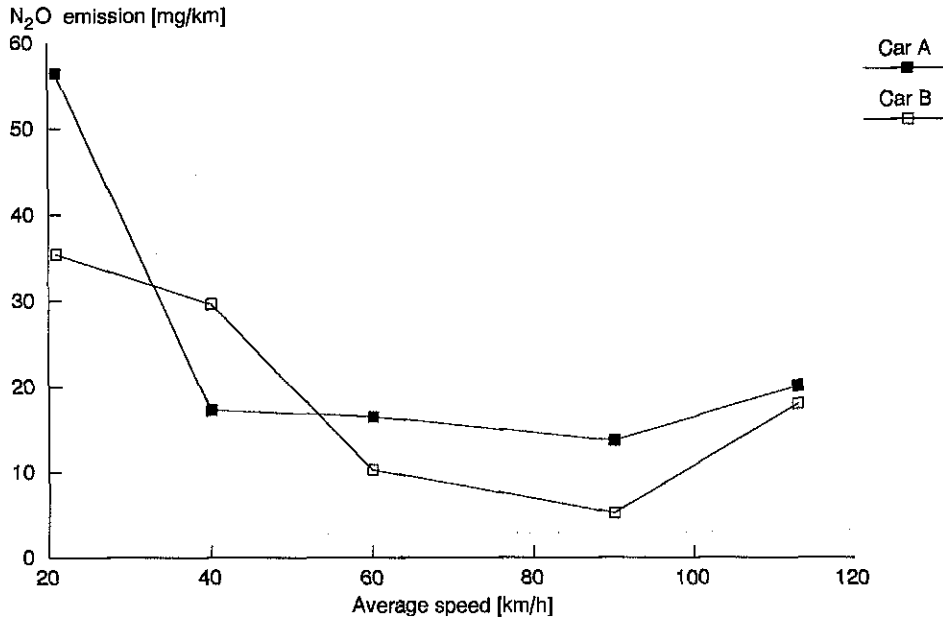


Figure 5.1 Nitrous oxide emissions from two three-way catalyst vehicles [43]

In table 5.2 various emission estimates for passenger cars are listed. The column on the right side lists emission factors which were used in MARKAL.

The difference in emission factors between old and new catalysts is probably caused by the regulation of the catalyst. When the catalyst is regularly adjusted, emissions can likely remain at a level of 0.010 kg/GJ. The regulated catalyst (catplus) and the standard 3-way catalyst were already modelled in MARKAL.

Table 5.2 N₂O emissions from passenger cars according to different sources

Car type	Reference	Emission	Emission	MARKAL emission [kg/GJ]
		[mg/km]	[kg/GJ]	
Gasoline	[44]	10-20	0.0036-0.0072 ¹	0.0025
	[11]	5	0.0009	
Diesel	[44]	10	0.0036 ¹	0.0020
	[11]	10	0.0019	
New catalyst	[44]	35	0.0126 ¹	0.0100
	[11]	19	0.0069	
	[43]	25	0.0091	
Old catalyst	[44]	120	0.0433 ¹	0.0200
	[11]	46	0.0013	

¹ Calculated with an assumed fuel use of 11.9 km/l.

5.3 Nitrous oxide from energy crop production

The production of five different energy crops has already been modelled [2]. This group reflects crops may play a role in the Netherlands' energy system. The group consists of poplar, miscanthus, rape seed, wheat and sugar beet. The MARKAL model contains different technologies to convert the biomass products into electricity, heat or fuel.

Irrespective the type of land use, some N₂O emissions occur from land. Additional N₂O emissions are related to the nitrogen application, e.g. to produce energy crops. The biomass feasibility study [45] on which the biomass production figures are based, assumes nitrogen application rates between 80 and 160 kg nitrogen (N) per hectare per year for the studied energy crops (see table 5.3). It has been reported that 0.4% to 3.2% of the given nitrogen fertilization is emitted as nitrous oxide to the atmosphere [46] with a medium emission estimate of 1%. This implies N₂O emissions for the different energy crops to range between 1.3 and 2.5 kg/ha/year. Considering natural emissions from nitrification of about 0.5 kg N₂O/ha/year [42], these emission figures are consistent with emissions for arable land in [42], which reported total emissions from arable land to range between 1.6 and 3.5 kg N₂O/ha/year. The N₂O emission factor for MARKAL (right column of table 5.3) is expressed relative to the expected production of the main biomass product for the year 2000.

Table 5.3 *Fertilizer applications for energy crops and nitrous oxide emissions factors for the year 2000*

Energy crop	Fertilizer application [kg/N/ha/year]	Yield of main product [GJ/ha.year]	MARKAL emission [kg/GJ/year]
Poplar	125	269	0.0072
Miscanthus	82	271	0.0047
Rape seed	135	49	0.0431
Wheat	160	63	0.0399
Sugar beet	160	120	0.0210

Energy crop production is expected to increase with 0.8%/year as a result of continuous technological improvements and the fertilizing effect of increasing atmospheric CO₂ levels. The fertilizer gift and the nitrous oxide emission factor per hectare are assumed to remain constant. Consequently, the emission figure per unit production is expected to decrease at a rate of 0.8% per year.

As little is known about options to reduce N₂O emissions from soils which are driven by the supply of nitrogen fertilizer, such options have not been considered in this study.

6. CARBON MONOXIDE (CO)

6.1 Energy related emissions of carbon monoxide

Emissions of carbon monoxide occur from fires in natural ecosystems, from incomplete combustion of carbon containing fuels and from process emissions. As far as we know, the natural CO emissions which occur within the Netherlands borders have not been quantified. The transportation sector accounts for most of anthropogenic emissions (see table 6.1).

Table 6.1 *Anthropogenic carbon monoxide emissions from the Netherlands, 1988 and expected for the year 2000 [42]*

Source	1988 [kton]	2000 [kton]
Energy sector	6	6
Industry	279	251
Commercial	5	5
Residential	79	79
Transportation	745	203
Total	1110	540

The basic steel industry is the second largest source of CO. As the steel industry has not been modelled explicitly in the Dutch MARKAL model, these emissions have not been taken into account in this study. In the residential sector, emissions largely stem from wood stoves. Emissions from power plants, gas boilers etc. are very low. Emissions of CO from transport are expected to decrease as a result of the increased penetration of catalysts in passenger cars. For this study emissions of CO have been considered from road transport and from wood-fired boilers and furnaces.

Carbon monoxide emissions outside the Netherlands which are indirectly linked to energy consumption in the Netherlands occur at oil production. When associated gas is flared, the combustion is often not complete and carbon monoxide is one of the burning product. However, as flaring rates are expected to decrease (see also section 4.4), CO emissions will not be significant and thus not be considered for this study.

6.2 CO emissions from transportation

The emissions of CO from cars depend strongly on the type of use of the car. The average emissions of car which is driven in a city are high, while emissions under constant use on highways are much lower. Cold start emissions of CO are high. Emissions of CO have been calculated from [47]. These figures have been averaged from total emissions of different way of car use and for cars from different weight classes. Table 6.2 shows that gasoline and LPG fuelled passenger cars have high emissions of carbon monoxide. Emissions of diesel cars are lower. Application of a catalyst

will reduce CO emissions considerably. However, due to high emissions of CO in the cold start period, emissions remain substantial.

Table 6.2 *Carbon monoxide emission factors for passenger cars in kg/GJ_{fuel} (year of production: 1992), mainly based on [47]*

Means of transportation	Emission factor [kg/GJ _{fuel}]
Passenger car	
Gasoline	5.0
Gasoline with 3-way catalyst	1.6
Diesel	0.23
LPG	0.96
LPG with 3-way catalyst	0.44
Natural gas	0.96
Natural gas with 3-way catalyst	0.32
Truck	
Diesel	0.28
Natural gas	0.03

Through substitution between the different car types, the MARKAL model is able to reduce CO emission from transportation. The model already contains the above listed types of passenger cars. In addition ethanol and methanol fuelled vehicles, with and without catalyst, are available in the model. For methanol and ethanol fuelled passenger cars the same emission factors are applied as for gasoline cars.

Emissions from cars with catalysts can be reduced further when a pre-heated catalyst is applied. Such a catalyst will considerably reduce CO emissions during the cold start period and consequently reduce average emissions to a level of approximately 0.5 kg/GJ_{fuel}. This reduction option has been linked to the advanced catalyst option in the model, which has operating and maintenance cost amounting Dfl 100 per car per year [48].

6.3 CO emissions from wood stoves and wood furnaces

Small residential wood stoves are usually operated under starved air conditions, to reduce the heat output of the stove. This results in relative high emissions of carbon monoxide, hydrocarbons and particles [49]. The emissions of CO occur as a result of incomplete combustion. A compilation of emission factors in [49], results in a factor for average conditions: 10 kg CO/GJ_{wood}. A catalyst which is installed in the smokestack reduces CO emissions with 70%. This technology is similar to catalysts which are being applied in gasoline cars. The lifetime of such catalysts, which are exposed to glowing particles, ash and to high temperatures, is still uncertain. A wood stove with catalyst has been modelled at an investment cost of Dfl 1500 [50].

CO emissions from large industrial wood furnaces are much lower than residential wood stove emissions. These emissions vary from 0.1 to 3; on average 0.6 kg CO/GJ wood [51]. Options to reduce CO emissions have not been modelled.

7. HALOCARBONS

7.1 Emissions of halocarbons

Because of their relation to the depletion of ozone in the stratosphere, chlorofluorocarbons (CFCs) and other halocarbons have received much attention. The use of the most important CFCs is regulated by the so-called Montreal Protocol and its updates, aiming at a complete phase out in the year 2000 or earlier. At the last Meeting of the Parties of the Montreal Protocol in November 1992 a reduction target has also been set for the consumption of hydrochlorofluorocarbons (HCFCs) [52]. The consumption of the HCFCs has to be reduced by 100% in the year 2030.

CFCs and some of the HCFCs and hydrofluorocarbons (HFCs) have a strong potential to directly change the heat balance of the atmosphere [12,13]. Indirectly, through reaction with ozone in the upper troposphere, CFCs may also have a cooling effect on the atmosphere (see also section 2.3). The cooling effect of HCFCs is much smaller as their potential to destruct ozone is much less. HFCs have no cooling effect [13]. Since the magnitude of the cooling effect is currently very uncertain, the indirect effect has not been included in this analysis for CFCs and HCFCs.

Frequently, a time lag occurs between the use and the emission of halocarbons. Halocarbons remain for (part of) the lifetime of the equipment in which they have been put. To be able to link to the most detailed statistics on halocarbon use and to get around problems related to the modelling of time lags, the use of halocarbons was treated as being the emission of halocarbons.

The use of CFCs in the Netherlands in the year 1992 is listed in table 7.1. The use of CFCs for foam production was the most important use of CFCs. The reduction of CFC use is behind schedule in comparison with the reduction scheme which was set in the CFC Action programme [53], see the right column in table 7.1. However, for the next years it seems likely that the reduction target will be met.

Table 7.1 *Realized and scheduled consumption of CFCs in 1992*

Use	Realized [ton CFC]	Scheduled [ton CFC]
Aerosols	139	100
Foams	4028	3050
Refrigeration	744	176
Solvents/cleansing agents	731	500
Total	5642	3826

The use of all CFCs in the Netherlands will be terminated before the year 2000. The use of HCFCs and HFCs will be allowed at the end of year 1995. For most applications of CFCs, the HCFCs and HFCs play a limited role as

alternatives. For foam, non-halocarbon blowing agents have been developed, which produce foam with similar qualities as the CFC blown foams [54]. The eventual use of HCFCs or HFCs as solvent or cleansing agent is not an energy related application and thus has not been considered in this study. The main use of HCFCs and HFCs will be as refrigerant. Consequently, the main use of HCFCs and HFCs will be as refrigerant for refrigerating equipment and for various types of electric heat pumps and gas-fired heat pumps. The naming convention of refrigerants is such that the indicator starts with an 'R'. In this chapter halocarbons will be referred to with their refrigerant name; this implies that e.g. R12 will be used for CFC-12.

The Dutch MARKAL model contains various applications that use HCFCs or HFCs, such residential refrigeration, commercial cooling and various heat pump applications. However, industrial refrigeration, cooling stores, mobile cooling equipment and automotive air conditioning are not considered in the Dutch MARKAL model and thus have not been included in this report.

7.2 Residential refrigeration

In the Netherlands' MARKAL model, combined refrigerators/freezers for household use have been modelled. A set of refrigerators has been characterized which represents a range of insulation, compressor cycles, absorption cycles and linkages with heat recovery [55].

Currently, refrigerators and freezers (compression cycle type) contain R12 as refrigerant and CFC-11 in the foam of the polyurethane insulation. Following environmental policy, CFC-11 and CFC-12 will have disappeared from refrigerating equipment in 1996. Blowing agents for polyurethane foam alternatives have been developed, such as pentane, which give insulation foam with a similar quality as CFC-11 blown foam [54]. As pentane has a very low GWP, the emission of gases from foam have not been taken into account further.

As reference refrigerating equipment, a system is taken which contains 158 gram of R12 [55]. A similar refrigerator with R134a, which is already replacing R12 in the residential refrigerators [56], contains 133 gram refrigerant. R134a is a HFC which has a considerable GWP (see also section 2.3). Considering the percentage of refrigerators that needs service, refrigerant emissions from domestic refrigerators during use are negligible. After service life the refrigerant content will normally be emitted to the atmosphere. The investment cost for a refrigerator with R134a as refrigerant is estimated to be Dfl 25 higher than for a refrigerator with R12 [55].

These emissions can be reduced by various means:

- recycling of refrigerant after the use;
- reduction of the refrigerant content;
- the use of alternative refrigerants or alternative refrigerating cycles.

Currently, the refrigerant of 35% of currently dumped household refrigerators (always R12), is recovered [57]. This percentage is expected to in-

crease further. It is not yet known if R134a from refrigerators will also be recovered. For this study, recycling of 80% of the refrigerant content was modelled at the same cost to collect R12 from current refrigerators: Dfl 25 per refrigerator.

Other alternative refrigerants which are being studied to replace R12 include R152a, propane, butane and mixtures of different HCFCs [56]. As yet it seems likely that propane and butane will be most dominantly applied. The Netherlands MARKAL model already contains absorption refrigerators. Absorption cycle refrigeration relies on a mixture of ammonia-water-hydrogen as the working fluid and can use either an electric heater or combustion (natural gas, hydrogen). Absorption refrigerators consume more than double the site electricity as electrically driven compression refrigerators. In the year 2000 a gas-fired absorption refrigerator is modelled at additional costs which amount to Dfl 440 [55].

A well insulated cooling compartment requires less cooling capacity and thus less refrigerant. The relation between the annual cooling load and the cooling capacity is not linear. Therefore a scaling factor of 0.6 has been assumed; this implies e.g. that a reduction of the cooling load with 50% will reduce the refrigerant content with 34%. The refrigerant content of the refrigerators with different insulations are listed in table 5 of annex D.

7.3 Commercial refrigeration

Most of commercial refrigeration units can be found in retail food stores. A wide variety of retail refrigerators exists, such as multi deck, open tub and glass door reach-in types. Commercial refrigeration ranges in operating capacity from less than 1 kW up to several hundred kW. It is common to express the energy requirements, costs etc. for commercial refrigerating relative to the length of the units (e.g. kWh/(m.day)). In the Netherlands' MARKAL model refrigerators have been specified with additional insulation, with heat recovery and with improved compressor configurations [55].

Currently, R12, R22 and R502 are mainly used as refrigerants for commercial refrigerating. In this study, we assume R22 to be the reference refrigerant in the considered time period (between 2000 and 2040). The refrigerant content of commercial refrigerators is relatively high. [58] indicates refrigerant content to range between 3 and 13 kg/kW cooling capacity. [59] gives an average figure of 3 kg/kW. This implies a refrigerant content of 0.82 kg per meter refrigerant equipment. Estimates for annual losses during use range between 10% and 33% of refrigerant content [58]. Here a loss figure of 12% has been adopted. The equipments lifetime is assumed to amount to 10 years.

As different means to reduce refrigerant emissions, reduction of leakage losses and recycling have been characterized. In addition to ammonia based cooling cycles, substitution of the R22 refrigerant by other refrigerants has not been considered. Possible substitutes may be R134a, R152a and mixtures of different HCFCs and HFCs. Which one of these refrigerants will become most important, is still uncertain.

Leakage of refrigerant can be reduced by improved designs as well as improved maintenance and control. [60] lists improved design measures: use of tubes with thicker walls, replacement of bad soldered tube joints and the addition of vapour vessels in the design to contain refrigerant during maintenance. Emissions during maintenance may be reduced by using other gases than refrigerants for pressure and leakage control, by prevention of venting of refrigerant during repair and refrigerant accounting. Recycling of refrigerant at the end of the lifetime of the equipment is facilitated with the above mentioned design adjustments. We assume a reduction of losses with 75% to be possible at additional maintenance cost of Dfl 40 per meter equipment per year.

7.4 Electric heat pumps in new dwellings

For newly-built dwellings an integrated heat pump concept has previously been characterized in the Dutch MARKAL model [61]. This concept included both an electric heat pump for space heating and a small electric heat pump for warm water production. For space heating an air heating system was applied. This concept has been modelled in MARKAL with and without additional insulation options. A number of sensitivity analysis on the possibilities of market penetration of this heat pump system has been reported [62,63].

R22 is mostly used as refrigerant in small electric heat pumps. Emissions of R22 may occur after the lifetime of the equipment and through losses during the lifetime. The refrigerant content of current heat pumps is 5-6 kg R22 [58]. Annual losses amount to 4.7% to 6.6% of refrigerant content [58]. For the above mentioned new electric heat pumps, R22 is the standard refrigerant. As this heat pump will have a small capacity, it will contain a smaller amount of refrigerant (4 kg). For the annual losses in the year 2000 and thereafter, the lower percentage, 4.7%, is taken. Thus, total emissions during the 15 year lifetime of the equipment, amount to 7.0 kg R22⁵.

To reduce emissions of R22 various options exist:

- Refrigerant losses can be reduced.
- R22 can be recycled.
- Alternative refrigerants can be used.
- The refrigerant content of the heat pump can be decreased by reducing the heat pump's capacity.

In this study we mainly considered the option of alternative refrigerants. In addition, recycling has been considered. Recycling of the refrigerant which remains in the equipment after its lifetime has been assumed at an additional investment cost of Dfl 100 per heat pump.

As alternative refrigerants for R22, R134a and R152a have been mentioned. Respectively, their GWPs are slightly smaller and much smaller than the GWP of R22. The coefficient of performance (COP) of heat pumps with

⁵ Refrigerant content: 4 kg. Losses: $15 \times 0.047 \times 4 = 2.82$ kg. Content of warm water heat pump: 0.18 kg. Altogether: 7.0 kg.

R134a or R152a and an adapted design, is expected to be at least equivalent to the COP of R22 heat pumps [61]. However, compressor capacity has to be increased with approximately 65% to keep the same heating capacity [61]. Those costs of the heat pump which depend on the capacity will increase. According to [62] these costs amount to Dfl 1700. Calculated with the 0.7-formula, the increasing investment can be estimated to amount to $1.65^{0.7} \times 1700 = \text{Dfl } 714$. [61] expects the cost increase to be negligible, as technology improvements may increase COP and decrease costs. For our characterization we are less optimistic: we expect costs to increase with Dfl 300 in order to shift from R22 to one of the alternative fluids. Electric heat pumps with alternative refrigerants and additional insulation of the dwelling have also been modelled. As these heat pumps have a smaller capacity, their refrigerant content is also smaller.

To calculate the refrigerant content of R134a and R152a heat pumps, the differences in specific weights have been accounted for.

7.5 Electric heat pumps in existing dwellings and apartments

For existing dwellings a split system for electric heat pumps has been modelled [55]. Two small electric heat pump units (for room conditioning) have a gas-fired boiler as a back-up heating system. The heat pumps and the gas boiler both serve 50% of useful demand. A similar concept with additional insulation has also been modelled.

According to [56], the average content of refrigerant of split system electric heat pumps and air-conditioning is 0.26 kg R22/kW. With two units of 6 kW, the system contains approximately 3 kg R22. The annual leakage rate of refrigerant from split system heat pumps is between 4.7% and 6.6% of refrigerant content. A 4% leakage rate is adopted for the year 2000.

As an option to reduce R22 emissions, electric heat pumps with R152a as refrigerant, have been modelled. To use R152a, the capacity of the compressor needs to be enlarged with approximately 65%. Efficiency is assumed not to be affected. With the 0.7-formula the additional compressor costs have been estimated to amount to Dfl 200 for each of the two heat pumps.

The electric heat pump in apartments is of the same type as the heat pump in existing dwellings. However, the apartments contain only one split system heat pump. This heat pump concept contains 1.5 kg R22. An alternative system with R152a as refrigerant has been modelled at Dfl 200 additional investment costs.

7.6 Electric hot water heat pumps

One of the available options to produce warm water is with electric heat pumps. Such heat pumps have been characterized with a warm water vessel for warm water storage. The refrigerant content of the heat pump is approximately 500 gr R22. Assuming no losses during use and only the release of R22 at the end of the equipment's lifetime, emissions of R22 amount to 33 gram per annum.

An electric heat pump with R152a as refrigerant will be more expensive, due to the fact that larger compressor capacity is required and more expensive refrigerant is needed. The efficiency does not have to decrease. Additional cost are assumed to amount Dfl 50 per electric heat pump.

7.7 Heat pumps in the commercial sector

In the Netherlands' MARKAL model the demand for space heating in the commercial sector is disaggregated into four sector demands: small/medium offices, large offices, very large offices and greenhouses. For each of these demand sectors the gas-fired compression heat pump has been characterized and for three of these demand types, the electric heat pump was modelled. Currently R12 and R22 are mainly used as refrigerant [56]. Under current policies the use of R12 will have ended before the year 2000. Then R22 is probably the main refrigerant. For commercial electric heat pumps the ratio between refrigerant content and heating capacity is between 0.15 and 0.25 kg/kW [58]. For electric heat pumps in small/medium offices 0.20 kg/kW was taken. For larger equipment 0.15 kg/kW was taken to calculate refrigerant content. Since the waste heat of the gas engines is also used, the refrigerant content of gas-fired compression heat pumps expressed relative to heat production, is roughly half of the refrigerant content of electric heat pumps. For small and medium offices a loss figure of 4%/year has been adopted. The losses for greenhouses and large offices were calculated with an annual loss figure of 3%/year. The loss figure for very large offices is assumed to be the lowest: 2%/year. All refrigerant in the equipment at the end of the lifetime is assumed to be emitted to the atmosphere. The emission figures for R22, which are based on this information, are presented in table 2 of annex D.

As an option to reduce the climate change impact of refrigerant losses, a shift from using R22 towards using R152a has been considered. Taking into account the fact that a heat pump with R152a requires a larger capacity with a 10% larger refrigerant content and that R152a is flammable, precautions and safety measures will have to be taken. The additional costs were estimated to be relatively limited for the largest equipments (very large offices, 2% of investment costs or Dfl 50.000 per installation) and more significant for the small/medium offices (5.7% of investment costs or Dfl 5000). As a result of the switch to R152a equipment, leakage during use will become negligible. The COP of the heat pump is assumed not to be affected.

8. MODELLING RESULTS

The incorporation of emission factors for the non-CO₂ GHGs and the upstream CO₂ emissions in the integrated dynamic model of the energy system, allows to give new insight on cost-effective GHG abatement strategies. In section 8.1 the calculated emission levels for the individual GHGs are quantified for the reference case and the relative importance of the non-CO₂ GHGs are expressed. The emission levels for the GHGs in the emission reduction cases are presented and discussed in section 8.2. In section 8.3 the attention is concentrated on the differences in emission levels between an emission reduction approach which includes the non-CO₂ GHGs and an approach which neglects these emissions. In the sections 8.4 and 8.5 similar comparisons take place. In section 8.4 the results for primary energy sources and reduction options are illuminated, while in section 8.5 the results for individual technologies are addressed. The results of a sensitivity analysis with respect to the uncertainties in the GWP index are presented in 8.6.

8.1 Greenhouse gases emissions in the reference case

The base scenario or reference case is a case in which calculations were performed without a penalty for the emissions of GHGs. This reflects autonomous developments of the energy system without any special policy with respect to the abatement of GHG emissions. The reference case as calculated by the optimization model can be characterized as an economically efficient baseline, as most of the profitable efficiency improvements are captured. In the reference case the emissions of GHGs increase from 181.7 Mton CO₂ in 2000 to 241.3 Mton in 2030. Note that in order to express non-CO₂ GHG emissions as the CO₂ equivalent impact, the emissions were multiplied with GWP factors. These GWPs are presented in *italic* in table 2.4.

The direct emissions of CO₂ make up the main part of total GHG emissions. In the year 2000 these will amount to 165 Mton. As a net result of increasing energy demands and changes in the fossil fuel mix on the one hand and efficiency improvements and increasing use of renewables on the other, emissions of CO₂ will rise to 212 Mton CO₂ in 2030 (see figure 8.1). Together the emissions of upstream CO₂ emissions and emissions of non-CO₂ GHGs make up 10 to 15% of the total CO₂ equivalent emissions.

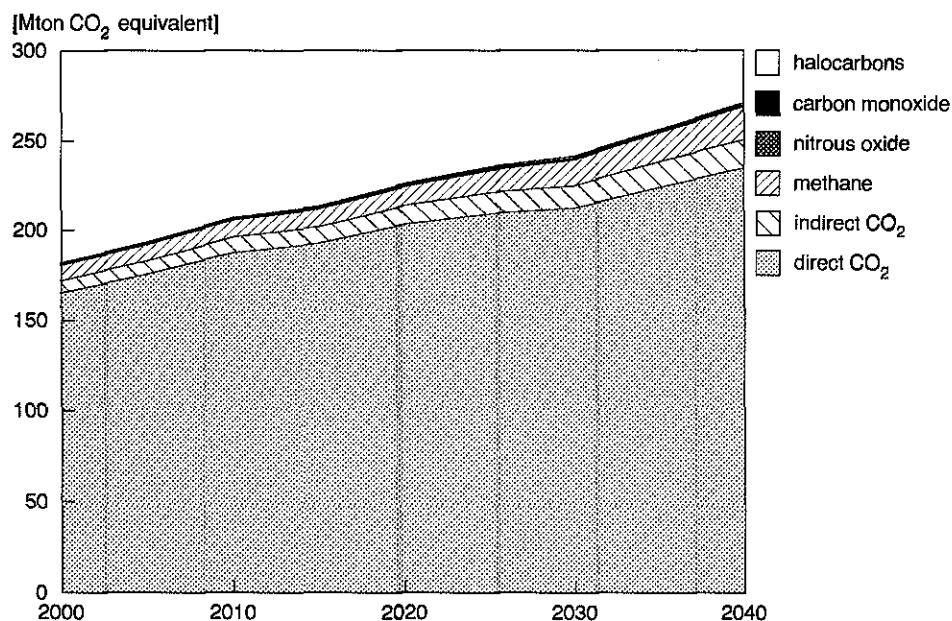


Figure 8.1 Emissions of individual greenhouse gases in the reference case (2000-2040), expressed as CO₂ equivalent emissions using GWPs of [12] and [13]

The indirect emissions amount to 6.7 Mton CO₂ in 2000 and will increase rapidly in the reference case (see figure 8.2). This is caused by the switch from natural gas to coal for the purpose of electricity generation and methanol production. As imports of coal correspond to relatively high upstream CO₂ emissions, total indirect CO₂ emissions will increase. In addition, the Netherlands will need to import increasing amounts of natural gas, as domestic natural gas reserves fall short, causing an increase in the indirect emissions which are linked to import of natural gas. By the year 2030 indirect CO₂ emissions will almost have doubled to amount to 12.8 Mton in 2030.

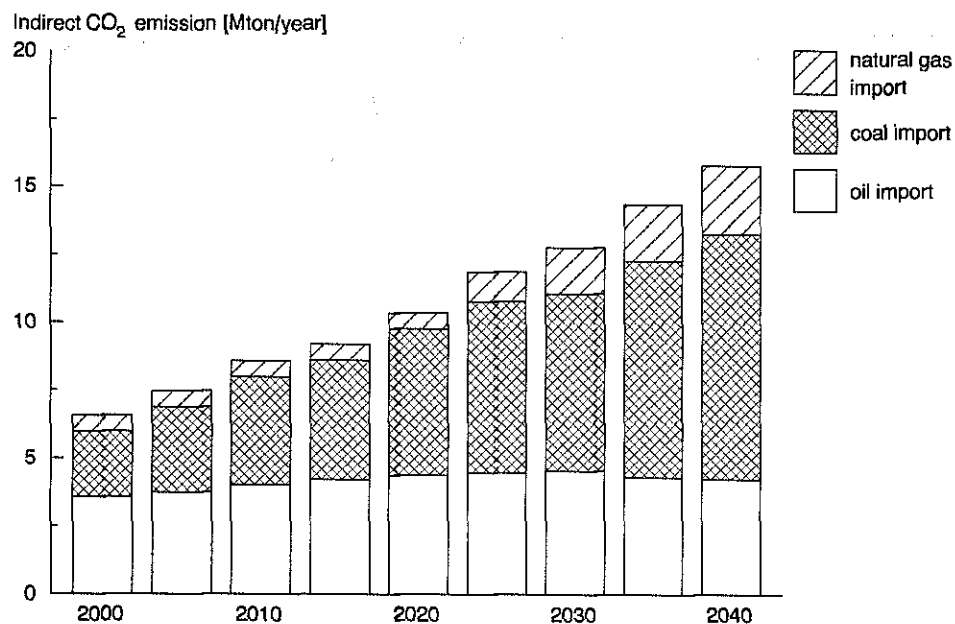


Figure 8.2 Indirect CO₂ emissions per source between 2000 and 2040 in the reference case

In the year 2000, total emissions of the non-CO₂ GHGs amount to the equivalent of 9.9 Mton CO₂. Methane accounts for the bulk of these emissions: 8.5 Mton CO₂ equivalent. Nitrous oxide, carbon monoxide and halocarbons only account for small CO₂ equivalent emissions. The emissions of non-CO₂ GHGs will increase up to 18.8 Mton CO₂ equivalent in the year 2030. Methane, nitrous oxide and halocarbons contribute to this emission increase.

Figure 8.3 shows which sources are responsible for the increase of methane emissions. Up to the year 2015 the increase of methane emissions will be limited. Although methane emissions from coal mining will increase during this period, the CH₄ emissions from domestic gas production and gas distribution will decrease at the same time. However, after the year 2020 emissions of methane will increase strongly. This is mainly due to the import of Russian natural gas and the continuing increase of coal consumption. It has to be noted that all increases of methane emissions linked to energy use within the Netherlands stems from sources *outside* the Netherlands.

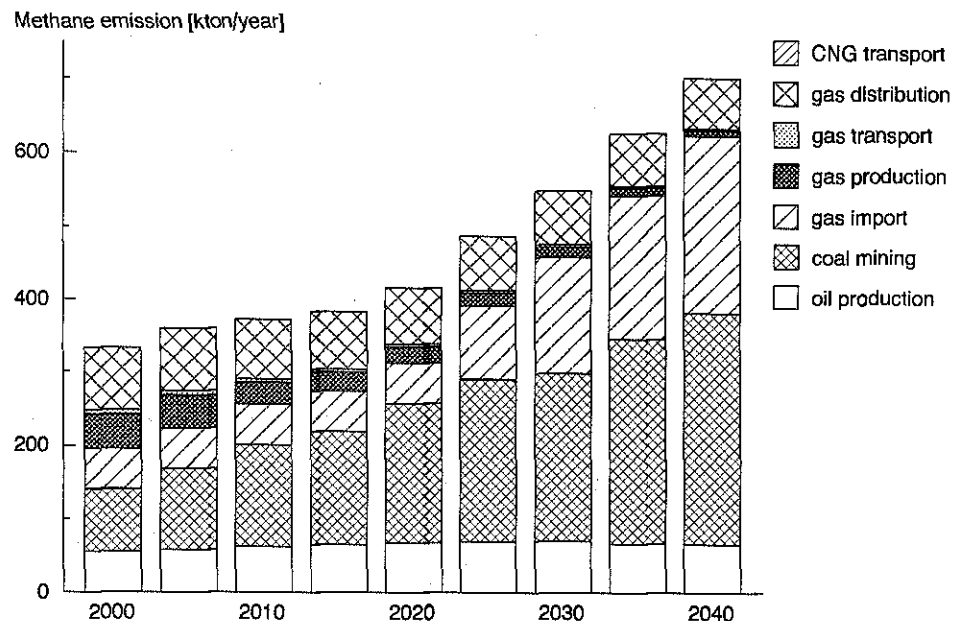


Figure 8.3 CH₄ emissions per source between 2000 and 2040 in the reference case

The relative increase of non-CO₂ GHG emissions and indirect emissions of CO₂ between 2000 and 2040 is considerably larger than the increase of direct CO₂ emissions between 2000 and 2040. This results in a decrease of the share of direct CO₂ emissions in total CO₂ equivalent emissions from energy use in the Netherlands from 90.8% to 86.7%.

8.2 Greenhouse gas emissions in reduction cases

In order to reduce the emissions of GHGs from the energy system, the emissions of GHGs have been penalized. The penalty is expressed relative to the CO₂ equivalent emissions of GHGs. This triggers the model to

change the mix of technologies and fuels in the energy system in such a way that those options, which have marginal cost that do not exceed the emission penalty, are included. In this analysis emissions of all different GHGs are reduced in an integrated way. Seven different penalty levels have been applied: 20, 50, 100, 150, 200, 500 and 1000 Dfl/tCO₂-equivalent. The higher the emission penalty, the further GHG emissions are reduced.

To ease the explanation of the changes in emission levels of individual GHGs at different emission penalties, the development of primary energy use at different emission penalties and the aggregated contributions of options are presented first.

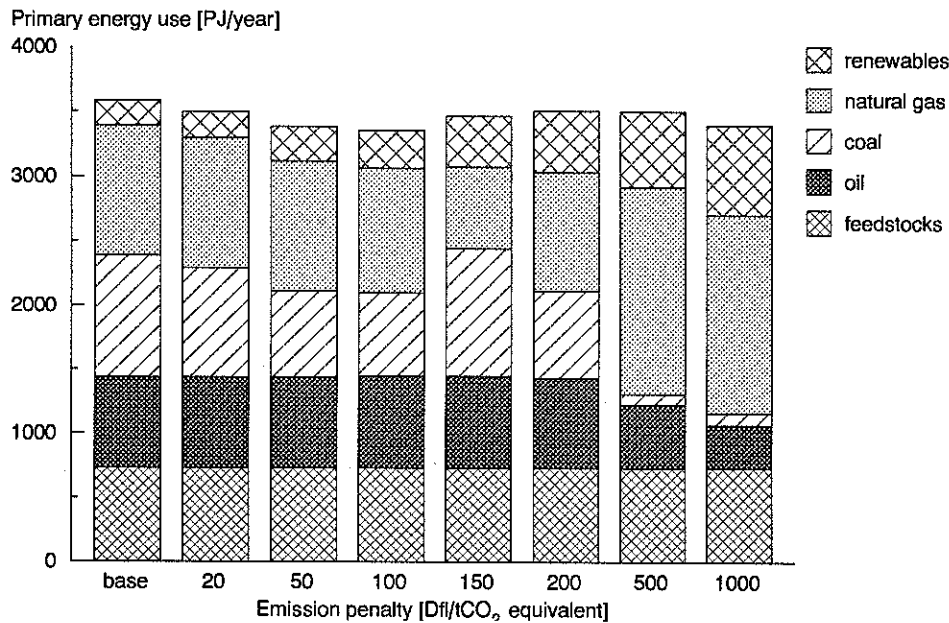


Figure 8.4 Primary energy use in 2030 at different CO₂-equivalent penalties

Figure 8.4 shows primary energy use in 2030 at different GHG emission penalties. Up to emission penalties of 100 Dfl/tCO₂, total primary energy requirements decrease, mainly as a result of the reduced consumption of coal. However, at a 150 Dfl/tCO₂ penalty, a revival of the use of coal occurs. Then coal is used for electricity generation and synfuel production in combination with CO₂ removal. Due to the losses in CO₂ recovery and CO₂ storage, primary energy use is higher at these medium emission penalties. At higher emission penalties the use of coal in combination with CO₂ removal is again replaced by natural gas use, also in combination with CO₂ removal. At the highest emission penalties the use of coal will decrease dramatically and the use of natural gas will increase strongly. With increasing emission penalties, renewables become steadily more and more attractive. The role of oil is only affected at high emission penalties (500 and 1000 Dfl/tCO₂).

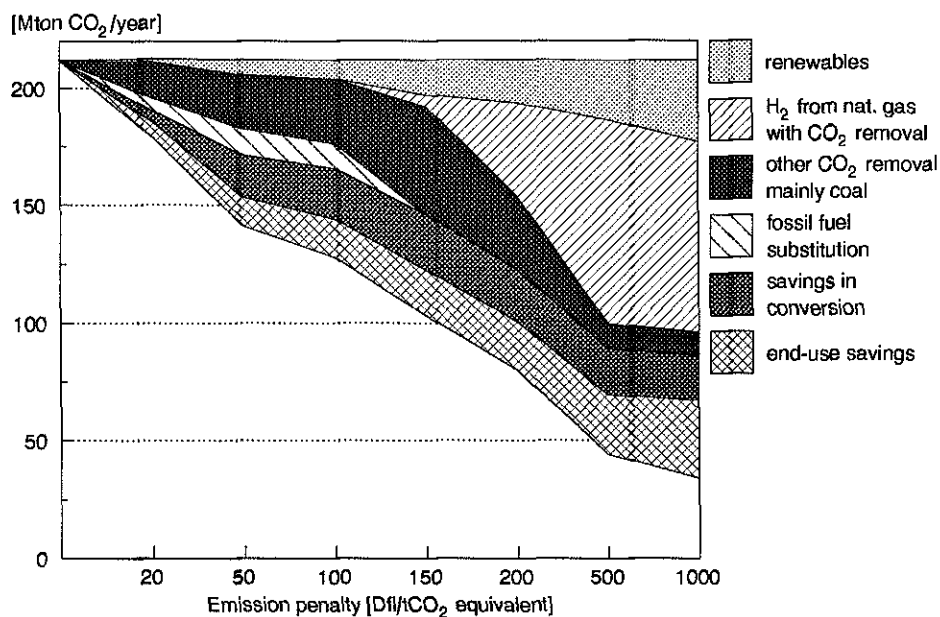


Figure 8.5 Contribution of groups of options to the reduction of direct CO₂ emissions in 2030 at different emission penalties

The contributions of groups of options to reduction of direct CO₂ emission in 2030, have been calculated from the aggregated model results (see figure 8.5). The contributions have been calculated relative to the average CO₂ emissions of fossil sources in the reference scenario. Substantial and growing contributions to emission reduction are made by renewables, end-use savings and savings in conversion. The options CO₂ removal from coal and CO₂ removal at hydrogen production from natural gas are also important. Hydrogen production from natural gas plays a role at emission penalties above 150 Dfl/tCO₂. To efficiently utilize the available CO₂ storage capacity, CO₂ removal at coal plants will then be replaced. At emission penalties of 500 and 1000 Dfl/tCO₂ the CO₂ removal options reduce 90 Mton CO₂ in 2030. At 1000 Dfl/tCO₂ renewables reduce about 30 Mton CO₂ in 2030.

The development of the total emission level of GHGs at increasing emission penalties, expressed as CO₂ equivalent emission, is projected in figure 8.6. In comparison with the reference case emissions, significant reductions of GHG emissions are already possible with small penalties (20 to 50 Dfl per tCO₂). With the existence of an exponential relationship between marginal costs and the emission reduction, additional reduction of GHG emissions is relatively difficult to achieve at high emission penalties (1000 Dfl per tCO₂). Going from a 500 Dfl/tCO₂ penalty to a penalty of 1000 Dfl/tCO₂ results only in an emission reduction step of 10 Mton CO₂ in 2030.

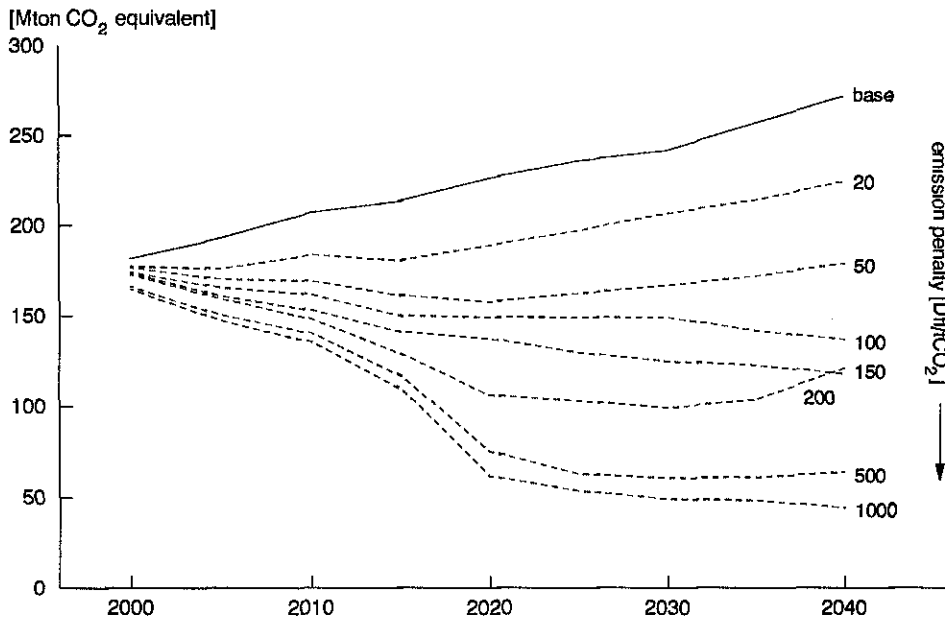


Figure 8.6 Development of total greenhouse gas emissions expressed as CO₂ equivalents between 2000 and 2040 at various greenhouse gas emission penalties

The direct emissions of CO₂ between 2000 and 2040 are shown in figure 8.7. Naturally, the development of direct emissions appears to be very similar to the total GHG emission graph, as direct CO₂ emissions make up the main part of the total CO₂ equivalent emissions. The percentage emission reduction achieved in 2030 is depicted in the graph.

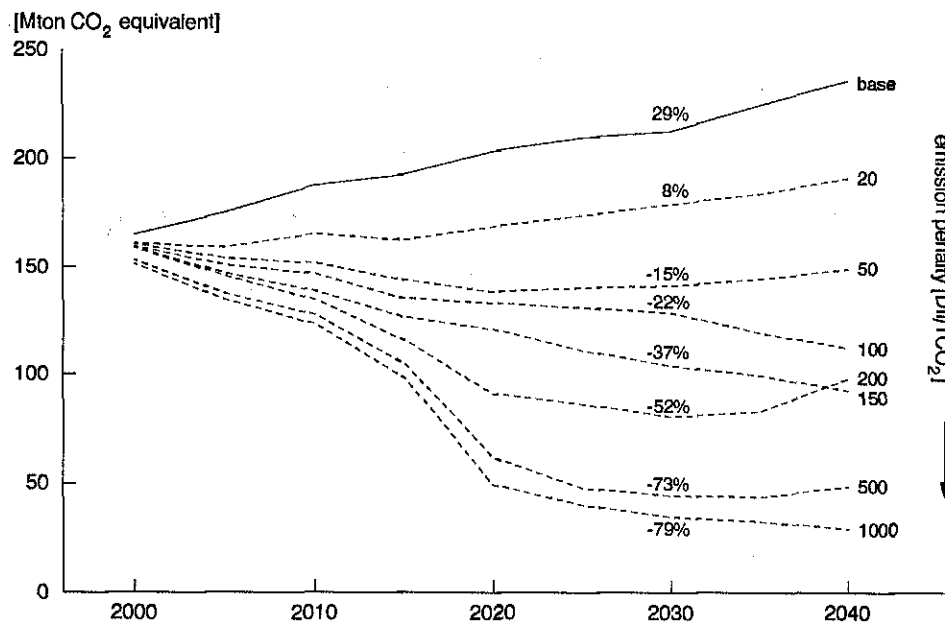


Figure 8.7 Development of direct CO₂ emissions between 2000 and 2040 at various greenhouse gas emission penalties

Figure 8.8 shows that the indirect CO₂ emissions have diverging trends under increasing emission penalties: the indirect emissions decline at low penalties, at medium emission penalties the indirect CO₂ emissions rise and at high emission penalties the indirect emissions decrease again. The in-

crease at the medium emission penalties (around 150 Dfl/tCO₂) is mainly caused by the increased coal use at these penalty levels. Large scale CO₂ removal at coal-fired power plants and at coal-based synfuel production is the most prominent option at these emissions penalties (see also figure 8.5), while CO₂ removal at natural gas fired plants is then not yet cost-effective. At 500 and 1000 Dfl/tCO₂ CO₂ removal at natural gas fired plants has become cost-effective and replaces CO₂ removal at coal-fired plants (see again figure 8.5). As a result indirect CO₂ emissions decrease.

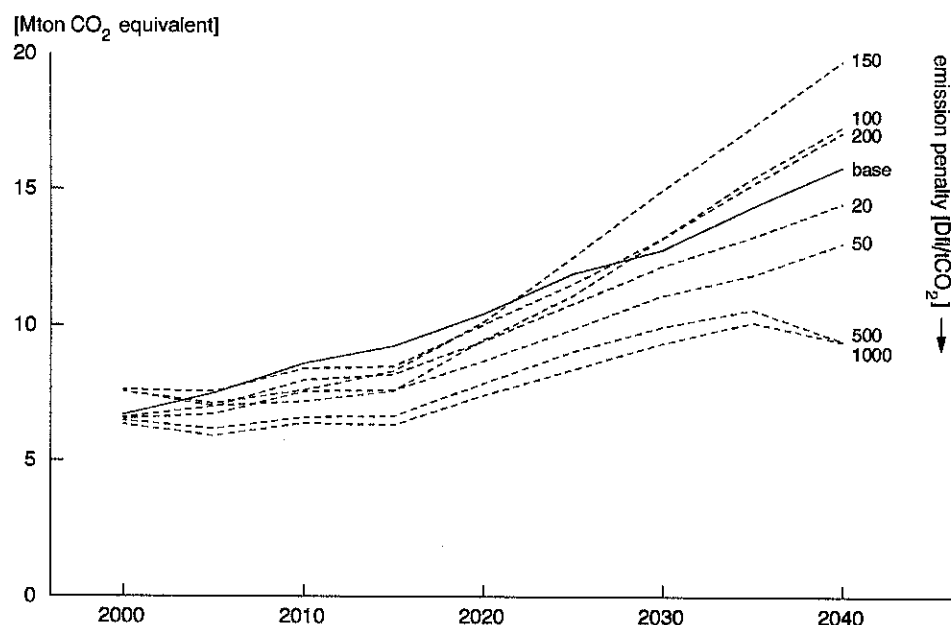


Figure 8.8 Indirect CO₂ emissions at different CO₂ equivalent penalties

The decreasing emission trend for methane with increasing GHG emission penalties is clearly illustrated for the year 2030 in figure 8.9. The decrease at emission penalties of 20 and 50 Dfl/tCO₂ is caused by the decrease in coal imports and due to adaptations to the offshore platforms for natural gas production to avoid part of the CH₄ emissions. CH₄ emissions decrease dramatically between penalties of 50 Dfl/tCO₂ and 100 Dfl/tCO₂. Then two switches occur. High leakage natural gas import is substituted by low leakage natural gas import and a switch occurs towards importing only surface-mined coal and no longer deep-mined coal. Total CH₄ emission levels do not vary much between emission penalties of 100 Dfl/tCO₂ and 1000 Dfl/tCO₂. However, the composition of these emissions does change. Replacement of grey cast-iron distribution pipelines for natural gas starts to be attractive at marginal cost of 200 Dfl/tCO₂, thus reducing emissions from the natural gas distribution system. At this emission penalty the imports of natural gas from Russia start to increase, thus increasing the matched CH₄ emissions and balancing the total CH₄ emissions at a level of approximately 30% of the CH₄ emissions of the reference case. It has to be noted that at high emission penalties over 90% of the remaining CH₄ emission takes place outside the Netherlands.

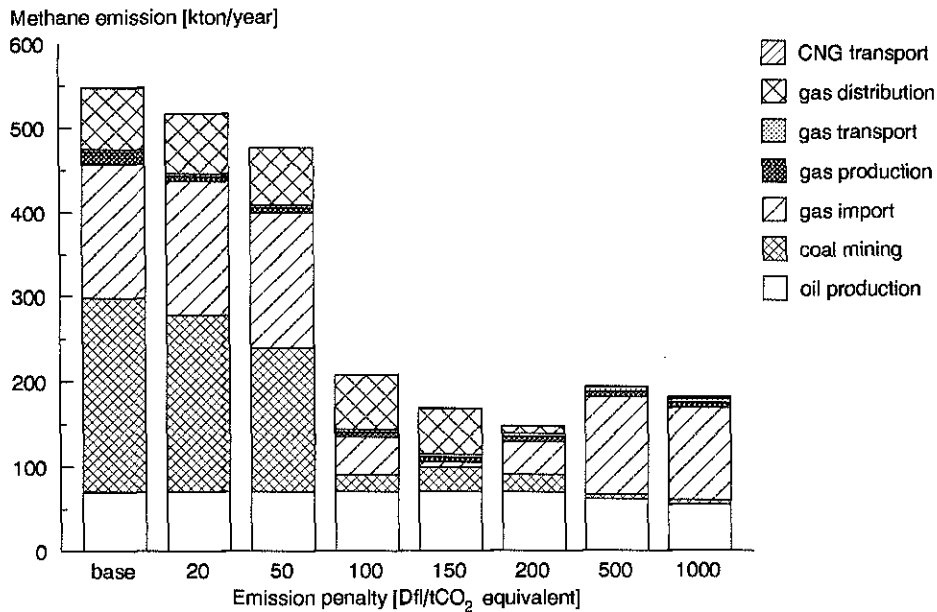


Figure 8.9 Methane emissions per source in 2030 at different emission penalties

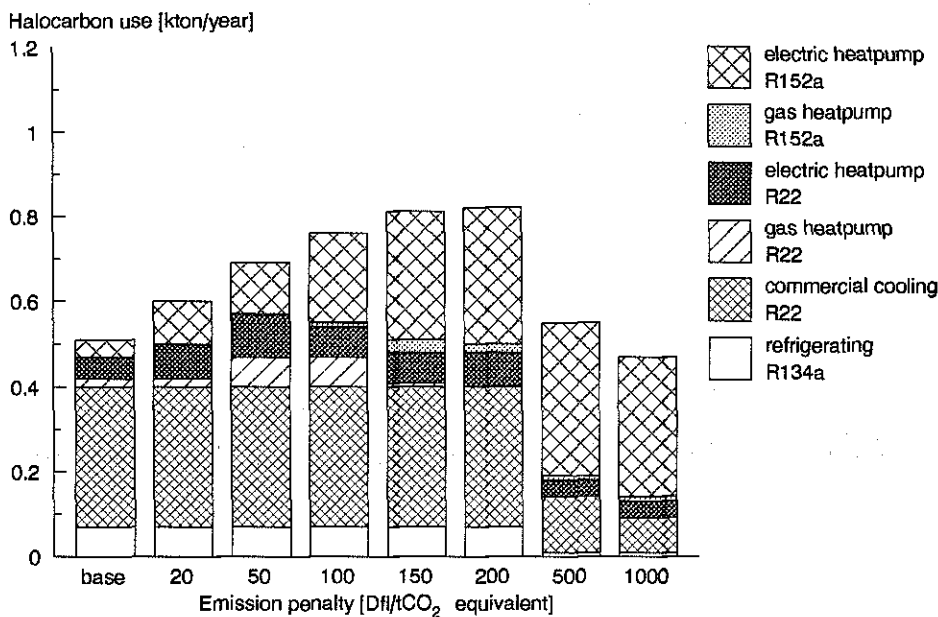


Figure 8.10 Halocarbon use per type and per application in 2030 at different CO₂ equivalent penalties

The emissions of halocarbons increase with low and medium emission penalties (see figure 8.10), due to the introduction of various types of heat pumps. Most of these heat pumps use R152a as working fluid. This component has a low GWP. The increase of the use of working fluids which have higher GWPs, such as R22, is very moderate at penalties between 50 and 200 Dfl/tCO₂. At higher penalties heat pumps which use these fluids are further replaced by heat pumps with R152a. Decreasing emissions from commercial cooling and refrigerating through recycling and increase of the leak-tightness is cost-effective at a penalty of 500 Dfl/tCO₂ equivalent.

Transport is the main source of N_2O emissions from the energy system. At modest emission penalties, the emissions are not much affected (see figure 8.11). The total N_2O emission from 3-way catalysts cause less N_2O emissions than the cars without catalysts. When the gasoline cars will be replaced at 200 and 500 Dfl/tCO₂, first the cars with catalysts are being replaced, because their specific N_2O emission is higher.

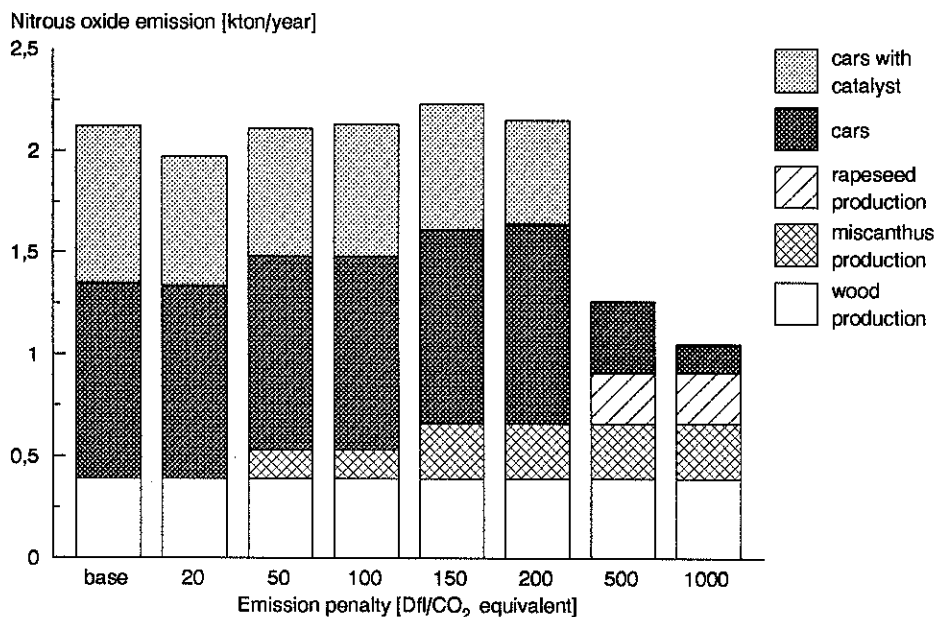


Figure 8.11 Nitrous oxide emissions in 2030 at different emission penalties

The N_2O emissions from biomass production increase, despite the increasing emission penalties. Apparently, biomass production remains an effective option to combat the net climate change effect of GHG emissions. At drastic emission reduction the biogenic N_2O emissions from energy crop production make up the main part of energy related N_2O emissions.

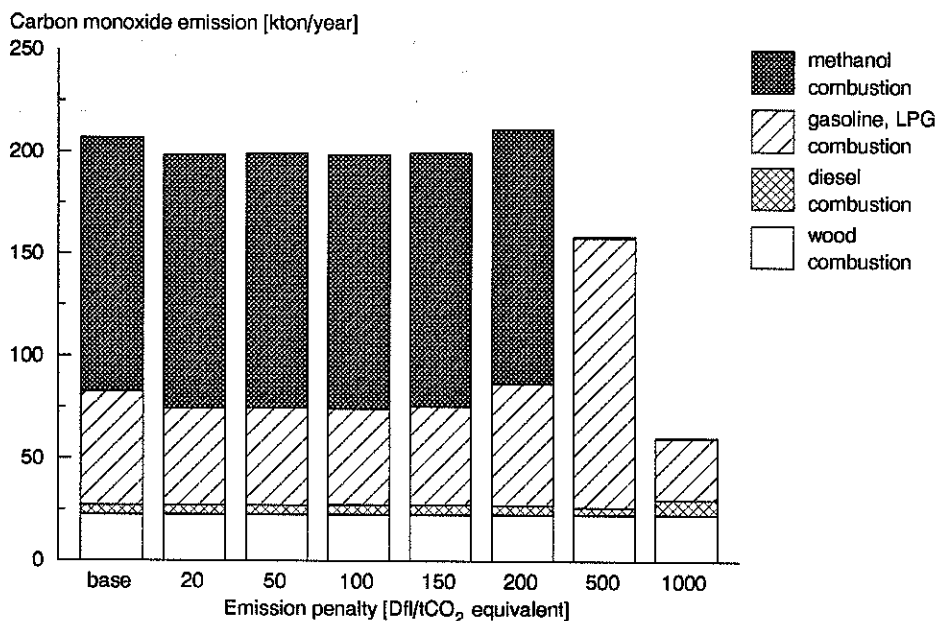


Figure 8.12 Carbon monoxide emissions in 2030 at different emission penalties

Figure 8.12 illustrates that total carbon monoxide emissions do not change much up to an emission penalty of 500 Dfl/tCO₂. Then the CO emissions, which mainly stem from the transport sector decrease due to changes in the transport mix.

8.3 All GHG reduction versus only CO₂ reduction: comparison of emissions

In addition to the model calculations which were presented in section 8.2, model calculations have been performed with only emission penalties on the direct CO₂ emissions. This is the most common method to perform studies to assess CO₂ emission reduction strategies (see also section 2.2). This analysis was carried out in order to be able to make a comparison between an approach in which the indirect emissions and the full basket of GHGs are included (full basket/energy chain approach) and an approach which does not include these emissions (national CO₂ approach).

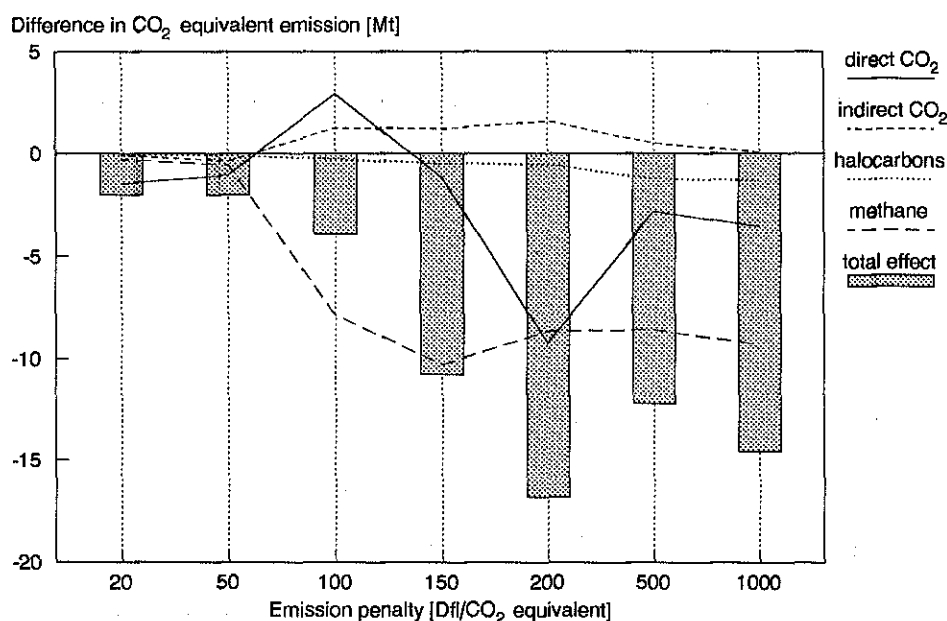


Figure 8.13 *Difference in CO₂ equivalent emissions of individual greenhouse gases between scenario with only penalties for CO₂ and scenarios with CO₂-equivalent penalties*

The main results of the comparison of GHG emission levels are shown in figure 8.13. The vertical bars give the difference in the total CO₂ equivalent emissions of all gases in 2030 at different emission penalties between the national CO₂ approach and the full chain GHG approach. Points at the negative part of the Y-axis refer to emission levels which are *lower* in the full chain GHG approach. The lines connect the differences in emissions for individual gases at various emission penalties. As expected, the total emission reduction is larger in the 'full basket/energy chain' approach than in the national CO₂ approach. The fifth bar from the left shows that the difference amounts to up to 17 Mton CO₂ equivalent emission in 2030 at a 200 Dfl/tCO₂ emission penalty. This difference is mainly due to the difference in methane emissions and the difference in direct CO₂ emissions (see

the dashed lines in figure 8.13). For methane this can simply be explained. Hence, if methane emissions are not being penalized, as in the national CO₂ approach, these emissions are not explicitly reduced.

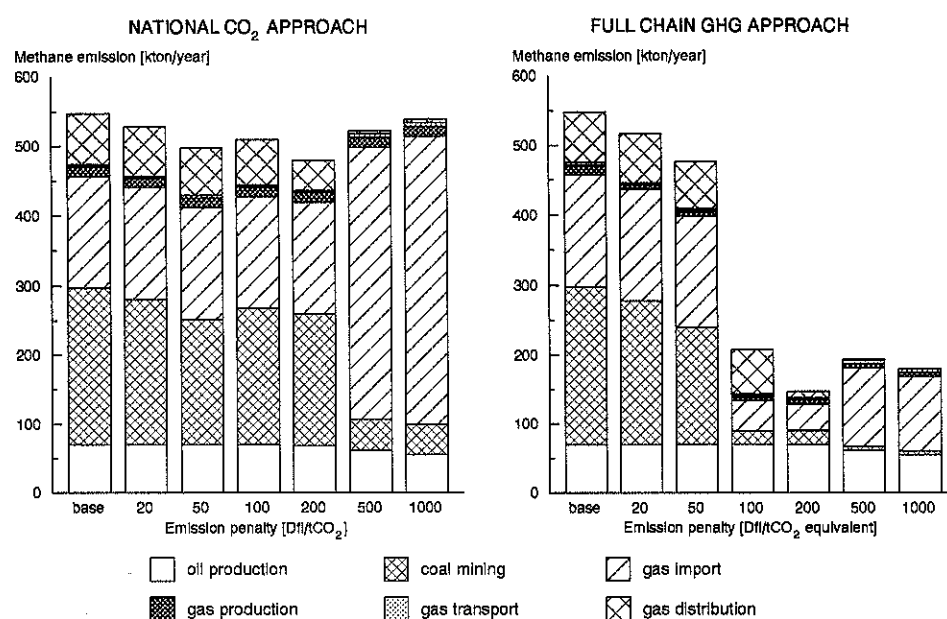


Figure 8.14 Methane emissions in 2030 in the approach with only CO₂ emissions generalized and in the approach with a CO₂ equivalent penalty

The differences in the emissions of CH₄ are shown in detail in figure 8.14. Emissions of CH₄ from energy related source remain constant in the national CO₂ approach, while they reduce with more than 50% in the full chain CNG approach.

The reason that direct CO₂ emissions are further reduced in the full basket/energy chain approach relate to the fact that the specific CO₂ equivalent emissions of the consumption of fossil fuels are considered higher in this approach, since the whole energy chain is taken into account. As all emissions are taken into account in an integrated way, larger reductions will be achieved at the same emission penalties. Some options which are not yet cost-effective at a certain penalty in the national CO₂ approach are cost-effective in the full chain GHG approach. Consequently, the direct CO₂ emission reduction is also larger.

The indirect CO₂ emissions are higher in the full basket/energy chain approach than in the national CO₂ approach. Apparently, the model prefers to reduce direct CO₂ emissions and methane emissions, although this slightly increases the indirect CO₂ emissions.

In the full basket/energy chain approach the level of total halocarbon emissions is not much different from the national CO₂ approach up to a 200 Dfl/tCO₂ emission penalty. The CO₂ equivalent impact of the respective emissions, however, varies considerably. In the national CO₂ approach R22 is the mostly used refrigerant in heat pumps, while in the alternative approach R152a, which has a much lower GWP than R22, is mostly used. At high emission penalties, the refrigerant use for cooling is reduced in the full

basket/energy chain approach, while it is unaffected in the national CO₂ approach.

The differences in CO₂ equivalent emission levels of N₂O and CO between the two approaches have not been depicted in figure 8.13. They are small.

8.4 All GHG reduction versus only CO₂ reduction: primary energy and contribution of options

Through the incorporation of indirect emissions and emissions of non-CO₂ GHGs, the roles of different primary fuels change. Considering the emission factors (see chapters 3 and 4), it can be expected that the changes are not so large that the order of attractiveness of the three main fossil fuels will change. However, it may imply that at specific emission penalties the relative roles may be affected and that the order of cost-effectiveness of individual options to reduce GHG emissions may change.

Figure 8.4 showed primary energy use at different penalties for the full basket/energy chain approach. The same bar figure for the only CO₂ approach looks similar. However, there are some small differences between the two approaches. These differences between the full basket/energy chain approach and the national CO₂ approach have been calculated and are depicted in figure 8.15.

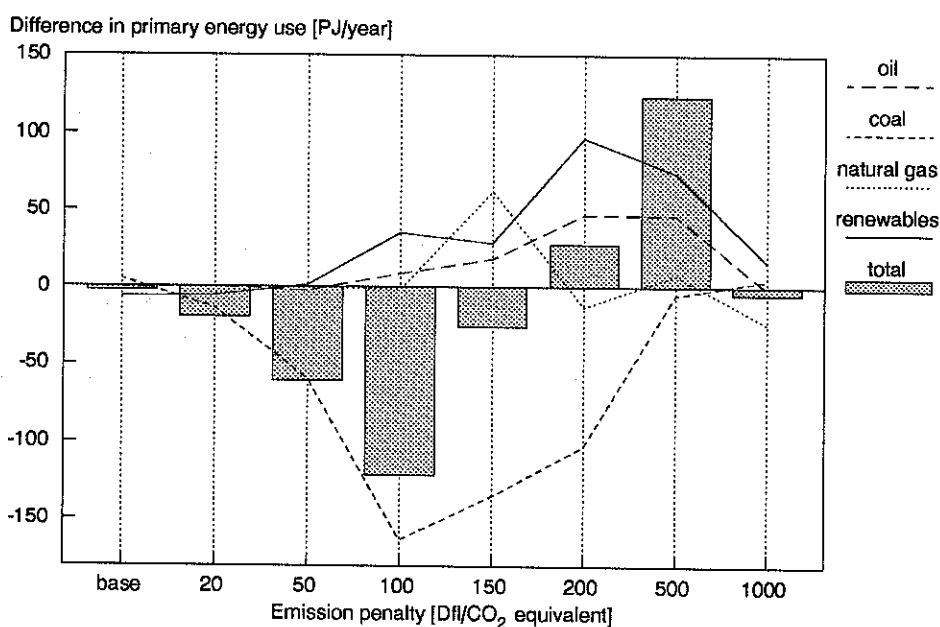


Figure 8.15 Differences in primary energy use in 2030 at different emission penalties between national CO₂ approach and full chain GHG approach

The main differences in the primary energy mix relate to the roles of coal and renewables. In the full chain GHG approach coal is less attractive. Renewables are always more attractive. The additional use of renewables occurs, despite the relatively high energy input to manufacture them. The

upstream emissions of GHGs for coal and natural gas counterbalance the additional energy use to manufacture the renewable technologies.

The result for natural gas depends on the level of the emission penalty: almost the same amounts of natural gas are used at 20, 50, 100, 200 and 500 Dfl/tCO₂, more natural gas is used at 150 Dfl/tCO₂ and less natural gas is consumed at 1000 Dfl/tCO₂. Oil products are more attractive in the full chain GHG approach due to the relatively low indirect and non-CO₂ emissions for oil. Oil products partly replace methanol from coal in the market for liquid fuels.

Regarding the competition between coal and natural gas, it can be concluded that coal becomes less attractive. However, natural gas does not benefit. Instead, renewables and oil benefit and increase their shares.

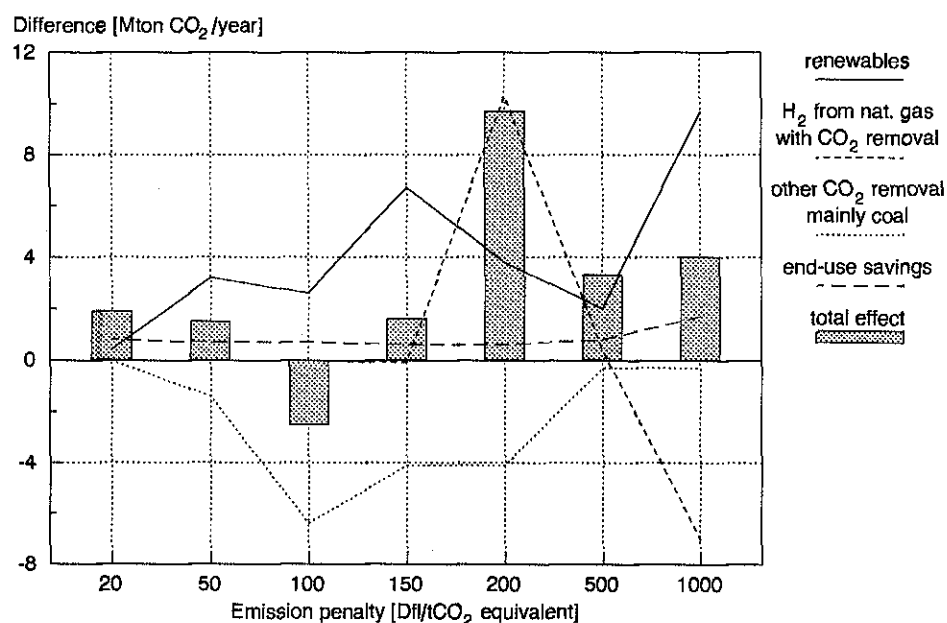


Figure 8.16 *Difference in contribution of options between national CO₂ approach and full chain GHG approach in 2030 at different emission penalties*

The contributions of options were already presented in figure 8.5. The differences in the contributions of options between the two approaches have been calculated and are depicted in figure 8.16. Positive points in this figure refer to options which give larger contributions to emission reduction in the full basket/energy chain approach. The option renewables is more attractive in the full basket/energy chain approach at all emission penalties. On average, the additional renewable technologies yield an additional CO₂ reduction of 4 Mton CO₂ in 2030. End-use savings are also more attractive, although the additional contribution is smaller. On the other hand, CO₂ removal at coal-fired equipment is less attractive in the full basket/energy chain approach. Finally, hydrogen production from natural gas in combination with CO₂ removal is more attractive at a 200 Dfl/tCO₂ emission penalty, but less attractive at a 1000 Dfl/tCO₂ emission penalty.

The above results can be explained from the specific GHG emission levels which are linked to the various options. Using the national borders as sys-

tem boundaries, the specific CO₂ emission factor for coal-based CO₂ removal technologies is approximately 10 kg CO₂/GJ. However, this emission factors is much higher (the equivalent of 25 kgCO₂/GJ), when the indirect emissions and CH₄ emissions are accounted for. In this way the net gain to shift from conventional fossil-fired equipment to coal-fired plants with CO₂ removal decreases. Considering the competition between coal-fired technologies with CO₂ removal and gas-fired technologies with CO₂ removal, a modest shift occurs at the benefit of gas-fired technologies due to the lower upstream GHG emissions and the higher efficiency. Consequently, hydrogen production from natural gas in combination with CO₂ removal is earlier attractive in the full basket/energy chain approach.

The gain in emission reduction achieved by renewables and by end-use savings is larger in the full basket/energy chain approach, as the indirect and non-CO₂ GHG emissions are included. The gain is especially large in comparison with the CO₂ removal technologies. Despite the higher investment costs for various renewable technologies to account for the additional material requirements, renewable options are more attractive.

8.5 CO₂ reduction versus full reduction: attractiveness of energy technologies

In this section the attractiveness of selected technologies in the year 2030 will be evaluated. Electricity generation, CO₂ removal technologies, biomass production and electric heat pumps are considered.

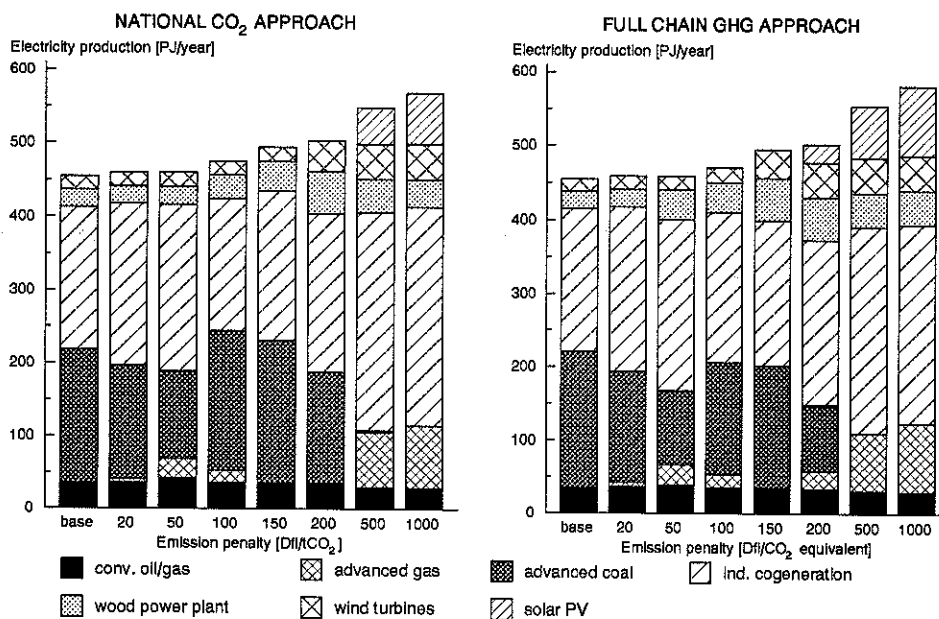


Figure 8.17 Electricity production at different emission penalties in 2030 in national CO₂ approach and full chain GHG approach

Figure 8.17 shows electricity production per technology at different emission penalties. At first glance the two bar diagrams look the same. However, there are some differences. In the full basket/energy chain approach renewable technologies are more attractive, coal-fired power production is

less attractive and the difference in attractiveness of natural gas-fired plants depends on the level of the emission penalty. The main renewable electricity generation technologies which have been distinguished in figure 8.17 are wood power plants, wind turbines and solar PV systems. In the full basket/energy chain approach offshore wind turbines become attractive between a 100 and 150 Dfl/tCO₂ marginal cost level. In the national CO₂ approach, offshore wind turbines become attractive between 150 and 200 Dfl/tCO₂. Similar differences between the two approaches occur for electricity from solar PV.

In figure 8.18 the results for CO₂ removal technologies are shown. At low and medium emission penalties, CO₂ removal at coal-fired plants plays a main role. At high penalties, hydrogen production from natural gas dominates the filling of depleted natural gas fields and aquifers. In the full chain GHG approach, coal-fired plants with CO₂ removal technologies are in general slightly less attractive than in the national CO₂ approach (compare left and right side of figure 8.18). This is due to the indirect CO₂ and CH₄ emissions which occur inevitably if CO₂ is recovered at the plant or not, thus increasing the CO₂ intensity of such technologies in comparison with the national CO₂ approach. Hindered by the own indirect CO₂ and CH₄ emissions, natural gas-fired technologies with CO₂ removal do not benefit much from the additional storage capacity, which comes available.

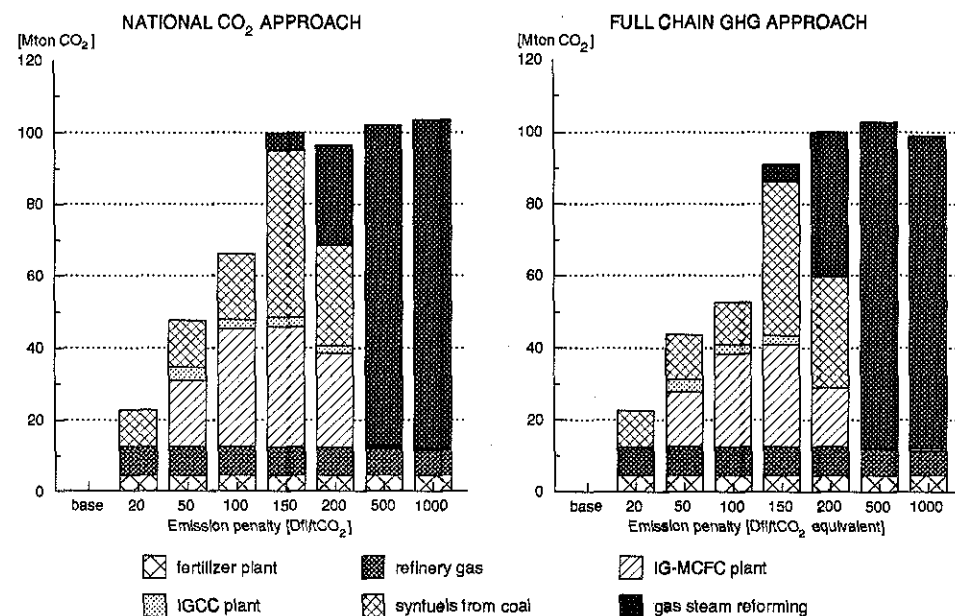


Figure 8.18 Storage of CO₂ in depleted gas fields and aquifers from CO₂ removal technologies at different emission penalties in 2030 in national CO₂ approach and full chain GHG approach

Due to the biogenic N₂O emissions which are linked to the production of energy crops, the role of agricultural energy crops is expected to be less important in the full basket/energy chain approach. However, this is not the case. At medium emission penalties (50-150 Dfl/tCO₂) lignocellulosic energy crops with low fertilizer input (miscanthus) perform even better than in the national CO₂ approach (see figure 8.19). Apparently, energy crop production becomes relatively a better reduction option as the competing alternatives themselves perform less with respect to indirect and non-CO₂

GHG emissions than the energy crops. A difference between the two approaches occurs at a 1000 Dfl/tCO₂ emission penalty. Rapeseed/diesel production is attractive at 1000 Dfl/tCO₂ in the full basket/energy chain approach, while sugar beet/ethanol production is attractive in the national CO₂ approach. This difference is caused by the difference in by-products. Rapeseed production is linked with straw production. This by-product has a higher value in the full basket/energy chain approach.

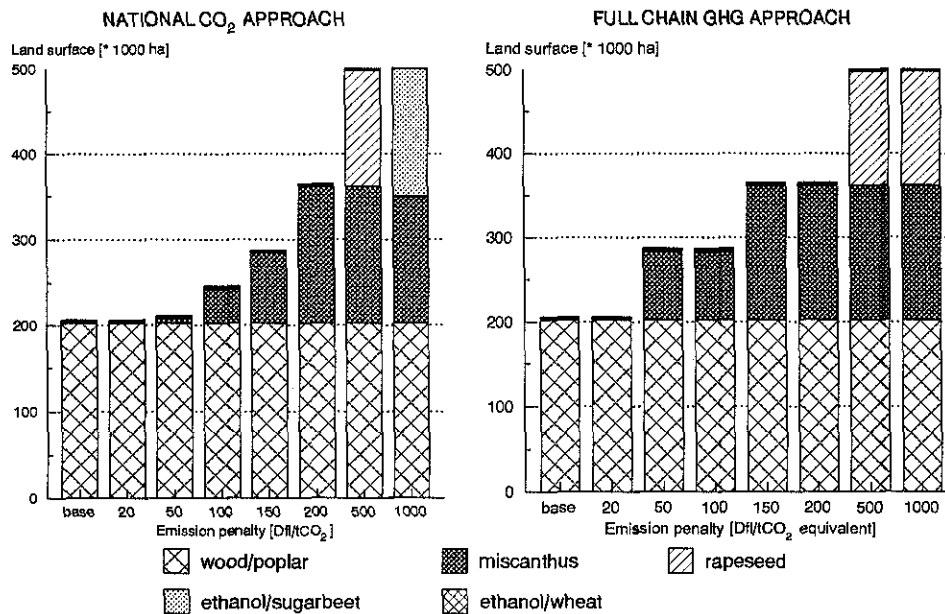


Figure 8.19 Land use for biomass production at different emission penalties in 2030 in national CO₂ approach and full chain GHG approach

Figure 8.20 shows the results for electric heat pumps in different applications in 2030 in the two different emission accounting approaches. The results do not differ much, although the warming impact of the refrigerant emissions has been considered in one approach, while it has not been considered in the other approach.

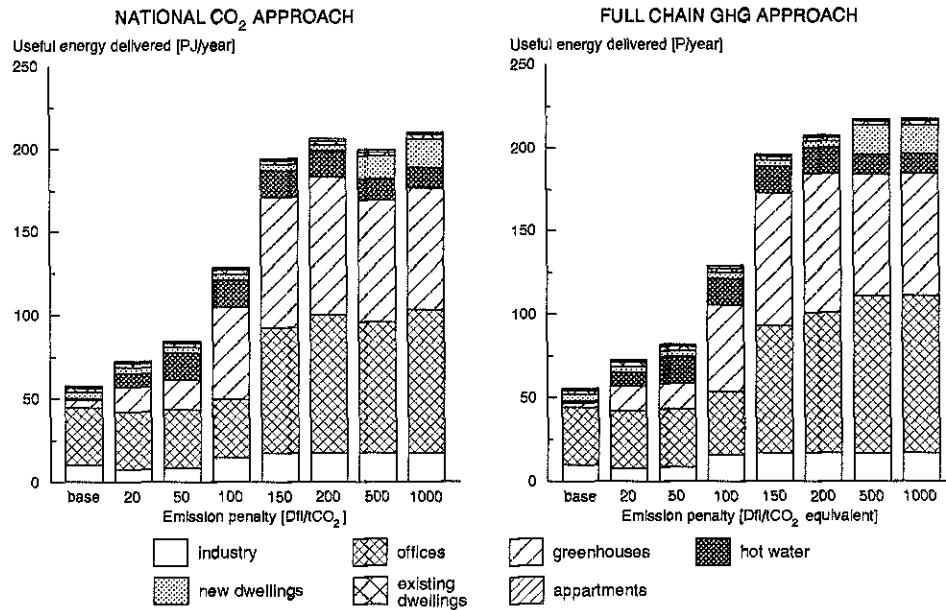


Figure 8.20 *Electric heat pumps at different emission penalties in 2030 in national CO₂ approach and full chain GHG approach*

In both approaches electric heat pumps become more and more attractive under increasing emission penalties. Apparently, the availability of refrigerants with low GWPs, such as R152a, allows for a high penetration of electric heat pump to combat the net warming effect of GHG emissions, even if the refrigerant emissions are considered.

8.6 Sensitivity case: adjusted GWP assumptions

To study the robustness of the main results in sections 8.1 to 8.5 with respect to Global Warming Potential assumptions, additional calculation were performed with adjusted GWPs. For this sensitivity analysis we took the low and high GWPs in table 2.5.

With lower GWPs for emissions of the non-CO₂ GHGs, these emissions are weighted less relative to CO₂ emissions. With higher GWPs, the opposite occurs: emissions of non-CO₂ GHGs are weighted more relative to emissions of CO₂.

The results for the direct and indirect CO₂ emissions of CO₂ are not much affected when adjusted GWPs for the non-CO₂ GHGs are used. Only the differences that occur in methane and halocarbon emissions are illuminated. Figure 8.21 shows the emissions of methane in the two results of the calculations with low and high GWPs. When high GWPs are applied the initial decrease in CH₄ emissions is more rapid with increasing emission penalties than when medium GWPs of IPCC (see figure 8.9) or low GWPs are applied. Both the shift to import of low CH₄ emissive coal and low emissive natural gas import are sooner attractive. However, the maximum CH₄ reduction level of the cases with medium and high GWPs is similar.

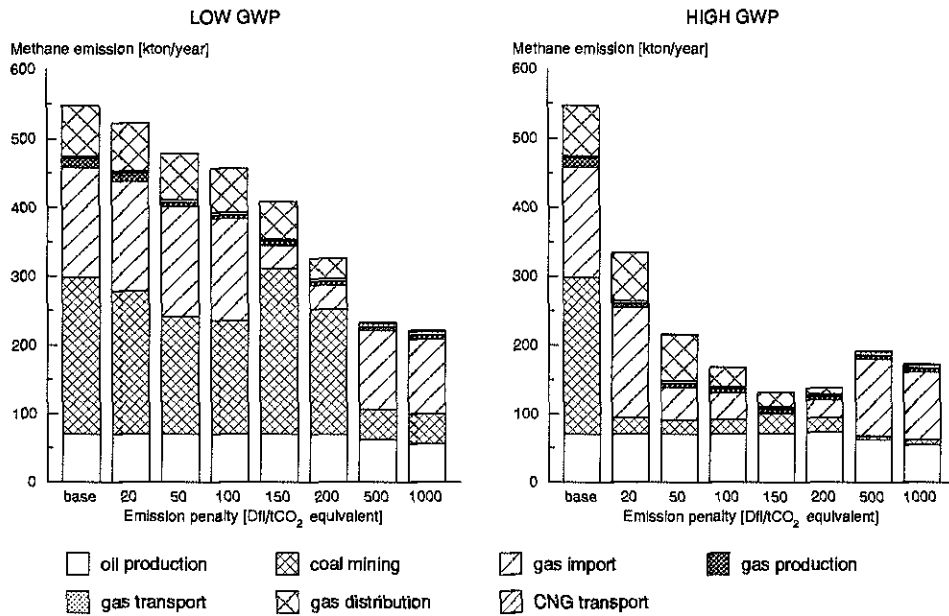


Figure 8.21 Methane emission at different emission penalties in 2030, calculated with low GWPs and high GWPs for non-CO₂ greenhouse gases

The use and emission of halocarbons from energy-related sources are affected by the use of adjusted GWPs (compare left and right side of figure 8.12). Applying low GWPs, slightly increases the use of electric and gas-fired heat pumps with R22 as refrigerant (compare figure 8.10 and left side of figure 8.22). Emissions of refrigerant from cooling are reduced at higher emission penalties. With the application of high GWPs, the opposite results are achieved; heat pumps with R22 become less attractive and emissions of refrigerant from cooling are more strongly reduced.

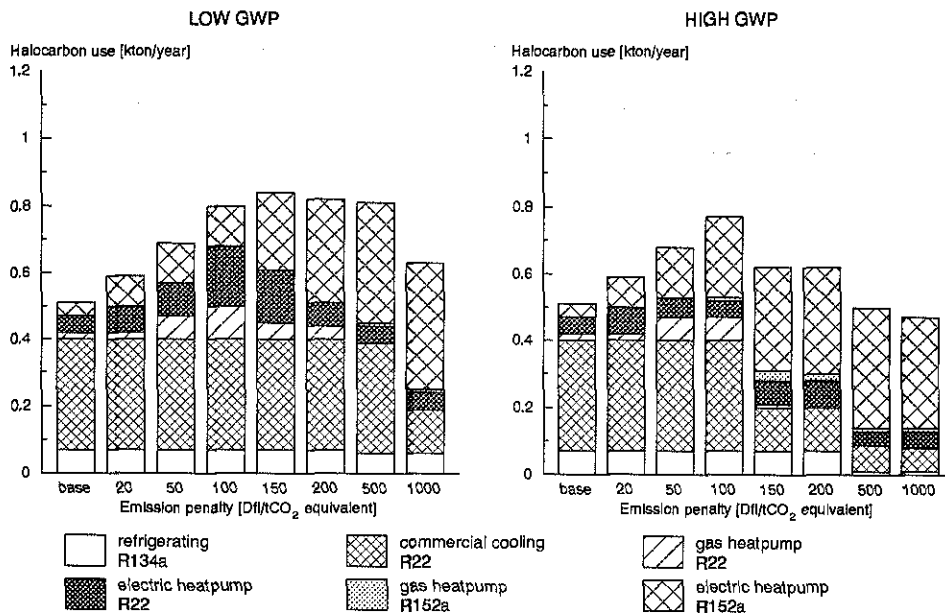


Figure 8.22 Halocarbon emissions per application at different emission penalties in 2030, calculated with low GWPs and high GWPs for non-CO₂ greenhouse gases

Adjusted GWPs also affect the technology options, discussed in sections 8.4 and 8.5. The use of high GWPs for non-CO₂ GHGs slightly decreases the attractiveness of natural gas technologies, since of the main fossil fuels the fuel related inevitable CH₄ emission is the largest for natural gas. However, the changes are only small. Coal technologies become slightly more attractive and the attractiveness of renewables increases further. With low GWPs the opposite results are achieved; renewables are less attractive.

9. CONCLUSIONS

An integrated analysis of the cost-effectiveness of energy technologies to reduce greenhouse gas emissions, has been performed with the inclusion of upstream CO₂ emissions and non-CO₂ greenhouse gas emissions. The main conclusions are:

- It is possible to include non-CO₂ greenhouse gas emissions and upstream greenhouse gas emissions in integrated energy analysis and this provides additional insight in assessing optimal emission reduction strategies.
- In the year 2000 the shares of the upstream CO₂ emissions and the methane emissions in the total CO₂ equivalent emissions from the energy system will be 4% and 5%, respectively. Energy related halocarbons, nitrous oxide and carbon monoxide contribute to less than 1% of the total CO₂ equivalent emissions.
- Between the year 2000 and 2040 and under autonomous developments, the indirect CO₂ and CH₄ emissions, increase more rapidly than direct CO₂ emissions. This is due to changes in the primary energy mix and the start of natural gas imports from Russia instead of domestic natural gas production. The increase in these emissions occurs exclusively outside the Netherlands.
- Strategies in which greenhouse gas emissions reduction is limited to direct CO₂ emissions, do not automatically lead to a decrease in indirect emissions of CO₂ and CH₄, N₂O and halocarbons.
- In an integrated analysis of greenhouse gas reduction technologies, methane emission reduction options appear to be relatively cost-effective.
- Including indirect, non-CO₂ GHG and manufacturing emissions in cost-effectiveness analysis causes modest changes in the order of cost-effectiveness of emission reduction options. Including these emissions is to the advantage of renewable technologies and is to the disadvantage of CO₂ removal technologies.
- The difference in relative roles with respect to greenhouse gas emissions between coal and natural gas is hardly affected by the inclusion of the full energy chain and non-CO₂ greenhouse gases. Oil becomes relatively more attractive.
- Irrespective the uncertainties in the index to compare emissions of greenhouse gases, the effectiveness of electric heat pumps or energy crops to reduce CO₂ emissions is not affected when the linked increases of respectively halocarbon and N₂O emissions are included in the analysis.
- In comparison with direct CO₂ emissions, relatively little is known about options to reduce indirect CO₂ or non-CO₂ greenhouse gas emissions.
- Non-CO₂ greenhouse gases and indirect CO₂ emissions are more uncertain than CO₂ emission factors for direct fuel combustion.

It is recommended to study the options to reduce emissions of greenhouse gases which are linked to energy use in the Netherlands and which occur outside the Dutch borders more extensively. These emissions include emissions connected to fossil fuel mining and production, processing and transport to the Netherlands. Clear conceptual options to reduce these emissions exist. However, the analysis of several of such options is inter-

linked with the mechanisms of regional and world markets for fossil fuels. Evaluation of the cost-effectiveness of such options requires additional work.

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ANNEX A. METHANE EMISSIONS

Table A.1 *Methane emission factors, as modelled in MARKAL*

MARKAL code	Emission source	Emission factor [kg CH ₄ /GJ]
IMPGXS1	Import of natural gas	0.367
IMPGXS2	Import of natural gas/price +10%	0.367
IMPGXS3	Import of natural gas/price +25%	0.367
IMPGXS4	Import of natural gas, low CH ₄	0.110
IMPGXS5	Import natural gas, low CH ₄ /price +10%	0.110
IMPGXS6	Import natural gas, low CH ₄ /price +25%	0.110
IMPHCO1	Import of hard coal, surface mined	0.025
IMPHCO2	Import of hard coal, deep mined	0.220
IMPDSH1	Import of heavy distillates	0.042
IMPDSL1	Import of light distillates	0.042
IMPGSL1	Import of gasoline	0.042
IMPGSR1	Import of naphta	0.042
IMPLPG1	Import of liquid petroleum gas	0.042
IMPPCK1	Import of petroleum cokes	0.042
IMPRFG1	Import of refinery gas	0.042
MINNGA1	Extraction natural gas, onshore	0.006
MINNGB1	Extraction natural gas, offshore	0.000
S6XCAP	Offshore gas, no CH ₄ abatement	0.070
S6YACT	Offsh. gas, medium CH ₄ abatement	0.053
S6ZACT	Offshore gas, high CH ₄ abatement	0.018
S6WCAP	Transmission of natural gas	0.003
S6TCAP	Main part of distribution network	0.037
S6UCAP	Grey cast-iron gas distribution	0.641
S6VACT	Replaced grey cast-iron gas distr.	0.037
R1NCAP	Wood stove, unabated	0.074
SR9CAP	CNG car, lean burn	0.068
SQACAP	CNG truck, lean burn	0.058
SU5CAP	CNG bus, lean burn	0.058

ANNEX B. NITROUS OXIDE EMISSIONS

Table B.1 *N₂O emission factors, as modelled in MARKAL*

MARKAL code	Emission source	Emission factor [kg N ₂ O/GJ]	
		year 2000	year 2030
SP6CAP	diesel car, unabated	0.0020	0.0020
SP7ACT	diesel car, optimal inject.	0.0020	0.0020
SR0CAP	gasoline car, unabated	0.0025	0.0025
SR3ACT	gasoline car, lean burn	0.0025	0.0025
SR4ACT	gasoline car, catalyst	0.0200	0.0200
SR5ACT	gasoline car, cat. plus	0.0100	0.0100
SR7ACT	LPG car, lean burn	0.0025	0.0025
SR8ACT	LPG car, cat. plus	0.0100	0.0100
SU1ACT	Methanol car, unabated	0.0025	0.0025
SU1ACT	Methanol car, lean burn	0.0025	0.0025
S41ACT	biomass from rapeseed	0.0431	0.0339
S42ACT	biomass from wheat	0.0399	0.0314
S42ACT	biomass from sugar beet	0.0210	0.0165
S44ACT	biomass from miscanthus	0.0047	0.0037
S45ACT	biomass from poplar	0.0072	0.0057

ANNEX C. CARBON MONOXIDE EMISSIONS

Table C.1 CO emission factors, as modelled in MARKAL

MARKAL code	Emission source	Emission factor [kg CO/GJ]
SP6CAP	diesel car, unabated	0.231
SP7ACT	diesel car, optimal inject.	0.050
SR0CAP	gasoline car, unabated	5.005
SR3ACT	gasoline car, lean burn	1.579
SR4ACT	gasoline car, catalyst	1.579
SR5ACT	gasoline car, cat. plus	0.500
SR7ACT	LPG car, lean burn	0.955
SR8ACT	LPG car, cat. plus	0.330
SR9ACT	CNG car, lean burn	0.864
SU1CAP	methanol car, unabated	5.005
SU2ACT	methanol car, lean burn	1.579
SU3CAP	ethanol car, unabated	5.005
SU4ACT	ethanol car, lean burn	1.579
SUIDACT	diesel stirling car	0.005
SUGACT	gasoline stirling car	0.005
SULACT	LPG stirling car	0.005
SQ4CAP	diesel truck, unabated	0.275
SQ5ACT	diesel truck, optimal inject.	0.050
SQ6ACT	diesel truck, catalyst	0.020
SQAACT	CNG truck, lean burn	0.029
SQBCAP	M33 truck, unabated	0.275
SQCACT	M33 truck, optimal inject.	0.050
SQDACT	M33 truck,	0.020
SQECAP	ethanol truck, unabated	0.275
SQFACT	ethanol truck, optimal inject.	0.050
SQGACT	ethanol truck, catalyst	0.020
SU0CT	methanol truck, cat. plus	0.020
SU8CAP	methanol truck, unabated	0.275
SU9ACT	methanol truck, catalyst	0.020
R1NCAP	wood stove, unabated	16.667
R1MCAP	wood stove, catalyst	5.000
I4WCAP	industrial wood furnace	0.750

ANNEX D. HALOCARBONS EMISSIONS AND REDUCTION OPTIONS

Table D.1 *R12 emission factors, as modelled in MARKAL*

MARKAL code	Emission source	Emission factor [kg R12/GJ]
RR1CAP	Household refrigerator, old type	0.0075

Table D.2 *R22 emission factors, as modelled in MARKAL*

MARKAL code	Emission source	Emission factor [kg R22/GJ]
R2SCAP	Electric heat pump, new dwelling	0.0168
R2TCAP	Elec. heat pump + insulation, new dwel.	0.0122
R2ACAP	Elec. heatp. + R22 recycling, new dwel.	0.0068
R1SCAP	Electric heat pump, existing dwelling	0.0065
R1TCAP	Elec. heat pump + insulation, exis. dwel.	0.0065
RMSCAP	Electric heat pump, apartment	0.0064
RMTCAP	Elec. heat pump + insulation, apartment	0.0064
R3SCAP	Electric hot water heat pump	0.0053
R4FCAP	Gas-fired compression heatp., small off.	0.0017
R4SCAP	Electric heat pump, small office	0.0034
R4XCAP	Elec. heat pump + add. saving, small off.	0.0034
R5FCAP	Gas-fired compression heatp., large off.	0.0011
R5SCAP	Electric heat pump, large office	0.0022
R6FCAP	Gas-fired compr. heatp., very large off.	0.0009
R7FCAP	Gas-fired compr. heat pump, greenhouse	0.0011
R7SCAP	Electric heat pump, greenhouse	0.0022
RC1CAP	Conventional retail refrigerator	0.0233
RC2CAP	Retail refrigerator with case cover	0.0197
RC3CAP	Retail refr. + case cover + add. insulation	0.0194
RC4CAP	Ret. refr.+cov.+add.insul.+multi compr.	0.0194
RC5CAP	Retail refrigerator + heat recovery	0.0128
RC6CAP	Retail refr. + heat recovery + case cover	0.0109
RC7CAP	Absorption retail refrigerator	0.0000
RCACAP	Conventional retail refrigerator, leak tight	0.0058
RCBCAP	Retail refr. with case cover, leak tight	0.0049
RCCCAP	Retail refr. + cov. + add. insul., leak tight	0.0048
RCDCAP	Ret.refr.+cov.+add.insul.,mul.com,leak t.	0.0048
RCECAP	Retail refr. + heat recovery, leak tight	0.0032
RCFCAP	Retail refr. + heat recovery + cov., leak t.	0.0021

Table D.3 R134a emission factors, as modelled in MARKAL

MARKAL code	Emission source	Emission factor [kg R134a/GJ]
RR2CAP	Standard refrigerator (3 cm insulation)	0.0063
RR3CAP	Standard refrigerator (4 cm insulation)	0.0056
RR4CAP	Standard refrigerator (5 cm insulation)	0.0050
RR5CAP	Standard refrigerator (6 cm insulation)	0.0048
RR6CAP	Krypton panel refrigerator	0.0042
RR7CAP	Soft vacuum refrigerator	0.0038
RR8CAP	Soft vac.refr.+enlarged heat exchanger	0.0036
RR9CAP	Soft vacuum refrigerator + heat exch. + dual compressor	0.0059
RRHCAP	Heat recovery refrigerator	0.0012
RRJCAP	Standard refr. (3 cm insul.) + recycling	0.0013
RRKCAP	Standard refr. (5 cm insul.) + recycling	0.0010
RRLCAP	Standard refr. (6 cm insul.) + recycling	0.0009
RRMCAP	Soft vac. refr. + enl. heat exchanger + recycl.	0.0009
RRNCAP	Soft vacuum refr. + heat exch. + dual compressor + recycling	0.0008
R2QCAP	Elect. heat pump, new dwelling, R134a	0.0274
R2YCAP	Elect. hp. + insul., new dwelling, R134a	0.0199

Table D.4 R152a emission factors, as modelled in MARKAL

MARKAL code	Emission source	Emission factor [kg R152a/GJ]
R2RCAP	Elec. heat pump, new dwelling, R152a	0.0191
R2ZCAP	Elec. hp. + insul., new dwelling, R152a	0.0138
R1RCAP	Elec. hp., existing dwelling, R152a	0.0072
R1UCAP	Elec.hp. + insul., exist. dwelling, R152a	0.0072
RMRCAP	Elec. hp., apartment, R152a	0.0071
RMZCAP	Elec. hp. + insul., apartment, R152a	0.0071
R3TCAP	Elec. hot water heat pump, R152a	0.0074
R4YCAP	Gas-fired compr. hp., small off., R152a	0.0010
R4ZCAP	Elec. heat pump, small office, R152a	0.0021
R5YCAP	Gas-fired compr. hp., small off., R152a	0.0008
R5ZCAP	Elec. heat pump, small office, R152a	0.0015
R6YCAP	Gas-fired compr.hp., very l. off., R152a	0.0007
R7YCAP	Gas-fired compr.hp. greenhouse, R152a	0.0008
R7ZCAP	Elec. heat pump, greenhouse, R152a	0.0015

Table D.5 *MARKAL input: Investment costs of added refrigerators in the household sector*

MARKAL code	Technology description	Investment cost [Dfl/GJ]
RRJ	standard refrigerator, refrigerant recycling	464
RRK	standard refrigerator (5 cm), refrigerant recycling	555
RRL	standard refrigerator (6 cm), refrigerant recycling	600
RRM	soft vacuum, heat exchanger, refrigerant recycling	748
RRN	soft vacuum, heat exchanger, dual compressor, refrigerant recycling	861

Table D.6 *MARKAL input: Investment cost and lifetimes of electric heat pumps for new dwellings*

MARKAL code	Technology description	Investment cost [Dfl/GJ]	Levensduur [jaar]
R2S	el. heat pump, R22	307	15
R2T	el. heat pump, R22, add. insulation	691	45
R2Q	el. heat pump, R134a	318	15
R2R	el. heat pump, R152a	318	15
R2Y	el. heat pump, R134a, add. insulation	723	45
R2Z	el. heat pump, R152a, add. insulation	723	45
R2A	el. heat pump, R22, recycling	310	15

Table D.7 *MARKAL input: Investment cost and lifetimes of electric heat pumps for existing dwellings and apartments and hot water heating*

MARKAL code	Technology description	Investment cost [Dfl/GJ]	Levensduur [jaar]
R1S	heat pump, R22, existing house	145	15
R1T	heat pump, R22, add. insulation, ex.	392	45
RMS	heat pump, R22, apartment	172	15
RMT	heat pump, R22, add. insul., ap.	317	45
R1R	heat pump, R152a, existing house	154	15
R1U	heat pump, R152a, add. insulation, ex.	401	45
RMR	heat pump, R152a, apartment	177	15
RMZ	heat pump, R152a, add. insul., ap.	322	45
R3T	electric hot water heat pump, R152a	324	15

Table D.8 *MARKAL input: Investment cost of electric heat pumps in the commercial sector*

MARKAL code	Technology description	Investment cost [Dfl/GJ]
R4Y	small/medium office, compres. heat pump, R152a	97.5
R4Z	small/medium office, electric heat pump, R152a	115.3
R5Y	large office, compression heat pump, R152a	83.2
R5Z	large office, electric heat pump, R152a	109.1
R6Y	very large office, compression heat pump, R152a	81.8
R7Y	greenhouses, compression heat pump, R152a	71.1
R7Z	greenhouses, electric heat pump, R152a	54.8